Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

PUBLIC AFFAIRS

October 19, 2011

In reply refer to: DK-7

Richard van Dijk
Another Way BPA
Ex 6

FOIA #BPA-2011-02052-F

Dear Mr. van Dijk:

This is a final response to your request for records that you made to the Bonneville Power Administration (BPA) under the Freedom of Information Act (FOIA), 5 U.S.C. 552.

You have requested the following:
Copies of all Agency Decision Framework's (ADF's) related to the Network Open Season 2009 and 2010. Also, all ADF's related to any line builds and/or upgrades associated with NOS 2009 and 2010.

Response:
BPA is providing the enclosed responsive documents either in their entirety or some information withheld under Exemption 5. These redactions are explained below.

Exemption 5

Exemption 5 protects from mandatory disclosure "inter-agency or intra-agency memorandums or letters that would not be available by law to a party other than an agency in litigation with the agency . . ." Exemption 5 incorporates the deliberative process privilege which protects advice, recommendations, and opinions that are part of the process by which agency decisions and policies are formulated.

Exemption 5 also protects attorney client information, which are communications between attorney and client that relate to a legal matter for which the client has sought professional advice. The privilege usually protects a client's disclosure to any attorney, but also extends to an attorney's opinion based on those disclosures, and to communications between attorneys that reflect client-supplied information.

The information in the ADF that is withheld under Exemption 5 involves customer options within the Network Open Season decision making process. Draft documents, by their very nature, are pre-decisional because they are prepared prior to the undertaking of any action by the agency. Draft documents are deliberative because they are part of the deliberative process by which that agency action was considered and taken. They reflect only the tentative view of their authors, views that might be altered or rejected upon further deliberation either by the authors or by their superiors. The withheld information does not represent final agency policy on the matters it discusses.

The information being withheld in its entirety is being withheld both because it expresses opinions that fall within the deliberative process privilege and it falls within the attorney-client privilege. It includes a legal analysis bearing on the Open Season options. Release of the material exchanged between attorneys and their clients could deter an open and candid exchange between the two parties. Moreover, attorneys would not feel they could adequately advise and represent their clients if the information is disclosed.

Pursuant to 10 CFR 1004.8, if you are dissatisfied with this determination, or the adequacy of the search, you may appeal in writing within 30 calendar days of receipt of a final response letter. The appeal should be made to the Director, Office of Hearings and Appeals, HG-1, Department of Energy, 1000 Independence Avenue, SW, Washington, DC 20585-1615. The written appeal, including the envelope, must clearly indicate that a FOIA Appeal is being made.

I appreciate the opportunity to assist you. Please contact Cheri Benson, FOIA/Privacy Act Specialist at (503) 230-7305 with any questions about this letter.

Sincerely,

/S/Christina J. Munro
Christina J. Munro
Freedom of Information Act/Privacy Act Officer

Enclosure: Responsive documents

Agency Decision Framework:

2010 Network Open Season Rolled-In Rates Determination

The Issue:

- BPA conducts an annual Network Open Season (NOS) to evaluate new long-term firm Transmission Service Requests (TSRs) on its network for which PTSAs were executed by the submitting customer. The process has three primary goals:
  1. Long-Term Firm (LTF) Queue management: BPA has limited transmission inventory on its network for new LTF requests. The NOS process allows the scarce inventory to be allocated to those customers that are willing to contractually commit to taking the transmission service.
  2. Identify necessary transmission system reinforcements or expansion facilities: Network requests for which there is no ATC at one or more flowgates are included in a cluster study so that all new requests with PTSAs can be studied simultaneously. The cluster study determines what, if any, new system reinforcements are needed to provide service to those TSRs in the cluster study.
  3. Respond to TSRs within the NOS structure in BPA's Open Access Transmission Tariff (OATT).
- As part of the NOS process, the PTSA requires the Administrator to determine whether any needed expansion facilities identified in the cluster study , and the TSRs that require those expansion facilities, will move forward at rolled-in rates. As part of this determination, the following are included as inputs and influences:
  1. Amount of NOS participation (as measured by the number of PTSAs and the amount of MW)
  2. Cluster Study results regarding needed infrastructure and its cost estimates
  3. Commercial Infrastructure Financial Analysis (CIFA) results (revenue supporting potential infrastructure additions, related Net Present Value (NPV) and rate pressure determinations)
  4. Regional Economic Benefit Analysis (REBA)
  5. Customer Comments
- The PTSA states that the rolled-in rate determination for the 2010 NOS must be made by May 31, 2011 for the customers to remain contractually bound to take the transmission capacity that they requested . If BPA does not notify customers by May 31, 2011, customers will have 15 days to determine whether they want to exercise the right to terminate their PTSA(s). However, if the customer does not inform BPA that they wish to terminate the PTSA during that period, the customer again becomes contractually bound to taking the service.
- For the 2010 NOS, the results from the cluster study identified new transmission expansion projects as well as significant upgrades of existing facilities. For the first time in the 2010 NOS, a number of the needed upgrades are required on third party systems. These third party upgrades are needed despite the fact that no transmission service request is required on the other transmission providers systems. The cluster study results indicate a continuation of the number of complex issues that are developing as the NOS process continues to mature.
- Note that if a rolled-in rates determination is made, the PTSA requires BPA to commence NEPA and preliminary engineering work at BPA's expense. It also requires BPA to provide notice regarding each TSR that can be accommodated by that infrastructure upgrade. For the customer to remain bound to take the service requested, the NEPA work needs to be completed within 39 months of the rolled-in rates determination.

1. Objective(s)?

Make rolled-in rates determinations for the 2010 NOS infrastructure projects consistent with the OATT and agency strategic objectives (as stated below). Note that procedurally, BPA must provide notice to the customer regarding which plan of service (if any) is required for BPA to be able to grant the requested service.

2. How does the objective connect to agency strategic direction?

- S1-Policy & Regional Actions-BPA policies result in regional actions that ensure adequate, efficient and reliable regional transmission and power services.
- S4-Open, non-discriminatory transmission services are provided at rates that are kept low through achievement of BPA's objective at the lowest practical cost.
- S6-Renewable Energy- BPA actively enables renewable resource integration and development through cost-effective, innovative solutions.
- F2-Cost Recovery-BPA consistently recovers its costs over time.
- I4-Asset Management-Integrated asset management practices maximize the long-term value of FCRTS assets.
- I8- Transparency- BPA process, decision making and performance are transparent.
- I9-Collaboration-Collaborative relationships with customers, constituents and tribes are supported by our managing to clear, long-term objectives with reliable results.

3. Who is the decision maker?

Decision makers	• Steve Wright	• Brian Silverstein
VP Sponsors	• Cathy Ehli (Policy) • Hardev Juj (Planning)	• Dave Armstrong • Larry Bekkedahl
NOS Management and Supervisory Team	• Bob King • Melvin Rodrigues • Mary Jensen • Dave Fitzsimmons • Rich Gillman	• Claudia Andrews • Deedee Vanderzanden • Rebecca Fredrickson • Mike DeWolf
Team Members	• Lauren Nichols-Kinas • Sean Egusa • Kyle Kohne • Pat Rochelle • Chuck Matthews • Berhanu Tesema • Matt Perkins • Camille Blakely • Tom Davis • Paul Fiedler • Lauren Tenney • Mike Linn • Damen Bleiler • Ryan Josephson • Dennis Oster • Ravi Aggarwal • Abbey Nulph	• Len Morales • Dennis Jackson • Erik Westman • Sandra Ackley • Gene Lynard • Theresa Berry • Mark Korsness • Brian Scott • Maryam Asgharian • Kurt Lynam • Eric Carter • Doug Johnson • Jennifer Boehle • Lori Blasdel • Tim Hein • Don Callow

4. What is the context?

The NOS process is governed by a Precedent Transmission Service Agreement (PTSA) that is part of BPA's filed OATT (Attachment O) and obligates BPA to take the following actions:

- At BPA's expense, conduct a Cluster Study to determine transmission system impacts of the TSRs submitted in NOS and to identify new facilities, modifications, or upgrades to BPA's network needed to provide the requested service.
- Evaluate the estimated costs and benefits of proposed expansion facilities consistent with the posted Commercial Infrastructure Financial Analysis (CIFA).
- Determine whether transmission service could "reasonably be provided under the applicable PTP or NT rate schedule" if BPA were to construct the expansion facilities (i.e., make a rolled-in rate determination). The PTSA requires BPA to make this determination and notify customers of its decision within 11 months of the deadline to submit new requests for the NOS or customers have the right to terminate their PTSAs.
- If BPA decides to move forward at rolled-in rates for one or more expansion facilities identified in the cluster study, BPA is then obligated to conduct and fund studies (NEPA) for evaluating the environmental impacts of new facilities, including preliminary engineering and design work necessary to carry out the environmental reviews.
- After the completion of the environmental review, BPA will issue a ROD documenting its decision regarding whether to build the necessary facilities or not. The ROD will take all pertinent information available at that time into account including, but not limited to, the project's business case.
- The PTSA requires BPA to complete any necessitated environmental review and decide whether to build facilities no later than 39 months from the date that BPA notifies customers about the rolled-in rate determination. If BPA did not take these actions within that timeline or offer conditional firm service, the customer would again have the right to terminate any PTSA(s) requiring that build.
- If BPA decides to build the necessary facilities, BPA will finance and construct the facilities.

Results of Previous NOS Processes

The following provides background information on the 2008 and 2009 NOS and summarizes the results of the Cluster Study, REBA and CIFA evaluations for the 2010 NOS.

1. Recap of 2008 and 2009 NOS results: On May 28, 2010, BPA posted the Administrator's decision for the 2009 NOS in which customers executed 34 PTSAs for 1,553 MW of LTF network service. These figures add to the 2008 NOS participation that consisted of 153 PTSAs for 6,410 MW of LTF network service and resulted in four new projects moving forward at rolled-in rates. For the 2009 NOS, TSRs that required only 2008 projects moved forward at rolled-in rates, one project was determined to be direct assigned, and two new projects did not move forward at rolled-in rates. Following is a quick summary of 2008 and 2009 NOS results:
    - Service granted without a build (using existing ATC)
        - 2008 NOS = 2,209 MW
        - 2009 NOS = 293 MW
    - Service moving forward at rolled-in rates
        - 2008 NOS = 3,210 MW
        - 2009 NOS = 1,121 MW
    - Service associated with terminated PTSAs

- 2008 NOS = 991 MW
- 2009 NOS = 139 MW

2. Summary of 2010 NOS Participation: BPA offered 121 PTSAs for 7,304 MW of service. Participants executed 76 of those PTSAs for a total of 3,759 MW of LTF network service.

3. Summary of 2010 Cluster Study: 3,759 MW were included in the 2010 Cluster Study. The Cluster Study determined that:

    - 53 MW of service could be authorized without new infrastructure
    - 60 MW of service require upgrades in Central Oregon that BPA has already decided to complete as reliability projects:
        1. Redmond 230/115kV Transformer
        2. Ponderosa 500/230-kV Transformer

    Construction on the Redmond 230/115kV transformer is underway, and the transformer is scheduled to be energized in August 2011. The business case for the Ponderosa 500/230-kV transformer was approved in March 2011 and energization is scheduled for October 2013.

    - 1,522 MW of service could be authorized if BPA completes construction of projects moving forward as a result of the 2008 NOS:
        - 1,489 MW require WOMR
        - 33 MW require WOMR and I-5
    - 2,124 MW of service require new projects as identified in the cluster study:
        - Colstrip Upgrade Project - West (CUP West) would allow approximately **480 MW** with additional capacity provided for when combined with the Northern Intertie project (see below). Note the capacity created by the CUP West requires that the generation source using that capacity be included in a Remedial Action Scheme (RAS). This requirement may make the capacity less usable for some customers (i.e., those who want to use it for market purchases at least part of the time, rather than just to move power from a specific project). Further, note that an additional study of sub-synchronous resonance is required to more firmly determine the amount of capacity that will be created by the CUP West upgrade.
        - Garrison – Ashe (GASH)[1] would allow **14 MW** of service if constructed alone; and an additional **530 MW** of service if Central Ferry-Lower Monumental[2] is constructed.
        - Four clusters of reinforcements on the Northern Intertie (NI), when combined with other 2010 or 2008 projects, would allow **1,100 MW**:
            1. NI (East): North-South would allow **100 MW** and would also require the I-5, WOMR, and Central Ferry-Lomo projects.
            2. NI (West): North-South would allow **825 MW** and would also require the I-5 and WOMR projects.

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[1] The CUP West and GASH projects create capacity in the same region. If CUP West does not move forward it is estimated that GASH could allow all 1,074 MW of offers total of the demand from the two cluster groups if Central Ferry-Lower Monumental is also constructed. When analyzing a scenario where only GASH was constructed, these additional MW were reflected.

[2] ROD for the Central Ferry – Lower Monumental project was signed on March 23, 2011.

3. NI (East): South-North would allow **125 MW** and would also require the CUP West project.
4. NI (West): South-North would allow **50 MW** and would also require the WOMR project.

The Northern Intertie plan of service includes required reinforcements on adjacent transmission systems. The costs for these commercial-based reinforcements include:

- *Reconductor of Avista's Addy – Devil's Gap 115 kV line ($0.6M),*
- *Rebuild of Tacoma Power's Tacoma – Cowlitz #1 and #2 230 kV lines and upgrade of Tacoma's Cowlitz 230 kV strain bus ($11.9M). However, if Tacoma moves forward with its own upgrade currently planned for 2012, these upgrades will not be needed.*
- *Creation of a scheduling entity on the eastside of the US-BC border. This cost includes system upgrades and coordination with BC Hydro and is also included in the CIFA.*
- *A second Portal Way 230/115 kV transformer on Puget Sound Energy's system is also required but negotiation with Puget is required to determine the allocation of costs (the full cost of the transformer is estimated at $25 million)*

The Northern Intertie plan of service does not include costs for the reliability fixes identified for the Puget Sound Area Study Team (PSAST). The costs for these facilities were <u>excluded</u> because these projects have been identified as required to meet existing commitments (i.e., they are needed whether or not BPA moves forward with offering the service requested in NOS). The BPA share of the cost allocation for the PSAST projects required for South to North transfers has been estimated to be about $14 million. However, as stated previously, these allocated costs were not included in the CIFA.

Based on staff's understanding, none of the upgrades on adjacent systems, whether reliability or commercial, would provide increased capacity or sales for the adjacent transmission provider as the upgrades primarily serve reliability or load service needs. Verify with Rebecca "Because these projects are on other transmission providers systems, these costs would be expensed by BPA." The following table identifies the specific upgrades required and its association with requested service, costs and other required upgrades, arranged by project identified in the NOS cluster study.

Third Party Upgrades for Northern Intertie Reinforcements

Upgrade	Upgrade Cost (in CIFA)	Adjacent System	Impacted Plan of Service	Impacted MW (TSR)	Customer	Other required upgrades
Eastside Scheduling Point	$500k	BC Hydro	NI (East) N→S	175 (3)	EX 5	I-5 WOMR CF-LoMo CUP West (75 MW only) Avista
			NI (East) S→N	50 (1)	EX 5	CUP West PSAST
			NI (West) S→N	50 (1)	EX 5	CUP West PSAST
Addy-Devil's Gap 115 kV Line	$600k	Avista	NI (East) N→S	175 (3)	EX 5	I-5 WOMR CF-LoMo CUP West (75 MW only)

Portal Way 230/115 kV Transformer	$0	Puget Sound Energy	NI (West) N→S	825 (9)	EX 5	I-5 WOMR Tacoma
Rebuild Tacoma-Cowlitz 230-kV #1 and #2 AND Cowlitz 230-kV Strain Bus	$11.9 million	Tacoma Power	NI (West) N→S	825 (9)	EX 5	I-5 WOMR Puget
PSAST Upgrades	N/A	Various	NI (East) S→N	50 (1)	EX 5	CUP West East Scheduling
			NI (West) S→N	50 (1)	EX 5	WOMR East Scheduling

The following table is a summary of the 2010 Cluster Study results:

NOS 2010 Cluster	NOS 2008 Projects Required	Original PTP	NT or Redirect Requests	Total
Authorized		20	33	53
Require NOS 2008 Projects Only	I-5, WOMR, CF LOMO	1,483	39	**1,522**
Reliability Projects				
Redmond and Ponderosa Transformers		60	-	**60**
Commercial Projects				
CUP (West)	CF LOMO	480	-	**480**
GASH	CF LOMO	530	-	**530**
GASH		14	-	**14**
NI (East): North -South	I-5, WOMR, CF LOMO	100	-	**100**
NI (East): North -South & CUP (West)		-	75	**75**
NI (West): North - South	I-5, WOMR, CF LOMO	700	125	**825**
NI (East) South - North & CUP (West)		50	-	**50**
NI (West): South - North	WOMR	50	-	**50**
Total *Not* Requiring Commercial NOS 2010 Projects		1,563	72	1,635
Total Requiring Commercial NOS 2010 Projects		1,924	200	2,124
Total MWs Submitted in NOS 2010		**3,487**	**272**	**3,759**

4. Summary of 2010 Direct Assignment Evaluation: All plans of service resulting from the 2010 Cluster Study were subject to a Direct Assignment evaluation led by Customer Service Engineering (TPC).

   - CUP West was determined to be a network upgrade given its location and improvement to several substations at and west of Garrison. As the projects costs are not direct assigned, and were evaluated in the CIFA.
   - GASH was determined to be a Network upgrade. As the projects costs are not direct assigned, and were evaluated in the CIFA.
   - Northern Intertie upgrades were determined to be Network upgrades as the specified reinforcements occur on the integrated network in the I-5 corridor and Puget Sound area. As the projects costs are not direct assigned, and were evaluated in the CIFA.

The following table is a summary of the projected costs and allocation of those costs by fiscal year for new projects identified in the 2010 cluster study:

PROJECT	Energization Date	Energization Fiscal Year	Reliability Benefit	2011	2012	2013	2014	2015	2016	2017	2018	Direct Cost ($M)
NOS 2010 Proposed Projects												
CUP (West)	10-2015	2016	$0.000	$0.000	$5.320	$29.320	$40.412	$40.412	$0.000	$0.000	$0.000	$115.464
GASH	10-2018	2019	$0.000	$0.000	$18.870	$28.304	$94.348	$235.869	$235.869	$188.695	$141.521	$943.477
NI (East): North-South	10-2015	2016	$0.000	$0.000	$0.250	$0.250	$0.450	$0.675	$0.000	$0.000	$0.000	$1.625
NI (East): South-North	10-2013	2014	$0.000	$0.000	$0.250	$0.250	$0.000	$0.000	$0.000	$0.000	$0.000	$0.500
NI (West): North-South	10-2014	2015	$0.000	$0.000	$21.364	$35.116	$13.676	$0.000	$0.000	$0.000	$0.000	$70.156
NI (West): South-North	10-2013	2014	$0.000	$0.000	$0.250	$0.250	$0.000	$0.000	$0.000	$0.000	$0.000	$0.500

5. Summary of 2010 CIFA:

The 2010 CIFA analysis determined the NPV and the rate impact for the plans of service and groupings identified in the cluster study that were new builds. The CIFA analysis did not revisit decisions already made by BPA on the 2008 NOS projects or examine the Central Oregon reliability upgrades. This is consistent with approach that has been done in prior years.

Any costs associated with reliability projects were excluded and in the case where a PTP request needed a 2008 project, these costs were treated as sunk costs and were also excluded from the CIFA[3]. Only original PTP requests were used in the analysis (NT and Redirect requests are excluded) and only costs for 2010 commercially-based projects were included.

The CIFA did not include costs that have been through the Columbia Grid and are awaiting cost allocation, due to the uncertainty of the cost allocation. The CIFA did run sensitivity analysis on capital costs to reflect the confidence level on the capital costs.

- Summary of CIFA results for Northern Intertie,
  - Plans of service could yield a -1.2% rate impact (assuming 2008 NOS costs are sunk and excluding costs for the above-mentioned projects on other TP's systems). The risk sensitivity showed that if there was a low confidence in capital, the rate impact would be -0.8%. In addition, the capital costs could go up another $40 million to get to a break-even rate impact.
  - Direct capital costs would be about $70 million (direct costs) including NEPA and PED.
  - NEPA and PED were estimated at $4 to $6 million.
- Summary of CIFA results for CUP West
  - Plan of service would yield a 0.7% rate impact excluding costs for identified RAS Costs for similar RAS were examined in '09? And estimated to be $2.3 million (is that the correct estimate for CUP-West RAS.

[3] CIFA looked at three sensitivities which were summarized and presented to customers on March 23, 2011. Of the three sensitivities, all numbers and results contained in this ADF reflect Scenario 1, where all 2008 project costs were sunk and only 2010 project costs were considered.

- Direct capital costs would be around $115.5 million (direct costs) including NEPA and PED.
- NEPA and PED were estimated at $4 to $6 million.

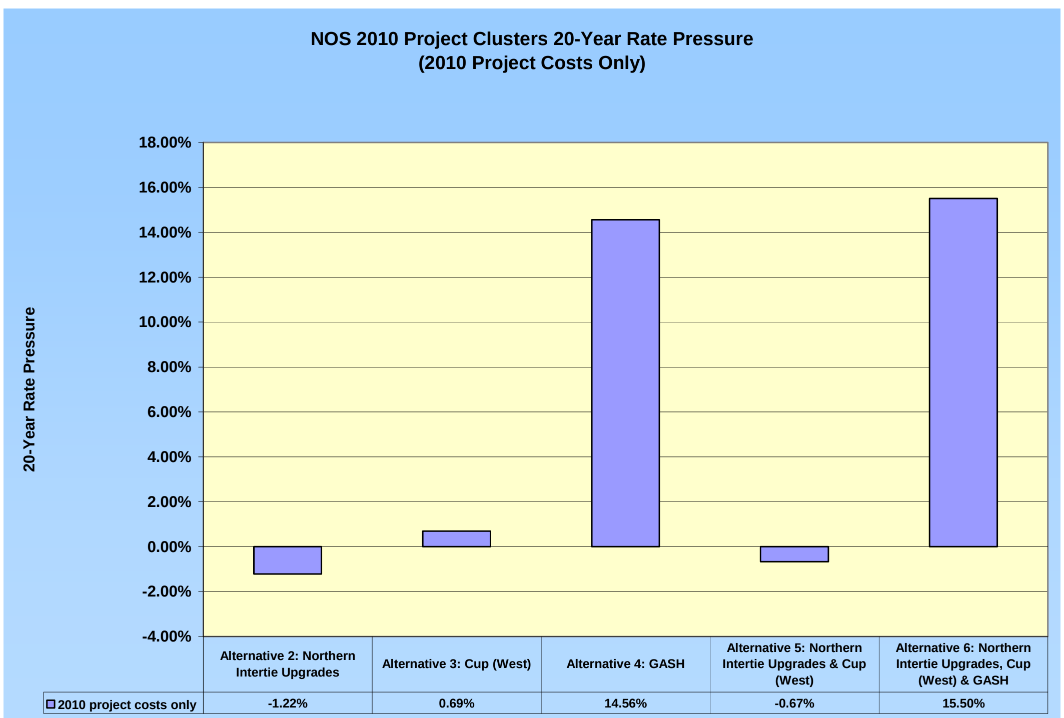
♦ Summary of combined CIFA results for Northern Intertie and CUP West

- NI and CUP West together would yield a -0.7% rate impact (assuming all caveats mentioned above).
- The total capital costs for the NI and the CUP West would be around $185 million (direct costs) including NEPA and PED.
- The NEPA and PED for both projects were estimated to be $6.2 million to $8.2 million.

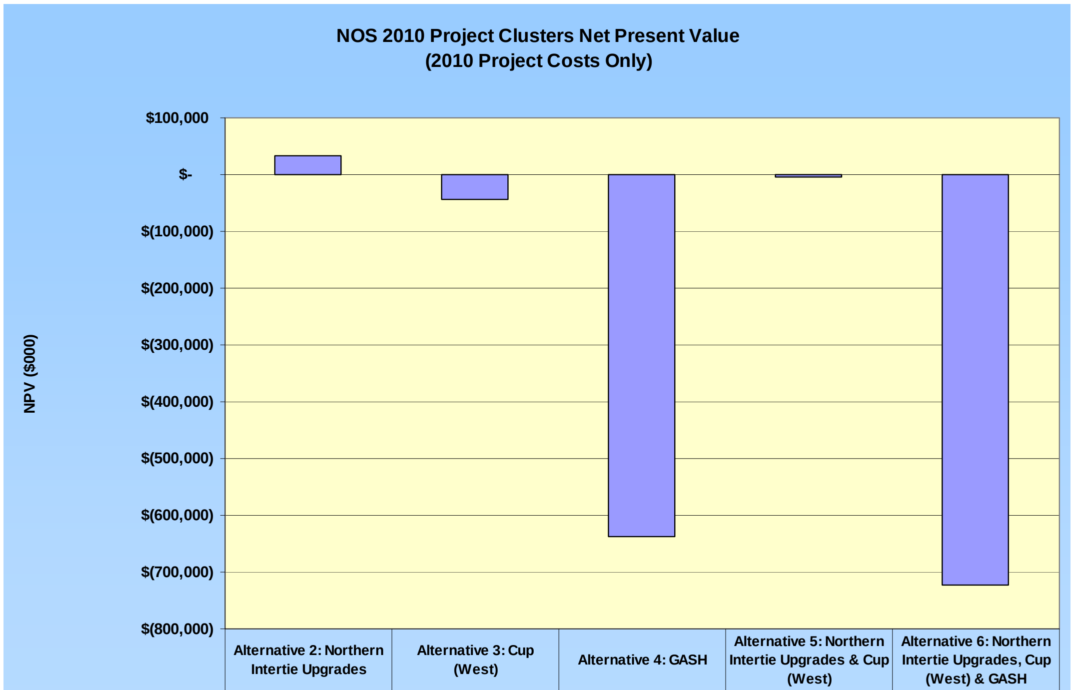
♦ If 2008 NOS builds do not go forward, none of the plans of service resulting from the NOS 2010 Cluster Study had a positive NPV and therefore did not pass the CIFA.

♦ If we look at the 2010 NOS costs only, the combination of NI and CUP West has a positive NPV and passed the CIFA. The major driver of the positive NPV is the NI which has a positive NPV when analyzed alone. This will no longer be true with the updated estimates, I don't think.

The following chart shows the resulting incremental rate pressure by 2010 project alternatives:

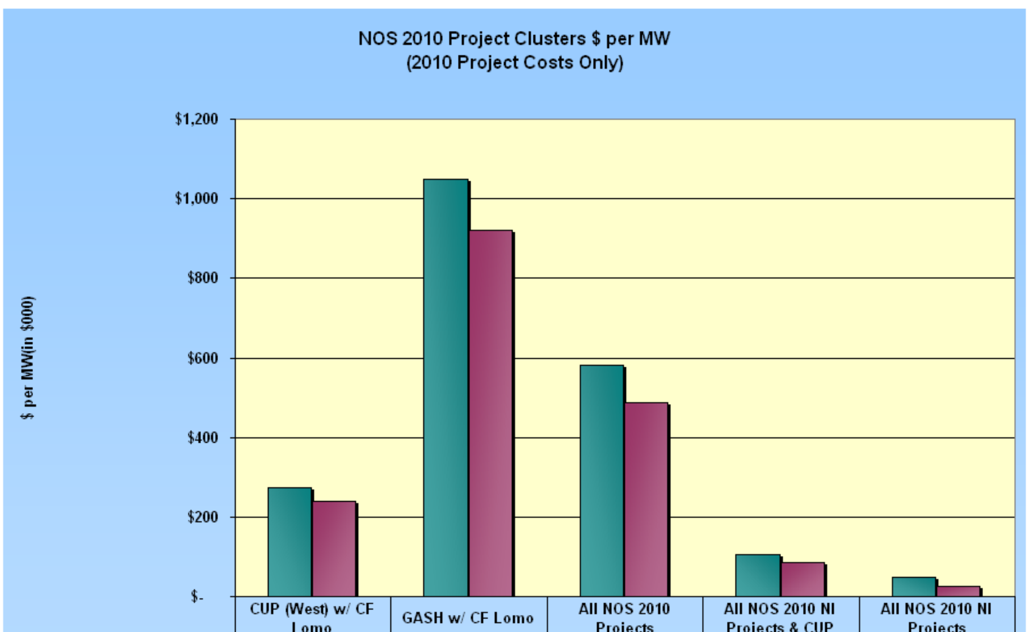


The following is a summary of the NPV for the 2010 NOS projects alternatives:



	Alternative 2: Northern Intertie Upgrades	Alternative 3: Cup (West)	Alternative 4: GASH	Alternative 5: Northern Intertie Upgrades & Cup (West)	Alternative 6: Northern Intertie Upgrades, Cup (West) & GASH
2010 project costs only	$32,343	$(43,025)	$(638,138)	$(3,807)	$(723,392)

The following chart shows a breakdown of the capital costs per subscribed MW by 2010 NOS project.



	CUP (West) w/ CF Lomo	GASH w/ CF Lomo	All NOS 2010 Projects	All NOS 2010 NI Projects & CUP	All NOS 2010 NI Projects
$ per MW Loaded Costs	$275	$1,048	$583	$106	$48
$ per MW Direct Costs	$241	$921	$488	$84	$27

Summary of the 2010 Regional Economic Benefit Analysis:

The Cluster Study identifies transmission requirements in order for BPA to provide firm service to the TSRs in the 2010 NOS. REBA considers the reinforcements identified by the Cluster Study and examines impacts to system congestion.

REBA Objectives

- Identify impacts to the existing Northwest generation and transmission system from the addition of the 2010 NOS TSRs and associated generation.
- Annual hourly dispatch production cost savings
- Increase or decrease in economic transmission congestion costs
- Increase and decrease of NW transmission loading at key points on the system
- Identify economic transmission congestion cost savings from the addition of proposed new transmission additions (from the 2010 Cluster Study) to the existing grid required in association with the TSR's
- Identify additional system stress conditions based on economic dispatch

REBA Observations

- Production Cost Savings
  - Leveraging the 2008 NOS projects and the 2010 NOS projects, $29M of production costs savings were seen across WECC, a significant portion realized in the Northwest
- System Congestion
  - A marked reduction in flows on the Montana – Northwest path was due to the addition of substantial wind near Garrison, Montana. That generation did cause a significant increase in congestion hours West of Garrison
  - 1,000 MW added at Garrison prevents low-cost coal-fired generation from getting out of Montana on many hours confirming a need for system expansion at this point.
- System Utilization
  - The West of Slatt loadings above 75% increased by 145 hrs and West of John Day increased by 65 hours
- Colstrip Upgrade Project (West)
  - Reduces overall 2019 WECC-wide variable cost by about $27 million assuming all the new wind generation has been added in Montana
  - Reduces West of Garrison congestion at or above 75% of path limit by 1,857 hours
- Northern Intertie
  - Reduce WECC-wide production costs in 2019 by about $4 million based on assumed generation addition in BC Hydro system
  - Reduce Northern Intertie (West) congestion by 559 hours, Raver-Paul by 48 hours, and increase Northern Intertie (East) by 129 hours, Montana-Northwest by 57 hours

REBA Conclusions

- The REBA analysis supports the Cluster Study project recommendations as the total amount of congestion hours and variable operating costs are reduced dramatically
- Even with the NOS 2010 TSRs added, the 2008 NOS line projects are still sufficient for relieving congestion on the paths that they reinforce (such as West of McNary and South of Allston).

- Additional projects identified in the 2010 NOS Cluster Studies (Northern Intertie Upgrades and Colstrip Upgrade Project West) are required to support the additional 2010 NOS PTSA's
  - Colstrip Upgrade West relieves over 70% of congestion hours above 99% of limit on West of Garrison.
  - Garrison - Ashe would relieve all of this congestion, but with a much higher cost
  - The Northern Intertie upgrades relieved 97% of the congestion associated with 2010 NOS generation on the Northern Intertie for north to south transfers.

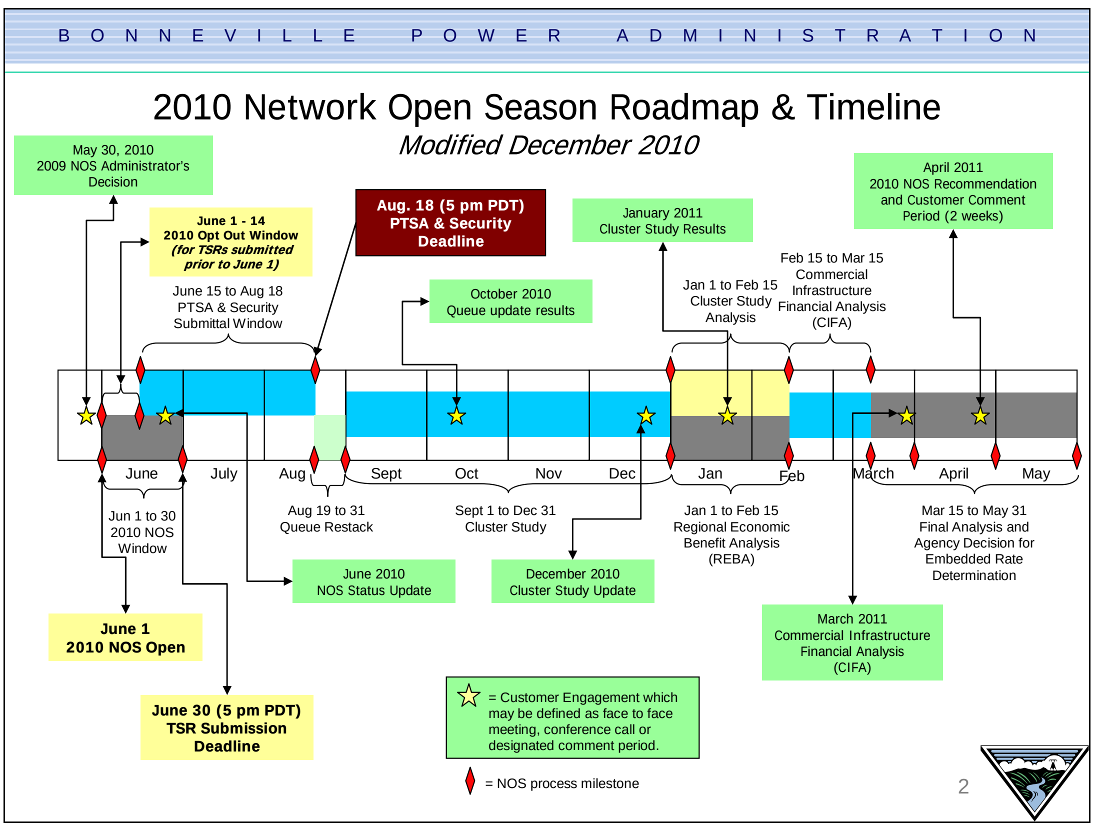
Internal Stakeholders	What They Want	What They Will Resist
Planning	Support for projects that upgrade reliability; Sound upgrades to the transmission system for commercial purposes; appropriate Remedial Action Scheme treatment for CUP West capacity	Lack of support for reliability upgrades; unsound projects ; Sale of CUP West capacity without BPA rights in place to ensure that it will be tied to a Remedial Action Scheme
Transmission Policy	Enough resolution of the issues associated with NOS to support the rolled-in rates determination prior to the deadline; exercise of caution in rolled-in rates determination for CUP West prior to sufficient clarity regarding the amount of capacity it will create	Lack of resolution of the issues associated with NOS to support the rolled-in rates determination prior to the deadline; rolled-in rates determination related to CUP West without sufficient clarity regarding the amount of capacity that the project will create
Project Management	Clarity regarding which projects to move forward with and the relationship to projects currently moving forward	Unclear direction regarding which projects to pursue or the inter-relationship between projects

External Stakeholders	What They Want	What They Will Resist
NOS participants needing system upgrades to enable their requests	Rolled-in rates determination for projects that support their TSRs for projects that don't have substantial upward rate pressure	Not receiving a rolled in rates determination for projects that don't have substantial upward rate pressure; delay in rolled in rates determination for CUP west for sub-synchronous resonance study
Resource developers not participating in NOS 10	Continued evidence that BPA will make rolled-in rates determinations for projects supporting new resources that don't have substantial upward rate pressure	Indications that BPA's support for development of new resources is waning
Load serving entities without TSRs in NOS	Rolled-in rates determinations that decrease their rates; Rolled-in rates determinations that they view as having reasonable rate	Rolled- in rates determinations that significantly increase their rates

External Stakeholders	What They Want	What They Will Resist
	impact	
Montana Resource Interests	Concrete support for resource development in Montana	Lack of concrete support for resource development in Montana
Individuals impacted by routes for new plans of service	Routes that impact them for projects moving forward at rolled- in rates	Routes that don't impact them

Timeframe for the decision:

The PTSA requires written notification be provided to each customer holding a PTSA no later than May 31, 2011 or the customer will have the ability to terminate their PTSA(s). The timeline for implementation of this obligation is described in the timeline below.



5. What are the decision evaluation criteria?

Business/Finance

a) Allows effective management of long-term firm transmission queue

b) Creates new revenue

c) Cost effectiveness indicated by minimum rate pressure.

d) No more than a 2-3% rate impact for the combined expansion facilities over 20 years

e) Negligible to low stranded investment risk

f) Consistency with BPA's financial targets, rate case assumptions, and treasury payment probability

g) Enhanced system operation by reducing reliance on curtailment calculators and remedial action schemes

h) Reliability benefits

i) Provide capacity for load growth and future commercial sales

j) Impact to future non-firm revenue

k) Support development of renewable resources

l) Ability to grant service to requestors where consistent with above criteria

m) Clarity regarding the amount of capacity created by the proposed upgrade

Legal:

a) Consistent with applicable statutes, BPA Tariff, and PTSA terms.

b) Legal issues and potential legal risks associated with recommendations fully understood and mitigated to the extent possible.

c) Clear statement of RAS requirements for transmission use where pertinent

Environment:

a) Impact on the environment is considered. Decision to construct any facilities is subject to NEPA review.

b) Recommendations not in conflict with fish and wildlife goals, energy efficiency goals, renewable resource development, and climate change response policy.

Public Interest:

a) Customers, merchants, transmission providers, elected officials, other stakeholders and media perspectives understood and taken into account.

b) Provide enhanced ability for region to meet Renewable Portfolio Standards (if needed?);

c) Provide regional benefits to the network customers.

BPA's People and Processes:

a) Demonstrated ability to carry out work necessary to complete NEPA and to construct projects in accordance with the capital program.

b) Acceptable impact on BPA people and culture objectives;

c) Supports Agency workforce/workplace goals for leadership, talent, motivation/alignment and positive work environment:

d) Recommendation consistent with BPA internal policies, procedures, and internal controls.

6. What are the risks to meeting the objective?

a) RISK OF INABILITY TO COMPLETE ENVIRONMENTAL REVIEW AND DECISION WHETHER TO BUILD BY OBLIGATED DATE: In this ADF, the recommendation to move forward with 2010 NOS projects that require projects that moved forward in the 2008 NOS in order to allow offers, relies on the assumptions underlying 2008 NOS decision. Termination of 2008 PTSAs could alter the assumptions upon which the 2008 rolled-in rate determination was based. For 2010 PTSAs, the NEPA review/decision to build deadline is 39 months from the *2010* Rolled-In Rate determination, which would be approximately August 2014. Note further that unless BPA modifies its methodology for calculating its Conditional Firm Inventory, little if any conditional firm is going to be available to 2010 TSRs, thereby making meeting the 39 months NEPA deadline more critical. BPA might be unable to complete environmental review and decide whether to build certain of the 2008 NOS projects or offer conditional firm service within the deadline in the PTSA. For the 2008 PTSAs, the environmental review and decision whether to build the 2008 projects must be complete, or BPA must offer conditional firm service, by 36 months from the 2008 Rolled-In Rate determination, which is mid-February 2012. If BPA does not meet that deadline, a customer with a 2008 PTSA would have the right to terminate its agreement.

- ♦ Four projects moved forward 2008 as a result of the 2008 NOS: McNary-John Day, Central Ferry-Lower Monumental, Big Eddy-Knight, and the I-5 Corridor reinforcements. Environmental review is complete for the McNary-John Day and Central Ferry-Lower Monumental projects, and BPA made a "Decision to Build" those facilities prior to the deadline prescribed in the PTSA. There is NO risk associated with failure to complete environmental review or the decision to build for those facilities.
- ♦ There is LOW risk that environmental review/decision to build will not be completed in 36 months of the 2008 NOS rolled-in rates determination (or 39 months of the 2009 NOS rolled-in rate determination) for the Big Eddy-Knight project.
- ♦ The current schedule for the I-5 NEPA review (January 2013) provides for a final ROD after the mid-February 2012 deadline in the 2008 PTSA. There is a HIGH risk that the environmental review and decision to build will not be completed for the I-5 project within that timeframe, but BPA has offered conditional firm service to the majority of the NOS '08 and '09 customers that need the I-5 project (which satisfies the PTSA obligation) and expects to make additional conditional firm offers in the future for most of the remaining '08 and '9 requests that need I-5. There is a low to moderate probability that at least one customer that has not been offered conditional firm service may terminate its PTSA for BPA's failure to complete NEPA on schedule. There is a MODERATE risk that the environmental review and decision to build will not be completed for the I-5 project by the August 2013 deadline in the 2010 PTSA.

  MITIGATION

  - BPA hopes to make conditional firm offers to most of the remaining 2008 and 2009 PTSAs needing the I-5 reinforcement within the decision to build deadline as identified in the PTSA (36 months for 2008 and 39 months for 2009 and 2010). BPA needs to assess its conditional firm inventory and eligibility factors to determine whether it can make these offers.
  - BPA does not currently have sufficient conditional firm inventory on South of Allston to make offers of conditional firm to the 2010 PTSA requests. The key mitigating factor is that we are already two years into the NEPA at the point that the 39 month clock starts for that requirement for the 2010 requests. In addition, if BPA feels that it is appropriate once we have more experience with conditional firm, BPA could explore modifying its conditional firm inventory methodology to make more available.

b) RISK OF DEFERRAL: Customers may elect to defer their service commencement date (start date) for up to five years. If the customer defers the commencement of service, BPA will extend the contract end date and the customer is still required purchase transmission service for the full requested service duration. Deferrals result in delayed revenues to Bonneville. There is lower risk that deferrals will affect rates substantially with a higher probability that some deferrals will occur.

MITIGATION

- BPA will make the deferred capacity available on the ST market. History indicates that likelihood of ST sales is LOW.
- Due to changes in PTSA language, BPA requires any deferring party for which a 'competitor' is identified to move up its commencement of service date to match that of the identified competitor. This may reduce the length of the deferral and thus reduce the length of time by which revenues are delayed. Further BPA has recently made a decision to change its Composite POD methodology, which will significantly increase its ability to do competitions of deferrals. Sensitivity analysis has been conducted to evaluate impact that increased deferrals would have on revenue.
- If the CUP West project moves forward, BPA needs to closely coordinate all steps of the project with that primary user to endeavor to ensure that their readiness to take the capacity as close as possible to when it becomes available (One requestors has approximately 80% of the capacity created by that project).

c) RISK OF ROFR AND SUBSEQUENT FAILURE TO RESELL CAPACITY: Customers may chose not to roll over service at the end of their contract terms, which would reduce the total revenue assumed in the determination of NPV and rate impact. The base case analysis assumes that all contracts with a duration of five years or longer will roll over. There is LOW risk and moderate probability that one or more customers will choose not to roll over their contract at the end of the contract term.

MITIGATION

- A significant portion of the requested transmission service is associated with the interconnection of new generators. Assuming the generation facility is constructed, this increases the likelihood that transmission service will be acquired at least for the life of the generating facility. The average duration for all PTSA commitments is twelve years. Sensitivity analysis has been conducted to evaluate the impact of tariff rights such as roll-overs and deferrals.

d) RISK OF CUSTOMER DEFAULT: Customers holding PTSAs could default, which would impact future revenues. Security provided by customers under the PTSA and held by BPA was not designed to protect BPA ratepayers from rate impacts due to default and is not sufficient to do so. There is low risk for increased rate impact with high probability that at least one customer may default. In 2011, at least one customer with a 2008? PTSA is in default already, and another PTSA holder has inquired through its consultant as to what would happen if it defaults on some of their PTSAs. The customer has indicated it no longer needs the transmission service and has asked its consultant to determine whether it could "turn in" those PTSAs. Another customer has indicated that they won't need the service they requested for more than five years, which means that even with use of deferral rights, they may be contractually committed to paying for transmission that they don't need for a period of time.

MITIGATION

- The amount of risk BPA ratepayers will bear is unique to each project, the number and diversity of customers that will take service over the projects, and the long-term financial viability of the participating customers. Some projects enable service for multiple customers over critical paths required for load service. Different projects have different likelihood of capacity being resold if a party does default. BPA would try to sell the capacity to another party if this situation arises. Sensitivity analysis has been conducted to evaluate impact that increased customer defaults would have on revenue.

e) **RISK OF INACCURATE ASSUMPTIONS AND RESULTS IN THE CLUSTER STUDY**: Cluster study planning analysis could include inaccurate assumptions, resulting in flawed identification of expansion facilities needed to enable service. Projects may not provide sufficient capacity to enable all of the LTF service that BPA is contractually committed to providing. There is a LOW to MODERATE risk that the plans of service are inadequate with a LOW probability that service cannot be enabled. If this occurs, it will could result in curtailments even when all lines are in service.

MITIGATION

- For the 2010 Cluster Study, BPA adopted a number of new assumptions based on a public process with customers to address concerns related to modeling the generation exceeding load in the BPA BAA. One of these assumptions included a new model of dispatching thermal generation to offset wind generation and some customers have requested that BPA revisit this assumption to ensure accurate representation in the base case and planning models. Note that the assumptions used in the cluster study regarding which thermal generators are off in specific cases does not in any way modify those customers rights to use their long-term firm service reservations.
- For the 2010 Cluster Study, BPA examined three different scenarios to more strongly test the sufficiency of the resulting plans of service under a broader set of conditions. One scenario also tested an alternate hydro configuration at the request of Power Service.
- Few curtailments occur on BPA's transmission system today and only a small portion of those curtailments result in curtailment to firm service.

RISK OF CHANGING PROJECT COSTS: Changes in cost due to changes in plans of service, environmental review costs, material and commodity costs, and/or construction costs could change for the projects moving forward, resulting in a different rate impact than anticipated from those projects at the time that the rolled-in rates decision is made or, for a number of the above costs, at the time that the decision to build is made. If project costs increases there is a MODERATE risk with a high probability that the rate impact will be significantly higher. Note that BPA has not previously developed plans of service during the 120 day cluster study period (plans for service for each of the builds that moved forward in '08 had been developed prior to the cluster study, and required only updating. The need to develop new plans of service for several projects in the short NOS timeframe increases the uncertainty around the plans of service and their related cost estimate. Further because upgrades on other transmission providers systems were identified for granting some of the NOS '10 requested service, and because the timeframe for NOS has not allowed BPA to work with those parties yet regarding those plans of service, those costs are unclear and the portion that BPA will be required to pay is unclear, there is additional uncertainty associated with the 2010 NOS projects.

MITIGATION

- Business case process required for projects greater than $5 million to provide additional oversight and justification for projects. Sensitivity analysis has been conducted to evaluate impact that changing capital costs would have on rate pressure.
- NOTE: Projected capital costs for the 2008 McNary-John Day project have been reduced by $87.7 million (original projection: $246.5 million; current projection: $158.8 million) so currently BPA is experiencing significant capital reductions associated with construction of the projects. The Central Ferry-Lower Monumental ROD was signed in March 2011 and is proceeding with its construction schedule on time and on budget per the costs stated in 2008 ($99 million). BPA has not yet decided whether to construct the Big Eddy-Knight or I-5

projects as they are currently in NEPA. When environmental review is complete, BPA will make a final decision whether to build those projects.

- BPA will have the opportunity to develop policy regarding its willingness to pay for the costs of upgrades to other transmission provider's systems. The pro forma OATT touches on this issue only briefly. Prior to the adoption of Attachment K on planning, these costs appeared to be allocated to the requesting customer. BPA's planning Attachment K provides for going to Columbia Grid for an advisory cost allocation. To the best of our knowledge, BPA has not recent experience with this issue, and it therefore will need to be worked out.

f) RISK FROM EXTERNAL POLICIES: External policies for reliability and ATC could impact the way existing network facilities are managed, the availability of ATC, and the need and timing for proposed projects. There is LOW risk and low probability that policy changes will result in changes to the plans of service.

MITIGATION

- BPA is an active participant in FERC, NERC, and WECC efforts to define new reliability and commercial rules for transmission management. While changes in criteria and process are inevitable, TS does not believe that any such changes will result in significant modification to the Cluster Study results. Furthermore, BPA has increased its coordination efforts with external parties in response to customer requests and internal strategy requirements.

g) LIMITED ACCESS TO CAPITAL: BPA is currently undergoing significant activity to delay capital expenditures due to capital limitations. There is SIGNIFICANT risk that these activities will influence BPA's ability to assume additional capital costs that don't have significant reliability and/or load-based requirements.

MITIGATION

- Don't allow any commercial-based system reinforcements. This could mean choosing not to proceed with the as yet unapproved 2008 infrastructure additions, and/or choosing not to proceed with the 2010 infrastructure projects even if a rolled-in rates determination is made for them. The PTSA allows for this determination
- Consider use of 3rd party capital to support projects that BPA chooses to move forward with.

h) RISK OF UNCERTAINTIES ASSOCIATED WITH COSTS AND COST ALLOCATION OF UPGRADES REQUIRED ON ADJACENT TRANSMISSION SYSTEMS: The 2010 cluster study identified a number of reinforcements to adjacent transmission systems that would be required to provide the requested LTF service. The PTSA does not explicitly address how BPA should consider upgrades on adjacent systems for purposes of the rolled-in rates determination, and BPA has not addressed this situation in previous NOS processes. BPA does not control the decision to complete upgrades on other systems, nor would it control the timing of completing such upgrades, so deciding to move forward with TSRs that require fixes on other systems presents unique uncertainties and risks.

The table on page 5 provides a summary of the third party upgrades for the NI project.

Following are additional considerations related to third party upgrades:

- Can BPA influence/accelerate construction without incurring additional costs?
- What are the potential costs (capital or expense) of each reinforcement to BPA?
- Are reinforcements commercial-based or reliability-based?
- Can BPA predict or influence the timing of construction?
- What degree of service is enabled by identified reinforcement?
- Is the reinforcement stand-alone or does it require additional third-party reinforcements?

- Does BPA have adequate funding to apply to these reinforcements?
- How can this be managed within BPA's contractual obligations as stated in the PTSA?
- Each reinforcement carries its own risk given it has a unique third-party and each reinforcement is in different stages of development, planning, etc.
- What is the customer's appropriate share of the cost of these reinforcements (if any)?
- Is the customer willing to pay for their share of these reinforcements (if any)?

MITIGATION

- The required coordination and communication with affected systems will be incorporated into the close-out letters to the PTSA holders of any TSRs determined at rolled-in rates. For those TSRs, the obligation associated with the NEPA process allows for up to 39 months from the close of the 2010 NOS which should provide adequate time for the required coordination and communication to take place.
- Incorporate the ability to end the TSR into the close-out letter if the issue regarding the builds cannot be resolved with 39 months.
- BPA or the customer will have to coordinate with the relevant adjacent transmission providers regarding upgrades on adjacent systems. Attachment K provides that BPA should notify Columbia Grid of TSRs that require upgrades on adjacent systems, and specifies a process to follow to coordinate and attempt to reach agreement on cost allocation. Provisions of the *pro forma* tariff place the coordination responsibility on the customer. BPA believes that it should take an active role in this coordination.

i) **RISK OF APPLICATION OF THE REMEDIAL ACTION SCHEME (RAS) REQUIREMENTS FOR THE CUP WEST PROJECT**: All of the capacity from the CUP-West project requires RAS from (a) generator(s) located in Montana (at a 1 to 1 ratio) for the capacity to be usable. This issue is recently identified and needs more exploration to fully understand the impact. Cost for a similar RAS scheme identified in the 2008 NOS was estimated at $2.3 million. However, tentative conclusions regarding this need are as follows: (Insert the conclusions from the email)

MITIGATION

- Use the delay in the rolled-in rates determination to more fully vet the impacts of this requirement and to determine any impact to the rolled-in rates decision and to the customer's ability to use transmission service resulting from this build.
- Make both customers aware of this requirement prior to the beginning of their 15 day period wherein they have the opportunity to terminate these PTSAs.
- Make a determination as to whether the resource providing balancing energy is going to need to be on RAS as well.
- Work closely with the customer to determine where the RAS requirement will be reflected.

j) **RISK OF SIGNIFICANT DECREASE IN AMOUNT OF CAPACITY FROM CUP WEST PROJECT**: The CUP West project requires an additional study of Sub-Synchronous Resonance (SSR) to be completed to more definitively determine the amount of capacity that will result from this project. That study is expected to take three to six months. While that study is extremely unlikely to result in more capacity than current study work suggests, there is a possibility that it may determine that there is less capacity that current study work suggests. In addition, it could result in finding a slightly different plan of service is needed, thereby changing the projected cost of the CUP West upgrade. As the rolled-in rates is TSR-based and not project-based, without clarity regarding the amount of MW of capacity that the upgrade will provide there is some risk of overselling the capacity on the upgrade.

MITIGATION

- BPA should delay the rolled-in rates determination for the CUP West until the results of the SSR study are available. If either the amount of capacity that CUP West will create or the cost of the project changes substantially, BPA should re-run sthe financial analysis associated with that project. Once the TTC is clearer, BPA can provide a rolled-in rates determination for the correct amount of TSRs, assuming that is what BPA determines to do.

k) RISK ASSOCIATED WITH COMMITMENTS WITH CUSTOMERS THAT HAVE NOT YET DEMONSTRATED CONTRACTUAL ARRANGEMENTS FOR DELIVERING POWER TO BPA'S SYSTEM:

Previously in NOS, the new generation for which service was being requested was in BPA's service territory, so while interconnection timing was an issue, there was no additional leg of transmission for which new infrastructure was going to be required for the customer to use the requested service.

MITIGATION:

- BPA should coordinate actions for NEPA review, PED, and if decision is made to construct, for construction very closely with the key customer (Gaelectric) and with Northwestern, to endeavor to first ensure that the transmission upgrade needed on Northwestern's system is moving forward, that Gaelectric is moving forward with acquisition and installation of turbines, and that the timing of those three elements will be completed as close together as possible.

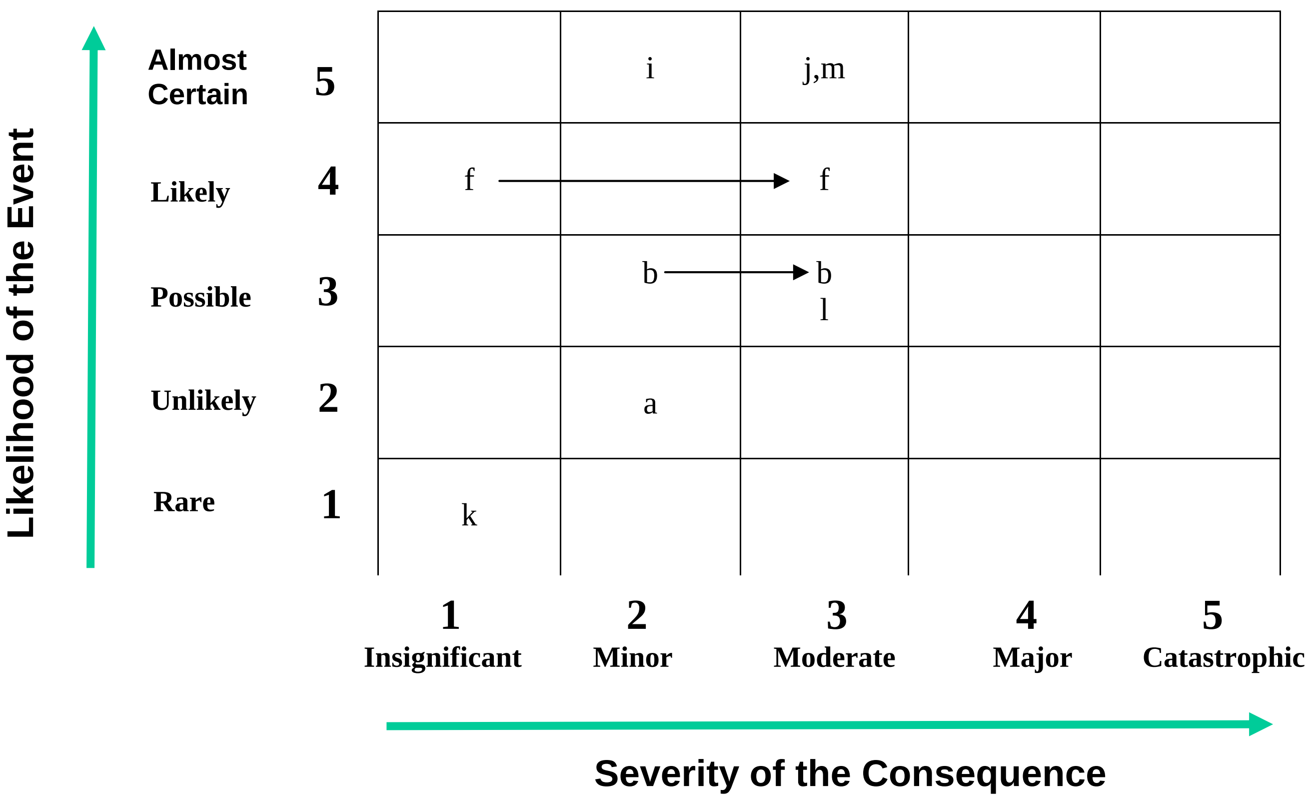
What are the existing controls?

- NOS Steering Committee – weekly meeting of oversight committee to review, address and act on any issue related to and/or potentially impacting the NOS process.
- Precedent Transmission Service Agreement – as filed and approved by FERC on August 18, 2009 and filed as part of BPA's OATT as Attachment O.
- Transmission Services' Policy Forum – weekly meeting to introduce, review and provide guidance on issues impacting existing policies and/or creating new policies.
- 2010 NOS Bulletin – http://transmission.bpa.gov/Customer_Forums/open_season_2010/2010_nos_bulletin_v2_current.pdf
- BPA's OATT - http://www.transmission.bpa.gov/business/ts_tariff/
- NOS Team issue discussions as needed to develop resolution to newly identified issues

Risk Map

Abbrev.	Risks
a	Not complete NEPA obligation within required timeframe
b	Commercial: Deferral, ROFR, Default
f	Changing project costs
h	Access to capital
i	Costs and cost allocation of third party facilities
j	RAS requirements
k	SSR study reducing marketable capacity
l	Absence of contractual arrangements to connect to BPA network

Add additional risks



Notes:

- Risk I and m are specific to the Northern Intertie project
- Risks j,k & l are specific to CUP West
- Each unacceptable risk is “treated” (made acceptable) by some element of the implementation plan for the recommended alternative.

7. Alternatives and Evaluation

This ADF will consider six (6) alternatives. The alternatives consider the 2,217 MW of TSRs that require one or more of the identified infrastructure projects resulting from the 2010 Cluster Study which were included in the CIFA. Each alternative assumes that the 1,522 MW requiring the 2008 NOS projects and the 60 MW requiring the Central Oregon upgrades will proceed. No decision is required for the 53 MW that BPA has been able to authorize using existing ATC.

Alternative 1: No 2010 projects move forward at rolled-in rates

- Northern Intertie, CUP West and GASH do not move forward at rolled-in rates.
- 0.0% rate pressure
- $0 in direct capital costs

Alternative 2: Northern Intertie upgrades move forward at rolled-in rates

- CUP West and GASH do not move forward at rolled-in rates.
- -1.2% rate pressure
- $71.2 million in direct capital costs

Alternative 3: CUP West upgrades move forward at rolled-in rates pending outcome of additional studies and appropriate treatment of the RAS requirements

- Northern Intertie and GASH do not move forward at rolled-in rates.
- 0.7% rate pressure
- $115.5 million in direct capital costs

Alternative 4: GASH upgrades move forward at rolled-in rates

- Northern Intertie and CUP West do not move forward at rolled-in rates.
- 14.7% rate pressure
- $943.5 million in direct capital costs

Alternative 5: Rolled-in rates decision for the Northern Intertie and a three to six months delay to the rolled-in rates decision on CUP West pending the outcome of additional studies to more precisely determine the amount of capacity the project will provide, and appropriate treatment of the RAS requirements.

- Delay the rolled in rates determination for Garrison-Ashe with the recommendation that the project does not move forward at rolled-in rates (due to the uncertainty of which TSRs would require GASH).
- -0.7% rate pressure (if both projects move forward at rolled-in rates)
- $186.7 million in direct capital costs (if both projects move forward at rolled-in rates)

Alternative 6: Northern Intertie, CUP West and GASH move forward at rolled-in rates

- 15.5% rate pressure
- $1,130.2 million in direct capital costs

Criteria	Alt #1 No 2010 Projects	Alt #2 NI Only	Alt #3 CUP West Only	Alt #4 GASH Only	Alt #5 a/b NI + CUP West	Alt #6 All 2010 Projects	Explanation of Evaluation
Business/Finance							
• Effective queue management	If any of the projects proceed at incremental rates, could create problems	If CUP West or GASH proceeds at incremental rates, could create problems	If NI or Garrison-Ashe proceed at incremental rates, could create problems	If NI or CUP West proceed at incremental rates, could create problems	Yes, unless GASH proceeds at incremental rates	Yes	NOS process enables effective queue management if only projects proceeding are at rolled-in rates. However, if one or more are at incremental rate, will create uncertainty regarding what to assume for future NOS. If rolled-in rates determination is made prior to clarity regarding the amount of capacity on CUP West, queue management difficulties could result in BPA being contractually overcommitted to providing service on CUP West if the SSR study results in less capacity.
• Creates new revenue	Yes – 1,563 MW of new PTP	Yes – 2,413 MW of new PTP	Yes – 2,043 MW of new PTP	Yes – 2,107 MW of new PTP	Yes – 2,943 MW of new PTP	Yes – 3,487 MW of new PTP	NOS process allowed authorization of 53 MW of new LTF service without new tx facilities and 1,522 MW using tx facilities from 2008 NOS proposed or under construction
• Passes the NPV test (CIFA)	No	Yes	No	No	No	No	See CIFA results above
• Within 2-3% rate impact threshold	Yes 0.0%	**Yes** -1.2%	**Yes** 0.7%	No 14.66%	**Yes** -0.7%	No 15.5%	While Alt 1 met this criteria, it failed the NPV and cost/MW. (How could it fail the cost/MW?

Criteria	Alt #1 No 2010 Projects	Alt #2 NI Only	Alt #3 CUP West Only	Alt #4 GASH Only	Alt #5 a/b NI + CUP West	Alt #6 All 2010 Projects	Explanation of Evaluation
• Negligible/Low stranded investment	N/A	Yes – customer with high credit rating and excellent business history with BPA	No – High risk associated with customer who would be on pre-pay for transmission.	No – High risk associated with customer who would be on pre-pay for transmission.	Probably, very dependent on EX 5 unless BPA could resell CUP West capacity if EX 5 defaulted	No	Plans of service are reliant on minimal number of customers increasing risk. If additional customers are included through future NOS or other processes this risk would be mitigated.
• Enhanced system operation	N/A	N/A	N/A	N/A	N/A	N/A	Additional sales on existing facilities could bring increased congestion on the network..
• Reliability Benefits	No	No	No	No	No	No	No reliability benefits were identified for 2010 NOS by planning; however, reliability benefits exist for 2008 NOS facilities used by 2010 TSRs.
• Future load growth	No	No (possibly unknown?)	No	Yes	No (possibly Unknown for NI?)	Yes on GASH, No for all other projects (if time, check on NI with planning)	Plans of service are built only for requested transmission service, not for projected commercial need. GIVEN THE LUMPINESS OF TX, THIS DOESN'T SEEM LIKE A TRUE STATEMENT IN SOME CASES
• Future commercial sales	No	Unknown, but possible.	No	Yes	No	See other entries.	
Legal							
• Consistent with Transmission policies and the OATT	See attached legal analysis						
Environment							

<table>
<tr><th>Criteria</th><th><u>Alt #1</u>
No 2010 Projects</th><th><u>Alt #2</u>
NI Only</th><th><u>Alt #3</u>
CUP West Only</th><th><u>Alt #4</u>
GASH Only</th><th><u>Alt #5 a/b</u>
NI + CUP West</th><th><u>Alt #6</u>
All 2010 Projects</th><th>Explanation of Evaluation</th></tr>
<tr><td>• Compliant with NEPA obligations</td><td>N/A</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Assumes normal NEPA procedures will be followed including NEPA for any third party system upgrades that BPA funds</td></tr>
<tr><td>• Supports renewable resource development</td><td>No</td><td>No</td><td>Yes, for approximately 80% of the capacity</td><td>Yes, partly</td><td>Yes, partly</td><td>Yes, partly</td><td>The 2008 NOS facilities leveraged by the 2010 TSRs enable continued renewable resource development</td></tr>
<tr><td>Public Interests</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>• Solicit and review customer/public comments on NOS process and results</td><td colspan="7">Customers had until Friday, May 13 COB to submit comments on the staff recommendation. We received five sets of comments, with three being from the Montana constituency and customers.

All five sets of comments supported the staff recommendation but urged BPA to conduct diligence in its continuing assessment and evaluation of the plan of service and associated cost of each project. Furthermore, customers ask that the CIFA be re-run, when it makes sense, to ensure that all NOS projects continue to be viable and are good investments for the region.

The comments from EX 5 and the EX 5 EX 5 did urge BPA to provide as much certainty and confidence as possible on the CUP WEST project.

Finally, there were specific comments on concerns related to BPA's access to capital situation and so it is advised that any public process associated with that issue be closely coordinated with NOS and other transmission expansion initiatives.</td></tr>
<tr><td>• Support RPS requirements</td><td>No</td><td>No</td><td>Yes, mostly</td><td>Yes, partly</td><td>Yes, partly</td><td>Yes, partly</td><td>Alternative 1 and 2 do not have any renewable generation associated with TSRs. However, most of the RPS requirements are and will be met without the additional Montana wind.</td></tr>
</table>

Criteria	Alt #1 No 2010 Projects	Alt #2 NI Only	Alt #3 CUP West Only	Alt #4 GASH Only	Alt #5 a/b NI + CUP West	Alt #6 All 2010 Projects	Explanation of Evaluation
• Promotes wind diversity	No	No	Questionable if out of BA generation is firmed up prior to being imported into BPA's BA (although there would be diversity in physical siting locations)	Questionable if out of BA generation is firmed up prior to being imported into BPA's BA (although there would be diversity in physical siting locations)	Questionable if out of BA power is firmed up prior to being imported into BPA's BA (although there would be diversity in physical siting locations)	Questionable if out of BA generation is firmed up prior to being imported into BPA's BA (although there would be diversity in physical siting locations)	
• Provides regional benefits	No	Yes	Yes	No	Yes	Yes	See REBA summary
BPA's People and Processes (e.g., potential work load, procedural, cultural and ethical impacts, etc.)							
• Able to complete NEPA and construct projects	N/A	Yes	Yes	Probably Not within 39 months	Yes	Unlikely for all due to GASH	Increased workload associated with new plans of service can be addressed. NI requires I-5 to provide service therefore NI NEPA should sync with I-5 NEPA process.
• Acceptable impact to staff and culture	Yes - Any work associated with the 2008 NOS projects is already accounted for.	Yes Project manager is Theresa Berry	Yes Project manager is Mark Korsness	Questionable No project manager has been assigned. Heavy degree of work involved in building new 500-kV line	Yes. See Alternatives #2 and #3.	Questionable See Alternative #4.	Increased workload associated with new plans of service can be addressed; however, adding 2010 NOS projects to workload already associated with 2008 NOS projects increases both workload and complexity of that workload.

8. Recommendation

Alternative 5: Rolled-in rates decision for the Northern Intertie and a three to six months delay to the rolled-in rates decision on CUP West pending the outcome of additional studies to more precisely determine the amount of capacity the project will provide, and appropriate treatment of the RAS requirements.

Delay the rolled in rates determination for Garrison-Ashe with the recommendation that the project does not move forward at rolled-in rates (due to the uncertainty of which TSRs would require GASH).

In addition, TSRs needing only 2008 projects or reliability projects will also move forward.

9. Document the Decision

The final decision (including potential decision for a delay in the rolled-in rates determination for CUP West) will be communicated to customers that signed PTSA for the 2010 NOS by letter no later than May 31, 2011. A communication plan, internal talking points and notice of final decision will be prepared for distribution.

10. Implementation

Prepare and post a NOS 2010 decision letter (under the Administrator's signature) summarizing the 2010 NOS process including

a) which TSRs require the 2008 NOS infrastructure projects that are moving forward either in construction or NEPA for that service and,

b) which TSRs require the 2010 NOS infrastructure projects that are moving forward at rolled in rate (recommendation for Northern Intertie), and

c) which TSRs may require the CUP West project for which BPA is delaying the rolled in rates determination (affected customers will have a 15 day window to withdraw their requests in accordance with the PTSA. BPA will base the final rolled in rates determination on the remaining TSRs), and

d) which TSRs may require the Garrison-Ashe project for which BPA will not move forward at rolled in rates; however, BPA will delay the execution of the affected PTSAs until the final determination of CUP West.

Subsequent to the final decision on CUP West (in three to six months from May 31, 2011), prepare and post a second NOS 2010 decision letter (under the Administrator's signature communicating the final rolled-in rates determination for CUP West including, if a rolled in rates determination is made, which TSRs require the CUP West project, and which TSRs require the GASH project and not moving forward at rolled-in rates and therefore terminating.

BPA will then offer the TSR holders associated with the terminated PTSAs a NEPA agreement under OATT. The customer will then need to determine whether to move this project forward at their own cost (i.e., whether to fund the NEPA and preliminary engineering work), or not. The performance assurance securing the terminated PTSAs will be promptly released to the customer. If the TSR holder does not sign and fund the NEPA agreement by the deadline, the TSR is put in final status and is no longer eligible for service. The customer may submit essentially the same TSR for participation in the next NOS if they wish to do so.

- Close-out letters regarding PTSAs requiring third-party reinforcements move forward, subject to the outcome of the necessary coordination and cost allocation and may require OATT-based coordination.

- In accordance with Attachment K, BPA will notify Columbia Grid of the required upgrades.
- Work with the identified third party transmission providers to obtain their plans of service and cost estimates for the impacts identified in the cluster study. Determine allocation of costs as appropriate to each situation. Update BPA costs to include any BPA-allocated costs for the third party upgrades.
- Complete the additional SSR study for CUP West as quickly as reasonably possible to enable the final rolled-in rates determination for CUP West. Provide the customers with TSRs needing CUP-West with the opportunity to terminate their PTSA per section XXXX of the PTSA (15 day period) and subsequent opportunity to withdraw the TSR or to move it forward under the pro forma OATT with obligation to pay for the associated NEPA and preliminary engineering costs. Adjust the queue accordingly if any of the TSRs are withdrawn.
- Fully develop the implications of the CUP West RAS need as quickly as possible, as customers with TSRs needing CUP West will need to understand those implications to make decisions regarding whether to leave PTSAs in force or terminate them.
- Determine how to contractually reflect the CUP West RAS requirement (whether in the transmission service request or elsewhere).
- Determine whether a wind generator's balancing resource will also need to be on RAS.
- Coordinate with adjacent transmission providers for which needed system upgrades were identified to obtain their determination regarding the plan of service for those upgrades and to negotiate cost allocations.
- If a rolled-in rates determination is made for CUP West, plan for and enter into the WECC three phase rating process as the appropriate point.

Communication Plan for Northern Intertie Update and 2010 Network Open Season Decision

	5/16	5/17	5/18	5/19	5/20	5/21	5/22	5/23	5/24	5/25	5/26	5/27	5/28	5/29	5/30	5/31
Inform Tier II	X															
Inform Steve Wright		X														
Powerex Conversation (this should occur before any general public/customer outreach)				X												
Option 2: Customer conference call					X											
Option 2: Customer comment period								X	X							
2010 NOS Decision Letter on TAC								X	X	X	X					
2010 NOS Decision Letter Signed (prepared to post to web)												X				
Send Rolled-In Rate Letters to PTSA holders												X				
Announce 2010 decision																X
TIPSC Briefing – Date TBD																

Option 1: Share updated $$ on May 31, 2011 (with rate determination)	**Option 2: Share updated $$ by 5/20 and hold brief comment period prior to close-out**
Pros: ♦ Avoids complication of trying to hold a second comment period and consider all comments prior to the deadline. ♦ May be seen by the region as making sense since the rate pressure is still negative Cons: ♦ Not as transparent, may seem disingenuous	Pros: ♦ Most responsive and considerate which is consistent with transparent NOS process Cons: ♦ Complicated and intent to be transparent may backfire considering all other external initiatives and internal workload ♦ Extended public process may impact timing of internal processes required to get to 5/31 decision point. ♦ Cost changes may not be perceived as needing additional comment since the rate pressure is still negative

Communication Plan for Northern Intertie Change in Plan of Service and Estimated Costs

For more information: call Lauren Nichols-Kinas at 360-619-6416 or Sean Egusa at (360) 619-6383.

On April 13th, BPA staff presented their 2010 NOS rolled-in rates recommendations. In that presentation, we recommended that BPA move forward with a rolled-in rates determination for the Northern Intertie based on an estimated capital cost of $25.6 million and an associated rate pressure of -2.1%. Since that time BPA has done additional work to further examine the plan of service for the Northern Intertie upgrade, particularly on the portion regarding the South Tacoma-Olympia line and a parallel Cowlitz-XX line.

Background

BPA found that a number of new challenges occurred in the 2010 NOS. One of those challenges was that BPA needed to develop plans of service for major reinforcements to the transmission system in 120 days. Another was that the cluster study identified a need for reinforcements not just on BPA's system, but on other utilities' systems to provide service for some of the NOS TSRs. One of those findings was the need to reconductor approximately 36 miles of line from South Tacoma to Olympia. However, upon deeper examination, BPA has determined that the towers that are currently in place needs to be rebuilt along the entire 36 mile segment. So while the cluster study correctly identified the portion of the transmission system that must be reinforced, the infrastructure upgrade will need to be a complete rebuild. The costs of just this upgrade have changed from $12 million to $36 million and, with other identified upgrades, the total estimated cost of the project has risen from $26.3 million to $70 million.

Key messages

1. The rate pressure for the Northern Intertie upgrade is still negative. With the increase in estimated costs, the rate pressure changed for -2.1 to -0.77. Further the rate pressure from the CIFA analysis would remain negative even with inclusion if BPA is determines that it needs to fund a significant portion of the Portal Way transformer (for which the current cost estimate is $25 million).
2. NOS 2010 was essentially the first time that BPA needed to develop plans of service for major upgrades to the transmission system in 120 days, as the plans for service for the upgrades that came out of the 2008 NOS existed prior to the undertaking of that NOS. This was possible because BPA was aware of the locations for which its transmission system likely needed to be reinforced next and had studied those portions of the system and their needed improvements thoroughly.
3. When BPA designed its Network Open Season, the intent was to provide a means for requests on BPA's network to be studied. However, in 2010, BPA encountered circumstances in which requests on BPA's system appear to require upgrades to the transmission infrastructure of adjacent transmission providers in addition to the upgrades needed on BPA's system. In these cases, the adjacent transmission provider will need to develop the final plan of service based on information from BPA regarding the impacts of the transmission service that needs to be accommodated. These coordinated plans of service, by their nature, will require more than 120 days to fully develop.

4. If the financial analysis supporting a particular infrastructure upgraded needed in NOS changes substantially prior to the decision regarding whether or not to build, BPA has the option to determine not to pursue construction of that upgrade. BPA will update the financial analysis for all NOS infrastructure projects prior to making the decision to build.

NEXT STEPS:

BPA will further develop the options for the Northern Intertie reinforcement due to the National Environmental Policy Act requirement to assess options. Further, BPA will work with the third party transmission providers whose systems the 2010 NOS cluster study found needed to be upgraded to enable offering of some of the service requested in the 2010 NOS. In addition, BPA will continue to refine the plans of service and the associated costs estimates.

COMMUNICATION STEPS:

1. Inform EX 5 about the modification to the plan of service for the Northern Intertie upgrade and the increase in the estimated costs for the Northern Intertie Upgrade.
2. Inform customers and stakeholders regarding the modification to the plan of service for the Northern Intertie upgrade and the increase in the estimated costs for the Northern Intertie. BPA can do this either, a) this week and offer a VERY brief window for additional customer comments or, b) when we announce our decisions regarding the rolled-in rates for NOS 2010.
3. Include the information in the Administrator's letter to the region regarding the outcomes of NOS 2010.
4. Discuss these findings and their impact on the estimated costs at the next TIPSC meeting.

LESSONS LEARNED:

1. BPA will do an analysis of the 2010 NOS to further examine potential changes that need to be incorporated in the next Network Open Season.
2. BPA will share its findings with its customers and stakeholders to enable us to work together to adjust the design of the Network Open Season so that BPA can more thoroughly develop the plans of service in future network open seasons prior to the rolled-in rates determinations.
3. BPA will provide any updates to the plan(s) of service and the cost estimates for the 2010 NOS projects as we move forward through NEPA and preliminary engineering.
4. At the time of the decision to build, BPA will take into account all pertinent information regarding the final plan of service, the estimated costs for the infrastructure upgrade, and the updated NPV and rate pressure information.

11. Glossary

While all acronyms used in this ADF have at least one introductory instance of being spelled out, this section serves as a quick reference to any acronym used in the course of this decision.

- CUP – Colstrip Upgrade Project
- NEPA – National Environmental Protection Act
- PED – Preliminary Engineering & Design
- CIFA – Commercial Infrastructure Financial Analysis
- NOS – Network Open Season
- MW – Megawatt
- ATC – Available Transfer Capability
- LTF – Long Term Firm
- PTSA – Precedent Transmission Service Agreement
- TSR – Transmission Service Request
- OATT – Open Access Transmission Tariff
- REBA – Regional Economic Benefit Analysis
- ROD – Record of Decision
- CAB – Capital Allocation Board
- WOMR – West of McNary Reinforcements
- GASH – Garrison to Ashe
- NI – Northern Intertie
- PSAST – Puget Sound Area Study Team
- SSR – Sub Synchronous Resonance
- NT – Network Transmission service
- TP – Transmission Provider
- RAS – Remedial Action Scheme
- NPV – Net Present Value
- WECC – Western Electricity Coordinating Council
- CF – Conditional Firm
- POD – Point of Delivery
- ROFR – Right of First Refusal (aka Rollover)

Agency Decision Framework:

2009 Network Open Season Rolled-In Rates Determination

The Issue:

- BPA conducts an annual Network Open Season (NOS) to evaluate new long-term firm Transmission Service Requests (TSRs) on its network for which PTSAs were executed by the submitting customer. The process has three primary goals:
  1. Long-Term Firm (LTF) Queue management: BPA has limited transmission inventory on its network for new LTF requests. The NOS process allows the scarce inventory to be allocated to those customers that are willing to contractually commit to taking the transmission service.
  2. Identify necessary transmission system reinforcements or expansion facilities: Those network requests for which there is no ATC at one or more flowgates are included in a cluster study so that all new requests with PTSAs can be studied simultaneously. The cluster study determines what, if any, new system reinforcements are needed to provide service to those TSRs in the cluster study.
  3. Respond to TSRs within the timelines in BPA's Open Access Transmission Tariff (OATT).
- As part of the NOS process, the PTSA requires the Administrator to determine whether the expansion facilities identified in the cluster study (if any), and the TSRs that require those expansion facilities, will move forward at rolled-in rates. As part of this determination, the following are included as inputs and influences:
  1. Amount of NOS participation (as measured by the number of and MW amount of the PTSAs)
  2. Cluster Study results
  3. Commercial Infrastructure Financial Analysis (CIFA) results
  4. Regional Economic Benefit Analysis (REBA)
  5. Customer Comments
- The rolled-in rate determination for the 2009 NOS must be made by May 31, 2010, and BPA must notify customers of the decision by that date. If BPA does not notify customers by May 31, 2010, customers will have the right to terminate their PTSAs.
- Transmission Services is recommending that only those 2009 NOS TSRs that would require the projects currently under construction or environmental review as a result of the 2008 NOS move forward at rolled-in rates. Adopting this recommendation would mean that 30 of the 34 PTSAs/TSRs in the 2009 NOS would continue to move forward in the process under the PTSA (ten PTSAs/TSRs can be authorized without new facilities and do not require a decision to move forward).

Objective

Make a rolled-in rate determination for the 2009 NOS consistent with the OATT and agency strategic objectives (as stated below).

How does the objective connect to agency strategic direction?

- S1-Policy & Regional Actions-BPA policies result in regional actions that ensure adequate, efficient and reliable regional transmission and power services.
- S4-Open, non-discriminatory transmission services are provided at rates that are kept low through achievement of BPA's objective at the lowest practical cost.
- S6-Renewable Energy- BPA actively enables renewable resource integration and development through cost-effective, innovative solutions.
- F2-Cost Recovery-BPA consistently recovers its costs over time.

- I4-Asset Management-Integrated asset management practices maximize the long-term value of FCRPS assets.
- I8- Transparency- BPA process, decision making and performance are transparent.
- I9-Collaboration-Collaborative relationships with customers, constituents and tribes are supported by our managing to clear, long-term objectives with reliable results.

Decision Makers

Decision makers	• Steve Wright	• Brian Silverstein
VP Sponsors	• Cathy Ehli (Policy) • Hardev Juj (Planning)	• Dave Armstrong
NOS Management and Supervisory Team	• Bob King • Melvin Rodrigues • Mary Jensen • Dave Fitzsimmons • Rich Gillman	• Claudia Andrews • Deedee Vanderzanden • Lauren Nichols-Kinas • Rebecca Fredrickson • Bena Kluegel
Team Members	• Sean Egusa • Kyle Kohne • Pat Rochelle • Matt Perkins • Rebecca Fredrickson • Tim Hein • Danny Chen • Mike DeWolf • Damen Bleiler • Ken Marks • David Barringer • Camille Blakely • Tom Davis • Margaret Olczak • Robert Edwards • Paul Fiedler	• Len Morales • Erik Westman • Ravi Aggarwal • Sandra Ackley • Gene Lynard • Mark Korsness • Gary Beck • Maryam Asgharian • Ryan Josephson • Eric Carter • Marilyn Czerwinski • Doug Johnson • Jennifer Boehle • Stan Williams • Marcus Harris • Chuck Combs • Kelly Johnson

What is the context?

The NOS process is governed by a Precedent Transmission Service Agreement (PTSA) that is part of our filed OATT and obligates BPA to take the following actions:

- At BPA's expense, conduct a Cluster Study to determine transmission system impacts of the TSRs and to identify new facilities, modifications, or upgrades to BPA's network needed to provide the requested service.
- Evaluate the estimated cost and benefits of proposed expansion facilities consistent with the Commercial Infrastructure Financial Analysis (CIFA).
- Decide whether transmission service could "reasonably be provided under the applicable PTP or NT rate schedule" if BPA were to construct the expansion facilities (i.e., make a rolled-in rate determination). BPA must make this determination and notify customers of its decision within 11 months of the deadline to submit new requests for the NOS or customers have the right to terminate their PTSAs.

- If BPA decides to move forward at rolled-in rates for one or more expansion facilities, it will conduct and fund studies for evaluating the environmental impacts of new facilities, including preliminary engineering and design work necessary to carry out the environmental reviews. If necessary, preliminary funding would be approved by the CAB.
- After the completion of the environmental review, BPA must decide whether to build the necessary facilities.
- BPA must complete any environmental review and decide whether to build facilities no later than 39 months from the date that BPA notifies customers about the rolled-in rate determination. If BPA did not take these actions within that timeline or offer conditional firm service, customers would have the right to terminate the PTSAs.
- If BPA decides to build the necessary facilities, BPA will finance and construct the facilities.

The following provides background information on the 2008 NOS and summarizes the results of the Cluster Study and CIFA evaluation for the 2009 NOS.

1. Recap of 2008 NOS results: On February 16, 2009, BPA posted the Administrator's decision for the 2008 NOS in which customers executed 153 PTSAs for 6,410 MW of LTF network service. As part of this decision, five plans of service moved forward at rolled-in rates, two plans of service did not move forward at rolled-in rates, and one plan of service did not move forward at rolled-in rates but was designated for a separate process.
    a. 2,209 MW of service have been granted
    b. 3,210 MW of service are awaiting environmental review and/or construction of facilities
    c. 991 MW of service are no longer active

2. Summary of 2009 NOS Participation: BPA offered 83 PTSAs for 4,867 MW of service. Participants executed 34 of those PTSAs for a total of 1,553 MW of LTF network service.

3. Summary of 2009 Cluster Study: 1,553 MW were included in the 2009 Cluster Study. The Cluster Study determined that:
    a. 293 MW of service could be authorized without new infrastructure
    b. 1,121 MW of TSRs could be authorized if BPA completes construction of projects moving forward as a result of the 2008 NOS
    c. 139 MW would require new infrastructure to enable BPA to provide the transmission service
        i. Northern Intertie Reinforcement (NI): Monroe-Echo Lake 500 kV No. 2 (33 miles) at an estimated $225 million (direct costs)
            1. The two TSRs that require the NI reinforcement also require the WOG reinforcement and part of Central Ferry-Lower Monumental in order to be authorized (EX 5 has two 50 MW requests).
        ii. West of Garrison Reinforcement (WOG): Addition of series compensation station west of Garrison and west of Taft substations at an estimated $91 million (direct costs).
            1. One TSR requires only the WOG reinforcement in order to be authorized (EX 5 has one 14 MW request).
        iii. Harney Area Reinforcement (Harney): Harney-Summer Lake 500-kV (108 miles) at $242 million (direct costs).

Cluster Study Results: PTSA Breakdown by Cluster

2009 NOS PTSA Grouping		
Grouping	**PTSA's**	**Demand**
Authorize	10 TSR's	293 MW
Harney	1 TSR's	25 MW
I-5	2 TSR's	100 MW
I-5, MCNY-JDAY, BIGE-KNGT	1 TSR's	125 MW
MCNY-JDAY, BIGE-KNGT	17 TSR's	896 MW
Northern Intertie, CFRY-LOMO, & West of Garrison	2 TSR's	100 MW
West of Garrison	1 TSR's	14 MW
Total	34 TSR's	1,553 MW

Cluster Study Results: 2009 Proposed Plans of Service

Project Description	**Estimated Direct Cost ($M)/Confidence Level**	**Potential Energization Date**
Northern Intertie	$225 /LOW	Sept. 2016
West of Garrison Reinforcement (BPA Share)	$91 /LOW	Sept. 2014
Harney Area Reinforcement	$242 /LOW	Sept. 2015
Total	$558	

Notes:

- Estimated costs in FY09 dollars.
- Energization dates assume embedded cost rate determination is made in May 2010.

4. Summary of 2009 Direct Assignment Evaluation: All three plans of service resulting from the 2009 Cluster Study were subject to a Direct Assignment evaluation conducted by Customer Service Engineering (TPC).

    a. In a memorandum dated March 30, 2010, the plan of service for a EX 5 EX 5 TSR (25 MW) was determined to be appropriate for Direct Assignment of the costs. As a result, this plan of service is not eligible for a rolled-in rates treatment and, consistent with the PTSA, BPA excluded the costs of these facilities from the CIFA evaluation.

    b. The plans of service for the NI and WOG were determined to be Network facilities and subject to the CIFA.

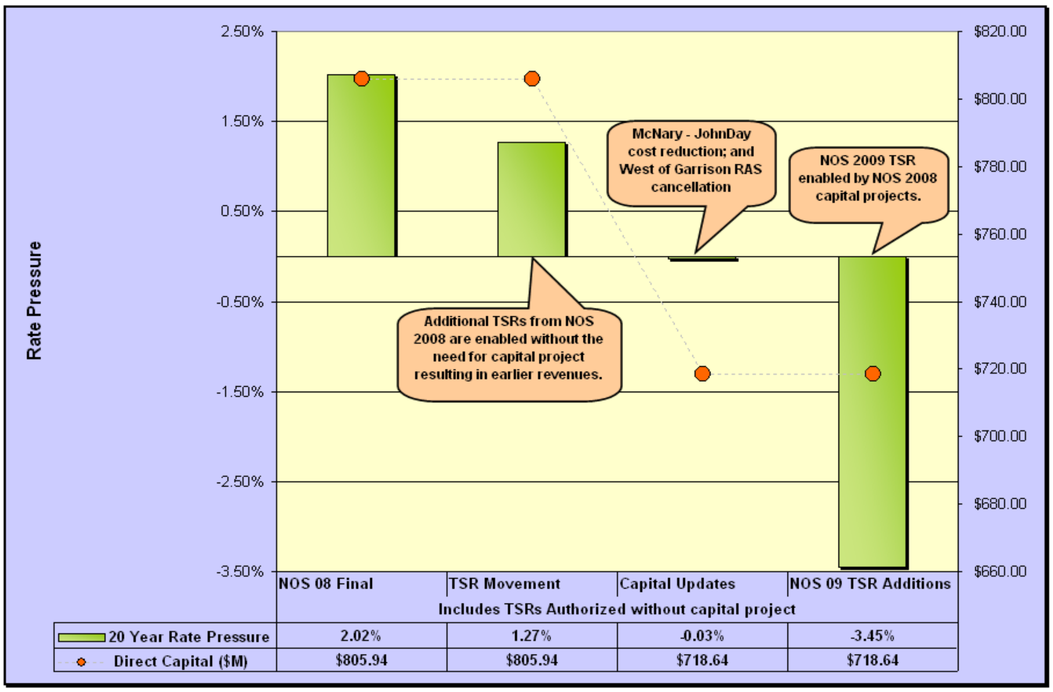
5. Summary of 2009 CIFA:

    a. Evaluation of 2009 NOS Requests that Require the McNary-John Day, Big Eddy-Knight, I-5 Corridor, and/or Central Ferry-Lower Monumental Projects

    As a result of the 2008 NOS, BPA is moving forward with four projects at rolled-in rates: McNary-John Day, Big Eddy-Knight, I-5 Corridor, and Central Ferry-Lower Monumental.

The 2009 NOS cluster study determined that 20 TSRs, representing 1,121 MW of requests, could be provided service with those 2008 NOS projects.

The 2008 NOS determination that these projects would move forward at rolled-in rates provided context for Transmission Services' evaluation of these TSRs in the 2009 NOS, and Transmission Services did not reevaluate the assumptions and analysis underlying the 2008 decision. Transmission Services did evaluate the effect of the additional revenue provided by the 2009 NOS TSRs (and other updated information) on the estimated costs and rate pressure associated with those 2008 NOS projects. Transmission Services found that the rate pressure associated with those projects decreased from 2.02% to -3.45% as a result of the additional revenue and other updated information. These results are captured in the following chart:

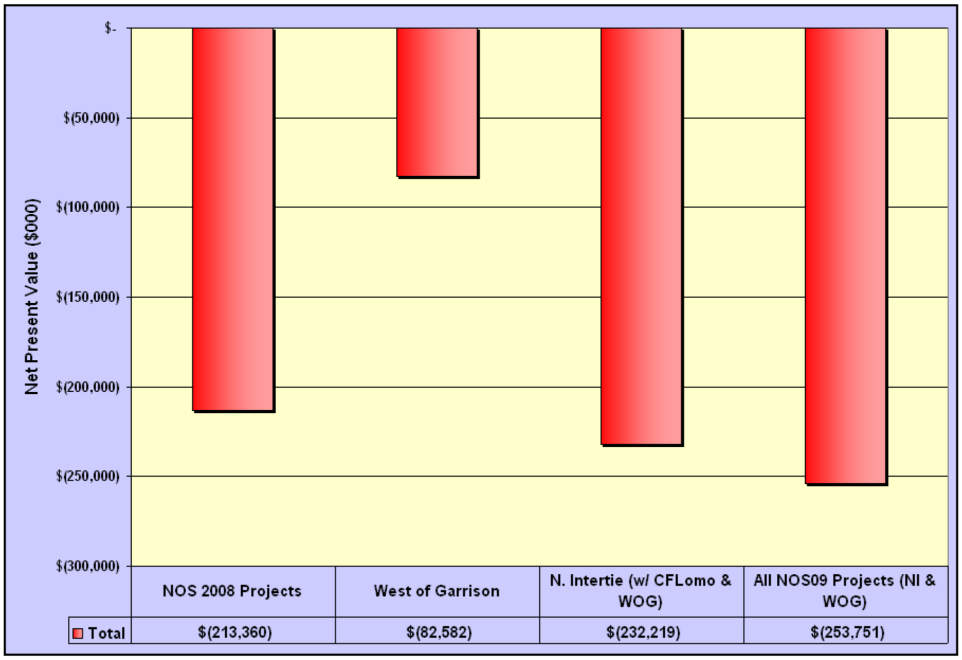


Agency Decision Framework:
2009 Network Open Season Rolled-In Rates Determination

b. Evaluation of the Northern Intertie (NI) and West of Garrison (WOG) reinforcements

Transmission Services evaluated the NI and WOG reinforcements in accordance with the CIFA. Both the NI and WOG reinforcements had a negative Net Present Value (NPV), and the CIFA and Cluster Study did not identify any reliability benefits for either project.

The following chart demonstrates the negative NPV results for all projects and combinations thereof.

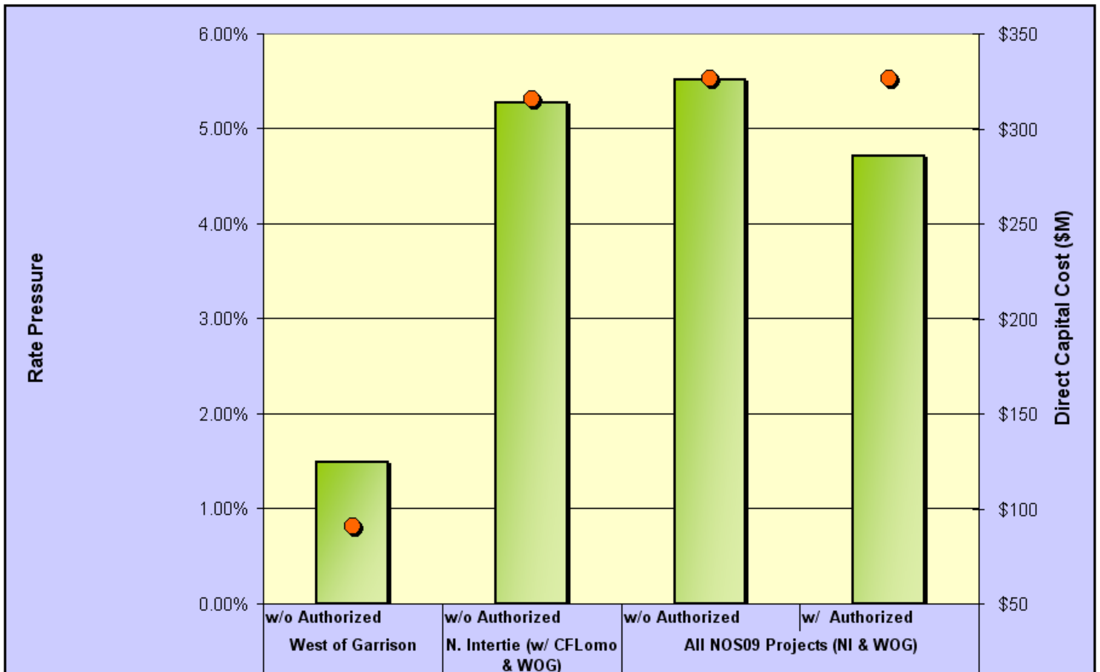


In addition, both the NI and WOG reinforcements resulted in unacceptably high rate pressure and costs per MW.

a. WOG (14 MW) is 1.5% rate pressure with direct cost per MW of $27 thousand per MW

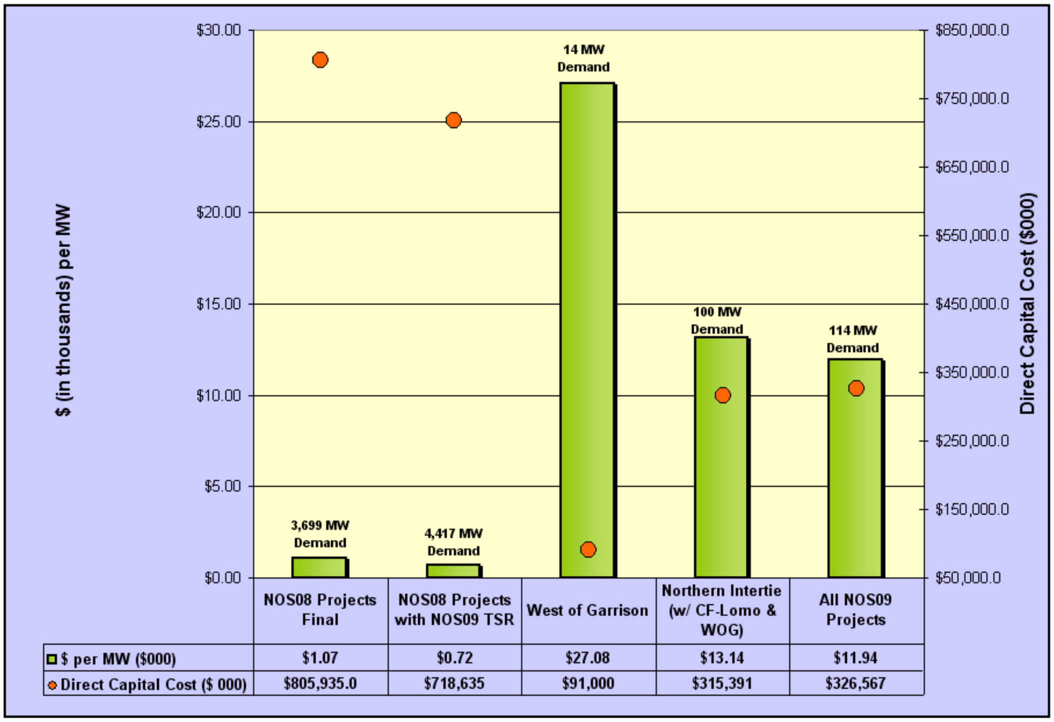
b. NI (100 MW) is 5.3% rate pressure with direct cost per MW of $13 thousand per MW.

Rate Pressure: The following chart shows the rate pressure associated with the capital costs of each project.



	West of Garrison (w/o Authorized)	N. Intertie (w/ CFLomo & WOG) (w/o Authorized)	All NOS09 Projects (NI & WOG) (w/o Authorized)	All NOS09 Projects (NI & WOG) (w/ Authorized)
20 Year Rate Pressure	1.49%	5.28%	5.51%	4.71%
Direct Capital Cost ($M)	$91	$315	$327	$327

CIFA Results: The following chart shows a breakdown of the capital costs per subscribed MW by 2009 NOS project.



	NOS08 Projects Final	NOS08 Projects with NOS09 TSR	West of Garrison	Northern Intertie (w/ CF-Lomo & WOG)	All NOS09 Projects
$ per MW ($000)	$1.07	$0.72	$27.08	$13.14	$11.94
Direct Capital Cost ($ 000)	$805,935.0	$718,635	$91,000	$315,391	$326,567

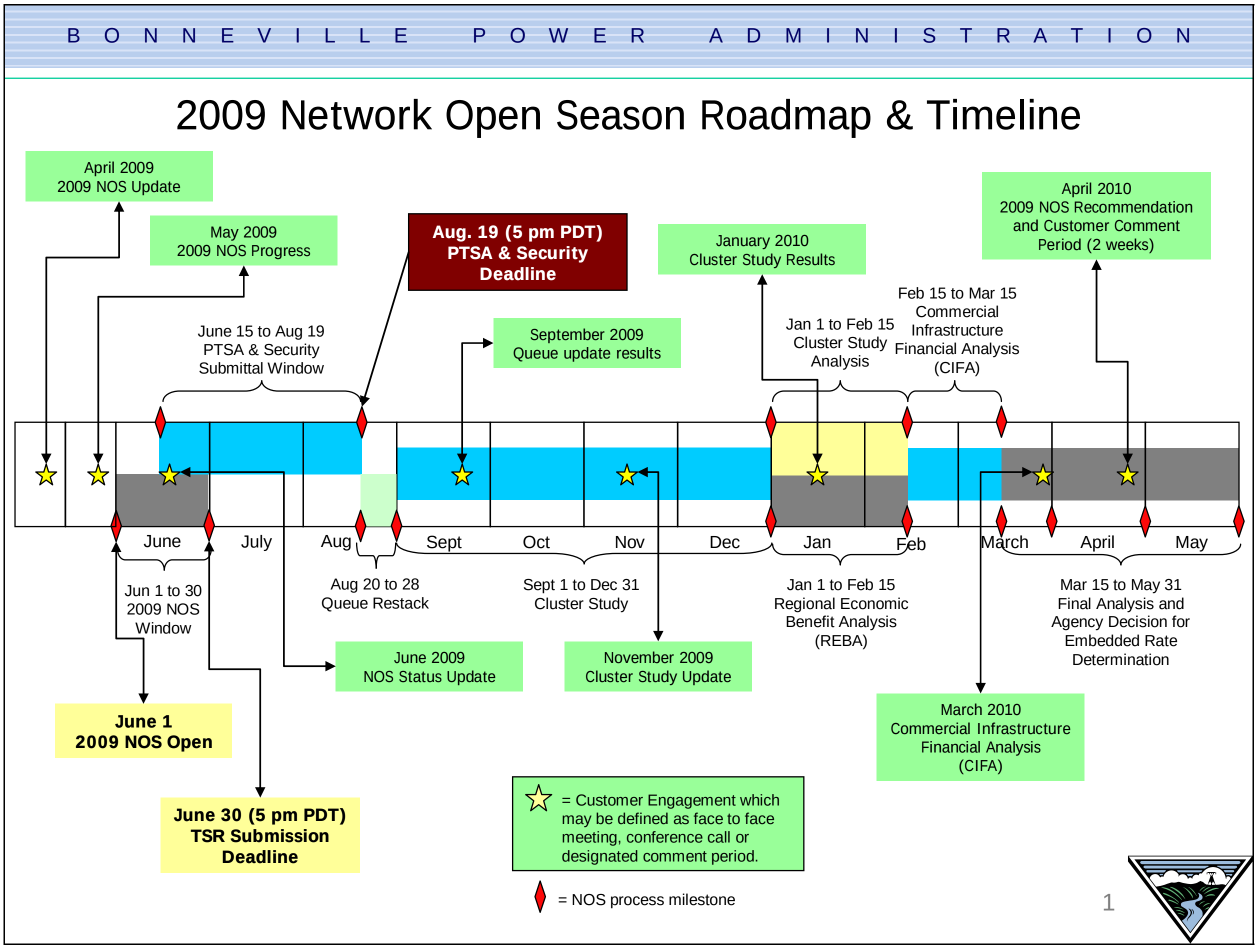
6. Summary of REBA: REBA results indicate most regional benefits are realized by leveraging 2008 projects.

- 2009 NOS generation additions result in substantial production costs savings and are accommodated with 2008 NOS transmission improvements, based on the paths, flowgates, and level of detail studied in the REBA.
    - About 36% of production cost savings occur in the Northwest, 54% occur in the Southwest, and the remaining 10% occurs in the Rocky Mountain and Great Basin regions.
    - However, the addition of generation associated with the 2009 NOS TSRs leads to increased transmission congestion.
        - Congestion on the West of John Day transmission flow gate more than doubled, due to coincident peak wind pushing to get to the California interties.
- The wind generation projects added to the study as a result of the 2009 NOS TSRs were in the same geographical area as the bulk of the additional wind resources assumed to result from the 2008 NOS TSRs, resulting in a lack of wind-regime diversity.
- At peak wind output, most of the Northwest fossil generation has already been displaced by the 'older' wind generators, leaving the new wind to displace out-of-region generators.
- At times of low wind in the Oregon-Washington wind zones, the new projects assumed from the 2009 NOS offer no diversity and only exacerbate operational problems.
- CO_2 emissions decreased by about 10% with a $33/ton cost and by about 20% with a $45/ton cost

Timeframe for the decision:

Written notification must be provided to each customer holding a PTSA no later than May 31, 2010. Implementation of this obligation is explained below.

Timeline for the 2009 NOS Process Beginning to End



What are the decision evaluation criteria?

Business/Finance

a) Allows effective management of long-term firm transmission queue

b) Creates new revenue

c) Cost effectiveness using NPV analysis consistent with the CIFA process and Agency financial assumptions;

d) No more than a 2-3% rate impact for the combined expansion facilities over 20 years;

e) Negligible to low stranded investment risk;

f) Consistency with BPA's financial targets, rate case assumptions, and treasury payment probability;

g) Enhanced system operation by reducing reliance on curtailment calculators and remedial action schemes;

h) Reliability benefits;

i) Provide capacity for load growth and future commercial sales;

j) Impact to future non-firm revenue;

Legal:

a) Consistent with applicable statutes, BPA Tariff, and PTSA terms.

b) Legal issues and potential legal risks associated with recommendations fully understood and mitigated to the extent possible.

Environment:

a) Impact on the environment is considered. Decision to construct any facilities is subject to NEPA review.

b) Recommendations not in conflict with fish and wildlife goals, energy efficiency goals, renewable resource development, and climate change response policy.

Public Interest:

a) Customers, merchants, transmission providers, elected officials, other stakeholders and media perspectives understood and taken into account.

b) Provide enhanced ability for region to meet Renewable Portfolio Standards (if needed?);

c) Provide for wind diversity;

d) Provide regional benefits to customers and consumers in the BPA balancing authority and western interconnection.

BPA's People and Processes:

a) Demonstrated ability to carry out work necessary to complete NEPA and to construct projects in accordance with the capital program.

b) Acceptable impact on BPA people and culture objectives;

c) Supports Agency workforce/workplace goals for leadership, talent, motivation/alignment and positive work environment:

d) Recommendation consistent with BPA internal policies, procedures, and internal controls.

What are the risks to meeting the objective?

a) **RISK OF INABILITY TO COMPLETE NEPA AND DECISION WHETHER TO BUILD BY OBLIGATED DATE**: BPA might be unable to complete NEPA review and decide whether to build certain of the 2008 NOS projects or offer conditional firm service within the deadline in the PTSA. For the 2008 PTSAs, the NEPA review and decision whether to build the 2008 projects must be complete, or BPA must offer conditional firm service, by 36 months from the 2008 Rolled-In Rate determination, which is mid-February 2012. If BPA does not meet that deadline, a customer with a 2008 PTSA would have the right to terminate its agreement. The recommendation in this ADF to move forward with 2009 NOS TSRs that require projects that moved forward in the 2008 NOS relies on the assumptions underlying 2008 NOS decision, and termination of 2008 PTSAs could alter the assumptions upon which the 2008 rolled-in rate determination was based. For 2009 PTSAs, the NEPA review/decision to build deadline for 2009 TSRs is 39 months from the *2009* Rolled-In Rate determination, which would be approximately August 2013.

- There is LOW risk that NEPA review/decision to build will not be completed in 36 months of the 2008 NOS decision (or 39 months of the 2009 NOS rolled-in rate determination) for the Big Eddy-Knight and Central Ferry-Lower Monumental projects.
- The current schedule for the I-5 NEPA review provides for a final ROD after the mid-February 2012 deadline in the 2008 PTSA. There is a HIGH risk that the NEPA review and decision to build will not be completed for the I-5 project within that timeframe, but BPA has offered conditional firm service to certain customers that need the I-5 project (which satisfies the PTSA obligation) and expects to make additional conditional firm offers in the future. There is a low to moderate probability that at least one customer that has not been offered conditional firm service may terminate its PTSA for BPA's failure to complete NEPA on schedule. There is a MODERATE risk that the NEPA review and decision to build will not be completed for the I-5 project by the August 2013 deadline in the 2009 PTSA. BPA hopes to mitigate this risk by offering conditional firm service to customers, if possible.
- Mitigation: BPA hopes to make conditional firm offers to PTSAs needing the I-5 reinforcement within the decision to build deadline as identified in the PTSA (36 months for 2008 and 39 months for 2009) BPA has the conditional firm inventory to make these offers and expects to do so at this time.

b) **COMMERCIAL RISKS:**

- RISK OF DEFERRAL: Customers may elect to defer their service commencement date (start date) for up to five years. If the customer defers the commencement of service, BPA will extend the contract end date and the customer must still purchase transmission service for the full requested service duration. Deferrals result in delayed revenues to Bonneville. There is lower risk that deferrals will affect rates substantially with a higher probability that some deferrals will occur.
    - Mitigation: BPA will make the deferred capacity available on the ST market. History indicates that likelihood of ST sales is LOW.
    - Due to changes in PTSA language, BPA requires any deferring party for which a 'competitor' is identified to move up its commencement of service date to match the identified competitor. This may reduce the length of the deferral and thus reduce the length of time by which revenues are delayed.
- RISK OF ROFR AND SUBSEQUENT FAILURE TO RESELL CAPACITY: Customers may not roll over service at the end of their contract terms, which would reduce the total revenue assumed in the determination of NPV and rate impact. The base case analysis assumes that all contracts with a duration of five years or longer will roll over. There is LOW risk and moderate probability that one or more customers will choose not to roll over their contract at the end of the contract term.
    - Mitigation: A significant portion of the requested transmission service is associated with the interconnection of new generators. This increases the likelihood that transmission service will be acquired at least for the life of the generating facility. The average duration for all PTSA commitments is thirteen years. Sensitivity analysis has been conducted to evaluate impact that reduced rollovers would have on revenue.
- RISK OF CUSTOMER DEFAULT: Customers holding PTSAs could default which would impact future revenues. Security provided by customers under the PTSA and held by BPA was not designed to protect BPA ratepayers from rate impacts due to default and is not sufficient to do so. There is low risk for increased rate impact with high probability that at least one customer may default.
    - Mitigation: The amount of risk BPA ratepayers will bear is unique to each project, the number and diversity of customers that will take service over the projects, and the long-term financial viability of the participating customers. Some projects enable service for multiple customers over critical paths required for load service. Different paths have different likelihood of capacity being resold if a party does default. BPA would try to sell the capacity to another party if this situation arises.

c) **RISK FROM INACCURATE RESULTS FROM THE CLUSTER STUDY**:

- RISK OF INACCURATE ASSUMPTIONS: Cluster study planning analysis could include inaccurate assumptions, resulting in flawed identification of expansion facilities needed to enable service. Projects may not provide sufficient capacity to enable service. There is a LOW to MODERATE risk that the plans of service are inadequate with a LOW probability that service cannot be enabled.
    - Mitigation: External review by Columbia Grid and NTTG has confirmed that plans of service moving forward as a result of the 2008 NOS are electrically feasible, do not result in adverse consequences for the western interconnection, and will provide sufficient capacity to enable service. If the 2008 plans of service turn out to be inadequate, in the short term, BPA might need to authorize the associated TSRs anyway with a rise in risk of curtailments with all lines in service (There could be some ATC-associated issues in doing so). In the long-term, this risk could be mitigated with an additional build, which would require commitment of additional capital. There is also a major review of the current cluster study for both customer inputs and planning assumptions to assess opportunities to ensure the most accurate and up to date information is accessible and usable (see 2010 Cluster Study Assumptions ADF).

d) **RISK FROM EXTERNAL POLICIES**: External policies for reliability, and ATC could impact the way existing network facilities are managed, the availability of ATC, and the need and timing for proposed projects. There is LOW risk and low probability that policy changes will result in changes to the plans of service.

- Mitigation: BPA is an active participant in FERC, NERC, and WECC efforts to define new reliability and commercial rules for transmission management. While changes in criteria and process are inevitable, TS does not believe that any such changes will result in significant modification to the Cluster Study results. Furthermore, BPA has increased its coordination efforts with external parties in response to customer requests and internal strategy requirements.

e) **RISK OF CHANGING PROJECT COSTS**: Environmental review costs, material and commodity costs, and/or construction costs could change for the projects moving forward as a result of the 2008 NOS, resulting in a different rate impact than anticipated from those projects. If project costs increases there is a MODERATE risk with a high probability that the rate impact will be significantly higher.

- Mitigation: Business case process required for projects greater than $5 million to provide additional oversight and justification for projects.
- NOTE: Projected capital costs for the McNary-John Day project have been reduced by $87.7 million (original projection: $246.5 million; current projection: $158.8 million) so currently BPA is experiencing significant capital reductions associated with construction of the projects. In addition, BPA has not yet decided whether to construct the other projects that are currently undergoing NEPA review. When NEPA is complete, BPA will make a final decision whether to build those projects.

What are the existing controls?

- NOS Steering Committee – weekly meeting of oversight committee to review, address and act on any issue related to and/or potentially impacting the NOS process.
- Precedent Transmission Service Agreement – as filed and approved by FERC on August 18, 2009
- Transmission Services' Policy Forum – weekly meeting to introduce, review and provide guidance on issues impacting existing policies and/or creating new policies.
- NOS Bulletin – http://www.transmission.bpa.gov/includes/get.cfm?ID=1496
- BPA's OATT - http://www.transmission.bpa.gov/business/ts_tariff/

Alternatives and Evaluation

The Agency Decision Framework will consider three alternatives. The alternatives pertain to the 1,121 MW of TSRs that require construction of the projects moving forward from the 2008 NOS and the 114 MW of TSRs that require the Northern Intertie and West of Garrison reinforcements. No decision is required for the 293 MW that BPA can authorize without constructing new facilities and the 25 MW that Transmission Services determined were subject to direct assignment of the costs.

Alternative 1: TSRs requiring the West of Garrison Reinforcements move forward at Rolled-In Rates in addition to TSRs requiring the 2008 NOS Projects

- To accommodate 1 TSR totaling 14 MW (EX 5)
- 1,121 MW would move forward based on the 2008 projects

Alternative 2: TSRs requiring the Northern Intertie AND West of Garrison Reinforcements move forward at Rolled-In Rates in addition to TSRs requiring the 2008 NOS Projects

- To accommodate three (3) TSRs totaling 114 MW (EX 5 at 2 TSRs for 100 MW and EX 5 at 1 TSR for 14 MW)
- 1,121 MW would move forward based on the 2008 projects

Alternative 3: Only the TSRs requiring the 2008 NOS Projects move forward at Rolled-in Rates

- Accommodates 1,121 MW of TSRs under construction or environmental review that is already underway for 2008 NOS requests
- TSRs requiring the Northern Intertie and/or West of Garrison Reinforcements would not move forward at Rolled-In rates

Criteria (list the criteria and the name(s) of the SMEs consulted)	Alternative #1 WOG	Alternative #2 WOG + NI	Alternative #3 2009 TSRs Needing 2008 Projects	Explanation of Evaluation
Business/Finance				
• Effective queue management	Yes	Yes	Yes	NOS process enables effective queue management
• Creates new revenue	Yes	Yes	Yes	NOS process allowed authorization of 293 MW of new LTF service without new tx facilities and 1,121 MW using new tx facilities from 2008 NOS
• Passes the NPV test (CIFA)	No	No	N/A	See CIFA results above
• Within 2-3% rate impact threshold	Yes (1.5%)	No (5.3%)	Yes (relieves rate pressure created from 2008 NOS)	While Alt 1 met this criteria, it failed the NPV and cost/MW.
• Negligible/Low stranded investment	No	No	Yes	Plans of service are reliant on minimal number of customers increasing risk. If additional customers are included through future NOS or other processes this risk would be mitigated.
• Consistent with sound financial principles (cost/MW)	No ($27,000/MW)	No ($13,000/MW)	Yes	
• Enhanced system operation	Yes	Yes	No	Additional sales on existing facilities will bring increased congestion on the network.
• Reliability Benefits	No	No	Yes	No reliability benefits were identified for 2009 NOS by planning; however, reliability benefits exist for 2008 NOS facilities used by 2009 TSRs.
• Future load growth	No	No	No	
• Future commercial sales	Yes	Yes	Yes	
Legal				
• Consistent with Transmission policies	See attached legal analysis	See attached legal analysis	Yes	

Criteria (list the criteria and the name(s) of the SMEs consulted)	Alternative #1 WOG	Alternative #2 WOG + NI	Alternative #3 2009 TSRs Needing 2008 Projects	Explanation of Evaluation
• Consistent with the OATT	See attached legal analysis	See attached legal analysis	Yes	
Environment				
• Compliant with NEPA obligations	Yes	Yes	Yes	Assumes normal NEPA procedures will be followed
• Supports renewable resource development	Yes	Yes	Yes	The 2008 NOS facilities leveraged by the 2009 TSRs enable continued renewable resource development
Public Interests				
• Solicit and review customer/public comments on NOS process and results	Yes	Yes	Yes	No customer comments on the 2009 NOS recommendation were received.
• Support RPS requirements	Yes	Yes	Yes	Alternative 1 and 2 do not have any renewable generation associated with TSRs
• Promotes wind diversity	No	No	No	Proposed new facilities do not facilitate new wind resources nor do they expand geographic diversity of wind development for the 2009 requests/participants.
• Provides regional benefits	No	No	Yes	See REBA summary
BPA's People and Processes (e.g., potential work load, procedural, cultural and ethical impacts, etc.)				
• Able to complete NEPA and construct projects	Yes	Possibly Not	Yes	Increased workload associated with new plans of service can be addressed. For NI plan of service, NEPA process could exceed 39 month obligation in 2009 PTSA.
• Acceptable impact to staff and culture	Yes	Yes	Yes	Increased workload associated with new plans of service can be addressed.

Recommendation

Transmission Services recommends Alternative 3. Under this alternative, the TSRs from the 2009 NOS that require facilities under construction or undergoing environmental review as a result of the 2008 NOS would move forward at rolled-in rates. The TSRs that require the Northern Intertie and/or West of Garrison reinforcements would not move forward at rolled-in rates.

The TSRs that require the 2008 projects would provide additional revenues associated with those projects and allowing those TSRs should benefit both customers and BPA. The extremely high cost per megawatt, the limited number of customers and total megawatts, and the potential rate pressure associated with TSRs needing the Northern Intertie and West of Garrison reinforcements all indicate that transmission service could not reasonably be provided at Rolled-in Rates.

Document the Decision

The final decision will be communicated to customers that signed PTSA for the 2009 NOS by letter no later than May 31, 2010. A communication plan, internal talking points and notice of final decision will be prepared for distribution.

DECISION: On May 20, 2010, the Administrator concurred with the ADF recommendation of alternative 3 (see Recommendation above). The Decision Letter communicating this decision to the region went on TAC the afternoon of May 20 and is expected to be finalized under the Administrator's signature no later than May 27, 2010.

Implementation

Prepare and post a NOS 2009 decision letter (under the Administrator's signature) summarizing the 2009 NOS process including which TSRs require the 2008 NOS infrastructure projects that are moving forward either in construction or NEPA or that service for the TSR would require new infrastructure projects that BPA will not move forward at rolled-in rates (total of 3 PTSAs). The PTSAs associated with the projects not moving forward at rolled-in rates will terminate. BPA will then offer the TSR holders associated with the terminated PTSAs a NEPA agreement under OATT. The customer will then need to determine whether to move these projects forward at their own cost (i.e., whether to fund the NEPA and preliminary engineering work), or not. The performance assurance securing the terminated PTSAs will be promptly released to the customer. If the TSR holder does not sign and fund the NEPA agreement by the deadline, the TSR is put in final status and is no longer eligible for service. The customer may submit essentially the same TSR for participation in NOS 2010 if they wish to do so.

Attachment A - Legal Analysis
Attorney-Client Privileged
5-17-10

EX 5

2008 NOS projects moving forward at rolled-in rates cost per MW: approximately $1,070 per MW;
2009 NOS West of Garrison reinforcement cost per MW: approximately $27,000 per MW;
2009 NOS Northern Intertie reinforcement cost per MW: approximately $13,000 per MW.
(Information from slide 13 of CIFA presentation, updated April 22, 2009, available at http://www.transmission.bpa.gov/customer_forums/open_season_2009/NOS_2009_CIFA_4222010.pdf.)

[2] Federal Columbia River Transmission System Act, § 9, 16 U.S.C. §838g (2006).

EX 5

Agency Decision Framework: Central Ferry-Lower Monumental

The Issue:

In the 2008 Network Open Season (NOS), BPA selected to move the Central Ferry-Lower Monumental (CF-LoMo) transmission line project forward at rolled-in rates to respond to commercial development and demand. Since the determination was made, and in spite of the project's Record of Decision (ROD) being signed this last March, significant changes to market conditions have potentially delayed and/or reduced the commercial need for CF-LoMo. BPA is about to award additional construction contracts. At the same time, BPA is conducting additional analysis in assessing the projected timing between CF-LoMo (originally scheduled for 2013 energization) and the development of the associated generation (Pomeroy and Lower Snake Phases 2 & 3). The result of this analysis will provide BPA management with guidance on how to proceed with CF-LoMo.

1. Objective(s)?

Determine whether or not to award the construction contract for the Central Ferry-Lower Monumental transmission line project.

2. How does the objective connect to agency strategic direction?

- S4-Transmission Access & Rates: BPA provides open, non-discriminatory transmission services at rates kept as low as possible consistent with sound business principles and achievement of BPA's objectives. *The objective will consider potential stranded costs and other capital investments against projected service and associated revenue from the project that will impact transmission rates.*
- S6-Renewable Energy- BPA actively enables renewable resource integration and development through cost-effective, innovative solutions. *The project in question primarily supports the integration of large scale wind generation.*
- F2-Cost Recovery-BPA consistently recovers its costs over time. *The objective will consider projected service and associated revenue against the expected capital investments.*
- I7-Risk-Informed Decision Making & Transparency: BPA's processes, decision making and performance are transparent, risk-informed and based on structured analysis. *The objective considers risk and analysis associated with the current business environment (August 2011).*

3. Who is the decision maker(s)?

Decision Maker(s): Steve Wright (A), Brian Silverstein (T)
Transmission VP Sponsors: Larry Bekkedahl (TE), Cathy Ehli (TS), Hardev Juj (TP)
Team Members: Lauren Nichols-Kinas (TSP), Theresa Berry (TEP), Sean Egusa (TSP), Rebecca Fredrickson (TSPQ), Pat Rochelle (TPP), Anders Johnson (TP), Stephanie Konesky (LC), Nancy Mitman (FT), Toni Timberman (TSE), Angela DeClerck (TSE), Kurt Lynam (DKE), Michelle Whalen (DKE)

4. What is the context?

CF-LoMo, one of four rolled-in rate transmission expansion projects resulting from the 2008 NOS, is driven by new renewable generation development in the Lower Snake River area of Southeastern Washington. Two key customers anchoring the new transmission service provided for by the project include EX 5 are the two key customers anchoring the new transmission service provided by the project. Both very commercially and fiscally stable entities in the Northwest energy market.

In the 2008 NOS, the CF-LoMo project was estimated to have a direct cost of $99 M[1]. When evaluated against the 940 MW of subscribed service via Precedent Transmission Service Agreements (PTSAs) (850 MW provided new incremental revenue plus a 90 MW redirect resulting in no new incremental revenue), resulted in a 20 year average rate pressure of 1.11%[2]. Most of these PTSAs also require other 2008 NOS projects such as McNary–John Day (WOMR I) and Big Eddy–Knight (WOMR II).

All 850 MW of the new incremental transmission service is related to new wind development in a geographically diverse area[3] of the BPA Balancing Authority Area (BAA). In developing the CF-LoMo plan of service, BPA projected an energization of 2013 which took into consideration the expected completion dates of the Pomeroy and Lower Snake wind projects, their collector substations under the associated Large Generator Interconnection Agreements, and the Big Eddy – Knight project.

To date, the CF-LoMo project has passed all internal review and approval processes up to and beyond the signing of the ROD on March 18, 2011. This includes:

- 2008 NOS Rolled-in Rates Decision: On February 16, 2009, CF-LoMo was one of four new transmission expansion projects that the Administrator determined could move forward at rolled-in rates.
- NEPA and Preliminary Engineering Design (PED) capital spending was approved by the Capital Allocation Board (CAB).
- On March 14, 2011, CF-LoMo was brought before the CAB for review of its business case and authorization of capital required for construction. The final budget quality estimated direct cost for the project was $90.0 million. The project was approved, though the project team was asked to provide additional information on key milestones for Big Eddy –Knight and CF-LoMo, potential off-ramps and the consequences of cancelling the project, and identification of impacted customers.
- On March 18, 2011, a ROD was issued notifying the region with BPA's decision to build the CF-LoMo project.

Since the ROD was signed, the project has moved forward with an energization scheduled for 2013, however, there have been significant market condition changes. These include:

-]EX 5 associated Pomeroy generator interconnection facility (collector sub-station) is significantly delayed from its projected 2013 energization date. Updated projections now show a completion date for Pomeroy of 2016-17. Associated with 300 MW of PTSAs.

[1] Updated estimates for the business case as of March 14, 2011 are now $90 M.
[2] 2008 Network Open Season Agency Decision Framework, pg 8.
[3] Geographic diversity as a separate area from the Columbia gorge.

- EX 5 Phase 1, now under construction, requires an addition 93 MW of transmission starting in February 2012. BPA feels that it could offer conditional firm service to the first 100 MW of the remaining 550 MW of PTSAs that require only CF-LoMo. This action would allow PSE to acquire transmission rights for the full capacity of Phase I.
- The remaining 450 MW of PTSAs are associated with EX 5 Phase 2 and 3 of its Lower Snake wind project which have been delayed from its projected 2013 energization date. Updated projections now show a completion date of Lower Snake 2 of 2017 and a completion date of Lower Snake 3 of 2019.
- EX 5 also have PTSAs from the 2010 NOS that require CF-LoMo. However, their PTSAs require other 2010 NOS projects such as the Colstrip Upgrade that are not expected to be completed before 2016.
- California's April 2011 approval of new Renewable Portfolio Standards that are biased toward the development of within-California renewable resources.

Since the ROD was signed, BPA has made significant capital investments and contracted with third parties to enable the successful coordination and completion of CF-LoMo. In summary:

- BPA has spent:
  - Total capital commitment to date of $14.78 M.
    - $6.22 M in NEPA and Preliminary Engineering & Design (PED)
    - $1.75 M in land acquisition
    - $14.46 M in transmission line materials ($7.65 M could be transferred to the Big Eddy-Knight project)
  - Total performance assurance associated with 2008 PTSAs = $11.7M[4]
- BPA has committed to:
  - A lease-financing agreement for the project which, if there is a significant delay, could result in required interest payments against the Master Lease.
  - Shunt reactor payments (could be transferred to Big Eddy-Knight's Wautoma substation)
    - A $1.2 M payment for a shunt reactor in October 2011
    - A $1 M payment for a shunt reactor in July 2012.

Additional information about Generator Interconnections

EX 5 Lower Snake Wind Project:

- Interconnecting to BPA's new Central Ferry 500/230 kV Substation (1250 MW capacity, $102 million advance funded by EX which is scheduled for completion in December 2011. The Lower Snake Wind Project Phase I, 343 MW, is scheduled for commercial operation by April, 15, 2012. BPA was able to authorize 250 MW of PTSAs without additional transmission reinforcement, while the remaining 93 MW requires CF -LoMo.
- BPA's Tiered Record of Decision for EX 5 generator interconnection (1250 MW) was signed in January 28, 2010. At that time, EX was awaiting Conditional Use Permit for 500 MW in Columbia County.
- A Large Generator Interconnection Agreement (LGIA) was executed May 13, 2010 for 750 MW, pending EX eceipt of the permit from Columbia County which they subsequently received in October 2010. EX has been requesting an LGIA for the remaining 500 MW and when BPA tenders this LGIA, PSE will have a total of 1250 MW interconnection capacity at Central Ferry
- Approximately $100 million of the advance funded facilities have been identified as Network Upgrades that qualify for Large Generator Transmission Credits. These credits will be applied to EX 5 transmission service from Central Ferry.

EX 5 Project:

- EX 5 has two generator interconnection requests (Pomeroy), for a total of 504 MW, proposed to interconnect at Central Ferry Substation. These requests are in the facility study review stage of the Large Generator Interconnection Procedures.
- They have PTSAs totaling 300 MW in support of this project.
- Currently, there is not certainty in the LGIA with regard to the schedule for completion of the interconnection facilities.

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[4] EX 5 has another $7.5 M in performance assurance for its 430 MW pending the completion of CF-LoMo and CUP West.

- An agreement with state of Washington's Department of Natural Resources (DNR) to complete construction across its lands within five (5) years from the signing of the agreement (to date, the agreement has not yet been signed) but with an opportunity to extend.
- A Memorandum of Agreement (MOA) with the State Historical Preservation Office (SHPO) and the tribes through May 2015[5].

BPA will take receipt of the initial order of materials on September 15, 2011 (drillage, plates & bolts). These materials are being considered for transfer to Big Eddy-Knight. In addition, there are scheduled capital investments as follows:

- $11.32 M[6] award scheduled for 8/26/11
- $19.02 M award scheduled for 2/1/12

If BPA delays the project and restarts at a later date, it would expect to incur additional costs related to material storage, although inflation in material prices if purchased later would offset a portion of the storage costs. Assuming a 1.8% annual inflation rate and $75.22 M in remaining costs to complete the project ($90.0 less 14.78 M); the expected impact of inflation would be $1.35 M per year of delay.

External Stakeholders	What They Want	What They Will Resist
EX 5	Any negotiated action that allows them to push out the current start date without incurring financial penalties (i.e. deferral charge). In fact, EX 5 may be willing to give up deferral rights as part of a negotiated delay. EX 5 strongly stands behind its contractual obligation with BPA and continues to see future value in the TSRs as they develop additional phases of their wind project at Lower Snake. EX 5 desires notification of the energization date and requests flexibility to respond to opportunities to market later project phases. EX 5 has stated support for a delay through 2015. That said, EX 5 would like the ability to give BPA a one-year notice to start the project on an earlier schedule.	Indefinite delay that does not consider timing of their resource development Cancellation of the project. Negative impact of project deferral on EX 5 projections for growth. Any softening of BPA's support for renewable resource integration.
EX 5	Any negotiated action that allows them to push out the current start date without incurring financial penalties (i.e. deferral charge). EX 5 has provided BPA with scenarios that include both delay and/or termination	Any action that requires them to give up their ability to defer service. From their comments: "…it is likely that EX 5 would exercise its OATT section 17.7 rights on a significant portion of the service that is not

[5] Associated with the construction schedule.
[6] This award was delayed on …..

Agency Decision Framework: Central Ferry-Lower Monumental

External Stakeholders	What They Want	What They Will Resist
	of some or all of their PTSAs. EX 5 is receptive to a delay through 2015.	currently effective, up to all such amounts for the maximum 5-year period." Any softening of BPA's support for renewable resource integration.
EX 5	A Power Purchase Agreement CF-LoMo is not delayed beyond CUP West. Coordinate timing of energization	Cancellation of CF-LoMo which is required for service associated with CUP West.
Rate payers	Equitable recovery of cost consistent with the original CIFA with minimal impacts to transmission revenues or other financial risks that would eventually impact rate payers.	Rate impacts higher than demonstrated in the 2008 CIFA (higher than 2%).
Washington state delegation	BPA to invest in local economies to create job growth, spending, etc.	Delay or cancellation of project-related economic benefits.
Wind, renewables, public interest community	Want BPA to be creative and flexible in accommodating needs of wind developers and working with them in a collaborative way. They want BPA to take some risks in supporting wind development. Some may attempt to leverage this delay as somehow being caused by BPA's ER policy.	Termination of the project. Also would resist the characterization of any delay as showing a "problem" with wind—they would argue that any project can have unforeseeable delays, this isn't a wind issue.
Tribes	The tribes would like us to either build the line and proceed with implementing the MOA or not build the line at all.	Delay of the project. Tribes may not be open to renegotiating the MOA. They will resist BPA not fulfilling our obligations stated in the MOA.
Department of Archaeology and Historic Preservation	Timely and thorough compliance, consultation, and mitigation related to the National Historic Preservation Act. DAHP does not want to be pushed hard to proceed through the Section 106 process just to have the project delayed. The process to obtain the MOA for CF-LM has harmed our relationship with DAHP and that is already having an effect on numerous other transmission project timelines, including BE-K.	Delay of the project. DAHP may not be happy when after pushing them to the limit to obtain the MOA we delay the project. Reopening consultation and renegotiating the MOA may also be very difficult.

Internal Stakeholders	What They Want	What They Will Resist

Internal Stakeholders	What They Want	What They Will Resist
Project Management	To maintain terms of the CF-LoMo ROD and to build the project on schedule. And, to that end, make appropriate construction awards to vendors. Minimize impacts to competing resources.	Any increased material costs, restarting or cancellation of project and any impediment to the continuation of land acquisition.
TSP/LT	Maintain consistency with the terms and obligations in the PTSA.	Any action that is inconsistent with or deliberately conflicts with the terms and obligations of the PTSA.
TSE/TSP	To ensure that commercially-driven projects are aligned with associated market need such as generator interconnection projects.	Proceeding ahead with builds that are misaligned and/or mistimed with associated generation development.
EX 5 EX 5	EX 5 EX 5 is neutral and could potentially terminate this request. The impacted reservation is a redirect from "Stateline" to "LGS to John Day Intertie". Because this a redirect request of PTP transmission, this is associated with EX 5 activities, and does not result in incremental transmission revenue. BPAP will continue to redirect on a short-term basis our "Stateline" reservation (90 MW) to other Network PTP paths, when needed for EX 5 surplus deliveries and obligations.	EX 5 EX 5 does not want this PTP Redirect to drive the project. The requested service will provide additional flexibility to the EX 5 EX 5 and will not impact EX 5 ability to meet its obligations (i.e. NT service).
Supply Chain	Maintain BPA's reputation as a reliable business partner in contracting for materials and services.	A decision not to award without a valid reason.

5. What are the decision evaluation criteria?

Business/Finance

a) Minimize stranded investment risk
b) Provides least cost Net Present Value (NPV)
c) Consistency with BPA's financial targets and rate case assumptions.
d) Considers relationship between transmission and generator interconnection requests.
e) Avoids cost shifts
f) Acceptable upward rate pressure
g) Reliable operations of the FCRTS.

Legal:

a) Consistent with applicable statutes, ROD, OATT and PTSA terms.

Environment:

a) Recommendations not in conflict with fish and wildlife goals, energy efficiency goals, renewable resource development, and climate change response policy.

Public Interest:

a) Customers, rate payers, transmission providers, elected officials, other stakeholders and media perspectives understood and taken into account.

b) Recommendation shows collaborative approach and flexibility in working with wind developers. Recommendation does not significantly delay commitments to new renewable resource development. Recommendation does not "blame wind".

c) Recommendation recognizes immediate financial impact on contractors, vendors and merchants of project-related services and products.

d) **Tribal Interest:** Recommendation considers current Cultural resources MOA between the NPT, the CTUIR, the Washington Department of Archaeology and Historic Preservation, and the Advisory Council on Historic Preservation assumes currently scheduled energization date and would have to be renegotiated if this was missed. Cultural resources MOA will be terminated May 2015 if the transmission line is not energized by this date and would have to be renegotiated (which would be difficult to do.)

e) **Washington Department of Archaeology and Historic Preservation Interest:** BPA has "burned a few bridges" as a result of working through the 106 process. This relationship issue is having an effect on numerous other transmission project timelines, including BEK. Not only will the MOA (see above) "expire", but BPA has committed to mitigation actions that are intended to occur over the next 4 years. By delaying building or not constructing at all, we will not be fulfilling this agreement. This as a potential concern for the tribes.

BPA's People and Processes:

a) Demonstrated ability to carry out work necessary to complete NEPA and to construct projects in accordance with the capital program.

b) Acceptable impact on BPA people and culture objectives;

6. What are the risks to meeting the objective?

<u>Legal Risk</u>

1. Risk that PTSA obligations are not met:
   - Need to ensure appropriate coordination and communication with customers who have signed and secured PTSAs. There are additional actions outlined in the PTSA, such as conformance of the TSR after the signing of the ROD that could be impacted by any decision to delay. BPA is currently in active discussion with all associated PTSA signers.
2. Risk that decision is inconsistent with CF-LoMo ROD:

- ROD was signed on March 18, 2011 and states that "BPA has decided to construct the proposed [PROJECT]." Need to ensure that the decision from this ADF is consistent with the terms of the ROD. All current alternatives are consistent with maintaining a "decision to build" and only the timing of the start of construction is at question.

Project Management Risk

- Risk of increased project costs if any changes to current schedule:

Financial Risk

1. Risk associated with lease financing terms:
2. Risk of higher credit repayment associated with generator interconnection investments:
   - Approximately $100 million of the advance funded facilities have been identified as Network Upgrades that qualify for Large Generator Transmission Credits. These credits will be applied to PSE's transmission service from Central Ferry.
3. Risk of stranded costs

Additional Risks

1. Risk of mis-timing coordination between PTSA reform and project construction timeline.
2. Risk of negative impacts to Big Eddy-Knight:
   - The status of CF-LoMo poses no significant risk to the use of or financial analysis for the Big Eddy-Knight project.
3. Risk of negative impacts to CUP West:
   - The project timeline for CUP West, originally scheduled for 2015 energization, is currently being re-evaluated. Current estimates indicate that 2016-17 may be a more realistic energization date. However the case may be, CF-LoMo is necessary for CUP West to provide service for the demand from the 2010 NOS. Therefore, if the delay is longer than 4-5 years, the impacts to the CUP West project and associated demand needs to be considered.

Risk Map

Abbrev.	Risks
Costs	Increased costs due to delayed construction
Rates	Stranded investment if generation projects aren't built and CF-LoMo isn't needed
Customer	RPS not met, generation not able to get to market
Vendor	Competition with other transmission project demands
Legal	Inconsistent with PTSA & ROD

Likelihood of the Event

Almost Certain	**5**			Costs #2	Costs #3 Legal #3	
Likely	**4**		Rates #1	Vendor #1 Vendor #3		
Possible	**3**		Rates #2	Customer #3		
Unlikely	**2**		Rates #3 Vendor #2			
Rare	**1**	Costs #1 Customer #1 Customer #2 Legal #1	Legal #2			
		1 **Insignificant**	**2** **Minor**	**3** **Moderate**	**4** **Major**	**5** **Catastrophic**

Severity of the Consequence

7. Alternatives and Evaluation

Alternative # 1 – Status quo - proceed with award of the CF-LoMo construction contracts on 8/26/11.

Alternative # 2 – Do not award the CF-LoMo construction contracts on 8/26/11. Allow additional time to work with customers to understand reform of existing PTSA agreements and make a decision whether or not to delay the project.

Alternative # 3 – Do not award the CF-LoMo construction contracts on 8/26/11. Decide now to delay the CF-LoMo project.

Criteria	Alternative #1 Award the contract	Alternative #2 Do not award	Alternative #3 Decide to delay
Business/Finance			
• Low stranded investment risk	Highest risk of stranded investment given unknowns around associated GI	Mitigates risk as better alignment with customer needs	Lowest risk as best alignment with customer needs and potential to guide projected capital spend on CUP West.
• Least cost NPV	Low risk	Increased risk	Increased risk
• Aligns with customer, market and business landscape.	Not aligned. However, once built, additional capacity could be marketed.	Better alignment but not ideal solution as would still come in 2 to 3 years earlier than earliest projected need.	Opportunity to align Pomeroy, Lower Snake and CUP West timing.
• Avoid cost shifts	Yes	Cost shifts due to conversion of capital to expense most likely avoided – see Alternative #3 for additional information.	A project generally has a two year window before expenses that are accounted as capital can roll over to expense if the capital project does not proceed. The current spend of $14.78 M, if expensed, would result in a 1-2% rate impact over a two year rate period (no long term impacts).
• Acceptable upward rate pressure of 1.11% as presented in 2008 NOS decision	0.2% rate pressure (TSPQ) recalculation including demand that requires other 2008 NOS projects such as WOMR (550 MW)	Ran sensitivity to test rate pressure considering a two year delay, a reduction in demand (including zero CUP West demand) and exercise of deferrals on 450 MW of PTSAs for two years. Sensitivity equated to a 0.5% upward rate pressure for all-NOS projects resulting in an overall -7.0% downward rate pressure.	Additional analysis required.
• Reliable operations of the FCRTS: "In the absence of any new generation in the Lower Snake or Montana areas, TOT does not have an operational need for CF-Lo Mo."	CF-LoMo would not provide significant operational benefits until additional generation is built in the respective areas.	Improved timing with operational needs as the associated generation could begin to materialize as early as 2015 (but more than likely would be delayed until at least 2016).	Best market intelligence indicates new generation would not be added until 2016 and beyond.
Legal			

Criteria	Alternative #1 Award the contract	Alternative #2 Do not award	Alternative #3 Decide to delay
• Consistent with PTSA	Consistent with the PTSA Energization date will be known to provide notice to customer by 2/16/12	Consistent with PTSA as long as BPA is able to provide customers with an energization date by 2/16/12	Inconsistent with PTSA. Unlikely that energization date will be known to provide notice to customer by 2/16/12. Provides potential for customers to shorten service duration by any "unprojected" delay.
• Consistent with ROD	Yes	CF-LoMo ROD makes decision to build and does not provide for the need for additional considerations or reevaluation	CF-LoMo ROD makes decision to build and does not provide for the need for additional considerations or reevaluation. Poses greater risk that environmental analysis would need to be updated prior to construction.
Environment			
• No conflict with renewable resource development	Maintains demonstrable support of renewables. Provides for geographic diversity of wind fleet.	Maintains demonstrable support of renewables Provides for geographic diversity of wind fleet.	May raise doubts concerning BPA's commitment to and support of renewable development.
Public Interests			
• Stakeholder perspectives, including customers', understood and considered	Low risk	Low risk if timely outreach messages delivers carefully aligned messages.	Increased risk BPA is seen as lacking competence in long term planning, or is unable to deliver on its commitments.
• Constituent perspectives understood and considered	Low risk	Risk that BPA is seen as delaying renewables development if coordination of construction schedules is not understood	Risk that BPA is seen as abandoning its commitment to support renewable energy development and corollary impacts to Montana wind development

Agency Decision Framework: Central Ferry-Lower Monumental

Criteria	Alternative #1 Award the contract	Alternative #2 Do not award	Alternative #3 Decide to delay
• Tribes: Nez Perce Tribe (NPT) and Confederated Tribes of the Umatilla Indian Reservation (CTUIR)	Cultural resources MOA proceeds as negotiated; no risk to relationship.	Cultural resources MOA between the NPT, the CTUIR, the Washington Department of Archaeology and Historic Preservation, and the Advisory Council on Historic Preservation will be terminated May 2015 if the transmission line is not energized by this date. If the project is delayed 2 years, we may need to "reopen" the agreement document and go back out to our consulting parties. The existing agreement was difficult to obtain.	Frustration among the parties who negotiated the MOA; perception that the work and compromises involved in getting the MOA were not worth it. Potential skepticism about future MOA negotiations – is BPA really serious about this project? Is it worth tribes' spending their limited resources on reviewing projects that may not materialize? Potential relief that the line will not be built and thus will not impact tribal cultural and natural resources.
• Wind, renewables, public interest community	Risk that BPA is seen as not being creative nor collaborative with needs of wind developers	Risk to BPA that some will use delay as grounds for attacking BPA's ER policy.	Risk that BPA is seen as abandoning its commitment to support renewable energy development and corollary impacts to Montana wind development
• Financial impact on contractors, vendors, merchants.	Immediate, positive impact	Low risk. Positive impact delayed but likely to occur in foreseeable future.	Increased risk. BPA viewed as not supporting economic recovery in the region.
BPA's People and Processes			
• Construct in accordance with capital program	No impact to capital program. In Fy12 budget.	Reduction in capital spending could benefit FY12 but could negatively impact FY13 budget.	There could be expense implications and furthers budget constraints associated with capital spend.
• Acceptable impact to BPA people	No Impact	Some impact.	Increase risk of significant if significant delay.
Project Management			
• Minimal impact to BPA vendors depending on project retaining status quo for jobs and economy.	No Impact to relationships with vendors.	Potential negative impacts to relationships and future costs associated with vendors. Probable loss of credibility for BPA and its bidding process.	Potential negative impacts to relationships and future costs associated with vendors. Higher probability of loss of credibility for BPA and its bidding process.
• Ability to maintain terms and meet deadlines of third party agreements (i.e. SHPO & DNR)	No impact	Minimal impact	Potential significant impacts if construction not completed by 2015.

Agency Decision Framework: Central Ferry-Lower Monumental

Criteria	Alternative #1 Award the contract	Alternative #2 Do not award	Alternative #3 Decide to delay
• Ability to order and receive required materials required for project (substation and line).	Status of the BE-Kn project's schedule could impact ability to order and receive remaining materials.	Reduction of potential conflicts primarily associated with Big Eddy-Knight	Possible conflicts associated with additional major transmission projects currently being studied (i.e. I-5)
• Material and labor cost escalation is mitigated.	No impact	Recent procurements have indicated a likely risk of 10% increase in material costs. Labor costs could increase up to 10% but at least by rate of inflation.	Recent procurements have indicated a likely risk of 10% increase in material costs. Labor costs could increase up to 10% but at least by rate of inflation.

8. Recommendation

Alternative 2: Do not award the contract and provide more time to evaluate the situation. Allows BPA the flexibility to rebid the contract after we gain certainty with customers on the PTSAs.

9. Document the Decision

C:\Documents and Settings\sre2326\My Documents\CF-LoMo ADF\ 08 22 11 CF-LoMo ADF (FINAL).doc

10. Implementation

Under the recommended alternative, BPA will move forward as follows:

- Not award the construction contract on August 26, 2011 to the notified vendor.
  - Supply Chain will notify the vendor by COB 8-26 that BPA will cancel the RFO and any issued contract.
  - Supply Chain will work with Transmission regarding the disposition of materials on order for CF-LoMo, their diversion to other projects, long term storage, etc.
- BPA will conduct a review of the PTSAs as part of the PTSA reform initiative.
- Upon completion of the PTSA reform and when the associated demand (MW) is clearly understood, BPA will review the business case and timing of CF-LoMo.
- Public Affairs will develop a communication plan in coordination with TS and TE.