Economic Assessment of RTO Policy

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Executive Summary

This study was commissioned by the Federal Energy Regulatory Commission (FERC or the Commission) to examine potential economic costs and benefits of a move toward Regional Transmission Organizations (RTOs). RTOs are intended to improve the operation of the nation's electric power system in a number of ways. The FERC issued Order No. 2000 to promote the formation of RTOs in all areas of the country.

The Commission stated that properly functioning RTOs could provide several types of economic benefits:

- Improvements in transmission system operations with resulting enhancements to inter-regional trade, congestion management, reliability and coordination; and
- Improved performance of energy markets, including
  - Greater incentives for efficient generator performance; and
  - Enhanced potential for demand response.

These changes to the regulation and operation of the electric power system would, according to the Commission, also lead to a reduced need for intrusive government regulation.

By identifying a set of potential changes to the operation of the electric power system, and resulting economic performance, this study seeks to be both comprehensive and rigorous, employing sufficient quantitative detail to accurately represent potential outcomes of RTO policy. Close collaboration with the Commission and cooperative efforts with other researchers and state regulators were an integral part of the scenario development process, resulting in an analysis that attempts to estimate a range of potential economic impacts using the best available information from a variety of sources. The potential benefits of RTOs are considered as are the tradeoffs involving RTO startup costs and the potential for regional cost shifting.

Under the set of assumptions analyzed regarding the effect of RTO formation on electric power markets, including the establishment of consistent and effective market rules, substantial net benefits should result from the Commission's policy. Once policy changes are fully in place the results suggest that $1-10 billion per year in economic gains could result. These estimated benefits do not take into account secondary economic impacts ('spillovers') or employment gains.

Table ES-1 shows the total system production cost changes from the Base Case (status quo or no-action case), in millions of year 2000 dollars, as well as the twenty-year net present value for each scenario.

Table ES-1: System-Level Production Costs for Regulatory Scenarios (Million 2000$, NPV in Billion 2000$)

	2004	2006	2010	2015	2020	NPV[1] 2002 - 2021
Base Case	**89,493**	**94,161**	**109,489**	**129,374**	**149,758**	**1,076.8**
RTO Policy Case	**88,414**	**91,972**	**104,254**	**123,057**	**142,289**	**1,035.9**
Savings from Base	***1,080***	**2,189**	**5,235**	***6,318***	***7,470***	***40.9***
% Savings From Base	***1.2%***	***2.3%***	***4.8%***	***4.9%***	***5.0%***	***3.8%***
Transmission Only Case	**89,089**	**93,805**	**108,723**	**128,568**	**148,468**	**1,070.6**
Savings from Base	***405***	***356***	***767***	***806***	***1,291***	***6.2***
% Savings from Base	***0.5%***	***0.4%***	***0.7%***	***0.6%***	***0.9%***	***0.6%***
Demand Response Case	**88,343**	**89,997**	**101,941**	**120,451**	**139,361**	**1,016.8**
Savings from Base	***1,150***	***4,164***	***7,548***	***8,923***	***10,398***	***60.0***
% Savings from Base	***1.3%***	***4.4%***	***6.9%***	***6.9%***	***6.9%***	***5.6%***

The scenarios analyzed in this study were developed using assumptions that come from previous analyses of these topics and from estimates based on available data. While it is important to recognize the uncertainty of these estimates, these estimates are not necessarily optimistic or upper bound estimates. Several key assumptions are actually conservative in the policy scenarios, and further sensitivity analysis would be required to estimate a true upper bound on the potential economic benefits of RTO policy.

Within the range of costs and benefits estimated here, a key finding is that the net benefits of RTO policy will depend on the effective and timely implementation of competitive electric power markets, and on minimizing delays and excessive startup costs. While the size of RTOs does matter given the set of analytic assumptions used, the size and configuration of RTOs matters less than the dominant impact of enhanced incentives for efficient market outcomes. This assumes that consistent and effective market design is put in place throughout the country.

Table ES-2 shows the results of two sensitivity cases developed to represent a smaller number of relatively large RTOs, as compared to a larger number of relatively small RTOs. The difference in production costs between these two cases is generally between $100-300 million per year, yielding an overall change in net present value of $1.2 billion over the study's time frame. To the extent that a clear link can be established between RTO scope and competitive market effectiveness, the benefits of larger RTOs would be more significant.

1 Net present value calculated using a 6.97% discount rate.

Table ES-2: Larger and Smaller RTO Sensitivity Cases (Million 2000$, NPV in Billion 2000$)

	2004	2006	2010	2015	2020	NPV[1] 2002 - 2021
Larger RTOs	**88,301**	**91,893**	**104,185**	**123,000**	**142,190**	**1,035.4**
Savings from Base	***1,192***	***2,267***	***5,304***	***6,374***	***7,568***	***41.4***
% Savings from Base	***1.3%***	***2.4%***	***4.8%***	***4.9%***	***5.1%***	***3.8%***
Smaller RTOs	**88,452**	**92,031**	**104,319**	**123,192**	**142,368**	**1,036.6**
Savings from Base	***1,041***	***2,130***	***5,171***	***6,182***	***7,390***	***40.2***
% Savings from Base	***1.2%***	***2.3%***	***4.7%***	***4.8%***	***4.9%***	***3.7%***

Costs of RTO formation are also uncertain. A central low cost estimate of $1 billion and a central high cost estimate of $5.75 billion are developed in the study report. These costs can be allocated as one-time, single year costs or amortized over time, and netted out against estimated benefits for a net economic impact estimate. Although the exact magnitude of costs and benefits is uncertain, the range estimated here yields a positive net benefit from pursuing RTO policy even if benefits are relatively low and costs are relatively high.

While there is a consistent national net benefit from RTO policy, as measured by total production costs, a more complex result arises when energy price impacts are considered on a regional level. Most regions are expected to experience price decreases when inter-regional trade increases under RTO policy. However, some regions show transient price increases that last a few years, followed by decreasing prices over time, and a few regions appear likely to experience increased energy prices for a prolonged period. The region with the greatest price increase in any one year in these results is the ILMO (downstate Illinois and Missouri) region where prices in one case rise 8% in 2006, while Montana and parts of the interior West show the most persistent, albeit small, price increases. In the Northeast there are similar small and transient price increases in portions of PJM.

An important limitation of this study involves short-term market imbalances and market power. The national scope and long time frame required for this analysis precludes a direct representation of inefficiencies that can result from poor market design, transient supply-demand imbalances, and systemic or episodic market power abuses. Some portion of the potential benefits of RTO policy could be lost if policy implementation fails to successfully address these issues.

In summary, this study cannot eliminate uncertainty regarding the ultimate outcomes of Commission policy on RTOs. It is intended to place such uncertainty into a quantitative context, to provide perspective, and to draw broad conclusions about the likely net economic impacts of changes in the national electric power system. On balance, the analysis conducted here suggests that a move toward RTOs, if it results in improved market operations, can deliver $1-10 billion dollars in long term annual savings. It is likely that larger RTOs would lead to slightly greater benefits, and that regional energy price impacts will vary, with most regions seeing price decreases.

The increased inter-regional trade that leads to regional variations in price impacts also leads to regional variations in export revenues and producer earnings. Regions with higher prices due to increased exports also gain revenues from the exports. This increase in regional power revenue, in the immediate form of producer earnings, raises issues of equity and distribution that go beyond this report's scope. Finally, it is also important to note that the changes in energy prices estimated here are wholesale energy prices; the ultimate consumer price impacts will be mediated by regulation, contract treatment, and other institutional mechanisms.

1 Introduction

The Federal Energy Regulatory Commission (FERC) commissioned a national cost/benefit study of regulatory policy concerning Regional Transmission Organizations (RTOs). This report is the main summary of the context, methods, and results of the cost/benefit analysis, carried out by ICF Consulting for the FERC.

1.1 Study Overview

The Commission's RTO initiative is part of a broader move toward more competitive energy markets. Because electric power must be transported using a single integrated transmission grid, the operation of transmission systems plays a direct role in how electric power is produced and used. The design of the transmission system can set economic incentives and physical limits that influence the operation of power plants. In addition, the establishment of centralized, independent market operators is a key element in the creation of competitive supply markets. The tight linkage between real-time operating decisions and economic outcomes enhances the importance of FERC policy regarding the structure, ownership and control of the interstate transmission system.

The US electric power sector is a critical element of the national economy. Regulatory policies affecting this sector can have large, long-term impacts that affect the entire country. This in turn requires regulatory analysis that is both national and long-term. The methods used in this study for the FERC reflect this, primarily through the use of dynamic computer simulations that forecast power system changes and economic outcomes under differing conditions. This methodology enables a detailed quantitative assessment of potential costs and benefits over long periods, taking into account interactions between power, fuel and environmental markets.

Previous analyses conducted by ICF at the FERC's direction include the Environmental Impact Statement for Order No. 888 in 1996 and the Environmental Assessment for Order No. 2000 in 1999. These were also national, long run analyses that relied on computer simulation modeling as an analytic method. This economic analysis of RTO policy, while sharing the geographic scope and time frame of previous FERC studies, considers a different set of substantive issues. Economic cost/benefit analysis requires broader consideration of the purpose and possible outcomes of FERC policy beyond environmental impacts to include, for example, the costs of supplying power, the relative prices of that power, inter-regional trade patterns and other changes to the operation and economic performance of the power system.

In conducting this study, existing data and previous research were relied on as much as possible. One purpose of this report is to place the results of this study in the context of related work, and to allow for comparisons when possible. By focusing on methods and data sources, the key factors that drive the results of different analyses can be determined. This can aid in an overall understanding of how regulatory policy may affect economic outcomes in the electric power sector.

Throughout this report, emphasis is placed on uncertainty and the role of multiple factors that, taken together, may result in differing degrees of change in economic outcomes. While this report cannot create certainty regarding regulatory impacts, it does attempt to explain the range of potential outcomes and quantify the importance of specific changes that may result from RTO policy.

The report is organized into three main sections. Section I describes the regulatory context, related work, and the basis for the analytic approach employed for this study. The second section details the analytic approach, including the role of simulation modeling, the specific model used, scenarios and assumptions. Section III presents results, both from the simulation model and integrated quantitative analysis that includes several important elements that were not directly represented in the model.

1.2 Regulatory Context

The regulatory policy being considered in this cost/benefit study is primarily embodied in the Commission's Order No. 2000. However, there are a number of FERC orders and actions that are related to RTO policy, as well as ongoing fact-finding and research. Commission staff and other parties have continued to learn about and respond to changing conditions in the electric power sector. This section of the report presents the regulatory context and the specific potential benefits that led the FERC to issue Order No. 2000. Subsequent Commission findings are also summarized, including the order that called for the present study to be carried out for the Commission. This regulatory context is the starting point for the choice of analytic methods, as discussed in the next section.

1.2.1 Basis for Current RTO Policy[2]

The movement toward more competitive energy markets has been underway for several decades, marked by such major developments as the Natural Gas Act and the Public Utilities Regulatory Policy Act in 1978, and the Energy Policy Act in 1992. Successive Administrations and Congresses have considered the issues involved in energy market restructuring on an ongoing basis during this period. The role of the transmission system has long been recognized as being of critical importance for the performance of energy markets. This has highlighted the role of the FERC in its oversight of interstate wholesale power markets.

FERC policy regarding the control and operation of the transmission grid has evolved over time, as shown most clearly in Order No. 888 in 1996 and Order No. 2000. In discussing the basis for the current policy on RTOs, the Commission provided economic rationales that describe a number of mechanisms connecting RTO policy to potential

[2] Excerpts from FERC Order No. 2000 Notice of Proposed Rulemaking (NOPR). Docket No. RM99-2-000. All parenthetical pages quotes refer to this edition.

changes in economic outcomes in the US electric power sector. The Commission's regulatory discussion provides the starting point for this cost/benefit assessment.

This section of the report relies on the FERC Order No. 2000 language in order to clearly establish the economic issues involved in evaluating RTO policy. Later sections of the report discuss the analytic approaches adopted for consideration of the specific issues raised (and several additional topics that are also relevant for a full economic cost/benefit assessment). Relying on the Commission's regulatory discussion in Order No. 2000 to frame the economic issues provides a consistent context and ensures that relevant economic issues are considered even when they are less well-suited for the types of quantitative assessment normally employed in analyses of this type.

The basis for current RTO policy is described by the Commission in the following terms (in the context of then-existing policies under Order No. 888):

"In 1996 the Commission put in place the foundation necessary for competitive wholesale power markets in this country -- open access transmission. Since that time, the industry has undergone sweeping restructuring activity, including a movement by many states to develop retail competition, the growing divestiture of generation plants by traditional electric utilities, a significant increase in the number of mergers among traditional electric utilities and among electric utilities and gas pipeline companies, large increases in the number of power marketers and independent generation facility developers entering the marketplace, and the establishment of independent system operators (ISOs) as managers of large parts of the transmission system. Trade in bulk power markets has continued to increase significantly and the Nation's transmission grid is being used more heavily and in new ways." (NOPR at 5) "Our objective is for all transmission owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate regional transmission institutions in a timely manner." (NOPR at 6)

"In April 1996, in Order Nos. 888 and 889, the Commission established the foundation necessary to develop competitive bulk power markets in the United States: non-discriminatory open access transmission services by public utilities and stranded cost recovery rules that would provide a fair transition to competitive markets." (NOPR at 14)

Prior restructuring efforts, according to the Commission, left important concerns unresolved and also led to the emergence of new issues. "In light of our experiences with ISOs and other utility restructuring activity in the aftermath of Order Nos. 888 and 889, and after almost three years of experience with implementation of Order Nos. 888 and 889, we believe that there remain important transmission-related impediments to a competitive wholesale electric market." (NOPR at 36-37) Order No. 2000 discusses the current situation in which these problems are attributed to:

1. The decentralized industry decision-making structure and the inefficiencies that come with it;
2. Relatively high and volatile capacity flows across the system due to the leap in wholesale energy trading since Order No. 888; and

3. The persistence of the potential for market power abuses in the regional generation markets due to both concentration of incumbent utility's generation assets and the potential for abuse the utility has, as manager of the transmission system, to favor its own units for dispatch over that of competitors.

The Commission discussed these problems in greater detail:

Reliability

"It is well accepted that the operation of interconnected transmission networks requires careful coordination and the exchange of information between many individual systems." (NOPR at 43) "At present, the industry's ability to maintain reliable grid operation is hindered by the existence of many separate organizations that directly or indirectly affect the operation and expansion of the grid. There are more than 100 owners of the Nation's grid who operate about 140 separate control areas. In addition, there are 10 regional reliability councils, 23 security coordinators, 5 regional transmission groups (RTGs) and 5 independent system operators. With so many entities, the lines of authority and communication are not always as clear as they should be. An additional complication is that many of these entities also own generation or have a decision making process that continues to be dominated by traditional vertically integrated utilities. Therefore, their independence and commercial neutrality as grid operators is subject to question." (NOPR at 44)

Available Transmission Capability (ATC) and Total Transmission Capability

"ATC numbers are still calculated on an individual company basis in many areas of the country. Separate calculations of ATC by individual companies are fundamentally inconsistent with the physical reality of an interconnected transmission system…. Accurate ATC numbers would require reliable and timely information about load, generation, facility outages and transactions on neighboring systems. Individual transmission operators will generally not have this information. They also may apply differing assumptions and criteria to ATC calculations, which may produce wide variations in posted ATC values for the same transmission path." (NOPR at 48)

Congestion

"Congestion occurs when requests for transmission service exceed the capability of the grid. When transmission constraints limit the amount of power that can be transmitted, the loads on the system may not be able to be served by the least-cost mix of available generators… The cost of congestion is the additional energy cost associated with the new pattern of dispatch. Without mechanisms for determining the cost of congestion, it will be virtually impossible to make rational, cost effective decisions to expand the grid." (NOPR at 50)

Planning and Expanding Transmission Facilities

"While uncertainty has always been a fact of life for any transmission planning exercise, the level of uncertainty has increased with the increasing number and distance of unbundled transactions and the wider variation in generation dispatch patterns… One troubling consequence of this uncertainty has been a noticeable decline in planned transmission investments. NERC recently reported that the level of planned transmission additions is significantly lower than five years ago despite an overall increase in load growth and unbundled transmission service." (NOPR at 53)

Pancaked Rates

"In most of the United States, a transmission customer pays separate, additive access charges every time its contract path crosses the boundary of a transmission owner. By raising the cost of transmission, pancaking reduces the size of geographic power markets. This, in turn, can result in concentrated electricity markets. Balkanization of electricity markets hurts electricity consumers, in general, by forcing them to pay higher prices than they would in a larger, more competitive, bulk power market." (NOPR at 56)

Potential for Market Power Abuses

"Utilities that control monopoly transmission facilities and also have power marketing interests have poor incentives to provide equal quality transmission service to their power marketing competitors. The exercise of transmission market power allows transmission providers with power marketing interests to benefit in the short-run by making more power sales at higher prices, and benefit in the long-run by deterring entry by other market participants. As a result, prices to the Nation's electricity consumers will be higher than need be.

"Order 888 required functional unbundling of transmission services from generation services within the corporate structure of the utility. Functional unbundling did not change the incentives of vertically-integrated utilities to use their transmission assets to favor their own generation, but instead attempted to reduce the ability of utilities to act on those incentives. In Order No. 888, the Commission received and considered numerous comments that functional unbundling was unlikely to work, and that more drastic restructuring, such as corporate unbundling, was needed." (NOPR at 59)

"Perhaps the most problematic aspect of relying on after-the-fact enforcement in the fast-paced business of power marketing, however, is that there may be no adequate remedy for lost short-term sale opportunities." (NOPR at 63)

Accurate Reporting of ATC

"Transmission providers with power marketing interests have incentives to understate ATC on those paths valuable to its marketing competitors, or to divert transmission capacity so that it is available for use by its own marketing interests." (NOPR at 67)

Standards of Conduct Violations

"To ensure the functional separation of a transmission provider's transmission and merchant functions, the Commission adopted standards of conduct that prohibit the transmission provider's marketing interest employees from having any more access to transmission system information than is available on OASIS, and requires the transmission provider's transmission employees to provide impartial service to all transmission customers. If a transmission provider's marketing interests have favorable access to transmission system information or receive more favorable treatment of their transmission requests, this obviously creates a disadvantage for marketing competitors.

"In spite of the standards of conduct, there continues to be a perception by many market participants that the transmission provider's marketing and transmission interests are not fully functionally separated. We are increasingly concerned about the extensive regulatory oversight and administrative burdens that have resulted from policing compliance with standards of conduct." (NOPR at 79)

Conclusion

The Commission concluded, in summary, as follows:

"Order No. 888 has not been able to produce a fully efficient and competitive outcome because it does not address ATC calculations, congestion management, reliability, pancaking of transmission access charges, and grid planning and expansion. These are regional problems. Therefore, we are proposing a rule to encourage the development of independent regional transmission operators that can promote both electric system reliability and competitive generation markets." (NOPR at 58)

The Commission's regulatory discussion identified a series of factors that could give rise to inefficiencies in wholesale electric power markets. It also enumerated a set of potential economic benefits that could result from the RTO policy being advanced. However, there are also potential costs to such a policy, and the specific mechanisms that could tie RTO policy measures to economic impacts need to be carefully evaluated in order to assess the overall effects of the policy. The next section presents the set of benefits set forth by the Commission; the purpose of this analysis is to assess how these changes, along with other changes that might result from RTO policy, could result in both costs and benefits to the economy.

1.2.2 Prospective Benefits from the Commission's RTO Policy

Appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management[3]; (2) improve grid reliability; (3) remove the remaining

[3]Appropriate regional institutions could improve efficiencies in grid management through improved pricing, congestion management, more accurate estimates of Available Transmission Capability, improved parallel path flow management, more efficient planning, and increased coordination between regulatory agencies.

opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter-handed regulation.

RTOs Can Improve Efficiencies in the Management of the Transmission Grid

The Commission, in developing its policy with regard to RTOs, has stated that properly functioning RTOs would:

- "improve efficiency through regional transmission pricing. The Commission has long recognized that transmission pricing reform is most effectively accomplished on a regional basis." (NOPR at 90)
- "improve the way congestion is managed over a large area, thus expanding the number of potential transactions over existing facilities while reducing the number of curtailments." (NOPR at 91)
- "improve efficiency by providing more accurate estimates of ATC than those currently provided by individual systems. An RTO would produce better ATC estimates because it would have access to complete regional usage information, would have current information because the RTO will be the security coordinator as well as the OASIS site administrator, and would calculate ATC values on a consistent region-wide basis using a regional flow model." (NOPR at 92)
- "more effectively manage parallel path flows. With an RTO in place, the geographic scope for scheduling and pricing transmission would be widened and parallel path flows would be internalized within the RTO." (NOPR at 92)
- "promote more efficient planning for transmission or generation investments needed to increase transmission capacity. One advantage of an RTO that is helpful in planning is that it will be able to see the 'big picture.'" (NOPR at 93)
- "increase coordination between separate state regulatory agencies by providing a single point of focus for transmission expansion review, possibly even encouraging multi-state agreements to review and approve new transmission facilities." (NOPR at 94)
- Reduce transaction costs. "For example, the consolidation of transmission control operations would cut general and administrative costs over the long term." (NOPR at 94)
- "facilitate establishing transmission rights and the 'tradability' of transmission rights." (NOPR at 95)
- "facilitate the success of state retail access programs by providing greater confidence in the markets and a larger regional market with access to more potential suppliers." (NOPR at 95)

RTOs Can Improve Grid Reliability

"A regional body that operates the regional grid and enforces reliability rules for the entire region could prove helpful to current efforts and should be considered. An RTO would enhance reliability by (1) operating the system for a large region, (2) ensuring coordination during system emergencies and restorations, (3) conducting comprehensive and objective reliability studies, (4) coordinating generation and transmission outage schedules, and (5) sharing of ancillary services responsibilities." (NOPR at 96)

RTOs Can Remove Opportunities for Discriminatory Transmission Practices

"An RTO would have no financial interests in any power market participant, and no power market participant would be able to control an RTO. This separation will eliminate the economic incentive and ability for the transmission provider to act in a way that favors or disfavors any market participant in the provision of transmission service." (NOPR at 96)

RTOs Can Result in Improved Market Performance

"By improving efficiencies in the management of the grid, improving grid reliability, and removing any remaining opportunities for discriminatory transmission practices, the widespread development of RTOs would also improve the performance of electricity markets in several ways and consequently lower prices to the Nation's electricity consumers." (NOPR at 98) "To the extent that RTOs foster fully competitive wholesale markets, the incentives to operate generating plants efficiently are bolstered. Suppliers will continuously seek to avoid being made uncompetitive by rivals . . . The incentives for more efficient plant operation can also affect existing generation facilities . . .All plants are coming under pressure to improve their availabilities and operating efficiencies. Individual firms have made decisions to seek to become more competitive, or to prepare themselves for future competition." (NOPR at 98-99)

RTOs Can Facilitate Lighter-Handed Governmental Regulation

"…To the extent an RTO is independent of power marketing interests, there would be no need for this Commission to monitor and attempt to enforce compliance with the standards of conduct designed to unbundle a utility's transmission and generation functions." (NOPR at 102)

An independent RTO with an impartial dispute resolution mechanism would:

- resolve disputes without resort to the Commission complaint process.
- streamline filing and approval procedures.
- result in more streamlined transmission rate proceedings.

1.2.3 The RTO: Functions, Characteristics, and Form

Based on the considerations listed above, the Commission decided to proceed as stated:

"In light of important questions regarding the complexity of grid regionalization raised by state regulators and applicants in individual cases, we are proposing a flexible approach." (NOPR at 8) "First, the Commission proposes minimum characteristics and functions that an RTO must satisfy." (NOPR at 10) **"**A properly structured RTO will be an entity that is independent from all generation and power marketing interests, and has the exclusive responsibility for grid operations, short-term reliability, and transmission service within a region." (NOPR at 116)

Minimum characteristics of RTOs:

- Independence from power market interests
- Scope and regional configuration
- Exclusive operational authority
- Maintain short-term reliability

Minimum functions of RTOs:

- Tariff administration and design
- Congestion management
- Parallel path flow
- Ancillary services
- Run a single OASIS node providing TTC and ATC information
- Market monitoring
- Planning and expansion

1.2.4 Developments Since Order No. 2000

Since the issuance of Order No. 2000, significant developments have taken place. The regulatory context of RTO policy has continued to evolve and to be informed by market events. The FERC has taken a number of actions that are relevant to the analysis undertaken here, as summarized in the following sub-sections.

Staff Investigation into Bulk Power Markets

The FERC issued a series of staff investigation reports after the issuance of Order No. 2000. These staff investigation reports contained a wide range of observations and conclusions, and pointed out a variety of continuing inefficiencies and problems in bulk wholesale electric power markets. The Commission's evolving policy regarding the transmission grid and RTO development can be seen as a response to these types of problems.

Each of the regional staff investigation reports is excerpted in this section, but the reports should be evaluated in their entirety for a full understanding of their contents.

Midwest Region

The Midwest staff investigation report discusses wholesale power prices from 1998-2000. As the report explains:

"The summer of 2000 was relatively calm for Midwest wholesale prices. A number of factors contributed to this situation. As will be shown, the weather was cooler than normal, especially in the upper Midwest. Also, there were no widespread generation outages, as in the 1998 price spike when many nuclear plants were simultaneously down for maintenance. More generation facilities have been built in the Midwest, too. Finally, except for TLRs (Transmission Loading Relief episodes), there were no major transmission problems like the central Ohio voltage sag or the loop flow problems in 1998 which threatened to isolate the Midwest from the rest of the grid."

"Table [1.1] shows the number of Level 2 TLRs and above, by region for each summer from 1998 to 2000. It tabulates the monthly and yearly totals for each region. The bottom row shows the total for each year and the grand total for all 3 years. There has been an enormous increase in TLRs between the summer of 1999 and the summer of 2000. Specifically, TLRs have grown from 86 during the summer of 1999 to 492 for the summer of 2000, an increase of 472 percent. For this analysis, Staff only counted a TLR at its highest level. When a TLR escalated in Level while it was active, Staff only measured it as one occurrence."

Table 1.1: Level 2 TLRs and Above, Summer 1998-2000

Region	1998	1999	2000	Monthly Totals	Region Total
ECAR					
June	13	8	51	**72**	
July	4	24	102	**130**	
August	4	15	66	**85**	
ECAR Total	**21**	**47**	**219**		**287**
MAIN					
June	40	10	31	**81**	
July	25	3	92	**120**	
August	21	12	75	**108**	
MAIN Total	**86**	**25**	**198**		**309**
MAPP					
June	0	0	0	**5**	
July	0	0	12	**12**	
August	0	0	0	**0**	
MAPP Total	**0**	**0**	**12**		**17**
SPP					
June	0	4	27	**31**	
July	0	6	20	**26**	
August	0	4	11	**15**	
SPP Total	**0**	**14**	**58**		**72**
All Regions	**107**	**86**	**492**		**685**

Source: FERC Congestion Management Team Reports compiled from NERC's website.

Western Region

The most recent staff report to be released is a follow-up to the Western region investigation. The report considers electric power prices at two Western market hubs (California-Oregon Border and Mid-Columbia) between February and September of 2000, followed by prices for both natural gas and electric power in November and December of 2000.

"Although power market prices spiked at certain points over the summer, the recurrence of high prices over the longer term may have a greater impact on customer bills. Prices spiked less frequently as the summer progressed and California imposed price caps at lower levels, but average prices continued to climb."

"In September and October, power prices appeared to be moderating from the sustained high levels of the summer. Prices continued to fluctuate considerably, but the trend was clearly downward from late August prices over $200 ($225 at Mid-Columbia on August 29) to prices under $100 in early November ($75 on November 4.) In mid-November, prices for natural gas and electricity started to rise again. The increases at first were small enough to be attributed solely to anticipation of the winter peak season, but then gas prices jumped over $10 per MMBtu and electricity prices rose to over $200. This significant trend was punctuated by dramatic increases in early December, but returned after the spikes subsided to close around $300 during the last week of December."

Northeast Region

In the Northeast region, the staff investigation examined three sub-regional markets (New England, New York, and Pennsylvania-New Jersey-Maryland or PJM).

"With the moderate temperatures in summer 2000, and some market design changes undertaken to inhibit exercise of market power, energy prices have been lower in summer 2000 than summer 1999."

"The New York ISO has experienced major problems with its operating reserve markets. Prices remained reasonable from the start of the market until mid-January 2000, when prices for both 10-minute operating reserves climbed dramatically. The ISO suspended both markets in late March and applied a price cap."

"The monthly average price for 10-minute spinning reserve prices hit a peak of $73.27/MW in February 2000. Following the application of a price cap of $6.68/MW, prices declined substantially in April 2000, to a monthly average price of $3.51/MW. That price cap was later rejected by the Commission and removed. The monthly average price has ranged between $3.10/MW and $4.45/MW from April to September 2000."

"A similar pattern holds for 10-minute non-synchronous, or non-spinning, reserves. The average monthly price hit a peak of $65.58/MW in February 2000. Following application of a price cap of $2.52/MW in April, average prices declined substantially in this market as well, to $1.75/MW in April 2000. The monthly average price has ranged between $1.47/MW and $2.30/MW from April to September 2000."

"Until summer 2000, the average regulation price was higher than the average energy price. This reflects market inefficiency. However, regulation prices have dropped over the course of summer 2000."

Southern Region

From the Southern regional report: "Peak prices were radically lower in the summer of 2000 than they were in the past two summers . . . The peak price in the region in 1998 was $2,386 per MWh. In 1999 it was $2,057 per MWh, but it was only $165 per MWh in 2000."

"The lower peak experienced this summer was due mainly to relatively lower temperatures for much of the summer in the Midwest. Lower temperatures in the VACAR sub-region relative to other regions in the Southeast increased the availability of generation to serve customers elsewhere in the Southeast. In addition, utilities appear to have been better prepared for peak events in the summer of 2000. According to utility interviews with the Commission staff, superior preparation took the form of increased hedging through the use of forward contracts, increased generation capacity on line and a reduced number of forced outages."

Staff Paper on Demand Responsiveness in Electricity Markets

Staff in the Office of Markets, Tariffs and Rates produced a paper on demand responsiveness in electricity markets that links market design and incentives for consumers to respond to electricity prices. This paper was revised on January 15, 2001.

The Executive Summary of the paper concludes:

"Past market designs and regulation have not promoted innovations in developing opportunities for demand side responses in electricity markets. The market rules in place today within ISO's are poor substitutes for the benefits obtained from real demand response. The volatility in wholesale markets has demonstrated the importance of a demand response in times of scarcity. Demand responsiveness plays a vital role in increasing efficiency and reducing price volatility in the electricity markets. It allows customers to communicate the value of electricity to the market. Currently, advances in technology are leading to innovative pricing structures and generation alternatives to allow customers to better respond to prices. This can benefit all consumers by promoting efficiency and stability in electricity markets."

Order of November 7, 2001 on State Coordination and Cost/Benefit Assessment

The Commission issued an order on November 7, 2001 concerning the process to be conducted on RTO filings and related matters resulting from Order No. 2000 compliance.

This order states in part: “The FERC has before it numerous ongoing proceedings involving RTO proposals, and it has recently assessed the status of these proceedings and the ongoing changes in the electricity marketplace. Taking into account the various stages of RTO efforts in the country, and the industry and state comments we have received in recent weeks (discussed below), in this order we state some of our goals and provide general guidance on how we intend to proceed on RTO filings and other related efforts.”

“The Commission intends to complete the RTO effort using two parallel tracks. The first track will be to resolve issues relating to geographic scope and governance of qualifying RTOs across the nation; these will be addressed in pending RT dockets following consultation with state commissioners as discussed below.”

“The second track for resolving RTO issues will be in the transmission tariff and market design rulemaking for public utilities, including RTOs, in Docket No. RM01-12-000. This will help address business and process issues needed for organizations to accomplish the functions of Order No. 2000.”

“The FERC will take several immediate steps to move the RTO process along these tracks: (1) a broader definition of how certain RTO functions will be fulfilled; (2) better state/federal dialogue; (3) further cost/benefit studies; (4) identification of areas where standardization is called for; and (5) creation of a time line for RTO implementation.”

The portion of this order that calls for the present study reads as follows:

“C. <u>Cost/Benefit Studies</u>

“On a parallel track to the organizational efforts listed above, the Commission will perform additional cost-benefit analyses on RTOs to guide our further efforts. These analyses are intended to demonstrate whether and, if so, how RTOs will yield customer savings and to provide a quantitative basis for the appropriate number of RTOs.”

“The Commission has established a working group with state commission participation to work with FERC staff and the study consultant in framing these further analyses.”

1.3 Related Studies

A number of organizations have already conducted some type of quantitative impact analysis of RTO policy or related matters. For purposes of comparison, the following section provides brief synopses of several of these studies, the methodologies they used, and their principal findings.

1.3.1 FERC Order No. 888 Environmental Impact Statement (National, FERC/EIS-0096)

In April of 1996, the FERC released the Order No. 888 Notice of Proposed Rulemaking's Environmental Impact Statement (EIS). The EIS was geared primarily toward calculating the possible effects of Order No. 888's open access transmission policy on national air emissions from the electric power system including NO_X, SO_2, and CO_2. The EIS also produce a bounded quantitative estimate of potential system savings of approximately $3.8 to $5.4 billion per year resulting from changes, including lower transmission access charges and transmission capacity reserve margins, that could be produced by the open access policy.

The FERC retained ICF Consulting to conduct the electric system simulation work for the EIS using the Coal and Electric Utility Model (CEUM). CEUM is a computer-based linear programming model with detailed representation of all electric generating facilities in the US. The model is used to determine the least cost means of meeting electric generation energy and capacity requirements while complying with specified air pollutant regulations. CEUM is forward-looking and optimizes the system over an extended time frame.

FERC defined several scenarios that were analyzed using CEUM to produce estimates of total emissions and economic gains from the Order No. 888 policies. The economic gains presented in the EIS were based on the following improvements (over a business-as-usual case) that the conditions from Order No. 888 would create:

- Better use of existing infrastructure;
- New market mechanisms;
- Faster technological innovation; and
- Less rate distortion and greater customer choice.

To quantify the potential magnitude of these economic gains, FERC identified the following specific improvements that were analyzed within the CEUM modeling framework:

- Lowered inter-regional transmission tariffs
- Decreased reserve transmission capacity
- Improvement in power plant availability and performance

The EIS concluded that air emissions under several iterations of an open access scenario would not be significantly affected on a national basis. Notably, in all scenarios run, the relative price of gas and coal tended to be a more powerful driver of emissions levels than transmission access policy.

The EIS did not address several issues that were potentially important from a legislative perspective. Due to CEUM's forward-looking nature, all operational dispatch and capacity upgrade decisions that affected the results reported in the EIS are made on a marginal-cost basis. Some cost issues involving the stock of existing or sunk capital, such as so-called "stranded costs" are not captured in CEUM calculations of potential costs or benefits. The EIS also did not attempt to treat state jurisdiction or power plant siting issues as they were outside of the scope of the FERC's authority.

The Order No. 888 EIS represents an early attempt to bound the potential savings from reduced barriers to transmission access on a national scale. While its scope was limited to specific system elements such as transmission charges and capacity reserve margins, the EIS provided quantitative estimates of the potential cost of existing transmission system inefficiencies at the time of its publication.

1.3.2 Supporting Analysis for the Comprehensive Electricity Competition Act (National, DOE/PO-0059)

In early 1999, The DOE published the supporting analysis for the Clinton Administration's proposed Comprehensive Electricity Competition Act (CECA). The report describes and quantifies the economic and environmental benefits of competition in retail electricity markets. The analysis produced a quantifiable cost savings estimate of switching to a competitive system of approximately $32 billion in the year 2010, as well as reductions in CO_2 emissions, relative to a base case.

According to the CECA analysis, competition provides strong economic incentives to raise productivity, encourages sellers to pursue efficient pricing practices, spurs development of innovative products and services that add value and better meet customer needs, and in the long run leads to increased productivity, new services, and better use of resources that will benefit the overall economy and electricity consumers.

The CECA analysis also described competition as having the following environmental benefits: Incentives to use fuel more efficiently (cutting emissions, costs, and fuel use) and retail-level customer access to energy efficiency services and green power, thereby decreasing air emissions from fossil-fueled power plants.[4]

The analysis uses the Policy Office Electricity Modeling System (POEMS) to simulate the US power market under Cost-of-Service Regulation and Competitive scenarios with a focus on economic and environmental impacts of a national transition to competition. The POEMS system is computer simulation model of the national electric power system, configured at the control area level and representing both short run operations and long run investment in a least-cost optimization framework.

4 The CECA also contains special provisions for energy efficiency and renewable energy development. Although greater market competition alone is not expected to lead inevitably to increased renewable energy capacity or utilization of energy efficiency resources, it will allow consumers access to alternative means of meeting their energy needs. To help maximize the reliance on alternative resources, the CECA proposes a renewable portfolio standard (RPS).

Although it did not isolate any specific state efforts to transition to a competitive market model, the analysis did incorporate some of the common elements in state deregulation processes in an attempt to realistically assess the probable course of deregulation on a wider scale. The focus of the analysis is a quantitative assessment of the impacts of national retail competition relative to a continuation of cost-of-service regulation that includes wholesale competition.

The report found the following results in comparing the two scenarios (Cost-of-Service Regulation vs. Competition Scenarios[5]):

Economic:

- Delivered cost of electricity to all consumers $32 billion lower in 2010 than in the Cost-of-Service Scenario, including estimates of stranded costs, recovery impacts and higher capital build costs in competitive scenario;
- Average national price of electricity estimated to be 14 percent lower than Cost-of-Service;
- Regions with highest prices under cost-of-service regulation tend to gain largest reductions in price under competition;
- Cost reductions for investor-owned and public utilities: O&M, administrative and general costs, more efficient use of transmission and distribution, and capital cost savings (estimated to exceed $20 billion a year).

Environmental:

- Generation of electricity from Renewable Portfolio Standard-eligible renewable energy resources is projected to triple by 2010 as a result of a cost cap provision in the RPS proposal;
- Emissions of CO_2 are reduced by between 40 and 60 million metric tons carbon equivalent in 2010 due to the effects of competition itself, and enhanced by an RPS provision, a public benefits fund, and a consumer information provision;
- NO_X and SO_2 emissions are subject to caps under the CAA, so their emissions are projected to be similar under competition and cost-of-service.

The CECA is not a full cost-benefit analysis, and is intended to analyze a transition to full retail competition (as opposed to the Commission's jurisdictional interest in wholesale competition). It does, however, provide a quantifiable estimate of total retail savings under a deregulated market system. Moreover, the CECA report incorporates an assessment of stranded cost recovery impact on the total system costs if the US were to transition to a competitive market, a relatively rare element of most going-forward competitive policy impact assessments.

5 The year 2010 was chosen as a comparison year to show the effects of competition in a medium-term view.

1.3.3 FERC Order No. 2000 Environmental Assessment (National)

In 1999 the FERC contracted with ICF Consulting to prepare an Environmental Assessment (EA) to analyze the impacts of implementing the Commission's proposed rule on RTOs, Order No. 2000. Although the EA was not meant to provide economic cost-benefit analysis, its methodology was similar to the study conducted for this report. The EA indicated changes in air pollutant emissions and generation, key market drivers of national energy markets, under the proposed rule compared to baseline trends without the rule.

Building on its earlier work on the EIS, ICF used the successor model to CEUM, the Integrated Planning Model (IPM®) to perform the work required by the EA. To simulate the effects of the proposed rule, ICF calibrated the model by incrementally adjusting transmission tariffs among NERC regions for simulations of 1998, until model generation results (by fuel mix and total MWh) reflected the actual 1998 generation mix in those regions to within 5%. As in the earlier Order 888 EIS, FERC identified a number of scenarios to be analyzed including:

- A lowered transmission tariff scenario to represent the removal of non-physical transmission constraints under the proposed rule
- A high-transmission capacity scenario
- A high generation efficiency scenario
- A high new market entrant scenario
- A "No-Action Alternative" case representing the status quo

The results indicated that the proposed rule would result in little generation change on a net national basis, but that there may be shifts in regional generation. The Midwest, for example, was expected to produce incrementally more power and the East Coast to produce incrementally less power. In addition, the EA indicated that the proposed rule would incrementally shift the baseline fuel mix projections toward coal and away from fuel oil (and to some extent natural gas). Air pollutant emissions, corresponding generally with generation and fuel mix, would also shift regionally but would not rise or fall significantly nationwide and would remain within regulated levels where such restrictions apply.

1.3.4 Mirant Study and LECG Response (Northeast)

Mirant commissioned Energy and Environment Analysis, Inc. (EEA) to perform an assessment (the Mirant Study) of potential efficiency gains from the integration of the three primary Northeast ISOs--PJM, New York, and New England--into a single RTO. EEA conducted an analysis of publicly available market price and energy flow data to provide evidence of transmission system inefficiencies in the Northeast. The study estimated impacts for a one-year snapshot based on year 2000 information. EEA determined a total annual efficiency savings of $440 million was available if the Northeast adopted an RTO system. EEA used the following methodology.

To test the current efficiency of the interregional transmission system, EEA compared year 2000 hourly wholesale energy prices from real-time and day-ahead markets across the three regions alongside actual energy flows between the adjacent regions. EEA posited that in a liquid energy market, these prices should be kept from converging only by physical transmission constraints between higher and lower priced areas. EEA compared the transmission constraints to the operational and market boundaries of the ISOs and concluded that no primary transmission constraints subdivide the Northeast region along currently drawn limits and that the existing ISO boundaries are based on political rather than physical constraints.

EEA surmised that the fundamental differentiation among regions in the Northeast energy markets is an East-West split based on fuel type. The majority of installed capacity in the West is coal- or nuclear-fueled, while more units in the East burn oil or gas. According to the Mirant study, this difference should impact energy prices, especially during peak gas demand periods in midwinter and midsummer in New England. But it should not be able to sustain the price differential between two adjacent ISOs where transmission capacity is available to move the low-price energy to the high-price region.

By examining instances where both available transmission capability (ATC) and a price differential existed between any two regions, EEA calculated a total annual efficiency loss of $440 million to the Northeast. EEA asserted that where there is ATC between a high-price and a low-price region, it is reasonable to assume that the $440 million efficiency loss is the result of operational failings in the greater northeast energy market. EEA attributed the operational failings to differences among the three ISO systems:

> "Differences in a variety of market-related rules, such as varying transmission rights, products and transmission scheduling systems, and different energy market structures (*e.g.*, the lack of a "Day-ahead" energy market in New England) contribute to inefficiency". (FERC Affidavit, Vidas&Henning/EEA p3)

According to EEA, these differences among the ISOs produce irreconcilable seams issues between adjacent transmission regions under the existing transmission market structure. Furthermore, although the Northeast could take steps to mitigate these seams problems, it would only realize the total efficiency gains by eradicating the seams altogether by adopting a single RTO system.

1.3.5 NYISO/LECG Response (Northeast)

New York ISO hired LECG, LLC to conduct a review and analysis of the Mirant Study. LECG replicated EEA's methodology and conducted several sensitivity analyses using the data for the same time period and for an extended time period. While LECG did not take issue with the Mirant Study's findings that differing market rules and design among the Northeast regions were to blame for the operational inefficiencies, it did question the magnitude of those inefficiencies and sought to show that EEA's methodology was flawed and led to erroneous final figures. According to LECG's report, the Mirant Study

- Compares real-time flows with day-ahead prices;
- Ignores real transmission constraints;
- Bases part of its conclusions on prices from NEPOOL, which does not use locational marginal pricing like NYISO and PJM do;
- Relies on overly flat supply curve estimates; and
- Focuses on a startup period for PJM's day-ahead market and ISO NY as an operational entity.

According to LECG, correction of these elements in EEA's methodology would drastically reduce the price efficiency savings that would result from combining the Northeast ISOs. LECG also claimed that the energy cost savings in New York would be minimal, and might even increase by as much as $90 million per year.

1.3.6 PJM Study (Northeast)

More recently, PJM conducted its own analysis (the PJM Study) of the costs and benefits of establishing an RTO in the Northeast. PJM used the GE Multi-Area Production Simulation (MAPS) to simulate the operation of Northeast energy grid for the year 2001 under several scenarios: a base case, a high demand scenario, and a low demand scenario. For each scenario, PJM ran the model under an ISO system assuming independent ISOs in each region, and under an RTO system, assuming RTO control of the entire Northeast. The run results, though varying significantly across scenarios, each confirmed an overall system savings to consumers, although those savings accrued most heavily to the New York region. In addition, most consumer savings carried a corresponding drop in operating profit to the generators in the regions where the savings occurred. For example, the base case scenario reported annual system savings to consumers of $299 million, even though costs to consumers actually rose in PJM and New England by roughly $70 million each. The results are discussed in greater detail below.

PJM used the following assumptions:

- NERC load forecast for 2001;
- A cost-based generation offer curve utilizing data from Resource Data International;
- Economic transfers among regions based on historic averages from the past 7 years;
- Firm generation capacity additions announced for 2001;
- No upgrades to the transmission system; and
- Phase angle regulators (PARs) not fully coordinated across ISOs.

For both the base case and RTO case, PJM modeled the hourly dispatch for 8760 hours under three scenarios in a Locational Marginal Pricing (LMP) market. LMP markets determine transmission costs on a nodal supply-to-load basis. Depending on demand, supply, and constraints between nodes, each node was assigned an hourly market clearing price for energy by the model. In the ISO case, each ISO represented a power pool with a series of dedicated nodal market points. The power pools could trade energy at contact points with adjacent pools, but were run as individual markets. In the RTO case, the region was run as a single power pool with node-to-node costs calculated across the Northeast.

PJM reported results in three categories: generation production cost, load payments (based on spot purchases), and generation revenue (based on spot purchases). The results from the Base Case scenario are provided in Table 1.

Table 1.2: PJM Study Results (Million 2001$)

Parameter	Northeast RTO Total	PJM Total	New York Total	New England Total
Load Payments	-299	71	-432	62
Generation Production Cost	-222	252	-640	166
Generator Revenues	-259	511	-1,094	324

Source: PJM, PJM Cost/Benefit Analysis for Northeast RTO, DRAFT, 1/04/2002, p. 7.

Although generator production costs rose in PJM and New England, in both cases generator revenues rose by a greater margin. The reverse was true of New York, where the consumers realize a savings of $432 million, but the net revenue to generators decreases by $434 million. The sensitivity scenarios returned similar patterns of gains and losses, although the welfare distributions tended to be magnified in the high demand case and diminished in the low demand case.

In addition to the net system costs, PJM also provided an estimate of $71 million in startup costs for the proposed RTO, most of which would be attributed to extending PJM's existing system architecture to New York and New England. PJM assumed the existence of administrative savings from switching to an RTO system, but did not provide a dollar estimate in its preliminary findings. At the time of this publication, the PJM Study results are tentative.

1.3.7 RTO West Benefit/Cost Study (Preliminary Report, Northwest)

In February of 2002, Tabors Caramanis & Associates (TCA) released the Preliminary Status Report (PSR) of their cost-benefit analysis for RTO West. TCA integrated a simulation of the WSCC NERC region electric system with a series of specialized extra-modeling analyses to create a report that addresses multiple aspects of the proposed transition to an RTO in the northwest region of the US.[6] Although they are *still*

6 The following utility service areas are to be consolidated under the RTO West proposal: Avista Corp., Idaho Power Company, Montana Power Company, PacifiCorp, Portland General Electric, Puget Sound

preliminary at the time of this writing, the results of the modeling process show that a net annual benefit to the RTO West territory of $358 million is available if it were operated as an RTO. According to the PSR, the greater WSCC region also stands to gain $400 million each year in efficiency savings from the formation of RTO West.

Like the PJM Study described above, the RTO West study uses the GE MAPS model[7] to simulate the possible impacts on generation costs and levels, energy flows across regions, and final energy prices for a single year -- 2004. TCA simulates operations in the WSCC area using a sub-regional breakdown of RTO west, CAISO, and the WestConnect ISO under two cases, a "With RTO" case and a "Without RTO" case. In the future, TCA plans to expand its analysis to test multiple sensitivities, such as alternative energy demand scenarios.

As per the request of the RTO West, TCA assumed that an RTO would provide the following benefits to its service area:

- Elimination of pancaked transmission capacity and loss charges;
- Better sharing of operating reserves;
- Better coordination of scheduled O&M;
- Internalized loop flows;
- More competitive generation markets;
- Lower transaction costs;
- Improved ATC;
- Maintenance of a single OASIS site;
- Better regional reliability; and
- Better transmission planning and expansion coordination.

TCA captured the proposed benefits in the modeling process via the following adjustments to the "Without RTO" case:

- Transmission rates between the three WSCC regions - raised for transfers between RTO West and the adjacent regions, leveled to and from WestConnect, and kept unchanged for CaISO;
- Plant O&M scheduling - optimized among all units at the regional rather than sub-regional level;
- Reserve margins reduced;
- Internal RTO tariffs and pancaked rates - removed, as was contract path scheduling for transmission flows; and
- Pancaked loss charges - reduced to zero within the RTO West territory.

Energy, Sierra Pacific Resources (Sierra Pacific Power and Nevada Power), Bonneville Power Administration, and BC Hydro.

7 Some of the features of the GE MAPS model noted in the PSR are: unit-by-unit marginal cost bidding in a real-time market; a region-by-region market clearing price (locational marginal pricing [LMP] aggregated up to zonal prices); and a cost of congestion calculated as the transmission shadow-price multiplied by the MWh energy flow.

The results of the simulation show annual region-wide savings of having RTO West operate the transmission system of roughly $358 million. TCA uses three metrics to estimate the net benefit: production costs, producer revenues, and energy costs paid by load. In the With RTO Case, RTO West operations provide energy cost savings to load of nearly $1.6 billion[8] and a corresponding drop in producer revenues of roughly $1.2 billion. Production costs for the region rise by about $37 million. To arrive at a net benefit estimate, TCA subtracts the revenue loss to producers ($1.2 billion) from the load energy cost savings ($1.6 billion) and then adds the additional production costs ($37 million) to arrive at a final benefit of $358 million. A sensitivity case assuming lower inter-RTO charges results in benefits over $400 million.

The PSR shows net welfare gains for all sub-regions within the proposed RTO area. Whether these gains accrue more heavily to load or to supply varies from region to region. The natural tendency is for consumers in high-cost regions to benefit from access to wider supply and for producers in low-cost regions to benefit from access to higher-price markets. Average energy prices[9] in all sub-regions within RTO West drop, with the exception of Montana, where prices rise nearly 3%.

The PSR shows no overall trend for transmission capacity congestion. Some lines are fully utilized more often while others tended to experience less congestion. According to the TCA, however, the major inefficiency of the non-RTO transmission system comes from the practice of contract path scheduling; a mechanism that poorly reflects actual energy paths, especially loop flows. In short, poor management of existing transmission capacity, as opposed to capacity shortage, in the RTO West area is the principle culprit in current system efficiency losses.

In a separate section of the PSR, TCA provides estimates of RTO startup and O&M costs independent of the simulation effort. Start-up investments are offered from studies on and previous experience with regional organizations (ISOs). TCA also provides "ball park" approximations for annual O&M costs for RTO West in the range of $126 to $146 million per year based on the same regional information. It did not, however, offer a cost for the same total transmission area under the Without RTO Case. The total cost of running the transmission system is expected to be lower in an RTO, however, due to the elimination of redundant functions among transmission regions and the consolidation of tasks and information in a single operating center.

In addition to the analysis above, the PSR makes qualitative investigations into other RTO topics such as increased information exchange among market participants, better system coordination, market consolidation, and organizational relationships. TCA discusses the potential impacts of the integrated market processes under an RTO system; they may make the system more efficient but also may add to the complexity. Furthermore, TCA notes that many of the proposed benefits of RTO West may be

8 Including $246 million in spinning reserve payments and $2.3 million in uplift charges, both of which are paid by load.
9 Simple average, not load-weighted in PSR.

achieved due to the natural progression of the energy system, absent an official RTO policy.

1.3.8 Conclusions

An increasing amount of research and information is becoming available about the likely or potential impacts of RTO development on regional and national electric power markets. While the studies summarized above rely on disparate methodologies, data sets, and scopes, it is important to make use of all relevant information in drawing conclusions about the potential costs and benefits of RTO policy.

Because the FERC has regulatory responsibilities across the entire country, the most comparable analyses are the limited set of national analyses previously carried out by the DOE and the FERC. The longer time frames and dynamic analysis in these previous studies are also more comparable to the present study. While the recent studies focusing on the Northeast region and the West were limited in terms of geographic scope and time frame, they provide an interesting basis for comparing results. When similar conclusions can be drawn from several parallel and robust analytic methods, it suggests greater confidence in such conclusions.

In developing the analytic approach for the present economic cost/benefit study, both the regulatory context and related work provide useful starting points. The next section describes the set of analytic requirements that this study is intended to meet, based on the forgoing contextual and background material.

1.4 Basis for Analytic Approach

In conducting this study, an analytic approach was developed to meet the requirements imposed by both the nature of the issues and the resources available. The foregoing sections discuss the context of the study, the issues to be addressed, and the analytic approaches that have been used in related studies. These issues, and the available methods for addressing them, resulted in a challenging set of requirements for this economic cost/benefit analysis.

Requirements for the Present Study

<u>Three-Month Schedule:</u> A major challenge for this study was a 90-day schedule. This limited both analytic methods and data development. Analytic methods had to be well tested and immediately available, while data and assumptions had to be taken from existing sources and/or developed over a short time period.

<u>National Scope:</u> The national scope of the Commission's jurisdiction meant that the study had to address economic issues across the entire contiguous US. Interactions among the electric power systems in various regions, and consequent market and economic impacts, required the study to use a single national framework for making quantitative assessments.

Regional Representation: Within the overall national scope of the study, regional levels of detail had to be represented. This applies to both physical elements of the power system and to the associated economic characteristics of these system elements. Thus a great deal of detailed data had to be incorporated into one national analytic framework.

Long-Term Time Frame: The electric power system is characterized by capital intensity and takes time to react to new incentives. In addition, national policy can have long-lasting impacts on the economy, and regulatory cost/benefit assessment should be able to assess such potential impacts over a period of years or decades. At some point impact assessment becomes too speculative, and the discounted present value of impacts becomes less important over time. But the present study had to take into account a reasonably long time horizon, not simply a one-year 'snapshot'.

Dynamic Assessment: Once impacts are being assessed over time, the dynamics of economic decisions and interactions become important. In particular, capital investment decisions are partly determined by expected future conditions. Consequently, this study had to use an analytic approach based on a dynamic framework to estimate how the power system might be operated in any given time period in which operating decisions take expectations of future system conditions into account.

Integration of Generation and Transmission: Another important characteristic of the electric power system is the tight linkage between the transmission grid and power plant operating decisions. As a network industry, electric power flows and feasible transactions are limited by transmission capacity under real-time operating conditions. Many of the key policy issues involved in the Commission's RTO policy also concern aspects of the transmission system. This requires an analytic framework that represents the transmission grid and its interactions with power generation.

Differentiation of Load Segments: Varying levels of demand (load) create quite different sets of system conditions in this industry. This is because of the changes in marginal costs of generation as more expensive power plants respond to higher demand, and the fact that different transmission links become full or congested as load increases. This means that the analytic framework must take varying load levels (load segments) into account.

Interregional Energy Flows and Capacity Markets: Interchanges between regions provide the basis for effective energy markets, allowing for price equilibration when transmission capacity is available and establishing price signals for operating and investment decisions. The framework used for this analysis thus had to be able to assess such interchanges on an economic basis, and to take them into account over time for dynamic analysis.

Accounting for Transmission System Investment: Investment in transmission system upgrades, including new lines and enhancement of existing line transfer capabilities, is especially relevant to assessment of RTO policy. Some form of accounting for such investments is another analytic requirement of the present study.

Using the issues identified by the Commission and building on previous work done by FERC and others, a foundation for this cost/benefit study has been established that ensures sufficient scope and analytic rigor. Where certain issues cannot be incorporated into a dynamic, long-run quantitative framework, they have been identified and efforts made to assess their impact using other methods. Similarly, where issues raise questions that go beyond the available resources or scope of this analysis, they have also been identified and suggestions made for further research.

The next section of this report lays out the analytic approach developed for national economic cost/benefit assessment of RTO policy. It also describes the development of a number of alternative scenarios intended to represent uncertainty and to identify critical factors that determine the outcome of the analysis, and the detailed assumptions that were employed in the analysis. Results are presented and discussed in the concluding section.

2 Analytic Approach

The preceding section describes a number of requirements for an analytic framework designed to conduct an economic cost/benefit assessment of RTO policy. By identifying a set of potential changes to the operation of the electric power system, and resulting economic performance, this basis for developing an analytic approach seeks to be both comprehensive and rigorous, employing sufficient quantitative detail to accurately represent potential outcomes of RTO policy. Close collaboration with the Commission and cooperative efforts with other researchers and state regulators were an integral part of the scenario development process, resulting in an analysis that attempts to estimate a range of potential economic impacts using the best available information from a variety of sources.

In most sectors of the economy, such assessments are conducted using techniques of industrial economics and institutional analysis. However, the characteristics of the electric power sector make it particularly well suited for computer simulation modeling. Such models have been used for planning and analytic purposes for decades, owing to the interconnected nature of the transmission grid, the prevalence of centralized dispatch for generation, relatively small number of decision agents, and high quality of data.

Taking advantage of the benefits of computer simulation modeling allows for national-scale analysis using extremely detailed models that are well tested. Most other economic sectors are represented poorly in national computer simulation models, typically at a high level of aggregation into simple production functions. The ability to utilize detailed optimization models gives an analytic advantage to studies in the electric power sector.

In this study, FERC produced estimates of economic impacts associated with the proposed policy primarily using ICF's IPM® computer simulation framework. The IPM® modeling framework is based on detailed, generation unit-level, publicly reviewed assumptions with regard to the costs and performance of electric power supply options, with full integration of fuel and environmental markets. IPM® has been used to support public agencies including the FERC in the preparation of formal rulemakings, and has undergone extensive public review and comment on technical aspects of the modeling framework.

While the IPM® framework is a central element of this cost/benefit analysis, there are critical topics that cannot be directly addressed using this particular computer simulation model. By placing the IPM® analysis into a broader overall framework, this study provides a quantitative context for consideration of the economic issues involved in RTO policy. When possible, issues falling outside the scope of the study or beyond the immediate analytical assessment are placed in perspective and suggestions made regarding the role of further analysis.

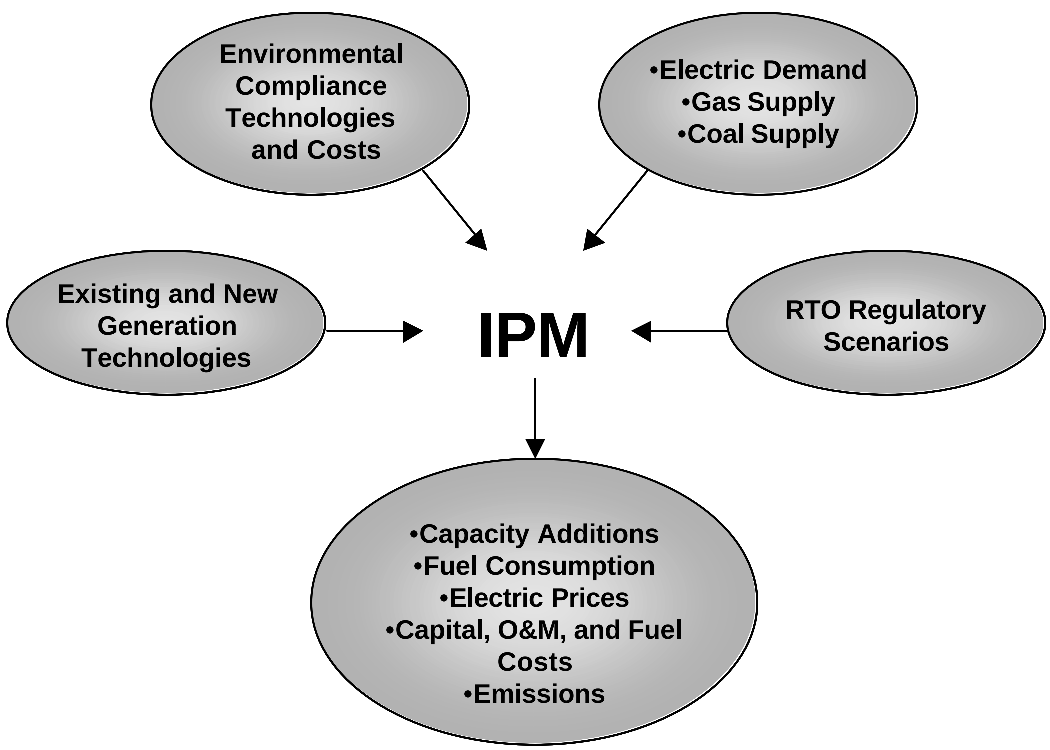
This section first discusses the IPM® framework. Next, it describes the scenarios used to evaluate the RTO policy. Finally, it discusses how IPM was used to model the scenarios and details key assumptions of the analysis.

2.1 Integrated Planning Model Overview

ICF's national Integrated Planning Model (IPM®) combines wholesale electric markets, air pollution regulations, and fuel markets into one integrated framework. IPM® is a computer-based linear programming model with detailed representation of every electric boiler and generator in the US. The model is used to determine the least cost means of meeting electric generation energy and capacity requirements, subject to transmission, fuel and air pollution limitations.

The following figure illustrates the integrated analytic approach that informs this part of the analysis. As discussed in later parts of this section, assumptions concerning the regulatory scenario to be simulated, cost and performance of new generation technologies, electric market conditions, transmission limits, and fuel supply and transportation costs are combined into model scenarios and input into the IPM® framework.

Figure 2.1: Integrated Analytic Framework



All IPM® regions have a representation of the electric transmission system that connects neighboring regions. The inter-regional transmission connections allow for the transfer of both capacity and energy and allow for broad price equilibration when transmission capability is available. These transmission links are aggregated from line-specific data and form a transportation-type network, which is not intended to assess engineering or reliability limits on a short-term basis but rather to represent a reasonable estimate of long-term transfer limits. IPM® divides the US markets into model regions based on persistent transmission bottlenecks (i.e. sub-regions in which spot prices are expected to diverge significantly). For this study, a total of 32 US regions were modeled in order to best capture the effects of RTOs on the national grid.

2.2 Modeling Scenarios: Base Case and Policy Scenarios

For this study, IPM® is used to analyze three main Policy Scenarios and two Sensitivity Cases developed by FERC to quantify the benefits described in FERC Order No. 2000. These cases are evaluated relative to a Base Case that assumes that regulatory and market conditions reflecting Order No. 888 as a no-RTO status quo govern the wholesale power market over the entire time horizon of the study. The policy scenarios differ from the Base Case in that they reflect an RTO structure as envisioned in Order No. 2000. The Sensitivity Cases isolate specific aspects of the scenarios, such as the RTO regional specification, to examine particular policy issues and indicate how key assumptions drive modeling results.

2.2.1 Base Case

The purpose of a Base Case is to establish points of comparison for policy analysis and to show how underlying trends in power markets play out in the IPM® framework. The Base Case represents current estimates of underlying market conditions and regulatory policy under Order No. 888, including market inefficiencies that exist within and across regions. Base Case assumptions are provided later in this chapter.

2.2.2 Policy Scenarios

The policy scenarios are defined to explore the five categories of benefits listed in Section III.B of Section 1 in Order No. 2000:

- RTOs would improve efficiencies in the management of the transmission grid;
- RTOs would improve grid reliability;
- RTOs would remove opportunities for discriminatory transmission practices;
- RTOs would result in improved market performance; and
- RTOs would facilitate lighter-handed governmental regulation.

Estimates of these benefits, to the extent that they affect elements of the electric system that are represented by model parameters, are made through comparison of the Base Case and policy scenario projections.

The RTO initiative is expected to increase power trading through better management of transmission infrastructure. The elimination of pancaked rates, better congestion management, internalization of loop flow effects, elimination of transmission related market power, and availability of more reliable ATC values all impact the power markets in the direction of removing transmission related barriers to competitive wholesale power markets.

The formation of RTOs is also expected to increase market liquidity. Markets function better when increased liquidity allows for more participants through price revelation, information transfer, and choices for both buyers and sellers. Greater liquidity can be achieved by lowering barriers to trade. There is thus a logical connection between a better functioning transmission grid, which serves as the transportation system for the power market, and improved market function in general.

For example, in an illiquid market, it is more risky for market participants to rely on short-term spot markets for final energy delivery, and it is more advantageous for owners of generation to hold back supply, partly in order to ensure they can meet their own delivery obligations. This can lead to increased reliance on higher-priced forward markets (relative to an optimal mix of spot and forward markets) and increased real-time reserve requirements.

Improvements in the functioning of power markets due to better utilization of the transmission infrastructure are also expected to impact some of the engineering and economic fundamentals of these markets. Increased opportunities for selling power in a larger area will heighten competition for customers, and thus would increase incentives for power plants to function more efficiently. As in previous FERC analysis, the enhanced incentives for power plant operation are assumed to result in improvement in their availabilities, a lowering of their heat rates, and a lowering of their O&M costs. Increased availabilities coupled with greater opportunities of importing power from neighboring regions in time of need could result in a lowering of reserve margins. In addition, lower wheeling charges and greater opportunities for building new transmission lines may also occur.

The policy scenarios analyzed here represent these benefits through a variety of assumptions about unit and system operation. The following table outlines the Base Case, Policy Scenarios, and Sensitivity Cases proposed for this analysis.

Table 2.1: Base Case and Policy Scenario Specifications

<table>
<tr><th rowspan="2">Parameter</th><th colspan="6">Scenario</th></tr>
<tr><th>Base Case</th><th>Transmission Only</th><th>RTO Policy</th><th>Demand Response</th><th>Sensitivity I: Larger RTOs</th><th>Sensitivity II: Smaller RTOs</th></tr>
<tr><td>RTO Configuration</td><td>No RTOs; 32 region structure</td><td colspan="3">4 RTOs and ERCOT</td><td>2 RTOs and ERCOT</td><td>9 RTOs and ERCOT</td></tr>
<tr><td>Reduced Inter-Regional Barriers to Trade</td><td>Base Case assumption</td><td colspan="5">No transmission charges within RTOs; charges converge to $2 per MWh between RTOs beginning in 2004</td></tr>
<tr><td>Transmission Capability Expansion</td><td>Base Case assumption</td><td colspan="5">Increased by 5% from 2004 onward</td></tr>
<tr><td>Capacity Sharing</td><td>75% of energy transfer capability</td><td colspan="5">100% of electricity transfer capability</td></tr>
<tr><td>Reserve Margins</td><td>Decline over time to system-wide average of 15% by 2020</td><td colspan="5">Decline over time to system-wide average of 13% by 2020</td></tr>
<tr><td>Efficiency Improvements</td><td colspan="2">Base Case assumption</td><td colspan="4">Fossil-fired Units: Heat rate improves by 6% by 2010 and availability increases by 2.5%</td></tr>
<tr><td>Demand Response</td><td colspan="3">Not analyzed</td><td>3.5% reduction in peak beginning in 2006</td><td colspan="2">Not analyzed</td></tr>
</table>

The Sensitivity Cases isolate a key factor in the evaluation of the RTO policy: regional RTO configuration. The two Sensitivity Cases vary from the RTO Policy Case only in the regional specification of the RTOs. Sensitivity Case I broadens the scope of the RTOs to the widest degree possible given current physical transmission constraints, while Sensitivity Case II disaggregates the 4 RTOs in the RTO Policy Case into smaller organizations, leaving existing ISOs largely untouched. The regional configurations for the RTO Policy Case and the Sensitivity Cases are described in Section 2.3.1.

2.3 Modeling RTO Scenarios with IPM®

This section provides an overview of how IPM® was used to model the scenarios described above.

2.3.1 RTO Regional Configuration

For this analysis, the 32 model regions shown in Figure 2.2 below are intended to capture commercially significant historical transmission bottlenecks within the US and can be considered to be potential building blocks of a power system blanketed end-to-end with RTOs.

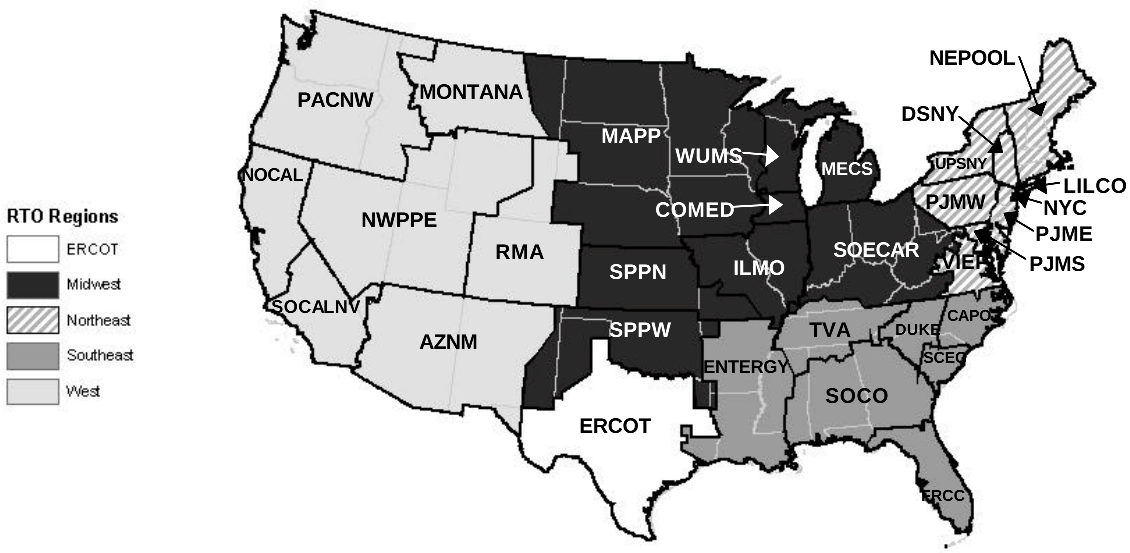
Figure 2.2: IPM® Regions

For the RTO Policy, Transmission Only and Demand Response Cases, four RTOs were specified, along with ERCOT, as the basis for this cost-benefit analysis. The sub-regions within the RTOs have separate load profiles and generating capacity, as in the Base Case, and are linked by transmission facilities with limited transfer capability, also as in the Base Case. Within the policy scenarios, however, the cost of sending power from one sub-region to another and other market and unit operational details will change relative to the Base Case, as described below. The RTO regional configuration used in the Transmission Only, RTO Policy, and Demand Response Cases is shown in the following table and figure.

Table 2.2: RTO Regional Specification – Main RTO Policy Cases

RTO	IPM® Sub-regions (Map Abbreviations)
West	Northern and Southern California (NoCAL and SoCAL), Pacific Northwest (PACNW), Montana, NWPP-East (NWPP-E), Rocky Mountain Area (RMA), Arizona and New Mexico (AZNM)
Midwest	SPP (SPP-N and –W), ECAR (So. ECAR and MECS), MAIN (ILMO, COMED, and WUMS), MAPP
ERCOT	ERCOT
Southeast	SERC (Southern, SCEG, CP&L, Duke, TVA, Entergy), Florida
Northeast	NEPOOL, PJM, New York, VIEP

Figure 2.3: RTO Regional Specification – Main RTO Policy Cases

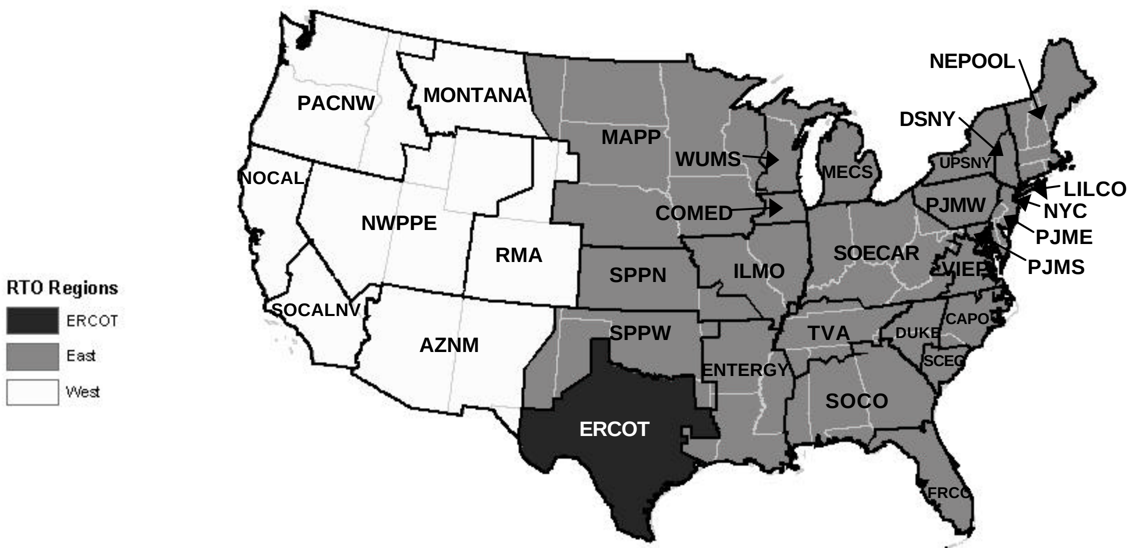


Sensitivity Case I, Larger RTOs, aggregates the RTOs shown above into only 2 large RTOs and ERCOT.

Table 2.3: RTO Regional Specification – Sensitivity Case I: Larger RTOs

RTO	IPM® Sub-regions (Map Abbreviations)
West	Northern and Southern California (NoCAL and SoCAL), Pacific Northwest (PACNW), Montana, NWPP-East (NWPP-E), Rocky Mountain Area (RMA), Arizona and New Mexico (AZNM)
East	SPP (SPP-N and –W), ECAR (So. ECAR and MECS), MAIN (ILMO, COMED, and WUMS), MAPP, SERC (Southern, SCEG, CP&L, Duke, TVA, Entergy), Florida, NEPOOL, PJM, New York, VIEP
ERCOT	ERCOT

Figure 2.4: RTO Regional Specification – Sensitivity Case I: Larger RTOs

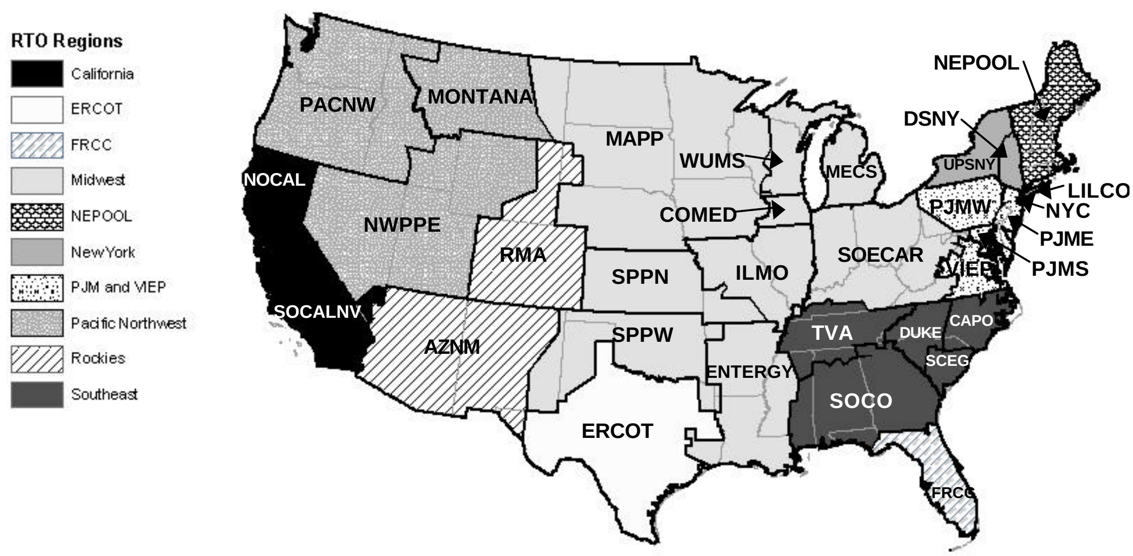


Sensitivity Case II, Smaller RTOs, instead disaggregates the RTO Policy Case RTOs into organizations that preserve, roughly, existing ISOs, and expand the Midwest to include Entergy.

Table 2.4: RTO Regional Specification – Sensitivity Case I: Smaller RTOs

RTO	IPM® Sub-regions (Map Abbreviations)
California	Northern and Southern California (NoCAL and SoCAL)
Pacific Northwest	Pacific Northwest (PACNW), Montana, NWPP-East (NWPP-E)
Rockies	Rocky Mountain Area (RMA), Arizona and New Mexico (AZNM)
Midwest	SPP (SPP-N and –W), ECAR (So. ECAR and MECS), MAIN (ILMO, COMED, and WUMS), MAPP, Entergy
Southeast	SERC (Southern, SCEG, CP&L, Duke, TVA)
FRCC	Florida
NEPOOL	NEPOOL
PJM and VIEP	PJM, VIEP
New York	New York
ERCOT	ERCOT

Figure 2.5: RTO Regional Specification – Sensitivity Case II: Smaller RTOs



2.3.2 Calibration

Current market impediments, such as congestion, strategic behavior and market power, and pancaking of rates, lead to out-of-merit dispatch resulting in increased costs. IPM® represents these inefficiencies within the current markets in the Base Case by calibrating the model to year 2000 generation by region. Transmission charges were therefore adjusted to represent the inefficiencies that the RTO policy purports to eliminate. These adjustments are called ‘transmission hurdle rates’ in this report to distinguish them from direct costs, such as tariffs.

Transmission hurdle rate assumptions (in dollars per megawatt-hour -- $/MWh) for this study were developed using IPM® in an iterative process. Hurdle rates were increased or decreased between ICF sub-regions a number of times in order to duplicate both the generation distribution and generation mix reported in actual year 2000 data for the entire US as provided in EIA Forms 714 and 900. Calibration was performed using historical data from 2000, including regional demand and hourly load, regional delivered fuel prices, hydro and nuclear generation, transmission capability, and foreign imports. The final hurdle rates in IPM® yield results matching regional generation levels within 5% and capture interregional transmission volumes.

Hurdle rates are used in this exercise to represent both actual transmission usage fees and market inefficiencies. The inefficiencies represented here include market power, open access limitations, non-economic contracts or other barriers that may impede the economic flow of power from one region to another. Existing ISOs (California, PJM, New York, and New England) are assumed to have no internal hurdle rates.

2.3.3 Base Case Specification

The hurdle rates resulting from the calibration exercise served as the basis for the Base Case projection. The Base Case assumes no further FERC policy regarding regional transmission structures, i.e. the Order No. 888 status quo. As a result, the hurdle rates are assumed to decline gradually at 2.5% per year until leveling off in 2010 and remaining constant thereafter to represent modest improvements in the management of the grid. Other Base Case assumptions will be provided in the assumptions section.

2.3.4 Policy Scenario Specification

Analyzing the policy scenarios and Sensitivity Cases requires that several adjustments be made to the Base Case assumptions. The key adjustments are described below for each Scenario. Many of these assumptions are adapted from previous FERC analyses, as reflected in the EIS for Order No. 888 and the EA for Order No. 2000.

The ***Transmission Only Case*** combines several potential benefits of RTOs into one scenario using the following model parameters:

- *Reduced Inter-Regional Barriers to Trade:* Hurdle rates within the four RTOs decline to zero for 2004 and onward. Rates between RTOs converge from the hurdle rates used in the Base Case to $2 per MWh by 2004 and remain at that level throughout the study horizon.

- *Transmission Transfer Capability Expansion:* RTOs may lead to better incentives for transmission investment and improved regional planning. In IPM®, this expansion is represented by increasing the effective transfer capability of transmission links among sub-regions within an RTO at no incremental cost by 5% beginning in 2004. Capabilities between RTOs are not changed from Base Case levels.

- *Capacity Sharing:* Regions can share generating capacity across transmission links in the IPM® simulation framework, in order to meet reserve margin requirements, but there are losses (effective capacity derating) when this occurs in the Base Case. Capacity sharing in the RTO Policy Scenario is allowed to equal total energy transfer capability beginning in 2004.

- *Reserve Margins:* Larger RTO regions will be able to pool their reserve resource more effectively, leading to reduced reserve margin requirements, particularly because larger regions lead to smaller contingency impacts from the loss of individual system elements (the larger the region, the smaller each element's share of capacity). As a result, reserve margin requirements in the Policy Scenarios decline by 2020 to a system average of 13% from the Base Case average level of 15%.

The ***RTO Policy Case*** maintains these transmission-related changes. In addition, changes are included to represent potential improvements in other aspects of the power markets:

- *Efficiency Improvements:* Previous work on competitive power markets done by FERC and others has often assumed that competitive pressure will result in generators moving toward the 'best practice frontier' in order to maintain competitive position. For this scenario, specific generator parameters, including unit availability and heat rates, are adjusted to reflect this effect.

The ***Demand Response Case*** includes the changes above and adds:

- *Demand Response:* Improvements in the ability of consumers to react to price changes can lead to dramatic improvements in market performance. In IPM®, this response is represented by reducing regional peak generation requirements by 3.5% beginning in 2004. This methodology is discussed in greater detail in the Assumptions section.

In discussing the results of these policy scenarios, greater attention is given to the RTO Policy Case, because this case is considered to be the most likely outcome of RTO policy by the Commission. The other policy scenarios are intended to capture uncertainty in the potential economic outcomes of RTO policy. Even in the Demand Response Case, however, assumptions are intended to be reasonable rather than optimistic, meaning that the Demand Response Case is not intended as an upper bound. Such an upper bound on estimated benefits would require a policy scenario that changes several assumptions and would produce substantially greater economic benefits than the cases modeled here.

2.4 Analytic Assumptions

In order to represent the key interrelationships among the power, fuel and emissions markets, IPM® draws upon a detailed database of all of the generating units connected to the US power grid. The database that supports IPM® contains information regarding unit heat rates, capacities, emission rates and operational constraints. This database, combined with IPM®'s capabilities to capture interactions in the converging power, fuel and emissions markets, provides a strong analytical tool that offers a unique level of detail in a national simulation model. This section describes the key assumptions that underlie the Base Case and policy scenarios.

For the purpose of this analysis, assumptions can be divided into two types: (1) assumptions that are altered among cases, and (2) assumptions that remain the same across the Base Case and policy scenarios. The previous section touched on the first category of assumptions. This section provides detailed discussion of those assumptions and their role in IPM®. Section 2.4.2 then discusses those assumptions that remained the same in all cases.

2.4.1 Assumptions That Change Across Cases

All of the policy scenarios modeled for this cost/benefit assessment include changes to the following IPM® assumptions:

1. Transmission charges and transfer capabilities
2. Reserve margins.

The RTO Policy Case added changes to the following classes of assumptions:

3. Unit cost and performance
    a. Availability
    b. Heat rates

The Demand Response Case adds one more category of assumption change:

4. Price response and distributed generation

Transmission Charges and Capacities

Central to the definition of the RTOs within IPM® are the transmission hurdle rate and transfer capability assumptions that define the links between the sub-regions. These characterizations are used in IPM® to represent the implementation of an RTO structure, and to simulate potential changes to grid operations and resulting economic shifts that could be realized under specific RTO policies.

For this study ICF has aggregated individual transmission lines into transmission paths that link the 32 model regions. This approach is consistent with the way NERC transmission studies group lines. IPM® models each interregional link as one line with a maximum flow capability, energy and capability loss, and hurdle rate. The hurdle rates are modeled in IPM® as transmission usage charges, or a dollar per MWh charge for each MWh sent through a particular path.

The hurdle rates are used to constrain inter-regional flows in order to reflect actual system usage, so these model charges also include implicit barriers to trade as seen in historic power flow data. For example, if the model simulated year 2000 market conditions but the result over-estimated the amount of power actually transmitted between two regions, the hurdle rate was adjusted upward to limit this flow of power to observed levels. This process was iterated until the hurdle rates limited all the regional power flows to within 5% of actual year 2000 generation patterns.

The actual tariffs, including OASIS posted and other publicly disclosed tariffs, are in principal included in the transmission hurdle rates used in this approach. But because there is limited information on the actual transmission rates paid for each transaction in the year 2000, it is not possible to directly compare the modeled hurdle rates to actual transmission charges for that year. Data on public tariffs is maintained and used for comparison purposes in other modeling applications, and can be used as the only representation of transmission charges. But this would not be an accurate representation of the actual rates paid (many or most of which are not disclosed), nor would it lead to an accurate model simulation for the year 2000.

Transmission path capability was developed by ICF using public sources. The primary sources were the 2000 NERC Summer Assessment and the 2000/2001 Winter Assessment. These studies are published by NERC annually and include estimates of transfer capability between NERC defined sub-regions. The IPM® regions shown in Figure 2.2 above are based on NERC regional definitions. Transfer capability modeled is the average of the NERC Summer and Winter Assessments between NERC regions. Where available, additional transmission studies have been used to augment the NERC data. This is the case specifically the in the Northeast where NE-ISO and NYPOOL studies were consulted to determine both intra- and inter-ISO transmission capability. Additional sources include the VACAR ECAR MAAC Study Group (VEM) and MAAC ECAR NPCC Study Group (MEN) studies and, in some cases, regional coordinating councils. In a few instances internal ICF assumptions were used for particular links; these are generally derived from load flow modeling and project-specific information.

This method of aggregating transmission links and using static transfer capabilities is an important aspect of the analytic framework used in this study. More detailed engineering models that can estimate actual power flows across all system elements are often used for reliability assessments and other short-run modeling applications. The results of such models are not directly comparable when system conditions change, and system conditions are constantly changing. As a result, any fixed estimate of transmission transfer capability is necessarily subject to important limitations. The established practice of using such transfer capability estimates in long-run optimization models, while a simplification, is required in order to allow other aspects of the system to be fully represented. This is why sensitivity analysis of important assumptions is often conducted, to assess the impact of uncertainty on analytic results.

The hurdle rates resulting form the calibration exercise were used as a starting point for the Base Case and policy scenarios to insure that all cases captured those barriers to trade. In the Base Case, the rates were assumed to decline at 2.5% per year until leveling off in 2010 to reflect moderate improvements to the management of the transmission grid without requirements beyond existing policies.

Adjustments were made to Base Case assumptions in the policy scenarios to simulate changes resulting from the proposed rule itself and from improvements in the transmission system brought about by better management of the grid. Hurdle rates within RTOs declined to zero for 2004 and onward. Rates between RTOs converged from the hurdle rates used in the Base Case to $2 per MWh by 2004 and remained at that level throughout the time horizon of the study. The policy scenarios also assumed expansion of transmission capability beyond Base Case levels. The effective transfer capability of transmission links among sub-regions within an RTO increased by 5% beginning in 2004. Capabilities between RTOs were not changed from Base Case levels.

Reserve Margins

IPM® models reserve margin requirements in order to capture ongoing reliability requirements. These reserve margins require the model to build economic capacity additions to meet peak demand plus a specified percentage in each model region. Historically, reserve margins have been declining as more inter-regional power transfers and increasing real-time response options have reduced the need for dedicated reserve capacity. Each model region has a specific trajectory of projected reserve margin requirements. Current reserve margin requirements are based on a number of sources, primarily NERC projections and regional reliability council estimates.

Reserve margins in the Base Case reach a system average of 15% by 2020. Except in the Northeast and Florida, reserve margins remain at a constant 15% over time. In the Northeast (PJM, New York and NEPOOL), reserve margins begin closer to 20% in 2003 before converging with the rest of the system at 15% by 2020. Florida maintains a 20% mandatory reserve margin through 2010, due to existing state reliability requirements, and then declines slightly in the long-term.

In the policy scenarios, regional reserve margins are adjusted downward to achieve a system average of 13% by 2020. This assumption is intended to capture the pooling of generation resources likely to occur within a large RTO region. With a larger base of assets available to meet generation needs, the loss of individual system elements will have a smaller impact on the region's ability to meet demand, thereby requiring a smaller reserve margin.

Unit Cost and Performance

The RTO Policy Case is based on the premise that open access transmission and clear market rules will increase incentives for generators to improve efficiency and unit performance. As markets widen and competition increases, less efficient, higher cost generators will face competitive pressure to improve, or be forced from the market. Several potential effects of such incentives are modeled, consistent with the methods employed in other national studies. Further analysis on unit performance and incentives could refine the assumptions used here.

The two main areas of improvement expected are in unit availability and efficiency. Increased competition is likely to encourage generators to reduce maintenance outage time, and at the same time improve maintenance procedures to decrease forced outages. For the purpose of this analysis, this improvement is assumed to be 2.5% on an annual basis for fossil units between 2004 and 2010. Efficiency gains were also modeled by decreasing the full load heat rate of fossil-fired units by 1% per year between 2004 and 2010. Both of these assumptions are held constant after 2010.

These assumptions were based directly on previous analyses of national electric sector restructuring policy conducted by DOE and the FERC. New research on the actual performance of generating plants in competitive markets was not available for this study; improvements in the knowledge base on this critical topic would be one important area for further research. The intent of this study is to indicate the importance of generator efficiency to the overall economic impacts of RTO policy using existing analysis that has been subject to public review and scrutiny, rather than establishing a specific estimate of improvements based on statistical analysis or other comparative methods.

An additional area of potential generator improvement, fixed operating and maintenance (fixed O&M), has been estimated in previous studies of competition in the electric power sector. This type of cost does not directly affect operating decisions in the model used here, since changes in production level at a unit do not change such fixed costs. However, an estimate of potential fixed O&M improvements was carried out using assumptions similar to those used in other studies. Because this was not part of the modeling it is discussed along with other non-modeled system elements in Section 3.

Demand Response

The demand estimates in the Base Case and policy scenarios already incorporate a limited degree of demand response. NERC estimates for load, the basis for the load assumptions in this analysis as described later in this section, include load management, or direct load control and interruptible demand. An analysis of the data suggests that these account for about 4% of peak demand nationally.

What is not included in these estimates, however, is price responsive load, or the load that is responsive to high peak prices. It is assumed that customers will lower their demand in the face of higher prices (i.e., demand elasticity). Customers can be exposed to higher peak prices through either time of use rates or real-time pricing programs. It is likely that these programs will be more prevalent in future years. The additional demand response included in the Demand Response Case reflects implementation of these pricing programs.

The introduction of time-varying demand (either time of use rates or real-time pricing) will introduce variable prices to customers at different points during the year and day. In particular, if customers are exposed during peak periods to prices that reflect on-peak wholesale prices, based on standard economic theory, it is expected that they will reduce or shift their load to lower price periods.

The staff paper on demand responsiveness prepared by Commission staff, as mentioned in Section 1, discusses the link between market design, infrastructure technology, and demand response. The paper also elaborates on the benefits that demand response can provide to consumers through lessened volatility and mitigation of potential market power abuse. This is consistent with other work in this area as well as the approach employed for this study.

In order to estimate this aspect of demand response, simple measures of elasticity were applied to a set of regional prices disaggregated by load segment. For the final demand response assumption used here, a short run price elasticity of –0.1 was applied to half the customer base in each region, yielding a conservative estimate of 3.5% as a peak reduction under assumed more transparent pricing conditions. This estimate was applied to all regions in the relevant scenarios. Because of the complexity, uncertainty and importance of demand response in electric power markets, this assumption was used as a sensitivity case and is meant to be illustrative, although it is reasonable and consistent with recent analytic work in this area.

2.4.2 Invariant Assumptions

Several types of assumptions remain the same across the Base Case and policy scenarios. This section provides an overview of those assumptions.

Regional Structure

The national IPM® framework captures key interrelationships among wholesale power, fuel and environmental markets. To capture regional variations in wholesale power prices, IPM® divides the US electric system into model regions with a representation of the electric transmission system connecting neighboring regions. The regional representation within IPM® is flexible and can be structured to offer a level of resolution that captures transmission bottlenecks located throughout the US electric power grid. For this analysis, the US is divided into 32 regions, each having a representation of the transmission interconnections that link one region with the next.

While the transmission charges among regions change from the Base Case to the policy scenarios to reflect the formation of the RTOs, the sub-regions maintain their Base Case demand growth and load shapes, new technology cost and performance assumptions, fuel market characterizations, and environmental regulatory requirements.

Load Growth and Load Shape

Forecast electricity demand growth represents a key assumption in this analysis. Given regional variations in demand growth, an individual demand growth forecast for each of the IPM® modeling regions is provided. The demand forecast for each model region is assumed to climb at about the rate of growth in GDP through 2005. Beyond 2005, growth in electric demand declines with the introduction of real time pricing for retail customers.

The table below details starting points and average growth rates for net internal demand and net energy for load for the 32 model regions included in this study. Net energy for load is the total electrical energy requirements of an electric system as provided by the "NERC Electricity Supply and Demand (ES&D)" for year 2000 and forecast. Net internal demand is modeled as internal demand less direct control load management and interruptible demand, again provided by NERC ES&D for year 2000 and forecast.

Table 2.5: Load Growth Assumptions

Region	2000 Net Energy for Load (GWh)	Average Annual Growth to 2020	2000 Net Internal Demand (MW)	Average Annual Growth to 2020
Arizona-New Mexico	87,895	3.8%	16,805	3.7%
CP&L	58,321	3.0%	10,424	3.1%
COMED	90,271	2.1%	19,295	2.2%
Downstate NY	34,632	1.4%	6,439	1.8%
Duke	101,435	3.0%	18,132	3.1%
Entergy	159,146	2.0%	29,262	2.1%
ERCOT	286,318	2.2%	54,451	2.7%
Florida	196,562	3.5%	34,476	3.9%
ILMO	91,737	2.1%	16,583	2.2%
LILCO	18,610	1.4%	4,200	1.9%
MAPP	165,028	2.4%	30,450	2.3%
MECS	94,986	2.3%	16,700	2.6%
Montana	12,462	1.8%	2,072	1.9%
NEPOOL	124,888	1.7%	21,919	2.1%
Northern California	113,379	2.2%	21,332	2.4%
NWPP-East	36,731	1.8%	5,284	1.9%
New York City	47,819	1.4%	8,891	1.9%
Pacific Northwest (PACNW)	191,898	1.8%	27,617	1.9%
PJM-E	133,522	1.8%	24,414	2.4%
PJM-S	62,955	2.7%	11,511	2.4%
PJM-W	65,845	1.7%	12,040	2.4%
Rockies (RMA)	51,481	2.2%	8,470	2.2%
SCEG	52,071	3.0%	9,309	3.1%
Southern California	170,070	2.2%	31,998	2.4%
Southern	210,023	3.8%	41,621	3.3%
Southern ECAR	450,973	2.3%	72,172	2.6%
SPP-North	58,241	2.8%	12,683	2.7%
SPP-West	111,213	2.8%	22,611	2.7%
TVA	160,549	1.7%	27,128	2.0%
Upstate NY	55,578	1.4%	8,608	1.7%
VIEP	83,512	3.0%	14,926	3.1%
WUMS	60,916	2.1%	10,268	2.2%
System	**3,639,067**	**2.4%**	**652,091**	**2.6%**

Fuel Market Assumptions

Effectively integrating the fuel markets, IPM® also simulates coal production, transportation, and consumption. For this purpose, the model has supply curves for 40 coal producing regions and contains over 10 coal types distinguished by rank and sulfur content. Each power plant is assigned to one of over 40 coal demand regions characterized by location and mode of delivery including rail, barge, and truck. Transportation costs are specified for each supply and demand region link.

Natural gas prices are determined within the model using a similar supply curve and transportation network representation. The natural gas price forecast and the related curves are derived in part from results from ICF's North American Natural Gas Analysis System (NANGAS). The NANGAS model allows assessment of gas resources and markets from reservoir to burner-tip, working from a database of more than 17,000 US and Canadian reservoirs. The Base Case gas price trajectory is provided in the table below.

Table 2.6: Base Case Henry Hub Gas Price Trajectory

Year	2000$ per Million Btu	Nominal $ per Million Btu
2003	3.20	3.45
2004	3.12	3.44
2005	2.78	3.14
2010	2.85	3.65
2015	2.74	3.96
2020	2.63	4.31

Environmental Regulation and Compliance

The Base Case and policy scenarios assume existing, final regulations for SO_2 and NO_X including implementation of future requirements in existing final regulations:

- Phase II of the Title IV Clean Air Act (CAA) SO_2 emissions trading program adjusted for the recent settlement of legal actions.
- NO_X SIP Call program that caps summer NO_X emissions in 19 states spanning the Northeast, Midwest and Southeast. The NO_X SIP Call Policy takes effect in May 2003 in SIP Call states currently participating in the Ozone Transport Region (OTR) trading program. The remaining SIP Call states enact the policy in May 2004.

No potential or speculative future air emissions regulatory changes are assumed in the Base Case or policy scenarios.

The integration of emissions markets in IPM® is achieved with a detailed representation of air regulations that are met through compliance decisions that reduce overall emissions for a given pollutant. IPM® endogenously determines the optimal compliance for meeting environmental air regulations for every plant in the US. The compliance options considered in IPM® encompass the full range of choices available:

- Pollution control technologies such as flue gas desulfurization (scrubber), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and gas-reburning,
- Allowance purchases,
- Repowering,
- Retirement,
- Dispatch adjustments, and
- Fuel switching.

Capacity Retirements

Within the IPM® modeling framework, fossil power plant retirements can be forced at a specific age and/or retirements can be determined endogenously based upon the relative economics of a unit. Because plant age has not been a reliable indicator of plant retirements in the past, fossil plant retirements are determined endogenously within the model. Economic retirements occur whenever the going forward fixed costs of a unit cannot be recovered from wholesale power price sales.

Many nuclear units located throughout the US are approaching the end of their existing operating licenses issued by the Nuclear Regulatory Commission (NRC). For the purpose of this analysis, nuclear units are assumed to not be decommissioned at the end of their 40-year operating license. Rather, it is assumed that owners of nuclear assets will move forward with relicensing efforts through the NRC.

Other Invariant Assumptions

Other classes of assumptions used to model the electric power sector in IPM® also remained unchanged across the Base Case and policy scenarios. These assumptions include:

- Financial assumptions
- Cost and performance of capacity additions

2.5 Treatment of Non-Modeled System Elements

In considering the role of simulation modeling in an analysis of this type, it is useful to consider the structure of general costs and revenues in the electric industry, and to identify what portion of the electric system is typically modeled using IPM®. Because the modeling framework only estimates costs that are relevant for system operation and investment decisions (as detailed below), a number of financial flows in the industry are not directly represented. Some of these costs are relevant to RTO policy assessment while others are not. This section lays out the conceptual framework for considering these issues, and the treatment of non-modeled, relevant system costs.

In 1997, the size of the electric industry amounted to about $215 billion. This includes revenues earned by investor- as well as publicly-owned utilities. By 2000, the industry grew by approximately 6 percent to $228 billion.[10] Table 2.7 shows the distribution of industry revenues between different types of utilities.

[10] Electric Power Annual 2000 Volume I, US Energy Information Administration, Table A-21 "Retail Sales of Electricity, Revenue, and Average Revenue per Kilowatt-hour by US Electric Utilities to Ultimate Consumers by Census Division, and State, 2000 and 1999."

Table 2.7: Revenue from Sales to Ultimate Users by Utility Type, 1997 (Million 1997$)

Utility Type	Total Revenue
Investor-Owned	168,701
Municipal	27,744
Cooperative	17,583
Federal	1,035
Total	215,063

Source: Supporting Analysis for the CECA, DOE/PO-0059, May 1999, Table 2.

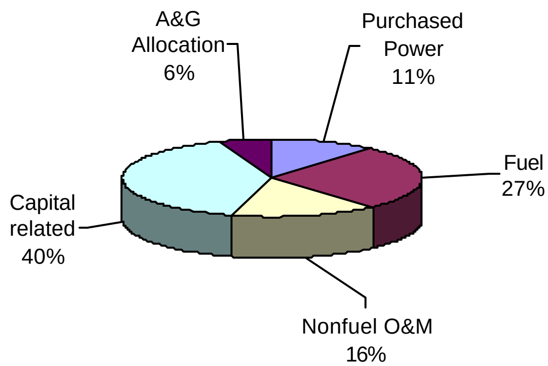
Complete data regarding the costs incurred by all types of utilities is not available. However, investor-owned utilities comprise the largest part of the electric industry. Thus, to give a sense of costs incurred by the industry, Table 2.8 lists the primary costs incurred by investor-owned utilities in 1995. Public entities, independent power producers and others would not be expected to have a similar cost breakdown; some public entities operate mainly transmission and distribution systems, while many independent power producers own generation resources exclusively.

The three cost categories directly represented in the IPM® simulation framework include future capital expenditures on new power plants and pollution controls, operation and maintenance costs, and the cost of fuel inputs. Figure 1 shows that these three categories comprise 83% of the production costs incurred by investor-owned utilities. Due to the forward-looking nature of the model, however, this leaves approximately 17% of production costs unaccounted for. Although it captures the bulk of the industry with production costs, IPM® does not directly calculate any of the costs related to the transmission and distribution of power.

Table 2.8: Investor-Owned Utility Costs, 1995 (Million 1995$)

Cost Category	Amount
PRODUCTION	**107,191**
Purchased Power	12,131
Fuel	28,991
Non-fuel O&M	17,184
Capital Related	42,637
A&G Allocation	6,245
TRANSMISSION	**11,620**
DISTRIBUTION	**43,470**

Figure 2.6: Production Cost Categories



Source, Table 2 and Figure 1: Supporting Analysis for the CECA, DOE/PO-0059, May 1999, Table 4.

Table 2.9 shows the system capital costs from a typical IPM® run. Over time, the capital costs estimated by IPM® approach the level of investor-owned capital costs as listed in Table 2 above. However, IPM® does not take into account any sunk capital costs that may have been expended prior to the first IPM® run-year. This is because such sunk costs are not relevant for system operation and dispatch (this follows from the microeconomic theory of the firm, as production decisions are based on marginal costs, not average costs that can include sunk capital). Capital costs shown in Table 3 are strictly costs incurred to build new power plants or install pollution controls, and are thus marginal in the sense that they can be affected by production decisions. In the long term, current sunk capital is fully depreciated and all system capital is represented in the model.

Table 2.9: Example Capital Cost Output from IPM®
(Million $)

2005	2008	2012	2017	2022	2027
4,126	7,668	13,245	22,101	30,479	40,006

2.5.1 Treatment of Cost Categories Not Represented in Modeling

Sunk capital costs are not affected by RTO policy. The regulatory treatment of these sunk costs, some of which can become so-called ‘stranded costs’, is an important policy issue, but not directly relevant to this economic analysis. So this major category of industry revenue is not directly considered in this analysis.

Other major cost categories do raise analytic issues in the context of RTO policy. Transmission and distribution, taken together, are important elements of the electric power system that may be affected on a going forward basis by the Commission’s actions with regard to RTOs. In particular, transmission system operating costs and potential expansion are directly affected by the ownership structure and associated incentives created by RTOs.

Similarly, administrative and general (A&G) costs may be affected by RTO policy. Consolidation of system operators has both costs and potential savings, depending on the implementation of RTO policy, and these potential costs and benefits need to be estimated and taken into account. This is the major area where direct costs of RTO establishment are estimated.

In order to estimate startup costs for RTOs, this study relies for the most part on existing studies of the costs of system operations, which typically use static comparative analysis, to estimate a range of possible economic outcomes for this cost category. Specifically, a number of cost indicators are developed that relate existing system costs to the size of the system in terms of capacity, energy, number of customers, etc. These cost indicators are then used to extrapolate a range of potential RTO startup costs for a nationwide RTO-based system.

2.5.2 Short-Term Market Events

The IPM® simulation framework is designed for relatively long run analysis. Because of the large set of variables required for detailed national simulation, including integrated treatment of fuel and environmental market drivers, simplification of temporal detail is traded off against other relevant system attributes. As a result, the IPM® framework treats power markets as spot pools that clear on a marginal cost basis within a set of defined demand segments.

This treatment of the time dimension is not intended to represent very short-term market events such as temporary price spikes. If longer-term underlying market conditions are out of equilibrium (such as during a chronic capacity shortage or glut), these market conditions can be simulated. However, severe price volatility as a result of poor transmission management will generally be a transient effect that will not be forecast using a model like IPM®.

Although there is no direct accounting for such short-term effects in the analytic framework used here, the economic issues associated with such effects are discussed in Section 3 in order to place them into perspective and suggest possible analytic approaches for related work.

2.5.3 Native Load and Contracts

The current wholesale power market is made up of a diverse set of transactions. Short-term spot purchases, bilateral contracts of varying terms and durations, and native load generation commitments all coexist. Furthermore, there is great regional variation in the makeup of wholesale market transactions.

In the long run these various transactions will tend to lead to similar market results (all of these transaction types, including native load commitments, can be viewed as contracts with values based on opportunity costs, which in turn are established by a real-time marginal transaction). However, the long run in this context can be as long as is required for the longest duration contracts to be renewed and possibly longer if multiple contract renewals are needed to allow for information revelation and adjustment of prices.

The IPM® framework is normally run as a market with full spot or pool price treatment, dispatching all supply resources in a common clearing mechanism. This approach treats all transactions as spot or the equivalent of spot transactions. To the degree that various transaction types approach the marginal cost solution (keeping in mind that a good deal of the short run volatility is already eliminated in this approach), such a method gives reliable estimates for actual market conditions.

3 Results

Based on the analytic approach described in the preceding section, computer simulation modeling and other related analyses were carried out. The results of the analysis are presented in this section, beginning with Base Case results. The main policy scenarios and the various Sensitivity Cases are also presented in this section. Integration of computer model results with other quantitative analysis is presented, followed by overall conclusions from this economic cost/benefit assessment.

3.1 Summary Results: Base Case

This section provides national and regional level summary results for the Base Case, including capacity and generation projections. Where applicable, the summary data provided includes a comparison to the Energy Information Administration's *Annual Energy Outlook 2002* (*AEO 2002*) base case forecast. This comparison is provided because the AEO forecasts are often useful as a starting point for assessing other long-run forecasts of the energy sector.

3.1.1 Base Case Capacity and Generation Projections

This section presents trends in generating capacity, including economic additions, retirements and modifications, as well as generation levels by plant type for the Base Case. Tables 3.1 and 3.2 contain IPM® and *AEO 2002* projections for 2005, 2010, 2015 and 2020. Tables 3.3 and 3.4 contain regional IPM® projections from the Base Case for the same years. Because the Base Case does not include 2005 as a run year, 2005 IPM® projections reflect an average of 2004 and 2006. The reported years were selected because they provide a reasonable representation of the study period and allow for a comparative assessment of the IPM® and *AEO 2002* national forecasts.

The Base Case reflects the future of the electric industry without any change from current policies regarding RTOs and other relevant regulatory policies in the electric power sector (the current 'status quo' or no-action case). The major findings in this case as they relate to installed capacity and dispatch trends are summarized below.

Base Case: National Results

Table 3.1 lists national generating capacity forecasts from the Base Case and from *AEO 2002*. Base Case total generating capacity increases by 352 GW (38 percent) from 2005 to 2020, whereas *AEO 2002* projections show an increase of 253 GW (31 percent) over the same period. Both the total amount of capacity and growth in capacity is greater in the Base Case relative to the *AEO 2002* projection, reflecting higher electric demand growth rates over the study period. The Base Case includes an assumed annual average demand growth rate of 2.3 percent, while the *AEO 2002* reference case assumes average annual demand will grow at 1.8 percent.

Regardless of the absolute amount of capacity forecasted, both projections indicate that new capacity additions will rely heavily upon gas-fired combined cycles and combustion turbines (included in the oil/gas classification) to meet growing demand for electric power. Nearly 100 percent of the new capacity in the Base Case comes from either new combined cycles or combustion turbines. In the *AEO 2002* forecast, 90% of new capacity additions are either combined cycles or combustion turbines, with the remainder largely coming from new coal and renewable plants late in the forecast period. The Base Case forecast reflects the expectation that costs to build and operate new gas-fired facilities are likely to be lower relative to new coal-fired plants through 2020.

Table 3.1: National Generating Capacity by Plant Type: Base Case and *AEO 2002* (GW)

Plant Type	2005[1]		2010		2015		2020	
	Base Case	*AEO 2002*[2]	Base Case	*AEO 2002*	Base Case	*AEO 2002*	Base Case	*AEO 2002*
Coal	308	305	308	306	308	313	308	329
Oil/Gas	417	292	514	385	632	446	770	505
Nuclear	96	98	96	94	96	89	96	88
Renewable/Other[3]	117	115	117	122	117	130	117	140
Total	938	809	1,034	907	1,153	979	1,291	1,062

[1]2005 projections for the Base Case are represented as the average of 2004 and 2006.
[2]Source: EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington DC, December 2001).
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, wind, distributed generation and pumped storage.

Table 3.2 presents national generation forecasts by plant type from the Base Case and from *AEO 2002*. Consistent with new capacity additions, the most significant growth in generation occurs at natural gas-fired plants, which increase generation by 269 percent from 2005 to 2020 in the Base Case and by 225 percent in the *AEO 2002* forecast. As with the addition of new capacity, the larger growth in electric generation in the Base Case relative to the *AEO* 2002 forecast reflects higher demand growth rates.

Increased gas-fired generation is accompanied by higher levels of coal generation, albeit to a much lesser extent. From 2005 to 2020, Base Case coal-fired generation increases by 4.2 percent, while the *AEO 2002* projection shows coal generation increasing by 16.2 percent over the same period. Much of the boost in coal generation that occurs in the *AEO 2002* forecast occurs late in the analysis, with the addition of new coal-fired generation as described above. The Base Case projection also shows growing coal-fired generation, in this case reflecting increased utilization at existing units rather than coal-fired capacity additions. In the Base Case, average capacity factors for coal units increase from just over 80 percent in 2005 to nearly 84 percent in 2020.

As with coal-fired generation, average capacity factors for oil/gas plants also increase over the study period, rising from 26 percent in 2005 to over 37 percent in 2020 under the Base Case. However, this is largely a reflection of a growing proportion of combined cycle units within the oil/gas classification, which includes combined cycles, oil-gas steam and simple cycle combustion turbines. The average Base Case capacity factor for each of these plant types is 50 percent, 11 percent and 8 percent respectively. The higher capacity factor for combined cycle units is an indicator of their intermediate-to-baseload position in the dispatch order.

Table 3.2: National Generation Projections by Plant Type: Base Case and *AEO 2002*
(TWh)

Plant Type	2005[1]		2010		2015		2020	
	Base Case	*AEO 2002*[2]	Base Case	*AEO 2002*	Base Case	*AEO 2002*	Base Case	*AEO 2002*
Coal	2,173	2,086	2,227	2,215	2,240	2,292	2,259	2,423
Oil/Gas	977	646	1,440	921	1,985	1,235	2,581	1,452
Nuclear Power	671	759	682	737	682	707	693	702
Renewable/Other[3]	400	374	399	390	397	400	396	406
Total	4,221	3,865	4,749	4,263	5,303	4,634	5,929	4,983

[1]2005 projections for the Base Case are represented as the average of 2004 and 2006.
[2]Source: EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington DC, December 2001).
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, wind, distributed generation and pumped storage.

Even with the increased utilization of existing coal units, natural gas becomes the dominant fuel source by the end of the study time horizon. Under the Base Case, growing demand pushes gas-fired generation above coal-fired generation for the first time in 2020. Over the Base Case study period the coal-fired share of total generation falls from just over 51 percent in 2005 to 38 percent in 2020. By 2020, gas-fired generation is less than 48 percent of national electric generation. The *AEO 2002* forecast indicates a less significant role for gas-fired generation relative to the Base Case, reflecting lower demand levels and the infiltration of new coal fired capacity late in the study period.

Base Case: Regional Results

Table 3.3 displays regional electric generating capacity from the Base Case over the study time horizon. National capacity additions increase at an average annual rate of just over 2.5 percent from 2005 through 2020; however, capacity growth rates vary considerably by region. For example, the average annual growth in new capacity is approximately 1.4 percent for NPCC and exceeds 4.1 percent for FRCC. Regional variation in capacity growth reflects regional variability in demand growth and transmission constraints assumed in the Base Case, which assumes no reorganization of regional transmission authorities.

Table 3.3: Generating Capacity by Region: Base Case (GW)

NERC Region	2005[1]	2010	2015	2020
ECAR	126	140	155	172
ERCOT	80	80	93	108
FRCC	54	65	74	88
MAAC	71	77	84	92
MAIN	65	67	74	82
MAPP	41	47	52	57
NPCC	74	79	83	90
SERC	217	242	274	311
SPP	47	55	62	69
WSCC	165	181	201	223
Total	**938**	**1,034**	**1,153**	**1,291**

[1]2005 projections for the Base Case are represented as the average of 2004 and 2006.

IPM® regional electric generation levels are shown in Table 3.4 for the Base Case. As with capacity growth, generation levels exhibit considerable variation among regions. Depending upon the specific region, growing generation levels vary in relation to growth in sales, and do not necessarily reflect a direct relationship to changes in demand. The growth in sales incorporates interregional electricity transmission charges and transmission limitations among neighboring regions. As long as transmission capability is available, regions with lower-cost power export energy to higher-cost regions, while considering any transmission charges (whether actual tariffs or hurdle rates incorporating implicit barriers to trade)under the current transmission structure.

Some regions exhibit higher growth in generation than in capacity, signifying higher utilization of existing plants. Other regions (ECAR, MAAC and SPP) add new capacity at a higher rate than increases in generation, signifying the need to meet regional reliability requirements. A large portion of increased generation originates from the addition of new gas-fired combined cycle capacity, even in regions that rely on increased utilization of existing fossil units to meet growing demand. The addition of new simple cycle combustion turbine units serve peak load in all regions.

Table 3.4: Generation by Region: Base Case (TWh)

NERC Region	2005[1]	2010	2015	2020
ECAR	652	702	771	868
ERCOT	305	343	388	439
FRCC	239	286	334	391
MAAC	297	322	349	369
MAIN	286	326	348	370
MAPP	192	217	240	278
NPCC	295	328	353	382
SERC	994	1,143	1,308	1,476
SPP	210	238	266	295
WSCC	753	843	946	1,061
Total	**4221**	**4,749**	**5,303**	**5,929**

[1]2005 projections for the Base Case are represented as the average of 2004 and 2006.

3.1.2 Base Case Energy Prices and Production Costs

Base Case production costs are shown below. These production costs are those that are relevant for operating and investment decisions, so sunk capital and transmission and distribution costs are not reflected in the IPM® production cost calculation. One consequence of this method of estimating production costs is that in all IPM® simulation runs, capital costs increase over time as generating units are added to meet growing demand. The Base Case production costs shown below follow this pattern.

Table 3.5: Base Case: System Level Annualized Production Costs (Million 2000$)

	2004	2006	2010	2015	2020
Fixed Costs	27,081	27,438	28,309	29,827	31,788
Variable Costs	5,369	5,714	6,204	6,831	7,554
Fuel Costs	53,574	54,067	61,878	70,800	78,551
Capital Costs	3,470	6,943	13,098	21,917	31,865
Total System Costs	**89,493**	**94,161**	**109,489**	**129,374**	**149,758**

While production costs are reported at the system-wide level for consistency purposes, more regional detail is presented for energy prices. These prices are annual average firm electricity prices. They aggregate a set of segmental marginal energy prices, and a set of capacity prices that reflect the marginal cost of meeting peak demand. Thus these prices represent the per-MWh cost of purchasing firm (non-interruptible) electricity. In general these firm electricity prices are dominated by the energy price as opposed to the capacity price. The prices in Table 3.6 are aggregated by the RTO specification used in the policy scenarios for comparison purposes.

Table 3.6: Base Case: Regional Firm Electricity Prices (2000$/MWh)

RTO	Sub-Region	2004	2006	2010	2015	2020
West	AZ-NM	39.3	36.0	35.0	32.2	28.5
West	RMA	39.2	37.0	35.4	32.9	29.0
West	Montana	34.2	31.6	31.4	31.5	28.3
West	NWPP-East	33.7	31.4	30.2	30.3	27.2
West	Pacific Northwest	38.8	35.9	34.5	32.9	29.1
West	Northern CA	43.4	40.0	36.4	34.5	30.5
West	Southern CA - NV	43.2	39.7	36.1	34.3	30.3
West Average		**40.6**	**37.4**	**35.2**	**33.3**	**29.5**
ERCOT		**26.1**	**24.7**	**32.7**	**31.5**	**29.2**
Midwest	COMED	30.0	29.5	32.6	32.5	31.4
Midwest	ILMO	27.9	27.2	30.4	32.2	30.9
Midwest	MAPP	33.8	32.3	32.5	32.4	29.3
Midwest	MECS	33.1	32.9	36.0	35.0	32.6
Midwest	So. ECAR	32.3	31.8	33.6	33.5	32.2
Midwest	SPP-North	30.4	30.7	32.5	31.4	29.2
Midwest	SPP-West	38.2	35.4	34.1	32.3	29.3
Midwest	WUMS	34.0	32.2	32.3	31.9	30.3
Midwest Average		**32.6**	**31.7**	**33.2**	**33.0**	**31.1**
Southeast	Entergy	26.5	24.5	27.0	31.2	29.3
Southeast	CP&L	36.3	34.3	34.2	32.8	32.5
Southeast	DUKE	34.8	34.2	34.1	32.7	32.5
Southeast	SCEG	37.4	35.6	34.9	33.3	33.0
Southeast	Southern	35.0	34.2	34.4	32.7	32.5
Southeast	TVA	32.3	31.6	33.7	32.5	30.2
Southeast	FRCC	41.1	38.3	37.1	35.2	33.2
Southeast Average		**34.6**	**33.2**	**33.8**	**33.1**	**31.9**
Northeast	Downstate NY	40.8	38.9	37.6	36.2	35.7
Northeast	LILCO	49.1	41.6	40.1	38.7	38.5
Northeast	New York City	43.5	41.9	40.6	39.1	38.9
Northeast	Upstate NY	33.1	32.9	34.3	33.4	32.9
Northeast	NEPOOL	30.2	36.9	38.0	36.5	35.4
Northeast	PJM-East	37.3	35.9	35.9	34.8	34.3
Northeast	PJM-South	35.1	34.6	35.1	34.5	34.3
Northeast	PJM-West	32.7	32.0	33.2	32.6	32.0
Northeast	VIEP	35.6	35.0	34.7	33.1	32.9
Northeast Average		**35.7**	**36.0**	**36.2**	**35.0**	**34.5**

Figure 3.1: Base Case 2010 Firm Power Prices
(2000$/MWh)

Regional variations in firm electricity prices are greatest in the initial run year, reflecting differences in installed generating base and firmly planned plant builds. Regional price variations diminish over time as the long run marginal cost of electricity is driven by natural gas plants at the margin in all regions. Some of these plants are combined-cycle and some are simple cycle turbines. The mix of combined cycle to simple cycle depends on each region's need for energy as opposed to reserve margin or backup capability. The relative economics of the two types of natural gas-fired power plants turn mainly on the expected capacity factor, since the higher capital cost of a combined cycle plant can be offset by its higher operating efficiency if it operates in enough hours in the year.

3.2 RTO Policy Case Results

As discussed in Section 2, the RTO Policy Case is designed to represent the primary scenario representing potential impacts of RTO policy. It incorporates both transmission grid improvements and a set of market improvements that could result from heightened performance incentives caused by increased wholesale competition.

The major impact of RTO policy as implemented in the IPM® framework is to allow increased inter-regional trading of energy and capacity. As a result, the regional distribution of generation and capacity builds changes. Regions with high barriers to trade generally require larger amounts of reserve margin capacity, for example. If the transmission grid allows greater trade, the need for some capacity may be deferred or eliminated, leading to cost savings.

3.2.1 RTO Policy Case: Changes in Inter-Regional Trade

Because of the importance of the inter-regional trade flows in explaining the results of this analysis, a set of maps is presented below that document the exports and imports between all IPM® regions. The maps are presented by major US region for clarity. Each mapped region has an arrow pointing to any interconnected region, with the flows in each direction shown numerically. The two numbers are the Base Case and RTO Policy Case flows, respectively.

Lowering of hurdle rates leads to major shifts in power flows in both the Eastern and Western Interconnections. One of the ways this study differs from most others recently addressing RTO issues is geographic scope; studies of the Northeast that do not consider changes to Southeastern power markets, for example, may miss important dynamics that can drive the ultimate outcome of regulatory changes. The results of the RTO Policy Case demonstrate this, as the opening of higher-price regions in the Southeast, particularly Florida but also Entergy, attracts exports from neighboring regions. This leads to a cascading effect in which the Midwest reduces flows to the Northeast and sends them to the Southeast instead. As a result, Northeast regions such as PJM must meet more of their own energy and reserve margin requirements.

In the maps presented here, this overall effect is most evident in the Southeast regional map showing the large increase of power transfers into Florida and to a lesser extent Entergy. Note that some of the power sent into Entergy is actually wheeled through as increased transfers into Southern, part of the dominant influence of the Florida export market in a more liberalized transmission grid.

As a result of this increase in transfers toward Florida, both SoECAR and CP&L reduce their Base Case power transfers into the Northeast and re-route power to the Southeast. It is noteworthy that such shifts occur as far away as ILMO and MAPP. By opening up the closed Southeastern markets, the entire power flow pattern of the Eastern Interconnection can be shifted to a considerable degree, with consequences for both production costs and energy prices.

A similar pattern emerges in the West, with California as the dominant export market. Transfers from the interior Western regions flow through to California, with some transfers flowing through the PACNW region on their way to the final demand region. Both Northern and Southern California increase their energy imports relative to the Base Case, with Southern California wheeling through some energy to Northern California.

These shifts in power flows are not large relative to the overall size of the US electric power sector. But because inter-regional trade flows are often at the margin, they can determine prices and investment patterns in some regions, especially smaller regions. This dynamic explains the economic results, which are presented following the transmission flow maps.

These maps of inter-regional transmission flows show each link between regions as an arrow with two ends. One end indicates the flow in one direction and the other end indicates the opposite flow. The number shown by each arrow reflects the change in transmission flows from the Base Case to the RTO Policy Case in TWh. For example, in the first map of Northeastern regions, the arrow pointing to PJMW and coming from So.ECAR indicates that transmission flows drop in the RTO Policy Case by 7.0 TWh relative to the Base Case level. In other words, Southern ECAR is transmitting less power to PJM West in the RTO Policy Case. Flows from PJMW to PJME, on the other hand, increase in the RTO Policy Case by 1.5 TWH relative to the Base Case level.

Figure 3.2: Northeast RTO Energy Transfers in 2006: Change from Base Case to RTO Policy Case (TWh)

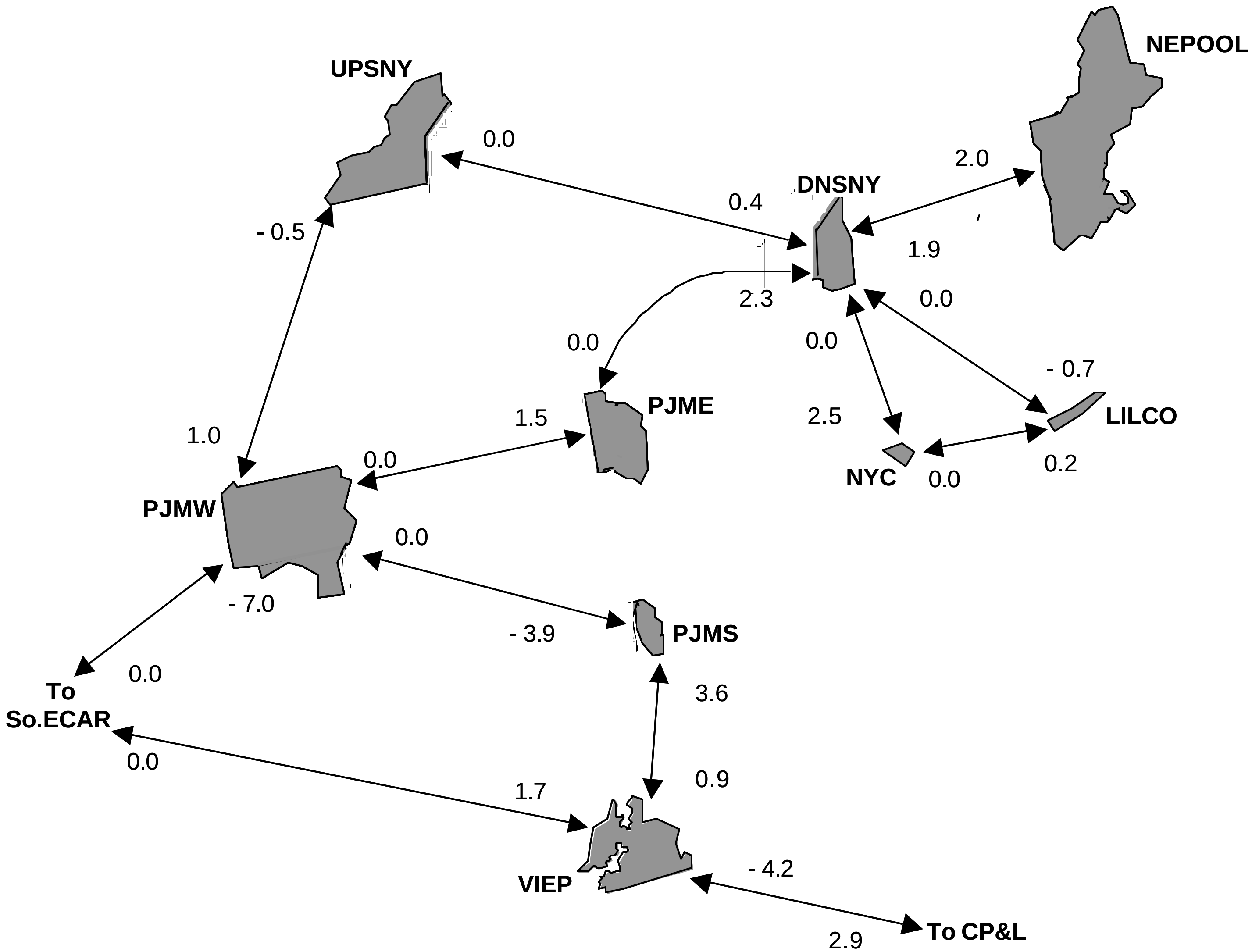


Figure 3.3: Southeast RTO Energy Transfers in 2006: Change from Base Case to RTO Policy Case (TWh)

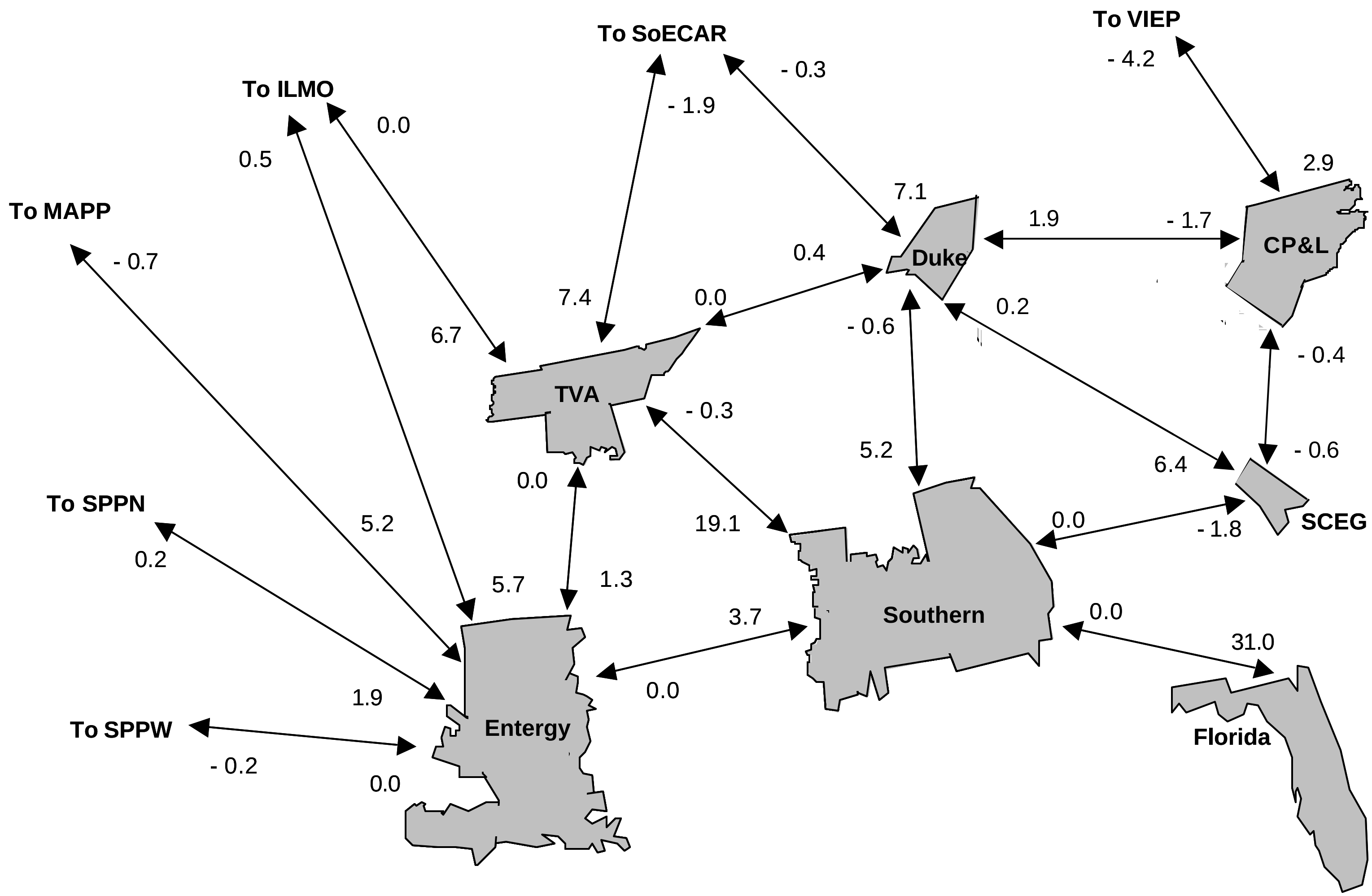


Figure 3.4: Midwest RTO Energy Transfers in 2006: Change from Base Case to RTO Policy Case (TWh)

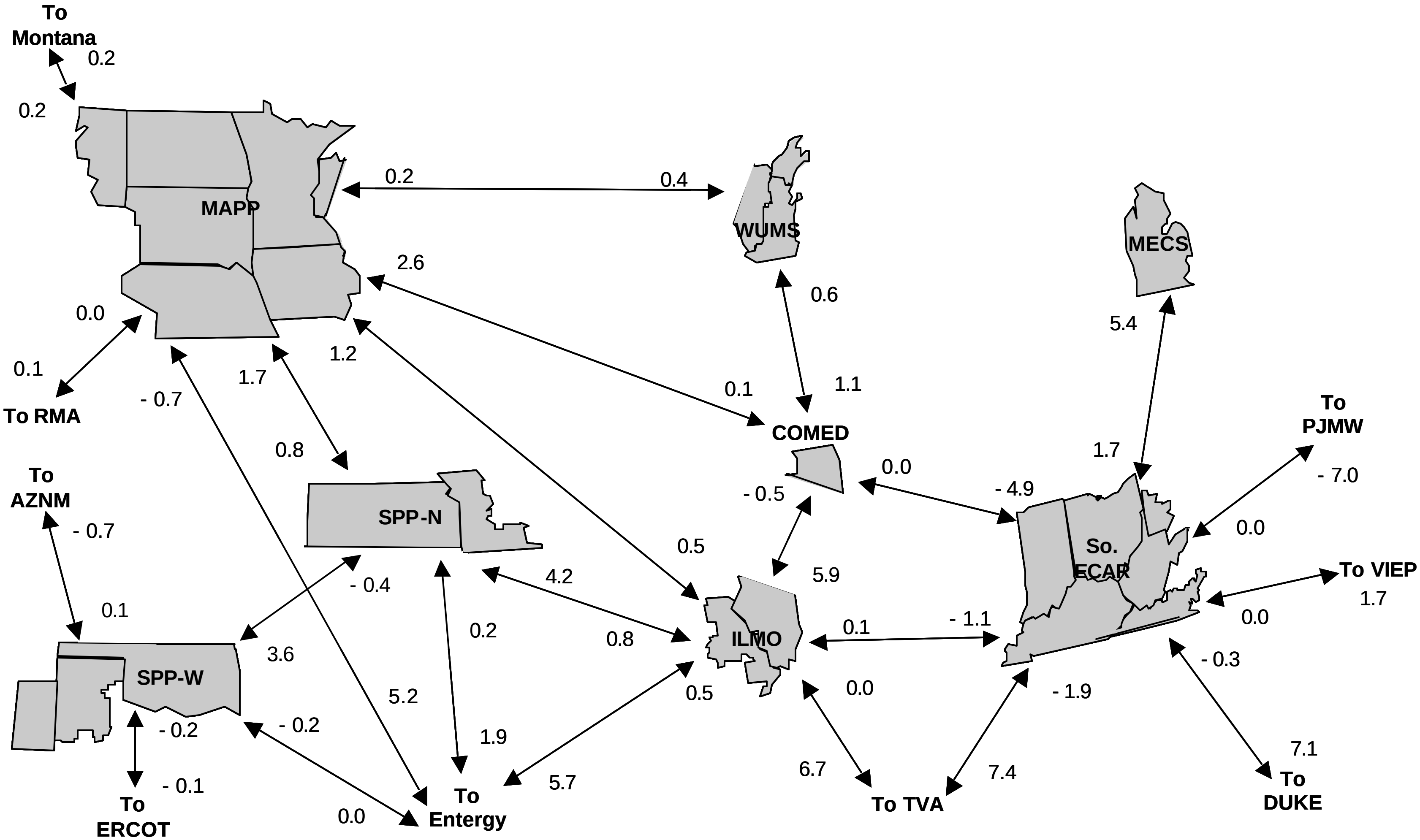


Figure 3.5: West RTO Energy Transfers in 2006: Change from Base Case to RTO Policy Case (TWh)

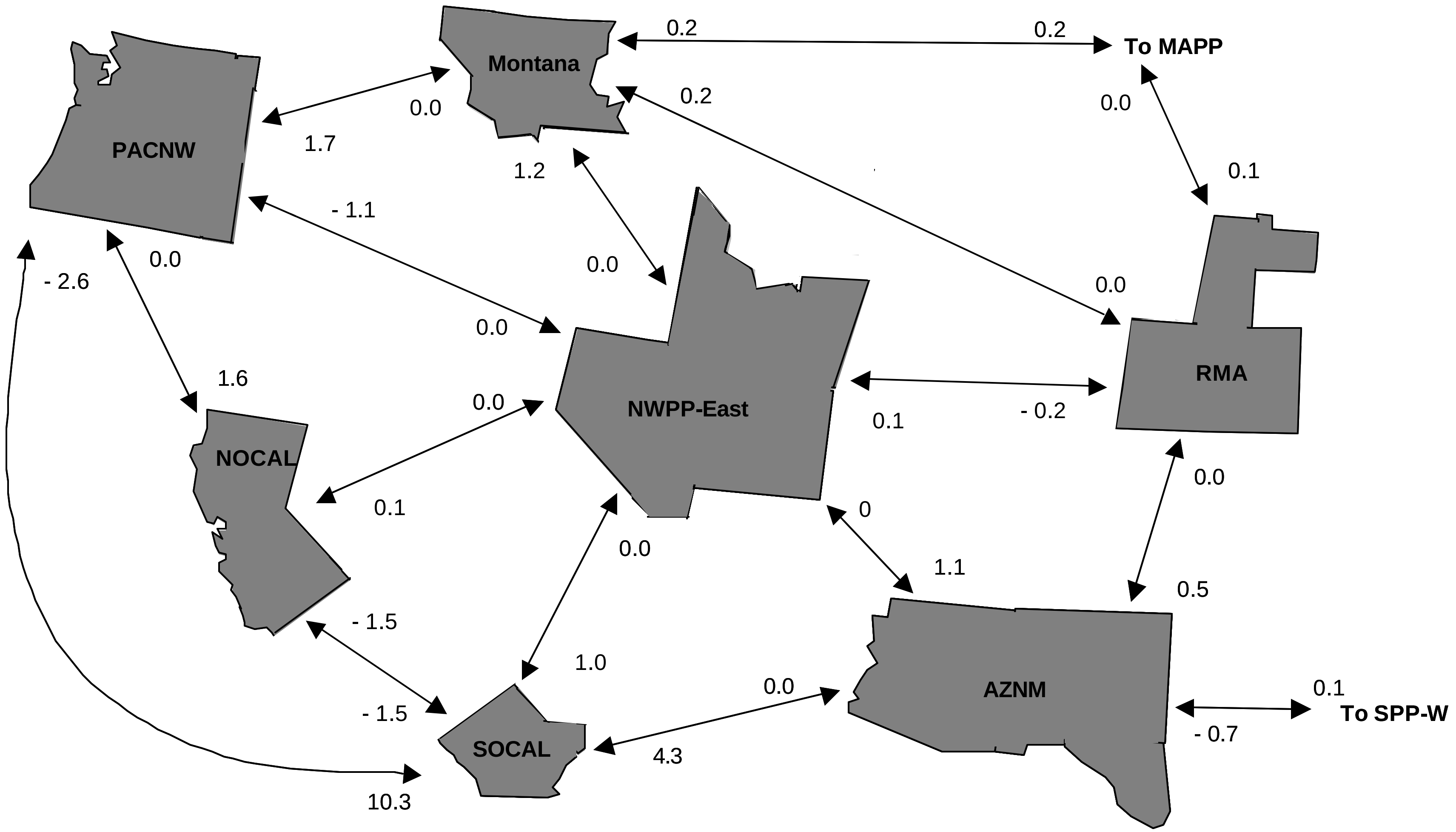
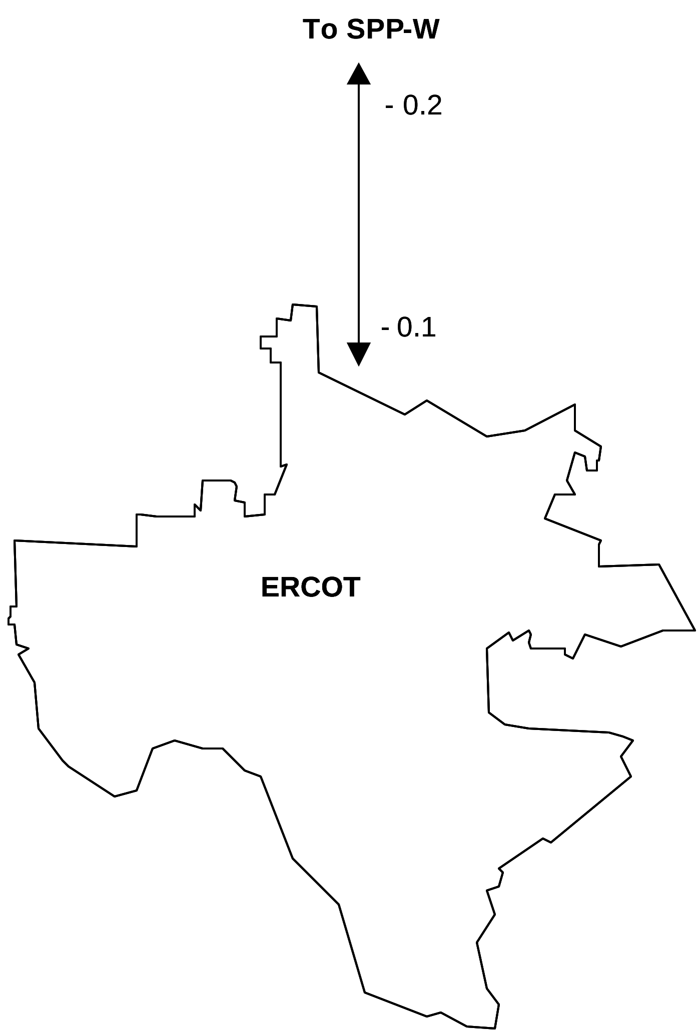


Figure 3.6: ERCOT Energy Transfers in 2006: Change from Base Case to RTO Policy Case (TWh)



3.2.2 RTO Policy Case: Changes in Production Cost and Electricity Prices

The following table shows the production costs for the RTO Policy Case. The effects of the policy are gradual, leading to an increase in production cost savings over time. By 2010, changes in assumptions and the effects on the electric power system are fully in place. The overall effect is to decrease production costs significantly, with annual savings reaching over $5 billion per year in 2010 in the RTO Policy Case. These savings are in range of 1-5% of the total production costs estimated in the model, although the total sectoral revenue is larger (as discussed in Section 2), so these savings are smaller fraction of the total revenue in the electric power industry.

Table 3.7: RTO Policy Case: System Level Annualized Production Costs (Million 2000$)

	2004	2006	2010	2015	2020
Fixed Costs	27,042	27,384	28,126	29,564	31,311
Variable Costs	5,389	5,739	6,211	6,839	7,569
Fuel Costs	52,678	52,147	57,628	65,872	73,187
Capital Costs	3,304	6,702	12,289	20,782	30,222
Total System Costs	**88,414**	**91,972**	**104,254**	**123,057**	**142,289**
Savings from Base	*1,080*	*2,189*	*5,235*	*6,318*	*7,470*
% Savings from Base	*1.2%*	*2.3%*	*4.8%*	*4.9%*	*5.0%*

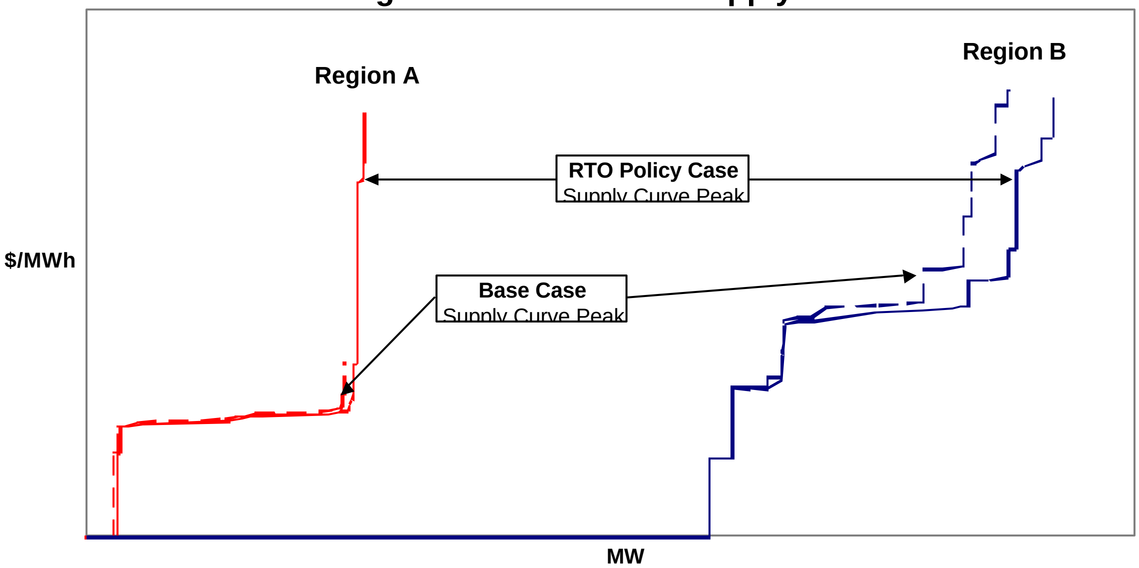
On a regional basis, firm electricity prices (as defined in Section 3.1.2) undergo a complex set of changes. Changes are defined relative to Base Case prices in any given year. While the majority of regions experience price declines in the 3-5% range, some regions have more substantial decreases of over 8% by 2010. The region with the greatest price increase in any one year in these results is the ILMO (downstate Illinois and Missouri) region where prices in one case rise 8% in 2006, while Montana and parts of the interior West show the most persistent, albeit small, price increases.

Table 3.8: RTO Policy Case: Regional Firm Electricity Prices (2000$/MWh)

RTO	Sub-Region	2004	2006	2010	2015	2020
West	AZ-NM	38.2	35.9	33.6	31.0	27.4
West	RMA	37.1	36.8	34.3	31.6	28.1
West	Montana	35.6	33.1	32.1	31.4	28.1
West	NWPP-East	33.8	31.7	30.3	29.9	26.8
West	Pacific Northwest	38.5	35.9	32.5	31.5	27.9
West	Northern CA	42.0	39.4	35.0	33.2	29.4
West	Southern CA - NV	41.4	38.9	34.8	32.9	29.1
West Average		**39.5**	**37.1**	**33.8**	**32.1**	**28.4**
ERCOT		**25.9**	**23.6**	**31.1**	**30.1**	**28.1**
Midwest	COMED	30.6	29.6	31.8	31.6	30.1
Midwest	ILMO	29.5	29.6	30.4	31.1	29.6
Midwest	MAPP	32.1	31.4	31.5	31.2	28.3
Midwest	MECS	31.1	30.0	32.7	32.7	31.3
Midwest	So. ECAR	32.4	31.3	32.3	32.2	30.8
Midwest	SPP-North	30.5	31.0	31.4	30.8	28.4
Midwest	SPP-West	38.0	34.8	32.8	31.1	28.2
Midwest	WUMS	33.7	32.0	31.2	30.7	29.2
Midwest Average		**32.4**	**31.3**	**32.0**	**31.7**	**29.8**
Southeast	Entergy	24.7	22.9	24.8	29.3	27.8
Southeast	CP&L	34.3	33.1	32.7	31.3	31.1
Southeast	DUKE	34.4	33.2	32.7	31.4	31.2
Southeast	SCEG	35.0	33.7	33.5	32.0	31.7
Southeast	Southern	34.4	33.3	33.0	31.5	31.1
Southeast	TVA	32.5	31.5	32.7	31.1	29.1
Southeast	FRCC	39.2	37.0	35.5	33.8	31.8
Southeast Average		**33.5**	**32.1**	**32.2**	**31.6**	**30.6**
Northeast	Downstate NY	39.5	37.7	36.1	34.7	34.1
Northeast	LILCO	48.8	41.0	38.6	37.2	36.9
Northeast	New York City	43.5	41.0	39.0	37.5	37.2
Northeast	Upstate NY	33.0	32.2	32.6	31.9	31.5
Northeast	NEPOOL	30.8	36.0	36.4	35.0	33.9
Northeast	PJM-East	37.3	35.4	34.6	33.5	33.0
Northeast	PJM-South	35.7	34.2	34.0	33.1	32.9
Northeast	PJM-West	33.2	31.9	32.1	31.3	30.8
Northeast	VIEP	37.0	34.6	33.3	31.9	31.5
Northeast Average		**36.0**	**35.4**	**34.8**	**33.6**	**33.0**

The implications of these price effects are discussed after the full set of scenario results is presented. Here the focus is on the reason for the price changes. The model is based on a database of actual generating plants, augmented by new units that are selected by the model as needed for reasons of economic efficiency and system reliability. The specific sets of generating units within each model region are dispatched according to economic costs ('merit order dispatch'), leading to sets of regional supply curves for energy as illustrated below (using just two model regions as an example).

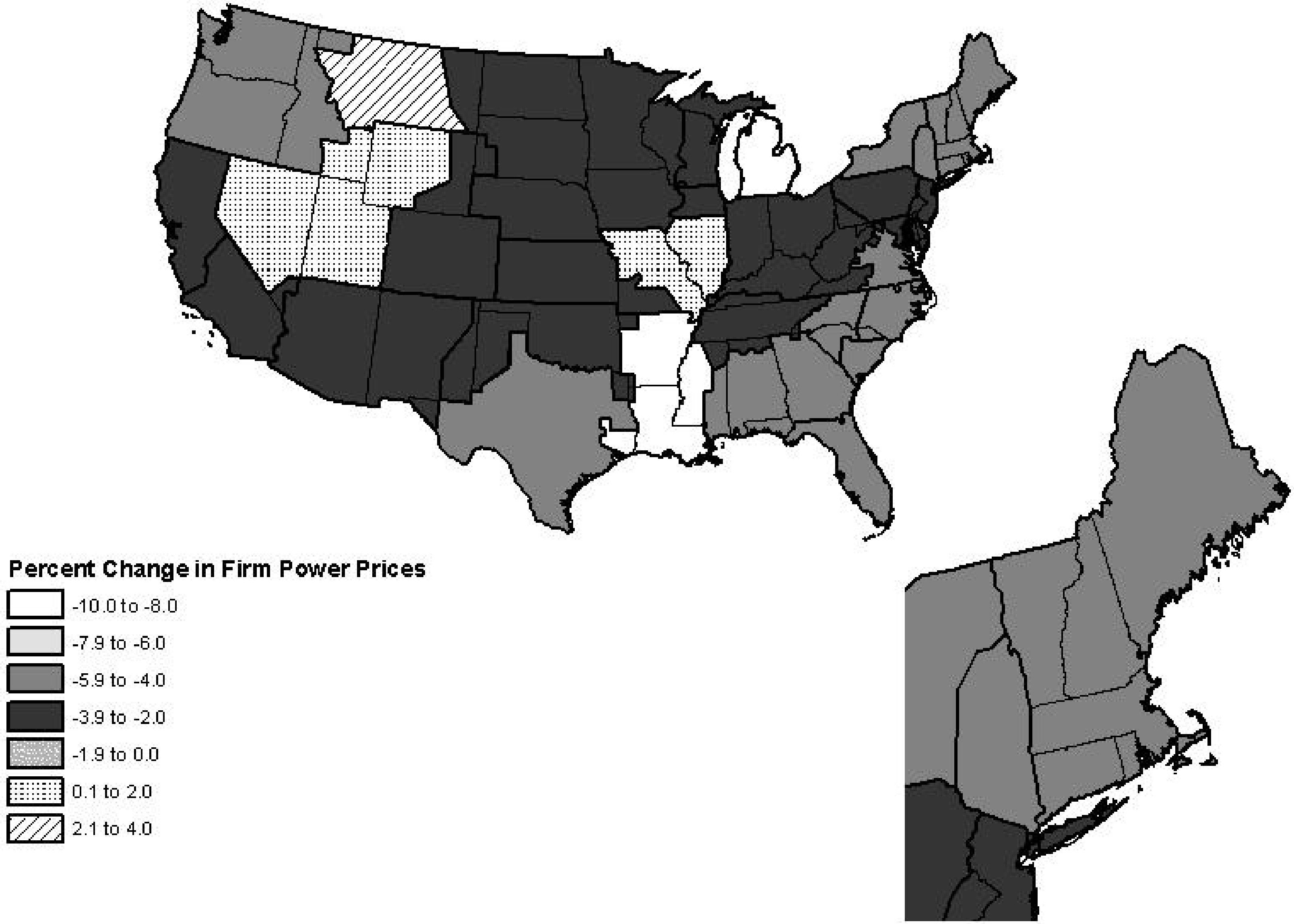
Figure 3.7: Illustrative Supply Curves



The figure shown above illustrates how small shifts in transmission transfer capability and hurdle rates can yield significant price increases in some regions, but only modest price decreases in neighboring regions. Note that when transmission transfer capability between Region A and Region B is expanded only slightly we can see dramatic increases in marginal energy costs in Region A and slight decreases in Region B. This effect can be related to either increased transmission transfer capability, or lowered hurdle rates between regions. Of course this effect can also work the other way around, with an exporting region's prices increasing only slightly (or not at all, if exports shift the regional supply curve along a flat segment) and the importing region's prices declining more. It is the complex set of interactions among the regional supply curves that determines the overall economic impact of changes in inter-regional trade.

Below the changes in regional energy prices between the Base Case and the RTO Policy Case are mapped for the year 2010, when the changes in assumptions representing RTO policy impacts are fully in place.

Figure 3.8: Percent Change in 2010 Firm Power Prices from the Base to RTO Policy Case



3.3 Transmission Only Case

In addition to the RTO Policy Case, which is intended to represent a best estimate of potential economic benefits of RTO policy, a number of other scenarios were developed as described in Section 2. The results of each scenario are presented in turn, beginning with the Transmission Only Case.

The Transmission Only Case resulted in the following estimates for system-wide production costs:

Table 3.9: Transmission Only Case: System Level Annualized Production Costs (Million 2000$)

	2004	2006	2010	2015	2020
Fixed Costs	27,067	27,425	28,230	29,707	31,553
Variable Costs	5,348	5,699	6,189	6,830	7,560
Fuel Costs	53,254	53,798	61,572	70,651	78,471
Capital Costs	3,420	6,884	12,732	21,381	30,884
Total System Costs	**89,089**	**93,805**	**108,723**	**128,568**	**148,468**
Savings from Base	*405*	*356*	*767*	*806*	*1,291*
% Savings from Base	*0.5%*	*0.4%*	*0.7%*	*0.6%*	*0.9%*

The Transmission Only Case is intended to represent a “limited benefits” scenario in the Commission staff’s view of the potential economic impacts of RTO policy, considering only direct benefits to increased reserve pooling and transmission coordination. The benefits in this case (as detailed in Table 3.9) are significant even though assumptions are conservative.

In terms of more detailed regional results, the Transmission Only Case resulted in the following firm electricity prices (on an annual average basis, accounting for both energy and capacity value):

Table 3.10: Transmission Only Case: Regional Firm Electricity Prices (2000$/MWh)

RTO	Sub-Region	2004	2006	2010	2015	2020
West	AZ-NM	38.6	36.4	35.0	32.3	28.5
West	RMA	38.5	37.6	35.6	32.8	29.0
West	Montana	35.8	33.7	33.4	32.7	29.2
West	NWPP-East	34.4	32.9	32.5	31.2	27.8
West	Pacific Northwest	38.9	36.5	33.9	32.9	29.0
West	Northern CA	42.4	40.0	36.4	34.5	30.6
West	Southern CA - NV	42.0	39.6	36.1	34.3	30.3
West Average		**40.0**	**37.8**	**35.2**	**33.4**	**29.5**
ERCOT		**26.0**	**24.6**	**32.6**	**31.5**	**29.2**
Midwest	COMED	31.6	30.9	33.4	33.1	31.6
Midwest	ILMO	30.4	30.7	32.1	32.5	31.0
Midwest	MAPP	32.7	32.5	33.2	32.5	29.4
Midwest	MECS	32.1	31.4	34.8	34.4	32.7
Midwest	So. ECAR	33.3	32.8	34.2	33.7	32.2
Midwest	SPP-North	31.3	32.1	33.2	32.2	29.5
Midwest	SPP-West	38.3	35.4	34.1	32.3	29.3
Midwest	WUMS	34.6	32.7	32.8	32.2	30.4
Midwest Average		**33.2**	**32.5**	**33.7**	**33.1**	**31.1**
Southeast	Entergy	25.5	24.4	26.4	30.9	29.3
Southeast	CP&L	35.1	34.3	34.1	32.7	32.5
Southeast	DUKE	35.1	34.4	34.2	32.8	32.6
Southeast	SCEG	35.9	35.0	34.7	33.2	32.9
Southeast	Southern	35.2	34.6	34.5	32.8	32.5
Southeast	TVA	33.3	32.7	34.1	32.5	30.3
Southeast	FRCC	39.5	37.7	37.0	35.3	33.2
Southeast Average		**34.2**	**33.3**	**33.7**	**33.0**	**31.9**
Northeast	Downstate NY	39.9	38.5	37.7	36.2	35.6
Northeast	LILCO	48.6	41.6	40.1	38.7	38.5
Northeast	New York City	43.5	41.7	40.5	39.1	38.9
Northeast	Upstate NY	33.7	33.1	34.4	33.4	32.9
Northeast	NEPOOL	31.1	37.0	38.1	36.5	35.5
Northeast	PJM-East	37.7	36.3	36.2	34.9	34.4
Northeast	PJM-South	36.6	35.3	35.5	34.5	34.2
Northeast	PJM-West	33.9	33.0	33.8	32.9	32.1
Northeast	VIEP	37.6	35.2	34.8	33.2	32.9
Northeast Average		**36.5**	**36.3**	**36.4**	**35.1**	**34.5**

The dynamics of the Transmission Only Case are similar in most respects to the RTO Policy Case. Because the changes in inter-regional flows are caused by the changes in transmission hurdle rates, and these changes are maintained in the Transmission Only Case, the overall pattern of flows shifts towards the Southeast in the Eastern Interconnect and towards California in the Western Interconnect. Relative changes in generation, production costs, and electricity prices follow suit. In this case, however, there are no efficiency gains on the part of generators, so the changes to inter-regional flow patterns are the only driver of economic gains throughout the forecast horizon.

One significant difference between the Transmission Only Case and the RTO Policy Case is the presence of more regional price increases in the Transmission Only Case. The underlying economics of power supply in the various regions determine how prices will change when inter-regional trade patterns shift. Some regions can export power without price increases (since they have available generating capacity that is no more costly than the Base Case generation mix), while other regions may have prices rise with only small changes in exports. Even though these price increases are small in percentage terms, with none over 10% in any region or year, the implication is that improvements in market functioning are critical for securing clear consumer benefits. Such market improvements, as modeled in the RTO Policy Case, allow for increased exports and price declines in most parts of the country.

Even in the absence of competitive incentives for energy market improvements, improvements in the management of the transmission grid offer significant potential economic gains on a national production cost basis. Sensitivity cases designed to show the effect of RTO scope and configuration are presented later in this section. Transmission-related changes do affect the economic results estimated here, and are significant, even though generator efficiencies lead to much greater changes in economic outcomes.

3.4 Demand Response Scenario

The Demand Response Scenario presented next adds a limited amount of price-responsive demand (intended to represent a conservative estimate of real-time pricing impacts and distributed generation, taken together as a simplifying assumption) to the same underlying assumptions as in the RTO Policy Case. The Demand Response Scenario leads to the following changes in estimated production costs:

Table 3.11: Demand Response Case: System Level Annualized Production Costs (Million 2000$)

	2004	2006	2010	2015	2020
Fixed Costs	26,943	26,883	27,584	28,969	30,644
Variable Costs	5,382	5,750	6,225	6,854	7,585
Fuel Costs	52,642	52,348	57,763	65,998	73,357
Capital Costs	3,377	5,016	10,370	18,631	27,775
Total System Costs	**88,343**	**89,997**	**101,941**	**120,451**	**139,361**
Savings from Base	*1,150*	*4,164*	*7,548*	*8,923*	*10,398*
% Savings from Base	*1.3%*	*4.4%*	*6.9%*	*6.9%*	*6.9%*

The Demand Response Case is not designed as an upper bound, in the Commission staff's view, to the possible savings under a successful RTO policy implementation. All of the assumptions used in this scenario are based on earlier related analysis, or other existing information, as discussed in Section 2. Hence these are changes that could reasonably be expected to occur in a more competitive electricity market. Additional changes to assumptions could be made in order to estimate a reasonable upper bound on potential RTO benefits. The Demand Response Case is instead intended to isolate the important role of price information and consumer choice in determining economic outcomes in the electric power markets.

The detailed regional results for firm electricity prices are as follows:

Table 3.12: Demand Response Case: Regional Firm Electricity Prices (2000$/MWh)

RTO	Sub-Region	2004	2006	2010	2015	2020
West	AZ-NM	38.3	35.9	33.7	31.0	27.4
West	RMA	37.8	36.5	34.4	31.6	28.1
West	Montana	35.5	33.1	31.4	31.4	28.2
West	NWPP-East	33.8	31.8	30.3	29.5	26.7
West	Pacific Northwest	38.5	36.0	32.5	31.5	27.9
West	Northern CA	42.1	39.3	35.0	33.1	29.5
West	Southern CA - NV	41.5	39.0	34.7	32.9	29.1
West Average		**39.6**	**37.1**	**33.8**	**32.0**	**28.4**
ERCOT		**25.9**	**23.6**	**24.4**	**30.2**	**28.1**
Midwest	COMED	30.6	29.3	30.4	31.5	30.2
Midwest	ILMO	29.4	28.3	30.2	31.2	29.5
Midwest	MAPP	31.9	31.4	31.4	31.2	28.3
Midwest	MECS	31.0	29.7	31.5	32.8	31.4
Midwest	So. ECAR	32.3	30.9	32.4	32.1	30.9
Midwest	SPP-North	30.2	29.6	31.5	30.8	28.3
Midwest	SPP-West	38.1	34.8	32.8	31.2	28.3
Midwest	WUMS	33.6	32.0	31.1	30.7	29.2
Midwest Average		**32.3**	**30.9**	**31.8**	**31.7**	**29.9**
Southeast	Entergy	24.6	22.9	24.7	29.4	27.7
Southeast	CP&L	34.5	33.2	32.6	31.3	31.2
Southeast	DUKE	34.3	33.2	32.8	31.5	31.2
Southeast	SCEG	35.0	33.8	33.4	31.9	31.7
Southeast	Southern	34.3	33.4	33.0	31.5	31.1
Southeast	TVA	32.4	31.1	32.7	31.2	29.1
Southeast	FRCC	39.5	37.0	35.5	33.8	31.8
Southeast Average		**33.6**	**32.1**	**32.2**	**31.7**	**30.6**
Northeast	Downstate NY	39.5	36.5	36.1	34.7	34.1
Northeast	LILCO	50.3	40.9	38.6	37.1	36.9
Northeast	New York City	43.5	39.3	39.0	37.6	37.3
Northeast	Upstate NY	33.0	31.1	32.4	31.9	31.5
Northeast	NEPOOL	34.3	35.1	35.7	35.1	34.0
Northeast	PJM-East	37.3	35.4	34.7	33.5	32.9
Northeast	PJM-South	35.6	34.2	33.9	33.1	32.8
Northeast	PJM-West	33.2	31.9	32.2	31.4	30.8
Northeast	VIEP	37.1	34.5	33.3	31.9	31.5
Northeast Average		**36.7**	**34.9**	**34.7**	**33.6**	**33.1**

These economic results indicate the importance of fully functioning markets, in that the tradeoffs between demand levels and the need for generating capacity drive both production costs and prices down in the Demand Response Case relative to the other cases presented here. Demand response also helps avoid short-term price spikes and can moderate the potential for market power abuse, effects this study does not explicitly capture. If RTOs do present opportunities to improve market functioning, including enhancing demand response, the economic gains could be quite large.

3.5 Sensitivity Case I: Larger RTOs

One of the critical issues for this study concerns the geographic scope and configuration of RTOs. A primary purpose of this study is to assist with a quantitative basis for determining the appropriate number of RTOs. In order to address this issue directly, two sensitivity cases were prepared. This first sensitivity case considers very large RTOs, encompassing the entire Western and Eastern Interconnects (with ERCOT remaining separate). This three-RTO configuration is described in Section 2 in conjunction with the RTO Policy Case configuration. Results for this Larger RTOs Case are as follows:

Table 3.13: Larger RTOs: System Level Annualized Production Costs (Million 2000$)

	2004	2006	2010	2015	2020
Fixed Costs	27,050	27,393	28,144	29,563	31,311
Variable Costs	5,396	5,740	6,216	6,837	7,573
Fuel Costs	52,575	52,096	57,542	65,884	73,142
Capital Costs	3,280	6,665	12,283	20,716	30,164
Total System Costs	**88,301**	**91,893**	**104,185**	**123,000**	**142,190**
Savings from Base	1,192	2,267	5,304	6,374	7,568
% Savings from Base	1.3%	2.4%	4.8%	4.9%	5.1%

Table 3.14: Larger RTOs: Regional Firm Electricity Prices (2000$/MWh)

RTO	Sub-Region	2004	2006	2010	2015	2020
West	AZ-NM	38.2	35.9	33.6	31.0	27.4
West	RMA	37.5	37.0	34.3	31.6	28.1
West	Montana	35.6	33.1	32.1	31.4	28.1
West	NWPP-East	33.8	31.7	30.3	29.9	26.8
West	Pacific Northwest	38.5	35.9	32.5	31.5	27.9
West	Northern CA	42.0	39.4	35.0	33.2	29.4
West	Southern CA - NV	41.4	38.9	34.8	32.9	29.1
West Average		**39.5**	**37.1**	**33.8**	**32.1**	**28.4**
ERCOT		**25.9**	**23.6**	**31.1**	**30.1**	**28.1**
East	COMED	31.0	30.4	32.2	31.9	30.3
East	ILMO	29.9	30.3	30.6	31.4	29.6
East	MAPP	32.3	32.1	31.9	31.5	28.4
East	MECS	31.5	30.9	33.7	33.2	31.3
East	So. ECAR	32.8	32.2	32.8	32.6	31.1
East	SPP-North	30.7	31.8	31.7	31.1	28.4
East	SPP-West	38.0	34.8	32.8	31.1	28.2
East	WUMS	34.2	32.4	31.5	31.0	29.2
East	Entergy	24.4	23.0	25.5	29.3	27.6
East	CP&L	34.2	33.5	32.8	31.4	31.2
East	DUKE	33.9	33.4	32.8	31.5	31.2
East	SCEG	34.8	33.8	33.4	31.9	31.6
East	Southern	34.1	33.4	33.0	31.5	31.1
East	TVA	32.1	31.5	32.7	31.3	29.1
East	FRCC	39.2	37.0	35.5	33.8	31.8
East	Downstate NY	39.4	37.6	36.1	34.6	34.1
East	LILCO	48.8	40.9	38.6	37.2	36.9
East	New York City	43.5	40.9	39.0	37.5	37.3
East	Upstate NY	32.3	31.7	32.6	31.8	31.3
East	NEPOOL	30.7	36.0	36.4	35.1	33.9
East	PJM-East	36.9	35.3	34.6	33.4	32.9
East	PJM-South	34.7	33.8	33.9	32.9	32.8
East	PJM-West	32.2	31.3	32.1	31.3	30.8
East	VIEP	35.6	34.2	33.3	31.9	31.5
East Average		**33.5**	**32.8**	**32.9**	**32.2**	**30.8**

These results tend to confirm the conclusion drawn from the primary policy cases reported first, that the scope and configuration of RTOs does make a difference in the potential economic benefits of RTO policy. Larger RTOs could reduce more barriers to inter-regional trade, leading to greater efficiency gains. But the size of these gains is small relative to the much larger gains that could come from market improvements and better generator performance.

In the analysis carried out here, it is more important to have well-functioning competitive markets than it is to have one specific RTO configuration, although fewer and larger RTOs do lead to the greatest potential benefits. To the extent that a clear link can be established between RTO scope and competitive market effectiveness, the benefits of larger RTOs would be more significant. Further research, and perhaps further experience, would be needed to fully assess such possible links between RTO scope and the functioning of competitive markets.

3.6 Sensitivity Case II: Smaller RTOs

A second sensitivity case was developed to complement the Larger RTOs Case described above. This case maintains a greater number of RTOs, including leaving existing ISOs largely intact and creating three Western RTOs instead of one. This RTO configuration is described and mapped in Section 2. Results for this sensitivity case are as follows:

Table 3.15: Smaller RTOs: System Level Annualized Production Costs (Million 2000$)

	2004	2006	2010	2015	2020
Fixed Costs	27,045	27,396	28,134	29,571	31,313
Variable Costs	5,391	5,736	6,214	6,836	7,560
Fuel Costs	52,719	52,166	57,669	65,991	73,281
Capital Costs	3,297	6,733	12,302	20,795	30,214
Total System Costs	**88,452**	**92,031**	**104,319**	**123,192**	**142,368**
Savings from Base	*1,041*	*2,130*	*5,171*	*6,182*	*7,390*
% Savings from Base	*1.2%*	*2.3%*	*4.7%*	*4.8%*	*4.9%*

Table 3.16: Smaller RTOs Firm Electricity Prices (2000$/MWh)

RTO	Sub-Region	2004	2006	2010	2015	2020
Rockies	AZ-NM	37.4	33.8	32.9	30.9	27.4
Rockies	RMA	37.6	36.1	34.2	31.6	28.1
Rockies Average		**37.5**	**34.5**	**33.4**	**31.1**	**27.6**
Pacific-NW	Montana	35.3	32.3	31.8	31.6	28.1
Pacific-NW	NWPP-East	32.9	29.9	27.7	28.2	25.3
Pacific-NW	Pacific Northwest	38.6	35.3	33.0	31.6	28.0
Pacific-NW Average		**37.5**	**34.3**	**32.2**	**31.1**	**27.6**
California	Northern CA	43.4	39.3	35.0	33.1	29.4
California	Southern CA - NV	42.8	39.0	34.7	32.9	29.1
California Average		**43.1**	**39.1**	**34.9**	**33.0**	**29.2**
ERCOT		**25.8**	**23.6**	**31.1**	**30.1**	**28.1**
Midwest	COMED	30.6	29.5	31.9	31.6	30.2
Midwest	ILMO	29.4	29.5	30.6	31.2	29.6
Midwest	MAPP	32.0	31.5	31.8	31.3	28.4
Midwest	MECS	31.0	29.9	32.7	32.7	31.3
Midwest	So. ECAR	32.3	31.2	32.4	32.2	30.8
Midwest	SPP-North	30.3	30.9	31.7	30.8	28.4
Midwest	SPP-West	38.0	34.8	32.8	31.1	28.2
Midwest	WUMS	33.9	32.0	31.3	30.8	29.2
Midwest	Entergy	24.6	23.0	25.6	29.3	27.4
Midwest Average		**31.3**	**30.2**	**31.3**	**31.4**	**29.6**
Southeast	CP&L	34.4	33.4	32.5	31.3	31.2
Southeast	DUKE	34.3	33.3	32.6	31.5	31.2
Southeast	SCEG	34.9	33.9	33.3	31.9	31.6
Southeast	Southern	34.1	33.2	32.8	31.4	31.1
Southeast	TVA	32.3	31.5	32.6	31.2	29.1
Southeast Average		**33.8**	**32.9**	**32.7**	**31.4**	**30.7**
FRCC		**39.6**	**37.2**	**35.5**	**33.8**	**31.7**
New York	Downstate NY	40.2	38.2	36.1	34.8	34.1
New York	LILCO	49.7	40.9	38.6	37.2	36.9
New York	New York City	43.4	41.3	39.1	37.6	37.3
New York	Upstate NY	34.0	33.5	32.9	32.2	31.6
New York Average		**40.3**	**38.0**	**36.3**	**35.1**	**34.7**
NEPOOL		**30.6**	**35.9**	**36.5**	**35.1**	**33.9**
PJM & VIEP	PJM-East	37.2	34.6	34.0	33.3	32.8
PJM & VIEP	PJM-South	35.5	33.9	33.8	33.0	32.7
PJM & VIEP	PJM-West	33.1	31.4	31.7	31.3	30.7
PJM & VIEP	VIEP	36.4	34.4	33.1	31.9	31.5
PJM & VIEP Average		**35.9**	**33.8**	**33.3**	**32.5**	**32.1**

Again, the results using the assumptions and analytic approach adopted here support the idea that RTO configuration does matter, with larger RTOs being more beneficial. Market improvements lead to greater potential economic benefits than changes to the transmission system alone, but changes to the transmission system do offer the potential for economic gains.

Note that benefits in these sensitivity cases are derived only from changes in the transmission assumptions. As noted earlier, to the extent that RTO scope is linked to overall market improvements the importance of scope for overall benefits would be greater.

Having presented results from the modeling scenarios, the next section of the report turns to integrating these results with potential RTO costs, and placing the modeling results into a more comprehensive framework. The section also discusses a number of important economic issues that are not directly represented or fully analyzed in the modeling framework alone.

3.7 Discussion and Integration of Costs

The results of the analysis show that there are large potential benefits to RTO policy as envisioned by the Commission. Even accounting for significant uncertainty as to the effectiveness of incentives for market improvements, the scenarios analyzed suggest that multi-billion dollar net benefits are the most likely outcome of a nationwide move to an RTO structure. The most important driver of this result is the set of assumptions regarding competitive market incentives and the potential for improved generator performance resulting from Commission policy.

Summarizing the results of all the cases, and taking a net present value of changes in total production costs over a 20 year period, shows that benefits of the policy are uncertain but lie within a positive range under the analytic approach adopted for this study.

Table 3.17: System Level Production Costs Across Cases (Billion 2000$)

	2004	2006	2010	2015	2020	NPV[1] 2002-2021
Base Case	89.5	94.2	109.5	129.4	149.8	1,076.8
RTO Policy Case	88.4	92.0	104.3	123.1	142.3	1,035.9
Savings from Base	*1.1*	*2.2*	*5.2*	*6.3*	*7.5*	*40.9*
Transmission Only Case	89.1	93.8	108.7	128.6	148.5	1,070.6
Savings from Base	*0.4*	*0.4*	*0.8*	*0.8*	*1.3*	*6.2*
Demand Response Case	88.3	90.0	101.9	120.5	139.4	1,016.8
Savings from Base	*1.2*	*4.2*	*7.5*	*8.9*	*10.4*	*60.0*

[1]Assumes 6.97% discount rate

It is reasonable to expect that these benefits will vary across regions and will increase over time. The wide range of potential economic benefits assessed here indicates substantial uncertainty with regard to the exact mechanisms and magnitudes of policy-induced changes to the electric power system. It is likely that further research would do little to narrow this range at the present time, although evidence from other industries and countries that have undertaken competitive market transitions can offer limited analogies and evidence. Estimating a wide range of benefits allows for the actual uncertainty of potential policy effects to be taken into consideration.

In comparison to the other studies summarized in Section 1.3, the estimated production cost savings from this study appear to fall into a reasonable range. In percentage terms, cost savings in the range of 1-5% are consistent with other work of a related nature. Note that these percentages are in comparison to the relevant production costs calculated in the IPM® framework and not the total industry revenues as noted in Section 2.5. In comparison to the more than $200 billion in overall industry revenue the percentage savings estimated here are in the range of 0-3% per year.

As has been made clear throughout this report, there are some economic issues that the analytic framework adopted here cannot address directly. This is a consequence of the challenging set of analytic requirements laid out in Section 1.4. The approach taken in this study is to place these issues into perspective and make any informed conclusions that can be developed from available information.

In particular, the geographic and temporal distribution of potential economic impacts is an important consideration in evaluating the overall policy. A number of economic issues arise in this context including:

- The costs of RTO establishment;
- Avoidance of short-term market imbalances and market power abuses;
- Regional variations in economic outcomes; and
- Net impact of near-term costs and long-term benefits.

Each of these topics is discussed in this section.

3.7.1 Costs of RTO Establishment

In order to fully evaluate RTO policy from an economic cost/benefit standpoint, estimates of the costs of RTO establishment are required. As noted in Section 2, the IPM® framework does not estimate costs that are not relevant for system dispatch and generation investment. In addition, available information on the costs of RTO establishment indicates a great deal of variation and uncertainty.

To make the best assessment of the net economic impact of RTO policy, a range of RTO startup costs can be considered. The relationship between the expense of RTO establishment and the functional effectiveness of a specific RTO remains unclear, so it is premature to expect that more or less costly RTO structures will ultimately be needed for an effective nationwide system. Taking this uncertainty into account explicitly is therefore the most accurate assessment at present.

There are five established independent system operators in the US: NEPOOL, NYISO, PJM, ERCOT and CAISO. For purposes of this cost estimate ERCOT is excluded due to the limited amount of information available on startup costs. In considering how the startup costs of these existing structures might be extended throughout the country, several metrics for relative cost were considered: cost per MW of installed capacity, cost per GWh of delivered energy, cost per customer served, and cost per network node. Table 3.14 below shows the existing ISOs in comparison to the entire US (excluding Texas and Alaska).

Table 3.18: Characteristics of Existing ISOs

	CAISO	PJM	NEPOOL	NYISO	Total National (Less TX+AK)
Installed Capacity (MW)	44,200	57,100	24,600	36,100	630,710
Annual Energy (TWh)	220	249	121	149	3,434
Population Served (Millions)	27	22	13	22	257
Network Nodes	3,000	1,900	1,100	1,168	46,000

Two existing assessments of RTO startup costs form the basis for a low and high estimate of nationwide RTO establishment costs. On the low end, the extension of PJM's operating systems throughout the Northeast was estimated to cost $71 million, reflecting maximum use of existing infrastructure. If extended nationwide using this starting cost estimate, total startup costs could be as little as $500 million-$1.5 billion nationwide, for a central low cost estimate of $1 billion.

On the high end, startup costs can reflect the construction of dedicated infrastructure such as IT systems and new, separate control centers. If these costs are extended using the various relative cost metrics, costs for nationwide RTO startup could range as high as $4.2-7.3 billion, for a central high cost estimate of $5.75 billion.

This range of more than 5 to 1 in startup cost uncertainty could probably be narrowed with a more focused research effort. For the purposes of this study the major observation is that even if startup costs are at the high end of the range, they are essentially one-time costs that are netted out against the ongoing economic benefits of RTOs. Even a $5 billion initial cost would be rewarded after several years with economic gains that appear to justify the initial expense.

Startup costs and operating costs are two distinct cost categories. Although some comparative studies of ISO operating costs have been completed, these studies have not compared the ISO operating costs to the operating costs of the existing systems or the systems replaced by the ISOs. As a general matter, it could be argued that merger and acquisition-type savings could be realized from a move to larger ISO or RTO structures. At the same time the increased functional responsibilities of RTOs could lead to higher operating costs. For this analysis it is assumed that operating costs will be a relatively unimportant element of the overall economic impact of RTO policy once existing system operating costs are taken into consideration. It remains an open question whether a small overall cost or benefit may be realized in this area.

It is worth noting that if RTO costs are at the high end of the range and RTO benefits are at the low end of the range (as reflected in the Transmission Only Case results), the national net cost/benefit outcome is close to even. This indicates that there is relatively little downside risk to the Commission's policy. Based on the analysis carried out for this study, the chances of a net loss from RTO policy is small on a nationwide basis. However, a major portion of the potential net gains from RTO policy could be lost if startup costs are high or if realized benefits are low. This reinforces the importance of policy implementation as a means of maximizing the net benefits of RTOs.

3.7.2 Short-term Market Imbalances and Market Power

As discussed in Section 2, the analytic approach relied on for this economic cost/benefit assessment had to be national and long-term in scope. The simulation modeling framework and associated analysis is therefore limited in several important respects. One important limitation concerns short-term price volatility. The modeling framework estimates prices by load segment, including a peak pricing segment, based on an efficient spot or pool pricing mechanism. This approach yields good estimates of prices over time, but as configured for a national long-term analysis, this use of the modeling framework will not predict or assess market imbalances that can cause significant divergence from equilibrium pricing in certain times and places. Additional analysis could focus on such short-term pricing effects, and the Commission has conducted retrospective analyses of such effects. Market and regulatory responses could limit the duration of market imbalances, but they can represent significant short-term energy price risk for market participants.

The analysis conducted here also does not attempt to assess the potential for market power abuse, and assumes that all individual supply units participate in least-cost dispatch under spot pricing mechanisms. Several types of market conditions can contribute to a given market's vulnerability to market power. These include concentration of ownership, lack of demand response, transmission constraints and barriers to timely and sufficient entry of new supply options (including substitute markets). Such market conditions can be assessed. Similarly, instances of non-competitive pricing can be addressed as they occur.

3.7.3 Regional Variations in Economic Outcomes

An important finding of this analysis is the persistence of regional variations in costs and benefits of RTO policy. Different regions have different starting points in terms of their supply and demand characteristics, and their degree of interconnection with other regions. These variations play out over a long time horizon as RTO policy allows increased inter-regional trade.

Persistent increases in production costs and/or firm electricity prices can occur in a particular region if that region has an effective supply curve that is steeply sloped relative to other regions. In other words, when a relatively small amount of power is exported from such a region, it requires that other generating units operate to meet local demand, and these units can be considerably more expensive that the supply that was operating in the absence of the increased inter-regional trade. So for such effects to occur there must be a relatively low-cost region with a relatively steep supply curve that can export to a higher-cost region. As a result of the special characteristics of each region's market conditions, some regions experience long-term price increases, while others do not.

There are analytic methods that go beyond the net efficiency analysis conducted for this study; changes in production cost and energy prices are not the only measures of economic impact. Within a region, revenues including net imports and exports and producer earnings can also be estimated. Regions where prices increase should also experience gains from trade in the form of increased export revenue and supplier earnings. This suggests that more detailed regional analyses could trace the revenue flows and begin to consider distributional questions that fall more properly into other policy contexts. Such detailed regional analyses could also consider the impact of market and regulatory uncertainties on local economic outcomes, and bring a finer degree of resolution to specific transmission flow and network characteristics.

In addition, this analysis does not consider macroeconomic impacts such as secondary benefits, economic development, and employment. Such effects could offset (or magnify) the consumer impacts of energy price changes, but these dynamics are highly specific to local economic conditions and have not been assessed here.

This study estimates changes in wholesale electric power prices that could result from RTO policy. However, concerns have been raised about the role of contracts and especially native load commitments in effectively reducing the responsiveness of the power system to changes in regulatory policy. If contracts, including native load, are in fact non-responsive to underlying market conditions, then consumers will not experience the potential benefits (or costs) of policy changes as much or as quickly as they would in a more responsive transactional environment. This 'dampening' effect of contracts and native load treatment is not directly represented in the analysis, but is a factor to be kept in mind when interpreting results.