Comments to the DOE Federal Register Notice of Inquiry (NOI) on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

Received as of March 9, 2006

The following material comprises the comments received by DOE in response to the *Federal Register* Notice of Inquiry [FR Doc. E6–1394] issued on February 2, 2006. This notice solicited comment and information from the public concerning its plans for an electric transmission congestion study and possible designation of National Interest Electric Transmission Corridors (''NIETCs'') in a report based on the study pursuant to section 1221(a) of the Energy Policy Act of 2005. Through this Notice of Inquiry, DOE invited comment on draft criteria for gauging the suitability of geographic areas as NIETCs and announced a public technical conference concerning the criteria for evaluation of candidate areas as NIETCs.

DOE presents the comments as received and without any endorsement of their validity. The comments are listed in alphabetical order by commenter, including the date and time that the comments were received. This document includes comments received as 5:00 p.m. EST on March 9, 2006. Any comments received after this time will be updated on www.electricity.doe.gov/1221. Please sign up for the 1221a service list on the same website for updates on additional comments received, the technical conference agenda, requests for designation and any other related information on this effort. For questions regarding the comments, please email EPACT1221@hq.doe.gov or call 202-586-1411.

Alphabetical List of Commenters (including date and time the comments were received):
Note: Comments can be accessed by clicking on the page numbers listed to the right below

1. 3M Company, Received Mon 3/6/2006 4:58 PM

Dear Ms. Agrawal:

The Federal effort to designate National Interest Electric Transmission Corridors (NIETC) is to be commended and supported. While a significant undertaking, it is an important step toward helping the nation meet its energy needs. The end product of this review will certainly help shape future investment in this most essential part of our nation's critical infrastructure.

As DoE proceeds with this process, we hope that it will include the community of electric transmission planners and developers who should be involved in looking at ways to upgrade as well as maximize the use of existing transmission corridors, as these NIETCs are being defined and designated. One aspect of this planning and development activity that should be encouraged is the use of emerging technologies.

Specifically, there are some new and exciting options available that deserve to be included in any analysis of potential solutions to the bottlenecks facing NIETCs, and high capacity conductors are such an example.

A particular high capacity conductor coming into more widespread use is Aluminum Conductor Composite Reinforced (ACCR), also known as the Aluminum Matrix Composite conductor. Replacing existing conductor with ACCR can normally double the capacity of an existing line where the only other option might seem to be the construction of a new line, including new towers. ACCR can, in many cases, postpone or eliminate the need to build a new line.

ACCR is a technology that allows a utility to maximize existing infrastructure and may, for certain installations, provide the opportunity for significant cost savings while alleviating the thermal bottleneck. Additionally, these potential cost savings do not take into consideration the benefits to local communities that can be realized by avoiding the adverse impact of building new towers and expanding existing rights of way.

There is also a potential role for ACCR in some cases where a totally new line is being constructed. To help maximize the use of that new right of way, ACCR should be considered due to its superior strength and current carrying capability. It can maximize the capacity in the new corridor.

Prior to being commercialized, the ACCR underwent four years of rugged, extensive field testing by several utilities, partially funded by the Department of Energy, and met all expectations. In addition to this testing, 3M retained the National Electric Energy Testing, Research and Applications Center (NEETRAC) at the Georgia Institute of Technology to test the conductor during development. Recent tests of the conductor at Oak Ridge National Laboratory demonstrate the conductor's integrity after exposures to temperatures even higher than the rated continuous operating temperature for a limited time – a significant safety factor over 210 degrees Celsius. That ACCR is based on aluminum means that the conductor is not adversely affected by environmental conditions, such as moisture or UV exposure and it has the durability typically associated with aluminum-based conductors.

In conclusion, we support the work of designating National Interest Electric Transmission Corridors and hope your study will encourage transmission planners to include new technologies like high capacity conductors in their analysis of potential solutions.

Sincerely,

Tracy Anderson
Business Development Manager
3M Company

2. ABB, Received Mon 3/6/2006 5:00 PM

ABB Comments on the Establishment of NIETCs

Introduction

As a leading supplier of power systems and equipment, ABB is pleased to provide input to the Department of Energy (DoE) in response to its Notice of Inquiry (NOI) regarding the establishment of National Interest Electric Transmission Corridors (NIETCs).

We understand that the DoE's intent is to have the market provide transmission solutions that lead to reduced economic congestion, enhanced reliability, wider market participation, improved overall competition, improved efficiency, greater fuel diversity, and lower overall costs of delivered electricity. But DoE is also concerned that, for whatever reason, the market may not implement anything in the designated corridors that will meet these objectives. To avoid this situation, DoE needs to have a process in place which can help make the NIETC designation more market oriented and more universally applicable in all regions in the country.

Our comments focus primarily on the methods used to identify transmission-constrained areas, the criteria for NIETC designation, and some observations on the applicability of certain technologies that can address transmission bottlenecks.

Identifying Constrained Areas

Transmission expansion needs can be generally categorized by two primary objectives: system reliability enhancement and market efficiency improvement. The challenge lies in identifying such expansion needs and justifying the regional reliability benefits and the financial impacts to different market participants. One major task is the determination of the fair allocation of costs for projects identified in the planning process. Appropriate metrics and methods are needed to quantify the strategic value of improved transmission capability so that the expansion investment can be accurately justified to different transmission customers.

Designation of NIETCs based on analysis of historic congestion along with estimates of future congestion is a necessary planning process to address capacity and reliability. However, this alone is insufficient given the pace of change in applicable technologies and generation fuel mixes. Another important fact is that the historical congestion may be the cause of a given region's imperfect power trading structure. Therefore, historical congestion alone does not indicate all the economic problems per se, nor will it properly evaluate the impact or efficacy of potential solutions.

Similarly, fragmented studies monitoring only known flowgates and interfaces may fail to identify potential limiting elements in various future supply scenarios. A more integrated regional planning process is needed.

In addition to reviewing the regional transmission expansion plans, we believe DoE should perform its own independent assessment. For this purpose, effective planning tools are required to support and augment the regional transmission expansion planning process, which involves a wide range of public interests, cost and benefit, and market protocols. In particular, market simulation models with accurate representation of the transmission system are essential to evaluate the expected system performance. That includes system reliability, market economics and environment impacts, as well as energy prices based on input from market participants. Therefore, we recommend DoE perform a comprehensive analysis with consideration of past congestion costs, future market activities, fuel diversity needs and goals and renewable energy implementation. We would also encourage the Department to undertake this analysis as soon as possible. ABB has developed a market simulation tool, GridView, which is currently being used by several RTO/ISOs, utility companies, and government agencies (e.g., Western Governor's Association) in transmission planning and expansion studies. A tool like GridView would be instrumental in performing a more inclusive analysis that gives consideration to the many factors affecting the performance of the grid.

Conducting the Congestion Study

As pointed out in the NOI, the nation's transmission systems today are not fully able to deliver generation to load. There are two aspects to this deliverability problem—one that makes the Load Serving Entities (LSEs) unable to meet demand (i.e., the reliability aspect), and one that prevents a generator from accessing the market or providing the full value of its capacity (i.e., the economic aspect). However, these two considerations are interrelated, reflecting the nature of the grid itself. Accordingly, we believe both reliability and economic considerations should be incorporated in a single model to evaluate potential solutions.

An example of forward-looking congestion relief is the continuous effort by the Western Governor's Association (WGA). WGA adopted a Resolution entitled "Clean and Diversified Energy Initiative for the West" that calls for the development of additional clean energy in the West by the year 2015 and a reduction in electricity use. WGA formed a Clean and Diversified Energy Advisory Committee (CDEAC) and associated Task Forces to identify the potential clean energy resource mix (wind, clean coal, solar, geothermal, biomass, natural gas and efficiency improvements) and the associated transmission enhancements required to integrate the resources and move them to market. WGA used a market simulation model to identify potential problems, and prospective transmission upgrades were put back into the simulation model for market efficiency and system reliability tests.

Beyond the use of a comprehensive planning model, standard industry methods should also be used in the congestion study. For example, to test the deliverability of all excess upstream generation to downstream load pockets, DoE should observe NERC/ERO reliability standards such as N-1 planning criteria with an eye toward replicating the processes used by transmission owners in their own analyses. Failure to properly consider contingency requirements may result in inconsistent market response to the NIETCs designated.

Finally, with regard to the triennial DoE study, we believe a common database and transparent study process would be highly useful to the NIETC process. Transmission planning studies are notoriously data intensive. For the market to respond to the designated NIETCs positively and expeditiously, DoE should develop a thorough national database and stakeholder process for the industry to study its own versions of prospective transmission expansion projects based on prevailing power markets and financial and environmental conditions.

Criteria for designating NIETCs

As stated in the NOI, DoE's proposed criteria for determining NIETC status include:

1. the need for transmission to maintain reliability;
2. the need for transmission to achieve economic benefits for consumers;
3. the need for transmission to ease electricity supply limitations in load pockets, and to diversify fuel sources;
4. the benefit of transmission for enhancement of U.S. energy independence;
5. the likelihood that transmission will further national energy policy;
6. the need for transmission to reduce vulnerability to natural disasters or malicious acts;
7. the area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions; and
8. the extent to which non-transmission alternatives have been sufficiently considered.

As noted earlier, one integrated modeling of economic costs and grid reliability is needed to address potential solutions satisfying both Criteria 1 and 2. Criteria 1, 2, 7 and 8 can also be addressed effectively with a market simulation model such as ABB's GridView. A possible advantage of the combined economic and reliability analysis is that the results can help to bring various stakeholders together in a public forum to reach consensus on potential solutions to congestion once NIETCs are designated.

The proposed criteria should allow regional flexibility to account for different market designs and regional differences when developing the framework for long-term rights. The criteria would require that long-term firm transmission rights are available with term lengths sufficient to meet the needs of LSEs with long-term power supply arrangements, either existing or planned, that are used to satisfy their service obligations. Therefore, both physical and contractual limits should be included in the study.

Technologies to Address Transmission Congestion

We would also point out that in the congestion study, power grid controllable devices such as phase shifter transformers, HVDC and FACTS devices should be modeled correctly, and their operating range constraints correctly represented. An HVDC link, for example, can be continuously controlled to precisely match scheduled transactions. The complex reliability and inadvertent power flow issues that arise with the use of conventional AC transmission technologies are virtually nonexistent with HVDC. Again, the study tools and criteria used in DoE’s congestion study should have capability similar to those currently used in transmission planning.

Advanced technologies such as HVDC and FACTS can also help improve the likelihood of construction of transmission expansion projects from both aesthetic and environmental permit perspectives once a NIETC is designated. Public opposition in many cases has thwarted building new overhead transmission lines. This has led to lengthy and expensive approval processes with uncertain outcomes. Installation of transmission underground or within existing right-of-ways provides a viable alternative that can satisfy system needs and aesthetic considerations simultaneously.

Adequate transmission rate incentives are also needed to promote the deployment of advanced technologies, another initiative of the EPAct 2005. The criteria for creating these should reflect the objective of enhancing transmission capacity, both in new construction and enhancement of existing facilities, by working with FERC and state regulators. Consequently, capacity expansion should be covered in the rate incentive rulemaking.

Summary

We submit that DoE needs a national transmission planning study process that focuses on both reliability and economics of the infrastructure investment needed to support competitive markets and consumer best interests. This planning study will involve a combined engineering and market simulation analysis to identify the physical transmission limitations, evaluate transmission upgrade options, and quantify the value of expansion investments. The NIETC identification process should proceed as soon as possible, and should observe all available technology solutions. ABB has adequate knowledge on advanced, readily implemented technologies, simulation software capability, and system modeling expertise required to perform a comprehensive national planning study. We stand read to assist DoE in any way the Department sees fit.

For more information on any of the points raised here, please contact:

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3. Allegheny Energy, Received Mon 3/6/2006 3:01 PM

COMMENTS AND REQUEST OF ALLEGHENY POWER FOR EARLY DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDOR

Pursuant to the Notice of Inquiry Requesting Comment and Providing Notice of a Technical Conference[1] (NOI) issued by the Department of Energy's Office of Electricity Delivery and Energy Reliability, Allegheny Power[2] submits these Comments and Request for Early Designation of National Interest Electric Transmission Corridor.

I. Comments on Criteria Development

The NOI identified eight draft preliminary criteria along with identified metrics that the Department proposes to use in evaluating the suitability of a geographic area for designation as a National Interest Electric Transmission Corridor (NIETC). Allegheny Power supports

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1 71 FR 5660 (February 2, 2006)

2 Allegheny Power is the trade name for Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company. The Allegheny Power companies are public utilities that supply electric energy at retail in parts of Pennsylvania, Virginia, West Virginia and Maryland. All of the Allegheny Power companies own electric transmission facilities subject to the functional control of PJM. Monongahela Power Company owns generation facilities. The Allegheny Power companies are owned and controlled by, and are direct subsidiaries of, Allegheny Energy, Inc., a public utility holding company.

the implementation of these criteria and metrics for the assessment of NIETC proposals provided the Department does not apply these measures of NIETC worthiness in a rigid manner by determining that every proposal must meet all eight of the criteria or satisfy all of the metrics for each of the criteria determined to be applicable. For example, a specific proposal may not meet the expectations of both Draft Criterion 1 and Draft Criterion 2. Draft Criterion 1 relates to action needed to maintain high reliability and Draft Criterion 2 relates to action needed to achieve economic benefits for consumers. Although these criteria are not mutually exclusive, not all proposals requiring NIETC designation will necessarily fulfill both. A proposal may justify NIETC designation solely for reliability reasons but will provide minimal or no economic benefits. The failure to meet both requirements should not prevent NIETC designation.

A close examination of the draft criteria suggests that it should be sufficient for NIETC designation if a proposal substantially meets any one of the first six criteria and its associated metrics with Draft Criteria 7 and 8 used as factors in evaluating the merits of the proposal. For example, a project may meet the economic benefits test of Draft Criterion 2 but the need for the project may be encumbered with unduly contingent uncertainties associated with analytic assumptions as described in Draft Criteria 7. In other words, the project may show economic benefits many years into the future but is fraught with the uncertainties of the assumptions inherent in the analysis that, on balance, the project should not warrant NIETC designation when other proposals demonstrate more pressing and certain needs or benefits. In short, Allegheny Power believes the criteria have been correctly identified in the NOI. However, the Department's method for applying the criteria is as important as the criteria themselves. Allegheny Power urges the Department to apply the criteria and associated metrics in a flexible and non-exclusive manner that permits NIETC designations that meet any of one of the first six criteria and allows for evaluation of the proposal in the context of one or more of those criteria under the seventh and eighth criteria.

II. Request for Early Designation of National Interest Electric Transmission Corridor

The NOI invited parties to identify areas that they believe merit designation as an NIETC, and to explain why early designation is necessary and appropriate. The NOI stated that the Department will consider for early designation as NIETCs only those proposed corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

Pursuant to the invitation extended by the NOI, Allegheny Power requests the Department to assign an early designation as NIETC to the corridor necessary for the construction of the Trans-Allegheny Interstate Line (TrAIL) Project. As a transmission-owning member of PJM Interconnection, L.L.C. (PJM), Allegheny Power submitted its proposal for the TrAIL Project to PJM on March 1, 2006 for inclusion in PJM's next iteration of its Regional Transmission Expansion Plan. (Project details are set forth in Attachment A, which is a copy of the TrAIL Project proposal as submitted to PJM.)

The area for which Allegheny Power seeks early designation as NIETC for the TrAIL Project is shown on Attachment B and highlighted in yellow. The proposed TrAIL Corridor will extend from the West Virginia western panhandle area, through the southwestern Pennsylvania-Northern West Virginia area, along the eastern West Virginia panhandle and western Maryland area, to the central Maryland area. As shown on Attachment B, the TrAIL Corridor will include

several existing transmission facilities, including:[3]

- Wylie Ridge 500/345 kV Substation
- Kammer 765/500 kV Substation
- Fort Martin – Pruntytown 500 kV Line
- Pruntytown – Mt. Storm 500 kV Line
- Mt. Storm – Doubs 500 kV Line
- Black Oak – Bedington 500 kV Line
- Doubs 500/230 kV Substation

The TrAIL Project will:

- Enhance the reliability of the PJM Transmission System,
- Provide economic benefits to consumers,
- Ease congestion on the PJM Transmission System,
- Diversify available generation sources,
- Strengthen the energy independence of the PJM Energy Market and the markets of adjacent RTOs, and
- Further national energy policy.

A. Reliability Enhancement

The TrAIL Project will enhance the reliability of the PJM Transmission System by adding an additional EHV[4] transmission line across the AP Zone[5] and lessen reductions in west-to-east transfers and re-dispatching of generation during single contingency events. During 2005, PJM issued approximately 350 load-dump warnings for the AP Zone. Allegheny Power estimates that TrAIL will reduce this number by approximately 30%. In the same year, PJM called for about 480 TLRs (Transmission Load Relief Orders) in the AP Zone, with more than 50

[3] Allegheny Power owns all or portions of these facilities.
[4] Allegheny Power refers to EHV as "Extra High Voltage" and as voltages at 345 kV and above.
[5] The AP Zone is identified in Attachment J of the PJM Open Access Transmission Tariff as the "APS Zone."

of these related to EHV facilities. Allegheny Power estimates that TrAIL will eliminate most of the EHV- related TLRs within the AP Zone. In addition, there has been an increase in generation retirement announcements in the mid-Atlantic area of the PJM Region.[6] By increasing the available transmission transfer capacity through the construction of TrAIL, Allegheny Power will contribute significantly to alleviating many of the reliability concerns associated with potential generation retirements in the PJM Region.

B. Economic Benefits

The TrAIL Project will improve the economic vitality and development of markets within the PJM Region. The proposed line will provide the high-cost electric energy markets in the eastern PJM Region with access to lower-cost generation in the Midwest by increasing the west-to east transfer capacity of the PJM Transmission System. TrAIL will allow generation to be dispatched to minimize electric energy costs across the corridor and into the electric energy market of the eastern PJM Region. This aspect of TrAIL is of particular importance because PJM has been unable to timely implement market devices that mitigate the high-cost of electric energy in this portion of the PJM Region, and merchant generation has not stepped forward to construct generation plants to alleviate high prices.

Results of load flow analyses performed by Allegheny Power using PJM's 2010 Summer RTEP (50/50) load flow model are summarized in Table 1 below. These results demonstrate that TrAIL will increase the west-to-east total transfer capability of the PJM Transmission System by 3800 MW over base case levels and supports the conclusion that TrAIL will provide economic benefits to consumers within the PJM Region, especially those in the high-cost electric energy markets in the eastern portion of the region.

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[6] *2004 State of the Markets Report* issued by the Federal Energy Regulatory Commission, June 2005, Docket MO05-4-000, page 110.

Table 1

System Configuration	Limit Type	**FCITC (MW)**	*Limiting Constraint*	**Contingency**	**Incremental Transfer Capability (MW)**
Base Case	Voltage	400	Meadow Brook 500kV bus voltage	Black Oak-Bedington 500kV Line	-
Base Case	Thermal Loading	600	Black Oak-Bedington 500kV Line	Pruntytown-Mt. Storm 500kV Line	-
Base Case	Thermal Loading	1450	Mt. Storm - Doubs 500 kV Line	Greenland Gap - Meadow Brook 500 kV Line	
TrAIL Project	Thermal Loading	4200	Lexington-Dooms 500kV Line	Bath Co-Valley 500kV Line	3800
TrAIL Project	Thermal Loading	5200	Pruntytown - Mt. Storm 500 kV Line	502 Station - Mt. Storm 500 kV Line	4800

C. Congestion Reduction

As part of the economic planning component of its Regional Transmission Expansion Plan (RTEP), PJM has been monitoring and posting to its website the gross congestion costs associated with each individual transmission constraint in the PJM Region since August 1, 2003.[7] For those individual transmission constraints in which the gross congestion costs exceed predefined thresholds, PJM then calculates the unhedgeable congestion costs associated with those constraints.[8] PJM defines unhedgeable congestion as costs that cannot be hedged by the use of Financial Transmission Rights (FTRs) or other hedging instruments pursuant to the PJM Tariff or the Operating Agreement. Unhedgeable congestion costs are also posted on the PJM website.[9]

The existing transmission facilities in the TrAIL Corridor listed above account for a significant amount of the gross and unhedgeable congestion in PJM, as these facilities provide a primary transmission path within the PJM Region for electric energy from sources in the

[7] Gross and Unhedgeable congestion costs were calculated from the “2003-04-05-monthly-congestion-summary.xls” file located on the PJM website (www.PJM.com/planning/economic-planning/).
[8] *Id.*
[9] *Id.*

Midwest and the western portions of the PJM Region to loads in the eastern portion of the PJM Region.[10] Total congestion costs in PJM during 2004 were 9% of total billings, which totaled $808 million.[11] One of the facilities located in the TrAIL Corridor contributing to the congestion is the Bedington-Black Oak 500 kV Line. This line was constrained for 1,131 hours during 2004 and 54 percent of the line's congestion occurred during on-peak hours. This constraint increased the average LMP on the average affected load of 39,170 MW by $12 or 20%.[12] The Bedington-Black Oak Line was the most frequently constrained facility on the PJM system throughout 2004.[13] In 2005, the total gross congestion costs associated with facilities in the TrAIL Corridor accounted for $3.7 billion, or nearly two-thirds, of the total $5.6 billion accumulated in PJM.[14] These facilities have accounted for $4.8 billion of gross congestion, or 60% of the total in PJM, and nearly $150 million of unhedgeable congestion, or nearly one-third of the total in PJM, between August 1, 2003 and January 31, 2006. Along with plans currently underway to increase transformer capacity of the three substations in the TrAIL Corridor, construction of the TrAIL Project is expected to significantly reduce congestion by relieving loading on the four-500 kV lines in the TrAIL Corridor. Table 2 below lists the impact of the TrAIL Project on these 500 kV lines.

Table 2

Congestion Area	**4-Hour**	**Line Loading (% 4-Hour Rating)**		**Contingency**
	Rating	**2010 RTEP**	**With Trans-Allegheny Interstate Line**	
Black Oak - Bedington 500 kV	2744	97.9	70.9	Pruntytown - Mt. Storm 500 kV

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10 *2004 State of the Market*, issued by PJM's Market Monitoring Unit, March 8, 2005, page 218

11 *Id.*, footnote 11, page 37

12 *Id.*, footnote 11, page 59

13 *Id.*, footnote 11, page 218

14 Gross and Unhedgeable congestion costs were calculated from the "2003-04-05-monthly-congestion-summary.xls" file located on PJM web site (www.PJM.com/planning/economic-planning/).

Mt. Storm - Doubs 500 kV	2598	94.1	76.1	Mt. Storm - Greenland Gap 500 kV
Mt. Storm - Doubs 500 kV	2598	94.1	76.1	Greenland Gap - Meadow Brook 500 kV
Mt. Storm - Doubs 500 kV	2598	92.0	72.0	Black Oak - Bedington 500 kV
Fort Martin - Pruntytown 500 kV	2434	87.1	67.7	Harrison - Pruntytown 500 kV
Pruntytown - Mt. Storm 500 kV	3326	89.8	67.5	Black Oak - Bedington 500 kV

D. Increase Generation Diversity

The TrAIL Project will provide loads in the eastern portion of the PJM Region with access to a larger, more diverse, lower cost sources of generation. This will allow generation to be dispatched to minimize the electric energy costs. Also, the corridor will provide better access to these loads for new wind and coal-fired generation facilities being developed in areas along and adjacent to the proposed corridor.

E. Strengthen Energy Independence

Construction of the TrAIL Project will reduce the dependence of loads in the mid-Atlantic area on imported oil and liquefied natural gas by providing reliable lower-cost sources of energy from the western PJM Region and the Midwest. In short, the TrAIL Project strengthens the energy independence of the United States.

F. Further National Energy Policy

Congress and the Federal Energy Regulatory Commission have identified the need for capital investment in the national transmission infrastructure.[15] Additionally, the Department has concluded that the electric system in the United States is in need of substantial capital investment to meet the future needs of the Information Economy.[16]

[15] *Energy Policy Act of* 2005, Sections 1241 and 1242; Promoting *Transmission Investment through Pricing Reform*, 113 FERC ¶ 61,182 (November 18, 2005)
[16] *"GRID 2030" A National Vision for Electricity's Second 100 Years*, issued by United States Department of Energy – Office of Electric Transmission and Distribution, July 2003, page iii

The TrAIL Project will be a significant capital investment in the national transmission infrastructure that will enhance the reliability of the PJM Transmission System and provide energy cost reducing benefits to consumers in the mid-Atlantic areas within the PJM Region.

G. The TrAIL Project Merits Early Designation as an NIETC

Based on the foregoing and the project details set forth in Attachment A, an early designation as an NIETC is both necessary and appropriate for the TrAIL Project. A compelling need exists for the designation so that Allegheny Power and PJM can begin to bring about the reliability enhancement, economic, congestion relief, generation diversity, energy independence and furtherance of national energy policy benefits offered by the TrAIL Project. Allegheny Power requests the Department to provide an early NIETC designation to the corridor needed for the TrAIL Project.

III. Correspondence and Communications

Correspondence or communications with respect to these comments and request should be addressed to the following:

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Respectfully submitted,

Allegheny Power

By Randall B. Palmer

Dated at Greensburg, PA this 6th day of March 2006.

Attachment A

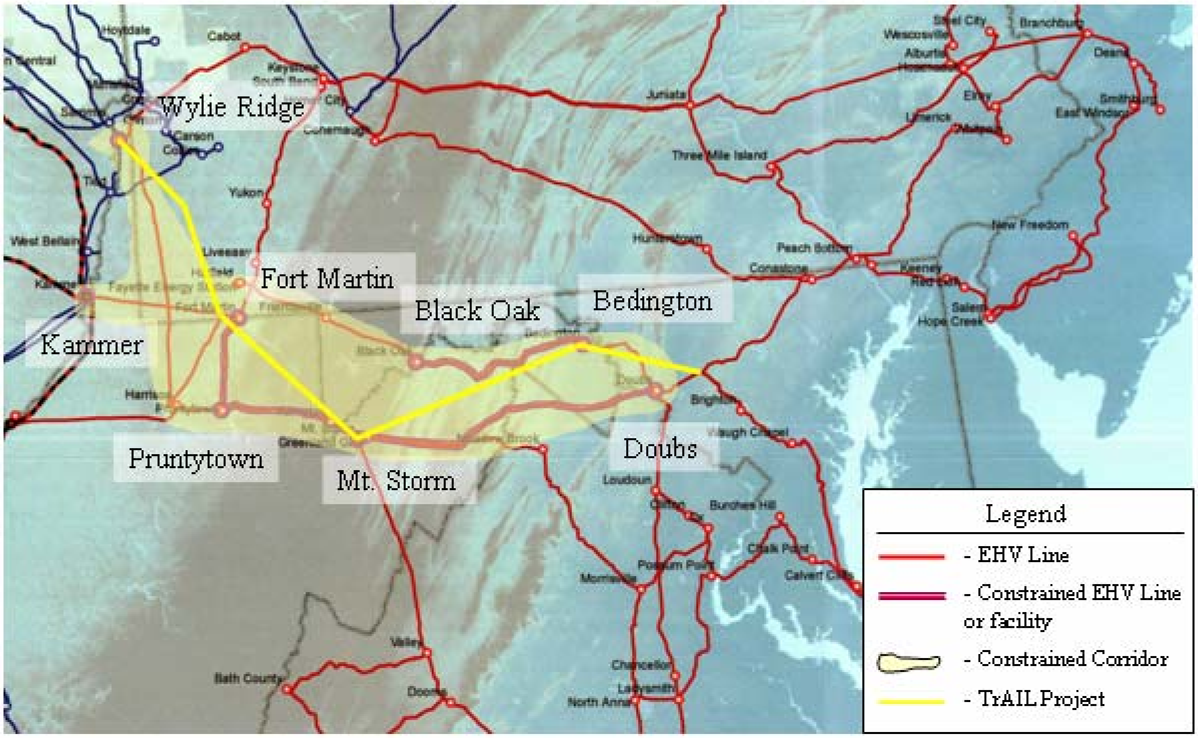
[Note from the U.S. Department of Energy: The submission of this report by Allegheny Energy has been noted. The body of this report is not included but is available on the Internet to the public at the following address:
http://www.alleghenypower.com/TrAIL/LineProposal-SystemPlanning-02-28-06-Final.pdf]

The Trans-Allegheny Interstate Line Project

A 500 kV Transmission Line Through the AP Zone

February 28, 2006

Attachment B



4. American Corn Growers Foundation, Received Mon 3/6/2006 1:09 PM

March 5, 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
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1000 Independence Avenue, S.W.
Washington, D.C. 20585

By e-mail to: EPACT1221@hq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

The **American Corn Growers Foundation** wishes to comment on the Department of Energy (the "Department")'s efforts in conducting its initial electric transmission congestion study required by the Energy Policy Act amendment to the Federal Power Act subsection 216(a)(1). We understand the Department intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity could lessen potential adverse effects borne by consumers.

We support the Department's goal to identify corridors for potential projects as generalized electricity paths between locations, as opposed to specific routes for transmission facilities. We also believe that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion.

We wish to emphasize that the Department's initiative is an opportunity to identify wind-rich regions that offer both economic development along potential transmission corridors and economical energy from wind power development. While some early wind projects may have been built in the wind-rich area(s) of Nebraska, the grain producing states of the Great Plains from Texas to Canada and various states in the corn-belt, the potential for more wind energy development should be included in the Department's review. We believe there is a true need to plan for more transmission to move wind power from future wind developments to consumers, thereby providing economic benefits, fuel diversification, and clean energy for our citizens.

Thank you,

Gale Lush, Chairman
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5. American Electric Power, Received Mon 3/6/2006 4:47 PM
March 6, 2006

Ms. Poonum Agrawal
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
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1000 Independence Avenue, S.W.
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Submitted by e-mail to: EPACT1221@hq.doe.gov

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Notice of Inquiry and Request for Comments, 71 Fed. Reg. 5660 (February 2, 2006)

Dear Ms. Agrawal:

I. Executive Summary

The nation needs an infusion of investment in new electric transmission facilities. Congress recognized this in enacting new Section 219 of the Federal Power Act. As stated by the Edison Electric Institute ("EEI"), capital spending in transmission must increase by twenty five percent, or one billion dollars annually, to assure system reliability and to accommodate wholesale electric markets. The Department of Energy ("DOE" or "Department") has stepped forward to tackle one of the most important provisions of the 2005 Energy Policy Act, the designation of National Interest Electric Transmission Corridors ("NIETC"). The companies of the American Electric Power System (collectively "AEP")[1] applaud the DOE for its prompt positive actions in promoting this national policy. In these comments, AEP offers suggestions on how the DOE's proposals can be strengthened and focused to achieve the necessary goal – reducing congestion and increasing reliability – by building the interstate transmission superhighway necessary to power the American economy in the 21st century.

The intent of the 2005 Energy Policy Act is to get transmission sited more expeditiously if it is indeed determined that transmission is the right solution. The DOE will play a critical role in this process by creating the rules and process by which NIETCs are identified, selected, and designated. To accomplish this, the DOE should leverage procedures that were developed under the auspices of the Federal Energy Regulatory Commission ("FERC") to help facilitate open policies and evaluate situations and problems. Given the need to provide timely relief to congested areas, AEP offers the following five-step plan to maximize the efficiency and effectiveness of the NIETC designation process.

- First, the DOE should identify cut planes, or interfaces that exhibit significant congestion or reliability issues. The DOE plans to accomplish this with the services of CRA and input from individual TOs, RTOs, or any other appropriate industry participants. Once justified by its studies, DOE should designate each of those geographic areas a national interest electric transmission corridor ("NIETC") thereby providing the FERC with the authority to issue construction permits under appropriate circumstances.

- Second, established regional planning bodies such as RTOs or ISOs should determine the optimal solution to alleviate congestion in the area identified by the DOE. Transmission owners or other entities may also identify solutions for early consideration and expedited treatment at this step to resolve significant and obvious reliability and congestion problems.

- Third, if new transmission is the solution and the transmission route does not already fall within a previously designated NIETC, then the DOE should designate a broad corridor encompassing the transmission solution as an NIETC. The corridor should be broadly

[1] AEP Texas North Company, AEP Texas Central Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company, Wheeling Power Company, and AEP Transmission Company, LLC.

defined to allow sufficient alternative routing of the proposed solution during the federal, state and local processes defined in the next steps. The corridor should be broad enough at this stage as to not require environmental impact statements ("EIS") at this level. Any EIS should be conducted in the next steps.

- Fourth, state and local agencies should be fully engaged with the transmission developer at this step to comply with siting requirements as specified in the applicable laws and regulations, including any necessary EIS. To the extent possible, environmental assessments should be conducted at this stage in order to narrow the broadly defined corridor to specific alternate routes. For federal land and similar actions (i.e., land where state and local requirements do not apply), the process should engage the FERC as lead agency to employ their already robust and similar siting processes used to determine proper routes for gas pipelines.

- Fifth, as a last resort for state and local processes, FERC should use its backstop siting authority as defined in the Energy Policy Act of 2005, after "full and complete" applications are made to state and local siting authorities. However, "full and complete" applications must employ reasonable, efficient and explicit requirements that are for the public good and not made to simply delay the siting process.

AEP believes this multi-step process is a clear, open, and well defined method to expedite siting transmission that is in the national interest with due respect to federal, state and local requirements, including the environment. This process also places the environmental assessments at the level where they will address needs, requirements and issues within the specific alternative routes.

AEP also believes that the DOE should delegate siting immediately after corridor designation to the proven siting processes employed by the FERC. The delegation is immediate for alternative routes across federal land and across land where state and local requirements do not apply. Where state and local processes are applicable, delegation of siting authority will be made to FERC with its backstop authority after the statutory period as defined in the Energy Policy Act has passed.

AEP supports eight draft criteria created by the DOE. AEP suggests when evaluating criteria for the NIETCs that DOE also focus on the long-term stability of any corridor it designates, because these corridors will be operational and relied upon for decades. The DOE should also leverage existing transmission facilities when designating corridors. This will help to quickly solve congestion problems while minimizing costs and environmental impacts.

Finally, areas where reliability issues or congestion is obvious should receive the earliest and most expeditious designation as an NIETC without more detailed calculations or further studies that only serve to delay the solution or confirm the obvious.

II. <u>Background</u>

On February 2, 2006, the Department of Energy released a Notice of Inquiry regarding the designation of NIETCs. The notice was issued pursuant to Section 1221(a) of the Energy Policy Act of 2005 ("EPAct"), which requires the Secretary of Energy to conduct a study on electric transmission congestion and issue a report that may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." Once an area has been designated as a NIETC, FERC may then issue permits for the "construction and modification of electric transmission" in the NIETC.

AEP is an electric utility holding company system providing electric service to customers in parts of eleven states. As the pioneer of 765 kV transmission facilities, AEP has experienced many of the obstacles that need to be overcome before new transmission can be built. For instance, it has taken AEP 14 years to site the Wyoming – Jacksons Ferry line, a much-needed 765 kV transmission line to serve West Virginia and Virginia. This line, originally proposed to be in service in 1998, will be completed in June 2006. In the interim period, AEP developed an automatic load-shedding plan to drop up to 1,000 MW of load to avoid an uncontrolled blackout in anticipation of heavy power flows and outages on the system. Fortunately, even after arming the load-shedding system in anticipation of a critical outage, it was not used and an outage did not occur. The United States economy deserves a better interstate transmission system and an expedited, but responsive siting process.

III. General Comments

The intent of the EPAct is to get transmission sited more expeditiously for reliability and congestion if it is indeed determined that transmission is the right solution. AEP applauds the DOE for promptly beginning the process to establish rules for the designation of NIETCs. As the lead government agency for the NIETC process the DOE will play a critical role in its implementation. The DOE will be required to designate cut planes and NIETCs broadly enough to allow these corridors to grow as conditions change over time. The DOE should work with various types of transmission organizations ("TOs") to determine whether new transmission is the best solution to alleviating congestion.

To help the DOE implement the new NIETC process more easily AEP suggests that the DOE should adopt several of the policies, procedures, and directives established by FERC. Specifically, the establishment of RTOs and ISOs has greatly improved the process of regional planning for new facilities to addressing specific reliability problems. We recommend that the DOE leverage the well-established planning processes used by RTOs and ISOs to determine the proper solution for alleviating congestion in DOE identified areas. Given the need to provide timely relief to congested areas, AEP suggests the use of the following five-step plan to designate NIETCs and site transmission:

- Problem Identification and DOE Delegation Stage – First, the DOE should designate cut planes, or interfaces with significant congestion or reliability issues. This is the easiest way to place the problem on a map. These interfaces can be identified through input from individual TOs, RTOs, or any other appropriate industry participants. An EIS or public hearings are not necessary and should not be conducted at this stage. Preparing an EIS before there are alternative routes would not be time well spent, and conducting public hearings before transmission is selected as the best solution to the congestion would be unnecessary. As permitted under the statute, DOE should designate NIETCs at this step as justified by its studies. At this point, the DOE should delegate siting authority to FERC for federal land or land where state and local requirements do not apply, and as a backstop authority for state and local processes.

- Solution Identification Stage – Second, the determination of whether new transmission is the right solution should be made by an open and timely stakeholder process, an individual TO, or any other knowledgeable body, including any interested state agency. All well established RTOs and ISOs have the procedures and expert staff necessary to carry out an open and transparent evaluation of the alternatives to determine whether transmission is the best solution to alleviate congestion. DOE should rely on these RTO and ISO established planning processes to develop the optimal solution to the problem identified in the first step. Transmission owners or other entities may also identify solutions for early NIETC consideration and expedited treatment at this step to resolve significant reliability and congestion problems.

- Additional Corridor Designation Stage – Third, if additional transmission is recommended in the Solution Identification Stage and the proposed solution falls outside a previously designated NIETC, then the DOE should designate a broad corridor or set of broad corridors where the transmission line is proposed from the previous step, then delegate siting authority to FERC (similar to the first step in this process). The corridor should be broadly defined to allow sufficient alternative routing of the proposed solution during the federal, state and local processes defined in next steps. The corridor should also be broadly defined so as not to require an EIS at this level. Any EIS should be conducted in the next steps.

- Siting Process – Fourth, state and local agencies should be fully engaged with the transmission developer at this step to comply with siting requirements as specified in the applicable laws and regulations, including any necessary EIS. The environmental assessments should be conducted at this stage in order to narrow the broadly defined corridor to specific alternate routes. For federal land or land where state and local requirements do not apply, the process should engage the FERC as lead agency to employ their already robust and similar siting processes used to determine proper routes for gas pipelines.

- FERC Backstop Authority – Fifth, as a last resort for state and local processes, FERC should use its backstop siting authority as defined in the EPAct after "full and complete" applications are made to state and local siting authorities. However, "full and complete" applications must employ reasonable, efficient and explicit requirements that are for the public good and not made to simply delay the siting process.

AEP believes this multi-step process provides a clear, open and well defined method of expediting the siting of transmission that is in the national interest and provides due respect to federal, state and local requirements, including the environment. This process also places the environmental assessments at the level where they will address needs, requirements and issues within the specific alternative routes. Once these broad corridors are narrowed to specific routes, applicable rules and regulations can then be effectively applied.

AEP also believes that the DOE should delegate lead agency authority to the proven siting processes employed by the FERC. The delegation is suggested to be immediate for alternative routes across federal land or land where state and local requirements do not apply, and immediate, following the statutory period defined in the EPAct, as backstop authority for state and local processes.

IV. DOE Congestion Study Questions

1. Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

Yes, the DOE should distinguish between "persistent" and "dynamic" congestion. This is part of the Problem Identification and DOE Delegation Stage. Once a problem area is identified through TO input, RTO input, etc., the DOE should then be able to identify the cut planes necessary to alleviate the congestion.

The DOE's priority should be to identify persistent transmission constraint locations by identifying those transmission paths (in market areas) for which there has been a high Locational Marginal Price ("LMP") differential over a number of recent peak load seasons. In market and non-market areas, frequent Transmission Loading Relief ("TLR") events resulting in curtailment of transactions would provide another indication of persistent congestion. The megawatt-hours ("MWHs") curtailed and number of tags curtailed may also be used to identify the level of congestion. In non-market areas, a persistent transmission constraint can be identified by quantifying the amount of long-term firm transmission service that was denied for which there was little or no posted Total Transfer Capability ("TTC") or Available Transfer Capability ("ATC"). In these non-market areas, a high denial rate accompanied by a low (or zero) posted ATC must both be observed over a number of recent peak load seasons. For example, a zero firm ATC for the majority of a peak period but a comparatively high TTC could be the result of the transmission path being fully utilized but fully adequate for the activity. Conversely, a low TTC with a high denial experience for long-term firm transmission service would likely be an indicator of persistent congestion.

2. Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

It is not clear what the Department means by "contractual congestion." One might assume that such congestion is related to limitations imposed by financial transactions. If that is the case, such limitations may or may not be related to real physical limits on the transmission system's capability to reliably transfer power and energy. The distinction between these two different types of congestion should be made at the Solution Identification Stage. If the problem is purely contractual, then building new transmission will not be the best solution to alleviating the congestion. However if the congestion is caused by physical constraints, then the stakeholders may decide that building new transmission is the best solution to alleviating congestion.

3. Appendix A lists those transmission plans and studies the Department has under review. In addition to those listed in Appendix A, what existing specific transmission studies and other plans should the department review? How far back should the Department look when reviewing transmission planning and path flow literature?

The DOE should review any proposal introduced during the Problem Identification Stage. This will ensure that all congestion areas are identified and reviewed to determine the best solution to alleviate the congestion.

Appendix A is a reasonably comprehensive listing for the Eastern Interconnection. However, similar transmission assessments for East Central Area Reliability Counsel ("ECAR"), Mid America Interconnected Network Reliability Counsel ("MAIN"), and Southwest Power Pool ("SPP") should also be added. Although, the DOE needs only go back two or three years in reviewing past literature and transmission assessments.

4. What are the categories of information that would be most useful to include in the congestion study to develop geographic areas of interest?

A. <u>Categories of Information</u>

Corridor designations should be made through the stakeholder process and then recommended to the DOE. There are several categories of information that would be useful to include during this process. These include:

- North American Electric Reliability Counsel ("NERC") or Electric Reliability Organization ("ERO") reliability standards,
- NERC and Regional reliability assessments,
- Quantification of the magnitude of long-term firm transmission service denials,
- Historical LMP prices between various resource and load areas for market areas,
- TTC and ATC values for non-market areas,
- Electric hub prices where there were no organized markets,
- TLR history,
- Reliability Must Run ('RMR") contracts,
- Operation performance/procedure reports from RTOs and individual utilities,
- Power transfer patterns,
- Reports on local and regional disturbances,
- Population growth trends,

- Penetration of new technologies in consumption or supply (e.g., distributed generation, plug in hybrid autos, consumer electronics, etc.),
- Prices of various fuels and their relative use in generation,
- Climate trends,
- Concentrations of aging generation susceptible to retirement,
- Barriers to new generation technology, fuel diversity, environmentally friendly generation or renewables,
- Market studies conducted by independent RTOs/ISOs

B. Transmission Studies

When studying regional transmission assessments stakeholders need only review data from the past two or three years. Any constraints from these assessments that are over three years old may already have been addressed through incremental transmission enhancements and/or generation additions.

V. Evaluation of DOE Criteria

A. General Comments on Criteria

AEP agrees with the types of questions asked by DOE and the evaluation criteria established by DOE to help identify general areas that may require NEITC designation. As previously discussed, the DOE should identify areas with a significant amount of congestion or reliability issues. After this identification, these areas should be referred to regional planning boards to select the best solution for alleviating the congestion. When creating the criteria for the identification and selection of NIETCs, the DOE should consider that both the DOE and the regional planning boards might use these criteria. Thus the criteria should be developed taking both of these groups into account. Areas where reliability issues or congestion is obvious should receive the earliest and most expeditious designation as an NIETC without more detailed calculations or further studies that only serve to delay the solution and confirm the obvious.

The corridors should not be designated at the level of a specific right-of-way ("ROW") location. Instead, corridors should be broadly defined to allow flexibility to consider alternative routes within jurisdictional processes, but not so broad as to hamper focused siting efforts. We envision broad corridors as miles wide instead of hundreds of feet wide. These broad corridors will then be narrowed down to specific transmission routes in the later stages of the process.

Finally, and certainly not least, NIETCs must be established to maintain national reliability standards that will be established by the ERO designated by FERC, and must take into consideration national security due to the nation's reliance on electric transmission infrastructure.

B. Comments on DOE Proposed Criteria

Draft Criterion 1: Action is needed to maintain high reliability. **Maintaining high electric reliability is essential to any area's economic health and future development. Accordingly,**

an area would be of interest for possible NIETC designation if there is a clear need to remedy existing or emerging reliability problems.

Metrics: **A definition of the affected area in terms of load, population, and demand growth; a description of the expected degree of improvement in reliability associated with a proposed project; if appropriate, identification existing or projected violations of NERC Planning Criteria TPL–001, –002, –003, or –004.**

The ability of the transmission system to reliably serve a load area is a fundamental requirement for the nation's economy and for national security. In all cases, all load areas must be able to be served under a single contingency situation at projected peak load. As the load area under consideration increases in size, the transmission system should be able to continue to serve the load under more severe conditions. For example, a transmission system supplying a city of 50,000 people should be able to continue to supply this load following the unexpected outage of any single transmission element. However, if the load area under consideration contains several million people, the ability to withstand the unexpected unavailability of two or more transmission facilities or the loss of an entire right-of-way may be appropriate. In addition, an over-reliance on local generation resources to maintain transmission adequacy should be minimized. There must be a reasonable balance between local generation and the dependence upon transmission to serve a load area.

DOE should designate a broad set of corridors that will enable corridors to grow as the needs of a particular area change. The metrics needed to maintain high levels of reliability should go beyond measuring load and population impacted. A measure of equipment loss-of-life should also be included since EHV equipment can be severely damaged before any load is lost. Such a condition jeopardizes reliability by setting the stage for cascading outages as well as extended restoration times. To maintain reliability, the equipment must be operated within its capability and within the operating standards defined by NERC or the ERO.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers. **An area may need substantial transmission improvements to enable large economic electricity transfers that would result in significant economic savings to retail electricity consumers.**
Metrics: **Estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets. A demonstration of expected reduction in end-market concentration and how economic benefits for consumers would be affected.**

This is a valid criterion. For example, PJM's analyses indicate that transmission congestion has added about $1 billion to consumer cost during 2005. However, areas where reliability issues or congestion is obvious should receive the earliest and most expeditious designation as an NIETC without more detailed calculations or further studies that only serve to delay the solution or confirm the obvious.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Metrics: **Areas that are dependent on ''reliability-must-run'' plants would benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both. Similarly, areas that are highly dependent on specific generation fuels could economically benefit from supply diversification. Estimate the likely magnitude of such benefits, showing calculations.**

Generally no load area should depend upon any single generating unit or generating station to ensure adequate supply reliability. The transmission system should be able to accommodate various generation dispatches including the temporary or permanent outage of any single generation plant or unit. Where reliability must run units are needed to maintain minimum acceptable reliability, society as a whole may be accepting higher cost, for units that may not be economically viable. In some cases, where the must-run unit may not be environmentally friendly, society will have to endure environmental damages, when more environmentally friendly generation resources may be available but cannot be delivered due to transmission limitations. Therefore, significant load areas that require a particular generation facility to be operating during peak periods should be designated as NIETCs to ensure adequate transmission is constructed to remove the dependency upon this single facility and allow for more flexible use of local generation as well as access to more distant generation resources.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Metrics: **Provide calculations showing how specific actions aided by designation as an NIETC would increase fuel diversity, improve domestic fuel independence, or reduce dependence on energy imports. Quantify these impacts, including possible impacts on U.S. energy markets.**

Renewable resources such as wind and hydro that are typically remotely located away from load centers can play a role in diversifying U.S. fuel supply. In addition, conventional fueled resources (coal and nuclear) that use domestic fuels could also have socio-political benefits and reduce dependence on imported fuels. Such resources are also typically located at some distance from large population centers. In all of these cases, transmission infrastructure improvements will be needed to enable a better energy position in the United States and to enable retirement of older, economically and environmentally challenged generating plants. Greater transmission transparency is the enabler of a better energy position for the United States.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

If properly applied, this criterion has merit. For example, this criterion could be used to encourage transmission development that would level the playing field for new generators to enter the market and compete head to head with incumbent generators that are located "downstream" of a constrained transmission interface. Consequently, a transmission reinforcement plan must be assessed on its ability to integrate any potential generation resources. A reasonably accessible transmission infrastructure is critical to allow fair and robust competition among alternative generation resources. Again, a more transparent interstate transmission system is the enabler of a better energy position for the United States.

***Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts. Metrics:* For this criterion, relevant metrics would be case-specific.**

This is a valid criterion that could apply not only to individual critical loads, such as a major military installation, but also to concentrated population centers. The load centers located in the northeastern and mid-Atlantic portions of the Eastern Interconnection are highly dependent upon relatively few transmission corridors. Additional high capacity corridors would result in a more robust transmission system that would provide access to diverse generation resources and would improve the ability to withstand natural disasters and/or willful destructive acts.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

A robust transmission system should allow for various generation resource dispatches, fuels, and resource locations. Any assessment of these alternatives should determine the ability of the transmission system to reliably deliver power under various resource assumptions. As an example, a specific technique to accomplish this objective, as part of the transmission system analysis would be the inclusion of transmission reliability margin when evaluating transmission needs. However, the wide variety of assumptions could lead to paralysis of analyses, and must be reasonable to enable timely results.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

This criterion should be used by the regional planning body in determining the best solution to address a congested transmission interface. When making comparisons of alternatives to the construction of new transmission and judging the relative merits, the entire range of attributes of the competing alternatives should be evaluated. As an example, if new generation were being compared to new transmission, the flexibility of the transmission project to satisfy other future needs, such as connecting new loads or generators along its path, and loss savings must be considered and weighed in the final decision. Additionally, the value of a new transmission project in releasing uneconomic reliability must run ("RMR") generation should also be taken into account.

C. Other Criteria the DOE Should Use in Making a NIETC Designation

When creating corridors the DOE should look beyond an areas immediate need and plan for the future. Designated corridors and associated reinforcements should be planned to last for decades, so that they are not outdated before they are placed in service. Thus, criteria for designating corridors should not be too narrowly prescriptive.

Designated corridors should also take advantage of the existing EHV transmission infrastructure. This will allow new corridors to quickly serve congested areas, by leveraging existing EVH foundation, while minimizing costs and environmental impact.

Finally, corridors should be designed to account for scale economies and for re-development of existing corridors for higher voltage transmission. For example, one 765 kV line is equivalent to 3-500 kV, 5-345 kV or 30-138 kV lines (based on surge impedance loading characteristics). The single 765 kV line would be less expensive and cause far less environmental impact than any of the equivalent groups of lower voltage facilities. Furthermore, NIETCs should provide for transmission development that would enable the ability to connect newer technology, environmentally friendly, and fuel diverse generating plants, and to enable the full potential of renewable resources. NIETCs should also anticipate intermediate tap stations near load centers to address load growth and market efficiency needs, as well as relieve future congestion.

VI. Proposal for Expedited NIETC Designation of the AEP I-765 Corridor

On January 31, 2006, AEP submitted a proposal to the DOE for a 765 kV transmission line from the Amos substation in West Virginia, through the Doubs substation in Maryland and ending at the Deans substation in New Jersey. AEP is currently working with PJM to get this transmission line included in PJM's regional transmission expansion plan ("RTEP") process to determine final terminations and related infrastructure needs. AEP requests that DOE designate this proposed line as a NIETC as early and expeditiously as possible because 1) it was previously identified by PJM in their "Project Mountaineer" announcement as a one of the corridors needed to relieve congestion, 2) the designation will be geographically broad enough to cover any PJM RTEP revisions to the plan, and 3) the reliability need and congestion relief is abundantly obvious in our request of January 31, 2006, citing benefits from our own studies, PJM congestion, and a Maryland Public Service Commission report. Any delays in this line will continue to expose millions of consumers to high electricity costs and jeopardize basic reliability needs of the Mid-Atlantic and surrounding states.

VII. Conclusion

AEP offers some practical suggestions to improve the effectiveness and efficiency of the NIETC designation process by taking advantage of existing facts, expertise, and processes. AEP believes that DOE's initiative is critical to the national agenda of achieving energy independence and providing a fair and robust platform for economic development in the nation. AEP respectfully submits the above suggestions to support DOE in achieving this very important national agenda, and we believe our position as the largest transmission owner in the United States, including over 2,000 miles of efficient and reliable 765 kV interstate transmission warrants due consideration.

Respectfully Submitted,

Electronically Filed_________

Craig Baker

6. American Public Power Association, Received Mon 3/6/2006 4:47 PM

March 6, 2006

VIA E-MAIL

Office of Electricity Delivery and
Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
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1000 Independence Avenue, S.W.
Washington, D.C. 20585
EPACT1221@hq.doe.gov

Re: **Comments of the American Public Power Association on the Department of Energy's Notice of Inquiry, *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors,* 71 Fed. Reg. 5660 (February 2, 2006)**

In accordance with the February 2, 2006, Notice of Inquiry ("NOI") issued by the U.S. Department of Energy ("DOE" or "the Department") on *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors,* the American Public Power Association ("APPA") submits its comments regarding DOE's plans for an electric transmission congestion study and the proposed criteria for the designation of National Interest Electric Transmission Corridors ("NIETCs" or "Corridors"). The NOI was issued to implement Section 1221 of the Energy Policy Act of 2005 ("EPAct 2005"), which amends Part II of the Federal Power Act by adding Section 216, "Siting of Interstate Electric Transmission Facilities."

I. OVERVIEW

APPA very much appreciates the opportunity to provide comments to the Department of Energy on the subject of transmission congestion and expansion of the transmission grid through the designation of NIETCs. APPA strongly supported Section 1221 of the Energy Policy Act of 2005 when it was being debated in Congress. APPA has long argued that a more streamlined, predictable siting process that gives the federal government limited authority to ensure the siting of interstate transmission lines is essential to achieving a more robust transmission grid. Even where the transmission owner is ready, willing and able to expand the system, it has been very difficult to site new facilities. APPA is therefore hopeful that the new system provided under Section 1221 — with DOE designating the NIETCs and the Federal Energy Regulatory Commission ("FERC") providing "back-stop" authority on transmission lines being proposed within the NIETCs when the states fail to act — will provide the certainty lacking in the current siting process.

The recent experience of APPA members is that extensive upgrades to existing facilities as well as substantial expansion of new bulk transmission facilities are required in nearly every region and subregion of the nation to remedy the transmission investment deficit that has developed since the last transmission investment cycle ended in the late 1980s. Thus, APPA concludes that it is inappropriate to single out a very few transmission ***corridors*** as uniquely deserving designation as NIETCs. Instead, DOE should identify load pockets or import regions that would gain substantial benefits in areas such as reliability, consumer benefits (economics), market power mitigation, and generation fuel supply/technology diversification if they were specified as ***delivery regions*** for one or more NIETCs.[2] Further, DOE should identify potential

[2] *See, e.g.*, the comments being filed in response to this NOI by the Bay Area Municipal Transmission Group regarding the San Francisco Bay Area load pocket.

generation pockets or ***export regions*** from which new or surplus baseload coal, nuclear and renewable resources can be exported on a long-term basis to supply the firm-power-supply requirements of load-serving entities ("LSEs") in one or more such delivery regions. APPA suggests that DOE should designate multiple NIETCs connecting adjacent regions to support the transition of electric power markets in the United States from local and regional to multi-regional.

DOE's planned studies of congestion in the Eastern and Western Interconnections will in all likelihood identify many such export and delivery regions. APPA, however, cautions that measurable congestion by itself is often heavily dependent on short-term spot market price differentials between regions driven largely by input fuel price differences — particularly natural gas. The volatility of natural gas prices may make the congestion-based designation of export and delivery regions unstable if, for example, modeling scenarios are run with natural gas prices that are at either of the extremes experienced over the last five years. Weather patterns, particularly temperature differentials between regions as well as rain and snowpack variability in hydro-dependent regions, can and will affect measurable congestion and the likely designation of NIETCs. In addition, to the extent that natural gas-based generation is currently "on the margin" in both potential export and delivery regions, quantifiable congestion will substantially understate the long-run benefits of increased interregional transfer capability.

For these reasons, APPA would give greater weight in the designation of NIETCs to the power supply needs and plans of LSEs to meet their long-term service obligations to their retail customers. In retail access states, resource adequacy requirements applicable to LSEs and generation procurement policies for default suppliers should also take into account the interests of consumers in obtaining greater assured access to remote generation resources and DOE should in turn take such resource adequacy requirements into account in NIETC designations. Investment in new bulk and subregional transmission is critically needed to ensure the deliverability of new generation facilities, particularly baseload capacity and renewable energy facilities. These facilities are often sited at locations that are remote from load centers of the project participants that have agreed to take an ownership position or long-term purchase contract for these resources — or would take an ownership position in these projects if firm transmission rights were in fact going to become available on a timely basis at a known and reasonable price. Thus, DOE's criteria should identify the impact of a proposed NIETC on the firm or assured deliverability of new base-load and renewable resources to delivery regions. Approved NIETCs should, either by themselves or in concert with other NIETCs, provide increased firm transmission rights between identified export and delivery regions.

Further, DOE's criteria should examine the willingness of a broad, diverse cross-section of the electric power industry to participate in the development of transmission facilities in NIETCs. While APPA would not place a bar in front of a NIETC designated to support the proposed transmission project of a single large market participant, most interregional bulk transmission projects provide benefits to and should be sponsored by multiple market participants, including generation interests and LSEs. Broad participation — in export, delivery and intervening regions — is critically important to gain public support in the areas where such facilities are to be sited, to ensure the financial viability of the new lines, and to address the concerns of other transmission owners and transmission rights holders who may be affected by parallel flows resulting from use of facilities constructed within the NIETC. Further, major interregional transmission lines will require extensive transmission upgrades to other facilities in both the export and delivery regions, which will also directly affect the interests of third parties.

II. APPA'S INTERESTS

APPA is the national service organization representing the interests of not-for-profit, state, municipal and other publicly owned electric utilities throughout the United States. More than 2,000 public power systems provide over 16 percent of all kilowatt-hour ("kWh") sales to ultimate customers, and do business in every state except Hawaii. Approximately 1,840 of these systems are cities and municipal governments that currently own and control the day-to-day operation of their electric utility systems. Public power systems own about 10 percent of the nation's electric generating capacity, but purchase nearly 70 percent of the power and energy used to serve their ultimate consumers.

Public power systems own about eight percent of the nation's high-voltage transmission lines, although many of these lines are configured to deliver energy to their own load centers, and not to provide transmission service in interstate commerce. Many public power systems, however, are transmission-dependent and rely upon transmission services provided by vertically integrated utilities and Regional Transmission Organizations ("RTOs") to obtain access to remote generation sources, particularly base load and renewable energy sources, to provide reliable, economic power to their customers. Public power systems seek opportunities to become equity owners of new local and bulk transmission facilities in exchange for transmission rights needed to ensure the reliable and economical delivery of their owned and purchased generation resources to their load centers. Public power systems also seek the opportunity to invest in existing transmission networks, as joint owners of shared transmission systems and, where allowed under state law, equity owners in transmission companies. An APPA issue brief describing a number of such joint ownership arrangements is appended to these comments as **ATTACHMENT A**.

For these reasons, APPA welcomes the February 2 Notice and the opportunity to comment on these issues.

III. Communications

APPA requests that service in this proceeding be made upon, and communications directed to, the following:

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IV. RESPONSES TO SPECIFIC QUESTIONS

APPA responds below to the specific questions raised in DOE's NOI and elaborates as required on the points raised above in Section I.

Section II.C.: In their comments on the criteria set forth below, the Department invites commenters to address how broadly or narrowly the Department should consider and define corridors in its [congestion] study and its NIETC designations.

The transmission plans that result from NIETC designations must be sufficiently granular to allow LSEs to determine if the resulting facilities and associated physical or financial transmission rights will meet their generation resource delivery needs. As discussed in Section I above, APPA recommends that corridors be identified by source/export region and sink/delivery region. But DOE also needs to consider how construction of transmission facilities in NIETCs will impact the existing transmission facilities in the export and delivery regions, so that congestion is not just shifted to a new location. When DOE and the Federal Energy Regulatory Commission ("FERC") exercise their new FPA Section 216 responsibilities, they should ensure that any new "transmission freeways" they authorize have the necessary "on and off ramps" to allow those freeways to be fully used.

APPA further recommends that DOE and FERC implement new Section 216 of the FPA to further the objectives of EPAct 2005 Section 1233, which added Section 217, Native Load Service Obligation, to the Federal Power Act. Section 217(b)(4) provides that FERC will:

> "…[E]xercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of load-serving entities and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs."

DOE should therefore consider the planned new long-term generation resources of LSEs (especially baseload or renewable resources) needed to meet their service obligations in developing its NIETC designations. In particular, DOE should consider the needs of LSEs in RTO regions for long-term transmission rights ("LTTRs"). EPAct 2005 Section 1233(b) requires FERC to implement FPA Section 217(b)(4) in RTO regions within one year of the date of enactment of EPAct 2005. FERC on February 2, 2006 issued in Docket Nos. RM06-8-000 and AD05-7-000 a "Notice of Proposed Rulemaking" to implement LTTRs in RTO regions. In that NOPR (at PP 86-92), FERC discusses the close tie between the allocation and use by LSEs of LTTRs and the need to ensure the continued viability of these LTTRs through adequate RTO transmission planning and construction processes. *See, e.g.,* P 88 ("…[T]ransmission organizations will need to have effective planning and expansion regimes in place, and may need to expand the system where necessary to ensure that the long-term transmission rights can be accommodated over their entire term without modification or curtailment."). APPA believes that DOE's designation of NIETCs should take into account the need to assure the continued viability of LTTRs awarded to LSEs.

III.A. Congestion Study: DOE requests comments on the following questions:

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

The meaning of and distinction between persistent and dynamic congestion is not defined in the NOI. If by "persistent congestion" DOE intends to distinguish between congestion that occurs over an extended period of time for a significant number of hours per year, as compared to "dynamic congestion" that depends upon current system conditions driven by generation outages or current input fuel prices, then APPA agrees that persistent congestion is likely to provide a better indicator of congestion that would give rise to support for new long lived transmission facilities. Nonetheless, dynamic congestion is a recurring reality on the grid. When planned and forced outages occur, LSEs strive to replace the lost generation output with the most economical replacement capacity and energy available. Expanding the geographic area from which replacement capacity and energy can be obtained will provide reliability benefits, support generation reserve sharing, and lower consumer costs. Recurring dynamic congestion also reflects lost opportunities to expand energy trading to take greater advantage of seasonal diversity in energy demands between regions. A well designed transmission grid accommodates such increased and variable customer demands.

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

Yes, DOE should distinguish between physical congestion and contractual congestion, but APPA is concerned that a focus by DOE on physical congestion may downplay the fact that for market participants it does not matter that some congestion is physical and other congestion is due to contractual limits such as contract path limits, local rather than regional calculation of Available Transfer Capability ("ATC"), or seams between RTO regions. It is inappropriate to base congestion modeling on a hypothetical interconnection-wide least cost or bid-based dispatch that assumes away seams between adjacent systems or regions, because market participants will invest billions of dollars in new generation in the near future based on the *actual* availability of firm ATC and LTTRs in RTO regions, and projections of the actual real time market prices and congestion charges in these regions.

(3) Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

APPA cautions that the transmission plans the NOI identifies may not fully reflect the needs of LSEs that do not own transmission and who had little or no opportunity or ability to participate in the development of such studies. Further, until recently, the prevailing practice of most, if not all, RTO regions has been to "roll up" the transmission plans of each participating transmission owner, without the RTO performing its own comprehensive RTO-wide transmission need assessments. Further, some RTOs have maintained a distinction between "reliability" and "economic" upgrades for a number of years (in some cases requiring participant funding of economic upgrades), only to discover that few upgrades were ever justified purely on the basis of economics (particularly in regions with the short time horizons brought on by retail competition) and that operators could muddle through for a number of years without jeopardizing reliability. (That period, however, is fast coming to an end.)

For these reasons, existing transmission studies will be helpful in determining the limits of regional transmission systems as they exist today, but may provide limited guidance as to future needs and the optimal character of the future grid.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

As discussed in response to Section I and II.C., above, DOE should consider and give substantial weight to the new generation resource plans of LSEs with service obligations that have focused on the import of base load generation and a variety of remotely located renewable energy resources.

Section III.B. The Department invites comment on what criteria it should use in evaluating the suitability of geographic areas for NIETC status.

Draft Criterion 1: Action is needed to maintain high reliability.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

The criteria identified in the NOI are generally inclusive and address considerations that should be taken into account if specific regional and inter-regional transmission corridors are to be identified as being of "national interest." As discussed above in Section I, however, APPA would adopt metrics that give greater weight to now-ongoing long-term power supply planning and fuel supply diversification than to currently quantifiable congestion. These considerations are reflected in Draft Criteria 2 and 3.

With respect to Draft Criterion 2, metrics for economic benefits to consumers should focus on sustained, long-term economic benefits under a reasonable range of assumptions.

Draft Criterion 4, energy independence, does not appear directly relevant to the designation of current NIETCs. Energy independence should nonetheless be retained as a criterion to reflect changing circumstances. If, for example, the nation were to fully embrace a strategy of reduced reliance on petroleum for transportation purposes, “plug-in” hybrid automobiles have the potential to substantially reduce the nation’s oil imports, while increasing the off-peak energy demands placed on the nation’s electric utilities, which would in turn increase the utilization of and need for new baseload generation sources.

Similarly, Draft Criterion 5, “targeted actions in the area would further national energy policy,” should reflect metrics such as increased reliance by LSEs on renewable energy sources, which are often located in areas that are remote from major load centers.

APPA suggests that Draft Criterion 7 risks paralysis by analysis — it is always possible to construct scenarios that suggest doing nothing is the best course. If by this criterion DOE is indicating that it will give less weight to projects that depend on speculative assumptions, *e.g.*, that a technological breakthrough will take place that would make an otherwise lackluster project viable, then APPA agrees. DOE’s corridor designations should depend on proven technologies as well as assumptions on which generation investment decisions are being made today.

Finally, with respect to criterion 8, alternative means of mitigating the need for transmission additions will always be raised prior to the construction of a major new transmission facility, during the certification of need and the development of project sponsors.

DOE should not eliminate potential corridors solely on this basis.

The Department also seeks comment on two additional questions:

(1) Are there other criteria or considerations that the Department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.

Yes, as discussed in Section I above, the Department should adopt criteria and metrics that require an NIETC applicant to show how the proposed project:

- Ensures the deliverability of new and existing surplus baseload generation to potential delivery regions;
- Ensures the deliverability of new and existing surplus renewable energy resources to potential delivery regions;
- Ensures that LSEs can obtain long-term firm transmission rights to deliver owned or purchased generation resources to their load centers to meet their service obligations;
- Has broad direct participation by or the support of diverse market participants in export, delivery and intervening regions.

(2) Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

See Section I Overview and comments in response to the Draft Criteria.

WHEREFORE, APPA submits these comments for DOE's consideration in its Notice of Inquiry.

Respectfully submitted,

AMERICAN PUBLIC POWER ASSOCIATION

By ___________**/s/ Allen Mosher** ___________

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Joint Ownership of Transmission

(Revised and Reissued January 2006)

Joint ownership of transmission facilities is a structural solution that can address many of the access-related issues that Regional Transmission Organizations ("RTOs") were intended to address. Proportional ownership by those load-serving entities providing service in the region is an effective means to mitigate the transmission market power of utilities seeking market-based rate authority from the Federal Energy Regulatory Commission ("FERC"). If the responsibility for building and owning the transmission grid is spread more broadly among entities serving loads in a region, then joint transmission planning will be facilitated, simply because there are more participants at the planning table. If network customers of a dominant regional transmission provider are encouraged to buy in to their load ratio share of the transmission system, transmission usage and ownership will be more closely aligned, and the frictions between transmission-dependent utilities and transmission owners can be reduced.

Public power utilities have participated in jointly-owned transmission arrangements for many years. One model of joint ownership that has worked for public power is investment in a transmission-only company. A second model is joint ownership in a shared system. A third model is joint ownership of individual lines that are planned on a coordinated project basis. The experience of public power utilities in the West—where joint ownership of individual transmission lines is the typical model—is particularly illuminating as it shows the benefits of joint transmission planning as well as joint ownership.

Investment in a Transmission-Only Company

There are two transmission-only companies that are partially owned by public power utilities. These are the American Transmission Company and the Vermont Electric Power Company.

American Transmission Company

American Transmission Co. LLC ("ATC") was organized in 2000 and assumed ownership and operation of transmission assets on Jan. 1, 2001. Four investor-owned utilities—Wisconsin Electric Power Company, Madison Gas & Electric Co., Wisconsin Public Service Corp. and Wisconsin Power & Light Co.—transferred their transmission assets to ATC at net book value. In return, the utilities received 50 percent of the assets' value in cash and the remainder as ownership interests in ATC. The fifth founding member, Wisconsin Public Power Inc. ("WPPI"), a public power utility that owned no transmission, purchased a 5.7 percent ownership interest in ATC for $17 million. The percentage amount was based on WPPI's proportionate share of electric load in Wisconsin, and the purchase price was based on the net book value of the transmission facilities transferred to ATC by the other owners. WPPI is a municipal joint action agency that provides full requirements power and energy and other services to its 39 member cities and towns in Wisconsin.

Currently, ATC has 27 members who have contributed some combination of transmission assets or cash to the system. These members include the Upper Peninsula Public Power Agency, which was created to facilitate the participation of seven Michigan municipal utilities in ATC, as well as four electric cooperatives in Wisconsin and Michigan.

ATC has total assets of approximately $1.3 billion, including 8,900 circuit miles of transmission lines and 460 substations. The company is governed by a Board of Directors, which includes four independent directors and a director representing each of the five founding members. The company raises capital by selling bonds and by equity contributions from its members. Its bonds are rated by all three major credit rating agencies: currently ATC's long-term debt is rated "A" by Fitch, "A+" by Standard & Poor's, and "A1" by Moody's.

ATC was created in response to the Reliability 2000 legislation signed into law in October 1999 as part of Wisconsin's 1999 budget bill. The legislation represented a compromise: it raised the cap on investor-owned utility investments in non-regulated businesses to 25 percent of utility assets, if the utility voluntarily transferred its transmission assets to a separate transmission-only company that would in turn improve system planning, construct needed transmission facilities, and ensure a more reliable system. The legislation addressed regulatory jurisdiction over the new company, to be structured as a utility subject to state jurisdiction for issues including certification of transmission projects but ceding rate jurisdiction to FERC.

A June 2000 filing with the Wisconsin Department of Financial Institutions established ATC as a limited liability company. This structure was selected in part to facilitate the participation of a diverse mix of utility owners. Next, ATC filed with FERC for approval of its Open Access Transmission Tariff ("OATT"); the tariff created a single-zone transmission rate, phased-in over a 5-year period.

In August 2000, ATC and the five member companies filed with the Wisconsin Public Service Commission for certification of ATC as a transmission company and for approval to transfer transmission assets with a book value of more than $545 million from the member companies to ATC. ATC filed for and received necessary approvals from FERC, as well as state regulators in Wisconsin, Michigan and Illinois, in time to meet the January 1, 2001 launch date.

ATC is a member of the Midwest Independent Transmission System Operator ("MISO"), transferring operational control of its transmission facilities to MISO in December 2001. ATC transmission customers began taking transmission service under the MISO OATT in February 2002.

Each year ATC conducts a transmission system assessment, including public input in system-wide meetings, which results in recommendations for system upgrades and expansion. In its 2005 10-year transmission expansion plan, ATC projects new investment of up to $3.4 billion. Since operations began in 2001, ATC has invested approximately $500 million in transmission infrastructure.

Vermont Electric Power Company
ATC was created just a few years ago, but the idea of a jointly owned transmission-only company is not new. Vermont's investor-owned utilities established Vermont Electric Power Company ("VELCO") in 1956 to develop an integrated transmission system in the state. The Burlington municipal utility became a shareholder in the 1960s through conditions placed on nuclear plant licenses to address situations inconsistent with the antitrust laws. However it wasn't until the late 1970s that agreement was reached to allow all of Vermont's municipal and cooperative utilities to acquire shares in VELCO; the agreement forestalled a legislative proposal directing the State of Vermont to take over VELCO.

Vermont's 15 municipal and two cooperative utilities have increased their shares in VELCO over time, finally achieving a load ratio ownership share in 2001. Today, municipal utilities have two seats on the VELCO Board, and cooperative utilities have one.

When VELCO needs new equity for its capital program, each shareholder is allowed to invest a proportionate amount based on its load ratio. Shares are owned by the individual municipal utilities, and many obtain financing from Vermont Public Power Supply Authority, the joint action agency in the state.

Ownership in a Shared Transmission System
In shared or joint transmission systems, two or more load-serving utilities combine their transmission facilities into a single system. Examples of public power participation in shared transmission systems are found in Indiana, Georgia, Minnesota, and the upper Midwest region. In the West, public power systems are often joint owners of individual transmission lines.

Indiana
Cinergy Corp., Wabash Valley Power Association ("WVPA"), and Indiana Municipal Power Agency ("IMPA") own a Joint Transmission System ("JTS"), an integrated transmission system covering two-thirds of Indiana, part of Ohio and a small part of Kentucky. IMPA, a joint action agency that now serves the power supply needs of 40 Indiana municipal utilities, acquired its interest in the JTS in 1985 through the purchase of transmission facilities from Public Service Company of Indiana ("PSI"). (PSI has since been acquired by Cinergy.) WVPA has had a similar arrangement with PSI since 1983.

IMPA's participation in transmission ownership and the establishment of the JTS followed several years of negotiations between the parties. At the time, PSI was constructing the Marble Hill nuclear plant and had severe financial problems. PSI was looking for co-investors in

Marble Hill and invited IMPA to participate. IMPA declined, and countered with the suggestion of investing in PSI's transmission assets.

In November 1985 IMPA executed ownership and licensing agreements with WVPA and PSI. These agreements provide that each utility owns specific lines and substations in the system, but has all rights, as tenants in common, to the use, output and capacity of the entire JTS. IMPA issued $31.6 million in revenue bonds to purchase about seven percent of PSI's transmission assets. If a joint owner's use of the system is more than its investment share, the utility makes payments to one or both of the other owners. This arrangement—owning specific assets, but operating as if the entire system were jointly owned—was used rather than a partnership arrangement, because IMPA is a political subdivision of Indiana, and state law prohibits it from entering into partnership agreements with private entities. IMPA also signed an operating agreement with PSI, providing for IMPA to pay PSI (now Cinergy) a monthly fee for the operation and maintenance of the IMPA assets.

Cinergy, WVPA and IMPA jointly plan for JTS system upgrades and expansions. The planning group uses forecasts of total load growth to determine where the need for new transmission is greatest. The planners assign ownership of specific capacity additions among the three utilities in proportion to each utility's percent of total load, and each utility then provides the investment money for its assigned portion. The goal is to keep each utility's investment in proportion to its use of the system. IMPA currently owns 4.6 percent of the JTS.

The JTS is directly connected with eight other electric utilities in or adjacent to Indiana, and is under the operational control of MISO. MISO treats the JTS as a single entity, and pays Cinergy revenues collected for the use of the system. Cinergy, in turn, pays WVPA and IMPA their portion of the revenue.

The Georgia, Minnesota and Upper Midwest systems described below have very similar arrangements to the Cinergy/WVPA/IMPA JTS model. Brief descriptions are provided for each of the three.

<u>Georgia</u>
Georgia's Integrated Transmission System ("ITS") is jointly owned by four Georgia electric utilities: Georgia Power Co., a subsidiary of Southern Company; Georgia Transmission Corp., an affiliate of Oglethorpe Power Corp., which is a generation and transmission cooperative; MEAG Power, a municipal joint action agency; and Dalton Utilities, a municipally-owned utility. A 1975 Georgia statute authorized the creation of MEAG Power, and in 1976 the agency began purchasing transmission assets and ownership interests in generating facilities from Georgia Power to serve the needs of its 49 municipal utility members.

Georgia Power has separate, two-party agreements with each of the other three joint owners, and also has supplemental agreements regarding operations and maintenance of the transmission system. Each utility owns individual transmission assets, but may use all transmission facilities in the system, regardless of ownership, to serve its customers.

Georgia Power operates the transmission network, and each utility is responsible for the operation and maintenance costs of the lines it owns. Through a joint planning process each owner maintains an investment in transmission that is in parity with the investments of the other joint owners. The parity formula is generally determined each year based on each system's five-year rolling average peak demand. MEAG Power currently owns more transmission than its parity amount, and so receives parity payments from Georgia Power.

Minnesota

In the 1980s utilities in Minnesota signed a series of agreements for sharing of transmission systems ("STS agreements") that generally provide for investment in transmission assets in proportion to each utility's load and use of the shared system. By the end of 1983, Southern Minnesota Municipal Power Agency ("SMMPA"), for example, had signed STS agreements with two investor-owned utilities (Interstate Power and Northern States Power) and with two cooperative utilities (Dairyland Power Cooperative and United Power Association).

SMMPA's transmission assets are generally operated and maintained by the agency's partners in the STS agreements. The agreements with the investor-owned utilities ("IOUs") were terminated and converted to network transmission service as part of the two IOUs' merger activities. However, the IOUs continue to operate SMMPA's transmission in their service areas, and SMMPA receives a credit reflecting its investment in each system. SMMPA's joint ownership arrangements with the cooperative systems remain in effect.

Upper Midwest Region (Missouri River Energy Services)

Otter Tail Power ("OTP"), an investor-owned utility that serves customers in Minnesota, North Dakota and South Dakota, has separate transmission system agreements with Great River Energy ("GRE"), a cooperative in Minnesota, and with Missouri River Energy Services ("MRES"), a joint action agency serving public power utilities in Iowa, Minnesota, North Dakota and South Dakota.

The OTP/MRES integrated transmission system began in 1986 when MRES, then known as Missouri Basin Municipal Power Agency, purchased (via its financing agent, Western Minnesota Municipal Power Agency) eleven percent of OTP's transmission system. Otter Tail Power is responsible for the operation and maintenance of the transmission system, and the two utilities jointly plan for system expansions and upgrades.

Under the OTP/MRES agreement, each utility owns specific transmission assets, generally in proportion to its share of load in the system's service area, and each utility has use rights on the system. The OTP/GRE agreement works in a similar way. The two integrated systems partially overlap one another, and the effect of the two agreements is that each of the three utilities has the right to use the overlapping portions of the integrated transmission systems as if they were its own.

Joint Ownership of Individual Lines in the Western Region

There is a long tradition of collaborative regional planning and joint ownership of major transmission lines in the West, and this has included the participation of public power utilities. Many transmission projects are jointly funded by the utilities that will benefit from the project.

Projects built as a single undertaking typically include a percentage allocation of the ownership rights and responsibilities, including the resulting incremental transfer capability, to each participating utility based on capital input. Upgrades to project facilities are treated in the same way. The Green Path is an example of joint planning of a project with each utility responsible for separate sections of the project.

The Southwest Model

Joint ownership of generation and transmission projects has played a vital role in the ability of many Southwest utilities to serve rapidly growing customer loads for over 50 years. The result is a highly integrated transmission system that has fostered cooperation and economic coordination among owners. Jointly owned transmission facilities are viable solutions for multiple utilities to deliver power to their native load customers.

The Southwest model of joint ownership generally adheres to the following principles:

1) Transmission lines are owned by the participants as "tenants in common" with each participant owning a pro rata share of the land and common facilities;
2) All costs and liabilities are shared by the participants in proportion to their ownership percentage;
3) One of the owners typically acts as operating agent and takes direction from other owners;
4) Various administrative committees ensure all owners are appropriately involved in the oversight and administration of the project;
5) Pre-established voting processes are used for approval of budgets, major expenditures and significant operational matters;
6) Modifications to the joint ownership agreement must be approved by all owners;
7) Owners indemnify each other and the operating agent;
8) Owners have reasonable rights to approve assignment of another owner's share to a third party.

Two examples of joint ownership in the Southwest are the 500-kilovolt ("kV") transmission lines from the Palo Verde ("PV") and Navajo generating stations in Arizona. The lines from PV into Phoenix were constructed as a part of the PV project and are owned by Arizona Public Service Co. ("APS"), Salt River Project ("SRP"), Public Service Co. of New Mexico, and El Paso Electric Co. The plant itself and the switchyard are owned by these four utilities and the Los Angeles Department of Water & Power ("LADWP"), Southern California Public Power Authority, and Southern California Edison Co.

The Navajo South transmission lines that run from the Navajo plant to the Moenkopi switching station are owned by the six owners of the plant: SRP, APS, LADWP, the U.S. Bureau of Reclamation ("USBR"), Tucson Electric Power Co., and Nevada Power Co. Three of these utilities, Nevada Power, USBR and LADWP, built the Navajo West system that runs west from the plant.

The Transmission Agency of Northern California

The Transmission Agency of Northern California ("TANC") provides another example of public power's involvement in joint ownership of transmission lines. TANC was established in 1984 as a joint powers agency to plan, design and construct the California-Oregon Transmission Project ("COTP"), a 340-mile, 500-kV transmission line between southern Oregon and central California. As the largest percentage owner in the COTP facilities, TANC acts as the project manager working in partnership with the Western Area Power Administration ("Western"). A key feature of the COTP is the conversion of a pre-existing double circuit 230-kV line owned by Western to 500-kV for about half the length of the project. As initially proposed, the investor owned utilities—Pacific Gas & Electric Co. ("PG&E"), Southern California Edison Co., and San Diego Gas & Electric Co.—would have been significant participants in the COTP. However, these utilities could not get approval to participate from the California Public Utility Commission. Subsequently, PG&E has picked up about a 10 percent entitlement in the COTP by virtue of exchanges and acquisition. Each COTP owner has the right to schedule its percentage share of the project transfer capability to serve its individual utility's needs.

TANC's primary purpose as a joint powers agency under the laws of California is to provide electric transmission or other facilities for its public power members' use. Its 15 members include the California cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara and Ukiah, as well as the Sacramento Municipal Utility District, the Modesto Irrigation District, the Turlock Irrigation District and the Plumas-Sierra Rural Electric Cooperative. With the introduction of the California ISO transmission model in California in 1998, the COTP owners have demonstrated that both firm physical transmission rights and network transmission service can coexist on a single project.

The Green Path

In the fourth quarter of 2005, a joint venture of two public power utilities, LADWP and the Imperial Irrigation District ("IID"), and a non-profit corporation, Citizens Energy Corporation, announced an agreement to undertake the Green Path project. Its purpose is to increase access to over 2,000 megawatts of geothermal and renewable resources in the Imperial Valley, and to eliminate existing transmission constraints in the southern region of California.

The Green Path project represents a coordinated set of system additions and upgrades. Highlights will include a new 500-kV line through the southern portion of IID's service territory, and a 200-mile upgrade to 230-kV of existing transmission facilities owned by IID. In addition, LADWP will build a new 500-kV line connecting the LADWP and IID control areas and providing several new interconnections with the California ISO. The project will also provide benefits to the previously announced Palo Verde to Devers II
500-kV transmission line proposed jointly by LADWP and Southern California Edison. The business arrangement with Citizens Energy, a non-profit energy services company, will provide energy assistance to low-income IID and LADWP customers.

(Additional information on the Green Path is available on the LADWP Web site: http://www.ladwp.com/ladwp/cms/ladwp007434.jsp.)

The Role of Regional Planning

The Western Interconnection has a long history of broad participation in regional and sub-regional planning processes. This inclusive approach results in a number of projects addressing the needs of multiple participants, including public power utilities. Because of the success of the planning groups and participation models, projects move from planning to construction into service on a reasonable timetable.

Southwest Area Transmission and Central Arizona Transmission System Groups

The Southwest Area Transmission ("SWAT") group was established to promote regional planning in the southwest. SWAT now has four regional planning groups, each established to address specific issues. SWAT is an outgrowth of the Central Arizona Transmission System ("CATS") Study Group, which first met in 2000 with the goal of developing a regional plan to meet the needs resulting from strong growth in demand in the Phoenix and Tucson areas. Eighteen utilities, including investor-owned, cooperative and public power systems, along with the Arizona Corporation Commission ("ACC"), participated in the CATS study.

One result of the CATS study was the siting of new 500 and 230-kV lines, totalling approximately 160 miles, to serve Pinal and Maricopa counties. The project began as one but was divided into two projects, Palo Verde to Pinal West ("PV-PW") and Pinal West to Southeast Valley/Browning ("PW-SEV/BRG"). The PV-PW project participants are Salt River Project, Tucson Electric Power, and various Electrical Districts in Pinal County. Although the exact ownership make-up of the PW-SEV/BRG project is not yet determined, it will likely include most of the same entities. Both projects are managed by SRP and have received Certificates of Environmental Compatibility from the ACC.

Rocky Mountain Area Transmission Study

In 2003, the governors of Utah and Wyoming formed the Rocky Mountain Area Transmission Study ("RMATS") to identify potential generation projects and the transmission improvements needed to support these projects. A specific purpose of the RMATS plan is to provide transmission from resource-rich coal and wind states to load centers in population-dense states. The RMATS area includes the states of Colorado, Idaho, Montana, Utah and Wyoming.

In September 2004 the group recommended that two new 500-kV lines be built to export power out of the RMATS area. The report also recommended three transmission projects within RMATS and identified five possible paths for the power-export lines. In April 2005, the governors of California, Nevada, Utah and Wyoming signed a Memorandum of Understanding to pursue development of the Frontier Line Project, a 1,300-mile high-capacity transmission line from Wyoming to California.

The Wyoming Infrastructure Authority ("WIA"), a state agency created in 2004 to improve the state's transmission capabilities, is representing Wyoming in developing plans for the Frontier Line. WIA has the authority to plan, finance, develop, acquire and operate transmission lines, and has been involved in the development of other projects recommended by RMATS. WIA is working with Trans-Elect, Inc. on developing the TOT 3 project (a 345-kV line from the Power River Basin in Wyoming to northeast of Denver), and has provided funding to Basin Electric Power Cooperative for a 30-mile, 230-kV line from the Hughes substation. WIA has also signed a Memorandum of Understanding with National Grid to conduct a study building on the RMATS recommendations, and to work together on the development of transmission projects identified in the study.

WIA's current model is to provide loans rather than to acquire ownership shares of these projects. However, the active participation of a state agency illustrates the potential for different forms of joint projects and cooperative action.

7. American Transmission Company LLC, Received Mon 3/6/2006 4:48 PM

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

Considerations for Transmission	**)**
Congestion Study and Designation of	**)**
National Interest Electric Transmission	**)**
Corridors	**)**

COMMENTS OF AMERICAN TRANSMISSION COMPANY LLC

Pursuant to the Notice of Inquiry issued by the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE),[1] American Transmission Company LLC, by its corporate manager, ATC Management Inc. (collectively, ATCLLC) hereby files its comments concerning DOE's plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETCs").

Executive Summary

ATCLLC has significant experience with the issues that arise in all stages of completing transmission improvements – from the planning stage, to gaining regulatory approval to actually constructing facilities. ATCLLC has found that local issues dominate the approval process for transmission improvements even where the benefits of the improvements may have broader regional impacts. Accordingly, proposed transmission upgrades that are viable are those that

[1] *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors*, Notice of Inquiry, Office of Electricity Delivery and Energy Reliability, Department of Energy, 71 Fed. Reg. 5660 (Feb. 2, 2006).

provide benefits to impacted communities, have state regulatory support, and are reasonably assured of cost recovery. These are the ingredients of successful transmission improvement efforts. It is from this perspective that ATCLLC offers comments on the DOE's plans for an electricity transmission congestion study and its consideration of NIETC designations.

ATCLLC provides the following recommendations for DOE's consideration in developing processes for identifying congestion and designating NIETCs:

- Congestion is unavoidable, but not all congestion is of national importance. All congestion cannot, nor should, be eliminated. Reliability problems must be addressed. Over time, economic concerns will likely develop into reliability problems.

- Alleviating congestion is a planned and desired by-product of transmission construction. Furthermore, transmission solutions offer benefits in addition to alleviating current congestion, such as enabling new generation to interconnect, enabling future load growth needs to be met, and providing enhanced system stability over the long term.

- Close coordination among federal agencies, states, RTOs/ISOs, transmission owners, and reliability organizations is essential. DOE, however, should give deference to state agencies in addressing specific transmission expansion needs through their established processes. ATCLLC observes that there has been significant increase in coordination among the states.[2] Federal back-stop authority should only be necessary in limited circumstances where states are not adequately addressing siting issues and not collaborating with their neighbors. From our perspective, the best backstop process will be one that is never used.

- DOE should rely heavily on information and studies already available from RTOs/ISOs, transmission owners, states, reliability organizations, and federal agencies in developing its congestion study. Utilizing available information will not

[2] For instance, the National Governors Association's national energy and electricity policy position, which was renewed in 2005, "(encourages) multi-state cooperation in identifying the economics of, and need for, additional energy transmission and generation projects, including improved communication among the appropriate state and federal regulatory agencies, affected utility companies, and other affected parties." The policy statement can be found at: *http://www.nga.org/portal/site/nga/menuitem.8358ec82f5b198d18a278110501010a0/?vgnextoid=2a2b9e2f1b091010VgnVCM1000001a01010aRCRD&vgnextchannel=4b18f074f0d9ff00VgnVCM1000001a01010aRCRD*. Furthermore, the Midwestern Governors Association's regional electric transmission protocol calls for "closer cooperation among the Midwestern states and Manitoba on permitting and siting of transmission projects that cross state and national boundaries." The MGA's transmission protocol can be found at: *http://www.midwestgovernors.org/issues/Protocol.pdf*.

only give DOE a head start on identifying congestion corridors, but is cost efficient and leverages regional knowledge from across the country.

- NIETC designation should be based upon localized electrical paths rather then broad geographic regions. Overly broad designations will provide no new information and may increase the potential for duplication of state processes. However, DOE's focus should not be so narrow as to dictate a particular route selection, as this is best left to state and local officials, who are familiar with the impacted communities (*i.e.* land use restrictions, environmental concerns, and potential new development).

ATCLLC appreciates the opportunity to file these comments and would be pleased to provide additional information or answer any questions that may assist DOE in its consideration of these issues.

Description of ATCLLC

ATCLLC is a stand-alone transmission company that is a member of the Midwest Independent Transmission System Operator, Inc. (MISO).[3] ATCLLC provides day-to-day operation and system control of its transmission system, including the necessary maintenance, repair, and replacement of elements of its transmission system, as well as the planning, design, engineering, siting, certification, and construction of new facilities.

Since ATCLLC began operating in 2001, it has invested approximately $1 billion in the necessary strengthening of its system, essentially tripling the company's investment in transmission infrastructure over a five-year period. Over the next ten years, ATCLLC plans to invest approximately $3.4 billion in new transmission improvements to address load growth, accommodate new generation, improve transmission access by better connecting ATCLLC's system to adjacent regions, and repair or replace aging facilities.[4]

[3] Effective on February 1, 2002, ATCLLC transferred operational control of its transmission system to MISO. Transmission service is provided to various entities over ATCLLC's transmission system under the terms of the MISO's Energy and Markets Tariff.

[4] More information about ATCLLC's construction plans is available at *http://www.atc10yearplan.com/*.

Comments

1. Congestion That Creates Reliability Problems Must Be Addressed.

Congestion, *i.e.*, the presence of constraints or bottlenecks on the transmission system that impede the free flow of electricity, is not, in itself, an indicator of a situation worthy of national designation. Not all congestion can or should be eliminated. Congestion that creates reliability problems must be addressed. In addition, economic concerns cannot be ignored entirely as, over time, they will likely develop into reliability problems.

In characterizing transmission upgrades, it is helpful to view projects on a continuum, with the large majority of projects having both reliability and economic attributes. Some projects have greater reliability benefits, while others are more aimed at addressing economic concerns. Over time the driver for a project often becomes more reliability related. To the extent DOE is seeking to identify congestion problems worthy of national attention, it should focus on corridors that address reliability needs with the understanding that this <u>**will also provide**</u> economic benefits. It is ATCLLC's experience that projects designed to meet multiple needs are the most efficient and are the ones likely to be approved.

Reasonable lead-time must be factored in when evaluating the reliability attributes of a project. A large transmission project takes years to be place in service. As DOE seeks to identify economic congestion, it is important not to wait until capacity in the transmission system is reduced to a point where it becomes critical from a reliability point of view. Aside from the reliability risks associated with running the transmission system too close to the margins, "just-in-time" transmission facilities generally are more costly to build than those planned in advance.[5]

Alleviating congestion is a planned and desired byproduct of transmission construction. There are a variety of options available to alleviate congestion; some are less expensive and more rapidly implemented than transmission solutions. However, transmission improvements offer many other system benefits that cannot be obtained via other options (such as locating new generators close to load, installing distributed generation or utilizing demand response initiatives). For example, transmission enables new generation to interconnect, facilitates meeting the needs of future load growth and provides enhanced system stability over the long term.

2. DOE Coordination With State Agencies, RTO/ISOs, Reliability Organizations and Transmission Owners Will Be Crucial When Developing Congestion Study and Designating NIETCs.

Section 216 of the 2005 Energy Policy Act requires DOE to conduct a study of electric transmission congestion within one year after the date of enactment in "consultation with affected states and any appropriate regional entity."[6] Based on the results of the congestion study, DOE may designate geographic areas experiencing transmission capacity constraints as NIETCs. In accordance with these provisions, DOE has drafted eight preliminary criteria (and corresponding metrics) that it intends to apply to geographic areas identified in its congestion study to evaluate the suitability of such geographic areas for NIETC status. In completing both the congestion study and evaluation of NIETC designations, DOE should maintain a high level

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[5] "Just in time" transmission are those facilities that must be placed in service by a specific date, such as to connect a generator or to fulfill a transmission service request. Without the project, such requests would be delayed or denied. The cost of equipment, labor, and land is generally more expensive for just-in-time facilities than projects that are planned more in advance. Further, there is the economic risk associated with missing the in service date.

[6] Energy Policy Act of 2005, Pub. L. 109-58 (Aug. 8, 2005).

of coordination with state agencies, RTOs and ISOs, and the North American Electric Reliability Council (NERC) and the new Electric Reliability Organization (ERO) that is approved by the Federal Energy Regulatory Commission.[7]

Coordination should begin with identification of congestion problems. Many states, RTOs/ISOs, NERC and transmission owners have conducted comprehensive studies of congestion on various regional and local levels.[8] Such information should be readily available to DOE. Utilizing available information will not only give DOE a head start on identifying congestion corridors, but it is cost efficient and leverages regional knowledge from across the country. Federal/state/RTO/reliability organization cooperation should also extend to setting metrics for the criteria that will be used to designate corridors, particularly for those corridors seeking designation as "urgent" during the NOI comment process.

In addition, because the new ERO will have primary responsibility for system reliability, DOE must work with this organization in establishing metrics for corridor selection and designation of NIETCs, especially with respect to Draft Criteria 1, 3, and 6 proposed in the NOI.

Once the congestion study and NIETC designations are complete, DOE should, when possible, give deference to state agencies in addressing specific transmission expansion needs through their established processes. Federal backstop authority should only be necessary where states are not adequately addressing siting issues or not collaborating with each other in the process. Large transmission project can take from 7 to 10 years to receive regulatory approval

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[7] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for Establishment, Approval, and Enforcement of Electric Reliability Standards* 114 FERC ¶ 61,104 (2006).

[8] For instance, Appendix A of the NOI refers to such documents as the MISO Transmission Expansion Plan 2005 (MTEP) and the Michigan Public Service Commission Final Staff Report of the Capacity Need Forum. Wisconsin also conducts a state Strategic Energy Assessment and ATCLLC conducts its 10-Year assessment plan, which is submitted to MISO and incorporated in the MTEP.

and ultimately be constructed and placed into service.[9] Adding another layer of approvals has the danger of extending this already lengthy process.

Ideally, states will act promptly to review and approve needed facilities on a timely basis and thereby never give rise to the need for a federal backstop process. Although this NOI does not directly address the implementation of federal backstop siting authority, DOE's congestion study and ultimate designation criteria for NIETCs will set the tone and lay the foundation for that process. The success of DOE's efforts will depend on its ability to work cooperatively with the states in developing criteria and designations and then avoid duplicating approval processes later on.

3. NIETC Designations Should Be Based on Electricity Paths, as Opposed to Specific Routes or Large Geographic Areas.

NIETCs should be designated based on electrical conditions in specific local areas rather than broad geographic regions. Overly broad geographical designations appear to run counter to the objective of identifying specific corridors and are likely to provide minimal guidance to those seeking to prioritize development opportunities. Overly broad designations also likely increase the potential for duplication of state processes. Thus, DOE should designate sparingly at first and broaden as necessary as more experience is gained with the process and as system conditions change.

In localizing the solution to a congestion problem, however, DOE's focus should be to identify congestion and designate electric transmission corridors of national interest, not to dictate a particular transmission route selection. Route selection is best addressed at the state and local level. Thus, DOE should identify electrical paths that are congested, especially those that

[9] ATCLLC has been striving to shorten this timeline and has experienced significant improvements. For instance, ATCLLC collaborates with local stakeholders and conducts extensive local education and outreach prior to filing for necessary approvals by state regulators.

present existing and future system reliability vulnerabilities, and leave discretion for specific routes to state and local officials, who are familiar with the impacted communities (*i.e.*, land use restrictions, environmental concerns, and potential new development).

Conclusion

DOE should ensure reliability issues are addressed in conducting its congestion study and NIETC designation. Coordination with state agencies, RTO/ISOs, NERC and the new ERO, and transmission owners is essential for DOE when developing its congestion study and NIETC designations to avoid duplication of effort and delay. Finally, NIETC designations should be based on electricity paths and specific routes for transmission facilities should be left to state siting processes.

Respectfully submitted,

/s/ Nina Plaushin

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March 6, 2006

8. American Wind Energy Association, Received Mon 3/6/2006 12:15 PM

American Wind Energy Association
1101 14th St., NW, 12th floor
Washington, D.C., 20005

March 6, 2006

Office of Electricity Delivery and Energy Reliability, OE–20,
Attention: EPAct 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H–050
1000 Independence Avenue, SW.
Washington, DC 20585

Re: Comments of the American Wind Energy Association, Wind on the Wires, Interwest Energy Alliance, The Wind Coalition, the Center for Energy Efficiency and Renewable Technologies, and The Renewable Northwest Project on the Department of Energy's "Considerations for transmission congestion study and designation of National Interest Electric Transmission Corridors"

The American Wind Energy Association (AWEA), Wind on the Wires (WOW), Interwest Energy Alliance, The Wind Coalition, the Center for Energy Efficiency and Renewable Technologies, and The Renewable Northwest Project appreciate this opportunity to respond to the Department of Energy's Notice of Inquiry[1] concerning its plans for a congestion study and possible designation of National Interest Electric Transmission Corridors (NIETCs). We believe that with high and volatile fuel prices, climate change and air quality concerns, water conservation needs, and threats to security from importing fuel, our Nation's vast resources of wind in the middle of the country can and should be tapped. As President Bush stated recently on his Advanced Energy Initiative tour, "areas with good wind resources have the potential to supply up to 20 percent of the electricity consumption of the United States." In this comment we address the proposed criteria for corridors in response to questions in the Department's inquiry, describe studies to add to the list of relevant studies in Appendix A of the notice, and identify specific corridors from the set of relevant studies that we believe will qualify as NIETCs.

I. WHO WE ARE

AWEA is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States. AWEA's 780 members include wind turbine manufacturers, component suppliers, project developers, project owners and operators, financiers, researchers, renewable energy supporters, utilities, marketers, customers and their advocates. Many of AWEA's members are interested in developing wind projects in wind-rich areas but are currently prohibited from doing so because of a lack of transmission.

Wind on the Wires works on solving the technical (transmission) and regulatory barriers to interconnecting and delivering new wind power to market in the Upper Midwest. WOW

[1] Department of Energy, Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Federal Register notice Vol. 71, No. 22, February 2, 2006, page 5660.

members include nationally prominent wind developers and wind turbine manufacturers, AWEA, non-profit sustainable energy advocacy organizations, and other stakeholders. WOW has been actively involved in transmission planning with utilities and the Midwest Independent System Operator since 2001. WOW members have a substantial interest in the resolution and advancement of the issues in DOE's Notice of Inquiry.

The Renewable Northwest Project is a non-profit renewable energy advocacy organization whose members include environmental and consumer groups, and energy companies. RNP works in Oregon, Washington, Idaho and Montana to increase the development of clean renewable energy resources.

West Wind Wires is a wind industry advocacy program under the auspices of Western Resource Advocates that represents wind in transmission planning and operational forums throughout the Western Electricity Coordinating Council region.

The Wind Coalition is a non-profit corporation advocating for the expansion of wind energy use in Texas and the Southwest Power Pool. The Wind Coalition's members are: AES; Babcock & Brown, LP; Gamesa Energia Southwest; GE Energy, LLC; Horizon Wind Energy; PPM Energy; Renewable Energy Systems (USA); Siemens; Superior Renewable Energy; Trinity Structural Towers, Inc.; Vestas-Americas, Inc.; Environmental Defense; Public Citizen; Texas Renewable Energy Industries Association; and AWEA.

The Interwest Energy Alliance is a trade association that brings the nation's wind energy industry together with the West's advocacy community. The Alliance's members support state-level public policies that harness the West's abundant renewable energy and energy efficiency resources in Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.

The Center for Energy Efficiency and Renewable Technologies is a not for profit public-benefit organization founded in 1990 in Sacramento. CEERT's board and host of affiliates is comprised of concerned scientists, environmentalists, public interest advocates and individuals involved in developing innovative energy technologies that share a vision to benefit the environment with sustainable solutions to California's growing appetite for energy.

II. A "CORRIDOR" SHOULD BE BROADLY DEFINED

The first question raised in the notice is essentially "what is a corridor?" AWEA agrees with the Department that corridors should be identified as "generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities."[2] We believe this generalized approach is consistent with standard transmission planning practice and with the intent of the law. The approach avoids the obviously unworkable approach of finding that a specific route is of national interest while other routes connecting two areas are not. Congress and the Administration presumably chose the term "corridor" over other terms like "route" for a reason and we believe it was with this consideration in mind.

[2] DOE Federal Register notice, page 5661.

Specifically we believe that a corridor should be defined as follows: "a corridor connects two geographic areas, defined as utility service territories, control areas, resource production areas, or points on the electric transmission system which are separated by transmission limitations."

III. CRITERIA FOR CORRIDOR IDENTIFICATION

AWEA generally supports the proposed criteria but respectfully submits that they do not sufficiently address the criteria required by EPAct §1221. We suggest specific modifications below. We do not advocate wind-specific provisions but rather generally applicable provisions that we believe are required by the law.

Draft Criterion 1: Action is needed to maintain high reliability.

AWEA supports this criterion and notes that there are reliability benefits of accessing wind generators. The smaller unit sizes of individual wind turbines make them more reliable than a single large generator. Many types of failures can and do take large generators off line. Aggregations of wind machines do not suffer from a similar vulnerability. Reliability is composed of security and adequacy. Transmission corridors that access generation fueled by domestic resources, especially domestic renewable resources, should be recognized as improving both security and adequacy and enhancing the reliability of the overall power system. We suggest adding the following provision: "an area that would lead to supply from greater numbers of geographically dispersed small generating units that are less vulnerable to large sudden outages due to plant failure, natural disasters or malicious acts than large generating stations."

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

AWEA supports this criterion as far as it goes. However it does not address the statement in EPAct § (B)(i) that "economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy." Economic growth can be enhanced by the rural economic development associated with wind farms in the many regions of the country. We suggest the following clarification: "an area that promotes rural economic development through generation development in rural areas such as on farms and ranches." This provision of the act should be included in Criterion 2 or as an additional criterion.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

We suggest that this criterion be clarified to specifically state that supply diversification both at the local level (power used to serve load in a particular area) and national level are covered by the criterion. In other words, a corridor to an area that would increase national consumption of wind even if the particular state or region already has significant wind usage, would qualify given the low percentage of wind currently in the national electricity portfolio. We note that the criterion as written does not address the criterion in EPAct (B)(ii), "a diversification of supply is warranted." Supply diversification should be clarified in this criterion or added as another criterion.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

AWEA supports this provision and finds it to be consistent with EPAct criterion (C), "the energy independence of the United States would be served by the designation." We agree with the specific metrics of fuel diversity, improved domestic fuel independence, and reduced dependence on energy imports.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

We support this criterion and find it to be consistent with EPAct criterion (D) "the designation would be in the interest of national energy policy." However we note that the notice provides no clarifying language or metrics for this criterion unlike all of the other criteria. The Department should not and cannot shy away from implementing this provision of the law.

Metrics for this criterion should be based on the Advanced Energy Initiative in the President's State of the Union speech,[3] the Western Governors Association's (WGA) unanimous clean energy resolution,[4] the Midwestern Governors' Association (MGA) Regional Electric Transmission Protocol[5], and any other recent multi-state or national law or policy statement on energy policy. Together the State of the Union speech and the governors' associations resolutions provide clear criteria that are consistent with initiatives in states across the country and with initiatives in Congress.

The President's Advanced Energy Initiative includes the following: "replacing more than 75 percent of our oil imports from the Middle East by 2025," reducing demand for natural gas, diversifying energy sources, developing "cleaner," "cheaper," and "more reliable alternative energy sources."[6]

The WGA resolution states "To ensure that newer, clean energy sources play an important role in meeting this goal [of a clean, secure energy future], this resolution is specifically concerned with identifying ways to increase the contribution of renewable energy, energy efficiency, and clean energy technologies within the context of the overall energy needs of the West." It further states "the Western Governors will examine the feasibility of and actions that would be needed to achieve a goal to develop 30,000 MW of clean energy in the West by 2015 from resources such as energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies." The resolution identifies wind in particular: "Western Governors also believe there is long term wind energy potential in the western plains and mountain states but that a more aggressive effort to develop this energy resource is needed. Western Governors believe that a comprehensive study of the development and transmission of the West's wind energy resources is necessary. This study should build on the numerous subregional plans

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[3] http://www.whitehouse.gov/news/releases/2006/01/20060131-6.html
[4] http://www.westgov.org/wga/policy/04/clean-energy.pdf
[5] http://www.midwestgovernors.org/issues/Protocol.pdf
[6] http://www.whitehouse.gov/news/releases/2006/01/20060131-6.html

underway, such as the Rocky Mountain Area Transmission Study, but should emphasize policies that can facilitate wind development throughout the region."[7]

The Midwestern Governors' Association Regional Electric Transmission Protocol recognizes that additional investment in transmission is needed. The Protocol also states that the Midwest could become a substantial provider of wind-generated electricity, but the power needs to be moved to where it is needed. The Protocol also acknowledges that the benefits of additional infrastructure include more reliability, access to low-cost generation, diversity of supply, and economic development opportunities.

To derive metrics from the policy statements of the President, the MGA and the WGA, AWEA proposes that the following features from each be used. From the President's initiative metrics should include increasing supplies of clean, low cost, reliable, and domestic energy that diversifies the nation's energy portfolio. The WGA initiative includes these same metrics plus the development of "energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies." The MGA statement includes "low cost," "more diverse supplies leading to lower cost," "environmental benefits from improved access to renewable generation," "economic and job growth," and an "expanded tax base." Together, AWEA suggests that DOE adopt the following metrics for Criterion 5: "an area that allows for the development of clean, low cost, reliable, and domestic energy that diversifies the nation's energy portfolio including a demonstration that a corridor will increase the use of some or all of the following: energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies."

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

AWEA suggests the following metric for this criterion as well as Criterion 1: "an area that would lead to supply from greater numbers of geographically dispersed small generating facilities that are less vulnerable to large sudden outages due to plant failure natural disasters or malicious acts than large generating stations."

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

AWEA notes that this criterion is not identified in EPAct. The demonstration of whether corridors meet the other criteria should consider the issue identified here so this proposed criterion is at best redundant. Moreover, the undefined term "unduly contingent" provides little or no real guidance in selecting corridors.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

[7] http://www.westgov.org/wga/policy/04/clean-energy.pdf

AWEA supports this criterion but emphasizes that the *option* of transmission should be preserved through corridor status while other options are considered. Therefore we suggest a criterion that more closely tracks the language of EPAct.§ 1221: "Any reasonable alternatives presented by interested parties have been addressed sufficiently to warrant preserving the transmission option, recognizing that alternatives to transmission facilities must be considered for approval of any specific project."

IV. CONGESTION MODELING MUST ADDRESS NEW RESOURCES

The notice indicates that the initial electric transmission congestion study required by Federal Power Act subsection 216(a)(1) will be based on existing studies and congestion modeling of the Eastern and Western Interconnections. AWEA believes the study required by law must include the lack of transmission between supply resources like wind and electric load. Typical power system load flow and economic dispatch models take existing generators and load as given and therefore do not address this issue unless it is explicitly added. The Department's modeling should include not only existing generators but new supply sources like pockets of wind.

V. RELEVANT TRANSMISSION PLANNING STUDIES

The Department's notice indicates that it will publish its congestion study by August 8, 2006 and at that time it will invite interested parties to provide comments and recommendations concerning its needs assessments and potential corridors to address identified needs. Appendix A to the notice includes the list of transmission plans and studies the Department currently has under review for its congestion study. AWEA respectfully proposes the following five additional studies for use in the Department's congestion study.

These five additional studies are:

- Southwest Power Pool's (SPP) *Kansas/Panhandle Sub-Regional Transmission Study,* http://sppoasis.spp.org/documents/swpp/transmission/studies.cfm, January 26, 2006;
- *Report of the BPA Infrastructure Technical Review Committee* 2001 – 2004, http://www.transmission.bpa.gov/planproj/ITRC.cfm?page=ITRC;
- *Report of the Tehachapi Collaborative Study Group*, March 16, 2005, www.cpuc.ca.gov/Published/Graphics/48819.pdf;
- the *Report of the Imperial Valley Study Group*, September 30, 2005, www.energy.ca.gov/ivsg/; and
- Southwestern Area Transmission group planning for southeastern Colorado, http://www.azpower.org/swat/meetings/pdf/aug2005/maps.ppt.

The existing transmission studies, both those noticed by the Department and those studies suggested above, show Draft Criteria met with transmission expansions that serve large additions of wind. Below is a description of the studies that have specifically examined the potential to bring benefits to consumers through large amounts of wind development, or identified wind-rich regions and begun the planning for the development of the wind resource.

Southern Plains

The Southwest Power Pool *Kansas/Panhandle Sub-Regional Transmission Study,* also known as the "X-Plan" because of the shape of the new lines crossing from the Nebraska border through western Kansas and into Oklahoma and the Texas Panhandle, is an important study for the Department to include because it would diversify electricity supply by accessing an extraordinarily wind-rich region. This study was driven by requests from the developers of 2,500 MW of new wind generation currently seeking interconnection to transmission. SPP prepared this study during 2004 and revised it in 2005, showing $80 million of production cost savings annually in the Southwest Power Pool, and annual total fixed charges costs of $74 million.[8] The plan uses new 345 kV line segments: Spearville-Mooreland-Potter-Tolk-Tuco, Spearville-Knoll-Pauline, and connections from Mooreland to the Northwest substation and to Wichita. These segments would allow new wind generation from western Kansas, southwestern Nebraska, western Oklahoma and the Texas panhandle to supply Kansas, Missouri, Arkansas and eastern Oklahoma immediately, and, with added transmission, Louisiana and Mississippi.

Desert Southwest

Several studies of proposed new transmission in Arizona, southern Nevada and Southern California detail congestion reduction and renewable energy development opportunities associated with the proposed facilities. These include the *Report of the Imperial Valley Study Group (*for export of 2,200 MW of renewable resources from California's Imperial Valley); CAISO studies of the Palo Verde—Devers #2 project (to bring Southwestern resources to Southern California); the Report of the Phase III Study of the Central Arizona Transmission System; and the San Diego Gas & Electric Transmission Comparison Study (to provide a new 500 kV connection from the Southwest to San Diego County and Southern California). This collection of studies by regional utility companies, completed using WECC protocols, address reliability, congestion relief and new conventional and renewable generation supply for the region.

Central California

The *Report of the Tehachapi Collaborative Study Group* is a result of work directed under a California Public Utility Commission ("CPUC") order.[9] The report details a plan to connect 4,500 MW of wind generation in the Tehachapi region to the state 500 kV grid. The study was led by a stakeholder collaborative that included the CPUC, the California ISO, the California Energy Commission, Southern California Edison, Pacific Gas & Electric, wind developers, and the Center for Energy Efficiency and Renewable Technologies. The Tehachapi conceptual development plan allows wind generation potential in the Tehachapi region to meet state renewable resource goals. Lack of transmission capacity has prevented the development of renewable generation supply in this region to serve the state's well-known need for energy.

Pacific Northwest

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[8] Costs include underlying lower-voltage upgrades, and 15% cost of capital. Fuel cost assumed in 2005 study was $5/ MMBtu natural gas at the burner. *Addendum to the Kansas/Panhandle Sub-Regional Transmission Study* November 4, 2005. Higher natural gas prices would increase the plan's net benefits.

[9] CPUC Decision 04-06-010 identified 4,060 MW of wind resource in Tehachapi in proceedings related to the implementation of the Renewable Portfolio Standard required by California law.

The Pacific Northwest has several wind-rich areas. Transmission planning in the region has focused on moving power from east of the Cascades to the coast, and from Montana to the Northwest more generally. Transmission planning to move wind power to load centers on the coast has emphasized the shorter distance transmission from the Columbia Gorge region than from Montana. These transmission reports are not included in the Department notice. The 2001 *Report of the BPA Infrastructure Technical Review Committee*, written by representatives of investor-owned utilities and publicly-owned utilities, highlight regional transmission needs. Annual updates of this inventory of unsolved congestion can be found at the BPA website http://www.transmission.bpa.gov/planproj/ITRC.cfm?page=ITRC.

There are three congestion bottlenecks identified in these reports that are most relevant to move wind resources from east of the Cascades to the load centers of Western Oregon and Washington: 1) McNary-John Day; 2) Paul-Allston and Allston-Keeler path; and 3) the Cross-Cascades North and South paths.

The Department notice also includes the *Montana-Pacific Upgrade Study*. This recent study by the Northwest Power Pool examined the addition of 750 MW of generation in eastern Montana, or the alternative of wind development closer to load, in western Montana near Great Falls, to serve the Puget Sound and Portland areas. The transmission options to incorporate significant new generation in Montana include one or more 500 kV circuits.

Intermountain West

In September 2003, Wyoming Governor Dave Freudenthal and Utah Governor Michael Leavitt created the Rocky Mountain Area Transmission Study (RMATS) as a multi-state effort to reduce congestion and increase transmission. This work recommended two priority transmission upgrade projects in the region: the Bridger Expansion Project, and the Tot 3 Upgrade Project. RMATS also explored transmission export options. The Bridger Expansion Project adds transmission from the Jim Bridger switchyard/coal plant in southwest Wyoming East to the wind resources in central Wyoming; southwest to Salt Lake City; and West to southern Idaho. Initially, these additions would support 1,375 MW of new wind generation in southwest/south central Wyoming. Larger additions for export to Nevada and the West Coast are also described. The Tot 3 Upgrade Project would add new 345 kV facilities to export supply resources from eastern Wyoming to the Colorado Front Range load center, including export of 1,200 MW of wind generation from excellent wind resources in eastern Wyoming to Denver. The RMATS study also outlined alternatives for exporting as much as 10,000 MW of Rocky Mountain generating resources to the Pacific Northwest, Nevada and California.

Significant additional wind development in southeastern Colorado for Denver and for export via the Bridger Expansion Project will rely on transmission from the southeastern part of the state. This added transmission has been discussed in the Southwest Area Transmission regional planning effort. The reports in this effort have not been noticed by the Department. See the maps for southeastern Colorado at the website:
http://www.azpower.org/swat/meetings/pdf/aug2005/maps.ppt.

Midwest

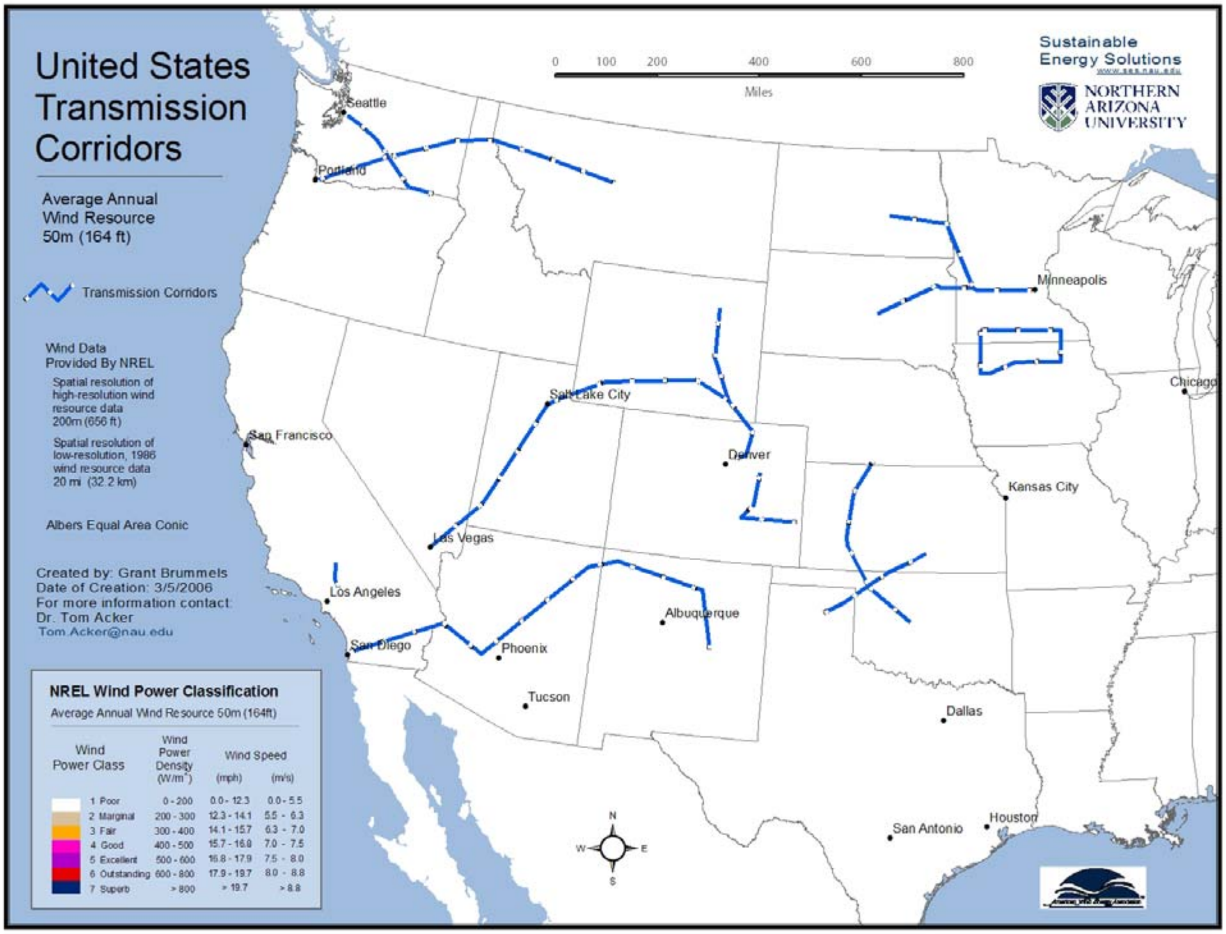
The Midwest ISO prepared a 2003 Transmission Expansion Plan (MTEP) and the MTEP 2005 with the knowledge that this ISO serves a region with over 700,000 MW of “proven reserves” of wind power in its nine state region.[10] MTEP 2003 and 2005 are listed in Appendix A of the Department’s notice. The economic analysis in the MTPEP 2003 study found transmission investments could reduce annual energy costs between $304 million and $1.6 billion when coupled with high amounts of wind, depending on natural gas price projections. 2003 MTEP includes an Exploratory Plan for Iowa and southern Minnesota for transmitting wind energy from this area (including the eastern edge of the Dakotas) to Minneapolis- St. Paul. When the study was performed, a gas price of $3.24-$3.85/mmBtu Natural Gas was the base case assumption, resulting in an annual benefit of $304 Million.[11] In MTEP 2005, the Exploratory Plans are refined, with 3,500 MW of wind generation for Iowa and Southern Minnesota, as well a Northwest Exploratory Plan for the Eastern Dakotas and Western Minnesota providing 1,500 MW of new wind generation.

VII. PROPOSED CORRIDORS

Using the information and analyses from the studies the Department has noticed and the additional studies suggested in these comments, we believe the Department will find that the corridors identified below satisfy the criteria for National Interest Electric Transmission Corridors. We are not requesting early designation per the opportunity provided in the Department’s notice; rather we provide these as preliminary suggestions on corridors that we believe should be considered in the Department’s study.

1. Northern New Mexico to San Diego as a group identified in the *Report of the Imperial Valley Study Group*, Documents on the Palo Verde—Devers #2 project, and the *Report of the Phase III Study of the Central Arizona Transmission System*;
2. Eastern Oregon/ Washington to Portland/Seattle as identified in the *Report of the BPA Infrastructure Technical Review Committee*;
3. Tehachapi to Vincent Substation, identified in *Report of the Tehachapi Collaborative Study Group*;
4. Southern Wyoming to Denver, as identified in RMATS Recommendation 1;
5. Southern Wyoming to Las Vegas, as identified in RMATS Recommendation 2;
6. Eastern Colorado to Denver, as identified in RMATS Recommendation 2;
7. Western Kansas and Oklahoma to Kansas City, identified in SPP’s *Kansas/Panhandle Sub-Regional Transmission Study*;
8. Eastern North Dakota to Minneapolis, identified in Midwest ISO’s *MTEP 03*; and
9. South Dakota to Minneapolis, identified in Midwest ISO’s *MTEP 03*.

[10] See *An Assessment of Windy Land Area and Wind Energy Potential, Pacific Northwest Laboratory*, 1991.
[11] Greater savings to consumers are shown for higher gas prices.


United States Transmission Corridors
Average Annual Wind Resource 50m (164 ft)
Transmission Corridors
Wind Data Provided By NREL
Spatial resolution of high-resolution wind resource data 200m (656 ft)
Spatial resolution of low-resolution, 1986 wind resource data 20 mi (32.2 km)
Albers Equal Area Conic
Created by: Grant Brummels
Date of Creation: 3/5/2006
For more information contact:
Dr. Tom Acker
Tom.Acker@nau.edu
NREL Wind Power Classification
Average Annual Wind Resource 50m (164ft)
Wind Power Class
Wind Power Density (W/m²)
Wind Speed (mph) (m/s)
1 Poor 0 - 200 0.0 - 12.3 0.0 - 5.5
2 Marginal 200 - 300 12.3 - 14.1 5.5 - 6.3
3 Fair 300 - 400 14.1 - 15.7 6.3 - 7.0
4 Good 400 - 500 15.7 - 16.8 7.0 - 7.5
5 Excellent 500 - 600 16.8 - 17.9 7.5 - 8.0
6 Outstanding 600 - 800 17.9 - 19.7 8.0 - 8.8
7 Superb > 800 > 19.7 > 8.8
0 100 200 400 600 800
Miles
Sustainable Energy Solutions
NORTHERN ARIZONA UNIVERSITY
Seattle
Portland
Minneapolis
Salt Lake City
Chicago
San Francisco
Denver
Kansas City
Las Vegas
Los Angeles
Albuquerque
San Diego
Phoenix
Tucson
Dallas
San Antonio
Houston
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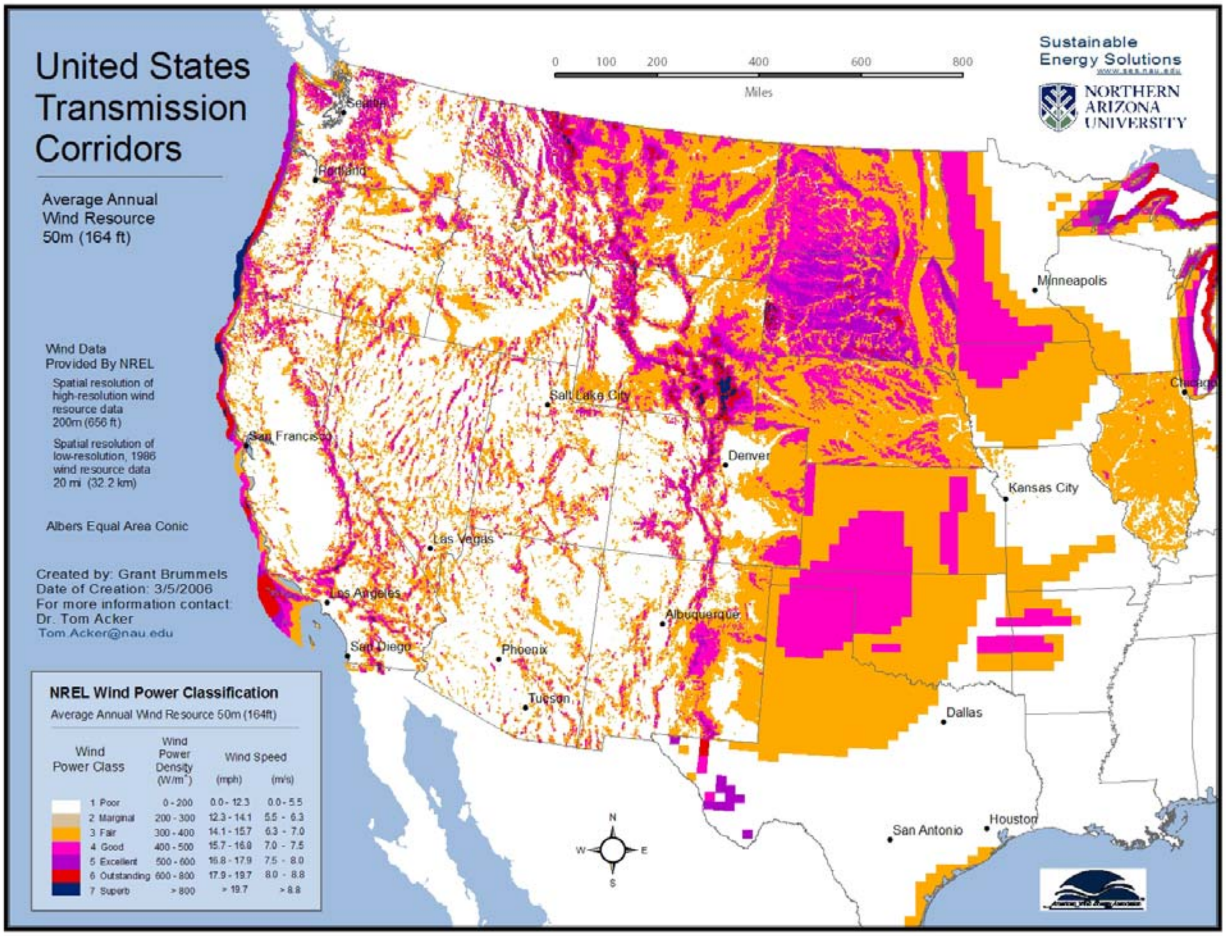

9. APS, A Subsidiary of Pinnacle West Capital Corporation, Received Mon 3/6/2006 2:12 PM

Name: Bob Smith
Title: Trans. Plng. Mngr.
Department: Trans. Plng.
Tel. 602-250-1144
Fax 602-250-1155
e-mail: robert.smith@aps.com
PO Box 53999
Mail Station 2259
Phoenix, Arizona 85072-3999

March 6, 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attn: EPACT 1221 Comments

U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, SW
Washington, D.C. 20585

Re: Notice of Inquiry regarding Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, FR Vol. 71, No. 22, page 5660 (February 2, 2006)

To Whom It May Concern:

Arizona Public Service Company ("APS") appreciates the opportunity to provide initial comments to the U.S. Department of Energy ("DOE") regarding Notice of Inquiry on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, FR Vol. 71, No. 22, page 5660 (February 2, 2006) ("NOI"). APS supports the comments submitted by the Edison Electric Institute ("EEI") and incorporates them here by reference.

Like EEI, APS generally supports the process undertaken by DOE to identify potential National Interest Electric Transmission Corridors ("NIETC"). APS applauds DOE's intent to take into account the work already underway or completed by regional planning groups in the West. APS believes that the use of studies and other information developed by those regional planning groups, combined with additional information developed through the current process, will allow the DOE to produce a report that clearly identifies the areas that meet the criteria for NIETC designation. APS also supports generally the criteria that DOE has identified for NIETC designation, as modified by EEI. APS encourages DOE to make its initial NIETC designations as soon as reasonably possible to further facilitate infrastructure development.

Annual system load growth throughout the Southwest is 3-5%, which is approximately three times the national average. APS, which is the largest electric utility in Arizona, serves one of the fastest growing areas in the country and that area covers federal, state and tribal lands. APS continually evaluates its need for new and upgraded transmission facilities, as well as for generation resources to serve its customers needs.

Based on APS's assessment of its future resource needs, including both transmission and generation, APS announced the TransWest Express Project in 2005. That project, which initially will be modeled as two 500kV AC transmission lines from Wyoming to the Southwest, seeks to provide access for APS and the Southwest to coal, wind and other resources in Wyoming. The initial routes under consideration for that project are consistent with and supported by both the Report to the Western Governors Association titled "Conceptual Plans for Electricity Transmission in the West" (August 2001) and the Rocky Mountain Area Transmission Study (RMATS) report. Both of those reports noted that electric transmission in the West is constrained and that those constraints result in the underutilization of the region's vast wind and coal resources, thereby demonstrating the need for additional transmission from the Wyoming area to the Southwest.

APS also believes that the TransWest Express Project meets several of the criteria identified by DOE in the NOI. APS currently is conducting a technical and economic feasibility analysis for the TransWest Express Project. APS also is examining the relevant environmental and regulatory considerations surrounding the project. APS contemplates that the feasibility analysis will be performed within the various regional and sub-regional transmission planning groups and reliability organizations in the West. In addition to studying the TransWest Express Project, the feasibility study will assess the benefits of integrating the project with other transmission projects already announced or planned. It is anticipated that along with other announced transmission projects, the TransWest Express Project will provide significant benefit and opportunity for remote resource access to Southern Nevada and Southern California as well as to Arizona. As the feasibility analysis proceeds, APS will provide additional information to DOE.

APS looks forward to participating in the process undertaken by DOE for implementing Section 1221(a) of the Energy Policy Act, including providing comments on the draft congestion study and potentially proposing specific transmission corridor(s) that APS believes are suitable for NIETC designation. In the meantime, if you have any questions, please feel free to contact me at 602-250-1144 or Robert.Smith@aps.com or Karilee Ramaley at 602-250-3626 or Karilee.Ramaley@pinnaclewest.com.

Sincerely,

By Robert D. Smith

Cc: Karilee S. Ramaley

10. Bay Area Municipal Transmission Group, Received Mon 3/6/2006 11:10 AM

BAMx comments, March 3, 2006

Comments of the Bay Area Municipal Transmission Group
on
Department of Energy's (DOE) Notice of Inquiry
on
Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

The Cities of Alameda (Alameda Power & Telecom), Palo Alto (City of Palo Alto Utilities), and Santa Clara (Silicon Valley Power) have joined together in an informal association called the Bay Area Municipal Transmission Group (BAMx). The primary objective of BAMx is to advocate for reliable electric supply to and within the Greater San Francisco Bay Area at reasonable cost. BAMx offers the following comments in response to DOE's Federal Register Notice (FRN) of February 2, 2006 on its Notice of Inquiry (NOI)[12] seeking comments and information from the public concerning its plans for an electricity transmission congestion study (Congestion Study) and possible designation of National Interest Electric Transmission Corridor (NIETC).

The NOI raises a number of questions related to the conduct of the Congestion Study required by the Energy Policy Act of 2005. DOE expects in the Congestion Study to present an inventory of geographic areas that have important needs related to the electric transmission infrastructure. DOE also expects to identify corridors or potential projects as "generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities," and invited comments on defining corridors. The NOI also invited comments on draft criteria for assessing the suitability of geographic areas as NIETCs and, further, invited comments on early designation of geographic areas for which there may be a particular acute need for such early designation.

Need for Early Designation of NIETC for Corridors Increasing Import Capability into the Greater Bay Area

BAMx wishes to alert DOE of the need for early designation of the San Francisco Greater Bay Area (GBA) corridors as NIETCs. Upon review of the inventory of studies listed in Appendix A of the NOI and upon review of the documents and approaches the Western Congestion Assessment Task Force (WCATF) is developing for the DOE Congestion Study, BAMx is concerned that the corridors for increasing imports to the GBA will be overlooked. The past and current transmission planning documents listed in both the NOI and the WCATF are focused on large, inter-regional and interstate transmission needs.[13] As such, we are concerned that the corridors for increasing the transmission import capability in urban areas and into load pockets such as the GBA will be overlooked and/or specifically excluded.[14] We believe there is an acute need to address the persistent congestion into the GBA. The BAMx members have submitted comments to DOE in its National Interest Electric Transmission Bottleneck (NIETB) proceedings in 2004 nominating the GBA as a NIETB believing that such designation would assist in relieving the current transmission congestion. These comments are attached here again. There are three major existing electric transmission corridors into the GBA formed by a cut-plane electrically creating what is known as the GBA load pocket: the Tesla/Tracy to Newark Corridor, the Metcalf Corridor, and the Vaca-Dixon to Contra Costa Corridor. The BAMx members respectfully recommend to DOE that these corridors be given early designations as NIETCs. Early designation for the GBA corridors are necessary and appropriate because of the

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[12] Federal Register, Volume 71, No. 22, Thursday, February 2, 2006, pages 5660 through 5664.

[13] For example the WCATF December 14, 2005 meeting notes discussed the templates of inventory of past transmission studies in the West with the focus on studies that were regional in nature including past reports of Seams Steering Group-Western Interconnection (SSG-WI) and from the various sub-regional planning groups. See WCATF_Meeting_Notes_14Dec05_rev1.pdf

[14] In discussions of the granularity of congestion – how far down into the system will we look for congestion, the DOE representative at the WCATF November 10, 2005 meeting stated that "although the focus (of the Congestion Study) will be primarily inter-state issues, the process will be open to intrastate facilities as they pertain to large load areas." See draft WCATF Meeting Notes November 2005

unlikelihood that the GBA would be identified in the Congestion Study being prepared by the WCATF for DOE with its primary focus on large inter-regional and interstate electric transmission congestion. To that extent, BAMx urges DOE to include in its categories of information in the Congestion Study geographic areas of interest such as large load pockets similar to the GBA. The BAMx members feel that many of the DOE geographic NIETC criteria suggested in the NOI, if applied to the GBA, would qualify these three GBA transmission corridors for NIETC designation.

Comments on Criteria Development

Draft Criterion 1: Action is needed to maintain high reliability. The BAMx members support the use of this criterion. The GBA has experienced greater risk of outages as noted in our attached comments in the NIETB proceeding. The GBA has a high reliance on inefficient and unreliable aged generating units and, due to population density, there exists a strong local resistance to additions of needed new generation. Although the GBA transmission system is planned and operated to meet WECC and NERC reliability criteria, there is a clear need to remedy existing and emerging reliability problems. The NOI draft criterion discusses metrics such as violations of NERC Planning Criteria. Other metrics as discussed in our attached NIETB comments include the concept of developing Loss of Load Probability (LOLP) index to measure the relative reliability of load pockets or regions. LOLP indices can be used for analyzing local area risks verses grid-wide risks. We recommend DOE consider the use of these probability indices to measure the relative risks of outages, particularly in load pockets, in addition to the Reliability Congestion Indices (RCI) and the Commercial Congestion Indices (CCI) on major WECC paths being proposed for recommendation by the WCATF to DOE.[15]

Draft Criterion 2: Action is needed to achieve economic benefits for consumers. BAMx supports the application of this criterion. We believe the GBA would qualify under this criterion as noted in our attached NIETB comments. The BAMx members believe the GBA "needs substantial transmission improvements to enable large economic electricity transfers that would result in significant economic savings to retail electricity consumers." The economic expansion of transmission in the GBA that reduces the need for existing "reliability-must-run" plants and/or local capacity requirements would achieve economic savings to the GBA consumers.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources. Again, the BAMx members support the use of this criterion. The GBA is subject to and dependent upon "reliability-must-run" (RMR) plants and would "benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both." RMR plants are needed in general to satisfy a transmission deficiency. BAMx provided comments in the DOE NIETB attached here addressing the inordinate high level of RMR units in the GBA. Additionally, as California addresses Resource Adequacy, including

[15] The WCATF proposes to calculate RCI and CCI congestion indices for the major WECC paths using historic OATI OASIS information and information from the WECC EHV Data Pool. See Proposed Congestion Indices, discussed at the February 2, 2006 meeting. This approach will fail to identify the utilization of paths leading to large load pockets such as the GBA since this focus will be for the major WECC paths. For this reason BAMx urges DOE to consider the GBA for early NIETC designation.

Local Capacity Requirements (LCR), proposals have been made to replace the local RMR requirement with a much larger LCR requirement, and to transfer the obligation to acquire the necessary LCR to load serving entities. This transfer of obligations could occur as early as June 2006 and would significantly increase costs over their current levels. This is another reason why the BAMx members recommend the GBA be given early designation of NIETC status as being appropriate and necessary. Further, the GBA could benefit from further supply diversification such as additional renewable generating resources.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States. BAMx supports the application of this criterion. As demand increases for renewable sources of energy as well as for new and cleaner coal generation, the GBA needs access to the renewable energy sources outside of the GBA in the WECC region and potentially the new sources of coal. Expanding transmission capacity into GBA will enable the GBA load center to contract for these new sources of clean and diversified energy thereby improving this nation's domestic fuel independence. Relieving the GBA congestion will reduce fossil fuel consumption and depletion, and also reduce dependence on foreign energy sources such as imported oil or liquefied natural gas, by shifting generation not only to renewable resources, but also away from less efficient fossil fuel generation to more efficient plants. Large load centers such as the GBA would have a great impact in fostering more renewable energy since long term contracts are necessary for entities to finance and build new sources of renewable generation. Increasing the import capacity into the GBA would open the door for these needed long term contracts. Connecting renewable/alternative generation to the grid is ineffective unless that energy is then deliverable to load centers such as the GBA.

Draft Criterion 5: Targeted actions in the area would further national energy policy. Although no explanation was provided in the NOI other than indicating that the national energy policy was one of the five stated considerations listed in Section 216(b) of the FPA for conducting the Congestion Study in identifying candidate areas for NIETC designation, the BAMx members support including this as a criterion. Increasing the transmission import capability into the GBA would diversify the energy resources available to GBA end users and would lead to enhancement of national security and energy independence. Relieving congestion has environmental benefits by shifting generation away from existing dirtier generating plants to cleaner resources. Also, relieving congestion will reduce opportunities and incentives for market manipulation; it will also help open up the grid to effective wholesale competition, by enabling more entities to have economical access to the grid.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce the vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts. BAMx supports the use of this criterion. As mentioned above the GBA load pocket is formed by the cut-plane across the three existing transmission corridors. The reliability of the GBA is highly dependent on these critical transmission facilities to reliably supply the load requirements of the GBA. These existing transmission facilities rights-of-way and corridors are being encroached by rapid housing development in both the GBA and the Central Valley of California. The GBA needs transmission corridors identified and protected to be able to serve its diverse load in a reliable and economical manner. Other critical infrastructure within the GBA includes RMR plants already mentioned in Criterion 3 above. Numerous high tech companies located in the GBA are sensitive to voltage fluctuations and power outages, consisting of both power quality and reliability. Additionally, BAMx members have customers throughout the GBA that have issues regarding power supply/voltage stability in certain high tech and industrial companies. The GBA hosts many different pockets of critical and vulnerable loads such as the San Francisco financial markets, high tech manufacturing, internet telecommunications and server farms in Silicon Valley, all are critical to the national economy and all of which would be vulnerable to both reliability issues and growth constraints without new transmission corridors.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumption about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies. BAMx members do not object to the use of this criterion as it may help identify needs based on speculative planning assumptions. The GBA reliance on RMR plants have been well documented by the CAISO and the costs have been real and current as mentioned in our attached NIETB comments. The GBA uncertainties deal more with the question of whether the existing transmission owners will be able to fix the identified transmission deficiencies and whether additional local generation can be added as opposed to the more traditional analytic planning assumption uncertainties. Additionally, there are uncertainties surrounding the status of several new GBA generating plants due to the plant owner's pending bankruptcy. With the pending retirement of aging local generating facilities, greater dependence on importing additional power for the GBA will be needed.

Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently. BAMx supports the use of this criterion. The substitution of local generation for adequate transmission has resulted in the GBA's reliance on RMR plants and/or requirements for local capacity requirements. In the GBA we essentially do not have much likelihood for additional generation facilities to have a tangible impact on our RMR dependence. This is one good reason that we request DOE to designate NIETCs to ensure access to generation outside of the GBA as well as from outside California.

The BAMx members thank DOE for the opportunity to submit comments on its Congestion Study and possible designation of NIETC. We trust you will consider our comments and recommendations in designating the San Francisco Greater Bay Area corridors for early NIETC designation.

Attached: Comments submitted by the BAMx cities in DOE's National Interest Electric Transmission Bottleneck proceeding dated September 17, 2004.

Copy to:
Rob Kondziolka, Chair, Western Congestion Assessment Task Force, Salt River Project
Gary DeShazo, California Independent System Operator Corporation

Dated: September 17, 2004

Comments of the Bay Area Cities
on
Department of Energy's (DOE)
Notice of Inquiry and Opportunity to Comment
on
Designation of National Interest Electric Transmission Bottlenecks (NIETB)

The Cities of Alameda (Alameda Power and Telecom), Palo Alto, and Santa Clara (Silicon Valley Power), hereafter called Cities, have joined together with the objective of promoting reliable electric supply to and within the Greater San Francisco Bay Area at reasonable cost. The Cities offer the following comments for DOE in response to its inquiry as published in the Federal Register Notice (FRN) of July 22, 2004 on Designation of National Interest Electric Transmission Bottlenecks (NIETB)[1]. The Cities commend DOE in seeking public comments in shaping its NIETB program and on issues relating to the identification, designation and possible mitigation of NIETB. DOE has stated in its FRN that this is an initial step to identifying transmission bottlenecks and that such designation will help mitigate such bottlenecks that are a barrier to efficient operation of regional markets, threaten the safe and reliable operation of the electric system, and/or impair national security.

Comments on NIETB Criteria

The FRN requested comments on the three criteria recommended by the DOE's Electricity Advisory Board (EAB). The Cities generally concurs with the EAB's recommended three criteria for designation of NIETB. Specifically, the Cities concur with the two criteria that the "bottleneck creates a risk of widespread grid reliability problems or the likelihood that major customer load centers will be without adequate electricity supplies," and "the bottleneck creates the risk of significant consumer cost increases in electricity markets that could have serious consequences on the national or a broad regional economy or risks significant consumer cost increases over an area or region." On the latter criteria, the Cities recommend removing the words "the risk of" and "risks." Thus, the second criteria would read, "the bottleneck creates significant consumer cost increases in electricity markets that could have serious consequences on the national or a broad regional economy or significant consumer cost increases over an area or region." The bottlenecks don't just pose a risk of cost increases, but cost increases are indeed a fact. The Cities believe both of these criteria describe the transmission constrained area known as the Greater Bay Area Load Pocket in northern California.

The Greater Bay Area Meets the Criteria of Widespread Grid Reliability Problems

DOE's Transmission Bottleneck Project Report of March 19, 2003 has already identified the San Francisco Peninsula as a bottleneck with a potential for "widespread grid reliability problems." While that report was conducted by surveying the ISOs across the country, the Cities believe that

[1] Federal Register, Volume 69, No. 140, Thursday, July 22, 2004, page 43833.

the Greater Bay Area Load Pocket should be listed as having widespread grid reliability problems. Although the grid is planned and operated to meet minimum reliability criteria, the California Energy Commission has demonstrated in its 2002-2012 Electricity Outlook Final Report that the risks of power supply shortages are greater in load pockets. In the San Francisco Bay Area load pocket the risk of insufficient supply is much greater than most other areas. See illustrative table below.

	Risks (Percent)		Maximum Deficits (MW)	
Transmission Zones	**Baseline Scenario**	**High Load Scenario**	**Baseline Scenario**	**High Load Scenario**
South CA	**1.3**	**4.3**	**1,730**	**5,210**
North CA	**0**	**0**	**0**	**0**
San Diego	**7**	**17**	**3,030**	**3,540**
San Francisco	**13.7**	**11**	**230**	**210**
IID	**7.3**	**18.3**	**280**	**310**
LADWP	**0**	**0**	**0**	**0**
SMUD	**0**	**0**	**0**	**0**
CCENT	**0**	**0**	**0**	**0**

Source: CEC 2002-2012 Electricity Outlook Report, page 45, Table 11-3-1,
Shortage Risks and Maximum Deficits by Transmission Zone

Additionally, actual events have demonstrated this higher risk of outages. On June 15, 2000 a number of power plants were off-line in the Bay Area and the transmission system was not adequate to maintain acceptable voltage levels. The California ISO implemented rolling blackouts affecting over 97,000 customers in the Bay Area and including customers in our Cities.

Although some improvements to grid planning standards specific to the Greater Bay Area have been implemented and other are being studied further, the Greater Bay Area is still recognized as a load pocket with transmission bottleneck that faces high "risks of widespread grid reliability problems." The Cities endorse the concept of developing a Loss of Load Probability (LOLP) index to measure the relative reliability of load pockets. The DOE could use these indices to show relative reliability of load pockets or regions within a single utility or ISO. LOLP indices for deliverability and local resource adequacy requirements are used in several ISOs in the Northeast markets. The California ISO has advocated that such LOLP deliverability tests be utilized in California in analyzing local area risks verses grid-wide risks, and for demonstrating the deliverability of adequate generating supply.

The Greater Bay Area Meets the Criteria of Significant Consumer Cost Increases
In addition to meeting the higher risks for reliability problems criteria, the Greater Bay Area also has the highest level of Reliability Must Run (RMR) generating units that are required to be designated in order to reliably operate the grid. Historically, this came about due to the former

vertically integrated transmission owner's decisions substituting local generation for transmission. Additionally, the current owners of these RMR designated plants could exert market power if not contracted for under RMR agreements. As such, the Cities believe inordinate high levels of RMR units are required in the Greater Bay Area load pocket to mitigate the unacceptable potential for high price differentials and market power. Ever since the initial operation of the California ISO, the RMR requirements for the Greater Bay Area have exceeded 4,000 MW for a load of about 9,000 MW in the Greater Bay Area. For 2004 the Greater Bay Area required 4300 MW of RMR from a total grid-wide requirement of 9,155 MW of RMR for the entire ISO service area. Annual RMR costs for just the Greater Bay Area portion of the PG&E system for 2004 are estimated to exceed $187 million.[2]

The following quote from the Bay Area Economic Forum[3] expresses the economic costs of reliability problems to the region.

> "California's experience shows the importance of reliability: In 2001, rotating outages in January through March may have cost the State as much as $150 million of lost gross state product and imposed as much as $300 million in economic costs on customers, based on the estimated value of service to customers. This does not include the high wholesale power-procurement costs incurred by utilities. In addition, prior analysis by the Bay Area Economic Forum and its partners indicates that sustained power shortages for the duration of a tight summer could reduce gross state product by $2 billion and impose $3 billion in lost value of service costs."

Source: Bay Area Is Still Coming Up Short in Electricity, BAEF, May 2003 Report

Nomination of the Greater Bay Area for NIETB Status

DOE's NIETB program should allow for consumer nominations of areas for NIETB status. The DOE July 14, 2004 bottleneck workshop invited such nominations. (Closing remarks of David Meyer in the July 14, 2004 NIETB workshop proceedings, page 24.) If consumers feel that transmission constraints prevent access to lower priced markets, then incentives and assistance for mitigating such constraints should be available. Although DOE has stated it will help mitigate such bottlenecks, the FRN did not specify what benefits would be available from such designation and how DOE would help. We have witnessed the benefits gained from national visibility in assisting the relief of the Path 15 bottleneck in California. As such, the Cities wish to nominate the Greater Bay Area as a bottleneck for NIETB designation status.

The Cities thank DOE for allowing the public to provide input to help shape the NIETB program. We trust you will be considering our comments and our nomination of the Greater Bay Area Load Pocket to be designated as a National Interest Electric Bottleneck to be mitigated.

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[2] Estimated RMR costs for the Greater Bay Area are based on figures from total estimated costs for RMR services for 2004 as filed by PG&E in the FERC Docket No. ER04-337-000 (commonly referred to as the TO7 case), Exhibit PGE-10.

[3] With an economy of almost $300 billion, the Bay Area ranks 24th in the world when compared to national economies. On a per capita basis, it ranks ahead of all national economies, including the U.S. The region is at the cutting edge of global technology, and is a leader in many key indicators of regional, global and national competitiveness. With a market of more than six million residents, the Bay Area is California's second largest and the nation's fourth largest metropolitan region. Source: Bay Area Economic Forum: The Region

11. Lisa Baugher Received Mon 3/6/2006 12:42 PM

Considerations for Transmission Congestion Study and Designation of NEITC

Elected officials, communities, local and state government are successfully working together for the better good of all. It's working for America, but not for the Power Companies who I believe spearheaded this national provision to run over all of us.

Energy deregulation was presented as good for the consumer and many found it to be good only for the energy companies. In my opinion, the same is true with this provision - it is only good for the energy companies.

Transmission is most efficient closest to the source, but this bill could be used to rubber stamp money-making projects where a Power Company could make much more money by selling power to areas where power is more expensive; such as from Ohio and West Virginia to New Jersey and New York.

This provision will exasperate ozone transport efforts that cost taxpayers millions and ruin decades of nationwide land planning, historic preservation, business planning – all for the benefit of who? The Power Companies? One has to assume that all of this new and possibly unnecessary infrastructure will be built at the ratepayer's expense, either at the front end or the back.

Planning is best handled through the current state and local government processes that address reliability issues and include local government.

Do not be blinded by the wording of this provision or the fact that it may allow the state process to go forward. If the process is not completed within one year or if the process does not approve the National Interest Electric Transmission Corridor, what do you think will happen?

This provision could silence everyone except for the Power Company who requested a NEITC designation.

Lisa Baugher
P. O. Box 99
Tuscarora, MD 21790

301-874-6162

12. Laura Beard, Received Wed 3/1/2006 10:05 AM

Dear Sirs:

I have just learned that Allegheny Power has applied for you to designate its planned 500Kv line that will run from WV to Kemptown, MD as a National Interest Electric Transmission Corridor. As I understand the implication of this designation, Allegheny could circumvent the regulatory authority of our local and state bodies and have you give them direct authority to proceed with whatever poorly planned route they choose if the time for the approval process exceeds one year.

We here in Urbana, Maryland have just finished observing how Allegheny Power operates when siting power lines. They have treated the residents here on Lynn Street in Urbana, Maryland with destain and arrogance and without regard for our property values, environmental damage, or aesthetics. They have refused to give weight to any recommendations of the local government bodies that have recommended against their siting plan including the Planning commission of Frederick County, the Board of County Commissioners, and the Maryland Department of Natural Resources. They have refused to consider any factors except their building cost over the objections of the Frederick Board of Supervisors, the Urbana Civic Association, the State Highway Department, the Frederick Historical Society, and Maryland Delegate Richard Weldon.

I feel that this request for designation as a National Interest Electric Transmission Corridor is a thinly veiled attempt to circumvent dealing with Maryland State and Frederick County authorities and residents who have been unreasonable in no way, but have persisted in requiring Allegheny Power to follow the current regulations in place in our county and state pertaining to site planing and notification of impacted residents. This has resulted in a delay for their plans. Had they followed the rules to begin with they would have avoided the loss of time they have suffered in this matter.

I invite you to study Allegheny case #9018 with the Maryland Public Utilities Commission and read the testimony and follow the course that this case has taken, including the delays necessary after Allegheny's initial lack of notification of local impacted residents. The following is a quote from today's Frederick News Post, “Allegheny said in its statement it will communicate fully and openly with communities and businesses and property owners "to balance all interests in an effort to minimize the environmental and land-use impacts." We here in my community have just witnessed that this company is incapable of such behavior. They have shown us that the only basis they use for site planning are their costs. That leads to very low standards on their part.

I am urging you to refuse to allow yourselves to be used by Allegheny Power to circumvent the proper regulatory authority of our state and local bodies. I believe there are enough provisions in place for the proper regulation of power distribution by this company.

Thank you for your consideration,

Laura Beard
2780 Lynn Street
Frederick , Maryland 21704
301-606-3713

Laura Beard
Frederick, MD
USA

13. Bonneville Power Administration, Received Mon 3/6/2006 4:14 PM

Gentlemen:

The Department of Energy ("DOE") issued a notice that was published on February 2, 2006, requesting comments on draft criteria for gauging the suitability of geographic areas as National Interest Electric Transmission Corridors ("NIETC"), 71 Federal Register 5660 ("NOI"). Bonneville Power Administration ("Bonneville") submits these comments in response to the NOI.

<u>Background</u>

The Administrator of Bonneville is charged under the Federal Columbia River Transmission System Act with

> Operat[ing] and maintain[ing] the Federal transmission system within the Pacific Northwest and . . . construct[ing] improvements, betterments, and additions to and replacements of such system within the Pacific Northwest as he determines are appropriate and required to:
>
> (a) integrate and transmit the electric power from existing or additional Federal or non-Federal generating units;
> (b) provide service to the Administrator's customers;
> (c) provide interregional transmission facilities; or
> (d) maintain the electrical stability and electrical reliability of the Federal system.
> . . .

16 U.S.C. § 838b. Pursuant to the statute, Bonneville strives to increase the efficient use of its existing transmission system, while constructing, and facilitating construction, of transmission infrastructure to develop and maintain a reliable and robust Pacific Northwest transmission grid.

The NOI states that "the system generally was not constructed with a primary emphasis on moving large amounts of power across multi-state regions." NOI, 71 Fed. Reg. at 5660. The Western Interconnection is an exception to that rule. Bonneville's system <u>has been</u> developed for the purpose of moving large amounts of remote hydro and coal to load and to enable large seasonal diversity exchanges with the Pacific Southwest. As a result, the increase in loading on Bonneville's system with the advent of wholesale electric markets has been more manageable than in other areas of the country. Nevertheless, the Pacific Northwest and Bonneville have experienced generation and load growth, and increased marketing transactions through the transmission system, which are now straining the system. Bonneville has completed three new 500 kV transmission line segments in the past two years to support reliability on major internal paths.

<u>Bonneville Response</u>

Bonneville submits the following answers to questions asked in the NOI.

1. "[T]he Department invites commenters to address how broadly or narrowly the Department should consider and define corridors in its study and its NIETC designations." NOI at 5661.

Once a problem or need is identified, it can usually be solved by several alternative projects. As the solutions are identified, some of them will be discarded as inappropriate and eventually a sponsor will identify a preferred option. But another sponsor might have a somewhat different need and may identify a different option. Parties with differing needs may together develop a solution that meets both needs. So corridor needs should be described very broadly at first and then narrowed as appropriate through the planning process. The DOE process should be designed to allow and encourage development of consensus solutions, which are most likely to result from regional planning processes.

Typically, one thinks of a corridor as a route for transmission lines, but Federal Power Act section 216(a)(2) specifies that the Secretary may designate "*any geographic area* experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." (Emphasis added). The statutory language specifies "geographic areas," and not just transmission lines, that experience congestion or constraints. Such definition of a "geographic area" necessarily references a load pocket, *i.e.*, the consumers that are adversely affected by transmission capacity constraints or congestion. Bonneville recommends that DOE adopts an interpretation of "geographic area" to include an area of adversely affected load. This allows for a greater variety of solutions to the problem than if the language were interpreted to limit the "geographic area" to the existing transmission facilities that are constrained.

Future flows on the transmission system are dictated by the location and attributes of load, generating resources and demand-side management tools. It is important to recognize this linkage in evaluating the NIETC criteria for specific corridors. For example, there will be a number of generation and/or demand-side management options for serving load growth. A NIETC designation should not be project specific; the designation should be framed to accommodate a range of potential projects. A NIETC designation should only last only a long as the underlying need exists.

2. Should the Department distinguish between persistent and dynamic congestion? NOI at 5662.

Although the NOI did not define persistent and dynamic congestion, Bonneville assumes that dynamic congestion has less duration than persistent congestion. Any analysis of whether to relieve congestion should consider the amount of time that the congestion occurs and the impacts of the congestion to determine the cumulative cost of the congestion. Thus, classifying the congestion as dynamic or persistent is less important than the expected benefit of relieving the congestion.

3. Should the Department distinguish between physical and commercial congestion? NOI at 5662.

As the solutions to these two types of congestion can be different they should be distinguished. Commercial congestion occurs when all capacity is sold but not used. Only physical congestion should be relevant to a study of needed electric transmission corridors because commercial congestion may be resolved through open access transmission tariff solutions. Thus, to the extent it exists, commercial congestion is a problem within the purview of the Federal Energy Regulatory Commission.

4. The NOI also asked whether DOE should consider other studies than those listed in Appendix A to the NOI and what categories of information would be most useful to include in the congestion study. NOI at 5662.

Bonneville believes that within the Western Interconnection, the congestion study should build on the work of existing studies that were developed with broad participation of various market participants and regulators over as wide an area as possible. The list of studies in Appendix A appears to be quite comprehensive. – the SSG-WI study IS listed.

5. Comments on draft criteria.

Of the eight draft criteria, there is some overlap.

For example, criteria 1 and 6 both cover reliability. Criterion 6 identifies reliable service to critical loads, but also identifies protecting the transmission system from natural disasters and malicious acts. Thus, criterion 6 covers both specific loads and the system as a whole, while criterion 1 covers the transmission system as a whole. Thus, criterion 6 should be narrowed to protection of specific loads, while reducing system vulnerability to natural disasters and malicious acts should be covered under criterion 1. Further, criteria 2 and 3 both cover a need for economical supply of electricity to consumers. The example of reducing Reliability Must Run generators to ease electric supply limitations in Criterion 3 is really another way to provide more economic supply to consumers and that is already covered by Criterion 2. Bonneville feels that criterion 2 is fine as written but Criterion 3 should be limited to actions needed to diversify generation sources. Further, criterion 5 is not clear. Since DOE has not identified a national energy policy and it is unclear what factors DOE would consider as metrics to evaluate this criterion. Bonneville recommends that criterion 5 be ranked low in priority.

The eight criteria should be reduced to six

1. Action is needed to maintain high reliability of the transmission system, including from natural disasters and malicious acts.

2. Action is needed to achieve economic benefits for consumers.

3. Action is needed to diversify sources of electric supply.

4. Action is needed to enhance the energy independence of the US.

5. Action is needed to reduce the vulnerability of critical loads.

6. Action is needed to further national energy policy when developed.

Draft Criteria #7 and #8 listed in the NOI appear to actually be metrics that can be used to evaluate the other six criteria.

DATED: March 6, 2006.

Respectfully submitted,

/s/ Marvin J. Landauer

____

Marvin J. Landauer,
System Planning Team Lead
Bonneville Power Administration

14. British Columbia Transmission Corporation, Received Mon 3/6/2006 4:59 PM

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY ("DOE")

Considerations for Transmission)

Congestion Study and Designation National Interest Electric Transmission Corridors	)))	Comments in Response to Notice of Inquiry

COMMENTS OF BRITISH COLUMBIA TRANSMISSION CORPORATION

Pursuant to the U.S. Department of Energy ("DOE") Notice of Inquiry ("NOI") requesting comment and providing notice of a technical conference, as published 2 February 2006 in the U.S. Federal Register, the British Columbia Transmission Corporation ("BCTC") submits these comments on certain issues discussed in the NOI.

BACKGROUND AND GENERAL PERSPECTIVE

BCTC is a government corporation that independently operates, plans, and maintains transmission in the province of British Columbia, Canada. BCTC is also the control area operator for British Columbia and a member of the Western Electricity Coordinating Council ("WECC").

BCTC independently operates, plans and maintains more than 18,000 kilometres of high voltage transmission in British Columbia. BCTC's transmission system is interconnected with the United States through interconnections with the Bonneville Power Administration ("BPA") transmission system at Blaine and Boundary, Washington. BCTC's transmission system is also interconnected with the transmission system in Alberta, Canada.

Over 7,800,000 MWh of north to south flow and 10,500,000 MWh of south to north flow have occurred (using annual averages) over the past 3 years across the tie lines between BCTC's transmission system and the United States. Electricity from both British Columbia and Alberta flows south to the US over these ties, and vice versa through the BCTC transmission system.

One of BCTC's key roles in British Columbia is identifying and proceeding with necessary transmission infrastructure to serve the needs of existing and potential transmission customers. In turn as system operator, BCTC offers open access wholesale transmission service to transmission customers pursuant to its open access transmission tariff ("OATT") that is based on FERC's Order No. 888 pro forma tariff. BCTC is regulated by the British Columbia Utilities Commission in undertaking these public utility functions.

BCTC views appropriate new investment in transmission facilities as critical to support efficient electricity transactions for customers and safe and reliable transmission system operations in British Columbia and throughout the rest of the WECC.

BCTC welcomes this opportunity to comment in support of the National Interest Electric Transmission Corrider ("NIETC") designation process and encourages the DOE to proceed swiftly with appropriate designations and support or initiate the necessary follow-up work for upgrading serious bottlenecks in the WECC region.

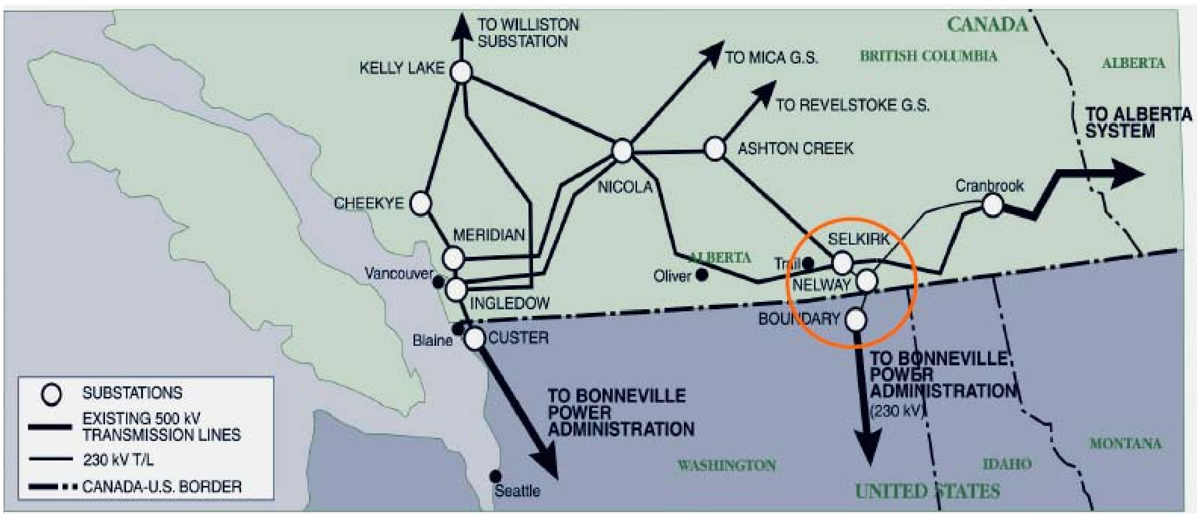
SPECIFIC COMMENTS ON THE NOI

Need for interregional efforts to include cross-border cooperation

BCTC appreciates the NOI's recognition of the opportunities to enhance reliability, access to resources and economic efficiencies by alleviating congestion. BCTC suggests there are potential opportunities for coordinated cross-border transmission enhancements that can be particularly compelling.

The many congestion points between northern and southern areas of the WECC region have been long studied and multiple solutions have been debated in response to the complexity and multi-jurisdictional aspects of the situation. A common thread running through the various studies and debates is general acceptance of the need to alleviate congestion in this area as a priority. BCTC observes that reliability imperatives and the interconnected nature of the integrated transmission grid structure are realities that must be recognized in developing optimal regional solutions.

Potential transmission system expansions and upgrades in one area benefit greatly from coordinated action in adjacent areas – as on either side of a national border. For example, if BCTC expansion of intertie capacity south to Boundary could provide benefits, those benefits likely could only be realized if coordinated with transmission reinforcement south of the border. Increasing transfer capacity in one area is not a whole solution if coordinated enhancements are not made in other areas of the interconnected system.



BCTC is optimistic that the process to designate a National Interest Electricity Transmission Corridor in the US will provide a mechanism for development of coordinated, integrated and optimized solutions to existing and future transmission congestion throughout the Pacific Northwest region and southward in the WECC region.

Breadth of designated transmission corridors

BCTC recognizes the difficulty of the DOE’s task in designating appropriate NIETCs that are neither so overly broad as to be unhelpful nor so narrowly drawn as to be unduly prescriptive. It may be necessary to approach an NIETC as a high level and necessarily broad construct within which specific transmission routing selection is left to be optimized.

BCTC would encourage DOE to be receptive to the specifics of anticipated case-by-case requests for NIETC designation rather than seeking to establish firm rules for corridor breadth that might ultimately constrain the DOE’s goal of most effective transmission system enhancement.

CONCLUSION

BCTC urges the DOE to take the foregoing comments into account in its consideration of criteria and processes for NIETC designation and investments in transmission infrastructure in connection with the US Energy Policy Act generally and the NOI in particular.

In particular, BCTC urges the DOE to develop appropriately collaborative processes to facilitate the development and implementation of optimal transmission solutions for the integrated North American transmission grid. BCTC encourages the DOE to recognise the opportunities for cross-border transmission expansion and to take these into account when considering corriders to be designated.

BCTC looks forward to working cooperatively with the DOE and other parties as transmission solutions in the Pacific Northwest in particular and the WECC region in general are brought forward.

Respectfully submitted,

/s/ Doug Little

Doug Little
Vice President Customer & Strategy Development
BC Transmission Corporation
1055 Dunsmuir Street, Box 49260
Vancouver, British Columbia V7X 1V5 Canada
Telephone: (604) 699-7300
Doug.Little@bctc.com

Filed electronically on March 6, 2006.

15. California Energy Commission, Received Mon 3/6/2006 4:55 PM

VIA ELECTRONIC MAIL

March 6, 2006

United States Department of Energy
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments, U.S. Department of Energy
Forrestal Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Re: Considerations for Transmission Congestion Study and
Designation of National Interest Electric Transmission Corridors
Comments of the California Energy Commission

In response to the Notice of Inquiry ("NOI") published by the Department of Energy's Office of Electricity Delivery and Energy Reliability ("OE") on February 2, 2006, (71 Fed. Reg. 5660) relating to DOE's plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETCs"), pursuant to section 1221(a) of the Energy Policy Act of 2005 ("EPAct-05"),[1] the California Energy Commission ("Energy Commission") submits its comments, below.

Communications concerning the Energy Commission's comments should be addressed to the following:

Judy Grau, Sr. Mechanical Engineer
Engineering Office, Siting Division
California Energy Commission
1516 9th Street, MS 46
Sacramento, CA 95814-5512
jgrau@energy.state.ca.us
(916) 653-1610

Kenneth L. Glick, Staff Counsel
Office of the Chief Counsel
California Energy Commission
1516 9th Street, MS 14
Sacramento, CA 95814-5512
kglick@energy.state.ca.us
(916) 654-3855

I. INTRODUCTION

The Energy Commission[2] has been the State of California's primary energy policy and planning agency for the last 30 years. In California, the construction and operation of any thermal power plant with a generating capacity of 50 MW or greater requires that a license (certificate) first be issued by the Energy Commission. This certificate takes the place of any other state, regional, or local permit that would otherwise be required. This certificate process examines all aspects of the proposed facilities, including engineering, environmental, health, and

[1] Section 1221 of the EPAct-05 provides, in part, that designated NIETCs be subject to "backstop" siting authority by the Federal Energy Regulatory Commission ("FERC") for facilities located within these designated corridors.

[2] The California Energy Commission is also known by its formal name, State Energy Resources Conservation and Development Commission, and is an organizational unit within the State of California Resources Agency.

public safety issues. In this capacity, the Energy Commission serves as the lead review agency under the California Environmental Quality Act ("CEQA"). When licensing new thermal power plants, the Energy Commission also licenses related transmission facilities up to the point of interconnection with the existing electricity transmission grid.

In addition, the Energy Commission takes a keen interest in ensuring adequate transmission infrastructure for the state. Since the late 1970s, the Energy Commission has actively participated in both state and federal efforts to address transmission corridor planning and permitting issues. The Energy Commission also has siting jurisdiction for thermal power plants of 50 megawatts (MW) or greater and related transmission facilities. As the result of the Energy Commission's long-standing participation and developed expertise in the area of transmission corridor planning and electricity infrastructure siting, we are pleased to provide comments on DOE's proposed implementation of EPAct-05 Section 1221(a) relating to NIETCs.

Beginning in the late 1970s and early 1980s, the Energy Commission became an active participant in the Bureau of Land Management's (BLM) corridor planning efforts. In the late 1980s and early 1990s, in response to state legislation, the Energy Commission conducted an extensive investigation of transmission issues in the state, culminating in a 1992 report to the Legislature recommending how best to address transmission problems in the state. More recently, the Energy Commission has made a number of recommendations to both the Governor and the Legislature under the state-mandated *Integrated Energy Policy Report (Energy Report)* and *Strategic Transmission Investment Plan (Strategic Plan)* to improve transmission corridor planning and permitting in California.

Finally, in late 2005, the BLM and DOE designated the Energy Commission as a cooperating agency in the federal Programmatic Environmental Impact Statement (PEIS) effort for energy corridors in the Western States, under Section 368 of the EPAct-05. The Energy Commission's role in this federal proceeding is to ensure that the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns are considered in the PEIS.

In California, the construction and operation of any thermal power plant with a generating capacity of 50 MW or greater requires that a license (certificate) first be issued by the Energy Commission. This certificate takes the place of any other state, regional, or local permit that would otherwise be required. This certificate process examines all aspects of the proposed facilities, including engineering, environmental, health, and public safety issues. In this capacity, the Energy Commission serves as the lead review agency under the California Environmental Quality Act ("CEQA").

II. GENERAL COMMENTS

Before responding to specific areas for comment outlined in the NOI, we have several issues and concerns, outlined below:

The Importance of State Laws and Policies in the Designation of National Interest Transmission Corridors

The Energy Commission believes it is important to explicitly address state energy laws and policies relating to transmission corridor planning to ensure that DOE's designation of transmission corridors of national interest both complements these efforts and leverages state expertise. Although the NOI states that DOE's initial study pursuant to EPAct-05 section 216 may include "enabling larger transfers of economically beneficial electricity to load centers, or enabling delivery of electricity from new generation capacity to distant load centers"[3] in its recitation of questions for public comment,DOE appears to be too narrowly focused on addressing congestion alone and needs to adequately consider the other important transmission planning objectives faced by California and other states. The need for transmission corridor planning in California is a long-running issue for the Energy Commission.

In 1988, recognizing both the growing importance of transmission with the interconnection of independent power producers and the escalating conflicts between transmission-owning and transmission-dependent utilities, the California Legislature passed Senate Bill (SB) 2431 (Section 1457, Statutes of 1988), which contained the following findings concerning the role of transmission in California's future development:

(a) The Legislature finds and declares that establishing a high-voltage electricity transmission system capable of facilitating bulk power transactions for both firm and nonfirm energy demand, accommodating the development of alternative power supplies within the state, ensuring access to regions outside the state having surplus power available, and reliably and efficiently supplying existing and projected load growth, are vital to the future economic and social well being of California.

(b) The Legislature further finds and declares that the construction of new high-voltage transmission lines within new rights-of-way may impose financial hardships and adverse environmental impacts on the state and its residents, so that it is in the interests of the state, through existing licensing processes, to accomplish all of the following:

  (1) Encourage the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically justifiable.
  (2) When construction of new transmission lines is required, encourage expansion of existing rights-of-way, when technically and economically feasible.
  (3) Provide for the creation of new rights-of-way when justified by environmental, technical, or economic reasons, as determined by the appropriate licensing agency.
  (4) Where there is a need to construct additional transmission, seek agreement among all interested utilities on the efficient use of that capacity.

In directing the Energy Commission to conduct an investigation and prepare a report outlining recommended policies and actions, SB 2431 plainly stated that the purpose of the

[3] 71 Fed. Reg. 22 at 5661.

report was to facilitate effective, long-term transmission line corridor planning.[4] One of the major findings of the report was that utilities should take appropriate mitigation measures to reduce the environmental impacts of approved projects. [5] The report also identified the absence of coordinated transmission and land-use planning as a major impediment to transmission development in California, and called for a process to identify environmentally sensitive areas, acceptable areas, and areas where urban encroachment into transmission rights-of-way could pose problems.[6] The basic principles and policies expressed in this effort formed a sound foundation for assessing and designating transmission corridors then, and are still persuasive today, nearly 20 years after they were first articulated.

In 2002, in highlighting the importance of reliable energy supplies, the California Legislature again concluded that state government has an essential role in ensuring that a reliable supply of energy is provided, consistent with protection of public health and safety, promotion of the general welfare, maintenance of a sound economy, conservation of resources, and preservation of environmental quality. As a result, SB 1389 (Bowen and Sher), Chapter 568, Statutes of 2002, requires that the Energy Commission adopt an *Energy Report* every two years. In preparing the *Energy Report*, the Energy Commission was directed to evaluate energy trends and issues facing California and develop and recommend policies to ensure reliable and economical energy supplies. Other state agencies with energy responsibilities are required to use the Energy Commission's assessments and forecasts to ensure consistency in the information that forms the foundation of California's energy policies and decisions.

In 2004, noting both the lack of an official state role in transmission planning and the failure of existing processes to consider broader state interests, SB 1565 (Bowen), Chapter 692, Statutes of 2004, added Public Resources Code (PRC) Section 25324:

> The [Energy] commission, in consultation with the [California] Public Utilities Commission, the California Independent System Operator [CAISO], transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures. The plan shall be included in the integrated energy policy report adopted on November 1, 2005, pursuant to subdivision (a) of Section 25302.

With passage of SB 1565, the California Legislature acknowledged the importance of the state's role in the transmission planning process and recognized the Energy Commission as the state agency best suited to undertake and accomplish this effort. The *Strategic Transmission*

[4] Energy Commission, *Transmission System and Right of Way Planning for the 1990's and Beyond*, March 1992, Publication P700-91-005, p. 1.
[5] Ibid, p. 7.
[6] Ibid, p. 15.

Investment Plan (Strategic Plan)[7] creates a blueprint for the development of an efficient and reliable bulk transmission system for California. The *Strategic Plan,* adopted by the Energy Commission in November 2005, identifies five prospective transmission projects needed in the near-term to provide strategic benefits to California's electricity grid through improvements to system reliability, reduced congestion, and/or interconnection to renewable resources. These are:

- Palo Verde-Devers No. 2 500kV Project (reduces congestion on lines connecting California and Arizona).
- Sunrise Powerlink 500kV Project (allows interconnections with renewable resources located in California's Imperial Valley, reduces congestion and improves system reliability).
- Tehachapi Transmission Plan Phase I - Antelope Transmission Project (allows interconnections with wind energy generated in the Tehachapi area of Southern California).
- Imperial Valley Transmission Upgrade (provides interconnection with renewable energy resources, to meet future load growth, and provide reliability benefits).
- Trans-Bay Cable Project (provides reliability benefits to the San Francisco Peninsula and CAISO control area).

The Energy Commission believes that the DOE process for designating transmission corridors of national interest should explicitly recognize the critical need for these projects. The *2005 Energy Report* also recommended that the Energy Commission actively participate in federal corridor planning processes, enacted as part of the EPAct-05.[8] In following through on this recommendation, the Energy Commission is pleased to provide comments and be an active participant in this DOE proceeding.

Applying Broad Principles in Assessing the Need for Transmission Corridors of National Significance

Establishing the need for transmission corridors is necessarily a flexible process that needs to consider regional differences in operational characteristics, planning considerations, and energy policies within California and across the Western U.S.. In order for designated "national interest" transmission corridors to blend seamlessly into state and regional energy strategies, it is critical that DOE processes adequately recognize critical transmission investments – identified by California and other states – that we believe are expressly allowed under federal law. In identifying the principles that underlie the need for transmission corridors of national interest, DOE should employ a broad set of definitional criteria, instead of engaging in a narrow modeling effort focused merely on relieving congestion.

[7] The Strategic Plan may be accessed through the Energy Commission's website at [http://www.energy.ca.gov/2005publications/CEC-100-2005-006/CEC-100-2005-006-CMF.PDF]
[8] The 2005 Energy Report may be accessed through the Energy Commission's website at [http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF]

California and federal policies addressing the need for additional transmission infrastructure investments can be fairly easily reconciled. The EPAct-05 (Subtitle B – Transmission Infrastructure Modernization) Section 1221 lays out a broad framework that designates interstate electric transmission corridors of "national interest." It directs the Secretary of Energy to do the following:

1. Conduct a study, in consultation with affected states, of electric transmission congestion.
2. Issue a report designating areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers.
3. Conduct the study and issue the report in consultation with appropriate regional entities.
4. Designate a national interest electric transmission corridor that considers whether:
   - (A) The economic vitality and development of the corridor, or end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity.
   - (B) i. economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and,
     ii. diversification of supply is warranted.
   - (C) The energy independence of the United States would be served by the designation.
   - (D) The designation would be in the interests of national energy policy.
   - (E) The designation would enhance national defense and homeland security.

The NOI correctly recognizes that investment in new transmission facilities has not kept pace with the increasing economic and operational demand for transmission services. The Energy Commission shares this concern and identified three urgent transmission issues in its *2005 Energy Report*:

- The state lacks a well-integrated, proactive transmission planning and permitting process. Overlapping and often conflicting roles and responsibilities between state and federal agencies cripple California's ability to effectively secure the investments needed to address dramatic increases in congestion costs and serious threats to electric system reliability.
- California urgently needs a formal, collaborative transmission corridor planning process to identify critical transmission corridors well in advance of need so that utilities can identify and retain needed lands and easements, and local governments can flag incompatible land uses.
- California needs major investments in new transmission infrastructure to interconnect with remote renewable resources in the Tehachapi and Imperial Valley areas, without which it will not be able to meet its Renewable Portfolio Standard (RPS) targets.[9]

DOE should explicitly include furthering key state energy policies and laws as a fundamental criterion when designating transmission corridors of national interest. The Energy Commission believes that state and federal transmission interests, as articulated in both federal and state laws and policies, can reinforce one another as long as they are carefully coordinated so

[9] *2005 Integrated Energy Policy Report*, Energy Commission, November 2005, pp. 88-89.

as to avoid unnecessary overlap, duplication of efforts, or delay and to allow transmission infrastructure investments to be made in the near term..

While provisions of federal law have as their goal “designating areas experiencing electric energy transmission *capacity constraints or congestion* that adversely affects consumers,” (Subsection 1221(a), emphasis added) the Energy Commission does have concerns that DOE has outlined an overly narrow focus on congestion alone in the NOI. The process outlined in the NOI envisions a “congestion study” that, as currently drafted, appears to be a precursor to designating transmission corridors of national interest. The Energy Commission believes that identifying transmission congestion is an important element of establishing the “need” for transmission infrastructure investments; however, it should not serve as the sole basis for such assessments. Relieving “capacity constraints,” as expressed in the EPAct-05 (Subsection 1221(a)), conveys a much broader meaning than merely addressing existing or forecasted transmission congestion. This broader interpretation is necessary to meet other provisions in the law relating to “adequate and reasonably priced electricity,” “diversification of supply,” and “energy independence” (Subsection 1221 (a)(4)).

California’s energy policy heavily emphasizes the need for the state to diversify its electricity supply. California’s growing dependence on natural gas as a fuel source for power generation, from 30 percent of power generation in 1999 to 41 percent in 2004, is a primary driver of the state’s energy policy. [10] In recent years, with extremely high and volatile natural gas prices, reducing natural gas dependence is foremost in the minds of California’s energy policy-makers. A centerpiece of the state’s strategy to diversify electricity supplies is the development of renewable resources.[11] RPS, which requires 20 percent of energy deliveries in the state to be sourced from renewable power generation by 2010, is the state’s primary vehicle to ensure development of renewable resources in California. Long-term contracts with renewable resources, which have no ongoing gas price exposure, are not only environmentally preferable in California, but also economically attractive because they serve as a true hedge against long-term natural gas prices. In addition, the RPS will be a prominent feature of California’s Climate Action Team strategies to reduce greenhouse gas emissions to meet Governor Schwarzenegger’s aggressive climate change goals.[12]

The lack of transmission access to the state’s most promising renewable resources, which are frequently in remote locations including the Tehachapi and the Imperial Valley areas, is one of the most significant near-term barriers to achieving California’s RPS goals.[13] In order to build sufficient transmission capacity to access these renewable resources, it is vital that “reasonably priced,” “diversity of supply,” and “energy independence” needs identified in federal law (Subsection 1221(a)(4)) are elevated and prominently featured in DOE’s assessment of transmission capacity constraints, congestion, and the subsequent designation of corridors of national interest.

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[10] *2005 Integrated Energy Policy Report*, Energy Commission, November 2005, at pp. 60-62.
[11] In this context, “renewable resources” represents power generation fueled by alternative energy sources, such as wind energy or geothermal steam, among others.
[12] *2005 Integrated Energy Policy Report*, Energy Commission, November 2005, at pp. 162-163.
[13] Ibid, at p. 90.

DOE efforts to study and “model” congestion are highly sensitive to the data and assumptions upon which they are based. Natural gas price assumptions are an extremely important driver of congestion modeling results. Thus, to a large extent the results of these models are simply products of natural gas price forecasts and assumptions of future generation resource types and locations, as well as assumptions of incremental transmission additions. In its *2005 Energy Report,* the Energy Commission concluded that it needs to investigate alternative natural gas price forecasting methods in addition to traditional models based upon “equilibrium models” that rely on market fundamentals. [14] The Energy Commission determined that current “equilibrium models” fail to capture the discrepancy witnessed over the last several years between the production costs of natural gas and actual prices paid in the marketplace, the latter of which reflect substantial scarcity rents. The large uncertainty about where natural gas prices are headed in the future brings into question the whole notion of DOE’s heavy reliance upon such modeling for the primary determinant of transmission corridor needs.

The Energy Commission’s *2004 Energy Report Update*[15] also concluded that current transmission modeling fails to capture important “strategic benefits” that are not easily quantified and fails to adequately account for the long-lived nature (30 to 50 years) of transmission facilities. Among the important strategic benefits are “diversity of supply” and “energy independence” reflected in federal law (Section 1221 (a)(4)). In our view, this and other short-comings call into question the validity of recent congestion forecasts for most years beyond the fairly near term, and DOE’s apparent over-reliance upon congestion modeling to identify transmission needs.

As highlighted by the CAISO in our *2005 Energy Report* proceeding, the existing transmission planning process for investor-owned utility (IOU) transmission systems operated by the CAISO in California (which is authorized under FERC tariffs) is overly reactive and insufficiently forward looking. While the CAISO announced development of a new “proactive” planning process in mid-2005, it has yet to design and implement such a system. For now, the DOE’s corridor designation process will be similarly hampered by the current state of tools and planning techniques. In recognizing these limitations we urge DOE to view modeling as only illustrative. Designations of national interest transmission corridors should be based primarily on current factual information, consistency with state and federal policy, and common sense judgment of where transmission is most needed, with appropriate emphasis on accessing renewable resources currently constrained by transmission limitations. Such an approach will be consistent with the phrase “capacity constraints” as used in the EPAct-05, Section 1221(a)).

Federal Delegation and Coordination with Other Federal Transmission Efforts

The lack of timely permitting for transmission in California continues to be of concern to the Energy Commission. While the state will not easily cede its sovereignty over land-use decisions relating to transmission development in California, there may be specific cases where federal back-stop siting authority might be justified and welcomed on a case-by-case basis. DOE

[14] Ibid, p. 133-134.
[15] See website: [http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF]

should focus its efforts on how such a process would be coordinated with state and regional entities.

In addition, the assessment, planning and environmental review involved in designating a NIETC will be enhanced by drawing upon the expertise of state agencies well-versed in the established planning processes and unique environmental characteristics of their respective states. DOE should consider federal delegation or at a minimum, coordination, of planning and environmental review to the states. This delegation can be modeled on the long-standing and successful federal-state relationship practiced by the U.S. Environmental Protection Agency (EPA). For decades, the EPA has relied upon state agencies toconduct environmental reviews under federal program standards. DOE should also address other issues of federal-state cooperation, such as cost allocation (which is an issue under the regulatory oversight of the Federal Energy Regulatory Commission), which continues to delay or restrain renewable and interstate transmission development in California.

The Energy Commission is already a cooperating agency in federal energy corridor designation efforts. EPAct-05, Section 368, requires DOE, BLM, and the U.S. Forest Service (USFS), in cooperation with the Departments of Agriculture, Commerce, Defense and Interior, to designate new right-of-way corridors on federal lands for electricity transmission and distribution facilities, and oil, gas, and hydrogen pipelines. The DOE, BLM, and USFS will prepare a West-Wide Energy Corridor Programmatic Environmental Impact Statement (PEIS) to evaluate issues associated with the designation of energy corridors on federal lands in 11 Western states. Public scoping meetings for the West-Wide Energy Corridor PEIS were held in California on November 1, 2005, and the public scoping comment period ended November 28, 2005. Based upon the information and analyses developed in the PEIS, each federal agency would amend its respective land use plans by designating appropriate energy corridors.

On November 10, 2005, because of the substantial energy-related information developed through the Energy Commission's *2005 Energy Report* and *Strategic Transmission Investment Plan*, the State of California Resources Agency requested that the Energy Commission represent California in the federal PEIS effort. In this role, the Energy Commission is ensuring that the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns are considered in the PEIS.

The Energy Commission then notified cities, counties, investor-owned and municipal utilities, and multiple state agencies of the need to submit comments on the PEIS. To date, the Energy Commission has received over 1,500 comments from individuals and organizations on the scope of the PEIS. On December 12, 2005, BLM and DOE designated the Energy Commission as a cooperating agency. Since that time, the Energy Commission has been working with an interagency team of federal and state agencies to review proposals to designate new and/or expand existing energy corridors and examine alternatives to these corridors on federal lands in California.

The Energy Commission also believes that important lessons learned in California, pursuant to SB 2431, should be incorporated into DOE's implementation of the EPAct-05.[16] The Energy Commission called for a process to identify environmentally sensitive areas, acceptable areas, and areas where urban encroachment into transmission rights-of-way could pose problems. In comments on the Section 368 federal energy corridor process, several California environmental and wilderness interests identified sensitive lands – including state and national parks, federal and state designated wilderness and wilderness study areas, and critical inventoried roadless areas in national forests – which they believe are not appropriate locations for energy corridors.[17] The list of identified sensitive lands forwarded to the Energy Commission by these organizations is included as Appendix A, below. The Energy Commission strongly recommends that DOE develop a process to identify lands, including those identified in the Section 368 process, that are unsuitable for transmission corridors as part of its NIETC efforts.

The Energy Commission, through its Public Interest Energy Program (PIER program), is funding the development of a web-based siting decision analysis tool called Planning Alternative Corridors for Transmission (PACT). PACT will assess proposed transmission corridors through comparing environmental, health and safety, community, engineering and economic values. Research goals for the project include: 1) assembling and involving appropriate technical and stakeholder committees to determine metrics and weighted factors for each discipline to populate the model, 2) expanding current capabilities of the framework to include a broader range of disciplines, and 3) improving the usability of the framework to all appropriate stakeholders. This effort may prove helpful as we move forward with ongoing transmission corridor assessment and transmission infrastructure permitting.

In addition, Section 925 of the EPAct-05 requires DOE to develop a five-year plan that establishes a comprehensive research, development and demonstration program to ensure the reliability, efficiency and environmental integrity of electrical transmission systems. The establishment of this plan should be coordinated with the Energy Commission's transmission R&D program plan that has identified specific activities to develop advanced grid reliability planning and monitoring tools, advanced energy delivery technologies and technologies to enhance existing grid components.[18] Technological development in the transmission areas need to be adequately considered in efforts to improve California's and the nation's transmission systems.

Resolving Renewable and Interstate Cost Allocation Issues

Securing sufficient investments in new transmission in California has been problematic, especially in light of the dilemma that faces renewable generation projects that need access to transmission, including interstate transmission, primarily because of financial/cost allocation

[16] *Transmission System and Right of Way Planning for the 1990's and Beyond*, March 1992, Energy Commission, Publication P700-91-005, p. 15.
[17] February 15, 2006 letter to California Energy Commission Chairman Joseph Desmond from the California Wilderness Coalition, Californians for Western Wilderness, Center for Biological Diversity, Defenders of Wildlife, Environment California, Sierra Club, Sierra Nevada Forest Protection Campaign, and Nations Parks Conservation Association.
[18] *Five-year Transmission Research and Development Plan,* California Energy Commission, November 2003, Publication No. 500-03-104F, [http://www.energy.ca.gov/reports/2003-11-25_500-03-104F.PDF].

issues. The new provisions of EPAct-05 should be interpreted to help address these questions in an integrated manner. We welcome the interest of the federal government in designating transmission corridors of national interest as a way to overcome obstacles to needed transmission infrastructure development.

Most new transmission projects involve multiple jurisdictions, markets, regions, and beneficiaries for which traditional rate base approaches may no longer be adequate. There is a need to research new approaches for assessing benefit streams, beneficiaries, and the quantification of benefits for cost allocation and cost recovery for new transmission investments. While reliability-related transmission investments are moving forward, projects that are viewed as serving an economic, market or policy objective – for example the Tehachapi transmission project – have no clear process for moving forward, in part due to issues relating to cost recovery and cost allocation. Consequently, it is important to review and document existing transmission approval processes, frame policy issues, and outline policy options for cost allocation and cost recovery. Without certainty in these areas, investors are reluctant to commit funds necessary for the construction of these needed facilities.

Last year FERC rejected an innovative proposal from Southern California Edison (SCE) to develop a renewable resource trunk line, operated by the CAISO, which would have interconnected a large concentration of potential renewable generation. The trunk line concept included several linked segments in the Tehachapi area and would have allowed SCE, Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and other CAISO grid users access to as much as 1,100 Megawatts (MW) of wind resources. The renewable resource trunk line concept could also have provided access other remote renewable resources such as geothermal and central station solar. Despite support from California's primary energy agencies, FERC did not approve this application. The FERC ruled that the third segment SCE identified as a renewable resource trunk facility was ineligible for rolled-in rates since the segment resembles more of a generation tie than a network upgrade. This illustrates the need for improved coordination between state and federal energy regulators and policy makers to achieve workable solutions to real world problems.

The advanced planning and construction of transmission facilities is essential to transmission development to access renewable resources. Renewable projects cannot secure contracts under RPS procurement procedures without knowing whether existing or future transmission will be able to accommodate them; at the same time, utilities are wary of investing in transmission to capture renewable power without assurance of cost recovery, which is premised on the renewable generation being built. This poses a major impediment to the achievement of state policy goals.

Even when a renewable developer requests new transmission capacity, the present system assigns the bulk of the costs to the developer who first requests an interconnection requiring system upgrades, regardless of when those upgrades are to go into service and whether system upgrades required by later-in-time requesters will go into service first. Transmission upgrades would be much more efficiently built through a plan that anticipates phased-in development of future renewable generation instead of additions of relatively small, individual projects.

However, phased-in development requires pre-building portions of transmission lines, currently not allowed under FERC regulation.

The September edition of the Natural Gas & Electricity Journal makes very important observations about the implications of FERC's decision on the Tehachapi renewable trunk line with which we agree. In its denial of SCE's renewable resource trunk line FERC failed to recognize the benefits access to Tehachapi wind resources would bring to users of the CAISO-operated transmission system. In the case of Tehachapi "numerous potential wind developers are poised to provide renewable energy to any and all users of the grid system, many of whom need access to the wind energy to meet their renewable portfolio standards (RPSs), the systemwide benefits of all the facilities needed for interconnection should have been apparent." Therefore, it appears surprising that although California clearly recognized these benefits, FERC did not. In addition, if the Segment 3 of Tehachapi were built without rolled-in rate treatment authorized by FERC, the retail ratepayers of SCE would bear all of the costs of those facilities, which may be used primarily to meet the RPS requirements of other California utilities.[19]

The *2005 Energy Report* recommended changes in the CAISO's FERC-approved tariff not only to allow recognition of transmission needs for reliability and economic projects, but also for access to renewable projects to meet RPS goals. FERC has already allowed tariff changes relating to transmission planning and expansion which suggest further refinements are needed in the CAISO tariff. For example, the Southwest Power Pool (Oklahoma, Kansas, parts of Arkansas, Louisiana, New Mexico, and Texas) is permitted by FERC to engage in a transmission study process which provides four-month "open seasons" for generator interconnection requests and the aggregation of the requests received for group processing. Moreover, FERC takes into account whether a new transmission line will increase fuel diversity when deciding whether these transmission costs will be allocated broadly or narrowly. See, *Southwest Power Pool, Inc.*, 110 FERC ¶ 61,028 (January 21, 2005); Southwest Power Pool, Inc., 111 FERC ¶ 61,118 (April 22, 2005) *Order on Rehearing and Compliance Filing*, Southwest Power Pool, Inc., 112 FERC ¶ 61,319 (September 20, 2005). See also, Midwest Independent Transmission System Operator, Inc. 114 FERC ¶ 61,106 (Februrary 3, 2006).

This provides a good example of where state and federal cooperation would further the public interest in development of environmentally-benign renewable resources that reduce our dependence on natural gas. If DOE can help remove cost-allocation barriers to transmission investments by changing cost allocation rules at the federal level, it will go a long way toward promoting adequate investment in new transmission and relieving capacity constraints and congestion.

The Energy Commission, through its Public Interest Energy Research (PIER) program is conducting research designed to address these questions, learn from case studies and best-in-class examples of transmission approval processes, and develop a framework to guide cost allocation and cost recovery, based upon a range of benefits of different transmission projects. The Energy Commission will continue to work with DOE and other federal agencies on these cost-allocation efforts.

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[19] "*Tehachapi Wind Power Setback Has Nationwide Implications*," Natural Gas & Electricity Journal (Darrell Blakeway), September 2005, pp 3, 11. Mr. Blakeway is an attorney formerly employed by FERC for 25 years.

III. SPECIFIC RESPONSES TO THE NOTICE OF INQUIRY

For clarity, the Energy Commission's comments on select NOI areas of interest are organized in a question and answer format, ranked in significance by their appearance below.

Question No. 1: *In the NOI, DOE has invited commenters to address how broadly or narrowly the Department should consider and define corridors.*

For purposes of the Section 1221 work, we strongly believe that national interest electrical transmission corridors should be defined in relation to anticipated electrical path needs, while recognizing that "capacity constraints or congestion that adversely affects customers" (Subsection 1221(a)) must include important state goals, such as the deliverability of remote renewables to load centers, as well as economic congestion. A corridor is broader than a path for a particular transmission line, and at a minimum must include not only a particular transmission path but the paths associated with competing projects that would serve the same market.

In addition, it is important to note that the term "corridor," as used in Section 1221 of the EPAct-05 is significantly different from its use in Section 368 (Energy Right-of-Way Corridors on Federal Lands). Section 368(e) states that "A corridor designated under this section shall, at a minimum, specify the centerline, width, and compatible uses of the corridor." As noted in Section 368(a)(2), the Secretaries of Agriculture, Commerce, Defense, Energy, and Interior are required to perform "any environmental reviews that may be required to complete the designation of such corridors…" Section 368(a)(3) requires local governments to "incorporate the designated corridors into the relevant agency land use and resource management plans or equivalent plans."

While the term "corridor" in Section 1221 is not defined explicitly, Federal Power Act Section 216(a)(2)[20] states that a national interest electric transmission corridor may be designated in "…any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers."

The NOI then notes that "The Department expects to identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities. The Department believes that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion."

Clearly there is a need for coordination between the Section 368 land use-centered approach toward transmission expansion and the Section 1221 electrical path-centered approach.
As noted earlier, the Energy Commission is serving as a cooperating agency in the Section 368 West-Wide Energy Corridor PEIS effort by ensuring that the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns are considered in the

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[20] Section 1221 amends Part II of the Federal Power Act (16 United States Code section 824 *et seq*.) to add Section 216 entitled "Siting of Interstate Electric Transmission Facilities."

PEIS. To date the Energy Commission has held two workshops in California to seek public comments on designating corridors in California on federal land and the corridors proposed for consideration by utilities and other entities during the federal scoping period.

With respect to transmission corridors in the Section 368 effort, two types of corridors have been identified: those with existing transmission facilities already in place, and those which may be needed in the future. We assume from the proposed future corridors that these are potential land use solutions[21] to anticipated electrical path needs. However, at this time there does not appear to be an explicit link between the electrical path analyses which form the basis for the proposed land use corridors identified in the Section 368 process and the electrical path analyses being conducted for the Section 1221 work. We believe it is essential that physical corridors designated under the Section 368 work be predicated upon the results of the Section 1221 work.

Question No. 2: *What criteria should be used in evaluating the suitability of geographic areas for NIETC status?*

Before commenting on the specific draft criteria in the NOI, we offer three general comments:

(1) We believe the criteria must be developed and applied in an open, transparent, and collaborative manner so that parties understand the drivers for, as well as the implications of, NIETC designation. In addition to the criteria themselves and their associated metrics, it would be useful to solicit input on the relative weight that should be assigned to each criterion. For example, the NOI asks: “Are certain considerations or criteria more important than others? If so, which ones, and why are they more important?” A logical extension of these questions is: “How much more important?”

(2) The permitting of proposed transmission projects in national interest electric transmission corridors can be preempted by the federal government if state or local permitting is ineffective or not done in a timely manner. Because the federal preemption includes the ability to exercise the right of eminent domain on property not owned by the United States or a state, it should be viewed as a “last resort” option.

(3) An additional criterion not included in the NOI list is the extent to which targeted actions are needed to help affected states achieve their energy policies. See the response to Question No. 3, below, for more information.

Below, we offer specific comments on *select* criteria from the eight draft criteria contained in the NOI.

Draft Criterion 1: Action is needed to maintain high reliability.

> We agree that remedying existing or emerging reliability problems is an important criterion. We recognize that utilities are bound to Western Electricity Coordinating Council and North American Electric Reliability Council rules; however, we can envision the situation where there could be local supply constraints because of the unforeseen or premature retirement of

[21] Approximately 46 percent of California is federal land.

aging power plants that would be consistent with the definition of capacity constraints (Subsection 1221(a)).

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

The calculation of savings to consumers should reflect state energy policies, as enacted in state energy law and policies or reviews of load serving entity resource plans. Specifically, if a state policy places a high priority on acquiring renewable energy generation, or makes a judgment about natural gas price risk, or establishes a carbon adder to reflect its determination of carbon risk, DOE should assume compliance with such policies in the calculations of economic benefits to consumers. However, it is unclear to us how FERC would treat competing interests between affected states for interstate projects.

Another aspect of reliability is the consideration of forced outages of transmission because of natural disasters such as forest fires. California relies upon a significant amount of imports from the Southwestern states, and in California the season of highest fire potential typically coincides with periods of high electricity demand. While in general we advocate the efficient use of rights-of-way and existing corridors in planning for transmission expansion, there may be situations where establishing new corridors is the best option to maintain high reliability.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and to diversify sources.

We agree that actions are needed to promote the diversification of energy sources, particularly with respect to renewable resources. California is a national leader in the development of renewable resources. Over the past 30 years, California has built one of the largest and most diverse renewable generation portfolios in the world. In 2002, California established its RPS program, with the goal of increasing the percentage of renewable energy in the state's electricity mix to 20 percent by 2017. The Energy Commission's *2003 Integrated Energy Policy Report* recommended accelerating that goal to 2010, and the *2004 Integrated Energy Policy Report Update* further recommended increasing the target to 33 percent by 2020.

However, many of California's best renewable resource areas are located far from load centers, requiring transmission expansion in order to meet state goals. NIETC designation, coupled with the Section 368 federal corridor designation process, could help ensure the interconnection of these resources.

As noted in our response to Draft Criterion 1, the retirement of aging power plants could create the need to increase transfer capability into affected local areas in order to ease supply limitations.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

As noted in the response to Draft Criterion 3, we have a state policy objective to promote renewable resources, which could play a significant role in increasing the energy independence of the United States.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent upon uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

As noted in our Part II: General Comments response, we agree that this is an important criterion. To the extent that varying assumptions about natural gas prices, hydro conditions, and other critical assumptions affect the need for transmission, it is essential to consider the robustness of the results as factors in NIETC determination. In general, modeling results which demonstrate the need for transmission constraint relief over a wide range of plausible input assumptions should take precedence over results that are more sensitive to analytic assumptions. Given that the congestion study will be conducted every three years, there should be time to reevaluate the need for corridors that may not receive NIETC designation the first time.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

We agree, and believe that this is an important criterion for all NIETC designations since a comprehensive review of alternatives may not be made for specific projects proposed within NIETCs.

For projects affecting California, CEQA requires an examination of alternatives, including no-project and non-transmission alternatives. If a proposed project is not able to demonstrate that it is the preferred alternative, it will be rejected by the state.

Federal Power Act Section 216(h)(3) states: "To the maximum extent practicable under applicable Federal law, the Secretary shall coordinate the Federal authorization and review process under this subsection with any Indian tribes, multistate agencies, and State agencies that are responsible for conducting any separate permitting and environmental reviews of the facility, to ensure timely and efficient review and permit decisions."

The Federal "backstop" permitting authority should be carried out so as to not undermine CEQA compliance determination. A comprehensive evaluation of alternatives prior to NIETC designation can help avoid conflicts at a later stage when a specific project is proposed in a NIETC.

Question No. 3: *Other than what are listed in the NOI, are there other criteria or considerations that DOE should consider when deciding whether to designate a NIETC? If so, please explain. In this explanation, indicate how the proposed criterion would be applied, if possible, within the context of a specific area or areas that you consider suitable for designation* *as a NIETC. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.*

As noted in the response to Question No. 4, an additional criterion not included in the NOI list is the extent to which targeted actions are needed to help affected states achieve their energy policies. In California's case, these state energy policies are laid out in the Energy Commission's biennial integrated energy report (the most recent one, the *2005 Integrated Energy Policy Report*, was adopted in November 2005), as well as the companion *Strategic Plan* (also adopted in November 2005).

Question No. 4: *Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?*

We believe the highest priority should be given to designation of transmission corridors that promote achievement of state energy policy objectives. Next in priority would be the designation of corridors in location-constrained generation resource areas. Lower priority should be given to the designation of corridors with contractual congestion but little physical congestion, unless there has been an evaluation which finds that solutions to contractual congestion are either not feasible or more costly than building new transmission.

Question No. 5: *Should the Department of Energy (DOE) distinguish between persistent congestion and dynamic congestion, and, if so, how?*

As noted in our comments in Part II: General Comments, we do not believe that congestion should be the sole basis for NIETC designation. However, to the extent that distinctions between definitions of congestion provide focus to the effort, we offer the following comments.

The term "dynamic congestion" is not defined in the NOI and does not appear to be a standard industry term. We infer from the wording of the question that "persistent congestion" is that which has shown, and is expected to continue to show, a consistent pattern of congestion on an ongoing or seasonal basis under "baseline" conditions (including generation and transmission additions and retirements), while "dynamic congestion" refers to current or possible future congestion caused by deviations from baseline conditions, such as extended multiple transmission outages or other unanticipated events that may temporarily cause congestion.

While dynamic congestion can be extremely costly to affected parties, we believe the NIETC designation process is not the appropriate mechanism for effectively addressing dynamic congestion.

Question No. 6: *Should DOE distinguish between physical congestion and contractual congestion, and, if so, how?*

As noted in our comments in Part II, we do not believe that congestion should be the sole basis for NIETC designation. However, to the extent that distinctions between definitions of congestion provide focus to the effort, we offer the following comments.

We believe that DOE should distinguish between physical and contractual congestion, and that findings of physical congestion that adversely affect consumers should guide the DOE's conclusions on congested paths. While contractual congestion can also adversely affect consumers, it is more appropriately addressed through institutional mechanisms. However, in the event that evaluations of contractual congestion find that institutional solutions at the state, regional, or federal levels are infeasible or more costly than building new transmission, it would be appropriate to address contractual congestion in the NIETC designation process.

IV. CONCLUSION

In conclusion, the Energy Commission recommends that DOE address the following critical issues in assessing and designating transmission corridors of national interest:

- Explicitly address state energy laws and policies relating to transmission corridor planning, consistent with federal law (Subsection 1221(a)), to ensure that DOE's designation of transmission corridors of national interest both complements these efforts and leverages state expertise.

- Elevate and prominently feature "reasonably priced," "diversity of supply," and "energy independence" policies in federal law (Subsection 1221(a) to identify transmission capacity constraints and the subsequent designation of corridors of national interest. DOE should recognize the short-comings in existing transmission congestion forecasts and avoid over-reliance on these modeling studies to identify transmission needs.

- Focus efforts on how the DOE NIETC process would be coordinated with state and regional entities, as well as federal energy corridor efforts already underway to implement EPAct-05 Section 368. DOE should consider federal delegation of planning and environmental review to states and model it on the U.S. Environmental Protection Agency's reliance upon state agencies to implement environmental review under federal program standards.

- Assist in removing cost-allocation barriers to renewable and interstate transmission investments by working with FERC to push cost allocation rules at the federal level to promote adequate investment in new transmission and relieve capacity constraints consistent with federal transmission corridor law (Subsection 1221(a)).

Respectfully submitted,

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APPENDIX A
WILD PLACES AT RISK

Bureau of Land Management Wilderness

- Black Mountain Wilderness, BLM California Desert Conservation Area
- Carrizo Gorge wilderness, BLM California Desert Conservation Area
- Chuckwalla Mountains Wilderness, BLM California Desert Conservation Area
- Coyote Mountains Wilderness, BLM California Desert Conservation Area
- Fish Creek Mountains Wilderness, BLM California Desert Conservation Area
- Kelso Dunes Wilderness, BLM California Desert Conservation Area
- Little Chuckwalla Mountains Wilderness, BLM California Desert Conservation Area
- Mecca Hills Wilderness, BLM California Desert Conservation Area
- Newberry Mountains Wilderness, BLM California Desert Conservation Area
- Nopa Range Wilderness, BLM California Desert Conservation Area
- Old Woman Mountains Wilderness, BLM California Desert Conservation Area
- Orocopia Mountains Wilderness, BLM California Desert Conservation Area
- Palo Verde Wilderness, BLM California Desert Conservation Area
- Piute Mountains Wilderness, BLM California Desert Conservation Area
- Rodman Mountains Wilderness, BLM California Desert Conservation Area
- Rice Valley Wilderness, BLM California Desert Conservation Area
- Sawtooth Mountains Wilderness, BLM California Desert Conservation Area
- Stepladder Mountains Wilderness, BLM California Desert Conservation Area
- Turtle Mountains Wilderness, BLM California Desert Conservation Area

Bureau of Land Management Wilderness Study Areas

- Cady Mountains Wilderness Study Area, BLM California Desert Conservation Area
- Death Valley #17 Wilderness Study Area, BLM California Desert Conservation Area
- Dry Valley Rim Wilderness Study Area, BLM Eagle Lake Field Office
- Skedaddle Wilderness Study Area, BLM Eagle Lake Field Office
- Soda Mountains Wilderness Study Area, BLM California Desert Conservation Area

National Forest Wilderness

- Cucamonga Wilderness, San Bernardino National Forest
- Desolation Wilderness, Eldorado National Forest
- Ishi Wilderness, Lassen National Forest
- Mokelumne Wilderness, Eldorado National Forest

National Forest Inventoried Roadless Areas

- Caples Creek Roadless Area, Eldorado National Forest
- Cajon Roadless Area, San Bernardino National Forest
- Circle Mountain Roadless Area, San Bernardino National Forest
- Cucamonga Roadless Area, San Bernardino National Forest
- Dardanelles Roadless Area, Lake Tahoe Basin Management Unit
- Fish Canyon Roadless Area, Angeles National Forest
- Freel Roadless Area, Lake Tahoe Basin Management Unit
- Grizzly Mountain Roadless Area, Plumas National Forest
- Heart Lake Roadless Area, Lassen National Forest
- Ishi Roadless Area, Lassen National Forest
- Magic Mountain Roadless Area, Angeles National Forest
- Middle Fort Feather River Roadless Area, Plumas National Forest
- Mill Creek Roadless Area, Lassen National Forest
- Red Mountain Roadless Area, Angeles National Forest
- Salt Creek Roadless Area, Angeles National Forest
- Salt Springs Roadless Area, Eldorado National Forest
- San Sevaine Roadless Area, San Bernardino National Forest
- Steele Swamp Roadless Area, Modoc National Forest
- Strawberry Peak Roadless Area, Angeles National Forest
- Tragedy-Elephant’s Back Roadless Area, Eldorado National Forest
- Tule Roadless Area, Angeles National Forest
- West fork Roadless Area, Angeles National Forest
- Wild Cattle Mountain Roadless Area, Lassen National Forest

National Parks

- Death Valley National Park
- Joshua Tree National Park
- Lassen Volcanic National Park

- Mojave National Preserve

State Parks

- Anza-Borrego Desert State Park

16. California Public Utilities Commission, Received Mon 3/6/2006 6:00 PM

COMMENTS OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION

The California Public Utilities Commission ("CPUC") appreciates the opportunity to provide comments to the Department of Energy (the "Department" or "DOE") in response to its February 2, 2006 Notice of Inquiry ("NOI") Requesting Comment and Providing Notice of a Technical Conference in the Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors ("NIETCs").

COMMUNICATIONS

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EXECUTIVE SUMMARY

(1) Although DOE has done a good job of elaborating a set of substantive criteria for evaluating the suitability of designating NIETCs in particular geographic areas, the NOI is deficient in seeking comment on the process by which such designations would take place. Accordingly, many of the CPUC's comments below will address important aspects of the process that DOE should follow in making NIETC designations. These comments are provided in keeping with the spirit of the text following the list of draft criteria in the NOI, in which DOE requests comment on whether there are " . . . other criteria or considerations that the Department should consider in making an NIETC designation . . . "

(2) In its NOI, DOE has set forth a set of evaluation criteria that it intends to apply to the various geographic areas under consideration for designation as NIETCs based on the outcome of the congestion study it has been conducting. Many of the CPUC's comments below pertain to Draft Criterion 8. Regarding this Draft Criterion 8, DOE states its desire to avoid designating NIETCs in a manner that undercuts the viability of alternatives to the transmission expansions that NIETCs would facilitate, and seeks comment on how to balance the clear need for new transmission in some areas with the value of alternatives to such transmission.

(3) The CPUC also recommends that DOE add an additional evaluation criterion to its consideration of the factors for designating NIETCs. Specifically, in determining whether to designate a specific geographical area as an NIETC, DOE needs to give highest priority to the designation of transmission corridors that enable the achievement of state and regional energy policy objectives, wherever state and regional transmission planning requires assistance in this area. This includes facilitation of the delivery of energy from location-constrained generation

resource areas, particularly from areas where there are substantial supplies of wind power or other renewable energy resources.

(4) Under Section 368 of EPAct, various federal agencies, in collaboration with state, tribal and local governments, are engaged in a process of designating corridors for oil, gas and hydrogen pipelines, and electric transmission through federal land in the 11 contiguous Western states. This Section 368 process needs to be coordinated with the separate Section 1221 process for designating NIETCs, since any western NIETCs may very well transit considerable federal land.

(5) In conducting its process of designating NIETCs, DOE needs to recognize and defer to on-going regional and state transmission planning, congestion management and resource planning processes. In particular, in the Western Interconnection, various collaborative regional and sub-regional transmission planning efforts have already resulted in the identification and designation of major transmission upgrades, and a number of specific projects resulting from these planning efforts are already in the active permitting process at the state level.

(6) DOE needs to recognize the potential significance of financing issues in connection with the identification and designation of NIETCs, and should recommend that FERC not exercise its preemption authority for any proposed project until the developer has produced clear evidence that it has all relevant financing issues, including rate and cost allocation issues, solved for its proposed project.

Finally, the CPUC notes that it is aware of the substance of the comments on DOE's NOI that will be submitted by the Western Interstate Energy Board and the Committee on Regional Electric Policy Cooperation ("WIEB/CREPC"). Based on its review of the WIEB/CREPC comments, the CPUC endorses the substance of said comments and urges the DOE to seriously consider those comments, as well as the CPUC's comments that follow.

BACKGROUND

On February 2, 2006, pursuant to Section 1221(a) of the Energy Policy Act of 2005 ("EPAct"), the DOE issued an NOI seeking comments and information concerning its plans for an electricity transmission congestion study and possible designation of NIETCs. Specifically, DOE is seeking comment on criteria for gauging the suitability of candidate geographic areas as NIETCs.

DOE's NOI points out that the Nation's electric system includes over 150,000 miles of interconnected high-voltage transmission lines that link generators to load centers; and that the electric system has been built by electric utilities over a period of 100 years, primarily to serve local customers and support reliability, but that the system generally was not constructed with a primary emphasis on moving large amounts of power across multi-state regions. Due to a doubling of electricity demand and generation over the past three decades and the advent of wholesale electricity markets, transfers of large amounts of electricity across the grid have increased significantly in recent years. This increase in regional electricity transfers saves electricity consumers billions of dollars, but significantly increases transmission facility loading. However, investment in new transmission facilities has not kept pace with the increasing economic and operational importance of transmission service. Moreover, congestion in the transmission system impedes economically efficient electricity transactions and in some cases threatens the system's safe and reliable operation.

EPAct, as well as DOE's National Transmission Grid Study (May 2002), and the Secretary of Energy's Electricity Advisory Board's Transmission Grid Solutions Report (September 2002), recommended that DOE address regulatory obstacles in the planning and construction of electric transmission and distribution lines. In exercising the Secretary's authority to designate NIETCs, EPAct Section 1221 states that the Secretary may consider, among other things, whether:

> (A) The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
>
> (B)(i) The economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and (ii) A diversification of supply is warranted;
>
> (C) The energy independence of the United States would be served by the designation;
>
> (D) The designation would be in the interest of national energy policy; and
>
> (E) The designation would enhance national defense and homeland security.

DISCUSSION

<u>The Need for a More Carefully Delineated Process for Designating NIETCs</u>

Section 1221(a)(2) of the EPAct specifies that, based on and subsequent to the congestion study due in August of 2006, the Secretary of the DOE shall issue a report that may designate NIETCs, "after considering alternatives and recommendations from affected parties (including an opportunity for comment from affected States). . . " Elsewhere, section 1221(b) states that the Federal Energy Regulatory Commission ("FERC"), after notice and an opportunity for hearing, may issue permits for construction in NIETCs, if finding that a state has withheld approval of an application to construct in an NIETC for one year, or has conditioned its approval in such as manner as to make the project "not economically feasible."

It is essential for DOE to recognize that designation of NIETCs represents the triggering event in a chain of procedural, financial and ultimately physical developments of potentially vast proportions. Once opened, it will be extremely difficult to put the genie back into this bottle. Accordingly, to avoid unwarranted or premature NIETC designations, it is important to think through and lay out the "downstream" process beyond the congestion study to be released this coming August. Looking ahead in this manner will rationalize the DOE's (and ultimately FERC's) activities with respect to transmission corridor designation, and will clarify the implications of the corridor selection criteria that DOE set forth in the NOI.

For this reason, any final NIETC designation criteria must be accompanied by administrative procedures explaining how the Secretary will apply such criteria. Given the vagueness of the statutory criteria (noted above) that the Secretary may use to designate NIETCs, it is important that DOE develop specific criteria for evaluating candidates for NIETC designation, as well as written procedures on how the Secretary will apply such criteria in corridor designation decisions. Since corridor designations can lead to federal preemption of state laws and condemnation of private lands, these procedures should provide opportunity for the states and public to comment on a proposed NIETC designation by the Secretary, should require that NIETC designations be based on a preponderance of the evidence and should be subject to a high standard of review.

In addition, DOE has not specified any process for appealing the designation of an NIETC. The states have a fundamental interest in guiding land use and development within their borders. Moreover, there is a real potential that development in and nearby to a designated NIETC will have to be limited for an extended period of time. Accordingly, key stakeholders need to have a reasonable opportunity to challenge the designation by DOE of an NIETC , which, in their view, are either not justified, or the purpose for which can be met by reasonably available and cost-effective alternatives.

Beyond the basic need for DOE to promulgate specific and detailed procedures indicating how NIETCs will be designated, if there is to be meaningful understanding, assessment and comment by affected parties on the full scope of the corridor designation process that DOE is undertaking, it is essential for DOE to consider a number of broader process-related questions, such as the following:

- How and under what approximate schedule will DOE move from the congestion study to a report that "may" designate NIETCs?
- When this happens, what opportunity will affected parties have to comment on and influence the designation of NIETCs?
- How will NIETCs be integrated (and made consistent) with energy corridors on federal lands pursuant to EPAct Section 368?
- How will DOE's consideration of criteria for, and alternatives to, NIETC selection inform any subsequent FERC permit approval process?
- How will the FERC permit approval process apply the DOE's NIETC selection criteria and objectives to particular permit applications?
- In designating NIETCs, which will have significant impact on any subsequent transmission permitting process, how will DOE isolate its corridor-designation role from the interests of its power marketing subsidiaries, such as the Western Area Power Administration ("WAPA")?
- What information, criteria and processes will be used by FERC to determine whether a state's refusal to approve an application to construct a given proposed transmission project in a designated NIETC is reasonable and should be upheld?

These questions suggest that the corridor designation process that the DOE is embarking on cannot, and should not, be carried out as quickly as the NOI seems to suggest. For example, the Report that Section 1221 calls upon the Secretary to complete by this August should not incorporate any final corridor designations. For it to do so would undercut the legitimate interests of stakeholders, especially states, who are concerned that DOE needs to engage in a careful and deliberate process in order to come up with a reasonable set of final corridor designations that will be productive and accomplish the purposes of Section 1221.

DOE must also be very careful to insulate the process it is undertaking in this NOI from the activities and interests of its power marketing subsidiaries, including, but not limited to, WAPA. Although the overall thrust of transmission planning and management in the country over the past decades or more has been in the direction of greater regional integration, in California, it has been our experience that WAPA has been moving in the opposite direction. FERC has strongly encouraged the formation of Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"). In California, the CPUC supported the formation of the California ISO in the late 1990s and has worked closely with the California ISO toward our common goal of assuring the reliable delivery of power in the state. However, as recently as 2004, DOE's subsidiary, WAPA, has undermined the California ISO by withdrawing from it. It would be a shame if DOE were to use this NIETC process to further the interests of WAPA, at the expense of the California ISO or of that great majority of California's citizens who depend on the California ISO to manage the transmission component of their electric service.

The corridor designation process must be fully informed by, and be reflective of, transmission planning information, activities, processes and goals at the state and regional levels. If the federal level corridor designation process that is getting underway in connection with this NOI is not conducted in collaboration with the states and regions, it could collide with them later on. To avoid any such potential conflicts in the future, DOE and FERC should specify with precision how, once the initial phase of conducting congestion studies is completed, this collaborative effort will be conducted. Similarly, DOE should make it explicit that any NIETCs initially designated based on the criteria addressed in the present NOI are only preliminary, and are subject to the consideration of alternatives and recommendations from affected parties, in particular, the states.

In conclusion, the designation of NIETCs is one link in a chain of connected actions. DOE should not finalize criteria for the designation of NIETCs until DOE and FERC have defined in detail all the links in the chain of actions that will implement Section 1221. Along these lines, DOE should recommend rules and procedures that specify how the responsibilities of federal agencies for review will be coordinated, how state agencies will meet a one-year deadline for siting projects proposed in an NIETC, and how federal review will mesh with state siting processes. DOE should also establish procedures to fulfill its agency coordination responsibilities. For example, DOE should specify how it will advise FERC whether a sponsor's project falls within a corridor and under what conditions a permit should be issued.

Corridor Designations Must Balance the Need for New Transmission with the Value of Alternatives to Transmission

The broad process questions, noted above, which DOE needs to consider as part of its corridor designation activities, necessarily shade into the substantive issues that DOE itself raised in the NOI. Specifically, Draft Criterion 8 raises the critical question of the need to find an appropriate balance between the clear need for new transmission in some areas, whereas in other areas, there may well be reasonable and cost-effective alternatives to such new transmission. Indeed, transmission corridors cannot and should not be designated without a necessary ruling out of alternatives that would achieve the same end, either in terms of eliminating congestion, enhancing the reliability of the grid, providing an economical supply of power, providing increased energy independence, or providing energy diversity. This is, of course, not an exhaustive list of objectives.

However, in order to determine that any individual alternative or set of alternatives are insufficient to justify avoiding or delaying the designation of a corridor, DOE will need to have an adequate understanding of state and regional transmission planning and siting issues, actions and policies. Otherwise, DOE will be unable to judiciously rule out alternatives. Section 1221 does not state a policy preference for transmission over generation or demand-based solutions, and in many cases, existing constraints can be more cost-effectively resolved through options other than expensive, large (especially multi-state) transmission projects that require more time and money to site and build than would new generation.

In many instances, state resource adequacy and integrated resource planning ("IRP") processes already provide vehicles that allow stakeholders to reasonably identify the bottlenecks and congestion of concern that could be alleviated by particular transmission projects, or by available alternatives. Moreover, congestion provides market signals that create incentives for the development of non-wires, demand and supply-side alternatives. Such market signals will drive new investment and may create solutions within a given region more efficiently and more economically than transmission corridors assigned from Washington. For this reason, potential NIETCs should be viewed with great skepticism if driven solely by the uncertainty regarding future supply options, future system conditions (including demand growth) or future developments in policy (such as those associated with demand-side management, location-constrained supply resources or renewable energy goals).

Furthermore, preliminary NIETCs must be of sufficient *geographic specificity* so as to allow meaningful and robust comment regarding: (1) how, and to what extent, a preliminary NIETC actually meets specified criteria and goals; (2) expected project costs and environmental impacts (NIETCs will not achieve the goals that Congress intended in enacting the EPAct without some reasonable balancing of the costs and benefits of the projects that can be expected to result from the designation of a corridor); and (3) what are the reasonably available alternatives to the likely transmission projects resulting from a corridor designation, and how attractive they are. Stakeholders will not be able to provide informed and useful input either on alternatives or on potential corridors without knowing what transmission options they are commenting on. A specification like “Montana to Los Angeles” is too vague and invites abuse, particularly since the condemnation of private property is involved.

With overly vague corridor designation, a sponsor could propose a line virtually anywhere and claim it is in the NIETC. Without some parameters limiting and specifying the NIETC’s location, no one will be able to tell whether a given proposed project would be in the corridor or not. Furthermore, an overly broad NIETC will generate a wide range of potential transmission projects, each of which will have a different range of possible alternatives, thus leaving an insufficient basis for the identification of actual project alternatives and whether they are preferable to a proposed transmission expansion. When there is an excessive diversity of potential projects within a corridor, it becomes impossible to define whether the corridor as a whole serves a purpose that cannot be met by the available alternatives.

Finally, it is critical to note that once a transmission proposal in a designated NIETC is brought to FERC, there is unlikely to be a reasonable opportunity for adequate evaluation of alternatives to that project. Such assessments, which may include, but are not limited to, IRP, necessarily incorporate a scope, depth, perspective and sensitivity to regional and state needs that can only be conducted on a state or regional level. Accordingly, such state and regional level transmission and resource planning efforts should inform DOE’s corridor designation process, rather than to be conducted in reaction to that process.

Proposed Draft Criterion 9: *Targeted actions in the area would be consistent with*

state and regional energy policy objectives

The CPUC recommends that DOE add an additional evaluation criterion (suggested language above) to its consideration of the factors for designating NIETCs. In determining whether to designate a specific geographical area as an NIETC, DOE needs to give highest priority to the designation of transmission corridors that enable the achievement of state and regional energy policy objectives.

In particular, California has developed an inter-agency Energy Action Plan laying out specific energy goals, as well as the steps necessary for achieving them in a coordinated manner. This plan includes a "loading" order, which establishes a hierarchy of energy development priorities. The highest priority is to obtain greater energy efficiency and demand response, followed by enhanced development of renewable energy and distributed generation. The next priority is the development of clean and efficient fossil generation. The achievement of resource adequacy at the state, load-serving entity and local levels is also a key element of the plan. These and other elements of the Energy Action Plan have a direct and substantial bearing on California's transmission needs and on the best strategies for meeting those needs, which are also addressed in the plan.

For example, a major challenge that California faces in meeting its energy priorities that should be recognized (and could be supported) by the envisioned NIETC program is facilitating the delivery of energy from location-constrained generation resource areas, in particular, areas where there are substantial supplies of wind power or other renewable energy resources. It has been our experience in California that a major obstacle to achieving renewable energy goals (now pursued in many states nationwide) is the planning, siting and financing of transmission needed to connect major, remote renewable resource areas to the main bulk transmission system and ultimately to load centers. This often requires long, high-capacity, costly transmission projects whose siting and financing difficulties (especially if crossing state lines) are compounded by the fact that, in comparison with typical fossil generation projects, renewable energy projects are typically smaller, involve multiple owners building out a resource area over time, and often suffer from constrained access to financing. If DOE's and FERC's administration of a future federal transmission corridors program could coordinate with, learn from, and support (and, if necessary, extend) these state and regional efforts to access renewable resources, this would represent a very valuable contribution, both in California and nationwide.

NIETCs are ultimately intended to benefit the American public. Transmission planning and investment decisions are best made at the level of government closest and most responsive to (1) the consumers ultimately paying the bills, and (2) the entities providing and financing electricity services (*i.e.*, transmission owners, generators, and load-serving entities). That level is generally the state. FERC is not the place where IRP or resource adequacy planning is supposed to be done, and IRP-type thinking needs to be done (on a state and regional level) to inform the designation of corridors. Failure on the part of DOE to take such sophisticated planning considerations into account could also have the unintended effect of picking winners and losers based on considerations that are simply not economic and that do not cost-effectively alleviate the problems that Section 1221 was intended to address.

Coordination of the Section 1221 Process with the Section 368 Process

Under Section 368 of EPAct, various federal agencies, in collaboration with state, tribal and local governments are engaged in a process of designating corridors for oil, gas and hydrogen pipelines and electric transmission through federal land in the eleven contiguous Western states. This Section 368 process needs to be coordinated with the separate Section 1221 process for designating NIETCs. The Section 368 process is currently engaged in a two-year study, which includes detailed analysis of potential routes under the National Environmental Policy Act ("NEPA"). An interagency planning group has been established in California to provide input into the Section 368 energy corridor NEPA process. A CPUC representative is attending these meetings along with other state and federal agencies, including the California Energy Commission, the Bureau of Land Management, the United States Forest Service, the State Lands Commission, the National Park Service, the US Air Force, and the US Marine Corps.

Coordination between the two separate corridor designation processes is critical, because if a given potential corridor through federal lands is not designated under the Section 368 process, it should certainly not be included in an NIETC. Moreover, any designated NIETC will also have to be subject to NEPA review before FERC could subsequently consider approving applications to construct transmission in that corridor. Therefore, coordination between these two corridor designation processes is necessary to eliminate duplicative environmental review efforts, and to ensure that one process does not get too far ahead of the other.

Because the Section 368 process is specific to the Western states, it is necessary that any potential NIETCs in the West be looked at in coordination with the multi-use corridor designation process that is already underway pursuant to Section 368. Moreover, no corridor designation in the West should receive a final designation as an NIETC until the 368 process – including all necessary environmental reviews – is completed.

The CPUC is concerned that in conducting its NIETC designation process, DOE may overlook the importance of coordinating these two processes, because Section 368 applies in the West with its extensive federal lands, whereas there is relatively little public land in the East, where the more serious transmission constraints exist. In this regard, DOE should also recognize that in the West, transmission corridors are generally much longer than in the East, which further enhances the likelihood that a potential NIETC will necessarily run through public lands.

Given the overlapping mandates of Section 368 and Section 1221, it is essential that in conducting its process for designating NIETCs in the Western states, DOE coordinate all actions that it intends to take regarding NIETCs with the process for designating energy corridors on federal lands that is already well under way pursuant to Section 368. Obviously, this includes the development of NIETC corridor designation criteria.

<u>Deference to Existing Transmission Planning Processes in the West</u>

In the Western Interconnection, we have a well-developed planning process. Various collaborative regional and sub-regional transmission planning efforts have already resulted in the identification and designation of major transmission upgrades, and a number of specific projects resulting from these planning efforts are already in the active permitting process at the state level.

The West has a history of cooperation to address transmission planning issues. This is due to the long distances between supply resources and load centers, the challenges of efficiently utilizing major hydroelectric systems across the western U.S. and Canada, and the great diversity of the demand patterns and supply mix among the electric utility service territories and sub-regions in the West. The Western Systems Coordinating Council ("WSCC") was formed in 1967 by electric power systems serving all or part of the 14 Western States and British Columbia. The Western Electricity Coordinating Council ("WECC") was formed in 2002 by the merger of WSCC, Southwest Regional Transmission Association, and Western Regional Transmission Association, and now represents an area of nearly 1.8 million square miles with a population of 71 million. Besides continuing the WSCC's responsibility for coordinating and promoting electric system reliability, WECC now supports efficient competitive power markets and open, non-discriminatory transmission access, and provides an environment for coordinating its members' operating and planning activities.

In recent years, sub-regional transmission planning organizations have formed and been active across the west, including NTAC, RMATS, SWAT, and STEP. Working with WECC, the states, the electricity industry and stakeholders, these organizations collaboratively address transmission expansion needs and projects in their respective sub-regions. The Seams Steering Group – Western Interconnection ("SSG-WI") was formed to address physical and market interface issues across the sub-regions and RTOs in the West, including congestion and its costs under different load and resource scenarios, using a comprehensive database and production cost modeling. We note that the SSG-WI database is freely available to any transmission developer that seeks to build a project in the Western Interconnection. Now, WECC is expanding its scope to take over and extend SSG-WI's role in such "economic" transmission planning. This expanded role has the support of the industry, the states, and regional organizations such as the Western Governors' Association ("WGA"), the Western Interstate Energy Board ("WIEB") and the Committee on Regional Electric Power Cooperation ("CREPC").

As DOE is well aware, WECC, via the ad hoc Western Congestion Assessment Task Force ("WCATF"), and with support from the CPUC staff, is helping DOE prepare the Western Interconnection portion of the congestion studies required by August 2006 under EPAct section 1221. In recent months, the WCATF has organized and packaged reports on a series of congestion studies for the Western Interconnection and is evaluating criteria for measuring historical congestion, as well as forward-looking congestion, under different generation scenarios out to 2008 and 2015. Using SSG-WI and CREPC studies that have already been, or soon will be, completed, WCATF will analyze the locations, prevalence and costs of congestion under additional scenarios out to 2015.

California participates closely in WECC, in sub-regional planning groups, and in regional energy organizations such as WGA, WIEB and CREPC. Transmission planning in California reflects and balances diverse goals and reflects collaboration among various organizations and stakeholders, extending to relevant sub-regional organizations (*e.g.*, STEP for Southern California and desert Southwest transmission planning). Besides numerous smaller projects, several major in-state and inter-state transmission projects are currently in various stages of development in California.

Ongoing transmission planning activities in California and across the Western Interconnection have been developed through a careful, collaborative process, and are addressing a range of key, interdependent issues including reliability, congestion, competitiveness and diversity of supply, state policy objectives, resource adequacy, local area needs, stakeholder interests, balancing of wires and non-wires alternatives, and both permitting and funding challenges. Effective organizations and organization relationships have been developed painstakingly over time, and we are making substantial progress. The evidence of this progress includes the activities of WECC, the sub-regional groups, west-wide organizations, and individual states, as well as the major transmission projects at various states of planning and development.

In view of this abundance of effective, large-scale transmission planning and transmission project development that is already taking place in the Western Interconnection, nothing that DOE does in its NIETC designation process should undermine or seek to trump these efforts. It is, first of all, up to the states to solve their transmission planning and siting problems. Federal agencies should not intervene on the state or regional level unless and until there is a demonstrated need for them to do so. Whether or not DOE ultimately identifies any NIETCs in the West, the CPUC believes that the DOE/FERC effort at the federal level to identify corridors and, potentially, to evaluate and permit specific projects should not only be consistent with, but necessarily will have much to learn much from, the West's current regional and sub-regional transmission planning efforts, objectives and concerns.

Deference to Congestion Mitigation Planning by ISOs/RTOs

Insofar as its studies of transmission constraints will be looking at problems within California and the states adjacent to it, DOE needs to recognize that in California, we currently have congestion management tools, but are also actively engaged in a new process, which is being managed by the California ISO, for further mitigating transmission congestion in this state. This new transmission congestion mitigation process is an integral part of a major market re-design project, the Market Redesign and Technology Update ("MRTU").

The MRTU project is nearing culmination. When implemented, it will provide a substantially improved environment for assessing and managing congestion and transmission planning. Moreover, this MRTU process, which is being overseen and is subject to regulatory approval by FERC, is attempting to accomplish, through the implementation of a complex series of pricing and electricity market design mechanisms, many of the same objectives as the process that DOE has initiated by the issuance of this NOI. Accordingly, any irreversible action that DOE might take with regard to the possible designation of NIETCs in California, or of NIETCs in the states neighboring California that would primarily serve load in California, should await the outcome of the implementation of the California ISO's MRTU process.

Because one of the key purposes of MRTU is to mitigate transmission congestion, DOE (and FERC) should allow the MRTU process, which is currently expected to be implemented next year, to have a reasonable opportunity to mitigate congestion before any action is taken on any transmission corridors identified as NIETCs on the basis of existing congestion.

Deference to State Energy Policies

There is a need for an exhaustive examination of any and all proposed transmission projects at the state level before the proponent of a proposed project should be able to rely on a DOE designation of an NIETC in order to go to FERC seeking to trump state siting authority. For this reason alone, DOE should make no final decision on criteria for the designation of any NIETC until both it and FERC have established rules and procedures to implement section 1221 in its entirety. (For example, FERC will need to establish rules about the contents of applications, the designation of when the one-year clock begins, and whether and how it will consider non-wires alternatives to particular proposed transmission projects seeking to rely on an NIETC designation.)

Similarly, the calculation of savings to consumers from projects to be built in NIETCs should reflect state energy policies as enacted in state law, as well as a review of the resource plans of relevant load serving entities. This is a matter of fundamental importance, because DOE's designation of an NIETC will effectively short-circuit the consideration of non-transmission alternatives. In many cases, load-based generation and demand-side actions can be more cost-effective solutions to transmission congestion than the construction of a new transmission line linking a load pocket to remote generation facilities would be. However, once DOE designates an NIETC and a transmission project application is received in a designated corridor, the state siting process, as well as important state policy requirements, will be compromised, and the ability to consider reasonable and cost-effective alternatives will be undermined. For example, the California Environmental Policy Act mandates the consideration of non-project alternatives as part of the state's process for approving major new projects. However, for a proposed major transmission project, the designation of an NIETC in California could essentially nullify the important public policy objectives embodied in that statute.

Accordingly, the process that DOE develops to implement NIETCs must recognize this potential for causing disruption to legitimate state resource planning processes. In particular, the process by which FERC may issue a permit to construct a transmission project within a NIETC, if a state has not approved the project within one year of an application, must fully recognize and allow for the state's specific reasons for not approving the project in the first place, including the consideration of reasonable and cost-effective alternatives.

DOE Should Not Overlook Financing Constraints

In many instances, financing issues are as much of an obstacle to transmission line development as are siting constraints. Given that EPAct Section 1221 anticipates the possible FERC preemption of state siting authority, DOE needs to recognize the potential significance of financing issues in connection with the identification and designation of NIETCs. It would be premature and useless to give FERC the ability to preempt state authority in NIETCs that DOE may designate without an explicit recognition of the need for the resolution of such financing problems. Indeed, the designation of NIETCs without such a recognition may in fact worsen these problems, as it would needlessly disillusion local stakeholders without improving the outlook for needed transmission line development. Accordingly, in connection with the process for designating NIETCs, DOE should recommend that FERC not exercise its preemption authority for any proposed project until the developer has produced clear evidence that it has all relevant financing issues, including rate and cost allocation issues, solved for its proposed project.

CONCLUSION

The CPUC respectfully requests that the DOE consider the above comments in this proceeding.

March 6, 2006

Respectfully submitted,

/s/ Laurence G. Chaset

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17. Canadian Electricity Association, Received Mon 3/6/2006 3:00 PM

COMMENTS OF THE CANADIAN ELECTRICITY ASSOCIATION

Pursuant to the Notice of Inquiry ("Notice") issued by the U.S. Department of Energy ("DOE" or "Department") on February 2, 2006, the Canadian Electricity Association ("CEA") submits the following comments addressing the proposed electricity transmission congestion study and issues relating to the designation of National Interest Electric Transmission Corridors ("NIETCs").[1]

[1] The Canadian Electricity Association is the national forum and voice of the electricity business in Canada. Its membership accounts for most of Canada's installed generating capacity and transmission capacity.

Background

The Department's Notice seeks comments concerning its plans for an electricity transmission congestion study and possible designation of NIETCs, as required by section 1221 of the Energy Policy Act of 2005. Section 1221 requires that the Secretary of Energy conduct a nationwide study of electric transmission congestion, in consultation with "affected states and any appropriate regional entity," and to issue a report in which the Secretary may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." In this study, the Department "expects to present an inventory of geographic areas of the Eastern and Western Interconnects that have important existing or projected needs related to the electricity transmission infrastructure." These corridors will be identified as generalized paths between locations, rather than specific routes.

On July 22, 2004, the Department of Energy had issued a notice of inquiry on the designation of NIETBs. At that time, CEA submitted comments that emphasized the international nature of the North American transmission grid and the benefits of including cross-border bottlenecks in all Department considerations. CEA further stressed the value of cross-border cooperation in determining methods for alleviating these bottlenecks to benefit the electricity security of the North American grid. The Department notes in its February 2, 2006, Notice that it has "considered the comments received via the [July 2004] notice and workshop."

The focus of the Notice is on the identification of "national" transmission corridors. However, the transmission grid in the United States does not stop at the Canadian border. As CEA explained in its comments on the July 2004 Notice, the grid is North American in scope. At that time, CEA stated: "Given the interconnected nature of the transmission system and the extent of U.S/Canadian electricity trade, the reliability of the transmission grid and the efficiency of electricity markets cannot be properly addressed without the full engagement of and cooperation of both U.S. and Canadian entities. Only a bi-national approach to addressing transmission bottlenecks will ensure a reliable transmission grid and robust electricity markets." CEA continues to believe that a North American approach should be incorporated into both the development of an electricity transmission congestion study and the consideration of NIETCs, as reflected in the comments, below.

DOE's Transmission Congestion Study and NIETC Criteria Should Reflect the International Nature of the North American Grid

In conducting its transmission congestion study, the Department intends to identify geographic areas where transmission congestion is significant and where additions to transmission capacity could lessen the potential adverse effects of such congestion. In terms of designating NIETCs, DOE offers eight draft criteria and seeks comment on the criteria and whether certain considerations or criteria are more important than others.

In terms of the congestion study, CEA believes that interconnections across the Canada-U.S. border should be assessed, as recognized by the DOE in its National Transmission Grid Study (May 2002, page 20):

> [S]olving the problem of transmission constraints within the United States will also require cooperation with Canada. Many scheduled power transactions within the U.S., particularly east-to-west transactions within the Eastern Interconnection, flow over transmission lines located in Canada before reaching loads in the U.S. This is a particular problem at points in the upper Midwest where the transmission systems of the two countries interconnect. These unintended flows (or "loop flows") often require transmission service curtailments in the U.S.

There are major interties in 5 geographic regions across the continent – British Columbia with the Pacific Northwest, the Prairies with the Midwest, Ontario with the Great Lakes States, Quebec with the Northeast, and the Maritimes with New England. CEA members and their U.S. counterparts regularly work together to address these cross-border constraints. Notwithstanding such efforts, however, constraints that are reflected to the border and within large regional markets will continue to inhibit further electricity trading and possibly compromise reliability.

Several examples exist of supply potentially available to constrained regions that cannot move because of transmission congestion. For example, the constraints in the Pacific Northwest limit the opportunities for cross-border trade between these jurisdictions. Constraints within the Northwest and Northeast regions constrain economic flows beyond the border. Enhanced transmission capacity between New Brunswick and Maine as well as between Manitoba and the Midwest ISO will allow for increased transfers to/from constrained regions in the U.S. Identifying such constraints in DOE's transmission congestion study could facilitate the deployment of appropriate measures to address those constraints, thereby helping to secure a reliable and efficient North American transmission grid in the future.

CEA believes that the criteria developed to evaluate geographic areas as candidates for NIETCs should also take into account the international nature of the transmission grid and the benefits of cross-border solutions to transmission constraints. An effective North American transmission grid allows for enhanced reliability and a diverse energy supply mix in the U.S. Reflecting the international nature of the transmission grid, CEA believes that the criteria for designating NIETCs could be expanded to include "international" considerations. Considering transmission constraints in a bi-national fashion will help to ensure a reliable and efficient transmission grid.

In light of this proposal that grid solutions should be examined from an international perspective, CEA would like to comment specifically on Draft Criterion 4, which suggests that

NIETC designation be based on actions that will “enhance the energy independence of the United States.” One of the identified metrics would examine how the proposed NIETC would “reduce dependence on energy imports.” CEA believes that this approach could have the effect of reducing energy trade between the U.S. and Canada, a move that could undermine both the reliability and the economic efficiency of the North American bulk-power system. To ensure a strong and robust transmission grid, criteria for designating NIETCs should look to measures that will enhance cross-border electricity trade between our two countries.

Conclusion

The integration between Canada and the United States will only increase as energy demand and trade continue to grow, thereby further taxing the North American grid. Given the interconnected nature of the transmission system and the extent of U.S/Canadian electricity trade, the reliability of the transmission grid and the efficiency of electricity markets cannot be properly addressed without the full engagement of and cooperation of both U.S. and Canadian entities. Only a bi-national approach to addressing transmission bottlenecks will ensure a reliable transmission grid and robust electricity markets.

Respectfully Submitted March 6, 2006

18. Cimarron County of Oklahoma, Received Wed 3/1/2006 5:36 PM

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

By e-mail to: EPACT1221@hq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of
National Interest Electric Transmission Corridors

Cimarron County of Oklahoma wishes to comment on the Department of Energy (the "Department")'s efforts in conducting its initial electric transmission congestion study required by the Energy Policy Act amendment to the Federal Power Act subsection 216(a)(1). We understand the Department intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity could lessen potential adverse effects borne by consumers.

We support the Department's goal to identify corridors for potential projects as generalized electricity paths between locations, as opposed to specific routes for transmission facilities. We also believe that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion.

We wish to emphasize that the Department's initiative is an opportunity to identify wind-rich regions that offer both economic development along potential transmission corridors and economical energy from wind power development. While some early wind projects may have been built in the wind-rich area**(s)** of our **state**, the potential for more wind energy development should be included in the Department's review. We believe there is a true need to plan for more transmission to move wind power from future wind developments to consumers, thereby providing economic benefits, fuel diversification, and clean energy for our citizens.

Thank you,

John H. Freeman
Chairman
Board of County Commissioners
Boise City Oklahoma

19. City of Fayetteville, North Carolina, Public Works Commission Received Mon 3/6/2006 3:58 PM

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors	Notice Of Inquiry

COMMENTS OF THE PUBLIC WORKS COMMISSION OF THE CITY OF FAYETTEVILLE, NORTH CAROLINA

Introduction and General Problem
The Public Works Commission of the City of Fayetteville, North Carolina (hereafter "Fayetteville" or "PWC") appreciates this opportunity to respond to the Department of Energy's

Notice of Inquiry, "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," which was published in the Federal Register on February 2, 2006. 71 Fed. Reg. 5660. PWC is a member of ElectriCities of North Carolina, Inc., and thus a member of the Transmission Access Policy Study Group ("TAPS"), which is filing generic overall comments today in this proceeding. We agree with those TAPS comments, but wish to add specific factual material to this record, as the TAPS comments have suggested will be done by TAPS members. The NOI as issued spells out:

> ***In that regard, if interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI.*** If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. If interested parties wish to identify areas for early designation, they should supply with their comments all available data and information supporting a determination that severe needs exist. Parties should identify the area that they believe merits designation as an NIETC, and explain why early designation is necessary and appropriate. The Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

Fayetteville owns and operates a municipal electric system that provides retail electric service to residential, commercial, and industrial customers in the City of Fayetteville, North Carolina and surrounding areas. In connection with this service, Fayetteville owns and operates generation, transmission, and distribution facilities used to provide electric service to the public. Fayetteville is interconnected with Carolina Power & Light Company, also known as Progress Energy Carolinas, Inc.[1]

On August 16, 1999, Fayetteville issued a request for proposals for firm power supply to meet its demand and energy requirements beginning July 1, 2003. In response to that RFP, Fayetteville received a number of proposals, and found that most sellers had proposed to utilize one version or another of the form contract prepared by a committee of representatives of Edison Electric Institute and the National Energy Marketers Association member companies (referred to hereinafter as the "EEI Agreement"). As a result of that RFP process Progress Energy was selected as the successful bidder and three interrelated agreements were – after extended negotiations – entered into and became effective on July 1, 2003: a Master Power Purchase and Sale Agreement, a Marketing Agency Agreement, and a Scheduling and Services Agreement.

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[1] We will refer to CP&L (or Progress Energy Carolinas, Inc.) as "Progress Energy" or simply "Progress" herein. Although there is also a Progress subsidiary in Florida, this filing addresses only issues applicable to Progress Energy Carolinas.

Those agreements continue in effect through June 30, 2012. Under those agreements, Fayetteville purchases firm base and intermediate power supply from Progress, and supplies the balance of its requirements from its own peaking resources or from short-term market purchases when available. Fayetteville also became a network transmission customer of Progress Energy under its OATT, although PWC has approximately 200 MW of internal generation serving part of its load, which is approaching 500 MW on peak.

Under those agreements, PWC is entitled to purchase power and energy above the amounts purchased from Progress from other competitive entities if it is cheaper for it to do so. But Fayetteville has found that transmission constraints on the Progress system severely limit its ability to actually purchase energy from short term markets outside the Progress control area to displace more expensive energy from its own generation facilities. The last time Fayetteville was able to make any off-system purchases from outside the Progress control area was more than a year ago, in December, 2004. Fayetteville's inability to purchase in the short-term market is largely due to physical limitations on the Progress system.[2]

Even more serious, however, than the inability to purchase power on the short-term market, is the lack of transmission capacity for power supply alternatives when the current contract expires in 2012. Progress undertook a Scoping Study of interface capacity which found that starting in 2010 there will be <u>no</u> long-term firm transmission capacity available for importing power into the Progress control area in North Carolina. Furthermore, the most likely transmission upgrades to alleviate this limitation could not be placed into service until 2016 or after. Because Fayetteville is a network transmission customer, Progress is responsible for planning its transmission system to provide for the needs of Fayetteville as well as for Progress's own needs. When Fayetteville's current power supply contract with Progress expires in 2012, however, if something is not done, it will be foreclosed from power supply options outside the Progress control area, and Progress is the only entity with sufficient base and intermediate power supply inside that area potentially available to meet Fayetteville's needs.[3] Consequently, Fayetteville will be limited to the current transmission supplier as its only power supplier option, unless new generating resources are constructed. Fayetteville is willing to participate in any way needed to promote transmission access and will consider joint ownership of a load ratio share of the transmission grid, if that will expedite transmission improvements. However, the failure of the transmission provider to solve this basic problem is a failure to meet the obligation to build for the needs of network customers (as well as for Progress's own customers). Clearly, something further needs to be done to assure transmission adequacy to support a competitive market.

Detailed Description of why the import limitations of Progress should qualify for early NIETC designation

Standards

As noted in the TAPS comments, TAPS members generally agree with the criteria proposed to be used in identifying transmission corridors of national interest. With respect, we believe that proposed criteria 1, 2, 3, 5, 6, 7 and 8 are met.

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[2] There may also be artificial constraints associated with the methods of calculating ATC and TRM.

[3] There is some potential that peaking capacity will be built by North Carolina Electric Membership Corporation, but no indication known to Fayetteville of base or intermediate power capacity being built.

Short-Term limitations

As described above, Fayetteville currently receives its base and intermediate power requirements (approximately 300 MW) from Progress under an agreement which extends until June 30, 2012. The balance of Fayetteville’s requirements is supplied from its own peaking generation, which is located in Fayetteville (approximately 200 MW), or from short-term market purchases when transmission is available. Fayetteville receives network transmission service from Progress under its OATT. The term of the transmission service coincides with the power supply commitment.

Because of current transmission constraints, Fayetteville is unable to purchase energy from the short-term resources outside the Progress control area to displace more expensive generation from its own resources (the Butler-Warner generating plant). Every morning at about 0720 a conference call takes place between the Progress traders and Fayetteville Control Room personnel. The purpose of this call is to develop plans for covering the projected Fayetteville load for the following day. The plans that were made on the preceding day for covering the Fayetteville load for the current day are also revisited at that time to determine if additional resources are going to be required or if the availability of any resources that were expected to be used has changed overnight. During that conference call, Progress advises Fayetteville whether there is any import capability to make market purchases of energy at a lower price than the cost of Butler-Warner generation. On every day during the summer months of 2005 for the hours that Fayetteville’s load was above the floor, the report from Progress has been that there is no import transmission capacity available. On some of those days, there may not have been energy available at a lower cost, but there would have been no transmission availability in any event. The last time PWC was able to make any off-system purchase from outside the Progress control area was in December 2004. Thus it seems clear that even now there is no ability to obtain electricity at a competitive price in the wholesale market (Draft Criterion 5, since it is stated national policy to have a competitive wholesale market; see also Draft Criterion 2 and 3).

The Prospect for Long-Term Relief Is Bleak

As noted above, studies conducted by Progress in connection with efforts by North Carolina Electric Membership Corporation to import long-term firm power supply into the Progress control area showed, among other things, that starting in 2010, there will be no long-term firm transmission capacity available for importing power into the Progress control area. While the limiting factor (a phase-angle difference at a point of interconnection with Duke Power) could be corrected through construction of a new high-voltage transmission line to the Progress interties with the Duke system, such a line could not be placed into service until 2016 or after.

Attached as Exhibit A is an Import Scoping Study prepared by Progress on April 23, 2004, evaluating constraints at interties with other utilities. It shows that interties are constrained and concludes that, in order to provide 250 MW of additional import capability, the most cost effective alternative would be to upgrade the Cumberland-Richmond-Newport tie line with Duke Power, which was estimated to cost $350 million and require at least ten years to complete. Obviously, this schedule would mean that Fayetteville will be deprived of any other alternative for supply of base and intermediate power (what is needed after the use of its own on-system peaking resources) when the current power supply contract expires in 2012, and that Progress has not expanded its transmission system for the known needs of network transmission customers like Fayetteville, as it is obligated to do.

Fayetteville believes that there should be a full evaluation of shorter term and less expensive options for interim relief on the tie line with Duke Power, such as modifications in switching facilities to allow the tie line to be loaded more fully. The additional capacity would be beneficial in the near term to provide much needed intertie capability until the proposed longer term project can be undertaken.

Among the alternatives being considered by Fayetteville are construction of its own transmission facilities to interconnect with suppliers outside the Progress control area and the construction of additional Fayetteville generation facilities to supply its base and intermediate power requirements. Neither of these options is the most efficient alternative, however.

Construction of transmission facilities likely will extend more than fifty miles and cross the path of Progress Energy's own 500 kV transmission lines. Construction of 300 to 400 MW of base load generation independently would not be the most efficient alternative either. Further, Fayetteville is not likely to be able to obtain environmental approvals to construct additional gas or coal-fired generation in its service territory.

Fayetteville will participate in any reasonable way needed to promote transmission access to more economical generation alternatives. Fayetteville also is willing to consider joint ownership of a load ratio share of the transmission grid if that will expedite funding of transmission improvements.

Fayetteville has participated, through ElectriCities of North Carolina, Inc., in a series of stakeholder meetings sponsored by the North Carolina Utilities Commission ("NCUC"), designed by the NCUC to "become better informed about the status of the electric transmission facilities in North Carolina and the potential transmission-related issues that might arise in the future" and to "identify any specific electric transmission issues that have the potential to impact the ability of transmission dependent load-serving entities to provide reliable and adequate service to their retail customers." The NCUC-sponsored process led to the recently executed "North Carolina Load Serving Entities' Transmission Planning Participation Agreement" among ElectriCities, NCEMC, Progress and Duke Power. While we are all hopeful that the process there established will lead to an adequate transmission network plan to solve the problems in the Progress region, over ten years will be needed, by Progress's own assessment. This time frame as estimated by Progress is not adequate to address Fayetteville's needs. We believe that this situation warrants designation of a transmission corridor in North Carolina by DoE to facilitate the necessary transmission system upgrades.

Since it seems clear that NIETC listing will help speed up planning and construction, and since it also appears clear that on a long-term basis the existing problem clearly meets Draft Criteria 1 (reliability), 2 (economic benefit for consumers), 3 (action needed to ease supply limitations in corridor), 5 (action would further the national energy policy of wholesale competition), 6 (action is needed to enhance the reliability of electric supply to critical loads and infrastructure), and 7 (alternatives have been thoroughly studied), Fayetteville respectfully requests that the constraints in the Progress Energy Carolinas grid which limit the ability of entities like Fayetteville to import power be included as a part of the NIETC listings.

Respectfully submitted,

/s/ James N. Horwood

Robert C. McDiarmid
James N. Horwood

Attorneys for
the Public Works Commission of the City of
Fayetteville, North Carolina

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1333 New Hampshire Avenue, NW
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March 6, 2006

20. City of New York, Received Mon 3/6/2006 4:36 PM

Attached please find comments of the City of New York and an attachment **[Note from the U.S. Department of Energy: The attachment provided (entitled System Reliability Assurance Study, prepared by the Consolidated Edison Company of New York, December 2005) is not available in Word format and thus is not included in the body of this document. The report is not available on-line; a PDF version can be obtained by contacting the Consolidated Edison Company of New York]** thereto responsive to the Federal Register Notice of February 2, 2006 concerning electric transmission congestion issues and the designation of NIETCs by the Department of Energy.

Michael Delaney

Vice President

NY City Economic Development Corporation

mdelaney@nycedc.com

212-312-3787

United States Department of Energy

Comments of the City of New York Concerning Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

March 6, 2006

The City of New York (City) hereby submits comments in response to the January 27, 2006 Notice of Inquiry issued by the Department of Energy (DOE or Department), as published in the Federal Register of February 2, 2006. DOE has requested public comments on: 1) the criteria for a forthcoming DOE transmission study, and 2) the possible designation of National Interest Electricity Corridors (NIETCs). These concepts were addressed previously in a Study authored by the Department pursuant to §1221(a) of the Energy Policy Act of 2005 (Act).

Background

The issues raised in the latest Notice of Inquiry are not novel, although the regulatory landscape has changed to a significant degree with the enactment into law of the Act, which vested new transmission powers and responsibilities in DOE and in the Federal Energy Regulatory Commission (FERC).

Efforts to develop merchant transmission lines without untoward financial risk to ratepayers have been addressed in the past by the Secretary of Energy.[1] In practice, however, there have been very few such entrepreneurial projects undertaken, suggesting the need for another model to address the realities of a partially deregulated electricity marketplace.[2] And as DOE and others have noted in the recent past[3] as well as in the current Notice, bulk transmission system investment has in recent years been in decline as compared to earlier periods of grid development, and has notably failed to keep pace with the economic and operational importance of transmission resources.[4] This is particularly true in

[1] Statement of the Secretary of Energy, PR-02-080, May 8, 2002

[2] The few projects as we have seen developed in recent years in New York State, such as the Cross Sound transmission line and the Neptune HVDC line from New Jersey to Long Island now under construction have resulted from long-term contracts, not from merchant development as such.

[3] DOE Federal Register Notice of July 14, 2004; Notice of February 2, 2006, p. 5660

[4] The declining trend in investment in the bulk transmission system over the last twenty years was specifically noted by the Edison Electric Institute and DOE Report entitled "U.S. Transmission Capacity: Present Status and Future Prospects" (2004).

light of the rapid recent growth in the electricity transmission volume of state and regional transmission organizations – a volume not contemplated when most national grid component elements were designed and built during an era characterized primarily by long-term investments made by vertically integrated utilities.

The facilitation of economic growth and prosperity through transmission system improvements is a goal that has been characterized as "essential"[5] – a view that recognizes the significant costs imposed on consumers by the continued existence of electricity system congestion. This problem is particularly acute in New York City, where electricity costs are among the highest in the nation. The City's comprehensive Energy Policy Task Force Report issued in 2004 recognized that addressing electricity reliability, cost, and environmental concerns will require a multifaceted approach, including greater use of demand side measures, the introduction of additional generation facilities, and importantly, transmission system improvements.[6] To cite another example making this point, the New York City Building Congress recently issued a Report that focuses on the period 2010-2025,[7] and concludes that between 6,000 and 7,000 megawatts of new electricity resources – including transmission facilities – will be needed by the City over the next twenty years.

The conclusion of these and other similar analyses appears inescapable: future transmission development clearly must form an important part of the overall energy supply solution for the City. This will mean both technological improvements to existing pathways and lines, and expansion of the bulk transmission facilities themselves. The 2002 National Transmission Grid Study cited in Appendix A of

[5] Statement of the Secretary accompanying dissemination of the National Transmission Grid Study (May 2002)
[6] New York City Energy Policy Task Force Report (2004), noting the need for additional transmission facilities at pp 13-15. The Report is accessible at www.nyc.gov/html/om/pdf/energy_task_force.pdf - 2004-01-21. The Notice herein at p. 5661 makes a similar observation concerning the existence of functional alternatives. It remains clear, however, that a greatly enhanced transmission infrastructure will be necessary in New York, as well as in other regions of the country.
[7] "Electricity Outlook 2010-2025" accessible at www.buildingcongress.com/code/research -2006-overview.htm

the Notice contained findings that some of the highest levels of congestion were located within the Eastern Interconnection between the Mid-Atlantic States (*i.e*., the PJM territory) and New York.

Transmission Congestion Study – Criteria Development

DOE states in the Notice herein that a national transmission congestion study will be published by August of 2006, and that public comment thereon will be invited. The City welcomes this proposed schedule as conveying an appropriate sense of urgency to begin the assessment and planning process. Given the long lead times typically required for planning, siting and building large-scale transmission facilities, such a course is well advised.

The Draft Criteria for the planned Congestion Study set out on page 5662 of the Federal Register Notice appear to be sound, and the City supports their inclusion in the Study scoping. The Notice poses a question whether other criteria are needed as well to have a complete and comprehensive study. One critical component must be included: the effect on overall community welfare of enhanced transmission resources, or conversely, the economic dislocation posed by a lack of sufficient electricity importation capacity. In a similar vein, the role of economic development in a currently constrained area is surely a valid criterion when assessing the need for potential remedies for transmission congestion. The imposition of significant economic costs on consumers on either a national, or perhaps more typically, a regional scale is clearly an important consideration in judging the need for transmission facilities.

NIETC Designation for the New Jersey to New York City Corridor

The City of New York should receive priority in the corridor designation process. As noted above, the PJM connection to New York State – and particularly to New York City – is highly constrained as compared to other areas. The City has unparalleled commercial, financial, and general economic importance to the nation, and the unusual degree of dependence that the City has on electricity is both well recognized and a sign of its high efficiency in energy use.

New York City is expected to reach a total population of some nine million by 2030,[8] and its total electric load is growing very rapidly. In the summer of 2005, for example, numerous all time records were set by the Con Edison distribution system.[9] This combination of circumstances, particularly when coupled with very high prevailing prices for both energy and capacity, warrants the highest DOE priority to be accorded to an assessment of the transmission needs of the City.

The Department should specifically add the New Jersey to New York City transmission corridor (*i.e.*, PJM PSEG-North to NYISO Zone J) to the inventory of presumptive NIETC designations. This corridor meets all of the noticed draft criteria for a NIETC. New transmission between New Jersey and New York City would have the following primary benefits:

- Increased reliability to both regions
- Heightened national and regional security
- Increased economic electricity transfers from the relatively low-cost PJM market to the extremely high-cost New York City load pocket
- Reduced reliance on antiquated and inefficient generating plants that raise air quality issues in the densely populated New York City urban environment
- Diversity of electric fuel sources for New York City, which at present is overly reliant on an increasingly constrained natural gas supply system

The "System Reliability Assurance Study" (SRAS) prepared by Consolidated Edison Company of New York in December 2005 concluded at page 11 that "transmission from PJM with firm generating

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[8] Demographic projections reported in the New York Times at Section 1, p. 33 (February 19, 2006)

[9] These included a peak summer load of more than 13,000 MW, the highest electricity sendout, highest monthly and weekend electricity use, highest summer gas usage, and 7 of the 10 highest demand days in the 123 years that the company has been in existence were experienced in the last year. Source: Con Edison company news releases of July 27, August 1, and September 4, 2005, accessible at www.coned.com/newsroom

capacity… appears to be cost effective" in comparison to the full range of demand- and supply-side options available at the City and State levels. USDOE should examine the Con Edison study as part of the NIETC process. A copy of the complete SRAS is included as an attachment to these Comments. **[Note from the U.S. Department of Energy: The attachment provided (entitled System Reliability Assurance Study, prepared by the Consolidated Edison Company of New York, December 2005) is not available in Word format and thus is not included in the body of this document. The report is not available on-line; a PDF version can be obtained by contacting the Consolidated Edison Company of New York]**

Two private transmission developers have submitted NYISO interconnection requests for the New Jersey to New York City corridor; however, it appears that neither of these projects is likely to move forward on a merchant basis.[10] If the corridor were to receive NIETC designation, it would provide a valuable impetus for such projects.

NIETC designation for the NJ-NYC corridor would also provide a critical link to the current PJM plans to upgrade the corridor from western Pennsylvania to northern New Jersey, and to AEP's plans to build the Mountaineer transmission Project from West Virginia to Deans Station, New Jersey. Extending these projects by the relatively short distance (some 20 to 30 miles) into New York City would benefit the City and entire Northeast United States.

In general, upgrading the New Jersey to New York City corridor has not been the subject of sufficient study by the ISOs or the transmission owners. The planning studies conducted by PJM and NYISO generally focus on their own respective territories. The upcoming USDOE study provides an opportunity to provide coordinated planning for the interface between the NYISO and PJM, and to thereby provide a truly integrated solution to current system constraints.

[10] See *e.g.*, footnote. 2, page 2 herein concerning the critical role of contracts in facilitating transmission projects undertaken to date in New York.

The Role of the Department of Energy

As explained in the Notice, the Department is weighing a number of approaches to establishing an inventory of geographic areas in the Eastern and Western Interconnections that have critical current or future needs, and invites commenting parties to suggest focus areas for Departmental review. The City of New York should clearly receive priority in the corridor designation process. As noted above, the PJM connection to New York State – and particularly to New York City – is highly constrained as compared to other areas. Moreover, the degree of dependence that the City has on the electricity system is well recognized, and the City's overall economic importance is unparalleled. Security concerns in New York City in the wake of the 9/11 terrorist attacks also argue in favor of additional transmission resources that will provide some measure of system redundancy. Given the broad portfolio of generation assets in PJM, generation fuel diversity would also be enhanced.

All of the foregoing circumstances, particularly when coupled with very high prevailing prices for both energy and capacity, strongly suggest that the highest DOE priority should be accorded to an assessment of the transmission needs of the City, and priority treatment for a NIETC there.

In practice, there must ultimately be developed a functional responsibility for state and federal regulators, as well as for representatives of regional transmission organizations and independent system operators. In addition, there must be recognition of overarching transmission system needs at the regional and national levels. And throughout the period of transmission assessment contemplated by the Notice here, the Department (and FERC in its coordinate role on such issues as transmission development incentives) must incorporate the recognition that the welfare of the public at large will not necessarily coincide with the parochial concerns of some incumbent participants in the transmission system.

There have been developments in transmission technology that may serve to make new infrastructure proposals more economically attractive and more acceptable, even in densely populated areas, such as the City of New York. The use of controllable HVDC lines can both benefit reliability and enhance the attractiveness of transmission investments to the extent that they can qualify for the greater capacity payments made available under a locational based pricing model in certain highly constrained areas. The City, NYISO Zone J, is one such area. These considerations should inform any proposed answers to the issues identified in the Department's planned Congestion Study.

Under the Energy Policy Act, the DOE Secretary has been given authority to designate transmission corridors of national interest, and to thereby address issues that go beyond the borders of any one state or combination of states. The Department should under the existing national energy policy assume a coordination role through the new jurisdictional authority it has been given under the Act. Such participation by DOE (and where applicable, other relevant entities such as FERC) will best address the inevitable regional and national transmission concerns that transcend traditional state jurisdiction, and that recent experience has shown cannot be left solely to market forces.

As the lead agency for the formulation of a sound national energy policy, DOE is well positioned to assert a leadership role in this area that remains consistent with the jurisdictional scope of other entities. The City welcomes the active role of the Department in making congestion assessments under the broad criteria established in the Notice and as further suggested herein, and in the designation of transmission corridors that will enhance the public welfare both in New York as the nation's preeminent financial and commercial center, and in the nation at large.

March 6, 2006

Respectfully submitted,

/s/ *Michael J. Delaney*

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Vice President

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/s/ *Thomas W. Simpson*

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Attachment

21. Rolan O. Clark, Received Wed 3/1/2006 11:10 AM

Dear DOE,

I live in southern Frederick County, Maryland, and I have just learned of two proposed electric transmission lines that will encompass our State, American Electric Power with a proposed 765KV line and Allegheney Power with a 500KV line. Please hold off on any "National Interest Electric Transmission Corridor" designation until local governments and citizens can have proper notification and hearings on these designations.

Last year I was a citizen intervenor in a proposed power plant about a mile from my house and I have been active in local issues and I did not even know about this until one of our State Delegates informed me. I really feel blindsided !

This "National Interest Electric Transmission Corridor" designation is apparently a new law, Public Law 109-58 on, 8/8/2005.

I sincerely hope it wasn't one of those 2 AM "ear marked" issues.

What is the process to get the "National Interest Electric Transmission Corridor" designation? Why aren't local governments, citizens and other interested parties notified in advance of these applications and asked for comments?

I will be expressing my concerns to my U.S. Senators, Senator Paul Sarbanes and Senator Barbara Mikulski, our U.S. Representative, Representative Roscoe Bartlett, our local State Delegation and our County officials by sending them this letter.

I especially implore our U.S. Congress persons to IMMEDIATELY look into this issue!

With much concern,

Rolan O. Clark
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22. Edison Electric Institute, Received Mon 3/6/2006 12:45 PM

March 6, 2006

Ms. Poonum Agrawal
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, DC 20585

Submitted by e-mail to: EPACT1221@hq.doe.gov

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Notice of Inquiry and Request for Comments, 71 Fed. Reg. 5660 (February 2, 2006)

Dear Ms. Agrawal:

The Edison Electric Institute (EEI) is submitting these comments in response to the above-referenced notice of inquiry and request for comments (NOI). EEI is pleased to provide formal comment to the U.S. Department of Energy (DOE) on DOE's proposed plan for implementing its responsibilities under new Federal Power Act (FPA) section 216(a), added by section 1221(a) of the Energy Policy Act of 2005 (EPAct 2005).

Section 216(a) requires the Secretary of Energy (Secretary) to conduct a study of transmission congestion within the United States and to issue a report by August 8, 2006 and every subsequent 3 years. Furthermore, based on that study, section 216(a) authorizes the Secretary to designate in the report as "national interest electric transmission corridors" (NIETCs) "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers."

EEI Has a Direct and Substantial Interest in This Proceeding

EEI is the association of United States shareholder-owned electric companies, international affiliates, and industry associates worldwide. Our U.S. members serve 97 percent of the ultimate customers in the shareholder-owned segment of the industry, and 71 percent of all electric utility ultimate customers in the nation. They generate almost 60 percent of the electricity produced by U.S. electric generators.

EEI members construct, own, and operate large portions of the nation's electric transmission grid. In addition, our members rely on the grid to supply power to their customers, either directly as retail suppliers or through wholesale sales to support other such suppliers. As a result, EEI has a keen and direct interest in the DOE congestion study and steps to implement the Department's NIETC authority.

<u>The Congestion Study and NIETC Provisions Are Very Important and Need to Be Implemented Properly</u>

With the enactment of the Electricity Modernization Act of 2005 contained in Title XII of EPAct 2005, Congress sought to accomplish four objectives:

- encourage the modernization of infrastructure, including the building of new transmission;
- improve reliability;
- make wholesale electricity markets work better; and
- attract new investment into the electric industry, particularly the transmission sector.

To achieve these objectives, Congress adopted a comprehensive set of policies, set forth in separate subtitles addressing transmission reliability, operational improvements, rate reform, and infrastructure modernization. While the Federal Energy Regulatory Commission (FERC or the Commission) is given responsibility for implementing provisions aimed at achieving a number of these objectives, DOE also is given a critical role to play in the implementation of the objectives.

In particular, Subtitle B of Electricity Title XII, dealing with transmission infrastructure modernization, gives DOE the FPA section 216(a) congestion and NIETC designation responsibilities that are the focus of this NOI. In addition, Congress vested DOE with a third responsibility under new FPA section 216(h) to act as a lead agency in coordinating all authorizations that may be required under federal law for specific transmission projects. If properly implemented, these new FPA provisions can help ensure that our nation's transmission grid remains well-suited to the task of providing electricity reliably, efficiently, and economically.

It is apparent from the NOI that DOE appreciates the significance of its new section 216(a) authorities in relationship to EPAct objectives and intends to implement them judiciously and in careful consultation with stakeholders. DOE's new authority and responsibility under FPA section 216(a) should help to ensure that regional and state planners and permitting agencies and other stakeholders recognize and promptly address transmission congestion issues, without supplanting or duplicating the planning, construction, and operation of transmission and other facilities that already are in place or underway. This will require DOE to take into account these ongoing processes, recognizing that ultimate transmission siting decisions will be made by utilities, transmission owners, states, regional entities, and FERC, without giving up the important role that section 216(a) creates for DOE.

EEI generally supports DOE's proposed plan for implementing its new responsibilities inasmuch as the plan contemplates the:

- conduct of a technically sound, unbiased transmission congestion study that considers transmission capacity constraint and congestion issues over a long-term horizon (we recommend 10 to 15 years), relying to the greatest possible extent on existing transmission studies and analyses, in particular for the first congestion report due August 8, 2006; and

- timely designations of NIETCs as broadly defined geographic areas through a process that allows for consideration of alternatives, as well as expedited designations where urgently needed, recognizing that NIETC designation does not pre-determine the best solution for transmission capacity constraints or congestion in the designated area, a decision ultimately to be made by utilities, generation and transmission owners, states, regional entities, and FERC.

Given the importance Congress has attached in EPAct 2005 to addressing transmission problems of national significance, the Secretary should: (a) produce a report that clearly identifies key transmission capacity constraint and congestion issues throughout the nation; (b) select those geographic areas that meet DOE's criteria for NIETC designation, where it would be in the nation's interest for local, state, regional, and federal officials and other stakeholders to take priority steps to address the constraint and congestion issues; and (c) designate those areas as NIETCs as soon as possible.

By designating such areas as NIETCs, DOE will help to ensure that state and regional planning and permitting authorities, with input by utilities, generation and transmission owners, and other stakeholders, promptly: (a) examine the underlying transmission capacity constraints and congestion in those geographic areas if they have not already done so; (b) determine whether an economically feasible solution is available and, if so, what the best solution might be, taking into account options such as new transmission, additional generation, demand side and efficiency measures, and facility upgrades; and (c) if such a solution is identified, implement the solution.

<u>EEI Recommends that DOE Adopt the Following Definition of Congestion and Essential Elements of the Congestion Study</u>

It is important for DOE to complete a congestion study that provides a clear view of transmission capacity constraint and congestion issues throughout the nation. A strong record will better serve the goals set by Congress and assist those who will be making decisions that can help resolve these issues.

In preparing such a record, in particular for the first congestion report due August 8, 2006, DOE is taking the right approach by relying as much as possible on the extensive existing catalogue of studies and reports that have been prepared through the various state and regional planning processes, as well as studies that FERC has approved. This approach recognizes the critical role that utilities, generation and transmission owners, states, regional transmission organizations

(RTOs), independent system operators (ISOs), FERC, and others have played and will continue to play in identifying and resolving infrastructure and resource needs. Also, focusing on existing studies and reports will help to make the congestion study and report manageable undertakings. In anticipation of future congestion studies, DOE should work with the state and regional planners and other stakeholders to assure that analyses necessary and relevant to applying designation criteria are available.

EEI sees many common attributes in the existing catalogue of studies and research. These attributes should be carried forward into the DOE study and process. In addition, DOE should tailor its study to a concept of congestion that focuses on a high-level, long-term view of the broad range of issues. We therefore recommend that DOE include in its congestion study the following definitions and considerations.

Congestion includes all transmission limitations impacting reliability and/or causing market inefficiencies that burden consumers with sustained higher costs. Congestion must be looked at from a broader perspective than just identifying short-term energy pricing differentials. It needs to be looked at over a longer term, taking into account a variety of reliability and economic factors that could cause harmful effects on consumers. While DOE should study congestion as required by the statute, not all congestion can be corrected economically. However, congestion that affects reliability must be addressed to support the well-being and security of the nation.

From an economic perspective, the cost of congestion is highly variable and is impacted by various controllable and uncontrollable factors including: fuel prices, generator or transmission line outages, transmission line losses, organized market rules, and locational marginal prices that may be influenced by legitimate bidding behavior. It is important to note that not all economic congestion can or should necessarily be remedied. DOE's congestion study should analyze congestion as broadly as possible and identify the causes of specific congestion, which will provide the most useful data to DOE for the designation of corridors.

For purposes of the DOE study on congestion, and to facilitate the future designation of NIETCs, congestion should be defined so as to capture all effects of transmission constraints and therefore should be broadly measured:

- Congestion should be measured over a large geographic area covering regions or multiple states within those regions, and neighboring regions.
- In addition to determining the reliability effects of transmission congestion, one way in which congestion may be measured would be to look at projected price differentials between zones or regions. These differentials should reflect differences in expected energy payments and, where applicable in structured markets, capacity payments, and they should reflect differences in the cost of reserves and prices for other ancillary services. DOE should be mindful that energy prices are notoriously difficult to predict with full accuracy, especially over long-term decision horizons. Therefore, DOE should be very cautious about the assumptions it uses or relies on, make those assumptions public, and provide a variety of sensitivity analyses that cover various scenarios.

- The inability to access alternative supply resources can be defined as congestion. Congestion calculations should measure the costs to customers of alternative supply resources.

- The analysis should not be limited to the current configuration of the transmission network but should include the benefits to customers of new corridors.

- Reductions in production costs over a wide area due to transmission upgrades are an appropriate measure of the energy value of such facilities to customers.
  Such a "macro approach" to studying the costs to customers of the absence of transmission is currently being undertaken by PJM.

- Valuations of congestion costs can be performed with a variety of methodologies. DOE should not limit its valuation analysis to only one methodology, but should consider various alternatives providing a range of such costs.

- Import capability into a region or sub-region should be evaluated, including the potential for imports to be economical.

- Dependence on imports over the course of the year and during peak periods should be evaluated by estimating the difference between load in a region and the generation capacity in the region.

<u>DOE Has Properly Identified Key Sources of Information to Consider in Preparing Its Congestion Report</u>

In Appendix A to the NOI, DOE lists a number of documents that it has compiled and is evaluating in preparing its first congestion report. In section III.A of the NOI, DOE asks four questions related to this information and its evaluation of congestion. NOI at 5662. EEI will address those four questions in this section of our comments.

DOE Questions 1 and 2: DOE's asks whether the Department should distinguish between "persistent" and "dynamic" congestion and between "physical" and "contractual" congestion. EEI does not believe that DOE should make these distinctions. These terms are not well defined; nor can congestion easily be categorized as one or the other. Instead of focusing on such distinctions, the key issue for DOE in identifying congestion and evaluating whether to designate an NIETC is whether transmission constraints are negatively impacting or likely to impact reliability, the ability to deliver electricity, or consumer costs. New transmission facilities and upgrades to existing ones will not ultimately be approved by states, regional entities, or FERC unless the facilities or upgrades are found to be a cost-effective solution to congestion and will serve the public interest. Therefore, DOE need not distinguish in its study or report between types of congestion as suggested. On the other hand, DOE certainly can and should discuss the potential magnitude and severity of congestion in areas listed in its report.

DOE Questions 3 and 4: DOE asks what transmission plans and studies it should consider, taking into account the ones listed in Appendix A, how far back it should look, and what information it should include in its own congestion study. With respect to the studies DOE is presently reviewing, EEI believes that Appendix A is a fairly complete list of documents that will help DOE and its consultant CRA identify congestion areas for purposes of the first congestion report due August 8, 2006. We and our members have provided DOE and CRA with some additional documents that we believe also are relevant, including for example reports produced by MAIN and ECAR not listed in Appendix A. We understand that DOE and CRA will include those additional documents in the analysis. Taken together, the Appendix A documents and the others that EEI and our members have noted should provide a solid foundation for evaluating key areas across the country where there are transmission capacity constraint and congestion issues. EEI member companies are also willing to make available subject area technical experts to provide additional background information and to respond to any requests for additional information.

As for the age of information to use, DOE should focus on valid information that is current, generally no more than one to three years old, because congestion issues change over time. A study or other information older than three years may not reflect current grid conditions. On the other hand, if a qualified expert demonstrates that an older study or information is still valid, DOE should consider such information as well.

As for categories of information to use, DOE should rely on any information included in those reports that indicates there is a congestion issue, whether related to reliability, getting supply to load, or other factors set out in section 216(a) or discussed in these comments. DOE should seek guidance from state and regional planners and permitting agencies and other stakeholders as to the most significant information and should rely on that guidance to the maximum extent possible. The input of these experts will be crucial to an effective and complete congestion study and report as well as the NIETC designation process.

EEI understands that CRA intends to use the Appendix A and other information just discussed to model congestion in the Eastern interconnection and to provide a fairly detailed analysis of key congestion areas within the interconnection. CRA apparently plans to rely on a complex computer program and to analyze the transmission grid using flowgates, transmission pathways, and other such big-picture concepts. EEI encourages DOE and CRA to identify and disclose the details of this analysis, including key assumptions and related sensitivity analyses, as soon as possible. We hope that this information can be made available at DOE's March 29 technical conference in Chicago, so industry representatives can provide feedback on the modeling details, assumptions, and sensitivity analyses at or following the conference.

EEI Supports DOE's Proposal to Define NIETCs as Broad Geographic Areas – EEI Encourages DOE to Use Existing State and Regional Planning Processes in Designating NIETCs and Not to Pre-Judge the Appropriate Response to the Underlying Transmission Capacity Constraint or Congestion Issues

FPA section 216(a) gives DOE discretion, based on the congestion study, to designate NIETCs, which are those geographic areas experiencing transmission capacity constraints or congestion that adversely affect consumers. In making the designations, the Secretary may consider: whether the economic vitality and development of the corridor or end markets served by the corridor may be constrained by lack of adequate or reasonably priced electricity; whether economic growth in the corridor or end markets may be jeopardized by reliance on limited sources of energy; whether diversification of the fuel supply is warranted; whether a designation would serve the nation's need for energy independence; and whether designation would be in the interest of national energy policy or enhance national defense or homeland security. Further, section 216(a) provides that the Secretary is to consider alternatives and recommendations from interested parties.

In the NOI, DOE solicits comments on the criteria it will use to select those areas experiencing transmission capacity constraints or congestion to be designated as NIETCs. In addition, DOE invites comment on how broadly or narrowly the Department should consider and define NIETCs. DOE suggests that it is likely to identify candidate NIETCs following initial publication of the congestion study for comment. But DOE also says that it will consider expedited designation of an NIETC based on a congestion analysis completed in advance of the main study, if a party persuades the Department that the designation is warranted and sufficiently urgent to justify an expedited approach.

EEI will comment on these NIETC issues in this section and the next two sections of these comments, focusing first on how broadly DOE should define the concept of an NIETC, then the timing of NIETC designations, and finally the NIETC criteria and metrics. As DOE undertakes NIETC designations, it is important that DOE consult with state and regional planners, utilities, generation and transmission owners, and other stakeholders to ensure that DOE has relevant information and to avoid duplicating the efforts of others.

EEI supports DOE's proposal to identify NIETCs as generalized electricity paths rather than as specific routes for transmission facilities. NOI at 5661, section II.C. When a congestion issue first arises, and in the early planning stages of seeking to address the issue, the nature of the actions and facilities that may best address the issue may not be known. Looking at the issue from a broad geographic perspective can help preserve a variety of potential solutions that might not fit in a narrow corridor. Further, even if and when new transmission capacity is identified as part of the solution, the specific location or route of the transmission line may not be known. While NIETC designations are a predicate to FERC backstop siting authority, the designations also are valuable simply as a tool for giving notice that certain transmission capacity constraints and congestion are a priority to resolve expeditiously from a national perspective.

By approaching NIETC designations in broad geographic terms, and making the designations early, DOE will properly avoid the role of picking winners and losers with respect to solutions. The job of the NIETC designation is to identify in general terms areas where resources and/or loads may require substantial attention in the long-term planning horizon. DOE's "National Transmission Grid Study" offers a model for the level at which DOE should view an NIETC designation.

Also, by designating generalized geographic areas as opposed to specific routes, DOE can defer detailed environmental and other analyses that are more appropriately undertaken in the context of specific solutions or projects. Such analyses will occur later as specific projects are pursued, whether in state or regional planning and permitting processes or at FERC.

In fact, in designating NIETCs, EEI encourages DOE not to pre-judge whether there is an economical solution to the underlying transmission capacity constraint or congestion and, if so, what the best solution might be. (Ultimately, the solution may involve some mix of generation, transmission, demand-side, or other options.) DOE need not and should not make these determinations. Instead, NIETC designations should be used to highlight the need for attention to transmission capacity constraints and congestion. In turn, DOE should prompt affected state, regional, and federal planners and permitting agencies (including federal land agencies when federal land is involved) to work together – and to work closely with utilities and generation and transmission owners – to respond to the constraint or congestion issue in a cost-effective, timely, and appropriate manner.

Also, if a transmission capacity constraint or congestion issue that might otherwise warrant NIETC designation is already actively being addressed by state or regional planning and permitting authorities – and those authorities can demonstrate that a solution either is not economically available or will occur within a reasonable time – DOE may wish to consider not making an NIETC designation. Where solutions are already demonstrably unavailable or being implemented, there may be less need for and value to be added by an NIETC designation.

In keeping with this point, DOE should clarify that not designating an NIETC does not mean that DOE believes there is no need for transmission in a given area. There may be a variety of reasons the transmission capacity constraint or congestion in a particular area does not meet the section 216(a) criteria for designation as a national interest corridor.

<u>EEI Supports DOE's Proposal to Pursue Prompt NIETC Designations, Both Through a Regularized Process in Conjunction with the Congestion Studies and Separately On Request to Address Urgent Needs</u>

EEI encourages DOE to make NIETC designations in conjunction with each congestion study and report, taking into account information compiled in the study and input by stakeholders in the area of the potential corridors. The initial August 2006 congestion report and the subsequent triennial reports are a good opportunity for DOE, utilities, states, regional planning, siting, and reliability entities, and FERC to take a fresh look at the issue of transmission congestion and the need for additional NIETCs. Specifically, DOE should include in each report a list of new NIETCs or at least candidate NIETCs, inviting input and committing to make designation decisions shortly thereafter. Thus the first identification of NIETCs or candidate NIETCs should be published in the August 2006 report.

In addition, EEI encourages DOE to provide for expedited designation of NIETCs, both before the first congestion study is completed and between congestion studies, if a transmission capacity constraint or congestion issue requires more immediate attention. In this regard, EEI supports DOE's proposal to consider the expedited designation of one or more corridors even before the first congestion report, upon request, if there is an acute need for such designation. NOI at 5661, section III.A.

If anyone reasonably requests that a geographic area be designated as an NIETC either during or separate from the regular congestion study/report process, DOE should respond promptly, after consultation and coordination with affected utilities, states, regional entities, and FERC. Such prompt responses would be especially helpful in encouraging innovative approaches to grid modernization.

In recent public presentations, DOE has posed several questions relating to NIETCs. Specifically, DOE has asked whether the designation of NIETCs should be project-specific or can be framed to accommodate a range of projects, and when in relation to the evolution of a transmission project an NIETC should be designated. DOE also has asked whether an NIETC should have a fixed term, if so how long, and whether it should be renewable or revocable.

In response, EEI encourages DOE not to delay NIETC designations until a specific transmission project has been identified or is being implemented. As we have indicated above, the appropriate response to transmission capacity constraints or congestion warranting NIETC designation is for others to decide, not DOE. DOE's role is to identify areas where such transmission capacity constraints or congestion are occurring and to designate those areas as NIETCs so others can promptly address these underlying issues. Furthermore, by defining NIETCs as broad geographic areas, DOE will necessarily and appropriately encompass a range of potential solutions.

As for the duration of an NIETC, an NIETC designation should stay in place until DOE believes that the underlying transmission capacity constraint or congestion issue either cannot be addressed or has been addressed or otherwise is no longer an issue of national concern. DOE can assess this as part of each triennial congestion study.

<u>EEI Generally Supports DOE's Proposed Criteria and Metrics for Evaluating Geographic Areas as Suitable for NIETC Designation, With Some Modifications</u>

In Section III.B of the NOI, DOE lists eight draft criteria and associated metrics that DOE intends to apply in evaluating whether geographic areas identified in the congestion study are suitable for NIETC status. NOI at 5662. In general EEI supports the eight criteria and associated metrics, with modifications we will discuss in this section of our comments.

The criteria and metrics that DOE has proposed are fairly general. This seems reasonable, especially for DOE's initial forays into studying congestion and designating NIETCs. By using general criteria and metrics, DOE can consider the variety of factors listed in section 216(a) as being relevant to NIETC designations, without deciding in advance that particular measurements demonstrate whether a given area qualifies. In time, and in consultation with the industry, DOE may be able to provide further guidance on application of the criteria and metrics, as DOE gains experience in applying them. On its website, DOE says that it plans to discuss the criteria further as a key focus of the March 29 technical conference in Chicago. We agree that this would be a useful issue to discuss.

EEI agrees that draft Criterion 1, "Action is needed to maintain high reliability," is an important factor in determining whether to designate an NIETC. A primary goal of the transmission grid is to enable delivery of a reliable supply of electricity. Instead of DOE's somewhat more limited proposed metric, we recommend that DOE use North American Electric Reliability Council (NERC) and NERC Regional Council reliability and planning standards – or their successors as FERC approves a successor Electric Reliability Organization (ERO) under new FPA section 215 – as the metric for applying this criterion. In using this metric, only standards that pertain to transmission capacity constraints or congestion should be considered relevant. Also, the focus should be on whether additional transmission may be needed in a given area to meet the standards. While a violation or potential violation of a relevant reliability standard may be one indicium of a transmission capacity constraint or congestion, the ability to meet the standards is a broader, more constructive concept.

EEI generally agrees with draft Criterion 2, "Action is needed to achieve economic benefits for consumers." In defining and applying the metrics for this criterion, DOE should focus on economic benefits in the contexts referred to in section 216(a), namely the economic vitality and development of corridors related to lack of adequate or reasonably priced electricity, and economic growth in the corridors and end markets related to reliance on limited supplies of electricity. We believe that DOE's first proposed metric, "estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets," is especially relevant in this regard. We also encourage DOE to reflect EEI's discussion of economic issues in the "definition of congestion" section of these comments above. In particular, we request that DOE reflect our points about factors that affect the cost of congestion, the variability of congestion costs, ways to measure congestion using price signals, the risks inherent in doing so, and the need to consider various methods for measuring the costs.

EEI agrees with draft Criterion 3, "Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources." Again, this ties logically into the section 216(a) NIETC factors focusing on adequate supply and diversity of supply. For example, if a load pocket or market relies on a single fuel or limited generation portfolio that is vulnerable to supply or price disruption, access to diversified supply may warrant NIETC designation. DOE should modify its metrics to reflect that this issue can relate both to economics and reliability. Thus, in the second sentence of DOE's metrics discussion, DOE should reflect that areas that are highly dependent on specific generation fuels could "benefit economically or in terms of reliability from supply diversification."

EEI agrees with draft Criteria 4 and 5, "Targeted actions … would enhance the energy independence of the United States [and] would further national energy policy." These criteria also tie directly to the section 216(a) NIETC factors. In applying these criteria, DOE should consider the need to transmit and the desirability of transmitting electricity from domestic energy sources, including renewable sources that may not be located close to load.

EEI agrees with draft Criterion 6, "Targeted actions … are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability … to natural disasters or malicious acts." Again, this criterion ties directly to the section 216(a) NIETC factor related to national defense and homeland security. However, this frequently will be a localized, fact-specific issue. For example, on balance, new transmission to import remote generation may or may not reduce such vulnerability. Therefore, we agree with DOE's metric that this criterion will need to be applied case-by-case.

With respect to draft Criterion 7, "The area's projected need … is not unduly contingent on uncertainties associated with analytic assumptions," DOE should clarify that this concept will be integrated into the overall NIETC designation process, including the application of each of the other criteria. In this sense, Criterion 7 does not stand alone. The assumptions that underlie NIETC designations should be reasonable and transparent. Further, DOE should include sensitivity analyses as part of its discussion of each NIETC. Fuel prices, demand growth, and the location and cost of generation facilities can be difficult to project accurately, especially over the long term. This highlights the importance of reasonable assumptions based on best available information and the need for sensitivity analyses.

With respect to draft Criterion 8, "The alternative means of mitigating the need in question have been addressed sufficiently," EEI encourages DOE to modify this to read "Alternatives and recommendations relating to NIETC designations and received from state and regional planners and other interested parties have been considered." This change would better track the section 216(a) requirement for DOE to consider such alternatives and recommendations before issuing its congestion reports. DOE should encourage state and regional planning authorities and other stakeholders to provide their input on this issue, including information as to alternatives that have been considered, and DOE should rely on that information to the maximum extent possible. DOE should avoid duplicating or supplanting the work of these other stakeholders, in particular state and regional planners. Furthermore, DOE should avoid evaluating specific transmission or other potential solutions to transmission capacity constraints or congestion. As discussed above, DOE should not engage in such analysis of specific solutions as part of the NIETC designation process.

DOE asks whether it should consider other criteria in making NIETC designations. NOI at 5662, end of section III.B. The criteria and metrics that DOE has proposed, with the modifications just discussed, appear to EEI to be relatively complete.

DOE also asks whether certain considerations or criteria are more important than others, and if so which ones and why. Id. The first two of the draft criteria, addressing reliability and economic benefits for customers, strike us as high priority, though each of the criteria and metrics focuses on important issues.

Conclusion

EEI appreciates the opportunity to provide these comments to DOE. If DOE staff have any questions about the comments, please contact me at 202/ 508-5613 or ecomer@eei.org, or please contact any of the following other EEI staff: Henri Bartholomot (202/ 508-5622, hbartholomot@eei.org), David Dworzak (202/ 508-5684), or Meg Hunt (202/ 508-5634, mhunt@eei.org).

Respectfully submitted,
- signature -

Edward H. Comer

23. Electric Power Supply Association, Received Mon 3/6/2006 2:17 PM

Comments of Electric Power Supply Association on Department of Energy's NOI Regarding "National Interest Electric Transmission Corridors"

The Electric Power Supply Association[1] appreciates the opportunity to comment on the Department of Energy's (DOE or Department) Notice of Inquiry (NOI) issued on February 2, 2006, concerning new approaches to siting interstate transmission facilities contained in the Energy Policy Act of 2005 (EPAct). Particularly, subsection 1221(a) of EPAct amends section 216 of the Federal Power Act directing the Secretary of Energy (Secretary) to study and report on the nature and extent of wholesale electric transmission congestion. Based on the report, the statute authorizes the Secretary to designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor (NIETC)." Provided certain conditions are met, FERC may issue permits to areas receiving NIETC status for the "construction and modification of electric transmission."

With its NOI, the DOE seeks industry input on the criteria and factors the Department should consider in assessing the suitability of geographic areas for NIETC status. Competitive power suppliers are committed to continuing to provide the most efficient and reliable power to consumers. Toward that end, we share the vital interest of all stakeholders in a transmission system that is maintained and operated in the most economically sound and reliable manner. Accordingly, EPSA applauds this effort and, beyond these initial comments on the Draft Criteria set forth in the NOI, looks forward to working with the Department and industry stakeholders to identify and implement the most efficient, most cost effective solutions to capacity constraints and transmission congestion.

- **Overview**

As a practical matter, to satisfy the "national interest" qualification and obtain NIETC status, geographic areas experiencing capacity constraints and transmission congestion should present the following characteristics: (1) the absence of viable redispatch options; (2) obstacles to non-discriminatory access to the grid creating barriers to entry beyond those that can be remedied through Open Access Transmission Tariff (OATT)

[1] EPSA is the national trade association representing competitive power suppliers, including independent power producers, merchant generators and power marketers. These suppliers, who account for more than a third of the nation's installed generating capacity, provide reliable and competitively priced electricity from environmentally responsible facilities serving global power markets. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

amendments; and (3) physical grid topology that abets market power a generation entity may exercise. Additionally, as this process moves forward, the DOE should clarify that NIETC designation decisions resulting from requests of a specific entity do not preclude other parties from proposing transmission projects within that corridor.

EPSA believes that the EPAct provisions will enable the DOE to play an important role in identifying and addressing NIETCs by building upon the prior and ongoing work of the regional transmission organizations (RTO), regional state committees (RSC) and regional reliability councils (Councils), [2] as suggested in DOE's 2002 National Transmission Grid Study. Some ISOs/RTOs have already identified constraints, and utilize mathematical models, simulation methods and other tools to anticipate the effects of system contingencies and identify solutions.[3]

More generally, this effort dovetails with the increasing realization of the need to create meaningful incentives for infrastructure investment. In conducting its study and in the subsequent process to designate NIETCs, EPSA encourages the DOE to promote alternative solutions to addressing congestion and capacity constraints. Below, EPSA provides more direct feedback on several of the Draft Criteria set out in the NOI.

- **Draft Criterion 1: Action is needed to maintain high reliability.**
- **Draft Criterion 2: Action is needed to achieve economic benefits for consumers.**

Due to the overlaps that exist, EPSA has combined its response to these two criteria. Competitive power suppliers share the concern and interest of all other industry stakeholders for a robust and reliable wholesale electric power grid. EPSA members actively participate in North American Electric Reliability Council (NERC) and North American Energy Standards Board (NAESB), and contribute to system reliability by complying with NERC and RTO/ISO operational requirements and directions. Clearly, capacity constraints and transmission congestion that could undermine reliability must be properly identified and addressed.

However, distinguishing "reliability" from "economic" concerns and impacts can be problematic as the two are, in fact, inextricably linked. Indeed, resolving capacity constraints and congestion that threaten system reliability can result in disparate economic impacts on market participants. Further, EPSA recommends that the phrase

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[2] As explained in the report and recommendations issued by NERC's Resource and Transmission Adequacy Task Force (RTATF) on June 15, 2004, all ten Councils and six ISO/RTOs surveyed apply NERC's Transmission Adequacy planning standards to ensure that adequate transmission levels are maintained. Further, seven Councils and all of the ISO/RTOs and their member systems must satisfy more stringent regional criteria. Additionally, regional and interregional assessments are conducted for both NERC compliance purposes, as well as by ISO/RTOs to fulfill the planning and expansion function outlined in Order No. 2000.

[3] In this connection, EPSA directs the DOE to two studies in particular: (1) the New York Independent System Operator Electric System Planning Process, Initial Planning Report (October 6, 2004); and (2) the PJM/Midwest ISO Single Economic Dispatch Production Cost Study (in progress).

“maintain high reliability” be deleted from Draft Criterion 1and replaced with: “ensure compliance with published reliability criteria.”

Failing to properly assess this linkage could result in unwanted consequences when transmission congestion is addressed, and result in inefficient outcomes. EPSA urges the Department to take this aspect of addressing reliability issues into account in its report and decisions to designate NIETCs. Moreover, EPSA discourages the Department from assessing transmission congestion as a purely economic matter. Indeed, the primary focus for evaluating NIETC proposals should concern reliability issues, particularly whether a portion of the bulk power system is, or can, satisfy published reliability standards and criteria.

However, to the extent NIETC designations are driven or based on economic considerations, cost/benefit assessments must be provided. Should historic pricing data indicate persistent congestion of significant duration, magnitude and geographic scope, a rigorous production cost study should be performed to identify the economic impacts and confirm that relieving the constraint will produce sufficient economic efficiencies. On balance, the DOE should coordinate with FERC, NERC, the ISO/RTOs, the RSCs and the Councils to ensure that the reliability and economic dimensions of transmission constraints are properly considered and addressed. in ways that promote both economic and operational efficiencies.

- **Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify resources.**
- **Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.**

Again, due to the interplay between the above two criteria, EPSA is combining them in our response. Regarding fuel source diversification, and the effort to identify and assess alternative congestion mitigation measures, it is critical to consider the ongoing work being done by RTO/ISOs and NERC. Additionally, beyond specific criteria that may provide the basis for NIETC designations, it will be important to include stakeholder processes and input.

By acknowledging the ongoing regional efforts, the DOE would ensure that stakeholders currently engaged in regional collaborative processes continue to have a meaningful opportunity to participate, especially where economic interests are involved. Accordingly, EPSA recommends that, wherever possible, the DOE incorporate in its analyses and deliberations the work being done by ISO/RTOs, particularly regarding measures that would affect the economic value of transactions impacted by capacity constraints and transmission congestion.

In this connection, it will be critical for the Department to avoid putting itself in a position to be picking “winners and losers.” With respect to geographic areas experiencing capacity constraints and transmission congestion, market solutions developed by stakeholder collaboratives within ISO/RTOs should be utilized to the fullest extent possible. A valuable aspect of the DOE's role should be to provide an overarching framework to facilitate and coordinate the resolution of transmission congestion across regional systems, and individual utilities outside ISOs/RTOs who fail to address constraints.

Solutions to transmission congestion are not necessarily limited to recommendations that a particular utility invest in its transmission system. EPSA encourages the DOE to utilize the NIETC designation process to explore innovative market solutions, including financial instruments by which the necessary investments will be made. As an intervenor in FERC proceedings, the DOE could recommend innovative public and private equity investment incentives and cost recovery methods. Thus, the DOE's engagement could accelerate the usually lengthy and costly process by which transmission projects are authorized and built.

Submitted by:

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March 6, 2006

24. Great River Energy, Received Mon 3/6/2006 5:16 PM

DEPARTMENT OF ENERGY
OFFICE OF ELECTRICITY DELIVERY AND ENERGY RELIABILITY

Considerations for Transmission	**)**	
Congestion Study and Designation	**)**	**Comments of**
Of National Interest Electric	**)**	**CapX Utilities**
Transmission Corridors	**)**	

I. Introduction

On February 2, 2006, the Department of Energy published a Notice of Inquiry in the Federal Register seeking comments and information concerning plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors (NIETCs). 71 Fed. Reg. 5660-5664. The CapX utilities offer the following comments for the

Department's consideration in conducting the initial congestion study and compiling an inventory of geographic areas where significant transmission needs already exist.

II. CapX Utilities

In the spring of 2004 a number of utilities serving customers in Minnesota and neighboring states initiated a concerted effort to ensure that the transmission system in the region was adequate to serve a growing demand for electricity and to plan for the major capital expenditures that would be required to construct major new transmission infrastructure in the near future. This effort is referred to as the CapX 2020 project, which is an abbreviation for "Capital Expenditures by the year 2020," usually called simply CapX.

CapX's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region; and
- Work to create an environment that allows these projects to be developed in a timely, efficient manner consistent with the public interest.

The following utilities comprise the CapX effort:

A. Great River Energy, headquartered in Elk River, Minnesota, is a generation and transmission cooperative that provides wholesale electric service to 28 distribution co-ops.

B. Midwest Municipal Transmission Group ("MMTG") is a consortium of public power entities in the upper Midwest, specifically the Iowa Association of Municipal Utilities, the Minnesota Municipal Utilities Association, and the Central Minnesota Municipal Power Agency. MMTG is headquartered in Ankeny, Iowa.

C. Minnesota Power, a division of Duluth-based ALLETE, Inc. provides electric service to 136,000 retail customers and 16 municipalities in northeast Minnesota.

D. Missouri River Energy Services ("MRES"), headquartered in Sioux Falls, South Dakota, is a municipal joint action agency formed under Chapter 28E of the Iowa Code. MRES is comprised of 57 full-member, and three associate-members, municipal utilities located in the States of Iowa, Minnesota, North Dakota, and South Dakota. MRES provides energy and energy services to 57 of its member systems, all of which are located within the Mid-Continent Area Power Pool region. The municipal utilities served by MRES in turn each serve over 135,000 retail electric customers.

E. Northern States Power Company ("NSP") is, inter alia, an investor-owned Minnesota corporation engaged in the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Minnesota, North Dakota, and South Dakota. Northern States Power Company (Wisconsin) ("NSPW") is, inter alia, an investor- owned Wisconsin corporation engaged in the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Wisconsin and Michigan. NSP and NSPW are both wholly-owned utility operating company subsidiaries of Xcel Energy Inc. Xcel Energy Services Inc. ("XES") is the service company for the Xcel Energy Inc. system.

F. Otter Tail Corporation, d/b/a Otter Tail Power Company ("Otter Tail"), is a corporation incorporated under the laws of Minnesota and is located at 215 South Cascade Street, Fergus Falls, MN 56537. Otter Tail provides electric service to over 128,000 retail customers over a 50,000 square mile area spanning portions of MN, ND, and SD.

G. Southern Minnesota Municipal Power Agency is a municipal corporation and political subdivision of the State of Minnesota. Headquartered in Rochester, it provides wholesale power and energy and related services to its 18 municipally-owned member utilities.

III. Transmission Plans and Studies

Appendix A included with the Notice of Inquiry lists a number of transmission plans and studies that the Department currently has under review. The Department asks whether there are other plans and studies that the Department should consult in preparing the congestion plan. CapX has several additional studies to bring to the Department's attention that we request the Department review as part of its effort. These studies and plans are described below. For the Department's convenience, a CD containing those studies listed below that are complete is included with the hard copy of these comments.

A. Midwest ISO Transmission Expansion Plans. In Appendix A the Department lists the 2003 and 2005 MISO Transmission Expansion Plans, often referred to as the MTEP-03 and MTEP-05 reports. CapX recognizes that these reports are important documents for the Department to consider and we are pleased to see them on the list. The point to add here is that the MTEP-05 report was issued by MISO in June of last year and the MTEP-06 report should be available later in 2006. Since the Department intends to finalize its congestion plan in August of 2006, the MTEP-06 report will be available for Department review, and CapX commends that report to your consideration.

B. Northwest Exploratory Study. One of the studies discussed in the MTEP-05 report is the Northwest Exploratory Study, but we want to emphasize the need to take this study into account as you proceed with your development of the congestion plan. The Northwest Exploratory Study shows that additional high voltage transmission lines from the Dakotas eastward are required to transmit large amounts (in the range of 2000 MW) of wind and coal generation that are being proposed in the region.

C. Iowa/Southern Minnesota Exploratory Study. Another study discussed in the MTEP-05 report is the Iowa/Southern Minnesota Exploratory Study. The purpose of this study is to examine transmission options to transfer large blocks of wind power from Iowa and Minnesota to markets in the Midwest. The reason CapX specifically mentions this study is that it is still underway and likely will not be completed until the MTEP-06 report becomes available.

D. CapX Vision Plan. In May 2005, CapX released its written report entitled CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs. A copy of the report is available on the Internet at:
http://www.capx2020.com/Images/5-11-05%20CapX2020%20Tech%20Update.pdf

In addition, a summary of the CapX Vision Plan can be found in the 2005 Minnesota Biennial Transmission Projects Report which is another document that CapX would bring to the Department's attention and is described in item E below.

As part of the planning process, the CapX utilities assumed two different rates of growth – a high growth rate of 2.49% per year (6300 MW) and a low growth of about 2/3 of that (4500 MW) – and assumed three different generation scenarios, including 2400 MW of wind development as part of each scenario, to illustrate potential locations of new generating plants and wind farms. The goal was to identify new transmission needs specific to certain generating scenarios independent of where that generation might occur and new transmission specific to particular generation scenarios.

As of result of this effort, CapX identified a need for more than 1600 miles of new 345 kilovolt transmission lines in Minnesota and neighboring states estimated to cost at least two billion dollars. In the Vision Plan, CapX identified three 345 kV lines of the most immediate priority, including a 345 kV line between the Buffalo Ridge area in southwestern Minnesota and the Twin Cities (Minneapolis/St.Paul), a 345 kV line between Fargo, North Dakota, and the St. Cloud, Minnesota, area, and a 345 kV line from the southeast corner of the Twin Cities to Rochester, Minnesota to the LaCrosse, Wisconsin, area. Because CapX is not a legal entity, one or more of the CapX utilities will take the lead in the state permitting process and seek approval for these three lines.

Several other lines were also identified as high priority in the Vision Plan – the Big Stone transmission project, the BRIGO projects, and a 230 kV line from the Bemidji area in northern Minnesota east and south for more than 100 miles. The Big Stone and BRIGO projects are discussed below. The 230 kV line to Bemidji is necessary to address a severe and immediate low voltage concern in the Bemidji area during winter peak conditions.

The CapX study work should be considered carefully by the Department in developing the congestion plan and identifying areas where significant transmission needs exist.

E. 2005 Minnesota Biennial Transmission Report. Under Minnesota law, utilities owning transmission lines in Minnesota must file a report with the Minnesota Public Utilities Commission by November 1 of each odd-numbered year providing an update on the current status of the Minnesota and regional transmission system and identifying transmission need that are being considered to maintain reliability. Minnesota Statutes § 216B.2425. The most recent report was filed with the Minnesota PUC on November 1, 2005. The 2005 Biennial Report can be found on the Internet at: http://www.minnelectrans.com/

In the 2006 Report, regional utilities, including those within CapX, identified more than seventy conditions in the transmission system that need to be addressed. While many of these conditions involve local load-serving issues, the Report will provide the Department with a summary of upcoming transmission needs in the State of Minnesota.

The Minnesota statute also establishes a mechanism for certifying the need for specific transmission projects. With the 2005 Biennial Report, two CapX utilities – Minnesota Power and Great River Energy – filed applications for certification of two new 115 kV transmission lines in northern Minnesota – the Tower line and the Badoura line. Both of these lines are under expedited review by the Minnesota Public Utilities Commission pursuant to a more informal process than is required under the traditional Minnesota certificate of need process.

F. *Big Stone Certificate of Need and Route Permit.* In 2005 Otter Tail Power Company, Great River Energy, Missouri River Energy Services, and Southern Minnesota Municipal Power Agency, participants in the CapX effort, along with three other regional utilities, applied to the Minnesota Public Utilities Commission for a certificate of need and a route permit for two high voltage transmission lines from a proposed new power plant in South Dakota into Minnesota. These applications are available on the Internet:

http://www.otpco.com/NewsInformation/BigStoneTransMNCertOfNeed.asp

http://www.otpco.com/NewsInformation/BigStoneTransMNRoutePermitsApp.asp

http://www.otpco.com/NewsInformation/BSTpdf/SDFacilityPermitApplication_1.12.06.pdf

The Certificate of Need Application and the Route Permit Application are significant documents for the Department to review and consider because they show the extent of the analysis that utilities are conducting before finalizing decisions to go forward with new transmission infrastructure.

G. *Southwest Minnesota → Twin Cities 345 kV EHV Development Study*. This study looked at the overall increase in outlet capacity from Buffalo Ridge that is achieved by integrating the Big Stone transmission lines with other 345 kV facilities connecting southwest Minnesota with the Twin Cities metropolitan area.

H. *Buffalo Ridge Incremental Generation Outlet Transmission Study (BRIGO Study).* This study analyzed ways to increase the outlet capacity from Buffalo Ridge through installation of relatively modest (i.e., 115 kV) facilities.

I. *Southeastern Minnesota-Southwestern Wisconsin Reliability Enhancement Study*. This study looked at lower voltage solutions for load serving issues in the Rochester, Minnesota, area and the Greater La Crosse, Wisconsin, area. The study concluded that a regional 345 kV line from the Twin Cities area to the Madison, Wisconsin, area would solve the load serving issues and congestion issues present in each area in a more economic way than localized lower voltage solutions and would significantly increase regional transfers between Minnesota and Wisconsin as well. The first phase of this line was identified in the CapX Vision Plan as one of the top priority lines.

J. Community-Based Energy Development Study. CapX is presently leading a study to determine what transmission upgrades might be necessary to implement "community-based energy development" (CBED) projects in the West Central Transmission Planning Zone in Minnesota, a seventeen-county area through the center of the state running from just west of the Twin Cities to the South Dakota border. C-BED projects are defined in Minnesota law as wind projects with certain ownership arrangements set out in statute for which the owners have obtained a county board resolution supporting the project from the county where the project will be located. Minnesota Statutes § 216B.1612, subd. 2(f). This study will supplement other transmission planning that CapX has engaged in to explore improvements in the system to transport more wind energy. CapX expects to complete this study by May or June 2006.

IV. Criteria Development

In the Notice of Inquiry, the Department invited comment on what criteria it should use in evaluating the suitability of geographic areas for NIETC status. The Department listed eight criteria that it has identified and asked whether any of these are more important than others and whether there are other criteria that could be applied.

The CapX utilities have read over the eight criteria, and at this point we cannot say that any one or two of the criteria are more important than the others. We would suggest that the Department make it clear that a particular corridor candidate does not have to meet all eight criteria (or however many there are) in order to qualify as a National Interest Electric Transmission Corridor. The ultimate decision to designate a NIETC is one the Department can make on the basis of any combination of the criteria, giving weight to each criterion as appropriate under the circumstances.

One important factor that deserves emphasis in considering whether a particular corridor deserves National Interest designation, which is not listed specifically in any of the eight criteria identified but which certainly is consistent with Criteria 4 (enhancing energy independence) and Criteria 5 (furthering national energy policy), is the issue of whether a particular area is an important area for promoting development of renewable energy sources. We would suggest that you make promotion of renewable energy sources a separate criterion. Minnesota has established Renewable Energy Objectives (REO), and other states have also established REOs or even Renewable Energy Standards (RES), and new transmission is going to be required for utilities to comply with these goals. The extent to which state objectives or standards for renewable energy would be furthered by a particular transmission line could be a useful metric for evaluating a corridor for National Interest designation.

In Minnesota and surrounding states, as indicated by the CapX Vision Plan and other studies, for instance, the present transmission system is not capable of supporting all the wind development potential that exists and that will have to come online in order to meet the REO. An area of concentration for the CapX utilities and others is how to transmit more wind power from areas of good wind speeds to areas of consumer demand.

V. Corridor Designation

The Department is seeking assistance on how broadly or narrowly it should define corridors in its study and NIETC designations. Our view of this is that it is less important to establish a width for any particular corridor than it is to simply identify areas of the country where the national interest supports an increased focus on the need to construct new transmission infrastructure to address a specific goal, whether it is energy independence, increased demand, promotion of renewable energy sources, or other legitimate national interest.

The designation could define a certain area, such as the Buffalo Ridge area in Minnesota, South Dakota, and North Dakota, or it could simply define endpoints, such as Bismarck, North Dakota, and the Twin Cities in Minnesota. It is less important that a National Interest designation establish a three mile or ten mile corridor width than it is that the designation highlight the need for new transmission infrastructure to carry out a certain objective and meet a certain need. Once the endpoints are established, it is not necessary to restrict consideration of the actual route to a particular corridor; the utilities, the state regulators, and the public will participate in a process to select the actual route.

The Department indicated in its Notice of Inquiry that it would consider early designations of National Interest Electric Transmission Corridors if there is a "particularly acute need" and "for which a compelling case is made." The CapX utilities are not requesting an early designation of any corridors. We prefer to see the Department focus its efforts on the development of the broader congestion study and deal with the corridor designations once the study is available.

As we understand the Department's efforts at this point in the development, the Department's August 2006 congestion plan will identify criteria for seeking designation of corridors as NIETCs and will also identify geographic areas where significant transmission needs exist. Without making an actual NIETC designation, CapX utilities would request that the August 2006 study recognize that there is an immediate need for new transmission infrastructure throughout Minnesota and surrounding states. At a minimum, we would urge the Department to include in its study the Buffalo Ridge area of Minnesota and the Dakotas, the I-94 corridor between Bismarck, North Dakota, and the Twin Cites, the southeast Twin Cities to Rochester, Minnesota, to LaCrosse, Wisconsin, area, and the Big Stone area in western Minnesota and the Dakotas, as areas that fit the definition of places where new transmission is going to be required.

VI. Pending Projects

One of the questions presented by the Department in the Notice of Inquiry asks interested persons to identify categories of information that would be useful to include in the congestion study for purposes of identifying geographic areas of interest. See Question No. 4 at 71 Fed. Reg. 5662. CapX suggests that one category of information that would assist the Department in carrying out its task relates to the status of transmission projects presently pending in the various regions around the country.

Learning about pending projects around the country will be helpful for at least two reasons. One, it will advise the Department of where transmission needs have already been identified and the reasons for the additional transmission infrastructure. Two, it will allow the Department to become aware of the various planning processes that are employed to determine new transmission needs and the processes for state review and approval of these projects. Information about both of these matters will inform the Department's judgment in developing the congestion plan.

In the Minnesota area there are several projects currently under review that we would like to bring to the Department's attention. We already mentioned above in paragraph III.F. the Big Stone II Transmission Project that is presently under review. Big Stone II refers to a proposed new 600 MW coal-fired power plant to be constructed in South Dakota. The transmission interconnection service necessary for the proposed plant involves construction of approximately 48 miles of 230 kV transmission and 90 miles of 345 kV transmission in South Dakota and Minnesota. The seven Big Stone applicants, which include CapX participants Otter Tail Power Company, Great River Energy, Missouri River Energy Services, and Southern Minnesota Municipal Power Agency, have already applied for appropriate permits from South Dakota and Minnesota officials for the plant and the transmission lines.

Several other projects in Minnesota have just begun the review process. These are what are called the BRIGO projects, a series of 115 kV projects in southwestern Minnesota designed to increase the capacity of the system and allow for additional wind generation. The BRIGO study is discussed in paragraph III.H. above. Recently Xcel Energy submitted a proposed Notice Plan to the Minnesota Public Utilities Commission, essentially the first step under Minnesota law to initiate PUC review of the need for proposed transmission.

In addition, as mentioned above in the discussion of the CapX Vision Plan in paragraph III.D, several CapX utilities anticipate initiating state review of several 345 kV transmission projects before the end of the year.

Many of these pending transmission projects, particularly the larger lines, cross the Minnesota border into neighboring states and require review and authorization from more than just Minnesota officials. Cooperation between states will be imperative to ensure prompt and consistent resolution of the issues relating to the need for and the routing of these crucial transmission projects. CapX has every expectation that state procedures will properly lead to a final decision in a timely fashion.

VII. Conclusion

Thank you for the opportunity to comment on the Department's efforts to prepare a congestion study and develop criteria for designation of National Interest Electric Transmission Corridors. It is an important effort that will be a valuable resource for utilities, government regulators, interest groups, and the general public as we all proceed to ensure a reliable and adequate electrical system in this country.

In sum, here's a list of our general comments and recommendations:

- Review and take into account the studies that we have identified in these comments.

- Give consideration to the effect of new transmission projects on the potential to develop wind and other renewables to ensure that transmission constraints do not restrict development of renewable energy sources.

- Recognize that Minnesota is going to require significant new construction of high voltage transmission lines in the near future and include at least the Buffalo Ridge area, the North Dakota to Twin Cities connection, and the southeast Twin Cities to LaCrosse, Wisconsin, connection within the inventory of areas of national interest.

- Consider the fact that utilities are and will be seeking approval of interstate transmission projects pending before state agencies and analyze the various state processes employed for reviewing such requests.

Respectfully submitted,

William R. Kaul
Chair of the CapX Utilities, and
Vice President of Transmission for Great River Energy

25. Horizon Wind Energy, Received Mon 3/6/2006 4:20 PM

COMMENTS OF HORIZON WIND ENERGY
ON THE DEPARTMENT OF ENERGY'S "CONSIDERATIONS FOR TRANSMISSION CONGESTION STUDY AND DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS"

March 6, 2006

Horizon Wind Energy ("Horizon") appreciates this opportunity to respond to the Department of Energy's Notice of Inquiry[1] concerning its plans for a congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETCs"). We believe that in the era of increasingly volatile fuel prices, concerns over the environment, and threats to security from growing dependence on imported fuels, our Nation's vast resources of wind in the middle of the country can and should be tapped. As President Bush stated recently on his Advanced Energy Initiative tour, "areas with good wind resources have the potential to supply up to 20 percent of the electricity consumption of the United States." These comments address the proposed criteria for corridors in response to questions in the Department's inquiry; propose studies to add to the list of relevant studies in Appendix A of the notice, and identify specific corridors from the set of relevant studies that we believe qualify as NIETCs.

[1] Department of Energy, Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Federal Register notice Vo. 71, No. 22, February 2, 2006, page 5660.

These comments also emphasize the importance of determining, sooner rather than later, how new transmission projects will be funded. It is imperative that the Department of Energy ("DOE") work closely with the Federal Energy Regulatory Commission ("FERC") in order to enable not only the physical designation of transmission priorities, but identify the process and responsible parties who will bring the capital required to enable the transmission corridors to actually be constructed.

II. WHO WE ARE

Horizon Wind Energy, formerly Zilkha Renewable Energy, develops, constructs, owns, and operates wind farms throughout the United States. With over 500 megawatts of wind farms operating in Iowa, Pennsylvania, Oklahoma, New York, and Costa Rica, Horizon is developing a portfolio of more than 4,000 megawatts in a dozen states. In 2006 alone, we will construct more than 700 megawatts in Texas, Washington State, New York, and Illinois. We are focused on diversifying our nation's energy supply, and we are committed to partnering with communities both to develop the abundant renewable resource and to provide rural economic development.

II. A "CORRIDOR" SHOULD BE BROADLY DEFINED

The first question raised in the notice is essentially "what is a corridor?" Horizon agrees with the Department that corridors should be identified as "generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities."[2] We believe this generalized approach is consistent with standard transmission planning practice and with the intent of the law. The approach avoids the obviously unworkable approach of finding that a specific route is of national interest while other routes connecting two areas are not. Congress chose the term "corridor" over other terms like "route" for a reason and we believe it was with this consideration in mind.

We encourage DOE to make sure it reviews the National Electric Reliability Council ("NERC") n-1 requirement when defining the width of transmission corridors, so that in situations where more than one high voltage transmission line is located, the n-1 standards will be achieved.

Specifically, we believe that a corridor should be defined as follows: "a corridor connects two geographic areas, separated by transmission limitations, defined as utility service territories, control areas, resource production areas, or points on the electric transmission system where all NERC n-1 requirements are met."

III. CRITERIA FOR CORRIDOR IDENTIFICATION

Horizon generally supports the proposed criteria but respectfully submits that they do not sufficiently address the criteria required by EPAct Sec. 1221. We suggest specific modifications

[2] DOE Federal Register notice, page 5661.

below. Our suggestions do not include wind-specific provisions, but rather generally applicable provisions that we believe are required by the law.

Draft Criterion 1: Action is needed to maintain high reliability.

Horizon supports this criterion and would add the following provision: "an area that would lead to supply from greater numbers of small generating facilities that are less vulnerable to national disasters or malicious acts than large generating stations."

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

Horizon supports this criterion as far as it goes. However it does not address the provisions of EPAct section (B)(i) "The economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy." Economic growth can be enhanced by the rural economic development associated with wind farms in the middle of the country. We suggest the following clarification: "an area that promotes rural economic development through generation development in rural areas such as on farms and ranches." This provision of the act should be included in Criterion 2 or as an additional criterion.

Both sides of the economic benefit issue can be observed in Kansas. The state has already benefited from a few wind farms which have provided new jobs and lower energy prices for local citizens. Kansas stands to benefit further from wind development if existing Southwest Power Pool ("SPP") transmission expansion plans, such as the Kansas-Panhandle transmission expansion plan, are put into action. On the other hand, the inability of these plans to move forward due to the current debate over appropriate cost allocation is causing economic losses to occur in existing rural communities, particularly in Southwest Kansas. This is primarily due to the inability of low-cost energy – both from traditional sources and wind power – to be moved to parts of Kansas that are currently obliged to pay high-price power production because of existing transmission constraints that prohibit the delivery of the most economic power.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

We suggest that this criterion be clarified to specifically state that supply diversification both at the local level (power used to serve load in a particular area) and national level are covered by the criterion. In other words, a corridor to an area that would increase national consumption of wind, even if the particular state or region already has significant wind usage, would qualify given the low percentage of wind currently in the national electricity portfolio. We note that the criterion as written does not address the criterion in EPAct (B)(ii) "a diversification of supply is warranted." Supply diversification should be clarified in this criterion or added as another criterion.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Horizon supports this provision and finds it to be consistent with EPAct's criterion (C) "The energy independence of the United States would be served by the designation." We agree with the specific metrics of fuel diversity, improved domestic fuel independence, and reduced dependence on energy imports.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

We support this criterion and find it to be consistent with EPAct's criterion (D) "The designation would be in the interest of national energy policy." However we note that the notice provides no clarifying language or metrics for this criterion unlike all of the other criteria. The Department should make it a priority to implement this provision of the law.

Metrics for this criterion should be based on the Advanced Energy Initiative in the President's State of the Union speech,[3] the Western Governors Association's unanimous clean energy resolution,[4] and any other recent multi-state or national law or policy statement on energy policy. Together the State of the Union speech and WGA resolution provide clear criteria that are consistent with initiatives in states across the country and with initiatives in Congress.

The President's Advanced Energy Initiative includes the following: "replacing more than 75 percent of our oil imports from the Middle East by 2025," reducing demand for natural gas, diversifying energy sources, developing "cleaner," "cheaper," and "more reliable alternative energy sources."[5]

To derive metrics from the policy statements from the President and the Western Governors, Horizon proposes that the following features from each be used: From the President's initiative metrics should include increasing supplies of clean, low cost, reliable, and domestic energy that diversifies the nation's energy portfolio. Horizon suggests that DOE adopt the following metrics for Criterion 5: "an area that allows for the development of clean, low cost, reliable, and domestic energy that diversifies the nation's energy portfolio including a demonstration that a corridor will increase the use of some or all of the following: energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies."

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

Horizon suggests the following metric for this criterion as well as Criterion 1: "an area that would lead to supply from greater numbers of small generating facilities that are less vulnerable to national disasters or malicious acts than are large generating stations."

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for

[3] http://www.whitehouse.gov/news/releases/2006/01/20060131-6.html
[4] http://www.westgov.org/wga/policy/04/clean-energy.pdf
[5] http://www.whitehouse.gov/news/releases/2006/01/20060131-6.html

generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

Horizon notes that this criterion is not identified in EPAct, and the demonstration of whether corridors meet the other criteria should be robust to the assumptions identified here so this proposed criterion is redundant.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

Horizon supports this criterion as written and agrees with the need for an explicit provision addressing energy efficiency alternatives.

V. CONGESTION MODELING MAY MISS THE POINT

The notice indicates that the initial electric transmission congestion study required by FPA subsection 216(a)(1) will be based on existing studies and congestion modeling of the Eastern and Western Interconnects. Horizon believes the study required by law must include the lack of transmission between supply resources such as wind and electric load. Many existing studies do address this issue. Typical power system load flow and economic dispatch models take existing generators and load as given and therefore do not address this issue. To the extent DOE intends to use these congestion models to perform the broad "study" required by law, the congestion model should include new wind generators placed in wind-rich areas on the grid. If that is not done, the model will only look at current congestion on the existing grid rather than the more important lack of transmission to supply sources.

V. RELEVANT TRANSMISSION PLANNING STUDIES

There has been a great deal of work done by transmission planners around the country to describe the opportunities to bring relief from congestion and reliance on imported energy. The Department listed many of these studies, but should take notice and include relevant studies that were not named. These three studies are notable for the attention given to development of wind or other renewable resources in the near-term:

The Southwest Power Pool's *Kansas/Panhandle Sub-Regional Transmission Study*, http://sppoasis.spp.org/documents/swpp/transmission/studies.cfm, January 26, 2006, the *Report of the Tehachapi Collaborative Study Group*, March 16, 2005. www.cpuc.ca.gov/Published/Graphics/48819.PDF, and the *Report of the Imperial Valley Study Group*, September 30, 2005 www.energy.ca.gov/ivsg/)

The existing transmission studies, both those noticed by the Department and the additional studies, show Draft Criteria met with transmission expansions that serve large additions of wind. Below is a description of the studies that have specifically examined the potential to bring benefits to consumers through large amounts of wind development, or identified wind rich regions and begun the planning for the development of the wind resource.

Southern Plains region

The Southwest Power Pool "*Kansas/Panhandle Sub-Regional Transmission Study,"* is also known as the "X-Plan" because of the shape of the new lines crossing from the Nebraska border through western Kansas and into Oklahoma and the Texas Panhandle, an extraordinarily wind-rich region. This study was driven by requests from developers of 2,500 MW of new wind generation currently seeking interconnection to transmission. SPP prepared this study during 2004 and revised it in 2005, showing $80 million of production cost savings annually in the Southwest Power Pool, and annual total fixed charges costs of $74 million.[6] The plan uses new 345 kV line segments: Spearville-Mooreland-Potter-Tolk-Tuco, Spearville-Knoll-Pauline, and connections from Mooreland to the Northwest substation and to Wichita. This allows new wind generation from western Kansas, southwestern Nebraska, western Oklahoma and the Texas panhandle to supply Kansas, Missouri, Arkansas and eastern Oklahoma immediately, and with added transmission, Louisiana and Mississippi.

Desert Southwest

A series of studies in the Desert Southwest, including The *Report of the Imperial Valley Study Group*, Documents on the Palo Verde—Devers #2 project, and the Report of the Phase III Study of the Central Arizona Transmission System, detail congestion reduction and renewable energy development opportunities. The important lines for large amounts of renewable energy from the interior regions to urban areas run from the Four Corners area across Arizona (Pinnacle #1 to Moenkopi, and then westward to Eldorado) and also west across southern Arizona (Palo Verde to Devers). Inside California, Devers and Imperial Valley connections to Los Angeles and San Diego. This collection of studies by regional utility companies concerned with reliability and congestion relief service all the cities of New Mexico, Arizona and Southern California with wind resources in each of these states.

Central California

The Report of the Tehachapi Collaborative Study Group is a result of work directed under a California Public Utility Commission ("CPUC") order.[7] The report details a plan to connect 4060 MW of wind generation in the Tehachapi region via a new central substation and 500 kV lines connecting to the Vincent, Antelope, and Midway or Gregg Substations. The study was led by a group that included the CPUC, the California ISO, the California Energy Commission, Southern California Edison, Pacific Gas & Electric, wind developers, and the advocacy organization CEERT. This plan can allow wind generation potential in the Tehachapi region to meet state goals for renewable resources that are the least cost and best fit for California. Transmission congestion has prevented this region from developing this potential and serving the state's well-known need for energy.

[6] Costs include underlying lower-voltage upgrades, and 15% finance rate. Fuel cost assumed in 2005 study was natural gas cost at the burner was $5/ MMBtu. *Addendum to the Kansas/Panhandle Sub-Regional Transmission Study* November 4, 2005.

[7] CPUC Decision 04-06-010 identified 4060 MW of wind resource in Tehachapi in proceedings related to the implementation of the Renewable Portfolio Standard required by California law.

Pacific Northwest
The Pacific Northwest has several wind-rich areas. Transmission planning in the region has focused on moving power from east of the Cascades to the coast, and from Montana to the Northwest more generally. Transmission planning to bring wind power into the region has emphasized the shorter distance transmission from the Columbia Gorge region. A summary of the needed work can be found at the website http://www.transmission.bpa.gov/PlanProj/Transmission_Projects/projectsonhold.cfm.

Intermountain West
In August 2003, Wyoming Governor Dave Freudenthal and Utah Governor Michael Leavitt created the Rocky Mountain Area Transmission Study (RMATS) as a multi-state effort to reduce congestion and increase transmission. This work identified two transmission projects. The Bridger Expansion Project adds transmission from southern Wyoming to southern Utah and to northern Idaho. Initially, these additions would support 1,375 MW of new wind generation in southwest Wyoming and southern Idaho, but larger additions for export to Nevada and the West Coast are also described. Also in the RMATS study is a Wyoming to Colorado transmission project. This addition of a 345 kV line and other upgrades would allow exports from over 1200 MW of wind generation from excellent wind resources in eastern Wyoming to Denver.

Midwest
The Midwest ISO prepared a 2003 Transmission Expansion Plan (MTEP) with the knowledge that this ISO serves a region with over 700,000 MW of "proven reserves" of wind power in its nine state region.[8] The study found transmission investments could reduce annual energy costs between $304 million and $1.6 billion when coupled with high amounts of wind, depending on natural gas price projections. The 2003 MTEP
includes an Exploratory Plan for Iowa and southern Minnesota that that includes moving wind energy from this area (including the eastern edge of the Dakotas to Minneapolis- St. Paul. When the study was performed, a gas price of $3.24-$3.85/mmBtu Natural Gas was the base case assumption, resulting in an annual benefit of $304 Million.

VI. PROPOSED CORRIDORS

Using the information and analyses from the studies the Department has noticed, the studies suggested in these comments, and the wind potential included in the forward-looking studies, we believe the Department will find persistent congestion and a national interest in designating the following corridors:

1. Northern New Mexico to San Diego
2. Eastern Oregon/Washington to Portland/Seattle
3. Tehachapi to Vincent Substation
4. Southern Wyoming to Denver

[8] See *An Assessment of Windy Land Area and Wind Energy Potential, Pacific Northwest Laboratory*, 1991.

5. Southern Wyoming to Las Vegas
6. Western Kansas and Oklahoma to Kansas City
7. Western Kansas, western Oklahoma and the Texas Panhandle to Denver
8. Maine to New York

VII. COST ALLOCATION FOR TRANSMISSION

Although this DOE comment process is focused specifically on the congestion study leading to the designation of NIETCs, we believe it is not too early for the DOE to consider the impact of providing a clear plan to fund resultant transmission projects in those corridors.

It is evident that for transmission projects proposed throughout the United States, planning alone is not enough. A national corridor system must have policy certainty regarding cost allocation of new or expanded transmission assets so that investors may plan accordingly. Transmission funding is currently handled on a regional basis, and progress on this question has been slow at best in most regions.

Horizon advocates that in order to turn the DOE National Interest Electric Transmission Corridor plan into reality, and to achieve success within a reasonable time frame that will both benefit the general public and meet the goals of the EPAct 2005, the cost allocation question must be handled at the Federal level very early in the process. We propose that the DOE work with the Federal Energy Regulatory Commission ("FERC") consider this issue alongside the designation of transmission corridors. We recommend that transmission cost allocation be structured in a manner similar to other successful Federal infrastructure projects such as the interstate highway system, various hydroelectric facilities, and the federal aviation system. Without providing guidance for the cost allocation of a transmission system that impacts the entire nation, the current status of regional debate on complex and in some cases impossible-to-finance transmission plans will continue to prohibit the vision of a truly effective national transmission system to be realized.

26. International Transmission Company, Received Mon 3/6/2006 4:57 PM

U.S. DEPARTMENT OF ENERGY

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

COMMENTS OF INTERNATIONAL TRANSMISSION COMPANY

International Transmission Company ("International Transmission") submits these comments in response to the Notice of Inquiry issued by the United States Department of Energy

("DOE") seeking comments on DOE's plans for designation of National Interest Electric Transmission Corridors ("NIETCs") pursuant to section 1221(a) of the Energy Policy Act of 2005. International Transmission is an independent electric transmission company that owns and maintains approximately 2,700 circuit miles of transmission facilities in Southeastern Michigan used for the transmission of electricity in interstate commerce. Transmission service is provided over International Transmission's facilities by the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") pursuant to the Midwest ISO Open Access Transmission and Energy Markets Tariff.

As the owner of the bulk power system in Southeastern Michigan, International Transmission's primary focus is on continuity and quality of service through best in class transmission planning, operating and engineering practices. International Transmission, therefore, has a keen interest in this proceeding. In addition to submitting these comments, International Transmission requests that it be given the opportunity to participate at the technical conference to be held in Chicago on March 29, 2006.

In general, the siting of transmission remains a roadblock to expansions needed to make the system reliable and provide to consumers the benefits of competitive markets, especially when the expansions involve multiple states. This and related DOE efforts can help resolve this issue.

RESPONSES TO PART III: QUESTIONS FOR PUBLIC COMMENT

General Comments:

DOE's determination of NIETCs must take into account the physical realities of our predominantly AC power transmission system and the limitations of that system. By "physical realities," we mean the laws of physics, which cause power to flow across the system is ways that defy simple "corridor," or "highway" designations and are the consequence of parallel flow phenomenon. A transmission bottleneck may be the result of events occurring hundreds or thousands of miles away. Similarly, the solution to one transmission bottleneck may result in new bottlenecks elsewhere on the system. For this reason, the designation of a NIETC by DOE must be based on a comprehensive view of the transmission system, the constraint proposed to be addressed by the NIETC designation, and the consequential effects of the proposed transmission enhancement elsewhere in the interconnection.

These parallel flows attributable to the actions of others are a primary concern associated with Michigan's transmission system. Equipment can be forced to its limits because power flows are not following contract paths, but instead go where physics dictate. These parallel flows of power across transmission lines in Michigan are a principal reason why transmission capacity in Michigan can be inadequate to accommodate transactions that would benefit consumers. Such power flows also consume reactive supply and make the system less reliable than it would otherwise be.

International Transmission is especially sensitive to the impact of such flows on its transmission system; while located on a peninsula, it is electrically interconnected with Canada.[1] Flows across this interconnection often consume the entire firm transmission capacity available; these flows also consume transmission capacity on either side of the interface which has further reliability consequences. Of particular importance in the Southeastern portion of Michigan served by International Transmission are plans by the Province of Ontario, Canada to retire its coal-fired generation facilities to comply with the Kyoto Accord. With the interface loaded to its

[1] These issues are discussed in the Michigan Capacity Needs Forum Staff Report and the Midwest ISO's Transmission Expansion Plan 2003 and 2005.

capability, one would expect that the addition of large scale, AC transmission lines elsewhere in the Eastern Interconnection would not have the intended benefit of providing additional transfer capability because the Michigan-Ontario interface would still be limiting.

The blackout of August 14, 2003 revealed the criticality of ensuring reliable transmission service in Michigan, specifically in International Transmission's service territory in the Southeastern region of the state, which has a considerable amount of industrial load.

Because transmission system changes anywhere in the Eastern Interconnection may have significant effects elsewhere in the Eastern Interconnection, International Transmission encourages the DOE not to define "Energy Corridor" too narrowly. The intent of Congress was to eliminate the current bottlenecks in the electric energy delivery system. Rather than focus on the notion of "corridor" as a simple right-of-way or particular congested facility, DOE should recognize that with alternating current transmission expansions, large power transfers do not just flow on the new project that may seek a NIETC designation, but will also flow on the existing system and potentially require additional system strengthening projects. The NIETC designation should be easily extended to further include the additional system-strengthening projects. In this way, an exchange of one problem for another can be avoided.

Finally, as the foregoing discussion of the unique transmission challenges in Michigan illustrates, no general criteria promulgated by DOE can encompass all situations. International Transmission urges DOE to be receptive to special circumstances justifying NIETC designation, and to provide as much guidance as possible as to how DOE will address case-by-case applications for such a designation, including details pertaining to the required elements of such applications.

A. Congestion Study

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

DOE should not be overly concerned with categorizing the “type” of congestion, but should focus, instead, on the consequences of it. Congestion can increase prices or more seriously, jeopardize system reliability. Due to the long lead times of transmission projects, and changing patterns of electricity supply and demand, the “type” of congestion addressed by a particular project may change by the time a project goes in service. DOE also should recognize that it may miss some very significant congestion because of modeling limitations. These limitations include: a) the number of monitored lines and contingencies are limited in size; b) serious congestion can occur at lower voltage levels that are not modeled; and c) generation patterns may change significantly in the future. In a modeling sense, the persistence of congestion should be indicated by the number of hours a constraint is binding in an economic dispatch security constrained study. However, because of inherent modeling limitations, any evidence of congestion, even for a few hours of the year (evident in real time or reflected in denial of service) can signal a potential problem on financial and reliability levels and has to be taken seriously.

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

Physical congestion must be addressed directly and with certainty. However, contractual congestion would appear to be an artifice that clouds the issue.

(3) Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

International Transmission would like DOE to refer to the excellent Michigan Public Service Commission "Final Report of the Capacity Needs Forum." We would recommend that DOE focus on future plans, studies and flows, rather than looking back. New base load generating plants and some major new transmission additions are being actively discussed in Michigan.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

a) Interdependence with foreign countries

b) Aggregate available generation resources and transmission capacity within a region vs. load

c) Risk to energy/homeland security

d) Economic importance to a region or a State or an Area

e) Current experience in observing congestion, as well as existing and projected use of the system, is a primary indicator of insufficient capacity and should be fully acknowledged.

B. Criteria Development

Draft Criterion 1: Action is needed to maintain high reliability.

International Transmission strongly supports the need to utilize NERC planning criteria to identify existing or projected violations of reliability standards. These and the companion Regional criteria developed by NERC regional reliability councils provide a clear and consistent standard that can serve as a basis for identification of deficiencies. These criteria have been developed and refined over many years by industry experts and have provided for reliable and secure operation of the entire grid. Other metrics such as load, population, demand growth, etc. are inherently accounted for when transmission plans are tested against such criteria.

Such criteria should include both transmission and generation resource standards and should reflect the interactive and interrelated nature of both. In the Michigan Capacity Needs Forum ("MI-CNF"), for example, the Michigan Public Service Commission ("MPSC") staff concluded that a reliability standard of Loss of Load Expectation ("LOLE") of 1 day in 10 years was an appropriate minimum standard. Both transmission capability as well as generation resource adequacy and their interrelationships are addressed by such a standard.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

In contemplating NIETC designations for this purpose, it is very important that the right metrics exist for defining the actual benefit that flows to consumers from transmission expansions. When defining the benefits that result from transmission expansions, variable production cost reduction alone does not adequately encompass the benefits that flow to consumers. When seller concentration is reduced, consumers are the winner. In RTOs that employ a Locational Marginal Prices ("LMP") based energy market, a reduction in LMPs signals competition, and consumer benefits. The variable production cost as a metric does not capture all the value created by transmission expansion. If this metric was the sole determinant, it would greatly undervalue transmission expansion. Because Financial Transmission Rights ("FTRs" in the MISO or their equivalent in other RTOs) cannot completely insulate consumers from all congestion costs, it is important to consumers to reduce LMPs in their respective markets. In non-RTO areas, the addition of transmission reduces the need for Transmission Loading Relief and uneconomic redispatch, the true costs of which are seldom fully appreciated or known.

If price differentials exist within a region, it should be a sign that the downward price pressure exerted by competition has not occurred uniformly. In order to address pockets of single (or few) owner generation concentration ("seller concentration"), transmission needs to built to allow the customer more choice in suppliers. It is unrealistic to think that the benefits of competitive markets will be attained without the infrastructure necessary to provide consumers with a choice of willing sellers and a market design that allows consumers to receive the benefit of access to lower cost suppliers. Resolving these infrastructure issues is a matter of vital importance to Michigan's economy with its dependence on manufacturing and a jobless rate that is currently the highest in the U.S.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end-use markets served by a corridor, and diversify sources.

As noted previously, seller concentration subverts the aims of competition, and limited access to suppliers produces such concentration. Given constraints, the reliance on a single fuel source, such as natural gas, within an area also can present problems when the price of that fuel rises, as we have seen with natural gas over the past two years. This can create wide price differentials within the region. When these price differentials exist, this should serve as a trigger for examining if transmission expansion is necessary to reduce the supply concentration. In a load pocket where congestion or lack of import capability exists, the customer may not have access to the most economic sources of power. Import transfer capability is a measure of this restriction and is a measure that DOE should also use beyond "congestion". The lack of import capability into a region will require higher reserve margins and prevent wider access to generation.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

International Transmission is affected every day by cross-border electricity flows and, as the August 2003 blackout demonstrated, Canada is affected directly by transmission reliability failures in this country. Thus, while International Transmission recognizes that Congress listed "energy independence" as one of the criteria for DOE to consider, we would suggest that this be considered in the context of energy security, even mutual energy security, rather than energy "independence." If a transmission inadequacy in a "corridor" has the potential to disrupt electricity reliability and security in either the U.S. or Canada that should be of concern to DOE.

Draft Criterion 5: Targeted actions in the area would further national energy policy:

International Transmission has no comments on this criterion.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

International Transmission supports this criterion since bolstering the transmission system will improve reliability and reduce the likelihood of service disruptions, whether from normal threat contingencies or from natural or malicious causes.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

International Transmission understands that the determination of a NIETC should be based in reality. If a national interest determination is contingent upon future events, it may raise questions with affected parties. The unfortunate reality is that forecasting and modeling is an indispensable part of transmission planning, simply because of the long lead times necessary to put projects in service, and because the failure to identify or address problems through a future oriented planning process will entail economic losses to consumers and a significant threat to the reliability of the system. In applying models, to insure robustness of the results, it is necessary to test key sensitivities such as different dispatch patterns, different load forecast assumptions, and different fuel assumptions improve the quality of the results.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

While alternatives to transmission should be considered, the reality is that transmission construction has not kept pace with demand, congestion is increasing and Congress intended to address this situation by granting DOE the new NIETC designation authority in the Energy Policy Act of 2005. The consideration of alternatives needs to be done in this context and with the understanding that multiple planning processes currently exist at the state and regional level for consideration of alternatives to transmission upgrades. DOE need not impose another layer of alternatives review.

Conclusion

International Transmission appreciates the opportunity to submit these comments and pledges its full support for the Department's efforts to enable the construction of transmission facilities in the national interest.

If DOE has any questions about these comments, please contact the undersigned at lstuntz@sdsatty.com or (202) 638-6588 or Gregory Ioanidis at gioanidis@itctransco.com or (248) 374-7251.

Respectfully Submitted,

/s/ Linda G. Stuntz

Linda G. Stuntz

Counsel for
International Transmission Company

March 6, 2006

27. ISO/RTO Council, Received Mon 3/6/2006 4:56 PM

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

Re: Considerations for Transmission
Congestion Study and Designation of
National Interest Electric Transmission
Corridors

Comments of the ISO/RTO Council on the Department of Energy's Notice of Inquiry re: National Interest Electric Transmission Corridors
March 6, 2006

The ISO/RTO Council ("IRC") submits these comments in response to the Department of Energy's ("Department") Notice of Inquiry regarding the Department's upcoming Congestion Study and its role in designating National Interest Electric Transmission Corridors.[1] Both items arise from responsibilities assigned to the Department by the Congress through section 1221 of the Energy Policy Act of 2005, Public Law 109-58, 119 Stat. 594 ("EPAct" or "Act"). Through these Comments, the IRC expresses its support for the Department's proposed criteria and details how those criteria can best be applied to the results of the open and independent regional transmission planning processes undertaken by the IRC's members.[2]

[1] *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors,* Notice of Inquiry, 71 Fed. Reg. 5660 (Feb. 2, 2006) ("NOI").

[2] The members of the IRC are the Alberta Electric System Operator ("AESO"); California Independent System Operator Corporation ("CAISO"); Electric Reliability Council of Texas ("ERCOT"); the Independent Electricity System Operator of Ontario ("IESO"); ISO New England Inc. ("ISO-NE"); Midwest Independent Transmission System Operator, Inc. ("MISO"); New York Independent System Operator, Inc. ("NYISO"); PJM Interconnection, L.L.C. ("PJM"); and the Southwest Power Pool ("SPP"). Due to their own unique jurisdictional circumstances, the Alberta Electric System Operator ("AESO") and the Independent Electricity System Operator of

I. Background on the IRC

The IRC was created in April 2003 by the nine functioning Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") in North America. The IRC's mission is to work collaboratively to develop effective processes, tools and standard methods for improving competitive electricity markets across North America. In fulfilling this mission, it is the IRC's goal to provide a perspective that balances reliability considerations with market practices so that each complements the other, thereby resulting in efficient, robust markets that provide competitive and reliable service to users of electricity.

The IRC focuses in these comments on the criteria the Department proposes to consider in reaching decisions on designating National Interest Electric Transmission Corridors. Individual members of the IRC may supplement these comments with comments applicable to their particular region as well as with requests for early designation of a transmission corridor pursuant to the invitation for such proposals set forth in the NOI.

II. A Balanced Approach to Congress' Directives

As a threshold matter, the IRC expresses its overall support for the NOI's criteria for designating National Interest Electric Transmission Corridors designations. The IRC believes that the NOI criteria strike the right balance between identifying true "national interest" corridors versus avoiding turning every transmission upgrade into a national interest project. In order to further clarify this distinction, the IRC proposes a clear definition of an electric transmission corridor, which is both workable and consistent with Congress' intent concerning the Department's role in this process.

The Role of the Department As Assigned by Congress – Congress devised section 1221 of the Energy Policy Act to ensure that necessary transmission infrastructure with national implications can be developed in a timely manner while respecting existing state processes for siting transmission facilities.**)** Congress delegated very specific yet very different tasks to the Department and to the Federal Energy Regulatory Commission ("FERC"). Through Section 1221(a)(2), Congress assigned to the Department the task of identifying and designating as a National Interest Electric Transmission Corridor "geographic area[s] experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers." In Section 1221(b), it assigned to FERC the task of permitting construction of specific transmission projects within designated National Interest Electric Transmission Corridors as a "backstop" if state authorities lack the power to permit the project or to consider its interstate benefits or, under certain circumstances, fails to authorize the project or imposes burdensome economic conditions within one year from the date of an application for such authority. In Section 1221(h)(9)(C), Congress directed the Secretary to "consult regularly" with among other entities, "Transmission Organizations approved by the Commission."[3]

III. Defining National Interest Electric Transmission Corridors

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Ontario ("IESO") are not joining these comments. ERCOT, as the ISO for an intrastate interconnection, also is not participating in these comments.

[3] In Section 1291(b)(29), Congress defined "Transmission Organization" as "a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities."

The IRC believes that the Act should be read in a manner that harmonizes the important roles of the Department, the states, RTOs and ISOs and the FERC and that provides the needed impetus to allow development of critical transmission projects to flourish. Specifically, the IRC believes that by identifying interfaces and other critical transmission facilities or areas which represent significant transmission constraints, the Department can best serve its important role under the Act without itself becoming a siting agency or usurping the siting process reserved to the states and ultimately to the FERC. As a result, the IRC believes that defining a corridor should not be undertaken with reference to a specific geographic path as identification of geographic paths is exactly the role of the siting process. The Department should instead identify "National Interest Electric Transmission Corridors" by identifying electrical paths between load areas and generation concentrations that are electrically and economically linked but where the transmission capability between them needs to be strengthened. The IRC proposes that the Department adopt the following definition of Transmission Corridor and National Interest Electric Transmission Corridor:

> *A transmission corridor consists of all transmission paths and potential transmission paths that provide power transfer capability between a defined area of load and the generating resources that may be delivered across the transmission system to serve all or a portion of that load.*
>
> *A National Interest Electric Transmission Corridor' is a transmission corridor that meets the criteria set forth in Section 1221 of the EPAct and the Department's implementing regulations.*

The IRC believes this approach of defining critical generating sources and load centers (and deficiencies in transmission between them) will allow the Department to focus on Congress' goal of identifying parts of the nation facing significant reliability problems or congestion which rise to a matter of national interest pursuant to the criteria defined below. The IRC approach will allow the Department to maintain the "big picture" analysis that Congress sought without embroiling the Department in the specifics of the siting process which EPACT leaves, even after Department designation, initially to the states and ultimately to FERC as a backstop.

IV. The Role of IRC Member Planning Processes in the Designation Process

Pursuant to FERC Orders 888 and 2000, the planning of the transmission system in regions was assigned, in the first instance, to RTOs and ISOs in regions where they exist. FERC made this assignment in recognition of the fact that *independent* planning was critical to ensuring nondiscriminatory access to the grid.[4] Congress clearly intended to ensure that RTOs and ISOs and the results of their planning processes become a critical input to the Department's work by directing the Secretary through EPAct section 1221 (h)(9)(C) to "consult regularly" with such independent entities.

[4] *See Regional Transmission Organizations*, Order No. 2000, 1996-2000 FERC Stats. & Regs. Preambles ¶ 31,089 at pp. 31,163-31,165 (1999) *order on reh'g*, Order No. 2000-A, 1996-2000 Stats. & Regs. Preambles ¶ 31,092 (2000), *pet. for rev. dismissed sub nom., Public Utility District No. 1 of Snohomish County v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) (The FERC affirmed that "the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with state authorities" and "that independent governance of the RTO is a necessary condition for nondiscriminatory and efficient planning and expansion.").

Each of the members of the IRC undertake their own, independent transmission planning processes consistent with Orders 888 and 2000. By design, those processes are open to all stakeholders and the public and fully transparent. Each RTO/ISO planning process is designed to transparently identify congested interfaces and reliability violations that could be remedied through transmission improvements. Transparent information concerning constraints on the system are publicly made available so as to stimulate the development of demand side and generation alternatives to resolve identified reliability or congestion problems. The planning process projects the needs of the system, taking into account these alternatives as well as load growth, in order to determine whether particular constrained parts of the grid trigger violations of North American Electric Reliability Council ("NERC"), regional, and RTO/ISO reliability criteria.[5] Plans are fully coordinated on an inter-area basis with neighboring systems and with the owners of the underlying low voltage systems to ensure a robust reliable plan. Stakeholders, including state commissions, actively participate in open stakeholder meetings each year concerning the plan and provide comments which are ultimately considered by the independent boards of the RTOs and ISOs. After review of the stakeholder comments, the boards may adopt, reject or modify the recommended plan and then publish their final adopted plan. That plan then becomes the basis for new construction by transmission owners or merchant developers, and has been relied upon by both state commissions and the FERC in undertaking their siting and regulatory responsibilities. [6]

Just as it did for its National Transmission Grid Study in 2002, the Department should use the results of these regional ISO/RTO plans as the key input to its identification of congested interfaces in its section 1221 congestion study. Although the Department should take comments upon any requested designation arising out of a plan, the Department should rely upon the IRC members' regional plans as a key input into its own congestion study. Most importantly, it should avoid recreating wholesale the open, independent ISO/RTO planning processes and the complex factual findings that result from them. Some commenters may argue that the Department should essentially become a "master planner" or utilize its new authority in a manner akin to undertaking a national integrated resource planning ("IRP") process prior to designating corridors. Any such approach would inevitably weaken the approved ISO/RTO planning processes that have been instituted and would invite parties to circumvent those processes. Moreover, the Department would need to staff a group of technical experts on the national level which would end up duplicating work of independent experts within each region. Finally, major projects often require associated improvements to underlying low voltage systems. RTO/ISOs are best suited to ensure that plans are developed and implemented reliably.

For these reasons, the IRC respectfully suggests that the Department, when reviewing the results of ISO/RTO planning processes for its own congestion review, should assess whether the results are within a "zone of reasonableness" and whether the process that led to those results was transparent and unbiased, rather than whether each regional plan's quantification of congestion or reliability impacts was "correct" or whether the solutions proposed in the plan were exactly those that the Department may have chosen. In short, Congress assigned the

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[5] Moreover, PJM, New England, SPP and the MISO also have specific authority to include in their respective regional plans upgrades of the transmission system in order to address economic concerns before they arise to reliability violations.

[6] *See e.g.*, *In the Matter Of The Amended Petition Of Atlantic City Electric Company*, Decision and Order As To The "Northern" Route, NJBPU Docket No. EE02080521 (Apr. 20, 2004).

Department the task of reviewing the results of such planning processes, after regular consultation with the ISOs and RTOs, to determine where there are impacts that arise to the national interest and need to be resolved consistent with national energy policy. The Department should resist suggestions that it should become the nation's master transmission planner, particularly in areas of the country where comprehensive, open, independent and balanced, ISO/RTO regional transmission planning processes already exist.

V. Timing of Designation Applications

ISOs/RTOs produce annual assessments of the state of their respective power grids. Although the Department is only planning to conduct triennial congestion reviews, the Department should, in its final procedures, not foreclose the opportunity for entities to seek timely designation without having to await the next congestion review if the facts and circumstances so justify. The Department should clarify that its rules are sufficiently flexible to allow for applications for designation outside of the triennial review timetable. The IRC is heartened by the Department's willingness to consider applications for early designation and urges the Department to keep its processes flexible going forward as well.

VI. IRC Comments on Proposed Criteria for Designation

Draft Criterion 1: Action is needed to maintain high reliability.

The IRC concurs with the Department that enhancing reliability should be one of the prime factors driving corridor designation. Reliability criteria are well documented in both the NERC planning standards, the regional standards, and RTO/ISO reliability standards that ISOs/RTOs use in their regional transmission planning processes. Reliability violations and associated remedies are identified and developed in open and inclusive processes where all stakeholders participate. Any participant can propose additional or different reliability solutions it believes are needed or appropriate. The IRC supports the Department's approach of relying on application of existing NERC and regional standards and criteria. Moreover, as noted above, the Department should rely upon the findings of existing or future violations of reliability criteria that are developed by ISOs/RTOs and other independent entities.

In applying this criteria, the Department should also consider the breadth and timing of the identified reliability violation. A number of reliability violations can be cured with upgrades which may not arise to a national standard. On the other hand, certain larger projects may be able to solve multiple reliability violations which affect major load centers or which represent longer term reliability solutions. These projects are ones which are appropriate for national designation.

<u>Proposed Metrics</u>: Determining whether violations of reliability criteria rise to the point of justifying designation of a national interest corridor necessarily will require exercise of the Department's judgment. In making such assessments, the IRC suggests that the Department should consider the nature of the violations, how frequently and over what period of time they have occurred or are expected to occur, and the scope of their effects, *i.e.*, how much load is affected or potentially affected and what is the nature of that load? Criteria violations that affect major metropolitan areas or critical components of the integrated transmission grid, or those that have recurred or are expected to recur or to worsen over time, warrant greater consideration for

corridor designation than those that affect very localized loads or that appear to be infrequent or unlikely to recur.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

The Department appropriately recognizes the role that transmission upgrades can play in stimulating additional transactions which can lower costs to consumers. Consideration of economic effects is essential to fulfilling Congress' intent to address significant congestion that adversely affects consumers.[7] As a result, the final rule should recognize not only the potential of lowering costs to consumers today but the role of transmission in ensuring low-cost supplies into the future to accommodate a region's economic growth.[8]

DOE should also recognize that by either measure of congestion, price differentials across a corridor could result from a variety of reasons. These range from the operation of an inefficient generator on one side of a corridor through substantially different fuel mixes of generation being used in different regions. DOE should consider other factors when evaluating economic benefits. These could include the effect on losses, access to capacity resources, and similar indicators of benefit.

<u>The Impact of Congestion on the Grid</u> – Congestion is a physical reality affecting power flows. It may occur even in the absence of a reliability violation. Most members of the IRC operate transparent spot wholesale markets for electricity. These spot wholesale markets provide the platform both for short term transactions to occur as well as to inform parties in negotiations of longer term bilateral purchase power contracts.

Congestion on the transmission grid interferes with the lowest cost resources reaching markets and adversely impacts wholesale customer options. For one, the ultimate price paid by a wholesale purchaser (and ultimately a retail purchaser) is affected by congestion. Congestion represents an added cost which can, under certain circumstances, make an otherwise economic transaction non-competitive and thus deprive purchasers of the array of options they seek. In addition, congestion between particular locations on the grid force RTOs to dispatch generation "off cost" or out of merit order. An RTO operating an organized market dispatches units based on their marginal bids starting with the lowest cost units. Congestion interferes with that efficient economic dispatch forcing units to run out of merit order in order to clear congestion. Such out of merit dispatch causes higher costs for consumers and can make otherwise economic transactions uneconomic. Finally, as noted below, under certain circumstances, congestion can limit competitive options and thus create opportunities for the exercise of market power. RTOs and ISOs then are forced to mitigate market prices as an administrative solution which the market would have otherwise addressed had the congestion not limited the number of generators available to serve customers.

The IRC wishes to make clear that it would be imprudent to try to eliminate all congestion. Congestion is a function of the flow of electricity which can change under different conditions. As a result, not all congestion is recurring or chronic to any significant degree. Moreover, in some cases, the cost of building upgrades to eliminate congestion is greater than the cost of the congestion itself. This is precisely the type of information which RTOs and ISOs

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7 *See* EPAct § 1221(b).

8 The benefits to consumers can include, among other things, reduction in production costs, reduction in congestion and losses and other similar benefits.

with organized markets make available publicly through the publication of locational marginal pricing data.

RTO/ISOs post congestion information on their websites in order to allow buyers to make intelligent economic decisions and in order to stimulate market solutions to congestion. RTO/ISO independent planning processes incorporate this congestion information in order to ensure that the marketplace can value given proposed projects. Some IRC members have been charged specifically with planning for economics and for relief of congestion[9] while others have been limited to planning and ordering upgrades only for reliability. Nevertheless, in each case, the RTO/ISO planning process provides the appropriate vehicle and transparent process for analyzing and evaluating the causes of congestion on its portion of the transmission system.[10]

<u>The Department's Role in Addressing this Criterion</u> – The Department should avoid requiring its own cost/benefit studies in those areas of the country where RTO/ISO planning processes are in place and have determined effective solutions to meet identified needs. Moreover, the Department should avoid parsing "economic benefits" into studies of how individual states or sub-regions benefit. RTOs and ISOs address this issue by allocating costs of upgrades pursuant to FERC-approved methodologies. The proposed cost allocations are reviewed in open stakeholder processes and ultimately filed with FERC where any party can challenge them in whole or in part. The Department should avoid becoming embroiled in these cost allocation debates by defining its economic benefit criteria broadly. The allocation of those benefits among customers can then be addressed by the FERC through the regulatory process.

<u>Proposed Metrics</u>: The IRC proposes that those seeking designation of a particular corridor provide metrics that focus on the economic costs associated with the particular constrained interface in question. Specifically, those IRC members operating organized markets would be able to provide:

- The frequency and extent of congestion on the interface;
- Price information by location;[11]
- Measures of market competitiveness before the transmission upgrade and expected impacts of a transmission upgrade on the competitiveness of the market; and
- Trends in generation development and retirement on each side of the interface.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Significant transmission constraints impact the marketplace in a number of ways:

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9 *See* Footnote 5, *supra*.

10 IRC members have also entered into inter-RTO planning arrangements so as to ensure a holistic review of the transmission grid across RTO/ISO boundaries. *See e.g.* Northeast ISO/RTO Planning Coordination Protocol: among PJM, NYISO and ISO-NE with participation by NPCC and its Canadian control areas; MISO/PJM Agreement – Joint Operating Agreement; MISO/PJM/TVA Agreement – Joint Reliability Coordination Agreement; MISO/SPP Agreement – Joint Operating Agreement; MISO/MAPP Agreement – Seams Operating Agreement; MISO/IESO Agreement – Interim Coordination Agreement.

11 The locational marginal price of power at busses on each side of the corridor reflect the price differentials caused by the constraint.

- Customers in constrained areas realize high prices and lose the benefits of the most economic dispatch;
- Chronic congestion in constrained areas, when coupled with load growth, can, over time, manifest itself as a violation of reliability criteria. The converse is also true, namely, chronic reliability problems can result in economic congestion with time;
- Short term remedies for transmission constraints often include a patchwork of administrative mechanisms such as reliability must run agreements and cost capping substituting for competition among generating units;
- Transmission constraints can lead to dependence on certain units needed to remedy the problem and maintain reliability. This reliance can create the opportunity for a given generator to exercise market power which RTOs/ISOs then must step in to address through mitigation tools;
- Constraints can lead to dependence on units that utilize a particular fuel source such as oil and natural gas thus working against the nation's goal of a diverse fuel supply portfolio; and
- Load's access to a variety of fuel sources for generation is limited.

Facilitating additions of transmission capability to provide access to non-local generation should alleviate both the reliability concerns and the need for market power mitigation. Additional transmission capability also should offer the added benefit of access to more fuel-diverse generation sources from a larger "pool" of economically viable alternative supplies of capacity and energy. In general, such alternative supplies should lower prices in the affected area, since generation that operates under "Reliability Must Run" contracts, by definition, is relatively high-cost generation. Designation of national interest corridors for transmission into load areas where supplies are limited or where there is an insufficient diversity of fuel sources thus promises both increased reliability and lower (wholesale) electricity prices for such areas.

Proposed Metrics: For quantitative assessments of consistency with this criterion, the IRC suggests that the Department compare the amount and fuel types in the generation mix currently available to load (or, if applicable, expected to be available after pending generation retirements in the affected load area) with the aggregate capacity and fuel mix of the generation that would be accessible to the load after an assumed increase in transfer capability across the relevant interface. This comparison will indicate the extent to which additional transmission capability would alleviate supply limitations and would diversify the fuel mix available to the affected load.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

The IRC believes that Congress' reference to "energy independence" can best be effectuated by analyzing the impact of a particular designation on making available a more fuel diverse portfolio of generation to the resource as a whole. A diverse fuel mix, which includes use of domestic coal, nuclear and renewable resources, serves as the best hedge against dependence on foreign oil. The IRC supports this criteria and believes that any application for designation should include the impact of a given transmission upgrade on diversifying the fuel mix on which the affected load center relies.

Recognition should be given, however, to the integrated international nature of the power grid. The United States has several critical ties to both Canada and Mexico. These North American countries provide access to economical power. For example, with approximately 95% of Quebec's capacity as hydro power, imports from that province provide additional benefits of fuel diversity. As a result, energy independence should be focused upon fuel diversity rather than the establishment of a policy which may inadvertently work against the important ties within the North American power grid.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

This proposed criterion, in the IRC's view, is complementary, rather than additional, to the Department's other proposed criteria. A principal focus of current national energy policy, in the context of the electric industry, is the removal of transmission constraints that threaten reliability of service and/or hinder economically efficient intra- and inter-regional wholesale electricity transactions. The National Energy Policy published in 2001 emphasized the importance of developing a truly national transmission grid:

> Large amounts of new generating capacity are slated for installation around the country …. However, there is a geographic mismatch between where we will generate energy and where it is needed.… But even with adequate generating capacity, we do not have the infrastructure to ensure reliable supply of electricity. Investment in new transmission capacity has failed to keep pace with growth in demand and with changes in the industry's structure. … As electricity markets become more regional, transmission constraints are impeding the movement of electricity both within and between regions.

National Energy Policy – Report of the National Energy Policy Development Group, at 1-5 (U.S. GPO May 2001). The authors of the National Energy Policy further stated that the current, state-by-state siting process for transmission lines contributes to constraints that are "resulting in higher prices for consumers and lower reliability" and, therefore, "must be changed." *Id.* at 7. Accordingly, the authors recommended that the Department identify transmission bottlenecks and the means to remove them, including legislation to provide for federal authority to grant rights-of-way for electric transmission lines, all "with the goal of creating a reliable national transmission grid." *Id*. at 7, 7-8. As it considered the Energy Policy Act of 2005, the Senate Energy Committee concurred with this recommendation, stating:

> Billions of dollars need to be invested in the national transmission grid to ensure reliability and to allow markets to function. Siting challenges, including a lack of coordination among States, impede the improvement of the electric system.

S. Rep. 109-078 at 8 (2005).

The new section 216 of the Federal Power Act represents Congress' intent to reform the siting process so that it would not remain an impediment to development of the national transmission grid. At the same time, Congress recognized the need to respect environmental laws and the key role of the states in the siting process. Further, it recognized the need for close consultation between the Department and independent RTOs and ISOs. Accordingly, affirmative efforts by the Department to identify and designate electric corridors that meet certain national interest criteria will further the broad policy objective of creating an integrated national electric transmission grid are fully consistent with the authority Congress has granted it.

Care must be taken to maintain independence and to not favor particular developers. For example, while it may be beneficial to designate national interest electric transmission corridors connecting major sources of wind power to areas that are highly dependent upon foreign oil, the Department should not designate such corridors simply to address individual interconnection arrangements for individual power developers.

Draft Criterion 6: Targeted actions in the area needed to enhance the reliability of electric supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

In certain cases, significant transmission construction can help to reduce vulnerability of critical loads to the impact of natural disasters or malicious acts. To the extent development within a given corridor can provide greater backbone strength to the system and additional redundancy, it can work to address security and reliability concerns resulting from natural disasters or malicious acts. In referencing homeland security, it is clear that Congress sought as an additional factor, the enhancement of the grid in specialized cases even where traditional NERC reliability criteria may not be violated.

Proposed Metrics: The IRC supports a case by case approach to the application of this criterion recognizing that each proposal is specific to the unique area that is being addressed. Part of this issue is addressed by giving due consideration to mitigating the consequences of extreme contingencies, such as loss of substation or right of way. While improvements are rarely driven by the need to protect against extreme contingencies, these types of analyses are conducted by RTO/ISOs to help ensure a robust design of the system.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

IRC regional planning processes are designed to analyze various assumptions that can affect the need for transmission upgrades. In undertaking a reliability review, IRC members examine various load growth scenarios for their impacts on need. By the same token, since ISOs and RTOs administer the interconnection of generation to the grid, they are the best repository of information concerning the location of new generating facilities as well as retirement of existing facilities. Regional planning processes administered by RTOs and lSOs are conducted with a high degree of technical proficiency, pursuant to established standards. These processes rely on input from representatives of both the industry and the public. Moreover, state regulatory authorities, who play an important role in the siting of transmission and recovery of transmission upgrade costs at the retail customer level, are important participants in these processes. Stakeholder review and input, along with the independent judgment of ISOs/RTOs, ensure that conclusions regarding the need for transmission expansions and upgrades that are developed through ISO/RTO regional planning processes are soundly based and do not depend upon highly uncertain economic or other assumptions.[12] As a result, the Department should defer to these findings of independent regional planning processes undertaken by RTOs and ISOs so long as their outcomes, when reviewed in the context of a request for designation, fall within a zone of reasonableness and have been undertaken through open stakeholder processes.

Proposed Metrics: Developing metrics applicable to assessment of this criterion will be problematic – as the NOI recognizes, transmission planning depends on forecasts, which inherently carry a degree of uncertainty. The Department should avoid itself becoming the master planner or undertake its own national IRP plan. Rather, the applicants for corridor designation can demonstrate how their planning process takes into account the range of expected outcomes and the probabilities of each. The Department's role is not to evaluate or approve particular projects, but only whether designation of a transmission corridor is appropriate in light of the circumstances before it.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

In the IRC's view, Congress intended the Department's consideration of potential corridors to be high-level and primarily process-oriented. The Department should identify areas of the country where persistent congestion or reliability problems occur that may be resolved by additional transmission capability, should transmission prove to be an economically feasible solution and provided the required facilities can be sited. Congress directed the Department to undertake a national study of congestion. It did not assign the Department with the *de novo* task of undertaking its own master planning process or considering whether all possible alternatives have been thoroughly vetted prior to a designation. In fact, the statute does not even list consideration of alternatives as one of the criteria for designation.

By definition, vetting of alternatives properly occurs in the context of evaluating specific projects through the RTO planning process and again through the state and FERC siting processes. The RTO/ISO market design, including the transparent publication of data concerning constraints, provides the platform for market alternatives, such as generation and demand side solutions to come forward. In most RTO/ISO markets, demand response resources are allowed to participate in the marketplace and respond to the LMP pricing that is transparently revealed. The same is true for generation which uses LMP signals and other posted grid information to make critical decisions concerning the best placement of generation resources. Thus, the *totality* of the ISO/RTO-administered markets along with their planning processes, are designed to ensure that a balance is reached between market-based and regulatory responses to congestion and other system needs. Therefore, when the Department considers designation of a potential national interest corridor based on the regional planning efforts of an RTO/ISO, it can be confident that additional transmission facilities will be planned and built only after potential market-based solutions to transmission issues have had ample opportunity to present themselves and, to the extent feasible and justified, to displace the need for additional transmission facilities. The state and FERC siting processes under the statute provide an additional subsequent check and balance.

[12] The Department may justifiably offer more limited deference, however, to corridors where assessments of need are not independent or transparent and subject to similar stakeholder review and state agency participation. Such plans instead may well be designed merely to promote the interests of a particular market participant over those of others in order to advance a competitive position.

The Department should not expect or attempt to require that the market's evaluation of non-transmission alternatives be completed before designation of a corridor pursuant EPAct Section 1221. Such "on-the-ground" planning goes beyond the Department's appropriate role as defined by Congress and is not in keeping with the sequencing associated with consideration of specific projects and alternatives to those projects through the planning process. As a result, while the IRC agrees that the Department should consider whether alternatives to transmission will have a fair opportunity to prevail in the markets relevant to potential national interest corridors, it should not, and indeed cannot as a practical matter, make an evaluation of potential non-transmission solutions to reliability or congestion issues a condition precedent to designation.

Proposed Metrics: In order to review whether the results of an RTO/ISO planning process (and any requested designations which arise from the process) are within a zone of reasonableness, the applicant should be required to demonstrate how the market mechanisms and the planning process will permit non-transmission alternatives to be considered. Any application for designation of a corridor should include a demonstration of how the relevant planning process allows such alternatives to present themselves and, when appropriate, to prevail over transmission solutions. This standard should not be absolute. One could postulate any number of hypothetical alternatives which may or may not develop. Relying on such hypotheticals could only delay the already difficult and time consuming siting process. The best balance is achieved by ensuring that the process used by the RTO/ISO (including the market results) will appropriately allow for the development and fair consideration of market-based alternatives both prior to and again after identification of a specific transmission project.

VII. Comments Concerning the Department's Congestion Study

In that section of the NOI focusing on the Department's congestion study, the Department asks:

(1) Should the Department distinguish between persistent congestion and dynamic congestion and if so, how?

IRC Response: Either type of congestion can be indicative of a serious reliability and/or an economic transfer bottleneck. However, the root cause of the congestion should drive the consideration of the National Interest Electric Transmission Corridor designation rather than a particular label. For example, a unique long term outage condition, perhaps due to construction activities, may cause severe congestion and yet not be indicative of a major system problem.

(2) Should the Department distinguish between physical congestion and contractual congestion and if so, how?

IRC Response: The Department should distinguish between physical congestion and contractual congestion. Physical congestion provides a transparent signal indicating that transmission capability may be required, and in some cases may be a precursor to reliability concerns. Contractual congestion is primarily a financial issue and may not indicate a deficiency of transmission capability that requires consideration.

(3) In addition to those (materials) listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

IRC Response: The Department should look to information that is periodically updated by the ISO/RTO's regarding congestion, in addition to the reports listed in Appendix A; and to the results of economic planning process evaluations where those processes exist. The historical period over which congestion information should be reviewed will be dependent, to a large extent, on when congestion information became transparent. The Department will need to determine on a case by case basis the extent to which data exists in the various regions, and assure that congestion information is calculated consistently over the entire historical period.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

IRC Response: Categories of information that would useful to include in the congestion study include summaries of: system plans (for both transmission and generation), control area and regional assessments, capacity margins and fuel sources, and information on planned and potential development for additional resources. The study should be a high level examination of transmission corridors where upgrades would promote the national interest criteria set forth above.

CONCLUSION

The IRC looks forward to serving as a resource to the Department. Moreover, individual IRC members may be submitting applications to the Department to apply these criteria to areas of the grid where national interest criteria are impacted. In keeping with Congress' directives, the IRC looks forward to "regular consultation" with the Department as this process moves forward.

Respectfully submitted,

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/s/ Stacy Duckett
Stacy Duckett
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415 North McKinley
#140, Plaza West
Little Rock, AR 72205-3020

March 6, 2006

C:\Documents and Settings\lgiles\Desktop\NIETC NOI compilation_March 9_3pm.doc

28. Kansas Electric Transmission Authority, Received Mon 3/6/2006 1:35 PM
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 122 1 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585
Sent via e-mail to: EPACT1221@liq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

The Kansas Electric Transmission Authority (KETA), a quasi-governmental authority of the State of Kansas, wishes to comment on efforts of the Department of Energy (DOE) to conduct its initial electric transmission congestion study as required by the 2005 Energy Policy Act (EPACT). We understand that DOE intends to identify geographic areas of significant transmission congestion, and areas where additional transmission capacity could reduce adverse effects of that congestion on electric utility consumers.

KETA was created in 2005 to ". . . further ensure reliable operation of the integrated electrical transmission system, diversify and expand the Kansas economy and facilitate the consumption of Kansas energy through improvements in the state's electric transmission infrastructure." (2005 HB 2263 Sec. 1(b)) Our statutory charge gives us an intense interest in DOE's congestion study.

In the short time that KETA has existed, we have developed a close working relationship with the Kansas Corporation Commission, which regulates Kansas electric utilities and with the Southwest Power Pool (the regional transmission organization to which most Kansas utilities belong) and as a result, we have a unique perspective on the energy transmission situation in Kansas and in the southern great plains. We support DOE's goal of identifying general, rather than specific, corridors for potential transmission projects. We encourage the Department to continue along that path in order to avoid defining corridors so narrowly that viable options are closed off for KETA, FERC, and regional transmission entities as we and they attempt to determine whether and how to proceed with their responsibilities for the nation's transmission infrastructure. Planning, authorizing, constructing, and operating transmission facilities designed to relieve congestion requires flexibility and cooperation of a number of public and private entities. Experts with whom we have consulted emphasize that congestion mitigation is an iterative process in which congestion relief in one area may reveal nascent congestion in another area. If DOE pursues a policy that reduces necessary flexibility on the part of entities closest to transmission problems, the entire system, and therefore energy consumers, will be denied the potential benefits of improvements.

In addition we see the Department's study under EPACT as an opportunity to identify regions, such as Kansas, with an abundance of wind power generation potential that cannot be realized without adequate transmission infrastructure. We see development of wind resources as both an economic development opportunity for residents of our state and as an opportunity to provide utilities with an avenue for diversifying their fuel portfolios. The latter objective, in particular, is recognized as being good for the nation as a whole from both an economic standpoint and in terms of reliability and security. Successful wind projects have been built in the wind-rich areas of Kansas. There exists in Kansas potential for more wind energy development if existing transmission system inadequacies are addressed appropriately. We urge DOE to include the potential for electricity generation fuel diversification in its review of congestion corridors so that electric service customers throughout the nation can benefit from access to Kansas' resources. Transmission corridors must be constructed from western Kansas so that existing constraints are not exacerbated as new wind generation facilities come on line.

Thank you for your attention,
Representative Carl Holmes, Chairman
Earnie Lehman, Vice-chairman
Tim McKee, Secretary

29. Kansas House of Representatives House Committee on Utilities, Received Mon 3/6/2006 9:45 AM

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 122 1 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585
Sent via e-mail to: EPACT1221@liq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

The House Committee on Utilities, a standing committee of the Kansas House of Representatives, wishes to comment on efforts of the Department of Energy (DOE) to conduct its initial electric transmission congestion study as required by the 2005 Energy Policy Act. We understand that DOE intends to identify geographic areas of significant transmission congestion and areas where additional transmission capacity could reduce adverse effects of that congestion on electric utility consumers.

Our Committee has jurisdiction over the issues impacting public utilities and energy consumers in Kansas. We have worked diligently over the past decade to create state policy that provides incentives for improved service and a sustainable market to utilities serving Kansans. A significant piece of that public policy was enacted in 2005 when the Kansas Electric Transmission Authority was created to " . . . further ensure reliable operation of the integrated electrical transmission system, diversify and expand the Kansas economy and facilitate the consumption of Kansas energy through improvements in the state's electric transmission infrastructure." (2005 HB 2263 Sec. 1(b)) Thus, we have a keen interest in the congestion study in which DOE is currently engaged.

As a result of our close working relationship with companies that wish to develop and distribute energy generated from Kansas' wealth of wind resources and the Southwest Power Pool (the regional transmission organization to which most Kansas utilities belong) we have an excellent perspective on the energy transmission situation in Kansas and in the southern Great Plains. That perspective leads us to support DOE's goal of identifying general, rather than specific, corridors for potential transmission projects. We encourage you to pursue that goal in order to avoid the pitfall of defining corridors so narrowly that undue restrictions would be placed on the abilities of state authorities, FERC, and regional transmission entities, to determine whether and how to proceed with their responsibilities. The planning, authorization, construction, and operation of transmission facilities designed to relieve identified congestion requires flexibility and cooperation of a number of public and private entities. Congestion mitigation also is an iterative process as relief in one area may disclose a previously unidentified friction point. If DOE were to pursue a policy that reduced necessary flexibility on the part of entities closest to the problems, the transmission system, and therefore energy consumers, would be denied the potential benefits of system improvements.

In addition, as Kansans, we see the Department's initiative as an opportunity to identify regions with an abundance of wind power generation potential that cannot be realized without adequate transmission infrastructure. That potential takes two forms: economic development along transmission corridors, and competitively priced energy that will enable utilities to diversify their fuel portfolios to their benefit and the good of the nation as a whole. A very few successful wind projects have been built in the wind-rich area of Kansas. There exists vast potential for more wind energy development if existing transmission system inadequacies are addressed appropriately. We urge DOE to include the potential for electricity generation fuel diversification in its review so that electric service customers throughout the nation can benefit from access to Kansas' resources. Critical transmission corridors from western Kansas must be identified so that existing constraints are not exacerbated as new wind generation facilities come on line.

Thank you for your attention,
Representative Carl Holmes, Chairman
Representative Carl Krehbiel, Vice-chairman
Representative Annie Kuether, Ranking Minority Member

30. Kentucky Public Service Commission, Received Mon 3/6/2006 3:04 PM

COMMENTS OF THE KENTUCKY PUBLIC SERVICE COMMISSION

In response to the U.S. Department of Energy's ("DOE" or "Department") Notice of Inquiry ("NOI") published in the Federal Register on February 2, 2006, the Kentucky Public Service Commission ("KY PSC") submits the following comments regarding the designation of National Interest Electric Transmission Corridors. The DOE raises a number of issues in planning to conduct an electric transmission congestion study. Vertically integrated states, such as Kentucky, have unique issues that the KY PSC urges the DOE to consider.

Specifically, the DOE asks in Section III(A) of the NOI if it should distinguish between persistent and dynamic congestion. To initiate the study, the DOE must rely upon a current snapshot of the transmission grid. The snapshot should take into account existing and historical transmission loading patterns and currently proposed resolutions from Appendix A. Any persistent congestion becomes apparent along with its proposed solution. Dynamic congestion should be addressed as needed through reliability coordinators/RTOs and by exercising security-constrained economic dispatch.

In that same Section, the DOE further requests input in distinguishing between physical and contractual congestion. In a commingled regulatory environment, the possibility of one triggering the other is real, as transmission lines are designed and constructed for a projected quantifiable load. Thus, it is wholly predictable that interstate power traversing the grid may well result in congestion when native load requirements are high.

Draft Criterion 2 states, "Action is needed to achieve economic benefits for consumers." The cost of transmission improvements to create these benefits raises issues of benefits and cost-sharing. In a regulated state, allocating costs to captive customers who have no opportunity to benefit from them appears to be unwarranted.

THEREFORE, the KY PSC appreciates the opportunity to comment and requests that the DOE take into account the circumstances of the multitude of fully regulated states, such as Kentucky, in formulating its plans for this study.

Respectfully submitted this the 6th day of March, 2006.

By: /s/ A. W. Turner, Jr.

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Counsel for Kentucky Public Service Commission

31. Lassen (Calif.) Municipal Utility District, Received Mon 3/6/2006 5:05 PM

Lassen Municicipal Utility District
65 S. ROOP STREET * SUSANVILLE, CA * 96130
(530) 257-4174 * FAX (530) 257-2558

March 6, 2006

Office of Electricity Delivery & Energy Reliability, OE-20
Attn: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Ave SW
Washington, DC 20585
Email: EPACT1221@hq.doe.gov

RE: Comments on DOE's Congestion Study and Designation of National Interest Electric Transmission Corridors

Gentlemen:

Lassen Municipal Utility District ("Lassen") is pleased to provide comments on the Department of Energy's plans for an Electric Transmission Congestion Study and possible designation of National Interest Electric Transmission Corridors ("NIETC's"), pursuant to section 1221(a) of the Energy Policy Act of 2005.

Lassen is a locally owned municipal utility district, which was formed in 1986, and commenced operation on May 10, 1988. The District, headquartered in Susanville, California, was acquired from California Pacific National Corporation, an investor owned utility. Lassen serves over 11,500 electric accounts in Lassen County, California. Its boundaries encompass over 50% of the county, and it serves approximately 65% of the county's population. Lassen's peak load averages 27 MW's, and its average annual energy sales are 137,000 MWh's.

Lassen owns no generation. Lassen purchases all of its energy and capacity from others. Since its inception, Lassen has purchased energy under contract from a multitude of suppliers. Currently, Lassen receives all of its energy under contracts with the Western Area Power Administration's Sierra Nevada Regional Office ("Western"), located in Sacramento. The supply includes a small base resource allocation, with the balance supplied from market purchases made by Western for its Full Load Service customers. Western serves as Lassen's Scheduling Coordinator and Portfolio Manager, and schedules all deliveries to Lassen over the California

Independent System Operator (CAISO) grid. Lassen interconnects to the CAISO grid at 60KV in Westwood, California, and delivers the energy and capacity to Susanville over two District owned 60 KV transmission lines, a distance of approximately 25 miles, from west to east.

From Susanville, two additional 60 KV lines extend further to the east to the Honey Lake Valley. Lassen wheels renewable energy over these two lines back to the CAISO grid, where it is delivered into the Pacific Gas & Electric Company's system. Two of the generators are small geothermal production facilities, and the other is a combination geothermal/biomass production facility, capable of 35 MW's of base load production. These three facilities are located in the "Lassen Energy Zone", an area that has been designated by Lassen's Board of Directors and the Lassen County Board of Supervisors, for development of clean and green energy development and associated transmission projects.

The Lassen Energy Zone is situated in a unique area of Lassen County that has seen construction in the past ten years of the Reno-Alturas 345 KV transmission line and the Tuscarora Gas Transmission Pipeline. The 345 KV line is a major north-south tie from Reno to the Bonneville Power Administration, PacifiCorp and California-Oregon Transmission Project, administered by Western. Our Energy Zone, and adjacent areas in Northeastern California and Northern Nevada, have been identified as prime prospects for development of major wind, biomass, solar and pumped storage projects of thousands of MW's. The primary market for these renewables is in Northern California, but there is no path to market.

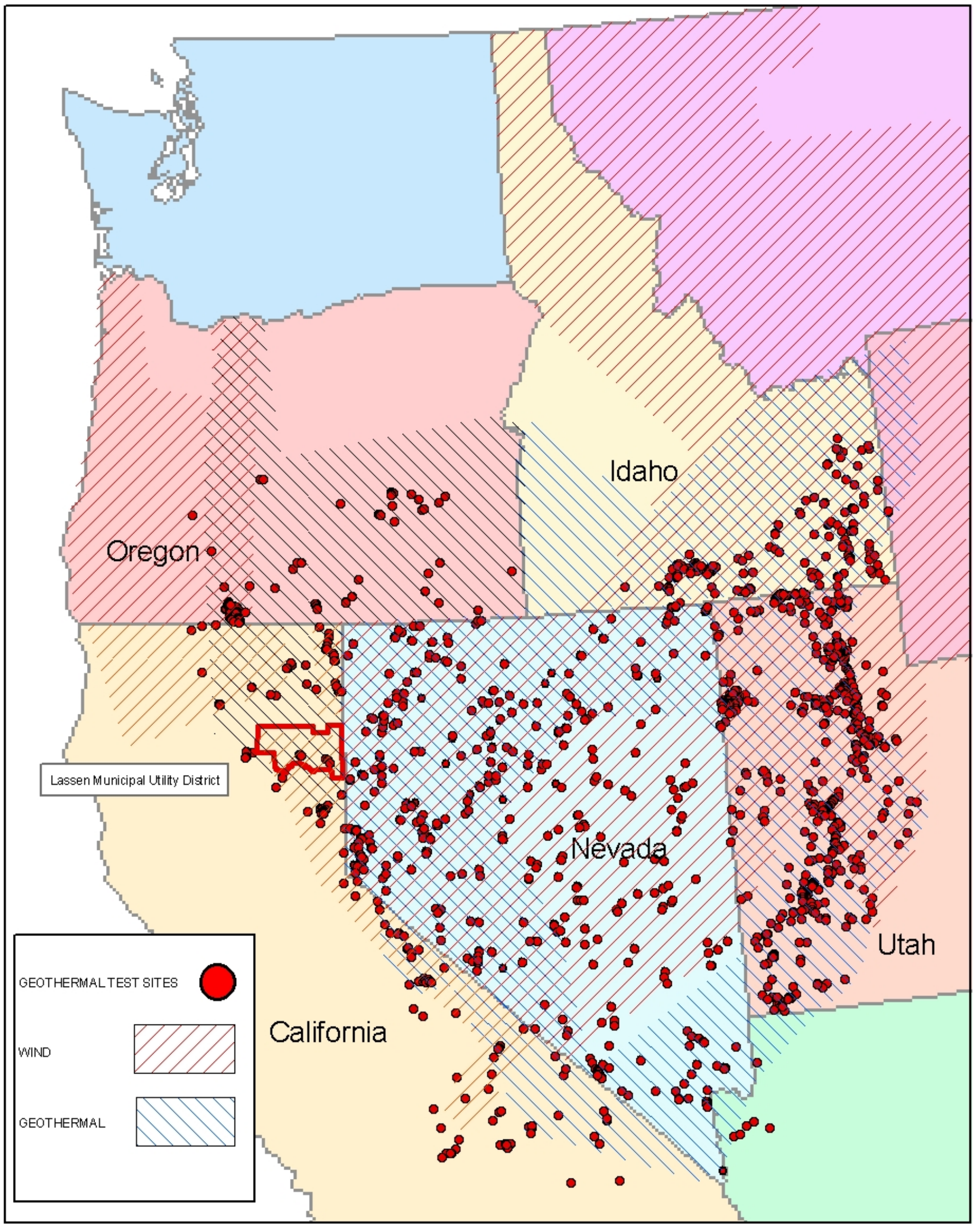
As a small municipal utility district, Lassen cannot finance construction of the large transmission projects, especially east to west, that will be necessary to deliver the energy and capacity that these many projects will produce. Lassen supports the development of energy corridor studies to determine electric transmission congestion and designation of constrained or congested areas as National Interest Electric Transmission Corridors. We believe that major potential for renewable electric resources exists in Northeastern California and Northern Nevada, and that lack of east-west transmission facilities will constrain them from market. Lassen believes a transmission corridor from Northern California to Northern Nevada, and possibly beyond, is in the best interest of DOE and the western states. Lassen would like to see such a corridor routed through our Lassen Energy Zone. Attached is a map depicting our preferred route, and other geological and geographic features mentioned above.

Lassen would appreciate the opportunity to participate in any further discussions of this vital issue, and will assist DOE in any possible way. Thank you for the opportunity to provide comments.

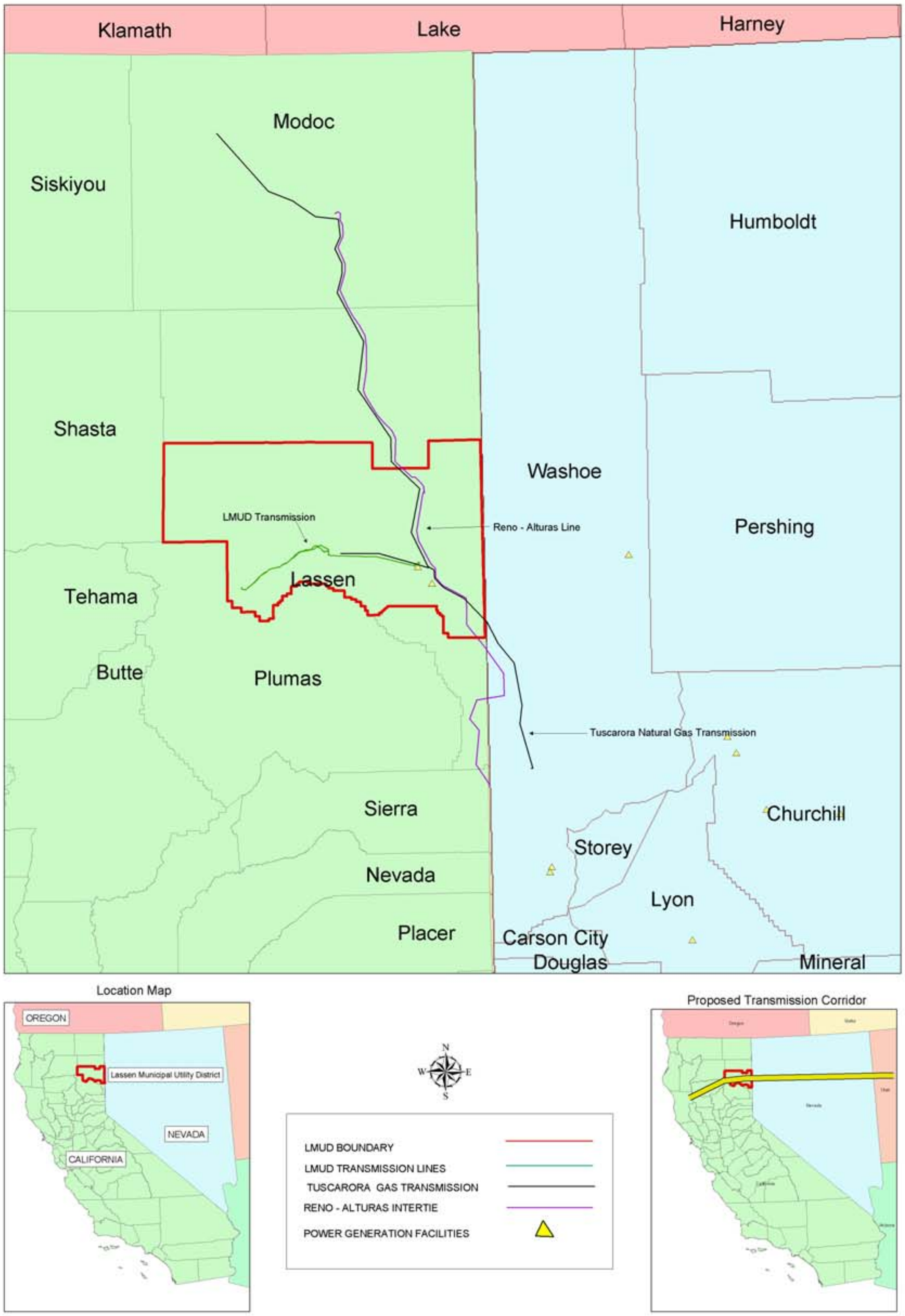
Respectfully submitted,

Frank D. Cady
General Manager

Geothermal and Wind Resource Areas



Transmission Corridor Map



32. Louisiana Energy and Power Authority and Lafayette Utilities System, Received Mon 3/6/2006 4:00 PM

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors	Notice of Inquiry

COMMENTS OF THE
LOUISIANA ENERGY AND POWER AUTHORITY AND
LAFAYETTE UTILITIES SYSTEM

The Louisiana Energy and Power Authority ("LEPA") and the Lafayette Utilities System ("LUS") appreciate this opportunity to respond to the Department of Energy's Notice of Inquiry, "Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," which was published in the Federal Register on February 2, 2006. 71 Fed. Reg. 5660. These comments are submitted in conjunction with the Comments of the Transmission Access Policy Study Group also being submitted to the Department of Energy in this proceeding ("TAPS Comments"). LUS is a member of TAPS and supports the TAPS Comments. LEPA and LUS agree with those TAPS comments, but wish to add specific factual material to this record, as the TAPS comments have suggested will be done by TAPS members and others. The NOI as issued spells out:

> ***In that regard, if interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI.*** If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. If interested parties wish to identify areas for early designation, they should supply with their comments all available data and information supporting a determination that severe needs exist. Parties should identify the area that they believe merits designation as an NIETC, and explain why early designation is necessary and appropriate. The Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

Description of the parties

Louisiana Energy and Power Authority

LEPA is a joint action agency created by the State Legislature in 1979. LEPA presently consists of eighteen (18) Louisiana cities and towns, each of which maintains its own independent municipal power system. The LEPA member communities are: Abbeville, Alexandria, Erath, Houma,[1] Jonesville, Kaplan, Lafayette, Minden, Morgan City, Natchitoches, New Roads, Plaquemine, Rayne, St. Martinville, Vidalia, Vinton, Welsh, and Winnfield, Louisiana. LEPA operates a NERC-certified (and SPP-certified) control area for its Pool Members, which are Houma, Morgan City, New Roads, Plaquemine, Rayne, Vidalia, Welsh and Winnfield, Louisiana. Some of these members (Houma and Morgan City) are within the congested Amite South region and others are within the congested West of the Atchafalaya Basin ("WOTAB") region. LEPA is also a member of the Southwest Power Pool ("SPP"), and participates in the SPP reserve sharing pool. LEPA has no transmission resources of its own. LEPA and several of its members are engaged in the generation, transmission and distribution of electric power and energy at wholesale, and the individual communities also distribute power and energy at retail. The LEPA member communities are transmission dependent utilities on the transmission systems operated by Entergy Systems Inc. ("Entergy") or Cleco Power LLC ("Cleco") (or both, in the case of Lafayette).
LEPA's 2006 Pool Member load is estimated to be approximately 216 MW, and the reserves required to meet SPP reserve sharing and operational obligations mean that LEPA is required to provide approximately 248 MW of capacity to meet that load.

Lafayette Utilities System

LUS is a 108 year old municipal utility serving the City and certain areas of the Parish of Lafayette, Louisiana. LUS serves a peak load within the City and Parish of approximately 430 MW which includes more than 55,000 retail customers. Although LUS is a member of LEPA, LUS has formed its own NERC-certified (and SPP-certified) control area. LUS constructed, operates, and maintains its entire transmission and distribution system and all generation resources within Lafayette. The LUS owned generation portfolio includes a 50% ownership in the Rodemacher Coal Unit in Boyce, Louisiana. LUS also owns a substantial amount of gas-fired generation, including the Louis "Doc" Bonin Generating Station which has a nameplate capacity of 325 Megawatts and the T. J. Labbé Power Plant which has a nameplate capacity of 100 Megawatts. LUS's transmission system consists of 14 miles of 230 kV and 25 miles of 69 kV facilities. LUS has numerous interconnections with Cleco and Entergy, forming the single largest interconnection between the Entergy and Cleco systems.

Communications

LEPA and LUS request that all communications relating to this proceeding be directed to the following individuals, whose names should be included on the official service list for this proceeding:

Mr. Robert C. McDiarmid

[1] Houma is also referred to as the Terrebonne Parish Consolidated Government.

Ms. Lisa G. Dowden

Mr. Stephen C. Pearson[2]

Spiegel & McDiarmid

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Mr. Cordell Grand[3]

General Manager

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210 Venture Way

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Phone: (337) 269-4046

Fax: (337) 269-1372

Mr. Frank D. Ledoux, P.E.

Mr. Ronald W. Gary[4]

Lafayette Utilities System

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Lafayette, LA 70502

Phone: (337) 291-5838

Fax: (337) 291-5995

Comments

The experiences of LEPA and LUS provide specific factual examples that demonstrate the general points raised by TAPS. Moreover, because NIETC listing will help speed up planning and construction, and since it also appears clear that on both a short- and long-term basis the existing problems in Louisiana meet Draft Criteria 1 (reliability), 2 (economic benefit for consumers), 3 (action needed to ease supply limitations in corridor), 5 (action would further the national energy policy of wholesale competition), and 6 (action is needed to enhance the reliability of electric supply to critical loads and infrastructure), LEPA and LUS respectfully

[2] E-mail may be addressed to: robert.mcdiarmid@spiegelmcd.com, lisa.dowden@spiegelmcd.com and steve.pearson@spiegelmcd.com.
[3] E-mail may be addressed to: grandca@lepa.com.
[4] E-mail may be addressed to: fledoux@ieee.org and rwgary@ieee.org.

request that the constraints in the Entergy and Cleco grid, including the constantly constrained Webre – Wells line, which limit the ability of entities like LEPA and LUS to import power be included as a part of the NIETC listings.

Incumbent Transmission Owners have starved the grid of investment to forestall competition

Requests for transmission are not met.

As noted above, LEPA and LUS are transmission dependent utilities on the transmission systems operated by Entergy and Cleco. The transmission system maintained by Entergy and Cleco is simply inadequate to sustain competition, much less encourage new competition. Both LEPA and LUS have found that transmission is simply not available to them for purposes of long-term planning to minimize costs. Moreover, in some instances transmission is simply not available. In order for transmission to be made available, LEPA has been asked to pay for millions of dollars in upgrades that are far distant from the path transmitted power would take. Making matters worse, LEPA and LUS are not offered the opportunity to own those upgrades.

In a recent filing in Federal Energy Regulatory Commission ("FERC") Docket No. TX06-1-000, LEPA filed an emergency request asking that FERC order Entergy and Cleco provide transmission service.[5] LEPA believes there is imminent danger that, due to the transmission constraints in Louisiana, LEPA will not be able to meet SPP control area reliability standards this summer if the Commission does not grant LEPA's request for transmission service.

LEPA's battles began well over a year ago. Anticipating the end of a power supply arrangement between LEPA and LUS, LEPA began negotiating with potential power suppliers and began utilizing Entergy's and Cleco's procedures to attempt to find transmission to deliver network resources to LEPA's network load. LEPA began its search for transmission with a January 5, 2005 Network Integration Transmission Service ("NITS") application for a 26 MW request from the Occidental Chemicals Taft Qualifying Facility ("Oxy Taft") (near Hahnville, Louisiana) to the LEPA control area. Entergy reported that it did not have available transmission capacity. According to the Entergy System Impact Study ("SIS"), LEPA would need to pay approximately $71.5 million for upgrades to enable this transaction. A copy of the Oxy Taft SIS is attached as Exhibit 1.

With this negative result, LEPA requested assistance from Entergy. Entergy directed LEPA to the Entergy "Scenario Analyzer" to determine whether there was available transmission service from Entergy or Cleco from any resource. LEPA tried every known generation resource that had been identified by Entergy or Cleco as competitive generation. The Entergy Scenario Analyzer reported that, for each resource, there was no available transmission to reach LEPA. When this result was brought to the attention of Entergy transmission personnel, they suggested that a formal application be made, since that formal application would trigger a more sophisticated study process, and it might turn out that transmission would be available. Accordingly, LEPA made several NITS applications. In making these applications, LEPA recognized that the Entergy system experienced significant east-to-west congestion, so LEPA's applications attempted to utilize a west-to-east flow under the assumption that the counterflow would

[5] The filing is available from FERC's website, eLibrary accession no. 20060217-5054.

alleviate congestion. But LEPA did not achieve better results with these applications than its earlier Oxy Taft application. LEPA received the following negative reports:

- No available capacity for a small expansion (from 6 MW to 13 MW) of existing transmission service from the Southwestern Power Administration ("SWPA"). The only available capacity was the rollover of the existing 6 MW transaction. According to Entergy's SIS, LEPA would need to pay approximately $39.5 million for upgrades to enable the additional 7 MW. Exhibit 2.
- No available capacity for a 45 MW request from the Entergy system to LEPA member Morgan City, Louisiana. Entergy reported that it did not have available transmission capacity. According to the Entergy SIS, LEPA would need to pay approximately $103 million for upgrades to enable this transaction. Exhibit 3.
- No available capacity for a 150 MW request from the Dynegy Calcasieu facility (near Sulphur, Louisiana) to the LEPA control area. Entergy reported that it did not have available transmission capacity. According to the Entergy SIS, LEPA would need to pay approximately $64 million for upgrades to enable this transaction. Exhibit 4.
- No available capacity for a 150 MW request from the Exxon Mobil facility near Beaumont, Texas to the LEPA control area. Entergy reported that it did not have available transmission capacity. According to the Entergy SIS, LEPA would need to pay approximately $70.3 million for upgrades to enable this transaction. Exhibit 5.

In other words, Entergy has made so little investment in its transmission system that it could not even grant a 7 MW request for transmission.

LEPA also has not had success with a NITS application filed with Cleco. To serve the Morgan City load, LEPA also requires transmission from Cleco. As a result, LEPA filed a 45 MW request with Cleco that paralleled the 45 MW request to Entergy. In the ensuing SIS (Exhibit 6) and Facilities Study (Exhibit 7), Cleco reported that it did not have available transmission capacity. While Cleco does not there assert that network upgrades are necessary, Cleco reports that some voltage support and metering are necessary, and conditions its study on the grant of transmission capacity for this purpose by Entergy. Further, Cleco apparently has only planned for imports of 21 MW to Morgan City. Cleco's lack of planning is completely inconsistent with the fact that it has received annual Morgan City load forecasts – the most recent of which reported an expected peak load of 41.8 MW. Cleco also has known that existing generation in Morgan City is very near retirement, very expensive to run, and, consistent with prudent utility practice, should only be run in block mode in emergencies. Cleco's lack of planning is even more incomprehensible as one of the underlying premises of the Cleco-LEPA interconnection agreement is anticipation of load growth. Thus, LEPA's experience has been as a victim of incumbent utilities' transmission systems with little or no excess capability.

The lack of transmission to Morgan City should raise serious alarms within the Department of Energy. The same inadequate lines that serve Morgan City also serve the Louisiana Offshore Oil Port, off the shore of Fourchon, Louisiana. Since LOOP handles approximately 15% of the Nation's oil import needs, one would think that national security considerations, if nothing else, would have long since called for an upgrade of those lines.[6]

LUS also has had difficulty obtaining reliable transmission service for its power supply resources. For example, LUS has found it increasingly difficult to access power from its share of the Rodemacher coal plant despite the fact that it pays Cleco $4.5 million per year for "firm" transmission service. Because of conditions on the Entergy system, LUS has been faced with repeated and increasing demands[7] that it bring up more expensive peaking units in Lafayette in order to solve congestion problems on the Entergy system that generate calls for Transmission Loading Relief ("TLR") curtailments and that result in LUS having to back down its Rodemacher power output. When these curtailments have occurred, LUS customers must pay more to run the expensive peaking generation to serve LUS native load customers, even though it is Entergy that needs the change to reliably serve its own loads. LUS receives no compensation for these repeated redispatch demands. Although Entergy claims that it must also redispatch its generation

units during such transmission curtailments, there is no independent market monitor or grid operator who can confirm that this is the case. Moreover, Entergy is well aware that the financial impact for Lafayette to redispatch its generation units is several orders of magnitude greater than the financial impact to Entergy.

Although transmission upgrades at the Wells substation largely financed by CLECO have resolved some of the TLR issues, those upgrades were developed to resolve issues on both the CLECO and Entergy systems and to facilitate the purchases by both Entergy and CLECO from the Acadia Project.[8] Specifically, the upgrade makes it possible for CLECO to purchase 500

[6] *See* http://www.dotd.louisiana.gov/programs_grants/loop/loop.shtml.
[7] Though the requests often come through the SPP, LUS understands that they are initiated by Entergy calls on SPP .
[8] The Acadia Project is a Cleco/Calpine joint venture consisting of gas-fired combustion turbines interconnected at the Richard substation. LUS understands that when the Acadia Project interconnection was modeled, Entergy erroneously assumed LUS generation used only at extreme peaks would be run around the clock. Entergy never contacted LUS prior to performing its study. Instead, Entergy has simply assumed the LUS generation would run. Thus, Entergy forced LUS ratepayers to subsidize Entergy ratepayers in that the LUS ratepayers must pay for

MW of low heat rate, combined cycled electric power from the plant and substantially relieve the loading on Entergy 138 kV circuits coming from the Richard substation.

Perhaps more disturbing to LUS than the fact that Entergy transmission is not available, Entergy and Cleco have both leaned heavily on the LUS system. There are very significant loop flows through Lafayette's transmission system because it is the strongest connection between Cleco and Entergy. In addition, in recent market based rate filings ("MBR"), Cleco has reported data that indicates that, at certain times, there is negative available transmission capacity into the LUS service territory.[9] There can be no clearer evidence that action is needed to bolster the grid. Yet neither Cleco nor Entergy are acting to solve the transmission constraints into and around Lafayette.

Because of the lack of transmission capacity, Both LEPA and LUS have been unable to access generation that Entergy has boasted exists in the region. While Entergy proclaims that there are 17,000 MW of IPP facilities in its region,[10] LUS has built and is building its own combustion turbines internal to its own system because it cannot access transmission. To provide an extreme example of the inability to obtain reliable transmission service, LUS considered purchasing the financially distressed NRG generator located in Bayou Cove, a mere 40 miles from Lafayette. LUS's transmission studies showed that, given the lack of capacity in the Entergy system, delivery from the NRG plant would be subject to curtailments in Entergy's frequent TLRs. As a result, LUS did not pursue the acquisition.

As a final indication of the remarkable lack of capacity on the Entergy transmission system, LUS data show that it, via its agent the Energy Authority, made 2359 transmission requests of Entergy between January 2002 and January 2005.[11] Only 1209, just over half, of those requests were accepted and confirmed. The large number of requests reflects the inability of LUS to perform long-term risk management and planning caused by the lack of available transmission. Further, the lack of requests that have been granted amount to economical purchases that were not made. The bottom line is that Entergy and Cleco know that the transmission system lacks sufficient capacity but are unwilling to do what is necessary to provide a robust transmission system that will lead to healthy, competitive power supply markets that will benefit retail ratepayers other than those of Entergy and Cleco.

The same transmission upgrades appear in many SISs.

In reviewing the SISs Entergy provided to LEPA following LEPA's NITS applications, LEPA noticed that the same multi-million dollar upgrades appeared time and time again. Digging deeper, LEPA reviewed 167 SISs from January 2005 through January 2006 that are publicly available on the Entergy OASIS website.[12] LEPA's review demonstrated that each of the

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generation that is nearly four times as expensive as the Rodemacher generation on which LUS ratepayers had relied since 1979. Entergy never compensated LUS ratepayers.

[9] *See, e.g.*, Cleco Compliance Filing, Commission Docket No. ER03-1368-002, *et al.*, (June 23, 2005), Affidavit of Paul H. Raab, at 3 (eLibrary Accession No. 20050629-0265).

[10] Response of Entergy Services Inc. to the Written and Oral Statements of Terry Huval on Behalf of the Lafayette Utilities System and the Transmission Access Policy Study Group, RM04-7-000, at 15 (March 15, 2005) (eLibrary accession no. 20050315-5044). It isn't clear whether the 17,000 MW includes Entergy's purchase at fire sale prices of distressed IPP facilities such as the Perryville Energy Partners' facility or the Attala facility – which facilities used to amount to over 1,000 MW of IPP power. The alarming bankruptcies of IPPs in Louisiana is discussed *infra*.

[11] LUS has not yet compiled these data for the 2005 calendar year.

[12] http://oasis.e-terrasolutions.com/documents/EES/studies1.html

limiting elements from the SISs Entergy provided in response to LEPA NITS requests appeared in many other requests. Moreover, LEPA's review is conservative because many SISs are not available on the Entergy website. For example, the LEPA requests themselves were not available on the website. The following table shows the number of other SISs on which a limiting element on an SIS prepared for LEPA appeared as a limiting or contingency element (or both) on an SIS prepared for another entity:

Element	Instances
Belle Helene - Licar 230kV	10
Belle Helene - Woodstock 230kV	10
Bonin - Cecelia 138kV	2
Bull Shoals - Bull Shoals SPA 161kV	13
Champagne - Krotz Spring 138kV	34
China Bulk - Sabine 230kV	17
Colonial Academy - Acadia GSU 138 kV	3
Colonial Academy - Richard 138 kV	6
Conroe Bulk - Plantation 138kV	10
Fairview - Gypsy 230kV	25
Dayton Bulk - Cheek 138kV	4
Dayton Bulk - New Long John 138kV	4
Georgetown - Helbig 230kV	14
New Long John - Tarking 138kV	4
Gibson - Humphrey 115kV	37
Gibson - Ramos 138kV	23
Gibson 138/115kV transformer	5
Greenwood - Humphrey 115kV	37
Greenwood - Terrebone 115kV	38
Habetz - Richard 138kV	9
Line 642 Tap - Krotz Springs 138kV	17
Livonia - Line 642 Tap 138kV	36
Livonia - Wilbert 138kV	38
North Crowley - Richard 138kV	10
North Crowley - Scott 138kV	15
Richard - Scott 138kV	16
Terrebone 230/115kV transformer	24
Vulchlor - Woodstock 230kV	10
Webre - Wells 500kV	41

When the same transmission elements are listed as overloading in connection with that many different transmission requests, it becomes obvious that the Entergy "backbone" transmission system has become seriously deficient due to a lack of investment by Entergy dating back many years. As there is no certainty as to when these upgrades might be incorporated as part of a transmission plan, much less completed, it is clear that action is needed immediately to ease electricity supply limitations in end markets and incumbent transmission owners are unwilling or unable to take the needed action.

Independent Power Producers have been strangled in Louisiana

The Entergy Weekly Procurement Process ("WPP") which Entergy uses to buy power from independent producers has established all the ingredients to poison the IPP market. The WPP serves only Entergy's needs. Thus, suppliers, attracted by Entergy's far greater needs, will bid their capacity into that auction. LEPA and LUS are thus not only barred from the WPP, but those sellers who participate in WPP cannot offer the capacity elsewhere until they know the results of the WPP. And, of course, there would still be the problem of getting transmission for any individual sale to LEPA or LUS, while winning WPP bids receive transmission service to deliver to Entergy loads (Entergy backs down more expensive generation that it would otherwise be forced to utilize to provide for the WPP purchases). Entergy thus soaks up this capability on its own system, while providing no access to regional markets.

Because Entergy is the only buyer in the WPP energy market, Entergy effectively gets the value of the IPP generation (especially knowing that sellers are unlikely to be able to sell to anyone else if Entergy does not select them in the WPP) without contracting for the capacity. This structure keeps Entergy's purchased power costs low, but it also causes financial problems for the IPPs, some of whom have been unable to service their debts on the units and have entered bankruptcy or restructuring. Without adequate recovery, the units must often be sold off cheaply – and Entergy is a willing buyer for such financially distressed units.

LEPA and LUS are aware of two formerly independent power producers in their region which have been swallowed by Entergy. Entergy Mississippi recently received final approval from the Mississippi Public Service Commission to purchase the Attala County, 480 MW combined-cycle generating facility from Central Mississippi Generating Co. LLC. Central Mississippi had bought the plant in a foreclosure sale. Entergy boasted in its press release that the acquisition price of $88 million was "a price far below what it would cost to construct a similar facility."[13] LEPA notes that this entire 480 MW generator cost Entergy less than the $103 million upgrade Entergy has claimed is necessary to move 45 MW to Morgan City. Entergy has also stated that it will spend $20 million in facility upgrades for the Attala plant, presumably in substantial part on

[13] Press Release, Entergy Services, Inc, Entergy Mississippi Approved to Purchase Attala Generating Plant (Jan. 23, 2006).

strengthening the transmission system.[14] Entergy has boasted that the total cost per kW of this acquisition, including upgrades and transaction costs, is $231 per kW.[15] By way of comparison, the transmission line upgrade costs alone for LEPA's 150 MW NITS applications were almost double that per kW cost for the Dynegy facility and more than double that amount for the Exxon Mobil facility. In addition, LEPA presumes the portion of the $20 million in facility upgrades related to transmission will be rolled into Entergy transmission rates. In contrast, the improvements Entergy claims are necessary so that LEPA has access to IPP power will not.

Another example of the unhealthy IPP market is Perryville Entergy Partners LLC.[16] Perryville operated a 562 MW combined cycle gas-fired generator and a 156 MW simple cycle gas-fired generator. Following Perryville's 2003 bankruptcy filing, Entergy Louisiana acquired the Perryville generator for $170 million.[17] Entergy's purchase price amounted to 50 cents on the dollar. After acquiring the former Perryville plant, Entergy committed to upgrade its transmission system to enable the plant to be a network resource.[18] The post-acquisition Entergy transmission upgrades strongly suggest that insufficient transmission could be obtained to operate the plant and that the lack of transmission contributed to the Perryville bankruptcy.

When LUS raised these complaints previously, Entergy did not even recognize that a problem exists. Because Entergy has created a situation where it has access to cheap power, in its view there is no problem. Entergy has stated:

> These 17,000 MW [of IPP generation] are in addition to the approximately 23,000 MW of generating resources of the Entergy Operating Companies that are available to supply the Operating Companies' approximately 22,000 MW of peak load. Although these merchant generators generally did not consult with Entergy to determine when, or whether, the generation being built would present an economic alternative to supply Entergy's native load, the resulting excess generating capacity has presented opportunities for many buyers to purchase energy that can increase savings to their customers. *In short, with the glut of generation in the Entergy region, there should be no surprise that energy prices are low.*[19]

In other words, it isn't Entergy's fault that generation lacks access to transmission, it is the victims' fault. Of course, Entergy does not explain why intelligent business people would loan

[14] Press Release, Entergy Services, Inc, Entergy and Central Mississippi Generating Company, LLC Reach Agreement for Purchase of Attala Power Plant (March, 17, 2005).
[15] *See, e.g.,* Press Release, Entergy Services, Inc, Entergy and Central Mississippi Generating Company, LLC Reach Agreement for Purchase of Attala Power Plant (March, 17, 2005).
[16] Perryville was a subsidiary of Cleco.
[17] Press Release, Entergy Services, Inc, Entergy and Cleco Reach Agreement for Purchase of Perryville (Jan. 28, 2004).
[18] *Entergy Louisiana, Inc. and Entergy Gulf States, Inc.*, Louisiana Public Service Commission Order No. U-27836, slip op. at 9 (April 20, 2005).
[19] Response of Entergy Services Inc. to the Written and Oral Statements of Terry Huval on Behalf of the Lafayette Utilities System and the Transmission Access Policy Study Group, RM04-7-000, at 15 (March 15, 2005) (e-Library accession no. 20050315-5044) (emphasis supplied).

and spend hundreds of millions of dollars on generation investment without assurances of the availability of transmission. But the real question is, "If there is such a glut and prices are so low, why is it that only Entergy has access to the cheap power?"

Action is needed to create a healthy transmission system with adequate capacity such that IPPs may compete for customers and so that customers have a choice in suppliers. The incumbent transmission owners have not proved up to the task. LEPA and LUS urge the Department of Energy to take action that will enable and encourage the construction of a robust transmission system in Louisiana and ongoing expansion to maintain the integrity of the transmission system.

End-users are denied access to lower cost power supply because of constraints

The preceding discussion demonstrates that the transmission system in Louisiana is insufficient to move power. LEPA cannot get access to economical bulk power supplies without millions of dollars of upgrade costs. LEPA cannot even get access to a small, 7 MW increase in transmission to access its entitlement to SWPA power. LUS cannot get transmission access to a power plant 40 miles away. LUS cannot even fully utilize its own generation for which it pays for firm transmission. Action is needed to ensure that end users have access to lower cost power supplies.

NIETC designations should encourage entities in addition to incumbent TOs to invest

In Louisiana, one of the major barriers to entities other than the incumbent TOs investment is the lack of ownership rights. As noted above, LEPA has been told that it would be responsible for paying for substantial backbone upgrades to the grid. But Entergy has informed LEPA that it would not own those backbone upgrades. Instead, Entergy would own the upgrades. In Entergy's view, LEPA is also not generally entitled to any repayment for those backbone upgrades to the grid. Instead, LEPA "would be eligible for transmission credits only for upgrades that are for service that creates new transmission revenue."[20] In Entergy's "participant funding" view of the world, Entergy seems to believe it is LEPA's obligation to pay for the network upgrades that Entergy has neglected to perform, and that LEPA should be stalled until Entergy receives the authority it has sought based on an Independent Coordinator of Transmission ("ICT") proposal now before FERC. Action needs to be taken to change the status quo and facilitate the necessary investment to restore the grid in Louisiana to a condition that promotes competition and enables all end-users to benefit.

As additional evidence that action is needed, in the wake of the devastation of Hurricanes Katrina and Rita, LUS and others have offered assistance to Entergy to rebuild and expand the transmission system. LUS's only request is that it receive ownership rights in what it pays to build. As other entities own major transmission lines in the Entergy service area (for example, Cleco owns a portion of the 500 kV Hartburg to Mount Olive transmission line), LUS's request

[20] Letter from Dennis Broussard, Entergy, to Kevin W. Bihm, LEPA, (May 20, 2005 [sic, Oct. 18, 2005]), at 2 ("Oct. 18 Entergy Letter") (attached as Exhibit 8).

is not unreasonable. To this date, however, LUS has only been successful at getting Entergy to the point of initial discussions without much apparent hope that anything fruitful will result.

Comment on Question: "Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

LEPA and LUS agree with TAPS comments that both physical and contractual congestion can impose costs that could qualify an area as an NIETC. Specific to the Entergy system, it appears that contractual congestion may be one of the biggest obstacles to entities gaining access to new network resources. Entergy's own documentation states explicitly that "Entergy Transmission utilizes a 'contract path' approach in determining ATC."[21] Moreover, while the above discussed SISs prepared for LEPA were performed prior to Hurricanes Katrina and Rita and Entergy has not provided the follow-up Facilities Studies, LEPA has no reason to believe the results which Entergy would report would be any different now, even after the exodus of load from the Entergy service territory.[22] Thus, if the NIETC is to be a solution for Louisiana, it must allow for siting in areas where contractual congestion is an obstacle to end-users access to economical network resources.

conclusion

LEPA and LUS believe that NIETC listing will help speed up planning and construction. Based on the above criteria, LEPA and LUS have shown that there are serious reliability problems in Louisiana. Not only have TLRs prevented LUS from using its own generation using its supposedly "firm" transmission service, but LEPA has just recently filed an emergency petition with FERC out of concern for its ability to meet SPP control area reliability standards this summer. Thus, Draft Criteria 1 is met. It should also be clear that the lack of transmission is preventing LEPA and LUS from accessing economical power, whether that power is IPP power or entitlements to federal SWPA power. Thus, NIETC listing will enable economic benefit for consumers. (Draft Criteria 2). As can be seen from the frequency with which the same problems appear over and over again with no plan in place to correct those problems, action is needed to ease supply limitations. (Draft Criteria 3). As IPPs are currently being strangled by the lack of transmission access and Entergy is acquiring former IPPs, it should be clear that action would further the national energy policy of wholesale competition. (Draft Criteria 5). Finally, the same inadequate lines that serve LEPA member Morgan City also serve the terminal for 15% of the nations oil imports. Action is needed to enhance the reliability of electric supply to this critical

[21] Calculation Of TTC/ATC Within The Entergy Control Area, at 1, available for download at: http://www.entergy.com/content/Operations_Information/transmission/Calculation_of_TTC_ATC_Within_the_Entergy_Control_Area.pdf

[22] *See, e.g.*, Entergy Corporation and Subsidiaries, Quarterly Report (Form 10-Q), (Sept. 30, 2005) (estimating that 36,000 customers of Entergy Louisiana and 87,000 customers of Entergy New Orleans are unable to receive electric and gas service, noting a third quarter decrease of 160 GWh of retail sales by EGSI as compared to 2004, noting a third quarter decrease of 482 GWh of retail sales by ELI as compared to 2004, and noting third quarter decrease of 522 GWh of retail sales by Entergy New Orleans as compared to 2004); Gordon Russell, *Comeback in Progress*, TIMES-PICAYUNE (NEW ORLEANS), Jan. 1, 2006 (citing estimates by Entergy New Orleans officials that 35% of electric power customers were back on-line); Mary O'Driscoll, *Entergy Seeking Lost Revenue in Hurricane Aid Bill*, ENVIRONMENT & ENERGY DAILY (October 5, 2005) (reporting that "Entergy reports that 156,300 of its roughly 190,000 customers in and around New Orleans still cannot receive power.").

load and infrastructure. (Draft Criteria 6). For all of the foregoing reasons, LEPA and LUS respectfully requests that the constraints in

the Entergy and Cleco grids which limit the ability of entities like LEPA and LUS to import power be included as a part of the NIETC listings.

Respectfully submitted,

/s/ Robert C. McDiarmid

Robert C. McDiarmid
Lisa G. Dowden
Stephen C. Pearson

Attorneys for
Louisiana Energy and Power
Authority; and,
Lafayette Utilities System

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March 6, 2006

33. Mary McQuillen, Received Mon 3/6/2006 5:32 PM

To Whom It May Concern at the Department of Energy--

Dear Sirs,

Hello. My name is Mary McQuillen and my family and I reside in Urbana, Maryland.

I am writing to comment regarding the Department of Energy's plans for an electricity transmission study and possible designation of National Interest Electric Transmission Corridors.

I wish to stress that I feel it is important that DEP work at a meaningful level with local government and communities affected by the numerous transmission projects that are anticipated.

I also hope that Land planning would be handled at the local level at best and state level as second best. I would hope that our community would be able to be involved in plans that would affect us here. We would expect to be able to present alternatives and have input on decisions that would impact us and do not wish to be superceded by the state.

Thank you for your consideration.

Sincerely,

Mary McQuillen
Urbana, Maryland

34. Michael Strategic Analysis, Received Fri 3/3/2006 11:18 AM

This email is in response to the Department of Energy's solicitation of comments on proposed power lines through southern Fredrick County, Maryland.

The entire three-mile Potomac to Doubs route of the Underground Railroad was designated last month by Scenic Maryland as one of seven "Last Chance" threatened Maryland historic sites deserving protection. The route begins on the stretch of the Potomac from Point of Rocks to Noland's Ferry in Frederick County and proceeds north through the Thomas Farm, the Calico Rocks Farm, the Middle Farm [which already has power lines on it], my Cooling Springs Farm and then the old Flag Pond Farm to Doubs, Frederick County. The proposed power lines would lie directly atop the route. Scenic Maryland¹s designation was awarded to the route specifically because of the threat of power lines and power plants.

In addition, The Journey Through Hallowed Ground, the federal-state designation recognizing the tremendous concentration of the nation¹s history from Gettysburg to Monticello, includes the proposed power line site, recognizes the Potomac to Doubs route of the Underground Railroad and includes it among Journey tours. Last year, the National Historic Trust designated the entire 175-mile Journey Through Hallowed Ground as one of the nation¹s eleven most endangered historic sites.

Cooling Springs Farm is on two national Underground Railroad registers including the federal government¹s, and the Maryland Historic Trust's Inventory of Historic properties, and is a registered Frederick County Landmark because of the farm's and the surrounding area's Underground Railroad history. The farm has been featured in the Frederick News-Post multiple times, Frederick magazine and Port of Harlem magazine. In the next month or so, the farm will be featured in Southern Living magazine and in an episode of Home and Garden Television's If Walls Could Talk program. There is an abundance of official and press recognition of the historic Underground Railroad here precisely where the power lines are proposed.

The area comprising the Potomac to Doubs route of the Underground Railroad and the proposed power line site enjoys the following additional official designations:

The Catoctin Mountain Scenic Byway
The Carrollton Manor Rural Legacy Area
The Carrollton Manor Land Trust
The Maryland Civil War Heritage Area
Permanent agricultural zoning

Further, the Potomac to Doubs route of the Underground Railroad traverses a national park adjacent to the proposed power line site and lies among the following:

Sugarloaf Mountain Park
Monocacy Natural Resources Area
Catoctin Mountain Natural Resources Area
Banner Park.

As you see, this is a singularly inappropriate place to think of constructing power lines. A few years ago, a large energy company wanted to build a 600-megawatt power station on this Underground Railroad route but was defeated because of virtually universal official and local community opposition. Please take into explicit consideration the very heavy official and local sentiment toward the rural and historic nature of the location where the two power companies want to construct power lines and against any industrial construction here, and disallow construction of the power lines here.

Please apprise me and all other recipients of this email of the Department of Energy[1]s disposition of the above request. Thank you.

Peter H. Michael, President

Michael Strategic Analysis
Strategic Planning, Market Analysis, and Economic Damages Testimony

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35. Montana-Dakota Utilities Co., Received Mon 3/6/2006 5:17 PM

Revised

March 6, 2006

Office of Electricity Delivery and Energy Reliability
OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building

Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Submitted by e-mail to: EPACT1221@hq.doe.gov

Re: Notice of Inquiry: *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors"*

Montana-Dakota Utilities Co, a Division of MDU Resources Group, Inc. (Montana-Dakota) thanks the Department of Energy (Department) for the opportunity to comment on the Notice of Inquiry on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors issued January 27, 2006.

Montana-Dakota is an investor-owned utility with electric generation, transmission and distribution facilities in a service territory encompassing parts of the states of North Dakota, South Dakota, Montana, and Wyoming. Montana-Dakota serves approximately 118,000 retail electric customers with a transmission system comprised of approximately 3,100 miles. Montana-Dakota's service territory has an abundance of lignite coal and wind power potential. Therefore, the ability to develop those resources to enhance energy independence of the United States and further national energy policy is important to our region. In addition to the greater good of energy independence, a robust transmission system will also provide economic choices for serving our retail customers, either by importing power which would could avoid new generation or the economies of scale associated with a new generator that can serve both local and remote load. It is from those perspectives that Montana-Dakota provides its comments.

The existing transmission system in the upper Midwest has minimal to no available capacity to allow the development of coal and wind resources in the area. The transmission system is not constrained by thermal ratings of the facilities as much as it is constrained by the stability limits due to the location of the generation sources versus the major load centers. Generation sources, both existing sources and potential source, primarily located in central North Dakota with the load centers anywhere from 400 to 600 miles away.

The present transmission system allows the existing generation resources to reliably serve area load and reliably transfer available energy to the remote load centers under system intact conditions, however, extensive transmission will be required to the load centers should new incremental generation be constructed in the region, regardless of whether it is coal fired or wind powered. In addition, physical constraints to the south and east of the transmission system in North Dakota, South Dakota, and western Minnesota further exacerbate the ability to develop new and beneficial generation facilities in the area. Therefore, Montana-Dakota will be recommending, in the comments that follow, that the

Department expand, or further define, the geographic area determined to be a National Interest Electric Transmission Corridor (NIETC).

Comments:
Congestion Study

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?
Montana-Dakota recommends distinguishing between persistent and dynamic congestion. Persistent congestion may signal the need for infrastructure additions, as it undoubtedly is caused by the demands that end-use load puts on the system or the long-term transfer of more economical generation resources to the end-use load. Dynamic congestion, however, is usually caused by a short term market condition or an unusual and short-term transmission configuration

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?
The Department must distinguish between physical and contractual congestion, assuming contractual congestion is defined as what is traditional known as contract path transmission service. As the Department is aware, electricity does not follow contract paths, it follows the paths determined by the electrical characteristics of the system. Whereas contract path may have significance where the power flow can be controlled by phase shifters or dc lines, construction of transmission because of a contract path being fully subscribed does not make economic sense. Therefore, in evaluating whether or not to designate a corridor as an NIETC, the distinction needs to be made.

(3) Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?
Montana-Dakota has no additional plans and studies to recommend for inclusion.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?
In addition to the criteria the Department has identified in the NOI, Montana-Dakota suggests that several additional categories be included in the study:

- The study needs to consider whether or not the congestion in the area being designated as a NIETC area is presently being addressed by the regional transmission organization or provider with potential mitigation or enhancements. Identification of the activity would not be intended to preclude inclusion as a NIETC, but would allow prioritization of which projects may need increased attention after the report is published. For those corridors where there is no action being taken, the DOE should still designate them as NIETC corridors, but should encourage private investments in facilities and not take the position that the DOE should construct, own, and operate facilities needed to relieve congestion.

- There may be occasions when a geographic area is designated as NIETC on the basis that the ability to import more economical generation resources is limited, or that the energy independence of the United States would be enhanced if the resolution of constrained were accomplished. Under those situations, for example, it would be useful to include, in the geographic area, those generation resources and the intervening area as part of the NIETC designation.

- In addition, Montana-Dakota is very concerned that the areas identified in the study do not jeopardize national security. The report which will result from this study is essentially going to be a road map of electrically sensitive areas in our infrastructure. Even more so if the report also contains information identifying critical loads such as is mentioned in Draft Criterion 6 then the existence of this report will represent a threat to our nation's security and its release needs to be very strictly controlled. Montana-Dakota suggests the areas that are designated as NIETC be screened to determine which ones would jeopardize national security if they were published in a publicly available report, and the list of those areas that would jeopardize national security only be made available upon request to the DOE and made available only to those who have met some criteria to ensure the security of the document would not be unduly compromised. Those designations that are deemed benign as to jeopardizing national security could be included in a public report.

Criteria

The Department invited comments on what criteria should be used in evaluating the suitability of geographic areas for NIETC status. When evaluating the priorities of the Criterion, the Department should have as the top priority Draft Criterion 1. Maintaining electric reliability is paramount when identifying an area for possible NIETC designation.

As part of the metrics for Draft Criterion 2, the Department needs to consider the location of the potential generation resources that could provide the economic benefits and include the geographic area between those potential resources and the constrained area in the NIETC.

Draft Criteria 4 and 5 should also have the same metrics as discussed previously for Criterion 2.

Draft Criterion 7: A regionally developed forecast of LMP congestion costs would be one metric that should be suitable in an area with an LMP market, as it should have regionally accepted forecast of fuel costs, demand growth and planned generation.

Another metric that would be suitable for this criterion is a metric that would define persistent congestion versus dynamic congestion. Montana-Dakota, as a member of the Midwest ISO (MISO) and a MISO market participant, is part of a locational marginal pricing (LMP) market which has, as part of the nodal LMP, a congestion component. By monitoring the congestion component, one can determine how severe and how long the path between to particular nodes has congestion. When congestion persists on a regular basis between two nodes, the need for re-dispatch and potential congestion mitigation is greater than if congestion only occurs a few hours in a moth or year. Knowing which congestion is persistent and which is dynamic (brief and varying) allows prioritization of resolution. Without a distinction between persistent and dynamic congestion, such a prioritization would be less obvious.

The means of determining whether congestion is persistent or dynamic could be through the analysis of the annual costs of congestion, as determined by the congestion component in LMP for an area with a LMP market, or, for areas not part of a LMP market, the number of hours and the duration of transmission loading relief (TLR) implementation could be used.

Conclusion

Montana-Dakota thanks the Department for the opportunity to respond to the notice. If DOE staff have any questions about the comments, please contact me at andrea.stomberg@mdu.com or call me at (701) 222-7752.

Respectfully submitted,

Andrea Stomberg
Vice-president Electric Supply

36. Montana Governor Brian Schweitzer, Received Mon 3/6/2006 12:12 PM

March 3, 2006

The Honorable Samuel Bodman
Secretary of Energy
1000 Independence Ave, S.W.

Washington, D.C. 20585

RE: Notice of Inquiry on criteria for designating National Interest Electric Transmission Corridors

Dear Secretary Bodman:

The federal government's approach to implementing Section 1221 of the Energy Policy Act can further or undermine the State of Montana's energy development and environmental protection goals. I am particularly concerned that pressures being generated by groups inside the Beltway will lead the Department to make ill-considered decisions to designate National Interest Electric Transmission Corridors (NIETC) that will ultimately thwart the objective of building needed transmission. Therefore, before considering any designations of NIETCs in Montana, I urge you and your colleagues in the federal government to:

1. Establish rules and procedures for implementing all elements of Section 1221 before deciding on criteria for designating NIETCs;
2. Specify that the one-year clock for state action on a proposed transmission line within an NIETC does not begin until a complete application, as defined by state law, has been received by the state;
3. Support current efforts to coordinate transmission permitting activities among federal agencies and with states;
4. Avoid adopting vague criteria for designating NIETC, such as criteria 4 and 5;
5. Establish administrative procedures by which the Secretary will apply NIETC designation criteria to ensure that such designations follow a rigorous, well-defined process
6. More closely link the implementation of Section 1221 with the designation of energy corridors on federal lands under Section 368 of EPAct.

The comments of the Western Interstate Energy Board elaborate on these points and other issues raised in the Department's Notice of Inquiry (attached). **[Note from the U.S. Department of Energy: Joint Comments of the Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation are found elsewhere in this document; the comments were not repeated here due to space constraints.]**

Part of national interests has to be the concerns of local citizens, tribes, communities, and states. Once again, I recommend you keep in mind location criteria such Montana uses in our own siting procedures. I detailed these in my letter of November 28 offering comments on the scope analysis for the designation of energy corridors on federal lands in eleven Western states under Section 368 (attached). Montana is a major exporter of electric power and we are working hard to develop our clean coal, wind and other energy resources. We also value our uniquely beautiful environment. There are areas of the state where new transmission should not be constructed.

I appreciate the effort your staff is putting forth to communicate with Montana and other Western states on the implementation of provisions of Section 1221 of the Energy Policy Act. To realize Montana's environmental and energy development objectives we need the collaboration, not the pre-emption of the federal government. I look forward to working with you in the constructive implementation of Section 1221.

Sincerely,

BRIAN SCHWEITZER
Governor

cc: Kevin Kolevar, Director, DOE Office of Electricity Deliverability and Energy Reliability
David Meyer, DOE Office of Electricity Deliverability and Energy Reliability

Attachment
Energy Corridor Designation Scoping Comments from Montana
Comments of Western Interstate Energy Board **[Note from the U.S. Department of Energy: Joint Comments of the Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation are found elsewhere in this document; the comments were not repeated here due to space constraints.]**

November 28, 2005

Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585
Fax: (202) 586-1472

RE: Energy Corridor Designation Scoping Comments

The State of Montana offers the following comments on the scope analysis to be conducted for the Programmatic Environmental Impact Statement (PEIS) to evaluate issues associated with designation of energy corridors on federal lands in eleven Western states. In order for linear transmission facilities to be constructed in Montana, we strongly recommend that the following areas of concern be considered early and throughout the PEIS process. Addressing these concerns and facilitating Montana State Agency cooperation will be critical to avoid conflicts later in the PEIS process.

Recognize the Western Governors Association Siting and Permitting Protocol
In 2002 the governors of eleven western states, along with the U.S. Departments of Energy, Interior, and Agriculture and the Council on Environmental Quality signed a Protocol Governing the Siting and Permitting of Interstate Electric Transmission Lines in the Western United States. The Protocol clearly describes steps to be taken to cooperate in the siting and permitting of new transmission lines. Recognize the intent of the protocol and work closely with state agencies while designating corridors and when siting and permitting new transmission lines. The protocol can be viewed at http://www.westgov.org/wieb/electric/Transmission%20Protocol/9-5wtp.pdf.

Work With Affected Montana Communities
Work with local communities when designating corridors on federal lands. The geographical location where corridors begin and end on public lands will affect where future private and state land right of ways will be sought and therefore will result in impacts there as well. Members of local communities have first-hand knowledge gained from working and recreating on public lands that will prove useful in finding energy corridors that satisfy national needs while at the same time considering local interests and concerns. By working with communities rather than dictating policies to them you can gain local support for federal initiatives rather than opposition

Work with Montana Agencies
One of the best opportunities to ensure a successful PEIS process will be to use existing data from the Department of Environmental Quality (DEQ), Fish Wildlife and Parks (FWP) and other agencies as needed together with professional input during the early process of developing corridor alternatives. In order for this to occur, the State of Montana proposes to share relevant data and professional opinion with the coordinators of the West-wide Energy Corridor PEIS. We also propose that reciprocate information be provided in useful format to Montana Agencies as requested especially during the development of draft corridor alternatives. Montana's agencies can better serve the public interest by conducting a thorough analysis of potential environmental, fish and wildlife, habitat and recreational resource impacts early on in the PEIS process. These analyses should help development of alternatives that might encounter fewer problems later in the PEIS process or when siting lines.

Concerns over Corridors through Western Montana
The Montana Department of Environmental Quality's Facility Siting Program has examined some constraints to siting new transmission lines to west coast markets. A copy of a presentation discussing selected constraints is attached. Note that some of these constraints may also apply to new pipelines as well as electric transmission lines. In general, lands managed as national, state and local parks, Wild and Scenic Rivers, Wilderness Areas, Tribal Wilderness and Primitive areas, and National Recreation areas severely limit where corridors can be designated. Superimposed on these land management constraints are other siting constraints for both public and private lands including habitat for federally listed threatened and endangered species, requirements for protection of remaining stands of old growth timber, terrain and geology, private land uses, public concerns over the visibility of lines and cleared rights of way, and health

concerns. These factors will make it extremely difficult to construct new transmission corridors traveling west through Montana.

Considerations for Upgrading Existing Lines or Consolidating Lines

Before any new transmission lines are constructed, every possible effort should be made to upgrade existing lines where appropriate in order to meet demand. However, consolidation of lines and use of existing rights of way should be considered using careful review of each existing right of way and line.

In the past, many planners felt that discouraging the proliferation of separate rights-of-way reduced the cumulative impact of linear facilities. In theory, consolidation or upgrades on existing rights-of-way would lessen adverse impacts and conserve resources by confining impacts to specific areas or existing areas where the impacts could be more efficiently mitigated and managed. In many areas these assumptions are fair. However, just because a line already exists in an area doesn't necessarily mean that the area is suitable, much less the best location, for another transmission line or pipeline or an upgraded line. Land uses may have changed, science may have advanced and increased our understanding of impacts, management goals may have changed, and there may be new public expectations for the area. Some existing lines are relatively small and may fit a landscape better than a much larger new line with a more massive structure type.

For example, the Department of Environmental Quality is working on current transmission projects that demonstrate that use of existing rights-of-way may not always be the best solution. One project involves a much-needed rebuild of a 115 kV line and possible upgrade of the line to 230 kV standards. The other involves upgrading a 161 kV line to 230 kV. Since construction of the first line, many homes have been built in a subdivision that now surrounds the line. Homes have been constructed at the edge of the right-of-way and there is insufficient right-of-way width to accommodate a 230 kV line. In this case it might make more sense to reroute a short segment of line to adjacent federal land than to disrupt a neighborhood with a 230 kV line and require removal of several buildings. The second line was built in the 1930's and now has a pole located in the middle of a high school track. It might make sense to relocate the rebuilt line in a new location that avoids school grounds.

Fish, Wildlife and Recreational Resources

Montana is fortunate to retain many world class fish, wildlife and recreational resources within its borders. These resources are the direct result of protecting and enhancing habitat for these species and managing these resources for long term sustainability. There are substantial economic benefits for Montana associated with these resources.

In general, construction within the proposed energy transmission corridors will result in changes to the structure and function of fish and wildlife habitat along the length of the corridors and may result in direct impacts to certain species. The consequences of these changes could result in significant impacts to fish and wildlife and their habitats as well as related recreational opportunities. Impacts may range from initial effects such as displacement of animals during construction to long-term habitat loss due to changes in habitat successional stage and fragmentation. Other impacts might include increased off road vehicle access, spread of noxious weeds and changes in hunting, fishing and other outdoor recreational patterns.

As the PEIS process progresses, heightened concern will exist for impacts to specific fish and wildlife species that are 1) Federally listed as threatened or endangered, and 2) species that are low or declining and are considered in greatest need of conservation to prevent their future listing as threatened or endangered. Likewise, heightened concern will exist for specific habitats and geographic areas that are essential to these species.

FWP has data that identifies species and habitats throughout Montana that are in greatest need of conservation including where important fish and wildlife movement corridors occur. This information should be considered when developing the initial corridor alternatives and as alternatives are reviewed.

Aquatic resources

Avoid establishing corridors in environmentally sensitive watersheds where construction of a transmission line or pipeline would adversely affect already impacted areas. These sensitive watersheds include watersheds that are not attaining their designated beneficial uses because of sediment problems or that provide habitat for species of special concern. In Montana, a list of watersheds not attaining beneficial uses can be found in DEQ’s 303(d) list (http://www.deq.state.mt.us/wqinfo/303_d/303d_information.asp). Montana Fish, Wildlife and Parks maintains databases that can identify the streams where species in greatest need of conservation occur.

When developing energy corridor alternatives, specific consideration should also be given to perennial streams that located within the proposed corridor. Construction of linear transmission lines that affect the bed and banks of these streams may require adherence to Montana's Natural Streambed and Land Preservation Act, also known as the 310 Act. Impacts can be avoided by implementing mitigating measures identified during the process of obtaining a 310 Permit from the local conservation district, through Major Facility Siting Act review, through 401 certification under the Clean Water Act and discharge permits under Montana’s Water Quality Act.

Considerations for Reliability

Caution should be exercised in designating corridors in a manner that would result in many transmission lines being located in close proximity to each other (general guidance is that they be separated by at least 1,000 to 2,000 feet or more) that if a natural or manmade disaster occurs, major supplies would be disrupted. For example a forest fire might remove several lines from service in a single corridor over a relatively short period of time. These concerns could be highlighted if occurring during a period of high demand on the west coast. Federally designated corridors should include sufficient geographic diversity to help ensure a reliable transmission system. However, this does not infer that only one line should be allowed in each corridor. Federally designated corridors should seek a balance between transmission needs, resource impacts, costs, and reliability.

Also be aware of the long-standing concerns of transmission line owners over co-locating electric transmission lines and pipelines in close proximity to one another. A fire resulting from a pipeline spill or leak may pose reliability concerns to the transmission line.

Montana's Major Facility Siting Act (MFSA)

In administrative rules implementing Montana's Major Facility Siting Act (MFSA), the Montana Board of Environmental Review lists preferred location criteria that are to be considered when selecting locations for new linear facilities. The following excerpt from Circular MFSA-2 identifies these preferred site criteria:

SECTION 3.1, PREFERRED LOCATION CRITERIA Preferred locations conform to the criteria listed in 75-20-301 (1)(c), MCA, and achieve the best balance among the following location criteria:

(1) for electric transmission lines:
(a) where there is the greatest potential for general local acceptance of the facility;
(b) where they utilize or parallel existing utility and/or transportation corridors;
(c) to allow for selection of a location in nonresidential areas;
(d) on rangeland rather than cropland and on non-irrigated or flood irrigated land rather than mechanically irrigated land;
(e) in logged areas rather than undisturbed forest, in timbered areas;
(f) in geologically stable areas with non-erosive soils in flat or gently rolling terrain;
(g) in roaded areas where existing roads can be used for access to the facility during construction and maintenance;
(h) so that structures need not be located on a floodplain;
(i) where the facility will create the least visual impact;
(j) a safe distance from residences and other areas of human concentration;
(k) in accordance with applicable local, state, or federal management plans when public lands are crossed; and

(2) for pipelines:
(a) conform to the criteria listed in (1)(a), (b), (e) through (g), (i) through (k); and
(b) cross lands which can be returned to their original condition through re-

contouring, conservation of topsoil and reclamation.

(http://www.deq.state.mt.us/MFS/LawRules/Circular2.pdf)

The above criteria along with recognition of guidance to applicants in Circular MFSA-2, and decision standards under MFSA in 75-20-301 and 303, Montana Code Annotated (MCA) should be considered when selecting corridors on federal land to help ensure that state siting decisions will mesh with use of federal corridors and that needed projects are constructed in a timely manner.

Corridor Width
Corridors should generally be as narrow as possible. Narrow corridors will aid in environmental analysis because they focus the analysis on resources that would likely be affected. Too broad a corridor may lead to an unfocused analysis that could turn out to be too generic to be useful to decision makers and may face unnecessary challenge either at the time of designation or when a specific project is proposed.

Federal/Non-Federal and Mixed Ownership Lands
Federal corridors should not be designated so narrowly that they for all intents and purposes create a corridor on adjacent private and state lands near the transition from private and state lands to federal lands. Flexibility may be needed by state siting agencies to locate lines on state and private lands as linear facilities approach federal corridors. In the past designating narrow corridors on federal land that would leave little or no doubt where a linear facility would have to be located on private land has been referred to as inverse condemnation. The adjacent private landowners would be expected to give up some property values now because of a corridor designation adjacent to their property but they are not compensated for these losses until an easement is obtained.

Try to avoid designating corridors in areas with mixed state, federal, and private ownerships. In Montana the state siting process in cooperation with federal agencies will sort out large transmission line or pipeline locations in these areas with mixed ownership. Efforts to designate corridors should be concentrated on large contiguous blocks of federal land.

Before designating corridors, consider potential adverse impacts that may extend from federal lands onto adjacent and nearby private lands. For example, potentially significant visual impacts of a cleared right of way or access road situated on a hillside on federal land may extend to private land in a nearby valley.

Consultation with Tribal Governments
In Montana, certain corridors that have been studied in the past cross tribally owned land. Tribes should be consulted for their endorsement prior to designating a corridor on adjacent federal land because such a designation would otherwise dead-end at a reservation boundary and provide mixed signals to potential project sponsors and tribes. If project sponsors are able to reach agreement with tribes, then a federal corridor designation might be added at a later date.

Build on past corridor studies when looking to the future
Over the years many corridors for linear facilities, both transmission lines and pipelines, have been studied in Montana by state and federal agencies. Terrain, land-use constraints, potential environmental impacts and costs were some of the major factors that were considered in selecting corridors for study. Many of the same corridors or portions of the corridors have been studied several times for good reason; the lay of the land dictates where projects can logically be sited in western Montana. We recommend that the PEIS start with these previously studied corridors once the location of generation is reasonably known and after likely markets are identified. Carefully review

why the corridors were either selected for a linear facility or why they were rejected. Next, as appropriate, update the information contained in these reports because land use and management objectives have changed. Then if markets or environmental constraints indicate that additional areas deserve study, examine additional areas.

Some of the corridors studied in the past can be found in the following documents, which may be viewed in the Montana Department of Environmental Quality office in Helena. These may also be available through interlibrary loan.

Montana State Department of Natural Resources and Conservation 1974. Draft Environmental Impact Statement on Colstrip Electric Generating Units 3&4, 500 Kilovolt Transmission Lines and Associated Facilities, Volume Four, Transmission Lines. Energy Planning Division. Helena, Montana.

Montana Department of Natural Resources and Conservation 1976. Draft Environmental Impact Statement on Anaconda-Hamilton 161 KV Transmission Line. Energy Planning Division. Helena, Montana.

Montana Department of Natural Resources and Conservation 1976. Draft Environmental Impact Statement on Clyde Park – Dillon 161 Kilovolt and 69 Kilovolt Transmission Lines. Energy Planning Division. Helena, Montana.

Montana Department of Natural Resources and Conservation 1979. Draft Environmental Impact Statement on the Proposed Northern Tier Pipeline System.
Helena, Montana.

Montana Department of Natural Resources and Conservation 1981. Report on Alternative Northern Tier Pipeline Routes Between Weeksville and Helmville, A report to the Northern Tier Pipeline Company. Facility Siting Division. Helena, Montana.

U.S. Department of Energy 1982. Draft Environmental Impact Statement Garrison-Spokane 500 kV Transmission Project. Bonneville Power Administration. Portland, Oregon.

Montana Department of Natural Resources and Conservation 1983. Draft Report Preferred and Alternate Routes: BPA 500 – Kilovolt Line From Garrison –West. Energy Division. Helena, Montana.

U.S. Department of Energy 1983. Draft Environmental Impact Statement, Great Falls-Conrad Transmission Line Project, Montana, Appendix A. Western Area Power Administration. Billings, Montana.

U.S. Department of Energy 1983. Draft Environmental Impact Statement, Conrad - Shelby Transmission Line Project, Montana, Appendix A. Western Area Power Administration. Billings, Montana.

U.S. Department of the Interior and Montana Department of Environmental Quality 1995. Express Crude Oil Pipeline Draft Environmental Impact Statement. Helena, Montana.

U.S. Department of the Interior 1995. Yellowstone Pipe Line Easement Renewal Final Environmental Impact Statement. Bureau of Indian Affairs Flathead Agency. Pablo, Montana.

Montana Department of Environmental Quality 1996. Draft Environmental Assessment of the Beartooth Pipeline Billings, Montana to Elk Basin, Wyoming. Helena, Montana.

Federal Energy Regulatory Commission 2003. Draft Environmental Impact Statement Williston Basin Interstate Pipeline Company Grasslands Pipeline Project. Washington, DC.

USFS Lolo National Forest 1999 Yellowstone Pipeline, Missoula to Thompson Falls, Draft Environmental Impact Statement. Missoula, Montana.

USDI BLM 1985 Airfoil/Dakota Carbon Dioxide Projects Draft Environmental Impact Statement. Cheyenne, Wyoming

Also note that in the late 1970’s through the early 1990’ s there was a joint state-federal (USFS and BLM) corridor planning effort in Montana. The work of the Corridor Oversight and Review Committee is characterized in the following report:

State of Montana, USDA-Forest Service, and USDI-Bureau of Land Management

1981. Utility-Transportation Corridor Study for Montana, The Existing Situation and

Options for Future Corridor Selection.

Thank you for the opportunity to comment on the scope of your planned analysis. Should you have any questions pertaining to these comments, please contact Tom Ring with our Department of Environmental Quality, Facility Siting Program at (406) 444-6785 and T.O. Smith with our Department of Fish, Wildlife and Parks at (406) 444-3889.

Sincerely,

BRIAN SCHWEITZER
Governor

Attachment **[Note from the U.S. Department of Energy: Joint Comments of the Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation are found elsewhere in this document; the comments were not repeated here due to space constraints.]**

37. Montana Legislature, Received Mon 3/6/2006 12:22 PM

In response to DOE's Notice of Inquiry soliciting comment on electric transmission congestion.

To whom it concerns:

Montana is seeing expansion of electric energy generation with two wind farm projects added to state sited electric transmission lines. Presently the in-state electric transmission systems carry electric generated power in a West direction VIA Idaho, Washington and Oregon. Most of the capacity of the electric transmission lines are close to full capacity and there is a strong need to develop additional transmission lines out of Montana.

There are a number of proposals pending in Montana to construct and operate various electric generation facilities, but there needs to be added electric transmission systems approved to make these proposed to be built. We would support a new electric transmission "corridor" system. Traveling South out of Montana, into either Wyoming or Idaho and on South to Utah and California. Also improvements to the present West corridor electric transmission system in place in Montana. There are many studies being done by Bonneville Power Authority as well as various private electric companies in addressing additional electric generated power to be transmitted out of Montana to the South and West of Montana.

We hope that Montana can be developed with various projects that will stimulate the State economy and provide jobs and economic development.

Thank you for reading our comments.

Signed:

Glenn A. Roush
Montana State Senator, S.D. 8
P.O. Box 185
Cut Bank, MT 59427

Alan Olson
Montana State Representative, H.D. 45
18 Halfbreed Creek Road
Roundup, MT 59072-6524

38. National Association of Regulatory Utility Commissioners, Received Mon 3/6/2006 4:44 PM

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

	)
Considerations for Transmission	)
Congestion Study and	)
Designation of National Interest	)
Electric Transmission Corridors	)
	)

COMMENTS OF THE
NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

The National Association of Regulatory Utility Commissioners ("NARUC") appreciates the opportunity to provide comments to the Department of Energy (the "Department" or "DOE") in response to its February 2, 2006 Notice of Inquiry Requesting Comment and Providing Notice of a Technical Conference in the *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors* Proceeding.

COMMUNICATIONS

All pleadings, correspondence, and other communications related to this proceeding should be addressed to the following person:

Grace D. Soderberg
Assistant General Counsel
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BACKGROUND

The Department of Energy seeks comment on its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors (''NIETCs'') in a Report based on the study required by Section 1221(a) of the Energy Policy Act of 2005 ("EPAct"). This notice of inquiry invites comment on draft criteria for gauging the suitability of geographic areas as NIETCs and announces a public Technical Conference concerning the criteria for evaluation of candidate areas as NIETCs.

INTRODUCTION

NARUC is the national organization of the State commissions responsible for economic and safety regulation of the retail operations of utilities. Specifically, NARUC's members have the obligation under State law to ensure the establishment and maintenance of such energy utility services as may be required by the public convenience and necessity, as well as ensuring that such services are provided at just and reasonable rates. NARUC's members include the government agencies in the fifty States, the District of Columbia, Puerto Rico, and the Virgin Islands charged with regulating the rates and terms and conditions of service associated with the intrastate operations of electric, natural gas, water, and telephone utilities. Both Congress[1] and

[1] See 47 U.S.C. § 410(c) (1971) (Congress designated NARUC to nominate members of Federal-State Joint Boards to consider issues of concern to both the Federal Communications Commission and State regulators with respect to universal service, separations, and related concerns); Cf., 47 U.S.C. § 254 (1996) (describing functions of the Joint Federal-State Board on Universal Service). Cf. *NARUC, et al. v. ICC,* 41 F.3d 721 (D.C. Cir 1994) (where the Court explains "…Carriers, to get the cards, applied to…[NARUC], an interstate umbrella organization that, as envisioned by Congress, played a role in drafting the regulations that the ICC issued to create the 'bingo card' system").

the federal courts[2] have long recognized NARUC as the proper party to represent the collective interests of State regulatory commissions.

I. PRELIMINARY MATTERS:

A full and productive consultation between the Secretary, affected States, and regional entities relating to the required congestion study will result in identification of an optimal set of NIETCs. Several times since the adoption of EPAct,[3] Department representatives have invited NARUC, regional entities, regional State committees, and NARUC member commissions to facilitate broad stakeholder input to develop strong regional consensus concerning findings and procedures in order to properly inform the Secretary of Energy's ("Secretary") NIETC determinations. NARUC welcomes DOE's recognition of the expertise and information that its members can bring to the process and will work hard to build these regional processes.

DOE Should Proceed Carefully

NARUC has long supported efficient, effective expansion of the transmission grid. Grid expansion plans must reflect the potential impact of supply and demand response resource choices, including conservation and energy efficiency. Indeed, EPAct's Electricity Title contains *many* transmission-affecting initiatives in addition to those for siting of new transmission. Responsibility for many initiatives is assigned to the Federal Energy Regulatory Commission ("FERC" or the "Commission"). These other initiatives, such as requiring FERC to encourage

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[2] See *United States v. Southern Motor Carrier Rate Conference, Inc.*, 467 F. Supp. 471 (N.D. Ga. 1979), aff'd 672 F.2d 469 (5th Cir. 1982), aff'd en banc on reh'g, 702 F.2d 532 (5th Cir. 1983), rev'd on other grounds, 471 U.S. 48 (1985).

[3] (1) October 4, 2005, National Council on Electricity Policy (annual face-to-face meeting); (2) October 5, 2005, University of Missouri's Financial Research Institute Symposium on State and Federal Issues; and (3) October 13, 2005, NARUC Leadership Meeting with DOE.

the deployment of advanced transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and requiring the adoption of rules providing incentives for new transmission construction, can also help to assure efficient, effective grid expansion. Because such initiatives are proceeding on parallel paths, their interrelated impact may not be fully understood for some time. As a result, a cautious, conservative near-term approach to the designation of NIETCs seems appropriate.

DOE Should Defer to Certain Existing Planning Processes

Many areas of the country have Regional Transmission Organizations ("RTOs") and organized wholesale markets with long-standing operational regional planning procedures.[4] These regional procedures include participation by stakeholders and public utility commissions within the regions. The resulting regional plans work in tandem with existing market rules designed to provide a level playing field and assure that resource owners of all types – local and remote generation, demand response, and transmission - can compete in an efficient market. Ratepayers are best served by allowing those regional markets to establish the value of electricity. The Northeast RTOs' plans require the identification of all upgrades needed for reliability and all efficiency opportunities. Accordingly, all critical NIETCs within the footprint of existing RTOs and similar regional planning bodies should, by definition, already be included in adequate Regional System Plans. There is no need to make additional NIETC designations in such areas. On the contrary, DOE should defer to the expertise of the RTOs and the stakeholder processes in the Northeast and in other regions where adequate regional planning exists.

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[4] For example, the New England RTO employs a collaborative regional system planning process, which incorporates the evolution of new technologies as well as demand-side resources and has been recognized by the U. S. Department of Energy as one of the best in the nation. *See*, http://www.iso-ne.com/pubs/whtpprs/delivering_value_to_the_region.pdf.

DOE Should Continue to Consult with Affected States

It is clear that Federal Power Act ("FPA") Section 216 requires DOE to consult with at least two parties—(1) Affected States and (2) Regional Entities—as part of the required transmission congestion study. Section 216 also gives interested parties, including Affected States, the opportunity to provide alternatives and recommendations as DOE develops a congestion study that designates NIETCs. More particularly, prior to designating a geographic area as a NIETC, the Secretary is required to:

1. Complete a study of electric transmission congestion by August 2007;
2. Consult Affected States and Regional Entities while the study is being conducted; and
3. Issue a report based on the study.

The Secretary may only designate an area as an NIETC if he:

1. Makes specific findings that such a geographic area is experiencing electric energy transmission constraints or congestion that adversely affect consumers;
2. Allows interested parties, *including Affected States*, to provide alternatives and recommendations;
3. Carefully considers the submitted alternatives and recommendations; and
4. Consults with Regional Entities on the proposal.

If the Secretary makes an NIETC designation, the FERC "may, after notice and an opportunity for hearing, issue one or more permits for the construction or modification of electric transmission facilities in a national interest electric transmission corridor."[5] The FERC may

[5] See §216(b).

issue such a permit only if (1)(a) a State in which the transmission facilities are to be constructed or modified does not have authority to approve the siting of the facilities or consider the interstate benefits expected to be achieved by the proposed construction or modification of transmission facilities in the State; (b) the applicant for a permit is a transmitting utility under this Act, but does not qualify to apply for a permit or siting approval for the proposed construction or modification of transmission facilities in the State; or (c) a State commission or other entity that has authority to approve the siting of the facilities has withheld approval for more than one year after the filing of an application seeking approval pursuant to applicable law or one year after the designation of the relevant NIETC, whichever is later, or conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible; (2) the facilities to be authorized by the permit will be used for the transmission of electric energy in interstate commerce; (3) the proposed construction or modification is consistent with the public interest; (4) the proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protects or benefits consumers; (5) the proposed construction or modification is consistent with sound national energy policy and will enhance energy independence; and (6) the proposed modification will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers or structures.[6]

NARUC appreciates the Department's recognition of the special consideration Affected States are granted in new Section 216. The invitation to NARUC's member commissions to work with broad stakeholder input to develop strong regional consensus was not just the right

[6] FPA Section 216(b).

policy choice, it constitutes compliance with the express terms of FPA Section 216. NARUC thanks the Department for its efforts to assure Affected States have adequate input in the process and commits to helping develop the proposed regional processes and to keep the Secretary advised of the progress being made in these efforts.

Other Issues That May Affect Efficient and Effective Transmission Grid Expansion Must be Considered

There are other factors that have significant impacts on grid expansion that are not directly addressed by EPAct and that should be considered in implementing FPA Section 216. These factors include issues caused by the lack of equitable cost allocation for newly constructed transmission facilities; financial difficulties for utilities under rate freezes, when incremental revenues are not able to offset additional transmission investment costs; deficiencies in existing transmission planning processes; and financial issues (including reasonable access to credit markets) stemming from unsuccessful utility forays into non-regulated ventures. NARUC's members have performed the traditional roles of planning, siting, and reliability assurance with much success. They have also generally attempted to work in concert with regional reliability councils and other similar organizations. NARUC's members can use this expertise to assure that the effects of these additional factors are adequately understood and addressed in the Secretary's transmission congestion study and in the development of the additional State and regional initiatives that are currently underway.

II. THE CONGESTION STUDY:

The Department is required by new FPA §216(b)(4)(A)-(E) to use five criteria to determine whether to designate a particular geographic area as a NIETC. The NOI requests that comments on specific topics be presented under separate headings.

Should DOE distinguish between persistent congestion and dynamic congestion, and if so, how.

Persistent congestion should be defined as congestion that can be expected to occur frequently over extended periods under normal grid operating conditions. Dynamic congestion may only differ from that which is persistent in terms of periodicity. Dynamic congestion can occur frequently and may occur under normal grid operating conditions, but it is usually only a temporary concern and can often be mitigated with available grid operating procedures. The Department may wish to study both persistent and dynamic congestion under criteria (A) and (B)(i). Both criteria contain economic (lack of reasonably priced electricity) and reliability (lack of adequate electricity) sub-criteria. However, as a temporary concern, relieving dynamic congestion might generally be expected to fail the economic cost-benefit tests that are required by both (A) and (B)(i). Though relieving dynamic congestion might fail economic tests, its presence might indicate the presence of longer term reliability issues. Bulk power system reliability is a very technical subject that EPAct entrusts to the Electric Reliability Organization (ERO) and the regional entities. Accordingly, DOE should focus the NIETC designation process on relieving persistent congestion, but should seek information from the ERO and regional entities as to whether certain instances of dynamic congestion reveal the presence of building reliability issues that should also be addressed.

Should DOE distinguish between physical congestion and contractual congestion and if so, how.

The DOE should not devote much effort to making minute distinctions between physical and contractual congestion. Instead, it should focus on levels of current and future physical congestion, since NIETC corridor designations should not be directed toward relieving artificial constraints arising solely from capacity hoarding or other activities that can be mitigated by changes in market rules.

The DOE should focus on physical congestion because the only way to relieve it is by constructing new assets, including new bulk transmission facilities or increased demand response. In organized markets using LMP, for example, attempts have been made to address the financial effects of physical congestion through contractual arrangements such as Financial Transmission Rights ("FTRs"). FTRs are designed to recognize the value of transmission facilities to load-serving entities, which have paid for existing transmission facilities for many years. While FTRs provide a financial hedge against congestion costs, they do not increase the capacity of transmission facilities and do nothing to relieve the underlying system congestion. An entity that constructs new transmission facilities does, however, receive what are sometimes called Auction Revenue Rights ("ARRs") from which revenues are derived. However, relieving physical congestion ultimately does require the construction of new generation or transmission facilities or increased demand response.

The DOE should further consider attempting to differentiate between levels of physical congestion. Physical congestion can be measured by the number of hours that a circuit, transformer or other component of the transmission system is subject to operating limits, usually listed as congestion event hours. The PJM Interconnection, LLC ("PJM") 2004 State of the

Market Report provides a useful example of this approach and indicates that physical congestion is increasing on the PJM system. There were 11,205 congestion-event hours on the PJM system in 2004 as compared to 9,711 congestion-event hours in 2003. This physical congestion directly translated into higher costs; congestion costs on the PJM system in 2004 were $808 million, 9 percent of total PJM billings, and a 28 percent increase over 2003. Information of this nature can be used to identify the most serious instances of physical congestion in order to focus the NIETC designation process on the appropriate corridors.

However, if DOE wishes to distinguish between physical and contractual congestion, the resulting definitions should work closely together. Physical congestion could be defined as congestion that is taking place presently or has taken place in the past. Contractual congestion could be defined as congestion that should be expected to manifest itself physically in the future as the result of an entity's lawful exercise of contractual rights (including rights derived from regulatory decisions, such as rollover rights). If the terms are so defined, differentiation of physical and contractual congestion should not be a significant issue.

In addition to the transmission plans and studies listed in Appendix A of the NOI, what existing, specific transmission studies or other plans should DOE review.

DOE should review studies and analyses resulting from the adequately independent regional transmission planning processes conducted by entities such as RTOs, Independent System Operators ("ISOs"), and, where appropriate, regional reliability organizations. The DOE should not duplicate existing regional planning exercises where those exercises produce valuable information. The findings resulting from these exercises are generally based on the best available data that has been sifted through a rigorous stakeholder review process. DOE should also carefully consider State commission comments on regional transmission exercises and studies.

DOE should focus its analytical efforts on studies that incorporate recent historical data and utilize reasonable assumptions and estimates of future electric system conditions. Older analysis provides information that may be useful in predicting future performance, but the DOE's primary focus should be on recent studies that reflect current estimates of future conditions on the electric system. For example, transmission studies conducted in 2002-2003 are too stale to provide a basis for decisions about the Eastern Interconnection, since the Midwest Independent Transmission System Operator, Inc. ("MISO") Midwest Market Initiative did not commence until April 2004. Obviously major market initiatives can devalue historical transmission studies.[7] As a result, DOE should rely principally on recent transmission studies performed through adequately independent regional transmission planning processes that incorporate reasonable estimates of future key system conditions.

III. DRAFT CRITERIA IN THE STUDY:

DOE also invited comment on what criteria to use when evaluating the suitability of geographic areas for NIETC status and requested comment on eight preliminary draft criteria. NARUC's comments on a number of these criteria are as follows:

Draft Criterion 1: Action is needed to maintain high reliability.

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[7] In addition to the studies listed in the NOI, DOE should consult the 2004 Cambridge Energy Research Associates ("CERA") Eastern Interconnection Congestion Study. The CERA study identifies specific transmission bottlenecks and assesses the costs and benefits addressing certain transmission system constraints in the Eastern Interconnection.

The reliability of electric service, including the adequacy of supply and the security of system operations, is essential to the economic well-being and domestic security of the nation. However, given that absolute reliability is not physically possible and that transmission reliability does not have infinite economic value, it is difficult to define the term "high reliability". Thus, DOE should be deferential to those federal, State and private entities most concerned with reliability issues in determining an appropriate level of transmission reliability.

The public interest in a reliable and cost-efficient transmission system requires that the level of reliability to be achieved and the applicable standards to be utilized be established with public input and oversight. There is a national interest in a transmission network that is reliable and available to support efficient, competitive wholesale electricity markets. Historically, the level of electric reliability experienced in the United States has been achieved through the voluntary efforts of the electric utility industry, working through the North American Electric Reliability Council ("NERC") and the regional reliability councils, subject to federal and State regulatory oversight. In light of EPAct's proposal for the creation of a single ERO and Regional Entities to be operated consistently with the procedures and substantive determinations made by FERC, the Department should defer to these bodies on issues of reliability.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

The NOI asks "interested parties" to identify "geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC." The DOE suggests that if such areas are identified, "the Department will consider whether it should complete its congestion study for the area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comments and designate that area as an NIETC on an expedited basis." As a result, NARUC understands "early designation" as described in the NOI as a separate procedure from the standard NIETC designation process.

Assuming that DOE intends to proceed with "early designations" of this nature, NARUC believes that DOE should (1) consider factors such as persistent and substantial congestion as revealed in previous studies in identifying corridors appropriate for "early designation" and (2) refrain from interfering with the results of adequately independent planning processes, such as those conducted in RTO regions. Although NAURC is not specifically requesting that any particular corridor receive an "early designation", any "early designation" process should incorporate the two factors stated above.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Transmission enhancements and additions can prove beneficial to congested end markets served by a corridor. Many control areas run units to prevent voltage collapse, instability, and thermal overloading. Inadequate reactive power leading to voltage collapse has been a causal factor in many major power outages. The Task Force Final Report on the August 14, 2003 Blackout noted that insufficient reactive power was an issue in that blackout.

While generators can supply and consume reactive power, transmission lines and transmission-related devices are also useful in controlling reactive power.[8] Consequently, those

[8] Transmission lines can supply reactive power under light loading and consume it under heavy loading. Further, transformers, being inductive devices, consume reactive power and regulate voltage. Transformer taps can pump reactive power from one side of the transformer to the other to regulate voltage. Transformer taps are relatively cheap in comparison to the cost of the transformer.

Phase angle regulators are used to control real power flow. Controlling the real power flow enables the reactive power along the same line to be consumed or produced as necessary. HVDC lines are self-sufficient in reactive power and are capable of controlling AC terminal voltages. Switched shunt and series capacitors can provide reactive power to the power system. Flexible AC Transmission Devices ("FACTS") are technologies that facilities can be used to displace reliability-must-run ("RMR") units that have high variable costs. Many RMR units, especially in certain parts of the South, are natural gas-fired. Displacement of these high cost units, with coal-fired generation, for example, could provide significant economic and diversity benefits.[9] This displacement can be achieved through usage of transmission facilities and devices to provide voltage regulation.

A good example of a region with a significant number of RMR units, which would potentially benefit from expanded transmission service, is the southeast region of the Entergy System, located in southeast Louisiana. The Entergy Transmission System has 16,000 miles of lines, and seventy-four external tie lines with fourteen adjacent utility systems. However, the maximum simultaneous import capability into the Entergy Transmission System is only about 3,900 MW. The load pockets in that area significantly depend upon the gas-fired Ninemile and Michoud Units to provide appropriate voltage supports in that region. Utilization of modern transmission devices, in the context of NIETCs, will enable diminished use of such units for reliability purposes and allow for the use of imported lower cost generation or new plant construction to both reduce fuel costs and provide fuel diversity.

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increase the flexibility of transmission systems and increase the stability limits of transmission lines. Examples of these are static VAR compensators and static compensators, which use microprocessors that automatically regulate bus voltages. Dynamic VAR voltage regulation systems are scalable and mobile, which allows utilities to install them at locations where they are most beneficial.

9 The extent to which such displacement actually benefits customers will depend upon the structures of the relevant market and similar issues.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.[10]

Metrics measuring the potential energy independence or national security benefits should primarily focus on fuel diversity.

1. *Reduced oil consumption.* A major transmission line could have the effect of replacing oil-fired generation with solid fuel generation. Reduced oil consumption, and increased use of coal or nuclear generation, would reduce the U.S. oil import bill, lower the balance of payments deficit (assuming the marginal barrel consumed is imported), and increase national security (if the marginal barrel comes from a county that is politically unstable). The resulting reduction in oil usage can be estimated by comparing the amount of oil used in generating electricity with and without a proposed line in service.
2. *Reduced natural gas consumption.* A major transmission facility that results in displacement of natural gas-fired generation with coal or nuclear generation should have an effect similar to that described for oil. The resulting reduction in natural gas usage can be estimated by comparing the amount of natural gas used to generate electricity with and without a proposed transmission facility in service. Since oil and natural gas can be substituted for each other in a variety of applications, oil savings resulting from diminished natural gas consumption can

10 While weighing national energy independence issues, care should be taken to not diminish the benefits gained from our integrated grid and markets with Canada.

be estimated by converting the heat value of the natural gas saved to barrels of oil or some other appropriate unit of measurement.

3. *Increased availability of natural gas for other economic sectors.* A reduction in the amount of natural gas consumed in electric generation should also place downward pressure on natural gas prices and increase its availability in other sectors of the economy, including use for home heating and as a raw material in the chemical, fertilizer and other industries. Some indication of the significance of this effect could be developed by comparing the amount of natural gas saved in generating electricity as a result of a transmission investment with the amount of natural gas consumed in various other economic sectors. The greater the relationship between gas saved and gas presently used in a sector, the greater the potential economic and national security benefit from new transmission construction.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

DOE should carefully consider the national security implications of designating specific corridors as NIETCs. DOE should carefully weigh the benefits of making security-related NIETCs publicly available against the possibility that such an action could allow any vulnerability in existing or proposed facilities to be exploited. If DOE publicly labels NIETCs that implicate national security, DOE should protect against the possibility that such vulnerabilities could be exploited once they are highlighted. As a result of the fact that this criterion is considered in the current NERC transmission planning requirements and processes, this issue will be addressed by the ERO under the Reliability Rule implementation at FERC.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

In the NOI, DOE recognized that regional stakeholders were currently engaged in assessing the growing needs of consumers for electricity and developing cost-effective solutions to address those needs given current and forecasted power system constraints. The DOE's appraisal of the various regional activities is accurate. While siting transmission may be one solution to a congestion-related problem, there are many functional alternatives to wires-only proposals that regional stakeholders should consider. If the DOE were to prematurely designate an area as a NIETC without a complete review of available alternatives, then it may inadvertently confer advantage on a proposed solution that is economically unsound or technically insufficient. Such an action could reduce the value of the regional stakeholders' investments in remedies designed to resolve consumer needs and may distort the market signals that regional transmission operators have been attempting to develop over the past several years.

Alternatives to transmission include, but are not limited to, demand response measures, local generation, distributed generation, energy efficiency and conservation. All of these alternatives can improve the delivery of electricity to consumers and support system reliability. Since each of these alternatives involves a commitment of human and capital resources, regional stakeholders in some areas of the country support the incorporation of what is referred to as the resource parity standard in their regional planning process.[11] The resource parity standard weighs all types of resources (demand response, generation, distributed generation, transmission, etc.) on an equal basis before determining whether a particular solution is cost-effective. Equally weighing all of the functional alternatives ensures that a proposal is selected on its economic merits. The FERC has also recognized that transmission, generation and demand-side resources can often be substitutes for one another and therefore deserve due consideration on an equal basis.[12]

Considering a host of viable alternatives on an equal basis may, however, present the DOE with another potentially insurmountable issue to resolve - timeliness. Assessing the viability of dozens of alternative solutions for every potential corridor within each of the nation's operating areas prior the August, 2006 deadline would be a task of monumental proportions. Fortunately, most of the DOE's work has already been completed for regions where there is an organized electricity market, an RTO/ISO, or another adequate planning process. In those regions, regional stakeholders review the needs of consumers and continually re-assess system requirements to meet those needs in order to develop an annual Regional System Plan. In the interest of time and convenience, it would be appropriate for the DOE to defer to the regional

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11 Specifically, the New England States (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut) urged the Chief Operating Officer of ISO-NE to "develop a resource planning protocol that is based on resource parity and involves a full and complete analysis that will identify that project which will be the least cost solution to the problem." S*ee*, Letter of February 4, 2003 from the New England Conference of Public Utilities Commissioners, Inc. ("NECPUC") to ISO-NE. Available at http://www.necpuc.org/NECPUCfilings.htm.

12 *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 100 FERC 61,138 at P 347 (2002) where the Commission stated "the planning process should leave open the question of how and by whom those [system expansion] needs should be met, without favoring one solution (whether it is transmission, generation or demand response) over another"; *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 FERC ¶ 61,032 at P 32 (2003) where the Commission stated "the most timely and cost-effective ways to meet demand for additional grid capacity will not always be additional transmission facilities; rather, they may be innovative operating practices, such as operation of facilities beyond traditionally accepted limits, distributed generation, demand response or demand side management."

processes that are currently underway and avoid making a designation without first incorporating the recommendations of the regional stakeholders.

Should the DOE decide to independently conduct its own congestion study, the DOE will have to make a number of important decisions prior to designating a geographic area as a NIETC in order to ensure that all functional alternatives have been sufficiently considered. Recognizing that transmission siting and construction are highly controversial, expensive and time-consuming, the DOE should also adopt the resource parity standard mentioned above. This standard should be applied, as it is in some areas of the nation, as an initial test that a transmission solution must satisfy prior to the designation of a NIETC. This would ensure that a NIETC designation would be limited to those instances where there are no better cost-effective alternatives.

In addition to the adoption of a resource parity standard as an initial screen, an independent DOE study should also consider the following issues:

1. A fair and adequate assessment of the needs in a region, which would necessarily include the development of its own long-term load forecast.
2. Adequacy of resource alternatives to transmission.
3. Local generation and distributed generation solutions, as well as market incentives to attract new base-load and quick-start generation.
4. Modern supply-side technologies, such as advanced materials that maximize the thermal-transfer capabilities of existing right-of-ways and provide additional voltage support in needed areas.
5. Advanced monitoring and control mechanisms, including pervasive integration of data communications and substation control systems.

NARUC urges the DOE to consider each of the above-captioned issues along with other considerations relevant to a particular region on an equal basis. Moreover, NARUC recommends that the DOE regularly communicate with the affected regions and provide notice of, and opportunity for comment on, their proposals for designation of NIETCs. Such an approach would most likely result in an optimal solution that appropriately balances the interests of all of the regions' stakeholders.

IV. FURTHER AREAS OF CONSIDERATION:

The notice proposes two ways by which corridors might be designated following standard procedures. The first method is designation by the Department on its own motion after applying its corridor criteria to the information revealed by the congestion study. This method should be the preferred and normal process. It gives the most assurance of even-handed application of designations on a national basis by the Department.

The other method contemplated in the notice is designations at the request of project sponsors or others. The notice suggests there may be situations so urgent that the preferred process – study, then application of the criteria to the results – is not sufficiently expeditious. This method raises concerns not presented by the first method. The "emergency designation" procedure could undermine the integrity of the Department's study process by allowing special treatment for some project sponsors. Even more importantly, an emergency procedure could lead in the longer term to competitive gaming if transmission investment becomes more attractive, since project sponsors would be tempted to obtain designations outside the ordinary study process. The Department should resist any such tendency. With study results just a few months away, jumping the queue to accelerate a designation is unlikely to serve a national purpose.

If the Department intends to accept applications for near-term designations, it will need to establish procedural rules for handling and deciding them. FERC's rules for energy projects provide a good model. The filing requirements should include certain basic elements. The application should set out the basis for an NIETC designation and the goals the requested designation should advance. The application should describe the nature of the planning process that points to the need for the designation. The application should indicate the amount of capacity needed to meet the needs in that corridor. Lastly, the rules should require that the application reflect prior coordination with affected States, regional reliability organizations, and RTOs/ISOs.

The Department's procedural considerations should also include specifying the electrical capacity and the duration of each NIETC designation. The needed capacity in the corridor is an essential guide to agencies, whether State or federal, that will consider individual project proposals within the corridor. The purpose of the designation is to invite construction of facilities that will relieve a certain amount of congestion. The purposes of the designation will not be served by overbuilding within the corridor. The duration of the designation is equally important. The Department is required to perform congestion studies every three years. Corridor designations should remain in effect only if supported by the most recent study. The basic statutory purpose for NIETC designations is the construction of facilities needed to relieve congestion. Once the construction of facilities is authorized within a corridor, the purpose of the designation has been fulfilled. Further authorizations are not needed to relieve the identified congestion and would not lead to an optimal use of investment capital. Thus, the Department should limit corridor designations to no longer than the release of its next triennial congestion study or the final authorization of transmission facilities of the capacity specified for the corridor, whichever is earlier.

CONCLUSION

NARUC respectfully requests that the DOE consider the above comments in this proceeding.

Respectfully submitted,

James Bradford Ramsay

GENERAL COUNSEL

Grace D. Soderberg

ASSISTANT GENERAL COUNSEL

By: _________/s/___________

Grace D. Soderberg

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March 6, 2006

39. National Electrical Manufacturers Association, Received Wed 3/1/2006 4:23 PM

Attached are comments of the National Electrical Manufacturers Association on the Notice of Inquiry requesting comments on the transmission congestion study and designation of National Interest Electric Transmission Corridors required by Section 1221 of the Energy Policy Act of 2005.

Ed Gray
Director, Energy Infrastructure
National Electrical Manufacturers Association (NEMA)
1300 North 17th Street, Suite 1752
Rosslyn, VA 22209
703-841-3265
<<COMMENTS TO DOE ON NIETC NOI 2.pdf>> PDF

February 28, 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Ave., SW
Washington, DC 20585

Herein please find National Electrical Manufacturers Association comments as follows:

NEMA Comments on National Interest Electric Transmission Corridors Study
Required by EPAct 2005 Section 1221
DOE Notice of Inquiry (NOI)

NEMA is the trade association representing about 400 manufacturers that make, among other things, the products in the electricity value chain commonly referred to as the electricity infrastructure, including many of the products and technologies used in the electric transmission system. Because NEMA's product scope covers the entire electricity value chain, NEMA is in a unique position to champion appropriate energy solutions from generation, transmission, distribution, and efficiency of end-use products without favoring any particular product solution over others.

NEMA appreciates the opportunity to comment on this important study. NEMA has commented to DOE on the matter of National Interest Electric Transmission Corridors (NIETC) on several occasions. We are concerned, as we have said before, about an apparent DOE emphasis on detailed assessment rather than timely results (paralysis by analysis). DOE needs to take some leadership rather than expecting that a process based on a least common denominator of public comments would suffice.

The US grid today resembles the highway system in America before the building of the interstate highway system. There are a number of well known bottlenecks in the national transmission system that continue to have adverse effects on congestion costs, local economic conditions, system reliability, and the ability of new generation to reach loads. We believe strongly that these choke points should be addressed immediately within the context of NIETC identification.

The prompt designation of National Interest Electric Transmission Corridors is essential because applications to the Federal Energy Regulatory Commission for federal transmission asset siting can only be considered if they are in NIETCs. The recent announcement by AEP of a major new line proposed to connect assets in West Virginia to substations in Maryland and New Jersey may the beginning of many proposed facilities that could benefit from federal siting and NIETCs need to be identified.

DOE in the NOI has asked if congestion costs and reliability concerns should be addressed in the DOE assessments. These should be included and, in addition, the value of energy not served because of transmission line loading reliefs (TLRs) that were implemented should be included. TLRs are implemented when the capacity is inadequate to assure reliability, so contracts to provide power are not honored. During peak periods over a thousand TLRs may be implemented on a particular bottleneck. These are, in fact, a major cost of inadequate capacity, even though an additional congestion charge was not paid. To the extent possible, all costs should be quantified in economic terms to facilitate incorporating them with the other economic-impact criteria.

DOE asks how specific or general NIETC designation needs to be. This is obviously a judgment DOE is going to have to make depending on the circumstances. While it would be good to have flexibility, the NIETC designation is going to have to be specific enough to be used in sound environmental assessments with some reasonable connection to the proposed project action. Many cases of proposed federal action could presumably be cases where state applications have failed and a poorly conceived federal backstop process could be overturned by actions in the courts, thereby gaining nothing. A touchstone for federal decision-making should be "are we facilitating the action", not prolonging an already too long process. Even with Federal backstop availability, the complexity, difficulty, and delays associated with the siting process are not going away. However, a variety of approaches are available today to expedite the strengthening of the grid. Underground transmission technology solutions can efficiently move power along corridors where rights-of-way for overhead lines are not feasible. Flexible AC Transmission Systems (FACTS) can enhance corridor transmission capacity and system stability, and they can be sited in existing substations. HVDC and hybrid DC and AC system configurations can move bulk power point-to-point along the NIETC corridors and also provide for local power requirements. These technologies will also serve as a foundation to support generation fuel diversity and renewable energy.

After the initial NIETC designations are made, we recommend an ongoing DOE-led process that conducts detailed transmission studies over a longer (at least a 10-year) timeframe to inform the establishment of additional NIETCs. These studies should take into consideration the impact of a given project on others, given the interconnected nature of the grid. They should also employ the most advanced modeling techniques available, perhaps using multiple approaches. This effort would supplement using existing regional transmission plans as a starting point, reevaluating deferred or cancelled projects, and improving low reserve margins as drivers for identifying NIETCs. Many of the regional plans recognize the short-term nature of their assessment.

EPAct 2005 calls for FERC to create incentives for transmission investments, and these should include special incentives for the application of advanced technologies to increase the transfer capability of NIETCs. FERC's views on these initial incentives and technologies appear in FERC's proposed rules to implement Sections 1223 *Advanced Transmission Technologies* and 1241 *Transmission Infrastructure Investment* of the Energy Policy Act of 2005. NEMA has commented to FERC to provide maximum flexibility in its Rules to encourage the application of these technologies to alleviate the congestion seen in the NIETCs.

NEMA agrees that a review of the regional transmission plans is a good place to begin to assess the locations of potential NIETCs. Some notable bottlenecks were considered in proposed projects, that were abandoned because of the onerous regulatory review later contributed to subsequent blackouts included Path 15 in California and possibly an underwater line between Ohio and Canada. So reassessing deferred or cancelled projects might also be advisable. Also, the tiny reserve margins in regional plans are a fraction of traditionally accepted values. (See *2005 Long Term Reliability Assessment*, NERC September 2005.) In addition, these regional plans typically only account for investments in the 5-10 year out timeframe with dotted line projections in later years. The bottom line is that regional plans understate the need for investment and consequently the need for potential NIETC designation, especially in the timeframe of planned major transmission line construction.

Time is of the essence. The sooner NIETCs are established, the sooner federal permitting can begin. FERC's incentives will be as important to attracting investment in NIETC areas as the NIETC designation itself. The fact that a number of advanced technologies exist today with a proven commercial track record gives the industry the means to readily increase the transfer capability of NIETCs.

Please contact Mr. Edward Gray, NEMA Director for Energy Infrastructure, at 703-841-3265 for additional information or follow-up to our submitted comments.

Respectfully submitted,

Kyle Pitsor,
Vice President, Government Relations

40. National Grid, Received Mon 3/6/2006 4:58 PM

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors (NIETC) — **71 Fed. Reg. 5660 (February 2, 2006)**

Comments of National Grid USA to the Office of Electricity Delivery and Energy Reliability ("OE"), Regarding the Notice of Inquiry (NOI) published on February 2, 2006 on the Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

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Introduction

National Grid USA (National Grid) is an investor owned utility whose core business is the ownership, development, operation and maintenance of energy delivery networks in electricity and gas. In the United States, National Grid owns and operates electric transmission and distribution systems in New England and New York, as well as gas distribution networks in New York. In the UK, National Grid owns and operates the high voltage electric transmission system in England and Wales, and the gas transmission and distribution networks throughout Great Britain, and operates the high voltage electric system in Scotland.

National Grid commends the Department of Energy ("Department") for its timeliness in addressing its requirements to conduct an electric transmission congestion study and initiating designation of National Interest Electric Transmission Corridors (NIETC) as prescribed in the Energy Policy Act of 2005 ("EPAct 2005).

Numerous studies have shown that underinvestment in the nation's electric transmission infrastructure is a widespread and growing problem.[1] The reasons for the under-investment

[1] *Promoting Transmission Investment Through Pricing Reform*, Federal Energy Regulatory Commission Docket No. RM06-4-000 at page 1 cites to an EEI survey, a report from Oak Ridge National Laboratory, and Congressional testimony to demonstrate that transmission investment is lagging behind load growth. In announcing the NOPR, Chairman Kelliher also stated that

include impediments to investing, such as uncertainty about cost recovery, the lack of clear and workable up-front cost allocation mechanisms, weak or incomplete regional planning processes, inadequate price signals or market indicators to support and promote transmission investments, and most relevant to the Department's consideration here, siting hurdles.[2]

And it's clear, as you indicated in your briefing, that the transmission grid has suffered from under-investment for a significant period, and that last year, for example, according to the OMOI State of the Markets Report, the transmission system expanded by a grand total of 0.6 percent in circuit miles in the last year, 2004, and that transmission congestion has been rising steadily since 1998.

Open Meeting Transcript at p.49, ll.14-21 (November 17, 2005).

Last spring, National Grid submitted data demonstrating that investment in the US transmission grid in relation to load is lagging behind several other countries that have consolidated, wide-area independent transmission companies. *See* National Grid May 2005 Comments on Transmission Independence and Investment at 6-13 (cited more fully *supra* n.4); *see also*, Statement of Shelton Cannon, AD05-5-000 Technical Conference Transcript at p.8, ll.10-16 (April 22, 2005) ("But if you skim through this [Bonneville Power Administration report], just reading even the headers, demand is growing, new investment is lagging, the grid is being used in all sorts of new and unanticipated ways, there are efficiency gains to be had, too many near misses on the system, growing congestion, more and more transmission paths are reaching their limits, reliability issues that are associated with a strained grid."); Statement of Brendan Kirby, AD05-5-000 Technical Conference Transcript at p.16, ll.21-23 (April 22, 2005) ("But in spite of that critical importance, if you look at the amount that we're spending on investing in transmission, it's not keeping up with the load growth."). Moreover, in its Original Proposed Pricing Policy Statement at P.19 (cited more fully *supra* at n.6), the Commission found nearly three years ago that

It is clear that over the past decade, investment in the nation's transmission infrastructure has not kept pace with load growth or with the increased demands brought about by industry restructuring, including open access transmission service and regional service provided by ISOs and RTOs. The result has been increased transmission congestion, which is evidenced by a dramatic increase in low ATC postings and use of Transmission Loading Relief (TLR) procedures, and in significant energy price differentials between regions.

This finding was based on substantial records developed in regional infrastructure conferences as well as reports and studies by the Department of Energy, the Edison Electric Institute, the Western Governors Association, and Cambridge Energy Research Associates.

[2] *See, e.g.,* Post Technical Conference Comments of National Grid USA, filed in Docket No. AD04-13-000 (January 28, 2005) ("National Grid January 2005 Comments on Wind Power"), which can be found here: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10388842; Motion to Intervene and Comments of National Grid USA, filed in Docket No. EL05-80-000 (April 14, 2005) ("National Grid April 2005 Comments in Response to SCE Petition"), which can be found here: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10495377; Post-Technical Conference Comments of National Grid USA, filed in Docket Nos. AD05-5-000 and PL03-1-000 (May 2, 2005) ("National Grid May 2005 Comments on Transmission Independence and Investment"), which can be found here: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10524165; and Post-Technical Conference Comments of National Grid USA, filed in Docket No. AD05-3-000 (May 27, 2005) ("National Grid May 2005 Comments on Transmission Planning and Expansion to Promote Fuel Diversity"), which can be found here: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10582424; Comments of National Grid USA, filed in Docket No. AD05-7-000 (June 27, 2005) ("National Grid TFTR Comments"), which can be found here: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID= 10633884; Comments of National Grid , submitted to the Electric Energy Market Competition Interagency Task Force, and filed in FERC Docket AD05-17-000 (November 18, 2005 with errata on November 22, 2005), which can be found here: http://elibrary.ferc.gov/

This well recognized underinvestment in electric transmission infrastructure, coupled with changes in the way the bulk power system is being used due to restructured markets, has resulted in electric transmission constraints and congestion, creating price disparities across states and regions to the detriment of consumers. These transmission bottlenecks prevent efficient, less costly generation and more diverse energy resources from meeting customer needs, raising overall costs. Some of these costs come in the form of "reliability must run" (RMR) contracts to support more costly local generators required to run for reliability reasons (when they otherwise would be uneconomic) because of the inability to access more remote generation, and locational capacity market designs that attempt to compensate for transmission constraints. These are just two examples of how an inadequate transmission network has prevented the benefits of restructuring from being fully realized by customers who are paying hundreds of millions of dollars per year in congestion-related costs.[3] Overall, the US invests in its transmission system at a rate of one-third or less than that of other countries with modern electricity systems and competitive markets.[4] More investment is clearly needed.

Through EPAct 2005, Congress and the Administration supported: modernizing the infrastructure including electric transmission; improving reliability; improving wholesale electricity markets; and attracting new investment, particularly in the electric transmission sector. NIETC designation highlights the national significance of key congested and constrained areas and may help expedite electric transmission investments where state siting processes break down.

Corridor Definition

National Grid has been involved in major electric transmission infrastructure projects around the world. Based on our experience of siting such projects, we support the Department's efforts to identify "corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities."[5] NIETC designation should be broadly defined. Corridors should not be defined based on a facility-by-facility analysis of the current transmission network but should recognize the benefits to customers of new corridors. An NIETC could be between two regions, across a number of states, between energy resources and loads, or between two major cities or load centers within a state.

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idmws/common/opennat.asp?fileID=10887937 ; Comments of National Grid USA, filed in Docket No. RM05-25-000 (November 22, 2005) ("National Grid OATT Reform NOI Comments"), which can be found here: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10887033

[3] "Transmission: The Critical Link, *Delivering the Promise of Industry Restructuring to Customers,*" page 7, National Grid, June 2005.

[4] "Transmission: The Critical Link, *Delivering the Promise of Industry Restructuring to Customers,*" page 19, National Grid, June 2005.

[5] Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, 71 Fed. Reg. 5660 (February 2, 2006).

The Department should not overly prescribe NIETCs based on specific detailed project studies, because a variety of factors or considerations may lead to a different final route designation for a particular project. For example, technical requirements, the state or regional stakeholder process associated with planning and/or siting, or the state environmental or National Environmental Policy Act (NEPA) processes may determine that a modified route would be more robust, cost effective, environmentally sound or socially acceptable (e.g., by avoiding culturally sensitive areas). Therefore, the Department's focus on broad corridors is an appropriate one.

Corridor Designations

Corridors should be broadly defined so as not to choose the specific route of one project developer or entity over another. The Department's role in designating corridors is not to explicitly or implicitly choose a particular project developer; rather it is to identify and designate a geographic area experiencing electric energy transmission capacity constraints or congestion. Moreover, if the Department determines that a corridor is of national significance based on the standards in Section 216 of the Federal Power Act and the criteria adopted by the Department as a result of this Notice of Inquiry (Notice), that corridor should remain designated as an NIETC unless or until the statutory standards and the criteria adopted by the Department no longer that warrant the corridor be designated as an NIETC. For some corridors, the relief of capacity constraints and the reduction of congestion may be accomplished in a few years, where in others it may take several years to resolve. At this juncture, the Department should not try and impose a time limit on the duration of NIETC designations.

EPACT 2005 clearly requires the Department to conduct a congestion study and draw from that study, in addition to the other considerations in Section 216(a)(4)(A-E), and then designate NIETCs. The statute calls for the Department to update the congestion study every three years but is silent on the time frame for designating corridors. National Grid encourages the Department to consider requests for NIETC designation between the triennial congestion studies and to act promptly on those requests. An NIETC designation should not be dependent on the congestion study time frame.

Congestion Definition

The Department asks a series of questions regarding congestion definitions. We encourage the Department to define congestion broadly in order to capture all effects of transmission constraints – including reliability, but also economic impacts. Congestion should be measured over large geographic areas covering multiple states and neighboring regions, as well as intra-state regions, consistent with the Department's proposed broad view of corridors. Along these lines, we respectfully offer the following definition of congestion:

Congestion is primarily a measure of the economic impact on customers of transmission constraints. The calculation of costs due to inadequate transmission should:

- Reflect both energy and capacity payments by customers, and also the effect on reserve costs and other ancillary service costs.
- Measure the costs to customers of barriers to access to both existing and potential supply resources in remote areas.
    - For example, the Frontier Line announced by four Western Governors in April 2005 employed this approach.
- Assess reductions in production costs over a wide-area due to transmission upgrades. Such a "macro approach" to studying the costs to customers of the absence of transmission is currently being undertaken by PJM.
- Determine the costs of congestion to areas experiencing reliability problems due to inadequate electricity supply, which may include a component that accounts for the Value of Lost Load (VoLL).[6]

Congestion Studies

The Department provided a fairly extensive list of studies in the Notice and appropriately is drawing on the exhaustive information available. The Department should not adopt a rigid rule that would preclude the consideration of studies based on their age. While it may be appropriate to consider only the most recent versions of periodic studies, other individual studies may contain useful information for the Department's consideration for a longer period of time. The Department should use judgment to determine whether and for how long a study may be relevant.

National Grid proposes the additional resources listed here:

- *U.S. Department of Energy Transmission Bottleneck Project Report*, Consortium for Electric Reliability Technology Solutions (CERTS), March 2003
- *NY ISO Markets Overview*, NY ISO Environmental Advisory Committee, Nov. 2004
- *2004 State of the Market Report* – New York ISO, Potomac Economics
- *ISO New England 2004 Annual Markets Report*
- *New England 2005 Triennial Review of Resource Adequacy*, ISO New England, Nov. 2005
- *Five Year Statement, 2006-2010*, National Grid, December 2005.

Criteria Development

The new Federal Power Act Section 216(a)(2) authorizes the Secretary of Energy to "designate any geographic area experiencing electric energy transmission capacity constraints or congestions that adversely affects consumers as a national interest electric transmission

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[6] VoLL is a measure of the cost of power outages to customers. The concept is sometimes used as a means of monetizing the value of lower outage probabilities versus the cost of transmission upgrades required to achieve such probabilities. VoLL is typically estimated using a survey approach by customer class and is expressed in $/kwh of power not delivered. Usually the cost estimates are higher for large industrial and commercial customers than for small customers in those classes or for residential customers.

corridor." Section 216(a)(4) lists five considerations that the Secretary may consider in deciding whether to designate an NIETC, the first two of which focus on economic impacts from electric transmission constraints and congestion. Section 216(a)(4) evidences that Congress intended that the Department consider a broad range of factors for the purpose of determining under Section 216(a)(2) whether a geographic area is experiencing electric transmission capacity constraints or congestion that adversely affects consumers.

The Department has correctly outlined broad criteria that may warrant designating a geographic area as an NIETC pursuant to Section 216(a)(2). Each criterion may be a reason for requiring a corridor designation. Each criterion can be a stand-alone basis for finding that a geographic area is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers, warranting an NIETC designation.

While the Department has indicated that any early corridors will only be named where "a particularly compelling case is made that early designation is both necessary and appropriate" and that "severe needs exist," Section 216 of the Federal Power Act clearly does not require congestion or constraints as a prerequisite for a corridor to be named. Section 216(a)(2) provides for two separate bases for NIETC designation. Congress' use of the word "or" in Section 216(a)(2) permits the Department to designate any geographic area experiencing electric energy transmission capacity constraints as an NIETC regardless of whether congestion is also present. The Department should consider both aspects of Section 216(a)(2) for the purpose of determining whether early designation of a corridor is necessary and appropriate.

Draft Criterion 1: Action is needed to maintain high reliability.

National Grid supports Draft Criterion 1: Action is needed to obtain and maintain high reliability. The Department correctly states that "reliability is essential to any area's economic health and future development," and indicates that "an area would be of interest for possible NIETC designation if there is a clear need to remedy existing or emerging reliability problems." Blackouts, such as that of August of 2003, caused economic hardship for entire regions through loss of products in manufacturing and loss of productivity in all industries. In addition to its proposed metric, National Grid recommends that the Department draw on broader metrics, those of the North American Electric Reliability Council (NERC) and NERC Regional Council reliability and planning standards, and those of the future Electric Reliability Organization (ERO), as appropriate. The relevant standards should be those pertaining to transmission capacity constraints or congestion and can include both existing and projected violations.

However, in addition to the metrics listed we recommend that the Department also consider designating NIETCs where "reliability-must-run" (RMR) contracts are required in congested areas. These contracts compensate generators for providing services to ensure compliance with reliability standards even where they are not economic to operate, thus imposing costs on customers. Such contracts are often expensive and are struck with older generation facilities in high population areas to prevent their retirement. Not only do they increase costs to customers, but such facilities are typically significantly less efficient and more polluting than newer facilities located more remote locations.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

Congestion is inherently measured by potential economic savings to consumers. While the Department appears to focus only on retail electric consumers, it is National Grid's view that the differential in wholesale market costs should also be used as a metric. National Grid supports the use of the metrics identified by the Department, with the understanding that "aggregate economic savings" are evaluated for the aggregate of consumers and will include, without limitation, reductions in energy prices, cost of losses, cost of congestion, and payments made to generators to provide capacity, operating reserves or voltage control.

National Grid also supports the Department's proposal to measure customer benefits of reductions in end-market concentrations from transmission upgrades. Market concentration is measurable and can affect customers even if there is no undue exercise of market power. The increased competition brought about by opening otherwise constrained markets is a critical component of the overall value of transmission to customers. Other economic benefits of a more robust transmission system include heightened attractiveness for industrial and commercial investment over wide regions and decreased energy price volatility. National Grid encourages the Department to consider these long-term economic benefits in addition to the relatively short-term benefits and savings already under consideration.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Criterion 3 is in keeping with the requirements in the Federal Power Act (FPA). Congress recognized that reliable electricity is critical for economic development. In load pockets and local regions, reliability-must-run (RMR) contracts are an indication of the need to ease electricity supply limitations and diversify sources. In addition to focusing on load pockets, the FPA points to "end markets served by the corridor" Section (216)(a)(4)(B)(i). End markets with supply limitations include broader regions, such as the Northeast United States and its dependence on natural gas, and states such as California with its need for more power. For broader regions, higher electricity prices, evidence of decreased reliability, and/or projected demand increases may be better metrics. National Grid further suggests that the Department should consider the benefits of enhanced fuel diversity to end market customers that additional transmission may provide. If the Department chooses to adopt a prescribed concentration level of a fuel resource in end markets as part of this or another criterion, the Department needs to be cognizant of resource availability in various parts of the country (e.g., large hydropower in the West).

Draft Criterion 4: Targeted actions in the area would enhance energy independence of the United States.

In EPAct 2005, Congress expressed concern about the United States' dependence on foreign sources of fuel supply. The ability to take greater advantage of indigenous energy resources such as wind and coal will require increased transmission infrastructure as these resources are often located remotely from load. The enhanced ability to link indigenous resources to markets should be one factor in the Department's consideration of corridor designation. However, this criterion, similar to each criterion, is a sufficient but not necessary criterion for designating a geographic area as an NIETC.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

Increased transmission infrastructure investment can help to advance national energy policy. For example to the extent that it is national policy to increase the use of renewable energy resources – whether for reasons of energy independence or concerns about environmental impacts – transmission can provide access to these resources.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

This criterion implements the new FPA provision whereby the Department may consider whether "the designation would enhance national defense and homeland security" Section (216)(a)(4)(E). National Grid agrees that for this criterion, it would be appropriate to look at case-specific metrics. For example, both New York City and Washington, DC, are recognized as critical load centers whose electric reliability must be ensured. This reliability could be enhanced by investment in additional transmission infrastructure and this criterion should be among those considered in designating NIETC.

Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

While National Grid agrees that there is inherent uncertainty in forecasting future needs, the Department should take care that this criterion does not lead to delay in or the failure to designate NIETCs where there is a reasonable likelihood that, as clearly stated in 216(a)(4)(A) of the FPA, "the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity." Because there are uncertainties, sensitivity analyses taking into account load growth, potential generation plant retirements and/or additions, technology advances and congestion should be conducted to assess the likelihood of future transmission constraints. Sensitivity analysis is particularly important because it can take years to plan and build transmission infrastructure and failure to take into account future needs could put major economic and population centers at a severe economic, reliability and security risk. While

National Grid recognizes that there may be concerns that a corridor should not be prematurely designated, the implementation of any particular project in a corridor will be scrutinized at the local, state and federal levels when it is actually proposed, providing assurance that it will not be developed if it is not needed. However, there are regions within the United States with well known projected growth which should not be ignored or dismissed due to an “analytic assumption” test.

Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

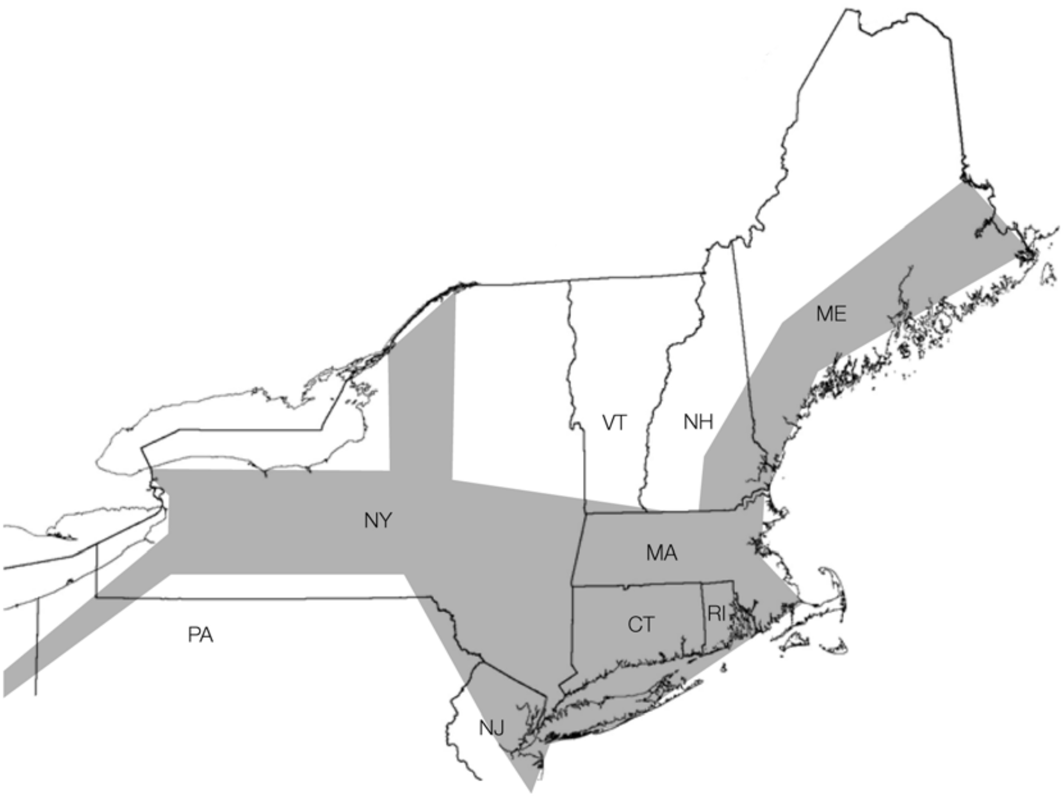
While National Grid understands that the Department is concerned that designation of an NIETC not unduly affect decisions about how to resolve specific congestion problems, we respectfully suggest that this concern should not lead to a requirement that identifying alternative means of mitigating the need in question be part of corridor designation. EPAct has charged the Department with identifying the problem (i.e., congestion), not the solution. The analysis of alternative means of addressing transmission constraints or congestion appropriately takes place in state siting processes or other federal processes, such as NEPA reviews. The Department should not delay designation of NIETCs in the name of exploring or exhausting all options other than transmission first. This would not be in the public interest, nor would it be consistent with the NIETC-related provisions of EPAct 2005. The Department’s role is to designate corridors with congestion problems, not to determine the solutions to these problems. It should not be sidetracked from this responsibility by those who may claim that identifying transmission constraints and congestion somehow predisposes a particular solution.

<u>Significant Potential Electric Transmission Corridors in the Northeast U.S.</u>

National Grid is not proposing any transmission corridors for early designation of NIETC. However, to aid the Department in its considerations, we offer the following analysis of transmission corridors in New England and New York that are potential candidates for designation as an NIETC. Figure 1 is a map with shading to indicate areas where transmission constraints currently exist or may develop. In many cases, projects are already under way to address current congestion, but there are indications of growing future need. The discussion that follows provides some additional detail on the shaded areas.

FIGURE 1

POTENTIAL NATIONAL ELECTRIC TRANSMISSION CORRIDORS IN NEW ENGLAND AND NEW YORK



The corridors are shown as broad geographic paths to illustrate that a strategic transmission corridor is not necessarily a specific transmission line or right-of-way.

While the immediate focus of attention is on corridors that exhibit electric energy transmission capacity constraints or congestion, National Grid believes that it is also important to identify corridors that are of importance from a national interest perspective that are not constrained or congested at the present time. There are two reasons for this:

1. Implementing projects to relieve national interest corridors that currently are constrained or congested may shift power flow patterns on a wide regional basis, and introduce new constraints or congestion on other corridors of national interest.

2. Over time, market forces and regional load and generation development may introduce new constraints or congestion in places where it does not currently occur.

The following table distinguishes between national interest transmission corridors that currently experience significant constraints or congestion and those that do not.

Corridors With Significant Congestion Now	
1: Maine-New Hampshire-Massachusetts Applicable draft criteria include but not limited to: 2 and 8	Transmission constraints between Maine and southern New England limit access to generation in Maine and resources within the Maritime Provinces of Canada as documented in the ISO-NE Regional System Plan 2005 (RSP05). The RSP05 specifically identifies the Maine-New Hampshire interface as limiting access to these resources and as limiting the resource adequacy benefit of any new resources in Maine. Additional limiting interfaces in series with the Maine-New Hampshire interface suggest the need for reinforcements in the corridor from northern Maine into Massachusetts.
2: Boston Applicable draft criteria include but not limited to: 2 and 3	The Boston area is dependent on existing generating resources within Boston due to limited import capability. Although present transmission projects will address existing reliability needs, the ISO-NE RSP05 cites concerns with fuel diversity and out-of-merit generation costs within the Boston area. Future load growth, generation retirements, or fuel supply interruptions could require additional transmission to meet reliability criteria.
3: Southern New England Applicable draft criteria include but not limited to: 1, 2 and 3	The transmission system in Southern New England experiences transmission constraints in Rhode Island, Connecticut, and the Springfield, Massachusetts areas. Limitations on Connecticut import capability that currently result in out-of-merit generation costs are projected to become a reliability issue by 2009 at which time available generation and transmission will no longer be adequate to meet resource adequacy requirements. The ISO-NE RSP05 indicates that the southern New England area would benefit from transmission reinforcements that better integrate the load serving and generating facilities within Massachusetts, Rhode Island, and Connecticut, and enhance the grid's ability to move power from east-to-west and vice-versa.

4: New York City and Long Island Applicable draft criteria include but not limited to: 1, 2, 3, and 5	The transmission path from Albany to New York City and Long Island experiences congestion on a regular basis and New York ISO's December 2005 Reliability Needs Assessment study shows that those areas will fail to meet supply reliability standards by 2008 unless transmission and/or generation developments are implemented. The new York City and Long Island areas consistently are subject to much higher prices for energy and capacity due to transmission congestion.
Other Corridors of Significance	
Corridor 5: Western To Eastern New York State Potentially applicable draft criteria include but not limited to: 3 and 4	The transmission path from the Buffalo/Niagara Falls area in western New York, across New York State through Rochester and Syracuse to Utica is not congested but provides a critical path for the large hydroelectric generation at Niagara Falls into the rest of the State. Between Utica and Albany, congestion sometimes occurs, resulting in higher energy prices in eastern and southeastern New York State. This corridor may become more vulnerable to future congestion as wind generation is developed in western and northern New York State.
Corridor 6: Interconnections with Ontario and Quebec Potentially applicable draft criteria include but not limited to: 2 and 3	In the Niagara Falls and Massena areas interconnections with Ontario provide opportunities for economic exchange of power and mutual assistance for reliability purposes. In the Massena area interconnections with Quebec provide similar benefits.
Corridor 7: Interconnections with PJM Potentially applicable draft criteria include but not limited to: 2 and 3	New York interconnects with the PJM system in several locations in Pennsylvania and New Jersey, facilitating the economic exchange of power and mutual assistance for reliability purposes.
Corridor 8: Interconnections Between New England and New York Potentially applicable draft criteria include but not limited to: 1 and 2	Power is frequently transferred between New York and New England, in either direction, and the two systems provide support to each other for reliability purposes. Forecasted generation developments in New York suggest that this corridor may become more congested in the future.

Conclusion

National Grid commends the Department for taking timely action on the requirements as outlined in the Federal Power Act to conduct a congestion study and identify National Interest Electric Transmission Corridors to assure that the nation has a robust, reliable and secure power transmission grid for the 21st Century. We appreciate the opportunity to offer these comments for the Department's consideration. We look forward to participating in the upcoming technical conference.

41. National Rural Electric Cooperative Association, Received Mon 3/6/2006 3:46 PM

Summary

NRECA offers the following comments in response to the U.S. Departments of Energy's (DOE) Office of Electricity Delivery and Energy Reliability's notice of inquiry on issues relating to a future transmission congestion study and the designation of NIETCs.

NRECA is supportive of DOE's efforts in publishing an electric transmission congestion study and in identifying potential NIETCs where transmission congestion impacts the ability of electric cooperatives to reliably and economically provide electricity to their member consumers. Transmission congestion continues to prevent some of NRECA's member electric cooperatives from being able to reach lower cost generation resources to serve their member consumers. This is potentially true with regard to areas where transmission needed to meet the reliability and long-term economic needs of load-serving entities (LSEs) has failed to materialize, thus continuing or increasing the market power of incumbent suppliers.

The designation of NIETCs may help to increase the speed at which new transmission facilities are constructed and placed into service, thereby providing electric cooperatives with additional opportunities to reach lower cost power supply. Until the transmission system is greatly expanded, the full benefits of wholesale competition cannot be realized by many load-serving entities (LSEs), including the nation's 930 electric cooperatives. NRECA looks forward to working closely with DOE on these important initiatives.

Congestion Study

Question 1 – *Should the Department distinguish between persistent congestion and dynamic congestion, and if so, why?*

DOE should recognize that there is a difference between persistent congestion and dynamic congestion, but the characterization of congestion as one type or the other should not disqualify a path from designation as an NIETC.

Persistent congestion is congestion that repeatedly occurs and is expected to continue over the long-term if not addressed. Persistent congestion that restricts LSEs from reaching lower cost power supply options is indicative of a problem that is not being addressed – transmission facilities are not being added to the grid to help address known and ongoing reliability and economic concerns.

Dynamic congestion may vary in location, magnitude or duration depending on infrequent events. While dynamic congestion is typically short-term in nature and not necessarily predictable, it can have impacts as great as, or even more severe than, persistent congestion. For example, dynamic congestion could cause an extreme increase in power supply prices for LSEs with limited access to generation resources, or deny LSEs access to long-term generation assets when that access is most needed.

Because both types of congestion can impact the ability of electric cooperatives and other LSEs to provide reliable and economic electricity to their consumers, both types of congestion should be considered in the designation of NIETCs.

<u>Question 2</u> -- *Should the Department distinguish between physical congestion and contractual congestion, and if so, how?*

DOE should distinguish between physical congestion and contractual congestion. Relief of physical congestion may require actions including the construction of transmission or generation facilities, or other actions. Relief of contractual congestion is not as clearly identifiable as the potential remedies for relieving physical congestion. While distinguishing between physical and contractual congestion is beneficial in helping to determine the appropriate actions to provide congestion relief, it is critically important to recognize that both can harm LSEs' ability to serve their consumers, and so both should be considered in the designation of NIETCs.

<u>Question 3</u> -- *What existing, specific transmission studies and other plans should the Department review (in addition to those listed in Appendix A)? How far back should the Department look when reviewing transmission planning and path flow literature?*

DOE should review studies conducted by the North American Electric Reliability Council's (NERC's) regional reliability councils, ISOs, RTOs, interregional study groups, and individual transmission owners. These entities have much of the needed data and planning information to study and analyze the transmission systems in their respective areas. Further, these entities should be aware of the transmission constraints in their region that exist today and where future transmission constraints will likely materialize.

In order to develop an adequate record on persistent congestion, NRECA recommends reviewing studies that represent at least the last 10 years in order to quantify the long-term nature of the persistent congestion. NRECA recommends reviewing studies from the last 5 to 10 years for dynamic congestion problems.

Question 4 -- *What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?*

The categories of information that would be helpful to incorporate into congestion studies include: NERC and regional reliability assessments, quantification of the magnitude and duration of long term firm transmission service denials, TTC and ATC values, historical LMP prices between various resource and load areas, Annual RTO/ISO State of the Market Reports, and data regarding the direction and amount of transfers between areas.

Criteria Development (only those with specific comments are addressed here)

Draft Criterion 1: *Action is needed to maintain high reliability.*

NRECA supports the description and metrics of Draft Criterion 1.

Draft Criterion 2: *Action is needed to achieve economic benefits for consumers.*

NRECA strongly supports the inclusion of Draft Criterion 2 and recommends that DOE not only focus on the aggregate economic impacts to consumers in a geographic area or market, but also focus on the impacts on consumers for particular loads and LSEs that are located in load pockets with limited transmission options to reach lower cost power supply. An aggregate view may not identify the serious economic impacts of a congestion problem if the consumers that are impacted represent a small subset of those included in the aggregate view.

NRECA opposes the artificial division of transmission problems into those that are "economic" or "reliability." Rather, NRECA believes that congested transmission corridors that make it more difficult for LSEs to serve their consumers reliably or economically should be considered for NIETC designation.

Draft Criterion 3: *Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.*

NRECA supports the description and metrics of Draft Criterion 3.

Draft Criterion 6: *Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.*

NRECA supports the description and metrics of Draft Criterion 6.

Draft Criterion 7: *The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions.*

NRECA supports the description of Draft Criterion 7 and recommends that the uncertainties described be addressed on a case-by-case basis.

Draft Criterion 8: *The alternative means of mitigating the need in question have been addressed sufficiently.*

Of course, NRECA believes that due diligence requires multiple options be considered to resolve any problem. Nevertheless, NRECA is concerned that this criteria is intended to require DOE to formally consider generation or demand response alternatives to transmission before designating an NIETC.

NRECA believes that requiring a formal process to consider these alternatives – or worse, to require a period of time during which market participants could offer generation or demand response alternatives – would unnecessarily and unreasonably slow down the designation process. Moreover, it inappropriately presumes that generation and demand response are perfect substitutes for transmission. That is not the case.

Demand response is an excellent tool for load shaping and for responding to immediate operational problems or short-term market volatility. Demand response can allow utilities under the right circumstances to avoid or delay investments in peaking resources. Demand response, however, is not a base load resource. Nor can it provide a long-term solution to long-running congestion, reliability, or market power problems

New generation constructed in a load pocket is also unlikely to provide a long-term solution to long-running congestion, reliability, or market power problems. If a new generator is constructed in a load pocket by the same entity that owns the existing generator, you have not solved the market power problem at all. If a competitive supplier builds generation in a load pocket, you may move only from a monopoly to a duopoly. In neither case are you giving the consumers in the load pocket free access to a broader electricity market. Neither are you giving system operators the full range of control options for maintaining reliability that could be obtained with new transmission.

DOE should recognize that transmission is not a commodity that should be asked to compete with generation and demand response. Rather, it is an enabler, a critical tool to allow the wholesale electricity market to operate. Particularly in light of the much longer planning horizon required to build transmission, the industry must plan and build a robust transmission infrastructure or highway system, that then enables those who are planning and investing in generation and demand response to make good decisions in the shorter term.

Additional Question 1 -- *Are there other criteria or considerations that the Department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider* *suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.*

The Department should recognize that over time, new metrics may develop as the industry evolves and any process established to designate NIETCs should be flexible to adjust to changing conditions.

Additional Question 2 -- *Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?*

Electric cooperatives' primary focus is on providing reliable electric service to its member consumers at the lowest reasonable cost. Therefore, NRECA recommends that DOE treat both reliability and economic impacts from transmission congestion as equally important in the designation of NIETCs.

Conclusion

NRECA looks forward to working closely with DOE on the critically important issues related to the reliability and economic impacts of transmission congestion.

Respectfully Submitted,

/s/

David L. Mohre
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March 6, 2006

42. Nevada State Office of Energy, Received Mon 3/6/2006 5:53 PM

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March 6, 2006

Mr. Kevin Kolevar, Director
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
US Department of Energy
Washington, DC

FILED VIA E-MAIL

Re: Comments by the Nevada State Office of Energy

Dear Mr. Kolevar:

Please find the following comments from the Nevada State Office of Energy regarding the Transmission Congestion Study and the Designation of National Interest Electric Transmission Corridors.

Nevada looks forward to working with DOE on the implementation of EPACT 2005.

Rebecca Wagner
Director, Nevada State Office of Energy
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rdwagner@gov.state.nv.us

Comments of the Nevada State Office of Energy regarding The US Department of Energy's Notice of Inquiry Regarding National Interest Transmission Corridors

The Nevada State Office of Energy (NSOE) respectfully submits these comments in response to the notice of the US Department of Energy (DOE) regarding "Considerations for Transmission Congestion Study and Designation of National Interest Corridors".

The NSOE appreciates the cooperative approach DOE has taken thus far in the implementation of Section 1221 of the Energy Policy Act of 2005. The NSOE is located within the Office of the Governor and is responsible for implementing energy policy in Nevada. Fundamental elements of Nevada's energy policy include supporting and encouraging a reliable, affordable and sustainable supply of electricity and natural gas as well as diversifying the electrical supply.

It is clear that the development of both intrastate and interstate transmission systems is critical to implementing Nevada's energy policy. Many of the State's renewable resources have not been developed since they are located in remote areas that lack transmission. With a very aggressive renewable portfolio standard, the need to improve intrastate transmission is of critical importance. Additionally, Nevada is the fastest growing state in the nation and access to affordable generation via a reliable, regional transmission system is also of critical importance.

The implementation of Section 1221 has reached a critical stage, which is the development of criteria by which the Secretary may designate National Interest Electric Transmission Corridors (NIETC).

The NSOE would like to make two general recommendations with regard to the implementation of Section 1221 as it relates to Nevada. Specifically, NSOE recommends that DOE make no final decision on criteria for designating NIETC until: (1) there is a clear process for coordinating NIETC designation with the designation of energy corridors on federal lands and, (2) DOE and the Federal Energy Regulatory Commission (FERC) have established rules and procedures to implement Section 1221 in its entirety.

It is important to note that over 80 percent of Nevada is owned by the federal government. As such, the designation of energy corridors on federal lands is of particular interest to Nevada.

To the greatest extent possible, both the criteria for designating NIETCs and the designation of NIETcs should align with criteria used to designate energy corridors on federal lands. DOE should explain how the criteria for designating NIETCs comport with the criteria that the Departments of Energy, Interior, Agriculture, Commerce and Defense are using to designate energy corridors of federal lands under Section 368. DOE should also explain how the designations of energy corridors under Section 368 are to be coordinated with DOE's designation of NIETCs.

The FERC backstop authority is also an area concern in Nevada. The final process and procedure should explain how all required federal permits and actions will be completed on a schedule consistent with the one-year siting/permitting time limit imposed on states. It is unproductive to limit state review to one year if federal permits cannot be obtained on the same schedule. It is important that DOE adopt rules clarifying that the one-year clock begins only after the state has received a complete application. DOE should not attempt to define a complete application, because no single definition will work for all states. DOE should encourage state regulators and transmission developers to work together to prevent abuse by either.

The NSOE generally supports the proposed criteria and has no further comments to offer.

43. New York Designated Transmission Owners, Received Mon 3/6/2006 2:18 PM

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March 6, 2006

Ms. Poonum Agrawal
Office of Electricity Delivery and Energy Reliability, OE-20
Attn: EPACT 1221 Comments
U.S. Department of Energy
Forrestal Building, Room 6H-050
1000 Independence Avenue, SW
Washington, DC 20585

Re: Response of the New York Designated Transmission Owners to Notice of Inquiry in Connection with the Electricity Transmission Congestion Study Required by Section 1221(a) of the Energy Policy Act of 2005

Dear Ms. Agrawal:

Consolidated Edison Company of New York, Inc., LIPA, New York Power Authority, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (referred to herein as the "New York Designated Transmission Owners") respectfully submit these comments for your consideration in connection with the electricity transmission congestion study required by Section 1221(a) of the Energy Policy Act of 2005 ("EPAct 2005").[1]

Background

On January 27, 2006, the Department of Energy ("DOE") issued a Notice of Inquiry ("NOI") seeking comment and information from the public concerning its plans for an electricity transmission congestion study and the possible designation of National Interest Electric Transmission Corridors ("NIETCs") in a report based on the study. The report and study are required pursuant to Section 1221(a) of EPAct 2005, which amended the Federal Power Act ("FPA") by adding a new Section 216 which requires the Secretary of Energy ("Secretary") to conduct a nationwide study of electric transmission congestion and issue a report based on the study, within one year of the enactment of EPAct 2005. In such report, the Secretary may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as an NIETC."

[1] The New York Designated Transmission Owners are comprised of six of the eight electric systems in the State of New York that own the transmission facilities operated by the New York Independent System Operator, Inc. ("NYISO"). The NYISO commenced operations under the Open Access Transmission Tariff ("OATT") and Market Administration and Control Area Services Tariff ("Services Tariff") on November 18, 1999. The New York Designated Transmission Owners are owners of the transmission facilities operated by the NYISO and recover their costs of operating those facilities under the NYISO OATT and Services Tariff.

In conducting the initial electric transmission congestion study, the DOE intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity could lessen potential adverse effects borne by customers. *See* NOI at 6-7. To assist the DOE in conducting and preparing its electric transmission congestion study, as well as identifying areas potentially suitable for designation as an NIETC, the DOE requests comments on the following questions:

- Should the DOE distinguish between persistent congestion and dynamic congestion and, if so, how?

- Should the DOE distinguish between physical congestion and contractual congestion and, if so, how?

- What existing, specific transmission studies and plans should the Department review (besides those listed in Appendix A)? How far back should the DOE look when reviewing transmission planning and path flow literature?

- What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

See NOI at 8. In addition, the DOE seeks comment on the eight proposed criteria developed in order to evaluate geographic areas identified in the congestion study as candidates for NIETCs. *See* NOI at 9.

Comments

Congestion Study

The New York Designated Transmission Owners appreciate the opportunity to provide comments to the DOE on the nature of any distinctions among the various types of congestion, and also submit that the DOE must carefully define "congestion" when conducting this study. As the NOI provides, congestion can be defined in a number of ways, and the DOE should strive for consistency in its study. The New York Designated Transmission Owners caution the DOE when studying the costs of congestion because the metrics used: (1) are highly variable; and (2) differ among markets.

For example, in the NYISO, the cost of congestion reported in the past was the simple sum of the Day-Ahead Market ("DAM") Locational Marginal Price ("LMP") congestion component times the amount of load being affected (positively or negatively) by congestion. But recently, the NYISO has undertaken considerable examination of the congestion issue and it concluded that this simple definition did not adequately portray the correct meaning of congestion. This level of congestion was potentially also an unfair indication of a congestion issue that would warrant NIETC designation.

The NYISO now defines congestion costs in its LMP market through four metrics, which report the difference between a constrained and an unconstrained value:

1. The change in production cost, which is a comparison of the total production cost, based on mitigated bids, with and without transmission constraints that limit the unit commitment and dispatch. It measures the economic inefficiency introduced by the existence of transmission bottlenecks, and is thus treated as the *societal* cost of transmission congestion;

2. The change in congestion payments, which is the sum of the LMP congestion component times the load affected. This metric ignores the change in the costs of energy as constraints are removed, and it can be adjusted to account for any hedging. This is treated as the *accounting* cost of congestion;

3. The change in generation payments with and without transmission constraints; and

4. The change in load payments with and without transmission constraints. This calculation uses simulation to include the local energy cost response when transmission constraints are removed.[2]

The NYISO Operating Committee uses the first metric, the change in production cost, as its primary congestion impact metric, since it is consistent with the minimization function in the algorithms in its unit commitment and dispatch programs. An advantage of this metric is that production cost will always decrease when constraints are removed.

In its NOI, the DOE appears to view congestion in a manner similar to the fourth metric, the change in load payments. While the first congestion metric measures efficiency, this fourth metric determines how much more New York load actually pays due to congestion. The NOI provides that the DOE intends to identify geographic areas where transmission congestion is significant, "and where additions to transmission capacity (or suitable alternatives) could lessen potential adverse effects borne by consumers." NOI at 6-7. Further, Draft Criterion 2 is that "[a]ction is needed to achieve economic benefits for consumers." *See* NOI at 10. While this language is similar to the view of congestion in the NYISO's fourth metric, it is unclear if this similarity is intended by DOE. Further, there are limitations in applying the fourth metric alone. The New York Designated Transmission Owners recommend that DOE focus congestion measurements to physical metrics, such as the percent of time that the market is congested.

Further, in areas of the country where there are no centralized markets, it will be difficult and potentially misleading to calculate the financial costs of congestion. Even among centrally-controlled LMP markets, the definition of congestion will differ. For example, as noted above,

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[2] *See* Congestion Cost Metrics, available on the NYISO internet site at: http://www.nyiso.com/public/webdocs/services/planning/congestion_costs/misc/congestion_metrics_042505.pdf.

the NYISO uses day-ahead data to calculate the cost of congestion.[3] On the other hand, PJM Interconnection LLC uses real-time data to calculate gross congestion for each congested facility on a monthly basis.[4] In the Midwest ISO, the cost of congestion is calculated as the difference of the marginal congestion component of LMP at the sink and the marginal congestion component of LMP at the source.[5] Additionally, each of the existing ISO/RTO markets has, or is developing, different methods of pricing energy, capacity, reserves, transmission line losses, and allocation and pricing of Financial Transmission Rights ("FTRs").[6] In some cases, these differences may indicate congestion that exists solely because of the different pricing methods, rather than as a result of actual congestion issues that need to be resolved. The DOE should recognize these differences, and consider that some apparent congestion may be resolved by addressing seams issues, and therefore may not warrant designation as a NIETC for siting purposes.

Not all congestion can be relieved economically with investments such as transmission upgrades or other alternatives. The NYISO has concluded that, while individual constraints may be relieved with new transmission investment projects, there are often additional underlying constraints that remain. Parties must be careful to perform appropriate cost-benefit analyses prior to embarking upon transmission construction, or any other investment for that matter, as a means to relieve congestion. Any analysis of proposed projects must also include impacts on the operating procedures and area-wide design criteria necessary to meet reliability needs.

In the NOI, DOE seeks comment on whether it should distinguish between persistent congestion and dynamic congestion. While it is not entirely clear what DOE means by "dynamic congestion," the New York Designated Transmission Owners wish to indicate that such a distinction is useful. Dynamic or temporary congestion that results from a temporary outage, for example, should not result in designation as an NIETC, since it is unlikely that a project to resolve such congestion will be proposed, or is necessary or beneficial to customers.

In addition, the DOE seeks comment on whether it should distinguish between physical congestion and contractual congestion. Physical congestion equates to congestion in the RTM, while contractual congestion equates to such congestion in the DAM. The NYISO has chosen to calculate congestion using bid prices in the DAM, since most of the NYISO's financial business is conducted in this market. Further, in this market, participants have the opportunity to manage energy supply costs, including congestion, with the use of FTRs. Market participants purchase such rights, and the revenues are provided to transmission owners to offset transmission costs to all consumers. As such, when considering NIETC designation, DOE should examine the

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[3] *See id.*

[4] *See* Regional Planning Process Working Group presentation (Sept. 1, 2005), available on the PJM internet site at: http://www.pjm.com/committees/working-groups/rppwg/downloads/20050901-rppwg-presentation.pdf.

[5] *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,235 at n.11 (2004).

[6] FTRs are called Transmission Congestion Contracts ("TCCs") in the NYISO market and provide the same congestion hedge product as FTRs.

existence of congestion where FTRs are available, with the suggestion that such designation may not be necessary when customers are not financially harmed by such congestion.

It is unclear from the NOI whether the DOE intends to estimate forecasted congestion or rely on historical congestion. While the ability to provide estimates of forecasted congestion is more valuable for market participants, such estimates are dependent on many factors, including future fuel costs, load growth assumptions, asset additions and retirements, and the availability of generation. The calculation of historical congestion would be more reliable and, as such, the New York Designated Transmission Owners submit that reports of historical congestion would in fact be more beneficial.

To conclude, the New York Designated Transmission Owners recommend that the DOE focus on physical congestion to identify potential corridors with a broad view. Further, the DOE should avoid any project-specific analyses or proposals. Existing ISO or proposed inter-ISO planning processes[7] should handle the analysis of specific projects, allowing willing buyers and sellers to decide which projects are needed, with a backstop process for those required projects that have not been willingly proposed. All such projects located in an area designated as an NIETC would be eligible for backstop federal siting as provided in EPAct 2005.

Respectfully submitted,

/s/ Elias G. Farrah by MR
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[7] Wherever such planning processes are developed through stakeholder processes, or already exist and have been approved by FERC.

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44. New York Regional Interconnection, Inc., Received Mon 3/6/2006 4:33 PM; Addended Thu 3/9/2006 10:28 AM

Dear Sir or Madam:

New York Regional Interconnect, Inc. ("NYRI") submits these comments in response to the Notice published in the Federal Register on February 2, 2006 by the Department of Energy ("Department"), Office of Electricity Delivery and Energy Reliability. (Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, 71 Fed. Reg. 5660 [February 2, 2006]). The Department has requested comments concerning its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETC") pursuant to Section 1221 (a) of the Energy Policy Act of 2005 ("Act"). The Department also invited parties to identify areas in which there is a "particularly acute need for early designation as NIETC."

NYRI requests that the Department designate as a NIETC a transmission corridor in New York state from the Edic substation in Marcy, Oneida County to the Rock Tavern substation in New Windsor, Orange County. The end markets that will be served by this corridor already experience the effects of constraints that result in a lack of adequate and reasonably priced electricity. Moreover, because of the need date for additional resources to serve these end markets, it is crucial for this corridor to be designated as a NIETC as soon as possible so that the needs of these end markets can be met.

I. Correspondence and Communication

Correspondence and communication regarding these comments should be directed to:

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II. Description of NYRI

NYRI is a privately owned corporation organized under the laws of the State of New York, including the New York Transportation Corporations Law, for the purpose of developing, constructing and operating transmission assets that allow for the provision of non-discriminatory access to the energy markets in New York. NYRI is not affiliated with any other New York energy company and does not own any generation, existing transmission or distribution assets in New York.

NYRI's core concentrations are to enhance reliability and to offer transportation products that will improve market efficiencies for stakeholders in the New York electricity markets. The NYRI Project is nominally a 1200 MW HVDC transmission facility that is planned to interconnect entirely within the New York Control Area between Edic substation in Marcy, New York and Rock Tavern substation in New Windsor, New York. The end market that will be served by this transmission facility is southeastern New York, one of the most highly constrained, high priced electricity markets in the U.S. It is NYRI's intention to: complete the permitting, construction, commissioning and operation of a proposed new transmission facility that will improve the reliability and security of the New York Bulk Power Transmission System; operate the proposed transmission facility so as to enable continued market development and increased competition; provide access for ratepayers and load serving entities seeking a more diversified supply base of technologies and fuel sources and for generators seeking to offer their energy products to deep load pockets; facilitate sustainable improvements in air quality; and provide reliability enhancements that will reinforce and stabilize the interconnected AC transmission system.

NYRI has been actively developing its proposed transmission facility for more than 3 years. This transmission project initially obtained a position in the New York Independent System Operator ("NYISO") interconnection project queue in August, 2001. In addition, NYRI secured site control for a portion of the proposed transmission route in 2003. Since that time NYRI has filed its interconnection application with the NYISO and executed a feasibility study agreement with the NYISO and the two interconnected Transmission Owners. More recently, in February, 2006, NYRI submitted its solution response to the NYISO's solicitation for needed reliability solutions in the NYISO's Reliability Needs Assessment. And, in May of this year, NYRI will file an application for a Certificate of Environmental Compatibility and Public Need for the transmission facility pursuant to Article VII of the New York Public Service Law.

III. DISCUSSION

A. NYRI's Proposed Corridor Should be Designated as a NIETC

Under section 1221(a) of the Act, (section 216 of the Federal Power Act, 16 U.S.C. section 824p), the Secretary of Energy may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." In exercising authority to designate a NIETC, the Secretary may consider, among other things, whether, "the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity." (Section 216 [a][4]).

The corridor proposed herein for early designation as a NIETC will result in additional transmission resources between New York Independent System Operator ("NYISO") Zone E and NYISO Zone G. There is no dispute that the end markets to be served by this proposed corridor, NYISO Zones G-K, are now, and are expected to continue to be, constrained in the near future by lack of adequate and reasonably priced electricity.

In its Transmission Bottleneck Project Report, dated March 19, 2003 ("Bottleneck Report"), the Department stated that "congestion in the U.S. electricity transmission system places daily constraints on electricity trade increasing both electricity costs to consumers and impacts reliable operations." (Bottleneck Report at 5.) In that report, three major bottlenecks in New York were identified: (1) flows from Western New York to Central East; (2) flows from North to South in eastern New York (Leeds to Pleasant Valley); and (3) flows from Pleasant Valley to cables feeding New York City and Long Island. (Id. at 10.) These constrained interfaces limit the amount of power that can flow from generating resources in the western part of New York, Canada and other regions into southeastern New York, including New York City, the largest load center in the Northeast.

The constraints both jeopardize reliable service in Southeastern New York ("SENY") and limit the flows of less expensive power into SENY and, thus, constrain the economic vitality of the end markets to be served by NYRI's proposed corridor.

1. Existing Transmission Constraints Jeopardize Reliable Service in SENY

In its Comprehensive Reliability Planning Process, Reliability Needs Assessment ("RNA") dated December 21, 2005, the NYISO concluded that SENY, defined as load zones G-K, may experience a resource adequacy criterion violation as early as 2008. (A copy of the December 21, 2005 RNA is available at www.nyiso.org/public/webdocs/newsroom/press_releases/2005/rna_final12212005.pdf) In the RNA, the NYISO found that:

> The New York State bulk-power baseline system for the first Five Year period (2005-2010) indicates that the forecasted system does not meet reliability criteria. Therefore, because of continued load growth and no resource additions, the second Five Year period does not meet reliability criteria. Load growth in excess of two percent per year which totals 5,000 MW in SENY, defined as load zones G-K, with the minimal addition of 1250 MW of net new generating capacity in that area over the last ten years, has led to increasing dependence on the transmission system to meet capacity and energy needs in SENY. The demands that are increasingly being placed on the transmission system in conjunction with other system changes, consisting primarily of generating unit retirements listed in table 1, neighboring system changes, and load growth have and will continue to result in voltage criteria violations at much lower transfer levels than had previously been observed. The result is that transfers into SENY will be limited by voltage constraints rather than thermal constraints. This reduced capability to make power transfers to SENY due to these voltage constraints, coupled with continued load growth in SENY results in a resource adequacy criterion violation as early as 2008.

(RNA at 4-5.)

The New York State Power System is planned to meet a loss of load expectation ("LOLE") that is less than or equal to an involuntary load disconnection that is not more than once in every 10 years or 0.1 days per year. In the RNA base case, the LOLE for NYISO Zone J (New York City) increases to 2.4 days per year in 2010, well above the 0.1 days per year considered acceptable by the NYISO. (Id. at 5). According to the NYISO, the additional generation needed to meet the 0.1 days per year LOLE reliability criterion for the New York Control Area in 2010 is 1,750 MW. This includes 250 MW in NYISO Zone I, 1250 MW in

NYISO Zone J, and 250 MW in NYISO Zone K. (Id. at 6.) The need for additional generation in SENY increases to 2,250 MW in 2015.

Consolidated Edison Company of New York, Inc. ("Con Edison") also has performed its own System Reliability Assurance Study, dated December 30, 2005 ("SRAS"), to, in part, determine the supply and demand resource options that may be needed to meet system demand, particularly in New York City, during the 10 year period from 2006-2015. While the Con Edison SRAS determined that the need for additional generation capacity in New York City was both later and less than in the NYISO RNA (Con Edison claims that NYC will need 118 MW in 2012 increasing to 672 MW in 2015) the Con Edison study concludes that, within SENY, the lower Hudson Valley need will be 430 to 770 MW in 2010 increasing to 2,508 MW in 2015. (Con Edison SRAS at 8, Figure ES-2. NYRI will provide a copy of the Con Edison SRAS to DOE upon request.)

Thus, the two most recent studies performed to determine electric system adequacy and reliability in New York State have determined that additional resources are needed in SENY in the near future. This serious need for additional capacity in SENY cannot be met through the existing transmission assets. The transmission interfaces into SENY are limited by both voltage and thermal constraints. According to the NYISO, the ability to transfer power into SENY will be significantly limited by voltage constraints in the Lower Hudson Valley unless corrective actions are taken. (RNA at 6.) With respect to thermal constraints, the import capability from Upstate New York to SENY is 4900 MW (RNA, Appendix at 17) and the import capability into NYISO Zone J (New York City) is 5,320 MW. (NYISO, Locational Installed Capacity Requirements Study, February 9, 2006 at 5; available at www.nyiso.com/public/webdocs/services/planning/resource_adequacy/2006_lcr_report.pdf) Clearly, transmission constraints of existing transmission resources significantly limit the ability to meet reliability needs in SENY.

The economic vitality and development of the end markets served by the corridor proposed by NYRI for designation as a NIETC will be constrained by lack of adequate electricity resources. As the Department states in the NOI, "[m]aintaining high electricity reliability is essential to any area's health and future development." (71 Fed. Reg. 5661.) With respect to SENY, the end market served by this corridor, the NYISO projects that unless corrective action is taken, the loss of load expectation in New York City Zone J in the year 2010 will be 2.4 days per year, well in excess of the 0.1 days per that is defined as adequate. The demonstrated reliability need in SENY meets the requirement of the Act for designation of a NIETC to address this need.

2. Existing Transmission Constraints Limit the Flow of Less Expensive Power into SENY

The Act also permits the Secretary to designate a corridor as a NIETC if the end markets to be served by the corridor may be constrained by lack of reasonably priced electricity. (Act at

Section 1221 [a][4][A].) The same constraints that result in the economic vitality of SENY being constrained by lack of adequate and reliable electricity, also prevent more reasonably priced electricity from flowing into this market.

The fact that transmission constraints prevent the flow of more reasonably priced electricity into SENY has long been recognized by the NYISO. In its Power Alert III Report, dated May, 2003, the NYISO stated:

> Since operations of NY wholesale electricity markets began in December 1999, the NY market has incurred $2.75 billion dollars in congestion cost. ... This level of congestion indicates there is significant potential to reduce system congestion cost by increasing the transfer capability between Marcy and Pleasant Valley and into the New York City and Long Island load pockets.

(NYISO, Power Alert III, May, 2003 at 35.)

The DOE has recognized that a large part of the congestion costs within the state of New York are caused by transmission constraints that limit the amount of power that can flow into SENY. (See Bottleneck Report 52.) As a result of this congestion, residential, commercial and industrial customers in that region have been charged hundreds of millions of dollars more each year for power as higher cost resources in the southeastern region are dispatched. According to DOE's own analysis, the estimated congestion costs resulting from the constrained areas into southeastern New York (which correspond with the Central-East interface) in 2000 alone were $784 million. Projected congestion costs for the entire New York control area in subsequent years are similarly high. The NYISO projected that statewide congestion costs in 2006 would be $481 million. This amount remains a significant drain on the New York markets. (Id. at 52.)

3. The Proposed Transmission Corridor Will Alleviate the Existing Constraints

As stated above, NYRI requests that DOE designate as a NIETC a corridor between National Grid's existing Edic substation in Marcy, Oneida County, New York and Central Hudson Gas & Electric's existing Rock Tavern substation in New Windsor, Orange County, New York. (The proposed corridor is shown on the map attached as Exhibit A.) This path traverses the major transmission constraints in New York that are described above. (The major transmission constraints in New York are shown on the map attached as Exhibit B.) If designated as a NIETC by DOE, the corridor would represent an optimal location for additional transmission facilities that could relieve current transmission constraints.

This corridor will provide a new transmission path between a point at which existing generation is available and a point at which there is an increasing need for new generation resources that cannot be met through existing transmission assets. The northern point of the corridor, the Edic substation, is west of the constrained Central-East and North-South interfaces, thus there are no transmission constraints into Edic. In addition to being an access point to existing excess generation capacity that exists in upstate New York, Edic provides access to generation in the PJM, ECAR, and Ontario Hydro and Hydro Quebec systems. It also is important to note that the Edic point provides access to the large amount of renewable power that is on line and in development in areas north and west of SENY and it provides access to many different fuel technologies.

The southern point of the proposed corridor, the Rock Tavern substation owned by Central Hudson, is within the end market that is constrained by the lack of transmission resources into SENY. Importantly, NYRI has determined that a new transmission interconnection from Edic to Rock Tavern will in fact alleviate both the adverse reliability and economic disparity issues that exist in the current system.

According to a report produced by General Electric Energy for NYRI using GE Energy's proprietary MAPS software, a project like NYRI's proposed transmission facility would provide economic benefits to New York electricity consumers by reducing the cost to serve New York load by $421 million per year, or roughly 3%.[1] Additional transmission capacity along the proposed corridor also would offer significant economic benefits by reducing the state's reliance on expensive must-run generation. Economic benefits also would accrue to other New York market participants by allowing them non-discriminatory access to additional transmission capacity connected to the load centers in southeastern New York.

NYRI's proposed transmission facility also would address reliability concerns by increasing the amount of transmission capacity available to deliver power from new or currently underused generation into southeastern New York. The additional transmission capacity will only improve reliability in the state by ensuring that adequate resources can reach demand centers. As discussed in NYRI's GE Report, the expected reliability benefits from NYRI's proposal are estimated to be $43 million per year.

The NYISO also expressed concerns that the "ability to transfer power into [southeastern New York] will be significantly limited by voltage constraints in the Lower Hudson Valley (LHV) unless corrective actions are taken." (RNA at 6.) NYRI's proposal to construct new transmission facilities along the proposed corridor would address these voltage concerns. NYRI estimates that the project will deliver up to 300 MVARs of supplementary reactive power support (in addition to its own reactive load requirements) to the system at Rock Tavern. The NYRI project would also provide the NYISO with the ability to precisely control power on the HVDC line, improving the interconnected system's stability and steady state voltage performance.

[1] The GE Report is not attached to this filing because it contains proprietary, trade secret information that cannot be disclosed to the general public.

A designated transmission corridor is the most efficient means of addressing the economic and reliability concerns identified by the NYISO. New large scale generation projects within SENY, to meet the reliability needs of this region within New York state, are at best speculative. Article X of the New York Public Service Law, which had streamlined the permitting process for major electric generating facilities, defined as facilities with a generating capacity of 80 MW or more (NY Public Service Law section 160 [2]), expired on January 1, 2003 and has not been reenacted. In the absence of Article X or a similar generation siting statute, the ability to site and permit a generating facility in New York will continue to be severely limited. Indeed, NYRI is aware of only one baseload generating project in New York that has sought certification since the expiration of Article X. Furthermore, because the need for additional generation to meet reliability criteria that has been identified by the NYISO exists in SENY, one of the most densely populated and highly urbanized areas in the United States, certification of a new generating facility in that geographic area to meet this requirement is even more unlikely.

However, there is existing generation capacity within the NYCA that could address the reliability needs in SENY identified by NYISO and Con Edison. In 2006, the existing generating capacity in NYISO Zones A-F is 19,301 MW (NYISO, Locational Installed Capacity Requirements Study, February 9, 2006 at 5.) Peak load in 2006 in Zones A-F is projected by the NYISO at 12,609 MW (Id.) As such, according to the NYISO, there is almost 6,700 MW of existing generating capacity in Zones A-F that is not needed to meet peak load in those zones.

The corridor proposed by NYRI as a NIETC would allow the large amount of existing capacity in Zones A-F, as well as capacity in PJM, ECAR, OH and HQ, to reach the SENY zones and alleviate the economic and reliability issues identified by the NYISO. Accordingly, designation of NYRI's proposed corridor is a practical and efficient solution to the constraint that exist in the SENY end market.

NYRI is aware of DOE's statement in the NOI corridors proposed for NIETC status be for a "generalized electricity path between two locations, as opposed to specific routes for transmission facilities." (71 Fed. Reg. at 5661). Accordingly, NYRI requests for designation as a NIETC a corridor between the Edic substation and the Rock Tavern substation. However, the route proposed by NYRI is the shortest reasonable distance between these two locations. A route between the two points that is further east than the route proposed by NYRI would encounter the Catskill Park and the existing Marcy South transmission facility. The other potential route involves running east to Albany and then south to SENY a route that likely would need to parallel the New York State Thruway to Albany and then run south along the thruway, existing railroad lines and/or the Hudson River. This route also is impractical compared to NYRI's proposed route.

B. Early Designation of The Proposed Corridor is Necessary and Appropriate

In the NOI, the Department invited parties to identify transmission corridors for which there is a particularly acute need for early designation as a NIETC. (71 Fed. Reg. at 4.) There are a number of reasons why early designation is necessary and appropriate here. First, studies by an independent transmission operator (NYISO) and an affected Transmission Owner (Con Edison) already have been performed that identify SENY as an area that will be constrained by lack of adequate and reliable sources of electricity in the near future. An additional national congestion study of this constrained geographic area is not necessary.

It is essential that the DOE designate the proposed corridor on an expedited basis. The NYISO RNA estimates that unless addressed this transmission constraint could result in a resource adequacy criterion violation as early as 2008, and that the "New York State bulk-power baseline system for the first Five Year period (2005-2010) indicates that the forecasted system does not meet reliability criteria." (RNA at 4.) Thus, immediate solutions to this constraint are needed. As presently contemplated, NYRI expects an in-service date to address reliability needs by 2011. The marginal difference between early designation and the standard designation process contemplated by DOE could well be critical to meeting the NYISO's imminent reliability needs.

Expedited designation of the proposed corridor as a NIETC would also help carve out rights for the NYRI Project that might otherwise not be available. For a project developer with no current transmission-related revenue stream, it would provide invaluable assistance in helping develop a project. This includes sending appropriate signals about the project's importance to other regulators and lenders and investors. The viability of a meritorious project will thus be bolstered.

Finally, early designation of the proposed corridor also is necessary and appropriate in light of the size and prominence of the load pocket in southeastern New York. For decades there has been major congestion in this area, and there is no reason not to recognize this expeditiously so that transmission solutions can materialize. Indeed, if any corridor merits early designation, this is it.

C. DOE’s Draft Criteria for Designating NIETCs

In the NOI, DOE also invited comments on the draft criteria it would use for gauging the suitability of geographic areas as NIETCs. (71 Fed. Reg. at 5660.) Because DOE has not yet finalized the criteria and NYRI is seeking early designation, NYRI does not have the benefit of being able to demonstrate how the proposed transmission corridor and project matches DOE's ultimate criteria. However, for purposes of this filing, NYRI addresses the draft criteria identified in the NOI.

The first three draft criteria in the NOI: (1) whether designation of the corridor will help achieve economic benefits for consumers, (2) whether designation of the corridor will help improve and maintain reliability and (3) whether designation of the corridor will help bring additional supplies and power from diverse resources into constrained areas, have been addressed above. The remaining draft criteria are addressed as follows:

4. The Proposed Corridor Will Aid U.S. Energy Independence

By relieving congestion and increasing the available capacity to transfer generation to load in New York, the designation of the proposed corridor will aid U.S. energy independence. In particular, new transmission facilities constructed along the corridor would increase the amount of renewable generation that can reach demand in southeastern New York. Increased transmission capacity available will encourage the development of renewable energy sources, which will proportionately lessen the dependence of New York resources on imported fossil fuels.

5. The Proposed Corridor Will Help Further National Energy Policy

Congress, DOE and the Federal Energy Regulatory Commission ("FERC") have articulated a national energy policy that seeks to encourage the development of new transmission infrastructure. See Energy Policy Act of 2005 § 1241, Pub. L. No. 109-58, 119 Stat. 594 (2005); Promoting Transmission Investment through Pricing Reform, Notice of Proposed Rulemaking, 113 FERC ¶ 61,182 (2005) ("Transmission Pricing NOPR"). On numerous occasions, FERC has discussed the need for new transmission facilities across the country, and particularly in constrained regions of the country such as southeastern New York. (See Transmission Pricing NOPR at 2; Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission, 111 FERC ¶ 61,473 [2005]; Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid, 102 FERC ¶ 61,032 [2003].)

As FERC noted, while investment in transmission infrastructure has declined over the last thirty years, electric load has more than doubled, "resulting in a significant decrease in transmission capacity relative to load in every North American Electric Reliability Council region." (Transmission Pricing NOPR at 1.) Designation of the proposed corridor as a NIETC would facilitate the construction of new transmission assets in this constrained region, which furthers this national policy of encouraging transmission investment.

Furthermore, Congress and FERC also have emphasized the importance of encouraging renewable and other environmentally friendly generation. Current constraints in the proposed corridor inhibit the ability to deliver large amounts of renewable energy products from upstate areas to southeastern New York. The proposed transmission facility would relieve these constraints and facilitate the delivery of an increased amount of renewable and clean generation to load in SENY.

Indeed, increased transmission along this corridor also will reduce the amount of SOx and NOx emissions from power plants, specifically in the southeast and Lower Hudson Valley of New York, as a result of newer, more compliant generating facilities gaining broader access to the market. GE Energy's analysis of the NYRI project shows that emissions of SOx will be reduced by 10,406 tons annually and emissions of NOx will be reduced by 2,032 tons annually as a result of this project.

6. The Proposed Corridor Will Reduce Load's Vulnerability to Disruption From Natural Disaster or Malicious Acts

The proposed corridor and any additional transmission facilities would encourage a diversification of resources and would provide those resources with improved access to the transmission grid. This diversity, in and of itself, will reduce the vulnerability of the transmission system and of load in the New York control area from disruptions of service due to natural disasters and/or malicious actions. A new transmission line into one of the most populous areas of the state will offer additional, redundant transmission options in the event other transmission lines are damaged or destroyed. New transmission will also make additional generation resources available should a generating unit be prevented from operating.

7. The Need for the New Transmission Facilities in the Proposed Corridor is Immediate and Non-Contingent

The need for additional generation supplies in southeastern New York is well documented and not contingent upon uncertain future events. (See Bottleneck Report at 50-52.) The area currently has a high level of demand that may not be able to be supplied in the future by the state's existing generation or transmission resources. Thus, it cannot be said that this need is unduly contingent upon any uncertainties. The need exists presently and will only continue to exist (and indeed, will grow) as the population in SENY maintains current levels or increases.

8. Alternative Means of Mitigating the Need Met by Designation of the Proposed Corridor are not Available

DOE has recognized that some areas of need "may be possible to address...through functional alternatives such as distributed generation, conventional generation sited close to load, and/or enhanced demand response capacity." (71 Fed. Reg. at 5661.) The availability of alternative means of mitigating the need in question is also one of DOE's draft criteria. Such alternatives are not available with regard to the proposed corridor or the proposed NYRI Project. There is an urgent need for generation in SENY, and the alternatives noted by DOE are not feasible solutions to this need.

First, generation development in SENY has been inadequate. According to the NYISO, continued load growth in SENY, in conjunction with impending generation retirements and changes to neighboring systems, will result in a resource adequacy criterion violation by 2008. (See RNA at 4-5.) Small-scale distributed generation is not sufficient to meet the vast generation needs in southeastern New York and larger-scale distributed generation has not been sufficiently developed in the area to ease the congestion. Second, it is extremely difficult and expensive to site conventional generation close to load in a heavily populated area like southeastern New York. It will be more efficient to construct additional transmission facilities bringing power into

SENY from another part of the state than it would be to construct new generation facilities in this region.

IV. CONCLUSION

For the reasons set forth herein, NYRI respectfully requests that the Department consider NYRI's proposed transmission corridor for early designation as a NIETC

Very truly yours,

COUCH WHITE, LLP

Leonard H. Singer

Leonard H. Singer

45. New York State Public Service Commission, Received Mon 3/6/2006 10:27 AM

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March 6, 2006

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Re: Notice of Inquiry Requesting Comments For Considerations On Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

To Whom It May Concern:

Attached, please find the Comments of the New York State Public Service Commission in the above-entitled proceeding. Should you have any questions, please feel free to contact me at (518) 473-8178.

Very truly yours,

/s/

David G. Drexler
Assistant Counsel

Attachment

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

COMMENTS OF THE PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK

BACKGROUND

On February 3, 2006, the United States Department of Energy (DOE) issued a notice in the Federal Register seeking comment and information on its plans for an electricity transmission congestion study and the criteria to be used in the study for possible designation of National Interest Electric Transmission Corridors (NIETCs) (Notice). Pursuant to the Energy Policy Act of 2005, the Secretary of Energy (Secretary) is required to conduct a nationwide study of electric transmission congestion, and issue a report based on the study in which the Secretary may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a [NIETC]."[1] If the Secretary designates an

[1] Energy Policy Act of 2005, §1221.

area as a NIETC, the Federal Energy Regulatory Commission (FERC) is authorized to issue permits for the construction and modification of electric transmission within the NIETC, provided certain findings are made.[2]

The New York State Public Service Commission (NYPSC) hereby submits its comments pursuant to the Notice in the Federal Register. Copies of all correspondence should be addressed to:

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EXECUTIVE SUMMARY

The NYPSC appreciates this opportunity to provide comments on DOE's draft criteria for designating NIETCs. We commend the DOE in undertaking this difficult task and acknowledge the considerable progress it has made to date. As our comments

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[2] Id. Among other findings, FERC must determine that in states, such as New York that have authority to approve the siting of transmission facilities, that the state has withheld approval for more than one year after the filing of an application, or conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion or is not economically feasible.

indicate, designating NIETCs is a complicated task, and doing so must carefully balance the designation with the impacts on competitive markets and consumers.

As indicated in the Notice, the DOE seeks to "avoid designating NIETCs in ways that might unduly affect stakeholders' decisions about how to meet specific needs, confer advantage on transmission options as opposed to non-wires options or generation options, or favor some transmission options over others." To address this concern, we recommend that DOE adopt a clear economic measure of congestion that reflects national, rather than parochial interests, and require the allocation of project costs to beneficiaries. This recommendation should narrow the selection of NIETCs and avoid favoring inefficient projects that could harm competitive markets and impose unnecessary costs on consumers.

The DOE should evaluate its designation of NIETCs for reliability purposes recognizing the existing regional planning processes approved by FERC. For example, in New York, the New York Independent System Operator (NYISO) has worked closely with the NYPSC and other stakeholders to develop a Comprehensive Reliability Planning Process. The NYISO planning process identifies reliability needs based on clearly defined criteria, and allows market participants to step forward with proposals (i.e., generation, transmission, or demand-response) to meet those needs. Adherence to this type of approach will help ensure that the designation of NIETCs is made in a workable manner that does not unnecessarily interfere with the workings of the market, and will recognize that the development of transmission alternatives, such as generation or demand-response may, in some cases, be superior from a cost and/or reliability perspective. This approach will also provide competitive markets with a chance to flourish, while ensuring reliability needs are met at the least cost.

If DOE designates a NIETC primarily for economic purposes, we recommend that a cost-benefit analysis be performed by the applicable Independent System Operators/Regional Transmission Organizations to ensure that a transmission solution will be the most economical from a national interest perspective. In particular, such analysis should examine savings to the system on the whole, by focusing more broadly than on only the positive benefits to downstream load. A useful measure of national interest is a long-run societal cost-benefit test (i.e., whether or not the long-run benefits of greater imports into high-cost load centers, including savings in production costs and the reduced need for generators in the high-cost areas, exceed the long-run costs of constructing the transmission upgrade).[3] Only where a clear net positive benefit is shown, should a NIETC be designated. Requiring the relief of all congestion, even where the costs exceed the benefits, could interfere with market signals and unnecessarily raise costs to consumers.

Finally, we offer responses to several of the questions posed in the Notice. Specifically, we address physical versus contractual congestion and suggest that DOE focus exclusively on physical congestion and not attempt to resolve contractual congestion, which can be handled through FERC rules governing provision of transmission service; we recommend that DOE distinguish between persistent and dynamic congestion, and only designate a NIETC for persistently constrained interfaces where net benefits would be derived from investments in the electric system; and, provide references to several NYISO transmission studies that would be useful in DOE's review.

DISCUSSION

I. The DOE Should Develop A Clear Measure of Congestion To Avoid Over-Broadly Designating National Interest Electric Transmission Corridors

[3] A load pocket is a portion of the electric system that is characterized by having more load than local generation and has limited transfer capability from the bulk transmission system.

The Notice broadly measures congestion as “adversely affect[ing] consumers,” and where “end markets…may be constrained by lack of adequate or reasonably priced electricity,” or where “economic growth…may be jeopardized.” Similarly, Draft Criterion 2 (i.e., “Action is needed to achieve economic benefits for consumers”) proposes to use estimates of the aggregate economic savings per year to consumers over a relevant geographic area and market, while Draft Criterion 3 suggests that “[a]ctions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.” However, these criteria are so broad as to make almost any region a NIETC. For instance, building new transmission facilities in most instances would provide greater access to supply and reduce costs for customers downstream from supply sources.

In order to designate NIETCs that are most in need of attention, we recommend that DOE adopt an objective measurement of congestion similar to that used by the NYISO. In particular, the NYISO reports the cost of congestion as the change in bid production costs that result from transmission congestion.[4] The

[4] NYISO Open Access Transmission Tariff, Attachment Y, Appendix A, §2. The NYISO also reports the following elements of

NYISO determines the change in bid production costs based on the differences in costs between the actual constrained system computed in the NYISO's day-ahead market and a simulation of an unconstrained system.[5] We note that the NYISO's analysis to date has been limited to measuring changes in energy costs in the short-run, by holding the stock of generation constant. An additional consideration should also be the long-run ability of additional transmission capacity to allow new generators to locate in lower-cost regions instead of in higher-cost load centers (subject to reliability requirements).

Criteria 1 (i.e., "Action is needed to maintain high reliability") should also be clarified to ensure it does not over-broadly designate NIETCs. The concept of "high" reliability appears to blend two concepts that should be considered individually (i.e., relieving congestion to comply with reliability requirements and relieving congestion for further reliability benefits beyond what is required). Currently, FERC is undertaking a process that will lead to enforceable national bulk electric system reliability standards.

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congestion-related costs: 1) impact on load payments; 2) impact on generator payments; and 3) hedged and unhedged congestion payments.

[5] Id.

Compliance with these standards will lead to a reliable electric transmission system. Designation of a NIETC in an area that does not meet applicable reliability standards, in the event that the FERC-approved planning process developed by the NYISO as well as other such organized markets proves insufficient, could complement FERC's efforts and could assist in having needed facilities constructed.

However, Criteria 1 appears to imply moving beyond compliance with reliability standards and using higher than required reliability to justify economic upgrades. System upgrades relying on reference to higher than required reliability standards should instead be subject to a societal cost-benefit analysis. Therefore, we suggest that applicable Independent System Operators/Regional Transmission Organizations perform a cost-benefit analysis to ensure that transmission solutions, which go beyond satisfying reliability standards, satisfy a societal cost-benefit analysis.

II. The DOE Should Ensure That Designation of National Interest Electric Transmission Corridors Do Not Interfere With Competitive Markets By Harmonizing The DOE Process With Regional Planning Processes

Congestion can be relieved through a number of means, including investments in generation facilities located within load pockets, increased transmission capacity into load pockets, or investment in demand reduction within load pockets. In restructured markets, generation, demand reduction and transmission are three tools that can achieve the same objective. In other words, carefully sited generation facilities or investments in demand reduction can offset the need for transmission investments. While there may be congestion at certain points of the transmission system, mitigating that congestion does not necessarily require investments in transmission. It may include investments in generation, or demand reduction, or both.

Because there may be a number of superior alternatives to transmission that may also relieve congestion, we recommend that DOE harmonize its process of designating NIETCs with regional planning processes that allow competitive markets to develop such solutions. For instance, the NYISO currently utilizes a Comprehensive Reliability Planning Process to identify long-term reliability needs for the bulk transmission system looking ten years ahead.

The NYISO's Planning Process starts with clearly defined reliability rules, and provides a well-defined process for determining reliability needs on the bulk transmission system. This process affords an opportunity for market participants to present proposed solutions, such as generation, transmission or demand-response, which meet the identified needs. Where the NYISO identifies any reliability concerns, its regional planning process encourages market participants to step forward with solutions, shifting the risk for these types of investments from ratepayers to developers. If no market-based solutions materialize, the affected utility is responsible for facilitating a regulated solution, considering generation, transmission, and/or demand-response solutions that may address the reliability need.[6]

However, there is currently no mechanism envisioned in the Notice to recognize FERC-approved planning processes being done at the regional level, which may cause developers of bona fide generation or demand-response projects to decide against going forward with their proposals due to the possibility that the proposed projects will be supplanted by a NIETC transmission facility. Therefore, DOE should develop a process that accommodates input from such regional planning processes and builds upon what is being accomplished regionally.

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[6] The regulated back-stop solutions are overseen by the NYISO and implemented by traditional investor-owned utilities, with costs allocated on the basis of "beneficiaries pay."

III. The DOE Should Consider The Following Responses To Specific Questions Presented In The Notice

A. Physical Versus Contractual Congestion

The DOE seeks further comment on whether it should distinguish between physical congestion and contractual congestion. We suggest that DOE focus exclusively on physical congestion and not attempt to resolve contractual congestion. Attempting to resolve contractual congestion could unnecessarily interfere with ISO/RTO market rules governing the provision of transmission service, which have been approved by FERC.

B. Persistent Versus Dynamic Congestion

We recommend that DOE distinguish between persistent congestion (i.e., historical energy flows indicate uneconomic congestion has consistently occurred and is projected to continue in the future) and dynamic congestion. Dynamic congestion, as we define it, refers to congestion that is temporary in nature, such as a major generation unit outage, changes in buying patterns or in fuel costs. Given this temporary nature, we suggest that a designation of a NIETC be made only for persistently constrained interfaces where net benefits would be derived from investments in the electric system.

C. Transmission Studies

The Notice asks what specific transmission studies, in addition to those listed in Appendix A of the Notice, should the DOE review. In addition to those studies identified in Appendix A, the DOE should review the NYISO's Initial Planning Process Report dated May 15, 2004 (Chapter 13 - Historical Congestion Reporting),[7] and the NYISO's Final Comprehensive Reliability Planning Process Report, scheduled to be completed in June, 2006. It would also be useful for DOE to look at flow patterns on target corridors within New York going back 10 years.[8]

CONCLUSION

The NYPSC thanks the DOE for its consideration of the above comments in its decision-making process. We look forward to working with DOE in the future as it performs and issues its study on electric transmission congestion.

Respectfully submitted,

/s/

[7] See, http://www.nyiso.com/public/webdocs/committees/bic_espwg/meeting_materials/2004-05-26/ippmaydiscussiondraft.pdf.

[8] Over time, patterns of congestion can shift due to changes in load, market rule modifications, additions and retirements of facilities, etc. Reaching back one planning period (i.e. 10 years) to review historical flows coupled with future system forecasts can provide a reasonable base to determine if congestion is persistent.

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Dated: March 6, 2006
Albany, New York

46. North American Electric Reliability Council, Received Mon 3/6/2006 3:02 PM

The North American Electric Reliability Council (NERC) offers the following comments in response to the U.S. Department of Energy's (Department) Office of Electricity Delivery and Energy Reliability's notice of inquiry relating to plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors (NIETCs). NERC is particularly interested in the identification and designation of NIETCs that jeopardize national security or create a risk of widespread grid reliability problems.

Summary

NERC's comments on the notice of inquiry are from the perspective of ensuring that the North American bulk electric system has the ability to reliably meet firm customer demand requirements and to be able to be operated without risk of uncontrolled cascading outages. Relief of economic congestion is a laudable goal for the identification of NIETCs, but is beyond NERC's scope.

NERC supports the concept, as described in the Energy Policy Act of 2005, of identifying as national interest electric transmission corridors "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affect consumers," as opposed to specific routes for transmission facilities.

NERC has supported the Department's congestion study by helping to arrange for transmission transfer capability studies conducted by regional and interregional study groups to be provided to the Department's consultant. NERC believes that the expertise of the industry and the studies that have already been completed should be utilized to the maximum extent possible for identifying transmission system congestion.

NERC also looks forward to participating in the March 29, 2006 technical conference on this subject.

Congestion Study

Question 1 — *Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?*

The Department should perform cost/benefit analyses for all congestion, both persistent congestion and dynamic congestion. The cost effectiveness of solutions to either type of congestion will vary.

Question 2 — *Should the Department distinguish between physical congestion and contractual congestion, and if so, how?*

The Department should distinguish between physical congestion and contractual congestion. Relief of physical congestion requires actions that may involve construction of transmission or generation facilities, or implementation of demand-side programs. Relief of contractual congestion may be accomplished through market or tariff revisions. The difference should be distinguished so that the appropriate actions and/or incentives to provide relief from congestion can be identified.

Question 3 — *What existing, specific transmission studies and other plans should the Department review (in addition to those listed in Appendix A)? How far back should the Department look when reviewing transmission planning and path flow literature?*

The Department should review studies conducted by the regional reliability councils, independent system operators (ISOs), regional transmission organizations (RTOs), interregional study groups, and individual transmission owners. These entities have the necessary tools, expertise, and experience to study and analyze the transmission systems in their respective areas and already know where transmission constraints exist today and where future transmission constraints will likely materialize. Because the bulk electric system changes over time, studies more than five years old may be too out of date to provide meaningful information.

Question 4 — *What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?*

The categories of information that would be helpful to incorporate into congestion studies include: NERC and regional reliability assessments, transmission owner/operator assessments, quantification of the magnitude of long term firm transmission service denials, total transfer capability (TTC), available transfer capability (ATC), and available flow gate capability (AFC) values, grandfathered roll-over rights, historical locational marginal prices (LMP) between various resource and load areas, establishment of the primary reason for designation of a NIETC (reliability and/or economics), assumptions about the direction and amount of transfers between areas, system plans for both transmission and generation expansion, and the availability of alternative methods to relieve congestion.

Criteria Development

Draft Criterion 1*: Action is needed to maintain high reliability.*

The ability of the transmission system to reliably meet firm customer demand requirements and to be able to be operated without risk of uncontrolled cascading outages or loss of supply to major customer load centers and other critical infrastructure loads is a fundamental requirement and should be addressed in this criterion. The Energy Policy Act of 2005 provides for the certification of an electric reliability organization with authority to set and enforce compliance with reliability standards by all users, owners, and operators of the bulk electric system. As such, NERC believes that Criterion 1 should specifically include a reference to violations of reliability standards promulgated by the electric reliability organization and approved by the Federal Energy Regulatory Commission, including regional standards that are approved as ERO standards.   A corridor that could accommodate transmission facilities able to mitigate violations of ERO reliability standards should qualify as a NIETC.

Draft Criterion 2*: Action is needed to achieve economic benefits for consumers.*

NERC has no comment on this criterion as it deals with matters outside its scope.

Draft Criterion 3*: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.*

NERC supports this criterion to the extent it addresses the enhancement of reliability. The bulk electric system should be flexible enough to accommodate various generation dispatches, including accommodation of the temporary or permanent outage of any single generation plant. Designation of a NIETC to ensure that adequate transmission is constructed to remove dependency of a major load center upon a single generation facility, a group of generation facilities using a single fuel type that could be subject to disruption, or transmission facility is appropriate.

Draft Criterion 4*: Targeted actions in the area would enhance the energy independence of the United States.*

NERC supports this criterion insofar as it relates to a having a strong and robust bulk electric system that is not vulnerable to the disruption of a single fuel source. NIETC designation should also consider the international and electrically interconnected nature of the North American bulk electric system and related natural gas pipelines.

Draft Criterion 5*: Targeted actions in the area would further national energy policy.*

NERC supports this criterion insofar as it relates to a having a strong and robust bulk electric system.

Draft Criterion 6*: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.*

The ability of the transmission system to comply with NERC reliability standards and to reliably meet firm customer demand requirements and to be able to be operated without risk of uncontrolled cascading outages or loss of supply to major customer load centers and other critical infrastructure loads is a fundamental requirement and should be addressed in this criterion.

Draft Criterion 7: *The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions.*

NERC also agrees that designation of a corridor as a NIETC should be considered for existing needs ahead of projected needs. However, a robust transmission system for the future would allow for various generation resource dispatches, fuel diversity, load levels, load growth in new areas, and resource locations. Criterion 7 should not be interpreted so strictly as to unduly limit the future flexibility of the bulk electric system. Incorporation of probabilistic planning techniques may be an appropriate methodology to quantify assumption uncertainties.

Draft Criterion 8*: The alternative means of mitigating the need in question have been addressed sufficiently.*

Alternatives to transmission line additions should be evaluated when establishing a NIETC. When evaluating alternatives, the entire range of attributes of the competing alternatives should be evaluated. Strategic location of efficient generation may be more cost effective than transmission additions. However, the analysis of alternatives should consider the market design of the areas. "Reliability-must-run" (RMR) contracts that require generation operation to satisfy bulk electric reliability requirements where the transmission system is inadequate to meet NERC reliability standards may lead to operation of older, less efficient generation facilities in populated areas. The full social cost of RMR contracts (fuel diversity, environmental discharges, reliability, and flexibility in supply) should be considered when evaluating them as an alternative to transmission additions.

Additional Questions

Question 1 *– Are there other criteria or considerations that the Department should consider in making an NIETC designation?*

The Department should recognize that over time, new metrics may develop as markets mature, more transparency develops, and improved planning systems, technologies, and techniques are put into place. Any process established to designate NIETCs should be flexible to adjust to changing conditions. The NIETC designation should be used to identify the benefit of connecting two areas, not for identifying specific rights-of-way. The appropriate point in the planning process for designation of a NIETC should be following the recognition by stakeholders that a requirement for the corridor exists, and that expansion of the transmission system is the appropriate means to address the specific requirements. NIETC designation should also recognize the international nature of the bulk electric system. Important ties exist between Canada and the U.S. that are critical to the reliability and the security of the bulk electric system, and should not be overlooked in the study process.

Question 2 *– Are certain considerations or criteria more important than others?*

NERC believes that the reliability of the bulk electric system in North America and its ability to reliably serve major load centers and critical infrastructure loads is fundamental to public health, safety, and well being. As such, significant emphasis should be placed on Criteria 1 and 6.

NORTH AMERICAN ELECTRIC
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47. North Dakota Industrial Commission, Received Mon 3/6/2006 4:31 PM

March 6, 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Re: Notice of Inquiry: *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors"*

Pursuant to the Federal Register Notice of Inquiry issued by the Department of Energy in the above entitled matter, the North Dakota Industrial Commission ("NDIC") submits the following comments relating to the Transmission Congestion Study and National Interest Electric Transmission Corridors.

The NDIC was created by the Legislature of the State of North Dakota ("State") to conduct and manage, on behalf of the State, certain utilities, industries, enterprises and business projects established by State law. Members of the NDIC are three state-wide elected officials--the Governor, Attorney General, and Agriculture Commissioner.

North Dakota is home to vast lignite and wind resources. However, transmission constraints that limit electricity exports are a barrier to further significant development of those resources, denying the benefits of additional low cost, reliable, and environmentally sound energy resources to the region's electricity customers. The NDIC has a keen interest in fostering a business and regulatory environment that will be conducive to alleviating those transmission constraints and developing the State's lignite and renewable energy resources. Toward that end, the NDIC established the Lignite Vision 21 Program to support development of new electric generation within the State. Additionally, the North Dakota Legislature established the North Dakota Transmission Authority, directed by the NDIC, to support the development of new electric transmission.

The NDIC participates in the Upper Great Plains Transmission Coalition and has been involved in the drafting of comments submitted by the Coalition. Therefore, the NDIC supports the comments filed by the Upper Great Plains Transmission Coalition in their entirety.

All communications concerning the NDIC's support of the Upper Great Plains Transmission Coalition comments should be provided to:

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Respectfully submitted this 6th day of March, 2006

NORTH DAKOTA INDUSTRIAL COMMISSION
Karlene Fine, Executive Director

48. Northeast Power Coordinating Council, Received Sun 3/5/2006 11:17 AM

**Comments of the
Northeast Power Coordinating Council
On the
U.S. Department of Energy's
Office of Electric Delivery and Energy Reliability ("OE")
Notice of Inquiry and Opportunity to Comment
on
Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors
(Federal Register, Volume 71 No. 22, Thursday, February 2, 2006)**

The Northeast Power Coordinating Council ("NPCC") offers the following comments in response to the U.S. Department of Energy's ("DOE") Office of Electric Delivery and Energy Reliability's notice of inquiry and opportunity to comment on issues relating to the subject transmission congestion study and designation of National Interest Electric Transmission Corridors ("NIETC").

NPCC is the international electric regional reliability council which was formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. That geographic area includes New York state, the six New England states, and the Ontario, Québec, and Maritime Provinces in Canada. The total population served is approximately 56 million. The area covered is approximately 1 million square miles. NPCC is one of eight Regional Reliability Councils throughout the United States, Canada and portions of Mexico that together currently form the North American Electric Reliability Council ("NERC").

NPCC establishes the processes that assure the reliable and efficient operation of the international, interconnected bulk power systems in Northeastern North America through development and enforcement of regionally-specific criteria that are not inconsistent with NERC broad-based continent-wide reliability standards. NPCC coordinates system planning, design and operations, assesses reliability, and monitors and enforces mandatory compliance with regional reliability criteria. NPCC, to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

COMMENTS

NPCC respectfully submits the following comments for DOE's consideration in the determination of criteria to be used for evaluating the suitability of geographic areas for NIETC status. [1]

[1] DOE NIETC NOI at page 9.

Consider Wide-Area, trans-Regional & potentially international reliability impacts
NPCC recommends that the DOE take into account the wide-area, trans-regional and potential international reliability impacts of the resultant future transmission infrastructure when designating NIETC believed to be beneficial in advancing the stated goal of designating "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers." [2]

NPCC supports the DOE's approach "to identify corridors for potential projects, as opposed to specific routes for transmission facilities." [3] NPCC believes the DOE should take an Interconnection-wide system viewpoint in their NIETC designations, in order to avoid the encouragement of potentially conflicting transmission projects that may increase the likelihood of undesired, adverse reliability impacts that could jeopardize a significant portion of the bulk electric system. These considerations are not limited to the United States grid system only but can extend beyond international borders into Canada and Mexico as well.

Designate NIETCs considering their potential combined reliability impacts
The transmission network is a complex, interactive interconnected system that must be designed and operated to adhere to NERC standards and specific regional reliability criteria. NPCC recommends that the DOE evaluate the benefits of proposed NIETC not only singularly, but in combination with other adjacent proposed NIETC designations. The overall reliability of the interconnected system must be paramount in these deliberations.

NIETC determination should consider both positive and negative reliability impacts
The designation of a NIETC should not result in unintended adverse reliability consequences, for example, increasing the potential for high circulating power flows, or resulting in restrictions of available generation output. The DOE needs to be aware of, and should identify, any potential reliability impacts, both positive and negative, on the international interconnected system associated from their NIETC designations, and designate NIETC that have complementary reliability benefits.

Consider the role of substation and lower voltage improvements in NIETC designation
NPCC recommends the DOE also consider the important role that substation switching arrangements and reactive power plays in the reliable operation of the bulk power system [4] in their NIETC designations. Also, lower voltage system improvements may be needed to support reliable, effective higher voltage improvements. The designation of NIETC should add reactive power supply considerations to the "existing or projected needs related to electricity transmission infrastructure." [5]

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[2] DOE NIETC NOI at page 5.
[3] DOE NIETC NOI at page 6.
[4] See: Principles for Efficient and Reliable Reactive Power Supply and Consumption, FERC Staff Report, Docket No. AD05-1-000, February 4, 2005.
[5] DOE NIETC NOI at page 6.

DOE NIETC designation should be consistent with its Presidential Permit criteria
As stated on the DOE website[6]:

"Executive Order 12038 states that, before a Presidential permit may be issued, the action must be found to be consistent with the public interest. The two criteria used by DOE to determine if a proposed project is consistent with the public interest are:

1. **Environmental Impact** - The National Environmental Policy Act of 1969 (NEPA) requires that Federal agencies give due consideration to the environmental consequences of their actions. Pursuant to NEPA, DOE must determine the environmental impacts associated with issuing or denying a Presidential permit. DOE published NEPA implementing procedures on April 24, 1992 (57 FR 15122). These rules, codified at 10 CFR 1021, specifically delineate the steps of the NEPA process.
2. **Impact on Electric Reliability** - DOE considers the effect that the proposed project would have on the operating reliability of the U.S. electric power supply system; i.e., the ability of the existing generation and transmission system to remain within acceptable voltage, loading and stability limits during normal and emergency conditions. The standards DOE applies include the standards of the North American Electric Reliability Council (NERC) and the standards of the member regional councils that are formulated by the utilities themselves."

Presidential Permits should be considered in the NIETC designation
When considering a Presidential Permit application, DOE determines if that issuance serves the national interest, through extensive consultation with concerned federal and state agencies, applicable regional reliability councils, and through the public comment process. NPCC recommends that any existing Presidential Permits [7] and projects actively seeking Presidential Permits [8] be considered by DOE in the NIETC designation process.

NIETC designation should facilitate reliable U.S. Trade in Electricity

As stated on DOE's website: [9]

"U.S. trade in electric energy with Canada and Mexico is rising, bringing economic and reliability benefits to the United States and its trading partners. Within the DOE's Office of Fossil Energy's Coal & Power organization, an electricity import/export team is responsible for authorizing the export of electric energy and the issuance of permits for the

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[6] See: http://www.fossil.energy.gov/programs/electricityregulation/Presidential_Permits.html
[7] See: http://www.fossil.energy.gov/programs/electricityregulation/Orders_Issued.html
[8] See: http://www.fe.doe.gov/programs/electricityregulation/Pending_Proceedings.html
[9] See: http://www.fossil.energy.gov/programs/electricityregulation/

construction, connection, operation, and/or maintenance of electric transmission facilities at the international border."

NIETC designations should result in transmission projects that eliminate or reduce the magnitude of constraints between the U.S. and Canada (as well as Mexico). There is considerable transfer capability available between the Canadian members of NPCC (Ontario, Québec, and the Maritimes Provinces) and the U. S. through the use of existing transmission facilities. NIETC designations should consider and promote reliable US – North American transfers.

NIETC designations should be geographic

NPCC encourages the DOE to identify those geographic transmission corridors that are consistent with the interest of the national energy policy, whether or not those NIETC designations are based on existing transmission paths or current rights of way, subject to the considerations outlined above.

NIETC designations should not be project specific

NIETC designations should not be project specific, and should not be announced prior to the completion of the comprehensive DOE study outlined by the legislation that takes into consideration extensive stakeholder review and comment.

NIETC designations should be periodically reviewed

Congestion that is prevalent in today's system, (as well as congestion that has been prevalent for several years), may not be as significant in the future, due to the siting of future resources, changes in demand patterns, and proposed future transmission enhancements. NPCC strongly supports DOE's approach of basing their analyses on a periodic review of the existing transmission expansion plans and related studies by "the regional coordination councils, other regional and subregional transmission planning groups, regional transmission operators, independent system operators and utilities."[10]

NPCC also recommends that DOE periodically review their NIETC designations, and be able to renew, change, augment, or revoke as necessary, as conditions merit, in order to meet its national policy and reliability objectives.

[10] DOE NIETC NOI at page 7.

ADDITIONAL STUDIES TO CONSIDER

In response to the DOE's request regarding "… what specific transmission studies and other plans should the Department review?"[11] NPCC recommends, in addition to the studies and reports listed herein, consideration of the following:

Northeastern Coordinated System Plan
In December 2004, ISO New England, the New York ISO, and PJM executed the Northeastern ISO-RTO Planning Coordination Protocol which provides for enhanced coordination of planning throughout the Northeast. The protocol is intended to contribute to the ongoing reliability and the enhanced operational performance and efficiency of the Northeastern bulk power system. Under the protocol, the parties have agreed to pursue: a) the sharing of information; b) the coordination of timing of planning activities; c) the performance of joint assessments; and d) the establishment of an open stakeholder process to accompany interregional assessments and system plans. While not parties to the protocol, the Independent Electricity System Operator (Ontario), Hydro-Québec TransÉnergie and New Brunswick share in these goals and have agreed to participate on a limited basis to assist in these initiatives.

As the first key step in the implementation of the protocol, the issuance of the Northeastern Coordinated System Plan: 2005 (NCSP 2005) consolidated the system assessments and plans of each of the participating control areas, highlighted existing inter-regional planning activities, summarized perceived issues and risks and identified potential issues for future analysis. [12]

Northeast Seams Projects
When the Federal Energy Regulatory Commission ("FERC") granted regional transmission organization ("RTO") status to ISO New England and the New England transmission owners (the filing parties) on March 24, 2004, [13] they directed the parties to resolve seams issues with its neighboring New York ISO. Since the New York ISO has significant trade with the Mid-Atlantic region's PJM RTO, FERC also directed the parties to also explain the role of PJM in the resolution of seams issues.

NPCC recommends the DOE include consideration of the current reliability related Northeast Seams Projects currently under way [14] when making their NIETC determination.

Hydro-Québec Phase II Interconnection Studies
The original reliability studies for the 2,000 MW Hydro-Québec to New England Phase II Interconnection [15] concluded that the loss of the facility carrying 2,000 MW to New England

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[11] DOE NIETC NOI at page 8.
[12] See: http://www.interiso.com/public/document/Northeast%20Coordinated%20System%20Plan.pdf
[13] FERC Docket Nos. RT05-2-000, ER04-157-000, -001 and EL01-39-000.
[14] See: http://www.nyiso.com/public/webdocs/newsroom/current_issues/current_seams_projects.pdf
[15] Overall Reliability Review of the Hydro-Québec/NEPOOL Phase II Interconnection, NPCC Task Force on System Studies, SS-32 Working Group on Reliability Review, Steering Committee Study No. 6, Final Report, June 3, 1988.

could have more severe effects on PJM and New York than the worst internal contingency that these systems individually protect against. Accordingly, an operating philosophy in which the Hydro-Québec HVDC exports to New England over Phase II would be limited to the extent necessary to ensure that the MAAC - ECAR - NPCC (MEN) system's thermal, voltage and stability operating criteria are not violated was agreed upon.

The original study [16] indicated, under the conditions assumed, [17] that the Hydro-Québec Phase II interconnection export to New England would be restricted to approximately 1,500 MW during periods of high transmission utilization in MAAC, in order to avoid unacceptable voltages in MAAC following the loss of the Phase II interconnection.

LEER
Specific reliability and commercial concerns are addressed through the NPCC Lake Erie Emergency Redispatch ("LEER") Procedure. [18]

NPCC Reliability Assessment For Summer 2005
This report [19] focused on the assessment of reliability within NPCC for the summer of 2005.

Report Summary
The forecasted capacity outlook for NPCC during the peak week (week beginning July 10, 2005) indicated a forecasted available capacity margin of 13,006 MW. During this week, 6,850 MW of the spare capacity is in the Québec and Maritimes Areas. The transfer capability between the Québec and Maritimes Control Areas to the remainder of NPCC will not permit the usage of all this forecasted spare operable capacity. This limitation could reduce the overall capacity margin by approximately 3,375 MW. During high transfers from New Brunswick to New England, capacity located north of the Maine- New Hampshire interface may be bottled or locked in due to existing transmission constraints. This will reduce the overall spare capacity to NPCC by up to another 400 MW. As a result, the spare capacity available to the remainder of NPCC in the peak week is reduced to approximately 9,630 MW.

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[16] 1990 Summer Interregional System Performance – Part 2 Dynamic Analysis, MAAC-ECAR-NPCC (MEN) Study Committee, April 1988.
[17] New York Total East Transfer Limit of 5,600 MW; ECAR to MAAC Transfer Limit of 3,950 MW.
[18] See: https://www.npcc.org/PublicFiles/LakeErieRedispatch/Archives/LEER_Re-filing_20021.pdf
[19] See: https://www.npcc.org/publicFiles/documents/seasonal/lastYear/NPCC_Reliability_Assessment_for_Summer_2005.pdf

49. Northwest Independent Power Producers Coalition, Received Mon 3/6/2006 4:57 PM

DOE Staff -

Please find attached the comments of the Northwest Independent Power Producers Coalition (NIPPC). We appreciate the time DOE has taken to brief our organization on this NOI. The issues that the Department is analyzing consistent with Section 1221 of EPAct are important to NIPPC and its members. We consider the attached testimony as the beginning of what we expect will be a sustained engagement with the Department as it navigates the issues involved in congestion management and new transmission infrastructure siting.

Thank you for the opportunity to participate and please continue to keep our Coalition informed as your investigations proceed.

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Northwest Independent Power Producers Coalition Comments to U.S. Department of Energy Considerations for Transmission Congestion Study & Designation of National Interest Electric Transmission Corridors

March 6, 2006

Pursuant to the Notice of Inquiry issued by the Department of Energy (DOE) on February 2, 2006 (NOI), the Northwest Independent Power Producers Coalition (NIPPC), hereby submits comments for consideration by DOE in its study of congestion and development of criteria for designating National Interest Electric Transmission Corridors (NIETCs).

Background

NIPPC members currently operate 3600 megawatts of capacity in the states of Oregon and Washington. NIPPC members have roughly an equal amount of new generation fully permitted or under development in Oregon, Washington and Idaho. One-third of this capacity is coal with two-thirds gas-fired combined cycle power plants.

The geographic area referred to in these comments is the Pacific Northwest and Inter-Mountain West. This is the same area that is generally served by the Northwest Power Pool. Thermal and renewable IPPs generators contribute approximately 18 percent of the capacity within this area.

NIPPC members have experienced significant curtailments of commercial transactions in recent years due to transmission congestion. The cost of these curtailments is a combination of lost revenues and, in some instances, liquidated damages paid to the purchaser who must make arrangements for replacement power. This is an example of physical congestion as it manifests on power scheduling personnel today.

NIPPC members have followed Federal Energy Regulatory Commission's Order 888/889 procedures for requesting transmission service only to have their requests languish in OASIS transmission service queues for years without action. This is but one example of contractual congestion as it affects power-marketing transactions today. Responding to utility resource acquisition requests for proposals (RFPs) without certainty that the power generated can be delivered through a third party transmission provider creates a very non-competitive offering. Contract path limitations commonly interfere with resource acquisition options proposed in response to Integrated Resource Plans.

Congestion Study

DOE's first objective is to complete a congestion study that will be presented to Congress in August 2006. In the study DOE "may" designate transmission corridors within which FERC would have backstop authority over transmission facility siting and permitting decisions. Clearly transmission problems today may be remedied by actions taken by DOE and FERC under Section 1221.

That said NIPPC fears that the results of congestion studies derived from assumption-driven production cost simulations, will only point to the most obvious areas of need while leaving real-life congestion short-changed. Production cost simulations model the power system as if a single, benevolent system operator continuously monitored all constraints and optimized system performance on a minute-by-minute basis. All generators are assumed to be nominally available to supply load within the transmission limits of the network. Hydro units are block scheduled according to "normal" water conditions at zero cost to the system. Thermal units are dispatched according to their incremental costs given fuel price and cost curves assumed to be representative of a future planning horizon. Given the complexities of power system modeling, these idealized assumptions greatly simplify the production of results. Unfortunately, they often fail to identify real-world problems that appear in the real-time operating horizon.

While planning models used in the West purport to evaluate options based on economic dispatch, they do not accurately model the base system as it is currently controlled and dispatched today. The starkest example of this is the fact that ten control areas in the Northwest are assumed to be economically dispatched as a single system when in fact they are autonomous and their competing objectives often complicate management of system constraints. Because economic dispatch is not handled on a regional basis, the individual objectives of multiple systems can create intractable barriers to entry for competitive providers.

Furthermore, cost data for these models has only begun to take shape under the auspices of SSG-WI. While this database will now be transferred to the stewardship of WECC, significant error checking, data scouring and model calibration is needed to ensure that the modeling data reflects both actual and potential outcomes.

In summary, the congestion study should not be limited to an academic exercise that indicates where congestion problems would occur in an otherwise perfect world. Congestion metrics should also include:

- Consideration of the commercial availability of transmission service and products that are reliably available for real-world commercial transactions. Available Transfer Capacity (ATC) postings should be reconciled with the number of outstanding requests for transmission service that were rejected or denied.

- Incidence rates of curtailments of transmission service. While the OATT has provisions for curtailing transmission service if necessary to preserve reliability, system congestion is causing transmission providers to curtail transactions that were supposed to be feasible under the conditions assumed for ATC calculations. Conceivably curtailments should coincide with congestion in the models if the models accurately reflect actual operating conditions.

- The “institutional congestion” expressed in Balkanization by control areas vastly limits the overall efficiency of the single integrated system that is the Western Interconnection. The limitations imposed on transmission operations and the insidious effects of parochialism that favors, for example, network transmission service over point-to-point transactions need to catalogued and considered.

- Distinctions between investor-owned and public transmission service should not distract DOE from its investigations.

Designated Corridors

The Northwest Independent Power Producers Coalition supports DOE in its efforts to identify National Interest Transmission Corridors. While we appreciate the difficulty involved in navigating through the countless interests that may affect these designations – NIMBY opposition, scenic designation, tribal sovereignty to name but a few.

NIPPC urges DOE to stake out a broad definition of potential NIETCs. In the West particularly, far too little study has been done to create consensus around specific corridors or even, for that matter, developable resource areas. For the DOE effort to be useful it should take an expansive view as it analyzes potential priority corridors.

NIPPC does suggest the following general criteria to assist DOE in its investigation. The Department should consider designation where:

- High voltage corridors located in highly populated areas, such as the Interstate 5 corridor, regularly provide insufficient to both meet load and simultaneously provided sufficient capacity to facilitate regional interchange schedules.

- Artificial, locally enacted land use restrictions have been enacted for the express purpose of constraining high voltage transmission development. The policy of Whatcom County, Washington, a community that abuts urbanized British Columbia, is one such example of institutionalized NIMBY.

- Opportunities exist to link major control areas with one another especially where redundant looping has long been identified. One such example is the opportunity to link the British Columbia Transmission Corporation (BCTC) with the Bonneville Power Administration (BPA) or Avista that is currently under study by the Northwest Power Pool.

- Areas of developed or permitted resources are repeatedly curtailed and transmission planners agree and clearly demonstrate that relief can only provided through new construction. One such example is the John Day/McNary path long identified as constrained by BPA.

- Transmission corridors that have been identified by recognized planning organizations particularly those with the capacity to fund construction. The Wyoming Infrastructure Authority is one such entity.

Conclusion

The Northwest Independent Power Producers Coalition is an association of independent generators that are entirely dependent on third-party transmission to deliver their product to regional power markets. NIPPC maintains that the framework for regional transmission operation and planning is incomplete and is in no position to advance the vibrant wholesale power markets that can best serve electric utility ratepayers.

NIPPC urges DOE to take a second – even a third look – at the debilitating assumptions and operational practices that have to date hobbled transmission operations and infrastructure development in the Northwest and Intermountain West. The quality of DOE's work will be enhanced to the extent that Department looks past the "institutional congestion" that plagues the region and evaluates reality as based upon its own independent and rigorous assessments.

NIPPC looks forward to the opportunity to comment further as DOE pursues its congressionally mandated assignment. The work that the Department is undertaking is extremely important in laying the groundwork for operations that enable economic dispatch and long-delayed investment in truly needed infrastructure.

50. NorthWestern Energy, Received Mon 3/6/2006 1:35 PM

Attached are the responses from NorthWestern Energy concerning DOE's NOI on National Interest Electric Transmission Corridors. NorthWestern Energy appreciates the opportunity to respond to the NIETC NOI. NorthWestern Energy is supportive of DOE designating corridors of national interest based on pre-determined criteria.

If you have any questions, please contact me by responding to this email or at the phone numbers listed below.

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DOE 1221 Notice of Inquiry

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

NorthWestern Energy Input and Response

NorthWestern Energy (NWE) is one of the largest suppliers of electricity and natural gas in the Upper Midwest and Northwest, serving more than 617,000 customers in Montana, South Dakota, and Nebraska. NWE currently owns, operates, and maintains approximately 7000 miles of electric transmission, 50 kV and above, and approximately 2000 miles of natural gas transmission in Montana. Within Montana, NWE has over 2200 MW of resources in its Generation Interconnection Queue. Most of the firm transmission capacity from our control area to other areas within the Western States is already committed. There is potential for even greater resource development in Montana if there is sufficient transmission to accommodate these additions. In order to accommodate this growth in electric resources, existing corridors will need to be expanded or new corridors established.

NorthWestern Energy appreciates the opportunity to comment on the Department of Energy's approach to fulfilling the requirements of Section 1221 to the Energy Policy Act of 2005. NorthWestern Energy supports the efforts to designate National Interest Electric Transmission Corridors (NIETC). The designation of such corridors should be made when it is found that the national interests are supported and regional energy costs are reduced. Designation should not be withheld in order to maintain just a few NEITCs.

The Department invites commentators to address how broadly or narrowly the Department should consider and define corridors in its study and its NIETC designation.

The corridors should be defined narrowly enough that one knows that the facility they are trying to site falls within a corridor and not take in an entire interconnection. For example, a corridor from Montana to California is too broad since it encompasses the entire Western Interconnection within the U.S. However, a corridor defined from central Montana to the Mid-Columbia is specific enough without defining which route should be used within the corridor.

An NIETC should be designated based on criteria adopted by the Department even if a project has not been identified within the corridor. Waiting until there is a project proposed in a corridor would open the process up to more political pressures than already exist. This approach would put the Department in the position of selecting between potentially competing transmission projects. The designation should be significantly broad enough that multiple projects could fall within the corridor.

The NIETC designation should not have a fixed time frame. There needs to be recognition of the time frame needed to site, design and begin construction. The designations should be periodically reviewed to determine if the same concerns still exist for the designated corridor. If other system changes have removed the concerns that designation was meant to cover, then consideration may be given to rescind the NIETC designation. Otherwise, let the designations continue.

Interested parties will be invited to comment on or identify potential transmission corridors they think could be relevant to addressing such needs and corridors suitable for designation as NIETCs.

A potential NIETC corridor in the west is the corridor from central Montana to the Mid-Columbia through the Idaho panhandle. This corridor has many significant barriers to siting transmission. These include geographic barriers, relatively few passes through the mountains suitable for transmission development, population centers located within these limited routes, special use lands such as wilderness designated areas, tribal lands, etc. Development of this corridor will allow renewable resource and coal development to occur in Montana resulting in a more diversified supply for the Northwest and perhaps California and less reliance on foreign fossil fuels such as natural gas. Montana has significant resource potential, as evidenced by the *number of projects in NorthWestern Energy's study queues, that may not be developed unless this corridor or others are designated out of Montana. The resources in the NWE queues represent mainly low cost coal and wind.*

Another potential corridor route is from southwestern Montana along I15 to south central Idaho. In contrast, this route offers fewer land barriers and already has significant interest for transmission development. In fact, NorthWestern Energy is currently in the second phase of the development of a 500 kV line in this corridor with support from generators, load serving entities and other participants. However, transmission beyond south central Idaho will be needed to integrate the resources in Montana with the potential markets.

If interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI.

To assist the Department in conducting and preparing its electric transmission congestion study so that the study will be the most useful in helping identifying areas of need and areas potentially suitable for designation as an NIETC, the Department requests comments on the following questions:

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

The nature of the congestion should not be a deciding factor. The criteria should be that the congestion restricts use of the transmission system and has a significant impact on efficient regional dispatch.

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

No. Both restrict the use of the transmission in different time frames. Contractual congestion limits the use of the system for new users and in the pre-schedule periods and in day-ahead markets. Physical congestion limits the use of the system during real-time and requires voluntary generation redispatch or transaction curtailments through processes such as TLR.

(3) Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

NorthWestern Energy does not know of any other pertinent studies for the Western

Interconnection. The Department should rely on the most recent studies. The older the studies, the greater the chances are that the system has had significant changes, such as load shifts, new transmission, and new generation additions that affect the congestion on the system.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

Some of the metrics to use in developing geographic areas of interest include ATC, transmission service request denials, curtailments, and inefficient generation dispatch. Also, physical characteristics of the corridors need to be taken into consideration. These include ability to acquire rights-of-way, restricted geographic routes, population centers in the corridor and special use lands such as tribal or park service lands.

The Department invites comment on what criteria it should use in evaluating the suitability of geographic areas for NIETC status. Commenters are also invited to apply any of the draft criteria to one or more specific geographic areas and demonstrate how the criterion helps to identify such areas as having national significance for NIETC designation.

Draft Criterion 1: Action is needed to maintain high reliability.

This criterion relates specifically to load service areas. The solution may be locally sited generation rather than transmission. If the area meets the prevailing reliability criteria then this criterion should not apply. If there is an area that does not meet the reliability criteria, one questions why the incumbent has not taken action to come into compliance with the reliability criteria. Suggest that this criterion be given additional scrutiny and perhaps removed from the list.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Draft Criterion 5: Targeted actions in the area would further national energy policy

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or electricity infrastructure to natural disasters and malicious acts.

This criterion is too specific and does not lend itself to identifying geographic areas for designation. Loads this critical should have onsite backup generation and if needed, redundant transmission to the load. Recommend removal of this criterion.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytical assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies. ***What metrics would be suitable for gauging such uncertainties?***

When considering uncertainties, one needs to bracket the problem by looking at scenarios that vary the parameters that provide the uncertainty. For example, scenarios should be conducted that take into consideration a range of natural gas prices since the future markets are so volatile. The uncertainty concerning load growth really affects the timing of transmission additions and not necessarily the need. The cost of any generation needs to be part of the mix. If the cost of a new technology is in question, one should err on the high side costs.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

This criterion needs to be augmented such that there are existing impediments to siting transmission into the geographic area from all directions. Ownership of adjacent systems should not be a consideration.

The Department also seeks comments on two additional questions:

(1) Are there other criteria or considerations that the department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.

An additional criterion may be impediments to siting transmission within a corridor that keeps one from achieving the goals outlined in the above criterion.

(2) Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

Each criterion should stand on it's own. Those potential corridors that meet multiple criteria should be considered ahead of those that meet only one.

51. Ohio Consumers' Counsel, Received Mon 3/6/2006 4:20 PM

BEFORE
THE UNITED STATES DEPARTMENT OF ENERGY

In the Matter of the Department of Energy's Notice of Inquiry and Request on Considerations for Transmission Congestion and Designation of National Interest Electric Transmission Corridors.	**)))))**	**DOE-1221**

MOTION TO INTERVENE AND COMMENTS OF THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

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March 6, 2006

I. INTRODUCTION

The Office of the Ohio Consumers' Counsel ("OCC"), on behalf of more than 4 million residential electric utility customers in Ohio, moves to intervene in this proceeding, requests to be placed on the service list, and submits these comments ("Comments"). OCC is responding to the Department of Energy's ("DOE") Notice of Inquiry on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, FR Vol. 71, No. 22 (February 2, 2006) ("NOI").

OCC represents a consumer interest which may be directly affected by the outcome of this proceeding in which DOE is charged with designating National Interest Electric Corridors ("NTEC") that will receive special attention (resulting in transmission construction, build-outs, applications of advanced technologies, and perhaps ratemaking treatments) by the Federal Energy Regulatory Commission ("FERC"). OCC represents the interest of Ohio's residential utility consumers who are dependant upon and must pay for electric transmission in order to receive delivery of their electric service. In other DOE proceedings, any representative of interested consumers may be permitted to participate.[1] While such requirements do not control the DOE's determination in this proceeding, by analogy, OCC should be permitted to intervene, or be admitted to the proceeding and placed on the official service list.

II. COMMENTS

The Energy Policy Act of 2005 ("EPAct 2005") delegated to the DOE the responsibility of determining which national transmission corridors suffer from transmission or reliability issues, thereby threatening the reliability of the national grid. Once DOE has designated such corridors, the FERC is empowered to order construction or modifications to the designated

[1] Federal Energy Regulatory Commission proceedings pursuant to 16 U.S.C. § 825g (a), Federal Power Act.

corridors.[2] This new designation process by DOE and the authority of FERC to correct transmission reliability and congestion in certain circumstances, raises a plethora of state's rights and process issues. Any single issue could result in substantial impacts to Ohio's residential consumers and the OCC is authorized by Ohio statute to represent these interests, including through participating in this NOI.

A. National Transmission Electric Corridor Designation

OCC requests participation in this NOI to ensure the requirements of EPAct 2005 have been satisfied. The statutory requirements for designation of NETCs follow:

- Constraints or lack of adequate or reasonable priced electricity affecting the end markets served by the corridor or the economic vitality or development of the corridor;[3]

- Reliance on limited sources of electricity which jeopardizes economic growth of the corridor or end markets served by the corridor;[4]

- Diversification of supply is warranted;[5]
- Designation of the corridor would serve the energy independence of the United States;[6] or,

- Designation would enhance national defense and homeland security.[7]

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[2] EPAct 5005, Section 216(b).

[3] EPAct 2005 Section 261(a)(4)(A).

[4] EPAct 2005 Section 216 (a)(4)(B)(1).

[5] EPAct 2005 Section 216 (a)(4)(B)(ii).

[6] EPAct 2005 Section 216 (a)(4)(D).

[7] EPAct 2005 Section 216 (a)(4)(E).

These policy interests established by the EPAct 2005 do not include criteria for determining when and under what circumstances they are satisfied. DOE must interpret the stated policies by establishing criteria for measuring when deficiencies exist and what deficiencies require correction. Any one of the statutory criteria raises several issues, *inter alia*:

- Whether the criteria established by DOE are appropriate and likely to advance the policy interest established by the statute; or
- Whether the cause of the corridor failures could have been prevented, and if so, what alternative approaches were available.

The second issue may not inform FERC's decision to order remediation for the designated corridor, but it may affect how the remedial action is funded (*see*, paragraph B, below). The first issue - whether the correct standards were used in determining what NTECS should be designated - may very well affect FERC's willingness to order remediation at best, and at worst, failure to use the correct standards for designating NTECs could cause the DOE to miss entirely corridors that should be designated. OCC requests participation in this process.

B. **FERC Use of Designated NTECs**

Once NTECs have been designated by DOE, FERC is authorized to order construction of transmission facilities or modification of transmission facilities in that corridor in the following circumstances:

- State blockage, inaction or incapacity;[8]
- The constructed or modified transmission facility will;

    1. be used for transmitting electricity in interstate commerce;[9]

[8] EPAct 200 Section 216 (b)(1).

2. be consistent with the public interest;[10]

3. protect the benefits of consumers and significantly reduce transmission congestion in interstate commerce;[11]

4. will be consistent with sound national energy policy and enhance energy independence;[12] and,

5. maximize the transmission capabilities of existing towers or structures to the extent reasonable and economical.[13]

Such actions by FERC could have substantial economic consequences to consumers who may be required to pay for FERC-ordered transmission expenditures. Because FERC's determination regarding expenditures for transmission improvements is based upon DOE's designation in this NOI, the determinations by DOE have far-reaching consequences for consumers.

FERC's decisions regarding transmission improvements also raise several important state issues, to wit: state economic and environmental concerns and states rights generally. These issues could easily have important consequences for Ohio's residential consumers.

For these reasons it is important that OCC participate in DOE's NOI.

III. CONCLUSION

In this proceeding the DOE must establish criteria for designating NTECs and then apply those criteria to the transmission corridors submitted to them for

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[9] EPAct 2005 216 (b)(2).

[10] EPAct 2005 216 (b)(3)

[11] EPAct 2005 Section 216 (b)(4).

[12] EPAct 2005 Section 216 (b)(5).

[13] EPAct 2005 Section 216 (b)(6).

consideration. OCC represents the interests of approximately 4 million consumers that will be affected by DOE's designations. These designations will have real and substantial impacts on consumers.

When the FERC orders remediation of NTECs to correct economic congestion or reliability issues, consumers will again be affected by the costs of such remediation. For all the above-stated reasons, OCC requests intervention in this proceeding and to be placed on the official service list.

Respectfully submitted,

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Filed electronically March 6, 2006

52. Old Dominion Electric Cooperative, Received Tue 3/7/2006 8:44 AM

COMMENTS OF
OLD DOMINION ELECTRIC COOPERATIVE

Pursuant to the February 2, 2006 "Notice of Inquiry Requesting Comment and Providing Notice of a Technical Conference" ("NOI") issued by the Office of Electricity Delivery and

Energy Reliability of the Department of Energy ("Department"), 71 Fed. Reg. 5660, Old Dominion Electric Cooperative ("Old Dominion") hereby provides its comments.

I. IDENTITY OF OLD DOMINION

Old Dominion is a not-for-profit power supply electric cooperative, organized and operating under the laws of Virginia and subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Old Dominion supplies capacity and energy to its twelve electric distribution cooperative members, all of which are located within the control area of PJM Interconnection, L.L.C ("PJM"), including on the Delmarva Peninsula. Old Dominion is a generation-owning utility, dependent upon use of the transmission facilities operated by PJM to deliver the output of Old Dominion's generation facilities located within PJM and to deliver periodic power purchases from third party sellers to the load of its member systems.

II. COMMENTS

A. General Considerations In NIETC Designations

The NOI indicates that the Department is interested in comments addressing "how broadly or narrowly the Department should consider and define corridors in its study and its NIETC designations." Old Dominion submits that corridor designations need to be "just right;" not too broad, but not too specific lest state routing considerations are usurped. With this overarching observation in mind, Old Dominion offers the following specific observations.

The Department should focus on establishing corridors between multiple existing infrastructure points with generalized paths in between. Where possible, existing corridors and upgrading existing transmission lines should be considered. This approach is consistent with the scope of effort set forth in the NOI. Corridors designated as NIETC would thus authorize FERC "to issue permits for the 'construction and modification of electric transmission' in the NIETC, provided that FERC finds that certain conditions have been met." This language clearly anticipates using existing infrastructure as appropriate as well as a level of specificity that balances conceptual corridor designation with the need for states to designate precise routes within these corridors.

A good example of an appropriate level of detail for a corridor designation may be found in Karl Pfirrmanns' testimony regarding Project Mountaineer in FERC Docket No. AD05-3-000, which Appendix A of the NOI indicates the Department already has under review.

Too broad a designation of corridors (*e.g.*, electrical interfaces) will frustrate Congress's intent to facilitate licensing. It is important to designate specific facilities rather than a family of alternatives if we truly wish to move forward with the construction of critical infrastructure. Multiple endpoints will only delay the process to specify and select a final route.

An important consideration for corridors, moreover, is identifying the load areas the corridor is meant to serve. Consideration must be given to meeting public need rather than simply to maximizing corporate profits. For example, vertically integrated utilities with dominant generation affiliates may wish to build transmission that facilitates delivery into a higher-priced market without giving consideration to serving their own load within an RTO.

Areas of load on the fringes of a system, such as Florida and the Delmarva Peninsula, deserve corridor support to serve their fast growing loads and should not be ignored. Corridors should be forward looking and address areas of high load growth.

Designated corridors should also be the product of an open and inclusive process assuring all affected stakeholders can meaningfully participate. Specifically, stakeholders need to participate in selecting between viable alternative transmission solutions (projects) that remedy reliability violations and economic congestion.

The Department needs to designate corridors that actually reach into congested areas. This is necessary to address the clear intent of the NOI: “Such needs may include relieving existing or emerging congestion, addressing existing or emerging reliability problems, enabling larger transfers of economically beneficial electricity to load centers, or enabling delivery of electricity from new generation capacity to distant load centers.” Proposals that do not reach actual load pocket areas would clearly not meet the intent of this NOI.

B. The Congestion Study

In the NOI, the Department solicits comments on several questions concerning the initial electric transmission congestion study required by section 216(a)(1) of the Federal Power Act (“FPA”). Old Dominion offers the following comments in response to the Department’s questions.

In conducting its congestion study, the Department should examine both dynamic (acute) as well as persistent (chronic) congestion. Acute congestion can provide a good indicator of future chronic congestion, as well as upcoming incremental reliability requirements.

The congestion study, moreover, should include both past and projected congestion. Past congestion impacts should be considered based on actual history. For PJM this analysis would begin from April 1998. Future congestion should be projected over at least a 15-year period to be consistent with the proposed revised planning protocol within PJM and to give perspective on growing “trouble” areas of the system.

The congestion study should consider gross congestion rather than the tiny subset of congestion that is unhedgeable. Consideration of only unhedgeable congestion masks the economic reality that hedging itself has an economic cost. As testimony to this, consider that after being in effect for two years, for example, the PJM Economic Expansion Planning Process based on unhedgeable congestion rather than gross congestion has not resulted in any transmission upgrades.

Further, in calculating congestion, the Department should calculate the amount of congestion between established liquid trading hubs (*e.g.,* PJM West) and known load pockets (*e.g.,* the Delmarva Peninsula).

Finally, in response to the Department's request that comments identify other relevant transmission congestion studies, Old Dominion notes that it evaluated historic and future congestion on the Delmarva Peninsula in FERC Docket No. PA03-12-000. That analysis indicated that, between April 1998 and 2002, Old Dominion experienced over $28 million in congestion. Projected congestion on the Peninsula was forecast to be $11.8 million by 2009. These materials were designated as Exhibits ODC-29 through ODC-36 in Docket No. PA03-12-000, and, Old Dominion submits, they offer excellent insight into the analysis of congestion and we offer this for the Department's consideration.

C. Criteria For NIETC Designation

Old Dominion generally supports the criteria proposed by the Department in the NOI with the exception of draft criteria number 8 (alternative means of mitigating the need in question have been addressed sufficiently). This criterion seems to be based on the misconception that transmission is a competitive commodity on an equal footing with generation and demand response.

Review of FERC Dockets AD05-5, PL03-1 and RM05-5 provides plenty of evidence that transmission construction has significantly lagged other utility investments in the recent past. In addition to the regulatory hurdles addressed below, a large part of the problem has been an "economic" view that transmission can be a competitive commodity. While this may have appeal in some theoretical circles, the stark reality is that transmission is a regulated asset, built over the years to serve load, paid for by those served and is a necessary regulated transportation system to facilitate competitive wholesale generation markets. As the industry continues to move into a competitive marketplace, we must change the way we plan the grid to recognize this significant paradigm shift.

D. Relevant Regulatory Considerations

The underlying premise of the NOI (and of FPA section 216 in general) is that investment in transmission infrastructure has not kept pace with the needs of customers due, at least in part, to difficulties in siting facilities. The designation of certain geographic areas as NIETCs, it is presumed, will facilitate investment in areas in which it might otherwise have been difficult to site transmission. Old Dominion does not doubt that concerns about siting have been a factor inhibiting transmission investment. Old Dominion submits, however, that there are other significant regulatory factors inhibiting transmission investment that need to be addressed in tandem with evaluations of potential NIETCs in a given region. In the NOI, there are several references directing the Department to address regulatory obstacles in the planning and construction of electric transmission and distribution lines. Although possibly beyond previous

Department areas of focus, the following issues are nonetheless relevant and require resolution to get necessary transmission infrastructure built:

Some hold the view that regulatory incentives are needed to promote transmission investment. In this connection, FERC currently has proceedings underway to address incentive rates for transmission (Docket No. RM06-4-000) pursuant to new section 219 of the FPA. Additionally, the Commission has explored impediments to transmission investment in Docket Nos. AD05-5-000 and PL03-1-000. In its comments in these forums, Old Dominion has, for instance, endorsed rates that allow recovery of construction work in progress and expensing of pre-operational costs in appropriate circumstances to give investors in transmission greater certainty of cost recovery. However, Old Dominion unequivocally opposes incentive adders on allowed rates of return for new transmission. Transmission rates of return as calculated under FERC's current cost-based policies are sufficient to attract investment. Other issues, such as retail rate freezes and regulatory certainty are obstacles to getting transmission built.

A regional long-term rate design is critical. In FERC Docket No. EL05-111-000, Old Dominion has filed a proposal for a "highway-byway" regional rate design. This design attempts to equitably define the middle ground between "postage stamp" rates (*i.e.*, where the same transmission rate applies regardless of the "source" and "sink" of the transmission) and zonal rates by allocating costs of transmission based on its functionality. Costs for high voltage facilities capable of transferring bulk power over great distances would be recovered from the entire region. Local facilities would continue to be recovered from their affected zone. The highway-byway rate design charges for transmission with regional benefits to the entire region and thereby recognizes cost-causation principles in a broad, holistic fashion.

Transmission market power must be eliminated. In FERC Docket No. RM05-25-000, Old Dominion identified the issues associated with transmission market power. In essence, a regulated transmission company with competitive generation affiliates can plan the system to favor its affiliate's generation and can be a strong advocate for "minimalist" transmission planning practices that provide only incremental improvements to stay ahead of short-term transmission reliability violations. With the current situation where many transmission companies are affiliates of generation companies, transmission can be built by a transmission owner to support its own generation while at the same time transmission investment is avoided when it disadvantages a transmission owner's generation. Traditionally the transmission owner or incumbent utility has been the only means to fund transmission upgrades. An important mechanism to overcome the roadblocks to expansion of the bulk transmission grid is through joint ownership of transmission projects. Publicly-owned and non-profit utility systems have been overlooked as potential partners in transmission facilities and systems. Joint projects could reduce the financial burdens on existing transmission owners and spread the perceived transmission-related risks.

The current "closed" transmission planning process that excludes certain key stakeholders must be open to a wider constituency. In FERC Docket No. RM05-25-000, Old Dominion described the current PJM planning process that has evolved from a tight power pool where incumbent vertically integrated utilities exclusively planned the regional grid. This process needs to continue to evolve into one where all affected stakeholders can collaboratively and inclusively participate in identifying transmission projects for both reliability-based improvements and for needed, yet rarely built, economic based improvements. The Department can help foster this transparency and inclusiveness by requiring any and all designated corridors be the result of an open and inclusive planning process that accommodates all affected stakeholders, including those who will ultimately pay for the transmission. The current process in PJM is not sufficient. For instance, the PJM Transmission Expansion Advisory Committee (TEAC) merely serves a report-out function for transmission owner-identified transmission solutions rather than as a participatory forum to collaboratively identify transmission solutions and to evaluate alternatives transmission projects.

Regional transmission must be built to facilitate a competitive energy market without excessive gross congestion or locational marginal price ("LMP") differentials. Even if financial transmission rights ("FTRs") are available to help hedge congestion, they are limited in effect and can be expensive to obtain. Notwithstanding the price signals arguably sent by LMP, there still remains insufficient transmission to relieve congestion in many areas within PJM, such as on its fringes in the Delmarva Peninsula. LMP sends some price signals to generators for locating, but it sends *no* signal on building rate-based transmission. Rate-based transmission is built based solely on reliability criteria violations and as a last-resort, "backstop" for unhedgeable congestion. After more than a year of being in effect, no transmission has been ordered to be built under this regulatory backstop in PJM. Total congestion, rather than the miniscule amount of unhedgeable congestion, is a function of LMP, but PJM does not build transmission based on LMP. As load-serving entities, the increased congestion costs and lack of adequate response thereto remains a dire concern.

III. CONCLUSION

Old Dominion appreciates the Department consideration of public comment in this process, and urges the Commission to consider the not-for-profit views of public power entities like Old Dominion in adopting criteria for gauging the suitability of geographic areas as NIETCs.

Respectfully submitted,

Old Dominion Electric Cooperative

_/s/ *Ed Tatum*___________________
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53. Oklahoma Municipal Power Authority, Received Mon 3/6/2006 3:56 PM

Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors	Notice of Inquiry

COMMENTS OF THE OKLAHOMA MUNICIPAL POWER AUTHORITY

The Oklahoma Municipal Power Authority ("OMPA") joins in and supports the comments of the Transmission Access Policy Study Group in response to the Department's Notice of Inquiry, "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors."[1] OMPA[2] files separately to address a particular transmission

[1] The NOI appears at 71 Fed. Reg. 5660 (February 2, 2006).

[2] OMPA is a governmental agency of the State of Oklahoma and a body politic and corporate created pursuant to the Oklahoma Municipal Power Authority Act of 1981. OMPA is authorized by statute to jointly plan, finance, own and operate electric power supply facilities. OMPA acts as a wholesale power supplier to 35 municipalities in the State of Oklahoma and is a supplier of contract capacity and supplemental energy to three cities in Kansas. The total coincident peak demand of all of OMPA's participating members in 2003 was in excess of 610 MW, including load

corridor for identification and designation as a National Interest Electric Transmission Corridor ("NIETC"): *i.e.,* the geographic area between the Electric Reliability Council of Texas ("ERCOT") and the Southwest Power Pool ("SPP"). The NOI as issued spells out:

> ***In that regard, if interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI.*** If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. If interested parties wish to identify areas for early designation, they should supply with their comments all available data and information supporting a determination that severe needs exist. Parties should identify the area that they believe merits designation as an NIETC, and explain why early designation is necessary and appropriate. The Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

It is this invitation to which OMPA here responds.

Transmission Between ERCOT and SPP is congested and substantial price differentials prevail between the regions.

NOI draft criteria 2, 3, and 5 concern action necessary: (1) to achieve economic benefits for consumers; (2) ease electric supply limitations in end markets served by a corridor and diversify resources; and (3) targeted to further national energy policy. Designation of the geographic corridor between ERCOT and SPP as an NIETC satisfies all of these criteria.

ERCOT and SPP are interconnected by means of the North and East DC ties. Within the last two years OMPA was forced to undergo costly and time consuming studies in order to be informed officially by a transmission owning utility as to a basic fact already well known to market participants in the region: transmission between ERCOT and SPP is congested. The American Electric Power Service Company informed OMPA that it would be necessary to build a wholly new North tie facility in order to provide OMPA 29 MW of additional firm service to move electricity from ERCOT into SPP out of a new entitlement in the coal-fired Oklaunion generating

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on the transmission system of AEP-affiliate Public Service Company of Oklahoma ("PSO") of 157 MW. OMPA is a member of SPP. To serve its participants, OMPA relies on the transmission systems of AEP affiliates PSO and Southwestern Electric Power Company, Oklahoma Gas & Electric Company "OG&E"), Western Farmers Electric Cooperative, and Westar Energy, all of which are also currently members of SPP station. While the right to that new entitlement in Oklaunion is presently moving its way through the Texas state court system, OMPA's experience is representative of a regional market failure characterized by prevailing price differentials between ERCOT and SPP and inadequate transmission capacity linking the two regions.

OMPA submits for DOE's benefit, and in support of OMPA's position, the Independent Market Monitor report dated May 31, 2005, and entitled "2004 State of the Market Report Southwest Power Pool, Inc." ("IMM Report").

The IMM Report was prepared by Boston Pacific Company, Inc., the Independent Market Monitor for the Southwest Power Pool, Inc. The IMM Report describes an increase in transmission service requests in 2004, which "can be a measure of both the demand for access to the transmission system in the SPP region and SPP's ability to grant access." IMM Report at 30. There were 15,612 requests per month in 2004, compared to only 12,788 per month in 2003 and 10,222 per month in 2002. *See* IMM Report at 31. Most significant were the figures about how many requests were denied by SPP for transmission service between ERCOT and SPP. According to the report, "much of the overall increase in requests during the second half of 2004 may have been due to requests submitted for use of SPP's DC ties with ERCOT." IMM Report at 34. Because of the large volume of requests, <u>in 2004 SPP denied 62,276 requests for exporting power out of SPP over the ERCOT East tie and 6,951 requests for exporting power out of SPP over the ERCOT North tie</u>. *See* IMM Report at 34 (emphasis supplied). The IMM correctly notes that "the large number of requests experienced by SPP for exports over the DC ties to ERCOT is a potential indicator of the demand for such service." IMM Report at 35. The denied transmission requests involved transmission primarily from North to South (from SPP to ERCOT).[3]

The IMM Report also presents data showing substantial price differentials between ERCOT and SPP. The IMM Report shows that the average annual on-peak energy price in SPP in 2004 was $45.29/MWh, while the annual on-peak energy price in ERCOT in 2004 was $47.32/MWh, for an annual average difference of $2.03/MWh. *See* IMM Report at 45, 52. Off-peak, the average SPP price was $20.58/MWh, while the ERCOT price was $31.49/MWh, for an average difference of $10.91/MWh. *Id.* The IMM Report observes that "the significant differences in power prices between SPP … and ERCOT should provide incentives for exports from SPP even after costs to move power are taken into account." *Id.* at 53.

OMPA's experience in trying to move power supply entitlements from ERCOT into SPP, the numerous transmission requests denied by SPP and the price differentials between SPP and ERCOT all point towards a need to address inadequate tie capacity between the two regions. A DC tie is bi-directional: any new or upgraded DC tie facility between ERCOT and SPP will thus provide transmission capability in both directions (*i.e.,* North to South and South to North). Additional DC tie capacity will alleviate existing constraints and allow SPP to grant more transmission requests in both directions.

[3] The IMM Report (at 34) state that there were 2,097 unconfirmed requests for exports over the DC ties between SPP and WECC and for importing power into SPP over the ERCOT DC ties.

NIETC designation is uniquely suited to address the complexities of expanding transmission capacity between ercot and spp

Notwithstanding the substantial prevailing price differentials between ERCOT and SPP, and the inability of the present DC ties to accommodate transmission service necessary to respond to these market conditions, OMPA is unaware of any efforts on the part of SPP and its planning process to expand DC tie capacity between the two regions.

It is a fact that the existing ties came about only through long and difficult litigation some thirty odd years ago: the vertically integrated transmission owners had to be forced to interconnect ERCOT and SPP. *See, e.g. Central Power & Light Co.*, 17 F.E.R.C. ¶ 61,078 at n.1 (1981) ("proceeding had its antecedents in a complaint filed [in] 1976"), *order on rehearing*, 18 F.E.R.C. ¶ 61,100 (1982).[4] Notwithstanding FERC's assertion of jurisdiction over the ERCOT-SPP ties, legal clouds continue to be raised concerning the scope of ERCOT-related transmission rights. New Federal Power Act § 216(2) is uniquely suited to cut through this legal fog. The Secretary "may designate <u>any</u> geographic area experiencing electric energy transmission capacity constraints or congestion that adversely effects consumers as a national interest electric transmission corridor." The geographic region between ERCOT and SPP falls squarely within the language of FPA § 216(2). Consistent with FPA § 216(k) OMPA is not requesting the designation of an NIETC "within" ERCOT. SPP is providing transmission service over the existing high-voltage DC ties and SPP (and the relevant stakeholders) treat the ties as facilities falling within the SPP Eastern Interconnection footprint. Designation of the ERCOT – SPP region as an NIETC will resolve all doubts as to ability of market participants and (ultimately) consumers to benefit from necessary transmission capacity between the two regions.

Issues of lumpiness, and the difficulties associated with participant funding also pose impediments to increased transmission service between ERCOT and SPP. Addressing OMPA's request for increased transmission service in connection with the Oklaunion facility, the Federal Energy Regulatory Commission noted that "[t]he cost of building a 29 MW upgrade is $23.7 million and the cost of building a 200 MW upgrade is $57 million, indicating that the cost of a 200 MW facility is only 2.4 times the cost of a 29 MW facility although the size is nearly seven times larger." *Oklahoma Municipal Power Authority*, 110 F.E.R.C. ¶ 61,228, n.6 (2005). OMPA is pursuing the issue of approving the facilities in question with the SPP, but if the constraints are designated as NIETC the chances of getting the facilities actually built become much greater.

COMMUNICATIONS

Communications with respect to these comments should be addressed to:

Mr. Roland H. Dawson, General Manager Oklahoma Municipal Power Authority P.O. Box 1960	Robert C. McDiarmid Cynthia S. Bogorad Peter J. Hopkins

[4] When OMPA sought to exercise its contractual rights to upgrade the HVDC tie facilities to accommodate its increased share of the Oklaunion power, AEP objected that it had no such rights because AEP was transferring control over its transmission facilities to SPP and OMPA was transitioning to SPP service.

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CONCLUSION

For the foregoing reasons, OMPA respectfully requests that the Department consider and identify the facilities within SPP control needed to expand access across the ERCOT-SPP border region as an NIETC.

Respectfully submitted,

/s/ Robert C. McDiarmid

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March 6, 2006

54. Ontario Independent Electricity System Operator, Received Mon 3/6/2006 2:10 PM

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

Re: Considerations for Transmission
Congestion Study and Designation of
National Interest Electric Transmission
Corridors

Comments of the Ontario Independent Electricity System Operator on DOE/OE Notice of Inquiry

March 6, 2006

The Ontario Independent Electricity System Operator ("IESO") submits these comments in response to the Department of Energy's Notice of Inquiry ("NOI") regarding the Department's upcoming Congestion Study and its role in designating National Interest Electric Transmission Corridors.[5] The IESO participated in and generally adopts the positions contained in submissions filed by the Canadian Electricity Association ("CEA") and the Northeast Power Coordinating Council ("NPCC"). The IESO's submission is intended to reinforce these other submissions.

I. <u>Description of the Ontario Independent Electricity System Operator</u>

The IESO is the organization responsible for establishing and administering wholesale electricity markets and directing the operation and maintaining the reliability of the integrated power system within the Province of Ontario. The IESO is the Reliability Coordinator and Control Area operator in Ontario, and is a member of NPCC. The IESO's responsibilities include a broad range of integrated operations, including security assessment and scheduling, administration of the wholesale electricity market and ancillary services, and real time direction and coordination of the power system.

[5] *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors,* Notice of Inquiry, 71 Fed. Reg. 5660 (Feb. 2, 2006).

The IESO-controlled electric power grid is interconnected with grids in two Canadian provinces and three U.S. states. The IESO's comments focus on the integrated nature of the power system across borders and the electricity trading relationship between Ontario and neighboring U.S. states.

II. <u>IESO Comments</u>

The IESO respectfully suggests that the Department of Energy consider the following in its deliberations:

- ***the interconnected nature of the bulk power system***

The IESO believes that enhancing reliability should be a primary factor in the Department of Energy's (DOE) consideration for the transmission congestion study and designation of National Interest Electric Transmission Corridors (NIET). This consideration should also include the potentially internationally reliability impacts given the interconnected nature of the power system. In doing so, the IESO recommends that the DOE use the findings of existing or future planning and congestion studies conducted by the international electric regional reliability councils, such as the NPCC, in analyzing and evaluating the reliability impacts on the interconnections. The IESO, including other Canadian control area operators actively participate in these studies by providing relevant data and system assessments.

- ***the benefits derived from the long-standing electricity trading relationship between Ontario and the neighboring U.S. states:***

Ontario has direct transmission interconnections to three neighboring U.S states (Michigan, Minnesota and New York) which have fostered long-standing electricity trading arrangements. Regulatory policy that has advanced non-discriminatory access to transmission systems (e.g., Federal Energy Regulatory Commission's Order Nos. 888) and comparability rules have also allowed for increased cross-border energy trading opportunities within these interconnections. The IESO believes that the DOE consider the benefits that have been realized through these north-south interconnections over the years by not only evaluating transmission constraints that threaten reliability but also those constraints that may hinder economically and efficient wholesale electricity transactions across the international connections.

- ***cross-border cooperation to reduce vulnerability of critical interconnections to natural disasters or malicious acts***

In adherence to NERC standards, Reliability Coordinators have in place procedures regarding the security of critical infrastructure and also conduct analyses to mitigate consequences of extreme contingencies. Should the DOE seek further actions beyond those carried out by Reliability Coordinators in meeting NERC reliability criteria, the IESO finds substantial merit in a process that would permit cross-border cooperation for identifying and evaluating impacts given the interconnected nature of the bulk power system.

III. <u>Conclusion</u>

The IESO appreciates the opportunity to offer comment in this proceeding.

Respectfully submitted,

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55. Optimal Technologies (USA) Inc., Received Mon 3/6/2006 5:01 PM

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March 6, 2006

Via: Email transmittal, to EPACTl22 l @hq.doe.gov

Office of Electricity Delivery and Energy Reliability, OE-20

Attention: EPACT 122 1 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1 000 Independence Avenue, S. W.
Washington, D.C. 20585

6450-01–P. Comments on Draft Criteria For Gauging the Suitability of Geographic Areas As NIETCs, and Related Questions

Gentlemen/Ladies:

In response to Federal Register Notice of Inquiry entitled Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors that was published on February 2, 2006, Optimal Technologies (USA) offers these brief comments on the Draft Criteria For Gauging the Suitability of Geographic Areas As NIETCs, and related questions.

Advanced grid analysis and optimization software now exists in the marketplace that can address, at new levels of accuracy and detail, solutions for improving the reliability, voltage profile, and load serving capability of power systems, and portions of power systems, using such measures as recontrol of existing reactive power resources, and next-most cost-effective resource changes and additions. Optimal's "AEMPFAST" (pronounced "AIM-fast") software is one such advanced software product.

Generally, we offer the comment that analyses conducted under Draft Criteria 3, 6, 7, and 8 to determine the degree to which areas of the grid are congested or supply-limited so as to qualify as NIETCs, should include analysis, using the new software tools now available, of (1) the degree to which re-control of existing system resources (notably including reactive power resources), reduction of active power losses and reactive power consumption, and improvement of voltage profile, can reduce or delay the criticality of the congestion or supply limitation; and (2) the ranked, next-most-cost-effective resource additions (or location-specific demand response reductions) (including potential added generation and new wires alternatives) and bus-specific locations for such additions.

The new tools allow extremely precise measurement of gains in system reliability, improvements in voltage profile, reduction of active power losses, reduction in reactive power consumption, and extension of load-serving capability, among other available metrics that should be brought to bear on classifying areas of the nation's grid as NIETCs.

AEMPFAST excels in speed, precision, repeatability, scalability, and domain independence, and in real-time contingency analysis, voltage stability, dynamic stability, multi-objective system optimization, and generation of Resource Sensitivity Indices™ ("RSIs"™) that uniquely detect and verify, on a ranked, bus-specific basis, real and reactive power stresses and sensitivities at every individual bus in the system model. AEMPFAST applications significantly reduce system losses of active (P) and reactive (Q) power, reallocate P and Q system resources available to the system, minimize congestion and loop flows, and result in an optimized system voltage profile, improved system reliability, and enhanced power quality. AEMPFAST's algorithms also can determine the secure operating area for a system as large as based on multiple constraints and resources and monitor, update, and rapidly re-optimize the system state within this secure operations envelope.

We attach to these comments studies performed using such new software that demonstrate approaches that we recommend be used in applying Draft Criteria 3, 6, 7, and 8.

Thank you for the opportunity to comment on the proposed Draft Criteria.

Sincerely,

Richard E. Hammond
General Counsel and VP, Projects
Optimal Technologies (USA) Inc.

Attachments

Attachment 1 – AEMPFest Product Description

AEMPFAST Product Description

AEMPFAST Technology Features and Benefits

AEMPFAST™ ("Aim-Fast") is Optimal's proprietary family of software technologies for grid operators, planners, and regulators.

Far more powerful than any Load Flow or Optimal Power Flow package, AEMPFAST uniquely integrates system analysis, optimization, and operation with asset optimization, financial risk management, and regulatory objectives. These are core to the development of future "smart power grids".

AEMPFAST provides an analysis, optimization, management, ranking, and prediction tool kit capable of solving previously "unsolvable" problems. It allows modern and changeable objective functions, it is fast, it handles discrete parameters, and it ranks resources as to their net benefit based on the objectives chosen. AEMPFAST is part of Optimal's family of SmartGrid™ technologies, which include SUREFAST™, and AskOT™.

These capabilities make possible many new planning, operational, and business applications that can help utilities or system operators toward next-generation optimized planning and operation of their T&D systems. Advanced applications include:

- determination of best remedial actions,
- automated network planning,
- advanced distribution system automation,
- system emergency control,
- system restoration,
- security- and/or environmentally-constrained economic dispatch,
- among others.

The core AEMPFAST technology also is designed to interface with real-time/object/relational data storage/retrieval systems. It therefore offers advanced coordination, robustness, and maintainability for interdependent applications.

AEMPFAST analyzes transmission and distribution networks, system generation, system loads, and constraint conditions to determine the best control action to meet the criteria (objectives) specified by the system planner and/or system operator.

AEMPFAST uses QuixFlow™, our proprietary set of complex algorithms to achieve exceptionally accurate and fast results, and is designed to incorporate any number or combination of objectives. The user can choose simple objectives or a weighted mix of multiple objectives -- including a mix of engineering, business, and environmental objectives. Any number of objectives can be added.

As an operational tool set, AEMPFAST provides control center operators crucial capabilities to optimize, control, and coordinate the generation, transmission, and distribution of electricity in the most cost-effective manner while also maximizing reliability.

As a planning tool set, AEMPFAST can determine cost effective upgrade paths to current grids, locate and size equipment, and collect data for system planning and design.

As a financial tool set, AEMPFAST can be used to quickly and accurately monitor, control and coordinate various constraint and marginal pricing concerns.

AEMPFAST is based on a new Optimal-developed near-real-time mathematical approach to network analysis, optimization, ranking, and prediction called QuixFlow™. QuixFlow is a proprietary N-Dimensional (true non-linear) analysis, optimization, and ranking engine that also has defendable predictive capabilities and is applicable to any problem that can be modeled as a network. (e.g., T&D grids, pipelines, air traffic systems, and financial markets, among others).

QuixFlow uses no approximations; handles multiple objectives; and enforces multi-objective inequality constraints. QuixFlow uses a modern "operating system" architecture that allows many industry-specific, complex optimization subsystems to be "layered" on. Optimal has named the specific commercial application of QuixFlow to electric power systems "AEMPFAST", an acronym for "**A**dvanced **E**nergy **M**anagement **P**ower **F**low **A**nalysis **S**ystem **T**echnology".

AEMPFAST benefits include:

1. **Exceptional "Asset Optimization and Ranking" Through Node-Specific Mathematical "Pressure Indices"**
   AEMPFAST simultaneously generates system-wide sensitivity indices ("Pressure Indices"), which provide precise and defendable ranking and predictive capabilities for system adjustments (recontrols, resource or load additions or subtractions) toward the chosen objective or objectives. AEMPFAST's Pressure Indices provide multi-dimensional, ranked indicators of magnitude, direction, and location for further local and system-wide improvements, at levels not possible using current technologies. AEMPFAST thus provides an unprecedented and powerful "systems approach" to meeting Asset Management and Asset Optimization goals.

   To identify a set of resource additions to a system that will achieve the greatest system performance improvement, recognizing that each modification changes the system's behavior, AEMPFAST identifies potential system additions (and/or evaluates utility- or third party-proposed system additions). It recognizes that each upgrade changes the system's behavior and ranks modifications according to their benefit to the system. It sequentially incorporates the most valuable modifications, and re-optimizes the system to identify and rank potential additions. This is repeated until incremental network performance improvement reaches a point of diminishing returns. This process, which proceeds quickly because of AEMPFAST's unparalleled speed, yields valid and repeatable results.

2. **Exceptional Flexibility for Addressing Multiple Simultaneous User-Defined Objectives**
   AEMPFAST allows simultaneous system optimization for multiple user-defined objectives, including, among others, engineering, business, financial, regulatory, and strategic objectives.

3. **Exceptional Ability to Solve for Infeasible Cases**
   In any real system, especially a system under stress, all constraints cannot be satisfied, but a system solution nevertheless must be found to determine and maintain system security. All competing optimization tools fail completely in identifying steps toward such solutions. This renders them useless precisely when they are most needed.

AEMPFAST is the only technology that continues to produce practicable solutions in such situations. It consistently provides the best, lowest-cost feasible solution to meeting "hard" system constraints, while violating and maintaining a minimum number of "soft" constraints.

4. **Exceptional Execution Speed**
   AEMPFAST runs analysis and multi-objective optimization on large system datasets in seconds vs. hours or days.

5. **Exceptional Scalability**
   AEMPFAST offers end-to-end functionality from RTO[1]-level scale to individual end-use device.

6. **Repeatability (No Hysteresis)[2]**

7. **Exceptional Convergence Ability**
   AEMPFAST converges where competitor and traditional methods cannot.

8. **Exceptional Accuracy**
   AEMPFAST algorithms are non-linear and enforce multi-objective "inequality constraints" (please see detail below), and thus, they accurately represent real-world systems and produce accurate, dependable results.

9. **Domain Independence**
   AEMPFAST always determines the best global answer for a network, regardless of starting point.

10. **Ability to Reach Network Solutions Without Network Simplifications**
    AEMPFAST does not require the establishment of "optimization zones"; thus, the results are not affected by how these regions are created or the assumptions made about the "external system". By characterizing the network as it exists, without simplifications, AEMPFAST yields accurate, useful results not otherwise possible.

11. **Ability to Reach Solutions Without Requiring Built-In Assumptions**
    AEMPFAST forces no assumptions on the treatment of control variables. Variables are handled as optimizable, fixed, or locally controllable, as they occur in real-world networks.

12. **Network Topology Independence**
    AEMPFAST works for any network topology including radial, mesh, or hybrid.

13. **Ability to Maintain Inequality Constraints**
    AEMPFAST maintains inequality constraints as they actually occur in the real system, without converting them into equality constraints (a practice known to distort conclusions concerning voltage stability) or the conversion of inequality constraints to equality constraints.

    Unlike other Non-Linear optimizers, AEMPFAST directly handles both system "equality constraints" (that is, fixed and ascertainable values; e.g., "Per schedule, this generator must produce exactly 200 MW of power"; or "These various loads are known to be

[1]Regional Transmission Operator.

[2]In the context of optimization, "hysteresis" is the ability of an optimizer to repeatedly determine the same solution regardless of starting point in the network or solution path chosen. Testing for hysteresis is one of the traditional methods used to evaluate competitor claims of determining a global optimum. Use of a starting point outside the local domain, but within the same data set, that produces an answer different from that reached using a starting point within the local domain, verifies the inadequacy of the method or tool used. \

exactly, in the aggregate, 1453 MW") and "inequality constraints" (that is, constraints expressed as limits that fluctuate dynamically within a permissible range in a functioning system, e.g., voltage limits, reactive power (Q) limits). Approximately 70% of the constraints that operate within power systems are in the form of inequality constraints or dynamic limits. Generally, other Non-Linear tools marketed as "Optimizers" attempt to overcome such shortcomings by changing inequality constraints into equality constraints and/or by using distortive penalty functions. A clear, but critical, example of AEMPFAST's unique ability to handle inequality constraints is its ability to optimize a system for improved voltage profile.[3]

Competing optimization approaches do not assess or value improvements in voltage profile in the optimization itself, and only treat voltage stability limits subsequently, as constraints to be met. Consequently, other optimization methods provide no direct feedback on voltage stability in a system where all prescribed limits are being met. It is left to the engineer to observe the voltage profile and then guess where and at what locations additional resources might be useful in improving system performance.

14. **Open Architecture for adding Subsystems, Agents, and Objectives**
AEMPFAST is an advanced framework for orchestrated and optimized cascading systems of subsystems (intelligent agents), with each agent optimizing for its notable requirements. AEMPFAST can include non-engineering objectives (e.g., financial, regulatory, environmental, risk assessment, etc.). For grid engineering, it has the capability simultaneously to address system security, voltage profile, reliability, congestion, minimum loss, minimum generation cost, minimum emissions, and minimum maintenance, among other possible system operating goals.

15. **Verification of Results**
Although AEMPFAST's optimization and analysis capabilities are unique, all AEMPFAST results can be verified using industry-standard software.

AEMPFAST

¥ Easily optimizes transmission grid control, simultaneously taking into account efficiency, reliability, cost, security, contingencies, and environmental responsibility.

¥ Provides ranked performance indicators.

¥ Is fast and accurate, and is applicable to both design and operational duties.

¥ Determines grid control effectiveness.

¥ Simultaneously identifies and resolves resource deficiencies and excesses at each point in the network.

¥ Provides flexibility in goal selection (Objectives).

¥ Handles infeasibility.

¥ Handles very large systems.

¥ Is designed to accept and process data from existing SCADA and DCS systems.

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[3]Competing optimization methods do not assess or value improvements in voltage profile in the optimization itself, but subsequently treat voltage stability limits only as constraints to be met

- Integrates with SUREFAST.
- Provides the ultimate "Treasure Map" T&D asset optimization.

Call for details.

Attachment 2 – AEMPFest Frequently Asked Questions

Frequently Asked Questions

DRAFT

1 Basic Questions

1.1 What is AEMPFAST?

AEMPFAST™ (pronounced "aim-fast") stands for "Advanced Energy Management and Power Flow Analysis System Technology." It is a new highly accurate and fast, analysis, optimization and management technology for electrical power Generation, Transmission, Distribution and Distributed Resource (DG and Demand Side and Load Management) applications.

Electricity prices show the greatest volatility among all common commodities and are strongly related to numerous physical characteristics of the power system including transmission and distribution network capability, loads, demand-responsive loads, local distributed resources, hydrological conditions for hydro dams, fuel prices, fuel diversity, unit operating characteristics, and emission allowances, among others. These physical characteristics are all non-linear (meaning very small changes in any parameter can have exceptionally large impacts) and are further exacerbated because electricity cannot be stored economically. **Currently available tools cannot accurately model** for these real-world **electric transmission and distribution systems** and none that can include, as well, now necessary engineering, financial, and environmental objectives. For additional detail, please see Competitor Comparison .

AEMPFAST is unique in its ability to simultaneously (in the same model) handle:

[4]All specifications subject to change without notice.

- engineering (for both planning and operations),
- financial,
- environmental,
- regulatory, and
- user-defined objectives.

AEMPFAST uses a new algorithm, called QuixFlow™, to achieve exceptionally accurate and fast results, and is designed to incorporate any number or combination of objectives (or, in mathematical jargon, "objective functions"). The user can choose simple objectives or a weighted mix of multiple objectives. AEMPFAST records all variables, parameters, and controls, and also determines unique performance indices which describe the net benefit, or provable value, of each resource on the system.

AEMPFAST allows transmission and distribution system control centers to apply advanced, state-of-the-art real-time analysis, optimization, and management to the power grid. Using AEMPFAST, control center operators can monitor, control, and co-ordinate the generation, transmission, and distribution of electricity in a cost-effective manner. As a planning tool, AEMPFAST is used to analyze new transmission systems, determine cost effective upgrade paths to current transmission grids, locate and size equipment, and to collect data for system planning and design.

1.2 What is QuixFlow and what technology does it use?

QuixFlow is a new, Optimal Technologies-developed true non-linear method of analyzing and optimizing complex network problems.[5] It is flexible and scalable. *QuixFlow is not a stand-alone product but is designed to be the core optimization and analysis "engine" to a host of potential optimization products***.** It has been designed specifically to address the analysis and optimization of large scale networks and is the core technology behind AEMPFAST for the electric utility industry.

Unlike all other methods, QuixFlow is able to perform detailed and defendable resource rankings using a unique and sophisticated "scoring" and "prediction" technique.[6] QuixFlow, unlike other Non-Linear Methods, handles infeasible problems.[7]

QuixFlow was developed to respond directly to industry needs. The following figure highlights the primary features required to meet industry needs. It should be noted; to provide real, defendable benefits, ALL of the listed features must be included and that no competing method meets these requirements.

Figure: 1 Optimization Technology Comparison

[5] Other non-linear methods include Newton's Method, Lambda Iteration, Gradient's Method, and non-linear Interior Point Method; QuixFlow does not use any of these methods.
[6] This unique technique is a significant advancement over the Interior Point Method.
[7] For power systems, the Interior Point Method collapses when faced with infeasible buses and cannot enforce voltage limits.

	QuixFlow	Linear Programming Methods[f] (LP)	Non-Linear Programming Methods (NLP)	Non-Linear Interior Point Methods (NLIP)
Resource Indices (for detailed asset management)	**YES**QuixFlow Resource Sensitivity Indices (RSIs) simultaneously indicate the sensitivity of th	No	No	No
Accuracy of marginal prices	**Accurate**	N/A	Inaccurate (Due to quadratic penalties)	Inaccurate (Due to logarithmic penalties)
Determines optimal resource allocation/reallocation ("Treasure Map" functionality)	**YES**	No	No	No
Solves for multiple objectives	**YES**QuixFlow's flexible architecture encourages modification and/or addition of objectives, su	No	Limited	Limited
Maintains inequalities as inequalities as in the real world	**YES**QuixFlow enforces inequality constraints. In	Yes	No	Limited (Handles better than Newton's)
Handles infeasible cases	**YES**	Limited	No	No
Non-linear optimization (models the real world)	**YES**	No	Yes	Yes
High convergence	**YES**	Yes	No	No (Solution must be within boundary)
Global optimum	**YES**QuixFlow also allows for segmentation and "regioning".	No	Solution must be within boundary (not defendable for real world networks)	Solution must be within boundary (not defendable for real world networks)
Near real-time speed	**YES**QuixFlow is able to handle very large datasets with near linear performance impacts. Fo	Yes	No	No
Handles large data sets accurately	**YES**	Yes	No	Limited

Notes:

a) QuixFlow Resource Sensitivity Indices (RSIs) simultaneously indicate the sensitivity of the optimization objectives to changes in and throughout the system.

b) QuixFlow's flexible architecture encourages modification and/or addition of objectives, subsystems, and agents.

c) QuixFlow enforces inequality constraints.[8] Inequality constraints are handled as inequalities. They do not have to be converted into binding equalities using penalties.
d) QuixFlow also allows for segmentation and "regioning".
e) QuixFlow is able to handle very large datasets with near linear performance impacts. For example, with QuixFlow doubling dataset size results in a doubling of run times. This is in stark contrast to the other methods, where a doubling of dataset size using only the simplest of objectives results in at least a four times performance reduction. Further, depending on which of the limited objectives are chosen, other methods can become sixteen times (or more) slower.
f) Comparison Product Source Information: KEMA Consulting/Lawrence Berkeley National Laboratory, "Analysis and Selection of Analytical Tools to Assess National-Interest Transmission Bottlenecks, Final Report", March 2003.
g) The Linear Programming (LP) approach is most commonly used among today's providers.[9] This technique transforms the non-linear optimization problem into an iterative algorithm that in each iteration solves a linear optimization problem resulting from linearizing both the objective function and constrains. The value of LP approach is mainly the capability to deal with the inequality constraints. As it applies a linear approach to a non-linear problem, its results are inaccurate.

1.3 Can QuixFlow be used for other network analysis and optimization problems?

Yes. QuixFlow can be applied to pipelines, data traffic, air traffic, highways, and other non-linear analysis and optimization applications.

1.4 Does QuixFlow use an iterative or non-iterative method?

QuixFlow uses an iterative method and is therefore mathematical verifiable for every step of the method. Non-iterative approaches typically are not mathematically verifiable as there are no "steps" in which to monitor critical parameters, including convexity.

Further, although QuixFlow is iterative, each iteration is computationally inexpensive -- it performs well on PC class machines.

1.5 What are QuixFlow RSIs?

Among its unique features, much of QuixFlow's distinguishing functionality and versatility derives from its proprietary (patent pending) "Resource Sensitivity Indices" (RSI's). The RSI's make certain all possible optimization options are both included and understood, including those that are non-obvious and unavailable in competing mathematical methodologies. The RSI's are measurable, defendable, and can be assigned various mathematical and economic "prices". RSIs are produced within the same near-real-time run as the optimization itself -- no additional steps are required. RSIs are not derived from iterative assessment of resource placement. However, unlike dual variables, the RSIs do reflect benefits beyond marginal benefits.

[8] Competitors change inequality objectives to equality constraints to determine a solution. This defeats the possibility of conducting true system optimization by assigning fixed values to factors that in actuality are dynamically varying.
[9] Source: Lawrence Berkeley National Laboratory March 2003

QuixFlow RSI's provide both direction and magnitude for each local component in each of the objectives chosen toward the optimum system solution. They provide a unique understanding of the specific system-wide or global impacts of individual components, or of individual resource or load changes, and thus they can be used to measure simultaneously the effectiveness of resources at every point in the system towards both local and system-wide optimization objectives. RSIs', therefore, directly reflect the risk/benefit capability of the real system.

AEMPFAST uses the RSI's to precisely show the sensitivities of resources at specific, individual locations for the entire system.

With the RSI's, AEMPFAST continually indicates the lowest "price" approach (magnitude and direction) to meeting planning and operational objectives even when the system is operating in the "infeasible" area. This gives AEMPFAST users the ability to fully understand and rank the list of available contingency actions and their related deployment "costs" even under operating conditions that are impossible to model with traditional tools.

One way to think of this is as an entirely new level of "asset optimization", where the grid itself is the "primary" asset, but where all component pieces (the "secondary" assets) are "tuned" to maximize the objectives of the grid (the primary asset). For example, with a single plot, one can determine globally which specific devices, loads, interchanges, and generators contribute positively or negatively, and to what precise degree, to the current optimization objectives. The RSI's therefore, allow the performance of dramatically superior analysis, optimization, and management of individual components, as well as of each separate or linked distribution and transmission system. This is in sharp contrast to the smaller, segmented regional approach traditionally used in Transmission or Distribution System analysis. Traditional analysis cannot optimize and rank for local AND interregional effects, since these effects are rarely contained or caused only within the smaller region. Further, because of AEMPFAST's unique ranking ability, the list of options for upgrade and expansion, as well as their contingencies, is complete, measurable and defendable.

For example, if we add some resource at a given location in the system, the marginal price of the location changes and hence once the resource is added, the location may not be the most sensitive location anymore (i.e., it may provide the most benefit for resource additions); or, if we add too much resource at the given location, the marginal price may reverse its sign and the location may become the most sensitive location at which to remove the next increment of resources (i.e., it may provide the most benefit for resource subtractions). To state this in another way, the best location at which to add, say, 50 MW of generation in a given system may not be the best location at which to add, say, 100MW of generation. AEMPFAST indices consider such situations when suggesting locations for resource additions/changes.

Further, for poorly performing devices already installed, RSIs are instrumental in showing precisely what changes are needed to provide and maximize a positive benefit.

1.6 Do other optimizers provide detailed performance indices?

No. In AEMPFAST, RSIs are maintained for all system resources, including buses, feasible or infeasible. Although oversimplified, for Voltage Profile Objectives, RSIs measure the effort required to bring each bus voltage within the desired voltage profile.

RSIs are not an add-on, they are an integral part of AEMPFAST, and a direct measure of QuixFlow's determination to improve the efficiency of the system. When used with buses, they are a direct reflection of the security of each bus.

1.7 Are RSIs Lagrangian Multipliers?

No. QuixFlow (AEMPFAST) RSI's directly reflect the Objectives chosen and are therefore very useful at ranking real risk and real options to reduce risk. Lagrangian multipliers can't do this.

1.8 Why does QuixFlow always produce a better result?

Optimal Technologies has developed QuixFlow to overcome all significant limitations of competitive mathematical methods, including Newton's OPF and Non-linear Interior Point methods.

Further, all competitive packages in common use today rely on Linear Programming methods for their core technology. Linear Programming methods are inaccurate and cannot meet non-linear network challenges as found in power systems. AEMPFAST, with its true non-linear engine (QuixFlow) easily produces a better result.

1.8.1 Does QuixFlow handle Inequality Constraints?

Yes, QuixFlow enforces inequality constraints. They are handled as they are in the real world -- they do not need to be converted into binding equalities using penalties.

One of the biggest drawbacks of competing Non-Linear Programming (NLP) methods is that they cannot handle inequality constraints. We are aware that Non-Linear Interior Point (NLIP)-based competitors often claim otherwise, but all NLIP methods must use logarithmic penalty factors to enforce voltage inequality constraints. As with all other known non-linear methods, this is done by converting binding inequality constraints into equality constraints to arrive at a solution. The biggest problem here is to determine binding inequality constraints accurately. This is a serious and fundamental drawback because approximately 70% of the constraints that operate within power systems are in the form of inequality constraints (dynamic limits). It is for this reason that AEMPFAST always produces a "better" answer than competing non-linear approaches -- especially when the system is under stress (managing inequality constraints becomes dramatically more difficult) and the best deployable answer is critical to maintaining reliability and throughput. Another serious problem with methods that convert inequalities into equalities is that, they diverge (or crash) when solving infeasible problems.

Although inaccurate, it is important to note that Linear Programming (LP) methods are the most commonly used among competitors (please see Competitor Comparison) because LP methods can deal with inequality constraints.

1.8.2 Does QuixFlow handles Infeasible Cases[10]

Yes.

All known competing methods, regardless of variation, cannot handle infeasible cases -- i.e., if there is no solution to a given optimization problem that satisfies all of the constraints, all methods, including NLIP-based methods, fail to converge. In other words, they cannot produce a viable answer. Even for the most practical T&D systems, there are at least a few limits that cannot be satisfied under all required conditions (e.g., voltage limits). This is especially true when the subject system is heavily loaded. This is an acute limitation, because an otherwise defendable solution may not be possible when the system is in trouble and a solution is hypercritical.

1.8.3 Does QuixFlow distort the model to maintain performance?

No.

QuixFlow is Fast: QuixFlow (AEMPFAST) run times are typically measured in seconds or sub seconds. Unlike traditional tools, which typically require run-times reflecting the square (for low complexity) or the cube of the dataset size (medium complexity), QuixFlow is super linear and therefore maintains the maximum possible performance as dataset sizes increase. Because competitors methods are not super-linear, they attempt to increase performance by introducing accuracy and robustness penalties that either linearize, simplify, or re-domain the problem space – all of which distort the ability to arrive at the best solution. Even when doing so, they continue to suffer the fact that they are not super-linear and slow dramatically as dataset sizes increase. QuixFlow does NOT require such distortive methods to maintain speed and accuracy, and scales much, much better than traditional technologies. For this and other reasons, we believe AEMPFAST is the only technology now available that makes future “smart grids” possible.

1.9 Can AEMPFAST optimize for “Market” and “Power Flow” objectives within the same model.

Yes. As described in the Final DOE Report entitled “Analysis and Selection of Analytical Tools to Assess National-Interest Transmission Bottlenecks”[11], **currently no other tools can perform market modeling and power flow optimization in the same tool**.

[10] Note: This does not mean that AEMPFAST converges for every possible situation, only that it has a very high degree of convergence and that it converges where other methods cannot.

[11] This report was coordinated by the Consortium for Electric Reliability Technology Solutions (Lawrence Berkeley National Laboratory) and funded by the U.S. Department of Energy, Office of Electric Transmission and Distribution under Contract No. DE-AC03-76SF00098, 2003

1.10 Can't any solver obtain a local optimum by methodically relaxing the fixed P and Q values at all buses, given the objective of minimizing losses and/or maximizing bus voltages.

No. While it is true that methodically relaxing P and Q values to systematically minimize the objective will result in a local optimum, there is no reasonable way to assure that such a solution results in a global optimum. (statistically speaking: the probability of luckily arriving at the global optimum is low).

Traditional methods, applied to the same system but starting from different points using the same dataset, fail to produce the same or even a single correct answer. AEMPFAST's founders were driven to seek and develop a new method that, among other functionalities, would generate consistently accurate global optimum values for a given system, starting from any point in the system.

Traditional methods are also extremely slow since the approach is more of a trial and error method than a systematic rigorous optimization.

1.11 How does AEMPFAST compete with other industry tools?

As can be seen in the following table, AEMPFAST is capable of reliable real-world analysis and optimization where competitive tools are not.[12]

Figure: 2 Competitor Comparison

Vendor	Package Name	Method	Accurate	Multi-Objective Engine	Accurate Resource Indices (Real-time Asset Assessment
ABB	GridView	LP	No	No	No
ABB	TRACE	LP	No	No	No
AREVA[13]	all	LP	No	No	No
EPIS	Aurora	LP	No	No	No
EPRI	TRACE	LP	No	No	No
EPRI	CAR	LP	No	No	No
GE	MAPS	LP	No	No	No
Henwood	PROSYM	LP	No	No	No

[12] Source: Final Report entitled "Analysis and Selection of Analytical Tools to Assess National-Interest Transmission Bottlenecks" coordinated by the Consortium for Electric Reliability Technology Solutions (Lawrence Berkeley National Laboratory) and funded by the U.S. Department of Energy, Office of Electric Transmission and Distribution under Contract No. DE-AC03-76SF00098, 2003. Additional information was gathered during September 2005 from each of the vendors websites.

[13] Formerly Alstom ESCA.

Henwood	RACM	LP	No	No	No
LCG	UPLAN	LP	No	No	No
Nexant	Scope	LP	No	No	No
Optimal Technologies	**AEMPFAST**	**QuixFlow**	**YES**	**YES**	**YES**
PowerWorld	Simulator	LP	No	No	No
PTI[14]	PSS/E	LP	No	No	No
PTI	TPLAN	LP	No	No	No
PTI	MUST	LP	No	No	No
Siemens	ProMod	LP	No	No	No
Siemens/New Energy	Power CC	LP	No	No	No
Siemens/New Energy	NOSTRADAMUS	Neural Network/LP	No	Limited	No
Tesla	TESLA	NLP	No[15]	Limited	No

1.12 Is AEMPFAST an operational tool or a planning tool?

It is both and more! The purpose of AEMPFAST is to improve significantly on the accuracy and flexibility of current systems without sacrificing speed. Presently, there is no known accurate and reliable product that is able to meet the needs of both the planner and operator. Current planning systems are too slow to be used for operational purposes, and current operational packages are not nearly accurate enough to be used for planning. This poses a fundamental problem: how can the operator possibly approach the control accuracy determined by the planners? AEMPFAST is the only product available that solves this fundamental problem: it can be used successfully for both operation and design.

Further, because AEMPFAST is fast AND accurate, it can be used to explore a great many more planning scenarios and options than is possible from any other tool. This translates directly into increased reliability and efficiency.

1.13 Does AEMPFAST give the Utility or System Operator the ability to "see" more detail than is possible with pre-AEMPFAST tools in use today?

Yes, much more. As is standard practice among competitor products, AEMPFAST does not suffer from inaccuracy (linearization), data granularity, simplification

[14] PTI is now a Siemens entity.
[15] Due to Quadratic penalties.

requirements, penalty factors, domain change concerns, and overly limited real-world objective functions to determine the best outcome. It therefore handles real-world load and network models much better than is possible from other available tools, including detailed models that can include individual loads, during analysis, optimization, ranking, and management.

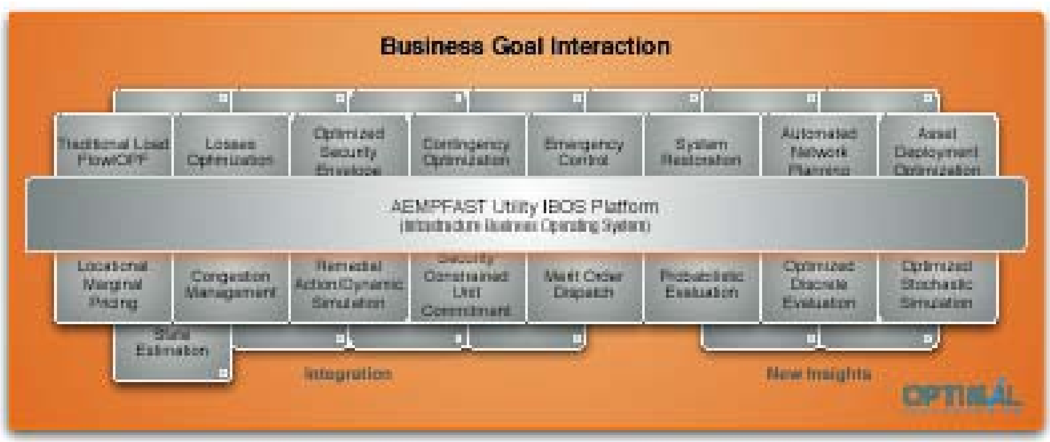
1.14 Does AEMPFAST use industry standard power and electrical engineering methods?

Yes. AEMPFAST uses industry standard formulas for all power and electrical engineering calculations.

1.15 Is AEMPFAST an OPF Program?

For various reasons (described in Optimization Technology Comparison), technologies traditionally classified as Optimal Power Flow (OPF) programs have not met with widespread technical or marketplace acceptance. Simply stated, they don't work well and don't work at all when they are most needed (when the system is running outside the reliability boundary).

In contrast, because AEMPFAST works very well and includes features and benefits that exceed those found in all OPF programs, Optimal Technologies does not describe AEMPFAST as an OPF tool but rather uses the term "Optimizer". Optimal Technologies does not wish to have AEMPFAST associated with the "OPF" industry acronym -- an acronym known primarily for its failures and inabilities. Comparison of AEMPFAST to other "OPF" programs is like comparison of a single-story building to a modern high-rise office building -- they both have doors, windows, rooms and hallways, but their ability, functionalities, features, benefits, and value are vastly different.



AEMPFAST provides a new analysis, optimization, management, ranking, and prediction tool kit capable of solving previously "unsolvable" problems. It allows new and changeable objective functions, it is fast, it handles discrete parameters, and it ranks resources as to their net benefit based on the analysis and optimization objectives chosen. These new capabilities make possible many new planning, operational, business, asset, and risk optimization applications that can help utilities or system operators toward next-generation, optimized planning and operation of their T&D systems. Looking only at engineering-related functions (and not the business, asset, or risk functions, which AEMPFAST also addresses) potential new AEMPFAST applications include, among many others, determination of best remedial actions, automated network planning; security- and/or environmentally-constrained economic dispatch; system emergency control; determination of best remedial actions and system restoration measures and sequences; and advanced Distribution System automation. Optimal Technologies also has designed AEMPFAST to interface with real-time/object/relational data storage/retrieval systems, and therefore it offers new levels of coordination, robustness, and maintainability for interdependent applications.

1.16 What is the difference between "Load Flow" and "Optimal Power Flow (OPF) technology"?

Load Flow is a software program that displays the currents, voltages, active and reactive loading of power system devices (e.g. lines, transformers, generators, etc.) after an iterative process of solving for node voltages and currents. Mathematically, Load Flow requires a solution of a system of simultaneous nonlinear equations usually using one of the following methods:

- Gauss-Siedel (which updates the node voltage one at a time)
- Newton-Raphson (solves a voltage correction for all nodes)
- Decoupled Newton-Raphson
- Fast Decoupled Method

Independent from solution-based methodologies (non-optimizing), Load Flow is used to answer "What If" questions. It is not used to answer the question of "What's The Best Option". For example, what will happen to a system if one takes a specific line out vs. what is the best option to keep the line from going out (or what's the best option to minimize the line outage)?

Load Flow is the "classical" approach to a variety of electric power system analysis problems. Load Flow is a simple "what if?" technology that is used to solve network equations and evaluate the performance of the electric system. It is used by virtually all planners and many operators and is generally considered accurate and scalable. It has traditionally been used in power system simulators, stability analysis, and contingency analysis. However, Load Flow only accurately shows what you have, it cannot itself find a better answer. Every change is driven by the operator.

To use load flow to determine the voltage, current, power, and power factor or reactive power at various (or all) points in an electrical network under existing or contemplated conditions of normal operation, you run a "case." To optimize the case, the engineer or operator must manually change certain factors, and then re-run it. Using Load Flow, you keep guessing and re-running the case until you run out of things to try. Since the correct solution is unknown, the answers provided by load flow technology are in effect, "educated guesses."

Imagine for a moment your "system" is a Picasso, but you want a Michaelangelo. Using Load Flow, you would need to manually change every brush stroke, every texture, every color, and so on to get from the Picasso you don't want to the Michelangelo you do want. After each and every manual change you would then re-run the Load Flow to see how well you did. Did it get better or worse? It is not difficult to imagine that given any significant changes your most likely outcome would be "mud" -- the least desirable of any option. In virtually all cases, unless you can use another new technology that guides your decisions, your only "safe" choice is to keep the Picasso, and accept the fact that you can make only small changes.

In contrast, Optimal Power Flow (OPF) technologies are presumed to use automated mathematical rigor, not manual "what if" changes, to arrive at the best answer.

An OPF program has to solve an optimization problem where the objective function, equality and inequality constraints are non–linear. This is an exceptionally difficult problem and many approaches have been presented in the literature over the years. Some of these approaches include:

- Lambda iteration method - Also called the equal incremental cost criterion (EICC) method. This method has its roots in the common method of economic dispatch used since the 1930s.[16]
- Gradient method[17]
- Newton's method[18]
- Linear programming method[19]
- Interior point method[20]

OPF should replace load flow technology for all infrastructure design and operating needs, but hasn't to date, because they produce inconsistent answers, are inaccurate or fail when most needed, are slow, and are inflexible. AEMPFAST overcomes these limitations.

Note: Virtually all power systems are built and designed using Load Flow. Because Load Flow produces an accurate "picture" of the system under review, it can be used to verify OPF results -- but cannot determine those results. Load Flow can, for example, show you have a Picasso or a Michelangelo but can't tell you what to do to change one to the other.

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[16] Source: A. J. Wood and B. F. Wollenberg, Power Generation Operation and Control, New York, NY: John Wiley & Sons, Inc., 1996, pp. 39,517.
[17] Source: H. W. Dommel and W. F. Tinney, "Optimal Power Flow Solutions," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-87, October 1968, pp. 1866-1876.
[18] Source: D. I. Sun, B. Ashley, B. Brewer, A. Hughes and W. F. Tinney, "Optimal Power Flow by Newton Approach," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, October 1984, pp. 2864-2880.
[19] Source: O. Alsac, J. Bright, M. Prais and B. Stott, "Further Developments in LP-Based Optimal Power Flow," IEEE Transactions on Power Systems, Vol. 5, No. 3, August 1990, pp. 697-711.
[20] Source: Y. Wu, A. S. Debs and R. E. Marsten, "Direct Nonlinear Predictor-Corrector Primal-Dual Interior Point Algorithm for Optimal Power Flows," 1993 IEEE Power Industry Computer Applications Conference, pp. 138-145.

1.17 **Why are multiple objectives required?**

Multiple objectives are required because society demands both economical use of resources and operating procedures that meet reliability, power quality, cost, environmental, and location specific considerations. Each utility will have varying planning and/or operational objectives.

Advanced Questions

2.1 **What Objective Functions are available for AEMPFAST?**

Any combination of the following Objective Functions can be customized for AEMPFAST.

2.1.1 **For Power Flow Planning and Operations Objectives**

- Improved system security / reduced system violations.
  This Objective improves system quality, and is always an objective in the analysis.
- Minimum generation cost
- Minimum active power loss
- Minimum reactive power loss
- Best voltage profile
- Minimum power cost
- Minimum Volt Amperes reactive cost
- Minimum Volt Amperes reactive loss
- Minimum control action / Curtailed control operation
  Optimization output often suggests changes to all controllable devices even though an operator cannot operate a large number of controls within a short duration. Therefore only the most effective control devices should be operated. By using this objective, only a manageable number of control operations are obtained.

  The curtailed control objective is used always in combination with one or more other objectives. Generally this objective is handled in two ways, as an objective, and/or as a constraint to the optimization process.
- Minimum deviation from current operating point.
  In a power system it is undesirable to adjust control devices by large amounts, due to time or mechanical constraints and because the sensitivities of these controls vary widely.
- Maximum reactive load at a selected bus
- Maintain a particular relationship/ratio between reactive load increase on a number of selected buses

2.1.2 For Business, Regulatory, and Environmental Objectives

- Global warming and minimum emission
  These Objectives are used to minimize harmful emissions of fossil fired generating stations. This Objective generally gives costlier solutions and is therefore used in combination with the minimum cost objective using an emission weight.
- Fuel diversity and fuel limitations
- Optimized “Ramp-rates”
- Statistical factors for scheduling (outages, planned or unplanned) objectives
- Price responsive demand and dispatchable load programs

Note: AEMPFAST is designed to give the user maximum flexibility in combining, mixing, and matching all objectives. It is also designed to allow easy addition of new, user-defined objectives. Optimal Technologies also develops new Objective Functions at the customer’s request.

2.2 Can AEMPFAST handle “Time Domains”?

Yes. As described in the Final DOE Report entitled “Analysis and Selection of Analytical Tools to Assess National-Interest Transmission Bottlenecks”[21], **currently no other tools can handle time domains and frequency of calculations objectives and constraints**.

2.3 Is there a need for additional Objective Functions?

Yes. New ways of doing business, open competition, environmental considerations, and changes in public attitude all have an effect on the design and operation of electric utilities.

2.4 Compared to other optimization systems, does AEMPFAST allow for multiple user-defined objective functions -- are they flexible?

Yes. Unlike other methods, where the mathematical algorithms are very tightly coupled to the problem definition and therefore are extremely inflexible, AEMPFAST is very flexible. In mathematical terms, AEMPFAST can be described as “decoupled”.

QuixFlow is a very flexible method. Decoupling lends itself to a large number of variations of the algorithm to handle a large variety of objectives, including multiple objectives. Because other optimization techniques are by necessity tightly-coupled, it is difficult, if not impractical to add new objectives.

[21] This report was coordinated by the Consortium for Electric Reliability Technology Solutions (Lawrence Berkeley National Laboratory) and funded by the U.S. Department of Energy, Office of Electric Transmission and Distribution under Contract No. DE-AC03-76SF00098, 2003

Due to its decoupled nature, QuixFlow can provide optimization for only parts of the system, as well as for the entire system, or optimizations based on different sets of objectives for different parts of the system.

Decoupling also provides a better framework for innovative new enhancements that allow QuixFlow to solve very large systems very quickly.

2.5 What power system control devices does AEMPFAST handle?

AEMPFAST handles both active and reactive power controls during optimization. Some of the controls are:

- Generator active and reactive powers
- Generator voltage control settings
- TCULs
- Phase shifters
- Switchable capacitors (SVDs, SVCs, etc)
- Load active and reactive power parameters
- HVDC control settings
- Power import/export

During optimization the variables are handled as optimizable, fixed, or locally controllable, as they occur in real-world networks

2.6 Can AEMPFAST prioritize regions of transmission/distribution systems using different weights on objectives and/or different objectives.

Yes.

2.7 Does AEMPFAST accept difficulty levels for constraints?

Yes. To avoid huge violations, planners can set up a graduated scale to vary relaxation steps. In the final analysis, however, constraints are constraints. AEMPFAST meets constraints.

2.8 What is infeasibility?

If the power to be transmitted on a network exceeds the transmission capabilities of that network, then the solution provided by the optimizer is *infeasible*, because one or more important parameters will have exceeded the specified limits. For example: buses will have voltages that exceed the specified limits. Such buses are called *infeasible buses*. The existence of infeasible buses can cause problems for optimization programs, and some actually fail when faced with this problem.

2.9 Is AEMPFAST designed to handle infeasibility?

Yes. AEMPFAST rates buses according to their degree of infeasibility and reduces the number of such buses. AEMPFAST always gives the best solution and keeps track of infeasible buses. In fact, AEMPFAST also lists and ranks buses that approach infeasibility, thus defining potential problem buses.

2.10 Does AEMPFAST handle voltage stability and dynamic stability?

Yes. Voltage stability and dynamic stability considerations can be added as constraints to AEMPFAST optimizations. Additionally, AEMPFAST also provides voltage and dynamic stability analysis modules.

2.11 Can AEMPFAST handle large networks?

Yes, AEMPFAST is exceptionally effective at handling large networks. AEMPFAST manages networks with over 150,000 buses with ease.

2.12 Does AEMPFAST handle HVDC systems?

Yes.

2.13 Does AEMPFAST handle multi-area systems?

Yes.

2.14 Does AEMPFAST handle distribution systems?

Yes. AEMPFAST handles distribution systems, in any combination of radial or meshed. It can also handle combined transmission and distribution systems.

2.15 Does AEMPFAST optimize radial lines?

Yes. Additionally, AEMPFAST RSIs will pinpoint the best location for VARs to improve voltage profile.

2.16 Does AEMPFAST accept preferential zones?

Yes. AEMPFAST provides zones where constraints are strictly enforced, and zones where constraints can be relaxed as selected by the user. This handles resources from outside the immediate control area, and resources where data is lacking.

AEMPFAST also handle scenarios where in a multi-area system, some areas are optimized and others are not.

2.17 **Does AEMPFAST optimization increase the responsiveness or reliability of the system to contingency actions?**

Yes. AEMPFAST-optimized systems, especially those for which AEMPFAST's advanced Resource Sensitivity Indices (RSIs) have been applied, have far fewer and less severe contingency exposures compared to cases that have not been AEMPFAST-optimized. As an example, the AEMPFAST study conducted on the California transmission system for the June 14, 2000 power outage showed that the AEMPFAST-optimized system was far more resistant to voltage collapses than the pre-AEMPFAST optimized one, even under generator outage cases. AEMPFAST also can handle constraints imposed on the system with security or stability considerations.

2.18 **Can AEMPFAST's results be validated against a Utilities load flow verification?**

Yes. AEMPFAST can input data from, and output data to GE PSLF, PTI PSSE, and IEEE models, including controllable devices. After optimization, AEMPFAST outputs a set of "real-world" control operations required to optimize the system. When its advanced features are applied, AEMPFAST also outputs precise locational Resource Sensitivity Indices for each and every bus in the system. The RSI's indicate specific system constraints and congestions, and further describe and rank (by system benefit) candidate changes/upgrades and locations at which to place/schedule distributed resources to benefit the optimization objectives. Verification of results normally is a simple exercise of inputting into Load Flow the optimization output of AEMPFAST.

2.19 **Is AEMPFAST's special architecture really needed?**

Yes. Today, modular structure is needed to meet multiple and/or changing objectives. AEMPFAST's advanced new architecture is designed around three main modules: an optimization kernel, applications, and objectives. Each of these in turn has a modular design, and each communicates directly with the other two. Because of this advanced architecture, adding new objectives is a relatively simple programming exercise. Adding or changing an objective requires only adding or modifying one module, not restructuring the complete package.

2.20 **What is meant by real-time management?**

Most network optimizers are created for designers and planners. Operators, however, are involved in the everyday management of the system. Networks can have a large number of generators, a large number of loads, numerous buses, and interconnections to other networks. The management of such a network is complex, particularly when emergencies such as generator, load, line, bus and interconnection losses occur. To minimize operational losses when they occur and maximize profits, fast, robust and accurate operational optimizers are a necessity.

Network data is currently gathered by the supervisory control and data acquisition (SCADA) systems. If an optimizer is robust and accurate, and can respond in less time than required by the SCADA systems, it is capable of *real time management* mode operation. Competitive non-linear packages typically do not meet the "real-time" criteria.

2.21 Is AEMPFAST designed to process data input from existing SCADA and DCS systems in real time?

Yes. AEMPFAST is also designed to be an open system with the ability to connect to databases currently used in the utility industry.

Evidence of Scientific Superiority

Note: All AEMPFAST functions (including the extensive use of RSI's) were used for each of the following projects.

3.1 Large Transmission System

In a landmark study sponsored by the California Energy Commission (CEC) and the California Independent System Operator (CaISO), Optimal Technologies showed that a rolling blackout in the San Francisco Bay area on June 14, 2000 could have been avoided completely, with available grid resources, using AEMPFAST.

Using AEMPFAST, and working with only a portion of the total controls in the system, and only with those available to the CaISO in real-time, AEMPFAST produced a feasible and precise, bus-specific re-control solution that reduced P losses by 8.1% (75.6 MW), reduced Q losses by 15% (1,147 MVAr), and improved P and Q power flows, power quality, and voltage profile in the Bay Area System. The AEMPFAST solution simultaneously avoided the blackout and dramatically improved system reliability.[22] It should be noted that AEMPFAST also managed to avoid blackouts and improve system reliability, even when taking the next contingency into consideration -- a 710 MW generator that was on-line during the actual blackout event. This is typical of AEMPFAST performance capability.

3.2 Smaller Distribution System

In another landmark study, also for the California Energy Commission but within the Silicon Valley Power (SVP) Distribution System, Optimal Technologies used AEMPFAST to optimize and then verify that small generators and aggregated managed load, strategically positioned in the distribution system, can indeed provide tremendous boosts to Distribution System efficiency, and can even improve the efficiency of the interconnected Transmission System. During the course of this work, it was shown that only AEMPFAST met all the necessary criteria to thoroughly perform the functions required for the Project.

AEMPFAST analysis, optimization, and ranking of the SVP system identified,

1. A 31 percent reduction in real power losses;

[22] The system under analysis consisted of 2506 buses -- only 412 re-controllable in real-time by the CaISO; 3,164 branches; 438 generators; 1,145 loads; and 19,054.8 MW of Load.

2. A 30 percent reduction in reactive power consumption; and
3. A large, diverse "population" of more than 300 valuable and viable power projects worthy of undertaking.

Losses were reduced at three times the system's average loss rate, by adding properly located theoretical DG.

It should be noted that these results are particularly promising in that the SVP system already is a well-designed, maintained, and operated system that does not suffer power delivery problems. Finding new potential for improvement even in this already efficient Distribution System suggests the potential for even greater returns from applying AEMPFAST to stressed distribution systems.

Please call for additional details.

Attachment 3 – CEC CERTS: Operations Review of June 14, 2000 PG&E Bay Area System Events Using Aempfast ® Software – October 2003 - available on-line at http://www.otii.com/pdf/CERTS_2003-11-21_500-03-085.pdf

Attachment 4 – CEC Draft PIER Consultant Report: Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet [SM] – April 2005 - available on-line at http://www.energy.ca.gov/2005publications/CEC-500-2005-061/CEC-500-2005-061-D.PDF

56. Oregon Department of Energy, Received Mon 3/6/2006 1:31 PM

Oregon Department of Energy
Comments on DOE's Notice of Inquiry on "Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors"

March 6, 2006

The Oregon Department of Energy (ODOE) is pleased to comment on USDOE's notice of Inquiry on Section 1221 of the 2005 Energy Policy Act (EPAct).

In Oregon, the Energy Facility Siting Council (EFSC) implements a consolidated review process for permitting of energy facilities, including generating facilities, electric transmission lines and gas transmission lines. The consolidated process takes in permits and standards of all other state

[23] All specifications subject to change without notice.

and local agencies, except permits that are federally delegated. Among other things, the EFSC conducts a state-level review for compliance with land use requirements.

The EFSC works closely with the Oregon Public Utilities Commission (OPUC) and the Northwest Planning and Conservation Council (NPCC), particularly in reviewing the need for proposed facilities. EFSC also works cooperatively with federal agencies such as the US Army Corps. Oregon statute requires that the EFSC reviews be coordinated with any federal NEPA review to ensure consistent timelines and to eliminate duplicative requirements.

In the past decade, the Council has approved nine natural gas fired generation plants with combined capacity of over 5,000 MW. We recently sited the largest wind facility in the Pacific Northwest, and a major natural gas transmission line routed through fast growing suburbs in the Portland metropolitan area.

Our siting process is notable for its success at developing fair compromises between developers and opponents. Our legislature and Council have worked hard to refine our siting process so that it is timely without sacrificing meaningful public involvement.

We have a track record of achieving buy-in from affected local authorities and property owners that FERC would be very unlikely to match. For this reason, we are justifiably concerned at the potential for abuse of FERC's preemptive authority. This authority should be wielded only when the need is great, the evidence of need is compelling, and the state's siting function has been given every reasonable chance to succeed. Section 1221 of the Act gives USDOE great latitude in identifying and designating National Interest Electric Transmission (NIETC) corridors.

In this NOI response, we offer general comments first, followed by specific answers to some of the questions posed in the NOI.

General Comments:

1. We support the comment by others that USDOE should make no final decision on designating NEITCs until it and FERC have established rules and procedures to implement Section 1221 in its entirety.

In particular, it is essential that the rules clarify that the one-year clock for state review starts with the filing of a complete application for the state permit, in accordance with duly adopted state requirements for content. Without this clarification, anyone can knowingly submit an inadequate application simply to get the clock started.

2. The notice of inquiry invites comments on how broadly or narrowly the Department should consider and define corridors. ODOE understands that USDOE does not want to define corridors too specifically. However, state agencies and local stakeholders who are faced with possible FERC preemption need to know if a proposed line is inside or outside the NIETC. This is not a

great problem when the NIETC's location is obvious but it is a problem if the NIETC is so vague that no one knows where the boundaries are (for example, "Montana to Northwest").

The NIETC need not be so narrow or specific as to allow only one potential project. The corridor could be broad enough to include a range of alternatives. However, it should be clear enough that reviewers and developers can agree on whether a proposed project is inside or outside, without requiring arbitrary decision making by FERC or USDOE.

3. Section 1221 of the EPAct focuses on siting, but the greater and more intractable problem is cost allocation. This was evident at the NARUC forum on electricity deliverability on February 15 and 16. The most heated discussions were those about cost allocation. The sessions on siting were tame by comparison.

It was clear based on the discussions at that forum that enhancing the transmission system requires solving familiar debates such as those about incremental vs. rolled in rates and postage stamp vs. distance based pricing.

Preempting the state in the siting of a controversial transmission line without solving these financial issues is pointless and probably counterproductive. It would needlessly disillusion local participants without solving the congestion problem.

On the West Coast we had a similar experience following the crisis of 2001. That crisis was largely blamed on generation siting. In Oregon we promptly sited four new generation facilities in response. Four years later, only one has begun construction. Financing, not siting, was the real problem.

USDOE should learn from this experience. Since the NIETC designation is based largely on a showing of need for the transmission, USDOE should include criteria requiring evidence that the needed transmission will be built.

Comments in Response to USDOE's questions

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

- Yes, USDOE should give greater weight to findings of persistent congestion. We support the recommendations the Western Congestion Assessment Task Force (WCATF) regarding how to make this distinction.

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

- Yes. USDOE may consider designating the NIETC when studies show physical congestion. However, it is inappropriate and costly to consumers for the federal government to push high-cost solutions to contractual congestion when other solutions are available.

(3) and (4) What specific transmission studies should DOE review and how far back should DOE look for such studies, and what categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

- We agree with the comments submitted by the Western Interstate Energy Board (WIEB)

(5) What criteria should be used in evaluating the suitability of geographic areas for NIETC status?

- Every state has its own criteria for evaluating specific projects. Before designating a geographic area for NIETC status, USDOE should determine if the area contains one or more paths that are “sitable” (capable of meeting that state’s siting criteria, either outright or through conditions).

- If the area under consideration includes federal land, USDOE should certainly prefer areas where the federal land includes energy corridors designated under section 368 of the EPAct.

- Since the designation of an NIETC can lead to federal preemption, USDOE should designate corridors only after completing a process that includes opportunities for affected state and local governments and the public to raise objections and concerns. At the very least, states should have the opportunity to identify corridors that have obvious showstoppers from a siting point of view.

- USDOE should recognize that certain areas inside a broadly defined corridor are not suitable for transmission siting. For example, studies might suggest that transmission across the Cascades is constrained, but iconic locations such as Mount Rainier or Oregon’s Smith Rock should be protected. States should have the opportunity to designate “exclusion areas” within the NIETC.

Comments on USDOE’s Draft Criteria

Regarding most of the criteria, ODOE supports the comments of the Western Interstate Energy Board. We offer specific comments on the following draft criteria:

Draft Criterion 5: Target actions in the area would further national energy policy.

- USDOE should recognize that some states have clearly articulated energy policies. Before designating a corridor based on this criterion, USDOE should ensure that the national energy policy being invoked is not at odds with regional energy policies. At the very least, if this criterion is the basis for NIETC designation, USDOE should clearly state which element of national energy policy is being invoked.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

- We agree. Assumptions regarding fuel price have been particularly unreliable in the last four years. The 2003 and 2008 congestion studies performed by SSGWI include a range of congestion forecasts based on a range of assumptions about fuel price and load growth. For the western states, the "Clean and Diversified Energy" committee (CDEAC) has prepared congestion forecasts for a range of assumptions regarding advanced coal, wind and conservation. Given the high uncertainty surrounding any of these forecasts, USDOE should only designate corridors where they are indicated under a very broad range of assumptions.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

- We agree. Transmission lines identified in integrated resource plans (for those states that have them) have been compared with non-wires alternatives. But in states without IRP's there is no guarantee that anyone has considered non-wires solutions in general or demand side management in particular. The chief result of NIETC designation is the likelihood of FERC preemption and the possibility of condemnation. Once the NIETC is designated, approval of proposed transmission within the corridor is essentially assured, without any mechanism to consider non-wires alternatives. Therefore USDOE should ensure that these alternatives are considered before making the designation.

Are there other criteria or considerations that the Department should consider in making an NIETC designation?

- Yes. The USDOE has not listed any criteria regarding the states' ability to site necessary transmission using their own processes. Since the major effect of NIETC designation is the likelihood of FERC preemption, USDOE should consider whether efforts to site transmission at the state level have been successful, unsuccessful, or simply not tested for lack of applications. At the very least, USDOE should consider whether anyone has tried to site a line at the state level. If no one has tried, then perhaps the need is not particularly urgent.

- USDOE should strongly consider the type of generation the NIETC will serve, and whether that generation is consistent with the energy policy of the state where the load would be. As noted above, USDOE should consider not only the states' siting policies but their ratemaking policies as well.

On February 21, USDOE gave a presentation to the WIEB, and invited comment on three additional questions:

1. *When, in relation to the evolution of a major transmission project, should an NIETC be designated? Should specific preconditions be met, such as …?*

The timing of NIETC designation could happen at almost anytime in the evolution of a transmission project, depending on circumstances. The designation should be based on congestion studies and on strong evidence that:

- There is persistent physical congestion that has significant economic impact, remains unresolved, and exists under a wide range of assumptions,
- Upgrades to existing transmission and non-wires solutions have been considered,
- State, local or regional siting presents a genuine barrier,
- At least one "sitable" path exists in the proposed corridor,
- The state and local siting authorities have had reasonable chance to comment,
- The proposed NIETC meets the criteria listed in the NOI, and
- There is a reasonable likelihood that the cost recovery challenges described above will be solved.

These conditions are not tied to any particular step in the evolution of a project, and could be met at almost anytime during the project's evolution, or even for areas where no project has been proposed.

2. *Should an NIETC be project-specific? Would doing so give undue advantage to the proposed project, in relation to potentially competing projects? Or should an NIETC be framed to accommodate a range of potential projects? Are both approaches potentially appropriate, depending on circumstances?*

Both approaches are potentially appropriate depending on circumstances. For example, USDOE could designate a NIETC for a specific project that is clearly needed, clearly supported by the congestion studies, likely to obtain financing and cost recovery, is the only reasonable congestion solution proposed, and cannot be built solely because of siting difficulties. But USDOE could designate a different NIETC in a different area where no particular project is proposed, and should definitely make it broad enough to accommodate a range of projects.

3. *Should an NIETC have a fixed term? If so, how long? Renewable, under certain conditions? Revocable, under certain conditions?*

In Oregon, the Site Certificate issued by our Siting Council has a shelf life. The licensee can apply for renewal. To be renewed, the project must show compliance with all applicable standards, and with any new or updated ones.

We believe the same policy should apply to the NIETC. The NIETC designation is intended to apply where congestion is persistent, has significant consequences, where new transmission would have clear economic benefits, and where the designation is indicated under a wide range of assumptions. If a NIETC is designated and no project is built, then the reasoning behind the designation should be revisited.

The shelf life in Oregon is not codified in rule. The Council can vary the shelf life of an individual site certificate based on the circumstances. USDOE could exercise the same discretion. However, three years might be a reasonable time period, simply because it coincides with the updated congestion studies mandated by the EPAct.

One of the reasons for a fixed term is the fact that the designation is based on assumptions. No matter how careful USDOE is not to rely too much on assumptions, some reliance is unavoidable. It is reasonable to revisit those assumptions after a certain number of years.

USDOE should also consider revoking the designation under certain circumstances. For example, if the congestion is relieved either by new transmission, non-wires solutions or some other factor, then the NIETC may no longer meet the designation criteria.

The Oregon Department of Energy appreciates this opportunity to comment and looks forward to working with USDOE as the NIETC process continues.

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57. Organization of MISO States, Received Mon 3/6/2006 3:41 PM [Revision received Mon 3/6/2006 3:56 PM]

Considerations for Transmission Congestion Study and
Designation of National Interest Electric Transmission Corridors

COMMENTS OF THE ORGANIZATION OF MISO STATES

In response to the U.S. Department of Energy's (Department) Notice of Inquiry (NOI) published in the Federal Register on February 2, 2006, the Organization of MISO States, Inc. (OMS) submits the following comments regarding the designation of National Interest Electric Transmission Corridors (NIETCs). The OMS previously submitted comments to the Department on September 17, 2004, regarding designation of national interest electric transmission bottlenecks, and requests that the Department review the attached copy of those comments in this proceeding.

NIETC Should Be Designated Sparingly:[1]

The OMS cautions that any designation of NIETCs should be applied sparingly with sensitivity and deference to the impacted states. Transmission siting is and has been held within the purview of state jurisdiction. Transmission siting has the potential for significant local impacts. Those most able to assess the need and balance a project's costs and benefits should have significant input into the siting process. National or regional oversight may very well have interests different and, in some cases, in contrast to those where the construction will actually take place.

While the goals of such designations may be well intentioned, federal designations of protected transmission corridors that would preempt state decisions on transmission siting issues should be used cautiously. Siting decisions have very real state and local impacts such as construction, environmental and political costs. Designation for purposes that may not have accompanying local benefits needs to be approached with care.

The OMS recommends that the Department avoid[2] NIETC designation of geographic areas where current planning and siting processes are functioning well and effectively addressing reliability and congestion issues.

[1] In this section, the North Dakota Public Service Commission, the South Dakota Public Utilities Commission, and the Illinois Commerce Commission would substitute the word "carefully" for the word "sparingly."

Furthermore, the OMS stresses that where the Department takes the serious step of designating a corridor with regional, state and local cost impacts, the designation must not only result in regional benefits, but it should not unduly burden one particular state or stakeholder for the alleged benefit of another.

NIETC Should be Defined as Generalized Paths:

In its notice, the Department stated that it expects to identify corridors for potential projects as generalized paths between locations as opposed to specific routes and invited comments to address how broadly or narrowly corridors should be defined.

The OMS agrees that NIETC corridors would be best defined as generalized paths. Defining generalized paths leaves maximum flexibility to develop routes that maximize system value while minimizing adverse effects. The Department should consider the purpose for designation of a particular corridor and designate only the geographic area necessary to accomplish this purpose. Furthermore, the designation of an NIETC should not be at the request of one particular provider or for a particular predetermined project. Finally, designation should not foreclose alternative solutions to reliability or congestion problems.

Congestion Study and Corridor Designation Processes:

The OMS appreciates that the Department will provide opportunities for public comment regarding designation of particular corridors. The OMS looks forward to an opportunity to provide further input after the congestion study is published and the final criteria are established. The OMS believes the early designation option provided in the NOI should not be used except in extraordinary circumstances. NIETC designations should flow from and be directly related to the congestion study results.

Congestion Study:

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[2]The North Dakota Public Service Commission, the South Dakota Public Utilities Commission, and the Illinois Commerce Commission would substitute “carefully consider” for “avoid” in this sentence.

To assist the Department in conducting and preparing its electric transmission congestion study, the Department requested comments on the following questions:

1. **The Department asks whether it should distinguish between persistent congestion and dynamic congestion, and if so, how?**

The OMS believes the Department should focus on persistent forward-looking congestion where the benefits of transmission upgrades would be most consistent and projects would be most likely to occur. The solution to persistent congestion should be a long term solution. The Department should define "persistent" in forward-looking terms that reflect numbers of events, amounts of MWs or the amount of difference between the real time price and the shadow price over a specified time period, such as years or seasons.

2. **Should the Department distinguish between physical congestion and contractual congestion and if so, how?**

The OMS believes the Department should focus on identifying physical congestion that can be remedied by physical system upgrades necessary to meet national standards. Physical congestion can be easily identified by performing steady state load flow studies.

3. **Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review: How far back should the Department look when reviewing transmission planning and path flow literature?**

The OMS believes the Department has done a good job identifying existing studies that reflect wholesale transmission transactions. However, the identified studies do not reflect the quality of service or impact of congestion on the prices seen by native load consumers. The Midwest Transmission Expansion Plan (MTEP) of the Midwest ISO and other such regional transmission plans should be the primary source for identifying congestion. In the Midwest ISO region, the Northwest Exploratory Study and Midwest ISO West RSG Consolidated Study included in the MTEP should be reviewed for possible NIETC designations. Additionally, the Western Area Power Administration's recent Dakota Wind Study provides detail on export constraints faced by North and South Dakota. The Northeast blackout studies and the 2004 CERA Interconnect Congestion Study may be further sources that could help with identification of NIETC designations.

The Department should be mindful of the relative need for NIETC designations in regions served by organized markets and in non-market regions. The results from studies prior to the Midwest ISO energy market start-up can indicate persistent congestion, but should be used with caution because flow and usage patterns may have changed with the start of the Midwest ISO's market.

4. **What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?**

All types of historical operational actions to prevent physical real time transmission line overloading should be included in the congestion study. The Department should include constraint information for areas where operating agreements have historically limited the need to curtail wholesale transactions. The Department should examine areas where independent regional planning has shown the need for transmission relief, but needed projects are not being addressed. Data regarding international congestion and cooperation in siting international transmission lines could also be useful when designating NIETCs where it does not increase the cost or congestion to U.S. customers. Seams between RTOs and market to non-market seams should be studied, especially where congestion can interfere with more efficient functioning of energy markets. Another category of information that could prove useful is data concerning the cost-effective development of remote resources such as clean coal and wind that can reduce the use of natural gas and oil.

Draft Criteria:

The Department invited comment on what criteria to use when evaluating the suitability of geographic areas for NIETC status and requested comment on eight preliminary draft criteria:

> **Draft Criterion 1:** *Action is needed to maintain high reliability.* Maintaining high electric reliability is essential to any area's economic health and future development. Accordingly, an area would be of interest for possible NIETC designation if there is a clear need to remedy existing or emerging reliability problems. Metric: A definition of the affected area in terms of load population and demand growth: a description of the expected degree of improvement in reliability associated with a proposed project: if appropriate, identification of existing or projected violations of NERC Planning Criteria.

It is unclear what is meant by "high reliability." The degree of reliability maintained is always a matter of cost. Accordingly, the cost of reliability should be no higher than necessary to meet FERC approved reliability standards. The OMS suggests metrics identifying existing or projected violations of these standards. The OMS further suggests that the Department consider the age of existing infrastructure and the recommendations of any regional planning groups who have assessed the existing infrastructure in an area as additional metrics. Finally, the DOE should consider prioritization of designations, so that areas with greater potential for economically significant blackouts are designated first.

> **Draft Criterion 2:** *Action is needed to achieve economic benefits for consumers.* An area may need substantial transmission improvements to enable large economic electricity transfers that would result in significant economic savings to retail electricity consumers. Metrics: Estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets. A demonstration of expected reduction in end-market concentration and how economic benefits for consumers would be affected.

The OMS generally agrees that economic benefit is in the national interest and an appropriate criterion. The OMS would request that the expected economic benefits be reasonably widespread among customer groups throughout a region and suggests that the DOE establish a metric that includes this consideration. In addition, the Department should consider establishing a threshold requirement for an appropriate minimum magnitude of benefits needed to meet this criterion.

The OMS would like to point out that the studies used to include this criterion have not been based upon benefits to end consumers, but rather upon studies of wholesale transactions. Accordingly, the OMS recommends the Department include a metric that reflects estimated economic benefits to all retail electricity consumers in the corridor if all savings were passed through.

> **Draft Criterion 3:** *Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.* Metrics: Areas that are dependent on "reliability-must-run" plants would benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both. Similarly, areas that are highly dependent on specific generation fuels could economically benefit from supply diversification. Estimate the likely magnitude of such benefits, showing calculations.

The OMS generally agrees with this criterion. In particular, there has been a growing trend towards reliance on natural gas-fired generation as a baseload energy resource, rather than as a supplemental peaking capacity resource. While the draft metrics are generally appropriate, the Department should consider adding a metric for considering whether congestion limits the output of certain generators during normal system operating conditions. The OMS would also like to see more specific metrics that measure the extent to which supply diversification available from the corridor could reduce dependency on natural gas or increase the use of other resources. The OMS recommends that the Department establish a threshold level of benefit requirement for meeting this criterion.

> **Draft Criterion 4:** *Targeted actions in this area would enhance the energy independence of the United States.* Metrics: Provide calculations showing how specific actions aided by designation as an NIETC would increase fuel diversity, improve domestic fuel independence, or reduce dependence on energy imports. Quantify these impacts including possible impacts on U.S. energy markets.

The OMS generally agrees that this criterion is appropriate. The OMS asks the Department to recognize that some of the natural gas being used for generating electricity in the United States is imported. The OMS recommends that the Department publish a prioritized list of energy resources it considers important to meeting this criterion.

> **Draft Criterion 5:** *Targeted actions in the area would further national energy policy*.

The OMS recognizes that "the designation would be in the interest of national energy policy" is listed in EPACT section 1221. However, as proposed, this criterion is too vague and undefined to be useful. Accordingly, the OMS suggests that the Department's efforts to capture national energy policy considerations in the other criteria would be more effective than attempting to do so in a separate criterion.

> **Draft Criterion 6:** *Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.* Metrics: For this criterion, relevant metrics would be case specific.

The OMS agrees with this criterion. The OMS notes that this criterion is considered under the current NERC transmission planning requirements and presumes it will be required under the new ERO transmission planning requirements that will ultimately be approved by the FERC.

> **Draft Criterion 7:** *The area's projected need [or needs] is not unduly contingent on uncertainties associated with analytic assumptions, e.g.,*

> *assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.*

The OMS understands this criterion to be asking: "are the load and capability projections reasonably robust across contingencies?" There is a need for transparency in the assumptions included in the modeling and forecasting of system needs to determine possible NIETC designations. A reasonable degree of forecasting certainty is necessary, but certainty in itself is not a criterion for designation. Therefore, as an alternative to making the accuracy of projections and forecasts a separate criterion, the OMS suggests that the Department consider applying analytical robustness as a metric for evaluating designation criteria.

The Department requested comment regarding what metrics would be suitable for gauging uncertainties under Draft Criterion 7. Some of the major factors that most models would use to project the need for future transmission projects include fuel prices, equipment prices, inflation levels, transportation prices, population trends, and economic trends. Some of these factors are much more volatile than others, especially during the short-run (e.g. fuel prices). Each model that could be used will have different levels of sensitivity, and as a result, will have different levels of confidence depending on the assumptions made. Stated another way, the more a model or analysis depends upon the more volatile/variable factors, the lower the level of confidence. The key phrase in Draft Criterion 7 is "unduly contingent." Each model will have some variability built in. It is up to each user to be aware of the potential variability.

> **Draft Criterion 8:** *The alternative means of mitigating the need in question have been addressed sufficiently.*

The OMS believes this criterion could be restated as "Have non-wire or other solutions been adequately considered in the geographic area?" The OMS believes it is critical to consider alternative non-wire solutions when evaluating each of the designation criteria. It appears that proper consideration of alternatives is necessary, but not in itself a criterion for designation. Therefore, as an alternative to making the proper consideration of alternative solutions a separate criterion, the OMS suggests the Department consider applying the identification of alternative solutions as a metric to be used when evaluating designation criteria. The OMS recommends the Department include new generation resources (including distributed generation) and demand side load reduction programs as alternatives to the construction of new transmission lines in its evaluations for possible NIETC designations.

Further Comment and Recommendations:

The Department seeks comment on whether there are other criteria or considerations that should be considered and whether certain criteria or considerations are more important than others. The OMS believes it might be worthwhile to consider criteria such as whether an NIETC is a well-suited candidate for a merchant transmission or advanced technology solution. With regard to whether certain criteria or considerations are more important than others, the OMS believes that the NOI generally presented the draft criteria in order of importance. Nevertheless, the Department should make an effort to apply all of the criteria to a geographic area when determining whether the area should be designated as an NIETC. Priority for designation should be given to geographic areas that satisfy multiple criteria.

The OMS recommends that the Department initiate a formal rule making proceeding to establish NIETC application and designation procedures.

The OMS recommends that the Department set a finite time period during which a designation remains in effect and establish a procedure to un-designate an area. The time period for a designation should not be longer than the three-year period between congestion studies and should expire with final authorization of transmission facilities fulfilling the needed transfer capability specified for the corridor.

The OMS recommends that the Department require or give additional weight to an assessment from an independent regional planning body that a geographic area should be designated or meets certain criteria.

Conclusion:

The OMS submits these comments because a majority of the members have agreed to generally support them. Individual OMS members reserve the right to file separate comments regarding the issues discussed in these comments. The following members generally support these comments.

Illinois Commerce Commission
Iowa Utilities Board
Kentucky Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Missouri Public Service Commission
Montana Public Service Commission
Nebraska Power Review Board
North Dakota Public Service Commission
Pennsylvania Public Utility Commission
South Dakota Public Utilities Commission
Wisconsin Public Service Commission

The Public Utilities Commission of Ohio abstained for procedural reasons.

The following OMS members did not participate in this comment:

Manitoba Public Utilities Board
Indiana Utility Regulatory Commission

The Iowa Office of Consumer Advocate, as an associate member of the OMS, participated in these comments and generally supports these comments.

Respectfully Submitted,

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Executive Director
Organization of MISO States
100 Court Avenue, Suite 218
Des Moines, Iowa 50309
Tel: 515-243-0742

Dated: March 6, 2006

UNITED STATES OF AMERICA

BEFORE THE
DEPARTMENT OF ENERGY

Office of Electric Transmission and Distribution

Designation of National Interest
Electric Transmission Bottlenecks

COMMENTS OF THE ORGANIZATION OF MISO STATES

I. SUMMARY

In response to the U.S. Department of Energy's (DOE) Notice of Inquiry (NOI) published in the Federal Register on July 22, 2004, 69 Fed. Reg. 43833, the Organization of MISO States (OMS) hereby submits the following comments. The NOI seeks comments on issues relating to the identification, designation and possible mitigation of National Interest Electric Transmission Bottlenecks (NIETBs). It states that by publicly identifying and designating NIETBs, DOE will help mitigate transmission bottlenecks that are a significant barrier to the efficient operation of regional electricity markets, threaten the safe and reliable operation of the electric system, and/or impair national security. OMS shares these goals, but it believes that DOE's approach may impede current mechanisms already in place to achieve these goals.[1] In any NIETB designation process, DOE must work closely and in conjunction with the applicable regional, state and local entities, and it must not hamper current mechanisms addressing bottlenecks.

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[1] The North Dakota Public Service Commission (NDPSC) believes DOE's designation of NIETBs can complement current mechanisms already in place to achieve these goals. NDPSC views NIETB designation as assisting to mitigate the most critical transmission constraints identified through state and regional transmission planning processes.

The OMS is a regional state committee comprised of fourteen state regulatory commissions[2] and the regulatory authority of Manitoba encompassing the footprint of the Midwest Independent Transmission System Operator (MISO). The OMS appreciates the DOE's request for information regarding NIETBs and as such the OMS wishes to submit comments to the DOE as it initiates its inquiry concerning NIETBs. However, as an initial matter, the OMS has two concerns. First, what will be done with the information gathered in the inquiry? Second, what action does the DOE intend to take in response to the information being gathered? Appropriate answers to these questions are crucial in order to understand how the DOE's proposed national designation process achieves its stated goals.

II. APPROPRIATENESS OF CRITERIA

In the NOI, DOE points to the DOE Secretary's Electricity Advisory Board (EAB) Transmission Grid Solutions Report issued in 2002 in which the Board recommends that to be designated a National Interest Electric Transmission Bottlenecks (NIETB), the bottleneck must meet one of three criteria:

> 1. The bottleneck jeopardizes national security; 2. The bottleneck creates a risk of widespread grid reliability problems or the likelihood that major customer load centers will be without adequate electricity supplies; or 3. The bottleneck creates the risk of significant consumer cost increases in electricity markets that could have serious

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[2] Members of the OMS are listed in the conclusion of this comment.

consequences on the national or a broad regional economy or risks significant consumer cost increases over an area or region.[3]

The NOI requests comments on these criteria as well as on a number of related questions. Are the EAB's recommended criteria for designation of NIETBs appropriate and sufficient? If not, what should they be? For example, should DOE also consider disaster recovery, economic development, and the enhancement of the ability to deal with market and system contingencies in designating NIETBs?

The OMS believes that an independent effort by DOE to identify NIETBs that meet the three recommended criteria would be duplicative of the efforts of FERC, the Regional Transmission Organizations (RTOs) and Regional State Committees (RSCs). In particular, the Midwest ISO either has in place, or is in the process of developing, policies that will identify bottlenecks that exhibit the reliability or economic concerns outlined in criteria two and three. Furthermore, there are potential infrastructure security concerns associated with designating a bottleneck as a threat to national security, as suggested by criterion number one.[4]

The EAB's report also suggests "additional criteria" regarding congestion and the exercise of market power. Again, the Midwest ISO either already has, or will shortly have,

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[3] NOI at 43834.

[4] NDPSC believes that transmission bottlenecks restricting the development of significant and economic domestic energy resources should be considered under criterion number one because these bottlenecks cause increased dependence on foreign energy.

policies or procedures in place to address these concerns. As explained in more detail below, there are RTO and ISO policies that are designed to both identify and resolve the problems associated with transmission system congestion. Furthermore, there are market monitors in place that have authority to address the potential exercise of market power that may result from transmission bottlenecks.

If the DOE chooses to move forward to implement NIETB procedures, one criterion that may warrant consideration for designation is bottlenecks that are the result of seams between RTOs and other transmission operators. Bottlenecks at seams are potentially critical, as they occur where two or more different entities are involved and where transmission connections bridge systems, states and even countries. Accordingly, it is vital that such bottlenecks not be allowed to either persist or develop. While FERC has made some progress on this issue in the Midwest, it has been slow. Should progress falter, the OMS believes that it would be helpful for the DOE to address these particular types of bottlenecks.

Economic development may also serve as a useful criterion for designation of a NIETB in order to alleviate such transmission bottlenecks. Supporting load growth, new resources, and business and market structures should be considered in the identification of NIETB. Significant economic development opportunities may only be captured if sufficient transmission is available in certain areas. For example, low cost resources may be available in remote areas that can only be utilized if transmission limitations are relieved. In addition to the lower cost of these resources, there could also be benefits from encouraging a more diverse portfolio of resources.

Economic development also can be served by developing processes to alleviate bottlenecks that might interfere with the proper functioning of electricity markets.

III. ROLE OF REGIONAL ENTITIES

DOE also asks what should be the role of transmission grid operators, utilities, other market participants, regional entities, states, federal agencies, Native American tribes and others in the process of identifying, designating, and addressing NIETBs?

OMS recognizes that transmission constraints are becoming more prevalent nationwide, and regional entities such as RTOs are working to identify regional needs and bottlenecks. In the Midwest, MISO and Mid-Continent Area Power Pool (MAPP) are developing regional transmission plans to identify and mitigate the negative impacts transmission constraints have on both reliability and the cost of electricity in the Midwest. These plans also incorporate elements intended to resolve local and regional needs. However, it is unlikely that the resolution of local and regional transmission issues will resolve the needs of other regions.

Nevertheless, the OMS believes that the identification and mitigation of bottlenecks is best performed at the state and regional level, using those practices that are currently in place. The OMS also supports a stakeholder process that recognizes differences in regional transmission constraints and provides regional solutions for the alleviation of these constraints. The OMS believes flexibility is needed to accommodate regional differences. The DOE should not independently designate NIETBs since it does not have institutional, detailed knowledge of local transmission issues and other system intricacies. In contrast, regional transmission plans from an RTO should be the primary source for identifying bottlenecks. RTOs have the requisite knowledge and operational understanding of the transmission system and would be best able to identify transmission constraints that endanger reliability and adequacy of the electric system and reduce the efficiency of electricity markets.

The DOE designation of NIETBs needs to serve a useful purpose. Criteria numbers (2) and (3) are set up to identify problem areas that FERC's Order 2000 already addresses. Specifically, Order 2000 requires RTOs, such as MISO and PJM to:

1. Independently calculate Total Transmission Capability and Available Transmission Capability (confirmed in the FERC's April 28, 2003 White Paper on Wholesale Power Market Platform)[5]

2. Be responsible for planning and for directing or arranging necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable, and non-discriminatory transmission service and coordinate such efforts with appropriate state authorities.[6]; and

[5] RTO function 5, in Appendix A to FERC White Paper on Wholesale Market Platform, April 28, 2003. The White Paper was issued to clarify the requirements of Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 at 31,226-27 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996- December 2000 & 31,092 (2000), affirmed sub nom. Public Utility District No. 1 of Snohomish County, Washington, et al. v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[6] RTO function 7, ibid.

3. Ensure the integration of reliability practices within an interconnection and market interface practices among regions and RTOs ... within an electrical interconnection (are required to) coordinate to resolve seams issues.[7]

FERC has also issued orders to MISO, PJM, and SPP that have consistently pushed those regional organizations toward a coordinated fulfillment of these required functions.[8] MISO also has regional seams negotiations and joint-operating agreements already completed, or well underway, with PJM, MAPP, and SPP. The OMS states are working with all these entities to assist in that process. Up to now, the state-federal cooperative relationship has enjoyed both: (1) A sharing of overall jurisdiction on transmission issues, with FERC having the lead on certain issues, states having the lead on others, and OMS helping to build consensus among its member states; and (2) DOE support of OMS through funding and information building activities. The relationship between FERC, MISO, and the OMS is starting to produce measurable success in resolving difficult issues. Furthermore, with other RTOs working to develop RSCs, the potential exists for similar success in other regions. Accordingly, the OMS appreciates DOE's recognition that it "must work with State, regional and local government officials to encourage proposals from industry participants and to monitor progress toward elimination of designated bottlenecks"[9] rather than take a unilateral approach.

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[7] RTO function 8, ibid.

[8] See, e.g., Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., 106 FERC ¶ 61,251 (2004) and Southwest Power Pool, Inc., 106 FERC ¶ 61,110 (2004).

[9] NOI at 43833.

In addition, if the DOE does move forward to implement NIETB procedures, it should do so only in consultation with affected states so that state regulatory commission findings are an integral part of any declaration of bottlenecks. If need be, most state regulatory commissions have the ability to order utilities to build transmission infrastructure to alleviate a specific bottleneck. Further, state commissions have a keen participatory interest in both the MISO expansion planning and approval processes, based partly on the fact that transmission projects will be subject to individual state permit processes.

The OMS believes that DOE should work toward coordinating federal agency facilitation of state siting efforts. In the past, federal land and waterway agencies have significantly delayed transmission expansion proposals, both during and after state permitting reviews.[10] As the OMS continues to work on effective regional strategies that address the challenges of coordinating the state siting of interstate projects, DOE could make a critical contribution by leading a similarly tasked initiative among federal agencies.

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[10] AEP's Wyoming-Jacksons Ferry project in Virginia and West Virginia is often cited as an example where federal agencies have had a major timing impact on transmission development. Details on that project's permitting history (spanning the years 1990 to 2001), and a discussion of Western states' problems with federal permits for transmission projects can be reviewed at http://www.westgov.org/wga/initiatives/energy/preemptfacts.pdf. DOE may also have a lead role of coordinating federal agency permit review when a Presidential Permit is required for international border crossings (four OMS states have land boundaries with Canada). A recent example, including a discussion of the complex timing and coordination required, is described in detail for an Arizona-Mexico project at http://www.ttclients.com/tep/eis.htm. The Minnesota Department of Commerce cites a series of state siting procedures for interstate transmission projects that were complicated by federal agency jurisdiction, and where there was significant uncertainty whether federal agency permits could be obtained after the state issued permits. All of the projects (Chisago-Apple River 230kV, Prairie Island-Eau Claire 345kV, Arrowhead-Weston 345kV) were proposed to cross the Minnesota-Wisconsin boundary, which is in large part coincident with the St. Croix River (National Scenic Riverway) and the Mississippi River (National Scenic Byway, National Wildlife Refuge). The Department also cites difficulties in how federal land crossings and/or right-of-way sharing are addressed during or following state siting procedures when national forests (DOA-FS), tribal reservations (DOI-BIA), airports (FAA), navigable rivers (Corps of Engineers-Civil), military installations (DOD), and interstate highways (DOT) are involved.

IV. IDENTIFYING BOTTLENECKS

The NOI also seeks comment on how might DOE identify bottlenecks in regions where much pertinent data are not available, in contrast to regions where transmission expansion plans have been developed and made public?

The OMS finds that this question does not apply to areas with operational RTOs or independent system operators or to areas such as the western interconnection states that have a long history of joint transmission planning. For areas such as the Southeast or those where electric transmission is provided by federal power administrations or authorities, OMS believes that the DOE should work closely with FERC and its jurisdictional transmission providers and owners in the area to obtain the necessary information.

DOE ACTIONS TO MONITOR PROGRESS

The NOI requests comments on what actions should DOE undertake to facilitate and monitor progress towards mitigation of designated NIETBs?

As explained above, FERC, RSCs and the RTOs have implemented numerous policies and programs intended to facilitate and monitor progress towards mitigation of transmission bottlenecks. These policies are in effect for a large portion of the United States. In these regions, the DOE's efforts to mitigate transmission bottlenecks would be most effective through close coordination with FERC, RTOs, RSCs and other stakeholders.

For about 40 years, various administrations have touted the compelling economic and reliability advantages of consolidating the existing three grids in the continental United States into a single national grid. However, there are too few interconnections between the three grids for unrestricted flow of power. The previous system designs result in limits on transfer capacity that do not automatically permit a single non-constrained market for economic purposes. Accordingly, within the three interconnections, the DOE might play a useful role in resolving differences among regions that have RTOs and those that do not. The OMS supports the DOE's continued commitment to the integration, participation, and coordination of the Tennessee Valley Authority and other federal power marketing agencies with RTOs.

DOE could also facilitate and monitor progress towards mitigation of designated NIETBs and stand ready to provide funding mechanisms for transmission expansion projects intended to alleviate NIETBs.11

VI. CONCLUSION

The Organization of MISO States submits these comments because a majority of the members have agreed to support them. The following members generally support these comments. Individual OMS members reserve the right to file clarifying comments or minority reports on their own regarding the issues discussed in these comments.

Montana Public Service Commission
North Dakota Public Service Commission
Minnesota Public Utilities Commission
Nebraska Power Review Board
Missouri Public Service Commission
Iowa Utilities Board
Wisconsin Public Service Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission

[11] Montana believes that any public funding mechanisms should not distort private investment decisions related to transmission projects.

Kentucky Public Service Commission
Pennsylvania Public Utility Commission
Michigan Public Service Commission

The Public Utilities Commission of Ohio will submit its views in a separate statement.

Members not participating in these comments are:

Manitoba Public Utilities Board
South Dakota Public Service Commission

The Minnesota Department of Commerce and the Iowa Consumer Advocate, as associate members of the OMS, participated in the preparation of these comments and support these comments.

Respectfully Submitted,

William H. Smith, Jr.
William H. Smith, Jr., Executive Director
Organization of MISO States
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Des Moines, Iowa 50309
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Dated: September 17, 2004

58. Pacific Gas & Electric Company, Received Mon 3/6/2006 5:00 PM

March 6, 2006

Ms. Poonum Agrawal
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, DC 20585

Submitted by e-mail to: EPACT1221@hq.doe.gov

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Notice of Inquiry and Request for Comments, 71 Fed. Reg. 5660 (February 2, 2006)

Dear Ms. Agrawal:

Pacific Gas and Electric Company (PG&E) respectfully offers these comments in response to the above-referenced Notice of Inquiry and Request for Comments (NOI) of the U.S. Department of Energy (Department or DOE). PG&E appreciates the opportunity to provide comments on the Department's proposed criteria for implementing its responsibilities under Federal Power Act (FPA) Section 216(a) (16 U.S.C. § 824p).[1]

Section 216(a) requires the Secretary of Energy (Secretary) to conduct a study of transmission congestion within the United States and to issue a report by August 8, 2006 and every subsequent 3 years. Based on that study and after considering alternatives and recommendations by interested parties, section 216(a) authorizes the Secretary to designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor " (NIETC). Pursuant to that authority, in the NOI the Department seeks comments from the public concerning proposed criteria for evaluating the suitability of geographic areas to be designated as NIETCs.

PG&E Has a Direct and Substantial Interest in This Proceeding.

PG&E is a public utility based in California that transmits electric energy in interstate commerce. PG&E is also a Participating Transmission Owner and constructs, owns, and maintains significant electric transmission facilities, which it has placed under the operational control of the California Independent System Operator Corporation (CAISO). In addition, PG&E is one of the largest Load Serving Entities in California, distributing natural gas and electricity to a population of approximately 14 million people throughout northern and central California. For these reasons, PG&E has a direct and substantial interest in the Department congestion study and proposed steps to implement the Department's authority to designate NIETCs under FPA Section 216(a). Accordingly, PG&E respectfully submits its comments to the Department for its consideration.

The DOE's Congestion Evaluation Process Should Respect Existing Regional and Developed Permitting Plans.

The Department's congestion study and report should build on the work of regional entities (*e.g.*, RTOs/ISOs, reliability agencies, state agencies, utilities, etc.) to identify areas of geographic constraint and congestion. In particular for the Western Interconnection, the Department should carefully consider and seek to coordinate with California's mature and developed processes for

[1] Added by Section 1221(a) of the Energy Policy Act of 2005 (EPAct 2005).

evaluating and permitting transmission projects based on considerations of wires and non-wires alternatives, including the processes and plans developed by the CAISO, the California Public Utilities Commission, the Western Electric Coordinating Council, and the on-going planning process authorized by Section 368 of the EPAct 2005. Such processes have already resulted in the identification and designation of major transmission upgrades, and a number of specific projects resulting from these planning efforts are already in the active permitting process at the regional level. It would be counterproductive and inefficient for the DOE process to ignore or undermine such decisions.

<u>The DOE's Broader Definition of Corridors Appropriately Identifies Areas of Congestion While Avoiding the Imposition of Specific Solutions.</u>

The Department has asked how broadly or narrowly the Department should consider and define corridors in its study and NIETC designations. In the NOI, the Department indicates that it expects to identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities.

A broader definition of corridors – and consequently broader designations of NIETCs – most appropriately balances the need to identify areas of congestion with the need to leave the consideration of potential solutions to appropriate regional entities or the Federal Energy Regulatory Commission (FERC), as contemplated by FPA Section 216. Looking at the issue from a broad geographic perspective can help preserve a variety of potential solutions that might not fit into a narrow definition of a transmission corridor. DOE analysis and perspective concerning the economics of potential solutions would be useful, However, the Department should not seek to determine whether there is an economical solution to the underlying transmission capacity constraint or congestion and, if so, what the best solution might be (such a solution may involve some mix of generation, transmission, demand-side, or other options). Rather, NIETC designations should highlight the need for attention to transmission capacity constraints and congestion, prompting affected state, regional, and federal planners and permitting agencies to work together – and to work closely with utilities and generation and transmission owners – to respond to the constraint or congestion issue in a cost-effective, timely, and appropriate manner.

Indeed, a narrow definition of corridors would implicate land-use, environmental, and community concerns that are best addressed in appropriate regional or local planning forums. By designating generalized geographic areas as opposed to specific routes, the Department can defer detailed environmental and other analyses that are more appropriately undertaken in the context of specific solutions or projects. Such analyses will occur later as specific projects are pursued, whether in state or regional planning and permitting processes or at FERC.

<u>The DOE Should Focus on Identifying Congestion, Not Distinguishing Between Persistent and Dynamic Congestion or Physical and Contractual Congestion.</u>

The Department should not distinguish between "persistent" and "dynamic" congestion or "physical" and "contractual" congestion. These terms are not well defined, nor can congestion easily be categorized as one or the other. Congestion occurs when the amount of power that can be transferred over a path is physically limited due to transmission and other electric system operating limitations incorporated inreliability standards. Transmission constraints may be either economic or uneconomic based upon to regional definitions and preferences and can be mitigated by uneconomic dispatch of generation, siting new generation in the load centers, voluntary and involuntary load reduction, reconfiguration of the transmission system, and/or building new transmission facilities. Each of these mitigation measures carries with it economic and environmental impacts. Whether congestion needs to be or should be eliminated would depend on the economic and social cost of the various mitigation measures. Rather than focusing on trying to differentiate and categorize different types of "congestion," the Department should identify areas of congestion and evaluate whether to designate an NIETC based on whether transmission constraints are negatively impacting or likely to impact reliability, the ability to deliver electricity, and/or consumer costs.

New transmission facilities and upgrades to existing ones should not ultimately be approved by states, regional entities, or FERC unless the facilities or upgrades are found to be a cost-effective solution to congestion and will serve the public interest. In addition, applicable reliability standards must be met. In meeting applicable reliability standards, sponsors of new projects, whether transmission or generation, must demonstrate that such projects would not adversely impact the transfer capabilities of the existing transmission system, or, if they do, that the new projects would mitigate such adverse impacts. The philosophy that new projects must not adversely impact the transfer capability of the existing system goes beyond commercial use by various parties. Rather, it is necessary to ensure that existing transmission system capabilities will not deteriorate with the addition of new projects. These determinations of adverse impacts and associated mitigation are case specific and complicated and must be performed when each specific project or group of projects is proposed.

There are already established processes in each region and sub-regions to do so.[2] Such processes need not and should not be duplicated. Therefore, the Department need not distinguish in its study or report between types of congestion as suggested. On the other hand, the Department certainly can and should discuss the potential magnitude and duration of congestion in areas listed in its report so that regional entities and transmission owners can further investigate whether eliminating such congestion is in the interest of the consumers.

Key Sources of Information that Should Be Included in the DOE Review

As discussed above, the Department should build on the work of appropriate regional entities to identify areas of geographic constraint and congestion. Thus, projects and plans approved by RTOs and ISOs would be a natural starting point for the Department, and the most critical documents for the Department to review include the transmission grid expansion plans of ISOs

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[2] *See, e.g.,*WECC Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports at http://www.wecc.biz/documents/library/procedures/planning/Overview_Policies_Procedures_RegionalPlanning_ProjectReview_ProjectRating_ProgressReports_07-05.pdf.

and RTOs. Some such documents for the California grid, however, appear missing from the Department's Appendix A, which lists those transmission plans and studies that the Department is currently reviewing.

The following additional transmission plans and studies are critical to the Department's studies and are available on the CAISO website:

> ISO/RTO Electric System Planning Current Practices, Expansion Plans, and Planning Issues, http://www.caiso.com/179c/179c9a256dda0.html;
>
> Documents on the CAISO's Policies, Standards, and Processes, http://www.caiso.com/docs/2001/06/04/2001060418221123496.html;
>
> Documents on the Generator Interconnection Process, http://www.caiso.com/docs/2002/06/11/2002061110300427214.html;
>
> Documents on the Northwest/California Subregional Group, http://www.caiso.com/docs/2003/07/22/20030722133104582.html; and
>
> Documents on the CAISO Controlled Grid Study, http://www.caiso.com/docs/2002/12/02/200212021600259660.html.

Comments on DOE Proposed Criteria

Generally speaking, the Department's proposed criteria seem reasonable, though a complete and definitive opinion is impossible, in part because it is unclear how such criteria will be applied. A critical factor in applying such criteria is the balancing of Draft Criterion 1, which focuses on reliability, and Draft Criterion 2, which focuses on economic benefits. These two factors are most important, but may result in conflicting pressures. For example, economic projects under Draft Criterion 2 should not be implemented where they would unduly or unnecessarily harm reliability in that or other areas. In contrast, action required under Draft Criterion 1 to ensure reliability should not be taken "at any cost." A well-functioning and efficient transmission plan that serves the public interest must balance reliability needs and economic imperatives to arrive at cost-efficient and effective solutions.

Draft Criterion 1: "Action is needed to maintain high reliability." In addition to the proposed metrics for this criterion, reliability standards applicable to local entities should also be met.

Draft Criterion 8: "The alternative means of mitigating the need in question have been addressed sufficiently." PG&E agrees that alternatives to transmission solutions must be considered in determining appropriate NIETCs. Such alternatives are typically addressed when planning transmission projects. In addition, individual states, such as California, have energy policies[3] to which local entities must adhere, which require such considerations. As set forth in FPA Section 216(b), prior to permitting a proposed project, FERC must also determine if a

[3] *See, e.g.,* California Energy Action Plan I (adopted in 2003) at http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF and California Energy Action Plan II (adopted on September 21, 2005) at http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

specific transmission project is in the public interest. Thus, alternatives to transmission solutions should be considered in designating NIETCs in the context of both Draft Criterion 2 ("Action is needed to achieve economic benefits for consumers") and Draft Criterion 6 ("Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts").

Conclusion

PG&E appreciates the opportunity to provide these comments to the Department. If DOE staff have any questions about the comments, please contact me at (415) 973-3386 or ATK4@pge.com.

Respectfully submitted,
MARK D. PATRIZIO
ALYSSA KOO

By: /s/ Alyssa T. Koo
Alyssa T. Koo

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59. Pacific NorthWest Economic Region, Received Mon 3/6/2006 5:37 PM

To Whom it May Concern:

On behalf of the Pacific NorthWest Economic Region (PNWER), a statutory entity created in 1991 by the member states of Alaska, Washington, Idaho, Montana, Oregon, and the Canadian provinces of British Columbia, Alberta, and the Yukon Territory, we would like to offer the following comments in response to the Notice of Inquiry (NOI) published by the Department of Energy's Office of Electricity Delivery and Energy Reliability (DOE) on February 2, 2006 regarding implementation of Section 1221 of the Energy Policy Act and the designation of National Interest Electric Transmission Corridors (NIETCs).
In general, DOE should:

- Expand the sources and avenues of input
- Ensure full coordination and integration with other relevant processes, and

- Exercise prudence in the designation of NIETCs

These suggestions will ensure a more open and coordinated process for the designation of NIETCs , broad public and private stakeholder support for the corridors so designated and greater predictability for developers, siting authorities, stakeholders and the public. Our goal is to balance the interests of both the public and private sectors while still expanding the region's transmission capacity.

Expand the Sources and Avenues of Input

Canada

Although political maps of the Western United States highlight the land border with Canada, no such border exists on maps of the Western Interconnection. Efforts to facilitate the building of transmission facilities in the United States, particularly in the west, must fully coordinate with similar efforts in British Columbia and Alberta. In a meeting organized by the Pacific NorthWest Economic Region in Vancouver on February 3, stakeholders in British Columbia suggested the identification of "gateways" between the United States and Canada so that corridors identified in the United States, pursuant to Section 1221 (or Section 368) of the Energy Policy Act are consistent with corridors identified by the British Columbia Transmission Corporation or the Alberta Electric System Operator. Working with partners in British Columbia and Alberta to identify "gateways" will ensure the relevance of any corridors that are designated within these processes. PNWER, through its Bi-National Regional Energy Planning Initiative, is prepared to assist in this effort. In addition to the February 3 meeting in Vancouver, we are organizing a series of meetings in Edmonton and Calgary on April 24 and 25. One of the issues on the agenda will be Section 1221.

State Legislators

DOE is doing a commendable job of reaching out to the Governors and Public Utility/Service Commissions in the affected states. In order to ensure more comprehensive input from the state level, DOE should expand its outreach efforts to include state legislators. All branches of state government are being asked to respond to the Energy Policy Act. In Washington, for example, legislation was passed giving the state authority to site transmission lines in corridors that may eventually be designated as NIETCs. Several state legislators are exploring the idea of establishing a multi-state compact for the purposes of siting transmission lines and renewable portfolio standards/incentives have the potential for increasing the need for new transmission. State legislators, particularly the leadership of energy committees and natural resource committees should be included in the Department's outreach and education efforts. Although we have worked with various lawmakers and committees to brief them on Section 1221 – and have regular conference calls with a Legislative Energy Chairs/Provincial Energy Ministers Task Force, DOE should include them in the official consultative process. PNWER is prepared, if appropriate, to facilitate these contacts and will continue its own outreach and education efforts.

Public Meetings for Stakeholders

The public scoping process for Section 368 included a series of public scoping meetings throughout the eleven contiguous western states. Although the National Technical Conference scheduled for March 29 in Chicago will help determine the criteria for designating NIETCs, DOE should explore ways to more fully engage public and private stakeholders, better explain Section 1221 and to solicit broad feedback on any proposed NIETCs. We would be pleased to work with the Department of Energy to help organize such meetings in Idaho, Montana, Oregon and Washington.

Ensure full Coordination and Integration with other Relevant Processes

Section 1221 and Section 368 both deal with the designation of corridors. Although implementation efforts are being coordinated within the department, additional steps must be taken to make this coordination more visible and to more fully ensure that these efforts are truly integrated. At its earliest convenience, DOE should explain how the criteria for designating NIETCs compare with the criteria being used to designate energy corridors on federal lands in the eleven western contiguous states.

Furthermore, in the interest of providing greater predictability to interested parties, DOE should delay designation of NIETCs until such time as the Federal Energy Regulatory Commission issues rules on how it will implement its backstop authority on transmission facilities in NIETCs.

Exercise Prudence in the Designation of NIETCs

Corridor Definition

There is some concern that the corridor definition being considered under Section 1221 may be too broad. Although in some instances a broadly defined corridor would facilitate the process of siting transmission projects, in other instances, a more narrow definition would be preferable. Depending on the geographic area, specific end points and a measurable width for a corridor may help developers, siting authorities, stakeholders and the public understand whether or not a specific project is located within an NIETC. DOE should recognize that certain areas inside a broadly defined corridor are not suitable for transmission siting based on historical or cultural significance. States should have the opportunity to designate “exclusion areas” within the NIETC based on these factors.

The Process for Designating Corridors

DOE should identify “potential” NIETCs before designating actual NIETCs. Adding this step to the process would have two significant benefits. First, it would send a signal to developers, siting authorities, stakeholders and the public that there is a need for additional transmission capacity in a given area. Second, it would allow time for the completion of an Environmental Impact Statement, which will generate information on alternatives, and permit DOE to make a more informed decision on designating an NIETC.

DOE should also incorporate a formal role for regional and sub-regional transmission planning groups – with their broad representation from the private sector - such as the Northwest

Transmission Assessment Committee here in the Northwest, in the process of designating NIETCs.

Early Designation of Corridors

The NOI published on February 6 indicated the possibility of designating NIETCs as early as August 6, when the draft congestion study is released. Although the NOI established an appropriately high threshold for early designation, corridors given early designation would be the result of a “compelling case” made by a developer and a separate comment period. These corridors would not be the result of criteria, definitions, processes and metrics that are the result of the public rulemaking process envisioned in the Section 1221 of the Energy Policy Act.

Completeness of Application

As part of this process, DOE should adopt explicit rules stating that the one year clock for states to consider applications for projects in NIETCs begins only after the state has received a complete application based on requirements adopted in each state. The requirements for a complete application will necessarily vary from one state to another but should remain the state’s prerogative to define. These requirements should be reasonable and the result of a public rulemaking process on the state level which includes input from developers, stakeholders and the public. If FERC is the appropriate agency for determining the start of the one year clock, then we respectfully request DOE to include this request in communications to FERC.

Fixed Term

Although they may be renewed, NIETCs should sunset after three years. Each triennial congestion study should include a separate section on current NIETCs with a recommendation as to why they should or should not be renewed. If the new congestion study shows that congestion in a previously designated NIETC has been relieved, this could lead to the non-renewal of NIETC status for that corridor. States where an NIETC is being recommended for renewal must concur with the recommendation. If an NIETC is recommended for renewal, it would be subject to a standard comment period, and would not be subject to the recommendation requesting the identification of “potential” corridors.

Thank you for the opportunity to share these comments with regard to the designation of National Interest Electric Transmission Corridors. If you have any questions about these comments, or would like additional information, please do not hesitate to contact Neil Parekh, our Policy and Communications Director and Program Manager for the Bi-National Regional Energy Planning Initiative, at (206) 443-7723 or neil@pnwer.org.
Thank you.

Matt Morrison
Executive Director, PNWER

60. Pennsylvania Department of Environmental Protection, Received Mon 3/6/2006 12:02 PM

NOTICE OF INQUIRY
CONSIDERATIONS FOR TRANSMISSION AND CONGESTION STUDY AND DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS

COMMENTS OF THE PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION

The Pennsylvania Department of Environmental Protection is pleased to submit these comments to the United States Department of Energy pursuant to the DOE Federal Register Notice of Inquiry (NOI) on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors.

The Pennsylvania Department of Environmental Protection (PA DEP) assumed many of the duties of the former Pennsylvania Energy Office with that office's closure in 1995. In 2003, Governor Edward Rendell established the Office of Energy and Technology Deployment within DEP to serve as the primary office for energy policy issues related to Pennsylvania.

Pennsylvania is currently a net-exporter of electricity. In 2004, according to information from the Energy Information Administration, electricity-generating units located in Pennsylvania exported 34% of their electricity out of state. Several states bordering Pennsylvania have been identified as including areas that currently or will soon face capacity shortages. These areas include northern New Jersey, the Delmarva Peninsula, and Baltimore-Washington. Pennsylvania, therefore, is unique in that it is an electricity rich state with neighbors that could likely benefit from additional access both to Pennsylvania generation and to low-cost generation to our west in states such as Ohio, Indiana and West Virginia. We understand that recent proposals from Allegheny Energy and AEP may seek NIETC designations that include portions of Pennsylvania.

For these reasons the criteria for designations of National Interest Electric Transmission Corridors (NIETCs) are particularly important to the citizens of the Commonwealth of Pennsylvania.

Transmission planning, siting, and construction are a lengthy and expensive process. PA DEP recommends that DOE take the following into consideration as it develops its criteria for NIETCs, particularly for areas or transmission corridors for which early designation is sought. These suggestions in most cases apply across proposed criteria and, therefore, we address the criteria in total instead of making specific suggestions to each criterion.

1. Has the interested party comprehensively considered alternatives that would make an NIETC designation unnecessary? Given the challenges and costs associated with new transmission, interested parties should be required to perform an analysis of the impacts that demand-response, energy efficiency, energy conservation and distributed generation can play in reducing the need for additional transmission. In cases in which transmission is being proposed largely as a response to growth in peak demand, demand-side management measures may be especially effective.

   DEP recommends that the Department of Energy develop a comprehensive set of demand-side management and distributed generation best practices for consideration in constrained areas and that interested parties would need to demonstrate why these best practices are not sufficient to address or reduce load concerns. Ideally a cost-benefits analysis of implementing distributed generation and demand-side management measures compared to transmission solutions would be required. Such best practices could include, but would not necessarily be limited to, net-metering and interconnection standards, rules that support the introduction of micro-grids, real-time price options, demand tariffs, and tariffs which encourage energy conservation.

Encouraging distributed generation is particularly relevant in light of the proposed criteria's emphasis on energy independence and energy security. Reducing peak demand can lessen our potential dependence on imported liquefied natural gas. Distributed generation and micro-girds can make the electricity system less vulnerable to central grid failures.

2. Following on our first point, parties interested in NIETC designations should be required to examine local generation alternatives. Generation retirements are part of the reason for transmission constraints in some parts of PJM. Opportunities to re-power or construct new power plants on existing footprints should be carefully examined as part of the NIETC process. Employing these options would minimize the need for both developing new transmission lines and siting facilities in new locations.
3. The commentary attached to the notice of public inquiry makes little to no mention of any public process related to NIETC designations. Transmission siting is an important public issue that has the potential to impact the daily lives of hundreds of thousands of citizens. It is absolutely critical that any NIETC designation process have robust local

and regional public participation opportunities. As such, and in response to one of the notice's directed questions, we recommend that any corridor designations be as broad as possible to allow maximum stakeholder input in determining the best footprint for any future transmission corridors should they be necessary.

4. Parties interested in NIETC designations should be required to demonstrate meaningful benefits to states hosting new transmission. In the northeast, interested parties may seek to designate portions of some states, particularly Pennsylvania, as NIETCs for the purpose of building transmission across those states primarily to serve load in coastal states from load inside Pennsylvania and elsewhere. Interested parties should be required to do a comprehensive cost-benefit analysis relative to electricity consumers in states such as Pennsylvania and in no cases should an NIETC designation require consumers to pay more in costs than they receive in benefits simply so load in other states can be served. This is especially true in cases in which states seeking transmission solutions have not fully explored and incentivized distributed generation, demand-side management and new generation solutions.

5. Pennsylvania is actively supporting the development of several significant alternative fueled power plants that will have substantial generating capacity. Any proposed new transmission projects should account for new facilities. Transmission projects that do not account for planned new generation would be inefficient, could jeopardize project finance for these power plants, and could leave significant stranded costs. Parties seeking NIETC designations should take planned new generation into account both in determining whether a transmission solution is necessary and to determine the appropriate pathways

for new transmission lines. DOE should pay particular attention to new generation projects as it assesses proposed NIETC designations.

The Commonwealth of Pennsylvania has adopted an energy strategy that focuses on fuel diversity and energy security. Our recent initiatives include the Alternative Energy Portfolio Standard which requires 18% of Pennsylvania's retail electricity load to be served by alternatives sources such as renewables and clean coal technologies by 2021, incentives for coal polygeneration and IGCC through our Pennsylvania EDGE (Energy Deployment for a Growing Economy) initiative, statewide net-metering and interconnection standards, and at least over $80 million in new funding for alternative energy projects over six years.

Transmission solutions need to be part of a sound energy strategy, but cannot be performed in isolation of other, possibly better, solutions. Our comments stress the need to consider all alternatives, especially demand-side management, before engaging in potentially costly, long-term transmission projects. Additionally, the benefits to consumers of transmission solutions must be clearly demonstrated and citizens must be ensured a voice at the table as transmission solutions move forward.

Again, we thank you for the opportunity to provide commentary on this critical matter. Questions on our commentary may be directed to Eric Thumma, Director, Office of Energy and Technology Deployment, Pennsylvania Department of Environmental Protection at ethumma@state.pa.us or 717-783-0540.

61. Pennsylvania Environmental Council, Received Friday 3/3/06 3:15 PM

Dear Sir or Madam:

I am contacting you on behalf of the Pennsylvania Environmental Council. The Council protects and restores the natural and built environments through innovation, collaboration, education and advocacy. PEC believes in the value of partnerships with the private sector, government, communities and individuals to improve the quality of life for all Pennsylvanians.

Although we are involved in a number of land use and watershed related issues in the Commonwealth, we are currently pursuing a new initiative to help preserve farmland in York County, PA. You may be aware that Pennsylvania has the most extensive farmland preservation program in the country. In February 2005, the state's farmland preservation board added 37 farms, covering 3,630 acres, to the program during its February meeting today. Pennsylvania leads the nation in the number of farms and acres preserved, with a total of 2,783 farms and 318,350 acres removed from development to date.

In York County, the Farm & Natural Lands Trust of York County and the Pennsylvania Environmental Council (PEC) are jointly working to

* assess the amount of coordination between county and municipal officials on implementing a comprehensive strategy for agricultural land preservation;

* create a coordinated education plan to demonstrate the value and benefit of municipalities supporting and funding agricultural preservation.

My understanding is that if FERC provides utilities with this National Interest Electric Corridor designation, it has the power to pre-empt state licensing. Even if FERC allows the state process, it would require that it be completed within one year and if not, or if the state approval was not given, FERC could approve the project and employ eminent domain powers. Under new FPA § 216(e), eminent domain would be available to the holder of a permit issued by FERC to acquire rights-of-way to privately owned land.

My question: If this is correct, how might the National Interest Electric Corridor designation impact York County and other counties that have preserved farmland in Pennsylvania?

Brian J. Hill
Interim President and CEO
130 Locust Street, Suite 200
Harrisburg, PA 17101
717-230-8044, ext 16
www.pecpa.org

The Pennsylvania Environmental Council protects and restores the natural and built environments through innovation, collaboration, education and advocacy. PEC believes in the value of partnerships with the private sector, government, communities and individuals to improve the quality of life for all Pennsylvanians.

62. Pennsylvania Public Utility Commission, Received Mon 3/6/2006 4:49 PM

The Pennsylvania Public Utility Commission (PaPUC) submits the comments appearing below in response to the Department's *Notice of Inquiry* published at 71 FR 5660 (February 2, 2006).

All communications with respect to this matter should be addressed as follows:

John A. Levin, Assistant Counsel
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3256
Telephone: (717) 787-5978
FAX: (717) 783-3458
email: johlevin@state.pa.us [please note spelling]

The PaPUC is a state administrative commission created by the General Assembly of the Commonwealth of Pennsylvania and charged with the regulation of electric utilities and licensing of generation suppliers within the Commonwealth of Pennsylvania. 66 Pa.C.S. §101, et seq. As a state regulatory agency charged by the Pennsylvania General Assembly with the protection of the public interest, the supervision of public utilities and electric generation suppliers, and enforcement of transmission line siting regulations at 52 Pa. Code § 57.1 *et seq.*, we are concerned about the impact of this proceeding on Pennsylvania consumers. The PaPUC is a supporter of retail competition in electric generation supply, and is therefore dependent on healthy and well functioning wholesale markets.

Pennsylvania is served by transmission companies belonging to two Regional Transmission Organizations, PJM Interconnection, LLC (PJM), and the Midwest ISO, Inc. (MISO)[1]. The PaPUC is a member of the Organization of PJM States, Inc., (OPSI) which is an organization consisting of the State utility regulatory Commissions in the 14 state PJM operating region, as well as a member of the Organization of MISO States (OMS), which consists of the State utility regulatory Commissions and one Canadian Provincial Board located in the MISO operating region.

COMMENTS

EPAct Section 1221 breaks novel ground by injecting the Federal government into the process of the traditional state role of approval and siting of transmission lines through designation of National Infrastructure Electric Transmission Corridors ("NIETC"s). Your department should recognize that the Federal government does not have lengthy experience with the process of the review and siting of electric transmission facilities and that the experience of siting of natural gas transmission lines under the provisions of the Federal Power Act is not directly transferable to planning electrical grids.

NIETC designation is a marked departure from previous law and substantially changes the relationship between the Federal Government and the States regarding transmission siting. As the principal responsibility for approval and siting of transmission continues to rest with the States, your Department should exercise great care in setting

[1] The NY ISO controls a single HV line from the Homer City Generating Station that crosses into New York State.

the conditions and parameters under which it will designate NIETCs and should not entertain any requests for “early designations” until DOE has had an opportunity to clearly define the procedures, terms and conditions under which it will make such designations. Further, NIETCs should only be designated where it is demonstrated that there is chronic physical congestion on the grid that has the potential for substantially impairing existing or future grid reliability.

Your Department should not consider any application for or make any designation of NIETCs that does not clearly identify the national interests sought to be protected and make findings of fact regarding how those interests are best served by a NIETC designation, rather than by approaches that are less intrusive into state laws and policies.

The Department should require that any application for a project’s designation as an NIETC be made only after a regionally based transmission planning process has considered the project and has approved it in accordance with a transparent and open process that permits all stakeholders to participate. If no regionally based planning process exists, your Department should require that such applications be supported by an independent expert analysis of the regional transmission grid that is substantially as rigorous as other established regionally based regional transmission expansion planning processes. Further, the applicant should discuss and demonstrate with specificity how the project will advance national interests.

The designation of NIETC corridors should be made on a point-to-point basis, not a geographic "box"[2] or specific line routing. Designations should be based upon a demonstrated need to relieve longstanding, chronic and otherwise unresolvable transmission congestion between those geographic points.

The Department should avoid designating either specific routes or broad geographic regions, as transmission congestion and the relief of congestion is primarily based upon the electrical characteristics, flows and topology of the existing grid, not the geographical location of specific facilities. There may be many different kinds of transmission upgrades and routings that will resolve such congestion and your Department should avoid designations that favor one type of developer over others or which favor projects within a certain geographical box.

Finally, your Department should ensure that adequate notice and due process is required before any final designation is made. Your Department should permit interested parties to evaluate and rebut evidence and assertions offered in support of (or in opposition to) corridor designation.

GENERAL GOVERNING PRINCIPLES IN NIETC DESIGNATION

There are some obvious principles that should be restated:

- Transmission is only one of the three major elements of a reliable electric system. The other two elements are generation and demand response. To some extent, each can substitute for the others, but only generation *creates* electrical energy. The public interest in long term planning requires balanced use of all three solutions.

[2] Point-to-point designation defines generation sources and load sinks, but does not define any geographic path or type of upgrade necessary to connect the two points, leaving it up to project developers to offer determine the optimal project design..

■ There are different financial, environmental and social costs and benefits associated with transmission, generation and load response. Of the three, load response is most dependent on a wholesale electricity market and regulatory structure that allows it to exist and to provide effective relief from transmission congestion and capacity shortages that would present reliability concerns. Long distance transmission is most intrusive upon land use and property rights concerns.

■ High-voltage alternating current transmission lines do not transmit energy from source to sink over specific lines, or on a "contract path". Instead, power flows through interconnected AC grids much like water flows through an interconnected series of canals. "Transmission congestion" is the result of energy flows that exceed the thermal or stability of specific portions or segments of a transmission grid and results in the need to redispatch other generating units to relieve the congestion. Such congestion may be caused by flows between points quite distant from the point of congestion and may stem from the sum of many different transactions.

■ Transmission congestion is not static, it appears and disappears on a minute by minute basis, although some corridors may suffer from a high percentage of congested hours.

■ Transmission congestion may be relieved by generation redispatch of higher cost "out of merit" units, or by "cutting" specific power transactions.

■ Before the existence of competitive wholesale markets, monopoly utilities generally did not permit their facilities to be used by competing generation owners. Both EPAct 1992 and EPAct 2005 have established the right of open access to the interstate transmission grid by competitive generation and customers.

■ Electrical energy may be and is transmitted economically over long distances, but there are energy losses and ancillary service costs associated with distance. A thousand megawatts ten miles away is not the same resource as a thousand megawatts a thousand miles away.

■ Of the three elements, major transmission facilities take the longest to bring into commercial operation – major projects may take from 10 to 15 years to be completed. By the time an interstate project is completed, the structure of the interstate market, the generation and fuel mix and the flows of energy among load centers may be significantly different that the assumptions that prompted the transmission project originally. Generation projects may take from 2 to 10 years to complete. Load response may become effective very quickly, but is dependent on regulatory approvals and market implementation.

■ Transmission projects may *or may not* provide equal reliability and cost benefits to all interconnected regions. Some transmission projects specificially benefit a limited region and a limited number of generation owners. Cost allocation of interstate transmission facilities is a major consideration in assessing the viability and benefits of a proposed transmission project. Public reaction to such projects is significantly influenced by the allocation of costs and benefits of new transmission facilities.

■ A decision to build a large new transmission facility requires the making of difficult assumptions regarding future flows of electrical energy on the interstate grid, future trends in population growth, future availability and mix of fuel sources, the future of fuel costs, future market structures and generation, transmission and demand response technologies.

■ The completion of a large new transmission facility creates winners and losers among generation and transmission owners and significantly affects the economics of demand response.

RESPONSE TO QUESTIONS POSED BY THE DEPARTMENT'S NOTICE OF INQUIRY:

Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

Yes. The Department should consider persistent congestion (congestion that occurs over a substantial number of hours during the year in a more or less predictable way) to establish a far more compelling case for designation purposes than "dynamic congestion". The PaPUC understands dynamic congestion to refer to the congestion caused by random and unpredictable transmission outages, generation unavailability and certain peak consumption events along with parallel flows from other regions of an intermittent nature. Most transmission paths have some form of congestion for some hours at some point in time. It is impossible and undesirable to remedy all transmission congestion everywhere and EPAct 2005 does not attempt to enlist your Department for that purpose. Before designating any corridor that is solely subject to dynamic congestion, your Department should find that there is a compelling requirement for such designation as an NIETC based upon national security or to protect human life or health.

Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

It is unclear what is meant by “contractual congestion”. If it means unavailability of firm transmission rights, with no physical congestion occurring within the corridor, that does not appear to be a circumstance requiring the application of Section 1221. FERC has plenary powers under the Federal Power Act to address circumstances where interconnection or access to the grid is being denied discriminatorily, or on non-comparable terms and conditions. FERC also has power, jointly with the US Department of Justice and the Federal Trade Commission to identify and remedy exercise of unlawful market power or restraint of trade. NIETC designation would appear to be unnecessary for “contractual congestion”.

Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

The PaPUC believes that Appendix A is a reasonably complete list of the most significant existing studies. It would be helpful to analysis if the Department looked back approximately 5 years in order to establish major trends or patterns in regional congestion.

What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

Since congestion is any thermal, voltage or stability constraint that requires either redispatch of generation or cutting of transactions, a primary source of information is TLR[3] events, historic redispatch and transaction cancellation and associated data. Further, information on the direction of energy flows and sources and sinks during congestion events is also necessary.

Are there other criteria or considerations that the Department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.

The PaPUC has not yet developed any additional criteria as is requested. We request that an opportunity to supplement these comments be permitted while the Department's study continues.

Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

Comprehensive planning process – No designation should be made solely on the basis of any regional planning process or study that does not fully and neutrally weigh transmission upgrades, generation siting and demand response implementation. The PaPUC supports the timely upgrade of the transmission grid where such upgrades are

[3] TLRs refer to the interregional congestion "Transmission Loading Relief" program administered by the North American Electric Reliability Council., and approved by FERC at Docket EL98-52-000. See *North American Electric Reliability Council*, 84 FERC 61,047 (1998) (Order Dismissing Requests For Rehearing And Denying Motions For Reconsideration, Vacatur, And Stay)

necessary to support the public interest in affordable, safe, adequate, and reliable electricity.

Cost benefit considerations – As noted above, congestion may be relieved either by transmission upgrades, generation siting or demand response. In some cases, transmission upgrades will be the only possible remediation. In other cases, a combination of generation, demand response and/or transmission upgrades may be most desirable. In addition, there are circumstances in which the economic benefits of relieving congestion are materially smaller than the cost of transmission investment. In such circumstances, no designation should be made unless necessary to protect human health and safety or national security, and only after a demonstration that all reasonable alternatives have been exhausted.

Cost Allocation and Environmental Considerations – While it plays no direct role in corridor designation, your Department should be aware that the equitable allocation of transmission upgrade costs and burdens is a major factor in determining the public response to any major investment of this kind. Designations of corridors in a way that would tend to load upgrade costs and burdens onto regions that are not primarily responsible for the congestion that is being relieved would be highly counterproductive.

Additionally, the electric power industry is one of the most capital intensive industries in any economy. There are certain unavoidable impacts on land, water and air that result from the production, transmission and consumption of electrical energy. Any process of corridor designation that does not consider the need to reduce these impacts to a reasonable minimum will set up a conflict with the public interests. It is expected that every corridor designation will be accompanied by a study of environmental impacts resulting from the designation.

Neutrality of Outcomes – The Department should not designate corridors in a way that predisposes some kinds of projects as "winners". Transmission congestion relief may be accomplished in many different ways. Large scale "backbone" projects may be called for in some circumstances. In others, a smaller project or series of related smaller upgrades may be best. States and Regions should continue to be responsible for selecting the mix of transmission solutions that best fit the case.

CONCLUSION

Congress continues to recognize that states and regions play a principal role in the transmission planning and siting process, and that your Department's role in the designation of NIETCs does not replace or repeal those state responsibilities or interests.

Respectfully Submitted,

s/ John A. Levin

John A. Levin
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Dated: March 6, 2006

63. Pepco Holdings Inc. (on behalf of PHI Companies), Received Mon 3/6/2006 3:30 PM

701 Ninth Street, NW
Washington, DC 20068
202-872-3227

William M. Gausman
Vice President – Asset Management

March 6, 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U. S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, DC 20585

Submitted by email to: epact1221@hq.doe.gov

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

Dear Sirs:

Pepco Holdings, Inc., on behalf of itself and its electric utility subsidiaries, Atlantic City Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company (together, the "PHI Companies"), submits these comments pursuant to the Notice of Inquiry and Request for Comments published at 71 *Fed. Reg.* 5660 (February 2, 2006).

Interest in this Proceeding

The PHI Companies are transmission owners within the PJM Regional Transmission Organization (RTO) managed by PJM Interconnection, LLC (PJM). The PHI Companies have already invested over $1 billion in transmission facilities in the Mid-Atlantic region, and they will be significantly impacted by NIETC designations in the PJM footprint. Implementation of the congestion study and NIETC requirements of the Energy Policy Act of 2005 are extremely important to the PHI Companies.

Comments of the PHI Companies

NIETC Designation Should Allow A Wide Range Of Alternative Solutions Pursuant To An RTO's Regional Transmission Plan.

The PHI Companies include three transmission-owning electric utilities, all of whose transmission facilities are located within the PJM Regional Transmission Organization (PJM RTO), managed by PJM Interconnection, LLC (PJM). The PJM RTO is responsible for operating the bulk power electric system across all or portions of twelve States and the District of Columbia in the Mid-Atlantic, Midwest and Southeastern United States, and serves as the transmission service provider, the regional transmission planner, and the market administrator for the wholesale energy and capacity market across that wide region. PJM's activities are closely regulated by the Federal Energy Regulatory Commission (FERC), and PJM performs all its RTO functions pursuant to agreements and tariffs on file with the FERC.

Where there is a FERC-regulated RTO performing the regional planning function, as in the PJM RTO, it is essential that DOE's designation of NIETC corridors not interfere with or pre-determine the outcome of the RTO's planning process by specifying a *particular* solution or a *particular* location for congestion-abatement facilities and/or by precluding direct substitutes such as generation or load management. The PHI Companies applaud DOE's statement, in the Notice, that:

> "The Department expects to identify *corridors* for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities. The Department believes that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion."

The PHI Companies note that in a past broad look at bulk power congestion, by the FERC's Office of Markets, Tariffs and Rates (then called the "Division of Market Development") in a study presented to the FERC at its open meeting on December 19, 2001, FERC staff identified the substantial transmission constraints across the United States in very generalized geographic terms. *See map,* "Electric Transmission Constraint Study" (December 19, 2001) at page 8, posted on the FERC website at:
http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9625894

An expanded subset of this study was presented by the Division of Market Development at the Northeast Energy Infrastructure Conference held by the FERC in New York City, NY. *See map,* "Northeast Energy Infrastructure Assessment" in Docket No. AD02-6-000 (January 30, 2002) at page 12, posted on the FERC website at:
http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9621567

Each of these studies accurately shows and describes the transmission constraints as limiting *transfers across interfaces.* An interface is a boundary that separates two large geographic areas, within which (in each area), bulk power transfers are relatively unrestricted by congestion, but between which (across the boundary), bulk power transfers are significantly restricted. Such an interface boundary may be tens or even hundreds of miles wide. If appropriate for NIETC designation, DOE should define each such entire interface as a "corridor," so that any new facility built across the interface, substantially for the purpose of relieving the congestion which it delineates, is "within the corridor." In this context the NIETC designation should be seen as offering the broadest and most flexible tool to complement the RTO planning process in addressing interface limitations.

DOE's draft Criterion 8 recognizes that there may be several possible transmission solutions within a corridor, each of which would attack the same congested interface, but with very different electric uplift and download consequences for the affected underlying transmission system, as well as different consequences for planned generation in the corridor and different effects on the health of competition in the energy market. In an RTO, like PJM, these are issues the RTO, as the regional planner, is expressly entrusted to sort through in the context of its existing regional plan and the changes to that plan that each specific cross-interface alternative would accomplish. For example, a transmission project that costs considerably more than the alternatives on a stand-alone transmission facility basis, may cost *less overall* when all associated changes to the RTO's regional plan are taken into account. Moreover, the designation of a NIETC corridor should not (and as proposed, will not) preclude merchant generation or load management solutions that come forward as market based alternatives to such new transmission facilities. Only the regional planner, working with the affected States, will have available the comprehensive information and resources needed to weigh these factors.

In sum, DOE's NIETC designation should not bias the regional planner towards (or away from) particular transmission facilities constructed in accordance with narrow geographic parameters. Rather, the NIETC designation should simply be a way to level the playing field among alternative remedies by helping to assure that if transmission facilities are the appropriate solution, they can be built. Again, this supports the view of the NIETC designation as a tool to facilitate the right selection among alternatives, not to predetermine any specific outcome.

Additional Comments On Certain Of DOE's Proposed Criteria

Draft Criteria 2 and 7, when considered together, seem to suggest that the evaluation of "action . . . to achieve economic benefits for consumers" must not be "unduly contingent on uncertainties associated with analytic assumptions" but should respond to "existing needs instead of projected needs." Large-scale, extra-high-voltage transmission projects, however, even with the assistance afforded by NIETC designation, cannot be authorized, financed, designed, sited and constructed in a time frame consistent with the abatement of "existing needs." By the time such facilities are completed, they necessarily will address economic needs projected years earlier and their efficacy will be dependent on forecasted events well beyond their in-service date. Limiting the designation to a corridor that addresses "existing needs" would preclude corridor designation in just the type of situation where a broad perspective is most required and market forces are least effective – that is, in the restructuring of transmission networks to address long term needs and efficiencies of scale – even while "existing needs" are met. Analytic uncertainties must not excuse the failure to anticipate future needs when the consequences of inaction are reasonably clear.

Similarly, draft Criterion 3 focuses on an *existing* supply limitation. The presence of reliability-must-run generation is a reasonable basis for DOE concern and may well merit NIETC designation if there is no likelihood of a local resource response, but it is essential that the RTO's planning process, and DOE's complementary designation of NIETC corridors, look beyond "existing needs" to the projected situation *if* no new transmission facilities are constructed *and if* no new generation or load management resources are reasonably likely to remedy the situation in a timely manner.

In contrast, draft Criterion 6 appropriately addresses the *long-term* goal of reducing the vulnerability of the electricity infrastructure and electric supplies to critical loads. The security of the bulk power grid, which stretches across thousands of miles of unguarded countryside, depends in large part on redundancy. That redundancy must be maintained independently of "existing needs." The PHI Companies provide electric service to numerous critical government facilities, including throughout the National Capitol region, and the resilience of transmission paths to supply that region is a significant concern, as the DOE is well aware.

The PHI Companies urge that "existing needs" be only one consideration. DOE's designation of an NIETC corridor identifies a problem; it does not and should not dictate a particular solution. As discussed above, in an RTO, the solution should come from the RTO's own marketplace and, if the market does not respond consistent with the RTO's criteria, then the solution should come from the RTO's regional planning process. That planning process necessarily involves long term projections (the PJM transmission plan looks out 15 years). The uncertainties surrounding such projections should not prevent the RTO from attempting them, or prevent DOE from considering the RTO's projections in weighing the intractability of a particular congestion interface.

Very truly yours,
THE PHI COMPANIES

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64. PJM Interconnection L.L.C., Received Mon 3/6/06 5:00 PM [Corrected Version Received Tues 3/7/06 1:15 PM]

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

REQUEST OF PJM INTERCONNECTION, L.L.C. FOR EARLY DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS

March 6, 2006

In response to the Department of Energy's Notice of Inquiry ("NOI")[1] regarding its upcoming Congestion Study and its role in designating National Interest Electric Transmission Corridors ("NIETC"), PJM Interconnection, L.L.C. ("PJM"), submits this request for designation of two NIETC within the PJM region. Designation as NIETC of these two corridors, which PJM calls the "Allegheny Mountain path" and the "Delaware River path," will facilitate bringing more reliable and fuel diverse electric service and more efficient electricity markets to millions of consumers in the eastern United States.[2] Both of these areas were identified as transmission bottlenecks with risks of significant costs to consumers in the Department's 2003 "Transmission Bottleneck Project Report."[3] PJM's regional transmission planning process has confirmed repeated violations of NERC reliability criteria associated with moving power from the west through these paths to the major metropolitan load centers they serve. Likewise, customers demand for

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[1] *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors*, Notice of Inquiry, 71 Fed. Reg. 5660 (Feb. 2, 2006) ("NOI").

[2] PJM generally supports the criteria the Department proposed in the NOI to apply to potential NIETC. PJM concurs with and relies upon the comments on the criteria that the ISO/RTO Council ("IRC") is submitting separately to the Department. In particular, PJM supports the IRC's definition of "transmission corridor" based on existing and potential transmission paths between load centers and generation resources that can be used to serve them. PJM is not seeking, nor would it be appropriate for the Department to designate, particular lines or geographic routes to meet the needs identified in this Request. These issues are best left to the state siting processes and, if necessary, the "backstop" authority of the FERC pursuant to section 1221(b) of the Energy Policy Act of 2005.

[3] *See* Consortium for Electric Reliability Technology Solutions, *U.S. Department of Energy Transmission Bottleneck Project Report* (Mar. 19, 2003) at 64-69, 95 *available at* http://www.electricity.doe.gov/documents/ current_transmission _bottlenecks_report.pdf.

lower cost supplies has been stymied by the ever-increasing congestion on the existing transmission lines on these two corridors.

Expansion of transmission capability on the Allegheny Mountain path can provide relief from persistent and well-documented transmission congestion that has totaled more than $1.3 billion over the past three years. Expansion of transmission capacity will also immediately enhance the reliability of service to critical loads in the Washington, D.C. and Baltimore metropolitan areas, which face numerous violations of reliability standards over the next 15 years. Transmission expansion on the Delaware River path likewise will alleviate numerous violations of reliability criteria, principally on the bulk transmission lines that supply densely populated areas of New Jersey and, which, with necessary additional local upgrades, provide the future potential to address transmission constraints affecting New York City and Long Island. PJM's planning analyses have identified these violations of reliability criteria in every year from 2005 through 2010. As PJM expands its planning horizon to fifteen years, PJM expects these reliability violations to worsen steadily. These violations are the result of continuing steady growth in demand, retirements of local generating plants, little construction of new generating facilities, and aging transmission and generation infrastructure. None of these trends shows any sign of abating, promising that violations of reliability criteria will recur for the foreseeable future. While PJM's regional transmission expansion planning process, to date, has been successful in mitigating these violations through numerous short-term upgrades to lower voltage facilities, such upgrades have become progressively more difficult to identify and to implement in a timely fashion. Enhancements to the Allegheny Mountain and Delaware River paths also would ensure their capability of meeting growing demand for a conduit for bulk transfers of power from predominantly coal-fired generation in western PJM to the eastern U.S. load centers in PJM, as well as the New York City metropolitan area and points north.

As more fully explained below, both of the corridors that PJM proposes meet the criteria for designation proposed by the Department in the NOI and both warrant such designation as NIETC at the earliest possible date and no later than December 31, 2006. As Secretary Bodman reportedly noted in a speech on March 2, 2006, it can take 10-15 years of planning, regulatory review and construction to complete major new electric transmission facilities and "[w]hat that means . . . is that we must get started now, if these facilities are to be in place when we will need them."[4]

In support of its proposed corridor designations, PJM submits this Request and the several appended documents, all of which are identified below and listed in the Index to Appendices at the end of this document. PJM stands ready to respond to questions and to provide further data and analysis, should the Department so request.

I. Introduction and Background

A. PJM and Its Role In the National Transmission Grid

PJM is a FERC-approved regional transmission organization ("RTO") that independently and impartially coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[5] Serving approximately 51 million people, PJM encompasses major U.S. load centers from Illinois' western border to the Atlantic coast, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Dayton, Newark and northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond and Washington D.C. The company dispatches more than 164,000 megawatts of generation capacity over more than 56,000 miles of transmission lines – a system that serves nearly 20 percent of the U.S. economy.

PJM operates the world's largest competitive wholesale electricity market and ensures the reliability of the largest centrally dispatched electric service territory in North America. Using advanced information technology, PJM provides a wide array of information, much of it in real-time, to market participants to support their daily transactions and business decision-making. The company has administered more than $28 billion in energy and energy-service trades since its regional markets opened in 1997.

PJM also manages a sophisticated Regional Transmission Expansion Planning ("RTEP") process to ensure the continued reliability of the electric system and to enhance

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4 *Electric Power Daily*, "US Energy Chief says Transmission Grid Expansion Must Begin Now" (Mar. 3, 2006) *available at* http://www.platts.com/Electric%20Power/News/ 7307390.xml?S=n.

5 *See PJM Interconnection, L.L.C.*, 101 FERC ¶ 61,345 (2002).

the efficiency of the wholesale electricity markets under its supervision. Since its inception in 1999 through completion of the most recent plan in December 2005, the RTEP has identified more than $1.8 billion of transmission expansion projects throughout the PJM region.

PJM has more than 400 market participants. Its members/customers include power generators, transmission owners, electricity distributors, power marketers and large consumers. State regulatory commissions and consumer advocates are actively involved in PJM's governance and administration of its RTO responsibilities.

B. Summary of PJM's Positions and Proposals

Section 1221 of the Energy Policy Act adds a new section 216 to the Federal Power Act.[6] The new provision requires, *inter alia*, the Secretary of Energy (1) to prepare a study, initially within one year after enactment of the statute and then not less than every three years thereafter, on electric transmission congestion, and (2) to "issue a report, based on the study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." Pub. L. No. 109-58, § 1221(a)(2), 119 Stat. 594.

In the NOI issued on February 2, 2006, the Department invites comment on, among other items, how it should define an "electric transmission corridor" and what criteria it should use in evaluating the suitability of particular geographic areas for NIETC status. PJM has joined in and supports the comments of the IRC on these matters. Of particular import to the instant Request, PJM concurs with the IRC that the Department should define transmission corridors in terms of transmission paths between generation sources and load centers that rely on those sources.[7]

It is in this context that PJM responds to the NOI's invitation to interested parties to identify any "geographic areas or transmission corridors for which there is a

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[6] Federal Power Act, as amended, 16 U.S.C. §§ 791a, *et seq.*

[7] Were the Department to adopt a narrower definition of transmission corridor, it would essentially become a siting agency. However, in EPAct 2005, Congress reaffirmed the role of states in siting new transmission facilities and provided FERC only "backstop" authority regarding siting within NIETC. Accordingly, the Department should resist efforts to become yet a third siting agency, leaving those determinations to others in keeping with Congressional intent.

particularly acute need for early designation as NIETC." NOI, 71 Fed. Reg. at 5661. PJM's regional planning analyses and markets reveal that there is such an acute need in two areas of the PJM transmission system.[8] Those areas are:

1) Allegheny Mountain path. The Allegheny Mountain path is the high-voltage, bulk power transmission pathway that serves load centers in the metropolitan areas of Washington, D.C., and Baltimore from generation resources located west of the Allegheny Mountains in western Pennsylvania, West Virginia and the Ohio and Kanawha River valleys and points west. This path is highly constrained as a result of insufficient capacity to meet all demand for transfers of power from western generation, demand that has grown and continues to grow substantially as population and electricity demand steadily increase, while local generation capacity continues to age and retire and is not fully or timely replaced.[9] The principal areas served by the Allegheny Mountain path, the Washington, D.C., and Baltimore metropolitan areas, are classic load pockets where the ability to develop new generating resources is extremely constrained by geography, limited fuel choices and ever-tighter air emissions and other environmental restrictions.

2) Delaware River path. The Delaware River path is the high-voltage, bulk power transmission pathway that serves load centers in the mid-Atlantic area of PJM, including the metropolitan areas of Philadelphia, Wilmington, Newark and northern New Jersey, and provides a conduit for electricity exports to load centers in New York City and surrounding areas, as well as points north,[10] from generation resources located west of the Allegheny Mountains in western Pennsylvania, West Virginia and the Ohio and Kanawha River valleys and points west. This path is currently constrained as a result of insufficient local generation to keep pace with ever-increasing local and export demands and inability to develop new generation to replace an aging generation fleet, substantial portions of which recently have retired on short notice and much more of which is likely to be retired during the next five to ten years. The principal areas

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[8] These areas are identified in the map attached in Appendix 1. The dashed lines on the map represent historically constrained transmission interfaces. The corridors that PJM proposes are designed to facilitate transmission of power from western generating facilities across the interfaces to eastern load centers.

[9] The Department is familiar with the limitations on service to the nation's capital from its recent proceeding and order involving the Potomac River generating plant in Alexandria, Virginia. *See D.C. Pub. Serv. Comm.*, DOE Order No. 202-05-3 (Dec. 20, 2005) ("*Mirant Potomac River Order*"). Increased transmission capability on the Allegheny Mountain path, along with local improvements to provide additional transmission capability into the Potomac River substation, is critical to ensuring reliable supplies to the Washington-Baltimore metropolitan area.

[10] The feasibility and extent of such exports will depend upon the upgrading of existing facilities or construction of new facilities in New York or other importing areas.

> served by the Delaware River path, New Jersey and the Delmarva Peninsula, are classic load pockets where the ability to develop new generating resources is extremely constrained by geography, limited fuel choices and ever-tighter air emissions and other environmental restrictions.

PJM urges the Department to grant PJM's request for designation of the Allegheny Mountain path and the Delaware River path as NIETC by August 2006. For the reasons PJM explains in detail below, PJM's regional planning studies, as well as the operation of the market itself, demonstrate that the need for these designations is clear and immediate. Deferring action on these transmission corridors would unnecessarily and unwisely exacerbate the reliability problems and economic factors that warrant prompt action. Further, delay would create new uncertainty in the marketplace that would stymie recent, promising efforts to develop the new infrastructure. Timely designation that these paths rise to the national interest is undeniably needed to continue reliable, economical electric service to the tens of millions of Americans who live and work in the load centers served by the Allegheny Mountain and Delaware River transmission paths.

II. There is An Immediate Need for NIETC Designation of the Allegheny Mountain and Delaware River Paths.

As noted, PJM has joined in and supports the comments of the IRC on the Department's NOI. In particular, PJM agrees with the IRC's proposed definition of transmission corridors in terms of transmission paths between generation sources and load centers that rely on them for either economic or reliability reasons. Accordingly, PJM's proposed NIETCs are based on the IRC's definition of "transmission corridor:"

> An "transmission corridor" consists of all transmission paths and potential transmission paths that provide power transfer capability between a defined area of load and the generating resources that may be delivered across the transmission system to serve all or a portion of that load.[11]

PJM supports this definition because the IRC's "path-based" approach best reconciles the role that Congress contemplated for the Department under section 1221. This definition means the Department will identify areas where there is a need for additional transmission capability, but ensures that defining, developing and siting specific projects to meet those needs do not become part of the NIETC designation process. This is appropriate because the statute clearly reflects Congress' intent for the Department to consider potential corridor designations on a "big-picture" basis – not that it become a federal transmission planning or siting agency.

Thus, while Congress through section 1221(a) directed the Department to designate NIETC, in section 1221(b) it allotted to FERC the task of permitting construction of specific transmission projects within designated NIETC, but only as a "backstop" in the event that state authorities lack the power to permit the project or to consider its interstate benefits or, under certain circumstances, if a state fails to authorize the project or approves it with burdensome economic conditions, within one year from the date of an application for such authority. Moreover, Congress expressed its intent that the Department not override or usurp existing regional transmission planning programs in section 1221(h)(9)(C), where it directed the Secretary of Energy to "consult regularly"

[11] This definition is found and explained more fully in the comments the ISO/RTO Council is filing pursuant to the DOE's NOI. *See* Comments of the ISO/RTO Council on DOE/OE Notice of Inquiry, at 3 (Mar. 6, 2006).

with, among other entities, "Transmission Organizations approved by the Commission," including RTOs and independent system operators ("ISOs").[12]

A. PJM's Proposed NIETCs

PJM's regional transmission planning program indicates an acute need for additional transmission investment to facilitate west-to-east wholesale power transfers within the PJM region to ensure reliable service and to provide lower-cost power to eastern markets.[13] Accordingly, PJM here proposes two transmission paths for early designation as NIETC:

1) Allegheny Mountain path. The Allegheny Mountain path is the high-voltage, bulk power transmission pathway that serves load centers in the metropolitan areas of Washington, D.C., and Baltimore from generation resources located west of the Allegheny Mountains in western Pennsylvania, West Virginia and the Ohio and Kanawha River valleys and points west. This path includes these and other load centers served from the 500 kV transmission lines and associated facilities that today extend generally from the vicinity of the Wylie Ridge and Kammer substations near the Ohio River, extending south and southeastward through Pennsylvania, West Virginia, Virginia and Maryland to the Washington-Baltimore area. These load centers are served from high voltage transmission facilities include, among others, the following 500 kV transmission line segments:

    - Keystone - Juniata 500 kV line
    - Conemaugh - Juniata 500 kV line
    - Conemaugh - Hunterstown 500 kV line
    - Hatfield - Black Oak 500 kV line
    - Pruntytown - Mount Storm 500 kV line

2) Delaware River path. The Delaware River path is the high-voltage, bulk power transmission pathway that serves load centers in the mid-Atlantic

[12] Section 1291(b)(29) defines "Transmission Organization" as "a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the [FERC] for the operation of transmission facilities."

[13] States throughout the region maintain the ability to retain the lowest cost supplies to serve their retail native load customers pursuant to the particular directives of each state's legislature. PJM's markets are voluntary, not mandatory, and provide additional options for wholesale customers, as well as needed price transparency, throughout the 13-state footprint and in the District of Columbia.

area of PJM, including the metropolitan areas of Philadelphia, Wilmington, Newark and northern New Jersey, and provides a conduit for electricity exports to load centers in New York City and surrounding areas, as well as points north,[14] from generation resources located west of the Allegheny Mountains in western Pennsylvania, West Virginia and the Ohio and Kanawha River valleys and points west. This path currently includes these and other load centers served by the 500 kV transmission lines and associated facilities extending generally from the vicinity of the Wylie Ridge substation near the Ohio River, extending eastward through Pennsylvania to the Philadelphia area and across the Delaware River into and through New Jersey and southward to Wilmington and through the Delmarva Peninsula. The load in these areas are served from facilities include, among others, the following 500 kV transmission line segments:

- Wescosville - Alburtis 500 kV line
- Juniata - Alburtis 500 kV line
- Alburtis - Branchburg 500 kV line
- Elroy - Branchburg 500 kV line
- TMI - Hosensack 500 kV line
- Peach Bottom - Limerick 500 kV line
- Rock Springs - Keeney 500 kV line

The facilities identified above are illustrated on the map attached as Appendix 1.

PJM principally bases its proposed designation of these paths as NIETC upon recent years' activity and experience in its markets and its analyses pursuant to its RTEP process, a comprehensive regional transmission expansion planning protocol.[15] PJM's RTEP process identifies transmission system upgrades and enhancements to provide for the operational, economic and reliability requirements of PJM customers. A region-wide planning effort, the RTEP determines the best way to integrate transmission, generation and load response to meet load-serving obligations. PJM currently applies planning and reliability criteria over a fifteen-year horizon to identify transmission constraints and other reliability concerns. Transmission upgrades and other projects that can mitigate identified issues are then examined for their feasibility, impact and costs, culminating in

[14] The feasibility and extent of such exports generally depends upon upgrades to facilities in New York or other importing areas.

[15] The RTEP protocol is formally designated as Schedule 6 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. FERC has approved and accepted the Operating Agreement, including Schedule 6, as PJM's Third Revised Rate Schedule FERC No. 24 *available at* http://www.pjm.com/documents/downloads/agreements/oa.pdf (last visited Mar. 6, 2006).

one plan for the entire PJM footprint. PJM discusses in more detail later in this submission the scope of the RTEP analysis and why it provides a solid foundation for the Department's decision regarding designation of the proposed Allegheny Mountain and Delaware River NIETCs.

Both the validity and the immediacy of the need for designation of these proposed corridors are underscored by the recent emergence of two major proposals, one a 550-mile, 765 kV system proposed by American Electric Power, the other a 330-mile, 500 kV system proposed by Allegheny Power, to construct new, high-voltage transmission lines in these areas. Both of these projects would be located entirely in the Allegheny Mountain and/or the Delaware River transmission paths for which PJM seeks NIETC designation. The Department should place particular emphasis in its evaluation of corridor designation on whether market participants are actually willing to commit capital toward specific solutions as opposed to more hypothetical requests. In this case, two companies, American Electric Power and Allegheny Power, have both put forward specific proposals to construct transmission lines in these proposed corridors. Although PJM is expressly not seeking review of these or any other particular projects in this request, the fact that commitments have been announced should weigh in the Department's analysis concerning the need and timing of designation.

B. The Need For Designation Of These NIETCs Is Acute.

PJM's RTEP studies highlight in several respects the severity and immediacy of the need for NIETC designation for both of the transmission paths that PJM advocates. Designation of the Allegheny Mountain path is warranted due to persistent, costly congestion on the existing 500 kV facilities in the corridor, as well as by a growing need for transmission improvements to maintain reliability of service for the Washington and Baltimore metropolitan areas. Both features are rooted in well-established electrical flows that reflect steadily increasing reliance in eastern PJM on generation resources located well to the west, combined with installation of little new generation and steady load growth in the east. The potential shutdown of the Potomac River generating station near Washington also contributes to the need for this corridor designation. Designation of the Delaware River path is driven by reliability issues presented by retirements of eastern generating units without development of sufficient replacement generating capacity, while the region's load continues to grow both locally and via new exports of power to New York City and surrounding areas through merchant transmission facilities.

The electricity needs of the Washington-Baltimore area and Eastern PJM (Philadelphia-Wilmington, New Jersey and the Delmarva Peninsula) are supplied not only by local generation, but also by significant energy transfers into those areas. A significant portion of these transfers flow through the interstate 500 kV, 345 kV and 230 kV transmission systems of northern West Virginia, northern Virginia, Maryland, eastern Ohio and central-southwestern Pennsylvania. The dependence of eastern PJM areas on west-to-east transfers has been growing steadily since approximately 2002, after Allegheny Power integrated into PJM. The growth in such transfers is illustrated on Appendix 2.

Imbalances between local supply and demand -- the result of load growth, lagging generation additions and generation deactivations -- require progressively more complex and expensive transmission upgrades. PJM's RTEP studies show that trends in load growth and in locating new generating facilities will impose increasingly heavy levels of west to east power flows across PJM's interstate transmission system. More than 9400 MW of new generation of which approximately 6700 MW are coal-fired units located in western Pennsylvania, western Maryland, eastern Kentucky, Ohio and West Virginia are pending in PJM's interconnection queues with commercial operation dates of 2006-2012. These new resources are being constructed both to serve local load and to participate in PJM's broader energy market to the extent that transmission capability permits. Provided it can reach eastern markets, this energy will have the effect of displacing in PJM's merit order dispatch higher-cost generation that located east of Bedington in the Baltimore/Washington area and in Eastern PJM.

The story is not complete, however, without coupling this generation scenario with anticipated load growth. The weather-normalized summer peak in the PJM region is forecast to increase at an average rate of 1.7% per year over the next ten years – from 2005 to 2015. The expected growth rates in individual utilities' geographic zones vary from 1.1% to 2.5%, as shown in Appendix 3 at 14, Table 2.1.1-1, but many of the highest projected rates of annual growth are in the eastern portions of PJM, for example: 2.1% annually for Atlantic City Electric (New Jersey), 2.5% annually for Delmarva Power & Light (Delmarva Peninsula), 2% annually for Potomac Electric Power (Washington). PJM's RTEP studies show that in order to meet this load growth during the most recent planning horizon (through 2010), Baltimore-Washington and eastern PJM both must rely on the interstate, high-voltage transmission network to obtain needed energy from western sources. Designation of the Allegheny Mountain and Delaware River paths will jump start the development of the needed transmission capability that will enable the interstate transmission grid to supply the power these eastern areas require both to ensure reliable service to consumers and to obtain the most economical, available electricity supplies.

1. <u>Allegheny Mountain Path to Washington-Baltimore Loads</u>

a. Expansion of Bulk Transmission Capacity in the Allegheny Mountain Path Is Critical To Reliability of Service And Mitigation of Significant Transmission Congestion Costs for Washington and Baltimore.

The electric power system in the greater Baltimore-Washington area faces growing customer demand, sluggish generating resource additions and reliance on transmission system facilities to bridge the two. Baseline reliability analyses since 1999 have revealed the need to address the ability of the generation and transmission resources in those areas to continue to serve load reliably. PJM in recent years has identified a number of reliability violations in the area, primarily on 230 kV facilities. PJM's experience teaches that after overloads on a region's 230 kV facilities are remedied with upgrades, the effects of continuing load growth and generation retirements then begin to stress the capability of higher-voltage, backbone transmission facilities. In the 15-year regional transmission expansion plan that PJM will complete in May 2006, PJM expects to find impending overloads on the 500 kV circuits in the Allegheny Mountain transmission path west of Washington and Baltimore.

PJM's planning studies thus have shown and will continue to demonstrate that reliable service to this region will depend to an ever-increasing degree upon transfers of power into the area through the high-voltage, backbone transmission facilities west and northwest of the Baltimore and Washington metropolitan areas, i.e., the existing facilities of the proposed Allegheny Mountain path NIETC. The weather normalized summer peak demand in the combined Potomac Electric Power-Baltimore Gas & Electric service areas is forecasted to grow at an average rate of 1.6% annually over the next ten years – from 13,459 MW in 2005 to 15,823 MW in 2015 – an increase of 2,364 MW over the forecast period. PJM's annual CETO/CETL analyses for this area have documented a steady decline in recent years of the ability of local generation to maintain load deliverability during peak times and increasingly frequent violations of load deliverability criteria in some local areas. Accordingly, there is little reason to expect local generation resources to be sufficient to serve Washington-Baltimore area's constantly growing demand for electricity.

Between 2003 and 2005, 585 MW of generation in the Baltimore-Washington were deactivated, the result of plant retirements, environmental restrictions on operations and other causes. The potential shut-down of Mirant's Potomac River generating plant near Washington accounts for 482 MW of this deactivated capacity. *See* Appendix 3 at 35, Map 3.2.1-1 for the location of the Potomac River plant.) The Potomac River plant currently remains available under certain circumstances due to an order of the Secretary of Energy under section 202 of the FPA.[16] Nevertheless, the plant's shut-down in August 2005 immediately triggered needs for significant transmission upgrades, including the installation of two new 230 kV transmission circuits, and an increase in the size of a planned dynamic reactive device at the 500 kV Black Oak substation in Maryland.

The final status of the Mirant plant has not yet been established, pending the owner's decision on whether and to what extent to upgrade the plant to meet environmental standards. However, with no new generation planned in the Washington-Baltimore area and the length of time required to build transmission to help meet load

[16] *See Mirant Potomac River Order, supra.*

requirements with remote generation, planning and implementation of additional transmission capability must begin now in order to ensure that it will be available when required. Recent planning studies found significant deliverability violations for Baltimore-Washington in 2008. These violations are to be resolved by incremental transmission upgrades, but those are only a temporary solution. Unless additional generation is sited in these areas, further load growth will require more costly, more extensive and more frequent transmission upgrades. Moreover, any additional unanticipated retirements of generation in the area could cause much more extensive load deliverability violations similar to those now occurring in New Jersey (*see* section II.B.2 below).[17]

Information from PJM's interconnection queues make it clear that additions of generating capacity in the Baltimore-Washington area will not keep pace with the effects of expected load growth and generation deactivations. Only 171 MW of generating capacity have been added in this area since 2000 and just 4.5 MW more are currently under construction. One other project, representing another 13.5 MW, remain active in PJM's interconnection queues. This additional generation is primarily the result of additions to existing generating plants that were planned. During its two most recent interconnection windows (designated Queue O and Queue P), PJM received just the one 13.5 MW interconnection request for new generation capability to be installed in the Washington-Baltimore area between 2005 and 2009.

Accordingly, providing reliable and economical electric service to customers in the Washington-Baltimore area both currently and for at least the next 15 years clearly depends on creating and maintaining sufficient bulk transmission capability to supply the area from the west. Immediate designation of the Allegheny Mountain transmission path as a NIETC will facilitate timely development of the facilities necessary to ensure that

[17] While PJM has not been informed of any impending further local generation retirements, the District of Columbia Public Service Commission, in response to public inquiries, recently asked PJM to analyze the effects on local electric service reliability of shutting down Pepco's 550 MW Benning generation plant. Among other problems, including increased loading of several important and already heavily congested, 500 kV circuits and transformers west of Washington, PJM's study indicated that deactivation of this plant would eliminate the Washington-Baltimore area's entire remaining available transmission import capability in 2008. *See* "Reliability Evaluation For The Potential Retirement Of Benning Generation," *available at* http://www.pjm.com/planning/project-queues/gen-retirements/20050610-reliability-benning-gen-retire2.pdf (last visited Mar. 6, 2006).

such service is maintained. PJM discusses in more detail below how the proposed Allegheny Mountain path meets each of the Department's proposed criteria for designation of NIETC.

b. Expansion of Bulk Transmission Capacity Will Relieve Burdensome Congestion in the Allegheny Mountain Path.

The facilities currently located in the Allegheny Mountain transmission path have experienced extensive congestion, particularly over the past three years, imposing significant costs on customers in and around Washington and Baltimore and throughout Eastern PJM. This experience highlights both the importance of power imports from western PJM to Washington-Baltimore and other eastern markets and the need to facilitate additional transmission capability on this path.

In 2005 alone, congestion on the principal facilities in the Allegheny Mountain path totaled approximately $862 million, making the three-year total more than $1.23 billion, as reflected in the following table:[18]

Congestion on the Allegheny Mountain Transmission Path 2003-2005 ($ million)	2003	2004	2005
Bedington-Black Oak Interface	$102	$320	$534
Mt. Storm-Doubs	$0	$0	$119
Kammer Transformer	$10	$8	$82
AP South Interface	$5	$4	$48
Pruntytown-Mt. Storm	$0	$0	$46
Wylie Ridge Transformer	$7	$29	$14
Ft. Martin-Pruntytown	$0	$0	$14
Totals	**$124**	**$361**	**$862**

This level of congestion underscores the extent to which demand for transmission capability on this path exceeds the currently availability capacity, particularly during periods of peak demand.[19] Another such indicator is the frequency and extent of higher locational marginal prices (LMPs) on the east side of the Allegheny Mountain path than

[18] All of the congestion cost and LMP differences presented in this Request are calculated from PJM's market records and are included in the attached Appendix 4. It should be noted that these congestion cost amounts are not fuel-cost adjusted and illustrate the high degree of sensitivity of congestion on this path to fuel cost volatility.

[19] It should be noted that a substantial portion of this congestion was hedged through use of financial transmission rights. However, as load continues to grow, absent upgrading of the transmission system, the availability of these financial transmission rights diminishes.

on the west side of the path. On an annual basis, LMPs were, on average, approximately $20.00 per MWh higher on the east side of the path in 2005 than on the west side. Over the past three years, this LMP difference has steadily increased, as shown in the following table:

Average LMP Differentials Across the Proposed Allegheny Mountain Transmission Path[20]		
	Average LMP Differential ($/MWh)	
Year	Day-ahead	Real-time
2003	4.76	9.00
2004	8.44	21.47
2005	21.47	20.10

The average 2005 LMP difference across the Allegheny Mountain path of $20 per MWh represents a premium of approximately 44% over the average 2005 LMP on the west side of the path. Reducing the growth of the already extremely costly congestion on the Allegheny Mountain transmission path is an additional and compelling potential benefit for electricity consumers and thus an additional compelling reason for designating the path as a NIETC.

2. <u>Delaware River Path to Eastern PJM Loads</u>

a. Reliable Service and High Transmission Congestion Costs In Eastern PJM, Particularly New Jersey, Require Immediate Designation Of the Delaware River Path.

[20] For purposes of calculating the LMP differences shown here, the Allegheny Mountain path is deemed to be a path from West Virginia to Baltimore-Washington.

A key finding of PJM's 1999 RTEP baseline analysis was that, by 2006, Eastern PJM (Philadelphia, New Jersey and the Delmarva Peninsula) would begin to experience reliability issues absent the addition of generation resources or transmission enhancements to meet growing consumer demand. Those reliability concerns were largely mitigated between 1999 and 2003 with the addition of new generating resources. Since 2003, however, continued load growth (including the impending start of large exports of power to New York City), retirement of generation resources, sluggish development of new generating facilities, and continued reliance on transmission to meet load deliverability requirements and to obtain access to more economical sources of power west of this area, are collectively and progressively degrading system reliability in Eastern PJM. This degradation is compounded by the stresses on the system of accommodating more than 1,600 MW of planned exports of power to New York City and surrounding areas, with about half of that amount slated to begin in 2007 with the completion of two new merchant transmission facilities. Present trends mean reliability criteria violations will continue to be identified in New Jersey and will spread to other areas of PJM where similar conditions exist.

PJM estimates that load in New Jersey will increase by 1,950 MW (9.8%) between 2005 and 2010, but generation additions will not keep pace. In 2003 and 2004, only 51 MW of new generation were constructed in New Jersey; only 1,340 MW are currently under construction.[21] Similarly, load growth in the Delmarva Peninsula is projected to be 2.7 percent per year, or an increase of 573 MW, over the next five years, but planned generation additions are minimal. Only 60 MW were added on the peninsula in 2004 and only another 150 MW are being studied in PJM's interconnection process.

Longer-term forecasts indicate continuing, significant load growth in this area. The weather-normalized summer peak demand in Eastern PJM is expected to grow at an average rate of 1.8% annually over the next ten years – from 32,301 MW in 2005 to 38,574 MW in 2015 – an increase of 6,273 MW.

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21 A substantial number of projects have been proposed for New Jersey in the most recent PJM interconnection queues, but projects at this earliest state of development in PJM typically suffer the highest rates of attrition, and therefore are highly uncertain.

In addition, two merchant transmission developers have signed interconnection service agreements with PJM for projects with terminals in New Jersey and associated withdrawal rights that collectively will permit PJM market participants to export up to 1090 MW of power to New York and systems beyond from generation resources located in PJM and/or in areas to its west and south. Both of these projects, the Neptune Regional Transmission System D.C. cable and East Coast Power's variable frequency transformer, are now under construction and both anticipate commencing commercial operation in 2007. RTEP studies have demonstrated the need for significant transmission upgrades to accommodate the two facilities going into service in 2007, based on the need to have sufficient transmission in place to "deliver" sufficient power to their New Jersey terminals to accommodate their planned withdrawals/exports. PJM expects its ongoing studies of projects still in the interconnection queue to document the need for extensive, additional transmission facilities to facilitate those projects' planned bulk power exports to New York. For PJM's transmission planning purposes, all of these merchant facilities' firm withdrawal rights electrically represent `a further increase in load in New Jersey.

Against this backdrop, the PJM region, particularly Eastern PJM, recently has experienced a dramatic spike in generation retirements. For the four years from 1999 through 2002, 274 MW of generation in the Mid-Atlantic region retired. In contrast, from January 1, 2003 through June 22, 2005, 1,709 megawatts of generation capacity retired, and an additional 1,694 MW are proposed for retirement in the Mid-Atlantic region from 2006 through 2008. Appendix 5 provides a listing of the generating units retired since January 2003 and those currently proposing retirement in the Mid-Atlantic region. Of the units identified in Appendix 5, 40% are located in New Jersey – representing actual and expected retirements of 2,500 MW of generating capacity in New Jersey alone between 2003 and 2009. *See* Appendix 3 at 30, Table 3.1.4-1. The generation owners responsible for these retirements generally have claimed that the retirements are due to the current excess of generation in PJM (which is located mostly in the western region of PJM), and the inability of these particular units to compete economically. More than 45% of the generation retirements in Eastern PJM are capacity that is more than 40 years old. *See id.*.

The FERC recently determined that PJM cannot compel owners of generation units proposed for retirement to keep their facilities in service and ruled that such retirements may take effect upon 90 days prior notice.[22] This time period is designed to allow PJM to assess the reliability effects of proposed retirements, and to make compensation arrangements with the owners of units that PJM finds must be retained in service for reliability purposes until replacement transmission or generation capability is placed in service. Although PJM's system was found reliable in prior RTEPs, the announcements in 2004 and 2005 of significant retirements with little notice since has resulted in PJM identifying reliability criteria violations for 2005 and for each subsequent year in the most recent planning horizon, i.e., 2006, 2007, 2008, 2009 and 2010.

Given the number of generation retirements implemented or announced in the last two years, and their short notice, the significant network upgrades needed to resolve the resulting reliability criteria violations cannot be completed before the time periods for which the violations were identified. Consequently, in order to assure compliance with reliability criteria, PJM identified several retiring generators that, if retained in service temporarily, would resolve the most immediate reliability violations. The operators of these facilities agreed to remain in service beyond their proposed retirement dates, subject to compensation in accordance with PJM's FERC tariff.

The retention of these units in service, along with the completion of a number of transmission upgrades, has enabled the PJM system to remain in compliance with all relevant reliability criteria for the current planning period (June 1, 2005 through May 31, 2006). However, as explained above, PJM already knows that it faces reliability criteria violations for each of the next five years. Additional transmission upgrades therefore will be needed before each of the next four summer seasons to ensure continued compliance with reliability criteria. PJM also will need to retain in service for a number of years beyond 2005 the retiring generators that have been identified as needed for reliability. How long these units must be kept in service will depend on the pace of transmission construction and the outcome of current 15-year RTEP

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22 *See PJM Interconnection, LLC,* 110 FERC ¶ 61,053, *order on reh'g,* 112 FERC ¶ 61,031 (2005).

studies, which are scheduled for completion in May 2006. PJM fully expects those studies to find more and increasingly significant reliability problems in New Jersey and elsewhere in Eastern PJM.

c. Expansion of the Delaware River Path Congestion Also Promises Substantial Economic Benefits.

Although less severe than on the Allegheny Mountain path, congestion also has been significant and also has been rising on the bulk transmission facilities in the Delaware River path. In 2005 alone, congestion on the principal facilities in the Delaware River path totaled approximately $459 million, making the three-year total more than $780 million, as reflected in the following table:

Congestion on the Delaware River Transmission Path 2003-2005 ($ million)	**2003**	**2004**	**2005**
50045005 Interface	$12	$6	$200
East Interface	$68	$44	$87
Kammer Transformer	$7	$5	$55
Central Interface	$37	$9	$44
West Interface	$3	$11	$40
Wylie Ridge Transformer	$17	$68	$33
Total	**$144**	**$143**	**$459**

Again, such congestion demonstrates the demand for west-to-east transfer capability on the Delaware River transmission path.[23] Also noteworthy is that these amounts include approximately $200 million of congestion in the 12-month period after the Branchburg 500/230 kV transformers were derated in 2004. The dramatic effect of that derating on congestion highlights the very high degree of sensitivity of the capability of the Delaware River path to the outage of key infrastructure elements.

That the congestion on this path has been considerably less than on the Allegheny Mountain path should not be taken to indicate that the need for expanded transmission capability in the Delaware River path is less immediate. Congestion is lower on this path only because PJM cannot transfer the energy across the Allegheny Mountains to reach

[23] Although a certain amount of this congestion can be addressed through financial transmission rights, as load continues to grow, the amount of unhedged congestion continues to rise.

many of the Delaware River path interfaces. If the path's transfer capability from west of the Alleghenies was improved, limits on the more easterly Delaware River interfaces would be controlling with much greater frequency.

The growing demand for west to east transfer capability on this path is likewise reflected in higher average LMPs on the east side of the Delaware River path than on the west side, as shown below:

Average LMP Differentials Across the Proposed Delaware River Transmission Path[24]		
	Average LMP Differential ($/MWh)	
Year	**Day-ahead**	**Real-time**
2003	4.92	4.72
2004	4.75	17.69
2005	17.69	15.29

In general, the location of generation on which eastern markets rely is increasingly shifting to the west, due both to retirements of eastern units and the location of most new generation capacity in western areas, i.e., western Pennsylvania, West Virginia, southeastern Ohio and beyond. There is no question, therefore, that Eastern PJM's reliance on the Delaware River transmission path for imports of power from the west will increase as it increases its reliance on transmission capability to replace retired generation and to meet growth in demand. This trend also will inevitably worsen congestion on the bulk transmission facilities in both the Allegheny Mountain and Delaware River paths. Thus, higher LMPs in the eastern portions of PJM than in western areas will persist. In the continued absence of investments in major new bulk transmission capacity, PJM must continue to utilize patchwork upgrades to existing transmission facilities to ensure the overall system remains functionally reliable, even if repeatedly in need of new upgrade "bandages," badly congested and far less

[24] For purposes of calculating the LMP differences shown here, the Delaware River path is deemed to be a path from the Midwest to Eastern Pennsylvania, New Jersey and Delaware.

economically efficient than it could be. Accordingly, there is an immediate need for action by the Department to designate the Delaware River path as a NIETC. PJM discusses in more detail below how the Delaware River path conforms with the Department's criteria for proposed NIETC designations.

2. Incremental Transmission Upgrades Are Becoming Insufficient.

Solutions to the reliability criteria violations described above have been, for the most part, accomplished with adding increments of transmission capability in the immediate area of the violation. In part as a result of generation retirements, PJM's RTEP process recently has had to order unprecedented levels of baseline transmission upgrades to the system. Of the more than $1 billion worth of upgrades in the most recent plan, almost 60% are baseline reliability upgrades. The aggregate cost of the transmission upgrades required to remedy reliability criteria violations in Eastern PJM is more than $600 million just for 2005 through 2009. *See* Appendix 3 at 32, Fig. 3.1.6-1. Of these, approximately $200 million in upgrades are needed to address reliability violations from the New Jersey retirements just for the years 2005 through 2007. A further $460 million of transmission upgrades will be presented to the PJM Board for approval in April 2006 to resolve additional reliability criteria violations through 2010. The 15-year planning studies PJM expects to complete in May 2006 is certain to lead to still more expensive upgrades to resolve further reliability problems in New Jersey and elsewhere in Eastern PJM through 2021. Moreover, should one more large generating unit in New Jersey retire, not only would extensive local upgrades be needed to maintain load deliverability, but a costly, major new 500 kV circuit almost certainly would be required as well.[25]

The RTEP also currently includes baseline transmission upgrades needed to address load criteria violations previously identified for the Baltimore-Washington area for 2008. In the Baltimore-Washington area, the addition of over 900 MVAR of capacitors are required over the next three years to maintain adequate voltages. In addition, a 500/230 kV transformer at Doubs substation will be replaced later this year with a higher rated transformer to provide additional transmission capability to support

[25] Though PJM has not been notified any such further retirements, it is mindful that the Oyster Creek nuclear generating plant in New Jersey is involved in a contested relicensing proceeding before the Nuclear Regulatory Commission.

the Baltimore-Washington load. The cost of these upgrades is estimated at $20 million. Should any additional generators in these areas announce their retirement, still more, costly transmission upgrades will be needed. Further, as previously noted, it has been PJM's experience that correction of repeated reliability violations on local facilities soon leads to the emergence of violations on bulk power facilities that serve the affected area.

The RTEP process thus documents in detail the bases for both of the high-voltage, interstate transmission paths that PJM proposes for designation as NIETC, as well as the immediacy of the need for action by the Department on both paths. Reliability criteria violations and congestion on both paths require prompt actions to develop incremental transmission capability to serve the major metropolitan areas and other load centers that depend on these paths for economical and reliable supplies of electricity. Designation of these paths as NIETC will indicate the national importance of ensuring reliable and least-cost service to the major eastern metropolitan areas in eastern PJM that rely upon the Allegheny Mountain and Delaware River transmission paths, will serve to focus stakeholders on the critical, immediate need to identify and develop viable bulk transmission optionsand, to the extent additional transmission capacity is added on those paths, will enhance the development of a national electric transmission grid.

However, the upgrades PJM has had to require through the RTEP have become progressively more complex and expensive, with longer and longer lead times needed for construction. Extension of some of the RMR contracts in New Jersey may become essential to maintain reliability until some upgrades already planned are completed. In short, PJM is rapidly reaching the limit where short-term, incremental fixes will no longer be sufficient and substantial new transmission will have to be constructed to maintain reliable and economical service to all east coast markets. Because of the lead time associated with the kind of interstate, EHV transmission projects that the PJM region requires, planning for these facilities needs to start now. One of the primary drivers for extending the PJM planning horizon to 15 years was the recognition by PJM and its stakeholders that the need for major new transmission capability must be identified in time to get it constructed before reliability suffers.

4. <u>Market Actions Underscore The Need For Immediate NIETC Designations For The Allegheny Mountain and Delaware River Paths</u>.

PJM's RTEP studies are not, however, the only compelling evidence of the immediate need for NIETC designation for the Allegheny Mountain and Delaware River paths. Market participants also recognize the need for new investment on these paths. This is perhaps best reflected in the proposals of American Electric Power ("AEP") and Allegheny Power ("APS") to construct new, high-voltage transmission lines in portions of one or both of the transmission paths for which PJM advocates immediate NIETC designation.

AEP proposes a 765 kV transmission line across both proposed paths. AEP's proposed line is comprised of a an initial segment from Amos, West Virginia, to the Doubs substation in Maryland – in the Allegheny Mountain path – and a second segment from Doubs to the Deans substation in New Jersey – in the Delaware River path. APS proposes a new 500 kV transmission line from the Wylie Ridge area of western Pennsylvania, via Mt. Storm and Bedington, to the Doubs substation in Maryland, west of Washington and Baltimore, all with in the Allegheny Mountain path.

Though PJM otherwise takes no position on the specific merits of either AEP's or APS's proposals, it concurs with AEP and APS that there is an immediate need to commence development of the high-voltage interstate transmission infrastructure that eastern PJM load centers will require for reliable and economical electric service. Both projects have indicated that the prospect of designation of NIETC corridors is one factor that led them to propose such large investments in new, bulk power transmission facilities. These proposals, as well as other projects which PJM expects will be announced, demonstrate recognition in the marketplace that there is substantial need for additional west-to-east transfer capability to transfer power into Eastern PJM and the Washington-Baltimore area. Such attention in the marketplace underscores the conclusion that early designation of the Allegheny Mountain and Delaware River paths as NIETCs is justified and appropriate.

C. The RTEP Process Provides a Solid Foundation For The Department's Designation Of The Proposed NIETCs.

In developing the RTEP, PJM annually performs a comprehensive load flow analysis, taking into account forecasted firm loads, firm imports from and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation and transmission facilities, of the ability of the PJM grid to meet applicable NERC and regional reliability council (MAAC, ECAR, MAIN, or SERC) criteria, nuclear plant licensee requirements and PJM reliability standards.

PJM then analyzes the effects on the system of numerous other factors, including:

- NERC and regional reliability council reliability assessments;
- operational performance of system facilities;
- requests to interconnect new generation and merchant transmission facilities;
- transmission owners' plans to modify or expand their transmission facilities;
- interregional transmission development plans;
- expected generation retirements;
- load-serving entities' demand forecasts and related capacity requirements;
- distributed generation and self-generation developments;
- requests for new or increased, long-term firm transmission service; and
- market-based proposals and PJM-developed alternatives to resolve persistent and costly congestion.

Preparation of the RTEP also includes testing the adequacy of the transmission system to deliver energy and capacity resources to loads in all areas of the PJM region. For this purpose, PJM tests load deliverability[26] for each relevant electric area within PJM. Specifically, PJM determines the amount of capacity that must be imported into an area during an emergency to ensure that such area can satisfy a transmission-related loss of load expectation of only one day in 25 years. This required emergency level of capacity imports is referred to as the capacity emergency transfer objective, or "CETO." After PJM determines the required level of emergency capacity transfers into a zone (i.e., the CETO), it then determines the capability of the transmission system to transfer capacity into such zone under those emergency conditions, referred to as the capacity emergency transfer limit, or "CETL." For the RTEP, PJM compares each area's forecasted CETO with the forecasted CETL for that area. If the CETO exceeds the CETL for a given area, PJM will identify transmission upgrades necessary to increase the

[26] Load deliverability refers to the system's capability to deliver energy from the aggregate of all capacity resources to an electrical area experiencing a capacity deficiency. The load deliverability test employs probabilistic techniques and a loss of load expectation ("LOLE") standard. In PJM, the LOLE is one day in 25 years.

CETL and resolve the problem. The relevant electric areas tested in this fashion are determined functionally, based on the topology of the electric system and the location of transmission constraints. The areas addressed may include transmission-owner zones, aggregates of such zones, or sub-zones within such zones, i.e., wherever there are constraints that are likely to limit emergency transfers into an area of load.

Several factors affect the system's ability to pass the CETO/CETL load deliverability test: (1) new generation installed in a zone, which reduces the need to import energy using the transmission system; (2) retirements of existing generation in a zone, which increases the need to import energy using the transmission system; and (3) load growth, which, in the absence of new generation, increases the need to import energy using the transmission system.

PJM's RTEP process is collaborative from start to finish. The PJM Transmission Expansion Advisory Committee and other stakeholder forums and processes provide opportunities for stakeholders to review PJM's planning analyses and offer input (including proposed projects) to help PJM improve the grid, ensuring reliability and access to robust, competitive markets for all market participants. PJM's governing committees, such as the PJM Members Committee and the Planning Committee, provide additional opportunities for stakeholders to provide input to the regional planning process. In addition, *ad hoc* stakeholder groups are periodically commissioned to address specific issues. Recent groups have developed planning modules and tariff changes relating to matters such as PJM's economic planning process and FERC's rules standardizing generation interconnection procedures and agreements. PJM also engages in planning activities that address issues of mutual concern to PJM and neighboring transmission systems. PJM participates in such super-regional coordination of planning with the Midwest ISO through a Joint Operating Agreement, with ISO New England and the New York Independent System Operator through the Northeastern ISO/RTO Planning Coordination Protocol, and with the Tennessee Valley Authority through a Joint Coordination Agreement.

III. The Allegheny Mountain and Delaware River Paths Meet The Department's Proposed Criteria For Designation Of NIETC.

PJM has joined in the IRC's comments on the Department's eight proposed criteria for evaluating transmission corridors proposed for NIETC designation. PJM thus generally supports the Department's proposed framework for carrying out its mandate to designate national interest corridors. Accordingly, PJM has evaluated the consistency of its proposed NIETC with that framework. As explained in the following discussion, both the Allegheny Mountain and the Delaware transmission paths fully satisfy the Department's proposed criteria for designation as NIETCs.

A. *Draft Criterion 1: Action is needed to maintain high reliability.*

1. Allegheny Mountain Path.

The importance of importing power from the west to replace local generation capacity is particularly acute on this path. Recent RTEP analyses have demonstrated violations of reliability criteria on three major facilities in the Allegheny Mountain path; overloading of the Mt. Storm-Doubs 500 kV transmission line, violation of the Bedington-Black Oak 500 kV voltage limit and overload of the Doubs-Dickerson 230 kV circuit. In addition, the RTEP has identified a need for over 1300 MVAR of capacitors on the PEPCO and BG&E systems, at an estimated cost of $17.5 million, to maintain reliability of service. PJM expects to find additional reliability violations in the ongoing 15-year planning studies that will be completed in May 2006.

The effects of these violations are exacerbated by the potential permanent shut-down of the Potomac River generating plant in Alexandria, Virginia. The Department is familiar with the reliability consequences of this event for the Washington-Baltimore metropolitan area.[27] Although the Department has ordered the owner of the Potomac River plant to keep it operational and to generate power under certain conditions through at least October 1, 2006, environmental pressures may still require the plant to shut down permanently after PEPCO completes installation of two new 230 kV transmission circuits.

27 *See Mirant Potomac River Order*.

PEPCO's addition of two new 230 kV circuits (construction of which is now underway) will ensure compliance, in the vicinity of the Potomac River substation, with applicable reliability criteria in the event the Potomac River plant is permanently shut down. Nevertheless, upon completion of the new circuits and shutdown of the generating plant, the reliability of service to the region in general will depend even more than it does today on imports of power from western sources over the Allegheny Mountain transmission path. Shutting down Potomac River of itself imposes additional contingency loading on the Bedington-Black Oak and Mt. Storm-Doubs 500 kV transmission lines,[28] exacerbating the constraints already experienced on those lines. Local pressures have led

[28] *See* PJM/PEPCO Joint Response to FERC Staff Data Request, response no. 1.e., FERC Docket No. EL05-145-000 (Aug. 26, 2005) ("August 26 Responses to FERC") (CEII document (non-internet public)).

the D.C. Public Service Commission to study the consequences of shutting down at least one other local generating facility, the Benning plant.[29]

Essentially, these events would have the effect of shifting to the already-congested high voltage transmission facilities on the Allegheny Mountain path, to the Bedington-Black Oak line in particular, the load that the local generating plants historically have supplied, particularly at times of peak demand (Benning and Potomac River together have nearly 1000 MW of generating capacity). Therefore, designation of the Allegheny Mountain path as a NIETC is indeed needed to maintain reliable service in the immediate future for the Washington-Baltimore metropolitan area. Even if all local generation continues to operate, continued load growth and the lack of any new generating sources will require that more and more power be imported from western resources. It is unlikely that the incremental transmission upgrades currently planned will accommodate all of the necessary imports. Therefore, new, large-capacity transmission facilities will likely be required. Because of the long lead time needed to construct such facilities, planning for them needs to begin now. The Department can assist in that planning by acting immediately to designate the Allegheny Mountain transmission path as a NIETC.

2. Delaware River Path.

PJM previously noted that its RTEP studies have identified violations of PJM"s Generator and Load Deliverability criteria on the PJM transmission system in New Jersey in each planning year of the period 2005 through 2010. These violations are primarily due to retirements of significant local generation capacity, combined with a lack of replacement generation and continuing load growth. The constraints on the affected facilities that the RTEP modeling studies found generally are (n-1) contingency voltage constraints and result from large power transfers into eastern PJM load centers. PJM has identified extensive system upgrades needed in New Jersey to maintain compliance with reliability criteria. *See* Appendix 3 at 31, 33-34, Map 3.1.6-1, Table 3.1.6-1. However, because the planned retirements of generation outpace the ability to construct the needed

29 "Reliability Evaluation For The Potential Retirement Of Benning Generation," *available at* http://www.pjm.com/planning/project-queues/gen-retirements/20050610-reliability-benning-gen-retire2.pdf (last visited Mar. 6, 2006).

transmission upgrades, PJM has had to enter into "reliability must-run" agreements with the owners of the oil-fired Hudson and Sewaren plants in New Jersey to keep approximately 835 MW of capacity at those locations in service through at least the summer of 2008. As noted, the lead time needed to build the increasingly complex and expensive transmission upgrades needed to maintain reliability after these plants retire may require PJM to seek extensions of some or all of these contracts, thus extending the costs of the RMR arrangements for New Jersey electric consumers.

The risk of more retirements is very real. Nearly 90,000 MW of the approximately 164,000 MW of existing generating capacity in PJM are from fossil steam generating units. More than 75% of that capacity is from units that are at least 30 years old; more than 20% is from units that are 50 or more years old. New limits on mercury emissions from coal-fired power plants now under consideration in Pennsylvania, New Jersey and Maryland, among other states, may prove to be an important factor in potential future retirements. PJM has been closely monitoring the states' deliberations on these requirements; its analyses indicate that, should the current proposed requirements be adopted, as much as 4,000 MW of older, coal-fired generation capacity potentially could be retired because the investment needed at such units to meet the new emission limits would be deemed uneconomic.

RMR contracts and RTEP-required transmission upgrades that will provide import capacity sufficient to replace retired generation will ensure year-to-year compliance with minimum reliability criteria, but they are no more than temporary solutions. As load in Eastern PJM continues to grow and there continues to be insufficient new local generation installed to make up for the retired capacity (much less to keep up with demand growth), the dependence of New Jersey and other Eastern PJM load centers on bulk power transfers from western generation will continually increase. The commencement in 2007 of exports of up to 1,090 MW of power from PJM to New York City via two merchant transmission facilities with terminals in New Jersey that are now under construction[30] will further compound the effects of the large net loss of local

[30] These are (1) a D.C. transmission line from Sayreville, New Jersey, to Long Island, owned by Neptune Regional Transmission System, L.L.C., with capacity and associated rights to firm withdrawals from PJM of up to 790 MW, and (2) a variable frequency transformer in Linden, New Jersey, owned by East Coast Power, L.L.C., with capacity and associated rights to firm withdrawals from PJM of up to 300

generation via retirements and the concomitant need for increased imports from western generation sources – and two more merchant transmission projects in PJM's interconnection queue could result in withdrawals of up to another 1,190 MW for export. Accordingly, transfer capability through the Delaware River transmission path will become even more important than it is today to maintaining reliable service to Eastern PJM – and New York City -- consumers. Immediate designation of this path as a NIETC is clearly warranted.

III. *Draft Criterion 2: Action is needed to achieve economic benefits for consumers.*

1. Allegheny Mountain Path.

Although it does not authorize any particular project or activities, designation of a transmission path as a NIETC should facilitate expansion of transmission capability within that path, provided that required regulatory and environmental approvals can be obtained. Accordingly, designation of the Allegheny Mountain path may have a role in leading to the development of additional capacity on the interstate, high voltage transmission grid for bulk transfers of power to the markets of Washington and Baltimore and surrounding areas. There can be little doubt that expanding transmission capacity on this path would achieve economic benefits for consumers.

Increased transmission capability would reduce the costly congestion (approximately $862 million in 2005 alone) on the Allegheny Mountain path that PJM described above. The most frequently congested facility in all of PJM over the past several years has been the Bedington-Black Oak 500 kV line across the West Virginia panhandle, with 1,044 constrained hours in 2002, 815 hours in 2003 and 1,131 hours in 2004. The PJM Market Monitoring Unit ("MMU") summarized the economic impact of this congestion in 2004 in its State of the Market Report for the same year:

> Bedington - Black Oak (AP). In 2004, the Bedington – Black Oak 500 kV line was constrained for 1,131 hours, with 54 percent of congestion occurring during on-peak periods. . . . The location and size of this line

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MW. *See* Merchant Transmission Interconnection – Queue G *available at* http://www.pjm.com/planning/project-queues/merch-queue-g.jsp (last visited Mar. 6, 2006).

> contributed to its substantial impact on the entire PJM system, with an average affected load of 39,170 MW. On average, this constraint caused a 20 percent increase in LMP during constrained hours. The affected load had an average LMP of $60, with $12 attributable to congestion from the Bedington – Black Oak line.[31]

Increased capability on the Allegheny Mountain path also may increase competition among suppliers of power in that path. The MMU periodically analyzes market concentration and market shares on various PJM facilities to assess whether generators in those areas should be exempt from offer-capping when transmission facilities are constrained. In an October 2004 report to FERC, the MMU reported finding that several facilities in the Allegheny Mountain transmission path should not be so exempted from offer capping because of high market concentration (as measured by the Hirschman-Herfindahl Index ("HHI")) and high maximum market shares among suppliers. Specifically, the MMU determined the following HHIs and market shares for the indicated facilities:[32]

Facility Name	HHI	Maximum Market Share
Kammer Transformer	2070	34.6%
Wylie Ridge Transformer	2638	44.7%
Mt. Storm Doubs	2053	35.5%
Black Oak Bedington	2083	29.5%

Increasing the transfer capability in the Allegheny Mountain path would reduce constrained hours of operation, making more suppliers available to buyers during more hours. Competition among suppliers would be enhanced, reducing or perhaps even eliminating the need for offer-capping on some or all of these facilities. In other words, the market should operate more efficiently and power prices should be lower, particularly during peak demand periods.

PJM has modeled the effects on PJM markets of two potential means of increasing transfer capability in the Allegheny Mountain transmission path. PJM's

[31] *2004 State of the Market Report*, PJM Market Monitoring Unit, at 59 (2005), *available at* http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2004.pdf.

[32] *See PJM Interconnection, L.L.C.*, "Report of the PJM Market Monitor Regarding Offer Capping of Major Transmission Constraints," FERC Docket Nos. ER04-539-001 *et al.*, at 8 (Oct. 26, 2004).

analysis examined the potential energy production cost savings of (1) adding a 350 MVAR SVC at the Black Oak substation, increasing the transfer capability on the Bedington-Black Oak line by approximately 230 MW, and (2) adding a new 500 kV transmission line from the Fort Martin substation on the Pennsylvania-West Virginia border, through Bedington, to the Hunterstown substation in south-central Pennsylvania, approximately 250 miles to the east. As shown in Appendix 6, PJM's one-year simulations for each expansion scenario indicated that the SVC at Black Oak could yield reductions in payments by loads of approximately $80 million, while the new 500 kV transmission circuit roughly paralleling the Bedington-Black Oak line could yield reductions in payments by loads of over $100 million. *See* Appendix 6.[33] This analysis dramatically reinforces the conclusion that incremental transmission capacity on the Allegheny Mountain path almost certainly would have significant economic benefits for consumers in the affected PJM load centers. This path, therefore, is fully consistent with the Department's draft criterion #2 for NIETC designation.

2. Delaware River Path.

Expanding transmission capacity in the Delaware River path likewise would benefit consumers in the affected market areas by facilitating their access to more diverse, primarily coal and wind-powered generation sources in western PJM. This access will become more and more important to these markets because of the ongoing "migration" of economical generation capacity to the western portions of the PJM region.

[33] While this sample calculation was intended to merely show the type of information that market simulation analysis can provide, it dramatically reinforces the conclusion that incremental transmission capacity on the Allegheny Mountain path almost certainly would have significant economic benefits for consumers in the affected PJM load centers. This path, therefore, is fully consistent with the Department's draft criterion #3 for NIETC designation.

PJM earlier detailed the numerous, recent and impending retirements of generation capacity in Eastern PJM, totaling nearly 3,000 MW, more than 85% of it in New Jersey. *See* Appendix 3 at 19, Table 2.3.1-1. Concurrently, the amount of new generation capacity proposed for interconnection with the PJM transmission system in New Jersey has decreased substantially. Appendix 7 illustrates this trend. In 1999-2000, PJM's interconnection queues included more than 12,000 MW of generating capability with proposed locations in New Jersey – more than 20% of all proposed new generation capacity in PJM. In contrast, in 2003-04, only about 1,700 MW of new capacity was proposed to be located in New Jersey – less than 10% of all proposed new capacity. Equally important here, more than half of the proposed new generation capacity in PJM's Queues M, N and O is located in the western PJM (Allegheny Power, AEP, Duquesne Light, Dayton Power & Light and Commonwealth Edison). As of January 31, 2006, more than two-thirds of all new generating capacity then pending in PJM's interconnection queue was proposed to be located in the PJM West region – a total of approximately 17,000 MW in the west versus about 6,800 MW in the Mid-Atlantic area and about 1,800 MW in PJM South.

The recent retirements of generation and slow development of replacement capacity already have combined to compel PJM to negotiate RMR contracts with the owners of five New Jersey units that were slated for retirement.[34] By definition, these units must run to maintain reliable service when less costly sources of power are unavailable because of insufficient power import capability on the Delaware River transmission path, the interstate transmission grid that supplies New Jersey. Incremental interstate transfer capability (or the development of economical, new local generation) would eliminate the need for these RMR contracts and thus should mean lower costs for consumers in New Jersey and elsewhere in Eastern PJM. Accordingly, designation of the Delaware River path as a NIETC is consistent with the Department's draft criterion #2.

C. *Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.*

[34] The RMR contracts are for (a) four units at the Sewaren plant, for a total of 453 MW, for a term extending through 2008, and (b) for one unit at the Hudson plant, for 383 MW, with a term extending through 2007.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Both of the NIETCs that PJM proposes conform with these criteria due to the same factors. To the extent that it may ensure the development of additional transmission capability, NIETC designation for these paths will alleviate current and potential future supply restrictions, will diversify sources of power available to the affected markets and will reduce the relative dependence of those markets on natural gas- and oil-fired generation.

Limitations on current power supplies in Baltimore-Washington and Eastern PJM currently are transmission limits that restrict imports of power from western sources, as demonstrated by the persistent congestion on the high voltage, interstate transmission facilities on both paths. The potential shut-down of the Potomac River plant near Washington would create an immediate need for replacement power, which most likely would need to be imported from western sources. The longer-term trends of steady load growth and failure to replace retiring generation capacity that PJM has previously explained likewise will require additional transfer capability from the west to ensure sufficient supplies of power in both market areas, but are particularly acute in New Jersey, where the pace of retirements and relatively high rates of demand growth already have compelled PJM to enter into RMR contracts with units that otherwise would have been retired, at an estimated cost to consumers of about $50 million per year in 2006-07. As previously noted, the effects of these trends are compounded in Eastern PJM by two merchant transmission projects' commencement of exports of up to 1,090 MW to New York in 2007.

Designation of these corridors further would improve the diversity of the generation mix available to both the Washington-Baltimore area and Eastern PJM. Local generation serving the load centers on these paths includes relatively more oil-fired generation capacity than in the western areas where competing wholesale supplies generally are more economical. For example, oil-fired generation comprises approximately 28.6% of all installed capacity in Maryland and the District of Columbia. *See* Appendix 3 at 109, Fig. 4.5.1-1. Oil-fired capacity comprises about 23.4% of the installed generation fleet in the Delmarva Peninsula. *Id.* at 86, Fig. 4.1.1-1.

Approximately 15.8% of New Jersey's installed capacity is oil-fired and only about 12.7% of its capacity is coal-fired. *Id.* at 122, Fig. 4.7.1-2.

The new generation installed since 1999 and currently pending in PJM's interconnection queues in these areas does not depend on oil, but neither does it significantly enhance fuel diversity – it is overwhelmingly fueled by natural gas. In Maryland and D.C., natural gas is the fuel for more than 82% of the capacity of recently installed and currently proposed generation. *Id.* at 110, Fig. 4.5.1-2. In the Delmarva Peninsula, 97% of the newly installed and currently proposed generation capacity is fueled by natural gas. *Id.* at 88, Table 4.1.2-1. In New Jersey, natural gas is the fuel for 93% of all newly installed and currently proposed gneration capacity. *Id.* at 124, Fig. 4.7.2-1. Such heavy reliance on one fuel potentially exposes consumers in these areas to significant costs when natural gas commodity prices spike, as they did during 2005, particularly in the wake of Hurricanes Katrina and Rita.

Enabling greater imports of power from the west would substantially increase the diversity of generation available to eastern and southwestern PJM markets. In contrast to the amounts in New Jersey and elsewhere in the east, the overall capacity fuel mix in PJM includes 41% coal and just 7.2% oil. *See id.* at 60, Fig. 3.5.2-1. Of greater significance, coal-fired generation is the source of 2/3 of all energy output by PJM generators. *Id.* at 17, Fig. 2.1.3-2. More than 6,700 MW of additional coal-fired generation is currently under construction or active in PJM's interconnection queue. All of this capacity is or will be located far from eastern PJM load centers.[35]

Moreover, approximately 9,300 MW of additional wind-powered generation is either under construction or pending in PJM's interconnection queue. *See* Appendix 3 at 65.[36] With the exception of one plant under construction on the New Jersey coast, all of

[35] This coal-fired capacity consists of plants that are pending in or which have completed studies through PJM's generation interconnection queue and under construction or proposed to be sited in western Maryland, western Pennsylvania, West Virginia, eastern Kentucky, or Ohio.

[36] Other portions of the RTEP (Appendix 3) refer to lesser amounts of wind-powered capacity in PJM's queue. *See id.* at 61. Those amounts reflect only the portion of total wind energy production capacity that qualifies as Capacity Resources in PJM's markets; most wind-powered generating facilities in PJM operate in large measure, and many in whole, as Energy Resources.

these facilities are or will be located west of the load centers involved in this discussion. *See* Appendix 9..[37]

Increased transmission capability on either or both of the transmission paths that PJM proposes for NIETC designation would increase the diversity of generation sources available to the affected markets. Both paths would enable coal and wind-powered generation from western portions of PJM to serve loads in all of these eastern markets, where retirements, emissions limits and land use restrictions significantly limit options for keeping up with load growth and the generation that does get built is, by far, predominantly gas-fired. Further, in both instances, additional transfers of power from the west would reduce the affected areas' relative dependence on oil-fired generating capacity and thus would contribute to reducing the need for oil imports. Accordingly, both the Allegheny Mountain path and the Delaware River path are consistent with the Department's draft criteria 3 and 4 for NIETCs.

D. *Draft Criterion 5: Targeted actions in the area would further national energy policy.*

For the reasons explained in the comments of the IRC on this draft criterion, PJM views this criterion as complementary, rather than additional, to the others proposed by the Department in the NOI. That is, any action the Department takes that is consistent with its other proposed criteria (particularly criteria 1 and 2) will be consistent with this criterion also. The National Energy Policy's emphasis on relieving transmission bottlenecks indicates that the Department should be proactive in designating NIETC in furtherance of creating a national electric transmission grid.[38] Greater transmission capacity on both of the transmission paths that PJM advocates for designation would better integrate existing and planned generation in western areas of PJM with the eastern and southwestern PJM markets. The proposed designations thus would increase the

[37] Wind generation's intermittent fluctuations of output is perceived as one of its principal limitations as a reliable source of energy. More robust transmission capability could alleviate that concern by providing sufficient capacity within the trnasmission system to "absorb" variations in wind generators' energy production without adversely affecting reliability of service.

[38] *National Energy Policy – Report of the National Energy Policy Development Group*, at 1-5, 7-7 – 7-8 (U.S. GPO May 2001) *available at* http://www.whitehouse.gov/energy/National-Energy-Policy.pdf.

efficiency of PJM markets, as well as serve the goal of enhancing the national transmission grid. *See* Appendix 6.

Other key aspects of national energy policy are also served by this designation. There are a variety of generation projects utilizing advanced coal technology under consideration in the Midwest. There also is considerable wind generation slated for development either along the Allegheny Mountains or the west. Both of these new sources of generation are enhanced transmission links to markets in the east. Added transmission capacity in the Allegheny Mountain and Delaware River paths also would reduce the need to site new generation facilities in and around the major urban centers of Eastern PJM. Essentially all of the principal metropolitan load centers served from the Allegheny Mountain and Delaware River paths are designated as non-attainment areas with respect to one or more air quality standards. This factor compounds the problems of developing new generation capacity that are presented by the classic load pocket characteristics of areas such as the Delmarva Peninsula and New Jersey, where there are no significant, indigenous fuel supplies and the surrounding rivers, bays and other waters, as well as (in New Jersey's case) dense urban development, limit the number of potentially viable sites for new plants and make fuel transportation expensive and logistically difficult.

The development of additional transmission capability in the Allegheny Mountain and Delaware River paths thus would enhance development of the national electric transmission grid and would facilitate compliance with environmental requirements in the several major metropolitan areas that are served through these paths. Accordingly, both proposed paths are consistent with the Department's draft criterion 5.

E. *Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.*

This criterion appears broader than draft criterion #1 in that this item appears to encompass particular areas where applicable NERC or other reliability criteria have not actually been violated, but there is nevertheless a need to ensure or enhance reliability of service. Loads in and around major, urban load centers and military or other facilities deemed critical to homeland security/national defense should be treated as critical load within scope of this criterion. This approach is consistent with the Department's recent finding that load in Washington, D.C., that would be at risk in the event of an unplanned transmission outage while the Potomac River generating plant was shut down constitutes "critically important facilities and operations."[39]

The trends in load growth, generation retirements and lagging development of new generating capacity in Eastern PJM and in the Baltimore-Washington area that PJM described above underscore the importance of ensuring that there is a robust transmission system capable of supplying the needs of such critical loads. Increasing transfer capability across the Allegheny Mountain path would offer that assurance to the critical loads in and around Washington and Baltimore. Likewise, incremental capacity in the Delaware River path would enhance reliability to the predominantly urban markets of Eastern PJM, particularly those in New Jersey, for the reasons PJM previously has described. Exports of energy to New York City and points north using the currently planned merchant transmission and other potential facilities previously described also require additional capability to remain feasible in the future.

Both of PJM's proposed NIETC would encourage the development of a more robust grid that would be better able to withstand damage from natural or malicious acts to key generation or transmission facilities in the eastern United States. The combined populations of the major urban centers from Washington to New York City total about 16 million. This is critically important load that includes countless health care, public safety, national security and other governmental functions and facilities. Both the Allegheny Mountain and Delaware River paths thus would enhance the reliability of service to all of this critical load and, therefore, both satisfy the Department's draft criterion 6.

F. *Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.*

39 *Mirant Potomac River Order* at 8.

PJM agrees that the Department must reasonably satisfy itself whether the claims made in support of designating a particular corridor as a NIETC fall within a zone of reasonableness. As the IRC's comments emphasize, this is where independent, ISO/RTO regional planning processes and assessments are of greatest value to the Department. PJM's proposals here are based on extensive data and analysis gathered in actual operations or prepared in PJM's RTEP process. All such material, therefore, is transparent and has been available for scrutiny by all market participants and regulatory commissions. All of the congestion and other market data PJM presents here are fully documented, as are the trends of eastern load centers' increasing reliance on west to east power flows due to growing locational divergence between generation and load. Further, because all of PJM's analysis has been a part of its RTEP process, its assumptions and conclusions have been developed independently, have been tested through stakeholder review, and have been approved by PJM's independent board of managers. PJM has explained the nature and scope of the RTEP process in considerable detail, and will not burden the Department with repetition of that discussion. As that material demonstrates, the Department can have a high degree of confidence in the validity of PJM's data and in the merit of its conclusions. Therefore, the Department should find that both the Delaware River path and the Allegheny Mountain path have been developed and supported in a manner that conforms with the Department's draft criterion 7.

G. *Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.*

The IRC asserts in its comments on the NOI that, at least when the Department is addressing a proposed corridor designation within an RTO/ISO region, this draft criterion should require only that the Department satisfy itself that RTO/ISO planning protocol ensures that potential market-based alternative solutions to congestion, economic and reliability issues will have ample opportunity to present themselves and, to the extent feasible and justified, to displace the need for additional transmission facilities. PJM unequivocally agrees. Consideration of specific alternative solutions is a matter that can and should be addressed in the context of particular transmission issues and, more importantly, only with respect to specific, proposed transmission solutions. Therefore, detailed evaluation of alternatives must be left to regional planning processes and to state and (if applicable) federal siting procedures.

PJM's RTEP clearly meets the appropriate standard under this criterion for designation of NIETC. PJM makes information on pricing and other relevant factors transparently available to all market participants and potential new entrants. The RTEP process evaluates reliability, operational performance and economic factors and openly elicits, accommodates and integrates all market-based solutions to all planning issues -- new generation of all types and sizes, A.C. and D.C merchant transmission, and demand response programs. The proposed Allegheny Mountain and Delaware River transmission paths are products of this process.

The PJM planning process builds in a specified "market window" where market-based generation or demand side solutions are able to come forward prior to a transmission solution being chosen. In these corridors, although there have been certain small projects proposed, no market solutions (either individually or collectively) have arisen to resolve the problems of the magnitude cited herein. The Department should recognize the importance of the emergence, after numerous RTEP market windows failed to elicit generation, market response, or other solutions to the identified constraints in the Allegheny Mountain and Delaware River transmission paths, of two proposed new EHV transmission lines (the AEP and APS proposals) that would be located in one or both of the NIETCs that PJM advocates. These proposals undeniably reflect willingness of some market participants to invest capital in transmission solutions to resolve the issues cited herein and a willingness of the capital markets to fund such projects. In short, the operation of the PJM market as well as the planning process and the lack of response to "market windows" all should serve to satisfy the Department that both of PJM's proposed NIETCs are consistent with draft criterion 8.

A finding of compatability with criterion 8 does not rule out the development of alternative solutions. It is for this reason that PJM is not seeking DOE designation of a particular line or particular facilities. PJM will continue to evaluate alternatives to transmission and utilize its robust competitive market to incent the development of such solutions. Nevertheless, based on the history and magnitude of the issues, the Department should find that PJM's proposal meets criterion eight. PJM has provided (and will continue to provide) open processes for development of market-based generation and demand response capability to resolve economic and reliability issues that also may be resolvable through transmission. The transparent RTEP process, as well as state siting proceedings and ultimately FERC siting proceedings, if necessary, are available to review the reasonableness of PJM's findings regarding any specific transmission proposal weighed against its alternatives. The Department should avoid a NIETC designation turning into an integrated resource planning or becoming duplicative of state siting process.

H. Possible Additional Criteria.

1. The Department Should Consider The Presence of Proposed Transmission Projects An Affirmation Of The Need For And Value of NIETC Designation.

The NOI solicits interested parties' suggestions of criteria additional to those proposed in the NOI that the Department should consider in evaluating a proposed NIETC. PJM contends the Department also should use as a criterion whether market participants have made specific, serious proposals to add transmission capacity in the transmission path for which NIETC status is requested. Such proposals are independent, objective evaluations from those willing to commit capital of the extent of need for additional transmission capability on the relevant path and of the perceived viability of investing in new transmission facilities to meet that need. The Department should give considerable weight to this factor, since it effectively filters out much of the "noise" of forecasts, assumptions and hypothetical projects on which many proposed designations may be based.

Application of this criterion further supports PJM's request for immediate designation of the Allegheny Mountain and Delaware River transmission paths as NIETC. As noted previously, two significant new long-distance transmission lines, both proposed by large, established transmission companies, have been proposed in recent weeks. Both would be built on routes that traverse the Allegheny Mountain path and/or the Delaware River path.

2. Should The Department Employ Criteria Additional Or Different From Those Proposed In The NOI, Proponents Of

Corridor Designations Should Have An Opportunity To Demonstrate Their Proposals' Conformance With Those Criteria.

The NOI solicits suggestions of additional criteria that the Department may apply in determining whether to designate NIETC. In the event the Department ultimately decides, either on its own motion or at the suggestion of other commenters, to apply additional or different criteria in reaching designation decisions, PJM requests an opportunity to address whether and how the Allegheny Mountain and Delaware River transmission paths meet those standards.

CONCLUSION

For the reasons stated above, PJM requests that the Department, concurrent with its initial congestion study under section 1221 of the Act, designate as NIETC the Allegheny Mountain transmission path and the Delaware River transmission path, both as defined herein.

Respectfully submitted,

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March 6, 2006

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LIST OF APPENDIXES

APPENDIX 1: Transmission Grid Map

APPENDIX 2: Pfirrman Presentation Graph

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APPENDIX 4: Raw LMP Data Spreadsheet

APPENDIX 5: Attachment 2 to Herling RPM Affidavit

APPENDIX 6: Regional Planning Process Working Group Presentation

APPENDIX 7: System Planning Slides - Comparing A/B/C Queue Locations with M/N/O Queue Locations

APPENDIX 8: Mountaineer Working Group Presentation (Intentionally omitted)

APPENDIX 9: System Planning Slides - Wind Projects by Status

[Note from the U.S. Department of Energy: The appendices submitted by PJM Interconnection L.L.C. have not been included in the body of this document. Instead, these appendices will be made available at the U.S. Department of Energy's web site at http://www.electricity.doe.gov/1221]

65. United States Congressman Todd Russell Platts (19th District, Pennsylvania), Received Wed 2/22/06 10:17 AM

The Honorable Samuel W. Bodman
Secretary
United States Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Secretary Bodman

I am writing in regard to the Department's Notice of Inquiry dated February 2, 2006. In this Notice of Inquiry, the Department solicited comments on considerations for the Transmission Congestion Study and the designation of National Interest Electric Transmission Corridors (NETCs). I strongly urge the Department to include environmental impact and the economic effect on non-served regions as significantly weighed criteria for determining the route, size, and location of NETCs.

As you are no doubt aware, American Electric Power Company (AEP) has announced plans to build a 550-mile electricity-transmission line from West Virginia to New Jersey, a portion of which could go through York County, Pennsylvania in my Congressional District. The power being transmitted on said line would presumably be generated by coal-powered plants in West Virginia to the benefit of electricity customers in New Jersey. AEP has indicated its intent to take advantage of a federally designated NIETC to facilitate this project.

I fully recognize the need for a national energy policy that will relieve electricity transmission congestion. However, I am deeply concerned about AEP's proposal for two reasons. First, efforts to modernize the power grid should be done in a way which focuses on newer and cleaner technologies that meet stricter environmental standards, not create a market for older technologies that contribute greatly to air pollution. The AEP proposal fails this test.

Second, Pennsylvania will not be served by the electricity being transmitted from West Virginia. Yet, the region will suffer from the increased air pollution, visual blight, noise pollution, and health and safety risks associated with the project. In addition, many landowners, particularly farmers, could suffer economic consequences if their property is taken to be used for such projects. Finally, customers in the region may find themselves being asked to subsidize the costs associated with delivering power to the end-market.

As the Department proceeds with the drafting of NETC criteria, I request that the aforementioned points be considered so that NETC designations do not cause significant environmental harm or impose economic costs on non-served regions. I also request that the Department keep my staff and I fully and timely informed of all pertinent developments regarding the designation of NETCs and AEP's proposal discussed above. If you have any questions, please feel free to contact my Chief of Staff, Scott Miller, at (202) 225-5836. Thank you in advance for your attention to this matter.

Sincerely,

TODD RUSSELL PLATTS
Member of Congress
19th District, Pennsylvania

66. PPL Companies, Received Mon 3/6/2006 4:30 PM

COMMENTS OF THE PPL COMPANIES

Pursuant to the Department of Energy (the "Department" or "DOE") Notice of Inquiry ("NOI") published in the Federal Register on February 2, 2006,[1] which seeks comment on the Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors ("NIETCs"),[2] the PPL Companies[3] submit the following comments. The NOI posed specific questions regarding the Department's designation of NIETCs and issues it should consider in its transmission congestion study. These comments respond to those questions and other issues relevant to NIETC designation.

The PPL Companies are committed fully to the development of a robust and efficient transmission system and believe that the establishment of appropriate NIETCs will facilitate investment in transmission infrastructure that will address substantial reliability and economic concerns. The PPL Companies appreciate the Department's efforts to solicit comments from interested stakeholders, such as the PPL Companies, on the criteria and process the Department will use to identify NIETCs.

As further described below, the PPL Companies believe the Department's development of a transparent process for designating NIETCs that focuses on reliability and substantiated economic concerns, but does not hamper the development of viable market solutions is vitally important. Existing processes are in place, such as the process embodied in the PJM Regional Transmission Expansion Planning Protocol ("RTEP process"),[4] to facilitate the identification of geographic areas of need for transmission enhancement and expansion. The PPL Companies strongly encourage the Department to consider whether a project or need has been identified by a Regional Transmission Organization ("RTO") planning processes such as the RTEP process in order to determine whether a proposal should be considered for early NIETC designation.

[1] Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Notice of Inquiry, 71 Fed. Reg. 5,660 (Feb. 2,2006).

[2] The National Energy Policy Act of 2005, Public Law 109-58 ("Energy Policy Act of 2005"), contained the Electricity Modernization Act of 2005 (Energy Modernization Act"), which required the Secretary of Energy to conduct a nationwide transmission congestion study and issue a report in which the Secretary may designate "any geographic area experiencing electrical energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." *Id.* § 1221, 16 U.S.C. § 216 (2005).

[3] The PPL Companies, for purposes of this pleading, consist of PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC and Lower Mount Bethel Energy, LLC. The PPL Companies are each affiliates of PPL Corporation which are subject to regulation under Part II of the Federal Power Act, 16 U.S.C. § 824 *et seq.* The PPL Companies own and/or operate transmission, distribution or generation facilities located in PJM Interconnection, L.L.C ("PJM").

[4] Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., PJM Interconnection, L.L.C. Third Revised Rate Schedule FERC No. 24, Schedule 6 ("PJM Operating Agreement"). *See also* Generation and Transmission Interconnection Planning, PJM Manual 14B, Revision 08 (effective Jan. 06, 2006), *available at* http://www.pjm.com/contributions/pjm-manuals/pdf/m14bv08.pdf ("PJM Manual 14B").

THE IDENTIFICATION OF SPECIFIC TRASMISSION CORRIDORS FOR STUDY.

The Department Should Use A Broad Definition Of Transmission Corridors In Studying And Designating NIETCS.

The PPL Companies urge the Department to define NIETCs broadly. By defining NIETCs broadly, the Department will provide entities the flexibility to address and modify transmission proposals in a changing environment. It is expected to take eight to ten years to complete the steps necessary to construct a new major transmission facility. This includes the time required to conduct the required transmission line siting evaluation, perform a preliminary and detailed engineering design, obtain necessary regulatory approvals, acquire rights-of-way, and to complete construction of the facility. During this eight to ten year period, changes may occur that require modifications to design proposals. Broadly defined corridors will allow changes to be made to design proposals without requiring revision of the transmission corridor.

In contrast, a narrowly defined corridor may not provide flexibility to modify the proposal without changing the NIETC. If a new NIETC designation were needed, additional and avoidable delay in construction of the transmission project would occur. If a narrow definition were used this would limit the area in which transmission enhancements could be sited. A broader definition is preferable as it will allow entities the flexibility to develop improvements and enhancements using the most cost-effective means and routes possible. By defining NIETCs broadly, the Department will provide market participants with important flexibility to ameliorate their proposed routes by making minor modifications and updates that may become prudent given issues identified in the detailed design and construction phases.

If DOE defines NIETCs more broadly this may also reduce costs by allowing those constructing transmission lines to bypass landowners that seek excessive rents to cede their property rights. Narrowly-defined NIETCs, on the other hand, may leave those constructing transmission beholden to negotiating with specific landowners and to the increased property values resulting along the narrowly designated corridor. This, of course will increase the cost of new transmission directly and indirectly through delay in obtaining necessary right-of-way.

DOE Should Work With RTOs, Such As PJM, In Considering Whether To Grant A Route Early Designation As An NIETC.

The Department should identify geographic areas or transmission corridors where there is an acute need for early designation. However, before granting such a designation, the Department should consider the results of RTOs' and others' transmission expansion planning studies to identify the routes that may warrant consideration for early designation as an NIETC. Under Order No. 2000, issued by the Federal Energy Regulatory Commission ("FERC"), RTOs must conduct or, at a minimum, coordinate regional transmission planning.[5] Thus, RTO planning processes, where they exist, must be the starting point for implementing the Electricity Modernization Act in an efficient and effective manner.

For example, PJM has established processes for identifying reliability and economic needs for increased transmission capability. PJM uses its RTEP process[6] to identify needed transmission system enhancements and expansions to address changing PJM reliability and economic needs.[7] Using the RTEP process, PJM identifies areas within the PJM system that are not in compliance with applicable reliability standards or that pose significant economic costs to transmission customers. To the extent PJM identifies a need for transmission expansion, the RTEP process determines a cost-effective solution and assigns construction of the necessary project to one or more transmission owners. PJM consults with stakeholders regarding the transmission enhancements it believes are necessary, and its proposed cost-allocations.[8]

DOE Should Designate The Allegheny Mountain Corridor And The Delaware River Corridor As NIETCs.

The PPL Companies are aware that PJM is planning to request the designation of two areas within the PJM footprint as NIETCs. These are the Allegheny Mountain Corridor and the Delaware River Corridor, both of which PJM believes warrant early designation as NIETCs.[9] The PPL Companies endorse the designation of these two interfaces. The PPL Companies note the importance of designating NIETCs within PJM consistent with established PJM interfaces.

[5] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs., Regulations Preambles (July 1996–Dec. 2000) ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), FERC Stats. & Regs., Regulations Preambles (July 1996–Dec. 2000) ¶ 31,092 (2000), *petitions for review dismissed sub nom., Pub. Util. Dist. No. 1 of Snohomish County, Wash. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) ("Order No. 2000").

[6] The PJM RTEP process was approved by FERC. *PJM Interconnection, L.L.C., et al.*, 101 FERC ¶ 61,345 (2002), *order on reh'g & compliance filing*, 104 FERC ¶ 61,124, *order on reh'g & compliance filing*, 105 FERC ¶ 61,123 (2003), *order on reh'g & compliance filings*, 109 FERC ¶ 61,067 (2004).

[7] *See supra* note 4.

[8] PJM Operating Agreement, Schedule 6, § 1.5.7(f); PJM Manual 14B at 46-47.

[9] *See* MRC Meeting Presentation, "Notice of Inquiry," (Feb. 16, 2006), *available at* http://www.pjm.com/committees/mrc/downloads/20060216-item12.pdf, included as Attachment A.

Designating interfaces in PJM as NIETCs will allow PJM, through the RTEP process, to identify any specific transmission lines that are necessary to relieve the congestion problems associated with the designated interfaces.

DOE Should Not Give Early NIETC Designation To The Corridors Proposed By AEP Or Allegheny Power Until Those Projects Have Been Approved Under The PJM RTEP Process.

Two additional requests for early designation of specific transmission lines in PJM as NIETCs are pending, and others may follow. Specifically, American Electric Power ("AEP") has submitted a proposed 765 kV transmission line for NIETC designation[10] and Allegheny Power ("Allegheny") has proposed a 500 kV transmission line for NIETC designation.[11] Early NIETC designation should not be granted until these proposals have been considered by the PJM RTEP process, which has not yet occurred. Although both proposals claim significant benefits for PJM customers, no analysis has been conducted to determine whether either proposal is the most cost effective solution to the problems they claim to address. Moreover, the RTEP process is designed to solicit alternative proposals and stakeholder input before any projects are endorsed. None of this has occurred yet.

A transparent review of those proposals and alternatives thereto through the RTEP process is necessary before any transmission proposal is given early NIETC designation. The PPL Companies have emphasized the need for such a review in a letter submitted to PJM on

[10] *Am. Elec. Power Serv. Corp.*, Request to the Honorable Samuel Bodman, Secretary Department of Energy, to include the AEP Interstate Project Proposal, a 765 kV Transmission Line from West Virginia to New Jersey, as a National Interest Electric Transmission Corridor (filed Jan. 31, 2006). The PPL Companies note that at the time of their filing of these comments, the Department had not yet noticed the AEP request for NIETC designation. By providing these limited comments on any specific proposal in the context of this NOI, the PPL Companies are in no way intending to waiver their ability to provide specific comments on those requests when they are posted by the Department.

[11] *Allegheny Energy, Inc., et al.*, Docket No. EL06-54-000, Petition for Declaratory Order filed by Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company to Confirm Availability of Incentive Rate Treatment for 500 kV Transmission Project, at 10 (filed Feb. 28, 2006) (stating that "in a filing to be made on or before March 6, 2006, [Allegheny] also intends to propose the route of the Project to the [DOE] for early designation in response to the DOE's recent [NOI] regarding Considerations for Transmission Congestion Study and [NIETCs].").

March 1, 2006.[12] Only after the transparent review provided for in the RTEP process, including an evaluation of pending proposals and other alternatives, can PJM designate one or more cost-effective and needed transmission enhancements. And only thereafter, should DOE grant coveted early designation as an NIETC to facilitate the construction of any such project. Accordingly, the PPL Companies strongly encourage the Department to await the results of PJM's RTEP process before assigning NIETC designations to any specific transmission corridor in the PJM region.

RESPONSE TO THE SPECIFIC QUESTIONS RAISED BY DOE.

1. Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

Although both persistent and dynamic congestion pose problems for the transmission system, the Department should focus its attention on addressing identified persistent congestion problems. Persistent transmission congestion problems are readily ascertainable. Transmission operators such as PJM spend significant resources identifying potential means to address persistent congestion. Dynamic congestion problems, on the other hand, are difficult to identify and are significantly less costly in terms of the effect they have on energy market prices than persistent problems. Moreover, given the infrequent nature of dynamic congestion, transmission construction may not be cost-effective and justified to relieve it. Market-based solutions may often be better suited to resolve such issues.

2. Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

The Department should focus its attention on physical congestion rather than contractual congestion. Contractual congestion can and should be addressed through existing market mechanisms such as day-ahead markets, financial hedging mechanisms or locational marginal pricing systems. Those affected by contractual congestion may address it through existing market mechanisms. For example, sellers in PJM experiencing contractual congestion can

[12] *See* Letter from John F. Sipics, President, PPL Electric Utilities Corporation, to Phillip G. Harris, President and Chief Executive Officer of PJM Interconnection, L.L.C. (Mar. 1, 2006), included as Attachment B.

purchase financial transmission rights to hedge such congestion. They also should address contractual congestion through the terms of their contractual arrangements.

3. What existing, specific transmission studies and other plans should the Department review and how far back should the Department look when reviewing transmission planning path flow literature?

The Department should focus its congestion study primarily on recent time periods. Significant changes have occurred in the energy industry and particularly to the operation of the transmission system in recent years that would make the results of a review of a long historical record misleading. Several landmark decisions have been issued by FERC that have changed the regulatory landscape regarding the operation of the transmission system. In 1996, FERC issued Order No. 888, which requires utilities to provide open access on their transmission systems.[13] In 1999, FERC issued Order No. 2000, which encouraged utilities to form RTOs and led to the formation of several RTOs across the country.[14] Both decisions have changed significantly the way transmission systems are operated and used.

The area in which the PPL Companies operate has also undergone significant changes in recent years. In 1997, several public utilities in Pennsylvania, New Jersey and Maryland formed the PJM Independent System Operator, which later became the FERC-approved PJM RTO. Since its inception, PJM has also undergone several expansions, which have significantly increased the size of the transmission system PJM operates and the number of customers that transmission system serves. Most recently, PJM stretched its southern border to include the transmission system owned by Dominion Virginia Power Company. In 1996, Pennsylvania, the state in which most of the PPL Companies are physically located, passed the Pennsylvania Electric Generation Customer Choice Act.[15] This act allows electricity customers in Pennsylvania to choose their retail supplier. Such changes have affected significantly the electricity landscape such that relying upon data from periods before these changes took place may not provide meaningful information.

This, of course, does not mean that historical transmission studies should be ignored. For example, a study of historical information might show that transmission was built to deliver relatively local generation (local by today's standards) to local load. Such information may help guide the Department in its evaluation of the need for and the benefits of corridor designation.

COMMENTS ON THE DRAFT CRITERIA.

The draft criteria proposed by the Department in the NOI address the considerations identified by the Energy Policy Act of 2005. Subject to the following specific comments, the

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[13] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles (1991-1996) ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs., Regulations Preambles (July 1996–Dec. 2000) ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part sub nom.*, *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.*, *New York v. FERC*, 535 U.S. 1 (2002).
[14] *See supra* note 5.
[15] Electricity Generation Customer Choice and Competition Act, 1996, Dec. 3, P. L. 802, No. 138 § 4.

PPL Companies support the proposed draft criteria for identification of areas where NIETC designation would be appropriate.[16]

Draft Criterion 1: Action is needed to maintain high reliability.

The PPL Companies believe that Draft Criterion 1, "Action is needed to maintain high reliability,"[17] is the most important criterion for the Department to consider. Reliability should continue to be the foremost consideration in planning and constructing transmission. Accordingly, this criterion should be a focal point for the Department's initial assessment of NIETCs.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

The PPL Companies caution the Department in applying Draft Criterion 2, "Action is needed to achieve economic benefits for consumers."[18] Unlike reliability concerns, concerns that are more economic in nature do not typically require urgent attention. Instead, such concerns should only be addressed through regulatory intervention if market forces do not otherwise respond to address the identified problem. DOE should not allow the designation of NIETCs to short-circuit market responses to economic problems.

In PJM, the RTEP process is used to identify both reliability and economic problems on the transmission system. PJM, however, only implements a transmission solution to relieve an economic problem if the cost associated with the problem exceeds the cost of the transmission solution that will mitigate it. PJM provides ample opportunity for PJM stakeholders to propose market-funded solutions to solve economic transmission problems.[19] This process allows market-based solutions to address economic problems before what may be more costly transmission enhancements or expansions are imposed.

The PPL Companies urge the Department to follow a similar approach in developing criteria to identify areas that require NIETC designation. The Department should not allow designation of NIETCs to prevent or discourage market-funded solutions from solving economic

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[16] 71 Fed Reg. at 5,662.
[17] *Id.*
[18] *Id.*
[19] PJM Manual 14B at 44-45. *See also* PJM Operating Agreement, Schedule 6, § 1.5.7(a).

transmission problems. If market-funded solutions are unable to resolve identified economic transmission problems within a reasonable period of time, the PPL Companies then fully support use of NIETC designation to promote transmission solutions. However, the PPL Companies strongly discourage the establishment of any regulatory system that will discourage market-funded solutions from resolving identified economic transmission problems.

CONCLUSION

The PPL Companies encourage the Department to designate the broad areas, such as the interfaces that PJM may propose, as NIETCs, and to rely upon existing review processes, such as the PJM RTEP process, to identify specific transmission lines eligible for NIETC designation.

Respectfully submitted,
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By *____/s/ Donald A. Kaplan _________*
Attorneys for the PPL Companies

Dated: March 6, 2006

67. Public Power Council, Received Mon 3/6/2006 1:39 PM

6 March 2006

VIA E-MAIL
Office of Electricity Delivery and
Energy Reliability – OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C.20585
EPACT1221@hq.doe.gov

Re: Comments of Public Power Council on the Department of Energy's Notice of Inquiry, *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors*, 71 Fed.Reg. 5660 (Feb. 2, 2006).

Dear Madam or Sir:

The Public Power Council (PPC) is writing in response to the Department's Notice of Inquiry requesting comment in the above-referenced Federal Register notice. PPC is a non-profit Washington corporation that represents the common interests of more than one hundred publicly- and cooperatively-owned electric utilities throughout the Pacific Northwest. PPC represents its members' interests in wholesale power and transmission supply, rate, and planning matters.

PPC member utilities are statutory preference customers of the Bonneville Power Administration (BPA), and meet some or all of their wholesale power requirements through purchases of BPA power. They also purchase and sell wholesale capacity and energy within the Northwest and the Western Interconnection. All PPC members purchase transmission services from BPA, and many of these utilities also purchase transmission services from interconnected investor-owned and consumer-owned transmission providers. A few PPC member utilities provide transmission services but the great majority of PPC's members are transmission-dependent utilities. PPC's members, therefore, have a significant interest in the sufficiency and reliability of the transmission system in the Western Interconnection.

New section 216(a)(2) of the Federal Power Act[1] directs the Department to "issue a report, based on the [congestion] study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." In its Notice of Inquiry, the Department solicits comments regarding how the congestion study should be designed and how national interest electric transmission corridors (NIETC) should be identified. PPC responds to the Department's questions as follows.

1. Definition and Designation of NIETC.

In its Notice of Inquiry, the Department states that it "expects to identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to

[1] Energy Policy Act of 2005 (EPA05), § 1221(a).

specific routes for transmission facilities."[2] The Department "invites commenters to address how broadly or narrowly the Department should consider and define corridors in its study and its NIETC designations."[3]

The Department should define corridors narrowly enough to allow all state and local jurisdictions to determine easily whether or not they are inside the corridor or affected by it. Defining a corridor using two or more points is an appropriate starting point. Use of a likely source or sources of generation and the location of the load, or sink, provides an electrical description of the corridor. It can, however, define a corridor that includes many, geographically dispersed transmission lines. In the West, generation is often remote from load. It is not unusual, in fact, for generation to be located hundreds of miles from the load. Using source and sink alone to define a corridor can involve whole systems in a corridor.

Source and sink information must be rendered into a description that can be used by state and local governments. In many cases more specific route information will be essential, even if it is general or preliminary.

2. Questions for Public Comment

A. Congestion Study

The Department poses two questions regarding its study of particular variants of transmission congestion: "[s]hould the Department distinguish between persistent congestion and dynamic congestion, and if so, how;" and "[s]hould the Department distinguish between physical and contractual congestion, and if so, how?"[4]

However the Department defines congestion, it is important for the Department to bear in mind that long-term transmission services must be honored. Not only is this an issue of enforcement of contract rights, which must not be disturbed, but these contracts are a crucial means for load-serving entities' to meet their service obligations to end-use customers.

B. Criteria Development

<u>Draft Criterion 2: Action is needed to achieve economic benefits for consumers.</u>

Power prices on the downstream side of a transmission constraint can be higher than in adjacent areas due to higher-cost generating resources or exercise of market power on the downstream side. Lowering prices in one area, however, is likely to increase prices in another because the effect of opening up the market is price convergence.

[2] Dept. of Energy, *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors*, 71 Fed.Reg. 5660, 5661 (Feb. 2, 2006).
[3] *Id*. at 5661.
[4] *Id*. at 5662.

The Department should take into account the negative impact on consumers whose prices will rise. A state-by-state analysis is necessary to determine whether the impact on consumers outside of the geographic area being studied is significant.

The metric for this criterion should be based on an estimate of the number of hours per year that a path is constrained, not on a generic statement of need. Historical transmission data and reliable load forecasts will be needed. If only a small number of hours is estimated, the Department should investigate the possibility of demand side management or other load reduction measures as a means of mitigating congestion. Because it is possible, if not likely, that some end markets can be served by more than one corridor, the Department's estimates should be made only on a corridor-by-corridor basis so that the relative merits of each corridor can be evaluated.

<u>Draft Criterion 3: Actions are needed to ease electricity supply limitations in end-markets served by a corridor, and to diversify sources.</u>

In order to distinguish this criterion from Draft Criterion 2, we assume that draft Criterion 3 deals with a physical lack of power sufficient to meet load within the geographic area, rather than a lack of low cost power, or a lack of fuel diversity within the geographic area. If not, there is substantial overlap with Draft Criterion 2 that the Department should address.

With regard to "reliability-must-run" generation, the Department should also consider direct regulation of the prices charged by these units as a means of reducing the impact of congestion. In many cases, direct regulation of price may be a more cost-effective means of alleviating congestion than transmission or generation construction. It may also delay construction, saving consumers money.

<u>Draft Criterion 5: Targeted actions in the area would further national energy policy.</u>

It is difficult, perhaps impossible, to provide comments on this draft Criterion as it has no limits. Greater definitions of what aspects of current federal policy fall within the ambit of this Criterion would be appropriate. While we suspect that the Department wishes to leave open a criterion to provide it with flexibility to meet the goals of current or future policy, this Criterion is so broad as to swallow all other criteria.

<u>Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.</u>

The Department proposes to develop metrics on a case-by-case basis. While this may be appropriate in many cases, the Department should recognize the inherent vulnerability of transmission facilities to both natural disasters and malicious acts. Transmission lines are vulnerable to acts as simple as damage from firearms or removal of bolts; at present, one individual was arrested in December 2005 for destruction of a federal transmission tower near Bend, Oregon. Major transmission lines in the West tend to be located in very isolated areas. The result of loss of major transmission facilities is often a widespread blackout.

Other Criteria

In identifying NIETCs, the Department needs to be mindful of international and tribal treaties and federal statutes. These include federal environmental statutes but also include statutes that regulate the ability of federal agencies to construct transmission facilities without Congressional approval.

PPC appreciates the opportunity to provide comments to the Department on its plans to study congestion and the possible designation of NIETCs. We hope that our comments are of assistance to the Department and look forward to participating in this process in the future. In that regard, please feel free to contact Nancy Baker, Senior Policy Analyst, nbaker@ppcpdx.org.

Sincerely,

/s/

Marilyn Showalter
Executive Director

68. Public Utilities Commission of Ohio, Received Tue 3/7/2006 3:43 PM

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY
OFFICE OF ELECTRICITY DELIVERY AND ENERGY RELIABILITY

Consideration for Transmission Congestion Study and)
Designation of National Interest Electric Transmission Corridors)

**COMMENTS OF THE CHAIRMAN OF
THE PUBLIC UTILITIES COMMISSION OF OHIO AND
THE OHIO POWER SITING BOARD**

In response to the U.S. Department of Energy's ("DOE" or "Department") Notice of Inquiry ("NOI") published in the Federal Register on February 2, 2006, the Chairman of the Public Utilities Commission as well as the Ohio Power Siting Board submits the following comments regarding the designation of National Interest Electric Transmission Corridors ("NIETCs"). Through this notice of inquiry, the DOE Office of Electricity

Delivery and Energy Reliability ("OE") seeks comments on draft criteria for gauging the suitability of geographic areas as NIETCs and announces a public Technical Conference concerning the criteria for evaluation of candidates' areas as NIETCs.

COMMUNICATIONS

All pleadings, correspondence, and other communications related to this proceeding should be addressed to the following persons:

Thomas McNamee Assistant Attorney General Office of the Attorney General 180 E. Broad Street, 9th Floor Columbus, OH 43215- Phone: 614.644.4785 Fax: 614.644.8764 Email: thomas.mcnamee@puc.state.oh.us	Kim Wissman Director, Ohio Power Siting Board 180 E. Broad Street, 6th floor Columbus, OH 43215- Phone: 614.466.6692 Fax: 614.752.8353 Email: kim.wissman@puc.state.oh.us

The Energy Policy Act of 2005 ("EPACT05"), signed into law by President Bush August 8, 2005, amended the Federal Power Act by adding Section 216 to address "siting of interstate electric transmission facilities and the designation of national interest electric transmission corridors" and a requirement that the Secretary of Energy (hereinafter the "Secretary") report to Congress no later than one year after the enactment of this section.

Now comes the Chairman of the Public Utilities Commission of Ohio (PUCO), who also holds the position of Chairman of the Ohio Power Siting Board (OPSB) (hereinafter the "Ohio Chairman.") to offer comments on the NOI. In representing these dual functions for the State of Ohio, the Ohio Chairman's comments come from a State that not only has the authority to approve the siting of the facilities addressed by the NOI, but uniquely, under section 4906, Ohio Revised Code, explicitly is required to consider the interstate benefits of such facilities.[1]

1 The Ohio Power Siting Board (OPSB) reviews, evaluates and approves the siting of "major" electric generating plants and major electric or natural gas transmission lines (ORC

BACKGROUND

In determining the designation the National Interest Electric Transmission Corridors (NIETC), Congress has asked the Secretary to consider whether (a) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by the lack of adequate or reasonably priced electricity; (b) economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and a diversification of supply is warranted; (c) the energy independence of the United States would be served by the designation; (d) the designation would be in the interest of national energy policy; and (e) the designation would enhance national defense and homeland security.[2]

COMMENTS AND RESPONSES TO QUESTIONS IN THE NOTICE OF INQUIRY

Consideration of Congress's Directives:

The Ohio Chairman is pleased to have this opportunity to comment on the Secretary's new authority under the Federal Power Act ("FPA"), section 216, to consult with the affected States in conducting a study of electric transmission congestion and to consider alternatives and recommendations from interested parties. The Ohio Chairman is also pleased to note that the OE recognizes that the Nation's electric system of over

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Chapter 4906). The definition of a major utility transmission facility is an electric transmission line of 125 kilovolts or more. The OSPB has several statutory criteria that are required to be met prior to the issuance of a certificate. Those include the need for the facility; the probable environmental impact of the proposed facility; whether the facility represents the minimum adverse environmental impact considering the technology that is available and the nature and economics of the various alternatives; that the facility is consistent with regional plans for expansion of the electric power grid of the electric systems serving Ohio and interconnected systems, and that the facility will serve the interest of electric system economy and reliability; the facility will comply with all air and water pollution control and solid waste disposal laws and regulation; the facility will serve the public interest, convenience and necessity; the facility's impact on agricultural lands; and, that the facility incorporates maximum feasible water conservation practices. (emphasis added).

[2] "The Electricity Modernization Act of 2005, sec. 1221, § 216, 119 Stat. 594, 946-953 (2005) (to be codified as amended at 16 U.S.C. 824p), (hereinafter, the "Act").

150,000 miles of interconnected high-voltage transmission lines were generally constructed primarily to serve local customers and support reliability[3]. As the OE looks at a new emphasis on moving large amounts of electricity across multi-state regions, the original purposes of the grid to serve local customers and support reliability of that service should not be lost or shoved aside. The first principle outlined by Congress regarding the economic vitality and development of the corridor and the end markets served by the corridor must be key in making sound and cost-beneficial designation decisions in consultation with the Affected States.[4]

In meeting the requirements outlined by Congress in considering "the economic vitality and development of the corridor," the Ohio Chairman asks the Secretary and the OE to consider this requirement carefully. In anticipating the development of national interest electric transmission corridors to create, as it were, an electric "interstate" highway system, the DOE must take care not to repeat the mistakes of the 1950s and 60s where construction of the Interstate Highway system for the movement of vehicular traffic led to extreme urban demolition measures and population relocation policies. These measures destroyed neighborhoods, displaced families, businesses and industries and condemned major urban areas to economic blight instead of revitalization, redevelopment and the protection and maintenance of historic sites, landmarks and green space.

NOI, I. C: Key Terms: Geographic Areas, Needs, and Corridors

In its notice, the DOE states that it expects to identify corridors for potential projects as generalized paths between locations as opposed to specific routes and invited

[3] NOI in ¶ I. A. Overview.

[4] *The Act*, at § 216 (a)(4)(A).

comments to address how broadly or narrowly corridors in its Study and NIETC designation should be defined.

RESPONSE: The NOI is correct in determining that NIETC corridors would be best defined as generalized paths that provide flexibility to develop routes that maximize system value and deliver the benefits of diverse energy resources and fuel sources and reliability, not only to the end market but to the corridor itself, while minimizing or altogether avoiding adverse demographic, economic, and environmental effects.

NOI, III. A: Congestion Study

The NOI states that in conducting the initial electric transmission congestion study in consultation with the States and any regional entity as required by § 216, the Department intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity (or suitable alternatives) could lessen potential adverse effects borne by the consumers.[5]

RESPONSE: We note that the Department is collecting an inventory of existing transmission expansion plans and studies by regional coordination councils, regional and subregional transmission planning groups, regional transmission operators and independent system operators and utilities. In that light, we caution that many of the existing plans are driven primarily to meet traditional native load needs, not necessarily the "national interest." The Ohio Chairman provides further responses to the NOI questions regarding the most useful way to identify areas of need and areas potentially suitable for designation as an NIETC as follows:

[5] NOI in ¶ III. A. Congestion Study

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

RESPONSE: So-called "persistent" congestion has been identified by regional reliability organization/regional coordination councils and the North American Electric Reliability Council (NERC) in their seasonal reports and forecasts for years and these reports bear looking at again.

As for determining the persistency of any congestion, the patterns of congestion may well have changed and new considerations identified, particularly where organized markets have attempted to place market value on points of congestion on the system with locational marginal prices (LMP). How much this persistency can be attributable to "dynamic" market forces is questionable. Changes in congestion tend to change with weather conditions, geography, and the seasons of the year, depending on whether the generating resources and demand on the system are Summer or Winter-peaking, or both.

Centralized economic security-constrained dispatch by the RTOs/ISOs has also changed congestion patterns, although there is some question about the persistency of that dispatch behavior as the RTOs/ISOs in Ohio gain more experience with their newly-formed and newly-expanded market operations. Dispatch behavior is also influenced by the age, capability, fuel type and pollution control limits of the generating resources. Without taking all these factors as well as related historical data into account, no amount of modeling by the DOE for the nature of congestion can identify valid trends in the "persistency" of such congestion.

(2) Should the Department distinguish between physical congestion and contractual congestion and if so, how?

RESPONSE: We find this question puzzling. We are not certain what is meant by "contractual congestion." Electrons do not respect contract paths.

The closest Ohio may have come to anything that could appear to be "contractual congestion," may have occurred when our new 1999 electric restructuring law was implemented. The PUCO Staff, reading the 2002 DOE National Transmission Grid Study with interest, noted the suggestion for a possible new proposed transmission route running Southwest to Northeast across Ohio that might make sense given the data collected by the DOE Staff at that time.[6] PUCO Staff reviewed the Long-term Transmission Forecasting Reports filed with us by our Ohio transmission owning utilities (TOs) that were "in the path" of this proposed route. Staff found that in 2000, the actual data reported by the TOs signaled an astonishing rush of literally hundreds to thousands of requests on OASIS for transfer capability--more than the TOs' transmission facilities had ever before experienced. The trend slackened dramatically by the year 2001 and all but fell to "normal" levels by 2002 and 2003. Informal questions asked concerning reasons for these declining trends were met with conjecture regarding the dramatic increase in numbers of more merchant generators transfer capability requests and the number of duplicated or redundant requests with no way to tell which were serious requests or just marketers hedging their searches to find an "empty" wire.

At the time of this rush to find transfer capability across Ohio, there were no organized wholesale markets (no Midwest ISO, no PJM) in Ohio beyond a fledgling retail choice market marked by considerable customer aggregation and a handful of

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[6] Department of Energy, *National Transmission Grid Study* (May 2002).

active competitive retail electric supply providers that nowhere accounted for the rush of OASIS applications. This observation now begs the question whether so-called “contractual congestion” can actually physically exist--given the physical nature of electricity. DOE may want to determine if there are any tests to assure that so-called “contractual congestion” is not a market behavior issue such as an attempt to “hoard” transfer capability reservations.”

(3) Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review: How far back should the Department look when reviewing transmission planning and path flow literature?

RESPONSE: The Ohio Chairman is concerned that the OE “hunt” for transmission plans not be treated as some sort of “literature search.” We realize the consideration of existing plans and studies is convenient and appropriate. We repeat that many of these plans may been undertaken with the needs of local native load in mind, rather than the national interest. Moreover, by their very nature many plans may be a random proffering of expansion not conducted with eye toward mitigating any artificial electrical “seams” inadvertently created when such disparate plans are “patched” together or observed in the aggregate. In attempting to develop “National interest” corridors, we caution that in the long run, the seams may be more important than the existing plans themselves.

As for the vintage of such plans, many plans and studies may be more appropriate today than they were when initially developed due a change in need or financial opportunities. Transmission planning traditionally has been a long-term planning effort. If the date of the plan is not put into context, the OE reviewer may be misled into thinking the plan is “too old” or obsolete.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

RESPONSE: The Ohio Chairman notes that DOE is planning some sort of modeling of the Eastern and Western Interconnections. It is hoped that taking on this new effort, the Department will be mindful of the study criteria developed and standardized technology already in place by regional reliability organizations/regional coordination councils as the Department attempts to duplicate the experience, knowledge and calculations applied to such modeling. Many parts of the system should be examined for more than one electrical contingency. In addition, not only physical congestion on the system, but the impact of electrical loop flows, both existing and those created by any new transmission construction must be taken into careful consideration. System impact studies should be conducted to observe the changes in the system created by proposed transmission expansion projects, or lack thereof.

The Department and the OE will find that there are in fact true “regional differences” in the existing grid system. These occur not only due by traditional approaches intended merely to serve local load, but more importantly by population growth and commercial development, and consideration of natural environmental, geological and historical characteristics. Mountains and other geological features, climate conditions, lakes, rivers and wetlands, old-growth forests and protected natural preserves, endangered species, and historically and archaeologically important sites all have been an integral part of a State’s siting considerations and responsibilities. The OE should do no less.

NOI, III. B: Criteria Development Draft Criteria:

The DOE invited comment on what criteria to use when evaluating the suitability of geographic areas for NIETC status and requested comment on eight preliminary draft criteria:

Draft Criterion 1: Action is needed to maintain high reliability**. Maintaining high electric reliability is essential to any area's economic health and future development. Accordingly, an area would be of interest for possible NIETC designation if there is a clear need to remedy existing or emerging reliability problems. Metric: A definition of the affected area in terms of load population and demand growth: a description of the expected degree of improvement in reliability associated with a proposed project: if appropriate, identification of existing or projected violations of NERC Planning Criteria.**

RESPONSE: Draft Criterion 1 suggests that demand or load forecasting be done, using historical data and testing through system impact studies, projected growth in demand, both in terms of the end markets served by the corridor, as well as in the corridor itself. "Improvement" in reliability itself may be harder to judge, given the nature of the data at hand regarding historical forced outage rates of generation resources on the system, historical and present short-term, repetitive, and long-term outages as well as deliberate Transmission Line Loading Relief measures (TLRS) in a control or operating area called by the Reliability Coordinator for that area.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers**. An area may need substantial transmission improvements to enable large economic electricity transfers that would result in significant economic savings to retail electricity consumers. Metrics: Estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets. A demonstration of expected reduction in end-market concentration and how economic benefits for consumers would be affected.**

RESPONSE: Determining "significant economic savings" and cost estimates are always tricky. Costs are not necessarily comparable, depending on the availability of fuel sources, the price of generation fuels, whether or not the statistical "prices" are fuel adjusted, as well as the additional costs and fees associated with organized markets. Assuming that costs are a clear bellwether of prices on which to determine "significant economic savings," the prices in organized markets are not based on costs at all, but on a "market clearing price," which can change every five minutes or less. In any case, there is no guarantee that increased demand for "cheap" power "hauled" at long distances will not produce a "national" price for electricity, resistant to any hoped-for downward pressure on prices as a result of competition. One must be able to determine a "breakeven" point at which any significant additional cost of developing NIETCs will not wipe out or exceed any savings in the total cost of delivered energy.

Draft Criterion 3: **Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources. Metrics: Areas that are dependent on "reliability-must-run" plants would benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both. Similarly, areas that are highly dependent on specific generation fuels could economically benefit from supply diversification. Estimate the likely magnitude of such benefits, showing calculations.**

RESPONSE: The validity of long-distance supply of the ancillary services needed to "support" the transmission system for reliability purposes is in certain circumstances questionable. VAR (voltage amperes reactive) support may be counted on for only about 100 miles from the generating source on the system. Spinning and regulation power available for reliability purposes may be localized unless, in the opinion of some RTOs/ISOs which operate the transmission system, that such support can be provided by a market for the operation of regional centralized security constrained economic dispatch. Again, depending on the load on the system, and certain contingencies, these services may be more local in nature than long-distance.

Draft Criterion 4: Targeted actions in this area would enhance the energy independence of the United States. **Metrics: Provide calculations showing how**

specific actions aided by designation as an NIETC would increase fuel diversity, improve domestic fuel independence, or reduce dependence on energy imports. Quantify these impacts including possible impacts on U.S. energy markets.

RESPONSE: The introduction and proliferation of new, cleaner technologies, such as Integrated Generation Combustion Turbine (IGCC) makes local fuel, such as our several hundred years' worth of domestic coal reserves, more attractive. IGCC processes can not only provide fuel diversity for baseload and peaking generation resources, but the by-products of this process can be converted into jet fuel and other transportation fuels as well as other petro-chemical products that have heretofore been dependent on fuel imports, thus adding to the fuel independence equation.. IGCC is more economic if developed near the fuel source. Likewise, renewable energy such as wind generation in certain, but not all, cases can be locationally limited. Natural gas supplies are limited by the natural gas transportation network. Thus it is logical, that if fuel source availability is also taken into account in the NIETC designation process, energy from remote geographical locations could be more efficiently delivered by well-reasoned determinations of NIETCs.

Draft Criterion 5: **Targeted actions in the area would further national energy policy.**

RESPONSE: Certain targeted action suggested by the Energy Policy Act could have positive effects in the Midwest region, of which our State is a part. For example, § 1813 of the Energy Policy Act 2005 is devoted to a study of rights of way on tribal lands. In certain cases, for the transmission of electricity, coordination with a neighboring RTO/ISO is recommended. This new measure is now a part of the national energy policy. Such measures are not so farfetched or far from home when one considers that major Midwest tribal lands exist in the vicinity or as neighbors to the Midwest ISO. In many cases, the people on Tribal lands are underserved, or worse yet, not served at all by electricity service. Inclusion of native Tribes by the Department and the OE would further National Energy Policy if such inclusion strictly adheres to Congress's requirement that the economic vitality and development of the corridor and the end markets served by the corridor be taken into account. Including Tribal Lands and rights-of-way studies, in conjunction with interest in resources and opportunities for NIETC corridors, must be done with the Tribes' permission and avoid at all cost any sense of exploitation by the industry or the ISO.

Draft Criterion 6: **Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts. Metrics: For this criterion, relevant metrics would be case specific.**

RESPONSE: Targeted actions to reduce vulnerability to natural disasters or malicious acts should look again at not only the new clean coal technologies, such as IGCC, mentioned in our response to Draft Criterion 4, but at critical infrastructure plans in the interest of both national homeland security and disaster relief. Even the DOE will it has no control over weather or natural disasters. However, one must consider that interconnected systems, including NIETCs, are only as secure as the redundancy built into these systems. If part of an NIETC is "down" or suffering an outage, other systems must be able to pick up the load. For this reason, all the ancillary services, reliability-must-run units, and other supporting services and infrastructure must be fungible. Recoordination of the system, in the case of a natural disaster, a weather or fuel supply event, or vandalism must be part of a deliberate security plan. Determination of NIETCs should require this security planning and coordination before they are considered ready for commercial operation.

Draft Criterion 7: **The area's projected need [or needs] is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.**

RESPONSE*:* We are pleased that OE recognizes the uncertainty of poorly construed assumptions, price uncertainty, speculative demand and growth uncertainty, as well as unrealistic consideration of new resource construction. Financial investment in an NIETC will be substantial. While long-term demand forecasting is essential, several iterations of such forecasting methodologies should be required and the assumptions used should be transparent, realistic, validated and subject to public hearing.

Draft Criterion 8: **The alternative means of mitigating the need in question have been addressed sufficiently.**

RESPONSE: While an NIETC may be one solution, the OE may want to refer to the States for consideration of local planning and alternatives to wires-only options. For example, it may be difficult to consider demand response over the long-term, or the viability of distributed resource options, or new transmission technology such as super conductors, but we suggest that all possible alternatives should be given equal treatment in considering how to mitigate the need for NIETC designation.

Further Comment and Recommendations:

The DOE seeks comment on whether there are other criteria or considerations that should be considered and whether certain criteria or considerations are more important than others.

RESPONSE: While it is difficult to set priorities on the question of NIETC designation, we noted that the NOI advances no suggestions as to the disposition of legal and procedural issues once the congestion study is complete, such as determining the right of eminent domain. In addition, no indication is made of the importance of determining both the need for an NIETC facility and the impact and effects on the surrounding area. Although "alternatives" are mentioned briefly in the NOI, we suggest that alternative sites for the proposed transmission project be required, with a one of the sites being designated as "preferred" by the transmission developer, without indicating any prior favor or prior approval for designation by the Department or OE. Finally, transparency and public input must be part of the designation process. We suggest when the project is deemed a potential candidate for NIETC designation, the Department assure that legal notices are published in local newspaper in those areas impacted by the proposed facility. The legal notice must include a listing of area libraries or depositories where a copy of the application for NIETC designation may be viewed.

CONCLUSION:

The Ohio Chairman appreciates that the DOE will provide opportunities for public comment regarding designation or suitable alternatives of particular corridors and looks forward to an opportunity for Ohio to provide further input after the congestion study is published and the final criteria are established.

Respectfully submitted,

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69. Reliant, Received Mon 3/6/2006 4:57 PM

Reliant Comments on DOE NOI
National Interest Electric Transmission Corridors
March 6, 2006

Reliant appreciates the opportunity to submit comments in response to the Department of Energy's Notice of Inquiry on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors ("NIETCs"). Reliant also looks forward to participating in the March 29, 2006, technical conference on this topic.

The designation of NIETC provides the Department an invaluable tool which is the first step toward increased development of needed infrastructure that can relieve critical transmission bottlenecks and consequently increase customer choices for electricity supply. The opportunity to increase customer choices for lower-cost electricity and, in general, to allow supply to reach more markets should be key factors in the decisions to designate these important corridors. Additionally, NIETCs may help facilitate additional transmission infrastructure that can ease the increasingly complex rules and administrative fixes associated with the organized electricity markets.

Reliant fully supports the Department's identification of national interest electric transmission corridors in "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affect consumers." While transmission need not, and should not, always be built to eliminate congestion, Reliant believes subsequent approval processes will be adequate to prevent unnecessary or uneconomic transmission expansions.

Since the NIETC designation is only the first step in a long path to get needed infrastructure built, its designation should not be applied in an overly conservative manner. Regulatory procedures and reviews will remain even after the corridor designations are made that ensure the transmission investment projects ultimately approved by the applicable regulatory bodies are in the long term interests of customers and the overall marketplace.

Key Terms: Geographic Areas, Needs and Corridors

The Department should move expeditiously in the identification of broad corridors in its NIETC designations. Reliant agrees that this approach affords the needed flexibility to facilitate the critically necessary investment in transmission facilities required to relieve problematic congestion on the grid.

In addition, when assessing need, Reliant believes the Department should not be excessively stringent in the threshold required to identify a need. The subsequent regulatory processes that will take place will undoubtedly examine the costs, benefits, and impacts of specific transmission proposals (including transmission alternatives) within the corridor. It would be very difficult for the Department to foresee all of the potentially beneficial projects that may be proposed within the NIETC or to unnecessarily screen projects on unknown economics. The Department should be wary of foreclosing opportunities that NIETCs provide to transmission and electricity customers.

Question 1 *– Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?*

The distinction between persistent and dynamic congestion may not be particularly useful when applied in isolation. The absolute quantity of time that a line is congested does not indicate the economic value or reliability concerns associated with the congestion. For instance, from an economic point of view, a path may be persistently congested, yet the cost of the congestion might be very low if the prices/costs on one side of the constraint are only slightly less than on the other side of the constraint. In such a circumstance, a corridor designation may not be needed. A dynamic constraint may have congestion for only short periods of time, but the price/cost differentials across the constraint may in fact be very significant and have a larger impact than many persistent constraints. Thus, the mere characterization of persistent versus dynamic congestion may not be particularly useful in the designation process. The economic and reliability impacts of the constraints should be the focus of the congestion studies.

Question 2 *– Should the Department distinguish between physical congestion and contractual congestion, and if so, how?*

Review of physical congestion should be the Department's focus in the independently administered LMP-based RTO markets[7]. In these markets, "contracted congestion" does not affect the physical scheduling and dispatch of the system. The financial transmission rights used in these markets do not block physical access to the grid by other market participants. The efficient day-ahead real-time dispatch alleviates the problems associated with "contracted congestion." Thus, the appropriate congestion to review in these markets would be the "physical congestion" on the system.

In regions providing traditional Order No. 888 service, it is extremely important to consider and distinguish "contracted congestion[8]" from the "physical congestion" that occurs. The "contracted congestion" has a real impact on the ability of customers to

[7] It should be noted that the physical congestion in these markets can be clearly identified by the locational prices.
[8] Reliant presumes that "contracted congestion" also includes congestion that results from native load transmission reservations.

choose both long-term and short-term electricity suppliers. Bilateral contracts between willing buyers and sellers are commonly thwarted as a result of the possible unavailability of transmission service by the transmission operator. Examining "physical congestion" alone would under-state the need and benefits of additional infrastructure in these markets. When "contracted congestion" does not "physically" occur in real-time, the forgone opportunities for trade and higher costs to customers remain. Thus, in these regions, the appropriate and applicable analysis should certainly include all "contracted congestion."

In addition, an unfortunate reality is that in regions with non-independent transmission administration, additional infrastructure may be needed to protect customers from the inherent trade constraints created by the non-independent providers. Customers outside of the independently administered markets are more susceptible to transmission market power and the ensuing transmission constraints that reduce access to adequate and reasonably priced supply choices.

Question 3 *– What existing, specific transmission studies and other plans should the Department review (in addition to those listed in Appendix A)? How far back should the Department look when reviewing transmission planning and path flow literature?*

The Department should also include in its review the independent studies developed by RTOs, ISOs, NERC, RRCs, and Interregional Study Groups.

Question 4 *– What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?*

DOE should include a close look at long-term and short-term service denials, differences in LMPs and TLR statistics. In the existing Day 2 RTO markets, the LMPs provide a transparent look at existing constraints and the congestion costs associated with those constraints.

In the traditional 888 markets the informational challenges will be more severe for the Department and more challenging due to the lack of transparency in both price and transmission information. The Department should certainly make the most of available information regarding transmission service denials, both long and short-term.

In reviewing these denials, the Department should attempt, in some manner, to take into account the numerous requests that are never made by customers because of the high expectation of transmission service denial in the first place. Potential transactions between buyers and sellers go unpursued every day because of the low expectation of getting transmission service approval in many areas.

Criteria Development

Draft Criterion 1: *Action is needed to maintain high reliability.*

Reliant fully supports this Criterion.

Draft Criterion 2*: Action is needed to achieve economic benefits for consumers.*

Reliant supports the use and expansion of the transmission system to provide economic benefits to customers and increase customer choices. To the extent that a corridor may have a reasonable expectation to provide economic benefits to customers, it should be designated as a NIETC. Since the NIETC designation is only the first step in a long process to get needed infrastructure built, its designation need not be applied in a restrictive manner. Sufficient regulatory processes and reviews will remain even after the corridor designations are made. The processes will act to ensure that the transmission investment projects that are ultimately approved by the applicable regulatory bodies are in the long-term interests of customers and the overall marketplace.

Draft Criterion 3*: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.*

As stated in Draft Criterion 2, Reliant supports the application designation of NIETC to ease supply limitations and diversify resources. It is important to keep in mind that the simple designation will not instantaneously result in new transmission construction. The designation facilitates the regulatory processes to allow economic, efficient, environmentally sensitive and reliable infrastructure investment to occur.

Draft Criterion 4*: Targeted actions in the area would enhance the energy independence of the United States.*

Reliant supports this criterion.

Draft Criterion 5*: Targeted actions in the area would further national energy policy.*

Reliant supports this criterion.

Draft Criterion 6*: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.*

Reliant supports this criterion.

Draft Criterion 7: *The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions.*

Reliant supports this criterion while supporting the broad application of the transmission corridors to facilitate needed investments. When a possible projected need is contingent on an extreme unlikely event, a designation may be unnecessary.

***Draft Criterion 8**: The alternative means of mitigating the need in question have been addressed sufficiently.*

Reliant does not support the application of this Criterion. As stated previously, there remains ample regulatory process following the corridor designation for efficient and cost-effective transmission alternatives to be developed. It would be premature for the Department to unilaterally dictate possible alternatives to the detriment of potentially needed transmission investment. Alternative solutions can and should be adequately addressed in subsequent regulatory proceedings. The efforts by the Department to address alternative means would slow the designation process significantly while adding little additional protections for customers.

Additional Questions

***Question 1** – Are there other criteria or considerations that the Department should consider in making an NIETC designation?*

The Department should recognize that a robust transmission infrastructure facilitates robust wholesale and retail markets. The NIETC designation process should keep in mind that in the end, customers benefit from the increased supply choices that result from a healthy, robust wholesale and retail marketplace. Many of the challenges, and much of the opposition, facing these markets are in large part due to the lack of sufficient transmission infrastructure. Significant time and effort is spent by market participants and regulators working to correct, modify and continually re-modify rules to accommodate the lack of transmission infrastructure. These include the shortage of available transmission rights, the implementation of market power mitigation rules, the need for out-of-market reliability-must-run contracts, and administratively determined demand curves for capacity. NIETC designations should also be made to support robust and healthy electric markets for customers.

The Federal Energy Regulatory Commission is in the process of developing rules that would provide customers with long-term transmission rights. The requests and desires of customers to obtain these rights may also be an item worthy of Department consideration in the determination of the NIETC. State-by-state jurisdictional siting burdens and parochial interests should not be a barrier to infrastructure that allows customers who are willing to pay for long-term transmission rights to obtain them. The Department should also consider customer demands for long-term transmission rights in the determination of NIETC corridors.

***Question 2** – Are certain considerations or criteria more important than others?*

Reliant believes that the Department should act aggressively in assigning these corridors based on any of the above-mentioned criteria. The Department should err on the side of caution, which is to designate more corridors rather than fewer. Even with the NIETC designations, large hurdles and challenges will remain before any infrastructure improvements are made. The NIETC designation process provides an important first step in streamlining the processes needed to get necessary investments in transmission infrastructure.

70. Salt River Project, Received Mon 3/6/2006 4:55 PM

Comments of
The Salt River Project Agricultural Improvement and Power District (SRP)

Department of Energy Notice of Inquiry
Considerations for Transmission Congestion Study and Designation of National Interest Transmission Corridors

I. INTRODUCTION

The Department of Energy (DOE) seeks comment and information from the public concerning its plans for an electric transmission congestion study and the criteria to be used for determining whether National Interest Electric Transmission Corridor (NIETC) designation is appropriate. DOE issues this Notice of Intent (the Notice) to collect information required to fulfill its obligation created by Section 1221 of the Energy Policy Act of 2005.

SRP is a political subdivision of the State of Arizona, organized and existing under Arizona Revised Statutes, with its principal place of business in Maricopa County, Arizona. SRP owns and operates electric, irrigation and water supply systems in Arizona, including approximately 1900 miles of high voltage (≥ 115 kV) transmission. SRP provides retail electric service to over 880,000 residential, commercial, industrial, agricultural and mining customers. SRP also provides open access transmission and power sales services to wholesale customers. In addition, SRP purchases, sells and transmits power in the wholesale power markets.

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II. COMMENTS

Section 216(a) of the Federal Power Act requires the Secretary of Energy, in consultation with affected states, to conduct a study of electric transmission congestion. The Secretary must report on the results of this study and may designate National Interest Electric Transmission Corridors (NIETCs). The designation of NIETCs is significant because it is necessary for obtaining a Federal permit to build new transmission facilities or modify existing facilities and exercise the related power of eminent domain.

A. Congestion Study

SRP urges DOE to establish a measure of congestion that correlates with electric system reliability. This correlated measure will allow for identification and construction of new transmission lines, allowing entities in the west to maintain and meet reliability criteria as load growth continues. Reliability studies, which are highly verifiable and include evaluation of alternate options and solutions, will precisely identify needs with respect to scope of facilities and timing. A measure that includes actual and projected usage may be beneficial. The approach could be based on the rated capacity of existing facilities and the relative frequency that actual line loadings approach the accepted ratings for the path and are projected to exceed the rating over a designated time frame if the path rating limit was unconstrained. DOE expresses an intent in the Notice to identify areas where transmission congestion is *significant*. SRP believes this is the right approach and suggests that a threshold be established based on a combination of historical physical measures of observed congestion and projected congestion based on simulation studies that are interconnection-wide and have been developed in open processes.

In any system, some congestion is an inevitable and accepted outcome of integrated resource expansion decisions that seek to balance and control total costs of delivered energy. For example, the overall cost of serving customers may be lower if higher priced generation is built near a load center than it would be if transmission were expanded to reduce the frequency of congestion on an existing path. DOE should focus on the physical aspects of congestion and use caution when considering or relying heavily on economic aspects.

B. Designation of NIETCs

The Federal Power Act Section 216(a)(4) broadly defines a number of issues the Secretary may consider when designating NIETCs. Some of these factors, such as enhancing national defense and homeland security, emphasize reliability. Others focus on economic factors. SRP encourages DOE to focus on the reliability factors.

The purpose of designating NIETCs is to facilitate the siting and construction of transmission. SRP cautions against basing NIETC designation decisions on a state's or region's economic development goals. This approach could increase or change the relative competitiveness of one geographic region, technology or business model over another. SRP asks the DOE to be particularly sensitive to actions that reduce the price of electricity in one region at the expense of customers in another region or that increase the total cost of electricity by encouraging additional investment in underutilized facilities. This is of particular concern where a NIETC designation terminates at a site where there are no existing generation resources and no commitments to build any additional generation.

SRP believes any NIETC designation must be based on a clear definition of the congestion problem to be solved and on comprehensive analysis of a variety of possible solutions. SRP does not support the designation of NIETCs to accommodate specific projects. Any designations the DOE chooses to pursue should be to address specifically identified areas of chronic congestion. SRP believes the designations should provide enough flexibility to allow for creative, possibly non-wires solutions, and not be designed to assist the developers of a specific project.

The Notice addresses the issue of early designation of NIETCs in areas shown to have an urgent need for DOE's attention. SRP is concerned that early designation of NIETCs runs the risk of circumventing the process envisioned in this Notice of comprehensive analysis of all critical decision factors. SRP is encouraged that the DOE states an early designation will only be granted for those corridors in which "a particularly compelling case is made."

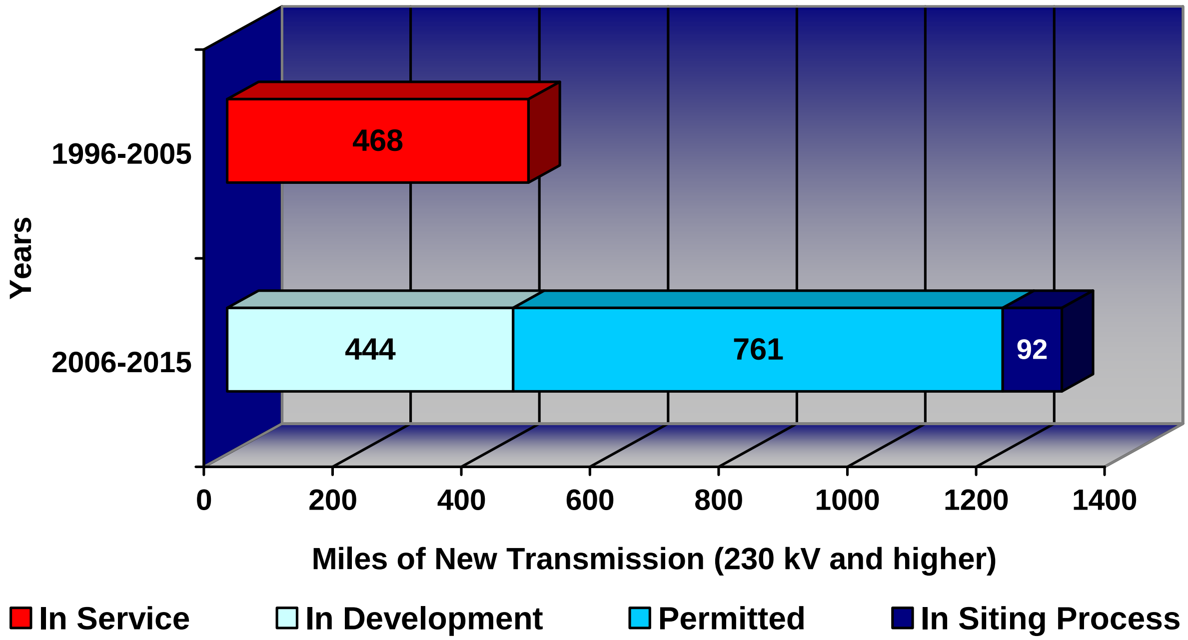
C. Transmission Siting Authority

1. State Siting Authority

SRP encourages the DOE to consider and respect the authority of states in the siting of transmission. State and local authorities are in the best position to determine the optimal transmission line siting that limits impacts on communities within their boundaries while permitting the transmission provider to meet the obligation to reliably serve loads. A federal siting role should only be pursued in limited circumstances.

In addition, enhanced deference should be granted to those states that have a proven record of siting and constructing transmission. The State of Arizona, through the Arizona Power Plant and Transmission Line Siting Committee of the Arizona Corporation Commission, is an example of such a state. Figure 1 below illustrates the success the State of Arizona has had in reaching consensus on the siting, construction and energization of needed transmission lines. A federal role in the siting of transmission should only be undertaken in states or regions where siting of necessary transmission lines has proven unduly difficult, not in those areas where state and local authorities have shown the foresight and political will to take on this responsibility.

FIGURE 1
Transmission Projects in the State of Arizona



2. Regional Planning Groups

SRP asks DOE to also consider the analytical results of successful and robust regional planning efforts in its determination of areas that may be designated as NIETCs. As with states with proven track records of success in siting and building transmission, the DOE should acknowledge the analytical planning work produced in those areas with successful, organized, long-standing regional and sub-regional planning processes in place. SRP suggests DOE consider the requirements already identified in regional planning processes, but not yet sited, when making initial designations of NIETCs.

Several areas in the Western Interconnection successfully employ sub-regional planning processes that have proven effective in resolving the issues of individual communities, relevant regulatory agencies and transmission providers with load-serving obligations in siting transmission. Due to the success of these planning groups, projects move from the planning stage to construction and into service on a reasonable timetable. The transmission documented in Figure 1 above is a result of work done by the Southwest Area Transmission sub-regional planning group.

III. CONCLUSION

SRP appreciates the opportunity to comment on the issues involved in the nationwide study of congestion mandated by the Energy Policy Act of 2005 and the possible designations of NIETCs.

Respectfully submitted,

/s/

Kelly J. Barr
Manager, Regulatory Affairs & Contracts
Salt River Project

March 6, 2006

71. San Diego Gas & Electric Company, Received Mon 3/6/2006 4:59 PM

March 6, 2006

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Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

San Diego Gas and Electric Company ("SDG&E") appreciates the opportunity to comment on the plan of the Department of Energy ("Department") for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETCs"), as called for in section 1221 of the Energy Policy Act of 2005 (the "Act"). 71 Fed. Reg. 5660 (February 2, 2006).

SDG&E urges the Department of Energy to identify now as an NIETC the corridor linking power sources in the desert southwest to San Diego, across the Imperial Valley, California. The California Energy Commission has already concluded that a project though this corridor is essential and meets the type of criteria that the Department has identified for NIETCs, stating that such a project --

> "…would provide significant near-term system reliability benefits to California, reduce system congestion and its resultant costs, and provide an interconnection to both renewable resources located in the Imperial Valley and lower-cost out-of-state generation. Without this proposed project, it is unlikely that SDG&E will be able to meet the state's RPS [Renewable Portfolio Standard] goals, ensure system reliability, or reduce RMR [Reliability Must Run] and congestion costs. The Energy Commission therefore believes that the proposed project offers significant benefits and recommends that it move forward expeditiously so that the residents of San Diego and all of California can begin to realize these benefits by 2010."[1]

SDG&E's comments will be directed mainly at supporting early designation of this corridor as an NIETC, through application of the Draft Criteria provided in the Department's notice. As part of demonstrating the acute need for early designation of a specific corridor, SDG&E will discuss the factors that most heavily weigh on such a designation, both in the case of this corridor, and in the case of corridors generally. Because there is overlap in some of the Draft Criteria, we will not respond to all of them individually. We do, however, propose that the Department consider an additional criterion to adequately cover all of the considerations outlined by Congress. Specifically, there should be an individual criterion for defense and homeland security considerations.

Criteria Development

The Department has indicated that it is inviting comment on the criteria that is should use in designating corridors. In subsection (4) (E), the Act indicates that "the Secretary may consider whether… (E) the designation would enhance national defense and homeland security." SDG&E feels that this is a critical consideration specifically called out by Congress, and should be added as one of the criteria the Department considers.

From the perspective of national security, reliability of service to the San Diego area is particularly important. Military bases in San Diego are critical to our national defense and play an integral role in Homeland Security. San Diego is the home base for the U.S. Pacific Fleet on the west coast. In addition, Camp Pendleton, the largest Marine Corps Base in the United States comprising over 125,000 acres is also located in San Diego County. The Navy and Marine Corps have 16 bases in San Diego County and are SDG&E's single largest transmission service customer, comprising over 15% of the total electric demand requirement in SDG&E's service area on peak. The total military population on these bases is approximately 108,000 military personnel and over 20,000 civilian personnel. In addition to the military bases, the Navy and Marine Corps also have over 20,000 family housing units that house over 101,000 military dependents.

[1] California Energy Commission, "Strategic Transmission Investment Plan" at 6 (November, 2005).

Reliable and economic electric power supplies for the Navy and Marine Corps bases in San Diego County are critical both from a national security standpoint and to support Homeland Security initiatives. North Island Naval Air Station is the home base for three nuclear powered aircraft carriers. Each of these aircraft carriers requires reliable and stable electric power to support ancillary nuclear power support equipment. Nuclear powered submarines are based at the Navy Submarine Base in Point Loma and also require reliable and dependable electric service to carry out their assigned mission. Quality of life issues for the Navy are extremely important. Without reliable electricity shore-based supplies, Navy personnel will need to remain onboard ships after returning from extended deployments to keep shipboard equipment operating.

As the single largest west coast base for the Navy and Marine Corps, the Navy is constantly deploying ships and aircraft squadrons to overseas destinations. The deployment schedules are classified information, so it is difficult to determine how many ships and squadrons will be in port at any one point in time. This means that electric demand requirements will vary depending on the number of ships in port in San Diego. Current readiness levels for naval forces in San Diego require all combatants to be ready to deploy with extremely short notice. Consequently, electric service must be available at all times and must be flexible, in order to meet the demands of the various Navy and Marine Corps units. In addition to the many surface and air combatants based in San Diego, there are also large military data and communications centers necessary for national security that require reliable electric service.

A prolonged lack of reliable electric service in San Diego would seriously cripple the defense capability of the Navy and Marine Corps bases in San Diego and would need to be reported to the United States Congress immediately.

Criterion 1: Action is needed to maintain high reliability

SDG&E currently provides electric utility service to 3.3 million customers through approximately 1.3 million retail meters in a service area that includes all of San Diego County and the southern part of Orange County, California. San Diego is the nation's seventh largest city and the nation's sixth largest county with an economy in excess of $70 billion of goods and services per year (not including the substantial area served in Orange County), and SDG&E is the sole electric utility serving this area. Demand in this area is served by a combination of internal capacity and imported power, virtually all of which is delivered through two points of interconnection—a 500 kV line at SDG&E's Miguel substation[2] that accesses power from the east and south, and a series of 230 kV lines connecting through the San Onofre Nuclear Generating Station ("SONGS")

[2] The SDG&E electric transmission system is also interconnected with Comision Federal de Electricidad ("CFE") in Mexico through two 230 kV transmission lines (Path 45), one at the Imperial Valley substation and the other at the Miguel substation.

switchyard to the north.[3] Neither of these paths is capable of serving the full peak-load requirements of the SDG&E local reliability area if the other is out of service.

Among the large electric service areas in the State, only San Diego is so underserved. SDG&E's sole 500 kV interconnection to the grid is the Southwest Powerlink ("SWPL"), a 500 kV transmission line connecting the Palo Verde Nuclear Generating Station in Arizona and SDG&E's Miguel Substation in California.[4] The SWPL was constructed primarily to import reliable and cost-effective energy from the desert Southwest into California. As a result of growing loads in Southern California, coupled with the addition of new generation in the desert Southwest, including new generation located in Mexico that is connected directly to the existing Imperial Valley substation, the import capability into the San Diego area is often fully utilized. The SWPL is owned jointly by SDG&E, Arizona Public Service Company ("APS"), and the Imperial Irrigation District ("IID").[5] Of the co-owners, only SDG&E has turned over its share of the SWPL to the operational control of the California Independent System Operator Corporation ("CAISO"). Thus, only SDG&E's share of the line is subject to the comparability and non-discrimination requirements of the CAISO tariff on file with the Federal Energy Regulatory Commission ("FERC").

The California Energy Commission ("CEC") has reviewed the current condition of California's transmission infrastructure and concluded that it is fragile. Indeed, one unforeseen event affecting transmission last August resulted in an outage that affected much of the State. The CEC, in its "Strategic Transmission Investment Plan" described its conclusions as follows:

> Disruptions on California's more than 31,000-mile electric transmission system can be catastrophic. As recently as August 25, 2005, the loss of the 500 kV Pacific DC Intertie from Oregon to Southern California caused rolling blackouts in Southern California, blacking out large blocks of the service territories of Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). This line loss occurred just before 4 p.m. as California was fast approaching its peak electricity demand on a hot summer day. The line loss forced the … [CAISO] to issue a Transmission Emergency Notice for Southern California and request that SCE and SDG&E reduce demand on the transmission system south of Path 26. This quickly escalated to the dropping

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[3] SONGS, while geographically located within SDG&E's service area, is connected to the SCE transmission system, and, from an electric reliability perspective, is outside the San Diego local reliability area.

[4] See, *In re Application of SDG&E for Certificate to Construct and Operate a 500 kV Transmission Line*, D.93785, 7 CPUC 2d 301 (1981).

[5] Pursuant to contracts executed in 1981 and 1983, SDG&E transferred specified undivided interests in portions of SWPL to APS and IID, respectively. As a result, SWPL is owned jointly by SDG&E, APS, and IID in ownership shares that vary among the segments of the line. The Palo Verde to North Gila segment is owned by SDG&E, APS and IID in shares of 76.22%, 11%, and 12.78%, respectively. The North Gila to Imperial Valley segment is owned by SDG&E and IID in shares of 85.64% and 14.36%, respectively. The Imperial Valley to Miguel segment is wholly-owned by SDG&E.

> of 800 megawatts (MW) of voluntary interruptible customers and 900 MW of firm load. The resulting outage to approximately 500,000 customers is the largest single disruption in California since the 2000-2001 energy crisis and is a graphic example of how a low-probability/high impact event, relatively short in duration, takes a disproportionately high social and economic toll on all Californians. This outage clearly demonstrates the need for comprehensive improvements to and investments in California's transmission system and highlights the inadequacies of current institutional arrangements to do so.[6]

Transmission from the desert southwest into San Diego via a corridor across Imperial Valley is needed to ensure that there is enough infrastructure available to meet San Diego area load beginning in 2010. Such a project would allow SDG&E and other load serving entities within the San Diego area to reliably serve their customers during periods of unusually high energy demand. Additionally, it would allow increased flexibility in operating California's transmission grid and provide additional import capability that may be urgently needed during a major outage or emergency event. Such transmission is needed to meet the CAISO's reliability requirements.

Since SDG&E built the Southwest Powerlink over 20 years ago (the only 500 kV connection between SDG&E and the grid), loads in the SDG&E service area have continued to grow.[7] The electric load served by the SDG&E transmission system is expected to grow by over 750 megawatts ("MW") over the next ten years (2006 through 2015). This is an increase of 19% and includes an expected reduction of 595 MW due to rather significant incremental energy efficiency savings and other demand-side measures that are assumed to occur over this period.[8]

SDG&E projects that beginning as early as 2010, there could be overlapping transmission and generation contingencies, as defined by the CAISO, under which the sum of available in-area generation and existing import capability could not meet load in the SDG&E service area during adverse weather conditions. In other words, absent increased transmission across the San Diego-Imperial Valley Corridor, or some other alternative, San Diego area customers are at risk for curtailment of firm service – rotating outages.

Reliability benefits encompass the ability to meet load under any reasonably plausible system condition as well as a range of system conditions that may fall outside of conventional planning standards. The G-1/N-1 criterion requires that there be sufficient

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6 California Energy Commission, "Strategic Transmission Investment Plan" at 1 (November, 2005).

7 In 1983, when the SWPL was built, the peak demand in the SDG&E service area was about 2070 MW. In 2004, the SDG&E service area recorded a peak demand of 4,065 MW.

8 This compares SDG&E's peak demand of 4,058 MW recorded in 2005 to its expected peak demand of 4,813 MW in 2015, based on SDG&E's "50/50" peak demand forecast which has a 50% probability of being exceeded in any given year. It should be noted that 342 MW of energy efficiency demand reductions represent *future* savings and do not reflect the significant contribution of past energy efficiency achievements which are essentially embedded in the forecast.

in-area resources and transmission import capability to serve the full adverse peak demand forecast during the worst G-1/N-1 event. The CAISO's G-1/N-1 reliability requirement for the San Diego area transmission system dictates that the sum of (a) available in-area generation less the largest single in-area generator[9], and (b) the maximum imports into the SDG&E service area assuming certain transmission contingencies, equals or exceeds the load within the service area under adverse weather peak load conditions. In particular, the CAISO's G-1/N-1 reliability criteria requires that there be no loss of load, thermal overloads, or unacceptable voltages in the event that (a) the largest generator in the local area and the most critical transmission element are already out of service, and (b) there is a subsequent outage of another transmission element.

Increasing the ability to import power from the desert Southwest will ensure that, if these overlapping contingencies occur during nearly any plausible adverse weather condition, all loads in the SDG&E service area could still be served. Indeed, absent such a project, if just the South Bay generating station retires as expected in late-2009, SDG&E will not be able to satisfy the CAISO's G-1/N-1 reliability requirement beginning in 2010, even with the needed addition of significant new in-basin generating capacity to be provided by the Palomar and Otay Mesa generating plants.

The California Energy Commission, in its "2005 Integrated Energy Policy Report", summarized well the conditions that the San Diego area faces and concluded that it needs new transmission into the area:

> The San Diego region's transmission problems are acute and graphically illustrate the importance of adequate transmission. In 2001 SDG&E identified transmission constraints and increasing congestion on its Mission-Miguel Line, a 230-kV line moving electricity from the southern part of its service territory to downtown San Diego. SDG&E at that time began the process of permitting and building upgrades to the line. By 2004, annual congestion costs totaled over $32 million, increasing to $48 million from July 2004 to July 2005. Over the next year until the Mission-Miguel upgrade finally comes online, congestion costs are expected to exceed $50 million. The Mission-Miguel No. 2 Line required only minimal regulatory approval since it was located in an existing right-of-way. Still, even under a creatively developed construction plan, it took SDG&E three years to permit and another two years to build this critically needed upgrade.

> SDG&E's transmission situation is very precarious. As its representative noted, "We have to weigh the question of do we take a line out to try to repair it. And if we do, we're sitting on one other line. And if we lose that line we can be in a blackout situation." For example, while making repairs to damage on two

[9] The CAISO's planning standards do not specifically indicate which generator should be considered the "G-1" outage for purposes of applying the CAISO's G-1/N-1 reliability criteria. However, in practice the CAISO has used the "largest" generator within a local area.

towers supporting 138-kV lines feeding Southern Orange County, SDG&E temporarily took one of the lines out of service. On July 28, 2005, the second line went out, causing 35,000 customers in Laguna Niguel to lose power."[10]

The table below illustrates the shortages that SDG&E projects under various scenarios absent development of transmission across the San Diego-Imperial Valley corridor.

Without the Proposed Transmission Addition
Surplus/(Deficiency) Outcomes (MW)

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
No Retirements (with Otay Mesa)	261	155	629	531	440	349	255	162	65	**(35)**
Encina 4 Retired (with Otay Mesa)	261	155	330	232	141	50	**(44)**	**(137)**	**(234)**	**(334)**
No Retirements and No Otay Mesa	261	155	88	**(10)**	**(101)**	**(192)**	**(286)**	**(379)**	**(476)**	**(576)**
South Bay Retired (with Otay Mesa)	261	155	629	531	**(262)**	**(353)**	**(447)**	**(540)**	**(637)**	**(737)**
Encina All Retired (with Otay Mesa)	261	155	629	531	440	**(611)**	**(705)**	**(798)**	**(895)**	**(995)**
South Bay and Encina All Retired (with Otay Mesa)	261	155	629	531	**(262)**	**(1313)**	**(1407)**	**(1500)**	**(1597)**	**(1697)**

The importance of reliable service without outage cannot be overstated. As discussed below, one of the purposes of building new transmission through the corridor into San Diego is to ensure SDG&E's continued ability reliably transmit an adequate level of power to all loads in the San Diego area, particularly when the system is stressed by adverse weather condition or contingencies affecting service, such as fires or outages for other reasons. In 2001, AUS Consultants performed a study on the economic impact of potential outages in 2001 for the California Alliance for Energy & Economic Stability. This study is instructive for assessing the impact of outages caused by failure to site needed infrastructure. The AUS study concluded:

- Rolling blackouts that culminate in 20 hours of electricity outage [which is what they estimated the average customer would experience in 2001] will have

10 California Energy Commission, "2005 Integrated Energy Policy Report" at 92-3 (November, 2005).

significant adverse implications for growth of the state economy and will result in lost jobs and reduced income for Californians.

- Gross State Output (GSP) for California would be reduced by $21.8 billion (constant 1996 dollars), or 1.7 percent, in 2001. This would reduce the growth rate of California GSP from the 2.3 percent currently [i.e. in 2001] projected by the UCLA Anderson Forecast to 0.6 percent for all of 2001. This loss has two components:

- A direct loss of output experienced by all industries due to the effects of blackouts in the amount of $6.8 billion. Of this, California's manufacturers would lose 18 percent, or more than $1.2 billion.

- An indirect effect reflecting the fact that each dollar of output by one industry represents the purchase of output (i.e. goods and services) by other industries. This amounts to $14.9 billion.

- A loss of output of this magnitude would reduce household income for Californians by $4.6 billion. This is a loss of $104 for every one of California's 11.5 million households. Important to note is that this loss is in addition to the impact of higher electricity costs resulting from recent rate increases.

- 135,755 jobs would be lost in all industries in the California economy.[11]

Such impacts can have far-reaching local effects. For example, in a survey conducted by the Connecticut Business and Industry Association, 34% of respondents said they would shift business operations out of their state if they experienced ten or more 1-hour to 1-day unanticipated power losses over a quarter of a year.[12]

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.
And
Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor and diversify sources.

The project that SDG&E is currently assessing for this proposed corridor will produce net energy savings of up to $57 million per year over the life of the project. These savings will result from reduced congestion and Reliability-Must-Run ("RMR")[13] costs and increased access to lower-cost sources of power in the desert Southwest. SDG&E projects that the total energy savings provided by the project to all CAISO consumers, before accounting for the project's fixed costs, are $210 million per year on a levelized

[11] AUS Consultants, "Impact of a Continuing Electricity Crisis on the California Economy", May 3, 2001.

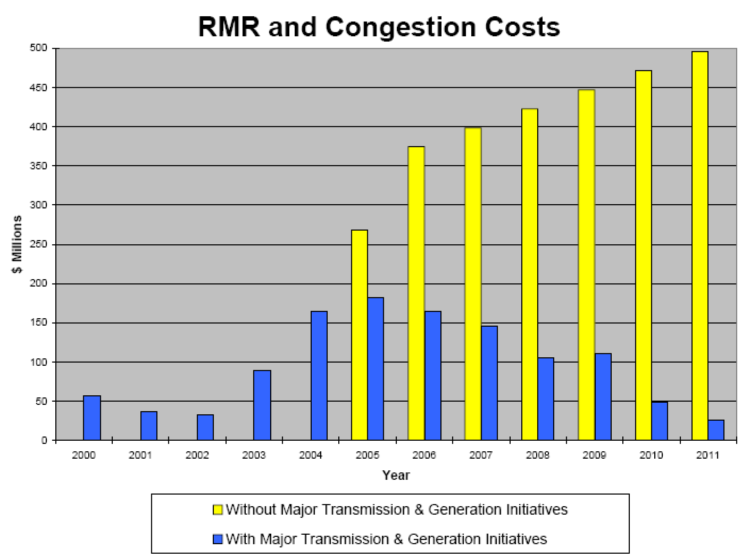
[12] http://www.cbia.com/3news/2002Releases/EnergySurvey.htm

[13] RMR describes contracts between the CAISO and generators in certain constrained areas that require such generators to be available and run at the CAISO's direction.

basis. This includes $96 million per year in savings as a result of reduced congestion and higher grid dispatch efficiency throughout the CAISO control area, and $114 million per year from reduced RMR contract costs in the San Diego service area.[14] Increasing RMR costs have been a significant issue for San Diego area customers.

The financial burden on SDG&E's customers has been particularly acute. Congestion costs have increased to massive proportions over the past few years. Several years ago, SDG&E undertook an initiative to mitigate these costs to our customers (known as the Valley-Rainbow project), and state regulators rejected it. Had the state provided for new transmission into San Diego, it would have cut congestion costs to our customers by half. By having failed to do so, unless both new transmission and generation is added, SDG&E's customers will see congestion costs nearly double again by 2010 to over $450 million each year.

The following chart illustrates the projected increase in these costs over the next few years. This chart also shows the significant savings that will be provided by the major transmission and generation initiatives being aggressively pursued in the San Diego area.[15] The proposed transmission addition will further reduce RMR costs and secure greater energy savings for San Diego customers, particularly if the project is expeditiously completed and not unnecessarily delayed.



[14] The project will also provide about $1 million per year savings as a result of reduced line losses.

[15] The chart reflects the combined effect of such measures as the Mission-Miguel transmission upgrade, and the future addition of major generation assets, most notably the Palomar plant (541 MW in 2006) and the Otay Mesa plant (561 MW in 2008). RMR as currently structured may not continue in the long-term. However, the fundamental nature of local reliability demands and the cost of meeting such demand must continue in one form or another.

A transmission line in this corridor will also augment existing transfer capability between the desert Southwest and California load centers and accommodate the retirement of aging and inefficient, gas-fired generation in the San Diego area by providing an increased ability to access capacity sources. By reducing congestion costs and losses, CAISO consumers[16] will be able to access low cost sources of power in the desert Southwest at reasonable prices. At the same time, the improved access offers developers of conventional power plants an incentive to build new, efficient, generating capacity. The project will also enhance competition among the generating companies that supply power to California, putting downward pressure on energy costs.

Not only would a transmission line in the proposed corridor meet the area's critical need for reliability, and reduce excessive congestion and RMR costs, adding transmission through this corridor also creates the opportunity for expansion at a later date by connecting with the 500 kV system to the north, completing a loop that will add further reliability. However, it is the east-west corridor between San Diego and Imperial Valley that requires urgent determination as a National Interest Electric Transmission Corridor.

Below, is a graphic showing the needed connection between San Diego and Imperial Valley, as well as the potential for a later north-south addition. The corridor is broadly defined as the connection between Imperial Valley and San Diego, without any specific route. A specific route is unnecessary and inappropriate for establishing a corridor.[17] Ultimately, the route that is used through this proposed corridor will depend on numerous political factors. For, example, as the California Energy Commission observed in its Strategic Transmission Investment Plan:

> It should be noted that SDG&E faces significant land use constraints that will require resolution prior to completion of the project. The areas to the east of San Diego contain national and state parks, military bases, tribal lands, and new residential and other developments. The state-led transmission corridor planning process proposed in the Energy Commission staff's transmission report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*, could assist in addressing ROW routing issues associated with this project. The Energy Commission recommends forming a Corridor Study Group to ensure that coordination with local, state, and federal agencies, tribal organizations, landowners, interested parties, and other stakeholders begins immediately.[18]

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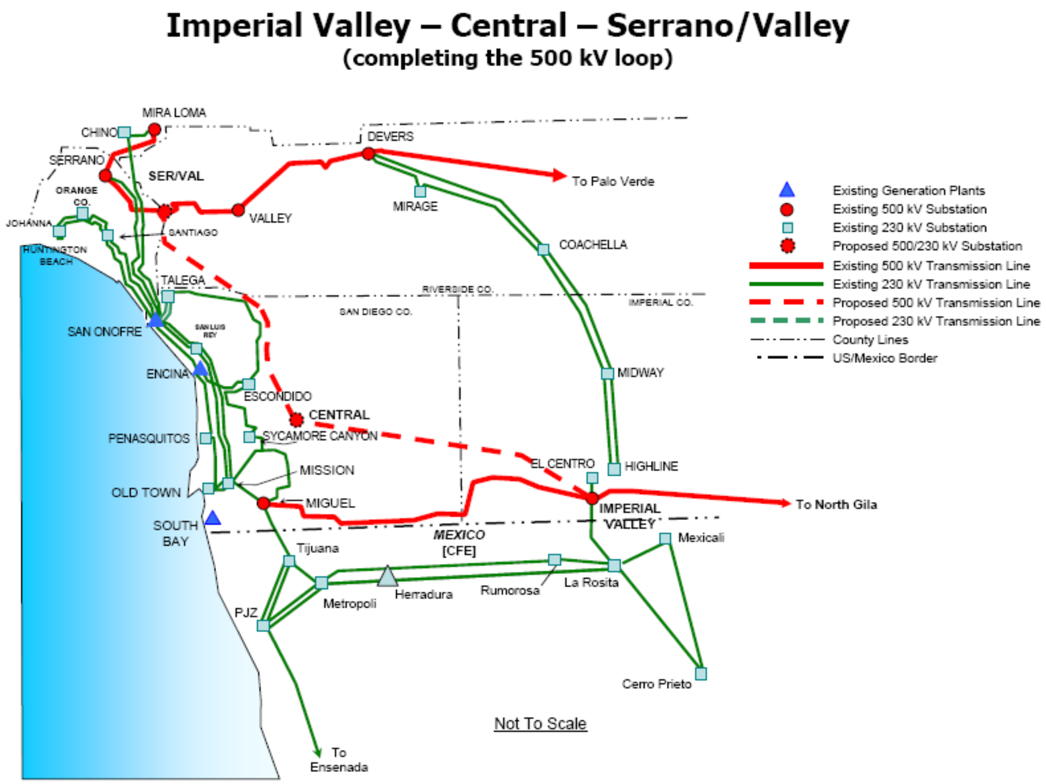
16 As noted previously, these benefits will accrue to ratepayers who receive transmission service from facilities that are under the operational control of the CAISO.

17 "The Department expects to identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities. The Department believes that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion." 71 Fed. Reg. 5661 (Feb. 2, 2006).

18 California Energy Commission, "Strategic Transmission Investment Plan" at 67 (November, 2005).



<u>**Criterion 4: Targeted actions in the area would enhance the energy independence of the United States**</u>**.**

The Energy Policy Act identifies as a criterion for supporting designation as an NIETC enhanced diversification of resources and promotion of energy independence:

`(ii) a diversification of supply is warranted;

`(C) the energy independence of the United States would be served by the designation;

The proposed corridor to San Diego will provide more economical access to remote areas with the potential for significant development of renewable energy sources and will encourage the development of new renewable generation thereby diversifying the state's resource mix and reducing California's reliance on fossil fuels.

The California Energy Commission has concluded –

> California needs major investments in new transmission infrastructure to interconnect with remote renewable resources in the Tehachapi and Imperial Valley areas, without which it will not be able to meet its RPS targets.[19]

SDG&E is moving aggressively to meet the 2010 goal of supplying 20% of SDG&E's bundled customer energy requirements with renewable energy sources. While some economically viable renewable resource potential appears to exist within the San Diego basin, principally wind generation on the eastern edge of SDG&E's service area and concentrating solar power in the Borrego Springs area, far greater quantities have been identified outside of the SDG&E service area. As clearly documented in both the IVSG report[20] and the San Diego Regional Renewable Energy Study Group Report,[21] the Imperial Valley and eastern San Diego County areas have significant geothermal, solar, and wind resource potential. Increasing the ability to import power from the Imperial Valley will allow SDG&E to meet the renewable resource goals at a cost that will not be burdened by high levels of congestion.

SDG&E has been negotiating with a number of developers to procure renewable energy resources in the Imperial Valley. A transmission link will ultimately be essential to delivering this renewable power to the San Diego area.[22] Through its negotiations, SDG&E has already taken significant steps to meet its renewable energy goals in 2010. SDG&E has signed a contract with Stirling Energy, a solar thermal developer, to purchase the output of a 300 MW facility to be located in the Imperial Valley. Commercial operation of this facility must begin no later than 2010. Two subsequent phases of the project could add another 600 MW of solar thermal power capability. The California Public Utilities Commission approved the contract for the first two phases in December 2005. SDG&E anticipates that the point of interconnection between the Stirling project and the CAISO grid will be at either the Imperial Valley substation; or at a new 500/230 kV substation that may be built along the proposed transmission line at a point that is on the edge of the Imperial Valley, due west of the southern tip of the Salton Sea. Either way, a transmission project in the San Diego-Imperial Valley corridor, along with other existing transmission connections between the Imperial Valley and the San Diego basin, will deliver a significant portion of the output of the Stirling project to the San Diego area.

Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disaster or malicious acts.

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19 California Energy Commission, "2005 Integrated Energy Policy Report" at 89 (November, 2005).

20 See *Development Plan for the Phased Expansion of Transmission to Access Renewable Resources in the Imperial Valley,* September 30, 2005, at http://www.energy.ca.gov/ivsg/documents/2005-09-30_IVSG_REPORT.PDF ; and *Potential for Renewable Energy in the San Diego Region* (August 2005) at: http://www.renewablesg.org/docs/Web/Ch1_ExSummary.pdf

21 Potential for Renewable Energy in the San Diego Region, dated August 2005 (http://renewablesg.org).

22 Additional information regarding the outcome of these negotiations may be available at a later date.

As noted above, the designated San Diego-Imperial Valley corridor should be broadly defined without any specific route. However, there is one consideration that needs to be taken into account when designating this corridor in order to reduce the vulnerability of the new electricity infrastructure within this corridor to the consequences of certain events. This consideration involves the proximity of planned electric transmission lines to existing electrical facilities.

SDG&E is required to plan its transmission system to the reliability criteria of NERC/WECC and the CAISO. The NERC, WECC and CAISO planning standards generally provide that if a planned transmission circuit is to be adjacent to another transmission circuit, a case-specific analysis is required to determine whether the proximity of the circuits, and the geography that the adjacent circuits traverse, dictates specific mitigation measures for common mode contingencies (up to and including a determination that such proximity would constitute a violation of the planning standards[23]). An exception is made where multiple circuit towers are used over short distances (e.g., station entrance, river crossings).[24]

The case-specific analysis takes into account the probability of occurrence of an outage of two adjacent circuits on separate towers, line design, the distance that the two circuits are adjacent to each other, location, environmental factors, outage history of existing circuits, operation guidelines and separation between the circuits.[25] In general terms, if two circuits on separate towers are adjacent for only a short distance; or if the geography over which the two circuits are adjacent is not subject to wildfires, lightning strikes or other common mode contingencies; then the likelihood of the common mode contingency is considered improbable (sometimes called “non-credible”) and no mitigation is required.

On the other hand, if two circuits on separate towers are adjacent for a longer distance; or if the geography over which the two circuits are adjacent is subject to wildfires, lightning strikes or other common mode contingencies; then the common mode contingency is considered “credible” and mitigation, including the possibility of “Planned/Controlled” load drop, is required.

Applying the above reliability criteria to the San Diego-Imperial Valley corridor suggests that a new line could be constructed on separate towers adjacent to the existing 500 kV Southwest Powerlink only for a short distance without violating applicable reliability criteria or requiring "Planned/Controlled" load drop in the event of a common mode

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[23] For example, Guide 4 of the CAISO’s Planning Standards do not allow more than 1400 MW of generation tripping as mitigation for a double contingency. Accordingly, if a case-specific analysis were to show that a simultaneous outage of two adjacent circuits was credible, and that required mitigation for such an outage involved tripping more than 1400 MW of generation, the planned adjacent transmission circuit would be in violation of applicable CAISO reliability criteria.

[24] See footnote “g” on Table I of the NERC/WECC Planning Standards.

[25] See, for example, Standard WECC-S2 and Guide WECC-G5 of the NERC/WECC Planning Standards and Risk Factors R1 through R11 of the WECC Reliability Subcommittee Common Corridor Task Force.

contingency event. If the two circuits were adjacent for longer distances, then it may be necessary to implement "Planned/Controlled" load drop in order to mitigate any unacceptable thermal line loadings or voltages that result because the distances that are practically available if the governing geography would make the facilities subject to common mode contingency events.

There have been 46 outages of the Southwest Powerlink in the last 15 years with 22 being fire-related within the San Diego County portion of the Southwest Powerlink. Since 1990, there have been two lightning strikes that tripped the Southwest Powerlink. These strikes also occurred on the San Diego County portion of the Southwest Powerlink.

Given the history of outages within the existing Southwest Powerlink corridor, and the reliability criteria exemption noted above, it is therefore acceptable to designate a San Diego-Imperial Valley corridor that includes the existing Southwest Powerlink within Imperial County (because the possibility of an outage of two adjacent circuits would likely be considered non-credible), but excludes the existing Southwest Powerlink corridor in San Diego County (because the possibility of an outage of two adjacent circuits would likely be considered credible).

With this important caveat, SDG&E believes the San Diego-Imperial Valley corridor should be broadly defined.

Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

The Department lists as an addition potential criterion for assessing the potential for designation as an NIETC that “alternative means of mitigating the need in question have been addressed sufficiently.”

SDG&E has explored alternatives to transmission into San Diego. SDG&E conducted a Transmission Comparison Study as an open stakeholder process and reported the results of that study to the collaborative regional planning meetings of the Southwest Transmission Expansion Plan (“STEP”). The Study reviewed a total of eighteen potential transmission corridor alternatives (many of which were alternatives linking Imperial Valley and San Diego). This assessment determined that among the transmission alternatives, projects through a San Diego-Imperial Valley corridor provided greater benefits.

Additionally, SDG&E explored in-area generation alternatives. This study concluded that the in-area generation alternatives are not economic when compared to the “no project” reference case and are clearly less economic than the option of a San Diego-Imperial Valley corridor. While the in-area combined cycle alternative reduces net energy costs for consumers within the CAISO controlled grid, it takes a much larger capital investment to achieve the same level of energy benefits as the preferred corridor option: $1.884 billion for the in-area combined cycle alternative versus $1.015 billion to $1.437 billion for the corridor option.

Not surprisingly, the in-area gas turbine alternative provides a lower level of energy benefits than does the in-area combined cycle alternative because of lower efficiency. The capital costs for the in-area gas turbine, while lower than the new combined cycle facilities, are nevertheless too high to overcome the efficiency advantage of the combined cycle facilities. Part of the reason that the capital costs of these options are not lower is that the in-area generation alternatives require significant transmission additions within the San Diego area to accommodate the maximum output of the generating facilities.

In addition, the in-area generation alternatives will not reduce RMR contract costs. The end result is that, when compared to the "no project" reference case, in-area the generation alternatives have benefit-to-cost ratios that range from 0.41/1 to 0.45/1. This analysis of the in-area generation alternatives does not include the capital costs that might be required on SDG&E's natural gas delivery network to accommodate maximum electric output of the new generating facilities. These additional capital costs are estimated at between $51 and $364 million depending on whether the new combined cycle generation elects interruptible or firm gas delivery service. Interruptible service would require 5.7 miles of new gas pipe. Firm service could require as much as 86 miles of new pipe. The additional capital costs also include on-site compression facilities. Including these additional costs in the economic analysis of the in-area generation alternatives would lower the overall benefit/cost ratios.

Economics aside, there are other reasons why in-area generation won't provide the long-term strategic benefits discussed in this filing. As a practical matter in-area generation that is effective in satisfying the CAISO's G-1/N-1 reliability criteria for the San Diego area transmission system must be fueled by natural gas. Recent events have demonstrated that the reliability and availability of natural gas supplies on a long-term basis are uncertain. It will be difficult to stabilize electricity prices for consumers within the San Diego area if the majority of in-area generation resources depend on the same volatile fuel source and if the ability of out-of-area suppliers to compete with in-area generation is constrained by import limitations.

Increasing import capability will allow a wider variety of resources to reach San Diego area consumers, thereby facilitating more competitive local and regional energy markets and minimizing any opportunity of local suppliers to exercise local market power. In contrast with the in-area gas-fired generation alternatives, transmission across the San Diego-Imperial Valley corridor affords cost-effective access to renewable resources that are mainly located in remote areas of the state and will connect to and traverse areas having the potential for significant levels of renewable resource development.

There are also practical limits to the amount of baseload generation that could be economically constructed within the San Diego basin. The WECC has established a south to north rating for the north of SONGS path ("Path 43") of 2,440 MW. When loads in the San Diego area are high, this limit is unlikely to be binding because a portion of the 2,150 MW output of the SONGS generating units will flow south into the San Diego area. The portion that flows north will be well below the 2,440 MW limit. However, when loads in the San Diego area are low, the output of in-area generation combined with imports into the San Diego area on the Imperial Valley-Miguel 500 kV line, and from Mexico on the 230 kV line, could easily exceed loads within the San Diego area and result in a northbound export on the five south of SONGS lines. These northbound exports would combine with the SONGS generation and easily consume all of the remaining south-to-north capability on the north of SONGS path. This situation would be aggravated with additional in-area baseload generation. When south to north flows reach the path rating, the CAISO will impose its congestion management protocols and it will be necessary to reduce the output of this baseload generation and/or curtail imports into the San Diego area from the desert Southwest and Mexico. This will cause local prices to drop. The combined effect of reduced output and lower prices during low load periods could compromise the economic viability of additional in-area baseload generation.

The Imperial Valley-San Diego Corridor Is Ripe For Urgent Consideration.

The Department's February, 2006 Notice (at 71 Fed. Reg. 5661) invites parties to identify "geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC". SDG&E submits that a San Diego-Imperial Valley corridor described above is ripe for such priority consideration for two reasons.

First, as demonstrated above, the San Diego region has a reliability need for a substantial transmission interconnection from the east of San Diego in 2010. For any designation of the necessary corridor through the Imperial Valley to support this national interest need, the designation should be made by the August 8, 2006 deadline provided by the Act. It will take at least three years to license and build the needed transmission interconnection, so the "backstop" federal authority provided in the Act must be in place by the end for this year to protect the national interest in the San Diego region as Congress intended. We submit that this is the sort of "acute" need contemplated by the Federal Register notice.

Second, the Department will not have to study the need for this corridor based on a blank slate. As described above, the need for a transmission interconnection to San Diego through Imperial Valley is amply documented in recent studies and regulatory findings, all of which resulted from transparent, multi-stakeholder processes. The Department will be armed with this trove of accessible and reliable information as it considers this designation, and is therefore well-positioned to give this designation priority consideration.

Conclusion

SDG&E appreciates the opportunity to comment. For the reasons described above, SDG&E asks that the Department consider, on a priority basis, designating a San Diego-

Imperial Valley corridor as an NIETC, and that this designation be published by the statutory deadline of August 8, 2006.

Respectfully submitted,

James P. Avery
Senior Vice President – Electric

JPA/rn

72. Donald Scherer, Received Sun 3/5/2006 10:17 PM

BACKGROUND

I am Donald Scherer, a member of the Ohio Wind Working Group (OWWG), and Vice-President of Green Energy Ohio (GEO), in Ohio the paramount not-for-profit voice for renewable energy alternatives. I am also Professor Emeritus at Bowling Green State University where I continue to help with energy policy matters. In that capacity I have worked with the Ohio Board of Regents (OBOR) and Renew Ohio on energy masterplans for Ohio public universities. Neither OWWG nor GEO nor OBOR has had the opportunity to meet in response US DOE's request for comments regarding Consideration for Transmission Conestion Study and Designation of National Interest Electric Transmission Corridors. Accordingly, there can be no response from any of them before the March 6 deadline. At the same time, my activity in the group, on the board and with OBOR and Renew Ohio staff provide a good bit of the background I bring to offering the following comment of my own regarding several issues that affect transmission reliability, interconnection and national security. Naturally, a much more fully detailed and documented statement will follow were any of these Ohio groups to develop the following comments into a NIETC proposal to US DOE.

GOALS

EFFICIENT TRANSMISSION WITHIN OHIO

Ohio has traditionally generated more power in southerly regions of the state and consumed more power in the north. With US DOE assistance, Ohio groups could investigate prospects for increasing efficiency and reducing costs of transmission within the state.

UNCONGESTED TRANSMISSION WITHIN OHIO

Through its Public Utilities Commission, Ohio has worked to identify areas of congestion within its transmission grid. An outcome of support from DOE could be a coordinated plan for alleviating transmission congestion, whether through new lines, managed routings or new sources of generation.

EFFICIENT AND RELIABLE TRANSMISSION BETWEEN ISOs.

Ohio is served by MISO and by PJM. It is in the national interest for communication between the units to ensure that should imbalance occur in either territory, the other provider could extend assistance without endangering service within its own territory. DOE support would facilitate ongoing efforts spurred on since the events of August 2004.

STUDY OF CONTRAST BETWEEN CLUSTERED AND DISTRIBUTED WIND TURBINES

The Ohio Board of Regents is issuing its call for all Ohio public institutions of higher learning to develop an energy master plan that includes consideration of use or ownership of electricity from renewable sources. With campuses in both ISOs and campuses both in and campuses far away from strong wind regimes (as indicated by the Ohio Department of Development's wind map), and in light of different regulations governing wind farms of various sizes and within various utility jurisdictions, study is appropriate to determine what wind farm locations would best serve Ohio's campuses and whether, in light of quickly and steeply rising electricity prices, which have recently imposed a $7.4M deficit on the University of Cincinnati, investment in wind turbine ownership would serve the interests of these institutions, with full examination of the implications for transmission and distribution across the state.

TRANSMISSION THROUGH OHIO TOWARDS NEW ENGLAND

National security interests are advanced as the United States moves to generate electricity from non-petroleum sources. In the west, Wyoming, Utah, Nevada and California have agreed to build a high-voltage transmission line from Wyoming, so rich in generation capacity, to California, which generates electricity from petroleum products. Ohio sits mid-way between the eastern plain states of Kansas, Nebraska, South Dakota and North Dakota and the New England states, which, like California, generate electricity from petroleum products.

American Electric Power, which serves many Ohio communities within MISO, is moving towards development of a high-voltage transmission line between Ohio and mid-Atlantic states. Conceivably, it could connect to similar lines connecting Kansas and Nebraska to Ohio.

Similarly, a line could be built from the Dakotas, stretching through northern Ohio to New England. An outcome of support from DOE could be an inter-state plan to develop new capacity for electric generation, whether from wind turbines, photovoltaics, clean coal or nuclear power, to alleviate congestion and provide for an efficient flow of electrons between the eastern plains and New England, with the goals of virtually eliminating petroleum as a source of New England electric generation, reducing the emission of pollutants in the production of electricity and improving national security both by distributing generation and by virtually eliminating the use of petroleum products for the generation of electricity east of the Mississippi.

If US DOE should choose to consider any such study Ohio, it would be appropriate for communication to go not only to me but also to Tom Maves, Renewable Energy Specialist at the Ohio Department of Development (tmaves@odod.state.oh.us), Bill Spratley (WSpratley@aol.com), Executive Director of GEO and ODOD's appointed manager of OWWG.

Donald Scherer
Environmental Ethicist
Professor Emeritus of Applied Philosophy
419 308 7312 CELL
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73. Seattle City Light, Received Mon 3/6/2006 4:06 PM

March 6, 2006

Secretary of Energy
Attn: Office of Electricity Delivery and Energy Reliability
EPAct 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Ave., SW
Washington, DC 20585

Via email: EPACT1221@hq.doe.gov

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

Dear Secretary Bodman:

The attached comments are submitted on behalf of the City of Seattle, by and through its City Light Department ("City Light") to express its views on the above mentioned Notice of Inquiry regarding National Interest Electric Transmission Corridors. City Light will continue to monitor developments related to this section of the Energy Policy Act of 2005 and respond accordingly.

Should you have questions regarding these comments, please contact: Marilynn Semro at (206) 386-4539 by phone or email Marilynn.Semro@seattle.gov.

Thank you for this opportunity to comment.

Sincerely,

William A. Gaines
Power Supply Officer

ADM04.66

Seattle City Light Comments to the U.S. Department of Energy

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

Pursuant to the Notice of Inquiry issued by the Department of Energy ("DOE") on February 2, 2006 ("NOI"), the City of Seattle, by and through its City Light Department ("City Light"), hereby submits comments for consideration by DOE in its study of congestion and development of criteria for designating National Interest Electric Transmission Corridors (NIETCs).[1] DOE should give careful consideration to many criteria, including a range of congestion metrics, prior to designation of NIETCs. While other load-serving utilities may share similar concerns, City Light would like to emphasize the following points relative to NIETC designation:

1. Transmission dependent utilities like City Light, rely on transmission for power delivery from distant generating resources—timely resolution of transmission issues is essential to the operation of reliable and economical transmission systems.

2. Curtailments are a clear indication of existing congestion. Criteria and metrics should consider both physical and contractual forms of congestion that occur in actual operations as well as simulated studies.

3. Exercise of FERC backstop authority for siting and permitting electric transmission facilities should be supported by rigorous analysis and be conducted in close consultation with affected state, provincial, tribal and local agencies to ensure timely action.

Background

City Light provides retail electrical service to over 350,000 residential, commercial and industrial customers in the City of Seattle, Washington and nearby suburbs, with sales of approximately 9,000,000 MWh per year. City Light relies on hydroelectric resources for nearly 95% of energy delivered to load. Inspection of a transmission map of the Western Interconnect reveals that the geographically compact topology of the City Light transmission and distribution system cannot provide commercially valuable long-distance transmission wheeling service to other regional electric utilities and market participants. Because of this limitation, City Light urges DOE to adopt an objective, functional approach in its implementation of the Section 1221 provisions of the Energy Policy Act of 2005 ("EPAct").

In common utility parlance, City Light is a transmission dependent utility or TDU. Over 60% of its generating resources are not directly connected to the City Light transmission and distribution system and, instead, are delivered primarily by the Bonneville Power Administration ("BPA") under BPA's Point-to-Point ("PTP") Open Access Transmission Tariff ("OATT"). Third party transmission service is therefore essential to enable City Light to provide reliable, low-cost

[1] The NOI is published at Federal Register Volume 71, No. 22, at 5660.

power to consumers. Seattle's interest in this NOI stems from its current exposure to transmission congestion and the virtual certainty that it will need to acquire firm, long-distance transmission service to integrate new generating resources into its resource portfolio as load grows, existing purchased power and transmission contracts expire, and plant retirements occur. Recent experience with wind resource acquisition foreshadows transmission acquisition challenges in the future.

Key Terms

Section I.C. of the NOI captures some Key Terms that are relevant to City Light's situation: geographic areas, needs and corridors. Congestion of the transmission system is a function of geography and transmission network topology—two characteristics that are often codependent. In the context of needs, City Light is a load center that relies on power produced by distant generators.[2] This geographic separation increases both the cost and reliability risk of a generating resource. Topology of the electrical network can mitigate the reliability risk by design.[3] In the Western Interconnect, "rated paths" define cutplanes, electrical boundaries that typically separate geographic areas within the electrical network.[4] Existing transmission corridors generally cross perpendicular to the cutplanes and affect the transfer capability of the path. It is expected that new corridors may also cross defined cutplanes, but in many instances a limiting facility may be located within a geographic area and not an element of the rated path. For example, the operating limit of a path may be based on the predicted loading of a downstream facility, such as a substation transformer, in the event of a contingency (loss) of one of the path elements. Thus designation of corridors that affect transfer limits may not be limited to hypothetical lines that connect to geographic areas separated by a cutplane. This characteristic argues in favor of adopting a broader definition of the term "corridor" which includes consideration of the electrical network topology.

Congestion Study

As noted in the NOI, congestion in the Western Interconnect has been the topic of numerous, recent studies that are the product of many person-years of effort. City Light concurs with DOE's plan to use these existing efforts as a starting point for its congestion study. In the comments below, City Light points to additional documented examples of congestion that merit inclusion in the congestion study.

City Light Experiences both Physical and Contractual Congestion

[2] The NOI at I.C. characterizes the load centers as distant. From City Light's perspective, the generators are distant.

[3] The transmission system is designed to perform without loss of load under single, and in some cases, multiple critical contingencies.

[4] There are many terms that are related to or synonymous with "rated path". These include: cutplane, interface and flowgate. A cutplane may consist of one or more transmission branch elements that, in aggregate, set a flow-based limit on the transmission system.

Congestion costs are primarily an economic concern since the interconnected network is nominally designed to deliver power to all loads, albeit under generation dispatch that may not reflect the individual operating objectives of load serving entities (LSE) and other market participants in the region. Reliability risk, while less common, may result from unanticipated operating conditions that have not been adequately studied. As illustrated by the August 14, 2003, blackout in the Midwest, the potential costs associated with reliability risks are immense. From the perspective of a load-serving entity certain congestion management measures implemented by transmission providers, such as real-time curtailments, represent distinct reliability risks to consumers who may lose power in the event that a source of replacement power cannot be acquired timely by the LSE.

Because no formal distinction between "physical" and "contractual" congestion was provided in the NOI, City Light proposes to distinguish the terms as follows:

- Physical congestion occurs when transmission facilities *reach* operating limits that constrain further loading in either actual or simulated operating states. During actual operations, dispatcher action typically takes the form of real-time curtailments. In simulations, physical congestion occurs when a path loading reaches its operating transfer capability (OTC) limit during specific time periods in the simulation. In production cost simulations these "binding constraints" cause marginal costs to diverge on a nodal or zonal basis.

- Contractual congestion occurs when commercial transmission service is not available or existing rights are diminished. One example of contractual congestion occurs when transmission service cannot be acquired on an OASIS due to lack of available transmission capacity (ATC). The second type of contractual congestion is the diminution of a contractual transmission right by the transmission provider. This may occur during periods where transmission circuits are de-energized for maintenance, or if the path becomes oversubscribed, load patterns change, or parallel flows affect multiple transmission provider systems. In some instances of contractual congestion, the actual path loading data may indicate that the path is typically operated substantially below its limit over many time periods. This may result from diurnal variations in loading, transmission reserve margin (TRM) requirements, or an inability to accurately assess physical flow impacts of contract path transmission services.

City Light Examples of Physical Congestion

During the past six years, City Light has responded to hundreds of requests by multiple control area dispatchers to curtail thousands of hourly scheduled wholesale power transactions. In general, curtailment requests occurred when actual path loadings approached the OTC limits and scheduled transactions affecting the overloaded path were identified for curtailment.[5] In most instances, Seattle was able to either redispatch its own generating units, or purchase replacement power from sources that did not contribute to adverse loading of the limiting facilities. The cost of these actions is not known with certainty, but the resulting change in dispatch certainly affected City Light's planned operating objectives and cost of power delivered during the periods of curtailment. In one instance, the requested curtailment of transactions could not be implemented without shedding load in Seattle and the requested curtailments were rejected by City Light dispatchers. Broad simulations used for grid planning are not well suited to predict incidents such as those described because simulations rely on idealized assumptions regarding unit commitment, scheduled interchange, generator dispatch, bus loadings, operating environment, transmission facility state, and other real world variables that affect actual operational outcomes.

The curtailments having the most direct effect on City Light are referred to as Puget Sound Area Northern Intertie (PSANI) curtailments.[6] In response to these curtailments, a study group was formed to evaluate near-term and long-term solutions that would reduce curtailment risk.[7] Simulation models tailored specifically for the analyses were developed. From this study, three portfolios of solutions were identified, and while construction of new transmission facilities is a component of these portfolios, line uprates (e.g. reconductoring), protection scheme modifications (RAS changes), and other topology changes that do not require new transmission rights-of-way are also key components of these solutions. Most of the identified lower-cost solutions have been implemented.

In May-July 2001 substantial curtailments of schedules impacting the West of Hatwai cutplane resulted in curtailment of hundreds of MW relied on by City Light and other utilities.[8] During this period, which coincided with the 2000-2001 power crisis in the west, the replacement energy during these curtailments cost City Light millions of dollars. In 2004, the Bell-Coulee 500 kV line was energized thereby increasing the West of Hatwai path rating by over 2000 MW (compared with the 2001 rating) and providing substantial congestion relief.[9] In spite of this improvement, transmission maintenance outages have derated the capacity of this path thereby increasing City Light power costs.

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[5] The BPA procedure is similar to the NERC TLR procedure used in the eastern interconnection. Grid sensitivity factors are used to identify and rank transactions that relieve loading on specific transmission facilities.

[6] See BPA-TBL Operating Procedure for Puget Sound Area Northern Intertie (PSANI) Curtailments effective 11/15/05.

[7] See the Puget Sound Area Upgrade Study Report published by NWPP/NTAC. November 2004. Reference to this study is included in Appendix A of the NOI.

[8] See discussion of System Need in Upgrading the Capacity and Reliability of the BPA Transmission System: Report of the Infrastructure Technical Review Committee at page 6. August 30, 2001.

[9] Ibid. Page D-32.

This illustrates an important principle that transmission margins must be sufficient to reliably deliver economical power, while at the same time accommodate normal system maintenance activities. Congestion study simulations should be designed to estimate the impact of transmission maintenance to ensure that outage costs are a component the estimated congestion cost.

These are a few examples of real-world, physical congestion that have affected City Light in recent years. Regional solutions have been developed and implemented where possible. What is important to note is that curtailments are often indicative of congestion problems that are not apparent in interconnection-wide planning studies. Therefore, regional entities assisting DOE with congestion studies should monitor curtailment incidents as indicators of transmission system congestion.

Metrics for this type of congestion are likely limited to incidence rates because customers rarely attempt to calculate the cost of curtailments. The process involves estimating an alternative economic outcome under the assumption that no curtailment took place, and comparing this with the actual outcome resulting from the curtailment. Utility staffs seldom have the time during curtailments to make such estimates. For this reason, developing a cost metric for congestion caused by curtailments is not considered feasible.

City Light Examples of Contractual Congestion

Contractual congestion has affected City Light in a few different ways in recent years. Here are a few examples of instances where contractual rights have been diminished or paths are substantially overcommitted under existing contracts.

- As a participant in the Third AC Intertie (Third AC), City Light was initially entitled to 160 MW of north-to-south transmission capacity on the California-Oregon Intertie (COI).[10] Following the 1996 disturbances in the Western Interconnection, the rating of the COI has been limited by nomograms that reduce the nominal operating limit of 4800 MW (north to south) by as much as 40% based on flows across other paths in the region.[11] Given the risk of curtailment of scheduled transactions on COI, City Light limits use of its contractual rights to no more than 120 MW in most hours. Curtailed schedules can result in congestion costs that must be paid by the seller that are analogous to replacement power costs.

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[10] The California-Oregon Intertie is WECC Path 66 which consists of the three 500 kV alternating current (AC) circuits that connect substations in Oregon and Northern California. The Third AC project is called the California Oregon Transmission Project (COTP) by the California participants. It connects the Captain Jack and Olinda substations.

[11] See http://www.transmission.bpa.gov/oasis/bpat/outages/oasiscontent.shtm under COI Constraints for a current listing of the derated path capacity.

- Path capacities are frequently derated for reasons ranging from transmission outages to expected nomogram conditions. The current practice of BPA-TBL is to post an allocation percentage that will be applied to transmission schedules utilizing a constrained path. These preschedule limits affect the ability of transmission contract holders to use the full contract capacity of point-to-point (PTP) transmission rights.[12] Any transactions that are affected by posted preschedule limits are typically booked-out at a loss equal to the basis difference in power purchase costs at the POR and POD.

- Most new power supply resources will require that City Light purchase additional transmission service from a third party provider such as BPA-TBL. Recent experience illustrates the futility of attempting to acquire long-term transmission for new resources. In April of 2001, City Light made three 50 MW requests to TBL for transmission across the Cascade mountain range from Vantage (Mid-C) to Seattle for delivery of the Stateline Wind resource. City Light requested start of service on 1/1/2002 and termination on 1/1/2022. In its response to City Light, TBL stated that over 1000 MW of transmission requests occupied the OASIS transmission queue in front of the City Light request, and that the sum of the queued requests far exceeded the ATC of the affected transmission paths. As a consequence, the request could not be accommodated, and City Light withdrew the request. Currently, City Light has no firm BPA transmission service from Mid-C to Seattle for its 175 MW share of the Stateline Wind generating resource. It relies on an exchange agreement and short-term, non-firm or surplus long-term firm transmission capacity rights to deliver the power to Seattle. The fact that physical capacity frequently exists in the short-term operating horizon suggests that this form of contractual congestion is primarily occurring in the long-term transmission contract queue.

  In 2012, the exchange agreement terminates. City Light will be responsible for securing transmission for up to 175 MW every hour from Mid-C to Seattle. Because

[12] See http://www.transmission.bpa.gov/OASIS/BPAT/outages/curtailments.htm for a list of current path capacity allocations.

a 175 MW intermittent generating project cannot justify building transmission across the Cascades, contractual mechanisms that are not susceptible to contractual congestion will be needed to integrate wind energy and other renewable resources. The inability of customers to acquire long-term firm transmission rights is illustrated by the BPA-TBL long-term transmission service queue at http://www.transmission.bpa.gov/OASIS/BPAT/oasis_html/ltreq.htm. It is not uncommon for requests to languish in this queue for years before being denied for lack of capacity, or withdrawn by the customer.

Congestion Impacts on Resource Planning

The examples provided above are descriptive of transmission congestion that has affected City Light operational planning efforts, real-time dispatch and settlements. While the distinct impacts can be described, the economic costs are not known, and as sunk costs, have the limited value of informing processes such as resource planning decisions at City Light and may be relevant to DOE's congestion study..

It is highly probable that new generating resources will be distant and will rely on transmission service that requires construction of new facilities. Comparable to the experience with Stateline Wind in 2001, current integrated resource planning (IRP) efforts are frustrated by uncertainties regarding the cost and availability of long-term firm transmission service for planned resources. The current approach of contract-path requests and incremental pricing fails to recognize the network characteristics of the transmission system. City Light observes with greater frequency, instances where resource plans of one entity have network impacts on the plans of other entities. In addition, the "lumpiness" of large transmission projects is incompatible with piecemeal approaches to transmission service. Work being done by the subregional planning groups and WECC to provide an interconnection-wide reference case production cost simulation database for evaluating resource economics will provide valuable information for screening the economics of new transmission on a systematic basis.[13]

Siting new generation close to load is offered as strategy which eliminates the risk and transactional cost of securing long-term firm transmission service. However, this strategy must also consider that the natural gas transmission system is also limited in its capacity and penetration into areas where facilities can be located. Environmental constraints, such as emission permits constrain potential locations for distributed generating facilities. In situations where a new powerplant is located in an area where generation resources are already adequate, transmission service to consumers in other markets must be feasible.

[13] WECC is in the process of seating a Transmission Expansion Planning Policy Committee (TEPPC) that will oversee the maintenance and distribution of the reference database.

For natural gas-fired generation, gas pipelines are an external network that impacts the reliability and economics of the electric power network. Any congestion study that relies on gas-fired generation to relieve electric transmission congestion must also consider potential gas pipeline congestion.

Consultation with State, Provincial, Tribal and Local Entities

The apparent intent of EPAct 1221 is to streamline the processes of siting and permitting electric transmission facilities—functions of state and local governments in most jurisdictions—by providing a Federal backstop that can advance projects that would otherwise stall. While the broad objectives of the governmental entities may fall into alignment under the considerations provided in subsection 216(a)(4), the means for achieving these objectives must be largely driven by consensus among the affected parties on a well-defined designation criteria. Consultation and coordination with affected States begins with the congestion study[14] and continues through Federal Authorization process.[15] The congestion study work must also be conducted in consultation with the *regional entity* having the authority to enforce reliability standards in the region.[16] City Light is encouraged that DOE has indicated its preference that the congestion study and criteria development be conducted through an open and transparent process where all stakeholders are invited to participate. While there is currently no formal delegation of enforcement authority to WECC, the efforts of WECC to facilitate congestion study activities through the Western Congestion Assessment Task Force (WCATF) are consistent with these statutory requirements. As an open, balanced, stakeholder process, the WCATF is able to actively consider the interests of state, provincial, tribal and local agencies.

As the process moves forward toward designation of specific corridors, state and local regulations will continue to govern environmental compliance requirements. By working in close consultation and coordination with the agencies and officials responsible for compliance, DOE will mitigate the potential for disputes during critical path activities.

Lead-time for transmission projects must match the timeline for new power resource commissioning or project feasibility may be adversely affected. Capturing the economic benefits and other objectives will require timely completion of projects under Federal authorizations.

Local Distribution versus Regional Transmission Facilities

City Light expects that the corridors designated, and the facilities for which project proponents seek permits under such designations, will be those which the Federal Energy Regulatory Commission (FERC) has jurisdiction. To this point, City Light recommends that DOE adopt a functional test that takes into account technical characteristics of facilities used for regional transmission service when considering its corridor designation criteria. Use of functional criteria

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14 Sec. 216(a)(1) and 216(a)(2)

15 Sec. 216(h)

16 Sec. 216(a)(3) referring to Sec. 215(e)(4)

such as the FERC 7-Factor Test would provide a basis for identifying types of facilities subject to designation.[17]

Comments on DOE Draft Criteria

Draft Criterion 1: Action is needed to maintain high reliability

As described above, curtailments are invoked to restore the system to a reliable operating state and are thus a strong indicator of both congestion and reliability problems. In support of changes to flow-based transaction scheduling, BPA and other utilities in the Northwest have cited instances where curtailments have been ineffective for congestion relief.[18] In addition to the criteria included in the NOI, DOE should consider the incidence and severity of curtailment actions in its criteria for evaluating NIETC designations.

As mentioned above, planning criteria may be satisfied under an idealized set of assumptions that differ from actual operating conditions. A system model that successfully passes all planning criteria may continue to exhibit operating limit violations under the stress of actual transactions that are simultaneously possible under existing transmission contracts and commercial transactions.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers

The production cost simulations being conducted regionally for the congestion study will indicate the theoretical extents to which higher priced generation can be displaced by lower cost resources. For base and change case simulations, project specific results can be calculated and compared using a common reference case model. Because each project will incrementally affect the economic value of other projects, it may be necessary to screen projects iteratively and consider the impact of project timelines. Furthermore, the order in which projects are implemented will affect the relative benefits of each project, including any non-transmission options being considered.

Long-term integrated resource plans are expected to identify economical resource options that are contingent upon sufficient long-distance transmission with a higher degree of cost certainty, timeliness and service availability than what is offered today. To provide these qualities, a proposed project must be planned within a regional framework which captures the network characteristics of transmission and resource options.

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17 The FERC 7-Factor Test can be found at 75 FERC 61,080. Order No. 888. Mimeo page 401 - 402.

18 See Decision Document describing BPA-TBL Constraint Schedule Management (CSM) proposal. http://www.transmission.bpa.gov/Business/Customer_Forums_and_Feedback/scheduling_automation/documents/CSM_Decision_Document_1_01-17-2006.pdf.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Diversity in resources available to the system for dispatch is predicated on the assumption that surpluses and deficits can be traded efficiently throughout the system. However, actual system operations do not always replicate the optimal dispatch algorithms used in modeling software which may predict efficient outcomes from system-wide resource diversity. For example, the question of whether resource owners in the Northwest are able to efficiently trade hydroelectric power with generators in other regions hinges as much on transmission contract rights and ATC as it does on physical corridor capacity.

When transmission capacity is limited, areas may be dependent on a subset of generators sometimes described as "reliability-must-run" (RMR) plants for the next increment of supply. When this occurs for only a few hours per year, it may be most economical to simply dispatch the higher cost RMR plants rather than constructing new transmission. A multi-year time-series analysis will likely be required to compare the economics of RMR plant dispatch with new transmission construction. Part and parcel to this analysis may be consideration of market power concentration depending on ownership of the RMR plants.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States

For the Northwest region, the existing interdependence with Canadian entities must be recognized. This is primarily a function of the highly coordinated operation of hydroelectric facilities including the Columbia River system. Such arrangements should not be viewed as contrary to national energy policy.

That said, Washington and many other states are likely to enact renewable portfolio standards (RPS) which will require utilities to obtain a defined percentage of their power from renewable resources by a certain target date. While such a requirement does not currently exist in Washington State, it may in the near future.[19] It is unlikely that sufficient renewable resources to meet the RPS requirements can be delivered to the major load centers without substantial transmission additions.

Draft Criterion 5: Targeted actions in the area would further national energy policy

The breadth of "national energy policy" may render this criterion too general for use in the designation process.

[19] See http://www.energysecuritynow.org/

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts

In addition to being case-specific, DOE action on this criterion may warrant consideration of Critical Energy Infrastructure Information (CEII) that is coordinated through FERC.[20]

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions

Based on the activities of the WCATF, DOE will be provided multiple studies that examine congestion on a finite set of rated paths in the Western Interconnection. These studies examine congestion from different perspectives, each of which contributes to combined congestion profile for each path. The path utilization studies by SSG-WI provide indications whether actual use of constrained facilities supports designation. The SSG-WI production cost simulations augment the utilization profile by estimating path utilization in a future period, albeit subject to assumptions built into a large number of variables.

While it may not be possible in the first year of the triennial congestion studies, future efforts should endeavor to qualify assumptions with a confidence interval statistic, and results should fall within ranges based on the model sensitivity to the assumptions. The congestion studies should evaluate how modeling uncertainties were handled using the following set of questions.

1. Describe the statistical validity of the assumptions used in the study. For example, are load forecasts expected to fall within a specific confidence interval?

2. Was the sensitivity of the result tested against a range of input assumptions or were the assumed values fixed (e.g. load, hydro generation, etc.)?

3. Describe the impact on the results relative to the range of input assumptions used.

Many of the studies done thus far have effectively used ranges of fuel prices, load forecasts, hydro production, wind production, etc. to test the sensitivity of the result (e.g.

[20] See http://www.ferc.gov/legal/ceii-foia/ceii.asp.

production cost) to these variables. Commercially available modeling tools are capable of simulating system performance under ranges of input assumptions.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently

Non-wires solutions (NWS) that consider alternatives to transmission system expansion are being considered in the Northwest.[21] For generation-based alternatives, the plant assumes a reliability-must-run status if it is going to effectively relieve transmission congestion (see comments under Draft Criterion 3 above). Non-generation alternatives, including load management, must be dispatchable with a high degree of certainty that loads will reduce timely in accordance with dispatcher instructions.

(1) Are there other criteria or considerations that the Department should consider in making an NIETC designation?

Assuming that the designation has been requested by a sponsoring entity, DOE should ascertain whether the sponsor is supporting the request with information derived from an open, regional expansion planning process or an information source that has been subject to regional peer review processes. For example, WECC has now assumed stewardship of the SSG-WI expansion planning reference cases which capture the best available information for the interconnection. Use of these reference cases by sponsors provides consistent bases for assumptions which drive the study results. Any alterations to the reference case assumptions should be explicitly described by the sponsors.

(2) Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

City Light suggests that the draft criteria be ranked in the following order of importance:

Draft Criterion 1: Action is needed to maintain high reliability

Generally this criterion should not be invoked because transmission providers are obligated to design and maintain their transmission systems to comply with reliability standards. Nevertheless, having been confronted with transmission service curtailment orders, City Light can envision a need for transmission facilities that address an impending inability to meet reliability standards. This was the case when BPA curtailed

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[21] See BPA Non-Wires Solutions Round Table information at http://www.transmission.bpa.gov/PlanProj/Non-Wires_Round_Table/

schedules affecting the West of Hatwai path which resulted in construction of the Bell-Coulee 500 kV line. Similar needs were present when BPA determined that it needed to conduct the Kangley-Echo Lake 500 kV line in 2003 to meet contractual obligations to Puget Sound area utilities and Canadian treaty obligations.

Because the economic impact of system disturbances far exceeds other plausible economic impacts of dispatch order and replacement power costs, this criteria must be paramount. Care must be taken to ensure that the reliability need is authentic.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers

While the transmission system may be capable of reliably serving all loads, there may be substantial time periods where the economic dispatch objectives of control areas are not being met. When applying this criterion, an applicant should be able to demonstrate the production cost savings potential of relieve transmission congestion. A tangible cost savings estimate should be given greater weight than qualitative criteria.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

In the process of running its congestion studies, DOE should consider the potential economic results of fuel price variations and hydro supply scenarios. Congestion is sensitive to these variables and the estimated economic benefits (Criterion 2) will reflect this sensitivity.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently

It is often the case that these alternatives are components of a utility's overall resource plan. For example, conservation may be accounted for in load forecasts. The congestion study framework should be designed to provide a clear means for considering transmission alternatives. As was found in the case of the Kangley-Echo Lake project, cost effective non-wires solutions were possible, but they could not provide sufficient transmission loading relief within the timeframe required. Nevertheless, the report on this project provides excellent examples of how to quantify non-wires alternatives.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions

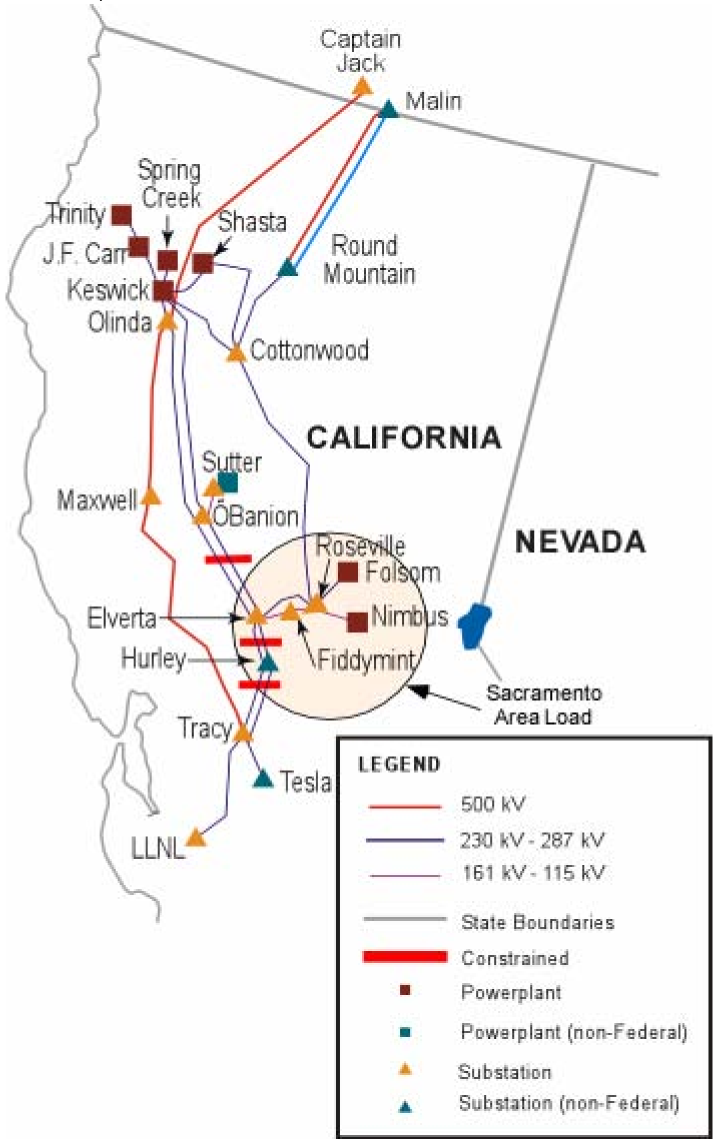
This criterion is qualitative in character and should thus be considered in conjunction with the quantitative measures. Studies that present results in reasonable ranges based on sensitivity to variables should receive greater weight than those based on a rigid set of assumptions applied to variables that are inherently uncertain. Fuel price uncertainty is probably the most obvious reason why this criterion is important.

74. Sierra Nevada Region of the Western Area Power Administration, Received Mon 3/6/2006 12:06 PM

March 1st, 06

Sacramento Area Transmission Reliability

Western Area Power Administration's (Western) mission is to market and deliver, cost-based hydroelectric power and related services. One of Western's strategic plan goals is to ensure reliability and availability of Western's transmission system. In addition to delivering the Federal hydropower to its preference customers Western also provides transmission service to its customers and others under its Open Access Transmission Tariff. Western's 230-kV transmission lines in the Sacramento, California, area have reached their maximum transfer capability limits for serving existing transmission customer needs. In fact, since late 1990s, the area load serving entities (LSEs) have installed an automatic load shedding scheme for managing the local area transmission reliability. Western has no end-use load connected to its transmission in the Sacramento area.

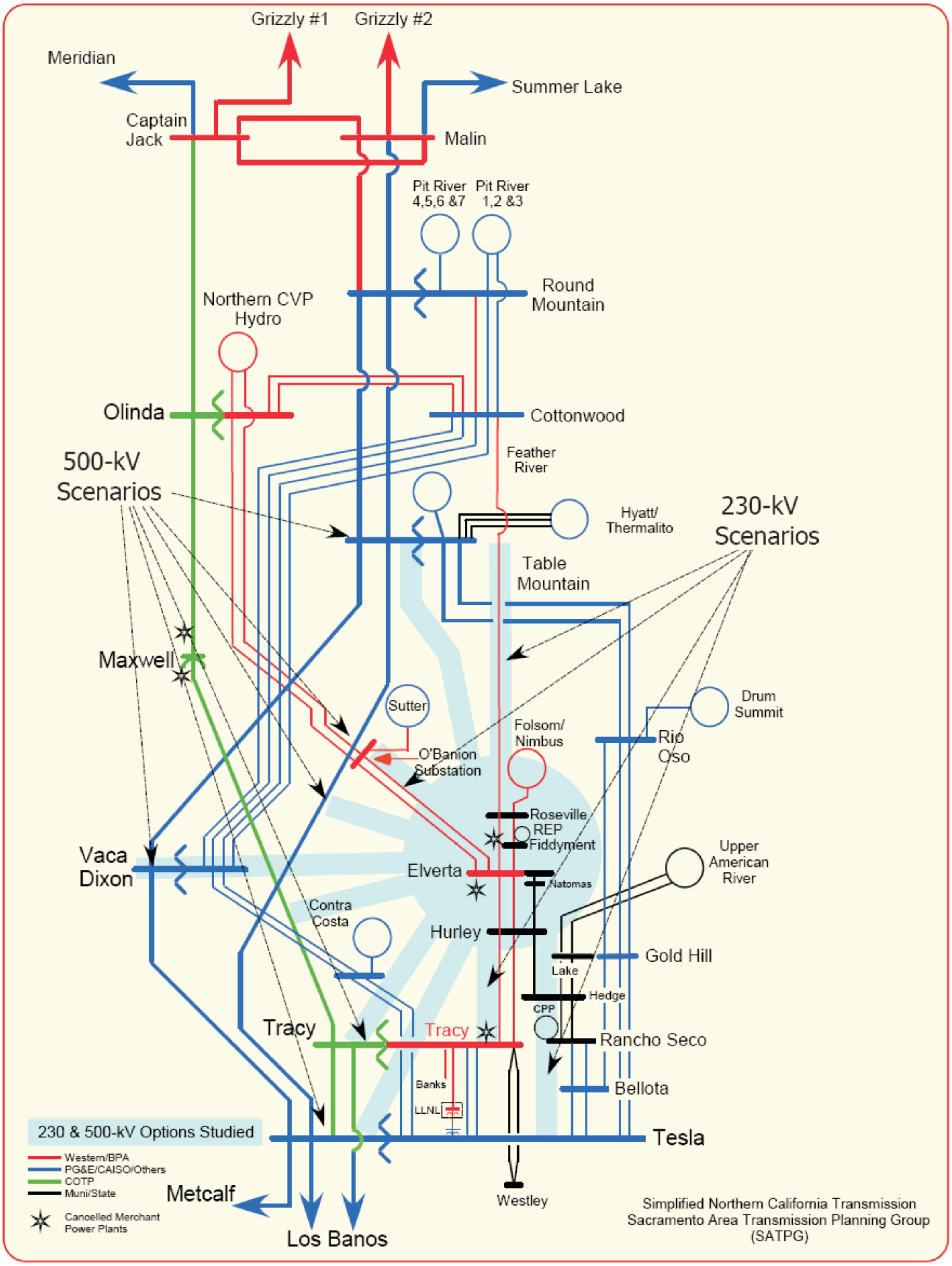


This transmission need has been identified since mid-1990 through a well coordinated and extensive transmission planning studies that included all area utilities, new merchant power plant developers and the California ISO. (See attached map). The above Western-led transmission planning effort attracted several power plant developers that filed Application For Certification (AFC) to constructing several power plants totaling up to 2500 MW of new generation. This would have eliminated the need for major transmission line additions. The local area opposition, environmental concerns such as air and water availability, natural gas supply/price and the 2000-2001 energy crises led to abandonment of these power plant developments. No new generation is planned for serving this local area reliability need therefore, a serious commitment in transmission and/or interconnection is necessary to mitigate this reliability and operational issues.

Like many other metropolitan load centers, Western’s 230-kV transmission network is a key bridge for bringing the remote generation to load centers. The area load growth remains steady about 100-150 MW a year and if no new commitment is made for a strong transmission addition such as a 500-kV interconnection the future reliability and security of the interconnected transmission system may be compromised. The coordinated transmission planning effort of the past 10 years has already identified several transmission lines/corridors that are necessary to maintain the interconnected transmission system reliability, reduce congestion while supporting the economic growth, fuel and resource diversity and integrate renewable resources into the local area LSEs resource portfolio. Western's transmission system in the area can no longer support the existing area load and Western may not be able to meet its existing transmission obligations soon without a commitment for new transmission.

Even though Western is not responsible for its customer load growth, Western has no funding mechanism to mitigate the transmission system reliability that is a direct result of parallel flow or flow encroachment on its system. During the past 10 years Western has evaluated many financing options with others. However since the reliability investment in transmission network does not yield any assignable transfer capability, it is difficult to attract new investment in the necessary transmission. Western has also encouraged many merchant power plant developers to locate their projects in the area in order to avoid constructing new transmission lines, but no commitment has been made as of this date. Therefore, automatic generation and load curtailment during the summer peak load periods remains as the only option for maintaining the interconnected system reliability.

Please see attached map for transmission corridors noted above. Route specific or project specific information could be provided at a later date.



75. Sierra Pacific Power and Nevada Power Company, Received Fri 3/3/2006 8:49 PM

Introduction

Sierra Pacific Resources is the investor-owned holding company for Sierra Pacific Power Company and Nevada Power Company ("The Companies"). The Companies provide electricity to over 1 million electric customers throughout Nevada and in northeastern California. Among the many communities served are Las Vegas, Reno-Sparks, Henderson, Carson City, Elko and South Lake Tahoe. Sierra Pacific Power also provides natural gas to over 120,000 customers in the Reno-Sparks area. The Companies have two distinct Control Areas with a combined service territory of 54,500 square miles – approximately the size of the State of New York. Of the total 109,788 square miles of geographic area within the State of Nevada, 82.9% is federally controlled.[1]

In the last 7 years, the Companies have constructed 100 miles of 230 kV, 350 Miles of 345 kV, and 40 Miles of 500 kV transmission lines. There are an additional 30 miles of 345 kV (2008) and 60 miles of 500 kV (2007) approved by the Public Utilities Commission of Nevada (the "PUCN"). The Companies have built interconnections for ~4000 MW of IPP generation in the last five years. These numbers reflect a doubling of the transmission capacity and a ~71% increase in total interconnected generation. An additional 1280 MW of generation is scheduled for commercial operation in the second quarter of 2006, raising the generation increase to 97%.

The Companies are highly versed in Federal, State and Local siting processes and greatly appreciate this opportunity to provide comments on Department of Energy's (DOE) plans for an electricity transmission congestion study and possible designation of National

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[1] Source: USDI. Bureau of Land Management. Public Land Statistics 1999. Washington, D.C. March 2000

Interest Electric Transmission Corridors (‘‘NIETCs’’) in a report based on the study pursuant to section 1221(a) of the Energy Policy Act of 2005.

Background

In exercising the DOE Secretary’s authority to designate NIETCs, subsection 216(a)(4) states that the Secretary may consider, among other things, whether—

> (A) The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
>
> (B)(i) The economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and (ii) A diversification of supply is warranted;
>
> (C) The energy independence of the United States would be served by the designation;
>
> (D) The designation would be in the interest of national energy policy;
>
> (E) The designation would enhance national defense and homeland security.

If the Secretary designates an area ‘‘experiencing electric energy transmission capacity constraints or congestion’’ as an NIETC, subsection 216(b) of the FPA authorizes the Federal Energy Regulatory Commission (‘‘FERC’’) to issue permits for the ‘‘construction and modification of electric transmission’’ in the NIETC, provided that FERC finds that certain conditions have been met.

The Companies’ comments are divided into two major sections. These sections are 1) Congestion study comments and 2) NIETC comments.

Congestion Study Comments

The DOE specifically requested comments on the following questions:

> (1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

(3) In addition to the studies that the DOE currently has under review, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

All congestion can have impacts on customers. The benefit of relieving all types (persistent, dynamic, physical, and contractual) of congestion should be evaluated. For example, relieving persistent congestion could provide more hours of benefit while relieving dynamic congestion could provide more economic benefits. The economic benefit analysis should be based on projected utilization with projected transmission and generation included and bus production costs analysis. Reliability benefits should also be considered which can translate into economic benefits by avoiding extended outages or cascading system problems. If a distinction is made for the type of congestion, that distinction may not be useful for the purpose of prioritizing NIETC.

Criteria for using existing studies in the DOE study should be as follows;

1. **The existing studies are less in age than the cycle time of the DOE studies, 3 years. For the first study, 1/1/2001 is an acceptable cut off date.**
2. **The existing studies must be regional in scope. Often only sub-regional evaluation are completed which may exclude impacts in other parts of the region.**
3. **Within the western interface, the existing studies should include all of the facilities in the WECC major facility addition list. This is the problem with most, if not all, existing studies that they go out-of-date very quickly.**
4. **Fuel and transportation costs are still reasonable.**

The study should also evaluate, as a sensitivity, the potential impact on the BPC of new transmission options using NIETC, existing corridors, and or corridors established by section 368 of the Energy Policy Act of 2005.

NIETC Comments

The Department also invited comment on what criteria it should use in evaluating the suitability of geographic areas for NIETC status. The provided preliminary criteria that might be used in evaluating these considerations for NIETC evaluation are listed below.

Draft Criterion 1: Action is needed to maintain high reliability.

Metrics: A definition of the affected area in terms of load, population, and demand growth; a description of the expected degree of improvement in reliability associated with a proposed project; if appropriate, identification existing or projected violations of NERC Planning Criteria TPL–001, –002, –003, or –004.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

Metrics: Estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets. A demonstration of expected reduction in end-market concentration and how economic benefits for consumers would be affected.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Metrics: Areas that are dependent on ‘‘reliability-must-run’’ plants would benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both. Similarly, areas that are highly dependent on specific generation fuels could economically benefit from supply diversification. Estimate the likely magnitude of such benefits, showing calculations.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Metrics: Provide calculations showing how specific actions aided by designation as an NIETC would increase fuel diversity, improve domestic fuel independence, or reduce dependence on energy imports. Quantify these impacts, including possible impacts on U.S. energy markets.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

Metrics: For this criterion, relevant metrics would be case-specific.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies. Other things being equal, arguably the

Department should be more inclined to designate NIETCs where there are existing needs instead of projected needs, particularly if those future needs rest upon relatively uncertain assumptions and contingencies. On the other hand, timely construction of transmission facilities often requires lead-times of five years or more, and all projections are based on assumptions and involve some degree of uncertainty. The challenge here is to determine what level of confidence can be reasonably imputed to specific projections.

Metrics: What metrics would be suitable for gauging such uncertainties?

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently. Recognizing the value of
transmission alternatives, the Department wishes to avoid designating
NIETCs in ways that might unduly affect stakeholders' decisions about how to meet specific needs, confer advantage on transmission options as opposed to non-wires options or generation options, or favor some transmission options over others. At the same time, the Department is mindful that even taking these other factors into account transmission expansion is clearly needed in many areas, and that transmission expansion is itself a protracted process. The Department seeks comments on how it should balance these concerns.

In general, we agree with the draft criteria. Reliability is of high concern, a requirement, and must be maintained to the appropriate level. Not all areas have the same level of reliability due to the nature of the loads, urban, industrial, or rural. Line construction must be allowed to maintain an area's reliability. The DOE should rely on the judgment of the entities that have the responsibility to maintain system reliability for this criterion.

Economics evaluations should include all the relative cost factors and options including rail, pipes, and wires.

The one criterion that may need the most change is #7. This NIETC evaluation is only the first of on going evaluations that DOE will complete. They will all be based on the best information available at the time and the assumptions will constantly change. This evaluation should follow the study effort time line of every three years.

The Department also asked if there is a particular acute need to for early designation as NIETC.

We do not have a specific acute need, but due to the LONG lead time to permit and construct transmission and the short lead time in the Energy Policy Act of 2005 to encourage wind development, we recommend the following;

Federal agencies use "categorical exclusion" on NEPA requirements for transmission permits required on federal lands to reliably integrate renewable generation until the end of 2007 that meet the following criteria;

1. **Above 200 kV and within ½ mile of an existing transmission line above 200 kV;**
2. **Below 200 kV, less than 15 miles in length.**
3. **The line route does not include any wilderness area, National Park, or previously identified prohibited area.**

Additional field checks and review of the Construction, Operation, and Maintenance Plan (COM Plan) should cover most of the agencies concerns.

The Department also seeks comment on two additional questions:

(1) Are there other criteria or considerations that the Department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.

(2) Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

In conclusion, we restate several of our comments on Section 368. The Companies request the following specific outcomes from this process:

- **No negative effects on existing projects or processes**
- **Flexibility to refine this EPAct NIETC project and its processes going forward**
- **Merit based corridor screening for inclusion as a NIETC**
- **Inclusion of all critical parties (federal, state, local)**
- **Access for corridors on military reservation and national forests**
- **2 mile wide corridors**
- **Deference to national and/or regional councils on electrical reliability and engineering design issues related to corridors**
- **Environmental Assessment and COM plan would be the maximum required to site in a designated NIETC corridor**

76. Southern California Edison, Received Mon 3/6/2006 3:34 PM

March 6, 2006
VIA E-MAIL
Ms. Poonum Agrawal
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, DC 20585

Submitted by e-mail to: EPACT1221@hq.doe.gov

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Notice of Inquiry and Request for Comments, 71 Fed. Reg. 5660 (February 2, 2006)

Dear Ms. Agrawal:

On February 2, 2006, the Department Of Energy ("Department") published the above-referenced Notice of Inquiry ("Notice"). In the Notice, the Department is seeking comment and information from the public "concerning its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETCs")", and is also requesting "comment on draft criteria for gauging the suitability of geographical areas as NIETCs." Notice at 5660. The Notice had been issued as part of the Department's proposed plan for implementing its responsibilities under new Federal Power Act ("FPA") section 216(a), added by section 1221(a) of the Energy Policy Act of 2005 ("Act"). Southern California Edison Company ("SCE") is hereby providing its comments, in response to the Notice, to the Department.

I. <u>SCE Has a Direct and Substantial Interest in This Proceeding</u>

SCE is an electric utility with customers, both business and residential, located in the State of California. SCE is a wholly-owned subsidiary of Edison International, and is an investor owned utility. SCE constructs, own, and maintains transmission facilities. As such, SCE relies on the national electric grid to ensure a reliable supply of power to its customers, and has a direct and immediate interest in the Department's congestion study, and any steps undertaken by the Department with respect to the designation of NIETCs.

II. SCE 's Comments On The Issues Raised By The Notice

A. Definition Of Corridors

In the Notice, the Department asks the parties to address how broadly or narrowly transmission corridors should be defined. Notice at 5661. The Department states that it believes that "defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion." *Id.*

SCE understands and shares the Department's concern that appropriate action at all levels be enabled to resolve the identified congestion and supply problems. SCE is concerned, however, that broadly stated and applied corridor designation criteria will hamper the very purpose of defining NIETCs as the transmission projects resulting from such designations may not address, or inadequately address the congestion and supply problems which have led to the designation of a geographical area as a NIETC in the first place. Such projects will only tie-up capital funding sources, ratepayer funds, and agency resources without delivering the results intended by Congress. With this overarching concern in mind, SCE herby offers its comments on the appropriate definition criteria for the designation of NIETCs.

First, the Department should only designate transmission corridors that encompass more than one state *i.e.*, NIETCs should be located exclusively on interstate paths. That is not only consistent with the Congressional intent expressed in Section 216 of the FPA, it is also most necessary to assure that urgent transmission congestion problems of significant import are timely addressed and resolved. Specifically, Section 216 is entitled "Siting of Interstate Electrical Transmission Facilities". Section 216 provides an express exemption from its permitting provisions to the States which have entered into multi-state compacts to facilitate the siting of transmission facilities. *See* Section 216(i)(4). In short, it is amply clear that Congress, in approving section 216, intended to create a resolution, via the transmission corridor mechanism, for problems that have plagued transmission lines that must traverse across more than one state and deal with various local siting authorities. Such Congressional focus is hardly surprising. Long experience indicates that it is transmission projects that traverse several states, and must therefore deal with numerous public utility commissions, and varying rules, that are most in need of the expedition envisioned by Congress in the passage of Section 216. It is also the interstate transmission projects that are most needed to serve the national supply, independence and security issues. Finally, interstate designations are useful and necessary to assure that NIETCs are of a national significance and impact.

Second, as noted above, the Department must differentiate between transmission and congestion issues of national importance, as opposed to transmission and congestion issues of a more local and limited impact using a set of fully vetted and quantifiable criteria. Not every congestion problem, regardless of its magnitude and impact, can or should be addressed through an NIETC designation. Rather, the Department must develop a set of objectively demonstrable criteria that distinguishes congestion and supply problems of national importance from more localized transmission issues.

Third, SCE believes the Department should, particularly at this time, not designate an area as an NIETC if the transmission capacity constraint or congestion issue in that area is already actively being addressed and resolved by the utilities, states, and sub-regional and regional entities. In such an instance, designation as an NIETC may actually serve to impede an ongoing resolution of the problem at the local level. Instead, DOE should focus its efforts on the congestion needs in areas that are not being addressed by a more localized process.

Fourth, the Department should consider the economic vitality of the corridor and the end markets served by the corridor in determining whether to designate a NIETC. In order to accomplish this, SCE recommends the Department base its study upon the existing transmission studies and analyses originally conducted by regional planning agencies and other groups in the Western Interconnection. Any NIETC designated by the Department should mitigate a need already identified by the appropriate agencies through these processes. The documents listed in Appendix A of the Notice will serve as a good foundation to the Department's study. SCE also believes the Department's congestion study should look at long-term solutions to transmission congestion and as such, must be based on a ten-year study horizon.

It is equally important that the Department and all parties recognize that the designation of any area as an NIETC does not necessarily pre-determine the best solution to relieving transmission congestion or capacity constraint issues in that area. Rather, all appropriate solutions must be considered, with appropriate weight and consideration given to the positions and experience of the entities that have historically made such decisions, including the affected utilities, the states, and the sub-regional and regional planning entities in the impacted areas. Indeed, Congress had intended as much in requiring that any applicant for a Construction Permit under Section 216(b) must establish, *inter alia*, that its proposed transmission project is "consistent with the public interest" and "protects or benefits consumers".

Finally, the Department should only designate NIETCs in a manner that creates a demonstrable and reasonably close relationship between the resolution of nationally significant congestion and supply problems, and the parameters of the designated corridor intended to resolve such significant congestion and supply problems.

B. Early Designation And Acute Need

In the Notice, the Department invites the parties to "identify geographical areas or transmission corridors for which there is a particular acute need for early designation as NIETC." Notice at 5661. The Department also notes that it will only consider early designation when "a particularly compelling case" demonstrates that such designation is "both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation." *Id*.

SCE believes that the Department should concretely, in terms of verifiable and objective factors, define what constitutes a "compelling case" such that early designation is appropriate, and what kind of "data and information" must be submitted for a corridor to be considered for early designation. Because areas of early designation apparently will not be subject to the same congestion study scrutiny as areas that are designated at a later date, there is a potential that erroneous designation will occur to rate payer and consumer detriment. Accordingly, as noted above, the Department should put forth objective and verifiable criteria for early designation.

The Department should also provide third-parties with an opportunity to comment on such criteria, and give itself the opportunity to revise and amend the early designation criteria in response to third-party comments. Likewise, to the extent the Department believes that any one geographic area meets the early designation criteria, the Department should give an opportunity for intervenors to provide their input into the proposed early designation, and should not make any early designation until such time as the Department has considered and resolved the issues raised by intervenors with respect to each proposed early designation.

C. Congestion Study Questions

The Department has also seeks input on four questions to assist the Department in conducting its congestion studies intended to identify NIETCs. Below, SCE respectfully provides its responses to the questions posed by the Department:

Question 1: Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

SCE Response: In responding to this question, SCE assumes that the Department is referring solely to economic congestion. As such, the Department should distinguish between persistent and dynamic congestion, and should specifically define these terms. "Persistent congestion" should be defined as the congestion that exists on a given path or a transmission line for a majority of the time. Persistent congestion is an appropriate metric to consider in conjunction with NIETC designation so long as it rises to the level national significance and impact. "Dynamic congestion" should be defined as congestion that occurs for a limited amount of time and is not an appropriate metric to consider in conjunction with NIETC designations.

Question 2: Should the Department distinguish between physical congestion and contractual congestion and if so, how?

SCE Response: Yes, the Department should distinguish between physical and contractual congestion because physical flows and contractual flows rarely match in real operation of the system. The Department should utilize only physical congestion (rather than contractual congestion) of national significance in identifying any NIETCs.

Question 3: Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the department review? How far back should the Department look when reviewing transmission planning and flow path literature?

SCE Response: The list of transmission plans in Appendix A appears to be appropriate and complete. With regard to "how far back" the Department should look, SCE believes that significant events, such as deregulation, should serve as the starting point for Department's review. For example, because of the California electricity deregulation in the late 1990s, the impact of that deregulation on the Western United States energy markets, and the events following the deregulation, the Department should review the transmission planning, system operations, and historical congestion on major paths in the Western Energy Coordinating Council ("WECC") from 1997 to present.

Question 4: What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

SCE Response: Please refer to Appendix A, Item III, 6.4, Information on the CAISO Transmission Economic Assessment Methodology (TEAM).

D. NIETC Suitability Criteria

In the Notice, the Department invited comment on the criteria that should be used in "evaluating the suitability of geographical areas for NIETC status." Notice at 5662. The Department also developed eight draft criteria, and invited parties to comment these draft criteria, as well as the possible application of any of the draft criteria to specific geographical areas that could be identified as a NIETC. SCE reserves its right to comment on any specific geographical areas proposed by any party for designation as an NIETC in conjunction with any criteria, including the draft criteria proposed by the Commission as is appropriate in the future.

Initially, it should be noted that SCE's input on the criteria for defining and designating NIETCs, as set forth above, is equally applicable here. It should also be noted many States currently have processes in place to facilitate the permitting and siting of transmission facilities and those processes should not be displaced or circumvented without demonstrable good cause. NIETC designations should and are best suited to be used to streamline the efforts of any entity that is attempting to site facilities in multiple jurisdictions, where each jurisdiction can not reach agreement with the other with regard to the economic, or reliability benefits achieved by the facility. Additionally, SCE below submits its comments on the eight draft criteria developed by the Department.

Draft Criteria 1: Action is needed to maintain a high degree of reliability.

SCE Comments: SCE agrees with the Department that maintaining a high degree of reliability is a critical factor in determining an area for possible NIETC designation. However, a definition of the affected area in terms of load, population, and demand growth may not be sufficient to identify an area of potentially needing improvement in reliability. Similar to the aging transmission infrastructures, existing old generating power plants located in some areas such as the Los Angeles basin have been permanently shut down or retired. The retirement of generating units near the load centers would have the similar effects as load, population, and demand growth. Therefore, the Department should also consider the potential unit shut down and/or retirement in its metrics.

Draft Criteria 2: Action is needed to achieve economic benefits for customers within the area affected by the constraint.

SCE Comments: As SCE noted earlier, it is important that the Department differentiate between transmission corridors of national importance and those of lesser or only local importance using a set of agreed upon (and quantifiable) criteria. SCE recommends the Department only designate NIETCs where economic benefits are considered on an interconnection-wide, or at a minimum, a sub-regional basis using the following characteristics:

(a) Economic evaluation using the regional assessment methodology, such as the California Independent System Operator's ("ISO") proposed Transmission Economic Assessment Methodology (TEAM) (or a successor), which shows significant customers benefits on a regional basis and with national impacts..

Draft Criteria 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

SCE Comments: The Department should only designate NIETCs where supply limitations in end markets have the following characteristics:

(a) A transmission alternative is the least-cost alternative to the continued dependence on reliability-must-run plants.

(b) A transmission alternative to reduce a region's high dependence on specific generation fuels should pass criterion number 4 metrics.

Draft Criteria 4: Targeted actions in the area would enhance the energy independence of the United States.

SCE Comments: The Department should only designate NIETCs where energy independence has the following characteristics:

(a) Increases regional fuel diversity over the long-term to a level of national significance; and

(b) Improves domestic fuel independence in a nationally significant way, and

(c) Energy independence should have some reasonable economic ceiling, for example such that the combined impact does not increase regional market energy prices by an average of X% per year.

Draft Criteria 5: Targeted actions in the area would further national energy policy.

SCE Comments: As discussed above, SCE believes NIETC corridors should be targeted to support the siting of interstate transmission facilities.

Draft Criteria 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

SCE Comments: Definition of critical loads and electrical facilities is needed in order to minimize or reduce misinterpretation. For example, is load in the Los Angeles basin considered to be more critical than that in the Phoenix area? SCE proposes that the Department better define "critical loads and facilities" so commenters may more accurately consider the question being posed.

Draft Criteria 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

SCE Comments: To avoid having the NIETC process debating congestion models and data, the Department should only designate NIETCs where there are existing needs having the following characteristics:

(a) An existing need of national importance (shown through historical data over the last X years where X could, for instance, be 5 years); and

(b) A persistent need of national importance that occurs for a minimum time period during the year and impacts a crucial time period (Y% of peak hours where Y could be 20 and critical time period could be peak); and

(c) An existing or future need significantly impacting energy market prices (difference in regional market prices must at least an annual average of $Z per MWh where Z could be greater than 1).

Draft Criteria 8: The alternative means of mitigating the need in question have been addressed sufficiently.

SCE Comments: The Department should, to the maximum extent possible, encourage and consider the input regarding various appropriate and/or considered alternatives from the parties to this process.

Very truly yours,
/s/signature   Anna J. Valdberg

77. Southern Company, Received Mon 3/6/066 2:51 PM

William O. Ball — 600 North 18th Street / 13N-8200
Senior Vice President — Post Office Box 2641
Transmission Planning — Birmingham, Alabama 35291
and Operations — Tel 205.257-6218   Fax 205.257-5390

March 6, 2006

Ms. Poonum Agrawal
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, DC 20585

Submitted by e-mail to: EPACT1221@hq.doe.gov

Re: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Notice of Inquiry and Request for Comments, 71 Fed. Reg. 5660 (February 2, 2006)

Dear Ms. Agrawal:

Southern Company Services, Inc. ("Southern Company") appreciates this opportunity to submit comments in response to the February 2, 2006 Department of Energy ("DOE" or "Department") Notice of Inquiry ("NOI") regarding its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETCs").[1] This NOI was initiated to implement Section 216(a) of the Federal Power Act, which was added by Section 1221 of the Energy Policy Act of 2005. Section 216(a) requires that by August 8, 2006, and every 3 years thereafter, DOE shall conduct a study of electric transmission congestion ("Congestion Study"). 16 U.S.C. §824p(a)(1). Based on that study, DOE is then to issue a report that may, in accordance with the criteria and requirements in Section 216(a), designate any geographic area experiencing transmission constraints or congestion "that adversely affects consumers" as an NIETC ("NIETC Report"). In the NOI, the

[1] 71 Fed. Reg. 5660 (February 2, 2006).

Department not only provided an overview of its plan for implementing these requirements, but also invited public comments on specific questions pertaining to the development of the Congestion Study and the specific criteria to be utilizing in preparing the NIETC Report.

Southern Company writes to support the Department's efforts and to commend it for allowing public comment at this initial stage in its development of its Congestion Study and NIETC Report processes. Southern Company generally supports the approach and criteria identified in the NOI and supports the comments being submitted by the Edison Electric Institute ("EEI") in response to the NOI. In addition to voicing that general support, Southern Company also takes this opportunity to provide specific comments on the following matters raised in the NOI. In particular, in EEI's comments, EEI commends the Department for relying as much as possible on existing transmission expansion plans and on studies prepared by regional planning groups, utilities, and other transmission planning groups. Southern Company likewise strongly supports this approach. In this manner, the Department will be able to utilize and build upon the collective technical expertise and regional knowledge of the various existing transmission planning institutions rather than attempting to unilaterally develop such foundational transmission analyses. As noted in EEI's comments, DOE has properly identified in Appendix A to the NOI the appropriate, existing transmission plans and studies to use in developing the Congestion Study.

In the NOI, the Department states an intention to present "an inventory of geographic areas … hav[ing] important existing or projected needs related to the existing transmission infrastructure" and to "identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities." NOI, Section II(C), 71 F.R. 5661. Southern Company supports this approach of identifying broad areas that are subject to congestion and of identifying general corridors for potential projects. In this manner, the Department will allow entities in the affected regions flexibility to develop optimal, specific solutions to address the problems that will be identified in the Congestion Study, and ultimately in the NIETC Report. If the Department, instead, were to adopt an approach of identifying very specific locations as being subject to congestion and the corresponding transmission facilities that would address the problem, then it might inadvertently preclude the development of superior solutions.

Southern Company generally supports as appropriate the preliminary criteria identified in the NOI that might be used in evaluating the suitability of a geographic area for NIETC designation, but take this opportunity to especially stress the importance of "Draft Criterion 1: Action is needed to maintain high reliability". NOI, Section III(B), 71 F.R. 5662. Maintaining the reliable operation of the grid remains of paramount importance, and the congestion study should consider the ability of the transmission system to reliably meet firm customer demand in accordance with NERC reliability standards. In response to the question in the NOI regarding whether there "[a]re certain considerations or criteria more important than others", given the critical importance of maintaining reliable operations, Draft Criterion 1 should be a strong consideration in determining whether to designate any area an NIETC.

Section 216 requires the Department to seek public recommendations and to consider alternatives to NIETC designation. 16 U.S.C. § 824p(a)(1)-(2). On this important matter, the NOI notes that "the Department wishes to avoid designating NIETCs in ways that might unduly affect stakeholders' decisions", such as conferring advantages to transmission options over non-wire options. NOI, Section III(B), 71 F.R. 5662. At the same time, the NOI notes that transmission expansion is needed in certain areas. The Department asks how to balance these concerns. In response, DOE, first and foremost, should allow for public input and consider alternatives to the transmission solutions that would be reflected in an NIETC designation. To avoid conferring an undue advantage to a particular solution, Southern Company recommends that the Department make it very clear that by designating any particular NIETC, the Department is not concluding or otherwise indicating that a transmission solution is the optimal means of addressing the underlying problem. Moreover, the Department should provide great weight to the recommendations of the affected States and to those of any regional planning institution in the region. In this regard, should there be a regional planning process in the affected area that has determined that there are other, non-wire solutions that are superior to constructing additional transmission infrastructure to address the underlying problem, then it would be prudent for the Department to refrain from designating such an area as an NIETC.

Southern Company also has a few recommendations regarding the processes the Department will utilize in preparing the Congestion Study and the NIETC Report. As an initial matter, Section 216(a)(1) requires that the Department conduct the Congestion Study "in consultation with affected States." 16 U.S.C. § 824p(a)(1). Given this mandate, it would appear prudent for the Department to adopt some formal consulting process with the States prior to the release of the Congestion Study by the August 8, 2006 deadline. In addition regarding "process" issues, the NOI is not completely clear regarding the process that will be used to actually issue the NIETC Report. Since Section 216(a)(2) requires that alternatives and recommendations from interested parties be considered prior to the issuance of the report, it is recommended that the Department adopt some process to allow for such input and consideration. A similar concern is raised regarding the proposal in the NOI that interested parties may request in their comments early designation of "geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC". NOI, Section II(C), 71 F.R. 5661. However, the NOI does not discuss a process whereby affected States and interested parties will be able to respond regarding such requests for early designation as required by Section 216(a)(2) prior to NIETC designation. Accordingly, Southern Company recommends that the Department allow for such public participation should requests for early designation be submitted.[2]

[2] Regarding the early designation of NIETCs, it also seems important that the Department use the same, or at least consistent, analytical tools and assumptions in any early designation process that the Department will use in the development of the Congestion Study and NIETC Report. Otherwise, the separate processes might produce disparate results. For example, if different processes and assumptions are used, then an NIETC that might be designated in an early designation process might be determined in a subsequent Congestion Study and/or NIETC Report to not be appropriate for designation.

In summation, Southern Company supports the Department's efforts and generally supports the approach and criteria proposed in the NOI. Should there be anything that Southern Company can do to facilitate the Department's efforts in this matter, feel free to contact me at the number provided above.

Sincerely,

William O. Ball

78. Stevens County [Kansas] Economic Development Board, Received Thu 3/2/2006 10:19 AM

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Please find the attached Letter of Support for the proposed Transmission Line
Study.

Thank you for your consideration,

Neal R. Gillespie, Director
Stevens County Economic Development
630 S. Main
Hugoton, KS 67951
(620) 544-4440
(620) 544-4610 fax
ecodevo@pld.com
```

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

By e-mail to: EPACT1221@hq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of
National Interest Electric Transmission Corridors

March 2, 2006

The Stevens County Economic Development Board wishes to comment on the Department of Energy (the "Department")'s efforts in conducting its initial electric transmission congestion study required by the Energy Policy Act amendment to the Federal Power Act subsection 216(a)(1). We understand the Department intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity could lessen potential adverse effects borne by consumers.

We support the Department's goal to identify corridors for potential projects as generalized electricity paths between locations, as opposed to specific routes for transmission facilities. We also believe that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion.

We wish to emphasize that the Department's initiative is an opportunity to identify wind-rich regions that offer both economic development along potential transmission corridors and economical energy from wind power development. While some early wind projects may have been built in the wind-rich area**s** of Kansas, the potential for more wind energy development should be included in the Department's review. We believe there is a true need to plan for more transmission to move wind power from future wind developments to consumers, thereby providing economic benefits, fuel diversification, and clean energy for our citizens.

Thank you,
Neal R. Gillespie, Director
Stevens County Economic Development Board
630 S. Main
Hugoton, KS 67951
ecodevo@pld.com

79. Tennessee Valley Authority, Received Monday, Mon 3/6/2006 4:40 PM

March 6, 2006

DEPARTMENT OF ENERGY (DOE) - CONSIDERATIONS FOR TRANSMISSION CONGESTION STUDY AND DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS

The Tennessee Valley Authority (TVA) is pleased to respond to the Department of Energy's (DOE) Notice of Inquiry (NOI) regarding plans for an electric transmission congestion study and designation of National Interest Electric Transmission Corridors (NIETC).

Deregulation of the electricity industry in the United States much more complex than in other countries because of the number of utilities, differences in structure and procedures, and differences in priorities of State and Federal entities. Uncertainties in the industry have resulted in loss of momentum, particularly in transmission investment. National goals could not be addressed in the environment that has existed for the past decade. TVA believes that the Energy Policy Act of 2005 and the concept of NIETC offer the opportunity for a quantum leap in achievement of national electric system goals. TVA plans to continue to be a leader in the conceptual development and an active participant in its implementation.

TVA comments are as follows. Some revisions to the approach described in the NOI are suggested.

<u>NIETC Definition</u>

TVA notes that the definition of NIETC is problematic.

As used by DOE in the NOI, an NIETC appears to designate a problem, with solutions to be developed not by DOE but by utilities or others. Actions in the national interest which may require special funding and application of authority should be separated from normal expansion of the grid. Yet this separation cannot be determined until a specific solution to a problem has been developed. This contradiction is amplified by the designation of NIETCs as "corridors".

TVA believes that the designation of NIETC should be reserved for specific solutions, selected only after full studies of all possible options, that are not justified for action within normal utility practice. It is suggested that the list of candidates for NIETC presently being developed in the congestion study for DOE should include recognition of this.

<u>NIETC Criteria</u>

Five factors (A-E) are listed for consideration.

The first two factors, A and B, address market economic issues. We believe that it is not intended that NIETC should address aspects of development for which adequate mechanisms and incentives already exist. While some developments for which economic justification exists may not have been built, the solution is to reinforce confidence in proven mechanisms rather than duplicate them.

Factors C, D, and E address strategic issues that are outside the normal range of utility planning considerations and experience, and conventional economic tools justification will not be found even on a combined regional basis. Existing study tools and planning techniques are unlikely to be adequate for these issues.

From these considerations we conclude that an NIETC solution is solely one where conventional planning is unable to justify a project that is in the national interest. This vision as embodied in the factors A-E offers, for the first time, a basis for development of a national grid.

A corollary is that a utility's regional interests or inability to respond cannot be permitted to slow implementation, and where necessary with appropriate mutual agreement an independent entity, such as a regional reliability coordinator or planning authority, may be assigned responsibility.

General Discussion

The Energy Policy Act requires that ongoing studies of electric transmission congestion be conducted by DOE. Obviously this must involve representatives from the utilities who have detailed knowledge of the grid. Additionally, consultants can bring the advantage of impartiality and national vision. It should be noted that TVA commissioned such a study in 2001, with results identifying some excellent examples of the NIETC definition above.

Following the conclusion of the initial congestion study, waiting a further 3 years for the next studies appears too long. It is suggested that the next round of studies, with an even more comprehensive work scope, be initiated quickly following the first designation of NIETCs.

As noted above the five factors (items A-E) cannot be met solely through technical studies. While some headway can be made through conventional enhancement of electric system reliability, a new approach will be required on issues such as national defense and homeland security.

Reliably

North American electric utilities are required to follow NERC planning criteria to ensure adequate reliability of the electric grid. As long as utilities follow these criteria, the reliability of the grid should be adequate. It is expected that utilities should be making the proper economic choices for their native load customers by either transmission or generation additions. Therefore reliability should not be the major goal for the NIETC program. Reliability has been addressed through NERC in the past, and will be addressed with the newly granted authority from Epact 2005 by FERC and the new ERO in the future. While any NIETC projects should embody reliability, it is not their focal issue.

Generation

In addition to new transmission corridors, the NIETC process should encourage the proper siting of new generation as an alternative to transmission. The optimal placement of new generation resources, including nuclear for energy independence, can help meet the five factors A-E. Similarly, obviously all existing and new technologies should be considered as tools; however, with the exception of more reliably designed FACTS devices, no new technologies presently appear capable of offering other than niche contributions.

Key Term: Corridors

DOE has invited comments about how broadly or narrowly “corridors” should be defined. The use of “corridor” implies limitation of NIETC to transmission solutions. However, solutions may be intra- or inter-state transmission, generation, operations, or some as-yet unrealized approach. The definition of “corridor” must be broad enough to encompass these, but not so broad that inappropriate projects are designated.

As noted above, TVA recommends that the solution process should consider all alternatives in its initial stages, with the designation of a project as an NIETC solution not made until careful review has ensured that all criteria are met and that conventional incentives are absent.

Questions for Public Comment

A. Congestion Study

Suggestions for NIETCs

As noted above, TVA commissioned an independent study in 2001 of strategic solutions around its service area. Since that time TVA has continued to address the issue through internal resources. These solutions address Factors A, B, and possibly C.

The 2001 study identified a “great electrical divide” to the north of TVA roughly from Chicago to the Carolina coast. Increasing export and import capabilities to the north and north-east by 10,000 MW suggested solutions including two HVDC “highways” across the TVA system, together with some 345 kV and 500 kV reinforcement in TVA and neighboring areas. Although these projects potentially offered broad value beyond TVA, TVA’s limitation to solutions required to benefit native load did not allow their construction.

In addition, limitations on transfer capabilities with the systems to TVA’s west were noted. The reliance on gas in the western portion of the TVA system could be considered under Factors C-E. Development of north-south electrical highways would relieve east-west congestion as well. TVA is presently working with neighboring utilities on expansion of transfer capabilities to the south. TVA also suggests that larger transfers from the coal fields of Kentucky to Florida should be considered.

The above strategic but unjustifiable examples were developed from TVA’s knowledge of its region. Other utilities will have similar insights for their regions. It is suggested that the present studies include a survey of utilities for this specific area of information. It is also suggested that encouragement of joint studies which include NIETC considerations will be fruitful for the future.

It is noted that a congestion study directed towards developing a preliminary list of NIETCs is in progress. TVA suggests that this study be significantly revised.

a) The study should address all 5 factors A-E. At present it addresses only congestion causing reliability concerns within factors A and B.

b) The study should be expanded to include a survey of key utilities to obtain their insights on strategic lines that are envisioned but currently unjustified.

c) A two or three person team of market economists should work independently to identify NIETCs. This will add an important dimension to the study. TVA has suggestions for this team.

<u>Response to direct questions from DOE</u>

(1) ‘Persistent’ versus ‘dynamic’ congestion: The significance of this is not clear. The word ‘dynamic’ implies a very short timeframe usually interpreted in the power utility world to mean less than a minute and caused usually as a result of a fault. These are termed ‘transient’ events.

The results of the DOE studies should be reported in a way that distinguishes the degrees of benefit in both magnitude and duration. This implies a metric to be used that identifies the economic/market impact of both the level of congestion and the amount of time that congestion exceeds the level. Presumably a NIETC should not be considered if congestion in an area is minor and occurs for only a few hours per year.

(2) The terms “physical congestion” and “contractual congestion” are similarly confusing. A contracted power transfer can cause “physical congestion”. A power transfer contract is an attempt to use the transmission system to achieve reliability or economic benefits. Contract-caused congestion should certainly be considered in the study but does not need to be treated or identified differently than other causes of congestion.

(3) Appendix A appears to be limited to publicly accessible documents. A number of copyrighted documents could be valuable. It is suggested that publishing entities (e.g., EPRI, CERA) be invited to allow use of selected publications for this work. TVA suggests that studies earlier than 2004 are unlikely to be helpful given the major increase in natural gas prices and changes in generator siting.

(4) Categories of information useful to include to develop geographic areas of interest would include:

- The total amount of generation in an area
- The total amount of generation in an area by fuel type
- The total amount of load in the area
- The net difference between load and generation for the area during both peak and off-peak times
- The growth rates of the area as identified best by load growth rates or alternatively by population growth rates

B. Criteria Development

The NOI lists eight Draft Criteria for comment.

As described above, TVA believes that NIETC solutions should not address problems that are already addressed through present methods and incentives. This should exclude both *Draft criterion 1* (reliability) and a portion of *Draft criterion 2* (economics where there are existing incentives).

Draft criterion 3 addresses electricity supply limitations and diversifying resources, and should be included. The metrics defined here are correct but it must be pointed out that it may not be economically justified to eliminate all “reliability-must run” units. Some must-run units are such because an economic decision has been made based on it being less expensive to run a unit out of economic order than to enhance transmission.

Draft criterion 4 should be included. While it is in this nation’s interest to reduce dependence on oil and gas, normal utility economic processes are unlikely to accomplish it. The most difficult part of the problem may be the identification of available existing generation resources fueled by something other than oil or gas that meet clean air requirements. Then the transmission facility to deliver the power from that facility would have to be justified using the metrics described in criterion 3. It is more likely that new generation would have to be constructed to reduce dependence on oil or gas in order to accomplish this goal.

Draft criterion 5 should be included; however, the specific meaning of this requires further work.

Draft criterion 6 should be included in part. As previously noted, reliability should be embodied in but not a target by itself for NIETC.

Draft criterion 7 discusses uncertainties. The only thing certain in transmission planning is that uncertainty about the future has and may continue to increase, such as where and when future generation may be added to the grid, what the impacts of the market will be on imports, exports, and transfers, and what delays there will be in construction completion of major transmission projects. Uncertainty is a very significant factor for planners, but methodologies have been developed to manage it. Like *Draft criterion 6*, management of uncertainty should be embodied in but not a target for NIETC.

Draft criterion 8 discusses DOE’s concerns about the possible ramifications of designating NIETCs. The DOE is to be complimented for being sensitive to these ramifications. We believe that concerns can be minimized by the overall NIETC process itself. As recommended above, NIETCs should be designated only after careful studies and review. Then a method must be found to provide incentives to implement the solution, with backstop authorization as necessary.

With regard to providing incentives, one possibility is that incentives for utilities will be developed through regulatory adjustments. For example, TVA’s ability to build an electricity highway across its system could be influenced by an ability to separate its transmission charges from the socialized charges for the remainder of the grid.

The NOI lists two additional questions.

Additional question (1) Are there other criteria or considerations that the Department should consider in making an NIETC designation?

Answer: TVA has offered specific criteria above to use for NIETC designations.

Additional question (2) Are certain considerations or criteria more important than others?

Answer: Definition of NIETC projects will require new approaches to planning. It is unclear what considerations may emerge as most important as the NIETC process continues; therefore, it is suggested this question be raised again at a later time.

General Comments

Assurances must be provided that once NIETCs are identified, that there is follow through and transmission improvements will really be constructed. DOE should continue to work with FERC and Congress to arrange for the means necessary to assure these facilities are indeed constructed in a timely fashion. DOE and FERC should also be mobilizing themselves at this time for their new roles facilitating this program.

I hope that these comments have been helpful.

Sincerely,

Terry Boston
Executive Vice President
Power System Operations

80. United States Senator Craig Thomas, Received Mon 3/6/2006 4:11 PM

March 6, 2006

Mr. Kevin Kolevar, Director
Office of Electricity Delivery and Energy Rliability, OE-20
Attention: EPACT 1221 Comments
US Department of Energy
Room 6H-050, Forestall Building
1000 Independence Avenue, SW
Washington DC 20585

Dear Mr. Kolevar:

Last year during the National Energy Policy debate, one of the most pressing issues was that of our nation's outdated electric transmission system. Our system needs to be modernized. The current system was not designed to support today's regional, competitive electricity markets. Investment in the transmission system has not kept pace with the growth in generation and the increasing demand for electricity. As a result, the system has become increasingly congested and less reliable.

With both the demand for electricity rising in key areas in the West and the ability to tap into abundant and relatively low-cost fossil and renewable resources, the States of Wyoming, Utah, Nevada and California see a unique opportunity. The proposed Frontier Line would be a new interstate high-voltage electric transmission line originating in Wyoming with terminal connections in Utah, Nevada, and California.

In response to the Department's notice of inquiry requesting comments in the Federal Register on February 2, 2006 (5660) I believe that the Frontier Line should be designated a National Interest Electric Transmission Corridor. In conducting an electricity transmission congestion study as referenced in the Federal Register, I am confident that you will come to the same conclusion that I have. There is no question that the steadily increasing levels of congestion in the Western Interconnect warrant the designation of the Frontier Line as a National Interest Electric Transmission Corridor.

In your efforts to more clearly understand the state of the electrical grid, I encourage you to take full advantage of the expertise that exists at the Federal Energy Regulatory Commission. The FERC is an invaluable resource that should be utilized in studying electricity transmission congestion and is uniquely prepared to assist with the National Environmental Policy Act and other siting issues when the time comes to begin construction of new transmission.

The Energy Policy Act of 2005 put us on a solid footing for strengthening our electricity sector. The inherent value of a study on electricity transmission congestion cannot be overstated. However, I encourage you to complete these efforts as expeditiously as possible lest the accumulation of projections and data hinder the implementation of solutions.

Building new transmission will serve to increase reliability, provide cheaper electricity to consumers, foster greater security, and allow for the development electrical generation source diversity. It is important to the states involved and the nation as a whole that this new transmission gets built. I will continue to support approaches to ensure that the Frontier Line becomes a reality.

Best Regards,

Craig Thomas
United States Senator

81. Tompkins Renewable Energy Education Alliance (TREEA), Received Thu 3/2/2006 10:33 AM

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

By e-mail to: EPACT1221@hq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

The Tompkins Renewable Energy Education Alliance (TREEA) wishes to comment on the Department of Energy (the "Department")'s efforts in conducting its initial electric transmission congestion study required by the Energy Policy Act amendment to the Federal Power Act subsection 216(a)(1). We understand the Department intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity could lessen potential adverse effects borne by consumers.

We support the Department's goal to identify corridors for potential projects as generalized electricity paths between locations, as opposed to specific routes for transmission facilities. We also believe that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion.

We wish to emphasize that the Department's initiative is an opportunity to identify wind-rich regions that offer both economic development along potential transmission corridors and economical energy from wind power development. While some early wind projects may have been built in the wind-rich areas of our NY**, the potential for more wind energy development should be included in the Department's review**. We believe there is a true need to plan for more transmission to move wind power from future wind developments to consumers, thereby ***providing economic benefits, fuel diversification, and clean energy for our citizens***.

Thank you,

Beth Ellen Clark Joseph
Tompkins Renewable Energy Education Alliance (TREEA)

82. Trans-Elect, Inc., Received Mon 3/6/2006 3:37 PM

Dear Mr. Kolevar:

Trans-Elect, Inc. appreciates the opportunity to comment on the NIETC process. While Trans-Elect has transmission business and development interests at sites scattered throughout the United States and is supportive of the NIETC process, the comments set forth herein pertain specifically to the TOT 3 transmission constraint located on the Wyoming-Colorado border. As such, our comments are supportive of the comments filed with your offices by the Wyoming Infrastructure Authority on March 3, 2006 as well as those filed by the Western Business Roundtable that will be filed on March 6, 2006.

The TOT 3 transmission constraint limits the export of low-cost coal and wind power from Wyoming to load centers along the Colorado Front range in Colorado. Limitations in power flows along the TOT 3 transmission path is a long-standing problem that has been identified in a number of stakeholder studies including the recently completed Rocky Mountain Area Transmission Study (RMATS). The elimination of the TOT 3 constraint was recommended in RMATS as one of three high-priority projects for the Rocky Mountain States. RMATS estimated that the constraint could be relieved with the construction of a 250 mile-long 345 kV transmission line for $318 million which would increase the TOT 3 transfer capacity by 750 MW. In order to address the resolution of the TOT 3 transmission constraint, a public/private partnership has been formed by the Wyoming Infrastructure Authority, Trans-Elect, and Western Area Power Administration (www.wyia.org/projects).

We have been tracking the evolution of the NIETC process and conclude that the TOT 3 project meets many of the criteria that have been identified as potential criteria for NIETC designation, as follows:

- It would reduce the risk of significantly higher rates or other costs for consumers;
- It would facilitate economic development and strengthen the economy along the corridor and particularly at the end markets which would otherwise be constrained by the lack of adequate or reasonably priced electricity;
- It would improve the reliability of the regional transmission grid;
- It would increase fuel diversity so that customers are not unduly dependent on “at-load” generation resources;
- It facilitates access to some of the strongest wind resources in the West to meet Colorado’s Renewable Portfolio Standards and customers’ demand for environmentally-friendly power; and
- It would provide a stimulus to economic development in a thinly populated area which has limited alternatives for economic development.

We look forward to working with DOE in the NIETC process. Should you have any questions concerning our comments or require further input, please contact me at your earliest convenience.

Sincerely,

Robert L. Mitchell

Managing Director

cc: Steve Waddington, Executive Director, Wyoming Infrastructure Authority

Jim Sims, Executive Director, Western Business Roundtable

Michael S. Hacskaylo, Administrator, Western Area Power Administration

Robert Kennedy, Restructuring Manager, Western Area Power Administration

83. Transmission Access Policy Study Group, Received Mon 3/6/2006 4:13 PM

COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

The Transmission Access Policy Study Group ("TAPS") appreciates this opportunity to respond to the Department of Energy's Notice of Inquiry, "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," which was published in the Federal Register on February 2, 2006. 71 Fed. Reg. 5660. TAPS is not submitting extensive comments, because the Department has done a good job of translating the considerations set forth in new section 216 of the Federal Power Act into criteria for designating National Interest Electric Transmission Corridors ("NIETC"). TAPS's comments provide factual background and recommendations that should guide the Department's application of the criteria. TAPS will not here suggest specific geographic areas or transmission corridors that should be considered for NIETC designation. However, individual TAPS members may submit such comments.

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[1] It participates in policy proceedings at Department, the Federal Energy Regulatory Commission (FERC), the Federal Trade Commission and other federal agencies that deal with electric transmission and market power in the electric utility industry. As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members have supported initiatives to form truly independent, regional transmission organizations and to foster efficient investment in transmission and generation facilities. TAPS recognizes the critical importance of structurally competitive markets, transmission adequacy, and access to long-term power supply (without exposure to debilitating congestion charges) to achieving a workably competitive electricity industry and enabling TAPS members to continue to provide reliable service to their customers at a reasonable, predictable cost.

TAPS has been particularly active in the policy arena concerning transmission infrastructure. In response to the Department's July 22, 2004 Notice of Inquiry, "Designation of National Interest

[1] TAPS is chaired by Roy Thilly, CEO of Wisconsin Public Power, Inc. Current members of the TAPS Executive Committee include, in addition to WPPI, representatives of: American Municipal Power-Ohio; Blue Ridge Power Agency; Clarksdale, Mississippi; ElectriCities of North Carolina, Inc.; Florida Municipal Power Agency; Geneva, Illinois; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric Co.; Missouri River Energy Services; Municipal Energy Agency of Nebraska; Northern California Power Agency; Oklahoma Municipal Power Authority; Southern Minnesota Municipal Power Agency; and Vermont Public Power Supply Authority.

Electric Transmission Bottlenecks," 69 Fed. Reg. 43,833 (July 22, 2004), TAPS submitted its June 2004 White Paper, *Effective Solutions for Getting Needed Transmission Built at Reasonable Cost*, which described structural changes and regulatory actions that can work to get needed transmission built.[2] Among these changes is wider adoption of joint ownership transmission models, including transmission-only companies with inclusive ownership, such as the American Transmission Company and Vermont Electric Power Company, and shared or joint transmission systems, such as those that exist in Georgia, Indiana and parts of the Upper Midwest. TAPS is confident that these models would be effective at getting transmission built in NIETCs and encourages the Department to support them.

Communications regarding these proceedings should be directed to:

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COMMENTS

Comments on Draft Criteria 2 ("Action is needed to achieve economic benefits for consumers"), 3 ("Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify resources") and 5 ("Targeted actions in the area would further national energy policy")

As noted at the outset, TAPS believes that the proposed criteria are generally on the right track. The Department also correctly links current inadequacies in the transmission grid to differences between the historical purpose of the transmission grid and the role that it must play in an era where competitive electricity markets are supposed to ensure reliable and economic power supply:

[2] The White Paper is available at http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf.

> The electric system has been built by electric utilities over a period of 100 years, primarily to serve local customers and support reliability; the system generally was not constructed with a primary emphasis on moving large amounts of power across multi-state regions.

71 Fed. Reg. at 7660. However, the current inadequacies are not solely attributable to historical accident. In some cases, incumbent transmission owners ("TOs") decided, and continue to decide, not to invest in needed transmission in order to forestall entry by competitive power supply, as the Federal Energy Regulatory Commission has observed:[3]

> Market participants also complain that companies that own both transmission and generation under-invest in transmission because the resulting competitive entry often decreases the value of their generation assets. Much of this problem is directly attributable to the remaining incentives and ability of vertically integrated utilities to exercise transmission market power to protect their own generation market share.

NIETC designation should open the door to transmission investment by willing utilities, such as TAPS members, thus allowing economic electricity to reach end-users, lowering their costs, and advancing a national energy policy premised on access to competitive power supply markets.

In applying the proposed criteria, the Department should pay attention to evidence that end-users are denied access to lower cost power supply because of constrained transmission. Such evidence might consist of recurring, significant differences in locational marginal prices in parts of organized markets attributable to constraints that prevent the dispatch of lower-priced resources to serve load within a load pocket. Another kind of evidence would be the inability of transmission customers to secure transmission paths, particularly on a firm basis, or congestion hedges needed to contract with alternative suppliers in order to lower their power supply costs or ensure reliable service.

National energy policy, as reflected in EPAct 2005, also supports NIETC designations that expand investment in the grid by transmitting utilities other than incumbent TOs. FPA § 216b(1)(B). In addition, continued exclusive ownership of transmission by incumbent TOs is contrary to EPAct 2005's support for transmission investment, "regardless of the ownership of the facilities." FPA § 219(b)(1). Joint transmission ownership models, whether in the form of

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[3] Proposed Pricing Policy for Efficient Operation and Expansion of the Transmission Grid, Notice of Proposed Policy Statement, Docket No. PL03-1-000, 102 F.E.R.C. ¶ 61,032, at P 15 (2003).

an inclusive, stand-alone transmission company or joint transmission systems, expand the universe of transmission owners and have a proven track record of getting transmission built at reasonable costs.[4] NIETC designation would facilitate investments in the grid by a wider range of entities (*e.g.*, municipals, cooperatives, private investors), and at the same time joint transmission models would make it more likely that transmission is, in fact, built. TAPS members either are participants in such joint ownership models[5] or have approached incumbent TOs proposing such models as a means to encourage much needed transmission investment.[6] TAPS believes that areas where interest in such models exists indicate a need for NIETC designation and that NIETC designations would encourage broader adoption of the models.

In examining proposals for NEITC designations, the Department should not credit claims of dominant TOs who resist such designations on grounds that the existing grid is adequate to serve *their* end-users. Congestion also significantly and adversely affects the end-users of wholesale customers, such as TAPS members, that also rely upon the transmission grid. Current transmission inadequacies prevent these transmission users from obtaining economic access to alternative power supply, which increases costs and impairs the development of competitive power supply markets where willing buyers and sellers can transact.[7] A number of TAPS members find themselves in areas where even very small transmission service requests (*e.g.*, from less than 1 MW to 10 or 20 MW) are denied and claimed to necessitate multi-million dollar upgrades.[8]

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[4] *See* White Paper at 9-13.

[5] *See id*. and White Paper Appendix.

[6] For example, TAPS members Lafayette Utilities System, Clarksdale, Mississippi, and the Missouri Joint Municipal Electric Utility Commission sent letters to Entergy offering to invest in rebuilding the Hurricane Katrina-destroyed transmission system, though Entergy has not exactly jumped at the offer. These letters are attached to the Comments of the Transmission Access Policy Study Group submitted in *Promoting Transmission Investment through Pricing Reform*, FERC Docket No. RM06-4-000, and available at http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10925219.

[7] In addition, transmission customers are often shut out of transmission planning and do not have access to information that might help support an NIETC designation. Thus, the absence of proposed designations from transmission customers, or designations that lack the same technical support as those coming from TOs, should not be construed as a lack of concern on the part of transmission customers.

[8] For example, in December 2004, Ms. Anne Kimber, speaking on behalf of the Midwest Municipal Transmission Group and TAPS, described to FERC the efforts of a small city on the MidAmerican Energy Company system to take service from the Municipal Energy Agency of Nebraska ("MEAN") at the end of its power contract: "According to the MAPP-MISO 'scenario analyzer' – the tool available to market participants to test the availability of transmission service, transmission from MEAN to Callender, Iowa (0.6 MW) impacted both MAPP and MISO (Alliant) flowgates. Frankly, it is hard to believe that a transmission request this small could cause such big problems." Written Statement of Anne Kimber on Behalf of MMTG and TAPS for the December 7 Technical Conference, at 6, filed December 7, 2004 *available* at http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10328815.

A recent system impact study conducted by Entergy for the proposed Plum Point plant in Arkansas identified a need for $14-28 million in transmission upgrades to accommodate delivery of the output of the plant to two small towns having a combined load of 5 MW. The identified upgrades, including a 500 kV facility located near Little Rock, *i.e.*, south and west of the Plum Point plant, whereas the towns are northwest and north of Plum Point, perennially show up as requiring upgrades in order to accommodate virtually any variety of service request. *See* Motion for Late Intervention, Protest, and Reply of Missouri Joint Municipal Electric Utility Commission, filed on December 7, Finally, it would not be appropriate to require "participant funding" for projects in NIETCs which, given the nature of the AC grid, will broadly benefit end-users. Participant funding forces one or more market participants to bear the cost of network upgrades that provide broad benefits that change over time on a dynamic AC grid, creating enormous free-rider effects, especially given the inherent lumpiness of efficient transmission upgrades. Further, where the market participant funding an upgrade receives Financial Transmission Rights ("FTRs") in exchange, and theoretically as compensation, for its investment, the FTR would have no value (and potentially a cost) if the upgrade eliminated the very congestion that is supposed to fund the FTR. Such a result would not be consistent with EPAct's requirement that "all prudently incurred costs related to transmission infrastructure development pursuant to section 216" be recovered. FPA § 219(b)(4)(B). Without assured cost recovery, needed upgrades, even in NIETCs, will not be built. Thus, the cost of NIETC investments, regardless of ownership, should be rolled-in, preferably allocating the cost of high voltage, backbone transmission on a regional basis to spread the cost burden and match cost responsibility to the broad regional benefits that will be realized from a robust grid.[9]

Comment on Draft Criterion 8 ("The alternative means of mitigating the need in question have been addressed sufficiently")

With respect to Draft Criterion 8, the Department explains that it "wishes to avoid designating NIETCs in ways that might unduly affect stakeholders' decisions about how to meet specific needs, confer advantage on transmission options, or favor some transmission options over others." 71 Fed. Reg. at 5662. TAPS notes that Draft Criterion 8 is not listed among the considerations set forth in section 216(a)(4) upon which the Department bases the other draft criteria. Indeed, EPAct with its provision for backstop federal siting of national interest transmission corridors,[10] its directive that the Commission exercise its authority to facilitate the expansion of the grid to meet the reasonable needs of load-serving entities,[11] and its provision for incentive/performance-based rates to benefit consumers by ensuring reliability and reducing delivered power cost by reducing transmission congestion[12] reflect Congress's desire to create a robust grid that supports competitive markets and to remedy congestion that imposes costs on consumers, rather than protecting those who benefit from congestion.

In any event, transmission needs in areas likely to be designated as NIETCs are so great that there is little risk that transmission will squeeze out alternative means of addressing grid inadequacies. Even if an area receives an NIETC designation, transmission itself will remain difficult to site and construct. If there are non-transmission alternatives that could be brought on line before the transmission upgrade, there is nothing in section 216's siting authority that would prevent such projects from going forward. Thus, NIETC designations alone should not create

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2005 in *Entergy Servs., Inc.*, Docket No. ER05-1065-000, at 7-8, *available at* http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10898733.

[9] *See* White Paper at 19-20.
[10] EPAct 2005 § 1221; FPA § 216.
[11] EPAct 2005 § 1233; FPA § 217(b)(4).
[12] EPAct 2005, § 1241; FPA§ 219.

roadblocks to non-transmission projects. If problems arise in the future, the Department can consider modifying the NIETC designation criteria at such time.

Undue concern for the alleged competition between transmission and non-transmission solutions could also delay or stymie needed investment. The PJM transmission planning process places proposed transmission upgrades identified as serving economic needs on "hold" for 12 months to give the "market" an opportunity to come forward with alternatives.[13] However, PJM is "very, very disappointed" with the results of this process,[14] and it recently testified:[15]

> Do we want a "minimalist" transmission grid that essentially serves as an "add-on" facilitating the reliable movement of power from generation sited close to load? In other words, should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its design, links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose? The "rules of the road" and the costs to build one system versus another are vastly different….
>
> In many ways, the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry.… Assuming that we wish a strong transmission system to provide load with many options, we believe a new set of "building blocks" is needed.

The Department similarly should stay focused on supporting a strong transmission system.

Comment on Question: "Should the Department distinguish between physical congestion and contractual congestion, and if so, how?"

Whether congestion is deemed physical or contractual, it can impose costs that could qualify an area as an NIETC. For example, where a transmission customer can schedule transmission only on a non-firm basis, even though it needs firm transmission, significant costs can be imposed, especially if the congestion prevents transmission customers from contracting for needed generation or building a plant needed to bring economic power to end-users. On a system with financial transmission rights, there may be significant, unhedged congestion charges, which raise costs to consumer and discourage investment in generation. In other areas, incumbent TO practices with respect to setting aside transmission capacity as Transmission Reserve Margin

[13] *PJM Interconnection, LLC*, 105 F.E.R.C. ¶ 61,123, PP 21-24 (2003).
[14] Transmission Investment Technical Conference, *Transmission Independence and Investment*, Docket Nos. AD05-5-000 and PL03-1-000, Transcript at 70, 72 (Apr. 22, 2005), *available at* http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10526335.
[15] Written Remarks of Audrey Zibelman, PJM's Executive Vice President, at the April 22, 2005 Transmission Investment Technical Conference, *Transmission Independence and Investment*, Docket Nos. AD05-5-000 and PL03-1-000, at 5, *available at* http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10507109.

("TRM") or Capacity Benefit Margin ("CBM") can reduce the amount of transmission capacity available to the market, thus foreclosing otherwise economic transactions.[16] In these and similar cases, if an area otherwise qualifies as an NIETC, the underlying characterization of the congestion should not be determinative.

Comment on Question: "Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?"

If "dynamic" congestion means congestion that comes and goes depending upon system conditions and "persistent" means congestion that is always present, the Department must bear in the mind that the economic costs and reliability consequences of dynamic congestion could be as great as, if not greater than, persistent congestion. Whether "dynamic" or "consistent," an area or corridor should receive NIETC designation if it otherwise meets the proposed criteria.[17]

Respectfully submitted,

/s/ Mark S. Hegedus

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March 6, 2006

[16] For example, the contract path between two or more systems may well cause actual, physical flows to occur on other systems ("loop flows"). TOs may have increased the size of their TRM or CBM set-asides because of claimed loop flows on their systems caused by contract paths between neighboring systems.

[17] TAPS here is not suggesting that a rare occurrence of transmission congestion should necessarily give rise to an NIETC designation and the potential investment in transmission infrastructure associated with it. In such cases, the designation criteria seem unlikely to be satisfied in any event.

84. Upper Great Plains Transmission Coalition, Received Mon 3/6/2006 4:04 PM

March 5, 2006

Office of Electricity Delivery and Energy Reliability
OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building
Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Re: Notice of Inquiry: *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors"*

The Upper Great Plains Transmission Coalition (UGPTC) is pleased to provide comments to the Office of Electricity Delivery and Energy Reliability (OE) relative to the above described Notice of Inquiry related to National Interest Electric Transmission Corridors (NIETC). The UGPTC represents the interests of electric power stakeholders within the Upper Great Plains region including North Dakota, South Dakota, and Minnesota. Its membership includes FERC-jurisdictional and non-jurisdictional entities including transmission providers, utilities, electricity generators, coal and wind project developers, fuel suppliers, and includes non-voting governmental entities. The charter for the UGPTC is to identify, publicize, and advocate solutions to increase the export of electrical energy from the Upper Great Plains. As such, the UGPTC has important perspectives to offer OE as it moves forward with the establishment of a process to designate NIETB. We welcome the opportunity to offer these comments which are intended to assure that the NIETC process is timely and will complement regional efforts to resolve the transmission constraints that impede the economically efficient operation of regional energy markets in the Upper Great Plains.

OE has reported to the UGPTC regarding the status of these proceedings on two separate occasions. We appreciate the opportunity to hear from and consult with OE officials in such instances.

Section 1221 of the Energy Policy Act of 2005 (EPAct 2005), requires the Secretary to conduct a nationwide study of electric transmission congestion. The EPAct 2005 further provides the Secretary with authority to designate any geographic area experiencing transmission capacity constraints or congestion that adversely affects consumers as a "National Interest Electric Transmission Corridor" (NIETC). If such a designation is made then FERC is given "back-stop" authority to assure that the siting of facilities within the NIETC is made on a timely basis.

As expressed in the Federal Register Notice, OE has set forth a clear case for new transmission investment in the United States (p.3)

> *"Today congestion in the transmission system impedes economically efficient electricity transactions and in some cases threatens the system's safe and reliable operation. The Department has estimated that this congestion costs consumers several billion dollars per year by forcing wholesale electricity purchasers to buy from higher-cost suppliers."*

Comments:

The following comments represent the views of the UGPTC after being reviewed and prepared by the UGPTC membership. Notwithstanding these comments, members of the UGPTC may submit comments of their own or as members of other organizations. Some members also suggest that OE consider national security interests as it displays and distributes information about critical weaknesses in the transmission grid.

Congestion study: We have participated in the previous OE processes regarding "national bottlenecks" and look forward to seeing the process proceed expeditiously. We support the use of existing inventories and studies as a starting point for producing an inventory of possible corridors.

1. *Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?*

We believe that such a distinction should be made, with persistent congestion given a higher priority. Persistent congestion is more indicative of present physical constraints within the grid, which are more likely to require new investment to be resolved. Conversely, dynamic congestion is likely to be the result of market forces, intermittent demand and possibly dynamic resources, such as wind. So, the need for an NIETC designation is greater where persistent congestion occurs. The OE should distinguish between persistent congestion and dynamic congestion by looking at the magnitude and hours that LMP markets have identified as having a significantly high congestion component in the LMP. Areas where the congestion costs are high for only a limited number of hours in a year would be considered dynamic, whereas those that experience high congestion costs for extended hours would be considered persistent. For non-LMP market areas, the frequency and magnitude of curtailments could be used in place of the congestion component of the LMP.

2. *Should the Department distinguish between physical congestion and contractual congestion, and if so, how?*

No, such a distinction should not be made. Contractual commitments, including rollover rights, must be recognized in evaluating the present and future availability of transmission capacity. To do otherwise would require engaging in a dubious exercise of investigating or second guessing the future intentions of those who hold and have paid for contractual rights. The NIETC designation is designed to encourage new transmission investment. Those investments should be made where a lack of capacity exists or is expected to emerge considering both committed and expected uses.

It is particularly important to note that a lack of present or historic congestion (as evidenced by curtailments or congestion costs) does not necessarily mean that a critical constraint is absent. It is not unusual for past and present uses to roughly match the transmission capacity across long-standing constraints. Few bother to ask for additional capacity where providing it is widely known to be difficult. In addition, historic indicators of congestion may not reflect the presence of contingency-based constraints where, through good fortune or otherwise, the limiting contingencies have not actually occurred. Because history is not necessarily a good indicator of future needs, the OE should pay particular attention to credible projections of future congestion, with due consideration of contingencies and other factors necessary to ensure ongoing reliability.

3. *In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review?*

In 2004, the UGPTC in coordination with the area utilities and the MISO initiated a transmission study (the "Northwest Exploratory Study") to determine the necessary transmission system additions to deliver over 2000 MWs of generation from the resource rich (coal and wind) Dakotas into the Minneapolis/St Paul load center. This study effort was an excellent example of many stakeholders working together to identify the regional transmission infrastructure improvements necessary to develop new economic generation resources. Through diverse stakeholder involvement, the needs of coal developers and wind developers as well as utility planners were addressed. The Northwest Exploratory Study is summarized in Section 7.2 of the *Midwest ISO Transmission Expansion Plan 2005* ("MTEP 05"). We have attached a scope of the study and a PowerPoint presentation to these comments. The geographic area addressed in the Northwest Exploratory Study should be considered for NIETC status in the future.

You should also consider:

- the CAPX 2020 Vision Study (Minn. 2005);
- Western Area Power Administration's Dakota Wind Study (2005); and
- Cambridge Energy Research Associates Study (2004) "Grounded in Reality: Eastern Interconnection" (attached).

4. *What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?*

Economic benefits to consumers
Cost of transmission solution for geographic region
Positive affect on reliability of electric grid
Diversity of energy resources, such as combined coal and wind
Congestion costs within Regional Transmission Organizations (RTOs)

Criteria Development:

UGPTC believes that OE has developed a sound list of criteria for considering NIETC designations. We have no recommendations for criteria beyond those listed in the NOI. However, we believe that not all of the criteria should have to be met to qualify for an NIETC designation -- that is, they should be considered to be *factors* rather than absolute criteria. The UGPTC also believes that the criteria should be given different weights based upon individual circumstances. For example diversity may not be an important factor for some designations, while in others it may be the most important factor. OE should assess each circumstance to see if the proposed region reaches a level of sufficient importance to warrant designation of a NIETC. The Secretary was provided with discretion within EPAct 2005. That discretion should be used in applying the final criteria.

The MISO Northwest Exploratory Study shows that exports of electricity from the Dakotas into Minnesota and the surrounding states are limited because of the ND Export Interface. We believe that most of the criteria below would apply if new transmission were added to resolve the ND Export Interface through the assistance of an NIETC designation.

#1: *Maintain high reliability:*

Our society and economy are critically dependent upon maintaining nothing less than the highest achievable levels of reliability in our electric supply. Thus a criterion addressing reliability is appropriate and important. Reliability considerations include compliance with national and regional reliability criteria, loss of load probabilities, and effects of contingencies on the availability of supply resources. For example, currently transmission constraints limit the export from the Dakotas to approximately 1950 MWs of electrical power and energy across the ND Export Interface. When certain transmission lines are out of service in the region the electrical generation in the Dakotas must be curtailed. New transmission lines will improve the reliability of exporting existing generation out of the Dakotas into the surrounding states. In addition, as new wind and coal resources are developed in the Dakotas, it is essential that new generation outlet transmission be constructed to maintain a high degree of reliability and a more robust electrical network in the Dakotas and surrounding states.

#2: *Economic benefits to consumers*

New transmission investments would enable large amounts of new coal-based and wind generation to be delivered into the Minneapolis and St. Paul, Minnesota and Wisconsin markets, providing new low-cost resource options for the benefit of consumers in these areas. The economic benefit is best measured in terms of electrical energy savings to those consumers. The estimated cost to deliver coal to local generation power plants in the Twin Cities area is \$1.50/mmBtu versus \$0.75/mmBtu for coal deliveries to western ND. For a 500 MW power plant located in Western ND the savings in fuel cost expressed in electrical energy is \$.0075/ KWH. For a single plant, this could save Minnesota consumers over \$3 million per year.

The MISO 2003 Transmission Expansion Plan (MTEP-03, June 2003) provides another example of economic benefit to consumers. It concluded that alleviating the transmission constraints in the North Dakota/Minnesota/Iowa areas through a $667 million transmission investment would save $444 million in energy costs annually compared to electricity from natural gas priced at $5.00/mmBtu.

Building new wind and new coal based generation in North Dakota along with the needed transmission lines is more cost effective and more beneficial to consumers than building new gas generation close to the load. Moving power from wind and coal-based generation through expanded and enhanced transmission corridors will benefit consumers through lower costs. (See Exhibit 1)

#3: *Ease supply limitations/diversify sources*

New transmission would strengthen the existing transmission system, increase reliability for existing generation, and enable new and diverse generation to be transmitted reliably into surrounding states. The upper Great Plains has a unique combination of rich wind and clean coal resources in the same geographic region, both of which can be maximized through collaborative transmission investment, further expanding the nation's energy diversity and supply.

#4: *Enhance energy independence of the United States*

The U.S. has a 250-year supply of coal (an 800-year supply of lignite in North Dakota at current production rates) and an unlimited supply of wind. Using existing and new technologies to develop coal and wind resources will lessen our dependence on foreign sources of energy. In addition, new generation resources will relieve demand on the limited supplies of higher priced natural gas, which can be better used for more beneficial purposes than generating electricity.

#5: *Further national energy policy*

As we continue to harness coal and wind as described above new technologies will continue to evolve. For example, conversion of coal-to-liquids is fast becoming a technology that could produce more domestic liquid fuels. However, coal-to-liquids projects will be more likely to succeed if the electricity they produce as a by-product can be transmitted and sold into remote markets. So, by solving the ND Export Interface problem through new investment, coal-to-liquids and wind-to-hydrogen projects will become more attractive. Development and commercialization of these new technologies will reduce our dependence on foreign oil and are in accordance with the US energy policy.

#6 Enhance reliability and reduce vulnerability to natural disasters or malicious acts.

Additional transmission will make the system more robust and increase reliability. Additional transmission will also utilize remote generation capacity (wind and coal) from areas that are less susceptible to natural disasters because of their location. And dispersing generation to remote areas, rather than concentrating generation near population centers reduces the risk from malicious acts

#7 Need is not unduly contingent

The need for new transmission and generation is well documented. The Minneapolis-St. Paul region is one of the fastest growing in the country. The Mid-Continent Area Power Pool (MAPP) forecasts that the load of their U.S. member utilities will grow by 5400 MW over the next ten years. The State of North Dakota conducted research in the same market and identified additional capacity needs of approximately 4000 MW between 2010 to 2015. The CAPX 2020 Interim Report (December 2004) projects a need of 6300 MW by 2020. (CAPX 2020 is a consortium of Minnesota utilities.) In each instance the need is well documented but transmission remains a challenge in need of a solution.

#8 *Alternative means of mitigating needs have been addressed*

NIETC designation of the ND Export constraint would facilitate making new energy supplies available to Minnesota and Wisconsin. Utilities in both of these states have aggressive demand side programs, yet their demand for electricity is growing rapidly, requiring new transmission.

Transmission-owning utilities in the upper Great Plains region have installed numerous small and medium-scale transmission expansion projects, including FACTS technology, to increase the capacity of the existing backbone system to its limits. Additionally, very sophisticated special protection schemes and operating procedures have been deployed to fully utilize every bit of the existing capacity. However, there is consensus among transmission planning and operations personnel that more projects or techniques of a similar nature will not provide significant new transmission capacity.

The NIETC process is vitally important to our nation's energy security, and will help to attract political support and recognition for those transmissions solutions receiving the designation. Such designation will help attract the investment necessary to implement solutions in those corridors receiving an NIETC designation.

In defining the corridors, the OE should pay particular attention to constraints that involve multiple states, because they are often the most difficult to solve due to differing regulatory requirements and political considerations. Constraints are often regional issues and NIETC designations should reflect that reality. The corridors should be sufficiently flexible as to reflect the differing needs of each geographic region. The UGPTC specifically suggests consideration of an interstate corridor spanning well-recognized constraints between the coal and wind fields of the Dakotas and load centers in the Minneapolis/St. Paul area and eastern Wisconsin.

Sincerely,

Robert W. Harms
Chairman
UGPTC

Attachments:
Northwest Exploratory Scope of Study **[Note from the U.S. Department of Energy: Attachment received; contact Robert Harms at HarmsRbrt@aol.com to obtain attachment.]**
Northwest Exploratory Study, presentation **[Note from the U.S. Department of Energy: Attachment received; please contact Robert Harms at HarmsRbrt@aol.com to obtain attachment.]**
Platts Study **[Note from the U.S. Department of Energy: Attachment not received.]**
CERA Study **[Note from the U.S. Department of Energy: Attachment received but is proprietary in nature.]**

Exhibit 1:

Summary Economics for a Typical Generation Technologies

		Wind	**Coal**	**CC Gas**	**SC Gas**
Assumptions:					
Project Life		25	33	25	20
Interest Rate:		7.0%	7.0%	7.0%	7.0%
Capital Cost $/kW Capacity		$ 1,400	$ 2,000	$ 900	$ 500
Annual Amortization (per kW)		$120.13	$156.82	$77.23	$47.20
Cost of Fuel ($/mmbtus)		N/A	$ 0.70	$ 6.00	$ 6.00
Efficiency of Generator		N/A	32%	49%	31%
Capacity Factor		40%	90%	50%	15%
Annual kWh Produced (per kW)		**3,504**	**7,884**	**4,380**	**1,314**
Fixed Ops & Mtce ($/kW-yr)		$ 22.00	$ 30.00	$ 10.00	$ 18.00
Variable O&M		$ 2.00	$ 2.20	$ 3.00	$ 3.00

Expected Cost per MWH (at generator -- no transmission included)

		Wind	Coal	CC Gas	SC Gas
Fixed Costs					
Amortization Cost per kWh		$ 34.29	$ 19.89	$ 17.63	$ 35.92
Fixed Ops & Mtce		$ 6.28	$ 3.81	$ 2.28	$ 13.70
Variable Costs					
Fuel		$ -	$ 7.35	$ 42.00	$ 66.00
Variable Ops & Mtce		$ 2.00	$ 2.20	$ 3.00	$ 3.00
ND Property Taxes @ *	2.5%	$ 1.50	$ 6.34	$ 5.14	$ 9.51

Total	**$**	**44.06**	**$**	**39.59**	**$**	**70.05**	**$**	**128.13**

*Wind property tax @30% of market value

Notes:
1) To serve firm load, wind may require an equivalent amount of backup generation to be available during periods the wind is not blowing. Thus the total cost of Wind may include any fixed cost of backup generation.
2) The above are general assumptions which will vary substantially from project to project. For instance, natural gas fuel costs can be volatile, project life assumptions can vary and capacity factors vary significantly
3) The property tax on Wind as shown assumes special tax treatment in ND/SD.
4) Assumes minimum commercial size. Economy of scale can reduce unit costs (i.e., a larger project will typically cost less per unit of capacity, as well as having lower costs per kWh generated)
5) Wind also qualifies for a 1.8 cent/kWh production tax credit (if available), as well as accelerated depreciation

The above analysis suggest that new coal-based generation will result in a 4.0 cent/kW cost of electricity, new combined cycle natural gas generation (base load) will cost 7.0 cents/kW and new simple cycle gas generation (peaking units) will cost 12.8 cents/kW.

85. U.S. Environmental Protection Agency, Received Mon 3/6/2006 4:44 PM

U.S. Environmental Protection Agency Comments in Response to the

U.S. Department of Energy's Notice of Inquiry on Considerations for Transmission Congestion

Study and Designation of National Interest Electric Transmission Corridors

Published in the February 2, 2006 Federal Register

I. INTRODUCTION

Pursuant to the Notice of Inquiry ("NOI") requesting comment and providing notice of a technical conference, the Environmental Protection Agency is pleased to have an opportunity to submit its comments on the proposed questions for public comment to support FPA subsections 216(a)(1) and 216(b)(4)(A)-(E), as amended by the Energy Policy Act of 2005. Specifically, these comments respond to the initial electric transmission congestion study and the development of criteria to evaluate geographic areas identified in the congestion study as candidates for National Interest Electric Transmission Corridors ("NIETCs").

The U.S. Environmental Protection Agency ("EPA") supports a variety of demand-side resources, including energy efficiency, clean distributed generation, and demand response as they can provide significant cost-effective air emissions reductions by serving electricity load as well as controlling load growth served by fossil fuel-fired power generators. The electricity generation sector is the largest contributor to U.S. greenhouse gas emissions, contributing a third of U.S. carbon emissions.[1] In addition to environmental benefits, demand-side resources provide reliability, security, and fuel diversity benefits.

For over 15 years, EPA has actively worked to remove barriers to cost-effective demand-side resource investments by energy end users, utilities and partner organizations. Through the EPA/Department of Energy ("DOE") ENERGY STAR program, partner organizations have helped control electricity load growth, providing 4 percent of U.S. energy consumption through efficiency. There is still a large untapped potential for additional energy efficiency in the U.S., particularly during peak periods of demand. This potential can defer the need for added transmission infrastructure in certain areas of the country.

II. COMMENTS

EPA recognizes that great potential for demand-side resources, including energy efficiency, demand response, and clean distributed generation, to address areas of transmission congestion. These resources not only address congestion in a cost-effective manner, but also reduce total emissions from the U.S. electric generation sector. Further, demand-side resources can often provide congestion relief sooner than the development of new transmission lines. The following two examples illustrate efforts to integrate what are being called "non-wires solutions" with transmission planning:

- In December 2003, ISO New England issued a Request for Proposal for up to 300 MW in order to provide near term congestion relief in Southwest Connecticut. Efficiency, demand response and distributed generation were included in the

[1] Based on 2002 data from U.S. Greenhouse Gas Emissions and Sinks: 1990-2002, Table 2-6.

award to provide congestion relief in Southwest Connecticut through 2007 when a new transmission project is expected to be completed.[2]

- In 1990, Bonneville Power Administration (BPA) successfully deferred the construction of a 500 kilovolt transmission line by constructing a new substation and implementing conservation and load management programs. BPA is currently using its Non-Wires Roundtable process to standardize and institutionalize how to look at non-wires options before making transmission investments. BPA is investigating non-wires solutions to defer a $22 million transmission upgrade.[3]

At the federal level, EPA is working with DOE and industry leaders on developing an Energy Efficiency Action Plan (EEAP), aimed at spurring an aggressive new national commitment to energy efficiency by electric and natural gas utilities and partner organizations across the U.S. The EEAP will document a set of business cases, best practices, and recommendations that are designed to cause greater investment in energy efficiency by utilities and energy end-users within the next five years. Of interest to DOE's transmission corridors study, the EEAP Planning Processes Working Group will explore in detail models and approaches for better incorporating non-wires solutions into traditional utility resource planning processes. EPA would be happy to provide information that the EEAP process generates that may be relevant to a study of the transmission corridors.

In addition, EPA has provided technical assistance to a number of state public utility commissioners who are striving to implement regulations in the electric sector that are consistent with their state's policy guidance on clean energy and reduced emissions.[4] Designating NIETCs through a process that provides fair value to the environmental and emissions benefits of a

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[2] *Demand Response in Southwest Connecticut* presentation by Bob Laurita of ISO New England.
[3] LeBlanc, William, "Using Energy Efficiency and Demand Response to Cut T&D Costs," ESource, September 2005.
[4] EPA also works across state agencies under our Clean Energy-Environment State Partnership and recently released the *Clean Energy-Environment Guide to Action* which provides additional information on policies to promote demand-side resource options. Report available at http://www.epa.gov/cleanenergy/stateandlocal/guidetoaction.htm.

transmission corridor should help facilitate approval and investment as many states and local communities are striving to coordinate environmental and energy policies and energy companies are increasingly considering environmental costs and risks in their investment decisions.

Regarding area evaluation for NIETC designation, EPA recognizes that the potential for cost-effective demand-side resources, including energy efficiency, demand response and clean distributed generation, may be greater in certain areas than others. Demand growth estimates do not fully capture the potential for an area to achieve cost-effective non-wires solutions. Several potential studies are available at the national, regional, and state levels for energy efficiency. According to a meta-analysis of multiple potential studies, the median achievable potential is 24 percent (averaging 1.2 percent per year) for electric energy efficiency.[5] A listing of available potential studies is attached.

Consistent with our above comments, EPA suggests the following:

1) **Include environmental benefits as a category to develop geographic areas of interest in the Congestion Study**, per Question 4 under Section III.A. of the NOI;
2) **Include an area's potential for demand-side resources in the definition of an affected area** within Draft Criterion 1 under Section III.B. of the NOI;
3) **Recognize the benefits demand-side resources provide to fuel diversity and enhanced energy independence** within Draft Criterion 4 under Section III.B. of the NOI;
4) **For areas with a high potential for demand-side resources, include non-wires solutions to reduce vulnerability of critical loads and electric infrastructure to natural disasters and malicious acts**,[6] per Draft Criterion 6 under Section III.B. of the NOI;

[5] Steve Nadel, Anna Shipley, and R. Neal Elliot, "The Technical, Economic and Achievable Potential for Energy Efficiency in the US – A Meta-Analysis of Recent Studies", American Council for an Energy Efficient Economy, Proceedings from the 2004 ACEEE Summer Study on Energy Efficiency in Buildings.
[6] Issue further discussed in Regulatory Assistance Project's Issues Letter titled *Electrical Energy Security:*

5) **Capture the full stream of values offered by non-wires solutions by including environmental benefits, potential to meet load within an affected area, energy independence, and reduced vulnerability**, among other things, per Draft Criterion 6 under Section III.B. of the NOI; and
6) **Include consideration of environmental and emissions benefits of corridors that provide access to renewable resources and designations that encourage non-wires solutions in areas with large demand-side resource potential** as another criterion when making a NIETC designation (comment provided in response to first Additional Question under Section III.B. of the NOI).

III. CONCLUSION

EPA believes this is an important study to help remove existing barriers to relieving congestion costs and improving reliability of the electric transmission grid in the United States. There is great potential for non-wires solutions through demand-side resources, including energy efficiency, clean distributed generation, and demand response, and these important resources should not be overlooked in this study. Further, when designating NIETCs, DOE should not overlook the environmental costs and emissions profile. Renewable energy and demand-side resources can reduce emissions of the electric generation sector in a cost-effective manner. EPA would be happy to further assisting DOE with this important aspect of the study.

Respectfully submitted,

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Washington, D.C. 20460
202-343-9003

Assessing Security Risks Part 1 (April 2002) available at http://www.raponline.org/showpdf.asp?PDF_URL=%22Pubs/IssueLtr/ElecSec1.pdf%22

March 6, 2006

Attached: Listing of energy efficiency potential studies

National and Regional Energy Efficiency Potential Analyses

Region	Title/Description	URL Address
National	**The Technical, Economic and Achievable Potential for Energy-Efficiency in the U.S. – A Meta-Analysis of Recent Studies**. Steven Nadel, Anna Shipley and R. Neal Elliott. 2004.	http://www.aceee.org/conf/04ss/rnemeta.pdf
Midwest	**Examining the Potential for Energy Efficiency to Address the Natural Gas Crisis in the Midwest. American Council for an Energy Efficient Economy.** Kushler et al, 2005.	http://www.aceee.org/pubs/u051.htm
Northeast	**Economically Achievable Energy Efficiency Potential in New England**. Optimal Energy, Inc. for Northeast Energy Efficiency Partnerships , November 2004, updated May 2005.	http://www.neep.org/files/Updated_Achievable_Potential_2005.pdf
Northwest	The Fifth Northwest Electric Power and Conservation Plan**. Document 2005-7. The Northwest Power Planning Council May, 2005. This is the Northwest Power and Conservation fifth Northwest Power Plan, a blueprint for an adequate, low-cost and low-risk energy future. Technical appendices include conservation cost-effectiveness methodologies.**	http://www.nwcouncil.org/energy/powerplan/plan/Default.htm
Southeast	**Powering the South, A Clean & Affordable Energy Plan for the Southern United States**. The Renewable Energy Policy Project 2001.	http://poweringthesouth.org/report/
Southwest	**The Potential for More Efficient Electricity Use in the Western U.S.: Energy Efficiency Task Force Draft Report to the Clean and Diversified Energy Advisory Committee of the Western Governor's Association, Draft Report for Peer Review and Public Comment.** Western Governor's Association. September 15, 2005.	http://www.westgov.org/wga/initiatives/cdeac/Energyefficiencydraft9-15.pdf
	The New Mother Lode: the Potential for More Efficient Electricity Use in the Southwest. Southwest Energy Efficiency Project, Report for the Hewlett Foundation Energy Series. November 2002.	http://wwwswenergy.org/nml/New_Motherlode.pdf

State Energy Efficiency Potential Analyses

State	Title/Description	URL Address
California	**California's Secret Energy Surplus: The Potential for Energy Efficiency.** The Hewlett Foundation Energy Series, The Energy Foundation and The Hewlett Foundation, September 23, 2002.	http://www.ef.org/documents/Secret_Surplus.pdf
Connecticut	**Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region.** Connecticut Energy Conservation	http://www.env-ne.org/Publications/CT_EE_MaxAchievablePotential%20Final%20Report-

	Management Board, June 2004.	June%202004.pdf
Georgia	**Assessment of Energy Efficiency Potential in Georgia.** ICF Consulting, Final Report submitted to the Georgia Environmental Facilities Authority, May 5, 2005.	http://www.gefa.org/pdfs/assessment.pdf
Iowa	**The Potential for Energy Efficiency in Iowa.** Oak Ridge National Laboratory, UT-Battelle, PLC. Contract No. DE-AC05-00OR22725. Sponsored by The Iowa Energy Center. June 2001.	http://www.ornl.gov/sci/btc/apps/Restructuring/IowaEEPotential.pdf
Massachusetts	**The Remaining Electric Energy Efficiency Opportunities in Massachusetts.** Massachusetts Division of Energy Resources Final Report. June 7, 2001.	http://www.mass.gov/doer/pub_info/e3o.pdf
Oregon	**Energy Efficiency and Conservation for the Residential, Commercial, Industrial, and Agricultural Sectors.** Ecotope, Inc. Prepared for the Energy Trust of Oregon, Inc., January 2003.	http://www.energytrust.org/Pages/about/library/reports/Resource_Assesment/ETOResourceAssessFinal.pdf
Oregon	**Natural Gas Efficiency and Conservation Measure Resource Assessment for the Residential and Commercial Sectors.** Prepared for the Energy Trust of Oregon, Inc. By Ecotope, Inc. August, 2003	http://www.energytrust.org/Pages/about/library/reports/Resource_Assesment/GasRptFinal_SS103103.pdf
New Jersey	**New Jersey Energy Efficiency and Distributed Generation Market Assessment.** Final Report to Rutgers University, Center for Energy, Environment and Environmental Policy. KEMA, August, 2004.	http://www.bpu.state.nj.us/cleanEnergy/KemaReport.pdf
New York	**Energy Efficiency And Renewable Energy Resource Development Potential In New York State. Final Report Volume One: Summary Report.** NYSERDA. 2003.	http://www.nyserda.org/publications/EE&ERpotentialVolume1.pdf
Wisconsin	**Energy Efficiency and Customer-Sited Renewable Energy: Achievable Potential in Wisconsin.** Energy Center of Wisconsin, November 2005.	http://energytaskforce.wi.gov/section.asp?linkid=34

86. Utah Clean Energy, Received Thu 3/2/2006 11:47 AM

March 2, 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

By e-mail to: EPACT1221@hq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of

National Interest Electric Transmission Corridors

Utah Clean Energy wishes to comment on the Department of Energy (the "Department")'s efforts in conducting its initial electric transmission congestion study required by the Energy Policy Act amendment to the Federal Power Act subsection 216(a)(1). We understand the Department intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity could lessen potential adverse effects borne by consumers.

We support the Department's goal to identify corridors for potential projects as generalized electricity paths between locations, as opposed to specific routes for transmission facilities. We also believe that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion.

We wish to emphasize that the Department's initiative is an opportunity to identify wind-rich regions that offer both economic development along potential transmission corridors and economical energy from wind power development. While some early wind projects may have been built in the wind-rich area(s) of our state, the potential for more wind energy development should be included in the Department's review. We believe there is a true need to plan for more transmission to move wind power from future wind developments to consumers, thereby providing economic benefits, fuel diversification, and clean energy for our citizens.

Thank you,

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87. Utah Energy Advisor to Governor Jon Huntsman, Jr. , Received Mon 3/6/2006 4:38 PM

Dr. Laura Nelson, Energy Advisor to Governor Jon Huntsman, submits these comments in response to the notice of the U.S. Department of Energy (“DOE” or the “Department”) regarding “Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors.” See 71 Fed. Reg. 5660 (Feb. 2, 2006). The comments are directed toward the proposed Frontier Line Transmission Project (“Frontier Project”).

The Department’s willingness to engage the states, the Western power industry, and proposed interstate electric transmission projects in the West in collaborative discussions, and to thereby use existing analyses of the Western transmission system developed in open transmission planning processes in the region, is laudable and comports with the Governors' request expressed in Western Governors' Association Resolution 05-30.

The implementation of Section 216 of the Federal Power Act (as enacted through Section 1221 of last year's Energy Policy Act) has reached a critical stage, which is the development of criteria by which the Secretary of Energy may designate National Interest Electric Transmission Corridors ("NIETC"). The approach taken in these comments is to facilitate the Department's successful implementation of its responsibilities under federal law.

The comments are divided into three sections. Section 1 is intended to provide background and support for the Frontier Project. The information which follows describing the Frontier Project provides strong support for its designation within a national interest corridor due to the Project's attributes and the benefits to consumers. It is not advocated that DOE proceed with early designation of the Frontier Project in advance of completion of DOE's study, but it is strongly recommended that the Project be included in the inventory of potential NIETCs and that, once the study and inventory are completed, NIETC designation should be conferred on the Project.

Section 2 is addresses the recommended scope and collaboration deemed critical to maximize the value in Section 216 for action in the West.

Section 3 of the comments is intended to provide answers to questions raised in the NOI that considered most relevant to the Frontier Project. In particular, it is requested that the Department, in considering NIETC designations in the West, not focus exclusively or even primarily on alleviation of existing congested transmission paths. In the West, NIETC designation is needed for large transmission projects that can forestall energy crises like the one that occurred in 2000-01 by connecting western resource areas with western load centers.

Section 1 - Background Information on the Frontier Transmission Project and Justification for Designation as a NIETC

The Department indicates that one of the results of its study will be an inventory of areas where planners believe significant transmission needs exist and where transmission additions could alleviate such needs. Following issuance of the study, and after taking further public comment, the Department will proceed with NIETC designations. Due to the significance of its scope and scale, the Frontier Line Project meets the overall criteria to warrant inclusion in the inventory and ultimate designation.

A more robust interstate electricity transmission system and access to more sources of clean energy is needed in the Western region to relive congestion, support significant load growth, and protect the overall quality of life in the region.

On April 4th, 2005, the Governors of Wyoming, Utah, Nevada and California signed a Memorandum of Understanding ("MOU") declaring their support for the Frontier Line. The

MOU generally described the Frontier Line as originating in Wyoming, traversing Utah and Nevada, and terminating in California. The MOU further stated that preliminary work had been done to identify an initial route but recognized that further detailed studies need to be performed. Some of these studies are currently ongoing.

This effort was undertaken in response to growing consumer energy demand, a desire to develop the vast resources across the West, including renewable resources such as wind and advanced, clean coal technologies, and the critical need to further diversify the West's energy portfolio in order to strengthen our nation's energy and national security.

The Frontier Line proposal grew out of years of study of western electric resource requirements and transmission needs following the western energy crisis of 2000-2001. The crisis led the Western Governors Association to prepare the 2001 report *Conceptual Plans for Electricity Transmission in the West*. The report concluded that new transmission and generation infrastructure located remotely from population centers could produce benefits for consumers throughout the West. The report also concluded that such an investment strategy would allow the West to diversify its electric generation resource base by promoting the development of renewable resources and new clean coal resources thereby protecting the West against excessive reliance on new natural gas-fired generation. Although the study did not identify specific projects, it did note the need for extensive upgrades to the western backbone transmission grid.

The western governors followed up this effort by asking the Seams Steering Group-Western Interconnection ("SSG-WI") to develop an ongoing proactive transmission planning process for the western interconnection. In 2003, SSG-WI issued a report on western transmission needs. The SSG-WI report examined various generation and accompanying transmission scenarios, developed a public data base to support transmission expansion analysis, but did not provide sufficient detail to enable development of specific transmission projects.

On August 22, 2003, Governor Freudenthal and former Utah Governor Michael Levitt announced the formation of the Rocky Mountain Area Transmission Study ("RMATS"). Noted was the critical need for new transmission in the West:

> For many years, utilities and other entities have been reluctant to make investments in needed electric transmission infrastructure. This has been due to a number of factors, including protracted uncertainties in the regulatory environment and nascent regional transmission organizations under development. As a consequence of this lack of transmission expansion, transmission congestion and bottlenecks are increasing.

The RMATS Phase I report was completed in September 2004. The report recommended a number of transmission projects within the Rocky Mountain Footprint states of Colorado, Idaho, Montana, Utah and Wyoming.

Although the RMATS study focused on the Rocky Mountain states, at the same time it was recognized that there was a critical need to tie together the resource needs of load centers in Utah, Nevada and California with the resource supplies of Wyoming, Utah and Nevada. That recognized need led to execution of the Frontier Line MOU last year.

In addition to the substantial economic benefits the Frontier Line can provide, it will:

- Strengthen the reliability of the West's transmission system.
- Better protect consumers from energy shortages and price spikes.
- Encourage a broader, diversified energy portfolio.
- Reduce reliance on foreign energy imports and enhance domestic energy security.
- Encourage new technologies that can accelerate the development of renewable energy generation and reduce the cost of controlling emissions from the West's vast fossil fuel resource base.

The Project satisfies the economic need criteria for NIETC designation as set forth in Federal Power Act § 216(a)(4)(A) and (B). As a region, the West has seen load growth of more than 60 percent in the last 20 years, but high-voltage transmission has expanded less than 20 percent. Demand for electricity in high-population states in the West is projected to continue to significantly expand in the coming decades. For instance, using a historical growth rate of 2 percent per year, California must add 1,000 MW of new capacity each year, *net of retirements*, into the foreseeable future. California and the West already experienced an energy crisis in 2000-2001, yet the California Energy Commission recently reported that "[t]he development of new energy supplies is not keeping pace with the state's increasing demands. Construction of new power plants has lagged and the number of new plants applying for permits has decreased." See 2005 California Energy Commission *Integrated Energy Policy Report* at E-1.

The Project would allow the wheeling of several thousand megawatts of both clean coal and renewable-generated power from the Intermountain West to consumers in Utah, Nevada and California. According to an analysis conducted by the Rocky Mountain Area Transmission Study, annual consumer and generator benefits for the Rocky Mountain region range between $926 million to $1.7 billion. California consumers also stand to benefit by $325 million to nearly $400 million annually. The California Energy Commission is in the final stages of completing an updated modeling evaluation of the potential public interest benefits which could be derived by building an interstate transmission line extending from resource rich Wyoming to California.

Analysis supports that the Frontier Project will meet the following criteria:

1. Promote Resource Diversity:

Resources developed to meet growing electrical demand must be clean, diversified and economically and technologically viable. Transmission projects should be designed to allow the fullest possible use of renewable resources.

Proposed projects should identify strategies that ensure renewable resource access to the transmission line, including innovative approaches that ensure a significant amount of capacity is available to renewable developers. Renewable-fossil partnerships are important because the combination of resource attributes can provide significant complimentary benefits for system operation. Additional transmission is needed to bring renewables online faster and more cost-effectively.

2. Incorporate Advanced Technologies and Design Concepts:

States are interested in innovative approaches that make use of the best technology for transmission infrastructure development. The use of such technology should facilitate the siting and permitting process. States also are interested in design concepts that will minimize line loss, improve reliability and minimize environmental impacts. Proposals also should identify opportunities to integrate with other transmission projects in order to reduce costs, enhance reliability and increase generation resource diversity.

3. Produce Economic and Reliability Benefits:

The project must demonstrate net economic consumer benefits in each of the states and in all of the four states collectively. A transparent approach to modeling economic benefits is important. Projects also should identify expected reliability benefits across the West. Because the Western Interconnection is a single interconnected electrical system that operates synchronously, participation in our efforts by other Western states is welcome and can add value to a well-planned project.

4. Ensure Broad Stakeholder Participation:

It is incumbent upon project developers and the States to engage with stakeholders throughout all phases of project development. States are particularly interested in outreach and education as a development objective. This communication process will require a coordinated effort across the public and government agencies at the federal, state, and local levels.

5. Promote Equitable Cost Allocation within a Regulatory Framework:

Recognizing that load growth and benefits of transmission will change over time, States are interested in the project's capital structure and its ability to lend itself towards equitable cost allocation methodologies. The region must consider new approaches to the allocation and recovery of project capital costs in a manner that recognizes the widespread benefits to electric generators and customers across a broad region. Working through these issues will require active participation of many parties over a period of time. Cost recovery proposals also will impact project financing. Proposed projects should identify how the anticipated capital structure will minimize costs to consumers.

6. Allow for Incremental Implementation:

The project should be designed to enable development in phases, with an initial phase of between 1500 and 3000 MW, accompanied by a long-term strategic plan for the eventual development of up to 12,000 MW. Wherever possible, rights-of-way and permitting should be sized to support future project expansion. Early-stage project analysis should include extensive engineering feasibility review as an integral component of development. Work should be coordinated with existing utilities, state, regional and federal planning organizations, as well as other ongoing Western transmission projects and control area operators. Project design in early phases should remain flexible.

7. Ensure Developer Commitment:

Developers should demonstrate to the Governors their ability to successfully plan, finance and construct the project while satisfying the aforementioned criteria. The project developers must have significant transmission system experience and the financial resources to commit toward implementing the steps necessary to complete the project in a timely fashion.

8. Build a Collaborative Relationship:

The States of California, Nevada, Utah and Wyoming can provide a unique, critical synergy to advancing infrastructure projects, built on the opportunity to move low-cost renewable and clean-technology conventional resources from remote locations where they are abundant to distant centers of rapid electric load growth. Our objective is to maximize economic value in resource rich regions of each state by providing political, regulatory, and community support for the development of a large-scale pathway to load-serving utilities in Utah, Nevada and California, thereby maximizing the project's value to customers.

Section 2 – Need for State-Federal Collaboration and an Integrated Federal Agency Implementation Strategy for Section 216

The very notion of a NIETC implies a major procedural undertaking of national policy significance. As stated in the DOE NOI, "Today, congestion in the transmission system impedes economically efficient electricity transactions and in some cases threatens the system's safe and reliable operations." NIETC designation sets in motion a series of interrelated, critical procedural actions among federal and state regulatory agencies that should be designed to follow an orderly sequence. It is imperative that DOE and other federal agencies provide a clear procedural message to the states and electric transmission project developers. This should be established prior to any NIETC designation. It is recommend that DOE carefully coordinate its determination of NIETC criteria and the corridors thereby designated in cooperation the FERC and its responsibilities under Section 216.

The Frontier Line Project has benefited from preliminary support from federal agencies. To succeed, however, a project of this scope and scale will be dependent upon comprehensive, integrated federal agency actions carried out in cooperation with activities in project footprint states. The designation of a NIETC is likely trigger transmission permit applications with state and federal agencies. Such action triggers the one-year clock for state review under Section 216 that then triggers FERC authority to grant eminent domain to condemn private lands. This interrelated series of regulatory actions merits a high level of procedural clarity and state-federal coordination before it is set in motion.

In order to preclude procedural abuses by project sponsors, it is recommended that FERC rules be established specifying that the one-year clock for state regulatory action on a proposed transmission line within a NIETC will not begin until a complete application has been received by a state as defined by state law. It is imperative as a matter of prudent state-federal coordination that local stakeholders be given the opportunity to raise legitimate concerns. DOE should specify how it intends to advise FERC if a sponsor's project falls within a corridor and the information it will provide to justify such a finding. This is particularly important if DOE designates geographically vague NIETCs.

The action or inaction of federal agencies will be a critical element in permitting major new transmission in the West, including the Frontier Line. Prior to finalizing NIETC criteria, DOE should clarify how the responsibilities of federal agencies in their review of applications for different federal permits will be coordinated among agencies in a coordinated manner, and how such process relates to the criteria that the Departments of Energy, Interior, Agriculture, Commerce and Defense are using to designate energy corridors on federal lands under Section 368. DOE should also explain how the designations of energy corridors under Section 368 are to be coordinated with DOE's designation of NIETCs.

Section 3 – Responses to Questions Raised in the NOI

How broadly or narrowly the Department should consider and define corridors?

The appropriate breadth of NIETC lies in an examination of congestion. Congestion should be defined for the purpose of NIETC designation so as to capture all effects of transmission constraints. This will require a broad measure.
Congestion should be measured over large geographic areas covering multiple states within an Interconnection, as well as the intrastate sub-regions that comprise the larger geographic area. Congestion calculations should address the costs to consumers of barriers to access to both existing and potential electric supply resources in locations distant from load centers. Congestion should also not be defined as merely localized congestion conditions but should include broader and truly national interest needs for additional interstate transmission investment so as to avoid future congestion as needed generation resources are added to meet future supply needs.

The Frontier Line is intended to address this broad definition of congestion by moving large amounts of electric power generation derived from advanced coal technologies and renewable wind resources located in resource-rich Wyoming to rapidly growing load centers in Utah, Nevada and California. The project is intended to add additional renewable resources, including geothermal, to the resource supply mix in Utah, Nevada and California.

As noted earlier in our comments, preliminary analysis indicates significant net savings are available from alleviating this congestion.

Should the Department distinguish between persistent and physical congestion?

These comments are based on the interpretation of “persistent congestion” as that which has repeatedly occurred and is expected to continue on known transmission facilities, most likely on an increasing scale. “Dynamic congestion” is more variable, reflecting outages, volatility in fuel prices and unanticipated events. The Department should distinguish between these different types of congestion with the recognition that both are critical to transmission expansion planning. Persistent congestion merits the greatest attention in the Department’s NIETC planning initiative, as it reflects a growing shortfall that tends to escalate in regions experiencing load growth. Sensitivity analysis and probabilistic analysis techniques are available to evaluate both congestions conditions.

Should the Department distinguish between physical congestion and contractual congestion?

Yes. “Contractual congestion” may result from underutilized transmission capacity reservations, and should certainly be distinguished from “physical congestion tied to technical or operational limitations. “Contractual congestion” may be resolved through tariff and regulatory reform, and may not require the construction of new facilities.

Findings of physical congestion should guide the Department’s conclusions on congested paths. In the Western Interconnection, the principal indicator of physical congestion should be a comparison of historical flows and Operating Transfer Capacity (OTC). Conclusions from such an analysis need to be informed by circumstances surrounding the specific path.

What specific transmission studies should the DOE reference?

It is recommended that the Department reference the transmission studies available in consultation with WECC, and the Wyoming Infrastructure Authority (www.wyia.org).

What criteria should be used in evaluating the suitability of geographic areas for NIETC status?

It is important that DOE not only develop specific criteria for evaluating candidates for NEITC designation, but that the Department have written administrative procedures on how the Secretary will apply such criteria in corridor designation decisions. Since corridor designations can lead to federal preemption of state laws and condemnation of private lands, these procedures should: (i) provide opportunity for the states and public to comment on a proposed NIETC designation by the Secretary; (ii) require that NIETC designations be based on preponderance of the evidence; and (iii) subject to a high standard of review.

The Frontier Line Project criteria are incorporated in Section 1 of these comments. These criteria are compatible with the majority of Draft Criteria identified in the NOI, and that the Department refers to them in its decision on setting criteria for NIETC designation.

Other

The Department also asked for comment on the criteria it should use in evaluating the suitability of geographic areas for NIETC status. The first six criteria proposed by the Department are supportable but the seventh and eighth criteria may not be consistent with the objectives of NIETC designation.

The seventh proposed criterion reads as follows: “The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.” While recognizing that, given long transmission construction lead times, NIETC designations require a certain number of assumptions to be made, the Department states that “[o]ther things being equal, arguably the Department should be more inclined to designate NIETCs where there are existing needs instead of projected needs, particularly if those future needs rest upon relatively uncertain assumptions and contingencies.”

These statements by the Department appear to reflect a view that the purpose of NIETC designations is primarily to eliminate existing congestion, a view that is too narrow given the broader concern articulated through Section 216 of the Federal Power Act. This section goes beyond the alleviation of local congestion pockets to reflect the broad view that transmission infrastructure was lagging significantly behind load growth as a result of the difficulty of transmission siting. The problem was seen not only in terms of existing congested transmission paths but also in terms of long-term development of necessary generation resources.

The need to view NIETCs in the context of long-term resource needs is particularly acute in the West. The western interconnection is much different than the eastern interconnection owing to the much greater distances between resource areas and load, the resulting reliance on very long radial lines, the relatively much larger cost of transmission per customer served, the high percentage of land in federal ownership, and the lack of unified market structures. As discussed above, following the western energy crisis in 2000-01 and as a result of interest at the highest level of western state government (and with the cooperation of the federal government), considerable study was undertaken on means for avoiding another crisis. The results of these studies pointed to the need to reduce reliance on natural gas-fired generating stations located close to load and to instead diversify to lower-cost but more distant sources of wind and coal energy. However, the key to this energy strategy was the construction of large, long interstate transmission lines.

An undue emphasis on alleviating existing congested path threatens to make the NIETC process of limited use to the West. The true “national interest” of the West is ensuring the construction of transmission from our resource areas to our load areas. It is therefore requested that the Department recognize a national interest in transmission development on a broader basis than that appearing to be reflected in the seventh proposed criterion.

Finally, it is recommended that the eighth criterion be eliminated as part of the NIETC review process based on the view that "alternative means" of addressing the resource needs in question is inconsistent with the intent of designation and that such decisions are best left to states. The purpose of NIETC is to preserve corridors to remove congestion as defined above. Moreover, state regulators are charged to superintend load serving entities and have the authority to require such entities to consider alternative means of acquiring power as compared with transmission of energy through an NIETC. For instance, most utilities are required to undertake resource planning processes, with stakeholder participation and full consideration of all alternatives, before they can commit to acquisition of resources. These resource planning processes are generally highly complex. If grafted on to the NIETC designation process, this type of resource planning could unduly delay NIETC designations contrary to Congress' intent.

The opportunity to submit these comments and your careful consideration are greatly appreciated. Dr. Nelson can be reached at 801-538-8802 or lsnelson@utah.gov.

88. Washington State Energy Facility Site Evaluation Council, Received Thu 3/2/2006 5:15 PM

March 2, 2006

The Honorable Samuel Bodman, Secretary
United States Department of Energy
1000 Independence Avenue SW
Washington, D.C. 20585

Attention: Ms. Poonum Agrawal
Office of Electricity Delivery and Energy Reliability

Dear Secretary Bodman:

The state of Washington appreciates the opportunity to comment on the Office of Electricity Delivery and Energy Reliability's (OEDER) notice of inquiry for its plans for a transmission congestion study and possible designation of National Interest Electric Transmission Corridors (NIETC) in a report based on the study pursuant to section 1221(a) of the Energy Policy Act of 2005.

We have reviewed and endorse the Western Interstate Energy Board's (WIEB) comments, and concur with the comments offered by the state of Oregon.

WIEB's comments urge particular attention to the integration of actions taken under Energy Policy Act Sections 368 and 1221. Both sections direct the U. S. Department of Energy (DOE) to lead or participate in establishing energy corridors in the West, which includes electrical transmission. This is very important. The public must clearly understand how the two different sets of corridors will work together, hopefully in a manner to minimize the need for taking of private property.

WIEB and Oregon State also correctly observe that the very broad and vague criteria of Pub. L. No. 109-58, section 216(a)(4)(A)-(E) need to be clearly defined.

For example, what constitutes "economic viability" and constraint by "lack of adequate or reasonably priced electricity" in section 216(a)(4)(A) bears directly on mitigation criteria that may be required by a state siting authority such as Washington State's Energy Facility Site Evaluation Council (EFSEC). State mitigation requirements should not be unreasonably constrained by DOE's interpretation of subsection 216(a)(4)(A)'s language.

Key among EFSEC's several statutory directives are the mandates to "provide abundant power at reasonable cost while protecting the public interest and the environment." This frequently results in the issuance of siting permits that require mitigation. In this context, when considering the economic benefit of new transmission, DOE should also include the non-monetized impacts of transmission, such as the impact of a transmission corridor on agricultural lands; designated urban growth; environmentally sensitive areas and land values.

Other Energy Policy Act criteria such as the "energy independence of the United States," the "national energy policy," and enhancement of "national defense and homeland security" are likewise vague and requiring clear standards.

The state of Washington also urges DOE to define clearly the geographic scope of NIETCs. While narrow corridors may unreasonably constrain development of needed transmission, we agree with the WIEB's observation that overly broad definitions could invite abuse and lead to unreasonable uncertainty regarding private land potentially subject to condemnation.

Finally, we strongly encourage both DOE and Federal Energy Regulatory Commission (FERC) to recognize and address within their respective rulemakings, the fact that financing rather than siting is frequently the major issue in bringing projects under our jurisdiction to fruition. An EFSEC license to construct a power plant or a transmission line is a valuable right which encumbers the environment within which the license is granted. The license which the state may grant for NIETCs is particularly encumbering against the backdrop of federal preemption and condemnation of private property for right-away. Accordingly, developers should be required to demonstrate by a preponderance of evidence that financing exists for the transmission line prior to the issuance of a license.

For these reasons, the state of Washington respectfully requests that prior to final adoption of rules, the Department of Energy hold a public meeting in Washington to explain its final proposals and to receive public comment.
Respectfully,

James Luce, Chair
Washington State Energy Facility Site Evaluation Council

89. Work Group Members of the Western Business Roundtable, Received Mon 3/6/2006 4:21 PM

Dear Ms. Agrawal:

The Western Business Roundtable (Roundtable) respectfully submits the following comments regarding the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability's "Considerations for Transmission Congestion" Study and Designation of National Interest Electric Transmission Corridors notice of inquiry and request for comments (NOI).

DOE is moving forward with these activities, pursuant to Section 1221 of the Energy Policy Act of 2005 (EPAct05), which provides DOE with the authority to designate any geographic area experiencing transmission capacity constraints or congestion that adversely affects consumers as a "National Interest Electric Transmission Corridor" (NIETC).

Such designations are important under EPAct05 because FERC is then given "back-stop" siting authority to assure that construction of those critical facilities can move forward on a timely basis. DOE is to identify those areas by conducting a study of transmission congestion within the United States and issuing a report by August 8, 2006 (and every three years subsequently).

Roundtable's Position

The designation of NIETCs is of keen interest to our member organizations – all of which are involved in the economic activities of the West. Our region has experienced explosive growth in recent decades. Forecasts show that this trend line will continue, unabated, into the future. This is putting tremendous pressure on an already challenged Western electricity grid. Transmission upgrades are essential to ensure that:

- Consumers in the West continue to enjoy reliable electricity;
- Energy-intensive industries stay competitive in world markets;
- Economic growth and jobs continue to be created throughout our region; and
- Fuel diversity is maintained and strengthened in the West and across the nation. Without transmission system improvements, it is unlikely that we will see diversity in new generation in the West. Reliance on a broad portfolio of fuel sources, including natural gas, coal and renewable resources, helps to protect consumers against price spikes and increases our energy alternatives and our national security.

Thus, we applaud DOE for moving forward aggressively to implement Section 1221 of EPAct05. If done right, these NIETCs can go far in increasing the regulatory certainty upon which energy infrastructure investment depends.

Specific Roundtable Recommendations

1. **DOE needs to recognize and properly assess the unique features of the Western electricity grid.**

   The Western Interconnect has a number of features that distinguishes it from the rest of the country. Among them:

   - Vast geography and long distances between populations centers;
   - Much of the nation's low-cost coal and wind resources. These resources are typically located great distances from load centers, requiring long transmission corridors. It is important to emphasize, in this regard, that the West is key to meeting the national vision for renewable energy production. Those resources cannot be brought on line without significant additional investment in interstate transmission facilities in the region;
   - Extensive federal land ownership and management;
   - Multiple electrical control areas and a patchwork of transmission owners, including FERC-jurisdictional utilities, but also federal power marketing agencies, generation and transmission cooperatives, municipalities and others;
   - Significant new generation and energy production is being developed in Wyoming, Montana and other interior Western States. That production is crucial to meeting the demands of the growth markets in locations such as Arizona, California and the Pacific Northwest.

   For these reasons among others, DOE's review of the West needs to be based upon a broad interpretation of congestion and bottlenecks.

2. **DOE needs to define potential NIETCs broadly, as generalized flow paths between two (or more) locations.**

   The Roundtable understands that DOE faces a difficult balancing act in implementing EPAct05 Section 1221. It is very important that NIETCs be defined broadly enough to allow flexibility for infrastructure providers to plan, construct and operate transmission facilities in an efficient and reliable manner. However, it is also imperative that DOE foster some degree of certainty for stakeholders and potential infrastructure investors. Thus, DOE must, in some way, define parameters for designated corridors, sufficiently clear for all affected parties to understand.

   We suggest that this balance be struck by defining NIETCs as generalized flow paths between two or more end-points. This will provide sufficient specificity, without constraining the consideration of alternatives.

3. **The Roundtable supports the early identification of NIETCs that meet the immediate energy needs of the West. Going forward, we believe that DOE must remain flexible regarding the timing of NIETC designations.**

   There are several major interstate transmission expansion efforts already underway in the West. DOE should recognize those efforts as among its initial NIETC designations.

   Beyond that, we strongly urge DOE to integrate flexibility into its NIETC process. While Congress ordered DOE to formally review congestion nationwide every three years, the Department should remain flexible and in a position to perform an early review and accelerated designation of specific NIETCs should the facts warrant it (i.e. the existence of transmission capacity constraints or congestion). Further, NIETC designations should not be delayed until a specific transmission project as been identified or is being implemented.

4. **DOE must fully recognize the features and characteristics of the Western transmission system. Reliance on the expertise and analyses of Western entities is important.**

   We applaud DOE’s account of Western transmission plans and studies it is reviewing. These plans and studies demonstrate the need for, and benefits from, transmission infrastructure investment in the West – both in the form of significant upgrades to existing transmission infrastructure and through construction of additional lines.

   We would also point DOE to the Western Electricity Coordinating Council’s (WECC) new Transmission Expansion Planning Policy Committee (TEPPC). This body was established by WECC to assess and forecast regional transmission congestion and congestion costs. The TEPPC has made one of its near-term deliverables assisting DOE in identifying NIETCs.

   The Department generally should avoid reliance on studies older than three years, unless a qualified expert demonstrates that an older study or information is still valid.

5. **DOE should avoid the temptation to adopt a one-size-fits-all approach towards evaluating geographical areas in the congestion study as candidates for NIETCs. However, some general criteria make sense.**

   The Roundtable supports the following proposed baseline criteria:

   a) Reliability improvements;
   b) Economic benefits for consumers;
   c) Easing of electricity supply limitations in end markets served by a corridor;
   d) Diversification of fuel sources for electric generation;
   e) Enhancement of the energy independence of the United States;
   f) Advancement of national energy policies;

g) Enhancement of the reliability of electricity supplies to critical loads and facilities and reduction in the vulnerability of such loads and facilities from natural disaster or malicious acts.

We are concerned, however, about the suggestion that, to qualify, an area's projected needs must be "not unduly contingent on uncertainties associated with analytic assumptions." While meeting existing needs is obviously the immediate priority, prospective congestion should be given weight as well. As discussed in the NOI, "timely construction of transmission facilities often requires lead-times of five years or more, and all projections are based on assumptions and involve some degree of uncertainty." Further, the transmission needs in the West are prospective, as it relates to enabling fuel-diversifying generation to develop. The DOE should place value around corridors and projects that are designed to meet the projected future needs of a specific region.

6. DOE should acknowledge the consequences of both persistent and dynamic congestion, but give particular weight to persistent congestion.

We interpret "persistent congestion" as that which has repeatedly occurred and is expected to continue on known transmission facilities. "Dynamic congestion" is more variable, reflecting outages, volatility in fuel prices and unanticipated events. We agree the Department should distinguish between these different types of congestion, though both are critical to transmission planning. Persistent congestion should be given particular emphasis in the NIETC planning initiative, as it reflects the growing shortfall that tends to escalate in regions experiencing load growth. This form of congestion is particularly hard on consumers over time.

7. DOE should distinguish between physical and contractual congestion, giving priority consideration to physical congestion.

Market considerations should be subordinate to reliability considerations. Contractual congestion may result from underutilized transmission capacity reservations, but physical congestion is tied directly to technical and operational limitations. The intent of EPAct05 is to strengthen and modernize the interconnected transmission system and thereby improve energy independence, economic growth and homeland security. These objectives can only be met if physical and reliability deficiencies are addressed with the corridor designations. By contrast, contractual congestion may be resolved through tariff and regulatory reform and may not require the construction of new facilities.

Conclusion

On behalf of the member companies of the Western Business Roundtable, thank you for the opportunity to comment on this important policy initiative, which is so important to the continued vitality of the West.

Sincerely,

Jim Sims
President and CEO

cc:

Vice President Dick Cheney
DOE Secretary Samuel Bodman
Federal Energy Regulatory Commission
House Energy and Commerce Committee Members
Senate Energy Committee Members
Western Governors
Western Governors Association

The Roundtable is a non-profit business trade association comprised of CEOs and senior executives of organizations doing business in the Western United States. Our member companies are involved in a broad range of industries, including agricultural products, accounting, chemicals, coal, construction and construction materials, conventional and renewable energy production, energy services, engineering, financial services, internet technologies, manufacturing, mining, oil and gas, pharmaceuticals, pipelines, telecommunications, and public and investor-owned utilities. We work for a common sense, balanced approach to economic development and environmental conservation, and we support public policies that encourage economic growth, opportunity and freedom of enterprise.

90. Work Group Members of the Western Congestion Analysis Task Force (WCATF), Received Mon 3/6/2006 4:11 PM

Introduction

The Department of Energy (‘‘Department’’) has requested comment and information from the public concerning its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors (‘‘NIETCs’’) (Title XII Electricity, Subtitle Transmission Infrastructure Modernization, Section 1221 Siting of Interstate Electric Transmission Facilities.) Through its Notice of Inquiry (NOI), the Department invited comment on draft criteria for gauging the suitability of geographic areas as NIETCs and announced a public technical conference concerning the criteria for evaluation of candidate areas as NIETCs.

The Western Congestion Analysis Task Force (WCATF)[1] was formed in October 2005 to assist the United States Department of Energy (DOE) in fulfilling its responsibilities to identify transmission congestion under the requirements of the Energy Policy Act 2005. The WCATF was created by a joint proposal from Western Electricity Coordinating Council (WECC)[2], the Committee on Regional Electric Power Cooperation (CREPC)[3], and the Seems Steering Group – Western Interconnection (SSG-WI)[4] to DOE to provide and perform the required technical study work for the western interconnection. The task force members include representatives from WECC, CREPC, SSG-WI, utilities, state government, public utility commissions, and consultants. The task force meetings are open to anyone who wants to participate. The purposes of the WCATF are to 1) assemble existing western interconnection-wide and sub-regional studies of transmission congestion; 2) complete an analysis of historical transmission usage that considers actual flows on transmission paths, Operating Transfer Capability, Available Transfer Capability, and schedules; and, 3) provide the results of on-going interconnection-wide studies of future transmission congestion under alternative generation and load scenarios to DOE for incorporation into their congestion study due to Congress in August 2006. The information provided to DOE by the WCATF has been developed in consultation with the western States. The WCATF has collected studies that relied on public, transparent and inclusive processes to develop and perform the analysis. The database of information used to perform the modeling to forecast future transmission use and congestion is portable, publicly available (consistent with critical infrastructure information protection requirements), and consistent with WECC confidential databases and 2004 publicly available versions of load serving entities' resource plans.

The Notice of Inquiry (NOI) requested comments within 30 days from release. The time frame, nature of the questions, and diversity of the task force members did not allow for a process to obtain acceptance and concurrence that allowed preparation of a document that would receive approval by all task force members. In lieu of a response from the entire WCATF, a work group of task force members was formed to provide a response to the NOI that reflected discussions and perspectives addressed at the WCATF meetings. This document represents the effort of the individuals of the work group and not the entire WCATF. This document is not an official approved work product of the WCATF, and some members do not support the submittal of these comments by the work group.

General Comments

We begin with comments regarding DOE's overall plan for implementing Section 1221 of the Act, and follow with responses to the individual questions in the NOI.

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[1] Western Congestion Analysis Task Force - http://www.wecc.biz/index.php?module=pagesetter&func=viewpub&tid=5&pid=42
[2] Western Electricity Coordinating Council - http://www.wecc.biz/
[3] Committee on Regional Electric Power Cooperation - http://www.westgov.org/wieb/site/crepcpage/index.htm
[4] Seems Steering Group – Western Interconnection - http://www.ssg-wi.com/

1. We recommend that any NIETC designation in the Western Interconnect be based on objective, measurable, and transparent criteria/metrics that are applicable to the West. The designation process should be fully defined upfront, including:

   i. definition of criteria and metrics,
   ii. analytical requirements and process,
   iii. the public comment process for proposed designations, and
   iv. linkages to the Section 368 process and to FERC's exercise of its backstop authority.

   This should provide for an orderly, objective, transparent, and analytically defensible process that will work now and every three years when the congestion study is updated.

2. We are particularly concerned about early designations. Corridor designation should be the result of carefully prepared analyses that address the NIETC criteria and metrics. We have provided more detailed explanation of our concerns below. The one exception might be an early designation for a specific project, and only if strict criteria are met. We have suggested criteria in more detail in our response to DOE's question about project specific designations.

3. The final process and procedure should explain how, for proposed transmission lines within the NIETC, all required federal permits and actions will be completed on a schedule consistent with the one year siting/permitting time limit imposed on states. It is unproductive to limit state review to one year if federal permits cannot be obtained on the same schedule.

   It is important that DOE adopt rules clarifying that the one year clock begins only after the state has received a complete application. DOE should not attempt to define a complete application, because no single definition will work for all states. However, states should be encouraged to provide application completeness guidelines in the form of duly adopted rules, written in an open process. DOE should encourage state regulators and transmission developers to work together to prevent abuse by either. One way to do this is to support ongoing efforts by organizations such as the National Association of Regulatory Commissioners (NARUC)[5] to produce model guidelines for application completeness. DOE should give these voluntary efforts time to produce consensus results.

4. We encourage the DOE to respect the states' siting experience. State and local authorities are in a unique position to facilitate dialogue between transmission developers and affected stakeholders, including property holders. State siting agencies often condition state permits to balance the interest of the various parties that a federal agency would be unlikely to

[5] National Association of Regulatory Utility Commissioners – http://www.naruc.org

match.   We thus believe the state siting process should be given a reasonable chance to succeed before federal intervention occurs.

In addition, DOE should consider the great differences between the various states' siting processes, even in adjacent states. In states with no central statewide siting authority, a federal corridor designation may be warranted if a national interest congestion or capacity constraints cause negative consumer impacts. DOE should exercise restraint overall and particularly in states with a well developed statewide program and a proven track records in the siting and successful, timely construction of energy facilities.

Corridor Definition Comments

The Department expects to identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities. The Department believes that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion. The Department invites those commenting to address how broadly or narrowly the Department should consider and define corridors in its study and its NIETC designations.

We are concerned that DOE will adopt too generalized or vague a definition of a NIETC. Final NIETC designations should be geographically specific although they need not be at the granularity of designating a centerline for a transmission line. We understand DOE's reluctance to specify precise locations for designated corridors. DOE does not want to impose its own solutions on transmission issues and it wants to avoid triggering NEPA until an actual project is proposed.

However, the designated corridors must have some parameters. For example, a corridor such as "Montana to Los Angeles" NIETC is too vague and invites abuse, particularly since the condemnation of private property is involved. With such a vague designation, a sponsor could propose a line virtually anywhere and claim it is in the NIETC. Without some parameters on the NIETC's location, no one can tell whether the proposed project is inside or outside the corridor. A case-by-case decision by the agency will be arbitrary at best. At worst, a proposed project will be subject to litigation over whether it is in the corridor or not. The litigation over this one point will take longer than a normal state permitting process, defeating the very purpose of the Act. In addition to identifiable boundaries, the corridor should have a beginning and end point, so that everyone can see where the potential for FERC preemption begins and ends.

A vague designation such as "Montana to Los Angeles" will not be acceptable to the public. At some point, the public will want to see the NIETC boundaries on a map. This was amply demonstrated at the scoping meetings for the EPACT Sec. 368 Programmatic Environmental Impact Statement, where the first question raised by the public was "Where are these corridors located?" This question will come from developers who want to take advantage of the favorable regulatory treatment, local reviewing agencies concerned about preemption, and property owners concerned about condemnation.

A designated corridor could be broad enough to include a number of alternatives. However, it must have enough specificity so that developers, local stakeholders and local permitting agencies can tell whether a project is inside or outside the corridor.

Expedited Designation Comments

In its NOI, the Department indicated it will consider well-supported recommendations from affected States and interested parties throughout the study process regarding areas believed to merit urgent attention from the Department. If interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, these are to be identified in their comments on this NOI. If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. The NOI indicates that the Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

While we recognize the importance of timely response to EPACT mandates, we believe early designation is likely to prove short-sighted and runs the risk of circumventing the formal process to be developed as a result of considering all factors. The DOE should consider limiting its first study to compiling and summarizing the studies available and identifying congestion and capacity constraints that merit further investigation.

Due to the complexity of the issues and definitions, we don't believe it is reasonable to expect that an early designation will be fully consistent with the final criteria and process used for determination of NIETC. Although we are encouraged that the DOE states an early designation will only be granted for those corridors in which "a particularly compelling case is made," we believe early designation runs contrary to the process that needs to be developed. What will be the basis and criteria for making the early designation and could the designation be removed if the final criteria are different from the criteria applied for early designation?

<u>Responses to Specific Questions Identified in the NOI</u>

> *(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?*

Yes. WCATF will work with DOE to evaluate alternative methods to make this distinction.

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

Because no formal distinction between "physical" and "contractual" congestion was provided in the NOI, we offer the following illustrative definitions to inform the dialogue regarding how to distinguish physical congestion from contractual congestion.

> Physical Congestion: This form of congestion occurs when transmission facilities reach operating limits that constrain further loading in either actual or simulated operating states. During actual operations, dispatcher action typically takes the form of real-time curtailments and generation re-dispatch. In simulations, physical congestion occurs when a path or element loading reaches its operating transfer capability (OTC) limit during specific time periods in the simulation. Most simulation programs refer to this as a "binding constraint" on the path or element.
>
> Contractual Congestion: This form of congestion occurs when additional commercial transmission service is not available or existing rights are limited. One example of contractual congestion occurs when transmission service cannot be acquired on an OASIS due to lack of available transmission capability (ATC). The second type of contractual congestion is the diminution of a contractual transmission right by the transmission provider. This may occur if the path becomes oversubscribed, load patterns change, or parallel flows cross multiple transmission provider systems. In some instances of contractual congestion the actual path loading data may indicate that the path is typically operated below its limit over many time periods. This may result from diurnal variations in loading, transmission reserve margin (TRM) requirements, or an inability to accurately assess physical flow impacts of contract path transmission services. Contractual congestion indicates that there is commercial demand for transmission service that cannot be supplied.

(3) In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

We support the studies provided to DOE by the WCATF, including those listed in the NOI. Studies prior to 2000 are of extremely limited value and those of most current vintage should be given greater weight.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

Information on Congestion areas can be obtained from both actual data from operating experience and from modeling forecasts of future use.

Information that is useful to identify congestion based upon operating experience includes OASIS and tagging data on transmission path reservations and schedules, available transmission capacity, actual path MW power flows and actual path hourly operating limits. Congestion Indices can be calculated from this data as indicators of a transmission paths physical and commercial usage. Information on Transmission Loading Relief (TLR) experience (Eastern Interconnection) and Unscheduled Flow (USF) mitigation experience (Western Interconnection) provides additional insight into those areas experiencing operational congestion.

The forecast of future transmission Congestion Areas from modeling studies is critically dependent upon the quality of the study assumptions. Because future use is difficult to predict with certainty, it is preferable to model and evaluate alternative future resource development scenarios to bracket a range of possible future use. Information that can be obtained from modeling forecasts to predict future congestion includes calculations of transmission path shadow prices, locational marginal prices, and path flow frequency distributions. Congestion Indices of forecasted physical usage can be calculated from the modeled path flow distribution curves.

Designation Criteria Comments

In the NOI, the Department identifies 8 criteria, including proposed "metrics" for some. Our comments below restate the DOE language in italics and then provide our initial observations/responses.

> ***Draft Criterion 1: Action is needed to maintain high reliability.***
> *Maintaining high electric reliability is essential to any area's economic health and future development. Accordingly, an area would be of interest for possible NIETC designation if there is a clear need to remedy existing or emerging reliability problems.*
>
> ***Metrics:*** *A definition of the affected area in terms of load, population, and demand growth; a description of the expected degree of improvement in reliability associated with a proposed project; if appropriate, identification existing or projected violations of NERC Planning Criteria.*

The Western Electricity Coordinating Council (WECC) working with the North American Electric Reliability Council Planning Standards merged the WECC Planning Standard into one document called the *NERC/WECC Planning Standards*. The narrative below is taken from this joint document and should be used to develop metrics for Criterion 1.

> "The interconnected transmission systems are the principal media for achieving reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

- **Deliver Electric Power to Areas of Customer Demand -** Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.
- **Provide Flexibility for Changing System Conditions -** Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.
- **Reduce Installed Generating Capacity -** Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.
- **Allow Economic Exchange of Electric Power Among Systems -** Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among all systems and industry participants. Such economy transfers help to reduce the cost of electric supply to customers.

Electric power transfers have a significant effect on the reliability of the interconnected transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability.

All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability."

The action that is needed to maintain high reliability through the designation of National Interest Electric Transmission Corridors is to follow the established NERC and regional reliability planning standards. One option for identification of existing or emerging reliability problems is system simulation (and associated assessments). System simulations are needed to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

Most new transmission and upgrades in the West will be driven by load growth and its associated need to access new resources while ensuring all reliability criteria is maintained and met. Corridors will be needed to connect load centers to remote resources such as wind, hydro, clean coal, large solar, and biomass. These represent the greatest need in the West.

> ***Draft Criterion 2: Action is needed to achieve economic benefits for consumers.***
> An area may need substantial transmission improvements to enable large economic electricity transfers that would result in significant economic savings to retail electricity consumers.
>
> ***Metrics:*** *Estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets. A demonstration of expected reduction in end-market concentration and how economic benefits for consumers would be affected.*

The calculation of savings should be based on production cost simulations and other analytical techniques. The analysis of impact on consumers should reflect state energy policies as enacted in state law, and take into account load serving entity resource plans. Specifically, if a state policy places a high priority on acquiring renewable energy generation, or makes a judgment about natural gas price risk, or establishes a carbon adder to reflect its determination of carbon risk, DOE should assume compliance with such policies in the calculations of economic benefits to consumers.

When considering the economic benefit of new transmission, DOE should also include the non-monetized impacts of transmission, such as the impact of a transmission corridor on agricultural lands and land values.

> ***Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources***
>
> ***Metrics:*** *Areas that are dependent on ''reliability-must-run'' plants would benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both. Similarly, areas that are highly dependent on specific generation fuels could economically benefit from supply diversification. Estimate the likely magnitude of such benefits, showing calculations.*

Fuel diversity is an important goal in the West. We recommend two additional metrics to determine whether a geographic area meets this criterion for purposes of national interest designation. First, DOE should require demonstration that additional transmission capacity is needed to enable market area to import power from renewable power generators to facilitate the market area's compliance with statutory renewable portfolio obligations. Second, DOE should require evidence that mitigation or elimination of transmission constraint would promote fuel diversity. Fuel diversification is not limited to renewable resources. The benefits of fuel diversification are driven by reducing reliance on a fuel that is subject to price escalation and volatility. Fuel diversification includes transmission to meet RPS, but is not limited to this.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Metrics: *Provide calculations showing how specific actions aided by designation, as an NIETC would increase fuel diversity, improve domestic fuel independence, or reduce dependence on energy imports. Quantify these impacts, including possible impacts on U.S. energy markets.*

The WCATF has not addressed this issue and we do not offer any comments on Criterion 4.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

The WCATF has not addressed this issue and we do not offer any comments on Criterion 5.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

Metrics: *For this criterion, relevant metrics would be case-specific.*

The WCATF has not addressed this issue and we do not offer any comments on Criterion 6.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

Metrics: *What metrics would be suitable for gauging such uncertainties?*

With respect to draft Criterion 7, we recommend that DOE integrate this concept into application of all other criteria. To accomplish this, DOE should require that all analysis supporting NIETC designation include key assumptions sensitivities. Key assumptions such as fuel prices, demand growth, and the location and cost of generation facilities can be difficult to project accurately, especially over the long term. However, they can have a significant impact on the results of the analysis. In addition, DOE should require that the assumptions underlying NIETC designations be transparent. Reasonable and transparent assumptions will be important in making sure that the designation process is objective.

In the absence of a parametric study that demonstrates otherwise, those assumptions that have wide variability and are projected further out in the future should not be given as much weight and value as those that have a narrow band width, are not projected into the future, and its variability do not significantly change the results.

Because of the uncertainties involved, DOE should only consider designating corridors where the needs and benefits are demonstrated under a wide range of assumptions.

> ***Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.***
>
> *Recognizing the value of transmission alternatives, the Department wishes to avoid designating NIETCs in ways that might unduly affect stakeholders' decisions about how to meet specific needs, confer advantage on transmission options as opposed to non-wires options or generation options, or favor some transmission options over others. At the same time, the Department is mindful that even taking these other factors into account transmission expansion is clearly needed in many areas, and that transmission expansion is itself a protracted process. The Department seeks comments on how it should balance these concerns.*

Once the Department has designated a NIETC, if siting shifts to the FERC, it is unlikely that consideration will be given to non-wires solutions. Once built, new transmission will give new generation an artificial economic advantage over distributed generation and demand-side management (DSM). The Act directs USDOE to designate corridors in those areas where the need for transmission is great. There is no way to reach this conclusion without first confirming that non-wires alternatives have been adequately considered prior to any NIETC designation.

At the same time, we appreciate the need to balance this concern with the real need for transmission enhancements or additions in some areas. In states with integrated resource plans (IRP), some of this balancing is done through the IRP process. The SSG-WI 2015 studies are built largely on data that factors in generation resources acknowledged in IRPs, including demand side management (DSM) and local generation. Some sub regional studies produced by NTAC, RMATS, and other also take IRPs into account. DOE can take advantage of this work by giving more weight to congestion solutions acknowledged in IRPs that have been agreed to through state regulatory review.

One option in states without IRPs, could include balancing these concerns by inviting state comments on proposed Nieces (prior to designation), and by specifically inviting local stakeholders to compare the proposed transmission corridor with DSM and other non-transmission alternatives. Comment periods should be widely publicized, and long enough to allow a well documented response.

Responses to Additional NOI Questions

(1) *Are there other criteria or considerations that the Department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.*

Yes. The Department should consider adding a regional or sub-regional planning process evaluation to its criteria for NIETC designation. We propose an additional criterion as follows:

Draft Criterion 9: Targeted actions in the area would be consistent with the findings of existing regional or sub-regional transmission planning groups in the area. In areas where there exists active regional or sub-regional transmission planning groups (RPGs), the Department should consider giving deference to the findings of such groups in identifying or designating NIETCs. The Department should utilize the following metrics to determine the scope and effectiveness of the RPGs and to determine the weight given to such groups' recommendations. DOE should ensure that end-runs and abuse are avoided by providing proper weight to alternatives that have been reviewed by well-constituted regional or sub-regional groups or ISO planning bodies.

Metrics:

- The RPG is broadly constituted and open to all relevant stakeholders.
- The RPG coordinates with the states in the region to incorporate strategic goals, such as diversifying of fuels, moving low cost generation from remote locations to growing load centers/markets, or accomplishing regional clean and diversified energy goals, including state RPSs, in its studies.
- The RPG has done studies to identify areas of potential congestion (present or future).
- The RPG has quantified the congestion costs in these areas (past, present, and future).
- The RPG has identified important areas where congestion is chronic, of significant economic impact, and unresolved.
- Solutions were not limited to wires solutions.
- The RPG coordinates with the Regional Reliability Organization to ensure projects proceed through the reliability review process, at the appropriate time.

(2) Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

Yes. The Department should give more weight to Criterion 9: *Targeted actions in the area would be consistent with the findings of existing regional or sub-regional transmission planning groups in the area,* and Criterion 7: *The area projected needs are not unduly contingent on uncertainties associated with analytic assumptions*. Criterion 9 is critical because it assures broad regional review of needs and conditions, and Criterion 7 is key because it assures that recommendations are not based on some whim of the day. The Department should give less weight to Criterion 4 and 5 because these criteria are not well defined.

Responses to Questions the Department Raised in Public Events

> *Should an NIETC be project-specific? Would doing so give undue advantage to the proposed project, in relation to potentially competing projects? Or should an NIETC be framed to accommodate a range of potential projects? Are both approaches potentially appropriate, depending on circumstances?*

In general we do not feel that NIETC designations should be project specific. At the same time, as stated previously, we do not support extremely broad or vague geographic areas being designated. Only quite clear paths, “swaths” or other specific links identified and demonstrated to be “national” interest linkages, based on an inclusive, transparent process should be designated.

As with all general rules, there could be unusual exceptions, for example in a case where: 1) a project was well identified before EPACT 2005; 2) the project has committed financing; 3) there are no workable competing projects or non-wires solutions; and, 4) siting proceedings have failed to reach resolution within a reasonable period of time.

It is possible that there are lines in the eastern U.S. that might qualify for specific project designation at this time.

> *Should an NIETC have a fixed term? If so, how long? Renewable, under certain conditions? Revocable, under certain conditions?*

All NIETCs should have a fixed term. As a starting point for discussion we suggest a three year term. In order to qualify for renewal, the next triennial congestion study must document continuing transmission capacity constraint or congestion adversely affecting consumers. In addition, affected states must concur that a re-designation is appropriate

NIETCs should also be revocable under certain limited circumstances. These could include, for example, demonstration that the grounds for initial designation were based on false information submitted knowingly by a corridor proponent; or, subsequent completion of wire or non-wire projects in the corridor that effectively meet the need or national interest specified at the time of designation.

> *When, in relation to the evolution of a major transmission project, should an NIETC be designated? Should specific preconditions be met, such as …?*

Yes, DOE should consider the identification of *potential* NIETC designations prior to the formal NIETC designation. The designation of *potential* NIETCs would:

- Send a signal to potential developers and states that the federal government is concerned with the need for more transmission capacity in an area.
- Enable coordination of the NIETC designation process with federal permitting processes by allowing time to complete an EIS which will generate information on alternatives to specific transmission corridors prior to a formal NIETC designation. This will permit DOE to make a much more informed decision on an NIETC designation since significant analysis of alternatives will be available.

Finally, we believe that DOE should develop an additional criterion that would state that the designation of an NIETC would further the energy policies of affected states as reflected in state law and state regulatory reviews of load serving entity resource plans.

Respectfully submitted by the following Work Group members of the WCATF:

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91. Western Electricity Coordinating Council, Received Mon 3/6/2006 3:46 PM

Comments in this response are from a few members of the Western Electricity Coordinating Council and do not represent a consensus of all members.

INTRODUCTION

Western Systems Coordinating Council (WSCC) was formed with the signing of the WSCC Agreement on August 14, 1967 by 40 electric power systems. Those "charter members" represented the electric power systems engaged in bulk power generation and/or transmission serving all or part of the 14 Western States and British Columbia, Canada.

The Western Electricity Coordinating Council (WECC)[6], was formed on April 18, 2002, by the merger of WSCC, Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). The formation of WECC was accomplished over a four-year period through the cooperative efforts of WSCC, SWRTA, WRTA, and other regional organizations in the West. WECC's interconnection-wide focus is intended to complement current efforts to form Regional Transmission Organizations (RTO) in various parts of the West.

The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the ten regional councils of the North American Electric Reliability Council (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. Transmission lines span long distances connecting the verdant Pacific Northwest with its abundant hydroelectric resources to the arid Southwest with its large coal-fired and nuclear resources. WECC and the nine other regional reliability councils were formed due to national concern regarding the reliability of the interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization.

The Western Congestion Analysis Task Force (WCATF)[7] was formed in October 2005 to assist the United States Department of Energy (DOE) in fulfilling its responsibilities to identify transmission congestion under the requirements of the Energy Policy Act 2005, Title XII Electricity, Subtitle Transmission Infrastructure Modernization, Section 1221 Siting of Interstate Electric Transmission Facilities. The WCATF was created by a joint proposal from WECC, the Committee on Regional Electric Power Cooperation (CREPC)[8], and the Seems Steering Group – Western Interconnection (SSG-WI)[9] to DOE provide and perform the required technical study work for the western interconnection.

The task force members include representatives from WECC, CREPC, SSG-WI, utilities, state government, public utility commissions, and consultants. In lieu of a response from the entire WCATF, a work group of task force members was formed to provide a response to the NOI that reflected discussions and perspectives addressed at the WCATF meetings. This document also

[6] Western Electricity Coordinating Council - http://www.wecc.biz/
[7] Western Congestion Analysis Task Force - http://www.wecc.biz/index.php?module=pagesetter&func=viewpub&tid=5&pid=42
[8] Committee on Regional Electric Power Cooperation - http://www.westgov.org/wieb/site/crepcpage/index.htm
[9] Seems Steering Group – Western Interconnection - http://www.ssg-wi.com/

represents the effort of the individuals of the work group and not the entire WCATF. This document is not an official approved work product of the WCATF or WECC.

GENERAL

The Department of Energy (the ‘‘Department’’) seeks comment and information from the public concerning its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors (‘‘NIETCs’’) in a report based on the study pursuant to section 1221(a) of the Energy Policy Act of 2005. Through this notice of inquiry, the Department invites comment on draft criteria for gauging the suitability of geographic areas as NIETCs and announces a public technical conference concerning the criteria for evaluation of candidate areas as NIETCs

<u>The following are comments regarding USDOE's overall plan for implementing Section 1221 of the Act, and follow with responses to the individual questions in the NOI.</u>

3. Any NIETC designation in the Western Interconnect should be based on objective, measurable, and transparent criteria/metrics. The designation process should be fully defined upfront, including:

   v. definition of criteria and metrics,
   vi. analytical requirements and process,
   vii. the public comment process for proposed designations, and
   viii. linkages to the Section 368 process and to FERC's exercise of its backstop authority.

   This will provide for an orderly, objective, transparent, and analytically defensible process that will work now and every three years when the congestion study is updated.

4. There are particular concerns about early designations. Corridor designation should be the result of carefully prepared analyses that address the NIETC criteria and metrics. More detailed explanation of concerns is given below. The one exception might be an early designation for a specific project, and only if strict criteria are met. Suggested criteria have been provided in more detail in the response to DOE's question about project specific designations.

5. The final process and procedure should explain how, for proposed transmission lines within the NIETC, all required federal permits and actions will be completed on a schedule consistent with the one year time limit imposed on states. It is unproductive to limit state review to one year if federal permits cannot be obtained on the same schedule.

6. It is important that USDOE adopt rules clarifying that the one year clock begins only after the state has received a complete application. USDOE should not attempt to define a complete application, because no single definition will work for all states. However, states should be encouraged to provide application completeness guidelines in the form of duly adopted rules, written in an open process. USDOE should encourage state regulators and transmission developers to work together to prevent abuse by either. One way to do this is to support ongoing efforts by organizations such as NARUC to produce model guidelines for application completeness. USDOE should give these voluntary efforts time to work.

7. DOE should respect the states' siting experience. State and local authorities are in a unique position to facilitate dialogue between transmission developers and affected property holders. State siting agencies often condition state permits so as to get a level of buy-in from local stakeholders that a federal agency would be unlikely to match. As the load serving entities that must stay and do business in these communities after the siting process is complete, the state siting process should be given a reasonable chance to succeed.

8. In addition, DOE should consider the great differences between the various states' siting processes, even in adjacent states. In states with no central statewide siting authority, a federal corridor designation may be warranted if a congestion problem exists. However, USDOE should exercise restraint in states with a well developed statewide program and a proven track record in the siting and construction of energy facilities.

Corridors

The Department expects to identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities. The Department believes that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion. In their comments on the criteria set forth below, the Department invites commenters to address how broadly or narrowly the Department should consider and define corridors in its study and its NIETC designations.

The concern is that DOE will adopt too generalized or vague of a definition of a NEITC. Final NIETC designations should be geographically specific although they need not be at the granularity of designating a centerline for a transmission line. We understand DOE's reluctance to specify precise locations for designated corridors. DOE does not want to impose its own solutions on transmission issues and it wants to avoid triggering NEPA until an actual project is proposed.

However, the designated corridors must have some parameters. For example, a corridor such as "Montana to Los Angeles" NIETC is too vague and invites abuse, particularly since the condemnation of private property is involved. With such a vague designation, a sponsor could propose a line virtually anywhere and claim it is in the NIETC. Without some parameters on the NIETC's location, no one can tell whether the proposed project is inside or outside the corridor. A case-by-case decision by the agency will be arbitrary at best. At worst, a proposed project will be subject to litigation over whether it is in the corridor or not. The litigation over this one point will take longer than a normal state permitting process, defeating the very purpose of the Act. In addition to identifiable boundaries, the corridor should have a beginning and end point, so that everyone can see where the potential for FERC preemption begins and ends.

A vague designation such as "Montana to Los Angeles" will not be acceptable to the public. At some point, the public will want to see the NIETC boundaries on a map. This was amply demonstrated at the scoping meetings for the 368 PEIS, where the first question raised by the public was "where are these corridors located?" This question will come from developers who want to take advantage of the favorable regulatory treatment, local reviewing agencies concerned about preemption, and property owners concerned about condemnation.

A designated corridor could be broad enough to include a number of alternatives. However, it must have enough specificity so that developers, local stakeholders and local permitting agencies can tell whether a project is inside or outside the corridor.

Early designation of NIETCs

The Department will consider well-supported recommendations from affected States and interested parties throughout the study process regarding areas believed to merit urgent attention from the Department. In that regard, if interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI. If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. If interested parties wish to identify areas for early designation, they should supply with their comments all available data and information supporting a determination that severe needs exist. Parties should identify the area that they believe merits designation as an NIETC, and explain why early designation is necessary and appropriate. The Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

The Notice addresses the issue of early designation of NIETCs in areas shown to have an urgent need for DOE's attention. The question appears driven largely by DOE's need to produce a first study, and to show progress.

Early designation is short-sighted and runs the risk of circumventing the formal process to be developed as a result of considering all factors. The DOE should consider limiting its first study to compiling and summarizing the studies available and identifying congestion and other problem areas that merit further investigation.

Due to the complexity of the issues and definitions it is not reasonable to expect that an early designation will be fully consistent with the final criteria and process used for determination of NIETC. Although we are encouraged that the DOE states an early designation will only be granted for those corridors in which "a particularly compelling case is made," we believe early designation runs contrary to the process that needs to be developed. What will be the basis and criteria for making the early designation and could the designation be removed if the final criteria is different from the criteria applied for early designation?

A. Congestion Study

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

Because no formal distinction between "physical" and "contractual" congestion was provided in the NOI, we propose the DOE distinguish physical congestion from contractual congestion by the terms as follows:

Physical congestion occurs when transmission facilities reach operating limits that constrain further loading in either actual or simulated operating states. During actual operations, dispatcher action typically takes the form of real-time curtailments. In simulations, physical congestion occurs when a path or element loading reaches its operating transfer capability (OTC) limit during specific time periods in the simulation. Most simulation programs refer to this as a "binding constraint" on the path or element.

Contractual congestion occurs when additional commercial transmission service is not available or existing rights are limited. One example of contractual congestion occurs when transmission service cannot be acquired on an OASIS due to lack of ATC. The second type of contractual congestion is the diminution of a contractual transmission right by the transmission provider. This may occur if the path becomes oversubscribed, load patterns change, or parallel flows cross multiple transmission provider systems. In some instances of contractual congestion the actual path loading data may indicate that the path is typically operated below its limit over many time periods. This may result from diurnal variations in loading, transmission reserve margin (TRM) requirements, or an inability to accurately assess physical flow impacts of contract path transmission services. Contractual congestion indicates that there is commercial demand for transmission service that cannot be supplied.

(3) In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

We support the studies provided to DOE by the WCATF and listed in the NOI. Also the WECC 2006 *Existing Generation and Significant Additions and Changes to System Facilities* lists specific transmission plans in the West and should be used as a reference for the Department.

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

Information on Congestion areas can be obtained from both actual data from operating

experience and from modeling forecasts of future use.

Information that is useful to identify congestion based upon operating experience includes OASIS and tagging data on transmission path reservations and schedules, available transmission capacity, actual path MW power flows and actual path hourly operating limits. Congestion Indices can be calculated from this data as indicators of a transmission paths physical and commercial usage. Information on Transmission Loading Relief (TLR) experience (Eastern Interconnection) and Unscheduled Flow (USF) mitigation experience (Western Interconnection) provides additional insight into those areas experiencing operational congestion.

The forecast of future transmission Congestion Areas from modeling studies is critically dependent upon the quality of the study assumptions. Because future use is difficult to predict with certainty, it is preferable to model and evaluate alternative future resource development scenarios to bracket expected future use. Information that can be obtained from modeling forecasts to predict future congestion includes calculations of transmission path shadow prices, locational marginal prices, and path flow frequency distributions. Congestion Indices of forecasted physical usage can be calculated from the modeled path flow distribution curves.

B. Criteria Development

Draft Criterion 1: Action is needed to maintain high reliability.
Maintaining high electric reliability is essential to any area's economic health and future development. Accordingly, an area would be of interest for possible NIETC designation if there is a clear need to remedy existing or emerging reliability problems.

Metrics: A definition of the affected area in terms of load, population, and demand growth; a description of the expected degree of improvement in reliability associated with a proposed project; if appropriate, identification existing or projected violations of NERC Planning Criteria

The Western Electricity Coordinating Council (WECC) working with the North American Electric Reliability Council Planning Standards merged the WECC Planning Standard into one document called the NERC/WECC Planning Standards.

The follow narrative is taken from the NERC/WECC Planning Standards and should be used as part of the metrics of Criterion 1:

The interconnected transmission systems are the principal media for achieving reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

- ***Deliver Electric Power to Areas of Customer Demand*** *- Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.*

- ***Provide Flexibility for Changing System Conditions*** *- Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.*

- ***Reduce Installed Generating Capacity*** *- Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.*

- ***Allow Economic Exchange of Electric Power Among Systems*** *- Transmission interconnections between systems, coupled with internal system transmission* *facilities, allow for the economic exchange of electric power among all systems and industry participants. Such economy transfers help to reduce the cost of electric supply to customers.*

Electric power transfers have a significant effect on the reliability of the interconnected transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability.

All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.

The action that is needed to maintain high reliability through the designation of National Interest Electric Transmission Corridors is to follow the established NERC and regional reliability planning standards. To remedy existing or emerging reliability problems is through system simulations and associated assessments. System simulations are needed to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

The vast majority of new transmission and upgrades in the West will be driven by load growth and its associated need to access new resources while ensuring all reliability criteria is maintained and met. Corridors will be needed to connect load centers to remote resources such as wind, hydro, clean coal, large solar, and biomass and represents the greatest needs in the West.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

An area may need substantial transmission improvements to enable large economic electricity transfers that would result in significant economic savings to retail electricity consumers.

Metrics: Estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets. A demonstration of expected reduction in end-market concentration and how economic benefits for consumers would be affected.

> The calculation of savings to consumers should reflect state energy policies as enacted in state law or reviews of load serving entity resource plans. Specifically, if a state policy places a high priority on acquiring renewable energy generation, or makes a judgment about natural gas price risk, or establishes a carbon adder to reflect its determination of carbon risk, DOE should assume compliance with such policies in the calculations of economic benefits to consumers.
>
> When considering the economic benefit of new transmission, DOE should also include the non-monetized impacts of transmission, such as the impact of a transmission corridor on agricultural lands and land values.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

Metrics: Areas that are dependent on ''reliability-must-run'' plants would benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both. Similarly, areas that are highly dependent on specific generation fuels could economically benefit from supply diversification. Estimate the likely magnitude of such benefits, showing calculations.

Two additional metrics are recommended to determine whether a geographic area meets this criterion for purposes of national interest designation.

- DOE should require demonstration that additional transmission capacity is needed to enable market area to import power from renewable power generators to facilitate the market area's compliance with statutory renewable portfolio obligations.
- DOE should require evidence that mitigation or elimination of transmission constraint would promote fuel diversity.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

Metrics: Provide calculations showing how specific actions aided by designation, as an NIETC would increase fuel diversity, improve domestic fuel independence, or reduce dependence on energy imports. Quantify these impacts, including possible impacts on U.S. energy markets.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

Metrics: For this criterion, relevant metrics would be case-specific.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

Other things being equal, arguably the Department should be more inclined to designate NIETCs where there are existing needs instead of projected needs, particularly if those future needs rest upon relatively uncertain assumptions and contingencies. On the other hand, timely construction of transmission facilities often requires lead-times of five years or more, and all projections are based on assumptions and involve some degree of uncertainty. The challenge here is to determine what level of confidence can be reasonably imputed to specific projections.

Metrics: What metrics would be suitable for gauging such uncertainties?

DOE should integrate this concept into the application of all other criteria instead of using it as a stand alone item. To accomplish this, DOE should require that all analysis supporting NIETC designation include key assumptions sensitivities. Key assumptions such as fuel prices, demand growth, and the location and cost of generation facilities can be difficult to project accurately, especially over the long term. However, they can have a significant impact on the results of the analysis. In addition, DOE should require that the assumptions underlying NIETC designations be transparent. Reasonable and transparent assumptions will be important in making sure that the designation process is objective.

In the absence of a parametric study that demonstrates otherwise, those assumptions that have wide variability and are projected further out in the future should not be given as much weight and value as those that have a narrow band width, are not projected into the future, and its variability do not significantly change the results.

Because of the uncertainties involved, DOE should only consider designating corridors where the needs and benefits are demonstrated under a wide range of assumptions.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

Recognizing the value of transmission alternatives, the Department wishes to avoid designating NIETCs in ways that might unduly affect stakeholders' decisions about how to meet specific needs, confer advantage on transmission options as opposed to non-wires options or generation options, or favor some transmission options over others. At the same time, the Department is mindful that even taking these other factors into account transmission expansion is clearly needed in many areas, and that transmission expansion is itself a protracted process. The Department seeks comments on how it should balance these concerns.

Once the Department has designated a NIETC, FERC will likely approve transmission projects with little if any consideration to non-wires solutions. Once built, new transmission will give new generation an artificial economic advantage over distributed generation and DSM. The Act directs USDOE to designate corridors in those areas where the need for <u>transmission</u> is great. There is no way to reach this conclusion without first confirming that non-wires alternatives have been adequately considered.

At the same time, we appreciate the need to balance this concern with the real need for transmission expansion in some areas. In states with integrated resource plans (IRP), some of this balancing is done through the IRP process. The SSG-WI 2003 and 2008 studies are built largely on data that factors in generation resources acknowledged in IRP's, including demand side management (DSM) and local generation. Some sub-regional studies produced by NTAC, RMATS, and other also take IRP's into account. USDOE can take advantage of this work by giving more weight to congestion solutions acknowledged for in IRP's.

Even in states without IRP's, USDOE could balance these concerns by inviting state comments in proposed NIETC's prior to designation, and by specifically inviting local stakeholders to compare the proposed transmission corridor with DSM and other non-transmission alternatives. Comment periods should be well publicized, and long enough to allow a well documented response.

<u>**The Department also seeks comment on two additional questions:**</u>

(2) *Are there other criteria or considerations that the Department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.*

The Department should consider adding a regional or sub-regional planning process evaluation to its criteria for NIETC designation as follows:

Draft Criterion 9: Targeted actions in the area would be consistent with the findings of existing regional or sub-regional transmission planning groups in the area. In areas where there exists regional or sub-regional transmission planning groups (RPGs), the Department should give substantial deference to the findings of such groups in identifying or designating NIETCs. The Department should utilize the following metrics to determine the scope and effectiveness of the RPGs and to determine the weight given to such groups' recommendations. DOE should ensure that end-runs and abuse are avoided by providing proper weight to alternatives that have been reviewed by well-constituted regional or sub-regional groups or ISO planning bodies.

Metrics:

- The RPG is broadly constituted and open to all relevant stakeholders.
- The RPG coordinates with the states in the region to incorporate strategic goals, such as diversifying of fuels, moving low cost generation from remote locations to growing load centers/markets, or accomplishing regional clean and diversified energy goals, including state RPS's, in its studies.
- The RPG has done studies to identify areas of potential congestion (present or future).
- The RPG has quantified the congestion costs in these areas (past, present, and future).
- The RPG has identified important areas where congestion is chronic, of significant economic impact, and unresolved.
- Solutions were not limited to wires solutions.
- The RPG coordinates with the Regional Reliability Council ensure projects proceed through the reliability review process, at the appropriate time.

(2) Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

The Department should give more weight to Criterion 9: Targeted actions in the area would be consistent with the findings of existing regional or sub-regional transmission planning groups in the area, and Criterion 7: The area projected needs are not unduly contingent on uncertainties associated with analytic assumptions. Criterion 9; because it assures broad regional review of needs and conditions, and Criterion 7; because it assures that recommendations are not based on some whim of the day. The Department should give less weight to Criterion 4 and 5 because these criteria are vague and undefined.

<u>The Department also seeks comment on three questions that were raised in public forums:</u>

Should an NIETC be project-specific? Would doing so give undue advantage to the proposed project, in relation to potentially competing projects? Or should an NIETC be framed to accommodate a range of potential projects? Are both approaches potentially appropriate, depending on circumstances?

In general we do not feel that NIETC designations should be project specific. At the same time, we do not support extremely broad or vague geographic areas being designated. Only quite clear paths, "swaths" or other specific links identified and demonstrated to be "national" interest linkages, based on an inclusive, transparent process should be designated.

As with all general rules, there could be unusual exceptions, for example in a case where: 1) a project was well identified before EPAct 2005, 2) the project has committed financing, 3) there are no workable competing projects or non-wires solutions, and, 4) siting proceedings have failed to reach resolution within a reasonable period of time.

It is possible that there are lines in the United States that might qualify for specific project designation at this time.

Should an NIETC have a fixed term? If so, how long? Renewable, under certain conditions? Revocable, under certain conditions?

All NIETCs should have a fixed term. As a starting point for discussion we suggest a three year term. In order to qualify for renewal, the next triennial congestion study must document continuing transmission capacity constraint or congestion adversely affecting consumers. In addition, affected states must concur that a re-designation is appropriate

NIETCs should also be revocable under certain limited circumstances. Among these could be: demonstration that the grounds for initial designation were based on false information submitted knowingly by a corridor proponent; or, completion of major wire or non-wire projects in the corridor that effectively meet the need or national interest specified at the time of designation.

When, in relation to the evolution of a major transmission project, should an NIETC be designated? Should specific preconditions be met, such as …? –

DOE should consider the identification of *potential* NIETC designations prior to the formal NIETC designation. The designation of *potential* NIETCs would:

- Send a signal to potential developers and states that the federal government is concerned with the need for more transmission capacity in an area.
- Enable coordination of the NIETC designation process with federal permitting processes by allowing time to complete an EIS which will generate information on alternatives to specific transmission corridors prior to a formal NIETC designation. This will permit DOE to make a much more informed decision on an NIETC designation since significant analysis of alternatives will be available.

DOE should develop an additional criterion that would state that the designation of an NIETC would further the energy policies of affected states as reflected in state law and state regulatory reviews of load serving entity resource plans.

Contact Information:

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92. Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation [Joint Comments], Received Sun 3/5/06 2:03 PM

Attached is a CORRECTED VERSION of the joint comments of the Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation on DOE's February 2 NOI on National Interest Electric Transmission Corridors (FR Vol. 71,No. 22,p 5660). On March 3, I inadvertently sent an earlier draft of the comments.

Please consider the attached file as the comments from WIEB and CREPC instead of the version emailed to you on Friday, March 3.

Thank you.
Doug Larson
303/573-8910

Comments of the Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation
on
DOE's Notice of Inquiry on "Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors"

The Western Interstate Energy Board (WIEB) and the Committee on Regional Electric Power Cooperation (CREPC) appreciate the cooperative approach the Department of Energy (DOE) has taken thus far in the implementation of Section 1221 of the Energy Policy Act of 2005. WIEB is an organization of 12 western states and three western Canadian provinces. Its geographic reach covers all areas of the Western Interconnection in the United States and Canada. This is important because the electric power systems of the western United States and Canada are inextricably linked. For example, much of the water used to generate electricity in the Northwest is stored in Canada. Power sale and exchanges between the western U.S. and Canada are central features of the western power market. CREPC is a joint committee of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners. All state and provincial energy planning, regulatory, and siting agencies are eligible to participate in CREPC.

DOE's willingness to engage the states and western power industry in discussions and to use existing analyses of the western transmission system developed in open transmission planning processes in the region is laudable and comports with the Governors' request expressed in Western Governors' Association Resolution 05-30.

The implementation of Section 1221 has reached a critical stage, which is the development of criteria by which the Secretary may designate National Interest Electric Transmission Corridors (NIETC).

To ensure that Section 1221 contributes to the western objective of the expeditious permitting and construction of needed transmission, WIEB makes the following recommendations. Our comments are organized into (1) recommendations that would put the NIETC designation process into the context of the larger objectives of Section 1221; and (2) recommendations that respond to specific questions in the Notice of Intent (NOI).

1. NIETC Designations Should be Done in the Context of All the Actions Required Under Section 1221

We recommend that DOE make no final decision on criteria for designating NIETCs until it and the Federal Energy Regulatory Commission (FERC) have established rules and procedures to implement Section 1221 in its entirety and there is a clear process for coordinating NIETC designation with the designation of energy corridors on federal lands.

The designation of NIETCs is one link, albeit a central link, in a chain of connected actions. DOE should not finalize criteria for the designation of NIETCs until the Department and FERC have defined in detail all the links in the chain of actions that will implement Section 1221.

To the greatest extent possible, both the criteria for designating NIETCs and the designation of NIETCs should align with criteria used to designate energy corridors on federal lands. DOE should explain how the criteria for designating NIETCs comport with the criteria that the Departments of Energy, Interior, Agriculture, Commerce and Defense are using to designate energy corridors on federal lands under Section 368. DOE should also explain how the designations of energy corridors under Section 368 are to be coordinated with DOE's designation of NIETCs.

The designation of a NIETC puts in motion a series of major federal actions which have not been defined. For example, the designation of an NIETC would likely trigger transmission permit applications to states and federal agencies. In turn, this action triggers the one-year clock for state review under Section 1221 which then triggers FERC authority to grant eminent domain to condemn private lands. To date, FERC has provided no rules explaining the nature of the application it will accept, establishing when the one-year clock begins, nor explaining whether and how FERC will weigh and consider alternatives to the sponsor's proposal, including non-wires alternatives. DOE has not explained whether or how it will advise FERC if the sponsor's project falls within the designated NIETC. Nor has DOE established procedures to fulfill its agency coordination obligations under Section 1221.

At a minimum, FERC rules must specify that the one-year clock for state action on a proposed transmission line within a NIETC does not begin until a complete application has been received by a state, as defined in state law. This will prevent abuse of Section 1221 by project sponsors whose interest may be to short circuit the careful review of their proposal by the states so that they can reach a friendly forum at FERC. Without this clarification, project sponsors have no incentive to ensure that their applications to the state are complete and well prepared. Moreover, project sponsors have no incentive to address any legitimate concerns raised by local stakeholders.

FERC should define the term "not economically feasible" as used in Section 1221's clause offering a federal override if state modifications to a transmission proposal render it uneconomic. The definition should require a demonstration that additional costs imposed by state modifications render a project both economically (overall costs outweigh benefits) and financially (out-of-pocket costs cannot be recovered) infeasible. In evaluating proposals for NIETC designation and for federal override, the benefits of a line should reflect the degree and persistence of congestion as well as the demand for and benefits of relieving that congestion. Further, the greater the benefits of a proposed line, the greater its ability to absorb state-imposed mitigation.

DOE should specify how it will advise FERC when it finds a sponsor's project falls within a corridor and the information it will provide to justify such a finding. This is particularly important if DOE designates geographically vague NIETCs.

In the West, the action or inaction of federal agencies has been the most critical element in permitting major new transmission. Prior to finalizing NIETC criteria, DOE should explain

(1) how the responsibilities of federal agencies for the review of applications for required federal permits will be coordinated among the agencies, (2) whether and how these agencies will meet a one-year deadline for a decision under Section 1221, and (3) how the process and timeline for federal agency permitting actions will mesh with state siting processes which must be completed within one year of an application.

Consistent with the requirements in Section 216(a)(2) of the Federal Power Act, the Secretary should consult with states on how the needs that give rise to a potential NIETC designation are identified and evaluated. This will help expedite state reviews of projects proposed in NIETCs.

2. ***Recommendations in Response to NOI Questions***

A. In the NOI, DOE has invited commenters to address how broadly or narrowly the Department should consider and define corridors. DOE "believes that defining corridors too narrowly would unduly restrict state authorities, FERC and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion."

- We are concerned that DOE will adopt too broad and vague definition of a NIETC. Final NIETC designations should be geographically specific although they need not be at the geographic granularity of designating a centerline for a transmission line. We understand DOE's reluctance to specify precise locations for designated corridors. DOE does not want to impose its own solutions on transmission issues and it wants to avoid triggering the National Environmental Policy Act (NEPA) until an actual project is proposed.

  However, the designated corridors must have some parameters. The designation of a "Montana to Los Angeles" NIETC is too vague and invites abuse, particularly since the condemnation of private property is involved. With such a vague designation, a sponsor could propose a line virtually anywhere and claim it is in the NIETC. Without some parameters on the NIETC's location, no one can tell whether the proposed project is inside or outside the corridor. A case-by-case decision by the agency will be arbitrary at best. At worst, a proposed project will be subject to litigation over whether it is inside or outside the corridor. The litigation over this one point will take longer than a normal state permitting process, defeating the very purpose of the Act.

  A vague designation such as "Montana to Los Angeles" will not be acceptable to the public. At some point, the public will want to see the discrete geographic boundaries of a NIETC on a map. This was amply demonstrated at the scoping meetings for the 368 PEIS, where the first question raised by the public was "where are these corridors located?" This question will come from developers who want to take advantage of the favorable regulatory treatment, local reviewing agencies concerned about preemption, and property owners concerned about condemnation.

A designated corridor could be broad enough to include a number of alternatives. However, it must have enough specificity so that developers, local stakeholders and local permitting agencies can tell whether a project is inside or outside the corridor.

B. Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

- Yes. The Department should give greater weight to findings of persistent congestion. Indications of persistent congestion should be derived from: (1) comparison of historical flows over paths and the respective path ratings; (2) examining denials of transmission service requests; and (3) running of production cost models to simulate historic or near-term future congestion. In addition, where there is agreement on the reasonableness of assumptions, studies that examine congestion further into the future should be used, particularly where such future congestion implies potentially significant economic harm to a large number of consumers in the form of unreasonably higher rates.

C. Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

- Yes. Findings of physical congestion should guide the Department's conclusions on congested paths. In the Western Interconnection, the principle indicator of physical congestion should be a comparison of historical flows and Operating Transfer Capacity (OTC). Conclusions from such an analysis need to be informed by circumstances surrounding the specific path. For example, some of the most heavily used paths in the Western Interconnection were sized exactly to carry power from a designated powerplant. A high utilization rate on such a path is not necessarily an indication of congestion that needs to be relieved.
- It is also useful to examine contractual congestion, however, the finding of contractual congestion should not lead directly to an NIETC designation. Rather, it should trigger an evaluation of institutional options for relieving such congestion. It is inappropriate and costly to consumers for the federal government to push high-cost solutions to contractual congestion when other solutions are available.

D. What specific transmission studies should DOE review and how far back should DOE look for such studies?

- The relevant studies in the Western Interconnection are posted on the WECC web site. We do not believe DOE should examine studies older than 2001.

E. What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

- Of highest value would be information from studies of historical physical congestion on paths because such studies contain the fewest speculative assumptions. In the Western Interconnection, DOE should compare historical flows with OTC. Paths where historical flows are near OTC should be investigated in more detail subject to the caveat discussed in Question C above.

F. What criteria should be used in evaluating the suitability of geographic areas for NIETC status?

- Any final NIETC designation criteria must be accompanied by administrative procedures explaining how the Secretary will apply such criteria. Given the vagueness of the statutory criteria the Secretary may use to designate NIETCs, it is important that DOE not only develop specific criteria for evaluating candidates for NIETC designation, but that the DOE have written administrative procedures on how the Secretary will apply such criteria in corridor designation decisions. Since corridor designations can lead to federal preemption of state laws and condemnation of private lands, these procedures should: (1) provide opportunity for the states and public to comment on a proposed NIETC designation by the Secretary; (2) require that NIETC designations be based on a preponderance of the evidence; and (3) be subject to a high standard of review.
- We note that the proposed criteria lack internal consistency and range from very detailed, site-specific criteria such as the location of "must run" reliability generators to vague, undefined criteria such as further national energy policy and energy security.

Draft Criterion 1: Action is needed to maintain high reliability.

- Few, if any, congestion areas should be identified using this criterion. Under WECC and NERC rules, and under future FERC-approved mandatory reliability rules, there should not be any instances where an operator is threatening reliability of the grid.

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

- The calculation of savings to consumers should reflect state energy policies as enacted in state law or reviews of load serving entity resource plans. Specifically, if a state policy places a high priority on acquiring renewable energy generation, makes a judgment about natural gas price risk, or establishes a carbon adder to reflect its determination of carbon risk, DOE should assume compliance with such policies in the calculations of economic benefits to consumers.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

- DOE should ascribe some, but not significant weight to eliminating the need for "must run" plants, except in cases where there are no policies that preclude such generators from exercising market power. Where reliance on the "must run" plant violates NERC planning criteria, the problem should be rectified by action to require compliance with reliability standards. DOE should not substitute its judgment for that of entities that have the responsibility to maintain system reliability.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

- DOE needs to further define what is meant by "targeted actions in the area would enhance the energy independence of the United States." For example, as written, this proposed criterion fails to recognize the international characteristics of the western electric power system. In the context of the western electric power system, interdependence, rather than energy independence, contributes to the appropriate goal of stable and adequate supplies of electricity for consumers in the western United States.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

- To reach such a conclusion, the Secretary should demonstrate that his/her finding that a specific NIETC designation would further national energy policy is consistent with other federal energy policies. The finding that the designation of an NIETC would further national energy policy should not be an aberrant conclusion that is inconsistent with other energy policies of the federal government. For example, if a corridor is designated because it is national policy to reduce reliance on natural gas for electric generation, then other federal policies must reflect the objective of reducing natural gas use for electric generation.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

- To avoid abuse of the application of this criterion DOE needs to identify what is meant by critical loads. Are these military bases, or hospitals, or government buildings, or telephone exchanges, etc.? We agree that case-specific assessments of such identified critical loads are needed. It is also important for DOE to consider non-transmission solutions for protecting these loads. Such non-transmission solutions may be lower cost and more secure than transmission solutions.
- DOE should support both proactive engineering to reduce/mitigate exposure of high-priority facilities, and a coordinated response and restoration plan in the event of natural disasters or malicious acts.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

- We agree. The greater the uncertainties that drive the finding of congestion, the less weight DOE should ascribe to the congestion finding and the less it should rely on such studies when designating NIETCs.
- One exception to this general rule would be where, because of its characteristics, a generating resource is location constrained (e.g., wind or geothermal power plants). In the case of location constrained resources, DOE should consider state policies on the choice of fuels used to generate electricity and determine if the designation would advance state energy polices.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

- We agree. The designation of an NIETC effectively short-circuits the consideration of non-transmission alternatives. In some cases, load-based generation and demand-side actions can be more cost-effective solutions to congestion. Unfortunately, once DOE designates an NIETC and a transmission project application is received in a designated corridor the state siting process has been compromised and the ability to consider and implement alternatives effectively constrained. We are particularly concerned that since FERC has no authority to order new load-based generation and limited authority to institute demand-side actions, its only choice will be to approve or deny the transmission application. For these reasons, we expect that little consideration to non-transmission alternatives will be given at FERC. Under Section 1221, the adequate consideration of non-wires alternatives must occur prior to the designation of an NIETC.

G. Are there other criteria or considerations that the DOE should consider in making an NIETC designation?

- Yes, DOE should consider the identification of *potential* NIETC designations prior to the formal NIETC designation. The designation of *potential* NIETCs would:
    - Send a signal to potential developers and states that the federal government is concerned with the need for more transmission capacity in an area.
    - Enable coordination of the NIETC designation process with federal permitting processes by allowing time to complete an EIS which will generate information on alternatives to specific transmission corridors prior to a formal NIETC designation. This will permit DOE to make a much more informed decision on an NIETC designation since significant analysis of alternatives will be available.
- DOE should develop an additional criterion that would state that the designation of a NIETC would further the energy policies of affected states as reflected in state law and state regulatory reviews of load serving entity resource plans.
- When considering the economic benefit of new transmission, DOE should also include the non-monetized impacts of transmission, such as the impact of a transmission corridor on agricultural lands, designated urban growth and environmentally sensitive areas, and land values.

H. Are certain considerations or criteria more important than others?

- Yes, highest priority should be given to designation of transmission corridors that enable the achievement of state energy policy objectives.
- Priority should be given to designation of corridors from location constrained generation resource areas.
- Low priority should be given to the designation of corridors with contractual congestion but little physical congestion, unless there has been an evaluation which finds that solutions to contractual congestion are not feasible or more costly than building new transmission.
- Low priority should be given to designations that would rely on studies with a high level of uncertainty in the assumptions used.
- Low priority should be given to criteria that are vague and unverifiable, such as Draft Criteria 4 and 5.

We appreciate DOE’s cooperative approach thus far in working with the western states and industry to shape the implementation of Section 1221 so that it will benefit western consumers.

Careful analysis and cooperative efforts will be needed if the federal government's implementation of Section 1221 is to make a useful contribution to the development of needed transmission in the international Western Interconnection.

93. Wyoming Governor Dave Freudenthal, Received Mon 3/6/2006 1:53 PM

Comments of Wyoming Governor Dave Freudenthal With Respect to The U.S. Department of Energy's Notice of Inquiry Regarding National Interest Electric Transmission Corridors

Dave Freudenthal, Governor of the State of Wyoming, submits these comments in response to the notice of the U.S. Department of Energy ("DOE" or the "Department") regarding "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors." See 71 Fed. Reg. 5660 (Feb. 2, 2006). Our comments specifically address the proposed Frontier Line Transmission Project ("Frontier Project").

The Department's willingness to engage the states, the western power industry, and proposed interstate electric transmission projects in the West in collaborative discussions, and to thereby use existing analyses of the Western transmission system developed in open transmission planning processes in the region, is laudable and comports with the Governors' request expressed in Western Governors' Association Resolution 05-30.

We are cognizant that implementation of Section 216 of the Federal Power Act (as enacted through Section 1221 of last year's Energy Policy Act) has reached a critical stage, which is the development of criteria by which the Secretary of Energy may designate National Interest Electric Transmission Corridors ("NIETC"). The approach taken in our comments is to facilitate the Department's successful implementation of its responsibilities under federal law. We also refer the Department to the comments of the Wyoming Infrastructure Authority filed today with the Department which we endorse.

Our comments are divided into three sections. Section 1 is intended to provide background and support for the Frontier Project. We believe the information which follows describing the Frontier Project, in and of itself, serves as strong support for its designation within a national interest corridor due to the Project's attributes and the benefits to consumers. Although we are not advocating that DOE proceed with early designation of the Frontier Project in advance of completion of DOE's study, we strongly believe the Project should be included in the inventory of potential NIETCs and that, once the study and inventory are completed, NIETC designation should be conferred on the Project.

Section 2 is intended to address the proper scope and collaboration that we believe is critical to maximize the value in Section 216 in action in the West.

Section 3 of our comments is intended to provide answers to questions raised in the NOI that we believe are most relevant to our Project. In particular, we wish to emphasize two points of an overarching nature regarding the Department's process for NIETC designations.

First, in considering NIETC designations in the West, the Department should not focus exclusively or even primarily on alleviation of existing congested transmission paths. In the West, NIETC designation is needed for large transmission projects that can forestall energy crises like the one that occurred in 2000-01 by connecting western resource areas with western load centers. NIETC designations should be used to avoid future congestion and to avoid the inability of load centers to access distant resources.

Second, although the Department states that it will give some consideration to early NIETC designations, it apparently intends that most, if not all, NIETC designations will be made as part of the initial and subsequent triennial study processes. We believe the Department should leave more room for case-by-case designations in response to applications. While Section 216 calls for a study, it does not preclude the Department from making designations upon application. It cannot be expected that, in the limited time available for the initial study, sufficient information can be compiled to support NIETC designations for every deserving corridor. On the other hand, such information could be available well before the Department performs its next study three years after the first study. Corridors meriting NIETC designation should not have to wait that long for designation.

Section 1 - Background Information on the Frontier Transmission Project and Justification for Designation as a NIETC

The Department indicates that one of the results of its study will be an inventory of areas where planners believe significant transmission needs exist and where transmission additions could alleviate such needs. Following issuance of the study, and after taking further public comment, the Department will proceed with NIETC designations. We believe the Frontier Line Project meets the overall criteria to warrant inclusion in the inventory and ultimate designation due to the significance of its scope and scale.

The Western region needs a more robust interstate electricity transmission system and access to more sources of clean energy.

On April 4th, 2005, the Governors of Wyoming, Utah, Nevada and California signed a Memorandum of Understanding ("MOU") declaring their support for the Frontier Line.[1] The MOU generally described the Frontier Line as originating in Wyoming, traversing Utah and Nevada, and terminating in California. The MOU further stated that preliminary work had been done to identify an initial route but recognized that further detailed studies need to be performed. Some of these studies are currently ongoing.

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[1] The MOU is available at http://psc.state.wy.us/htdocs/subregional/Frontier%20Liine%20MOU%20-%20FINAL.pdf.

This effort was undertaken in response to growing consumer energy demand, a desire to develop the vast resources across the West, including renewable resources such as wind and advanced, clean coal technologies, and the critical need to further diversify the West's energy portfolio in order to strengthen our nation's energy and national security.

The Frontier Line proposal grew out of years of study of western electric resource requirements and transmission needs following the western energy crisis of 2000-2001. The crisis led the Western Governors Association to prepare the 2001 report *Conceptual Plans for Electricity Transmission in the West*. The report concluded that new transmission and generation infrastructure located remotely from population centers could produce benefits for consumers throughout the West. The report also concluded that such an investment strategy would allow the West to diversify its electric generation resource base by promoting the development of renewable resources and new clean coal resources thereby protecting the West against excessive reliance on new natural gas-fired generation. Although the study did not identify specific projects, it did note the need for extensive upgrades to the western backbone transmission grid.

The western governors followed up this effort by asking the Seams Steering Group-Western Interconnection ("SSG-WI") to develop an ongoing proactive transmission planning process for the western interconnection. In 2003, SSG-WI issued a report on western transmission needs. The SSG-WI report examined various generation and accompanying transmission scenarios, developed a public data base to support transmission expansion analysis, but did not provide sufficient detail to enable development of specific transmission projects.

On August 22, 2003, I and Utah Governor Michael Levitt announced the formation of the Rocky Mountain Area Transmission Study ("RMATS"). We noted the critical need for new transmission in the West:

> For many years, utilities and other entities have been reluctant to make investments in needed electric transmission infrastructure. This has been due to a number of factors, including protracted uncertainties in the regulatory environment and nascent regional transmission organizations under development. As a consequence of this lack of transmission expansion, transmission congestion and bottlenecks are increasing.

The RMATS Phase I report was completed in September 2004. The report recommended a number of transmission projects within the Rocky Mountain Footprint states of Colorado, Idaho, Montana, Utah and Wyoming.

Although the RMATS study focused on the Rocky Mountain states, at the same time it was recognized that there was a critical need to tie together the resource needs of load centers in Utah, Nevada and California with the resource supplies of Wyoming, Utah and Nevada. That recognized need led to execution of the Frontier Line MOU last year.

In addition to the substantial economic benefits the Frontier Line can provide, it will:

- Strengthen the reliability of the West's transmission system.
- Better protect consumers from energy shortages and price spikes.
- Encourage a broader, diversified energy portfolio.
- Reduce reliance on foreign energy imports and enhance domestic energy security.
- Encourage new technologies that can accelerate the development of renewable energy generation and reduce the cost of controlling emissions from the West's vast fossil fuel resource base.

The Project satisfies the economic need criteria for NIETC designation as set forth in Federal Power Act § 216(a)(4)(A) and (B). As a region, the West has seen load growth of more than 60 percent in the last 20 years, but high-voltage transmission has expanded less than 20 percent. Demand for electricity in high-population states in the West is projected to continue to significantly expand in the coming decades. For instance, using a historical growth rate of 2 percent per year, California must add 1,000 MW of new capacity each year, *net of retirements*, into the foreseeable future. California and the West already experienced an energy crisis in 2000-2001, yet the California Energy Commission recently reported that "[t]he development of new energy supplies is not keeping pace with the state's increasing demands. Construction of new power plants has lagged and the number of new plants applying for permits has decreased." See 2005 California Energy Commission *Integrated Energy Policy Report* at E-1.

The Project would allow the wheeling of several thousand megawatts of both clean coal and renewable-generated power from the Intermountain West to consumers in Utah, Nevada and California. According to an analysis conducted by the Rocky Mountain Area Transmission Study, annual consumer and generator benefits for the Rocky Mountain region range between $926 million to $1.7 billion. California consumers also stand to benefit by $325 million to nearly $400 million annually. The California Energy Commission is in the final stages of completing an updated modeling evaluation of the potential public interest benefits which could be derived by building an interstate transmission line extending from resource rich Wyoming to California.

Based on our analysis, we believe the Frontier Project will meet the following criteria:

1. Promote Resource Diversity:

Resources developed to meet growing electrical demand must be clean, diversified and economically and technologically viable. Transmission projects should be designed to allow the fullest possible use of renewable resources.

Proposed projects should identify strategies that ensure renewable resource access to the transmission line, including innovative approaches that ensure a significant amount of capacity is available to renewable developers. Renewable-fossil partnerships are important because the combination of resource attributes can provide significant complimentary benefits for system operation. Additional transmission is needed to bring renewables online faster and more cost-effectively.

2. Incorporate Advanced Technologies and Design Concepts:

States are interested in innovative approaches that make use of the best technology for transmission infrastructure development. The use of such technology should facilitate the siting and permitting process. States also are interested in design concepts that will minimize line loss, improve reliability and minimize environmental impacts. Proposals also should identify opportunities to integrate with other transmission projects in order to reduce costs, enhance reliability and increase generation resource diversity.

3. Produce Economic and Reliability Benefits:

The project must demonstrate net economic consumer benefits in each of the states and in all of the four states collectively. A transparent approach to modeling economic benefits is important. Projects also should identify expected reliability benefits across the West. Because the Western Interconnection is a single interconnected electrical system that operates synchronously, participation in our efforts by other Western states is welcome and can add value to a well-planned project.

4. Ensure Broad Stakeholder Participation:

It is incumbent upon project developers and the States to engage with stakeholders throughout all phases of project development. States are particularly interested in outreach and education as a development objective. This communication process will require a coordinated effort across the public and government agencies at the federal, state, and local levels.

5. Promote Equitable Cost Allocation within a Regulatory Framework:

Recognizing that load growth and benefits of transmission will change over time, States are interested in the project's capital structure and its ability to lend itself towards equitable cost allocation methodologies. The region must consider new approaches to the allocation and recovery of project capital costs in a manner that recognizes the widespread benefits to electric generators and customers across a broad region. Working through these issues will require active participation of many parties over a period of time. Cost recovery proposals also will impact project financing. Proposed projects should identify how the anticipated capital structure will minimize costs to consumers.

6. Allow for Incremental Implementation:

The project should be designed to enable development in phases, with an initial phase of between 1500 and 3000 MW, accompanied by a long-term strategic plan for the eventual development of up to 12,000 MW. Wherever possible, rights-of-way and permitting should be sized to support future project expansion. Early-stage project analysis should include extensive engineering feasibility review as an integral component of development. Work should be coordinated with existing utilities, state, regional and federal planning organizations, as well as other ongoing Western transmission projects and control area operators. Project design in early phases should remain flexible.

7. Ensure Developer Commitment:

Developers should demonstrate to the Governors their ability to successfully plan, finance and construct the project while satisfying the aforementioned criteria. The project developers must have significant transmission system experience and the financial resources to commit toward implementing the steps necessary to complete the project in a timely fashion.

8. Build a Collaborative Relationship:

The States of California, Nevada, Utah and Wyoming can provide a unique, critical synergy to advancing infrastructure projects, built on the opportunity to move low-cost renewable and clean-technology conventional resources from remote locations where they are abundant to distant centers of rapid electric load growth. Our objective is to maximize economic value in resource rich regions of each state by providing political, regulatory, and community support for the development of a large-scale pathway to load-serving utilities in Utah, Nevada and California, thereby maximizing the project's value to customers.

Section 2 – Need for State-Federal Collaboration and an Integrated Federal Agency Implementation Strategy for Section 216

The very notion of a NIETC implies a major procedural undertaking of national policy significance. As stated in the DOE NOI, "Today, congestion in the transmission system impedes economically efficient electricity transactions and in some cases threatens the system's safe and reliable operations." NIETC designation sets in motion a series of interrelated, critical procedural actions among federal and state regulatory agencies that should be designed to follow an orderly sequence. It is imperative that DOE and other federal agencies provide a clear procedural message to the states and electric transmission project developers. This should be established prior to any NIETC designation. We recommend that DOE carefully coordinate its determination of NIETC criteria and the corridors thereby designated in cooperation the FERC and its responsibilities under Section 216.

The Frontier Line Project has benefited from preliminary support from federal agencies. To succeed, however, a project of this scope and scale will be dependent upon comprehensive, integrated federal agency actions carried out in cooperation with activities in project footprint states. The designation of an NIETC would likely trigger transmission permit applications to states and federal agencies. Such action triggers the one-year clock for state review under Section 216 that then triggers FERC authority to grant eminent domain to condemn private lands. This interrelated series of regulatory actions merits a high level of procedural clarity and state-federal coordination before it is set in motion.

In order to preclude procedural abuses by project sponsors, we recommend the establishment of FERC rules which specify that the one-year clock for state regulatory action on a proposed transmission line within a NIETC will not begin until a complete application has been received by a state as defined by state law. It is imperative as a matter of prudent state-federal coordination that local stakeholders be given the opportunity to raise legitimate concerns. DOE should specify how it intends to advise FERC if a sponsor's project falls within a corridor and the information it will provide to justify such a finding. This is particularly important if DOE designates geographically vague NIETCs.

The action or inaction of federal agencies will be a critical element in permitting major new transmission in the West, including the Frontier Line. Prior to finalizing NIETC criteria, DOE should clarify how the responsibilities of federal agencies in their review of applications for different federal permits will be coordinated among agencies in a coordinated manner, and how such process relates to the criteria that the Departments of Energy, Interior, Agriculture, Commerce and Defense are using to designate energy corridors on federal lands under Section 368. DOE should also explain how the designations of energy corridors under Section 368 are to be coordinated with DOE's designation of NIETCs.

Section 3 – Responses to Questions Raised in the NOI

How broadly or narrowly the Department should consider and define corridors?

We believe the answer to the appropriate breadth of NIETC lies in an examination of congestion. Congestion should be defined for the purpose of NIETC designation so as to capture all effects of transmission constraints. This will require a broad measure. Congestion should be measured over large geographic areas covering multiple states within an Interconnection, as well as the intrastate sub-regions that comprise the larger geographic area. Congestion calculations should address the costs to consumers of barriers to access to both existing and potential electric supply resources in locations distant from load centers. Congestion should also not be defined as merely localized congestion conditions but should include broader and truly national interest needs for additional interstate transmission investment so as to avoid future congestion as needed generation resources are added to meet future supply needs.

The Frontier Line is intended to address this broad definition of congestion by moving large amounts of electric power generation derived from advanced coal technologies and renewable wind resources located in resource-rich Wyoming to rapidly growing load centers in Utah, Nevada and California. The project is intended to add additional renewable resources, including geothermal, to the resource supply mix in Utah, Nevada and California.

As noted earlier in our comments, preliminary analysis indicates significant net savings are available from alleviating this congestion.

Should the Department distinguish between persistent and dynamic congestion?

We interpret "persistent congestion" as that which has repeatedly occurred and is expected to continue on known transmission facilities, most likely on an increasing scale. "Dynamic congestion" is more variable, reflecting outages, volatility in fuel prices and unanticipated events. Although we agree the Department should distinguish between these different types of congestion, both are critical to transmission expansion planning. Persistent congestion merits the greatest attention in the Department's NIETC planning initiative, as it reflects a growing shortfall that tends to escalate in regions experiencing load growth. Sensitivity analysis and probabilistic analysis techniques are available to evaluate both congestions conditions.

Should the Department distinguish between physical congestion and contractual congestion?

Yes. "Contractual congestion" may result from underutilized transmission capacity reservations, and should certainly be distinguished from "physical congestion tied to technical or operational limitations. "Contractual congestion" may be resolved through tariff and regulatory reform, and may not require the construction of new facilities.

Findings of physical congestion should guide the Department's conclusions on congested paths. In the Western Interconnection, the principal indicator of physical congestion should be a comparison of historical flows and Operating Transfer Capacity (OTC). Conclusions from such an analysis need to be informed by circumstances surrounding the specific path.

What specific transmission studies should the DOE reference?

We recommend that the Department reference the transmission studies available in consultation with WECC, and the Wyoming Infrastructure Authority (www.wyia.org).

What criteria should be used in evaluating the suitability of geographic areas for NIETC status?

It is important that DOE not only develop specific criteria for evaluating candidates for NEITC designation, but that the Department have written administrative procedures on how the Secretary will apply such criteria in corridor designation decisions. Since corridor designations can lead to federal preemption of state laws and condemnation of private lands, these procedures should: (i) provide opportunity for the states and public to comment on a proposed NIETC designation by the Secretary; (ii) require that NIETC designations be based on a preponderance of the evidence; and (iii) subject to a high standard of review.

We have incorporated the Frontier Line Project criteria in Section 1 of our comments. We believe they are compatible with the majority of Draft Criteria identified in the NOI, and that the Department refers to them in its decision on setting criteria for NIETC designation.

Evaluation Criteria

The Department also asked for comment on the criteria it should use in evaluating the suitability of geographic areas for NIETC status. We support the first six criteria proposed by the Department but believe the seventh and eighth criteria may be off track.

The seventh proposed criterion reads as follows: "The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies." While recognizing that, given long transmission construction lead times, NIETC designations require a certain number of assumptions to be made, the Department states that "[o]ther things being equal, arguably the Department should be more inclined to designate NIETCs where there are existing needs instead of projected needs, particularly if those future needs rest upon relatively uncertain assumptions and contingencies."

These statements by the Department appear to reflect a view that the purpose of NIETC designations is primarily to eliminate existing congestion. We believe this view is too narrow. The history of development of Section 216 of the Federal Power Act reflects a broader concern than simply alleviating local pockets of congestion. Instead, Section 216 reflects a broader view that transmission infrastructure was lagging significantly behind load growth as a result of the difficulty of transmission siting. The problem was seen not only in terms of existing congested transmission paths but also in terms of long-term development of necessary generation resources.

The need to view NIETCs in the context of long-term resource needs is particularly acute in the West. The western interconnection is much different than the eastern interconnection owing to the much greater distances between resource areas and load, the resulting reliance on very long radial lines, the relatively much larger cost of transmission per customer served, the high percentage of land in federal ownership, and the lack of unified market structures. As discussed above, following the western energy crisis in 2000-01 and as a result of interest at the highest level of western state government (and with the cooperation of the federal government), considerable study was undertaken on means for avoiding another crisis. The results of these studies pointed to the need to reduce reliance on natural gas-fired generating stations located close to load and to instead diversify to lower-cost but more distant sources of wind and coal energy. However, the key to this energy strategy was the construction of large, long interstate transmission lines.

An undue emphasis on alleviating existing congested path threatens to make the NIETC process of limited use to the West. The true "national interest" of the West is ensuring the construction of transmission from our resource areas to our load areas. We therefore ask the

Department to recognize a national interest in transmission development than is broader than appears to be reflected in the seventh proposed criterion.

Finally, we believe that the eighth criterion should be rejected. "Alternative means" of addressing the resource needs in question should not be a part of NIETC designation. State regulators which superintend load serving entities have ample authority to require such entities to consider alternative means of acquiring power as compared with transmission of energy through an NIETC. For instance, most utilities are required to undertake resource planning processes, with stakeholder participation and full consideration of all alternatives, before they can commit to acquisition of resources. These resource planning processes are generally highly complex. If grafted on to the NIETC designation process, this type of resource planning could unduly delay NIETC designations contrary to Congress' intent.

Case-by-case designations

Although the Department indicates it will consider early designations for corridors where well-developed information supporting designation is provided, it appears the Department intends to make most designations as a part of a unified process following the initial study and the subsequent triennial studies. We urge the Department to also provide for case-by-case designations following applications that may occur outside the study process.

It is true that the statute, in general, links designations to the required studies. On the other hand, the statute does not preclude the Department from making designations separate from the overall study process. The Department recognizes the flexibility it has in this regard in providing for early designations that will be made outside of the national study process. See 71 Fed. Reg. at 5661.

It is likely there will not be sufficient information to support NIETC designation for many corridors that may ultimately merit NIETC designation at the time the Department concludes its study in August. Such information is likely to be prepared and submitted to the Department by developers interested in undertaking transmission development within such corridors. However, for various reasons, those developers may not be ready to submit information during the study process or shortly thereafter. Nevertheless, there is no reason the Department should make these developers wait for another three years before there is a chance for NIETC designation. NIETC designation should be available if, as and when the necessary information is submitted to the Department.

We appreciate the opportunity to submit these comments.

94. Wyoming Infrastructure Authority, Received Fri 3/3/2006 12:14 PM

Attached is a letter to Mr. Kevin Kolevar and written comments of the Wyoming Infrastructure Authority, in response to DOE's notice of inquiry regarding the proposed transmission congestion study and subsequent designation of National Interest Electric Transmission Corridors.

Best Regards,

<<Comments to DOE on NIETC WIA cover letter.pdf>> <<Comments on DOE NOI on NIETC from WIA.pdf>>

Steve Waddington
307.635.3573

WYOMING INFRASTRUCTURE AUTHORITY

200 E. 17th Street, Suite B
Cheyenne, Wyoming 82001

March 3, 2006

Mr. Kevin Kolevar, Director
Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Room 6H-050
1000 Forestall Building
Washington, DC 20585

Note: Filed Electronically to: EPACT1221@hq.doe.gov

RE: Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

Dear Mr. Kolevar:

The Wyoming Infrastructure Authority ("WIA") appreciates the opportunity to comment on the Department of Energy's Notice of Inquiry regarding the proposed transmission congestion study and subsequent designation of National Interest Electric Transmission Corridors ("NIETCs"). Those comments are attached. In brief, WIA believes that it is important for the Department:

- To ensure that its criteria for designating NIETCs not be limited to those where persistent congestion obtains today. Doing so would put an inappropriate brake on the legislative intent to encourage transmission infrastructure to develop to reduce consumer prices and diversify the fuel mix.

- To expedite the study and designation of NIETCs, and to do so by designating corridors for potential projects broadly, as generalized paths between two (or more) locations.

- To recognize the features and characteristics of the Western transmission system, and take into account the numerous studies that have already demonstrated the need for, and benefit from, transmission infrastructure investment.

- To give full weight to the ongoing major transmission expansion efforts in the West, including the Frontier Line, the TransWest Express Project and WIA's two ongoing projects in partnership with Trans-Elect, Inc. and National Grid USA, and anticipate that one or more of these projects will likely apply to DOE for early designation as a NIETC.

- To remain flexible and in a position to accelerate an early review and the designation of corridors on a case-by-case basis, and establish the application process for such early designation.

- To reconsider the proposed criteria 7 and 8 as these are unduly conservative and should be abandoned or de-emphasized.

The WIA looks forward to working with DOE as Wyoming continues its efforts to stimulate development of needed transmission assets in the Western interconnection.

Sincerely,

Steve Waddington
Executive Director

Attachment (1)
Cc: Governor Dave Freudenthal
Honorable Michael B. Enzi
Honorable Craig Thomas
Honorable Barbara Cubin
Chairman Joseph T. Kelliher, Federal Energy Regulatory Commission

Comments of the Wyoming Infrastructure Authority
Submitted in Response to the Office of Electricity Delivery and Energy Reliability, United States Department of Energy, Notice of Inquiry Regarding Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

The Wyoming Infrastructure Authority ("WIA") offers the following comments to the February 2, 2006, Notice of Inquiry entitled "Considerations for Transmission Congestion Study and

Designation of National Interest Electric Transmission Corridors". WIA's key comments and suggestions are:

- When taking into account how transmission has historically developed, in combination with how the wholesale marketplace has emerged and the need for fuel diversity, it is critically important that DOE's designation of corridors not be limited to those where persistent congestion obtains today. Doing so would put an inappropriate brake on the legislative intent to encourage transmission infrastructure to develop to reduce consumer prices and diversify the fuel mix.

- DOE must expedite the study and designation of NIETCs, and do so by designating corridors for potential projects broadly, as generalized paths between two (or more) locations.

- DOE must fully recognize the features and characteristics of the Western transmission system, and take into account the numerous studies that have already demonstrated the need for, and benefit from, transmission infrastructure investment.

- DOE should recognize several ongoing major transmission expansion efforts in the West, including the Frontier Line, the TransWest Express Project and WIA's two ongoing projects in partnership with Trans-Elect, Inc. and National Grid USA, and anticipate that one or more of these projects will likely apply to DOE for early designation as a NIETC.

- DOE should remain flexible and in a position to accelerate an early review and the designation of corridors on a case-by-case basis, and establish the application process for such early designation.

- DOE's proposed criteria 7 and 8 are unduly conservative and should be abandoned or de-emphasized.

Each of these points is discussed below.

What is the Wyoming Infrastructure Authority?

The WIA was created in 2004, by the state legislature, and tasked with diversifying and growing Wyoming's economy through the development of electric transmission infrastructure. The Authority is also responsible for planning, financing, building, maintaining, and operating electric transmission and related facilities and may:

- Issue revenue bonds[2] to finance new transmission lines to support new generation facilities in the state;

[2] The WIA bonding capability is unlimited for transmission projects it would own. The WIA can also issue up to $1 billion in bonds to help finance transmission infrastructure owned by other parties. The WIA's first financing was in September, 2005. The

• Own and operate lines in instances where private investment is not offered;
• Enter into partnerships with public or private entities to build and upgrade transmission lines;
• Investigate, plan, prioritize and establish corridors for electric transmission in Wyoming; and,
• Establish and charge fees and rates for use of its facilities in consultation with the public service commission and other related government entities.

The WIA is an instrumentality of the State of Wyoming and is governed by a board composed of five (5) members appointed by the Governor, with the advice and consent of the State Senate.

The Western Electric Transmission System

It is critically important to recognize that the existing electric transmission system was built by electric utilities in a vertically integrated manner. As a result, the existing system was built and *sized* to serve local customers, integrate utility-owned generation and to support reliability. In addition, the existing regulatory and institutional system relied upon to address congestion and facilitate resource development on the grid has not functioned well. A wide variety of regulatory, financial and political uncertainties have significantly slowed the pace of both private sector and public power system investments in the utility transmission system. The impacts of these uncertainties on the consumer and overall economic activity have been, and continue to be, profound. Unless immediate improvements to the transmission grid are made, increasing pressure on existing facilities will intensify and system reliability will erode. At the same time, the Nation could find itself continuing to over-rely on natural gas fired generation located close to load centers. Such an outcome would not further the national interest. Each of these concerns have particular significance for the West.

In the West there is intensifying interest in securing a more diverse power supply through increasing reliance on low cost fuels, such as coal and wind, that are abundant in areas of the West that are distant from load centers. However, with few exceptions, in the West the transmission system was not designed to support economic transfers of power or the development of new sources of supply. To enable this development to occur will require new transmission facilities. The Department's NIETC authority is a key to that development.

The Western interconnection is especially vulnerable as a result of growth in the region. To meet these needs, load serving entities are seeking to build new power generation to keep pace with both the retirement of aging power stations and the need for more capacity to meet growing electric power demand. This, along with increasing requirements for fuel diversity to offset natural gas reliance and improved environmental performance, is placing added pressure on existing transmission facilities. There is an immediate need for transmission upgrades to enable

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WIA issued $34.5 million in bonds to contribute to the financing of a transmission line in Wyoming that will be owned and operated by Basin Electric Power Cooperative.

additional transmission-dependent generation facilities to serve load growth in the very near-term.

The Need To Take A Broad View Of Geographic Areas, Needs, and Corridors

The NOI requests comments on the scope of its congestion study and the identification of corridors for potential projects. In our view, both of these overarching criteria should be designed to be as broad as possible.

In its NOI, the Department makes clear that its inventory of geographic areas that have important existing or projected needs related to the transmission infrastructure includes needs related not only to congestion and reliability but also the need to enable larger transfers of economically beneficial electricity to load centers or enabling delivery from new generation capacity to distant load centers. This broad view of determining project needs as going beyond the classic definition of congestion to include economic benefits is important and should be pursued. First, it is exactly in line with the provisions of the Energy Policy Act of 2005 which provide, in new Section 217 of the Federal Power Act, that in determining whether to designate a NIETC the Secretary may consider among other things the "economic vitality and development" as well as the "economic growth" of a corridor as well as the end markets served by that corridor. See Section 216 (a)(4) of the Federal Power Act, to be codified at 16 U.S.C. § 824p(a)(4).

Second, the expansive view of needs presented in the NOI is particularly important for the West. The existing transmission system in the West may not manifest reliability concerns or persistent congestion in the classic sense. However, it is widely recognized that the future system in the West must be expanded to facilitate the goals of fuel diversification, energy independence and consumer benefits. If DOE narrows its focus to classic congestion for purposes of designating corridors as being in the national interest, it will be thwarting the legislative intent to encourage and expedite the siting and permitting of transmission infrastructure that is critically needed to support the growing economy in the West.

As a related matter, the Department's view, as stated in the NOI, that corridors are to be defined broadly rather than as specific routes for transmission facilities is the correct one. Limiting a designation to only specific routes runs the real risk of neglecting viable alternative routes. This is a particularly important consideration in the West where transmission remains undeveloped.

Several features of the Western interconnection underscore why the Department should not adopt a narrow definition of needs or corridors. Designation of corridors, and the backstop siting authority for FERC that this may trigger under certain circumstances, could greatly enhance prospects for transmission development in the West, due in part to features that distinguish the West from the rest of the Nation. These features include:

- The vast geography and distances in the West, with much of the low cost coal and wind resources that need to be developed located great distances from load centers, requiring long transmission corridors;

- Extensive Federal land ownership and management by the Bureau of Land Management, the Forest Service and other federal agencies;

- Multiple electrical control areas and a patchwork of transmission owners, including FERC-jurisdictional utilities, but also Federal power marketing agencies, generation and transmission cooperatives, municipalities, and others; and,

- With the exception of California, a notable lack of market organization, such as regional transmission organizations or system operators over a large area, to deal with the explosion in wholesale competitive market activity and to organize transmission planning and expansion.

Expanding the Western transmission electrical system will clearly save consumers billions of dollars with current technology and increasing savings as new technologies in both the generation and transmission areas are developed and deployed. DOE's role in designated corridors as NIETCs is critical to helping expedite this expansion. Particularly in the West, DOE's examination and study of the need should be based upon the broadest interpretation of congestion and bottlenecks.

FERC Backstop Authority

We believe that especially in the West, but elsewhere in the Country as well, designating transmission corridors for NIETC status may well serve, in some cases, as a significant regulatory "lift" vehicle enabling ultimate approval for the construction of needed transmission expansions. EPACT envisioned the prospect that a time might come, when traditional regulatory approval mechanisms involving state and federal agencies could not render a timely decision for the siting of needed transmission lines. To have the Federal Energy Regulatory Commission ("FERC") in a position to serve as a backstop, if all else fails, will serve to expedite the normal siting approval processes involving requisite state and federal agencies.

FERC has extensive experience in siting natural gas facilities and is accustomed to coordinating the reviews by other governmental agencies. WIA believes DOE should work closely with FERC as it considers NIETC reviews. FERC's expertise and understanding of the transmission system should provide valuable insights to DOE.

Case-by-Case Designations

While the WIA understands DOE's desire to comply with the nationwide study and report requirements of Section 1221 (a) of the Act in a timely manner, our reading of EPACT is that the

Department is not prohibited from reviewing and acting upon requests for project specific NIETC designations. The WIA believes it is completely consistent with Congressional intent that DOE remain flexible and in a position to accelerate an early review and the designation of an area(s) or specific corridor(s) as qualifying as a NIETC, when requested by a State, regional organization or project sponsor. DOE should also make provision to initiate (in collaboration with appropriate States and/or regional transmission organizations) early reviews in areas or corridors it believes are in the national interest.

DOE should recognize several ongoing major transmission expansion efforts in the West, including the Frontier Line, the TransWest Express Project and WIA's two ongoing projects in partnership with Trans-Elect, Inc. and National Grid USA, and anticipate that one or more of these projects will likely apply to DOE for early designation as a NIETC. DOE should remain flexible and in a position to accelerate an early review and the designation of corridors on a case-by-case basis, and establish the application process for such early designation.

Criteria for Evaluating NIETC Status

In the NOI, the Department asks for comment on the eight criteria is proposes to apply in evaluating geographic areas as candidates for NIETCs and whether additional criteria may be necessary. We believe that the first six criteria are workable and necessary and follow the intent of the Act. However, we suggest that the last two criteria, with their emphasis on existing needs over projected needs and mitigation alternatives should be abandoned entirely or, barring that, de-emphasized. In addition, we recommend that the Department extend its criteria to give great weight to local and regional plans.

The proposed criteria

The WIA strongly supports the proposed criteria one (1) through six (6): 1) reliability; 2) economic benefits for consumers; 3) diversifying fuel sources for electric generation; 4) enhancing energy independence; 5) furthering national energy policy; and, 6) reducing the nation's vulnerability from natural disaster or malicious acts are sound criteria for establishing transmission corridors as being in the national interest. As our comments reflect above, in the West economic benefits to consumers will materialize by building transmission to enable coal and wind development in remote areas distant from urban centers. Such development is clearly in the national interest and DOE can help encourage such development by liberally and broadly designating western corridors as NIETCs.

We take exception to proposed criteria seven (7) and eight (8). From our perspective, these criteria are unduly conservative and should be abandoned or de-emphasized. Criterion 7 raises the concern that *prospective* congestion, particularly if associated with forecasts of future economic conditions, should be given less weight in consideration for designation than existing needs. Relying on this criterion, particularly as it relates to the West, might reduce or eliminate the designation of corridors as being in the national interest. But, the transmission needs in the

West largely are prospective, as they relate to enabling fuel-diversifying generation to develop. As such, expectations of the future are always subject to some forecasting uncertainty. To ignore this critical need in the West by applying criterion 7 would put an inappropriate brake on the legislative intent to encourage transmission infrastructure to develop to reduce consumer prices and diversify the fuel mix in the West.

Criterion 8 should also be abandoned as being overly cautious. With regard to prospective needs, and the question of whether alternative means of mitigating the need have been addressed, DOE should rely on the marketplace and the regulatory system to make such determinations. An alternative means will almost always exist – such as locating natural gas fired generation close to load to avoid the need for transmission infrastructure. DOE should not invite such arguments in challenge of its designations of NIETCs. DOE's role should be to broadly and liberally designate corridors as being in the national interest. Whether those corridors are ultimately built, or alternative solutions are implemented instead, will be determined by the relative economics through the marketplace and regulatory system.

Additional criteria for NIETC designation

The DOE requested comments on whether there are other criteria that should be considered as it evaluates NIETCs and whether certain considerations are more important than others. Some evaluation criteria may be more important in one region than in another. Therefore, DOE should place great weight and importance on the conclusions and recommendations in transmission studies already underway throughout the country. Many have been underway for extended periods and have involved a wide-array of affected stakeholders who are intimately familiar with local and regional conditions and needs.

Undoubtedly, there are a number of areas and specific corridors throughout the country where DOE is keenly aware of the importance of relieving transmission congestion at the earliest possible time. As DOE has noted in its NOI, there have been a significant number of transmission studies completed, and others are under way, which have documented the need for new transmission facilities and upgrades to relieve current and anticipated congestion on the Nation's electric grid.

Certainly in the West, numerous studies have and continue to document the need for transmission expansion to enhance system reliability, fuel diversity, load balancing, economic growth, wholesale competition and the necessity to lower overall system costs to ratepayers. Many of these potential projects have been in the planning process for extended periods of time and have involved extensive stakeholder discussions.

Beginning in 2001, the Western Governors' Association released a report, the "Conceptual Plan for Electricity Transmission in the West," that made clear that, if new transmission and generation assets were deployed remotely from population centers, significant benefits could be produced to electric consumers throughout the West. This report was developed in the aftermath of the electricity price spikes and supply shortages that threatened much of the West. The report also made clear the necessity to diversify fuel resources away from a growing dependence on natural gas to other fuels, including coal and renewables. While the study did not make project specific recommendations, its conceptual framework was important for other studies that followed.

Also in 2001, the Western Governors requested the Seams Steering Group – Western Interconnection ("SSG-Wi") to develop a transmission planning process that was both proactive and contemporary. In 2003, SSG-Wi issued a report on the transmission requirements for the West-wide interconnection. The report looked at three generation and associated transmission scenarios. Even though the report did not make recommendations on specific transmission projects, the effort enhanced the analysis of transmission needs in the West.

In 2003, Wyoming Governor Dave Freudenthal and then Utah Governor Mike Leavitt cosponsored the Rocky Mountain Area Transmission Study ("RMATS"). The Governors found: "For many years, utilities and other entities have been reluctant to make investments in needed electric transmission infrastructure. This has been due to a number of factors, including protracted uncertainties in the regulatory environment and nascent regional transmission organizations under development. As a consequence of this lack of transmission expansion, transmission congestion and bottlenecks are increasing. While this is a problem throughout the western interconnection, it is becoming an acute issue in areas of the Rocky Mountain sub region."

The resultant RMATS effort was a consensus planning study conducted by regional industry, governmental, and environmental stakeholders in 2004. RMATS recommended that a series of new transmission lines should be constructed from Montana and Wyoming to its neighbors, including Colorado, Utah, Idaho, and markets further west.

Along with RMATS, other studies in the West are further refining regional transmission planning needs in the Western interconnection. DOE is aware of these efforts. They are important to reference, because WIA believes that other vital and nationally significant transmission project needs will flow from these and other sub regional planning efforts. These efforts include the Central Arizona Transmission Study ("CATS") which now includes New Mexico, parts of Colorado and Nevada and has been reconstituted as the Southwest Area Transmission ("SWAT") Planning Committee. CATS identified specific transmission projects, one of which is now under construction. Also, the Southwest Transmission Expansion Plan ("STEP") is analyzing transmission needs in the Arizona and Southern California-Southern Nevada region. Further, the Northwest Transmission Advisory Committee ("NTAC") is conducting a similar transmission expansion assessment in the Northwest region.

In all of these planning efforts in the Western interconnection, extensive modeling and critical real world analysis has been conducted. WIA believes it is essential that DOE take advantage of the expertise that has gone into these studies, in addition to the recommendations that have flowed from these important analytical efforts.

WIA is a member of the Western Electricity Coordinating Council ("WECC") and was an active participant in SSG-Wi expansion planning activities. We understand DOE is relying on WECC for advice and technical study support on the Western transmission system. We support your reliance on WECC but caution against overly studying this issue. The need for transmission development in the West to support goals such as expressed in DOE's proposed criteria one (1) through six (6) is widely recognized and has been already studied extensively.

A Summary of Ongoing Transmission Projects in the West

While this summary does not intend to represent all the transmission development activities in the West, it is a snap shot of the projects the WIA is actively involved in. As a result of the RMATS effort, Wyoming is embarking on a number of high priority transmission projects.

TOT 3 Expansion Project

RMATS identified the TOT 3 transmission constraint near the Colorado-Wyoming border as one of three high-priority projects for upgrade. Accordingly, the WIA has entered into a partnership with Trans-Elect, Inc. to pursue development of new electric transmission between Colorado and Wyoming along the TOT 3 path. The Western Area Power Administration has joined the WIA and Trans-Elect in signing a Memorandum of Understanding to jointly work together on the TOT 3 project to determine the public service benefits and interest in this transmission upgrade. A transmission investment across TOT 3 will facilitate the development of low-cost, clean-coal generating plants and high-efficiency wind turbines in both Colorado and Wyoming. The initial priority for the TOT 3 Partnership is to involve all developers and utilities with an interest in the corridor in northeastern Colorado and eastern Wyoming.

Wyoming - West Transmission Development Study

The WIA and National Grid have also signed a Memorandum of Understanding to jointly conduct a transmission study that will help lay the groundwork for a significant increase in electric transmission capacity between Wyoming and neighboring states to the West. The Wyoming – West transmission development study will also build upon RMATS. It will take a fresh look at the RMATS recommendations, with a focus on identifying new transmission that is required within Wyoming and between Wyoming and its neighbors to the west.

The Frontier Line

In April of 2005, the Governors of Wyoming, Utah, Nevada and California entered into agreement which proposed the development of a new interstate high-voltage transmission line originating in Wyoming and having terminal connections in Utah, Nevada and California. The purpose of the line is to provide much needed transmission capacity to serve the growing loads in Utah, Nevada and California. The line would also facilitate access to remotely located coal and wind energy resources in Wyoming. The Frontier Line transmission investment is estimated at $3 Billion, with associated generation projects investments estimated to be $15-20 Billion.

TransWest Express

Arizona Public Service Company (APS) has announced that it seeks to reach Wyoming with transmission lines from northern Arizona through Utah. The TransWest Express project is a proposed study of alternative corridors for two 500 kV AC transmission lines, designed to access Wyoming's Powder River Basin coal and vast wind resources. The key drivers for the project proposal are Arizona's rapid growth, an uncomfortable growing reliance on natural gas, and the need to diversify APS' energy resource mix.

Conclusion

The WIA urges the DOE to move forward with the NIETC process at the earliest possible time. Designations should be broad based, using proposed criteria one (1) through six (6), and recognize future needs as well as existing reliability and congestion concerns. DOE should also establish mechanisms and dedicate resources to review case-by-case requests for NIETC designation for projects that are poised to move forward in the near term. In the West, DOE should rely on the existing transmission planning studies and organizations, including WECC and sub regional studies like RMATS. These ongoing efforts are serving to support the need for both upgrades and new transmission facilities to relieve congestion and to provide capacity for future electric load growth in the Western interconnection. Policy makers at the state level have a high degree of comfort with these stakeholder efforts.

Respectfully submitted,

Steve Waddington
Executive Director
Wyoming Infrastructure Authority

Dated: March 3, 2006

95. **Xcel Energy, Received Monday, March 06, 2006 4:37 PM**

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Office of Electricity Delivery and Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, SW.
Washington, DC 20585

Sent via email – EPACT1221@hq.doe.gov

March 6, 2006

Dear Sirs,

Xcel Energy Services, Inc. ("XES") offers the following comments in response to the Notice of Inquiry ("NOI") issued by the U.S. Department of Energy ("DOE" or "Department") on February 2, 2006 in the above-captioned docket, on behalf of the public utility subsidiaries of Xcel Energy namely, Northern States Power (NSP), Northern States Power–Wisconsin (NSP-WI), Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS) (referred to jointly as the "Xcel Energy Operating Companies").[1]

The Xcel Energy Operating Companies operate in three distinct areas and two different interconnections, serving loads that are located, for the most part, distant from many sources of generation and therefore, reliant on transmission interconnections to provide reliable and economic deliveries of power for its customers. In addition, all four of the Xcel Energy Operating Companies are located near or adjacent to significant sources of renewable energy generation that is poised for development. The impact development of this natural resource base will have on the Xcel Energy Operating Companies' transmission systems will be notable.

In this inquiry, the DOE is seeking comment concerning its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors pursuant to section 1221(a) of the Energy Policy Act of 2005 (EPAct). The Department seeks

[1] XES is the service company for Xcel Energy Inc. ("Xcel Energy"), a Minnesota corporation and a registered holding company under the Public Utility Holding Company Act of 1935. XES performs a variety of administrative and general services for its affiliates within the Xcel Energy holding company system, including the Xcel Energy Operating Companies.

responses to general questions and comment regarding specific evaluation criteria to be used in the designation of NIETCs. XES provides the following responses to certain questions and criteria relating to the provision of reliable and economically efficient electric service to its operations and customers.

A. Congestion Study

The Department requests parties identify those geographic areas or transmission corridors for which there is an acute need for early designation as a NIETC. XES is unaware of any area or corridor in or near its areas of operations that at present would merit early designation as a NIETC.

(1) – Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

The Department should distinguish between persistent and dynamic congestion, especially if dynamic congestion is defined as congestion that varies in frequency and magnitude. Persistent congestion should be defined in accordance with some threshold metric and should be indicative of a more serious problem meriting designation as a NIETC. Dynamic congestion, by definition changing in frequency and magnitude, may be more easily resolved than persistent congestion and not necessitate a NIETC designation.

(2) ***Should the Department distinguish between physical congestion and contractual congestion, and if so, how?***

The Department should distinguish between physical and contractual congestion. Physical congestion implies congestion arising from actual electrical flows or loading on a given transmission element. Contractual congestion implies congestion arising from scheduled transactions in accordance with posted availability on transmission provider Open Access Same Time Information Systems (OASIS).

Many regions of the country, including those in which Public Service Company of Colorado operates, allocate transmission service based on contractual or contract path assessments and operate transmission systems based on contractual flows. In the instance of physical congestion, flow-based models are utilized to determine available transmission capability and real-time flow-based systems are used to operate the grid. Actual flows on a given element can significantly vary from records of contractual flows. But because the system is operated in accordance with scheduled flows apparent (contractual), congestion may vary significantly from real (physical) congestion. Through this proposed study of congestion to identify NIETCs, the DOE should seek to clarify the variance between real and apparent congestion. Highlighting this difference may help lead to increased utilization of the grid and reform of transmission system operating and scheduling practices.

(3) What existing, specific transmission studies and other plans should the Department review (in addition to those listed in Appendix A)? How far back should the Department look when reviewing transmission planning and path flow literature?

The Department should not rely on transmission planning data or path flow information that is older than 2003. Many regions of the country have undergone significant changes in their operation and transmission transfer capability allocation methods (e.g. implementation of

MISO’s Transmission and Markets Tariff) in the past three years and reliance on such older data would not provide the accurate information necessary for the congestion study.

(4) – *What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?*

The Department should acquire information relating to both physical and contractual flows, including records of real time operating data, transmission service schedules from OASIS, congestion management actions such as records of TLRs by balancing authorities and reliability coordinators, operations of unscheduled flow mitigation in the western interconnection, and balancing authority records of control area error (CPS1 and 2). Additional information that may be useful include quantifying the magnitude and frequency of long term firm transmission service denials and historical Locational Marginal Prices (LMP).

In response to the criteria proposed by the Department to be used in evaluating the suitability of geographic regions for NIETC status, XES provides the following comments.

Draft Criterion 1: *Action is needed to maintain high reliability.*

This criterion should be of paramount significance to the Department in the designation of NIETCs. Reference to standards promulgated by the North American Electric Reliability Council (NERC), successor Electric Reliability Organization (ERO) or Regional Entities should be incorporated into any metric to assess the impact of designation as a NIETC and on resultant project(s).

Draft Criterion 2: *Action is needed to achieve economic benefits for consumers.*
Congestion that creates or sustains economic inefficiencies should be a valid criterion for designation as a NIETC. Such criterion should be measured over broad regions and assessments of the benefits to be gained should not be limited to narrow definitions of a corridor.

Draft Criterion 3: *Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.*
Supply limitations can manifest through degradation in reliability metrics or through economic discontinuities to end use customers. Diversification is an appropriate goal but not just for diversity sake. Economic or reliability benefits of diversification must be quantified through rigorous study and examination.

Draft Criterion 4*: Targeted actions in the area would enhance the energy independence of the United States.*

Draft Criterion 5*: Targeted actions in the area would further national energy policy.*
Draft Criterion 6*: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.*

These criteria are worthy goals, but are limited in their practical application. In fact, such criteria may supplement other more transparent criteria such as reliability or economic based criteria.

Draft Criterion 7: *The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions.*

XES supports this straightforward and pragmatic proposition that the future is uncertain and should not unduly influence designation as a NIETC.

Draft Criterion 8*: The alternative means of mitigating the need in question have been addressed sufficiently*.

In concert with Criterion 3 to promote diversity of sources, XES supports not biasing a study by presupposing an outcome and conferring an unintended advantage to a wires solution in lieu of other alternatives

Xcel Energy appreciates the opportunity to respond to the Department's NOI and looks forward to working with the Department in the designation of NIETC's.

Sincerely Yours,

Steve Dayney
Manager Policy Analysis
Xcel Energy