Energy Market Impacts of Electric Industry Restructuring: Understanding Wholesale Power Transmission and Trading

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REPORT SUMMARY

This report, third in a series by EPRI and the Gas Research Institute (GRI) on the impact of electric utility restructuring on fuel use, addresses the question of how much more power might be able to flow from low to higher cost regions, especially during off-peak periods when the grid is most likely to have spare capabilities. While reviewing transmission issues and the limits of current knowledge, the report also defines key pacing issues that affect how much the generation mix can be expected to change in the wake of restructuring.

Background

Principal technical issues at the heart of gauging energy market impacts of electricity industry restructuring are transmission capabilities, which are changing, and price differentials, which must be large enough to warrant trading and change throughout the day. This report examines these issues in depth, based on recommendations from a prior study which systematically documented power generation and transmission markets in each major region of the country (EPRI TR-107900; GRI-97/0106). The first report in this series explained the difficulty of making definitive assessments of restructuring and offered preliminary analyses of effects on both fuel use and on organization priorities and skills (EPRI TR-107614; GRI-97/0109).

Objective

To evaluate the potential for increased electricity trading during off-peak conditions.

Approach

The project team, comprised of experts in transmission system operations, dispatch analysis, industry strategy and regulation, proposed a novel method of using publicly available system load and lambda data to estimate the extent of actual and potential inter-regional trading. (A compact disk with data on over 50 paired systems accompanies the report.) They downloaded hourly real-time transfer capability data from the PJM Open Access Same Time Information System (OASIS) and reviewed data on the WSCC 1996 disturbances. They supplemented these sources with interviews of power pool and utility transmission experts and obtained additional insights from leading analysts of power flow modeling. The team then conducted several regional dispatch simulations using a production costing model to evaluate hypothetical

scenarios of radically different transmission capabilities, reporting production costs and fuel consumption shifts across the northeast, southeast and WSCC regions. Finally, the team evaluated additional topics including non-utility generation, coal retirements, and power-by-wire economics and concluded with a discussion of major issues affecting the evolution and impacts of restructuring.

Results

This report reaches a similar conclusion to the prior EPRI-GRI report: even with widespread changes in transmission operations and market rules, the power industry will likely maintain much of its regional heterogeneity; and restructuring by itself appears unlikely to favor gas or coal generation. The report focuses on specific transmission questions and institutional considerations. Among the conclusions:

- Caution is warranted concerning the pace at which transmission capabilities can be expanded and new operational practices established. Work is proceeding on numerous fronts; yet technical, structural, and governance issues will likely lead to unique regional outcomes and delays in widespread trading.
- Short term transfer capabilities can be far different than those expected days or weeks in advance. Dynamic assessment is important to evaluating interregional trading and competition, but results are not uniform and many areas are unstudied.
- Dispatch studies modeling substantial elimination of inter-regional transmission constraints suggest that surprisingly modest changes in the generation mix are likely to arise from restructuring alone.

Perspective

Like its predecessors, this report provides both specific and general insights into the effects of restructuring. Readers will learn the pivotal role of transmission, gaining insight into changes in the generation mix, fuel use, and environmental implications of restructuring. Follow on research will provide further systematic analysis.

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Interest Categories

Fossil fuel assessment and cost management
Environmental compliance planning
Resource management
Combustion turbine/combined cycle plants

Key Words

Deregulation
Transmission transfer capability
Dispatch simulation
Fuel and strategic planning
Natural gas and coal demands

ABSTRACT

This is the third of three reports on the impact of electric utility restructuring on fuel use and energy markets. Prior research established which regions of the country appear most vulnerable to dramatic change and why. It also revealed that limits on the transmission transfer capability of inter-ties between adjacent market regions will prevent the electric transmission grid from performing like a "copper sheet" capable of transporting large amounts of power between arbitrarily remote locations in the U.S. Unfortunately, transmission transfer capability is not well understood, particularly in off-peak periods when a large share of the power exchanges are likely to occur, largely because traditional transmission capability analyses have only been concerned about on-peak grid reliability not bulk energy transfer potential. Absent more and better information about transfer capability it is difficult to predict changes in the pattern of power exchange brought about restructuring beyond the rough approximations obtained from the framework adopted in the prior study. Evidence is emerging that short-term off-peak capability can often be two or more times greater than traditional long-term firm limits determined by NERC studies. However, not all regions of the country are organizationally or technically ready to adopt short-term standards. This report sheds light on these transitional questions, examining the potential ability of the transmission system to support much more energy exchange in the off-peak and the strength of the economic incentives of the parties to do so.

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EXECUTIVE SUMMARY

Context and Purposes of This Report

Some proponents of power industry restructuring may have been expecting to discover that the U.S. electric transmission grid is effectively a "copper sheet" capable of transporting large amounts of power between arbitrarily remote locations in the U.S. This is not the case, among several reasons: the interties between adjacent control areas and power pools were largely developed for reliability, not for economy energy exchange. Grid architecture was largely laid out for flow management between local, franchise area generation and loads, not for the traffic patterns that arise under Kirchoff's Laws under multi-control area wheels. Transmission facilities have been expensive enough that it was (and remains) often more economic to build local generation than to import power from afar, or to simply allow transmission constraints to bind for moderate periods of time and to rely on out-of-merit dispatch. In fact, if the grid really was so elaborate as to be capable of supporting arbitrary rerouting of power, then we would have to conclude that it had been very inefficiently overbuilt.

This is just one, albeit extreme, example of how transmission transfer capability is generally not well understood by policy makers. But this is true even for industry specialists when it comes to non-peak periods that have not generally been the focus of past studies of transmission capacity adequacy. For fuel use impacts under restructuring, these off peak periods are important, as they are when a large share of potential power exchanges are likely to occur. It is at these times that there is both unused generation capacity and wide variation in incremental dispatch costs across regions. Absent careful scrutiny of non-peak transmission capability, it is difficult to predict changes in the pattern of power exchange, hence fuel use, likely to be brought about by industry restructuring. This report addresses fundamental transmission questions about how transmission transfer capability is being evaluated, reported, and made available in different parts of the country during peak and non-peak conditions, to see how much power exchange could in principle occur. It also examines the extent to which such exchanges seem to be occurring already, and the extent to which new transmission capacity limits and access fees may affect exchange between regions. The latter is evaluated by considering how much the market would open in an idealized situation where all transmission limits and fees were eliminated.

This report is the third of three reports on the impact of electric utility restructuring on fuel use. The first study reviewed and summarized the state of the existing opinion on this question as of 1995, and presented preliminary analyses of circumstances in which one fuel might dominate another to gain market share. The second report systematically documented the nature of the fuel, generation and transmission markets in each major region of the country, i.e. the starting conditions that will largely determine the relative vulnerability of each region's primary fuels to dramatic change under open access transmission policies. In that study the findings were: 1) the generation mix is quite varied by region around the country, creating different competitive threats and opportunities in each area; 2) limited inter-regional transmission capability exists to support changes in fuel use patterns and import capability is generally a small fraction of local production capacity; and 3) the greatest fuel-use shifts are likely to occur between competing cycling capacity power plants. In addition, the work led to the recognition of a number of 'Wild Card' factors that were very uncertain in nature but high in potential impact upon the industry's restructuring process. For instance, industry decisions about shutting down nuclear power plants prematurely (relative to their book lives) could have a major impact on fuel use, but such decisions depend on numerous complex factors that we have not analyzed.

The previous work also indicated that little was known of transmission in the non-peak condition during which time most energy trading would likely occur. This raised concerns about the usefulness of simulation results or even qualitative judgements about restructuring impacts if they were based on conventional measures of on-peak transmission transfer limits. Accordingly, non-peak conditions regarding both transmission and dispatch are a major focus in this current phase of research summarized herein. "What if" scenarios are examined to build the context of how great might be the consequences of changes in transmission. The current research also employs a novel method of using correlations between adjacent regions publicly available load and lambda data in order to summarize current inter-regional trading and to identify where that trading is likely to be intense versus weak. These correlation findings are buttressed through analysis of the key transmission limits and practices in different regions, based on interviews of grid managers directly involved in the restructuring process.

The relationship between the previous work and the current is depicted in Figure 1-1. The previous studies took a static approach to identify the vulnerabilities of each market region to restructuring of the electric industry. The current study approach examines the dynamic aspects of the industry; focusing more on the operational aspects of the industry and how those will be affected by restructuring and, ultimately, the affect on generation and fuel.

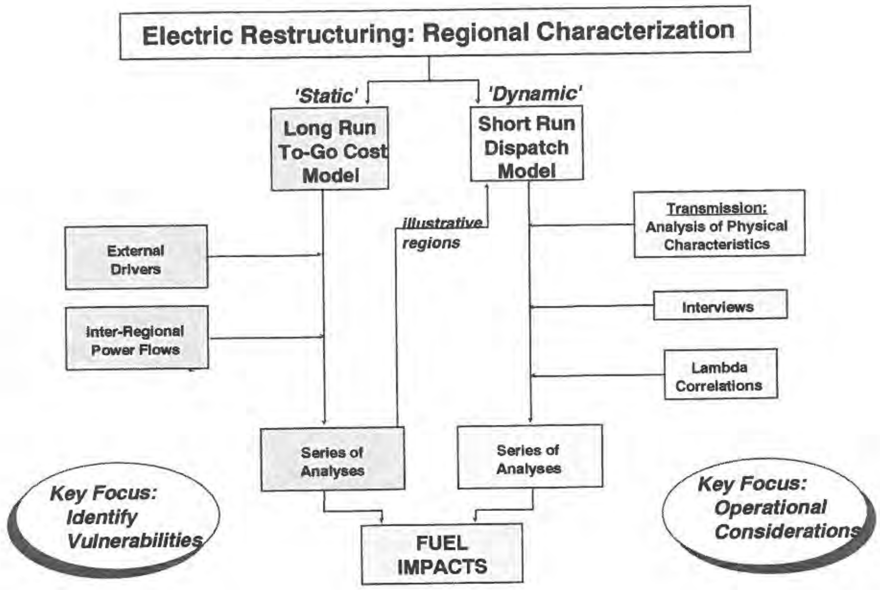

Figure 1-1
'Static' & 'Dynamic' Task Interrelationships

Key Points and Observations

- Transmission management is currently undergoing a metamorphosis — through rapid evolution of operating procedures and revolution in governance. The FERC and other policy advisory bodies such as NERC are asking for rapid development of real-time, publicly accessible grid information systems, but much standardization of measurements and communication protocols must occur first. "Tagging" of all flows over the interstate grid, i.e., keeping track of the actual shares of usage of parallel paths for all transactions, by source and sink, is deemed by many transmission operators to be essential, but it may be considered invasive access to proprietary information by shippers. Resolving this tension, along with addressing technical implementation questions, will likely delay growth of transmission capability.

  A time line depicting the development of these management initiatives is shown in Figure 1-2.

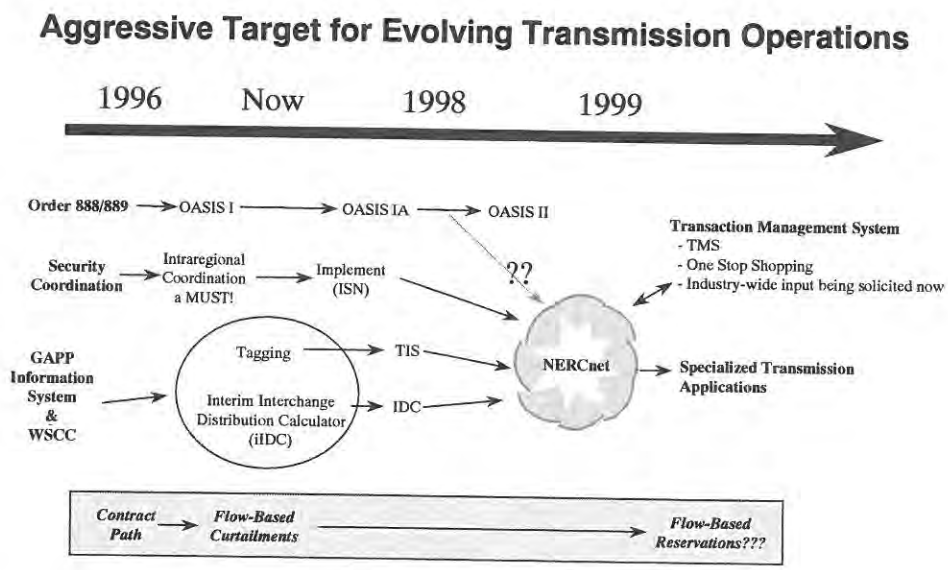

Figure 1-2
Trends in Electric Power Control Initiatives

- Different regions are approaching the measurement and reporting of available transmission capacity very differently. At one extreme is the PJM power pool, which has developed almost real-time estimates of available interface capacity that reflect prevailing load, line, and generator conditions. These short term interface capacities are often 2-3 times larger than the long term firm, first-contingency limits traditionally reported in NERC transmission adequacy studies. At the other end of the spectrum is the WSCC, which has recently decided that it must operate its system more conservatively than short term conditions might allow, in part because of anxiety over events like the cascading outages of 1996. These stark differences demonstrate how posted transmission limits depend critically on regional abilities to collect and coordinate the use of real-time information on the state of the grid system.

- Trading opportunities appear to be not yet fully exhausted in several regions of the country, in that the observed marginal costs in adjacent regions often are only weakly correlated much of the time. Generally, pairs of markets involved in active trading with each other should be expected to show high short run price correlation, indicating that opportunities for gains from trade have been pursued to the point where marginal costs are quite similar. Such a situation is depicted in Figure 1-3. This figure shows that there is a high degree of correlation of marginal costs between Entergy and Public Service Oklahoma indicative of a great deal of power transfers over the 'cycling' portion of their load curves. Observed low correlations in some regions suggests either the marginal cost differences between the regions are small relative to wheeling fees, or there are binding transmission limits, or the price differences are being ignored or overlooked.

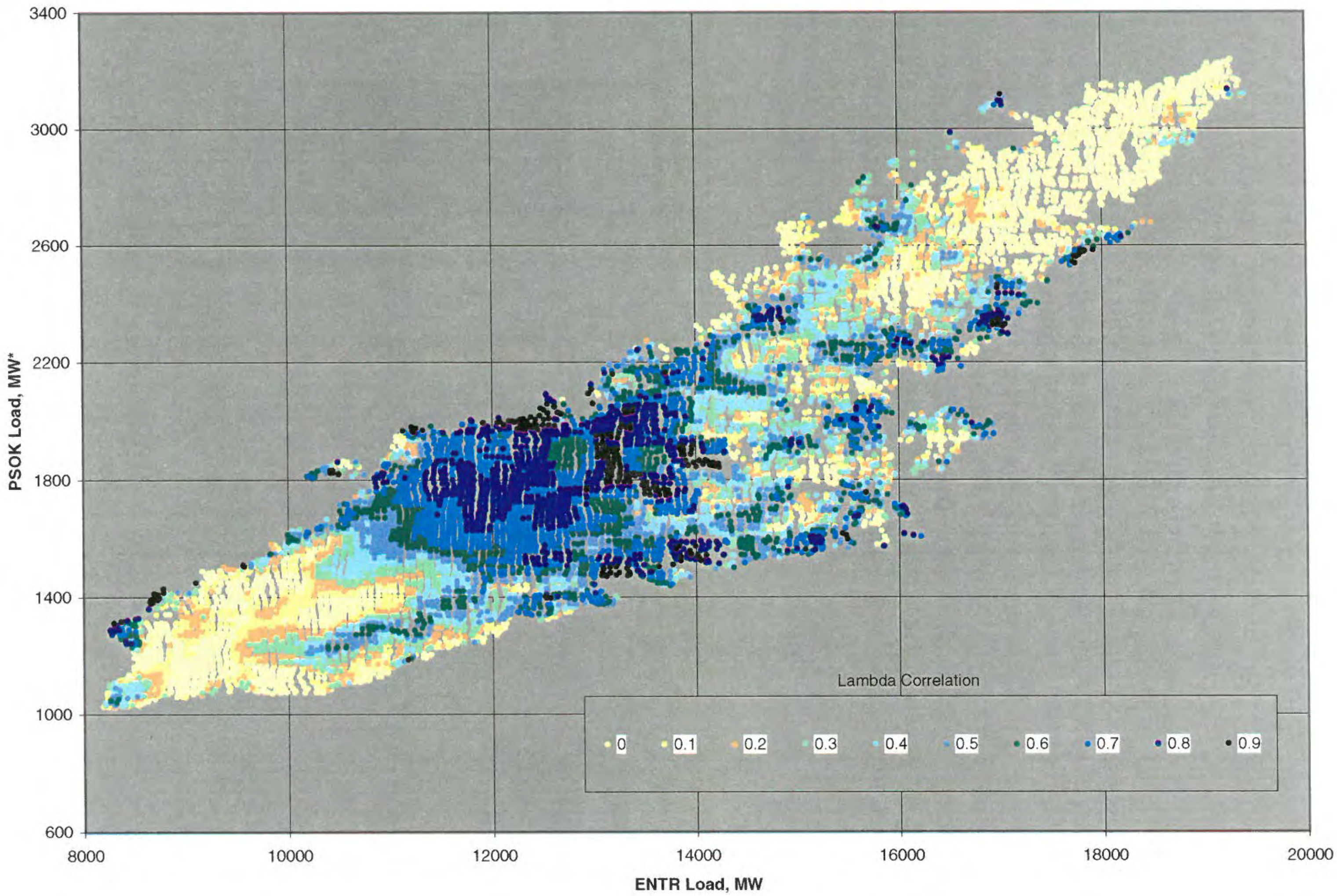

Figure 1-3
Lambda Correlations Between ENTR and PSOK at Varying Load Levels - 1995 Data

- The reductions in potential short run production costs, *i.e.* dispatch savings, foreseeable from restructuring and increased trade appear to be modest across a wide range of transmission access scenarios. When large regions are interconnected as if they had infinite, costless transmission interties, simulations of dispatch and trading show only a few percent reductions in annual energy production costs for most large regions of the country, suggesting that dispatch and wholesale trading are relatively efficient already. The result of these simulations for three regions is summarized in Figure 1-4. Percent reductions are measured as deviations from the base case; the base case simulates transmission constraints and fees as they exist today. Moreover, the simulations suggest that most of the gains from trade will come from eliminating transmission constraints not elimination of wheeling fees. Wheeling fees do appear not to be significant barriers to trade. In addition, a significant amount of the available gains from trade appear to already have been achieved in moving from a world where there was no trade between utilities to the base case, where there is trading within limits. One implication is that we should not expect a huge, immediate "competitive dividend" from improved dispatch under open access.

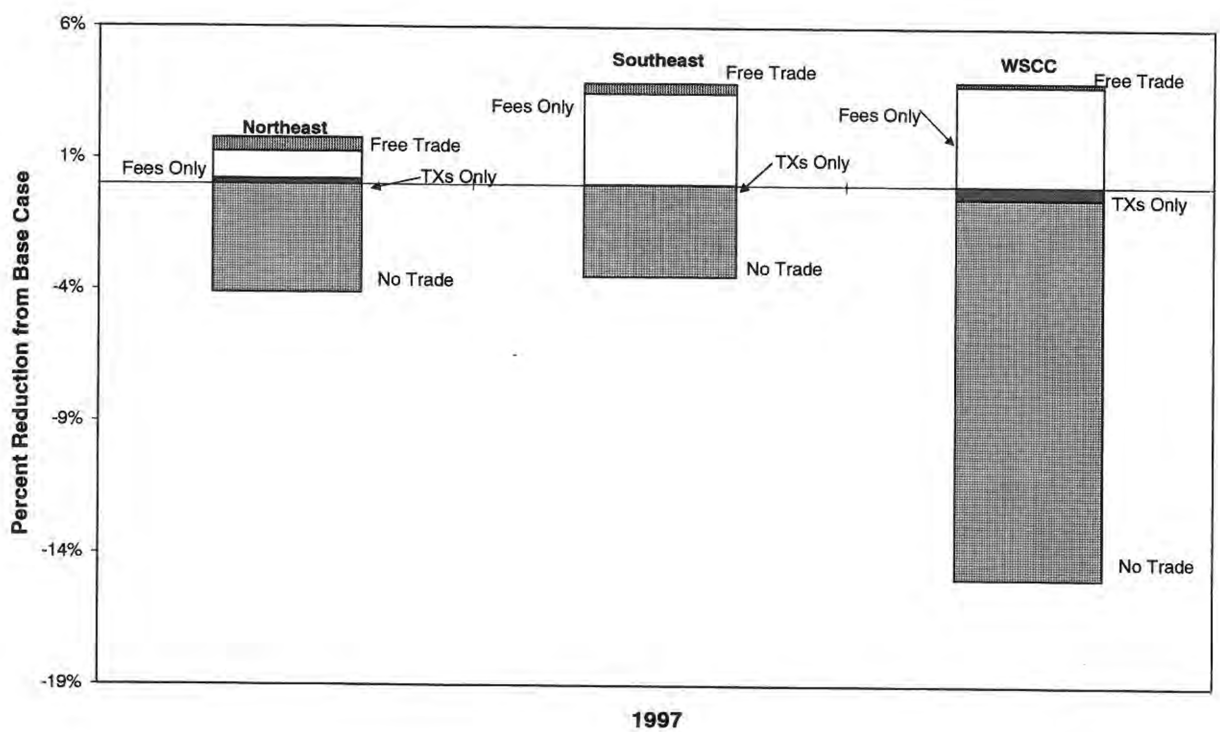

Figure 1-4
Percent Reduction in Total Productions Costs From Changes in Transmission Fees and Constraints (1997)

- The lifting of all transmission limits and fees generally creates a modest tilt towards coal generation and away from gas, though the effect is, again, quite small This analysis almost certainly overstates the actual likely shift towards coal for two reasons: First, the transmission constraint relaxation we have considered is far larger than what will in fact be realized, and second, these simulations do not explore the impacts of likely environmental policy changes that could penalize coal generation, alter market prices and the associated load growth, and alter relative fuel prices.

- These two types of transmission findings (that non-peak transfer capability can be much more, in some locations, than has been recognized in the past, but these amounts are still small compared to local generation, and that unlimited access would not induce a massive change in energy costs) suggest that the real fruits of restructuring may ultimately be found in other battle fronts, *i.e.*, in how currently marginal "dog units" are retired vs. refurbished, how soon must-run and must-take units become dispatchable rather than protected by regulatory terms for their use, how environmental policies for, e.g., NOx and CO_2 are implemented, how load growth and load shape respond to volatile, peaky spot prices; and how the capacity expansion decision ultimately shakes out between new wire to existing coal units or new pipe to new gas units. These battle fronts largely involve competition and regulatory policies affecting non-variable costs, reaffirming our assessment in earlier research that To-Go costs will be quite important.

- Finally, the uncertainty of various aspects of restructuring continues to cloud or delay the outcome of various issues. It is becoming increasingly plausible that restructuring may prove to be somewhat of an economic disappointment, in terms of near-term rate reductions, because 1) supply imbalances are shrinking as we argue about how restructuring should proceed; 2) stranded cost allowances and recovery policies to date tend to impose short term rate reductions but may include medium term rate increases; 3) the market-generation portion of the typical electric bill that can be reduced, even by very clever and aggressive shopping, is fairly small; and 4) some regulators are showing a tendency to preserve social policy and technology programs that many felt would prove uneconomic in a more competitive world. This simply means we must be patient for the real benefits, which will come in the longer run with improved capacity planning and consumption technologies.

- The politics of restructuring often seems to be driving the process more strongly than developments in the feasible electrical engineering. One consequence is that the process will continue to be a heterogeneous one, with each region taking a different view of its potential gains and how to capture them.

Report Organization

The remainder of this report consists of six chapters that provide in-depth discussion of the analysis and results. These are followed by two appendices that contain detailed supporting information. Appendix A describes the methodology and scope of the load and lambda correlations. Sixty-seven company pairs are listed, maps of control areas are plotted, and information is provided on the availability of load and/or lambda data sets for each company. Color plots of the results are contained on the enclosed CD. Appendix B contains supporting information for the short-run dispatch analysis. First presented are regional production cost savings calculations for each "what-if" scenario, along with data on simulated costs of power imports and exports for 1994, 1997 and 2000. Next presented are the changes in regional fuel consumption patterns fore each scenario compared to the base case. Two lists are then presented, one with each company's open access transmission tariffs per FERC Order 888, and the next showing the utilities included in each broad market area. Plots are then included summarizing subregional generation and capacity factors, separated into baseload, cycling and peak categories, for several of the scenarios studied. Appendix B concludes with a table reporting the subregional capacity factors according to fuel type for several scenarios.

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METHODOLOGY

Overview

A multi-pronged research approach was used to develop the insights presented in this report. The approach built upon research and insights generated by the project team in prior research. The framework for the analysis was designed to yield a greater understanding of transmission capabilities and of the role played by new rules and mechanisms for trading power. An in-depth examination of PJM and WSCC's transmission operations provides the basis for understanding the role of transmission in establishing power generation and fuel use patterns. Subsequent analysis empirically examines the relationship between transmission capability and inter-regional power flows as it currently stands and for the foreseeable future. An assessment of how transmission capabilities affect current trading patterns was facilitated by examining load lambda correlations across adjacent regions. Structured modeling techniques were employed to acquire a finer-grained understanding of the role of transmission capabilities in determining fuel patterns and power production costs in the future. Interviews helped buttress the evolving industry and insights being developed. The results of the different efforts were ultimately integrated together to assess potential fuel usage patterns and identify the 'New Battlefronts' that are likely to soon come to the fore in electric utility restructuring debate.

Progression of Electric Industry Restructuring Studies

This report presents the results of the third phase of a multi-phase research program to provide insight into potential changes in fuel consumption and generation patterns brought about by electric utility restructuring. Figure 2-1 shows how the analysis of key restructuring-related questions addressed in this report flow from the prior EPRI-GRI restructuring studies. The first phase defined the scope of the problem by identifying and organizing key external factors (in contrast to inputs traditionally modeled) driving the vulnerability of a market region to restructuring. These results were published in Volume I, "*Impacts of Electric Restructuring on Fuel Use-Analytical Challenges*," December 1996. The second phase developed a framework and tools to analyze factor exposure. Application of the tools yielded perspective and quantitative insights to a broad range of questions and problems. These results were published in Volume II, "*Regional Impacts of Electric Utility Restructuring on Fuel Markets*," April 1997.

This project addresses one of the more important areas of technical uncertainty underlying the evaluation of the impact of restructuring, transmission. Resulting insights allowed for confirmation or revision to conclusions reached in the earlier research.

From a methodological point of view, the work is pertinent to evaluating how thoroughly alternative models address particular power trading conditions and may help advance methodologies used for such analysis. In future work, EPRI and GRI plan to conduct some comparative analyses using different research methodologies and data, as well as to address smaller regions where findings to date may mask important generation and fuel use impacts. Furthermore, the environmental aspects and implications of this work now deserve more explicit treatment than first envisioned. Potential directions for this work are taken up in more detail in Section 7 of this report.

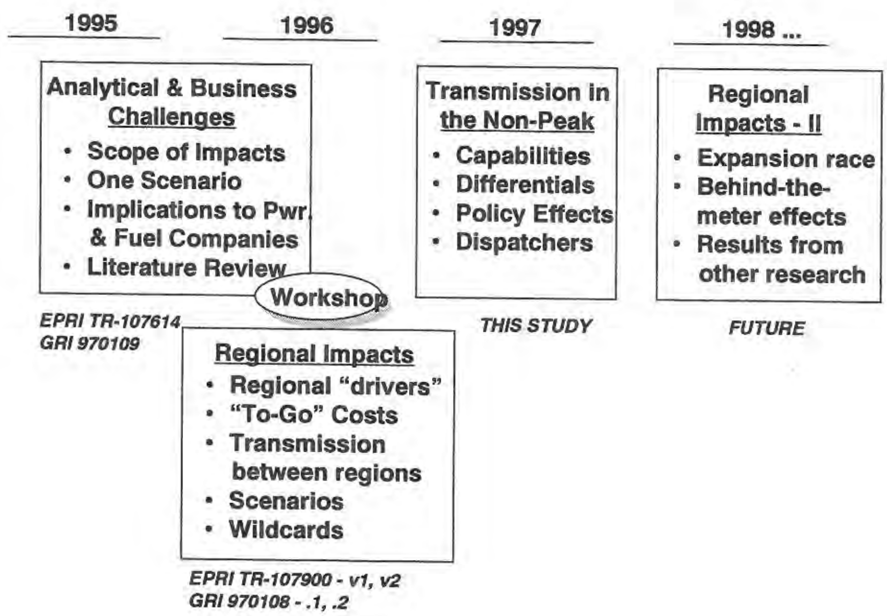

Figure 2-1
Progression of EPRI/GRI Studies

Research Approach

As illustrated in Figure 2-2, the research presented in this report builds substantially on prior work. Prior work relied on 'static' analytic techniques with the focus on identification of market region vulnerability to restructuring. The static approach accommodated the use of relatively simple tools to obtain rough-cut assessments of the impact of and sensitivities to a host of external factors that would not otherwise be subject to 'results by assumptions'.

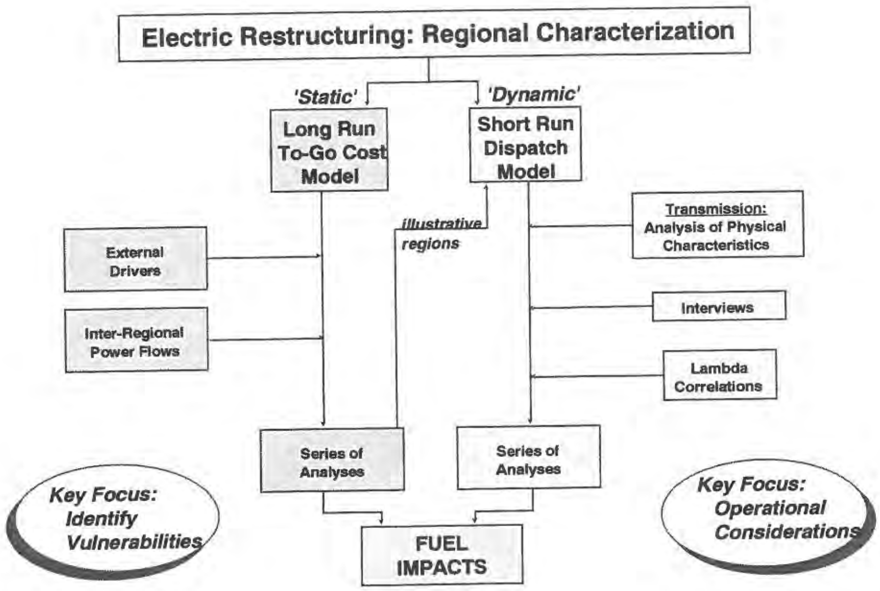

Figure 2-2
'Static' & 'Dynamic' Task Interrelationships

A key issue raised during the prior study was the robustness of the results from the static analysis to more realistic assumptions about operation of the electric system, specifically to variations in transmission capability and unit dispatch. The dynamic analysis undertaken to shed light on this issue was built around four efforts.

- Assessment of current and planned transmission system operation.
- Investigation of the current level, duration, and time of inter-regional power exchanges via analysis of load and lambda correlations.
- Examination of the impact of changes in transmission capability and costs on fuel patterns and productions costs using a short-run production cost based trading model.
- Interviews provided real time feed back on current trends in the industry.

The results of these efforts were then integrated together to develop a deeper understanding of regional fuel impact patterns.

Transmission Assessment

This research effort focused on further development of an understanding of the electric power transmission system in light of FERC's Orders 888 and 889. Assessments of transmission capability during on-peak and off-peak periods were made using Open Access Same-Time Information System (OASIS) data. Interviews and selected power flow analyses greatly aided this effort. Many key insights about the role of transmission in determining inter-regional power exchange patterns are presented in Section 3. Results obtained from this effort were implemented directly into the short-run dispatch modeling effort.

Load and Lambda Correlations

A novel analytic technique of analyzing utility load and lambdas was developed expressly for this research. This technique allowed for an empirical assessment of grid operations to be conducted using publicly available data. In this step, we compare data on simultaneous system load levels and associated production costs (lambdas) in adjacent regions. The load and lambda correlations provided a fruitful means to estimate the level of hourly inter-regional power trading that has occurred, and at what load levels (peak, cycling or base) this trading is apparently most prevalent. This analysis is valuable as much for the questions it raises as it is for the questions it answers. The analysis begs the question, "how will these trading patterns change, if at all, with restructuring?" Section 4 describes this effort in more detail supplemented by Appendix A.

Short-Run Dispatch Analysis

The methodology adopted in the previous work focused on long-run cost measures, To-Go costs, as a measure of regional vulnerability. The advantage of To-Go costs is that they expose problems and issues associated with nonvariable power costs that are likely to be central to a restructured and more competitive industry. The disadvantages of To-Go costs are (primarily) that they do not predict dispatch very well. Dispatch is likely to be determined by short-run variable costs. Consequently, short-run dispatch modeling is likely to provide a suite of insights into potential trading practices. Moreover, key transaction conditions with which we are concerned in this report (i.e., access and wheeling fees) can be explicitly modeled.

The short-run dispatch analysis serves as a check on the results from the To-Go cost analysis. In addition, the analysis can shed light on the magnitude of changes in power exchanges due to changes in transmission and the associated changes in fuel and production costs. In the absence of detailed time-of-use transfer capability, extreme conditions ("no trade" and "free trade") are examined to bound the outcome.

A chronological, multi-area production costing model called IREMM[1] (Inter-Regional Electric Market Model) was used to simulate the hourly trading activities within three very large regions for the years 1994, 1997, and 2000. The 1994 results provide a benchmark on which to calibrate the remaining years.

IREMM is similar to utility production costing simulation models used for planning and budgeting purposes in that it determines economic dispatch on the basis of variable generation costs, taking into account unit forced outages, maintenance requirements, hydro scheduling, transmission limits, and wheeling costs. It simulates dispatch and trading on an hourly basis for each defined market within the region. Customer loads and generating units of each market area are integrated as if they were a single power pool. Each market area has an obligation to serve its own load before it can sell its surplus energy to other market areas. Local supply can be replaced if surplus energy can be purchased elsewhere for less.

Integration of Results

The results of these different strands of research were integrated to provide an overall assessment of an electric industry in transition. Through this effort new potential 'Battlefronts' were uncovered as the process of restructuring continues. These battlefields are described in Section 6. Section 7 provides the major conclusions of the integrated analysis.

Interviews

Interviews of key industry stakeholders played a critical role in assessing the importance of a number of variables. PJM, The Southern Company, NERC and NYPP were particularly helpful in this effort.

[1] The IREMM model is developed and licensed by IREMM, Inc.

3

METAMORPHOSIS OF ELECTRIC POWER TRANSMISSION

Overview

Electric power transmission is undergoing a significant metamorphosis in which the concept of reliability is being redefined to support large-scale and active markets for power. FERC's Orders 888 and 889 have precipitated a rapid revolution in transmission operations and governance. How little the industry was prepared to deal with the realities of 'real-time' power marketing, and the resulting large-scale and unpredictable changes in the flows, is now apparent. What is not apparent at this time is how and when the various stakeholders will come to a consensus regarding transmission operations.

There are tantalizing glimpses of what the future of electric power transmission might look like. For example, a few transmission links are capable of two to three times of their nominally rated capability. However, efficient and wide-ranging coordination and allocation of this capability is necessary before these gains can be realized. The regional experiments in ISOs to control transmission and power market area formation ongoing throughout the U.S. are possible incarnations of what this future looks like. Those successful aspects of the regional experiments are likely to be adapted in other regions allowing for more efficient use of the existing transmission grid.

This chapter begins with a review of the 'static' world of transmission before examining key aspects of 'dynamic' world of transmission. Two specific illustrative examples, PJM and WSCC are used to compare two different interpretations of this dynamic world. Next the evolution of operations and revolution in governance that is driving metamorphosis of the industry is examined, concluding with a review of the uncertainties currently facing these aspects of industry restructuring. What appears certain is that years will be required before power transmission will begin to have large effects on inter-regional fuel usage patterns.

'Static World' Analysis

In this section the 'static world' analysis by which transmission capability has been assessed for decades is reviewed. Next the reasons for why this type of analysis is no longer appropriate are reviewed. Finally, the insidious and wide-ranging effects of parallel path flows are reviewed.

Background

In the prior report the regional assessment of transmission capability found that the 'size' of the 'wires' connecting regions was small compared to the generating capability within each region. Figure 3-1 illustrates this finding. In the figure it can be seen that the capability of transferring significant percentages of power from one region to another is rather limited ranging from under one percent to an exceptional 24 percent in the case of WSCC North to WSCC South (regions with a history of large-scale, long-haul power transfers).

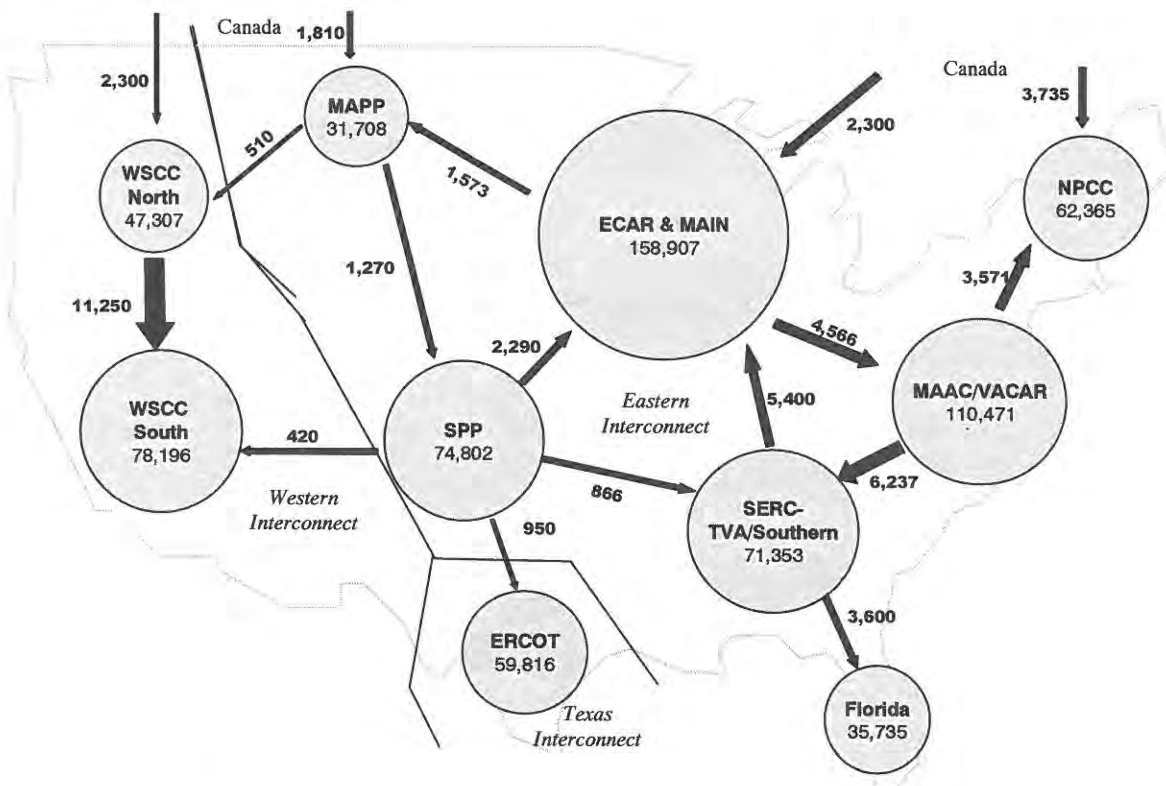

Figure 3-1
Comparing Generating Capacity and Total Transfer Capability

A conclusion that could be drawn from this 'static world' analysis is that few changes in fuel-usage patterns could be expected without significant expansion of power transfer capability. Since transmission expansion projects continue to face significant obstacles, the implication is that power-by-wire will remain a concept, not a reality, for the foreseeable future.[2]

The Off-Peak Question

While much was learned from the static world analysis a large amount of uncertainty surrounded the issue of off-peak transmission capability. The uncertainties revolved around the definitions and methodology that the North American Electric Reliability Council (NERC) uses to establish safe, reliable transmission capability. Foremost among the uncertainties is that transmission capabilities[3] are calculated for anticipated peak conditions during the summer and winter season.

There are several reasons why assuming peak conditions may be inadequate for assessing transmission capability. First, peak conditions on the electric system occur only a few hours throughout the year. The rest of the year, or even during daily off-peak and transition-to-peak times, the transmission system is not nearly as 'stressed' as during peak times. It is therefore reasonable to presume that more transmission capability might be available during off-peak periods.[4]

Second, the studies upon which the transfer capability estimates are derived are based under some assumed peak condition occurring six to eighteen months in the future. Since the capabilities published by NERC are widely used as 'actual' Total Transmission Capability (TTC) values, estimates of dispatch and equipment availability are made to provide conservative results. Some power marketers maintain that such practices are overly conservative when considering hourly and real-time markets.

The question of 'off-peak' capability therefore involves the questions of how much more TTC exists, under what conditions does it occur, and how and when will transmission system operations advance such that this 'additional' TTC can be realized.

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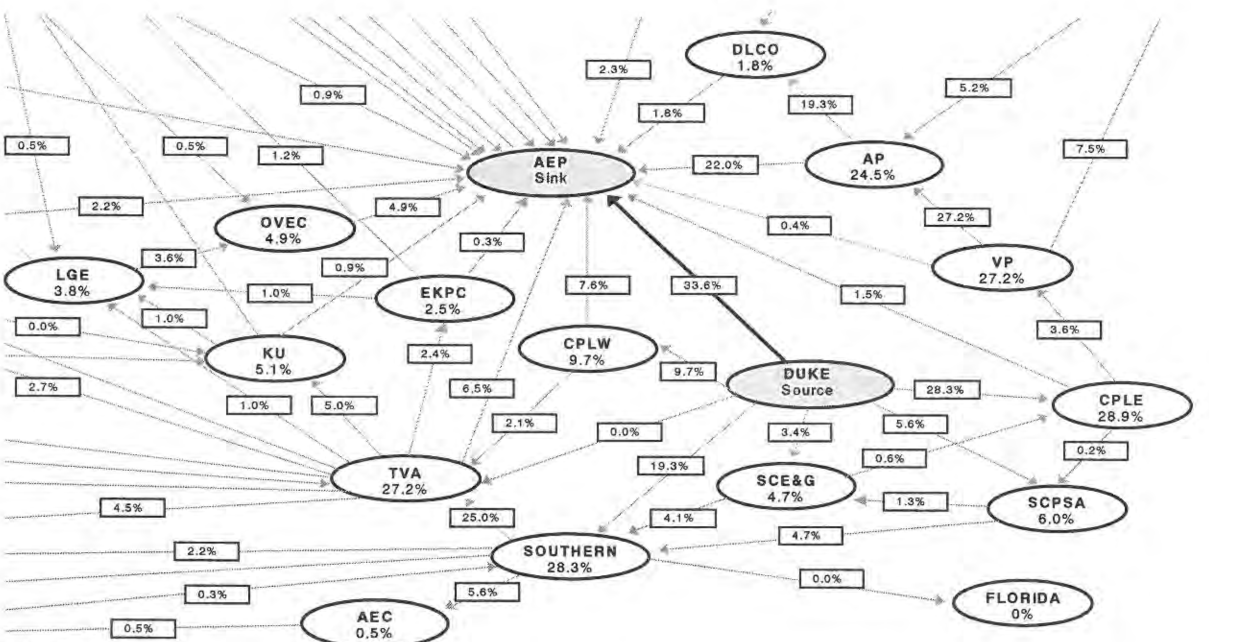
[2] Prior work, *Regional Impacts Of Electric Utility Restructuring On Fuel Markets* (EPRI TR-107900/GRI-97/0108.1), found that state-level and multiple jurisdictions, NIMBYism, and difficulties apportioning costs and benefits have stymied several transmission projects in recent years.

[3] Sometimes referred to as First Contingency Incremental Transfer Capability.

[4] Interestingly enough we found that in some instances the opposite is actually true (i.e. off-peak capability being less than at peak) This occurs because higher cost peaking supplies tend to be located closer to load centers. When these higher cost supplies are dispatched relieving flow on a constrained interface then the 'safe' import capability into that region is incremental.

The Parallel Path Factor

The one aspect of electric power transmission that limits reliably higher TTC is parallel path flows. Parallel path flows occur because flows within each of the synchronous, interconnected, regions are dictated by the impedances along each possible path on the grid - not along contract paths. Figure 3-2 illustrates the far reaching nature of parallel path flows. This example considers a single transaction from Duke to AEP control areas. Surprisingly, only 34 percent of the power actually uses the transmission lines that directly connect Duke to AEP. The remaining 64 percent of the power flows elsewhere in the eastern interconnect before making its way into the AEP system. In fact, seven percent of the power flows through systems as far away as Louisiana, Illinois and Missouri.



Notes:
1. Figure shown is only a subset of the Eastern Interconnect.
2. Values in bubbles are total power flow through the control area.
3. Value on lines are power flow on transmission lines directly connecting the control areas.
4. Source: Power Technolgies, Inc.

Figure 3-2
Example of Parallel Path Flows for a Duke to AEP Transaction

When considering the consequences of parallel path flows it bears remembering that this example represents just a single transaction. In the past, each control area took the results of NERC's, and others, modeling efforts and used there as static representations of 'rest-of-world' for everything outside their own system. Interestingly, even though the electric system is synchronized within each of the three North American interconnects very little real-time coordination among control areas has occurred in the past. Yet, it has become clear that simplistic representations, and lack of coordination, are no longer adequate since an increasing volume of transactions are not predictable. The real world of electricity supply and demand occurs in real time in response to a variety of volatile factors. As a result, the assumption that key inter-regional flows will be stable and consistent is no longer valid.

Evaluating Dynamic Transmission Capability

In evaluating dynamic transmission capability an examination of two different systems is presented. Through this process it is possible to begin building up the answers to the questions of dynamic transmission capability. In this case the TTC assessment methodologies of PJM and the WSCC's AC & DC Northwest intertie are closely examined. In addition, further insights into TTC evaluation gained from other industry interviews (Southern Company and NYPP) are also made, as appropriate.

PJM Transmission Capability Assessment

Arguably the most advanced transmission system control in the U.S. is that operated by the PJM Interconnection, L.L.C. First organized in 1927, PJM manages the bulk power transmission system over an area covering all or part of Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia, serving a 1997 peak load of 49,820 MW. Figure 3-3 shows the geographic area and the control areas to which it has direct connections.

On July 1, 1993 PJM was transformed from an organization owned by the utilities into a pool operated by independent staff. At that time market participants in bilateral and energy markets began using PJM's Open Access Same Time Information System (OASIS) to assess and request transmission services.

PJM dynamically adjusts TTC along each path into, out or, through its system in response to demand by market participants, dispatch patterns and host of other factors. The reasons for these adjustments include:

- Time horizon uncertainty
- Coordination among electrically similar paths
- Real-Time Monitoring of external dispatch
- Transmission equipment adjustments

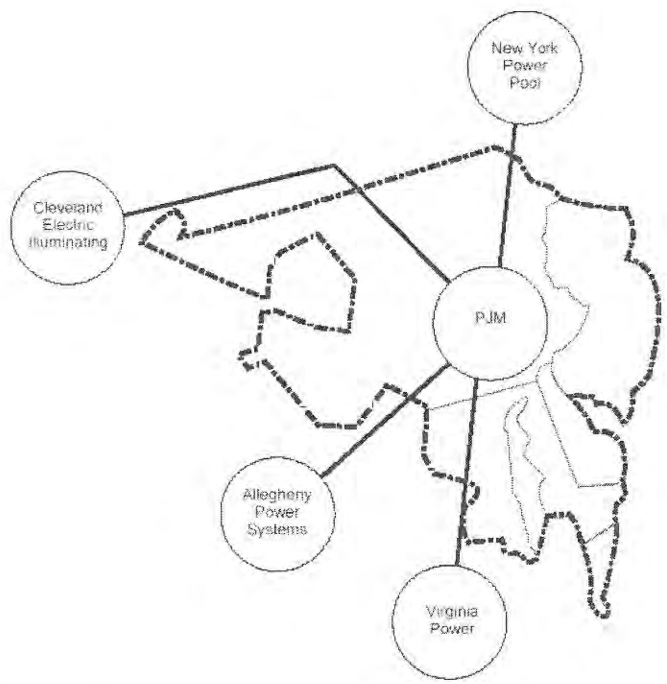


Figure 3-3
The PJM System

Time Horizon Uncertainty

An illustration of what PJM determines to be safe TTC for power flows from Allegheny Power System (APS) is shown in Figures 3-4 and 3-5. What is readily apparent from studying these figures is that TTCs between the same region can take on significantly different values depending on what time horizon is being considered.

The basic premise behind adjusting TTC within PJM to reflect 'actual' versus 'assumed' conditions lies in recognizing the reduced uncertainty in conditions that occurs when shorter time frames are considered in the near-term. PJM calculates transfer capabilities over three specific time frames:[5]

- Near-Term: Hour 0 (current hour) to Hour 168
- Mid-Term: 8 to 30 days in the future
- Long-Term: 1 to 13 months in the future

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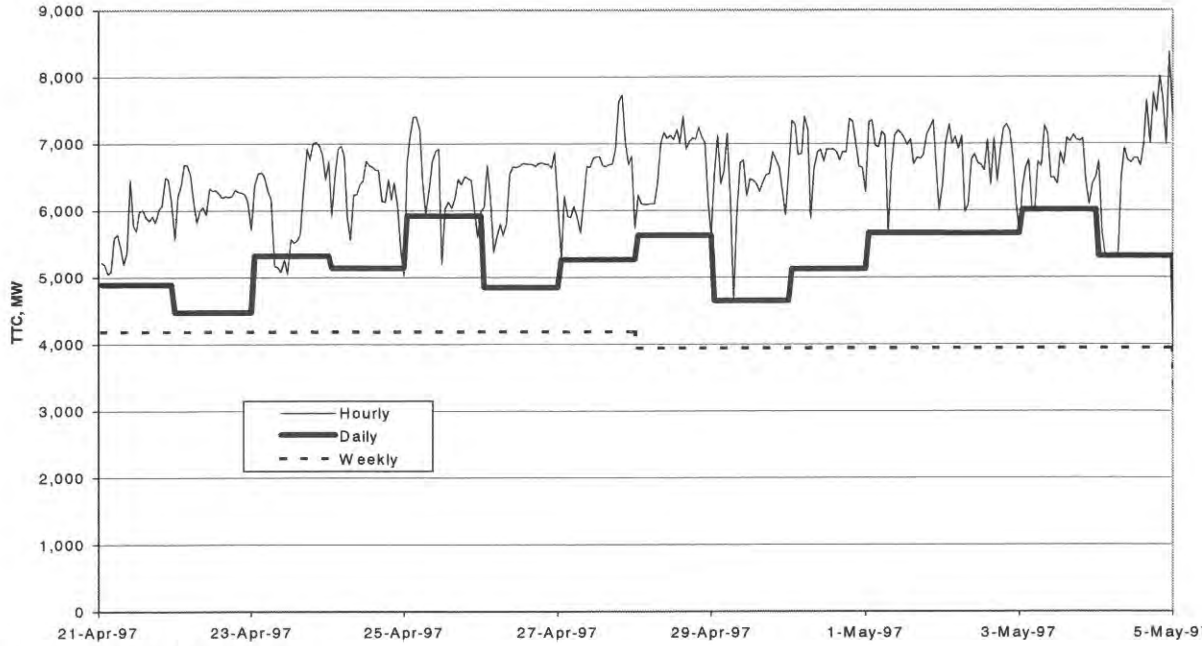
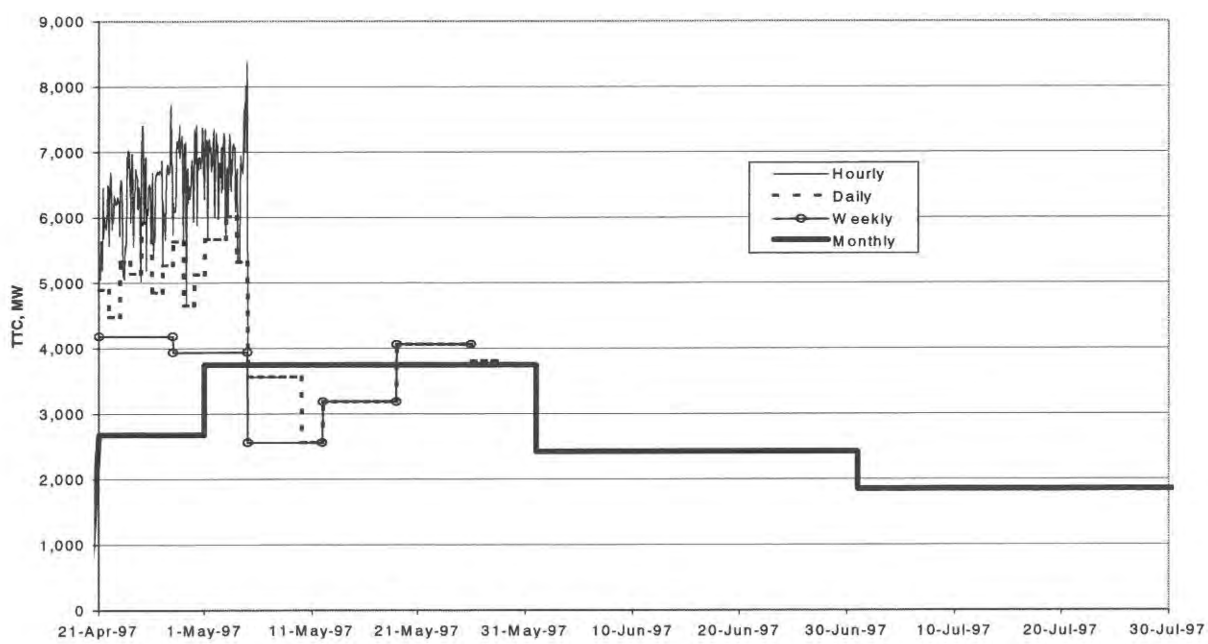
[5] PJM Interconnection Association (March 24, 1997) *Transmission Service Request Manual*, pp. 2-10 to 2-22.



Source: PJM OASIS and Project Team

Figure 3-4
APS to PJM Total Transfer Capability-Daily View



Source: PJM OASIS and Project Team

Figure 3-5
APS to PJM Total Transfer Capability-Monthly View

For each time horizon PJM uses a well developed methodology geared towards maximizing the use of pertinent information regarding transmission capability into and out of PJM. A few of the conditions that alter TTC includes: projected loads, actual transmission outages, adjacent control area power flows and temperature-dependent thermal ratings. An example of how anticipated changes in system conditions can effect PJM hourly TTC from APS to PJM is shown in the figures. For the hours shown in the exhibit TTC varies from a low of 5,054 MW to over 8,000 MW.

As the time frames lengthen uncertainty about the conditions affecting TTC grows. In addition, to allow reservations of Available Transfer Capability (ATC) over these longer time frames, the minimum TTC of the next shorter time frame becomes the limiting TTC for that time frame.[6] Therefore, the longer the time frame, the lower the TTC. This process is illustrated through comparison of the hourly, daily and monthly TTC postings over the same APS to PJM path. It is the TTC for the month of August that is directly comparable to the "summer peak" capability reported by NERC in its seasonal assessments.

Coordination Among Electrically Related Paths

As the hour of needed transmission capability draws nearer the more PJM operators can do to adjust the system to fulfill demanded ATC service. Over the years, detailed studies of MAAC, ECAR, NYPP (MEN) power flows and capabilities and similar and VACAR, ECAR, MAAC (VEM) studies have improved the ability of PJM planners and operators to learn what is the safe operating capability of each path given flows on other paths.

The case of TTC from APS, as shown in Figures 3-4 and 3-5, also serves as an example of the gains to be had through coordination. The TTC from APS as shown is actually a representation of the aggregate TTC available from APS, Cleveland Electric Illuminating (CEI) and Virginia Power (VP). The MEN and VEM studies have shown that these three paths are so closely related that they practically constitute a single path. As a result, PJM 'pools' the aggregated TTC. When an ATC reservation is made along one path the ATC on all three paths are decremented.[7]

Further gains to TTC can be had by reallocation among other paths. Figure 3-6 shows the "switching" of capability that can be safely accommodated between the paths of NYPP-West to PJM and APS to NYPP-West in response to system conditions. Such

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[6] For instance, weekly TTC must be expected to hold for every hour of the week to support service.

[7] The amount to decrement ATC for each path is found by multiplying the requested ATC by a distribution factor.

reallocations can be accomplished to meet demand on one interface with slack demand on the other.

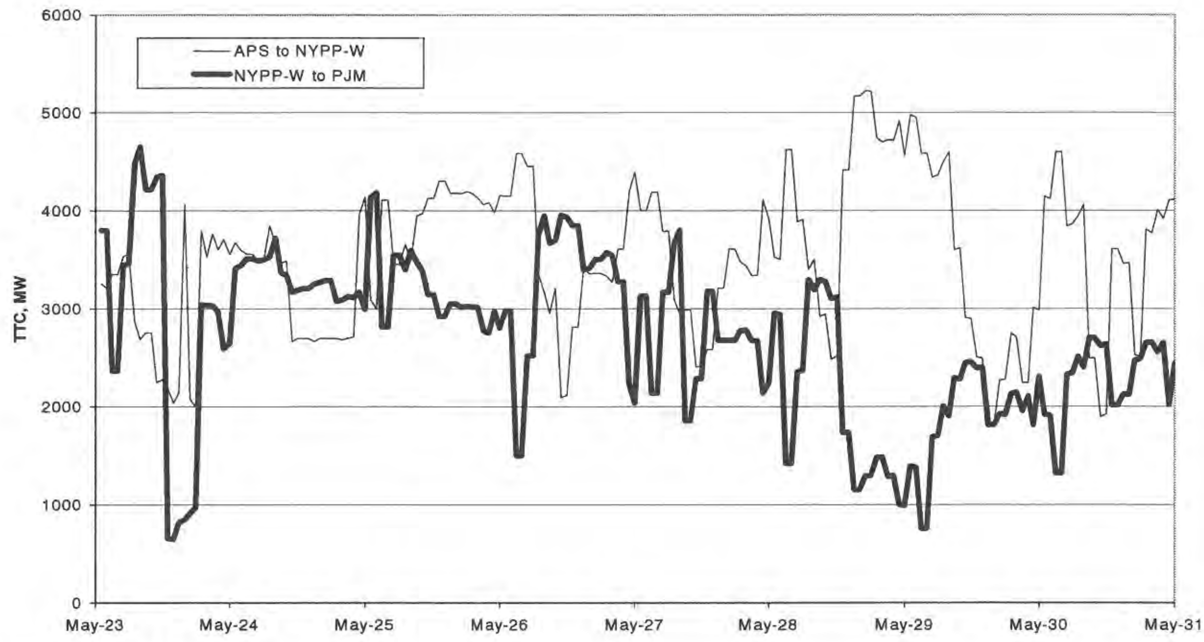

Figure 3-6
NYPP-West to PJM and APS to NYPP-West TTCs

There exists a great deal of significance of being able to switch capability from one path to another in response to real time conditions. In other regions of the country similar switching could occur but is not practical due to inadequate means to tightly coordinate operations. It must be remembered that most control areas, such as those shown in Figure 3-2, are operated virtually as islands. This has only been possible to accomplish in the past because most control areas throughout the interconnect kept power flows between the islands fairly constant and predictable.

Real-Time Monitoring of External Dispatch

The MEN and VEM studies have also led to PJM altering transmission operations in response to constraints and flows occurring outside its system. This was done in the late 1980s in response to constraints on power flowing from the west into PJM.[8]

[8] FERC Docket No. EC96-10-000, Baltimore Gas and Electric Company and Potomac Electric Power Company, "Prepared Supplemental Testimony of Andrew W. Williams."

The transmission constraint located outside PJM was identified and then a two part solution was developed and implemented. In the near-term a Reliability Coordination Plan (RCP) was developed which allowed for monitoring power flows on critical facilities within the APS system allowing for adjustments to be made to PJM operations. At the same time capacitors to alleviate the constraint were installed in both the APS and PJM system. Installation of the capacitors was completed in the early 1990s and transfer capabilities were further improved. The significance of the RCP is that real-time monitoring of conditions outside of PJM are used to modify its system capability, which was, and is still not, standard practice in the industry. Most control area operations still operate under the assumption that power flows outside their direct control are stable and therefore do not affect their operations.

Transmission Equipment Adjustments

Another method of boosting TTC available to PJM operators is through adjustments to the transmission system. One such method is through the use of phase shifters and capacitor banks to alter transmission grid impedances, and hence flows. In addition, detailed studies have discovered that taking some transmission lines **out** of service can increase TTC.

What this examination of PJM transmission system operations illustrates is the large gains that can be had in TTC along a particular path through well understood and coordinated operations especially as the time frame for transactions shortens. It also helps highlight how far transmission systems must evolve before such gains may be realized because, in fact, the APS to PJM capability indicated by PJM cannot be used. APS, at the time the data were collected, was using the static TTC value from NERC studies and, therefore did not have the capability to coordinate operations with CEI, VP and PJM. Improvements in transmission system operations that are required before TTC can be the same value for the same path for both control areas and safely utilized to the maximum extent possible is discussed later in 'transmission system evolution.'

Pacific Northwest AC-DC Transmission Capability

A contrast to PJM system operations may be found in the West. Transmission system operations in the West are characterized by high capacity AC and DC lines connecting distant loads and supplies. A major component in this system is the AC-DC intertie connecting the Pacific Northwest to California.[9] This intertie gained national notoriety when its failure on July 2nd and 3rd, 1996 resulted in 14,000 MW of lost load, effecting an

[9] The AC and DC intertie TTCs are usually considered jointly since a failure of the DC intertie greatly effects the AC intertie.

estimated 2 million customers. Further notoriety was achieved when just over a month later, on August 10th, another failure occurred resulting in 30,500 MW of lost load affecting 7.5 million customers.

Among the things that these two outages demonstrated was the wide-ranging and devastating impacts that an event can have on the transmission system. Much has been made of inadequate tree trimming being a direct cause of the outages. However, the August 10, 1996 outage could have been avoided.[10] The other factors contributing directly to the outage included:

- Unknowingly operating in a single-contingency condition.
- Outages of two transmission lines were not widely communicated to other WSCC members.
- Other known problems with the system had not been adequately studied.

AC-DC Intertie Capability

One outcome of the summer 1996 outages is that safe operation of the Pacific Northwest system is now guided by a committee of WSCC members. Studies conducted by this committee have aided in the understanding of the transmission system.[11]

The Pacific Northwest transmission system is shown in Figure 3-7. As indicated in the figure, transmission capability into California is highly sensitive to Northwest area dispatch. In particular, AC-DC TTC effects include:

- Increased flow across the John Day cut plane reduces safe AC-DC TTC.
- More hydro generation on the lower Columbia increases AC-DC TTC.
- More hydro on the Upper Columbia decreases AC-DC TTC.
- Changes in Midpoint, Utah to Summer Lake, Oregon flows shift the safe operating levels.

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[10] *Western System Coordinating Council Disturbance Report: For the Power System Outage That Occurred on the Western Interconnection, August 10, 1996,* dated October 18, 1996.

[11] *1997 Spring Operational Transfer Capability of California-Oregon Intertie and Pacific DC Intertie,* WSCC Operating Capability Study Group (OCSG), March 1997.

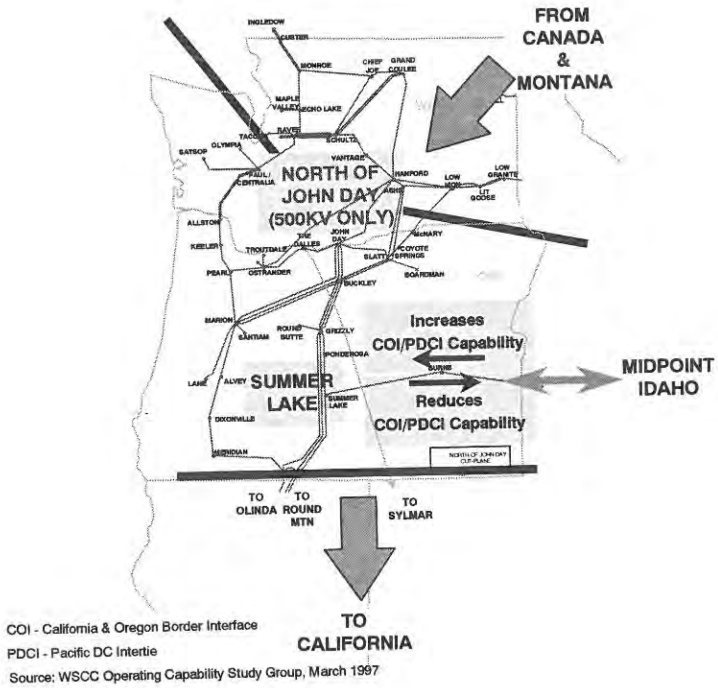


Figure 3-7
Pacific Northwest 500-kV Transmission System

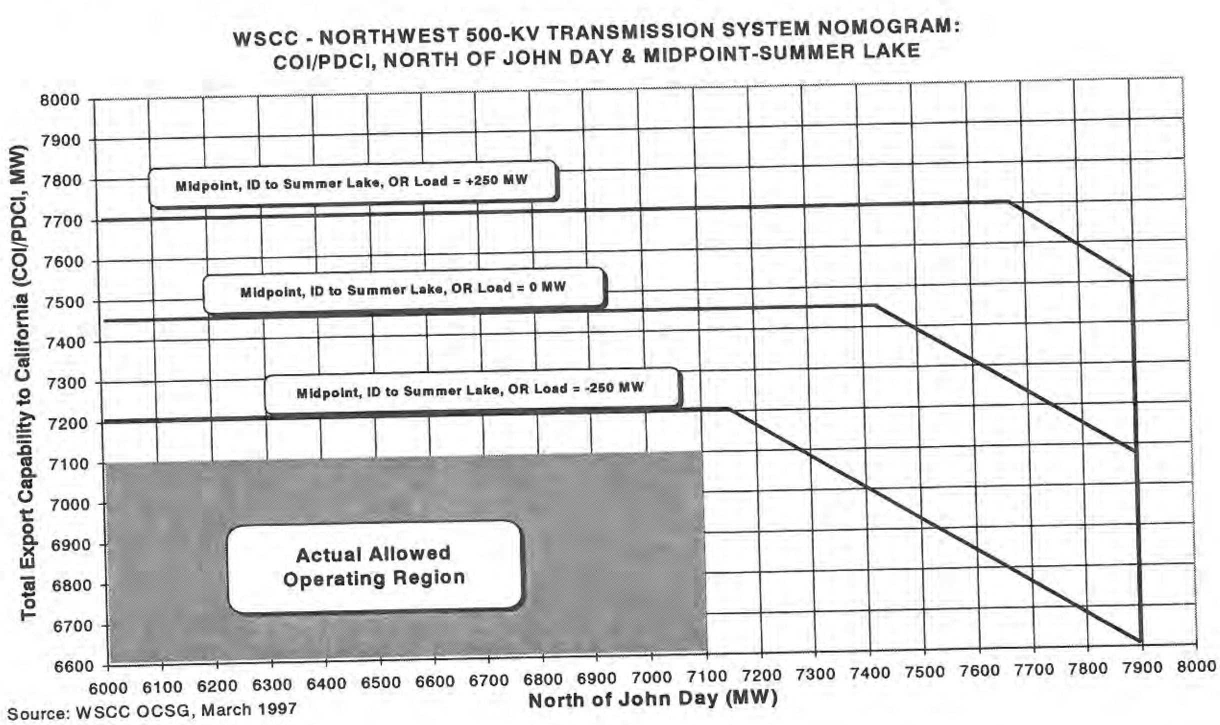


Figure 3-8
Rerating Potential of the Pacific Northwest AC/DC Intertie

The interplay of these factors, and how they affect the AC-DC TTC, are summarized in the nomogram, Figure 3-8. Power flows across the John Day cut plane are shown on the x-axis, while the y-axis represents the AC-DC intertie capability. Lines representing safe TTCs for both the John Day and AC-DC intertie are both dependent on the flow direction and magnitude between Oregon and Idaho. Among the contingencies limiting AC-DC operations is the loss of Palo Verde in Arizona.

An example of how the AC-DC intertie was actually rated and utilized is shown in Figure 3-9. Interestingly enough, the nomogram shown in Figure 3-8 is quite similar to that produced by PJM, Southern and others to allow dynamic rerating of TTC based on conditions. However, such dynamic rerating currently does not occur in the Pacific Northwest as illustrated by the shaded region of the nomogram and the time series representation of Figure 3-9. This lack of dynamic rerating is apparently due to the desire to completely avoid recurrence of further outages and the lack of an effective system in place to maximize the safe use of the grid.

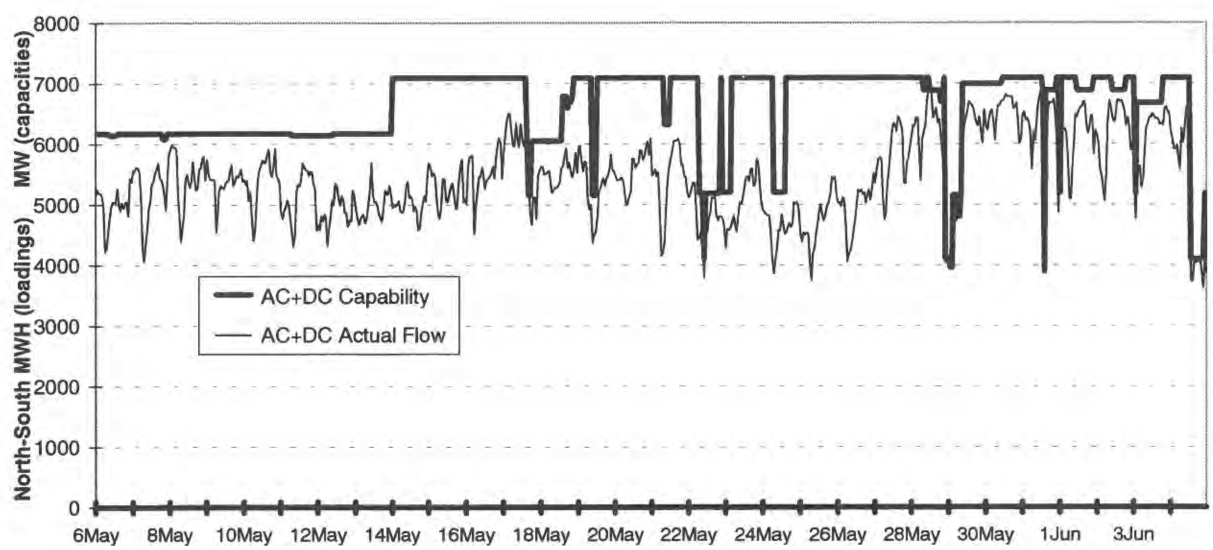


Figure 3-9
Actual Rating and Utilization of the AC-DC Intertie (May-June 1997)

The nomogram shown in Figure 3-8 also highlights the zero-sum nature of electric power transmission. Since exports to California can come from Canada/Montana, Idaho and the Pacific Northwest regions, the dispatch of each region effects the ability of all three to sell into the California market. For instance, consider operation of the AC-DC interties under the theoretical capability shown in Figure 3-8 with no flow between Idaho and Oregon (middle line in figure). In this case consider when Canadian marketers desire to export to California and Mexico. When these exports cause the

North of John Day flow to exceed 7,425 MW then the total export capability for all Canadian, Montana and Pacific Northwest sellers to access Californian markets is reduced. Conversely, generation located in Oregon and southern Washington can block Canadian and Montana power flows to Californian markets by keeping total exports to California high.

At the present time, efforts are underway to create an ISO, called IndeGO, that would encompass the Pacific Northwest and east out to Colorado. However, it is not clear at this time whether and when additional TTC would become available due to improved coordination of the transmission system. The prospects of significant gains in transmission capability appear to be good given that the operational complexity of the U.S. portion of the WSCC interconnect would decrease since only three entities would be responsible for operating the transmission system (California ISO, IndeGO and Desert STAR), instead of the 30 control areas currently responsible for operations within their own separate domains.

Metamorphosis Of Electric Power Transmission

The pace of electric utility restructuring is being dictated to a large extent by metamorphosis of electric power transmission. The metamorphosis of transmission, is in turn, being dictated by an evolution in operations and revolution in governance. Evolution of operations includes the wide variety of debate and experimentation in Independent System Operators (ISO) structures as well as the confluence of a host of new technologies and procedures either just recently emplaced or planned.

Most uncertainties concerning the outcome and pace of transmission metamorphosis spring from the revolution in governance of the transmission system. While this section only briefly discusses the issue of governance it is important to note that, who eventually governs the transmission system, and how, may completely alter the evolutionary changes currently being planned and implemented.

Transmission Evolution

Evolution of transmission operations is occurring mainly in response to the need to provide reliable and non-discriminatory commercial operation of the transmission system. Evolution can be seen through: (1) the great ISO experiments, and (2) trends in new transmission technologies and institutions.

Independent System Operator (ISO)

FERC's Order 888 encouraged, but did not mandate, the creation of ISOs due to the separation of generation and transmission. Some stakeholders in the electric industry have long held the view that the only way to achieve a level playing field for all is through full separation of generation and transmission assets from utilities, with transmission operated by an ISO. The operational control of transmission is instead evolving in response to regional characteristics. The resulting 'experiments' hold a great deal of promise as a variety of innovative structures and techniques that combine power markets and transmission operations are being developed to address the practical problems of ensuring reliability and providing for non-discriminatory commercial operations.

The advantages of an ISO over historical control area-based operations stems mainly from the observation that multiple control areas unduly complicate practical electricity markets areas. A comparison between PJM and SPP is shown in Figure 3-10. In the figure it can be seen that PJM, a single control area for nine utilities, served a 1996 peak load 26 percent lower than the aggregate peak load of SPP's 19 control areas. Yet, as a power market PJM clearly has the advantage over SPP since trading in SPP is impeded by the complexity of the numerous control areas. Specifically:

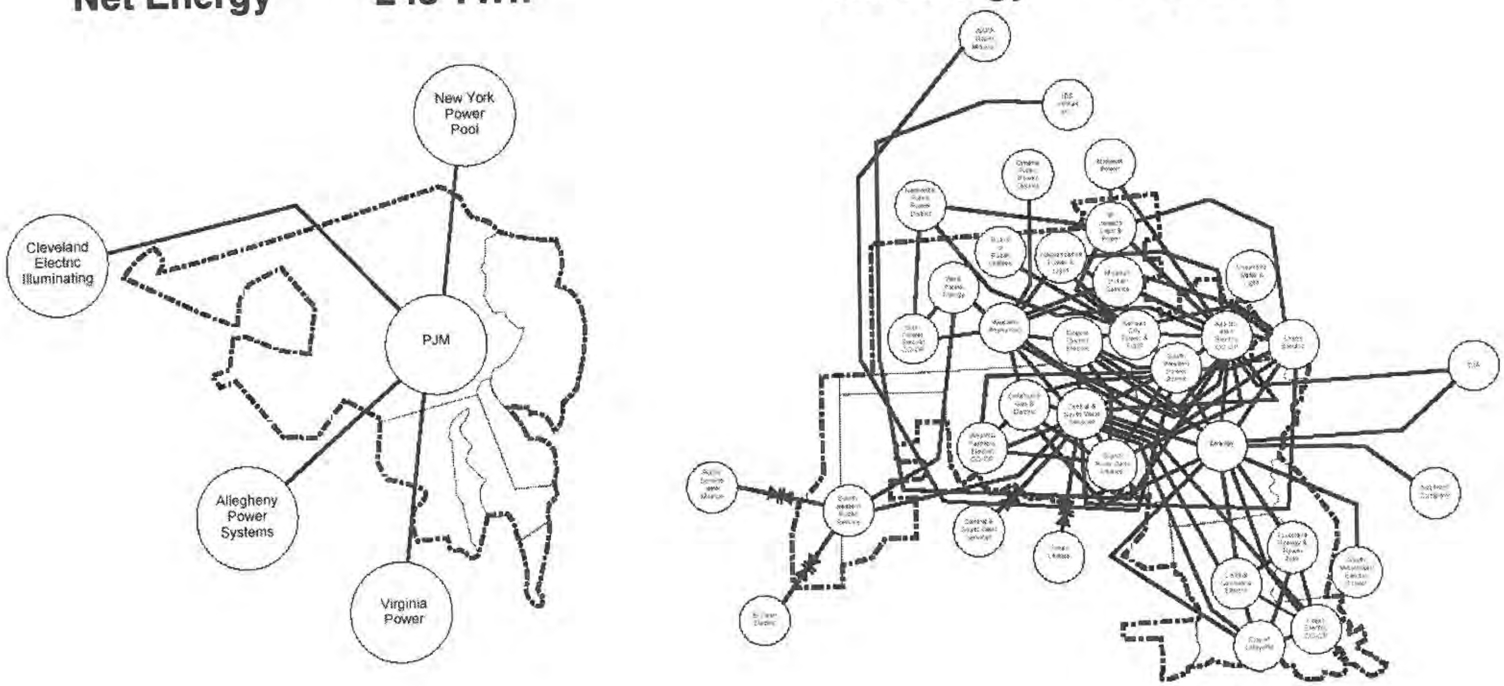
- *Pancaking of tariffs.* Each control area through which power is contracted to flow applies its own rates and extracts its share of losses.

- *Efficient use of transmission resources.* The prior discussion of PJM and Pacific Northwest transmission operations has already highlighted the gains to be had from coordinating resources in response to how power actually interacts within the transmission system. The systems necessary to enable a high degree of coordination among control area peers does not presently exist. In addition, since power does not flow along contract paths, pricing and accounting systems must be put into place which compensates for actual use of the grid.

- *Duplication of costs.* Each control area maintains separate staffing and control systems for each of their domains that unnecessarily add to costs.

- *Reliability costs.* Hand-in-hand with efficient use of transmission resources comes reliability considerations. Operating data that is not integrated to provide a complete picture of system dispatch and does not allow for well coordinated and timely control of the transmission system compromises reliability. Ensuring adequate reliability in such circumstances requires conservative operations which, in turn, limits operating capability available for commercial operations. For instance, at least one utility had to suspend all market activity for several days during the summer of 1997 due to not having an integrated picture of system dispatch.

PJM		SPP	
Peak Demand	44.3 GW	Peak Demand	60.0 GW
Net Energy	243 TWh	Net Energy	307 TWh



Trading facilitated by single large control area.

Trading impede by complex & numerous control areas.

Figure 3-10
Regional Power Market Comparisons: PJM & SPP (1996)

The practical benefits of ISOs have encouraged a number of utilities to form or plan ISOs. A partial listing of ISOs that are at various stages of completion are listed in Table 3-1. The tabulation can only be considered partial since uncertainties in the resolution of a variety of structural issues promotes a great deal of flux in who, where, or even whether, transmission-owning utilities will participate in an ISO.

Table 3-1 also lists the structural issues that each ISO must come to terms with. Each ISO 'experiment' has taken a variety of approaches to address the practical problems of region-wide transmission system operations. The Southern Company, for example, continues to operate its transmission assets under the umbrella of a single entity. The utilities of the SPP region are split on whether to join with MAPP to form an ISO covering more area than any other in the country, form an ISO from all to some of SPP members, or do nothing and have individual utilities continue to 'go alone' or cede entirely from the region.

Table 3-1
ISOs and Their Varied Structures

ISOs	Structural Issues
Southern Company	Timeline of Implementation
California	Governance
ERCOT	Market Structure & ISO relationship
PJM	° Power Exchange
NEPOOL	° Bilateral
MAPP & SPP	° Load Balancing
New York Power Pool	Transmission Tariff
IndeGO	° Nodal/Zonal/Postage Stamp/Directional
Desert STAR	Congestion Relief
Midwest ISO	° 'Must-Run' Dispatch/Market Mechanism
	Spinning Reserves
	° Market Mechanisms (Supply & Demand)
	° Mandate

The dynamic situation in SPP and other regions due to ISO experimentation highlights the importance of the details in assessing the viability and effectiveness of an ISO. It is likely that those successful methods in one ISO will be adopted in others subject to regional characteristics of each ISO. Indeed, it may be possible to compare and contrast the development of ISOs for more concrete indications of how electric industry restructuring itself will evolve to support the new era of power trading and interregional power flows.

Trends In Electric Power Control Technologies

The last few years have seen a veritable profusion of new systems and technologies proposed and being implemented in electric power transmission . Prior to the 1992 EPAct, flows between control areas were well understood by the cadre of operators and planners. Exchanges were often arranged for months in advance and followed routine patterns day-in and day-out throughout the season.

With the rapid growth of wholesale transactions and FERC's Order 888 this "grease pencil" approach to operations has become insufficient to support the changed structure of the industry. Now, literally thousands of transactions occur throughout an interconnect for a single hour's operation - down to the hour before in some instances - that can result in large variations in flow across control area interfaces from one hour to the next. Much of these changes in flows are due to unit availabilities and weather-driven demand patterns. Predicting such flows months, or even weeks, in advance is difficult, if not impossible.

Three initiatives in particular warrant attention when considering the evolution of the transmission system. These initiatives are:

- Open Access Same-Time Information System (OASIS)
- Inter-regional Security Network (ISN)
- Tagging and the Interchange Distribution Calculator (IDC)

A timeline depicting the development of these initiatives is shown in Figure 3-11. All three are targeted towards ensuring transmission system reliability in support of commercial operations. In addition, all three rely on a national-level communications network, with OASIS and Tagging implemented through the Internet. Recognizing the large strides in information technology and the market penetration levels of personal computers and the Internet allows a greater degree of access to information by large numbers of stakeholders nearly instantaneously. However, the scope and complexity of these initiatives makes the proposed time line for implementing very aggressive.

It is important to note the rapid technological progress that has already occurred. As indicated by the bottom bar of Figure 3-11, only contract path transaction can be accommodated. However, the new technologies can now in place enables flow-based curtailments, not contract path alone. The future world of transmission to be supported by the new technologies is one of flow-based reservations where cash transaction pays for actual loading on the grid.

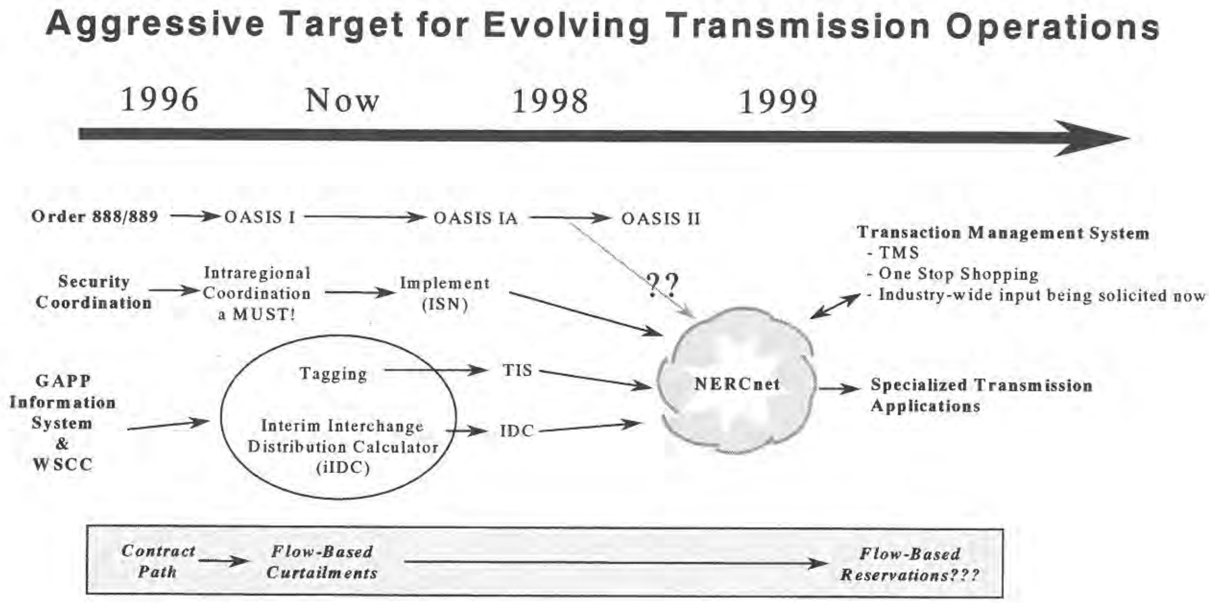


Figure 3-11
Trends In Electric Power Control Initiatives

(Source: EPRI/GRI Project Team.)

OASIS

The Open Access Same-Time Information System (OASIS) was brought into being by FERC's Order 889. In the development of Order 888 it became apparent that a standardized means to share transmission system information with all market participants in a non-discriminatory manner was required to allow true competition to take place. The industry, facilitated by EPRI and NERC, developed a decentralized system that could be accessed through the Internet.

By January 1997, OASIS was brought into operation. Over the next year a number of shortcomings became apparent.[12] In particular, since each control area was responsible for development and operation of its own systems, inconsistencies between transmission providers made conducting commercial transactions difficult. FERC and the industry have sought to improve the system in steps in response to criticisms and shortcomings of the present system with a longer-term view for further enhancements.

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[12] A concise summary of the present short comings and suggested long-term course of OASIS may be found in, *Industry Report to FERC on the Future of OASIS, October 31, 1997,* by the Commercial Practices Working Group and the OASIS How Working Group.

One possibility is an all-in-one system, such as that operated by ERCOT, where all energy market transactions and flows are implemented through the OASIS.

Inter-Regional Security Network (ISN)

The security coordination initiative was prompted by heightened concern by NERC members that insufficient coordination among control areas was increasingly compromising reliability. Events leading to this initiative included:

• SPP voltage depression	July 1993
• MAIN, ECAR & TVA loading problems	July 1993
• Eastern Cold Wave	January 1994
• WSCC system disturbance	December 1994

The SPP event was troubling because an after-the-fact review could not even be conducted since insufficient data gathering meant that the conditions leading to a major event could not even be described. A NERC task force was mobilized in light of these events to assess North American grid security, identify needs and recommend solutions.[13]

One outcome of NERC's assessment of the continued security of the grid was that greater regional coordination among control areas was required. As a result the NERC regions created 'Security Coordinators' to coordinate planning among control areas over wide geographic regions, and facilitate timely and effective solutions to crisis situations. In addition, NERC found that normal operations *must* be responsive to real-time conditions outside the control area (much like PJM's RCP described earlier). The sharing of critical operating data is to be facilitated by a computer network-based Interregional Security Network (ISN). While both the security coordinators and the ISN are scheduled to begin operation in January 1998 in all NERC regions encompassing the U.S., Canada and Mexico, it is not clear that the initiative will be allowed to succeed. The primary stumbling block is keeping as confidential data that is market sensitive.

Tagging

Tagging, and the Interchange Distribution Calculator (IDC), debuted amid much controversy during the summer of 1997. NERC ordered tagging as necessary tool to

[13] *Security Process Task Force Final Report to the NERC Engineering Committee and Operating Committee*, NERC, February 27, 1996.

allow control areas and security coordinators a means to assess the impact of commercial transactions on a regional basis and develop a consistent and fair means of curtailing commercial operations in the face of unforeseen transmission constraints.

Tagging is a means by which operators can completely identify the source and sink of every transaction, as well as all other necessary documentation. Tagging data is entered into the IDC to evaluate the aggregated parallel path flow effects of the individual transactions. The intent is to distribute all tags via email allowing system dispatch to be assessed quickly in response to quickly fluctuating forward power market.

Tagging and IDC were rushed out in 1997 as 'interim' packages. Power marketers were particularly aggrieved. They maintained that, Order 888 notwithstanding, deals they were brokering 'dried up' as, they allege, power marketing affiliates of the utilities learned of the deals and by-passed the independent marketers in subsequent transactions. In addition, tagging was not consistently implemented by the control areas. Power marketers have also maintained that utilities are using the tagging requirements as a means to block commercial activity from occurring, particularly in the comparatively more lucrative hourly and real-time power markets where adding any additional hurdles to completing a transaction can kill the deal. A coalition of power marketers have filed a motion for a FERC Cease and Desist order, but how FERC will rule is not yet known. While FERC has not yet ruled on the cease and desist order, it has given NERC and the transmission providers clear direction on curtailment. In order to be consistent with Order 888 curtailments of marketer and utility flows must be equal for the same class of transmission service.

Tagging and use of the IDC have been successfully utilized, however, since their inception to actually perform flow-based curtailments. The Southern Company has been a leader in the implementation of tagging. They have responded to emergencies occurring in other control areas to curtail transactions within their own system that were directly contributing to the emergency. Marketers point out, and some NERC members acknowledge, that tagging allows control areas to 'hit marketers first' with curtailments, with the result that they are unfairly bearing the brunt of ensuring reliability. Some NERC members see the only solution as implementing tags for every MW of generation (not just commercial transactions). This would allow curtailments to be evenly applied to all market participants - even those claiming priority in order to serve native load.

An Uncertain Future

The near-term evolution of these three major initiatives is toward: (1) upgrading capability, (2) addressing marketer, transmission provider, and FERC criticisms and direction, (3) implementing the initiatives consistently by all parties within the three U.S. interconnects, and (4) building broad consensus of the need and usefulness of the initiatives in supporting reliable operations and enabling commercial markets.

The next steps, as envisioned by NERC and others, is to consolidate the operational aspects of safe grid and commercial operations into a seamless system that enables the efficient utilization of the transmission grid by all stakeholders. The first of these is NERCnet which would provide a common and reliable, communication system. A Transaction Management System (TMS) would then be possible to allow 'One Stop Shopping' for transmission services. Conceivably, the reservation, use and billing of flow-based transactions could occur with much less effort than under today's more ungainly methods.

The timing of milestones suggested in Figure 3-11 is highly optimistic. Technically, the objectives are achievable. However, the initiatives are also quite ambitious in terms of scope and complexity. In addition, among the lessons that NERC has learned in the past two years is the critical importance of actively soliciting the participation of all stakeholders, principally power marketers, from the beginning of the process. The process of developing stakeholder consensus on needs and requirements can be expected to stretch out the timeline as seen with problems arising from concerns over confidentiality. Finally, even whether the future of transmission operations will evolve as described here is unknown given the uncertainties surrounding the revolution in transmission governance.

Revolution In Transmission Governance

EPAct, Orders 888 and 889 and evolving grid operations continue to cast a cloud over governance of transmission grid operations. NERC, due to its long history of promoting reliable operations, appears to be the primary entity for developing and implementing transmission operations to facilitate commercial operations. However, NERC is a voluntary membership organization whose membership spans three countries. The WSCC subregion is currently planning to transform its guidelines to mandates with monetary sanctions levied for non-compliance. Volunteerism to submit to de facto regulation by a NERC-derived body may be insufficient. Federal legislation, possibly even negotiated international treaties, may be required to legally enact such a body. NERC is to consider the future function and form of its organization in early 1998.

Other issues further cloud the future including:

- FERC taking over NERC's role in the development of transmission standards. Tagging could well be construed as electronic commerce, thus residing in FERC's domain and potentially giving it the legal authority to directly regulate it.
- The DOE's growing interest in transmission from a national security standpoint. Former FERC Chair Betsy Moler, now a DOE Deputy Secretary, has emerged as an active agent in bringing the DOE further into influencing grid operations.

- The states' role in transmission governance. At stake are coordinating capital investments in the transmission system for which the benefits may not trickle directly down to native load customers. Inter-regional disputes over zero-sum benefits seem likely, potentially acting to delay gains to be had through interregional coordination or even lead to further balkanization of the transmission system.

It is important to at least acknowledge the governance uncertainties regarding transmission since progress towards improving utilization of the current system, and installation of new transmission capacity, could be adversely affected by missteps in this area.

Summary

The outlook for U.S. transmission operations remains complex and uncertain. Increased gains in transmission capability that could have fuel usage pattern change effects have been demonstrated. However, the path that allows for harvesting these gains without new transmission lines requires superior short-term tracking of conditions over very large regions coupled with a very high degree of coordination. Indeed, transmission capability could actually decrease due to operational limitations and governance conflicts leading to balkanization of the grid.

What happens in transmission is likely to have far ranging impacts on how the restructured electric industry will evolve. It appears unlikely that a single ISO approach will evolve and what type or types of governance will be put into place to define the roles of transmission providers, NERC, FERC, DOE and others. It is likely that the pace of restructuring will be slowed by the need to resolve issues in the transmission segment. Indeed, due to the variety of uncertainties, large-scale 'power-by-wire' transfers of energy seem unlikely meaning that coal and gas competition will remain intraregional in scope.[14] Reinforcing this conclusion, as is explained in Section 5, is that the possible shifts in generation patterns and fuel use in a hypothetical world with complete elimination of transmission and tariff constraints are surprisingly modest.

[14] Interviews indicate that investment by utilities in even small capital investments in transmission that would have commercially significant gains in transmission capability are being deferred or abandoned. Restructuring has not proceeded far enough to allow utilities to plan for and recoup costs of long-lived investments in transmission from market participants focused on trading power one hour to six months in the future.

4

INTER-REGIONAL SYSTEM LAMBDA AND LOAD CORRELATIONS

Overview

Empirical insights into actual dispatch patterns can potentially reveal important characteristics of grid dispatch. Such analyses provide additional insights to understanding inter- and intra-regional power trading that, combined with other modeling results, provides a complete picture of regional dispatch efforts and for comparative purposes with other modeling efforts. This report presents a novel method, examining displays of lambda and load correlations to interpret dispatch patterns between two utilities. In this research the lambda and load correlations of over sixty pairs of utilities were developed in order to provide heuristic insight into regional dispatch patterns throughout the three U.S. interconnects. This technique indeed provided an indicator of power trading and transmission capability occurring between control areas.

The addition of this analytic aide, coupled with interviews, short-run dispatch modeling, and additional transmission analysis, provides for a rich mosaic of intra-regional dispatch patterns and possibilities to emerge. Combining multiple strands of evidence should limit the negative impacts of potentially erroneous assumptions from use of a single analytic method to dominate the results. Unfortunately, not all that could be gleaned from the lambda and load analysis was possible. Many more insights appear possible than that presented here.

This section introduces the load and lambda correlation technique and its advantage over other methods that have been suggested to analyze similar data. Next, selected load and lambda correlations are presented and discussed. Finally, directions for further work are presented.

Lambda and Load Correlation Description

Lambda and load correlation analysis is the calculation of lambda correlations under fixed load conditions between two control areas. Displaying the results enables inspection of what load levels between the two control areas lead to high lambda correlation levels, meaning that changes in marginal prices in one area are closely matched to changes in the other area. This in turn indicates that incremental trading of power between the two control areas is likely taking place. If correlations are low in certain load regions then the three main interpretations are: (1) all available transmission capability is in use preventing further arbitrage in response to changing conditions, (2) insufficient 'electricity price basis' exists at those load levels on the two control areas' supply curve to encourage arbitrage, and (3) potentially beneficial arbitrage opportunities involving the two control areas are being ignored or are otherwise constrained.[15] In addition, the analysis is constructed in such a way as to limit the influences of factors that would lead to high lambda correlations such as experiencing similar weather or diurnal demand patterns.

Lambda and Load Data

One of the motivations for the lambda and load correlation approach is that it makes economical use of readily available public data. The data itself is the hourly load and lambda values reported by the control areas to FERC.[16] This data is available in electronic format greatly aiding the analytic effort. At the time the lambda and load correlation analyses were conducted the latest data available was for the year 1995.

Other researchers have attempted to make use of lambda data with mixed results. The main problem revolves around the issue that lambda, as an indicator of marginal price, is not calculated uniformly by all control areas. As a result, comparison of lambda levels between two control areas, such as taking differentials, is of limited use since one control area may include fixed costs in its lambda that the adjacent utility does not.

Methodology

It is reasonable to presume that loads and lambdas in two adjacent control areas vary nearly in synch with each other. Each control area is, after all, responding to the same day/night cycle, regional weather patterns and other factors. This presumption is superficially confirmed by plotting data chronologically, as shown in Figures 4-1 and 4-2. In these figures it can be seen that both the loads and lambdas of the two control areas follow each other nearly identically. The correlations of the loads throughout the time period, although high at a ρ of 0.9, may be sufficiently 'out of phase' on an hourly

[15] Additional interpretations are possible. Some of these are discussed as they arise.

[16] FERC Form 714, *Annual Electric Control and Planning Area Report*.

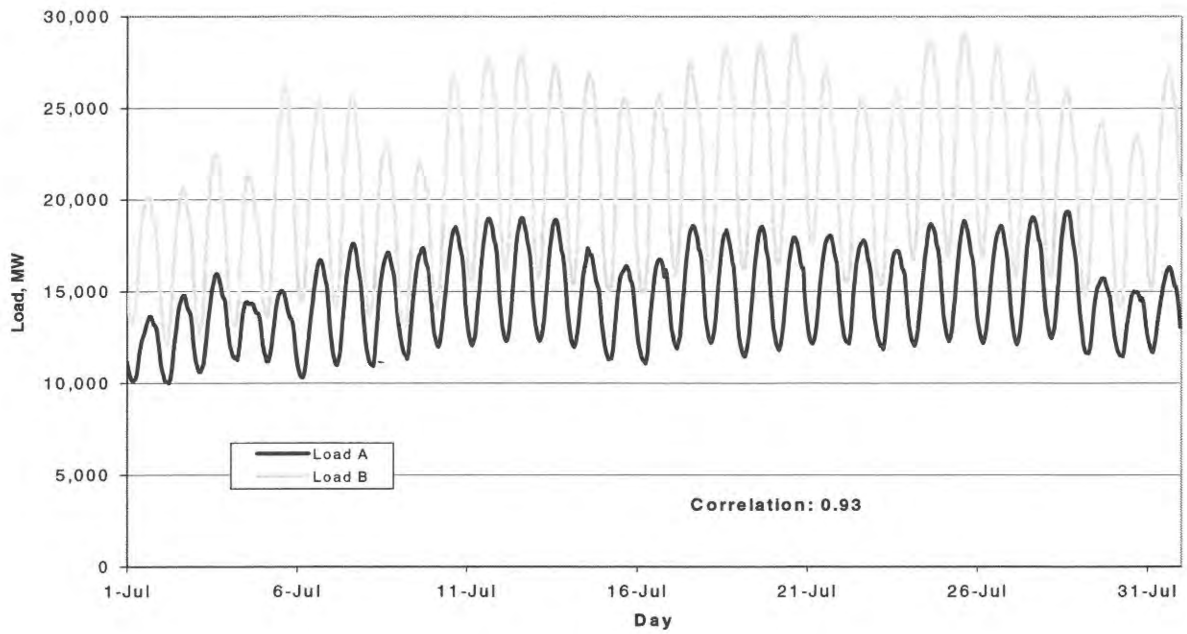

Figure 4-1
Chronological Load Data for Two Control Areas, July 1995

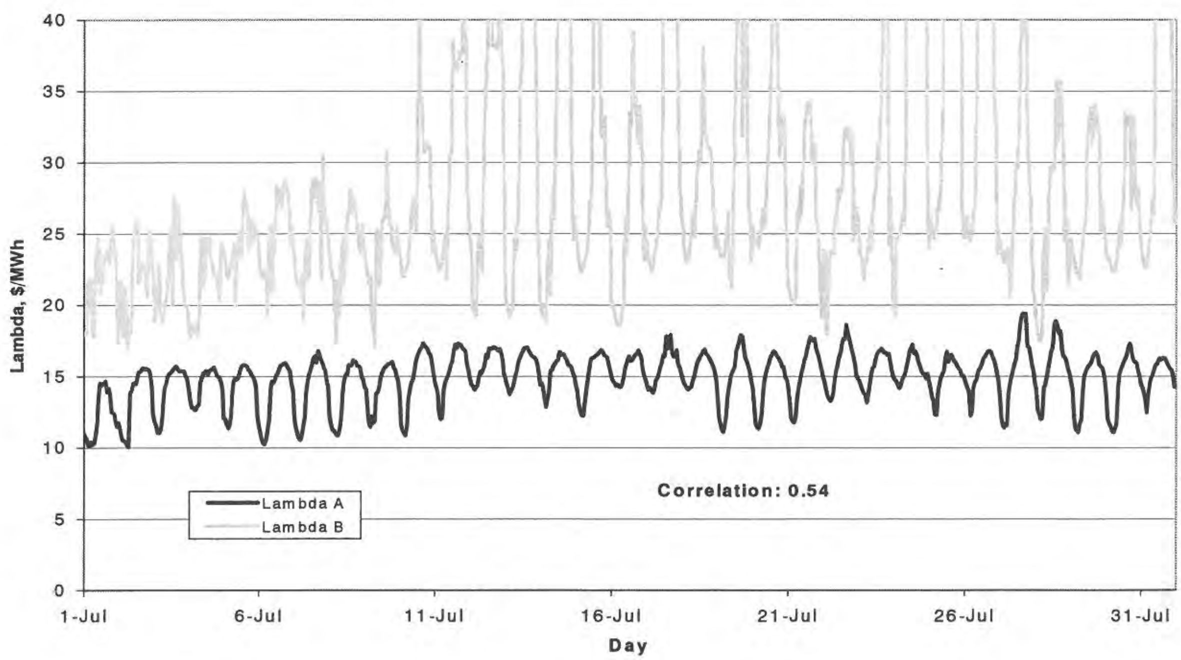

Figure 4-2
Chronological Lambda Data for Two Control Areas, July 1995

basis to suggest that sufficient load diversity exists to support hourly trading. Indeed, the correlation of the lambdas shown in Figure 4-2 lower at a ρ of 0.5, is further suggestive of potential for arbitrage opportunities.

Ordering load and lambda data of one utility and simultaneously plotting the contemporaneous data of the other provides additional insights as shown in Figures 4-3 and 4-4. By inspecting these figures it can be seen that for nearly the same levels of load and lambda (utility B in the figures) the load and lambda of the other utility (Utility A) can vary over a broad range.

The lambda and load correlation analysis takes this process one step further. Lambdas of one control area are taken from nearly identical load levels and compared to (i.e. correlated with) lambdas of the other control area taken the same way. Appendix A describes the development of this methodology in greater detail. An important consequence of this approach is that by fixing the correlation calculation to nearly fixed load levels of both utilities, factors affecting load, such as weather or day/night cycling, are controlled for. Only factors affecting supply, such as unit availability or fuel prices, that directly shift the supply curve, are used to measure the sensitivity to inter-control area arbitrage or trading.

A further advantage of a correlation analysis is that the results are not dependent upon control areas having price levels calculated on the same basis between the two regions. Rather, only the variations in the price levels are compared. High correlation indicates that a lambda increase in one control area tends to indicate a similar increase in the other control area (and vice-versa). This 'connection' between the lambda's of the two control areas implies that sufficient transmission capability exists and is being used to take advantage of the arbitrage opportunity.

Results

Over sixty lambda and load correlations were completed using full-year 1995 data. The full list of control area combinations is included in Appendix A. All plots may be viewed from the CD-ROM. A review of the results provide tantalizing glimpses of an industry probably not yet in trading equilibrium. Yet, it is cautioned that there may be too many simultaneous influences to fully interpret the results based on just a preliminary examination of these correlation plots. Nevertheless these plots were useful for raising questions about hourly regional power trading patterns and transmission effects.

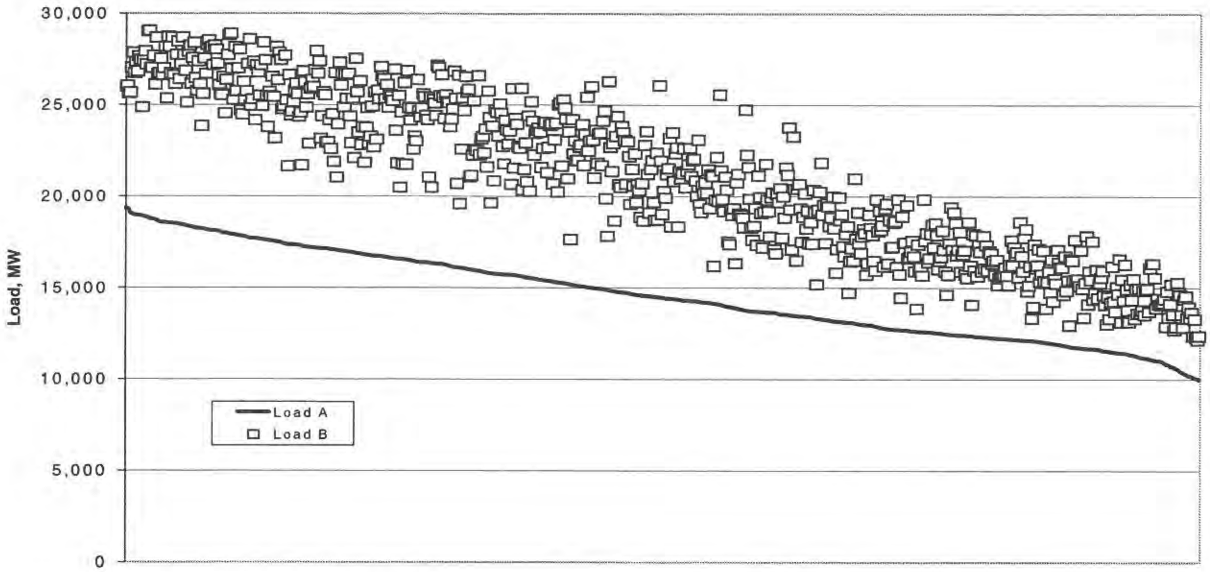

Figure 4-3
Sorted Load Data for One Control Area With Contemporaneous Load for the Second

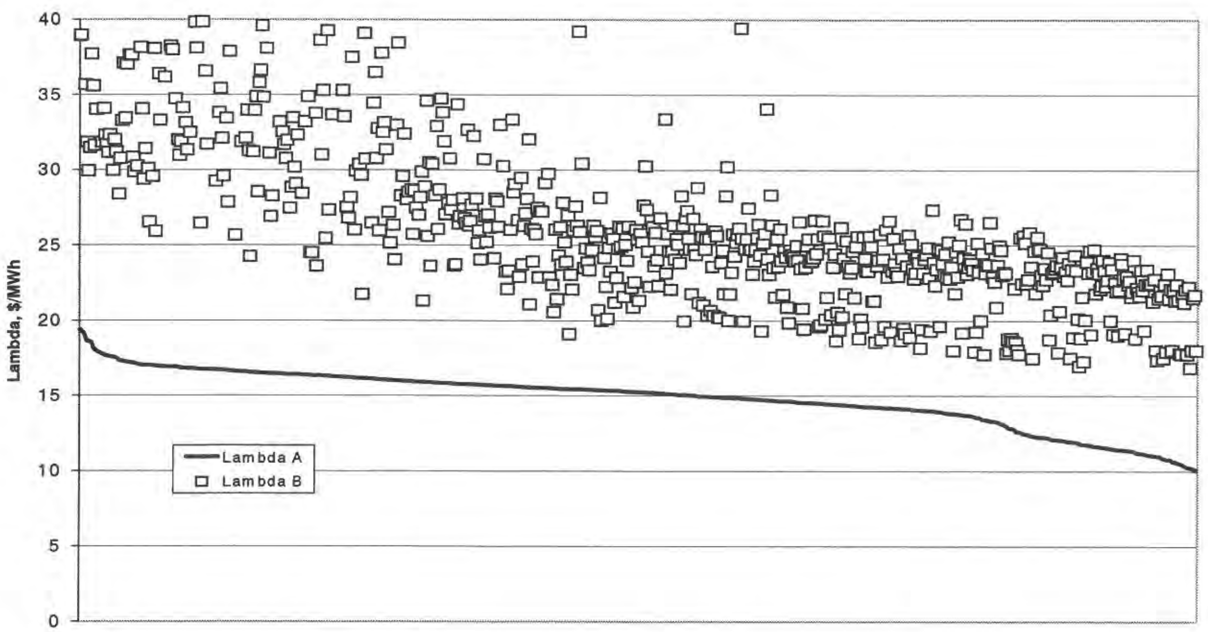

Figure 4-4
Sorted Lambda Data for One Control Area With Contemporaneous Lambdas for the Second

Figures 4-5, 4-6 and 4-7 are presented to illustrate some of the observations that may be made. The observations include:

- Hourly load diversity
- High, low and mid correlations
- Other observations

Hourly Load Diversity

Hourly load diversity provides a picture of how wide the range of loads exists between the two control areas. A 'fat' area, as illustrated by Figures 4-6 and 4-7, indicate that a wide range of loads exist for one control area given a fixed load level of the other control area. This implies that numerous arbitrage opportunities exist due to the wide variation in load which, in turn, results in a wide variation in prices. A 'skinny' supply curve, such as shown in Figure 4-5 indicates the opposite.

Note that these observations can be made without reference to the correlation values shown in the figure.

High, Low and Mid Correlations

Figure 4-6 is an example of a high degree of correlation occurring over a wide region of loads. In this case, Entergy and Public Service Oklahoma appear to engage in a great deal of power transfers over the 'cycling' portion of their load curves. This observation is consistent with interviews which indicated that Entergy was, and is, extremely active in hourly trading. A review of Entergy's sources of supply suggest that its dependence upon gas steam for a large portion of its supply is suggestive of its role in providing 'swing' capacity during transition to and from peak.

Figure 4-7 shows the lambda and load correlations between Entergy and Union Electric. In this case a lower degree of correlation between the two control areas is readily apparent, particularly over the same range that showed a high degree of correlation between Entergy and Public Service Oklahoma.

A preliminary conclusion to be drawn from the review of Figures 4-6 and 4-7 is that Entergy is engaged in more hourly power trading with Public Service Oklahoma. Table 4-1 presents additional clues as to what may actually be occurring among these three utilities. What this table shows is that Entergy actually schedules much more of its electric energy exchanges with Union Electric than with Public Service Oklahoma. In

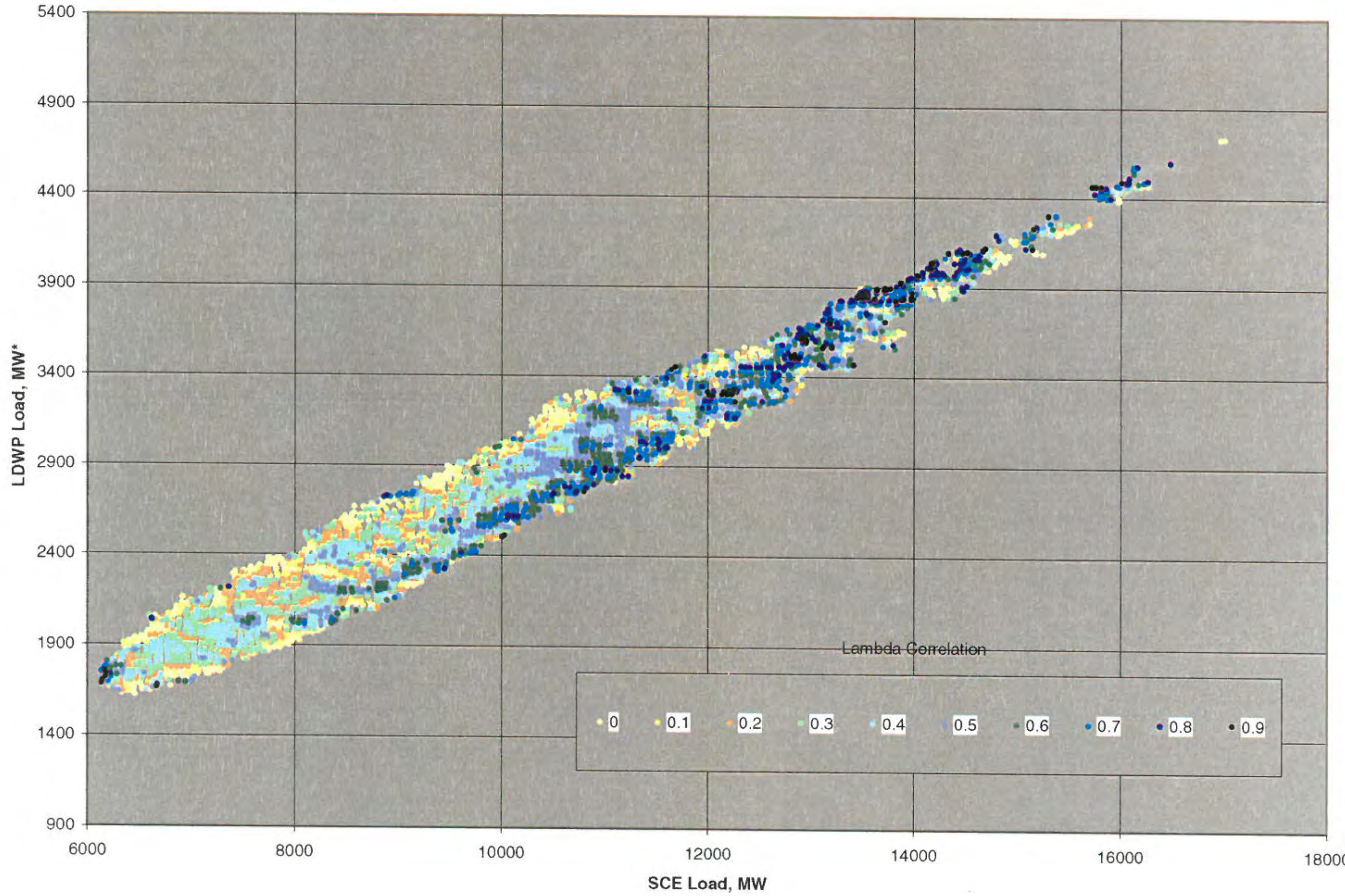

Figure 4-5
Lambda Correlations Between SCE and LDWP at Varying Load Levels 1995 Data

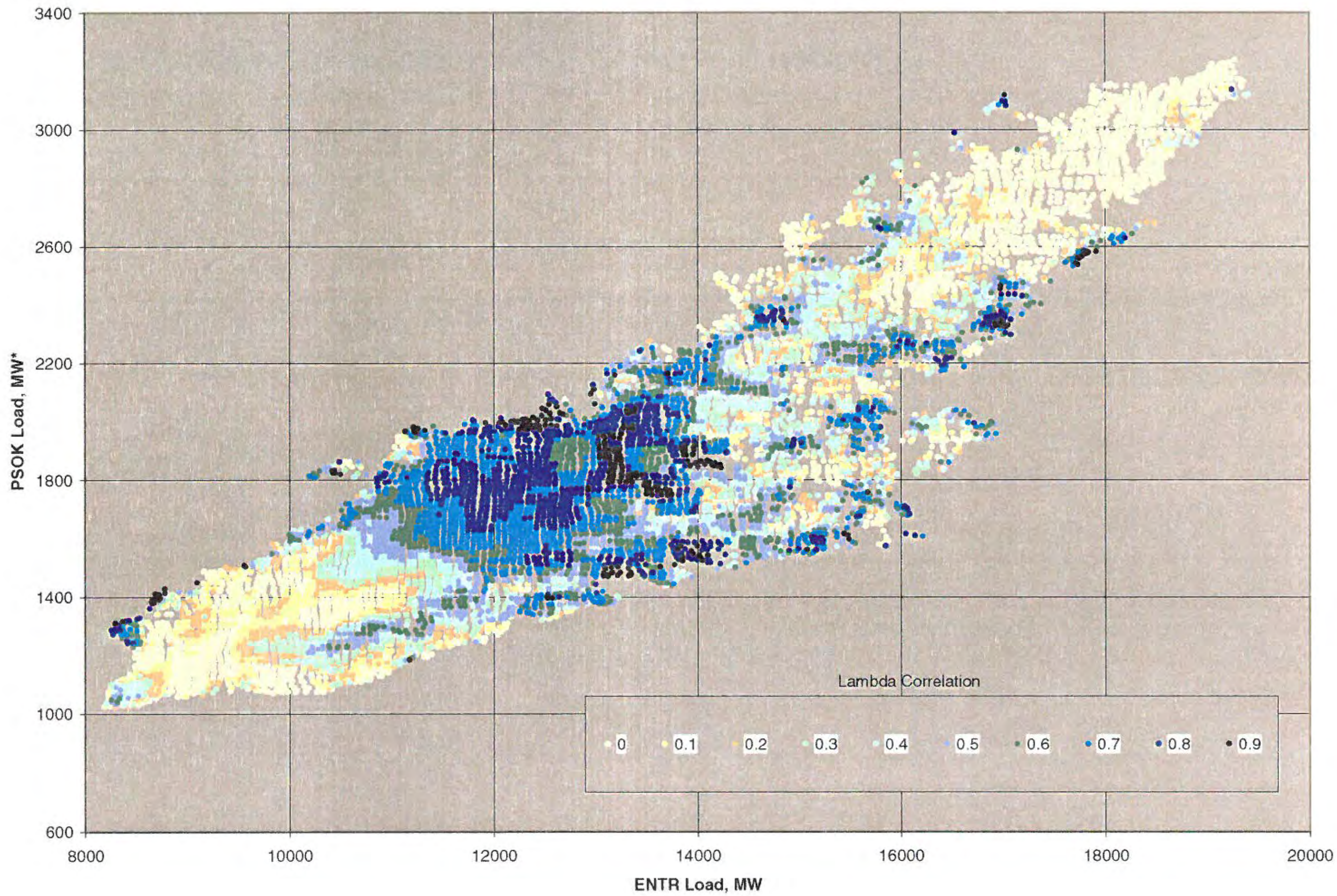

Figure 4-6
Lambda Correlations Between ENTR and PSOK at Varying Load Levels-1995 Data

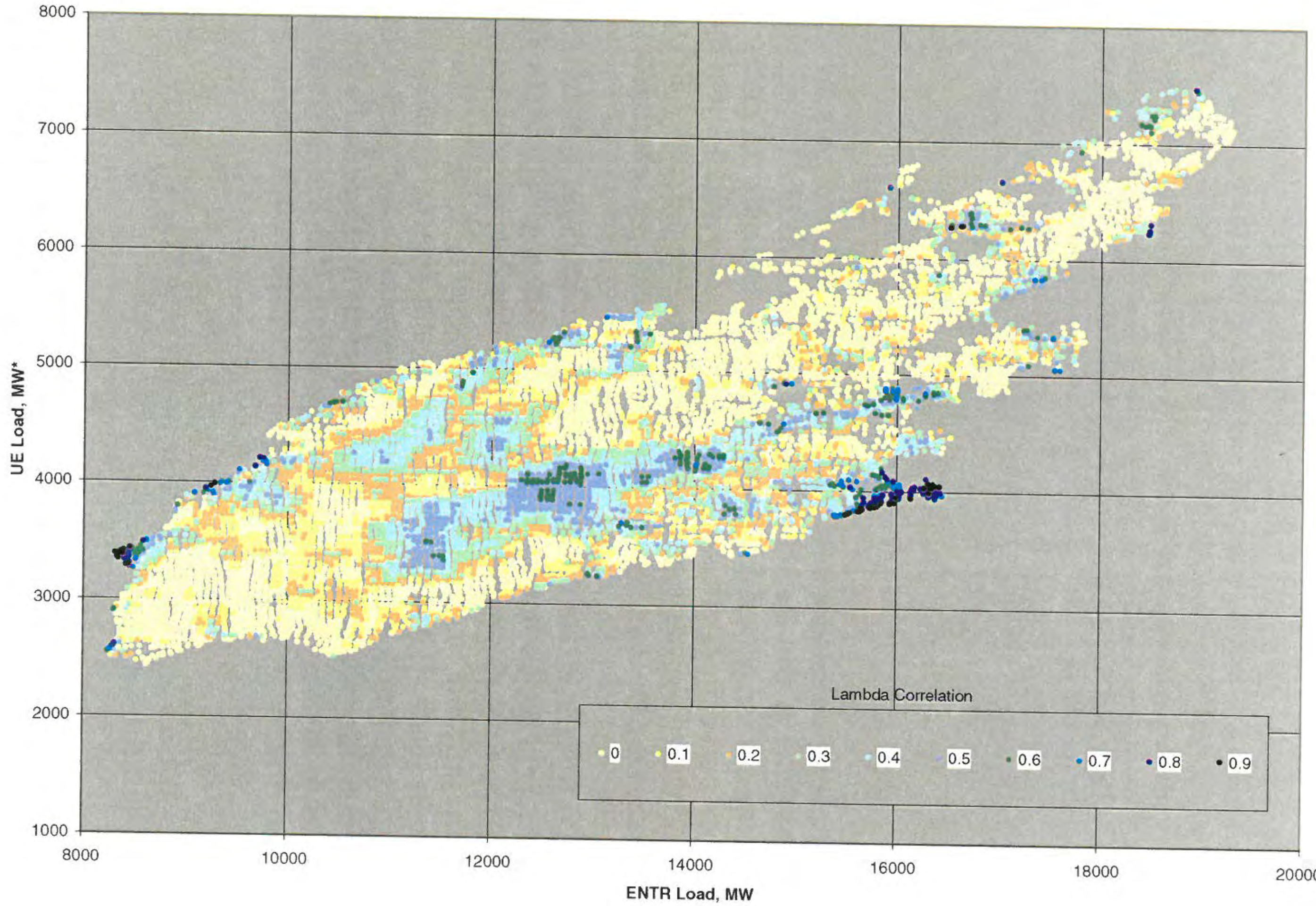

Figure 4-7
Lambda Correlations Between ENTR and UE at Varying Load Levels-1995 Data

fact, in spite of the lack of electric energy exchanges between Entergy and Union Electric implied by Figure 4-7, Entergy scheduled more electric energy from Union Electric than eleven of the other thirteen control areas with which it schedules energy exchanges.[17]

Table 4-1
Entergy's Power Exchanges With Public Service Oklahoma and Union Electric During 1995

	Scheduled Exchanges GWhs		Actual Exchanges GWhs	
	Received	Delivered	Received	Delivered
Public Service Oklahoma	454	151	3,216	333
Union Electric	2,175	1,624	<1	250

Source: FERC Form 714.

What may actually be occurring becomes a bit more clear when considering actual power exchanges between Entergy and the other two control areas. As can be seen, of the 3.8 TWhs of total energy exchanges *scheduled* with Union Electric, only 0.2 TWhs were *actually* exchanged on power lines directly connecting those two utilities. On the other hand, a total of 3.5 TWhs of electric energy was actually exchanged with Public Service Oklahoma, far exceeding the 0.6 TWhs of total energy exchanges scheduled.

What becomes apparent, therefore, is that the lambda and load correlations of the three utilities are driven by actual energy exchanges, not scheduled exchanges. This also is suggestive of another aspect of parallel path flows. Consider that Entergy schedules flow with Union Electric in response to price signals (plus contract path tariffs) that induces a transaction to take place. When the power arrives into Entergy's control area its dispatch is sufficiently altered as to effect its lambda. However, since the power did not actually flow from Union Electric its lambda was unaffected. Meanwhile, Public Service Oklahoma is induced to take power from Entergy, power that is largely not scheduled, that does alter its lambda. Understanding the dynamics of this arrangement is complete when one considers that:

- Public Service Oklahoma may be forced to receive power from Entergy that displaces its own supply without regard to cost.

[17] The highest scheduled exchanges are: Associated Electric Cooperative, Inc. (4.4 TWhs total scheduled) and Tennessee Valley Authority (4.2 TWhs total scheduled).

- Union Electric's lambda does not alter making it appear from Entergy's vantage to be a supplier or buyer with unlimited capacity to buy or sell at that price depending on conditions (i.e. power exchanges are not acting to equalize prices).

Additional Observations

Baseload

Lack of lambda correlation during baseload operations was nearly universal. One possible explanation is that the economics of baseload generation are so similar that there does not exist sufficient basis differentials to induce power exchanges during these periods. An alternative explanation comes from recognizing that baseload nuclear and coal-fired units lack a great deal of turn-down ratio. Since the output of these units is required during peak, a control area may be reluctant to actually shut down one of these units during low load times.[18]

Capacity Benefit Margin

Control areas often reserve a portion of transfer capability for use during peak or emergency times. The lambda and load correlations do show a few control area pairs where available transmission capability appears to be saturated (i.e. upper- to peak loads with low correlation), yet exchanges apparently resume during the very top peak loads of the year.

Summary

The production of lambda and load correlations of sixty control area pairs were produced for the first time ever as a result of this research. These plots provided tantalizing glimpses of *actual* system dispatch that served as an aide to more theoretical analytical methods.

Improvements to the analysis in order to harvest additional insights includes:

- Breaking the annual aggregations into seasonal or bimonthly increments. This would serve to isolate seasonal effects derived from differing demand and supply curves. In addition, this analysis would track increasing trends in correlations due to increased volumes of hourly power markets.

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[18] In fact, in deregulated generation markets these units may be willing to take negative prices for their power (pay for the right to operate) during low-load periods in order to reap higher revenues during the mid-to-peak portions of daily dispatch.

- Add 1996 (and 1994) analysis to observe evolving hourly power trading patterns as a result of restructuring.
- More directly integrate the lambda and load analysis with other analytic tools. The approach would be to examine the marginal supply curves, power flows, transmission capabilities, etc. for one selected region consisting of multiple control areas. This research would better explain the economic 'window' for power trading.

5

SHORT-RUN DISPATCH ANALYSIS

Overview

The correlation study discussed in the previous section provides a picture of current trading practices of an industry not yet in trading equilibrium. They provide tantalizing glimpses and insights into potential trading practices, but may involve too many simultaneous influences to fully interpret on their own. Short-run dispatch modeling is a tool that can be used to simulate these transactions under controlled conditions, *e.g.*, transaction conditions (i.e., access and wheeling fees) can be explicitly modeled.

This is not to say that the To-Go cost framework should be abandoned. The long-run supply curve, or To-Go[19] cost framework adopted in the previous study[20] provides an overview measure of regional vulnerability. Generating units must recover To-Go costs in the long-run to remain viable. Units that are viable in the long-run will largely determine the future pattern of fuel consumption. By their very definition as non-variable costs, analysis of the external factors driving regional vulnerability to restructuring is not afforded in traditional short-run dispatch models. This attractive feature of the To-Go cost framework, however, is also its primary disadvantage; To-Go costs do not predict dispatch very well. Unit dispatch, and hence power exchanges, will largely be determined by short-run variable costs with fixed To-Go costs likely to be recovered on peak, through scarcity premiums with little effect on dispatch order. Consequently, to gain insights into the impact of restructuring on generation and fuel use it is necessary to examine both long- and short-run costs.

This section presents the results of our short-run, dispatch analysis to examine the impact of restructuring on fuel consumption. The study employs a multi-area

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[19] To-Go costs include fuel costs, variable O&M costs, environmental adders, and average annual capital additions. See *Regional Impacts of Electric Utility Restructuring on Fuel Markets,* EPRI TR-107900, GRI-97/0108.2 (1997) for details.

[20] See *Regional Impacts of Electric Utility Restructuring on Fuel Markets,* EPRI TR-107900, GRI-97/0108.1, 1997 for details.

production costing model to simulate hourly trading activities for a majority of the U.S., i.e., the Northeast, Southeast, and Western System Coordinating Council (WSCC) over several years and under alternative transmission capacity and cost conditions. The Electric Reliability Council of Texas (ERCOT), Mid-American Power Pool (MAPP), and all of the Southwest Power Pool (SPP) subregions, with the exception of the southern subregion, are excluded. In addition to quantifying the economic tradeoff among competing fuels from restructuring, this analysis yields surprising insights on regional production costs. The study also provides additional insight into the base versus cycling competition issue raised in the previous study. However, the short-run modeling results presented here are not offered as a comprehensive analysis of restructuring. They are mainly designed to frame effects of specific assumptions.

Methodology

A chronological, multi-area production costing model called IREMM[21] (Inter-Regional Electric Market Model) was used to simulate the hourly trading activities within three very large regions for the years, 1994, 1997, and 2000. The 1994 results provide a benchmark on which to calibrate the remaining years.

IREMM is similar to utility production costing simulation models used for planning and budgeting purposes in that it determines economic dispatch on the basis of variable generation costs, taking into account unit forced outages, maintenance requirements, hydro scheduling, transmission limits, and wheeling costs. It simulates dispatch and trading on an hourly basis for each defined market within the region. Customer loads and generating units of each market area are integrated as if they were a single power pool. Each market area has an obligation to serve its own load before it can sell its surplus energy to other market areas. Local supply can be replaced if surplus energy can be purchased elsewhere for less.

A key feature of IREMM is that it simulates price formation and transactions under competition using a game theoretic framework as opposed to a strict marginal cost approach. Specifically, IREMM determines transactions and calculates market-clearing prices based on opportunities to buy and sell power among market participants within an interconnected system. It assumes that sellers attempt to maximize profits by selling at the highest possible price while buyers attempt to maximize savings by purchasing at the lowest possible price. These interactions of demand and supply are superimposed on transmission costs and line flow limits to determine regional market prices for electric power.

[21] The IREMM model is developed and licensed by IREMM, Inc.

Scenarios

The scenario analysis focused on transmission transfer capability and costs.[22] Section 3 demonstrated that total transfer capability can vary substantially, sometimes exceeding NERC's summer and winter transfer capability limits by 2 to 3 times. Therefore, it was desirable to simulate the dispatch with transmission limits that varied over time. Time-of-use transmission capability data, however, was available only for PJM. For regions without time-of-use transmission data the results could be bound by examining extremes, or corner solutions, *i.e.*, moving from "no trade" or no transmission capability to "free trade," i.e., "no transmission constraints" and "no fees" — the most favorable power exchange conditions.

Consequently, to capture the effect of restructuring on inter-regional power flows, fuel mix and productions costs five scenarios were simulated:

- Case 1: *No Trade* - no power trade among market areas, but trade among utilities within each market area;
- Case 2: *Base Case* - assumes power trade with transmission limits and wheeling fees, approximates current trading conditions;
- Case 3: *TXs Only* - assumes power trade with transmission limits only, no wheeling fees;
- Case 4: *Fees Only* - assumes power trade with wheeling fees, but no limits on transmission capability;
- Case 5: *Free Trade* - assumes power trade with neither transmission limits nor wheeling fees.

Table 5-1 below summarizes the scenarios.

[22] Note that these IREMM scenarios focus only on the interplay between transmission terms and conditions and trade volumes, not a numerous other factors such as load growth and changes in fuel costs which could arise from restructuring. They are not intended to describe most likely scenarios where all such factors would be simultaneously considered.

Table 5-1
Short-Run Dispatch Scenarios

		Wheeling Fees: Yes	Wheeling Fees: No
TXs Limits	Yes	"Base Case"	"TXs Only"
	No	"Fees Only"	"Free Trade"

Data on transfer capabilities were obtained from several sources. Time-of-use transfer capabilities for the Northeast region were obtained from PJM's OASIS and are provided in Table 5-2 below. Since OASIS went into effect on November 1996, many utilities and pools have published their total and available transmission capabilities. Transmission lines and regional interface limits for the Southeast and WSCC were obtained from the North American Electric Reliability Council (NERC) 1996 Summer Assessment. These data are provided in Figures 5-2 and 5-3 described below. The imports from Hydro Quebec into the New York Power Pool (NYPP) and the New England Power Pool (NEPL) are modeled as simply an external transaction, while all the generating units and loads in the other market areas were represented.

Wheeling fees between each market area were based on the average transmission tariff (when available) of the utilities within each market area. The transmission tariff was based on the hourly Open Access Point-To-Point Transmission *Pro Forma* Tariffs filed with the Federal Energy Regulatory Commission Order (FERC) per Order 888. These data are found in Appendix B.

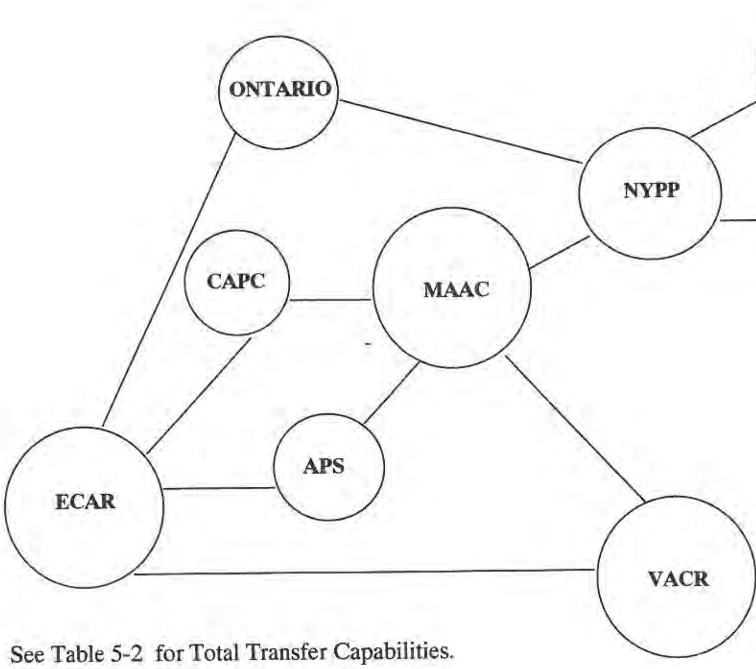
In addition to the transmission scenarios, we considered one nuclear shutdown scenario. The permanent shutdown of nuclear units, Connecticut Yankee, Maine Yankee and Millstone, was considered as a special case for the Northeast region in 1997.[23] Their capacity accounts for 1.5 percent of the total capacity in the Northeast region. In general, note that all nuclear units are modeled as must run.

[23] The study included Ontario Hydro's nuclear units in the analysis as their shut down announcement had not been made at the time we ran the model.

Table 5-2
Northeast Total Transfer Capabilities (MW)

Interface Name	On-Peak Rating		Mid-Peak Rating		Off-Peak Rating		NERC-Non Simultaneous	
	forward [1]	reverse [2]	forward [3]	reverse [4]	forward [5]	reverse [6]	forward [7]	reverse [8]
NYPP-MAAC	3,096	4,343	3,448	4,521	3,807	4,853	2,279	3,571
APS-MAAC	4,944	1,688	5,159	1,688	5,534	1,688	4,720	4,720
CEI-MAAC	1,643	1,519	1,643	1,519	1,643	1,597	1,643	1,643
VACAR-MAAC	4,944	1,813	5,159	1,813	5,534	1,813	2,700	4,000
ONT-NYPP	N/A	N/A	N/A	N/A	N/A	N/A	1,500	1,500
ONT-ECAR	N/A	N/A	N/A	N/A	N/A	N/A	2,300	2,810
HYQB-NYPP	N/A	N/A	N/A	N/A	N/A	N/A	2,000	2,000
HYQB-NEPL	N/A	N/A	N/A	N/A	N/A	N/A	2,000	2,000
APS-VACAR	N/A	N/A	N/A	N/A	N/A	N/A	6,718	6,718
ECAR-VACAR	N/A	N/A	N/A	N/A	N/A	N/A	1,966	3,184
NYPP-NEPL	N/A	N/A	N/A	N/A	N/A	N/A	1,500	1,500

Source: [1] to [6] – PJM OASIS, July 1997, [7] and [8] – 1996 NERC Summer Assessment.
Notes: On-peak is defined as M-F 12:00 pm-6:00 p.m.
Mid-peak is defined as M-F 7:00 am-12:00 p.m. and after 6:00 pm-11 p.m.
Off-peak is defined as other hours.
Forward and reverse TTCs are not always equal since changing or reversing power flows changes loading on the limiting constraint or exposes a different limiting constraint.



See Table 5-2 for Total Transfer Capabilities.

Figure 5-1
Northeast Defined Market Areas and Interconnections

Source: EPRI/GRI project team.

Regions

Northeast

The Northeast region was modeled to consist of nine market areas: 1) the Mid-Atlantic Area Council (MAAC); 2) the New York Power Pool (NYPP); 3) Ontario Hydro; 4) Hydro Quebec; 5) Allegheny Power System (APS); 6) Central Area Power Coordinating Group (CAPC); 7) the eastern part of the East Central Area Reliability Coordination Agreement (ECAR) excluding APS and CAPC; 8) the Virginia/Carolina Subregion of the Southeastern Electric Reliability Council (VACAR); and 9) the New England Power Pool (NEPL). Figure 5-1 illustrates the defined market areas in the Northeast and the interconnections. Transmission limits for the Northeast interconnections are provided in Table 5-2. The utilities in each of these areas are listed in Appendix B.

Current noteworthy characteristics of this region are:

- Forefront of retail-access restructuring, *e.g.*, in Pennsylvania, New England, and New York.

- Most generating resources are coal and nuclear.
- Three nuclear plants in this region, Connecticut Yankee, Maine Yankee, and Millstone were shut down.
- Numerous transmission bottlenecks from north to south (such as from Canada) and from west to east (such as across upstate New York or mid-Pennsylvania).

Southeast

The Southeast region was modeled to consist of seven market areas: 1) the Southern Company (Southern); 2) Tennessee Valley Authority (TVA); 3) the Southwest Power Pool-South (SPPS); 4) Allegheny Power System (APS); 5) American Electric Power Company (AEP); 6) the Virginia/Carolina Subregion of the Southeastern Electric Reliability Council (VACAR); and 7) the Florida Reliability Coordinating Council (FRCC). Figure 5-2 illustrates the defined market areas in the Southeast and the interconnections. Total transfer capabilities as modeled in the dispatch analysis are shown in parentheses. The utilities in each of these areas are listed in Appendix B.

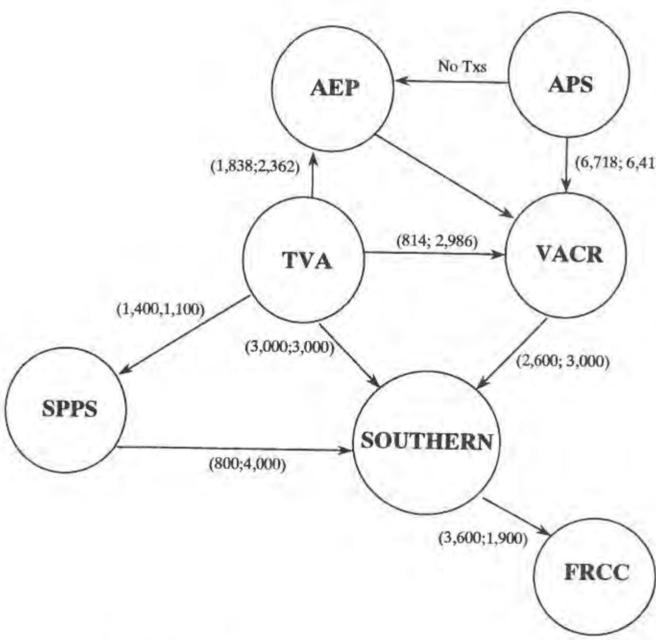


Figure 5-2
Southeast Defined Market Areas and Interfaces

Source: *1996 NERC Summer Assessment*, and Operation Simulation Associates, Inc., *Over/Under Study*, 6/1994.
Note: Numbers in the parenthesis are total transfer capabilities (forward rating; reverse rating).

Current characteristics of this region are:

- Dual fuel units (oil and gas) in FRCC.
- Strong coal base in VACR, TVA, Southern, AEP and APS.
- High demand growth and peak constrained.
- Transmission bottlenecks into Florida.

WSCC

The WSCC region consists of eight market areas: 1) the western half of the Northwest Power Pool (NWPP1); 2) the eastern half of the Northwest Power Pool (NWPP2); 3) Northern California (NOCA); 4) Southern California (SOCA); 5) the Rocky Mountain Power Area (RMPA); 6) Arizona and New Mexico (AZNM); 7) part of Mexico; and 8) part of Canada. Figure 5-3 illustrates the defined market areas in WSCC and the interconnections. Total transfer capabilities as modeled in the dispatch analysis are shown in parentheses. The utilities in each of these areas are listed in Appendix B.

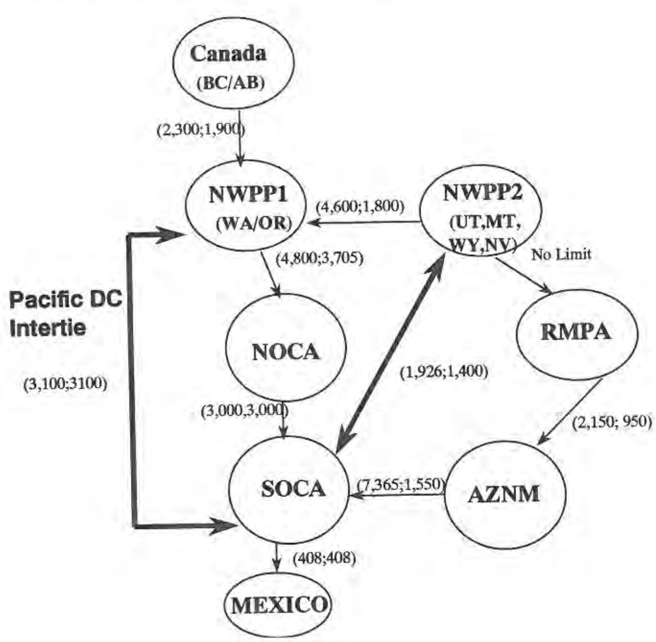


Figure 5-3
WSCC Defined Market Areas and Interfaces

Source: Western Systems Coordinating Council, *WSCC 1996 Path Rating Catalog*, February 1996.
Note: Numbers in the parenthesis are total transfer capabilities (forward rating; reverse rating).

Current relevant characteristics of this region are:

- Hydro energy from WSCC-North (such as NWPP1, and Canada).
- Strong gas base in California, and often used as must-run units.
- 12,465 MW of Qualified Facilities in 1994, approximately half are gas; the rest are biomass and hydro. All of these units are currently non-dispatchable, thus we assume they are must-run units.
- Power Exchange/Independent System Operator with retail access in California by 1998 (pending resolution of technical difficulties that have delayed startup until March 31, 1998).
- Long-haul transmission subject to instability risk.

Results

To provide insights on the impacts of the restructuring on fuel use, three main results are discussed in this section – total production costs, fuel consumption, and trade patterns.

Total Production Costs

Table 5-3 presents the 1994, 1997, and 2000 simulated total production costs and their changes relative to the base case for the Northeast, Southeast, and WSCC. Several conclusions can be drawn from the results. The most surprising result is that total annual production costs decline by only a few percent, ranging from 1.6% to 4.1% across regions and time, as the industry moves toward free trade. A priori, larger savings were expected. Much larger cost reductions are observed in the move from self-reliance, or no trade, to the base case; savings ranging from 1.9% to 14.9%. Thus, the majority of the production cost efficiencies to be gained from free trade have already been achieved.

Overall, WSCC has the largest savings in production costs as the industry moves to free trade due to locally under-diversified capacity mixes. Comparing 1994, 1997, and 2000, production cost savings are relatively constant in percentage terms, declining slightly for WSCC.

Relative to wheeling fees, transmission limits are a greater barrier to inter-regional power trade. Wheeling fees by themselves are less of a deterrent than physical limits without fees. This can be observed by comparing the reduction in total production costs as we move from the base case to the transmission limits only case to the

Table 5-3
Total Production Cost Savings* ($ millions)

Region	Scenario	1994		1997 w/Nuclear		1997 w/o Nuclear		2000	
	No Trade	$14,222	3.4%	$15,999	4.1%	$16,663	5.1%	$17,944	4.2%
	Base	$13,758		$15,367		$15,859		$17,213	
Northeast	TXs Only	$13,736	-0.2%	$15,335	-0.2%	$15,827	-0.2%	$17,195	-0.1%
	Fees Only	$13,613	-1.0%	$15,177	-1.2%	$15,553	-1.9%	$17,007	-1.2%
	Free Trade	$13,532	-1.6%	$15,097	-1.8%	$15,468	-2.5%	$16,946	-1.6%
	No Trade	$6,309	13.3%	$8,226	14.9%			$8,886	13.9%
	Base	$5,569		$7,158				$7,801	
WSCC	TXs Only	$5,586	0.3%	$7,191	0.5%			$7,823	0.3%
	Fees Only	$5,393	-3.2%	$6,886	-3.8%			$7,609	-2.5%
	Free Trade	$5,393	-3.2%	$6,875	-3.9%			$7,599	-2.6%
	No Trade	$12,447	1.9%	$14,411	3.5%			$16,353	2.4%
	Base	$12,214		$13,868				$15,972	
Southeast	TXs Only	$12,204	-0.1%	$13,864	0.0%			$15,956	-0.1%
	Fees Only	$12,000	-1.7%	$13,383	-3.5%			$15,587	-2.4%
	Free Trade	$11,933	-2.3%	$13,330	-3.9%			$15,528	-2.8%

* Percentage changes are compared to the base case.
(Source: EPRI/GRI project team.)

reduction from the base case to the fees only case. The reduction from the base case to the transmission limits only case yields a savings of only about 0.1% to 0.2%. Recall, the move from the base case to the case with transmission limits only is obtained by eliminating wheeling fees. Contrast these minimal savings to those obtained from the move from the base case to the fees only case, *i.e.,* elimination of the transmission limits, reductions range from 1% to 4%. These savings are nearly equal to the total amount of production cost savings achieved moving from the base case to free trade. (Compare the Fees Only rows to the Free Trade rows in Table 5-3.) This indicates that the generating cost differentials among market areas are much larger than typical wheeling charges.

Finally, a comparison of the results from the nuclear and without nuclear scenarios indicates that plant viability appears to play as big a role in power exchange as transmission constraints. To see this, note in Table 5-3 that the nuclear shutdown effect is of the same order of magnitude as the entire transmission constraint range in the Northeast, even though it is a constrained region. That is, there is roughly $400 million in production cost savings moving from the base case to the free trade case (under either the with or without nuclear scenarios). Similarly, there is nearly $400 million in increased production costs as units are shutdown, moving from the with to without nuclear scenarios. This result implies that plant viability or vulnerability questions explored with the To-Go cost framework are equally important in determining the impact of restructuring on fuel impacts as transmission constraints.

Fuel Consumption

A comparison of fuel consumption patterns for coal and gas for the various scenarios is provided in Table 5-4. Fuel consumption for the base case is provided in millions of MMBTUs; consumption for the other scenarios is measured as percentage deviations from the base case.

The results in Table 5-4 and Figures 5-4 to 5-6 show that for all three regions fuel use shifts toward coal and away from gas, and, to a lesser extent away from oil, when all power flow constraints are eliminated. The largest percentage increase in gas consumption is observed in the Southeast, largely because of the severe transmission limits into Florida. There is only about 3,600 MW of transfer capability into Florida. WSCC has the lowest percentage decrease at roughly 12%. Note that through time the percentage increase in coal consumption stays roughly the same (except for the Southeast), but the percentage reduction in gas consumption declines (except for WSCC).

It is important to realize two factors when reviewing the numbers in Table 5-4, first, the percentage increase in fuel consumption from coal may look small because the underlying coal usage in the base case is quite large (especially relative to gas). On the

Table 5-4
Fuel Consumption Patterns* (Change From "Base Case" Scenario)

		1994		1997 w/Nuclear		1997 w/o Nuclear		2000	
Region	Scenario	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas
	No Trade	-3%	27%	-3%	21%	-3%	27%	-3%	17%
	Base	7,251	778	7,903	914	8,219	1,178	8,191	1,249
Northeast	TXs Only	1%	-2%	0%	-3%	0%	6%	0%	-2%
	Fees Only	4%	-16%	3%	-11%	3%	-5%	2%	-9%
	Free Trade	7%	-33%	4%	-22%	4%	-11%	3%	-14%
	No Trade	-15%	32%	-11%	34%			-6%	24%
	Base	2,630	1,223	2,590	1,078			2,595	1,319
WSCC	TXs Only	-1%	1%	1%	0%			3%	-5%
	Fees Only	11%	-9%	13%	-12%			9%	-14%
	Free Trade	11%	-10%	13%	-12%			9%	-14%
	No Trade	-4%	22%	-5%	23%			-4%	17%
	Base	5,976	802	6,569	905			6,821	1,411
Southeast	TXs Only	0%	0%	0%	1%			0%	0%
	Fees Only	7%	-25%	8%	-36%			6%	-24%
	Free Trade	10%	-43%	9%	-37%			7%	-24%

* Base case fuel consumption is measured in millions of MMBtus (trillion Btus). Multiplying this number by 1.055 converts the value to million gigajoules.

(Source: EPRI/GRI project team.)

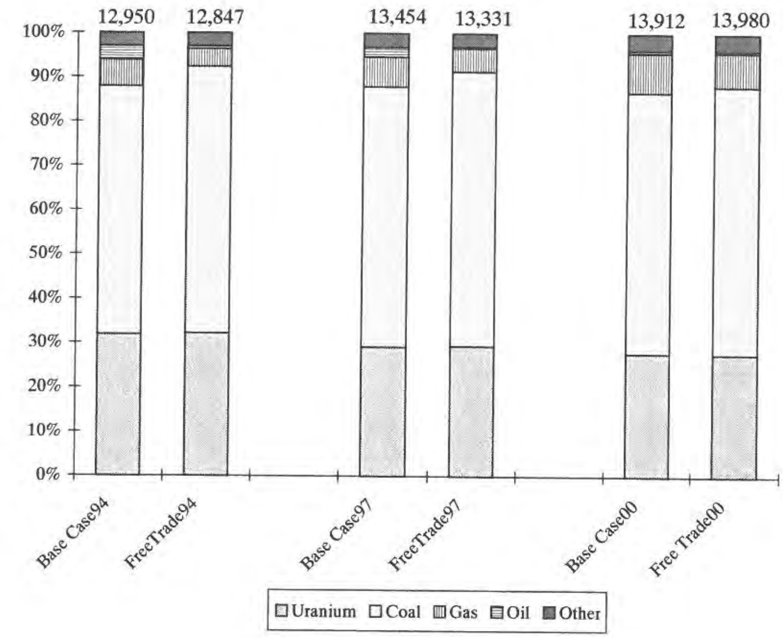


Figure 5-4
Northeast-Region Fuel Mix Comparison

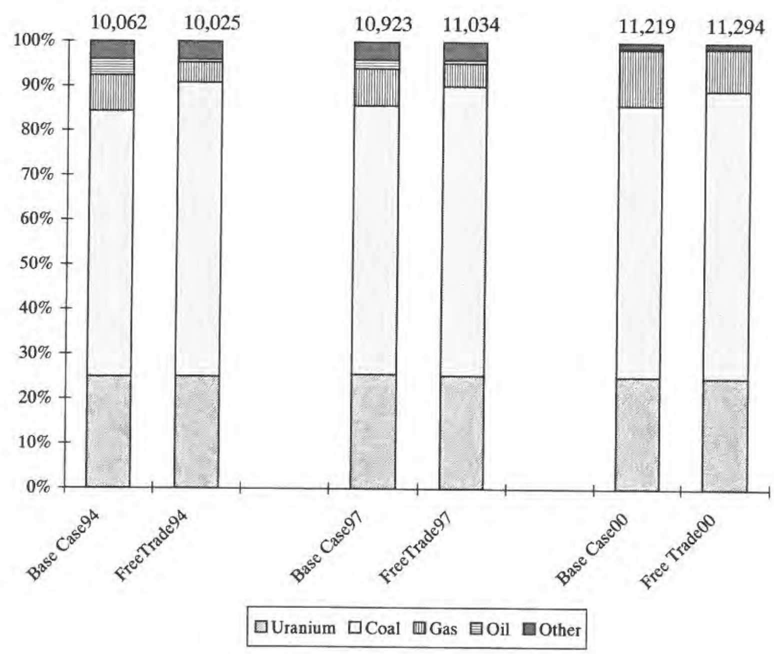


Figure 5-5
Southeast-Region Fuel Mix Comparison

Note: Number above each bar is total fuel consumption in millions of MMbtu.

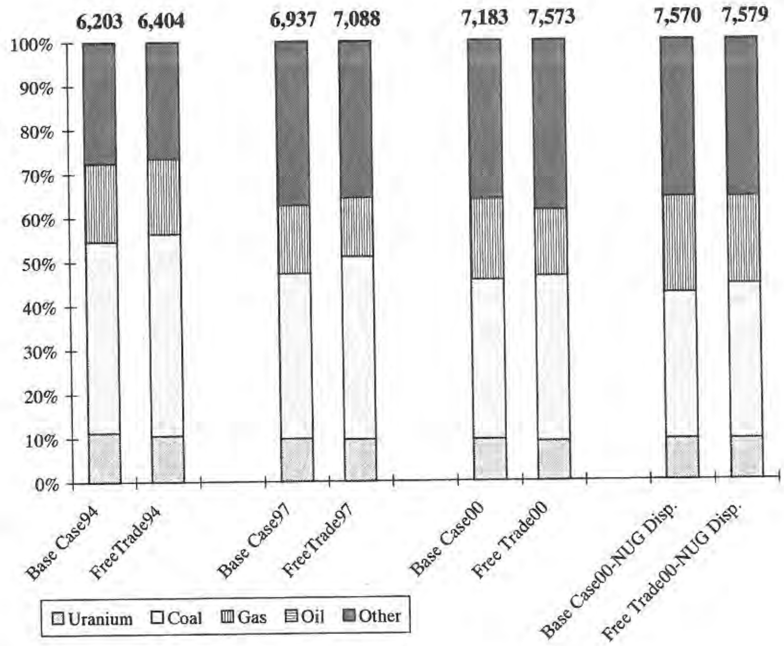


Figure 5-6
WSCC-Region Fuel Mix Comparison

other hand, these regions are not the biggest gas consuming regions. Modest reductions in gas consumption can translate into large percentage changes. The lower percentage reductions in gas consumption observed in WSCC are associated with relatively large base amounts of gas consumption compared to the other regions.

Consistent with the results observed in Table 5-3 on production cost changes, the impact of restructuring on fuel-mix is insignificant as long as each region still has physical transmission constraints. The evidence for this conclusion is the low percentage changes in the "TXs Only" rows for each region.

The trade-off between coal and gas varies by location. The substitution ratios between coal and gas are calculated in Table 5-5.[24] The WSCC region has the smallest trade-off effect as compared to the Southeast and Northeast regions. One percent increase in coal consumption reduces gas consumption by 1.3-1.6% for WSCC, 7.2%-4.6% for Northeast with 2.8% for Nuclear Outages Scenario, and 5.2%-1.09% for Southeast. This may due to the quality of coal delivered to different regions. Coal delivered to the Northeast region provides more heat to generate electricity than does coal for the WSCC region. Alternatively, the WSCC gas plants operate more efficiently than the ones in the Northeast.

[24] We ignore the shift of other fuel consumption such as oil since they have a very small change. Nuclear and NUGs are assumed to be must-run units.

Table 5-5
Substitution Ratio of Gas to Coal-Base Case vs. Free Trade Case

Region	1994	1997 w/Nuclear	1997 w/o Nuclear	2000
Northeast	-7.2	-5.7	-2.8	-4.7
WSCC	-1.6	-1.3	N/A	-1.6
Southeast	-5.2	-4.3	N/A	-1.1

(Source: Percent change in gas consumption divided by percent change in coal consumption for the Free Trade scenario from Table 5-4.)

Finally, gas may benefit more from demand growth and nuclear outages. Overall, the substitution ratios decline over time. Moreover, without two of the nuclear units in the Northeast region, gas consumption in the Free Trade scenario decreases by only 11 percent relative to 17 percent in the scenario with the nuclear units; the substitution ratio is actually cut in half.

Trading Patterns

In this section we assess changes in power flow patterns resulting from relaxing transmission limits and eliminating wheeling fees from the Base Case. Generation displacement between and within market areas is examined. Generation unit capacity factor and energy production data are aggregated into broad unit type categories, base load, cycling, and peak by market area to facilitate the within market area analysis and to provide a more detailed look at inter-regional power displacement. This is not precisely the same definition of baseload vs. cycling as was used in previous report.[25] In Appendix B, we provide more detailed disaggregation of plants by fuel type within each market area to unbundle which types of units gain or lose share in a very large pool.

Northeast

Figures 5-7 to 5-9 present these data for four market areas within the Northeast region, ECAR, MAAC and NEPL. The solid bars present production in GWh by unit type. The solid lines plot the average capacity factors for each unit type. Figure 5-7 shows that ECAR gains market share predominantly from more baseload generation. While the

[25]Here, baseload units include hydro, pumped storage, nuclear, and steam coal. Cycling units consist of steam gas and gas CC units. The peak category includes steam oil, CTs, and other miscellaneous peaking technologies. In the previous study, baseload units were defined as units with capacity factors exceeding the average load factor for the region; cycling units were defined as units with capacity factors exceeding 5% and less than the average regional load factor. In the dispatch analysis described here, units are defined as baseload or cycling based on technology.

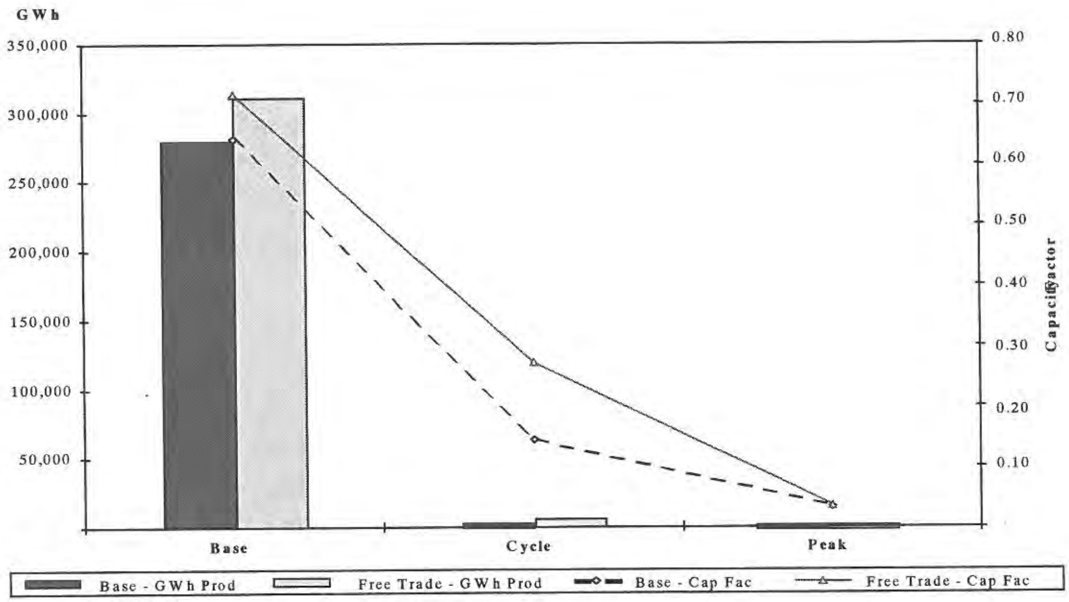


Figure 5-7
ECAR 1997 Energy Production and Capacity Factor by Unit Type

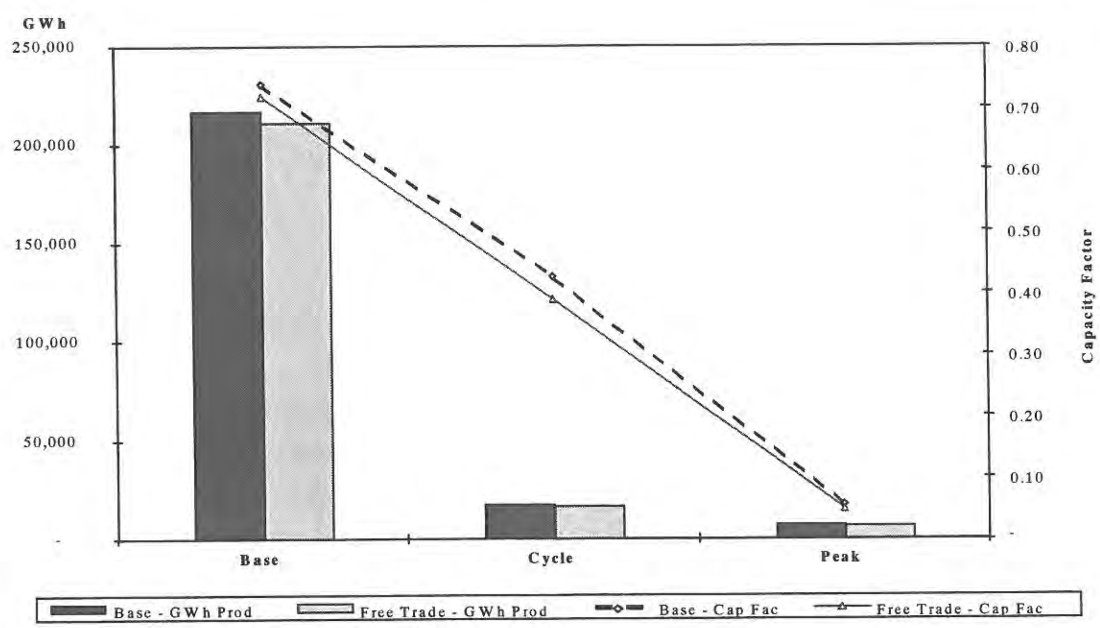


Figure 5-8
MAAC 1997 Energy Production and Capacity Factor by Unit Type

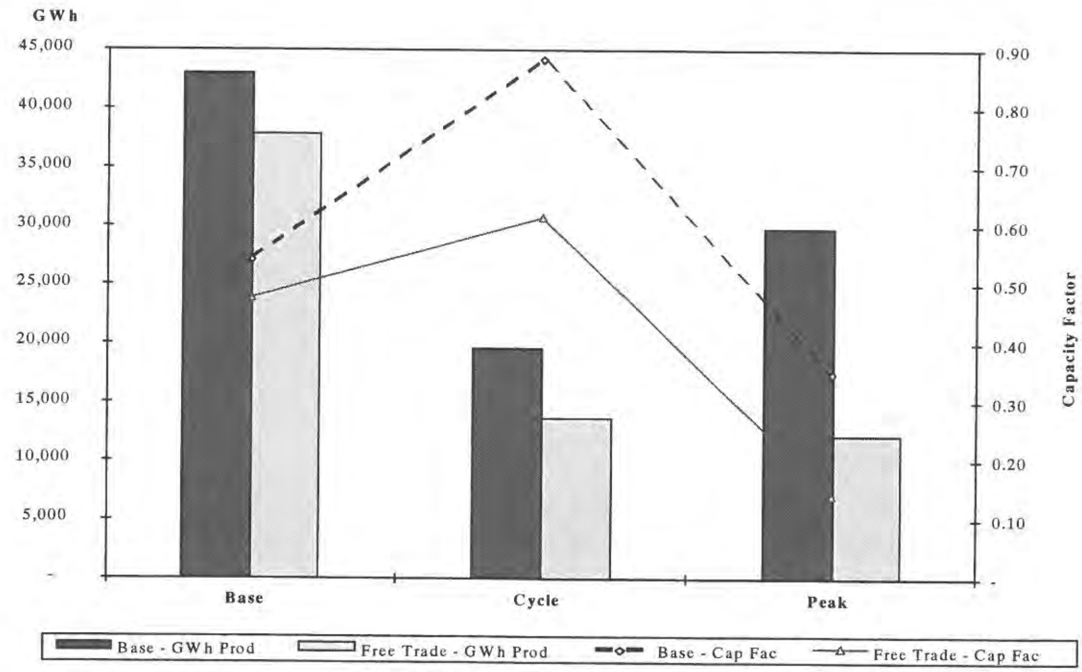


Figure 5-9
NEPL 1997 Energy Production and Capacity Factor by Unit Type

total increase in production from the cycling units seems minimal in the move to free trade, the capacity factors on the cycling units increased more than either the base or peak units, which didn't change at all. NEPL is the just the opposite. All of NEPL's units produce less electricity; NEPL becomes a net importer under free trade. On a capacity factor basis, the cycling units are displaced the most, presumably by generation from ECAR's base units. MAAC loses a small share of generation. The generation comes from an equal reduction in capacity factors across all units.

Figure 5-9 summarizes the winners (units and regions which increase production), and losers (units and regions which reduce production) in the Northeast region. In the figure, "+ share" next to a market area indicates that the market area increased production, and vice versa for "- share". The notation "+ unit", *e.g.*, +cycling, next to a market area indicates that the capacity factor on that category of units increased relatively more than the other unit types in the market area, and vice versa for "-unit".

Figure 5-10 shows that ECAR, CAPC, Ontario, and VACR become net exporters of power; NEPL and NYPP are net importers. Our analysis shows no gains or losses for MAAC and APS. The unit capacity factor data suggests that cycling units are largely displacing other cycling units. Detailed production and capacity factor figures for the remaining market areas for the Northeast, WSCC, and the Southeast can be found in Appendix B.

With free trade, NYPP and NEPOOL become bigger buyers, while ECAR and VACR increase production.

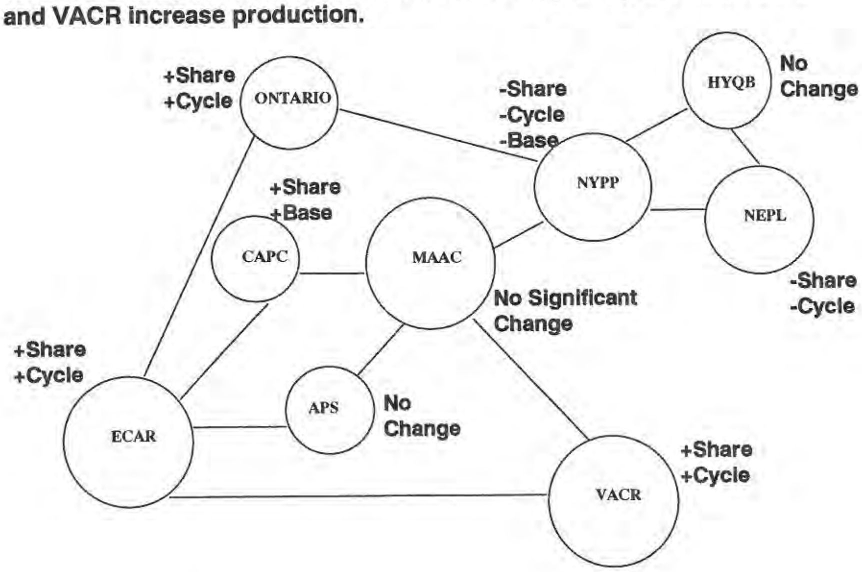


Figure 5-10
Northeast Shifts Due to Increased Trade

WSCC

Figure 5-11 summarizes the WSCC trading shifts. For the WSCC region, there is no surprise. Free trade strengthens the existing flow patterns. The eastern half of NWPP exports to the western half, NWPP, Southern California and RMPA. RMPA export to AZNM; AZNM finishes the chain by exporting to Southern California. Power from the North, NWPP1, also continues to flow south to California. The displacement all appears to be coming from the cycling units, as their capacity factors have, in most cases, increased more than the baseload or peaking units.

Free trade strengthens existing flow patterns in WSCC

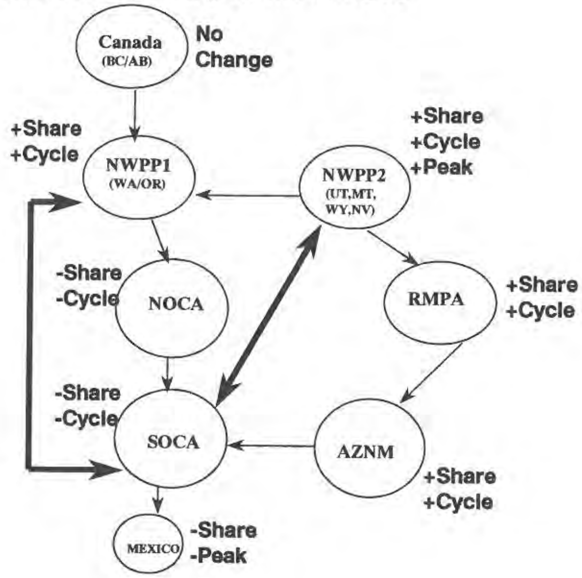


Figure 5-11
WSCC Trading Shifts

Southeast

Figure 5-12 summarizes the trading shifts in the Southeast region. The characteristics of Florida, dual fuel technology and transmission bottlenecks, result in significant power flows from the North to the deep South in a hypothetically unrestricted power market. Florida and SPPS are the only net importers in the region. The capacity factor data indicate that some baseload units are displacing cycling units, *e.g.*, TVA and SPPS. Elsewhere, there seems to be an even number of regions where the base load units are contributing incrementally more, and others where the cycling units are increasing more on the margin.

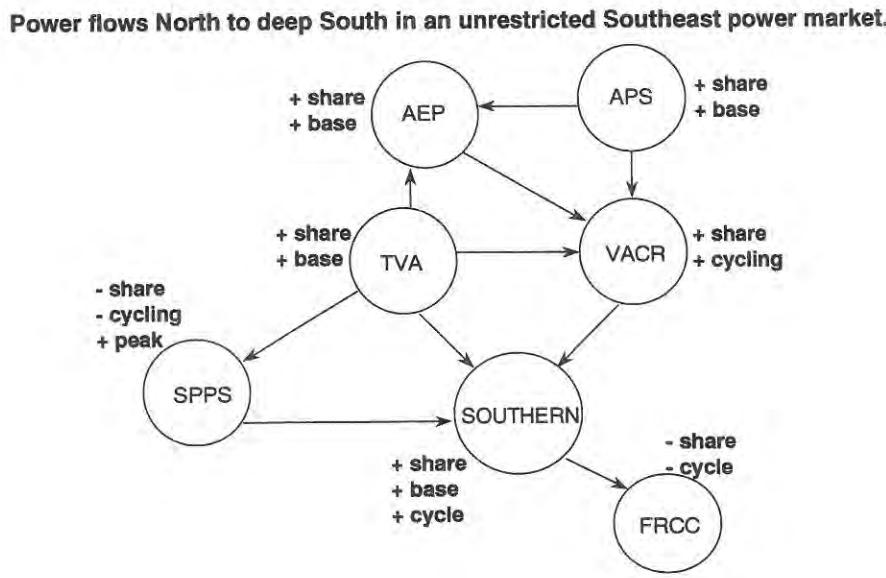


Figure 5-12
Southeast Trading Shifts

Which Units Got Displaced?

So far we have only discussed which market areas appear to gain most from deregulation and free trade totally unrestricted by transmission system limitations. An extension is to identify which units got displaced. Table 5-6 shows average 1997 capacity factors by fuel type for each market area, and their average dispatch costs for the Base Case, the Fee Only Case and the Free Trade Case. To be consistent with our earlier fuel study (1996), units with a capacity factor greater than 62% are defined as baseload units; those with a capacity factor between 62% and 5% are cycling units; otherwise they are peaking units.

Table 5-6
Comparison of Trade Wars

		New Results
Region	**Units Boosted**	**Units Displaced**
Northeast	Baseload coal- ECAR/CAPC, and cycling coal in VACR.	Coal, oil, and gas-NPCC.
WSCC	Baseload coal-RMPA, NWP2, NWP1.	Baseload coal - SOCA.
	Cycling gas-AZNM.	All gas-the rest of WSCC.
	Cycling gas-RMPA, NWPP1, NWPP2.	Cycling gas-NOCA, SOCA.
Southeast	Baseload coal-TVA, AEP.	Baseload coal-Florida.
	Cycling coal-AEP, VACR.	Baseload coal and cycling gas-SPSS, and cycling gas in Florida.
	Cycling coal-VACR, Southern.	Peaking units-Florida.

(Source: EPRI/GRI project team.)

Northeast: In the Free Trade scenario of the Northeast region, generating units in NEPL are the most vulnerable to be displaced. Both coal and gas units in NEPL could be in jeopardy as they are expected to be displaced by the Midwest baseload coal units -- ECAR, CAPC, and to a lesser extent coal cycling units in VACAR. The capacity factor of NEPL's coal units is expected to decline about 16%; 24% for its gas units. Both coal and gas units of NYPP are also displaced by the Midwest cheaper units.

WSCC: Without any transmission limits and fees, NOCA's and SOCA's generating units lose market share in all three categories. SOCA's baseload coal units are displaced respectively by baseload coal units in RMPA, NWP2 and NWP1. The degree of displacement, however, is not as great as for the gas units. Gas dominates in the SOCA and NOCA market areas; it accounts for about 59% of their generating capacity. Cycling coal units in AZNM are more likely to displace cycling units for the remaining gas units. Cheaper cycling gas units in RMPA, NWPP1 and NWPP2 also displace the more expensive ones in NOCA and SOCA. There are no changes in the peaking units capacity factor. (Efficient new CCs for capacity expansion will eventually have a similar effect, displacing old gas in addition to meeting capacity needs.)

Southeast: Without transmission bottlenecks into Florida, opportunities for displacement by imported power are high. The results show that baseload coal units in TVA and AEP displace Florida's baseload coal units. Cycling coal units in VACAR and AEP are expected to replace baseload coal and gas units in SPPS as well as cycling gas units in Florida. The VACAR and Southern cycling units are likely to displace peaking units in Florida.

NUGs

NUGs are treated as must-run units for all scenarios. If NUGs were allowed to dispatch freely, our year 2000 results for the WSCC region suggest that both gas and non-gas NUGs would lose their market shares. Gas consumption of NUGs units would be reduced by about 12%. This is also true for the non-gas NUGs units.

Issues/Conclusions

A study using a short-run dispatch/trading model to simulate the impact of electric industry restructuring on productions cost, fuel mix and trading patterns was undertaken to complement the To-Go cost analysis of previous research. Three large regions, the Northeast, Southeast and WSCC were analyzed under various scenarios for 1994, 1997, and 2000.

Expected production cost savings from restructuring are likely to be minimal. The largest benefits have already been obtained by moving from no trade to the trade we have today, which is limited by transmission constraints and wheeling fees. Reductions of at most 4% were observed even under extreme conditions where all trading constraints were eliminated. Shutdown of two nuclear plants eliminated the savings altogether. That is, plant shutdown appears to be equally as important as transmission constraints in assessing the impact of restructuring on fuel.

Overall, wheeling fees are not much of a deterrent to power trade. Elimination of wheeling fees had minimal impact on production costs and fuel consumption patterns.

In these simulations, fuel consumption tends to shift from gas to coal when transmission constraints are eliminated. The magnitude of the change diminishes over time with load growth and existing plant retirements. It is important to recognize that this result is predicated on no significant change in environmental constraints on either coal or gas units. If those were to occur (e.g., as OTAG/EPA, and CO_2/Kyoto global warming protocols), they could well dictate: (1) these new regulations might overwhelm the above competitive shifts; (2) all fuel prices would have to reequilibrate at levels not considered in these studies (e.g., gas prices might rise dramatically relative to conventional forecasts).

Overall, the results from the short-run dispatch analysis are consistent with those obtained from the To-Go cost analysis. Examination of both is beneficial in order to fully understand the impact of restructuring in the electric industry on fuels consumption and generation patterns.

6

NEW BATTLEFRONTS

Overview

As electric restructuring continues to evolve so too will the competition between the major fuels for electric generation. Not only will fuel competition continue along historic lines (e.g., dispatch at the bus bar and new plant economics), but it will extend into new arenas, or battlefronts, as policies, regulations and commercial practices change. While it is impractical to identify all of these emerging battlefronts, this chapter briefly analyzes three areas where fuel competition, as a result of electric restructuring, is likely to significantly intensify. The three areas are:

- *Non-Utility Generation:* Historically, a high percentage of NUG units have had nondispatchable contracts. However, as a result of electric restructuring the 'must-run' nature of these facilities could change which could adversely impact gas utilization for power generation in the near to intermediate-term.

- *Retirement of Older Units:* A common assumption is that electric restructuring will accelerate the retirement of older, smaller units - the majority of which are coal-fired. If this comes to fruition, it would largely benefit gas consumption within the electric sector. However, the first regional restructuring requirements to unfold have raised doubts about this assumption, which negates some of the potential near to intermediate-term benefits for gas.

- *Power by Wire:* One aspect of the competition between fuel sources that is occurring is increased scrutiny of whether or not it is less expensive to move power by wire or to move selected fuels to power plants within load centers. This is a relatively complex issue that could impact a number of analyses in selecting fuel sources for generation, including the choice between large scale centrally located, or mine-mouth, coal-fired plants versus new gas-fired facilities located within load centers.

While resolution of the issues for each of these battlefronts will not be immediate, they remain highly pertinent to analyses of power generation trends.

Non-Utility Generation

Over the last decade non-utility generation (NUG) has grown very rapidly as a result of the Public Utility Regulatory Policies Act of 1978 (PURPA). One of the primary fuels to benefit from the growth in non-utility generation was natural gas, which at the end of 1996 accounted for 51 percent of NUG capacity and 54 percent of NUG generation.[26] This large percentage of overall NUG capacity has resulted in gas-fired NUG capacity at the end of 1996 being 35.4 GW with total gas-fired NUG generation of 215 TWh (i.e., approximately 2.3 TCF, or 86 BCM). As is the case for the electric utility gas-fired facilities, this gas-fired NUG capacity is regionally highly concentrated. Three regions account for approximately 70 percent of existing gas-fired NUG capacity (i.e., West South Central, Middle Atlantic and Pacific, or more specifically the states of Texas, California and New York), while some of the other regions account for less than one percent. In addition, the principal type of gas-fired NUG unit to date has been the qualified cogeneration facility, which accounts for nearly 95 percent of existing gas-fired NUG capacity.[27]

Figure 6-1 summarizes the annual growth in gas-fired NUG capacity over the last 11 years. 1995 marks a milestone year for these capacity additions as it represents, approximately, the end of significant annual additions of gas-fired *qualified* cogeneration capacity. The viability and attractiveness of such capacity has declined significantly as a result of both changes in PURPA guidelines at the state level and electric restructuring. As a result only a few grandfathered qualified units are being built with almost all of the recent capacity additions, as well as expected additions, being exempt wholesale generators or independent power producers.

As a result of the annual increases in NUG gas-fired capacity, NUG gas-fired generation has steadily increased over the last decade. However, recently the percentage of growth in NUG gas-fired generation has not kept pace with the percentage growth of capacity additions. For example, in 1996 NUG gas-fired capacity increased 6.6 percent, while NUG gas-fired generation increased only 0.8 percent. The primary reason for this lower rate of growth in NUG gas-fired generation is the decline in nondispatchable units. Historically, many of the NUG units obtained nondispatchable contracts from

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[26] See Edison Electric Institute, *1996 Capacity and Generation: Non-utility Sources of Energy, October 1997.*

[27] There are a number of types of NUG capacity, including qualified and nonqualified units under Section 201 of PURPA, small producers, exempt wholesale generators and independent power producers. This report focuses almost exclusively on the qualified cogeneration unit, which historically has been the principal type of gas-fired NUG capacity. See Edison Electric Institute, *1996 Capacity and Generation: Non-utility Sources of Energy, October 1997,* pages viii and ix for a complete definition of each of these categories. Also, see EPRI, *Framing Scenarios of Electricity Generation and Gas Use* (TR-102946), July 1996 Section 4 for a description of NUG capacity and characteristics by region.

host electric utilities. This resulted in these units operating during periods when they were not the lowest cost power (e.g., during non-peak periods), which allowed gas-fired generation to displace other fuels, particularly coal and in some cases, nuclear. While data specific to gas-fired NUG capacity is not generally available, in 1988 71 percent of all NUG capacity was nondispatchable. This figure has declined, particularly over the last several years, to 59.2 percent. Furthermore, in the future the percentage of NUG gas-fired units which are dispatchable is likely to grow - perhaps significantly - as several electric utilities have instituted buyout and buydown programs for NUG contracts within their service territory, particularly nondispatchable contracts.

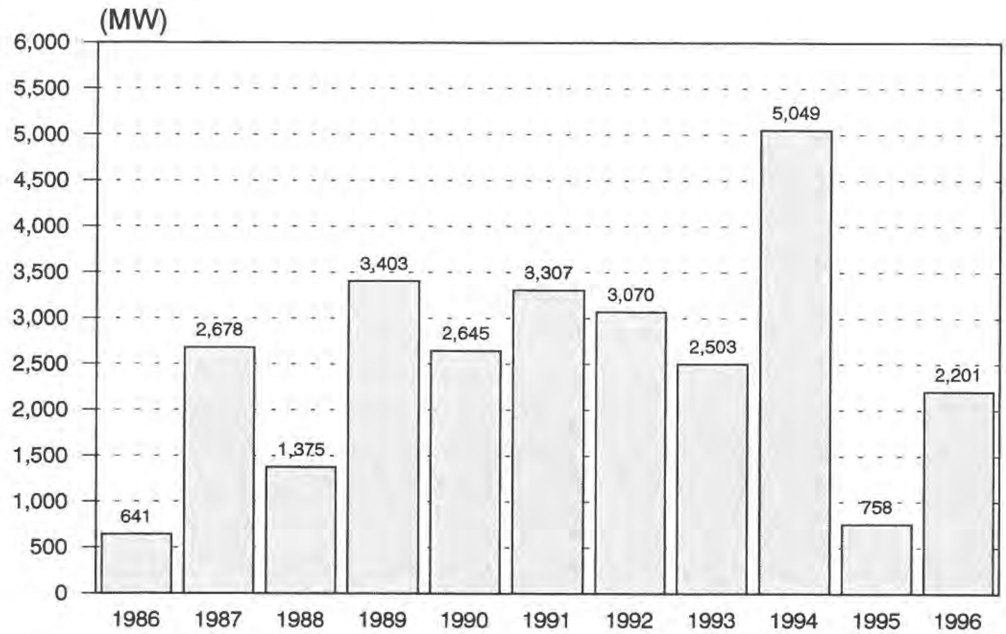

Figure 6-1
Annual Additions of NUG Gas-Fired Capacity

(Source: EEI, *Capacity and Generation: Non-Utility Sources of Energy,* 1986 to 1997.)

The success of these programs, which are just in their infancy, varies by region. An example of such a program is the one instituted by Niagara Mohawk Power Corp. (NMPC), which may have the highest concentration of gas-fired NUG capacity in the nation. This New York based combination utility has an agreement, which is subject to various approvals, that either terminates or restructures about 80 percent of NMPC's NUG contracts for $3.6 billion in cash and about 25 percent of the firm's common stock.[28] In some cases existing NUG plants will likely be mothballed and in the

[28] Details of the Niagara Mohawk proposed agreement are contained in various financial statements (e.g., 10-Q and 10-K) for the firm.

remaining instances almost all of the facilities will convert from dispatchable to nondispatchable contracts. In the short to intermediate-term this should result in a reduction in NUG gas-fired generation in New York, particularly in the off-peak periods.

In California, which is another area with a high concentration of gas-fired NUG capacity, recent state legislation concerning stranded costs has allowed for a similar set of NUG contract buyouts and buydowns. However, negotiations appear to be moving at a very slow pace and at present it appears unlikely that anything as dramatic as the NMPC agreement will occur in California, largely due to different incentives for the electric utilities. In both Texas and Virginia (i.e., areas with significant gas-fired NUG capacity) nearly all of the NUG units were initially, or have become, dispatchable facilities.

As a result of (1) the decline in nondispatchable gas-fired NUG units that has already occurred, (2) various utility buyout and buydown programs, as well as (3) the eventual expiration of existing contracts, many of which were for 15 to 20 year terms starting about 1990, in the short to intermediate term gas-fired generation from existing NUG units is expected to decline, as more and more of these units are subject to competitive dispatch. Predicting how much gas-fired generation from these existing units will decline is a difficult task because of the number of unknowns still facing the industry. However, one indication of the potential decline can be extracted from the IREMM model analysis done for this report.[29] The IREMM model analysis examined industry changes as a result of restructuring in three regions. The results from the WSCC region, which is a region with a large amount of NUG capacity, indicate that gas-fired generation from existing NUG units could decline 8 to 14 percent, as a result of the units becoming fully dispatchable (see Table 6-1). In Table 6-1 the 'No Trade' and 'Base Case' scenarios approximate the current situation for non-dispatchable NUGs, while the other scenarios assumes the NUG units are fully dispatchable.

[29] See Section 5 for a complete discussion of the IREMM model.

Table 6-1
WSCC NUG Fuel Consumption in 2000 (million MMBTU)

	Scenario				
	No Trade	Base Case	TX Only	Fee Only	Free Trade
NUG - Gas Consumption (MMBTU)	496	462	450	427	426
Percent of No Trade Scenario	100%	93%	91%	86%	86%
Percent of Base Case Scenarios	107%	100%	97%	92%	92%
(Source: EPRI/GRI Project Team.)					

Retirement of Older Units

One common assumption concerning electric restructuring is that many older, smaller electric generation facilities will be retired, as a result of the new competitive forces that emerge with the restructuring of the industry. While the fuel type of these older, smaller units varies by region, in general, it is viewed that most of these units are coal-fired units and as they retire their generation will be replaced by generation from more efficient gas-fired combined cycle units.

The first in this series of reports on electric restructuring addressed this general concept.[30] The report examined the general topic of 'at risk' capacity, including the possible early retirement of some nuclear capacity. With respect to the early retirement of older, smaller units the report estimated that approximately 270 coal units totaling nearly 8,000 MW might be subject to early retirement. Similar estimates of older, smaller capacity for other fuels were not made because it was thought the majority of such capacity would be coal-fired.

While this assumption on the surface has some merit, as region specific restructuring requirements unfold, it has been called into question. The first such test case was California. In the case of California most of the older units are gas-fired steam generator units, rather than coal-fired units, because of the unique characteristics of the region. Under California's recently announced ISO guidelines over 90 percent of the

[30] EPRI, *Regional Impacts of Electric Utility Restructuring on Fuel Markets, April 1997 (TR-107900), Volume 1,* pages 4-2 through 4-7 and *Volume* 2, Section E, "The Economics of Aging U.S. Nuclear Capacity". Also, Section 3 of EPRI, *Framing Scenarios of Electricity Generation and Gas Use (TR-102946),* July 1996, presents an analysis of the impact of the retirement of nuclear capacity.

electric utility fossil fuel units were classified as must-run units under some circumstances. While ISO plans to periodically reexamine the requirement for these units being designated must-run units, for the time being these older units will not retire and make room for new capacity. Instead these units will continue to exist with a special status. Figure 6-2 identifies the gas-fired steam generator units in California and recent capacity factors for these plants, some of which are less than 10 percent. Within the WSCC gas-fired capacity is concentrated heavily within California as 70 percent of the gas-fired units in the region (i.e., excluding peaking units) are located within that state.

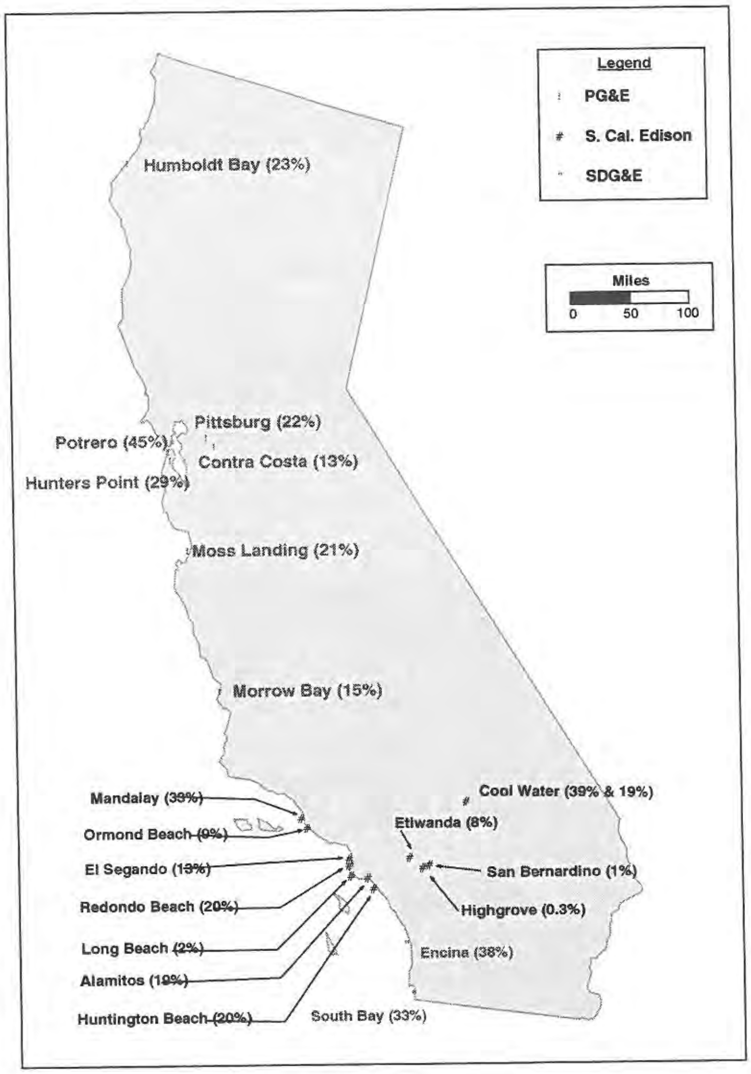

Figure 6-2
California Gas-Fired Plants and Capacity Factors

(Source: U.S. DOE/EIA, *Monthly Power Plant Report (EIA Form 759)*, 1996).

While ISO guidelines for other regions have not yet been announced, there appear to be a number of these older, smaller units (which are fueled by a variety of fuels) that may be classified as must-run units because they are located in, or near, large metropolitan cities. How closely other regions copy these aspects of the California guidelines is unclear. However, if they do, then in many regions there will not be a reduction in coal-fired generation in the short to intermediate-term and as a result, gas-fired generation on balance could be less than contained in various forecasts incorporating this assumption concerning the early retirement of older, smaller units.

The outcome of this issue for each region will impact the near to intermediate-term competition between the two major fuel groups, namely coal and gas. Longer term gas-fired generation is likely to displace generation from these older, smaller units as additional highly efficient gas-fired combined cycle units come on line. Furthermore, these more efficient combined cycle units likely will displace both (1) older coal-fired capacity, which will be to the net benefit of gas consumption, and (2) older gas-fired steam generator capacity, which will be to the net detriment of gas consumption (i.e., 10,000 BTU/kWh heat rate versus 7,000 BTU/kWh heat rate).

Power By Wire

As electric restructuring continues to evolve, the power industry has become more competitive. In this competitive environment, which looks beyond the traditional bundled approach for providing electricity, industry participants are reexamining the economics of almost every segment and subsegment of the industry in order to gain an advantage on their competition. One of the areas receiving increased attention in both industry seminars and the trade press is whether it is less expensive to move power by wire to load centers or to move fuel to power generation facilities within the load centers. Admittedly, this issue has greater impact on the longer term battle between the competing fuels and only represents one component of the economic analysis for a new facility. However, it does have bearing on the future competition between the two primary power generation fuels, namely the centrally located, or mine-mouth, large scale coal-fired plant versus the load center located gas-fired unit, which could be a normal-sized combined cycle unit or a distributed gas-fired power generator unit. This is particularly true in regions where capacity expansion is required.

To help flesh out the issues surrounding this 'battlefront,' the report has undertaken a preliminary examination of the capital cost to transport energy, notwithstanding the need to take into account myriad site specific considerations. As a result a generic analysis, such as that contained in Figure 6-3, can only provide insights, rather than definitive conclusions, into which of the two alternatives is more attractive. In Figure 6-3 the unit capital cost of building a new alternating current (AC) transmission line, presumably from a centrally located coal-fired facility, is compared to the equivalent costs for a pipeline to move gas to a load center power generation facility. The units are capital dollars (i.e., excludes operating costs) per MW per mile. This unit cost is plotted against various sized facilities or complexes using a logarithmic scale.

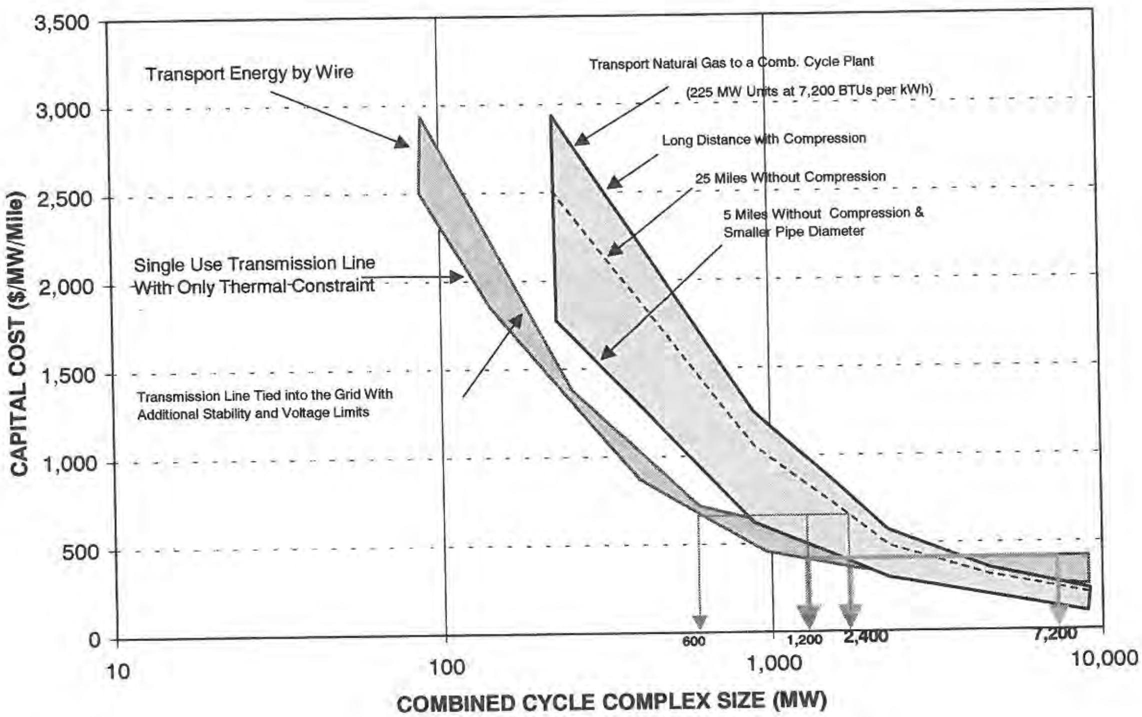

Figure 6-3
Capital Costs of Energy Transport: Gas and Electricity

(Source: EPRI/GRI Project Team.)

The shaded area on the left is for the transmission line and consists of two scenarios. The first scenario is for a single use point-to-point transmission line that is only limited by thermal constraints. The second scenario is for an AC line tied into the grid, which subjects the line to additional stability and voltage constraints. For each scenario unit capital costs were determined on a variety of plant sizes, which in turn determined the size of the transmission line. The individual cases analyzed range from a 138 KV line for a 90 to 144 MW plant to a 765 KV line for a 2,500 to 4,000 MW complex.

Similarly, the shaded area on the right is for the unit capital costs of a natural gas pipeline and includes three cases: (1) a long-distance pipeline with compression, (2) a 25-mile lateral without additional compression and (3) a 5 mile lateral without additional compression. The size of the pipeline was adapted to the fuel requirements of the power plant being examined and ranged from a 12″ to 48″ diameter pipeline.

The capital costs for constructing both the transmission line and the pipeline were taken from government and trade press publications.[31]

An initial comparison of these two alternatives indicates that for smaller power generation facilities transporting power by wire is the less costly alternative and that for larger facilities or complexes (i.e., > 1,000 MW) the costs between the two alternatives can be highly competitive. However, this direct comparison is of limited value because gas pipelines transport fuel for other uses than power generation. As a result, these other users of natural gas (e.g., residential, commercial and industrial users), in essence, pay for part of the pipeline's capital cost, whereas 100 percent of the cost of the transmission line is borne by the power generator.

At present approximately 25 percent of the primary demand for gas is for power generation and 75 percent is for other sectors. Utilizing this proportion would indicate the effective complex size for a natural gas facility would be four times that of the actual size of power generation plant being served by the pipeline. Using this approach, which takes into account that other uses of natural gas bear a portion of the pipeline's capital cost, then in Figure 6-3 a 600 MW complex for transmission line would be compared to a 2400 MW complex for a gas pipeline. In this instance transporting natural gas to a gas-fired facility located within a load center would be the more economic alternative. Since electric power is the primary growth sector for natural gas and thus would represent higher percentage of incremental growth, this case would represent an upper bound.

In order to provide further insight into this competition between power by wire and natural gas pipelines, a similar analysis was done for high voltage direct current (DC) lines, as DC lines are an alternative in the West.[32] Key conclusions from this analysis were that DC lines are less expensive than AC lines for very long distances (i.e., 1,000 to 2,000 miles), but were a higher cost alternative for shorter distances (i.e., 400 miles or less). At distances in between these limits the capital costs of DC and AC lines were comparable. The net effect was that unless the movement of power by wire was over a

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[31] Arthur H. Fuldner, "Upgrading Transmission Capacity for Wholesale Electric Power Trade," Electric Power Monthly (DOE/EIA - 0226), 1996 and "Pipeline Economics," Oil and Gas Journal, August 4, 1997.

[32] Currently, the majority of DC lines are used to interconnect isolated regions. However, there are four DC lines used for the long-haul of power. These include the Pacific Intertie (OR-CA 3,100 MW), Intermountain (VT-CA 1,920 MW), CU Project (ND-MN 1,000 MW) and Square Bubble (ND-MN 500 MW).

very long distance that the use of a DC line would not impact the analyses summarized in Figure 6-3.

Further complicating the analysis is that significant gains in effective transmission capability may be possible without installation of new capital in the form of wires. Section 3 provided additional detail into this possibility with the observation that realization of these gains may be years away. Developing a workable framework for grid investments is likely to be delayed even longer. On the other hand, capital investment in new gas transmission is a relatively straight-forward, short-term process.[33]

In summary the unit capital costs for the two alternatives are very close, particularly for larger facilities. However, transporting via pipeline appears to have the edge for the larger-sized power plant complex when other uses of gas are taken into consideration assuming these other uses are relatively large or rolled-in rates are applicable. In addition, this analysis is for only one component of the overall capital equation for comparing the cost of facilities using different fuels. Site specific factors can often dominate such an analysis.

Summary

As electric restructuring pushes the industry with a more competitive environment, other factors will begin to influence the intensified competition between the two major fuels for power generation, namely natural gas and coal. Specific examples of this phenomenon include a changing outlook for non-utility generation, uncertainty concerning the early retirement of older facilities, and the competitiveness of moving power by wire. While these items are likely to be secondary to the primary forms of competition between these two fuels - namely increased capacity factors for existing coal units and overall new plant economics - they will impact the overall utilization of coal and gas within the power sector.

For example, the benefit natural gas has enjoyed over the last 10 years, as a result of the nondispatchable status of NUG facilities, is likely to continue to erode as a result of electric restructuring. However, the conversion of existing NUG gas-fired facilities from a nondispatchable to dispatchable status is likely to have regional overtones with the East moving more quickly than the West in eliminating the 'must run' nature of these plants.

[33] See EPRI, *Pipelines to Power Lines: Gas Transportation for Electricity Generation (TR-104787)*, January 1995 and Gas Research Institute, *Pipelines to Power Lines: The Operational Day (Volume II), GRI-96/002*, October 1996 for a complete discussion on the interface between gas transmission and power generation.

With respect to the anticipated early retirement of the older, smaller units, which are largely coal-fired, the natural gas industry may not achieve the net benefit of this phenomenon in the near to intermediate-term, if other regions copy California ISO guidelines and categorize a significant percentage of these units as 'must run' units. Results likely will vary by region and will be dependent upon the unique characteristics of each region.

Lastly, movement of gas by pipeline rather than power by wire appears to be the more competitive alternative under the conditions analyzed. This implies that there might not be significant additions to the existing transmission grid for the purpose of moving power from one region to another. At the very least, the result underscores the interplay between generation capacity siting and capacity additions, power transmission planning and investment, and natural gas pipeline project planning and investment. The results do not preclude additions to transmission capacity for reliability or unique site specific reasons involving existing power generation units.

7

CONCLUSIONS

Overview

This is the third in a series of EPRI/GRI reports analyzing generation and fuel impacts of electric utility restructuring. In several instances the research performed for this report, while providing a more complete and in-depth analysis of various aspects of restructuring, confirmed the conclusions provided in the prior reports. As a result, some of the major conclusions from the prior research are incorporated below. This section provides a brief, but complete overview of key conclusions for all of the research performed for this series of reports.

In addition to the primary conclusions reached to date, this section reviews areas where additional research would be beneficial in more fully understanding the generation and fuel impacts of electric restructuring. Furthermore, this section, as has been done previously, includes a discussion of alternative scenarios for the path that may be taken by electric restructuring. While none of these scenarios is the most likely scenario, they are all plausible and underscore the dynamic nature of the transition of one of this country's major industries.

Major Conclusions

The principal conclusions of this and prior research on this topic are:

- ***Restructuring is likely to play out differently in each region and as a result the impact on fuel consumption patterns is likely to vary regionally.*** There is a significant lack of homogeneity among the regions, which manifests itself in a number of different areas. These areas include current transmission conditions, geographic, as well as demographic characteristics, and existing power generation fuel mix. This heterogeneous nature of regions is likely to continue into the future as each region builds upon current differences in finding restructuring solutions that are optimum for that region. The different regional approaches to ISO governance and guidelines are an added dimension of this heterogeneity.
- ***Interregional wires are "thin" relative to the amount of power served in the major load centers, even when fully utilized.*** This is true even when taking into

consideration that for some regions the short-term (i.e. daily) total transfer capability is greater than the longer term (i.e. annual) total transfer capability (i.e., because of the reduced risk for contingency situations). Much of the public discussions of the benefits of electric restructuring have assumed, often implicitly, that the transmission system could support much longer wheels and greater use so as to facilitate a massive reallocation of generation shares across regions. This is simply not the case. Transmission transfer capability is much more subtle than is often appreciated, and there is no obvious technical or political cure on the near horizon for dramatically upgrading the grid. As a result, the fuel and power markets, for at least the intermediate term, will retain a strongly regional character. *The electric transmission grid is not now, nor will it foreseeably become, a "copper sheet" capable of transporting large amounts of power between arbitrarily remote locations in the U.S.*

- ***Restructuring fundamentally will not alter the character of past fuel wars; no fuel can make a "clean sweep" of all generation market shares.*** This is partly a result of the "no copper sheet" finding about electrical transmission and is reflective of the impact of electric restructuring over the intermediate term, absent any consideration of longer term changes in environmental regulations, which likely will favor natural gas. In the intermediate term neither thousands of coal plants in the Midwest nor thousands of gas plants in the Southeast could serve the rest of the nation, no matter how cheap the fuel at the source. Relatedly, neither gas nor coal can be transported cheaply in large enough quantities and without restrictions to every other region to displace local fuels. Some of the factors that created the ascendancy of gas in the recent past have begun to diminish or disappear, especially the non-dispatchable high-cost PURPA contracts that ushered in the IPP suppliers. In addition, units with costs greater than new, state-of-the-art machines likely will not be retired, as various regional ISO groups have designated many such facilities as must-run units, because they are in urban areas that are transmission-constrained. Indeed, it is unlikely that there will be enough turnover in total generation stock over the next several years to alter much the average fuel mix within individual regions. At the margin, the key tension point in the battle between the two primary fuels for power generation will be increased capacity factors for existing coal units versus the construction, largely by IPPs, of new state-of-the-art gas-fired units. The "mining of existing reserves" and seeking more efficiency from existing plants are likely to be very strong drivers for industry participants, which should result in higher capacity factors for existing units. Lastly, in some regions new or improved units will simply displace other units of the same fuel, rather than substitute for a different type.

- ***There will be opportunities at the margin for regions with relatively flat supply curves to increase power flows to neighboring regions with steep supply curves and/or requirements for new capacity.*** As electric restructuring evolves, regions with relatively flat supply curves (i.e., slack baseload and cycling capacity) will have opportunities to supply less costly power to nearby regions with relatively steep supply curves. This displacement, in essence, involves the use of baseload or cycling capacity to displace peaking capacity, or potentially high cost cycling units. During peak periods this use of more economic power may be limited by transmission constraints, and when it does occur the impact on overall fuel utilization will be small. During non-peak periods the additional transmission charges will have to be overcome to displace the higher cost cycling units. Examples of regions where this may occur include power flows to WSCC-South; from MAPP to ECAR/MAIN; and from MAAC/VACAR to NPCC.

- ***Industry survivors are ultimately likely to be determined more by non-variable costs than the traditional variable cost measures.*** The examination of plant utilization using both short-term dispatch costs (i.e., this report) and longer term To-Go costs (i.e., the prior report) illustrate the importance that a series of non-traditional factors (i.e., factors other than incremental fuel costs, O&M costs and heat rates) will play in determining which facilities survive in a restructured industry. Even with no transmission constraints and thus the potential for unlimited dispatch, model results based upon marginal cost dispatch indicates that both production costs and fuel use are not radically different from base case results.

Focus on Transmission

At the center of the debate surrounding a number of electric restructuring issues are the technical and political concerns over the future role of transmission and its capabilities in the restructured environment. It is because of this critical importance of transmission that one of the major areas of research for this report was to provide a better understanding of a variety of transmission related issues. The principal conclusions from this research, which were presented in Section 3, are:

- ***There are so many transmission issues that are still in flux that widespread trading is likely to be delayed.*** There is still considerable uncertainty over technical, structural and governance issues concerning transmission. On the technical side it is unclear how quickly the industry can integrate universal tagging requirements with the appropriate security coordination procedures in order to create a highly functional transaction management system on an entirely new network system (i.e., NERCnet). In any event, this event likely will occur much later than originally anticipated. With respect to structural and governance issues there is not a universal model for the evolving regional ISOs to follow. In addition, there are a host of issues for these evolving ISOs to resolve, such as type of governance, relationships between the ISOs and the market (e.g., power exchange), resolution of confidentiality issues, types of transmission tariff (e.g., modal, zonal, postage stamp or directional tariffs), appropriate resolution of how to relieve congestion areas and others. Furthermore, regions are likely to build upon their unique differences and create different ISO structures that yield different resolutions to many of these issues. The net result is it will take some time before functional ISOs are created in all regions and key transactional systems are in place. Until these events occur widespread trading and any corresponding shifts in generation and fuel utilization will be delayed.

- *Conventional (static) measures of transmission capacity are inadequate and can be misleading.* Measures of simultaneous long-term transfer capability that historically have been published by the NERC regions are based upon long term reliability considerations that consider a variety of contingencies. While this measurement is useful for some purposes, it does not measure short-term transmission capability that could be available for economic trading. Furthermore, because of the lack of detailed industry data on the subject, the longer term NERC measure is often misinterpreted or misused (e.g., estimations for non-peak periods). In fairness to the industry, some regions currently lack the systems to fully assess transmission contingencies on a real-time basis and thus adjust capability to immediate, short-term conditions and contingencies.

- *In the dynamic world short-term transfer capability can be two to three times traditional NERC long-term figures in some instances. However, only a few areas have reached agreement and/or achieved the technical capability to report short-term capability.* As a practical matter most transmission lines during a year are only utilized an average 20 to 30 percent of their rating because of considerations for relatively rare contingencies and seasonal variation in loads. A few regions, such as PJM, have the systems and procedures in place to pre-determine this short-term transfer capability based upon contingencies for that point in time. For these regions short-term transfer capability is greater than the long-term NERC figures. However, it will be some time before other regions are able to duplicate these state-of-the-art systems and procedures and thus, tap this latent transfer capability. Nor is it clear that the same pattern of expanded capability will emerge. The likelihood of other regions following the lead of PJM is not universally possible, as there are a few regions where short-term transfer capability cannot be increased significantly (e.g., Florida to SERC).

- *The outlook for U.S. transmission capability remains a rich mosaic with several sharp contrasts.* For example, in PJM transfer capability has increased as a result of superior short-term tracking, while in the WSCC transfer capability has decreased as a result of operational limitations and governance conflicts arising from the investigation of the 1996 power outages.

- *The pace of restructuring will be affected (i.e., slowed) by the outcomes within the transmission segment.* It will be a challenge for the industry to resolve the numerous issues surrounding the formation of regional ISOs, particularly in light of the need and/or desire to accommodate unique regional differences, on a timetable that meets the expectations of many industry observers (e.g. power marketers, proactive legislators, and even the new organizations whose mission is to facilitate trading). Similarly, the entire industry will be challenged to resolve the technical issues associated with developing an integrated transaction management system within the current ambitious timetable. Importantly, *delays in improved technology and operational policies for transmission will cause corresponding delays in changes in generation and fuel use patterns.*

Future Research

The research to date on electric restructuring has provided a number of valuable insights and helped establish some general conclusions about the impact of electric restructuring on competition within generation and fuel markets. However, this is an extremely dynamic topic that is still evolving with distinctly different regional approaches and timetables on some issues. As a result, there are still a number of uncertainties concerning this topic and its potential impacts that merit additional research. The following briefly describes several of these potential areas.

Environmental

In nearly every seminar and conference where the material from this report and its predecessor have been presented there have been requests to integrate the conclusions of this research, which focused strictly on the impacts on electric restructuring on fuel markets, with an assessment of recent and proposed environmental regulations (e.g., ozone transport, fine particulates and global warming) that impact power generation. Indeed the two major forces that will impact the future of power generation and fuel markets are: (1) electric restructuring and (2) changing environmental regulations. To date, analytical reports have typically focused on one of these two drivers, but not both. As a result, the reader is left with difficult and complex task of integrating the results and developing a net assessment. In many cases these drivers have the opposite impact on fuel related issues - for example, one accelerates the retirement of old units, while the other may delay retirements and one is likely to increase electricity demand, while the other is likely to cause it to decline. Furthermore, the fact that the impact of these two drivers on fuel markets play out over different timetables further complicates the integration process. A single comprehensive report on the net fuel impacts of the two drivers that references, in large part, previously completed research in both areas would appear to be of significant benefit to a variety of industry participants.[34]

[34] The EPRI Fuel Supply Management Target is pursuing research on both areas; thus, either in combination or with close coordination, this recommendation appears achievable in 1998 (J. Platt, EPRI).

Forum For Comparative Analysis and Discussion

Since electric restructuring is a very dynamic topic that is likely to be impacted by a number of political, institutional and technical factors that are subject to change over time, it would be useful to establish a periodic forum on electric restructuring. It is envisioned that this forum would be conducted on a periodic basis, rather than being a single event, so that industry observers could continually update their outlooks and perspectives on key factors shaping the restructuring of the industry. The forum would provide a platform for presenting integrated analyses and discussing key assumptions, as well as identifying different perspectives on major issues. A major part of the forum would be the examination of technical issues facing the industry and the potential emergence of new technologies. The forum would focus on industry-wide issues and aim to multiply the rate of learning for all participants, including experts in given areas. Participants could use this forum for the demonstration of new methodologies for examining either specific issues, or electric restructuring in its entirety.

Load Growth, Elasticity and Load Shaping

There are several restructuring issues that could significantly affect demand for electricity and as a result impact fuel markets. To date these issues have not been examined and integrated with other research on electric restructuring. For the most part, research to date has been based upon existing NERC forecasts for electricity demand and assume future load profiles will remain the same as current ones. Industry changes as a result of electric restructuring have called into question both assumptions.

With respect to load growth there is a general assessment that electric restructuring will result in lower prices for electricity. While some aspects of this assessment are debatable, in several regions (e.g., California, Pennsylvania and Texas) regulatory commissions have been able, for at least the short to intermediate term, to obtain rate reductions from electric utilities as part of the overall quid pro quo process associated with the number of issues encompassed by electric restructuring. While these rate reductions may be due more to regulatory adjustments than reductions in underlying cost, the net result is that customers will be paying less for electricity and this should result in increased demand (i.e., price elasticity). The potential magnitude, timing and impact of this additional demand growth due to price elasticity could have significant impacts on generation requirements and fuel consumption and should be integrated in any overall analysis. For example, a one to two percent increase in demand above the current average 1.8 percent growth contained in the NERC forecast, as a result of this price elasticity effect, would increase electricity demand 200 to 400 TWhs by 2000 to 2002. The impact on fuel consumption could range from an additional 1.7 TCF (i.e., 63 BCM) per year for gas to 100 million tons (i.e., 91 million metric tons) for coal. As a result, the portrait of these two fuels battling to increase market share in a limited market could be changed to where both fuels are growing in an expanding market.

Similarly with respect to load profiles, electric restructuring is likely to make time-of-use pricing available to all consumer groups, though many may also choose to ignore this pricing option. To the extent such real time, marginal cost pricing penetrates the market, it is likely to result in a reshaping of electric utility load duration curves. (Indeed, some of the policy rhetoric in support of rapid, comprehensive retail access is buttressed by claims that enormous efficiency gains might ensue in response to real time pricing.) If this shift occurs, it could impact industry fuel consumption and the fuel impact is likely to be different in different regions.[35] The real likelihood of deep penetration of spot pricing and corresponding strong price responses is not yet well understood, and available data has not been extrapolated consistently up to the national level in a credible fashion. We can predict that in most instances gas consumption would decline as non-peak power requirements increased and either increased utilization of existing local units were used to meet this change in load requirements or increased off peak interregional power flows were tapped. Appropriate analytical models and reasonable scenarios to analyze the potential full impacts of this phenomenon would further advance the overall research by relating the many developments in retail markets to their supply-side consequences.

Stranded Cost Recovery

The treatment of stranded costs is a significant consideration for both the final customer and the financial stability of industry participants. To date there has been significant variation in the treatment of stranded costs, as various regions experimented with different approaches. In addition, the limited sales to date of electric utility generating plants, which are offsets to stranded costs, have resulted in figures ranging from near book value to several times book value. Without further research it is unclear whether stranded costs will result in relatively high transmission surcharges, as proposed in some regions, or will have very limited impact. In the case of the former, the cost of electricity in the retail market could increase which could impair demand and/or offset any price elasticity due to declining costs in other areas. Research into regional differences on this issue, the overall impact on electricity prices and the net impacts on load growth, generation and fuel consumption would dimension some of the more important impacts of stranded costs.

Regional Structure of Competition for Energy Supply and International Trade

Current research has been limited to an examination of 10 large electric regions. Dividing the nation into smaller regions - potentially to the level of the 27 NERC

[35] An initial analysis of the impact load management or changes in fuel consumption is contained in Section 3 of EPRI, *Framing Scenarios of Electricity Generation and Gas Use (TR-102946)*, July 1996.

subregions - would provide even greater insight into the fuel impacts of electric restructuring. This sharper focus also would result in a better definition of transmission bottlenecks and better highlight where the tension between the two primary fuel alternatives (i.e., coal and gas) is the greatest. While it is not necessary to analyze all 27 of the NERC subregions, further division of the most heterogeneous of the original 10 regions will help identify fuel and generation impacts that have been overlooked. This would also provide additional insights into capability of baseload and cycling units in one subregion to replace higher cost cycling and peaking generation in another subregion.

In addition, U.S. electric restructuring will likely create opportunities for its neighboring countries, namely Mexico and Canada. These countries have different electricity policies and export protocols than those being adopted in the U.S. As a result, they may be able to take advantage of certain opportunities in the restructured U.S. electric market better than participants in the U.S. This could impact power competition and fuel consumption patterns in some regions. The examination of this potential change in international competition, along with an assessment of potential transmission upgrades that could impact the import/export balance for electricity, would be beneficial in assessing the net impact on electric restructuring.

Pipelines Versus Transmission

This report provides an initial examination of question of whether it is cheaper to build new gas pipelines to transport fuel to generation facilities within load centers or to build new transmission lines to wheel power to the load center. The preliminary conclusion to be drawn was that the pipeline option was less costly, if alternative users of gas supply shared in the cost of the pipeline. This implies that there will not be a significant addition of new transmission capacity in order to increase power transfers based upon regional price differentials. However, some new transmission capacity could be built based upon reliability concerns.

While this is a relatively important insight, this initial analysis was done on a generic basis without any consideration to site specific or case specific factors which vary considerable from region to region. Additional analyses on the economic tradeoffs of these two alternatives, which systematically evaluated a variety of site specific and case specific situations and developed a checklist of how to make the appropriate assessments, would provide additional insight into and test the robustness of this conclusion concerning the addition (i.e., lack of) of new transmission capacity and consequently increased levels of power transfers between regions.

Beyond the engineering assessment, the political and institutional factors need to be appreciated. Indeed, the entire process for capital investment in new transmission is an open question. EPAct made utilities responsive to requests for new transmission (i.e., specific path on long-term basis), however, most commercial operations are conducted only weekly to days ahead across varying transmission paths. Power marketers commitments to underwrite or guarantee the use of new transmission is unlikely. In addition, transmission providers face uphill battles in pushing projects that may cross the jurisdictions of many states - for which native load customers of those states could receive little benefit.

Independent System Operators and Growth of TTC

One of the most surprising results of our inquiries was the uncertainty that exists concerning the nature and development of a regional ISO, as ISOs are a central issue to future utilization of transmission capacity and interregional power flows. For the few ISOs that have been formed to date there are sharp differences on a variety of issues (e.g., governance, tariffs, structure, and congestion relief). The timetable for the remaining regional ISOs and resolution of these issues for them are unknowns at this time. Furthermore, a few regions (i.e., SPP) have been restructured as utilities have opted to leave one NERC region and join another for a variety of reasons. Such reformation of regional pools will likely impact regional fuel consumption to some degree. Comparing and contrasting how these issues are eventually resolved by the regional ISOs and then assessing their net impact on power transfers and fuel consumption would further advance understanding of the timetables and regional nature of electric restructuring and implications for power competition, generation and fuel utilization.

Examination of Economic Window of Power Trading

The lambda and load correlation analysis presented in Section 4 provided some tantalizing glimpses of hourly power trading activity throughout the country as of 1995. Further examination of the evolution of power trading is possible using an adaptation of the lambda and load correlation technique and other tools. The approach would be to examine the marginal supply curves, power flows, transmission capabilities, seasonal and distribution factors, etc. for one selected region and compare these to the strength of power linkages indicated by the lambda and load correlation analysis. This research would document the growth of the hourly power trading market over time in response to economic conditions and transmission constraints. Concentrating on one or selected regions would allow for a more detailed understanding of hourly intra-regional power market dynamics.

Alternative Scenarios

Most of the research on electric restructuring has focused on a relatively smooth transition from regulated to a largely non-regulated electric power industry and, in general, has assumed a business as usual scenario. This approach was necessary because of the large number of issues that were examined, in order to gain an understanding of electric restructuring and its impact on fuel markets. However, the subject matter is very dynamic and there are still a number of uncertainties concerning restructuring. As a result, there are a number of other scenarios, which may evolve for electric restructuring, some of which have materialized because of the occurrence of other events. While none of these alternative scenarios are currently the most likely scenario for electric restructuring, they are highly plausible scenarios given certain outcomes for these various uncertainties.

Several of these alternative scenarios are briefly reviewed in order to stimulate the thinking of industry participants and prepare them for unexpected outcomes.

Economic Disappointment

There is the possibility that due to timing, electric restructuring will be an economic disappointment to many, if not most, customers. This possibility could emerge under the following sequence of events. Marginal costs climb rapidly and exceed average costs just when new capacity is needed. In addition, incumbents are allowed to offer transitional 'standard offer' services which new entrants can't beat. Also, the anticipated financial dividend that is supposed to evolve from electric restructuring is spent many times (e.g., to subsidize demand side management and/or renewable generation). Furthermore, the avoidable generation portion of an unbundled electric bill turns out to be quite small (i.e., 10 to 20 percent). A 20 percent saving in generation could represent only a two to four percent savings in the total unbundled electric bill. As a result, any generation saving turns out to negligible or is totally offset by increases in the unavoidable portion (e.g., transmission surcharges for stranded cost recovery and/or subsidies for programs). Under some combination of these events, customers do not receive any significant reduction in their retail electric bill and come to view the alleged benefits of electric restructuring are a myth. Disenchantment could grow further as costs of new environmental compliance initiatives are passed along.

No Advantage For Fuel Suppliers

This series of reports has focused on the potential impacts of electric restructuring on generation and fuel markets and attempted to provide insights into the competitive advantages of each of the fuels. However, even in the case where a fuel gains market share, electric restructuring could be a disappointment for the suppliers of that fuel. This occurs under the scenario that over-building and over-discounting by eager new entrants occurs. This is advantageous for customers; however, fuel suppliers and transporters are pressured into sharing generation risks in order to achieve greater dispatch. Bearing this additional risk in an environment of excess capacity would place a greater burden on fuel suppliers and could lower their financial results. Under this scenario fully depreciated plants are likely to achieve better results as margins are razor thin (i.e., for a depreciated plant any electric price above variable costs provides profits, whereas relatively new facilities must use this difference for both return of and return on capital investment). Over time this scenario could result in a further consolidation of fuel suppliers and changes in the terms of fuel contract arrangements. Both of these latter items bear watching.

Long Delays

The real economic benefits of restructuring, other than short-term regulatory adjustments, are likely to be derived from the following areas:

- *More Efficient Pricing*: The change to time of use pricing is likely to result in more efficient utilization of electricity by the customer. This would include the use of new appliances, better home energy management and various other means to reduce expensive peak demand requirements, with the net result being lower overall electric bills.
- *Capital Commitments*: One of the disadvantages of the regulated environment for the industry was considerable over expansion as a result of large incremental capacity additions which exceeded incremental demand. This inefficient use of capital was embedded in the cost of electricity to the customer. In the restructured industry capital additions for supply are most likely to match incremental demand requirements, as the market place will bear the cost of inefficient lumpy capital additions. The net result will be lower overall cost.
- *New Technologies*: Fuel utilization is likely to improve significantly as old, less efficient (i.e., high heat rate) units are replaced by new, more efficient technologies (e.g., combined cycle and distributed generation technologies). This too should lower overall cost.

While the benefits in each of these areas represents real economic gains for the industry, it may be many years before they are fully realized and passed on to the customer. It will likely take years to turn over the capital stock of the industry and change customer behavior. As a result, the significant tangible benefits of electric restructuring will likely not occur in the near term, but be realized much later.

Third Competitor Emerges For Utility Fuel Markets

In the most likely scenario for electric restructuring the battle for market share for fuel consumption for power generation will be fought between coal and gas. However, if electric restructuring is used as a platform to advance certain global warming policies, it is possible that a third competitor could emerge in this battle for electric utility fuel consumption market share. For example, the use of large tax subsidies to stimulate increased utilization of renewables on a non-dispatchable basis could evolve and the growth in renewables could be explosive, as was the case for unconventional gas supplies when the Section 29 tax credit was used to promote their development. This potential growth in renewables is similar to what occurred in California during the early stages of the PURPA programs in that state. Another example would be the increased use of nuclear generation in order to meet CO_2 limits. This could slow down or preclude any additional retirements of existing nuclear plants and further enhance nuclear's high capacity factors for these units. The net result is that the battle between coal and gas for market share may become secondary events as both of these fuels are squeezed out of future growth opportunities.

Electric Restructuring: A Common Definition?

Electric restructuring means different things to different people. It is plausible that the various stakeholders never agree on a common definition and/or implementation program for electric restructuring. In this scenario federal legislation never passes or is non-specific. As a result, a series of state statutes, which are based upon regional characteristics, dominate electric restructuring. Similarly, regional ISOs evolve to meet the unique needs and characteristics of each region. The net impact on fuels becomes highly regionalized and can't be examined on a generic basis.

Politics Race Ahead Of Science

This is somewhat of a disaster scenario for electric restructuring which raises concerns over the pace of restructuring and the ability of the industry to absorb mandates from those in the political arena that lack expertise on certain critical aspects of the industry. In this scenario new definitions of reliability begin to emerge, but they are not universally accepted. This, in turn, precipitates a major event or series of events in the industry, potentially of the magnitude of the 1965 blackout. For example, control areas can't handle a dramatic increase in transactional volumes; or marketing programs result in inadequate deliveries of power during a period of stress. The net result is the nation or specific regions retrench and readopt historical solutions akin to the current regulated environment. In this case, there potentially could be a much longer horizon for restructuring to reach its intended potential of greater efficiency in generation, and for restructuring-driven changes in fuel use (i.e., even if modest) to play out.

Summary: A Final Message

Suffice it to say that the above discussion of alternative scenarios is by no means a full accounting of the political, institutional and technical factors clouding the future. As a result, readers are cautioned not to be too dogmatic or limit the range of views about future market effects. The best of models and most precise representations of industry circumstances will always be relied upon for insights, but must be taken within the context of specific business and political conditions. Thus, the authors underscore the need to bring a continuing appreciation of the dynamism and uncertainty associated with such analyses.

A

LOAD AND LAMBDA CORRELATION METHODOLOGY DEVELOPMENT

Introduction

This Appendix documents the development of the methodology used in determining the load and lambda correlations. In addition, the list of full-year 1995 lambda and load correlations performed is also provided. The actual lambda and load plots may be viewed from the CD-ROM enclosed. The CD-ROM also contains an expanded, graphical description of the methodology, showing how a specific point on the load and lambda correlation plot is derived.

Methodology Development

The purpose of the lambda and load correlation plots is to show at what combinations of load levels that two utilities engage in economic trading of power. The two utilities used as the test case are Southern California Edison (SCE) as utility A and Sierra Pacific Power (SPP) as utility B.

The diversity of loads between utility A and utility B can be seen in Figure A-1. In this exhibit, utility A's loads are sorted highest to lowest with the contemporaneous utility B's loads also plotted. From this plot it can be seen that utility B load varies about 200 MW, or about 20%, for a given level of utility A's load.

Figure A-2 shows a scatter diagram of A's and B's load throughout the year. Each point in Figure A-2 represents the observed simultaneous loads for each control area for a single hour. The "Equal Increments" approach takes a subset of the data which is defined as all observations within a small increment along both utilities' load curve and then calculates $\rho_{\lambda_A,\lambda_B}$ using all observations falling with that range.

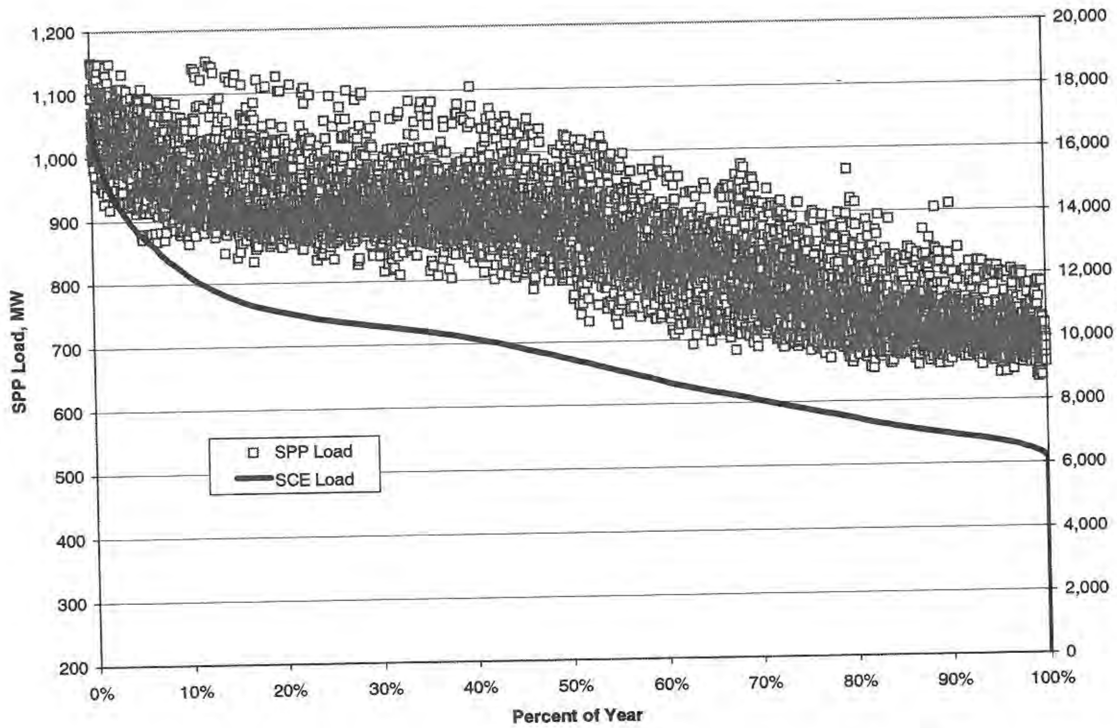

Figure A-1

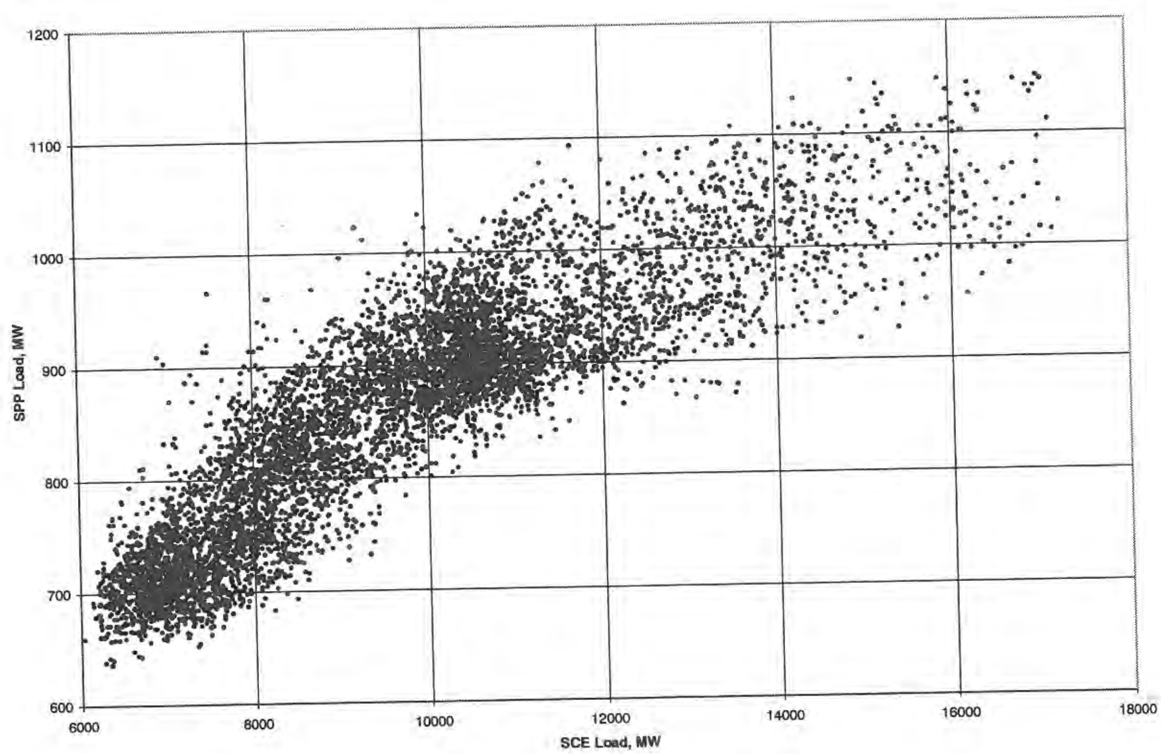

Figure A-2

The methodology is summarized as follows:

Step 1: Find the maximum and non-zero minimum loads for each utility.

Step 2: Calculate the increment in MWs for utility A & B that correspond to 0.5%[1] of the range between the minimum and maximum loads.

Step 3: Starting with L_A and L_B at their minimums select all observations within four times the increment away from L_A and L_B.[2]

Step 4: Calculate the mean of L_A, the mean of L_B and $\rho_{\lambda_A,\lambda_B}$

Step 5: Repeat Steps 3 and 4 at increasing levels of L_A and L_B by the increments calculated in Step 2.

In order to provide the necessary resolution it is necessary to plot many points representing the average loads and the observed correlations. In addition, it is necessary to provide "averaging" along each axis to improve the readability of the output. Figure A-3 shows the results of applying the Equal Increments approach to the A and B example.

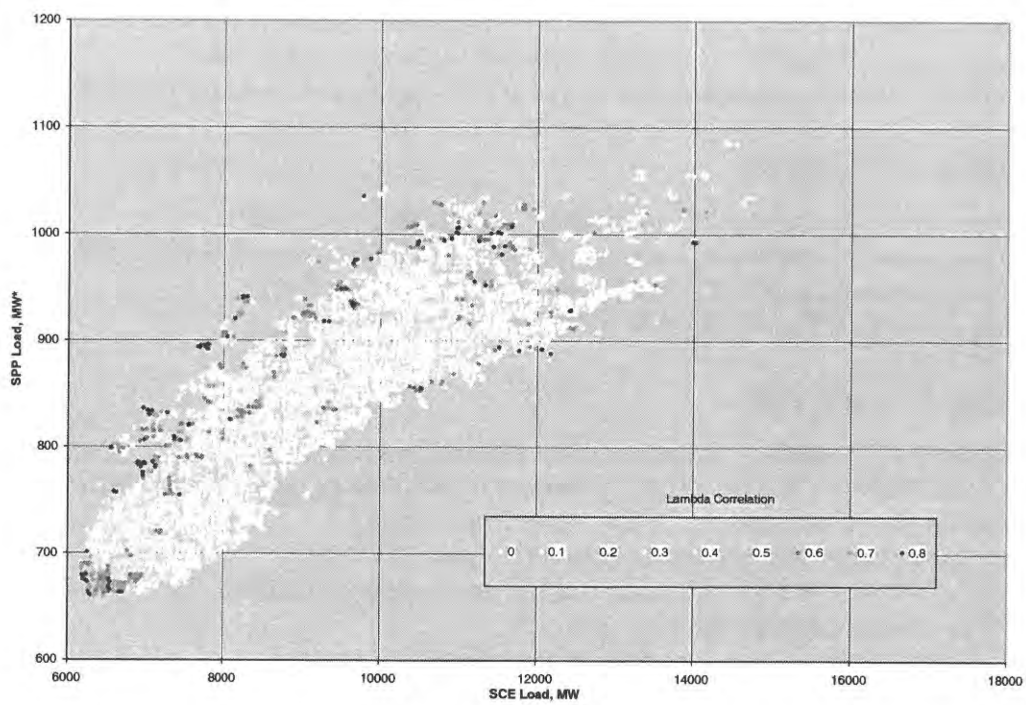

Figure A-3

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[1] This percentage may be varied to provide additional resolution or lower number of points as appropriate.

[2] Also variable.

LAMBDA AND LOAD ANALYSIS CORRELATION PLOTS (Available on CD ROM)

ECAR Lambda Correlations

1. American Electric Power System (AEP) - Central Illinois Public Service (CIPS)
2. American Electric Power System (AEP) - Cinergy Corporation (Cincinnati Gas & Electric, CGE)
3. American Electric Power System (AEP) - Commonwealth Edison Company (CECO)
4. American Electric Power System (AEP) - PA-NJ-MD Interconnection (PJM)
5. American Electric Power System (AEP) - Tennessee Valley Authority (TVA)
6. American Electric Power System (AEP) - Union Electric (UE)
7. American Electric Power System (AEP) - Virginia Electric & Power (VIEP)
8. Cinergy Corporation (PSI Energy Company, PSI) - Tennessee Valley Authority (TVA)
9. Louisville Gas & Electric (LGE) - Cinergy Corporation (PSI Energy Company, PSI)
10. Louisville Gas & Electric (LGE) - Tennessee Valley Authority (TVA)

ERCOT Lambda Correlations

1. Houston Lighting & Power (HLP) - Texas Utilities Electric Company (TUEC)
2. San Antonio City Public Service (SNT) - Houston Lighting & Power (HLP)
3. San Antonio City Public Service (SNT) - Texas Utilities Electric Company (TUEC)

MAAC Lambda Correlations

1. Allegheny Power Systems (APS) - PA-NJ-MD Interconnection (PJM)
2. Cleveland Electric Illuminating Company (CEI) - PA-NJ-MD Interconnection (PJM)
3. New York Power Pool (NYPP) - PA-NJ-MD Interconnection (PJM)
4. Virginia Power (VIEP) - PA-NJ-MD Interconnection (PJM)

MAIN Lambda Correlations

1. Big Rivers Co-Op (BREC) - Commonwealth Edison Company (CECO)
2. Central Illinois Public Service (CIPS) - Commonwealth Edison Company (CECO)
3. Central Illinois Public Service (CIPS) - Union Electric (UE)
4. Illinois Power (IP) - Commonwealth Edison Company (CECO)
5. Kentucky Utilities (KUC) - Commonwealth Edison Company (CECO)
6. Kentucky Utilities (KUC) - Illinois Power (IP)
7. Union Electric (UE) - Commonwealth Edison Company (CECO)
8. Wisconsin Electric Power (WEP) - Commonwealth Edison Company (CECO)
9. Wisconsin Power & Light (WPL) - Commonwealth Edison Company (CECO)
10. Wisconsin Public Service (WPS) - Commonwealth Edison Company (CECO)
11. Wisconsin Public Service (WPS) - Wisconsin Power & Light (WPL)
12. Western Resources (WR) - Commonwealth Edison Company (CECO)

MAPP Lambda Correlations

1. Interstate Power Company (IPC) - Commonwealth Edison Company (CECO)
2. Interstate Power Company (IPC) - Wisconsin Power & Light (WPL)

3. Lincoln Electric System (LES) - Kansas City Power & Light (KCPL)
4. Lincoln Electric System (LES) - Omaha Public Power District (OPPD)
5. Northern States Power (NSP) - Commonwealth Edison Company (CECO)
6. Northern States Power (NSP) - Illinois Power (IP)
7. Northern States Power (NSP) - Southern Minnesota Municipal Power Agency (SMMP)
8. Northern States Power (NSP) - Wisconsin Electric Power (WEP)
9. Northern States Power (NSP) - Wisconsin Power & Light (WPL)
10. Northern States Power (NSP) - Wisconsin Public Service (WPS)
11. Otter Tail Power (OTP) - Minnesota Power & Light (MPL)
12. Western Resources (WR) - Omaha Public Power District (OPPD)

NPCC Lambda Correlations

1. New York Power Pool (NYPP) - New England Power Exchange (NEPEX)

SERC/FRCC Lambda Correlations

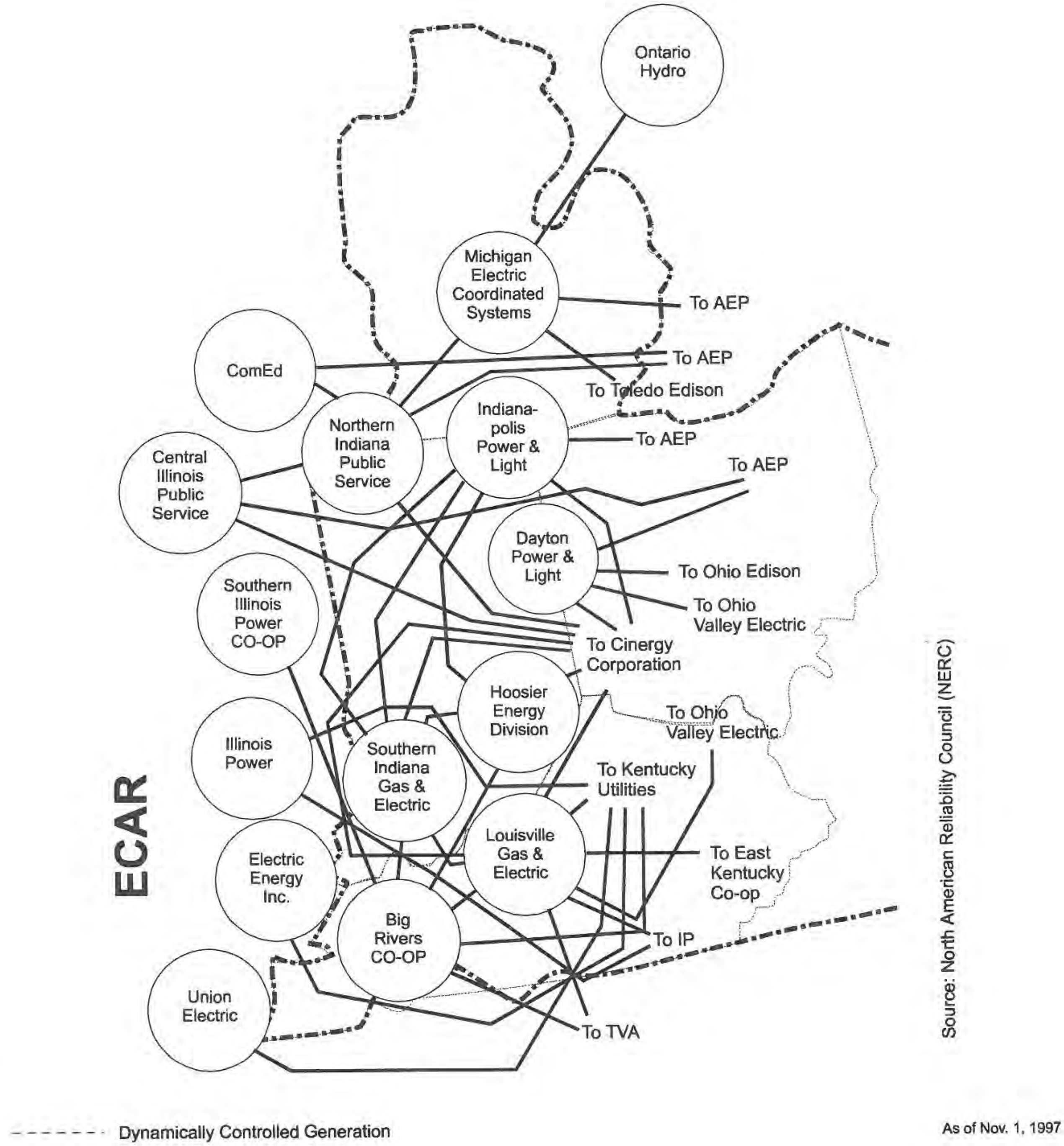
1. Duke Power Company (DUKE) - Southern Company (SOCO)
2. Duke Power Company (DUKE) - Tennessee Valley Authority (TVA)
3. Entergy (ENTR) - Southern Company (SOCO)
4. Entergy (ENTR) - Tennessee Valley Authority (TVA)
5. Florida Municipal Power Pool (Authority) (FMP) - Southern Company (SOCO)
6. Florida Power Corporation (FPC) - Southern Company (SOCO)
7. Florida Power & Light (FPL) - Southern Company (SOCO)
8. Union Electric (UE) - Tennessee Valley Authority (TVA)

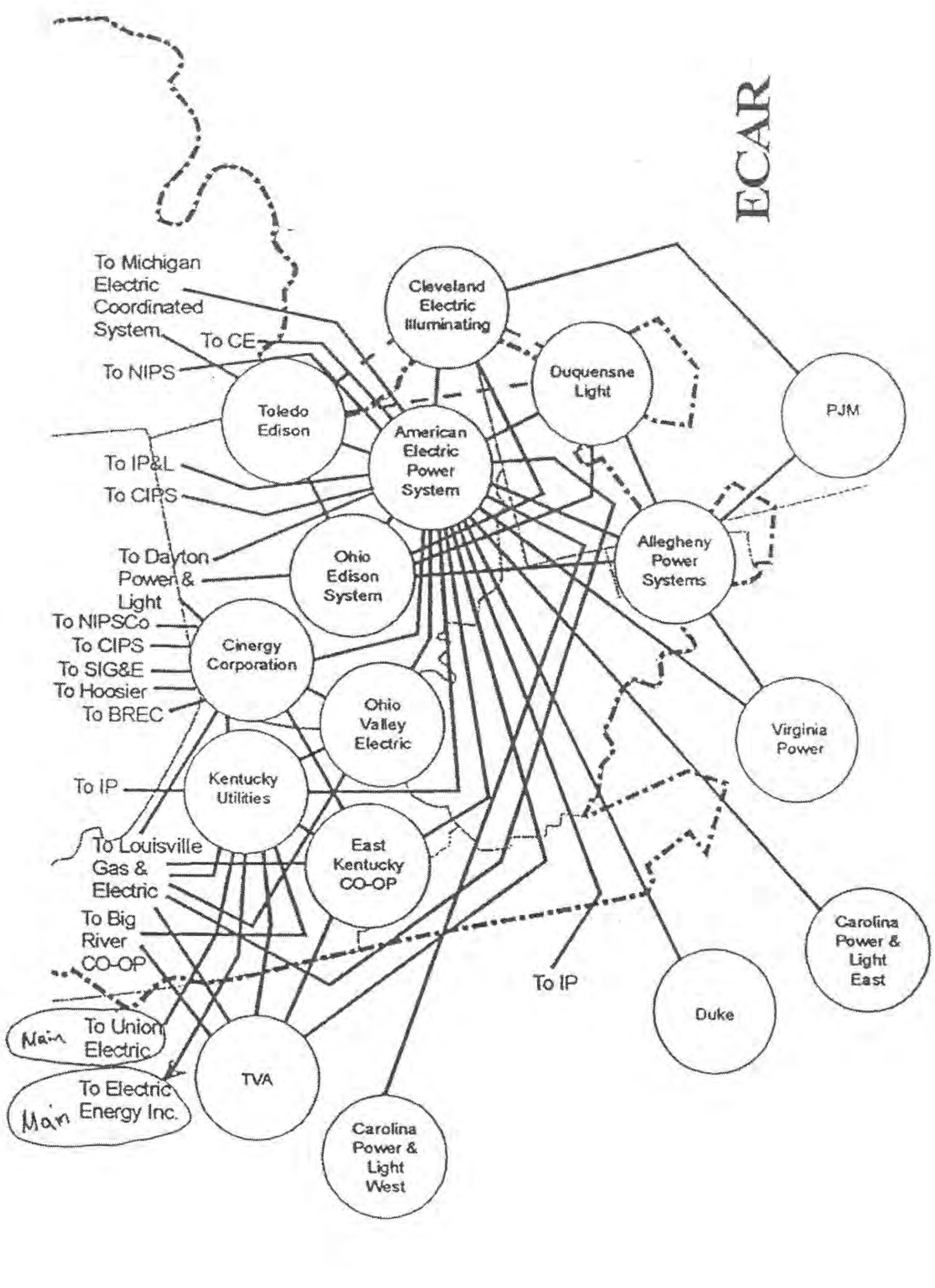
SPP Lambda Correlations

1. Entergy (ENTR) - Public Service Oklahoma (PSOK)
2. Entergy (ENTR) - Southwestern Electric Power Company (SWEP)
3. Entergy (ENTR) - Union Electric (UE)
4. Oklahoma Gas & Electric (OKGE) - Union Electric (UE)
5. Public Service Oklahoma (PSOK) - Union Electric (UE)
6. Western Resources (WR) - Kansas City Power & Light (KCPL)
7. Western Resources (WR) - Union Electric (UE)

WSCC Lambda Correlations

1. Arizona Public Service (APS) - Los Angeles Department of Water & Power (LDWP)
2. Arizona Public Service (APS) - Pacific Gas & Electric (PG&E)
3. Arizona Public Service (APS) - Public Service New Mexico (PNM)
4. Arizona Public Service (APS) - Public Service Colorado (PSC)
5. Arizona Public Service (APS) - Southern California Edison (SCE)
6. Southern California Edison (SCE) - Los Angeles Department of Water & Power (LDWP)
7. Southern California Edison (SCE) - Pacific Gas & Electric (PG&E)
8. Southern California Edison (SCE) - Public Service Colorado (PSC)
9. Southern California Edison (SCE) - San Diego Gas & Electric (SDG&E)
10. Southern California Edison (SCE) - Sierra Pacific Power (SPP)

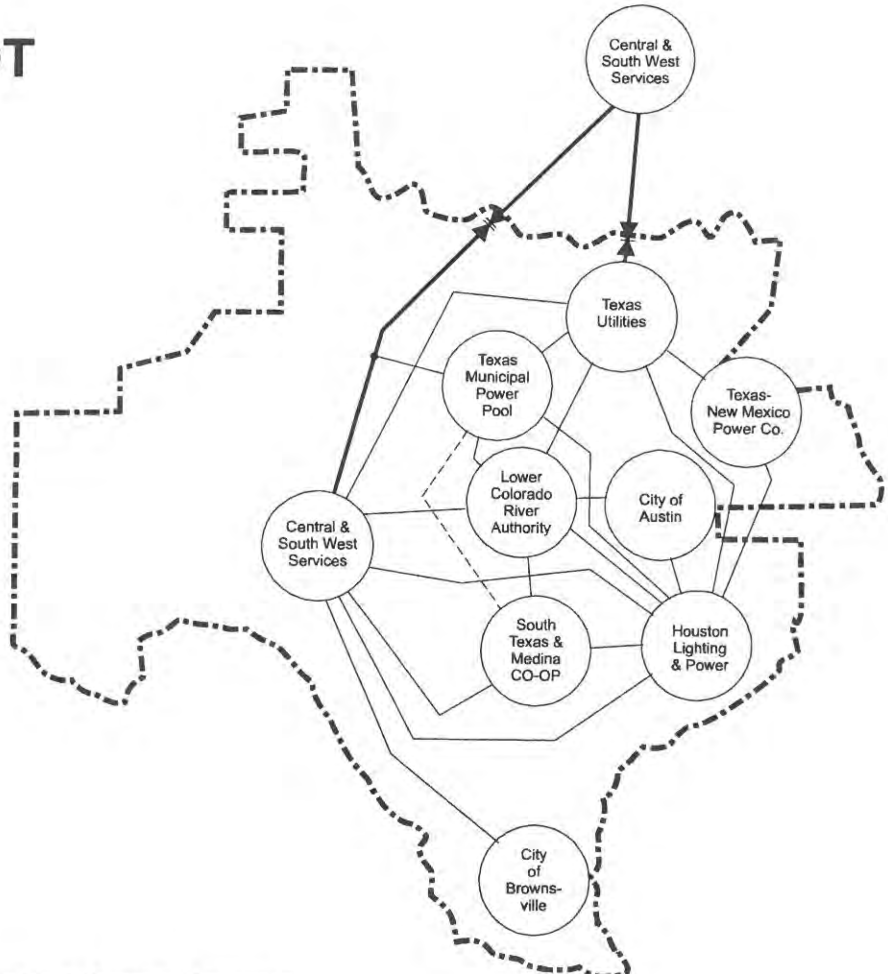

Ontario Hydro
Michigan Electric Coordinated Systems
To AEP
ComEd
To AEP
To Toledo Edison
Northern Indiana Public Service
Indiana-polis Power & Light
To AEP
To AEP
Central Illinois Public Service
Dayton Power & Light
To Ohio Edison
To Ohio Valley Electric
Southern Illinois Power CO-OP
To Cinergy Corporation
Hoosier Energy Division
To Ohio Valley Electric
Illinois Power
Southern Indiana Gas & Electric
To Kentucky Utilities
ECAR
Electric Energy Inc.
Louisville Gas & Electric
To East Kentucky Co-op
Big Rivers CO-OP
To IP
Union Electric
To TVA
Source: North American Reliability Council (NERC)
Dynamically Controlled Generation
As of Nov. 1, 1997


ECAR
To Michigan Electric Coordinated System
To CE
To NIPS
Cleveland Electric Illuminating
Duquesne Light
PJM
Toledo Edison
American Electric Power System
To IP&L
To CIPS
Allegheny Power Systems
To Dayton Power & Light
Ohio Edison System
To NIPSCo
To CIPS
To SIG&E
To Hoosier
To BREC
Cinergy Corporation
Ohio Valley Electric
Virginia Power
To IP
Kentucky Utilities
To Louisville Gas & Electric
East Kentucky CO-OP
To Big River CO-OP
Carolina Power & Light East
To IP
Duke
Main
To Union Electric
TVA
Main
To Electric Energy Inc.
Carolina Power & Light West

ECAR Utility Information			
Utility	Acronym	1995 Load Data	1995 Lambda Data
Allegheny Power Systems	APS	X	X
Duquesne Light	DLCO	X	X
American Electric Power System	AEP	X	X
Buckeye Power, Inc.	BPI	X	
Big Rivers Electric Corporation	BREC	X	X
Centerior			
Cleveland Electric Illuminating Company	CEI	X	X
Toledo Edison Company	TECO	X	X
Cinergy Corporation			
Cincinnati Gas & Electric	CGE	X	X
PSI Energy Company	PSI	X	X
Union Light Heat & Power Inc.			
Dayton Power & Light	DPL	X	PARTIAL
East Kentucky CO-OP	EKPC	X	X
Hoosier Energy Division	HEC	X	X
Indianapolis Power & Light	IPL	X	X
Kentucky Utilities	KUC	X	X
Louisville Gas & Electric	LGE	X	X
Michigan Electric Coordinated Systems			X
Northern Indiana Public Service	NIPS	X	X *
Ohio Edison System	OES	X	X
Ohio Valley Electric Corporation	OVEC	X	
Southern Indiana Gas & Electric	SIGE	X	X

* Indicates missing lambda data for periodic days

ERCOT

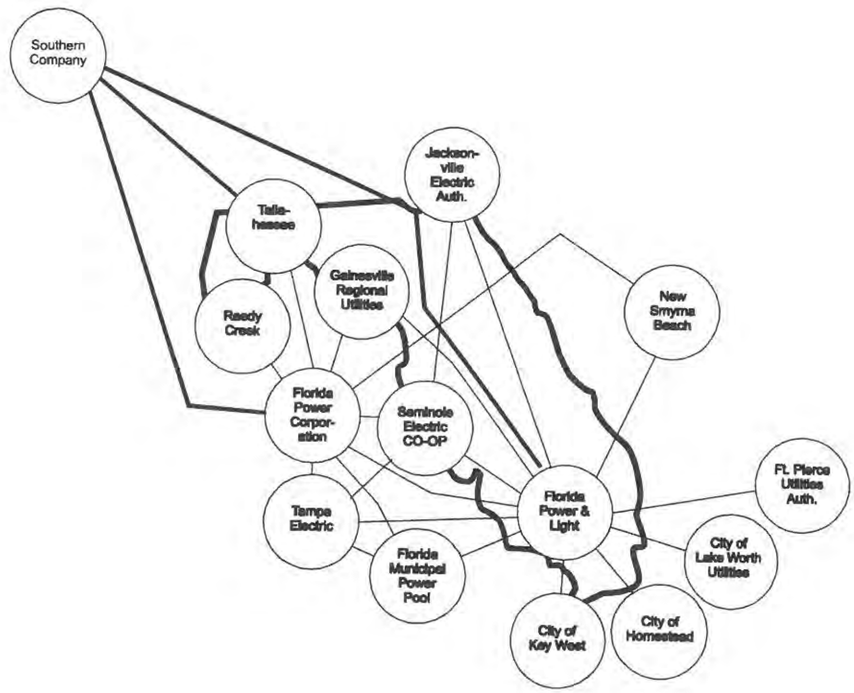


- - - - - - Dynamically Controlled Generation

Source: North American Reliability Council (NERC)

As of Nov. 1, 1997

ERCOT Utility Information			
Utility	Acronym	1995 Load Data	1995 Lambda Data
Central & Southwest Corporation	CSW		
Central Power & Light Company	CPL		X
West Texas Utilities Company	WTU		X
City of Austin			
City of Brownsville			
Houston Lighting & Power	HLP	X	X
Lower Colorado River Authority			
San Antonio City Public Service	SNT	X	X
South Texas & Medina CO-OP			
Texas Utilities			
Southwestern Electric Service Company			
Texas Utilities Electric Company	TUEC	X	X
Texas Utilities Generating Company			
Texas Municipal Power Pool			



FRCC

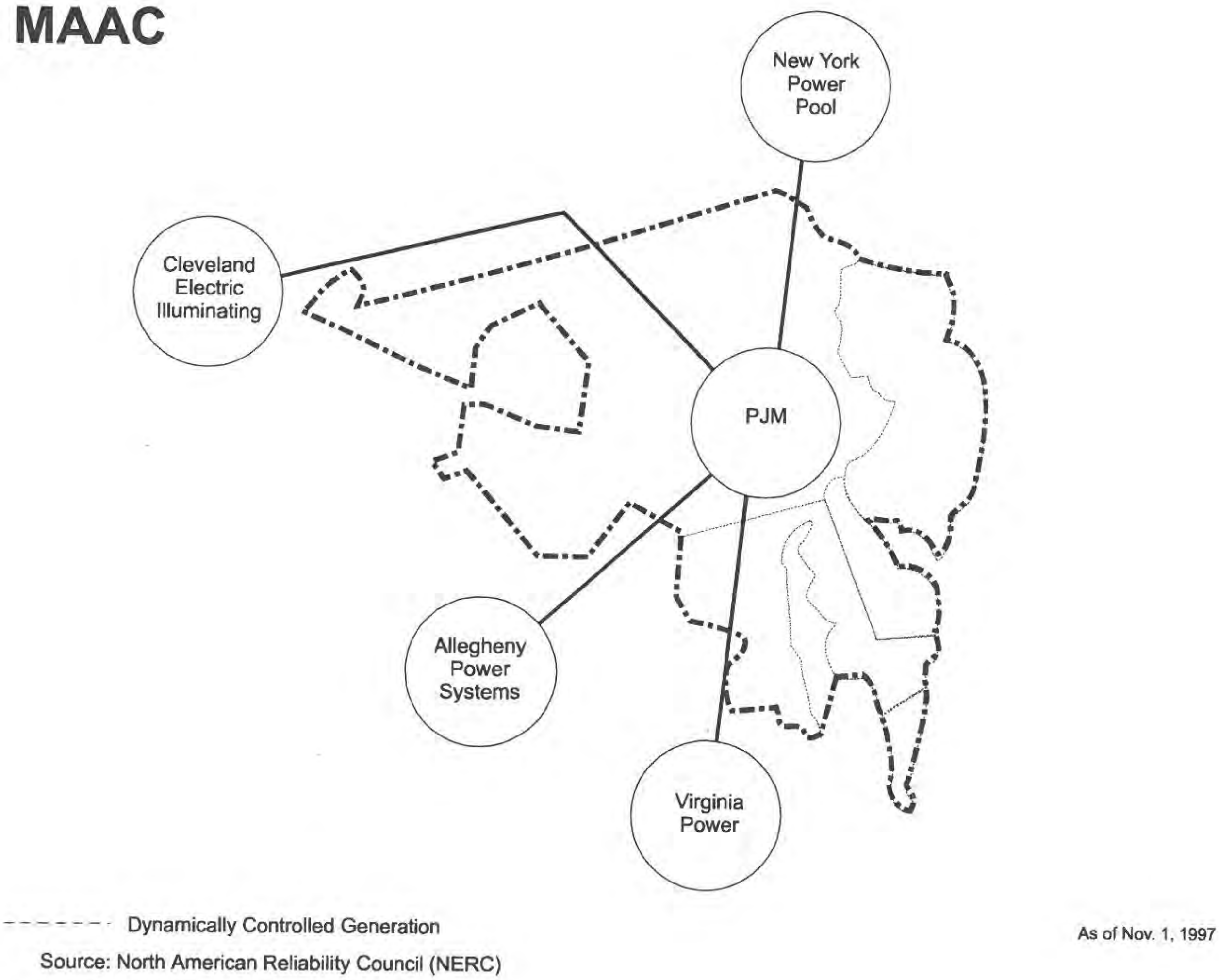
- - - - - - Dynamically Controlled Generation

Source: North American Reliability Council (NERC)

As of Nov. 1, 1997

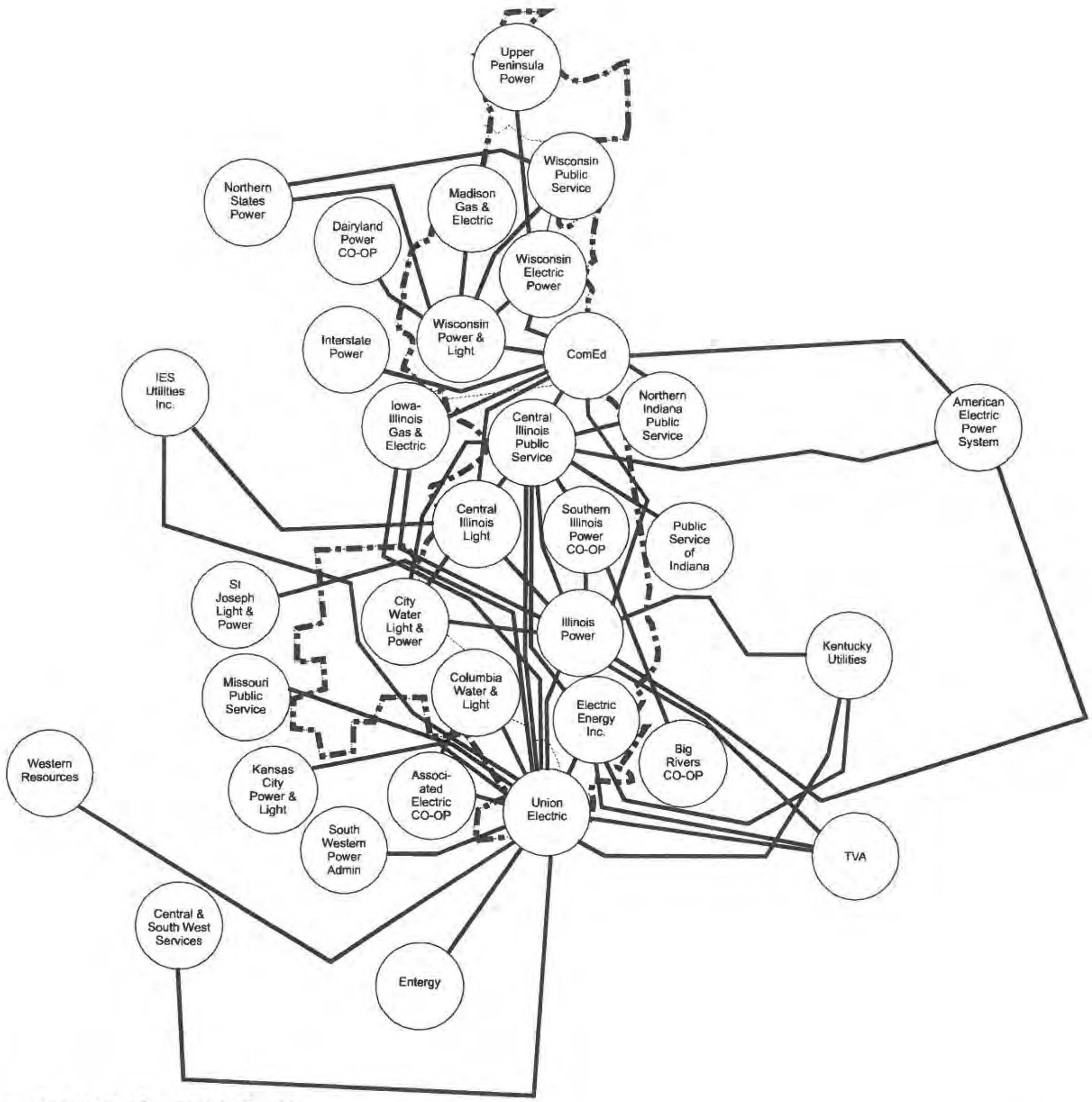
FRCC Utility Information			
Utility	**Acronym**	**1995 Load Data**	**1995 Lambda Data**
City of Homestead			
City of Starke			
Florida Municipal Power Pool (Agency)	FMPA	X	X
City of Key West			
City of Lake Worth Utilities	LALW		
Ft. Pierce Utilities Auth.			
Vero Beach	VERO	X	
Florida Power & Light	FP&L	X	X
Florida Power Corporation	FPC	X	X
Gainesville Regional Utilities	GAIN	X	X
Jacksonville Electric Authority	JEA		X
Kissimmee Utility - - -			
New Smyrna Beach			
Reedy Creek			
Seminole Electric CO-OP			
Tallahassee	TAL	X	X
Tampa Electric	TECO	X	X

MAAC


New York
Power
Pool
Cleveland
Electric
Illuminating
PJM
Allegheny
Power
Systems
Virginia
Power
Dynamically Controlled Generation
Source: North American Reliability Council (NERC)
As of Nov. 1, 1997

MAAC Utility Information			
Utility	Acronym	1995 Load Data	1995 Lambda Data
PA-NJ-MD Interconnection	PJM	X	X

MAIN

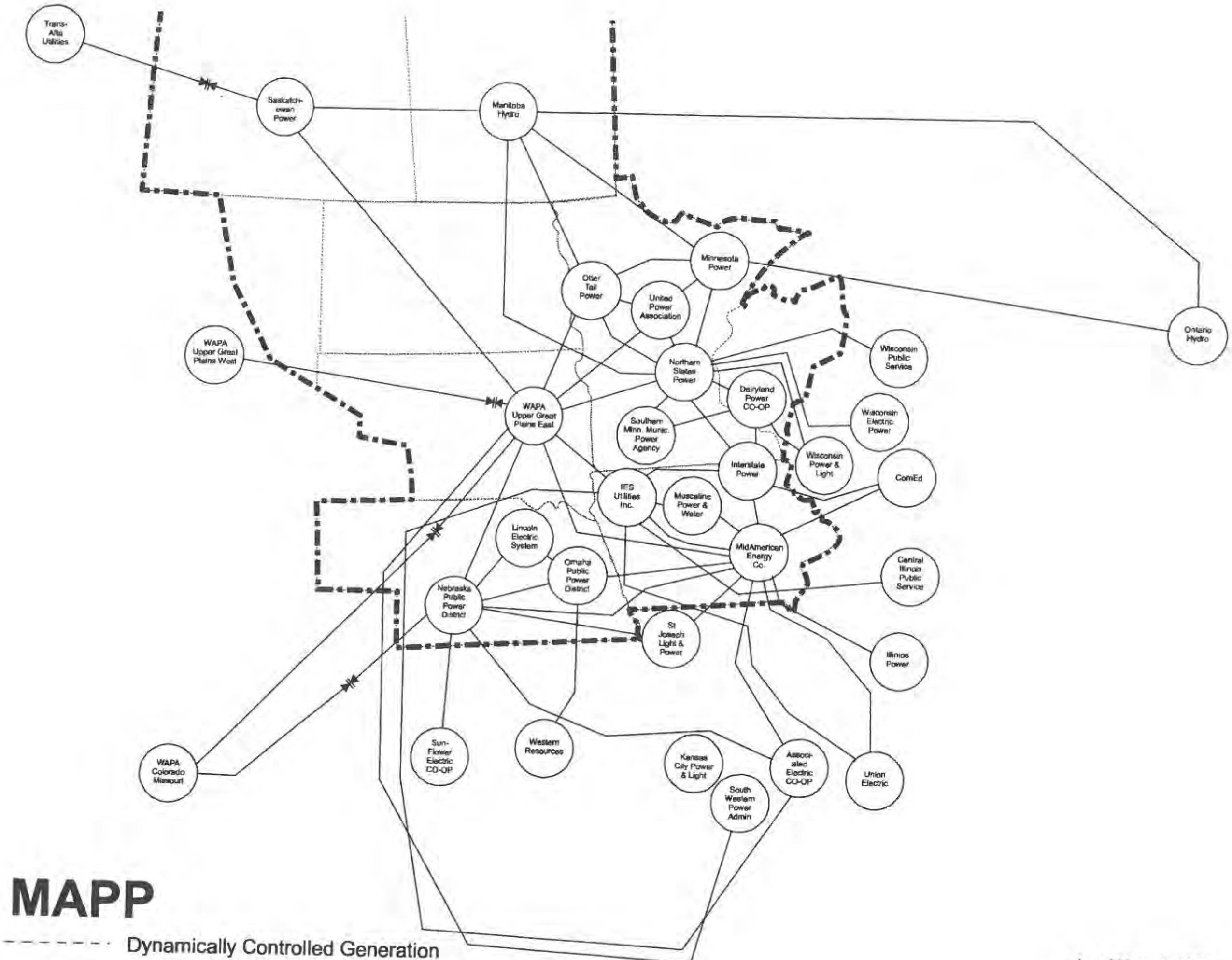


Source: North American Reliability Council (NERC)

- - - - - - Dynamically Controlled Generation

As of Nov. 1, 1997

MAIN Utility Information			
Utility	Acronym	1995 Load Data	1995 Lambda Data
Central Illinois Light	CILC	X	X
Central Illinois Public Service	CIPS	X	X
City Water Light & Power	CWLP	X	X
Columbia Water & Light			
ComEd	CECO	X	X
Electric Energy Inc.	ELEC	X	X
Illinois Power (ILLINOVA)	IP	X	X
Madison Gas & Electric	MGE	X	X
Southern Illinois Power CO-OP	SIPC	X	X
Springfield, Illinois CWPL	SPIL	X	X
Union Electric	UE	X	X
Upper Peninsula Power			
Wisconsin Energy Corporation			
Wisconsin Electric Power	WEP	X	X
Wisconsin Power & Light	WPL	X	X
Wisconsin Public Service	WPS	X	X



MAPP

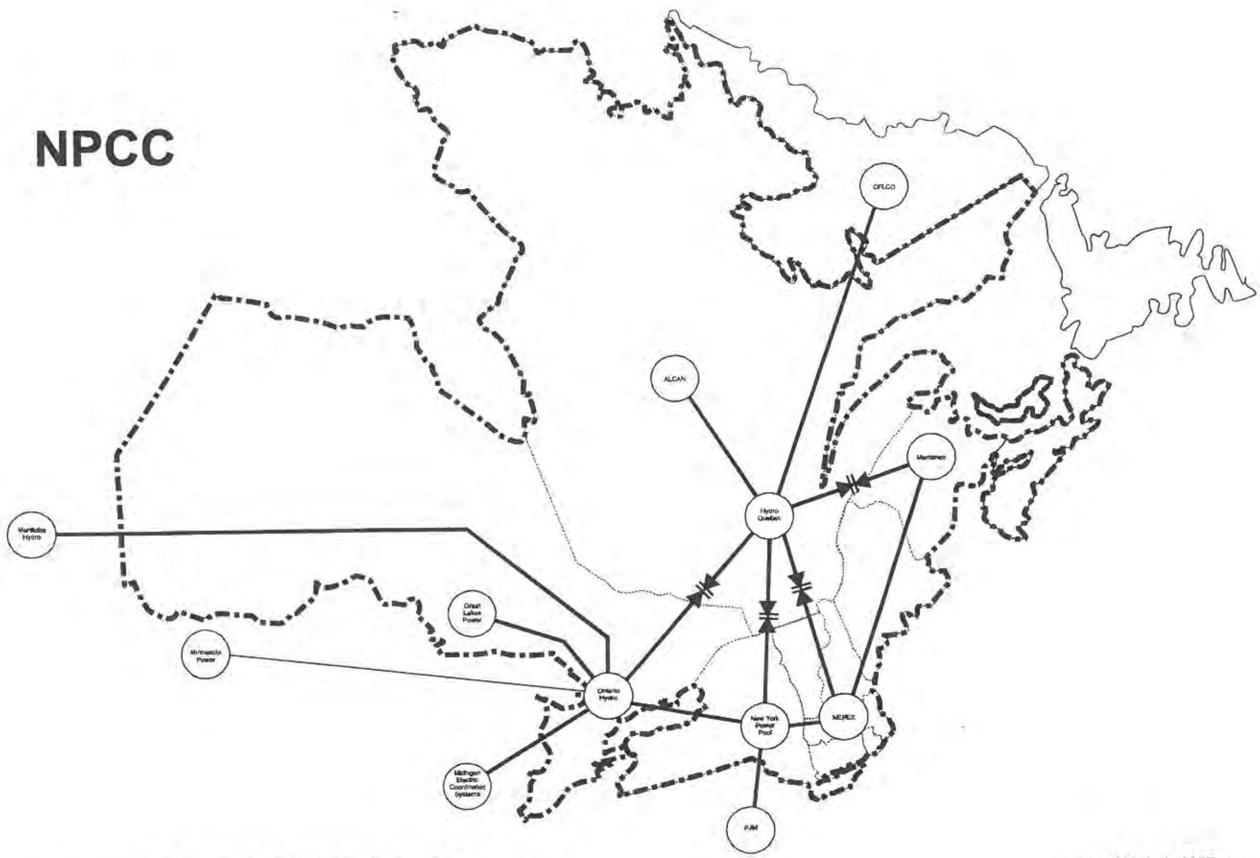
- - - - - - - Dynamically Controlled Generation

Source: North American Reliability Council (NERC)

As of Nov. 1, 1997

MAPP Utility Information			
Utility	**Acronym**	**1995 Load Data**	**1995 Lambda Data**
Dairyland Power CO-OP	DPC		X
IES Utilities Inc.	IES		Ends 12/3/95
Lincoln Electric System	LES	X	X
Manitoba Hydro			
MidAmerican Electric Co.	MAEC		
Interstate Power	IPC	X	X
Iowa Illinois Gas & Electric	IIGE	Ends 8/31/95	Ends 7/31/95
Midwest Energy Co.	MEC	X	
Minnesota Power & Light	MPL	X	X
Muscatine Power & Water	MPW	X	X
Nebraska Public Power District	NPPD	X	
Northern States Power (3 Divisions)	NSP	X	X
Omaha Public Power District	OPPD	X	X
Otter Tail Power	OTP	X	X
Saskatchewan Power			
Southern Minnesota Municipal Power Agency	SMMP	X	X
United Power Association	UPA		
WAPA Upper Great Plains East	WAPA	X	

NPCC

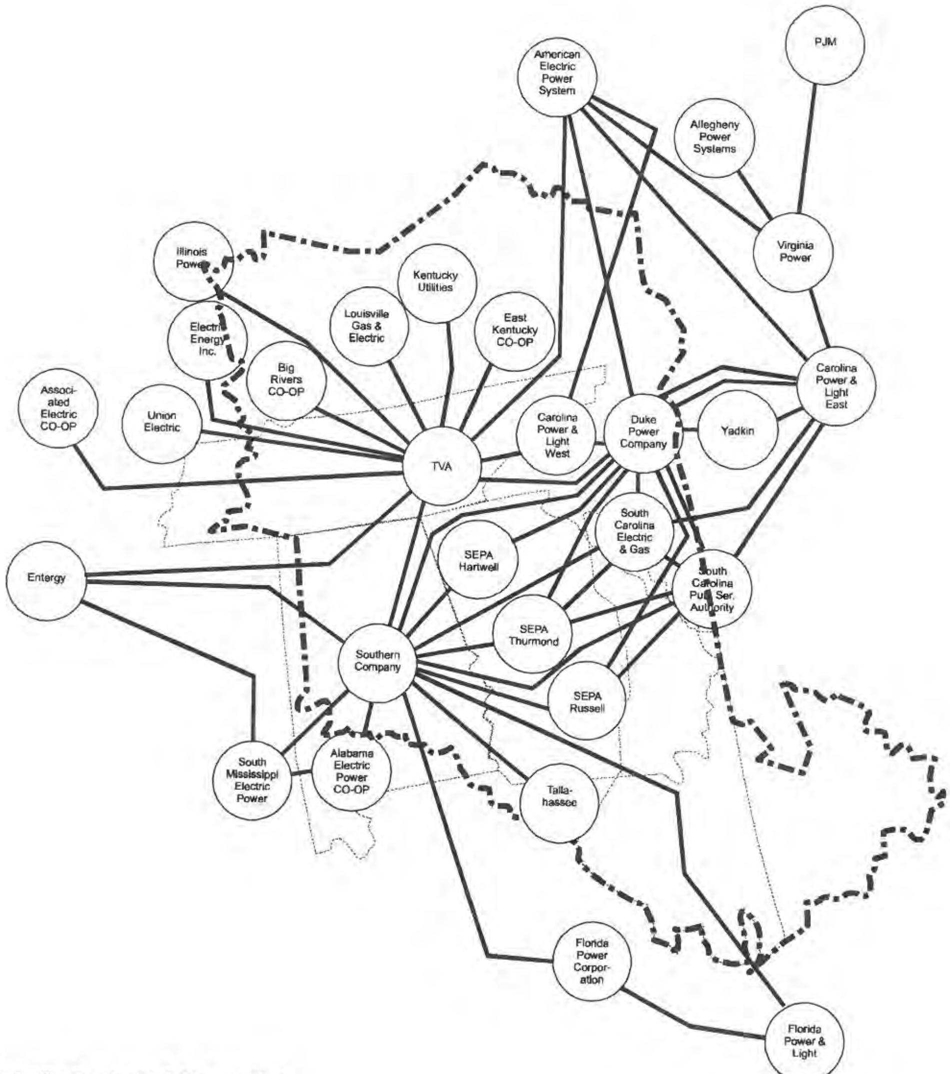


- - - - - - - Dynamically Controlled Generation

As of Nov. 1, 1997

Source: North American Reliability Council (NERC)

NPCC Utility Information			
Utility	**Acronym**	**1995 Load Data**	**1995 Lambda Data**
New England Power Exchange	NEPEX	X	X
Boston Edison Company	BECO	X	X
Bangor Hydro Electric Company	BHE	X	X
Central Maine Power Company	CMPC	X	X
Commonwealth Energy System			
Cambridge electric Light Company	CAMB	X	X
Canal Electric Company			
Commonwealth Electric Company	COMW	X	X
Eastern Utilities Association	EUA	X	X
Massachusettes Municipal Electric Company	MMWC	X	X
Northeast Utilities	NU	X	X
United Illuminating	UI	X	X
VELCO-Green Mountain Power	GMP	X	X
New York Power Pool	NYPP	X	X
Central Hudson Gas & Electric	CHGE	X	X
Consolidated Edison Company of NY, Inc.	COED	X	X
Long Island Lighting Company	LILC	X	X
New York State Electric & Gas Corporation	NYS	X	X
Niagra Mohawk Power Corporation	NMPC	X	X
Orange & Rockland Utilities, Inc.	O&R	X	X
Rochester Gas & Electric Corporation	RGE	X	X



------ Dynamically Controlled Generation

As of Nov. 1, 1997

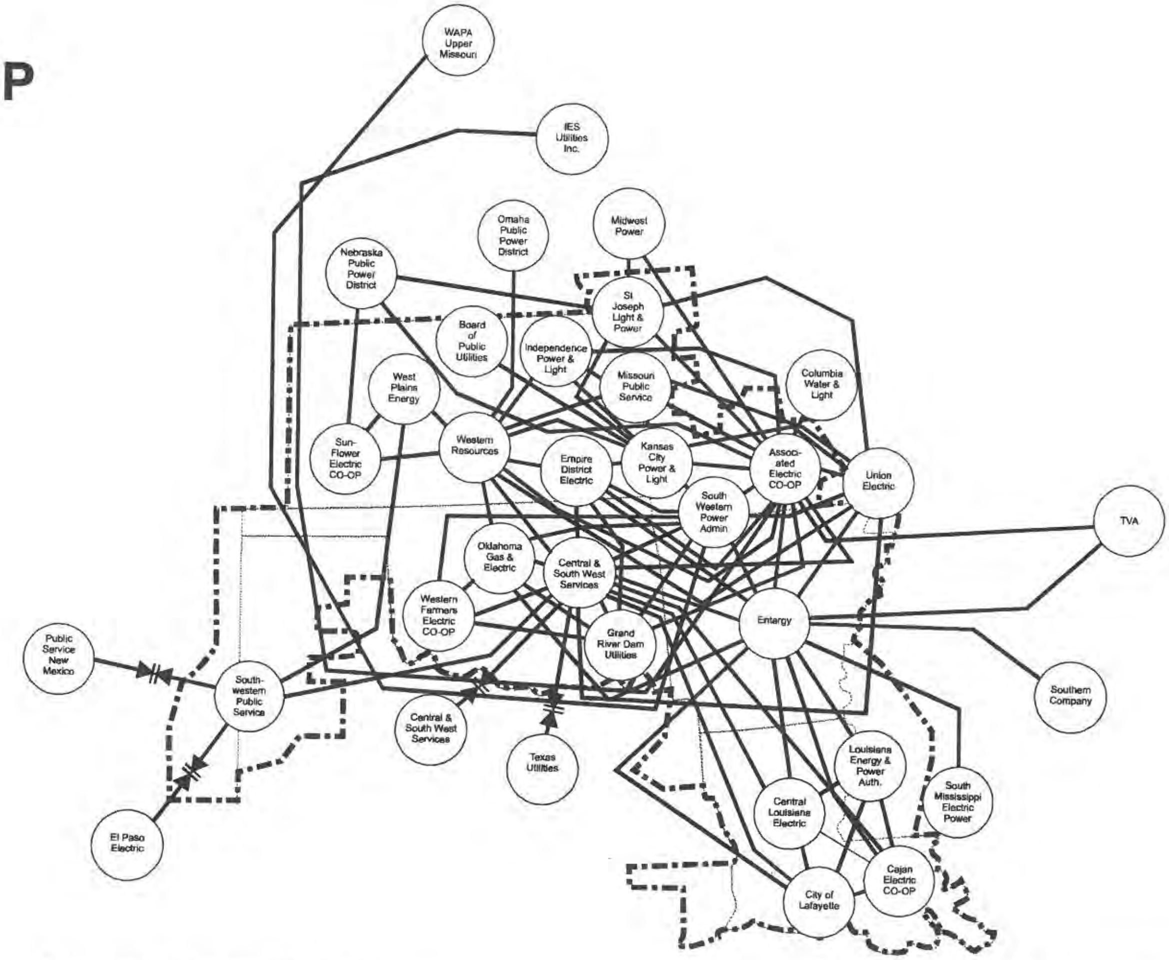
Source: North American Reliability Council (NERC)

SERC

SERC Utility Information			
Utility	**Acronym**	**1995 Load Data**	**1995 Lambda Data**
Alabama Electric Power CO-OP	AEC	X	X
Carolina Power & Light (East/West)	CP&L	X	X
Duke Power Company	DUKE	X	X
South Carolina Electric & Gas	SCEG	X	8/2/95 & ON
South Carolina Pub. Serv. Auth.	SCPS	X	X
South Mississippi Electric Power	SMEA		X
Southern Company **	SOCO	X	X
SEPA Hartwell			
SEPA Russell			
SEPA Thurmond			
Tennessee Valley Authority	TVA	X	X
Virginia Power	VIEP	X	X
Yadkin			

** SEPA may be included in SOCO

SPP

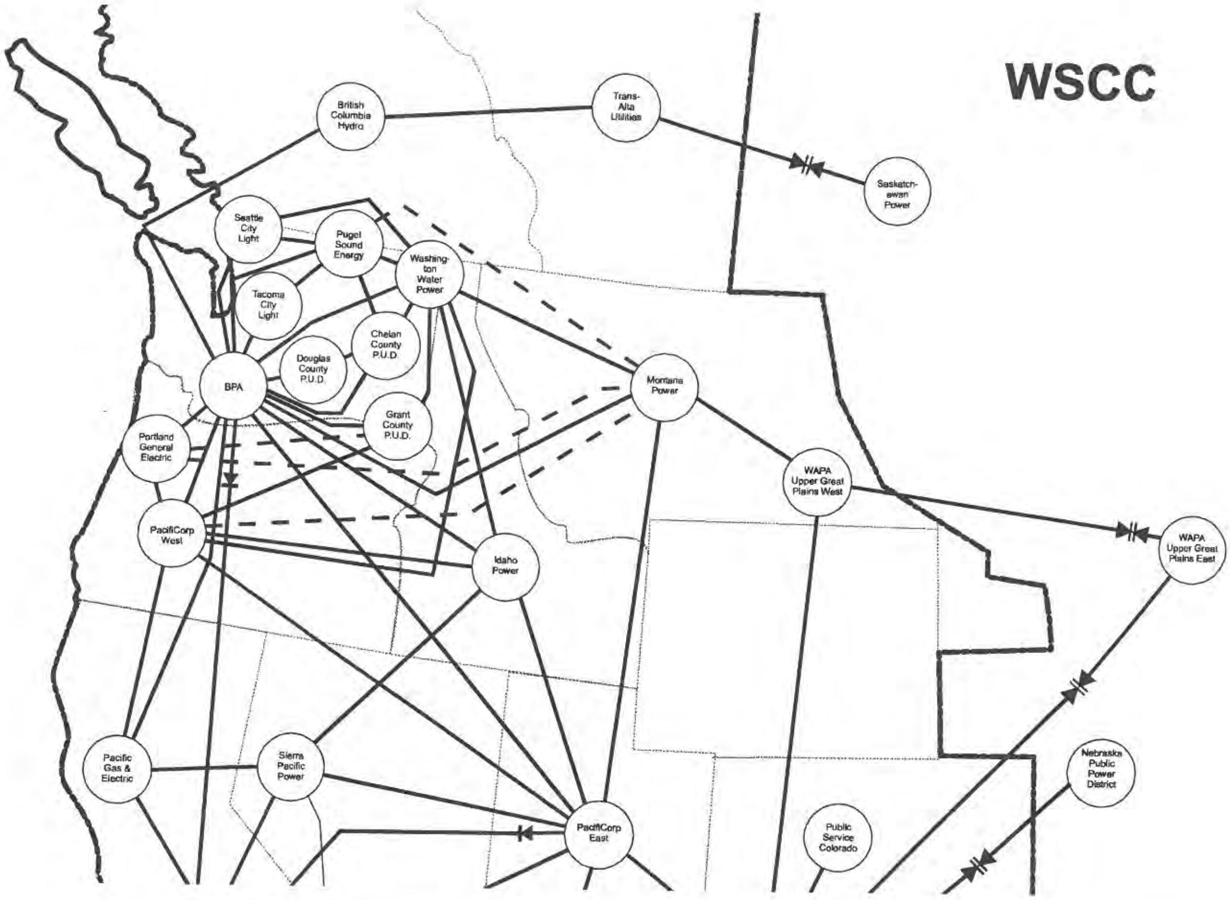


- - - - - - Dynamically Controlled Generation

Source: North American Reliability Council (NERC)

As of Nov. 1, 1997

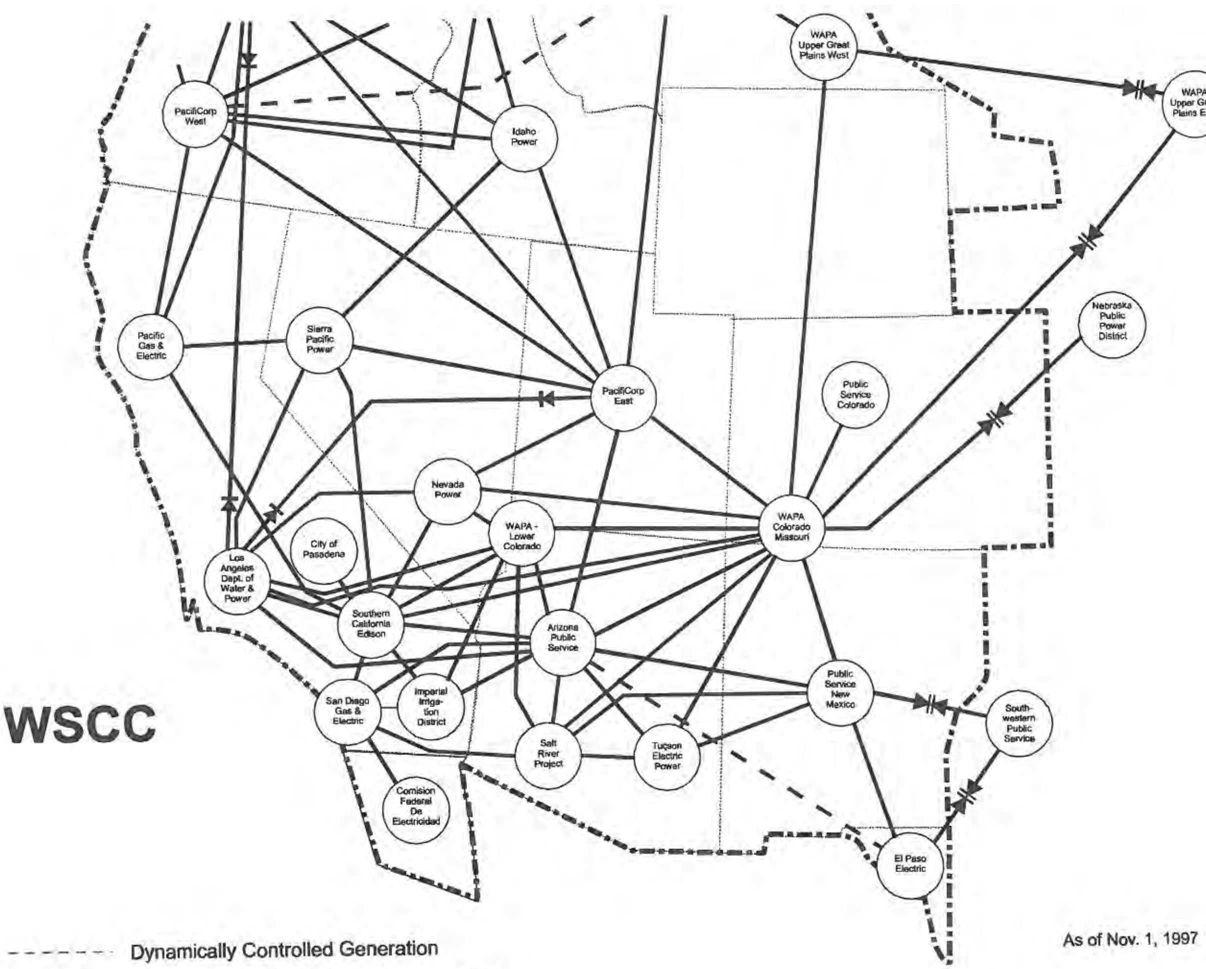
SPP Utility Information			
Utility	Acronym	1995 Load Data	1995 Lambda Data
Arkansas Electric Co. (not a control area ?)	AEC	X	
Associated Electric CO-OP		X	
Board of Public Utilities		X	
Cajun Electric CO-OP	CAJN	X	X
Central Louisiana Electric	CLEC	X	X
City of Lafayette	LUS	X	
City Power & Light, In (not a control area ?)		X	
City Utilities, Springfield, MO (not a control		X	
Empire District Electric	EMDE	X	X
Entergy	ENTR	X	X
Grand River Dam Utilities		X	
Independence Power & Light			
Kansas City Power & Light	KCPL	X	X
Louisiana Energy & Power Authority	LEPA	X	
Midwest Energy, Inc. (Mid-American)	MEC	X	
Missouri Public Service		X	
Oklahoma Gas & Electric	OKGE	X	X
Oklahoma Municipal (not a control area ?)		X	
Public Service of Oklahoma	PSOK	X	X
Southwestern Electric Power Co.	SWEP	X	X
Southwestern Power Admin		X	
Southwestern Public Service	SWPS	X	X
St. Joseph Light & Power		X	
Sunflower Electric CO-OP	SEPC	X	Incomplete
West Plains Energy	WPE	X	
Western Farmers Electric CO-OP	WFEC	X	X
Western Resources	WR	X	X



- - - - - - Dynamically Controlled Generation

Source: North American Reliability Council (NERC)

As of Nov. 1, 1997



Source: North American Reliability Council (NERC)

WSCC Utility Information

Utility	Acronym	1995 Load Data	1995 Lambda Data
Arizona Public Service	APS	X	X
BPA	BPA	X	
British Columbia Hydro	BCHA	X	
Chelan County P.U.D.	CHPD	X	
City of Pasadena	PASA	X	X
Comision Federal De Electricidad	-		
Douglas County P.U.D.	DOPD	X	
El Paso Electric	EPE	X	X
Grant County P.U.D.	GCPD	X	
Idaho Power	IPC	X	
Imperial Irrigation District	IID	X	
Los Angeles Dept. of Water & Power	LDWP	X	X
Montana Power	MPC	X	
Nevada Power	NEV	X	
Pacific Gas & Electric	PG&E	X	X
Pacificorp	PAC	X	
Portland General Electric	PGE	X	
Public Service Colorado	PSC	X	X
Public Service New Mexico	PNM	X	X
Puget Sound Power & Light	PSPL	X	
Salt River Project	SRP	X	X
San Diego Gas & Electric	SDG&E	X	X
Seattle City Light	SCL	X	
Sierra Pacific Power	SPP	X	X
Southern California Edison	SCE	X	X
Tacoma City Light	TCL	X	
Trans-Alta Utilities	TAUC	X	
Tucson Electric Power	TEP	X	
WAPA Colorado Missouri	WALM	X	
WAPA Lower Colorado	WALC	X	
WAPA Upper Great Plains West	WAMP	X	
Washington Water Power	WWPC	X	

B

SHORT-RUN DISPATCH ANALYSIS DETAILED RESULTS

Total Production Cost Savings - Northeast

Table A1-94 Total Production Cost Savings - Northeast ($ Millions)

Market Area		Total Prod. Cost Base Case (Scenario 1) [1]	Change in Total Production Cost: No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
MAAC		2,707	105.1%	-1.3%	-8.7%	-8.3%
APS		645	78.8%	-1.1%	-1.1%	0.2%
ONTARIO		899	82.7%	-7.9%	19.8%	9.8%
ECAR		3,384	95.3%	4.8%	10.5%	17.1%
CAPC		871	86.5%	1.9%	4.9%	8.0%
NYPP		1,652	126.4%	0.5%	-17.5%	-19.8%
NEPL		1,277	115.5%	-4.6%	-11.3%	-41.8%
VACAR		2,324	111.3%	-1.5%	-1.9%	5.2%
Total Production Cost	[6]	13,758	14,222	13,736	13,613	13,532
Change in Total Production Cost from Base Case	[7]		3.4%	-0.2%	-1.0%	-1.6%

Market Area		Net Prod. Cost Base Case (Scenario 1) [8]	Change in Net Production Cost: No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
MAAC		2,838	0.2%	-0.3%	-98.0%	-2.2%
APS		493	3.1%	0.4%	-68.8%	-0.1%
ONTARIO		707	5.2%	0.9%	-56.2%	-3.3%
ECAR		3,210	0.4%	-0.1%	-74.6%	-1.7%
CAPC		746	1.0%	-0.7%	-72.0%	-1.6%
NYPP		2,087	0.1%	-0.7%	-100.0%	-4.8%
NEPL		1,464	0.8%	-0.3%	-99.9%	-7.0%
VACAR		2,575	0.5%	-0.2%	-95.1%	-0.3%
Net Production Cost	[13]	14,118	14,222	14,084	13,856	13,756
Change in TC from Base Case	[14]		0.7%	-0.2%	-1.9%	-2.6%

Sources & Notes:
Base Scenario -- TXs and Fees.

[1]Table A2-94, column [2].
[2]Table A2-94, column [1]/[1]-1.
[3]Table A2-94, column [6]/[1]-1.
[4]Table A2-94, column [10]/[1]-1.
[5]Table A2-94, column [14]/[1]-1.
[8]Table A2-94, column [9].

[9]Table A2-94, column [1]/[1]-1.
[10]Table A2-94, column [9]/[1]-1.
[11]Table A2-94, column [13]/[1]-1.
[12]Table A2-94, column [17]/[1]-1.
[6] and [13]Table A2-94.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table A2-94 1994 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade	Scenario 1 Base Case				Scenario 3 TXs Only			
	Production Cost [1]	Production Cost [2]	Import [3]	Export [4]	Net Cost [5] =[2]+[3]-[4]	Production Cost [6]	Import [7]	Export [8]	Net Cost [9] =[6]+[7]-[8]
MAAC	2,844	2,707	203	73	2,838	2,671	206	48	2,829
APS	508	645	0	152	493	637	1	143	495
ONTARIO	744	899	28	220	707	827	19	133	713
ECAR	3,223	3,384	84	258	3,210	3,546	13	354	3,205
CAPC	753	871	4	129	746	887	6	154	740
NYPP	2,088	1,652	453	19	2,087	1,660	425	13	2,072
NEPL	1,476	1,277	195	8	1,464	1,218	256	15	1,459
VACAR	2,587	2,324	289	39	2,575	2,289	311	29	2,570
Total	14,222	13,758	1,258	897	14,118	13,736	1,237	889	14,084

Market Area	Scenario 4 Fees Only				Scenario 5 Free Trade			
	Production Cost [10]	Import [11]	Export [12]	Net Cost [13] =[10]+[11]-[12]	Production Cost [14]	Import [15]	Export [16]	Net Cost [17] =[14]+[15]-[16]
MAAC	2,471	395	93	2,774	2,482	350	58	2,774
APS	637	1	143	495	646	1	154	492
ONTARIO	1,077	15	421	671	987	7	310	684
ECAR	3,739	45	588	3,196	3,964	6	815	3,155
CAPC	913	8	184	737	941	2	209	734
NYPP	1,362	626	20	1,968	1,325	663	1	1,987
NEPL	1,133	320	0	1,452	743	620	1	1,362
VACAR	2,281	389	107	2,563	2,446	248	126	2,568
Total	13,613	1,797	1,555	13,856	13,532	1,897	1,672	13,756

Sources & Notes
[1] is from IREMM' s Report 20.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Table A1-97 Total Production Cost Savings - Northeast ($ Millions)

Market Area		Total Prod. Cost	Change in Total Production Cost			
		Base Case (Scenario 1) [1]	No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
MAAC		2,950	104.6%	-1.4%	-6.5%	-7.7%
APS		634	85.6%	-0.1%	-0.2%	0.0%
ONTARIO		1,017	97.0%	-4.3%	10.2%	5.5%
ECAR		3,806	90.3%	1.8%	9.7%	13.6%
CAPC		986	85.8%	4.2%	3.8%	6.4%
NYPP		1,950	120.6%	-0.7%	-10.4%	-11.5%
NEPL		1,429	118.2%	-2.1%	-14.7%	-37.3%
VACAR		2,595	118.0%	-0.5%	-3.6%	3.1%
Total Production Cost	[6]	15,367	15,999	15,335	15,177	15,097
Change in Total Production Cost from Base Case	[7]		4.1%	-0.2%	-1.2%	-1.8%

Market Area		Net Prod. Cost	Change in Net Production Cost			
		Base Case (Scenario 1) [8]	No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
MAAC		3,148	-2.0%	-2.3%	-96.8%	-4.7%
APS		519	10.2%	-0.1%	-75.4%	-0.1%
ONTARIO		963	39.5%	0.4%	-83.7%	-0.8%
ECAR		3,395	7.0%	-0.2%	-69.1%	-3.2%
CAPC		832	13.4%	-1.5%	-70.9%	-2.7%
NYPP		2,305	12.6%	0.1%	-98.2%	-3.1%
NEPL		1,673	15.4%	-0.6%	-99.7%	-7.4%
VACAR		3,025	19.0%	-0.1%	-96.3%	-0.6%
Net Production Cost	[13]	15,859	15,999	15,756	15,486	15,357
Change in TC from Base Case	[14]		0.9%	-0.6%	-2.3%	-3.2%

Sources & Notes:
Base Scenario -- TXs and Fees.

[1]Table A2-97, column [2].
[2]Table A2-97, column [1]/[1]-1.
[3]Table A2-97, column [6]/[1]-1.
[4]Table A2-97, column [10]/[1]-1.
[5]Table A2-97, column [14]/[1]-1.
[8]Table A2-97, column [9].

[9]Table A2-97, column [1]/[1]-1.
[10]Table A2-97, column [9]/[1]-1.
[11]Table A2-97, column [13]/[1]-1.
[12]Table A2-97, column [17]/[1]-1.
[6] and [13]Table A2-97.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table A2-97 1997 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade	Scenario 1 Base Case				Scenario 3 TXs Only			
	Production Cost [1]	Production Cost [2]	Import [3]	Export [4]	Net Cost [5] =[2]+[3]-[4]	Production Cost [6]	Import [7]	Export [8]	Net Cost [9] =[6]+[7]-[8]
MAAC	3,085	2,950	245	47	3,148	2,910	231	66	3,075
APS	543	634	12	127	519	634	11	126	519
ONTARIO	987	1,017	75	130	963	974	72	79	966
ECAR	3,436	3,806	72	483	3,395	3,872	15	499	3,388
CAPC	846	986	5	160	832	1,028	2	211	819
NYPP	2,350	1,950	414	59	2,305	1,936	423	52	2,307
NEPL	1,689	1,429	254	10	1,673	1,399	275	12	1,662
VACAR	3,064	2,595	464	34	3,025	2,582	461	23	3,020
Total	15,999	15,367	1,540	1,049	15,859	15,335	1,489	1,067	15,756

Market Area	Scenario 4 Fees Only				Scenario 5 Free Trade			
	Production Cost [10]	Import [11]	Export [12]	Net Cost [13] =[10]+[11]-[12]	Production Cost [14]	Import [15]	Export [16]	Net Cost [17] =[14]+[15]-[16]
MAAC	2,758	398	159	2,997	2,724	378	102	3,000
APS	633	12	123	522	634	12	128	518
ONTARIO	1,122	53	226	949	1,073	39	157	955
ECAR	4,173	49	871	3,352	4,322	12	1,050	3,284
CAPC	1,024	4	212	816	1,049	2	242	809
NYPP	1,747	518	57	2,208	1,725	552	42	2,234
NEPL	1,219	427	3	1,642	895	659	5	1,549
VACAR	2,501	601	102	3,000	2,675	445	111	3,008
Total	15,177	2,062	1,753	15,486	15,097	2,097	1,837	15,357

Sources & Notes:
[1] is from IREMM' s Report 20.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Table A1-97 Nuke Out Total Production Cost Savings - Northeast ($ Millions)

Market Area		Total Prod. Cost Base Case (Scenario 1) [1]	Change in Total Production Cost: No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
MAAC		2,935	105.1%	-1.5%	-4.1%	-5.6%
APS		636	85.3%	-0.2%	-0.2%	0.2%
ONTARIO		1,035	95.2%	-5.3%	11.1%	5.1%
ECAR		3,817	90.0%	2.0%	10.4%	14.4%
CAPC		988	85.8%	4.5%	3.9%	7.0%
NYPP		2,137	110.0%	-2.2%	-12.3%	-14.8%
NEPL		1,720	136.7%	-0.2%	-25.2%	-41.5%
VACAR		2,591	118.3%	-0.3%	-1.4%	5.1%
Total Production Cost	[6]	15,859	16,663	15,827	15,553	15,468
Change in Total Production Cost from Base Case	[7]		5.1%	-0.2%	-1.9%	-2.5%

Market Area		Net Prod. Cost Base Case (Scenario 1) [8]	Change in Net Production Cost: No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
MAAC		2,752	12.1%	11.0%	9.0%	12.5%
APS		520	4.5%	-0.3%	0.3%	-0.4%
ONTARIO		967	1.9%	0.5%	-1.8%	-1.6%
ECAR		3,397	1.2%	-0.4%	-1.7%	-3.7%
CAPC		833	1.8%	-2.0%	-2.1%	-3.3%
NYPP		2,323	1.2%	0.3%	-3.3%	-0.9%
NEPL		2,231	5.4%	0.0%	-5.1%	-9.2%
VACAR		3,024	1.3%	-0.1%	-0.7%	-0.5%
Net Production Cost	[13]	16,046	16,663	16,327	15,990	15,977
Change in TC from Base Case	[14]		3.8%	1.7%	-0.4%	-0.4%

Sources & Notes:
Reflects retirement of Maine Yankee and Millstone Plants
Base Scenario -- TXs and Fees.

[1]Table A2-97 Nuke Out, column [2].
[2]Table A2-97 Nuke Out, column [1]/[1]-1.
[3]Table A2-97 Nuke Out, column [6]/[1]-1.
[4]Table A2-97 Nuke Out, column [10]/[1]-1.
[5]Table A2-97 Nuke Out, column [14]/[1]-1.
[8]Table A2-97 Nuke Out, column [9].

[9] Table A2-97 Nuke Out, column [1]/[1]-1.
[10] Table A2-97 Nuke Out, column [9]/[1]-1.
[11]Table A2-97 Nuke Out, column [13]/[1]-1.
[12]Table A2-97 Nuke Out, column [17]/[1]-1.
[6] and [13]Table A2-97 Nuke Out.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table A2-97 Nuke Out 1997 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade Production Cost [1]	Scenario 1 Base Case Production Cost [2]	Import [3]	Export [4]	Net Cost [5] =[2]+[3]-[4]	Scenario 3 TXs Only Production Cost [6]	Import [7]	Export [8]	Net Cost [9] =[6]+[7]-[8]
MAAC	3,084.30	2,935	268	452	2,752	2,893	253	91	3,055
APS	543.10	636	12	128	520	635	11	128	519
ONTARIO	985.00	1,035	71	139	967	980	74	83	971
ECAR	3,436.80	3,817	71	490	3,397	3,894	13	522	3,384
CAPC	848.00	988	2	157	833	1,033	1	217	816
NYPP	2,350.20	2,137	297	112	2,323	2,091	338	99	2,329
NEPL	2,351.10	1,720	514	3	2,231	1,717	515	1	2,232
VACAR	3,064.80	2,591	471	38	3,024	2,584	463	26	3,021
Total	16,663	15,859	1,706	1,519	16,046	15,827	1,667	1,167	16,327

Market Area	Scenario 4 Fees Only Production Cost [10]	Import [11]	Export [12]	Net Cost [13] =[10]+[11]-[12]	Scenario 5 Free Trade Production Cost [14]	Import [15]	Export [16]	Net Cost [17] =[14]+[15]-[16]
MAAC	2,814	378	194	2,998	2,770	351	26	3,096
APS	635	12	126	521	638	11	132	518
ONTARIO	1,150	49	249	950	1,087	37	173	951
ECAR	4,214	45	920	3,339	4,364	4	1,099	3,270
CAPC	1,027	4	216	815	1,058	1	253	805
NYPP	1,873	492	119	2,246	1,821	547	66	2,302
NEPL	1,287	832	1	2,117	1,007	1,020	1	2,025
VACAR	2,554	562	112	3,004	2,724	416	130	3,010
Total	15,553	2,373	1,937	15,990	15,468	2,387	1,879	15,977

Sources & Notes:
[1] is from IREMM' s Report 20.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Table A1-00 Total Production Cost Savings - Northeast ($ Millions)

Market Area		Total Prod. Cost	Change in Total Production Cost			
		Base Case (Scenario 1) [1]	No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
MAAC		3,280	36.8%	0.5%	-8.9%	-9.4%
APS		688	87.6%	0.2%	-0.1%	0.9%
ONTARIO		1,160	319.8%	-3.3%	9.9%	7.1%
ECAR		4,231	88.0%	0.3%	9.8%	12.1%
CAPC		1,018	87.9%	8.5%	11.0%	13.8%
NYPP		2,147	110.1%	-2.5%	-11.2%	-13.6%
NEPL		1,530	118.6%	-3.0%	-9.8%	-30.4%
VACAR		3,159	114.9%	0.0%	-5.2%	1.8%
Total Production Cost	[6]	17,213	17,944	17,195	17,007	16,946
Change in Total Production Cost from Base Case	[7]		4.2%	-0.1%	-1.2%	-1.6%

Market Area		Net Prod. Cost	Change in Net Production Cost			
		Base Case (Scenario 1) [8]	No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
MAAC		3,682	-67.3%	-4.3%	-98.9%	-2.7%
APS		579	4.2%	0.2%	-78.4%	0.1%
ONTARIO		1,149	223.1%	0.1%	-82.5%	-1.3%
ECAR		3,659	1.7%	0.0%	-66.3%	-3.9%
CAPC		871	2.8%	-1.6%	-63.5%	-3.3%
NYPP		2,340	1.0%	0.1%	-96.7%	-2.3%
NEPL		1,786	1.6%	-0.5%	-99.8%	-5.5%
VACAR		3,587	1.2%	0.0%	-95.0%	-0.8%
Net Production Cost	[13]	17,652	17,944	17,474	17,296	17,184
Change in TC from Base Case	[14]		1.7%	-1.0%	-2.0%	-2.7%

Sources & Notes:
Base Scenario -- TXs and Fees.

[1]Table A2-00, column [2].
[2]Table A2-00, column [1]/[1]-1.
[3]Table A2-00, column [6]/[1]-1.
[4]Table A2-00, column [10]/[1]-1.
[5]Table A2-00, column [14]/[1]-1.
[8]Table A2-00, column [9].

[9] Table A2-00, column [1]/[1]-1.
[10]Table A2-00, column [9]/[1]-1.
[11]Table A2-00, column [13]/[1]-1.
[12]Table A2-00, column [17]/[1]-1.
[6] and [13]Table A2-00.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table A2-00 2000 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade	Scenario 1 Base Case				Scenario 3 TXs Only			
	Production Cost [1]	Production Cost [2]	Import [3]	Export [4]	Net Cost [5] =[2]+[3]-[4]	Production Cost [6]	Import [7]	Export [8]	Net Cost [9] =[6]+[7]-[8]
MAAC	1,206	3,280	423	21	3,682	3,297	397	171	3,523
APS	603	688	12	121	579	689	11	121	580
ONTARIO	3,711	1,160	132	143	1,149	1,123	129	101	1,150
ECAR	3,722	4,231	11	584	3,659	4,243	4	589	3,658
CAPC	895	1,018	11	159	871	1,105	10	258	857
NYPP	2,363	2,147	296	103	2,340	2,094	345	97	2,343
NEPL	1,815	1,530	261	6	1,786	1,484	302	10	1,777
VACAR	3,630	3,159	517	88	3,587	3,160	491	63	3,587
Total	17,944	17,213	1,663	1,225	17,652	17,195	1,688	1,409	17,474

Market Area	Scenario 4 Fees Only				Scenario 5 Free Trade			
	Production Cost [10]	Import [11]	Export [12]	Net Cost [13] =[10]+[11]-[12]	Production Cost [14]	Import [15]	Export [16]	Net Cost [17] =[14]+[15]-[16]
MAAC	2,989	648	56	3,580	2,971	651	40	3,582
APS	687	11	118	581	694	10	125	579
ONTARIO	1,276	99	251	1,124	1,243	92	201	1,133
ECAR	4,644	9	1,061	3,592	4,744	4	1,232	3,515
CAPC	1,130	1	289	843	1,158	1	318	842
NYPP	1,906	481	115	2,272	1,855	508	77	2,287
NEPL	1,381	387	1	1,766	1,065	624	3	1,687
VACAR	2,995	732	188	3,538	3,216	525	181	3,559
Total	17,007	2,367	2,078	17,296	16,946	2,414	2,177	17,184

Sources & Notes:
[1] is from IREMM' s Report 20.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Total Production Cost Savings - WSCC

Table B1-94 Total Production Cost Savings - WSCC ($ Millions)

Market Area		Total Prod. Cost Base Case (Scenario 1) [1]	Change in Total Production Cost: No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
SOCA		2,050	23.9%	1.4%	-30.0%	-30.4%
NOCA		813	38.6%	1.3%	-15.8%	-22.6%
RMPA		446	5.3%	4.7%	4.9%	11.2%
CANADA		668	21.3%	-5.6%	5.4%	0.3%
AZNM		606	-33.8%	-4.8%	60.0%	61.6%
NWP1		476	-3.1%	-0.5%	11.0%	11.6%
NWP2		508	-13.2%	5.0%	18.6%	29.8%
MEXICO		2	2362.5%	-12.5%	-83.3%	-83.3%
Total Production Cost	[6]	5,569	6,309	5,586	5,393	5,393
Change in Total Production Cost from Base Case	[7]	-	13.3%	0.3%	-3.2%	-3.2%

Market Area		Net Prod. Cost Base Case (Scenario 1) [8]	Change in Net Production Cost: No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
SOCA		2,496	1.8%	0.2%	-4.5%	-4.9%
NOCA		1,099	2.5%	-0.4%	-4.2%	-5.9%
RMPA		460	2.0%	-1.0%	-0.5%	-2.6%
CANADA		777	4.3%	0.0%	1.0%	-0.4%
AZNM		272	47.4%	-138.2%	-1.2%	-2.5%
NWP1		264	74.8%	-22.3%	-86.3%	-68.8%
NWP2		424	4.1%	-2.3%	-5.4%	-10.1%
MEXICO		43	37.4%	-10.0%	-9.8%	-21.9%
Net Production Cost	[13]	5,836	6,309	5,383	5,426	5,394
Change in Net Production Cost from Base Case	[14]		8.1%	-7.8%	-7.0%	-7.6%

Sources & Notes:
Base Case -- TXs and Fees

[1]Table B2-94, column [2].
[2]Table B2-94, column [1]/[1]-1.
[3]Table B2-94, column [6]/[1]-1.
[4]Table B2-94, column [6]/[1]-1.
[5]Table B2-94, column [10]/[1]-1.
[8]Table B2-94, column [9].

[9] Table B2-94, column [1]/[1]-1.
[10]Table B2-94, column [9]/[1]-1.
[11]Table B2-94, column [9]/[1]-1.
[12]Table B2-94, column [13]/[1]-1.
[6] and [13]Table B2-94.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table B2-94 1994 Simulated Costs of Imported and Exported Power By Scenario (1994 $ in Million)

Market Area	Scenario 2 No Trade Production Cost [1]	Scenario 1 Base Case Production Cost [2]	Import [3]	Export [4]	Total Cost [5] =[2]+[3]-[4]	Scenario 3 TXs Only Production Cost [6]	Import [7]	Export [8]	Total Cost [9] =[6]+[7]-[8]
SOCA	2,541	2,050	493	47	2,496	2,079	464	41	2,502
NOCA	1,126	813	289	2	1,099	824	274	3	1,095
RMPA	470	446	31	17	460	467	28	39	456
CANADA	811	668	126	17	777	631	158	12	777
AZNM	401	606	13	347	272	577	9	690	(104)
NWP1	461	476	76	288	264	474	72	340	205
NWP2	441	508	15	100	424	534	16	135	414
MEXICO	59	2	42	1	43	2	41	4	39
Total	6,309	5,569	1,085	818	5,836	5,586	1,061	1,265	5,383

Market Area	Scenario 4 Fees Only Production Cost [6]	Import [7]	Export [8]	Total Cost [9] =[6]+[7]-[8]	Scenario 5 Free Trade Production Cost [10]	Import [11]	Export [12]	Total Cost [13] =[10]+[11]-[12]
SOCA	1,435	969	19	2,385	1,428	947	-	2,375
NOCA	684	372	3	1,053	629	407	2	1,034
RMPA	468	25	35	458	496	19	67	448
CANADA	704	93	13	785	670	130	26	774
AZNM	970	18	719	269	979	3	717	265
NWP1	528	83	575	36	531	65	514	82
NWP2	603	1	203	401	660	-	279	381
MEXICO	0	40	2	39	0	35	2	34
Total	5,393	1,601	1,568	5,426	5,393	1,607	1,606	5,394

Sources & Notes:
[1] is from IREMM' s Report 20.
[2]to[4],[6]to[8] and [10]to[12]are from IREMM' s Report 23.

Table B1-97 Total Production Cost Savings - WSCC ($ Millions)

Market Area		Total Prod. Cost Base Case (Scenario 1) [1]	Change in Total Production Cost No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
SOCA		2,712	12.7%	0.1%	-28.5%	-27.7%
NOCA		1,178	20.3%	-1.6%	-15.8%	-25.0%
RMPA		489	6.0%	3.3%	9.7%	19.1%
CANADA		751	30.8%	-1.8%	3.7%	-1.4%
AZNM		715	-27.2%	-1.0%	68.0%	70.2%
NWP1		573	83.5%	9.6%	48.5%	5.2%
NWP2		735	-24.7%	0.1%	-20.0%	21.1%
MEXICO		6	2127.6%	-10.3%	-96.6%	-98.3%
Total Production Cost	[6]	7,158	8,226	7,191	6,886	6,875
Change in Total Production Cost from Base Case	[7]	-	14.9%	0.5%	-3.8%	-3.9%

Market Area		Net Prod. Cost Base Case (Scenario 1) [8]	Change in Net Production Cost No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
SOCA		3,054	0.1%	-0.5%	-4.9%	-5.1%
NOCA		1,395	1.6%	0.7%	-4.4%	-5.6%
RMPA		509	1.7%	-0.1%	-1.5%	-3.8%
CANADA		901	8.9%	0.8%	1.4%	0.4%
AZNM		639	-18.5%	-73.8%	-42.4%	-44.4%
NWP1		643	63.4%	7.4%	-33.2%	-32.3%
NWP2		502	10.3%	-0.8%	-18.9%	-19.6%
MEXICO		91	41.8%	-1.3%	-11.9%	-21.3%
Net Production Cost	[13]	7,734	8,226	7,308	6,938	6,876
Change in Net Production Cost from Base Case	[14]		6.4%	-5.5%	-10.3%	-11.1%

Sources & Notes:
Base Case -- TXs and Fees
[1]Table B2-97, column [2].
[2]Table B2-97, column [1]/[1]-1.
[3]Table B2-97, column [6]/[1]-1.
[4]Table B2-97, column [10]/[1]-1.
[5]Table B2-97, column [14]/[1]-1.
[8]Table B2-97, column [9].
[9]Table B2-97, column [1]/[1]-1.
[10]Table B2-97, column [9]/[1]-1.
[11]Table B2-97, column [13]/[1]-1.
[12]Table B2-97, column [17]/[1]-1.
[6] and [13]Table B2-97.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table B2-97 1997 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade	Scenario 1 Base Case				Scenario 3 TXs Only			
	Production Cost [1]	Production Cost [2]	Import [3]	Export [4]	Total Cost [5] =[2]+[3]-[4]	Production Cost [6]	Import [7]	Export [8]	Total Cost [9] =[6]+[7]-[8]
SOCA	3,056	2,712	413	71	3,054	2,715	414	89	3,040
NOCA	1,417	1,178	234	17	1,395	1,158	272	26	1,404
RMPA	518	489	37	17	509	505	37	33	509
CANADA	982	751	172	21	901	737	215	43	909
AZNM	521	715	14	91	639	708	8	548	167
NWP1	1,050	573	323	253	643	628	301	239	690
NWP2	554	735	7	240	502	736	9	246	498
MEXICO	129	6	86	1	91	5	86	2	90
Total	8,226	7,158	1,287	710	7,734	7,191	1,342	1,225	7,308

Market Area	Scenario 4 Fees Only				Scenario 5 Free Trade			
	Production Cost [10]	Import [11]	Export [12]	Total Cost [13] =[10]+[11]-[12]	Production Cost [14]	Import [15]	Export [16]	Total Cost [17] =[14]+[15]-[16]
SOCA	1,941	1,015	51	2,904	1,961	939	0	2,900
NOCA	992	347	5	1,334	883	437	4	1,316
RMPA	536	13	47	502	582	8	100	490
CANADA	779	145	9	914	740	174	9	905
AZNM	1,201	7	841	368	1,217	1	863	355
NWP1	850	0	421	429	602	253	420	435
NWP2	588	269	450	407	890	0	487	403
MEXICO	0	80	0	80	0	72	0	72
Total	6,886	1,875	1,823	6,938	6,875	1,884	1,883	6,876

Sources & Notes:
[1] is from IREMM' s Report 20.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Table B1-00 Total Production Cost Savings - WSCC ($ Millions)

Market Area		Total Prod. Cost	Change in Total Production Cost			
		Base Case (Scenario 1) [1]	No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
SOCA		2,771	14.3%	1.1%	-21.6%	-20.9%
NOCA		1,243	22.7%	-1.3%	-11.8%	-20.3%
RMPA		544	11.6%	2.9%	5.5%	11.6%
CANADA		844	13.4%	-1.1%	2.8%	-0.9%
AZNM		840	-27.2%	-1.1%	48.1%	52.4%
NWP1		678	90.1%	2.0%	2.1%	2.4%
NWP2		809	-23.8%	0.2%	12.0%	17.3%
MEXICO		71	55.5%	-5.0%	-25.2%	-32.3%
Total Production Cost	[6]	7,801	8,886	7,823	7,609	7,599
Change in Total Production Cost from Base Case	[7]	-	13.9%	0.3%	-2.5%	-2.6%

Market Area		Net Prod. Cost	Change in Net Production Cost			
		Base Case (Scenario 1) [8]	No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
SOCA		3,160	0.3%	-0.1%	-4.2%	-4.3%
NOCA		1,479	3.2%	-0.4%	-3.8%	-5.0%
RMPA		587	3.6%	-0.1%	-0.6%	-1.6%
CANADA		909	5.4%	0.0%	2.3%	1.7%
AZNM		817	-25.1%	-2.1%	-40.3%	-41.9%
NWP1		762	69.2%	3.7%	-22.4%	-19.4%
NWP2		565	9.2%	0.1%	-9.1%	-12.5%
MEXICO		96	13.8%	-0.5%	-21.6%	-10.4%
Net Production Cost	[13]	8,373	8,886	8,374	7,630	7,599
Change in Net Production Cost from Base Case	[14]		6.1%	0.0%	-8.9%	-9.2%

Sources & Notes:
Base Case -- TXs and Fees

[1] Table B2-00column [2].
[2] Table B2-00, column [1]/[1]-1.
[3] Table B2-00, column [6]/[1]-1.
[4] Table B2-00, column [10]/[1]-1.
[5] Table B2-00, column [14]/[1]-1.
[8] Table B2-00 column [9].

[9] Table B2-00, column [1]/[1]-1.
[10] Table B2-00, [9]/[1]-1.
[11] Table B2-00, [13]/[1]-1.
[12] Table B2-00, column [17]/[1]-1.
[6] and [13]Table B2-00.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table B2-00 2000 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade Production Cost [1]	Scenario 1 Base Case Production Cost [2]	Import [3]	Export [4]	Total Cost [5] =[2]+[3]-[4]	Scenario 3 TXs Only Production Cost [6]	Import [7]	Export [8]	Total Cost [9] =[6]+[7]-[8]
SOCA	3,168	2,771	452	63	3,160	2,801	443	87	3,156
NOCA	1,525	1,243	254	18	1,479	1,227	275	30	1,472
RMPA	608	544	58	16	587	560	58	32	586
CANADA	958	844	119	55	909	835	129	56	909
AZNM	612	840	10	33	817	830	7	38	799
NWP1	1,289	678	369	285	762	692	368	270	790
NWP2	617	809	5	249	565	811	3	249	565
MEXICO	110	71	39	13	96	67	43	14	96
Total	8,886	7,801	1,306	733	8,373	7,823	1,326	776	8,374

Market Area	Scenario 4 Fees Only Production Cost [10]	Import [11]	Export [12]	Total Cost [13] =[10]+[11]-[12]	Scenario 5 Free Trade Production Cost [14]	Import [15]	Export [16]	Total Cost [17] =[14]+[15]-[16]
SOCA	2,174	908	54	3,027	2,193	833	2	3,023
NOCA	1,097	331	6	1,422	991	418	4	1,405
RMPA	575	46	37	583	608	38	69	577
CANADA	868	93	32	929	837	113	26	924
AZNM	1,244	8	764	488	1,280	0	805	475
NWP1	692	320	420	592	694	310	390	614
NWP2	907	-	393	514	949	-	455	494
MEXICO	53	40	17	76	48	41	3	86
Total	7,609	1,745	1,724	7,630	7,599	1,753	1,753	7,599

Sources & Notes:
[1] is from IREMM' s Report 20.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Total Production Cost Savings - Southeast

Table C1-94 Total Production Cost Savings - Southeast ($ Millions)

Market Area		Total Prod. Cost	Change in Total Production Cost			
		Base Case (Scenario 1) [1]	No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
Florida		2,182	118.0%	-0.3%	-26.5%	-39.3%
Sout		2,490	88.6%	-6.8%	14.5%	4.5%
TVA		1,555	81.3%	0.0%	6.3%	6.3%
SPPS		1,744	114.4%	2.1%	-30.2%	-38.6%
VACR		2,316	111.5%	0.6%	7.6%	20.7%
APS		614	83.1%	3.9%	8.3%	12.6%
AEP		1,313	100.3%	7.0%	15.6%	36.7%
Total Production Cost	[6]	12,214	12,447	12,204	12,000	11,933
Change in Total Production Cost from Base Case	[7]		1.9%	-0.1%	-1.7%	-2.3%

Market Area		Net Prod. Cost	Change in Net Production Cost			
		Base Case (Scenario 1) [8]	No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
Florida		2,553	0.8%	-0.1%	-100.0%	-5.6%
Sout		2,200	0.2%	0.0%	-79.4%	-1.0%
TVA		1,188	6.4%	-1.1%	-59.5%	-0.4%
SPPS		1,991	0.2%	-0.1%	-97.8%	-5.8%
VACR		2,571	0.4%	0.0%	-88.0%	-0.6%
APS		502	1.6%	-0.7%	-58.2%	-4.1%
AEP		1,308	0.6%	-0.1%	-59.7%	-3.0%
Net Production Cost	[13]	12,314	12,447	12,294	12,056	11,955
Change in TC from Base Case	[14]		1.1%	-0.2%	-2.1%	-2.9%

Sources & Notes:
Base Scenario -- TXs and Fees.

[1]Table C2-94, column [2].
[2]Table C2-94, column [1]/[1]-1.
[3]Table C2-94, column [6]/[4]-1.
[4]Table C2-94, column [10]/[4]-1.
[5]Table C2-94, column [14]/[4]-1.
[8]Table C2-94, column [9].

[9] Table C2-94, column [1]/[1]-1.
[10] Table C2-94, column [9]/[1]-1.
[11]Table C2-94, column [13]/[1]-1.
[12]Table C2-94, column [17]/[1]-1.
[6] and [13]Table C2-94.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table C2-94 1994 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade	Scenario 1 Base Case				Scenario 3 TXs Only			
	Production Cost [1]	Production Cost [2]	Import [3]	Export [4]	Net Cost [5] =[2]+[3]-[4]	Production Cost [6]	Import [7]	Export [8]	Net Cost [9] =[6]+[7]-[8]
Florida	2,574.40	2,182	371	0	2,553	2,176	375	0	2,550
Sout	2,205.60	2,490	26	316	2,200	2,320	27	145	2,202
TVA	1,263.60	1,555	12	379	1,188	1,555	12	392	1,175
SPPS	1,995.50	1,744	263	16	1,991	1,781	224	16	1,990
VACR	2,581.60	2,316	273	18	2,571	2,329	255	13	2,572
APS	510.30	614	0	112	502	638	0	140	498
AEP	1,316.00	1,313	93	97	1,308	1,404	43	140	1,307
Total	12,447	12,214	1,037	938	12,314	12,204	935	845	12,294

Market Area	Scenario 4 Fees Only				Scenario 5 Free Trade			
	Production Cost [10]	Import [11]	Export [12]	Net Cost [13] =[10]+[11]-[12]	Production Cost [14]	Import [15]	Export [16]	Net Cost [17] =[14]+[15]-[16]
Florida	1,605	860	0	2,465	1,325	1,085	0	2,410
Sout	2,852	46	750	2,147	2,603	28	453	2,179
TVA	1,653	11	495	1,169	1,653	12	482	1,184
SPPS	1,218	725	32	1,911	1,072	849	44	1,876
VACR	2,491	290	220	2,561	2,794	70	308	2,557
APS	665	0	168	497	691	0	210	482
AEP	1,517	12	223	1,306	1,794	2	528	1,268
Total	12,000	1,945	1,889	12,056	11,933	2,046	2,023	11,955

Sources & Notes:
[1] is from IREMM' s Report 21.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Table C1-97 Total Production Cost Savings - Southeast ($ Millions)

Market Area		Total Prod. Cost Base Case (Scenario 1) [1]	Change in Total Production Cost: No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
Florida		2,795	116.7%	-0.3%	-31.1%	-41.2%
Sout		2,623	91.5%	-5.2%	14.6%	5.1%
TVA		1,532	90.5%	-0.1%	10.5%	10.1%
SPPS		2,078	111.9%	3.2%	-35.1%	-31.6%
VACR		2,657	114.7%	-1.8%	-75.6%	17.1%
APS		629	86.9%	0.9%	351.3%	3.6%
AEP		1,554	88.7%	7.7%	24.0%	32.6%
Total Production Cost	[6]	13,868	14,348	13,864	13,383	13,330
Change in Total Production Cost from Base Case	[7]		3.5%	0.0%	-3.5%	-3.9%

Market Area		Net Prod. Cost Base Case (Scenario 1) [8]	Change in Net Production Cost: No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
Florida		3,235	0.8%	0.0%	-99.9%	-7.0%
Sout		2,372	1.2%	0.1%	-79.9%	-1.8%
TVA		1,336	3.7%	0.2%	-66.3%	-4.5%
SPPS		2,310	0.7%	0.0%	-94.3%	-9.4%
VACR		3,018	1.1%	0.0%	-90.6%	-1.0%
APS		527	3.6%	-0.4%	-69.2%	-5.0%
AEP		1,336	3.1%	-0.6%	-34.8%	-11.0%
Net Production Cost	[13]	14,134	14,348	14,128	13,524	13,385
Change in TC from Base Case	[14]		1.5%	0.0%	-4.3%	-5.3%

Sources & Notes:
Base Scenario -- TXs and Fees.

[1]Table C2-97, column [2].
[2]Table C2-97, column [1]/[1]-1.
[3]Table C2-97, column [6]/[4]-1.
[4]Table C2-97, column [10]/[4]-1.
[5]Table C2-97, column [14]/[4]-1.
[8]Table C2-97, column [9].

[9]Table C2-97, column [1]/[1]-1.
[10]Table C2-97, column [9]/[1]-1.
[11]Table C2-97, column [13]/[1]-1.
[12]Table C2-97, column [17]/[1]-1.
[6] and [13]Table C2-97.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table C2-97 1997 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade	Scenario 1 Base Case				Scenario 3 TXs Only			
	Production Cost [1]	Production Cost [2]	Import [3]	Export [4]	Net Cost [5] =[2]+[3]-[4]	Production Cost [6]	Import [7]	Export [8]	Net Cost [9] =[6]+[7]-[8]
Florida	3,262	2,795	441	2	3,235	2,786	451	3	3,235
Sout	2,400	2,623	76	326	2,372	2,485	58	170	2,374
TVA	1,386	1,532	45	241	1,336	1,530	39	231	1,339
SPPS	2,327	2,078	291	59	2,310	2,146	229	65	2,310
VACR	3,049	2,657	378	18	3,018	2,610	420	12	3,017
APS	546	629	13	115	527	634	13	121	525
AEP	1,378	1,554	54	272	1,336	1,673	21	365	1,328
Total	14,348	13,868	1,297	1,031	14,134	13,864	1,230	967	14,128

Market Area	Scenario 4 Fees Only				Scenario 5 Free Trade			
	Production Cost [10]	Import [11]	Export [12]	Net Cost [13] =[10]+[11]-[12]	Production Cost [14]	Import [15]	Export [16]	Net Cost [17] =[14]+[15]-[16]
Florida	1,926	1,132	3	3,056	1,643	1,370	5	3,008
Sout	3,006	52	758	2,300	2,756	51	477	2,330
TVA	1,692	40	464	1,269	1,687	39	450	1,276
SPPS	1,349	853	84	2,119	1,422	804	132	2,094
VACR	647	13	143	517	3,113	157	283	2,987
APS	2,837	412	262	2,987	651	12	162	501
AEP	1,926	3	651	1,277	2,059	1	871	1,189
Total	13,383	2,505	2,364	13,524	13,330	2,435	2,380	13,385

Sources & Notes:
[1] is from IREMM' s Report 21.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Table C1-00 Total Production Cost Savings - Southeast ($ Millions)

Market Area		Total Prod. Cost	Change in Total Production Cost			
		Base Case (Scenario 1) [1]	No Trade (Scenario 2) [2]	TXs Only (Scenario 3) [3]	Fees Only (Scenario 4) [4]	Free Trade (Scenario 5) [5]
Florida		3,243	113.7%	-0.1%	-28.8%	-38.2%
Sout		3,105	91.2%	-3.5%	14.2%	6.2%
TVA		1,656	103.2%	1.5%	12.1%	12.3%
SPPS		2,287	108.1%	1.9%	-23.1%	-20.1%
VACR		3,214	111.6%	-0.7%	5.4%	16.8%
APS		633	94.5%	1.1%	9.3%	11.5%
AEP		1,835	80.1%	2.4%	11.0%	13.4%
Total Production Cost	[6]	15,972	16,353	15,956	15,587	15,528
Change in Total Production Cost from Base Case	[7]		2.4%	-0.1%	-2.4%	-2.8%

Market Area		Net Prod. Cost	Change in Net Production Cost			
		Base Case (Scenario 1) [8]	No Trade (Scenario 2) [9]	TXs Only (Scenario 3) [10]	Fees Only (Scenario 4) [11]	Free Trade (Scenario 5) [12]
Florida		3,677	0.3%	0.0%	-99.9%	-4.4%
Sout		2,813	0.6%	0.0%	-79.3%	-1.2%
TVA		1,679	1.8%	0.6%	-79.3%	-2.1%
SPPS		2,444	1.2%	-0.6%	-90.3%	-5.2%
VACR		3,569	0.5%	0.1%	-89.6%	-0.7%
APS		588	1.7%	-0.1%	-72.5%	-5.1%
AEP		1,407	4.5%	-0.8%	-39.1%	-12.8%
Net Production Cost	[13]	16,176	16,353	16,163	15,720	15,585
Change in TC from Base Case	[14]		1.1%	-0.1%	-2.8%	-3.7%

Sources & Notes:
Base Scenario -- TXs and Fees.

[1]Table C2-00, column [2].
[2]Table C2-00, column [1]/[1]-1.
[3]Table C2-00, column [6]/[4]-1.
[4]Table C2-00, column [10]/[4]-1.
[5]Table C2-00, column [14]/[4]-1.
[8]Table C2-00, column [9].

[9] Table C2-00, column [1]/[1]-1.
[10] Table C2-00, column [9]/[1]-1.
[11]Table C2-00, column [13]/[1]-1.
[12]Table C2-00, column [17]/[1]-1.
[6] and [13]Table C2-00.
[7] =line[6]/(line[6] col.[1])-1.
[14] =line[13]/(line[13] col.[1])-1.

Table C2-00 2000 Simulated Costs of Imported and Exported Power By Scenario ($ Millions)

Market Area	Scenario 2 No Trade	Scenario 1 Base Case				Scenario 3 TXs Only			
	Production Cost [1]	Production Cost [2]	Import [3]	Export [4]	Net Cost [5] =[2]+[3]-[4]	Production Cost [6]	Import [7]	Export [8]	Net Cost [9] =[6]+[7]-[8]
Florida	3,687	3,243	438	3	3,677	3,238	445	4	3,679
Sout	2,830	3,105	87	379	2,813	2,996	85	269	2,812
TVA	1,709	1,656	178	155	1,679	1,680	97	89	1,689
SPPS	2,473	2,287	248	91	2,444	2,331	206	108	2,430
VACR	3,586	3,214	386	31	3,569	3,193	411	32	3,571
APS	598	633	17	62	588	639	15	67	587
AEP	1,470	1,835	3	432	1,407	1,879	2	485	1,396
Total	16,353	15,972	1,357	1,153	16,176	15,956	1,261	1,054	16,163

Market Area	Scenario 4 Fees Only				Scenario 5 Free Trade			
	Production Cost [10]	Import [11]	Export [12]	Net Cost [13] =[10]+[11]-[12]	Production Cost [14]	Import [15]	Export [16]	Net Cost [17] =[14]+[15]-[16]
Florida	2,310	1,258	4	3,563	2,004	1,517	4	3,516
Sout	3,546	68	867	2,747	3,298	63	581	2,780
TVA	1,856	139	363	1,632	1,860	132	347	1,644
SPPS	1,758	729	139	2,348	1,827	725	236	2,316
VACR	3,389	461	314	3,536	3,754	162	372	3,544
APS	691	15	132	574	705	14	162	558
AEP	2,038	3	720	1,320	2,081	2	856	1,227
Total	15,587	2,672	2,538	15,720	15,528	2,615	2,558	15,585

Sources & Notes:
[1] is from IREMM' s Report 21.
[2]to[4],[10]to[12] and [14]to[16]are from IREMM' s Report 23.

Fuel Consumption Patterns
(Change from "Base Case" Scenario)
Northeast

Table A3-94 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Scenario 1 -- No Trade

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [1]	Coal [2]	Gas [3]	Oil [4]	Other [5]	Total [6]	Uranium [7]	Coal [8]	Gas [9]	Oil [10]	Other [11]
MAAC	940	1,002	308	449	34	2,733	0%	-1%	30%	280%	0%
APS	-	339	1	1	3	344	0%	-18%	0%	0%	0%
ONTARIO	901	147	3	-	6	1,057	-4%	-36%	50%	0%	-33%
ECAR	151	3,481	7	13	20	3,672	0%	-3%	-60%	0%	0%
CAPC	251	465	0	1	-	717	0%	-15%	-50%	0%	0%
NYPP	312	232	433	618	259	1,854	0%	8%	37%	500%	0%
NEPL	440	163	197	251	10	1,062	0%	3%	9%	78%	0%
VACAR	1,092	1,203	37	50	54	2,436	0%	12%	40%	100%	0%
TOTAL	4,088	7,032	985	1,383	386	13,874	-1%	-3%	27%	244%	-1%

Scenario 3 -- TXs Only

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [12]	Coal [13]	Gas [14]	Oil [15]	Other [16]	Total [17]	Uranium [18]	Coal [19]	Gas [20]	Oil [21]	Other [22]
MAAC	940	1,002	231	71	34	2,277	0%	-1%	-2%	-40%	0%
APS	-	408	1	1	3	413	0%	-1%	0%	0%	0%
ONTARIO	941	188	2	-	8	1,139	0%	-19%	0%	0%	-11%
ECAR	151	3,742	21	13	22	3,949	0%	4%	30%	0%	7%
CAPC	251	560	1	1	-	813	0%	2%	0%	0%	0%
NYPP	312	219	313	103	259	1,206	0%	2%	0%	0%	0%
NEPL	440	153	164	136	10	903	0%	-4%	-9%	-3%	-1%
VACAR	1,092	1,055	26	25	54	2,252	0%	-2%	0%	0%	0%
TOTAL	4,128	7,326	759	351	389	12,953	0%	1%	-2%	-13%	0%

Table A3-94 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Scenario 4 -- Fees Only

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [23]	Coal [24]	Gas [25]	Oil [26]	Other [27]	Total [28]	Uranium [29]	Coal [30]	Gas [31]	Oil [32]	Other [33]
MAAC	940	935	191	-	34	2,099	0%	-8%	-19%	-100%	0%
APS	-	408	1	1	3	413	0%	-1%	0%	0%	0%
ONTARIO	947	340	4	-	9	1,300	0%	47%	100%	0%	0%
ECAR	151	3,903	26	13	22	4,116	0%	8%	60%	0%	7%
CAPC	251	574	1	1	-	827	0%	5%	0%	0%	0%
NYPP	312	189	241	-	259	1,001	0%	-12%	-23%	-100%	0%
NEPL	440	152	165	78	10	845	0%	-5%	-8%	-45%	0%
VACAR	1,092	1,051	26	-	54	2,223	0%	-2%	0%	-100%	0%
TOTAL	4,134	7,551	655	94	391	12,824	0%	4%	-16%	-77%	0%

Scenario 5 -- Free Trade

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [34]	Coal [35]	Gas [36]	Oil [37]	Other [38]	Total [39]	Uranium [40]	Coal [41]	Gas [42]	Oil [43]	Other [44]
MAAC	940	943	189	-	34	2,107	0%	-7%	-20%	-100%	0%
APS	-	412	1	1	3	417	0%	0%	0%	0%	0%
ONTARIO	947	283	3	-	9	1,242	0%	23%	50%	0%	0%
ECAR	151	4,082	38	13	22	4,306	0%	13%	130%	0%	7%
CAPC	251	592	1	1	-	845	0%	8%	0%	0%	0%
NYPP	312	182	180	-	259	933	0%	-15%	-43%	-100%	0%
NEPL	440	106	80	26	10	662	0%	-34%	-56%	-82%	-3%
VACAR	1,092	1,134	31	25	54	2,337	0%	5%	19%	0%	0%
TOTAL	4,134	7,734	522	67	390	12,847	0%	7%	-33%	-83%	0%

Table A3-97 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Market Area	Scenario 1 -- No Trade										
	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [1]	Coal [2]	Gas [3]	Oil [4]	Other [5]	Total [6]	Uranium [7]	Coal [8]	Gas [9]	Oil [10]	Other [11]
MAAC	866	1,097	285	66	28	2,342	0%	-4%	22%	125%	-2%
APS	-	377	2	5	2	386	0%	-15%	400%	1900%	0%
ONTARIO	886	259	14	6	13	1,178	-1%	-12%	75%	200%	-7%
ECAR	255	3,491	4	10	21	3,781	0%	-8%	-68%	0%	0%
CAPC	318	443	0	0	-	762	0%	-16%	-33%	0%	0%
NYPP	342	252	467	82	288	1,430	0%	10%	26%	43%	0%
NEPL	164	222	309	320	12	1,027	0%	4%	13%	75%	0%
VACAR	1,076	1,517	24	15	57	2,690	0%	18%	54%	50%	0%
TOTAL	3,909	7,657	1,105	504	420	13,596	0%	-3%	21%	72%	0%

Market Area	Scenario 3 -- TXs Only										
	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [12]	Coal [13]	Gas [14]	Oil [15]	Other [16]	Total [17]	Uranium [18]	Coal [19]	Gas [20]	Oil [21]	Other [22]
MAAC	870	1,126	230	28	29	2,281	0%	-1%	-2%	-6%	0%
APS	-	442	0	0	2	445	0%	0%	0%	10%	0%
ONTARIO	897	266	8	2	14	1,187	0%	-10%	0%	0%	0%
ECAR	255	3,842	12	10	21	4,139	0%	2%	-4%	0%	0%
CAPC	318	548	1	0	-	867	0%	5%	0%	0%	0%
NYPP	342	229	366	57	288	1,281	0%	0%	-1%	0%	0%
NEPL	164	206	257	195	12	835	0%	-3%	-6%	7%	0%
VACAR	1,076	1,280	15	8	57	2,437	0%	0%	-2%	-17%	0%
TOTAL	3,923	7,938	889	301	422	13,472	0%	0%	-3%	3%	0%

Table A3-97 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Scenario 4 -- Fees Only

Market Area	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [23]	Coal [24]	Gas [25]	Oil [26]	Other [27]	Total [28]	Uranium [29]	Coal [30]	Gas [31]	Oil [32]	Other [33]
MAAC	870	1,077	208	20	29	2,204	0%	-5%	-11%	-31%	0%
APS	-	441	0	0	2	444	0%	0%	0%	0%	0%
ONTARIO	897	361	9	2	14	1,283	0%	23%	13%	0%	0%
ECAR	255	4,091	15	10	21	4,392	0%	8%	25%	0%	0%
CAPC	318	545	1	0	-	864	0%	4%	0%	0%	0%
NYPP	342	211	322	49	288	1,212	0%	-7%	-13%	-14%	0%
NEPL	164	200	239	103	12	718	0%	-6%	-13%	-44%	0%
VACAR	1,076	1,212	17	10	57	2,372	0%	-6%	8%	0%	0%
TOTAL	3,923	8,138	812	195	422	13,489	0%	3%	-11%	-33%	0%

Scenario 5 -- Free Trade

Market Area	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [34]	Coal [35]	Gas [36]	Oil [37]	Other [38]	Total [39]	Uranium [40]	Coal [41]	Gas [42]	Oil [43]	Other [44]
MAAC	870	1,068	205	-	24	2,167	0%	-6%	-12%	-100%	-16%
APS	-	443	0	-	2	445	0%	0%	0%	-100%	0%
ONTARIO	897	327	10	-	9	1,243	0%	11%	25%	-100%	-36%
ECAR	255	4,212	18	-	21	4,506	0%	11%	50%	-100%	0%
CAPC	318	560	1	0	-	879	0%	7%	0%	0%	0%
NYPP	342	203	322	-	288	1,155	0%	-11%	-13%	-100%	0%
NEPL	164	128	137	29	12	470	0%	-40%	-50%	-84%	-4%
VACAR	1,076	1,315	19	2	55	2,466	0%	2%	19%	-83%	-4%
TOTAL	3,923	8,255	712	31	410	13,331	0%	4%	-22%	-89%	-3%

Table A3-97 Nuke Out Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Market Area	Scenario 1 -- No Trade												
	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [1]	Coal [2]	Gas [3]	Oil2 [4]	Oil6 [5]	Other [6]	Total [7]	Uranium [8]	Coal [9]	Gas [10]	Oil2 [11]	Oil6 [12]	Other [13]
MAAC	823	1,129	380	1	36	44	2,412	0%	-3%	22%	100%	35900%	-2%
APS	-	379	9	-	2	-	390	0%	-15%	400%	0%	0%	0%
ONTARIO	871	304	26	0	6	13	1,220	-1%	-15%	63%	0%	100%	-7%
ECAR	255	3,698	10	0	0	15	3,978	0%	-8%	-63%	0%	0%	0%
CAPC	318	416	2	1	-	23	760	0%	-16%	-33%	0%	-100%	0%
NYPP	342	227	528	-	10	26	1,133	0%	7%	22%	0%	9900%	0%
NEPL	361	199	474	29	267	79	1,409	0%	2%	43%	0%	5240%	0%
VACAR	1,077	1,617	64	2	9	28	2,798	0%	19%	52%	0%	8900%	0%
TOTAL	4,047	7,969	1,493	33	330	228	14,100	0%	-3%	27%	100%	4978%	-1%

Market Area	Scenario 3 -- TXs Only												
	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [14]	Coal [15]	Gas [16]	Oil2 [17]	Oil6 [18]	Other [19]	Total [20]	Uranium [21]	Coal [22]	Gas [23]	Oil2 [24]	Oil6 [25]	Other [26]
MAAC	826	1,129	326	0	15	45	2,341	0%	-1%	-2%	0%	14900%	0%
APS	-	446	2	-	0	-	448	0%	0%	0%	0%	0%	0%
ONTARIO	880	315	16	0	3	14	1,228	0%	-12%	0%	0%	2900%	0%
ECAR	255	4,083	29	0	1	15	4,384	0%	2%	11%	0%	900%	0%
CAPC	318	518	3	0	-	23	862	0%	5%	0%	0%	-100%	0%
NYPP	342	208	452	0	11	26	1,040	0%	-2%	6%	0%	10900%	0%
NEPL	361	192	375	5	164	79	1,177	0%	-2%	13%	0%	3180%	0%
VACAR	1,077	1,341	43	0	6	28	2,496	0%	-1%	2%	0%	5900%	0%
TOTAL	4,060	8,233	1,247	6	200	230	13,976	0%	0%	6%	0%	2978%	0%

Table A3-97 Nuke Out Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Scenario 4 -- Fees Only

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [27]	Coal [28]	Gas [29]	Oil2 [30]	Oil6 [31]	Other [32]	Total [33]	Uranium [34]	Coal [35]	Gas [36]	Oil2 [37]	Oil6 [38]	Other [39]
MAAC	826	1,107	321	0	14	45	2,313	0%	-3%	-8%	0%	13900%	0%
APS	-	446	2	-	0	-	448	0%	0%	0%	0%	0%	0%
ONTARIO	881	441	20	0	2	14	1,358	0%	24%	25%	0%	1900%	0%
ECAR	255	4,279	37	0	1	15	4,588	0%	9%	41%	0%	900%	0%
CAPC	318	515	3	0	-	23	859	0%	4%	0%	0%	-100%	0%
NYPP	342	199	369	0	11	26	947	0%	-6%	-10%	0%	10900%	0%
NEPL	361	185	319	0	74	79	1,018	0%	-5%	-4%	0%	1380%	0%
VACAR	1,077	1,318	47	0	7	28	2,478	0%	-3%	12%	0%	6900%	0%
TOTAL	4,061	8,491	1,118	1	109	230	14,010	0%	3%	-5%	0%	1578%	0%

Scenario 5 -- Free Trade

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [40]	Coal [41]	Gas [42]	Oil2 [43]	Oil6 [44]	Other [45]	Total [46]	Uranium [47]	Coal [48]	Gas [49]	Oil2 [50]	Oil6 [51]	Other [52]
MAAC	826	1,084	299	0	13	45	2,267	0%	-5%	-8%	0%	12900%	0%
APS	-	448	2	-	0	-	450	0%	0%	0%	0%	0%	0%
ONTARIO	881	390	22	0	3	14	1,310	0%	9%	38%	0%	2900%	0%
ECAR	255	4,430	44	0	0	15	4,745	0%	12%	67%	0%	0%	0%
CAPC	318	531	5	0	-	23	877	0%	8%	0%	0%	-100%	0%
NYPP	342	194	400	0	9	26	971	0%	-8%	-11%	0%	8900%	0%
NEPL	361	142	217	-	61	78	859	0%	-27%	-35%	0%	1120%	-1%
VACAR	1,077	1,358	55	0	7	28	2,526	0%	4%	30%	0%	6900%	0%
TOTAL	4,061	8,577	1,044	1	93	229	14,004	0%	4%	-11%	0%	1334%	0%

Table A3-00 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Scenario 1 -- No Trade

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [1]	Coal [2]	Gas [3]	Oil2 [4]	Oil6 [5]	Other [6]	Total [7]	Uranium [8]	Coal [9]	Gas [10]	Oil2 [11]	Oil6 [12]	Other [13]
MAAC	824	1,192	429	2	49	28	2,524	0%	1%	37%	95%	206%	-2%
APS	-	393	3	-	1	2	400	0%	-12%	68%	0%	900%	0%
ONTARIO	877	315	49	1	14	20	1,276	0%	-15%	207%	3233%	79%	-7%
ECAR	255	3,591	12	0	0	2	3,860	0%	-10%	-53%	0%	0%	0%
CAPC	318	439	1	0	-	-	758	0%	-11%	-71%	0%	0%	2%
NYPP	342	232	492	0	6	417	1,489	0%	6%	14%	0%	-40%	2%
NEPL	164	222	423	3	101	8	921	0%	4%	10%	9900%	115%	1%
VACAR	1,084	1,557	53	2	8	48	2,752	0%	16%	22%	1900%	60%	1%
TOTAL	3,865	7,941	1,462	8	179	525	13,979	0%	-3%	17%	15128%	121%	0%

Scenario 3 -- TXs Only

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [14]	Coal [15]	Gas [16]	Oil2 [17]	Oil6 [18]	Other [19]	Total [20]	Uranium [21]	Coal [22]	Gas [23]	Oil2 [24]	Oil6 [25]	Other [26]
MAAC	826	1,135	355	0	17	29	2,362	0%	0%	2%	0%	6%	0%
APS	-	448	2	-	0	2	452	0%	0%	0%	0%	0%	0%
ONTARIO	881	342	16	0	3	21	1,263	0%	-7%	0%	0%	0%	0%
ECAR	255	3,992	26	0	0	2	4,276	0%	0%	2%	0%	900%	0%
CAPC	318	540	3	0	-	-	861	0%	10%	7%	0%	0%	0%
NYPP	342	219	410	0	10	411	1,392	0%	0%	-4%	0%	0%	0%
NEPL	164	201	370	0	49	8	791	0%	-6%	-4%	0%	4%	0%
VACAR	1,084	1,341	43	0	6	47	2,522	0%	0%	0%	0%	20%	0%
TOTAL	3,871	8,218	1,225	0	85	520	13,919	0%	0%	-2%	0%	5%	0%

Table A3-00 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Northeast

Scenario 4 -- Fees Only

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [27]	Coal [28]	Gas [29]	Oil2 [30]	Oil6 [31]	Other [32]	Total [33]	Uranium [34]	Coal [35]	Gas [36]	Oil2 [37]	Oil6 [38]	Other [39]
MAAC	826	1,044	331	0	11	29	2,242	0%	-8%	-12%	0%	-31%	0%
APS	-	447	2	-	0	2	451	0%	0%	0%	0%	0%	0%
ONTARIO	881	445	17	0	3	21	1,367	0%	21%	6%	0%	0%	0%
ECAR	255	4,236	34	0	0	2	4,528	0%	8%	34%	0%	900%	7%
CAPC	318	550	3	0	-	-	871	0%	12%	21%	0%	0%	0%
NYPP	342	208	359	0	10	411	1,330	0%	-5%	-15%	0%	0%	0%
NEPL	164	196	351	0	36	8	755	0%	-8%	-9%	0%	-23%	0%
VACAR	1,084	1,238	43	0	6	47	2,419	0%	-8%	0%	0%	20%	0%
TOTAL	3,871	8,365	1,141	0	66	520	13,963	0%	2%	-9%	0%	-18%	0%

Scenario 5 -- Free Trade

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [40]	Coal [41]	Gas [42]	Oil2 [43]	Oil6 [44]	Other [45]	Total [46]	Uranium [47]	Coal [48]	Gas [49]	Oil2 [50]	Oil6 [51]	Other [52]
MAAC	826	1,037	331	0	11	29	2,235	0%	-9%	-12%	0%	-29%	0%
APS	-	450	2	-	0	2	454	0%	1%	0%	0%	0%	0%
ONTARIO	881	421	18	0	3	21	1,344	0%	14%	13%	0%	0%	0%
ECAR	255	4,298	38	0	0	2	4,593	0%	10%	47%	0%	900%	7%
CAPC	318	565	3	0	-	-	886	0%	15%	29%	0%	0%	0%
NYPP	342	203	379	0	10	411	1,345	0%	-7%	-18%	0%	0%	0%
NEPL	164	131	259	0	30	8	592	0%	-38%	-36%	0%	-36%	0%
VACAR	1,084	1,345	47	0	6	47	2,530	0%	0%	9%	0%	28%	0%
TOTAL	3,871	8,450	1,077	0	61	520	13,980	0%	3%	-14%	0%	-25%	0%

Fuel Consumption Patterns
(Change from "Base Case" Scenario)
WSCC

Table B3-94 Fuel Consumption Patterns (Change from "Base Case" Scenario) - WSCC

Market Area	Scenario 1 -- No Trade										
	1994 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [1]	Coal [2]	Gas [3]	Oil [4]	Other [5]	Total [6]	Uranium [7]	Coal [8]	Gas [9]	Oil [10]	Other [11]
							Coal	Gas	Uranium	Oil6	
SOCA	182	246	818	-	295	1,541	0%	2%	34%	0%	0%
NOCA	178	8	607	-	66	859	0%	0%	37%	0%	0%
RMPA	-	395	5	0	74	474	0%	-11%	28%	0%	0%
CANADA	-	443	100	-	6	549	0%	6%	104%	0%	0%
AZNM	238	437	10	1	69	756	-4%	-34%	-82%	0%	0%
NWP1	49	149	76	-	719	993	-31%	-36%	2300%	0%	-25%
NWP2	-	559	3	-	160	721	0%	-10%	-96%	0%	-20%
MEXICO	-	-	-	18	-	18	0%	0%	0%	1700%	0%
TOTAL	648	2,237	1,619	20	1,388	5,911	-5%	-15%	32%	628%	-17%

Market Area	Scenario 3 -- TXs Only										
	1994 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [12]	Coal [13]	Gas [14]	Oil [15]	Other [16]	Total [17]	Uranium [18]	Coal [19]	Gas [20]	Oil [21]	Other [22]
SOCA	182	239	625	-	295	1,341	0%	-1%	2%	0%	0%
NOCA	179	8	449	-	66	701	0%	0%	1%	0%	0%
RMPA	-	463	4	0	74	542	0%	5%	0%	0%	0%
CANADA	-	395	45	-	6	446	0%	-5%	-8%	0%	0%
AZNM	248	647	42	1	69	1,006	0%	-3%	-25%	0%	0%
NWP1	72	229	58	-	959	1,318	0%	-2%	1740%	0%	0%
NWP2	-	631	7	-	200	837	0%	1%	-88%	0%	0%
MEXICO	-	-	-	1	-	1	0%	0%	0%	0%	0%
TOTAL	680	2,612	1,230	3	1,668	6,192	0%	-1%	1%	0%	0%

Table B3-94 Fuel Consumption Patterns (Change from "Base Case" Scenario) - WSCC

Scenario 4 -- Fees Only

Market Area	1994 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [23]	Coal [24]	Gas [25]	Oil [26]	Other [27]	Total [28]	Uranium [29]	Coal [30]	Gas [31]	Oil [32]	Other [33]
SOCA	182	234	353	-	295	1,064	0%	-3%	-42%	0%	0%
NOCA	179	8	374	-	66	627	0%	0%	-16%	0%	0%
RMPA	-	463	4	0	74	542	0%	5%	0%	0%	0%
CANADA	-	419	66	-	6	491	0%	0%	35%	0%	0%
AZNM	248	858	238	1	69	1,414	0%	29%	329%	0%	0%
NWP1	72	255	15	-	999	1,341	0%	9%	360%	0%	4%
NWP2	-	670	66	-	200	936	0%	8%	14%	0%	0%
MEXICO	-	-	-	-	-	-	0%	0%	0%	-100%	0%
TOTAL	680	2,909	1,116	2	1,707	6,414	0%	11%	-9%	-37%	2%

Scenario 5 -- Free Trade

Market Area	1994 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [34]	Coal [35]	Gas [36]	Oil [37]	Other [38]	Total [39]	Uranium [40]	Coal [41]	Gas [42]	Oil [43]	Other [44]
SOCA	182	230	353	-	295	1,060	0%	-5%	-42%	0%	0%
NOCA	179	8	345	-	55	587	0%	0%	-22%	0%	-17%
RMPA	-	484	4	0	74	563	0%	10%	8%	0%	0%
CANADA	-	395	65	-	6	466	0%	-5%	33%	0%	0%
AZNM	248	870	238	1	69	1,426	0%	31%	329%	0%	0%
NWP1	72	252	68	-	999	1,390	0%	8%	2040%	0%	4%
NWP2	-	689	22	-	200	911	0%	11%	-62%	0%	0%
MEXICO	-	-	-	-	-	-	0%	0%	0%	-100%	0%
TOTAL	680	2,929	1,096	2	1,697	6,404	0%	11%	-10%	-37%	2%

Table B3-97 Fuel Consumption Patterns (Change from "Base Case" Scenario)-WSCC

Market Area	Scenario 1 -- No Trade: 1997 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [1]	Coal [2]	Gas [3]	Oil [4]	Other [5]	Total [6]	Uranium [7]	Coal [8]	Gas [9]	Oil [10]	Other [11]
SOCA	148	255	595	-	423	1,421	0%	1%	18%	0%	0%
NOCA	145	9	455	-	94	703	0%	0%	19%	0%	0%
RMPA	-	469	6	0	128	603	0%	-1%	21%	-50%	0%
CANADA	-	445	177	-	8	630	0%	2%	133%	0%	0%
AZNM	331	536	10	-	88	965	-1%	-19%	-86%	-100%	0%
NWP1	42	140	79	-	1,210	1,471	-20%	-23%	176%	0%	-22%
NWP2	-	459	8	-	288	755	0%	-20%	-21%	0%	0%
MEXICO	-	-	1	32	-	33	0%	0%	900%	3100%	0%
TOTAL	666	2,313	1,331	32	2,238	6,580	-2%	-11%	23%	1317%	-13%

Market Area	Scenario 3 -- TXs Only: 1997 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [12]	Coal [13]	Gas [14]	Oil [15]	Other [16]	Total [17]	Uranium [18]	Coal [19]	Gas [20]	Oil [21]	Other [22]
SOCA	148	252	505	-	423	1,328	0%	-1%	0%	0%	0%
NOCA	145	9	377	-	94	625	0%	3%	-1%	0%	0%
RMPA	-	481	5	0	128	614	0%	1%	8%	0%	0%
CANADA	-	429	74	-	8	511	0%	-2%	-3%	0%	0%
AZNM	335	686	75	1	88	1,185	0%	3%	5%	0%	0%
NWP1	52	182	34	-	1,556	1,824	0%	0%	17%	0%	0%
NWP2	-	572	10	-	288	870	0%	0%	-2%	0%	0%
MEXICO	-	-	0	1	-	1	0%	0%	300%	0%	0%
TOTAL	681	2,612	1,081	2	2,584	6,959	0%	1%	0%	0%	0%

Table B3-97 Fuel Consumption Patterns (Change from "Base Case" Scenario)-WSCC

Scenario 4 -- Fees Only

Market Area	1997 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [23]	Coal [24]	Gas [25]	Oil [26]	Other [27]	Total [28]	Uranium [29]	Coal [30]	Gas [31]	Oil [32]	Other [33]
SOCA	148	242	312	-	423	1,125	0%	-4%	-38%	0%	0%
NOCA	145	9	323	-	94	571	0%	0%	-16%	0%	0%
RMPA	-	489	6	0	128	623	0%	3%	31%	-50%	0%
CANADA	-	443	87	-	8	538	0%	1%	14%	0%	0%
AZNM	335	946	179	0	88	1,548	0%	42%	150%	-50%	0%
NWP1	52	199	28	-	1,556	1,835	0%	9%	-1%	0%	0%
NWP2	-	611	17	-	288	915	0%	7%	61%	0%	0%
MEXICO	-	-	-	0	-	0	0%	0%	-100%	-90%	0%
TOTAL	681	2,938	953	1	2,584	7,156	0%	13%	-12%	-68%	0%

Scenario 5 -- Free Trade

Market Area	1997 Fuel Consumption (million MMBtu)						% Change in Fuel Consumption from Base Case				
	Uranium [34]	Coal [35]	Gas [36]	Oil [37]	Other [38]	Total [39]	Uranium [40]	Coal [41]	Gas [42]	Oil [43]	Other [44]
SOCA	148	235	322	-	426	1,131	0%	-7%	-36%	0%	1%
NOCA	145	9	289	-	100	543	0%	3%	-24%	0%	7%
RMPA	-	498	8	0	128	634	0%	5%	66%	-50%	0%
CANADA	-	438	72	-	8	519	0%	0%	-5%	0%	5%
AZNM	335	938	207	0	88	1,569	0%	41%	190%	-50%	0%
NWP1	52	200	20	-	1,463	1,736	0%	9%	-29%	0%	-6%
NWP2	-	616	30	-	311	956	0%	8%	183%	0%	8%
MEXICO	-	-	-	0	-	0	0%	0%	-100%	-90%	0%
TOTAL	681	2,934	948	1	2,524	7,088	0%	13%	-12%	-68%	-2%

Table B3-00 Fuel Consumption Patterns (Change from "Base Case" Scenario) - WSCC

Scenario 1 -- No Trade

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [1]	Coal [2]	Gas [3]	Oil2 [4]	Oil6 [5]	Other [6]	Total [7]	Uranium [8]	Coal [9]	Gas [10]	Oil2 [11]	Oil6 [12]	Other [13]
SOCA	148	306	702	0	-	458	1,614	0%	1%	3%	400%	0%	0%
NOCA	145	9	559	3	-	129	845	0%	0%	16%	100%	0%	0%
RMPA	-	475	7	2	0	163	646	0%	1%	49%	100%	-50%	0%
CANADA	-	441	165	-	-	43	649	0%	1%	46%	-100%	0%	0%
AZNM	331	557	65	-	-	123	1,075	-1%	-8%	-20%	-100%	-100%	0%
NWP1	42	153	100	2	-	1,302	1,599	-20%	-18%	908%	100%	0%	-19%
NWP2	-	488	8	-	-	323	819	0%	-16%	27%	0%	0%	0%
MEXICO	-	-	26	0	13	35	74	0%	0%	-83%	344%	225%	0%
TOTAL	661	2,428	1,632	7	13	2,576	7,317	-3%	-6%	24%	100%	198%	-7%

Scenario 3 -- TXs Only

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [14]	Coal [15]	Gas [16]	Oil2 [17]	Oil6 [18]	Other [19]	Total [20]	Uranium [21]	Coal [22]	Gas [23]	Oil2 [24]	Oil6 [25]	Other [26]
SOCA	148	255	545	0	-	458	1,406	0%	0%	-13%	0%	0%	0%
NOCA	145	9	373	1	-	129	657	0%	0%	-6%	0%	0%	0%
RMPA	-	485	5	0	0	163	653	0%	3%	13%	0%	0%	0%
CANADA	-	431	117	0	-	43	591	0%	-1%	4%	0%	0%	0%
AZNM	335	710	167	0	0	123	1,335	0%	14%	227%	0%	0%	0%
NWP1	52	187	10	1	-	1,591	1,840	0%	0%	283%	0%	0%	0%
NWP2	-	587	13	0	-	323	923	0%	1%	104%	0%	0%	0%
MEXICO	-	-	26	0	1	35	62	0%	0%	-83%	0%	-50%	0%
TOTAL	681	2,663	1,256	3	1	2,864	7,468	0%	3%	-5%	0%	-45%	0%

Table B3-00 Fuel Consumption Patterns (Change from "Base Case" Scenario) - WSCC

Scenario 4 -- Fees Only

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [27]	Coal [28]	Gas [29]	Oil2 [30]	Oil6 [31]	Other [32]	Total [33]	Uranium [34]	Coal [35]	Gas [36]	Oil2 [37]	Oil6 [38]	Other [39]
SOCA	148	244	309	0	-	458	1,160	0%	-4%	-39%	0%	0%	0%
NOCA	145	9	283	0	-	129	566	0%	0%	-16%	0%	0%	0%
RMPA	-	490	5	-	0	163	658	0%	4%	20%	-100%	-50%	0%
CANADA	-	385	124	-	-	43	552	0%	2%	10%	-100%	0%	0%
AZNM	335	891	337	0	0	123	1,686	0%	44%	833%	0%	-50%	0%
NWP1	52	198	19	0	0	1,648	1,917	0%	6%	93%	0%	0%	4%
NWP2	-	614	37	-	-	323	974	0%	6%	465%	0%	0%	0%
MEXICO	-	-	23	-	0	35	58	0%	0%	-85%	0%	-98%	0%
TOTAL	681	2,831	1,138	0	0	2,921	7,571	0%	9%	-14%	-19%	-91%	1%

Scenario 5 -- Free Trade

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [40]	Coal [41]	Gas [42]	Oil2 [43]	Oil6 [44]	Other [45]	Total [46]	Uranium [47]	Coal [48]	Gas [49]	Oil2 [50]	Oil6 [51]	Other [52]
SOCA	148	216	291	0	-	458	1,113	0%	-5%	-37%	0%	0%	0%
NOCA	145	9	250	0	-	129	533	0%	0%	-24%	0%	0%	0%
RMPA	-	478	6	0	0	163	647	0%	5%	40%	0%	-50%	0%
CANADA	-	365	84	0	-	43	492	0%	1%	1%	0%	0%	0%
AZNM	335	950	424	0	0	123	1,832	0%	45%	927%	0%	-50%	0%
NWP1	52	198	23	0	-	1,648	1,921	0%	6%	133%	0%	0%	4%
NWP2	-	618	37	-	0	323	978	0%	6%	469%	0%	0%	0%
MEXICO	-	-	21	0	0	35	56	0%	0%	-86%	0%	-98%	0%
TOTAL	681	2,832	1,137	1	0	2,921	7,573	0%	9%	-14%	0%	-91%	1%

Fuel Consumption Patterns
(Change from "Base Case" Scenario)
Southeast

Table C3-94 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Southeast

Scenario 1 -- No Trade

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [1]	Coal [2]	Gas [3]	Oil [4]	Other [5]	Total [6]	Uranium [7]	Coal [8]	Gas [9]	Oil [10]	Other [11]
Florida	285	588	284	510	3	1,670	0%	5%	22%	64%	0%
Sout	450	1,162	31	2	115	1,760	0%	-11%	-44%	0%	0%
TVA	205	717	43	4	218	1,187	0%	-22%	150%	0%	0%
SPPS	383	407	583	13	5	1,391	0%	4%	24%	0%	0%
VACR	1,092	1,201	36	75	54	2,458	0%	12%	37%	200%	0%
APS	-	354	1	1	3	359	0%	-14%	0%	0%	0%
AEP	99	1,325	0	3	10	1,437	0%	1%	0%	0%	0%
TOTAL	2,515	5,755	977	609	409	10,264	0%	-4%	22%	69%	0%

Scenario 3 -- TXs Only

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [12]	Coal [13]	Gas [14]	Oil [15]	Other [16]	Total [17]	Uranium [18]	Coal [19]	Gas [20]	Oil [21]	Other [22]
Florida	285	562	232	298	3	1,379	0%	0%	0%	-5%	0%
Sout	449	1,223	33	2	115	1,823	0%	-6%	-40%	0%	0%
TVA	205	918	34	4	218	1,380	0%	0%	100%	0%	0%
SPPS	383	403	478	13	5	1,283	0%	3%	2%	0%	0%
VACR	1,092	1,082	27	2	54	2,258	0%	0%	4%	-90%	0%
APS	-	423	1	1	3	429	0%	3%	0%	0%	0%
AEP	99	1,394	0	3	10	1,506	0%	6%	0%	0%	0%
TOTAL	2,514	6,005	805	324	409	10,056	0%	0%	0%	-10%	0%

Table C3-94 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Southeast

Scenario 4 -- Fees Only

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [23]	Coal [24]	Gas [25]	Oil [26]	Other [27]	Total [28]	Uranium [29]	Coal [30]	Gas [31]	Oil [32]	Other [33]
Florida	285	531	141	64	3	1,024	0%	-5%	-39%	-80%	0%
Sout	450	1,454	129	2	115	2,151	0%	12%	136%	0%	0%
TVA	205	984	17	4	218	1,428	0%	7%	0%	0%	0%
SPPS	383	305	285	13	5	991	0%	-22%	-39%	0%	0%
VACR	1,092	1,169	30	25	54	2,370	0%	8%	13%	0%	0%
APS	-	438	1	1	3	444	0%	7%	0%	0%	0%
AEP	99	1,489	0	3	10	1,601	0%	13%	0%	0%	0%
TOTAL	2,515	6,371	603	112	409	10,010	0%	7%	-25%	-69%	0%

Scenario 5 -- Free Trade

Market Area	1994 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [34]	Coal [35]	Gas [36]	Oil [37]	Other [38]	Total [39]	Uranium [40]	Coal [41]	Gas [42]	Oil [43]	Other [44]
Florida	285	486	101	35	3	910	0%	-13%	-57%	-89%	0%
Sout	449	1,355	68	2	115	1,990	0%	4%	24%	0%	0%
TVA	205	983	17	4	218	1,427	0%	7%	0%	0%	0%
SPPS	383	286	226	13	5	915	0%	-27%	-52%	0%	0%
VACR	1,092	1,316	41	2	54	2,506	0%	22%	57%	-90%	0%
APS	-	453	1	1	3	458	0%	10%	0%	0%	0%
AEP	99	1,707	0	3	10	1,819	0%	30%	0%	0%	0%
TOTAL	2,514	6,587	454	61	409	10,025	0%	10%	-43%	-83%	0%

Table C3-97 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Southeast

Scenario 1 -- No Trade

Market Area	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [1]	Coal [2]	Gas [3]	Oil [4]	Other [5]	Total [6]	Uranium [7]	Coal [8]	Gas [9]	Oil [10]	Other [11]
Florida	251	651	478	231	3	1,613	0%	3%	23%	30%	0%
Sout	453	1,231	46	2	135	1,867	0%	-9%	-19%	0%	0%
TVA	450	841	50	2	222	1,566	0%	-15%	200%	0%	0%
SPPS	406	409	499	26	8	1,347	0%	-6%	17%	43%	0%
VACR	1,076	1,448	26	30	57	2,637	0%	13%	62%	200%	0%
APS	-	381	19	5	2	407	0%	-14%	4900%	1900%	0%
AEP	161	1,287	0	3	13	1,463	0%	-10%	900%	0%	0%
TOTAL	2,798	6,248	1,116	299	439	10,900	0%	-5%	23%	41%	0%

Scenario 3 -- TXs Only

Market Area	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [12]	Coal [13]	Gas [14]	Oil [15]	Other [16]	Total [17]	Uranium [18]	Coal [19]	Gas [20]	Oil [21]	Other [22]
Florida	251	633	390	170	3	1,446	0%	0%	1%	-4%	0%
Sout	453	1,283	46	2	135	1,919	0%	-5%	-19%	0%	0%
TVA	450	990	25	2	222	1,690	0%	0%	50%	0%	0%
SPPS	406	435	440	22	8	1,311	0%	0%	3%	22%	0%
VACR	1,076	1,259	15	10	57	2,417	0%	-2%	-4%	0%	0%
APS	-	445	0	0	2	448	0%	1%	0%	0%	0%
AEP	161	1,541	0	3	13	1,717	0%	7%	0%	0%	0%
TOTAL	2,798	6,586	916	210	439	10.949	0%	0%	1%	-1%	0%

Table C3-97 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Southeast

Scenario 4 -- Fees Only

Market Area	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [23]	Coal [24]	Gas [25]	Oil [26]	Other [27]	Total [28]	Uranium [29]	Coal [30]	Gas [31]	Oil [32]	Other [33]
Florida	251	552	220	81	3	1,106	0%	-13%	-43%	-54%	0%
Sout	453	1,513	85	2	135	2,188	0%	12%	51%	0%	0%
TVA	450	1,114	8	2	222	1,797	0%	12%	-50%	0%	0%
SPPS	406	354	237	5	8	1,010	0%	-19%	-44%	-74%	0%
VACR	1,076	1,342	25	10	57	2,510	0%	4%	57%	0%	0%
APS	-	454	0	0	2	457	0%	3%	0%	0%	0%
AEP	161	1,759	0	3	13	1,936	0%	23%	0%	0%	0%
TOTAL	2,798	7,088	575	103	439	11,003	0%	8%	-36%	-51%	0%

Scenario 5 -- Free Trade

Market Area	1997 Fuel Consumption (million mmbtu)						% Change in Fuel Consumption from Base Case				
	Uranium [34]	Coal [35]	Gas [36]	Oil [37]	Other [38]	Total [39]	Uranium [40]	Coal [41]	Gas [42]	Oil [43]	Other [44]
Florida	251	479	183	59	3	974	0%	-24%	-53%	-66%	0%
Sout	453	1,393	73	2	135	2,056	0%	3%	30%	0%	0%
TVA	450	1,110	8	2	222	1,793	0%	12%	-50%	0%	0%
SPPS	406	336	273			1,029	0%	-23%	-36%	-66%	0%
				6	8						
VACR	1,076	1,499	28	10	57	2,670	0%	17%	77%	0%	0%
APS	-	457	0	0	2	459	0%	3%	0%	0%	0%
AEP	161	1,874	0	3	13	2,051	0%	31%	0%	0%	0%
TOTAL	2,798	7,148	566	83	439	11,034	0%	9%	-37%	-61%	0%

Table C3-00 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Southeast

Scenario 1 -- No Trade

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [1]	Coal [2]	Gas [3]	Oil2 [4]	Oil6 [5]	Other [6]	Total [7]	Uranium [8]	Coal [9]	Gas [10]	Oil2 [11]	Oil6 [12]	Other [13]
Florida	251	647	579	0	79	102	1,657	0%	3%	19%	0%	46%	0%
Sout	453	1,256	93	0	0	-	1,803	0%	-8%	-18%	0%	0%	0%
TVA	450	925	361	0	-	-	1,737	0%	-4%	213%	0%	0%	0%
SPPS	413	409	573	-	-	1	1,396	0%	0%	13%	-100%	0%	0%
VACR	1,084	1,488	30	0	1	32	2,635	0%	10%	26%	0%	900%	0%
APS	-	444	19	-	0	-	463	0%	-7%	500%	0%	0%	0%
AEP	165	1,358	0	0	-	-	1,523	0%	-19%	0%	0%	0%	0%
TOTAL	2,815	6,527	1,656	1	80	135	11,214	0%	-4%	17%	-100%	48%	0%

Scenario 3 -- TXs Only

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [14]	Coal [15]	Gas [16]	Oil2 [17]	Oil6 [18]	Other [19]	Total [20]	Uranium [21]	Coal [22]	Gas [23]	Oil2 [24]	Oil6 [25]	Other [26]
Florida	251	629	506	0	54	102	1,541	0%	0%	0%	0%	0%	0%
Sout	453	1,331	106	0	0	-	1,890	0%	-3%	-14%	0%	0%	0%
TVA	450	965	166	0	-	-	1,582	0%	1%	33%	0%	0%	0%
SPPS	413	409	588	0	-	1	1,410	0%	0%	3%	0%	0%	0%
VACR	1,084	1,330	43	0	0	32	2,489	0%	0%	-3%	0%	0%	0%
APS	-	430	4	-	-	-	433	0%	1%	0%	0%	-100%	0%
AEP	165	1,723	0	0	-	-	1,888	0%	2%	-90%	0%	0%	0%
TOTAL	2,815	6,817	1,413	1	54	135	11,235	0%	0%	0%	0%	0%	0%

Table C3-00 Fuel Consumption Patterns (Change from "Base Case" Scenario) - Southeast

Scenario 4 -- Fees Only

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [27]	Coal [28]	Gas [29]	Oil2 [30]	Oil6 [31]	Other [32]	Total [33]	Uranium [34]	Coal [35]	Gas [36]	Oil2 [37]	Oil6 [38]	Other [39]
Florida	251	559	328	0	19	102	1,258	0%	-11%	-40%	0%	-65%	0%
Sout	453	1,507	256	0	0	-	2,217	0%	10%	53%	0%	0%	0%
TVA	450	1,116	42	0	-	-	1,607	0%	16%	-67%	-70%	0%	0%
SPPS	413	370	381	0	-	1	1,164	0%	-10%	-33%	0%	0%	0%
VACR	1,084	1,389	55	0	0	32	2,560	0%	3%	23%	-70%	0%	0%
APS	-	459	4	-	0	-	462	0%	8%	0%	0%	0%	0%
AEP	165	1,858	0	-	-	-	2,023	0%	10%	0%	-100%	0%	0%
TOTAL	2,815	7,256	1,065	0	19	135	11,292	0%	6%	-24%	-40%	-64%	0%

Scenario 5 -- Free Trade

Market Area	2000 Fuel Consumption (million mmbtu)							% Change in Fuel Consumption from Base Case					
	Uranium [40]	Coal [41]	Gas [42]	Oil2 [43]	Oil6 [44]	Other [45]	Total [46]	Uranium [47]	Coal [48]	Gas [49]	Oil2 [50]	Oil6 [51]	Other [52]
Florida	251	498	273	0	12	102	1,136	0%	-21%	-50%	0%	-78%	0%
Sout	453	1,414	226	0	0	-	2,094	0%	4%	34%	0%	0%	0%
TVA	450	1,116	50	0	-	-	1,616	0%	16%	-60%	-70%	0%	0%
SPPS	413	354	421	0	-	1	1,189	0%	-13%	-26%	0%	0%	0%
VACR	1,084	1,520	87	0	0	32	2,722	0%	15%	48%	-70%	0%	0%
APS	-	466	7	-	-	-	473	0%	9%	100%	0%	-100%	0%
AEP	165	1,899	0	-	-	-	2,063	0%	13%	-90%	-100%	0%	0%
TOTAL	2,815	7,266	1,065	0	12	135	11,294	0%	7%	-24%	-40%	-78%	0%

Open Access Transmission Tariff (Order 888)

Open Access Transmission Tariff (Order 888)

$/kW of Reserved Capacity per period	Yearly	Monthly	Weekly	Daily	Hourly * ($/MWh)
ECAR (average)					**$ 3.18**
American Electric Power	$ 24.25	$ 2.04	$ 0.47	$ 0.095	$ 3.94
Cinergy Services, Inc.	$ 12.11	$ 1.01	$ 0.23	$ 0.047	$ 1.96
Cleveland Electric Illuminating Co. and Toledo Edison	$ 26.16	$ 2.18	$ 0.50	$ 0.101	$ 4.21
Dayton Power & Light Co.	$ 27.96	$ 2.33	$ 0.54	$ 0.108	$ 4.50
Duquesne Light Co.	$ 19.57	$ 1.63	$ 0.38	$ 0.054	$ 2.25
Hoosier Energy R E C, Inc.	$ 33.04	$ 2.75	$ 0.64	$ 0.127	$ 5.30
Kentucky Utilities Company	$ 19.30	$ 1.61	$ 0.37	$ 0.074	$ 3.08
Louisville Gas & Electric Co.		$ 1.16	$ 0.27	$ 0.054	$ 2.25
Northern Indiana Public Service Co.	$ 32.88	$ 2.74	$ 0.63	$ 0.130	$ 5.42
Ohio Edison Co.	$ 14.13	$ 1.18	$ 0.27	$ 0.054	$ 2.25
Ohio Valley Electric Corp.		$ 0.44	$ 0.10	$ 0.020	$ 0.83
Southern Indiana Gas & Electric Co.	$ 13.35	$ 1.11	$ 0.26	$ 0.051	$ 2.13
ERCOT					**$ 3.88**
Texax-New Mexico Power Co.	$ 33.95	$ 2.83	$ 0.65	$ 0.130	$ 5.42
West Texas Utilities Co.	$ 14.58	$ 1.21	$ 0.28	$ 0.056	$ 2.34
MACC (average)					**$ 4.13**
Atlantic City Electric Co.	$ 34.86	$ 2.91	$ 0.67	$ 0.134	$ 5.58
Baltimore Gas & Electric Co.	$ 14.39	$ 1.20	$ 0.28	$ 0.055	$ 3.46
Delmarva Power & Light Co.					
General Public Utilities					
PJM Interconnection	$ 22.38	$ 1.87	$ 0.43	$ 0.086	$ 3.59
Pennsylvania Power & Light Co. (at 138 or 69 kV)	$ 26.80	$ 2.23	$ 0.52	$ 0.100	$ 4.17
Public Service Electric & Gas Co.	$ 24.12	$ 2.01	$ 0.46	$ 0.093	$ 3.88
MAIN (average)					**$ 2.67**
Central Illinois Public Service Co.	$ 27.46	$ 2.29	$ 0.53	$ 0.105	$ 4.38
Central Illinois Light Co. (M-F)	$ 11.54	$ 0.96	$ 0.22	$ 0.044	$ 1.83
Commonwealth Edison and ComEd of IN (M-F)	$ 16.80	$ 1.40	$ 0.32	$ 0.065	$ 2.71
Electric Energy, Inc.	$ 2.76	$ 0.23	$ 0.05	$ 0.011	$ 0.44
Illinois Power Co. (on-peak)	$ 13.58	$ 1.13	$ 0.26	$ 0.052	$ 2.17
Madison Gas & Electric Co.	$ 25.68	$ 2.14	$ 0.50	$ 0.099	$ 4.13
South Illinois Power Coop.	$ 27.72	$ 2.31	$ 0.53	$ 0.107	$ 4.44
Union Electric Co.	$ 13.20	$ 1.10	$ 0.25	$ 0.051	$ 2.13
Wisconsin Electric Power Co. (M-F)	$ 9.63	$ 0.80	$ 0.19	$ 0.037	$ 1.54
Wisconsin Power & Light Co. (M-F)	$ 19.20	$ 1.60	$ 0.37	$ 0.070	$ 2.92
MAPP (average)					**$ 4.39**
Interstate Power Co.	$ 27.16	$ 2.26	$ 0.52	$ 0.104	$ 4.33
IES Utilities Inc.	$ 25.15	$ 2.10	$ 0.48	$ 0.100	$ 4.17
Minnesota Power & Light Co. and Superior	$ 27.72	$ 2.31	$ 0.53	$ 0.107	$ 4.46
MidAmerican Energy Co. (M-F)	$ 19.12	$ 1.59	$ 0.37	$ 0.074	$ 3.08
Northern States Power Companies	$ 17.70	$ 1.48	$ 0.34	$ 0.068	$ 2.83
Northwestern Public Service Co.	$ 46.44	$ 3.87	$ 0.89	$ 0.179	$ 7.46
NPCC (average)					**$ 4.28**
Bangor Hydro-Electric Company	$ 28.00	$ 2.33	$ 0.54	$ 0.077	$ 3.20
Boston Edison Co.	$ 21.60	$ 1.80	$ 0.15	$ 0.059	$ 2.47
Central Hudson Gas & Electric Corp.	$ 31.81	$ 2.65	$ 0.61	$ 0.122	$ 5.10
Consolidated Edison Co. of NY Inc.	$ 42.81	$ 3.65	$ 0.84	$ 0.170	$ 7.08
Green Mountain Power Corp.	$ 17.76	$ 1.48	$ 0.34	$ 0.068	$ 2.83
Long Island Lighting Co.	$ 35.94	$ 3.00	$ 0.69	$ 0.140	$ 5.83
New York Port Authority	$ 26.76	$ 2.23	$ 0.51	$ 0.100	$ 4.17
New York State Electric & Gas Corp.	$ 33.98	$ 2.83	$ 0.65	$ 0.130	$ 5.42
Niagara Mohwak Power Corp.	$ 25.78	$ 2.15	$ 0.50	$ 0.099	$ 4.13
Orange and Rockland Utilities, Inc.	$ 32.15	$ 2.68	$ 0.62	$ 0.124	$ 5.15
Rochester Gas & Electric Corp.	$ 23.85	$ 1.99	$ 0.46	$ 0.092	$ 3.82
United Illuminating Co.	$ 26.39	$ 2.20	$ 0.51	$ 0.072	$ 3.00
Vermont Electric Power Co.	$ 21.53	$ 1.79	$ 0.41	$ 0.083	$ 3.45

Open Access Transmission Tariff (Order 888)

$/kW of Reserved Capacity per period	**Yearly**	**Monthly**	**Weekly**	**Daily**	**Hourly *** **($/MWh)**
SERC (average)					$ **2.63**
Duke Power Co. (on-peak)	$ 12.36	$ 1.03	$ 0.24	$ 0.048	$ 2.00
Carolina Power & Light Co. (on-peak)	$ 17.06	$ 1.42	$ 0.33	$ 0.066	$ 2.75
South Carolina Electric & Gas Co.	$ 20.33	$ 1.69	$ 0.39	$ 0.060	$ 2.50
South Carolina Public Service Authority	$ 22.48	$ 1.87	$ 0.43	$ 0.090	$ 3.75
Southern Companies	$ 20.75	$ 1.73	$ 0.40	$ 0.057	$ 2.38
Tampa Electric Co.	$ 15.29	$ 1.27	$ 0.29	$ 0.042	$ 1.75
TVA	$ 20.56	$ 1.71	$ 0.40	$ 0.079	$ 3.30
Virginia Electric & Power Co.					
SPP (average)					$ **2.59**
Central Louisiana Electric Co., Inc.	$ 16.54	$ 1.38	$ 0.32	$ 0.064	$ 2.65
Empire District Electric Co.	$ 23.29	$ 1.94	$ 0.45	$ 0.090	$ 3.75
Kansas City Power & Light Co. (losses not supplied; 34 & 69 kV)		$ 1.01	$ 0.23	$ 0.047	$ 1.96
Oklahoma Gas & Electric Co.		$ 1.82	$ 0.43	$ 0.087	$ 3.63
Omaha Public Power District (losses not supplied)	$ 12.80	$ 1.07	$ 0.25	$ 0.049	$ 2.05
Public Service Co. of Oklahoma and	$ 14.58	$ 1.21	$ 0.28	$ 0.056	$ 2.34
St. Joseph Light & Power Co. (at 69 kV)	$ 19.33	$ 1.61	$ 0.37	$ 0.07	$ 3.08
Public Service Co. of Oklahoma and	$ 14.58	$ 1.21	$ 0.28	$ 0.056	$ 2.34
Southwestern Electric Power Co.					
Southwestern Public Service Co.	$ 17.06	$ 1.42	$ 0.33	$ 0.055	$ 2.29
Western Resources, Inc.	$ 15.60	$ 1.30	$ 0.30	$ 0.043	$ 1.78
Entergy Services, Inc.					
WSCC (average)					$ **3.77**
Nevada Power					
Pacific Gas & Electric Co.	$ 16.81	$ 1.40	$ 0.32	$ 0.065	$ 2.69
San Diego Gas & Electric Co.	$ 29.53	$ 2.46	$ 0.57	$ 0.114	$ 4.73
PacifiCorp	$ 24.30	$ 2.03	$ 0.05	$ 0.093	$ 3.88

Source: Order 888, Schedule 7 "Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service.

Note: * Hourly Rate = Daily Rate / 24 hrs. x 1,000.

Lists of Utilities By Market Area

Northeast

APS: Allegheny Power System

CAPC: **Central Area Power Coordinating Group**
Cleveland Electric Illum Co.
City of Columbus
City of Cleveland
Duquesne Light Company
Ohio Edison
Toledo Edison Co.

ECAR: **East Central Area Reliability Coordination Agreement**
Allengheny Electric Cooperative
American Electric Power
American Municipal Power-Ohio, Inc.
Big Rivers Electric Corporation
Cinergy
Consumers Power
Dayton Power & Light
Kentucky Utilities Company
Louisville Gas and Electric
Northern Indiana Public Service Company

MAAC: **Mid-Atlantic Area Council**
Atlantic City Electric Company
Allegheny Electric Cooperative
Baltimore Gas and Electric Company
Delmarva Power & Light Company
General Public Utilities Corporation
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric & Gas Company
UGI Utilities Inc.

NEPL: **New England Power Pool**
Bagor Hydro Electric
Boston Edison Co.
Central Main Power
Chicopee Municipal Lighting Plant
Commonwealth Energy System
Connecticut Municipal Electric Energy Cooperative
Eastern Utilities Associates
Fitchburg Gas and Electric Light Co.
Great Bay Power Corp.
Holyoke Gas and Electric Dept.
Hudson Light & Power Dept.
Hinghamipal Light Dept
Houlton Water Company
Ipswich Municipal Light Dept
Maine cooperative
Middleborough Gas and Electric Dept
Milford Power Limited Partnership
Maine Public Service Company
Marblehead Municipal Light Dept.
Massachusetts Municipal Wholesale Electric Company
New England Electric System Operating Companies
New Hampshire Electric Cooperative
North Attleborough Electric Dept.
Northeast Utilities
Peabody Municipal Light Dept.
Princeton Municipal Light Dept.
Shrewsbury Electric Lighting Plant
Sterling Municipal Light Dept.
Taunton Municipal Light Plant

	The United Illuminating Company
	UNITIL Power corp. Companies
	Vermont Group
NYPP	**New York Power Pool**
	Power Authority of New York
	New York State Electric and Gas
	Niagra-Mohawk Power Corporation
	Rochester Gas and Electric Corporation
	Central Hudson gas and Electric
	Consolidated Edison Company of New York
	Orange and Rockland Utilities
	Long Island Lighting Company
ONTARIO:	Ontario Hydro
HYQB:	Hydro-Quebec
VACR:	**Virginia-Carolinas Subregion**
	Carolina Power and Light
	Duke Power Company
	Natahala Power & Light Company
	North Carolina Electric Membership Cooperatives
	Southeastern Power Administration
	South Carolina Public service Authority
	South Carolina Electric & Gas Company
	Virginia Per Company
	Yadkin, Inc.

Southeast

FRCC:	**Florida Subregion**
	Florida Keys Electric Cooperative Association, Inc.
	Florida Power Corporation
	Florida Power & Light Company
	Florida Municipal Power Agency
	Fort Pierce Utilities Authority
	Gainesville Regional Utilities
	City of Homestead
	Jacksonville Electric Authority
	Utility Board of Key West
	Kissimmee Utility Authority
	City of Lake Worth Utilities
	City of Lakeland
	Utilities Commission of New Smyrna Beach
	City of St.Cloud
	Seminole Electric Cooperative, Inc.
	City of Starke
	City of Tallahassee
	Tampa Electric Company
	City of Vero Beach
	City of Wauchula
SOUTHERN:	**Southern Subregion**
	Alabama Electric Cooperative, Inc.
	Alabama Per Company
	Crisp County Power Commission
	Georgia Power Company
	Gulf Per Company
	Mississippi Power company
	Oglethorpe Per Corporation
	Savannah Electric and Power Company
	Southeastern Power Administration
	South Mississippi Electric Power Association
TVA:	**Tennessee Valley Authority Subregion**
	Southeastern Power Administration
	Tapoco, Inc.
	Tennessee Valley Authority

SPPS: **Southern Subregion of the Southwest Power Pool**
- Arkansas Electric Cooperative Corporation
- Cajun Electric Power Cooperative
- Central Louisiana Electric Company
- City of Alexandria, Louisiana
- City of Clarksdale, Mississippi
- City of Greenwood, Mississippi
- City of Lafayette, Louisiana
- City of Ruston, Louisiana
- Gulf States Utilities Company
- Louisiana Energy and Power Authority
- Entergy Corporation
    - Arkansas Power & Light Company
    - Louisiana Power & Light Company
    - Mississippi Power & Light
    - New Orleans Public Service Inc.
    - Energy Power Incorporated
- Sam Rayburn G&T, Inc.

Western Systems Coordinating Council

AZNM: **Arizona-New Mexico Area**
- Arizona Electric Power Coop
- Arizona Public Service Co
- El Paso Electric Co
- Farmington Electric Utilities
- Imperial Irrigation Distr
- Los Alamos County
- Navajo Tribal Utility
- Plains Elec Gen & Trans C
- PSC of New Mexico
- Salt River Project
- Tucson Electric Power Co.
- WAPA-Phoenix Area Office

NWPP1: **Northwest Power Pool 1 (WA/OR)**
- Bonneville Power Admin.
- Eugene Water & Electric B
- Pacificorp
- Pud No 1 of Chelan County
- Pud No 1 of Pend Oreille
- Pud No 2 of Grant County
- Portland General Electric
- Puget Sound Power & Light
- Seattle City Light
- Tacoma Public Utils-light
- Washington Water Power Co

NWPP2: **Northwest Power Pool 2 (ID, UT,MT, WY, NV)**
- Idaho Power Co.
- Montana Power Co.
- Sierra Pacific Power Co
- Utah Associated Mun Power
- Nevada Power Co

CANADA: **Northwest Pwe Pool-Canada**
- British Columbia Hydro
- Transalta Utilities Corp.
- West Kootenay Power Ltd.

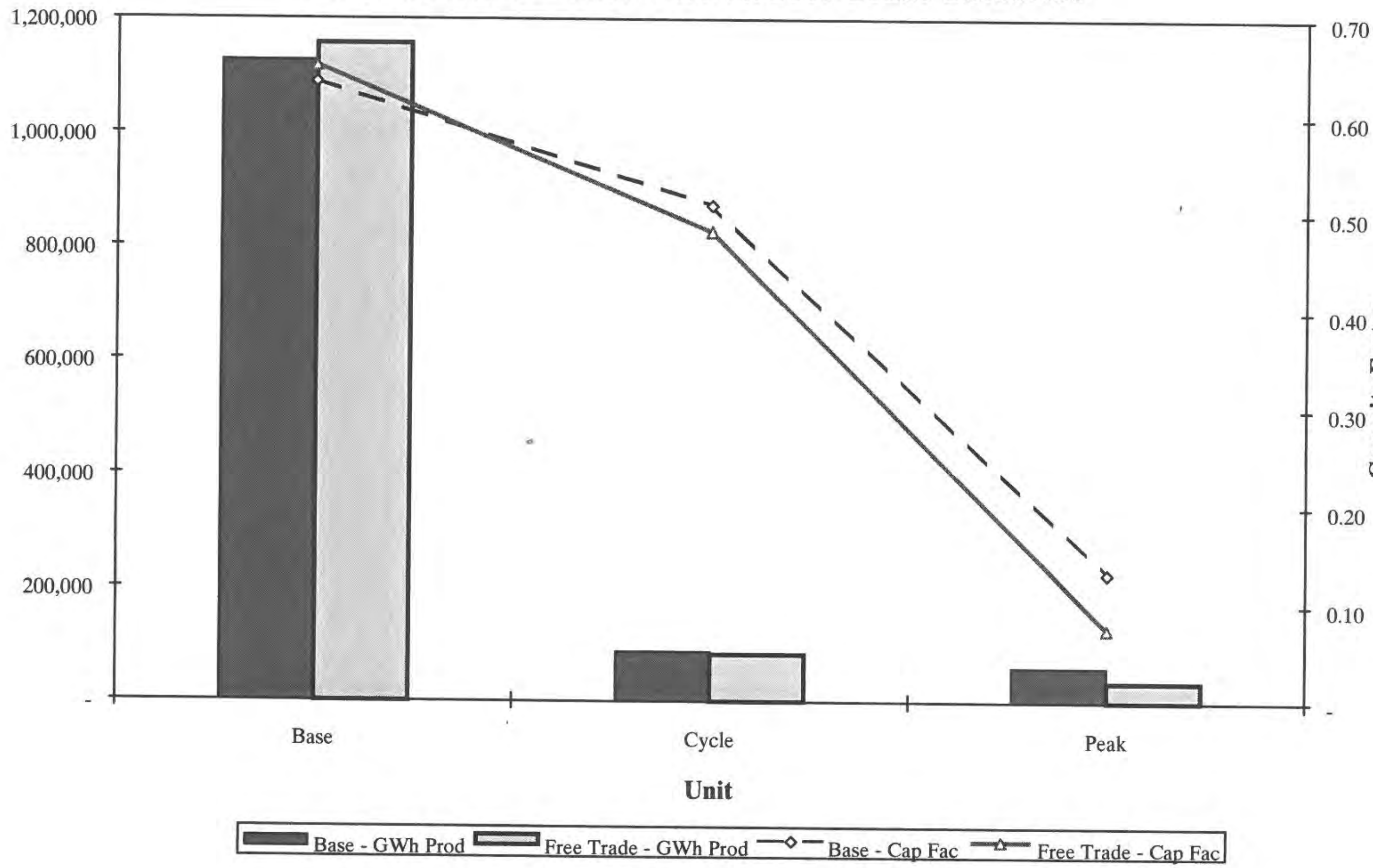
RMPA: **Rocky Mountain Power Area**
- Black Hills Corp.
- Colorado Springs Utilities
- Platte River Power Authority
- PSC of Colorado
- USDOE-WAPA-Fort Collins
- WAPA-Salt Lake City Integ
- Westplains Energy

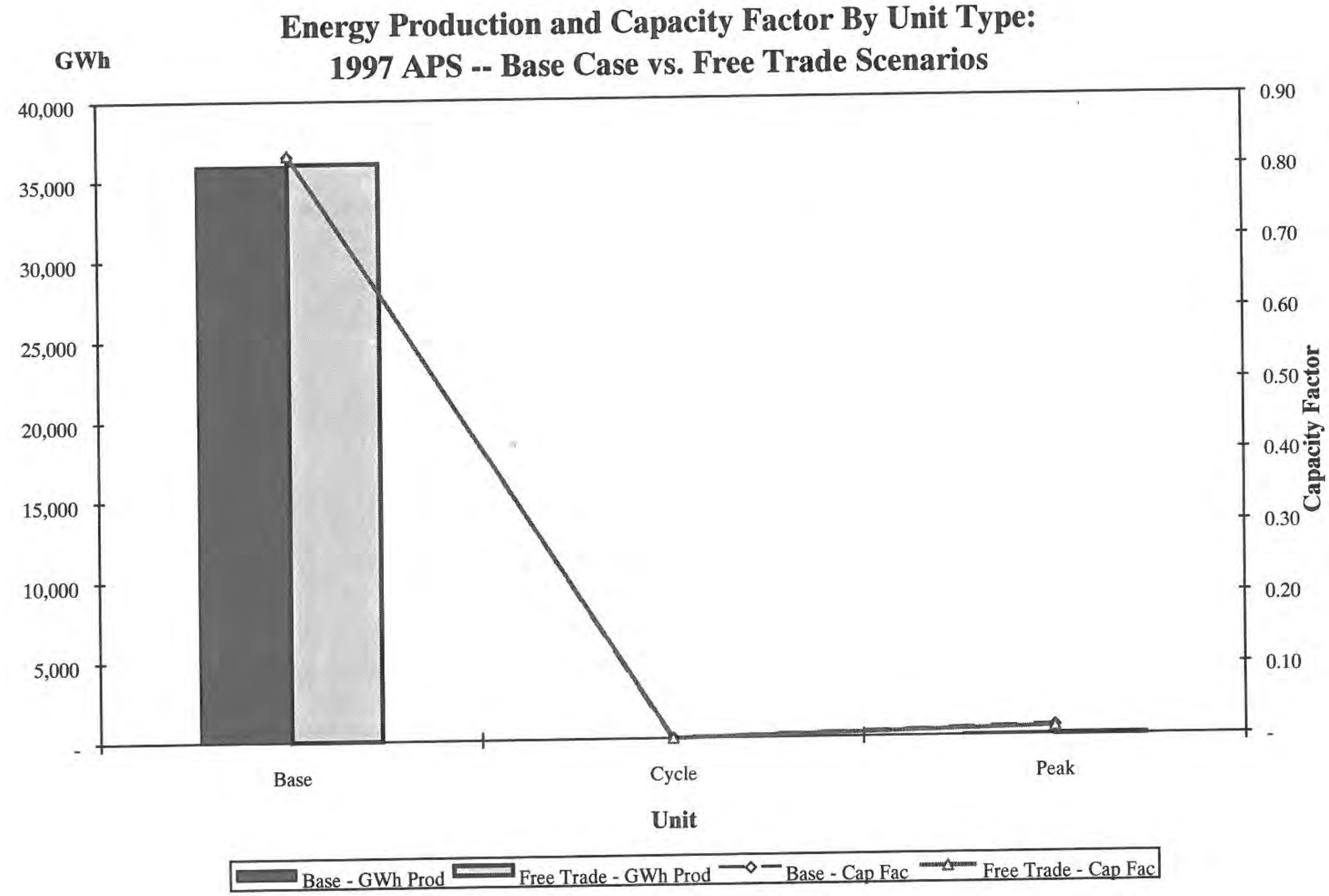
SOCA:	**Southern California** Anaheim Public Utilities Burbank Public Service Dept. Los Angeles Dept of Water Modesto Irrigation Distr. Southern California Edison San Diego Gas & Electric
NOCA:	**Northern California** Northern California Power Pasadena Water and Power Pacific Gas and Electric Co Riverside Utilities Dept. Sacramento Municipal Utilities Santa Clara Electric Dept. Turlock Irrigation Distribution Vernon Municipal Light Dept Western Area Power Admin.
MEXICO:	**Mexico** Commission Federal de Electricidat

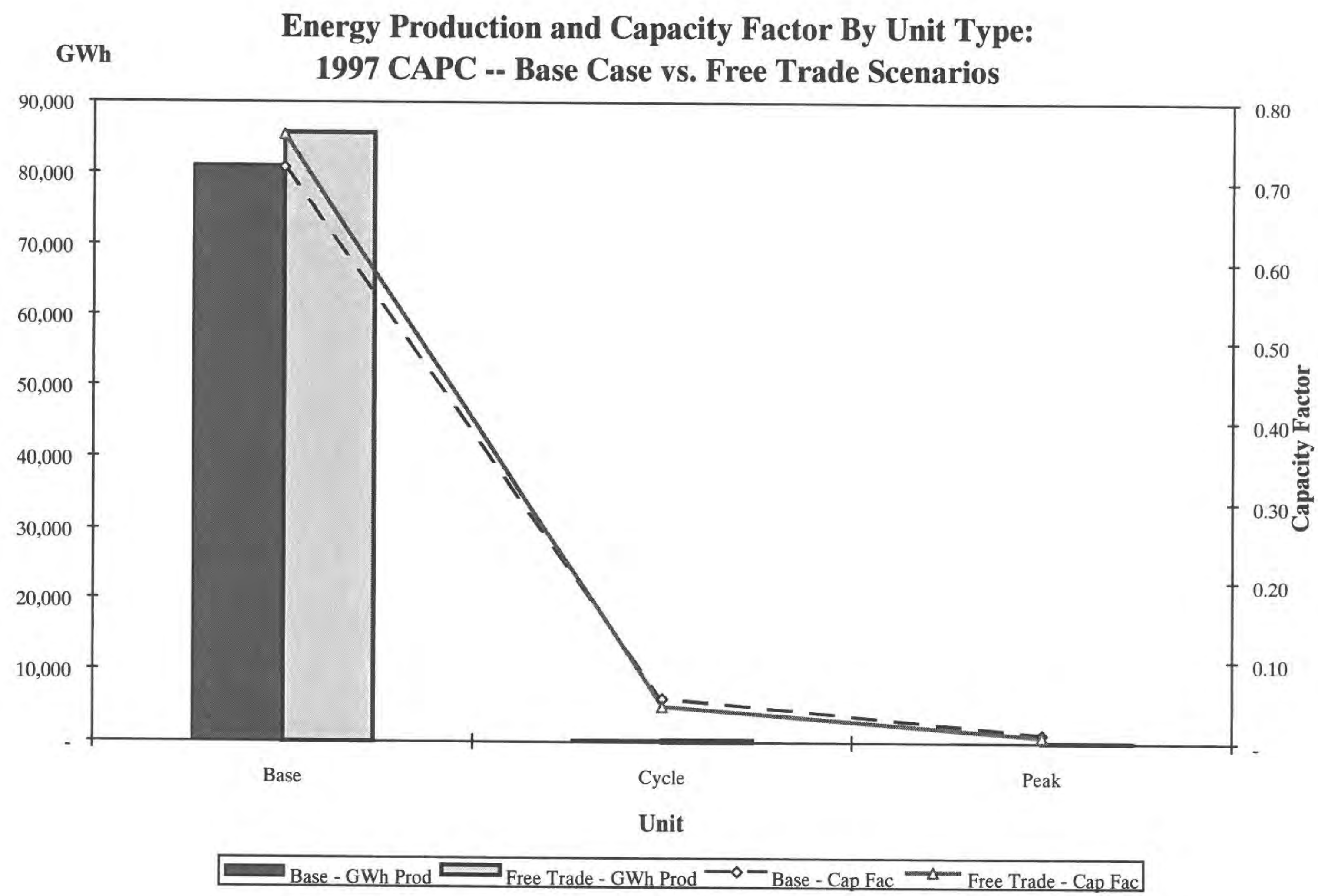
1997 Energy Production and Capacity Factor By Unit Type

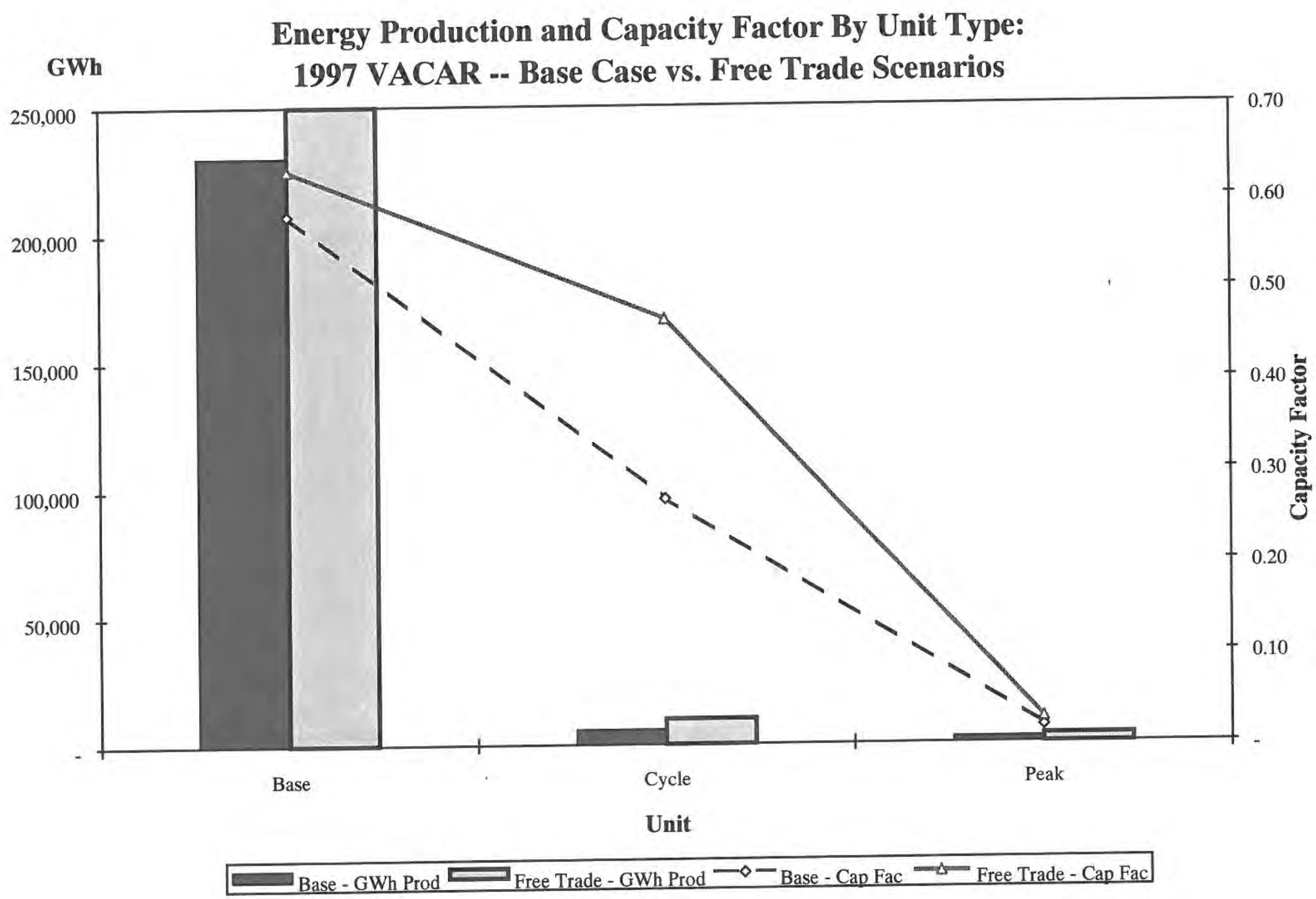
Northeast

Energy Production and Capacity Factor By Unit Type: 1997 Northeast -- Base Case vs. Free Trade Scenarios

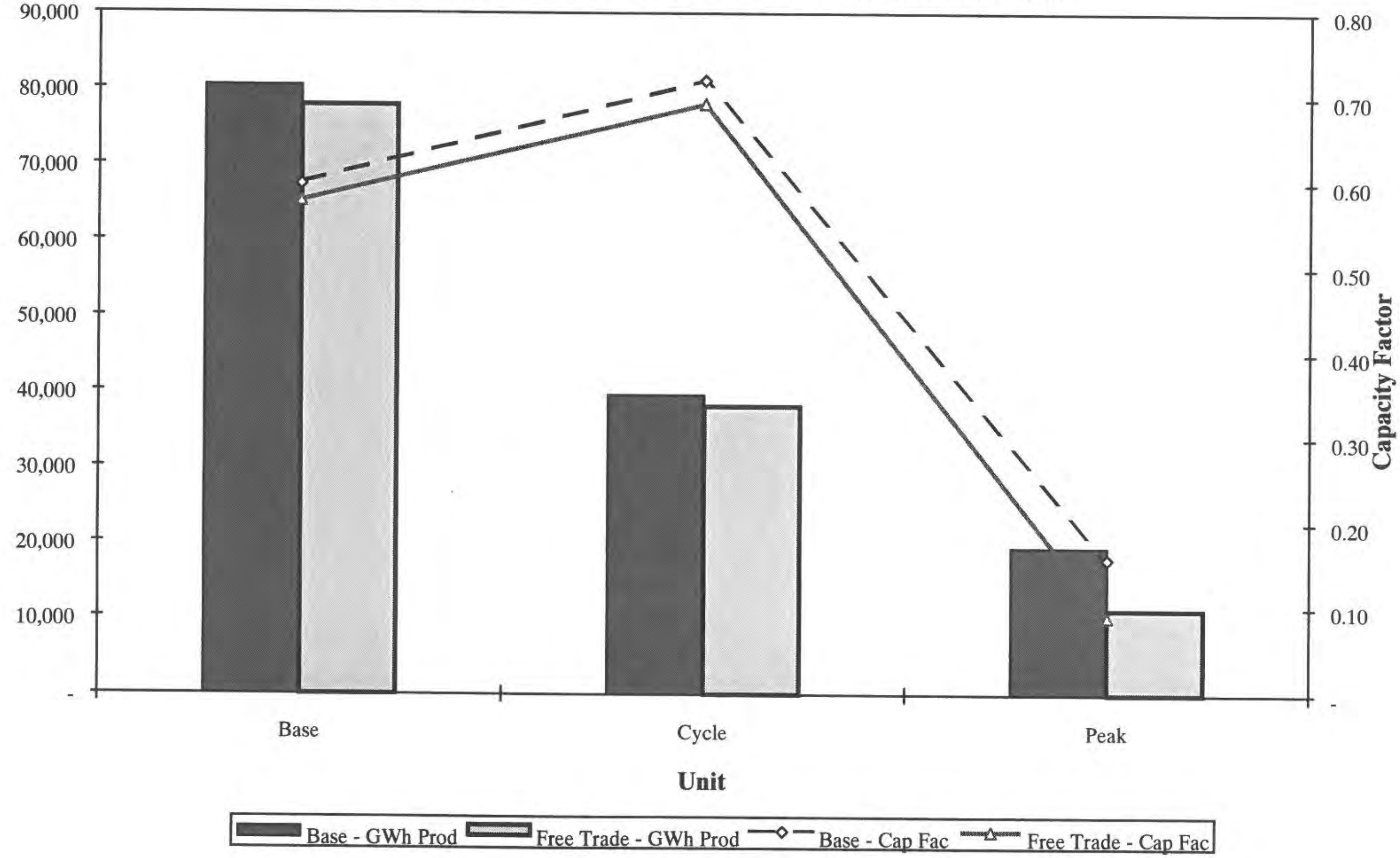



Energy Production and Capacity Factor By Unit Type:
1997 APS -- Base Case vs. Free Trade Scenarios
GWh
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

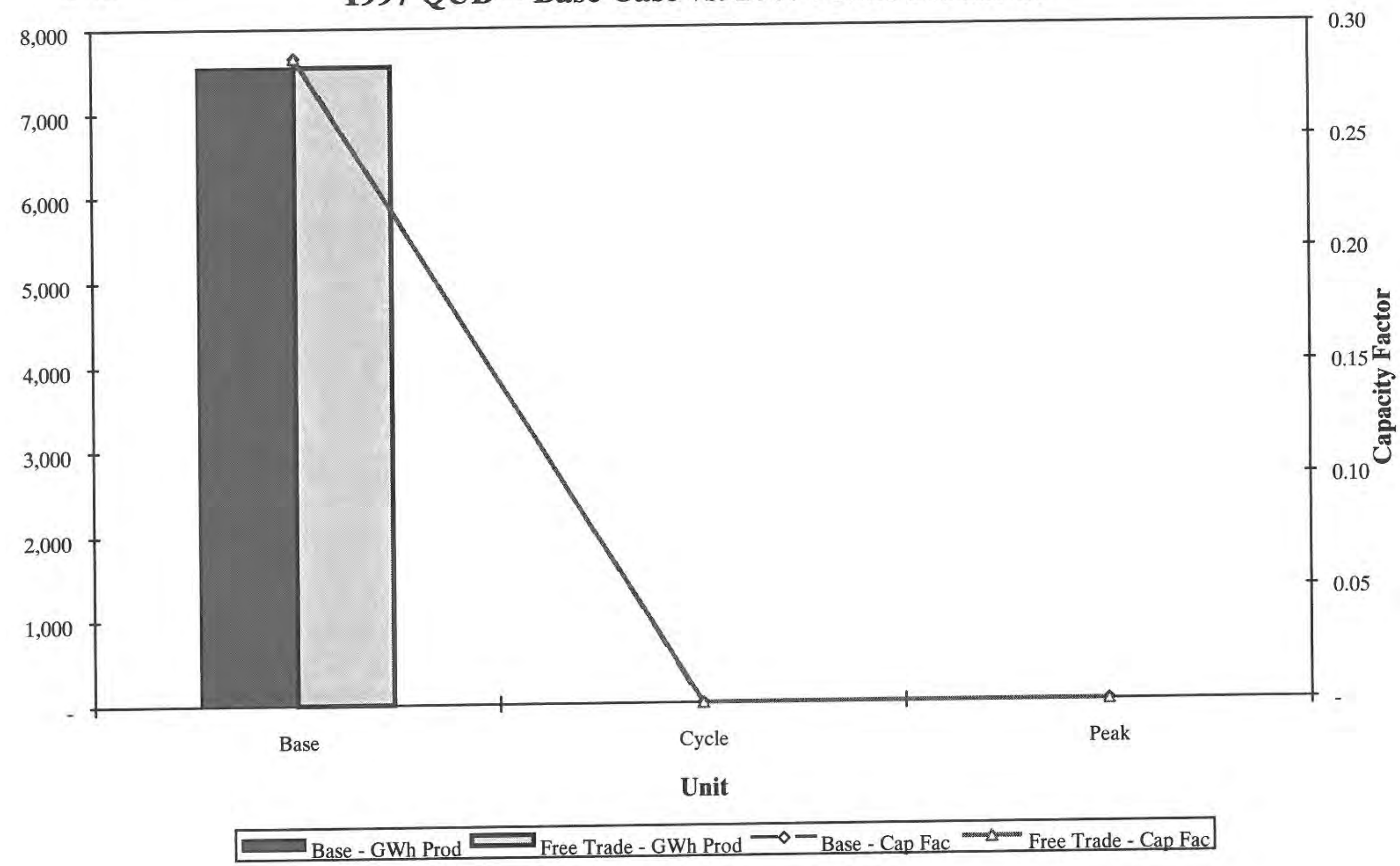

Energy Production and Capacity Factor By Unit Type:
1997 CAPC -- Base Case vs. Free Trade Scenarios
GWh
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

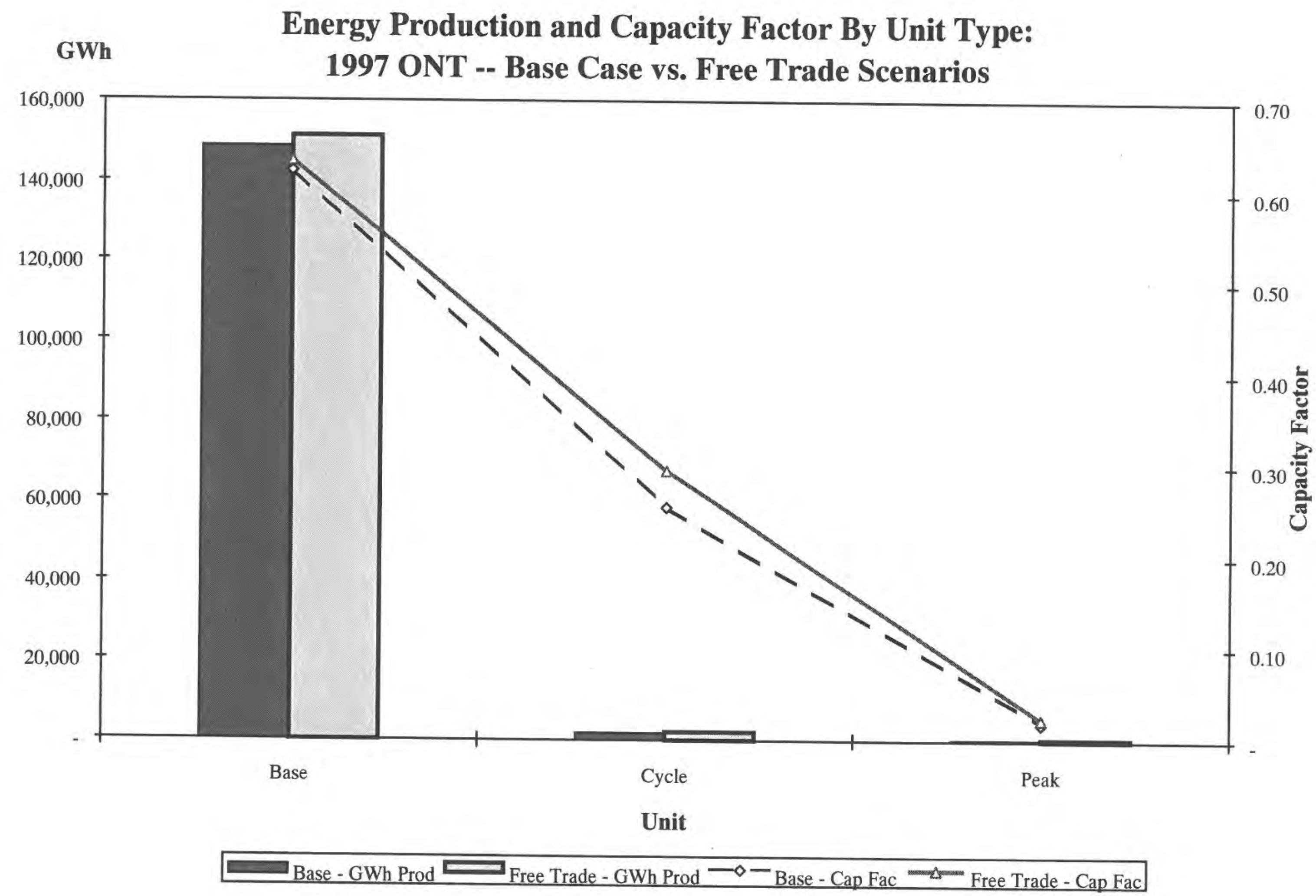

Energy Production and Capacity Factor By Unit Type:
1997 VACAR -- Base Case vs. Free Trade Scenarios
GWh
250,000
200,000
150,000
100,000
50,000
-
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

Energy Production and Capacity Factor By Unit Type: 1997 NYPP -- Base Case vs. Free Trade Scenarios



Energy Production and Capacity Factor By Unit Type: 1997 QUB -- Base Case vs. Free Trade Scenarios

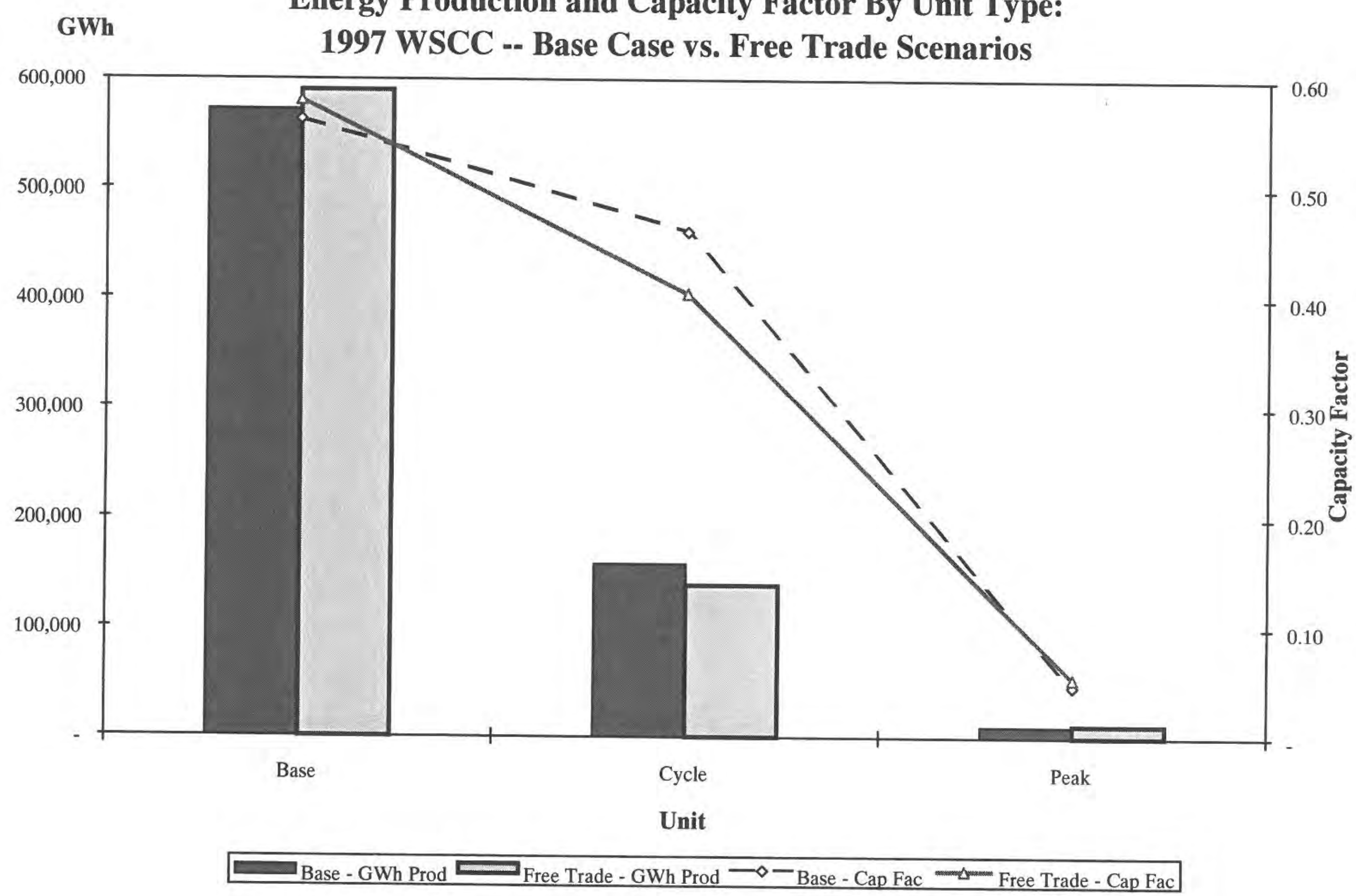



Energy Production and Capacity Factor By Unit Type:
1997 ONT -- Base Case vs. Free Trade Scenarios
GWh
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

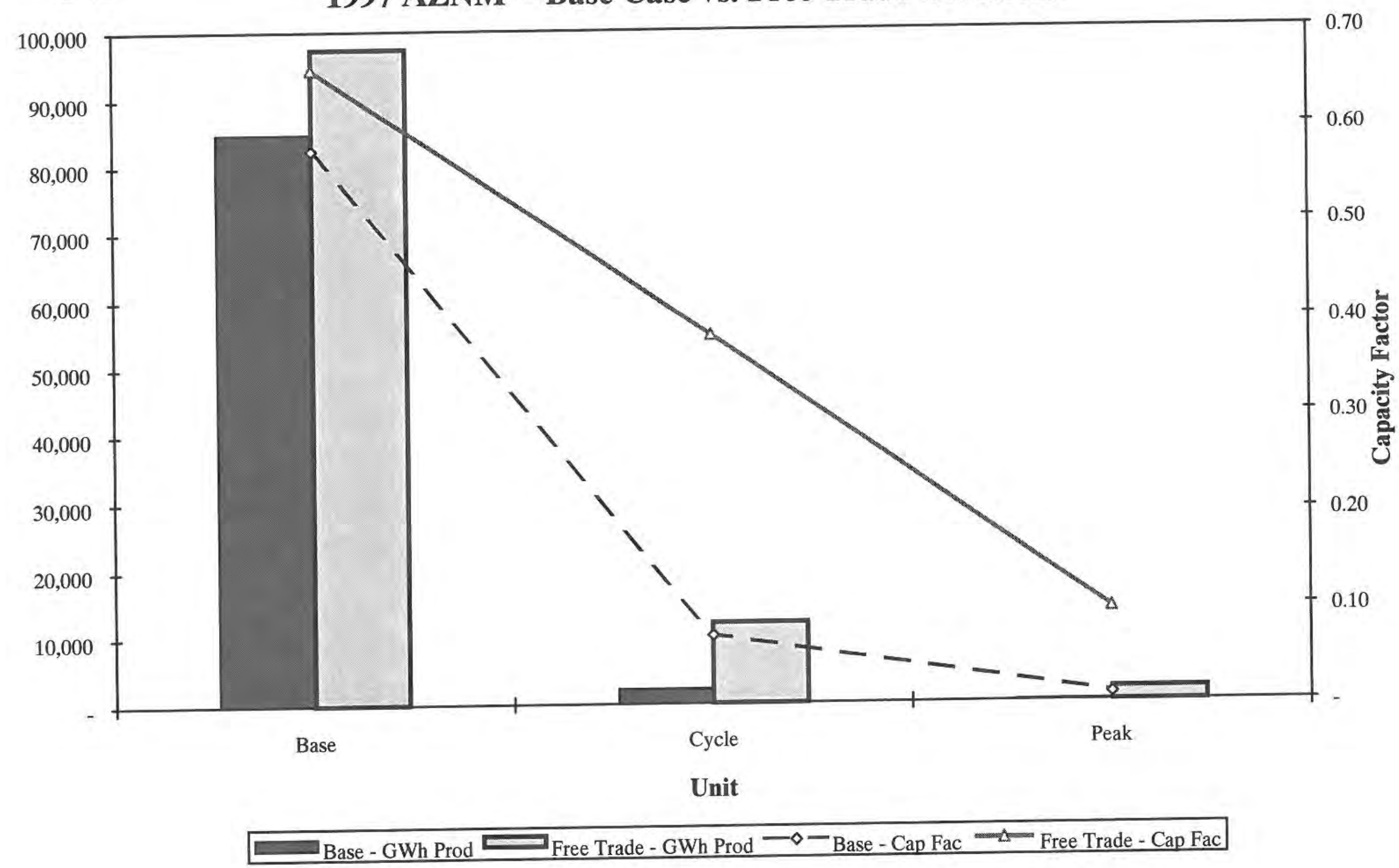
1997 Energy Production and Capacity Factor By Unit Type

WSCC

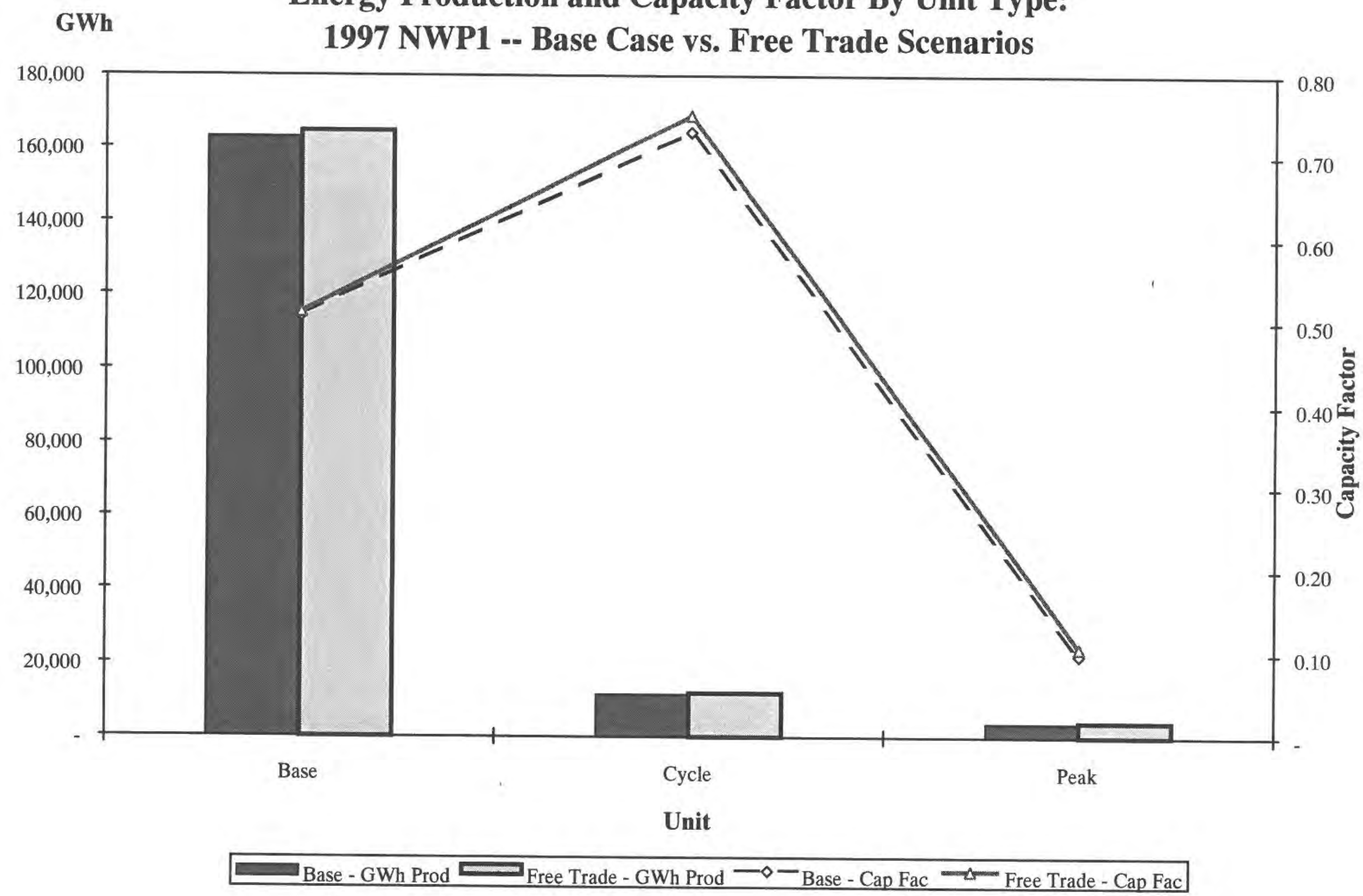
Energy Production and Capacity Factor By Unit Type: 1997 WSCC -- Base Case vs. Free Trade Scenarios

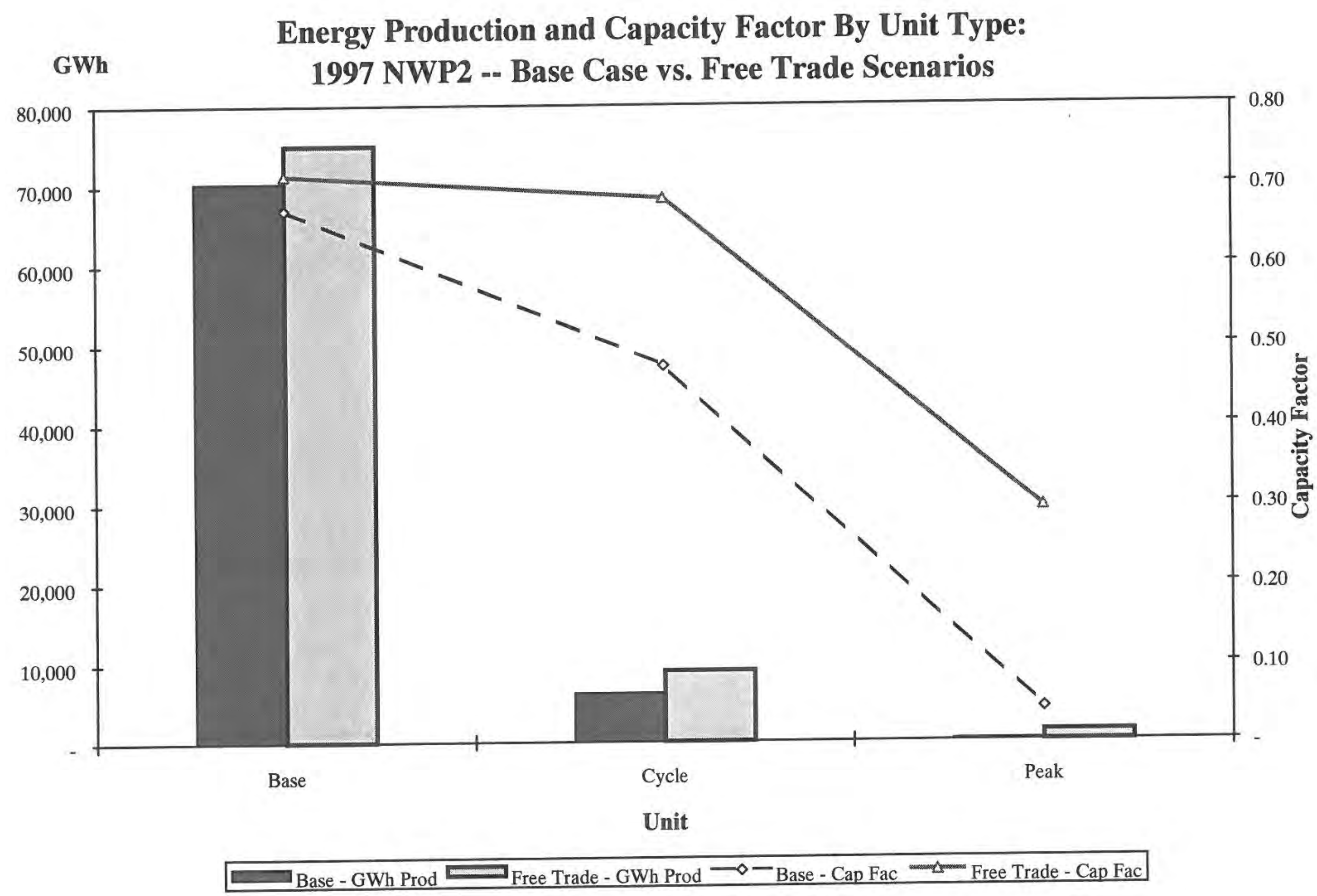


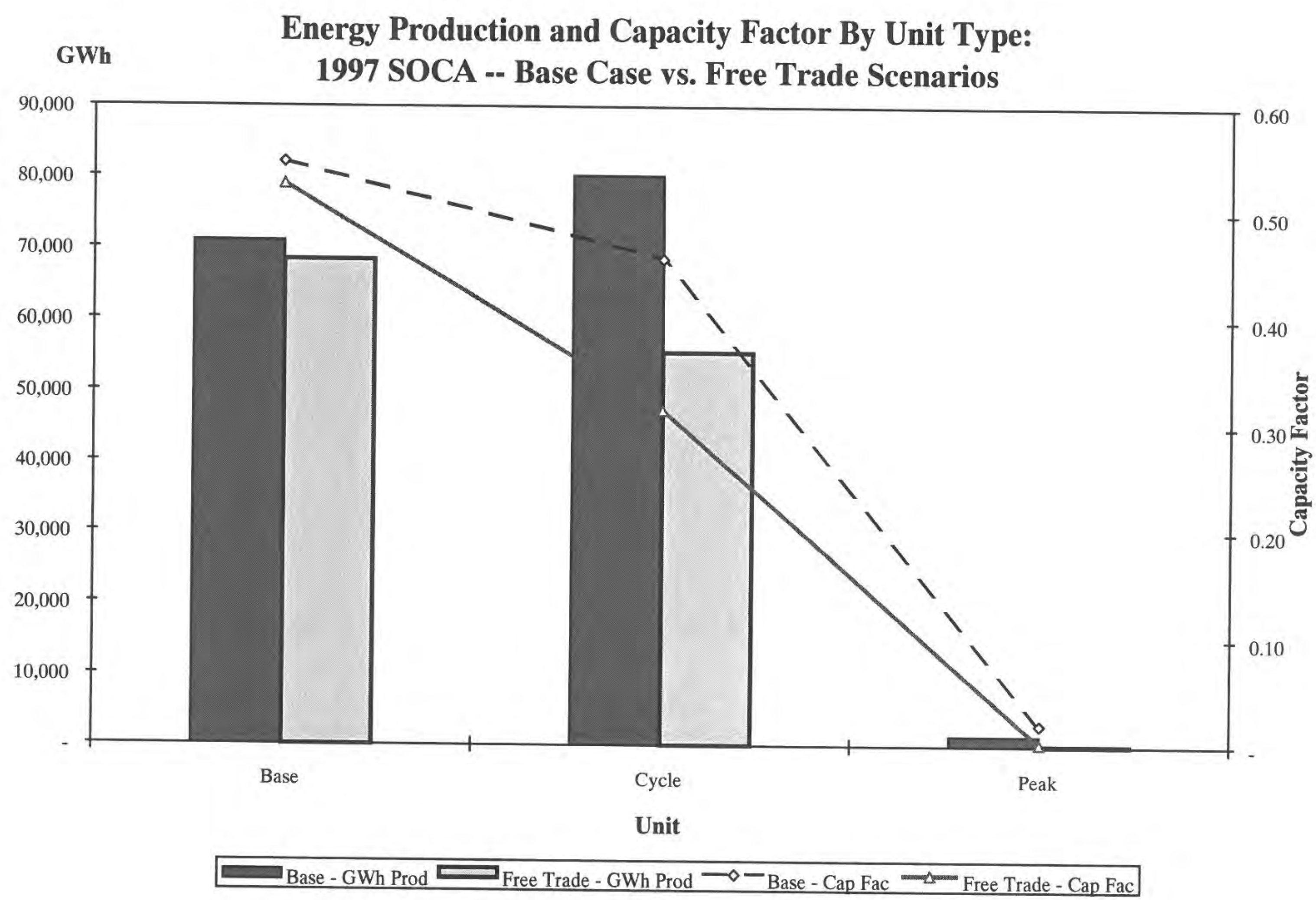
Energy Production and Capacity Factor By Unit Type: 1997 AZNM -- Base Case vs. Free Trade Scenarios

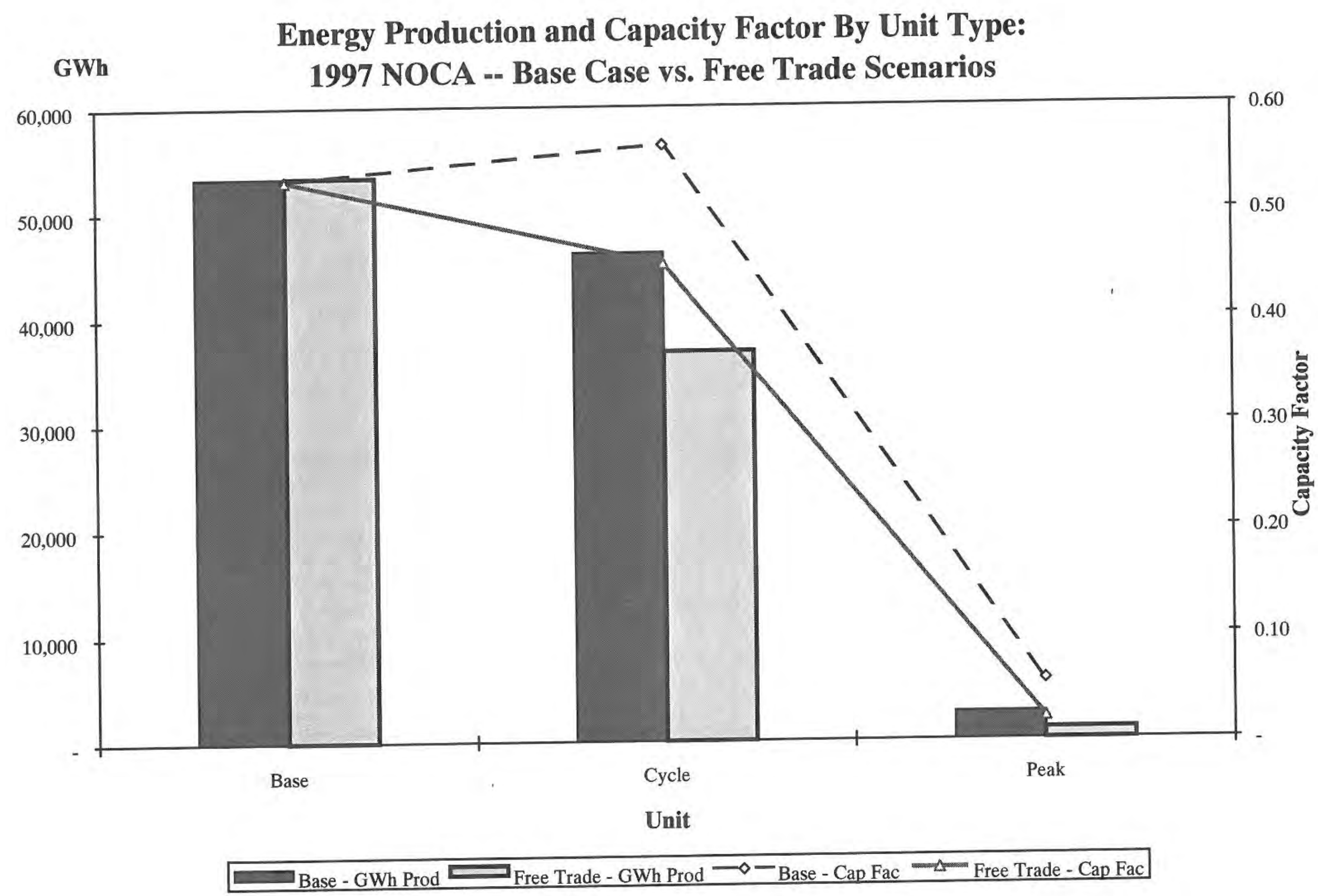


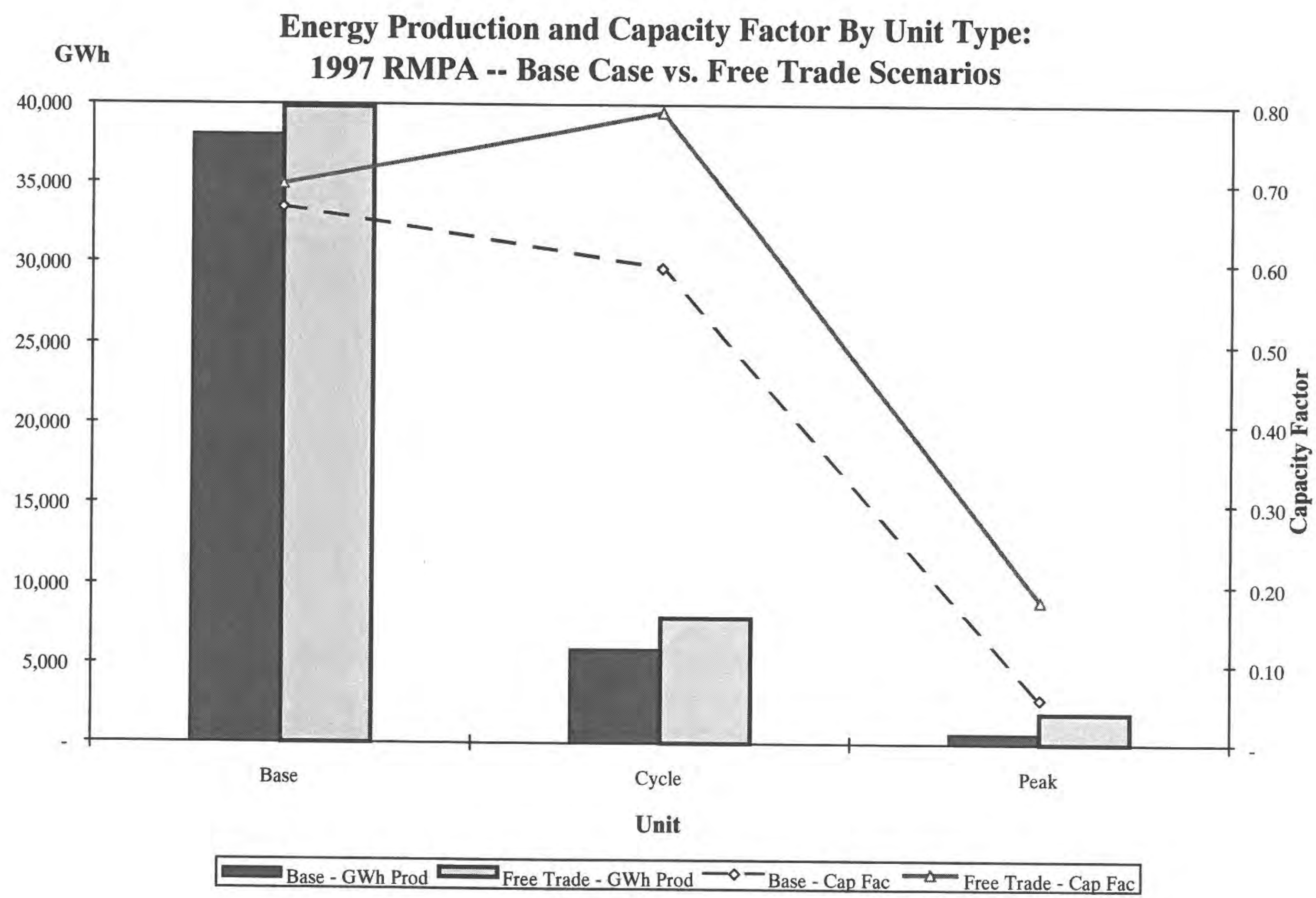
**Energy Production and Capacity Factor By Unit Type:
1997 NWP1 -- Base Case vs. Free Trade Scenarios**

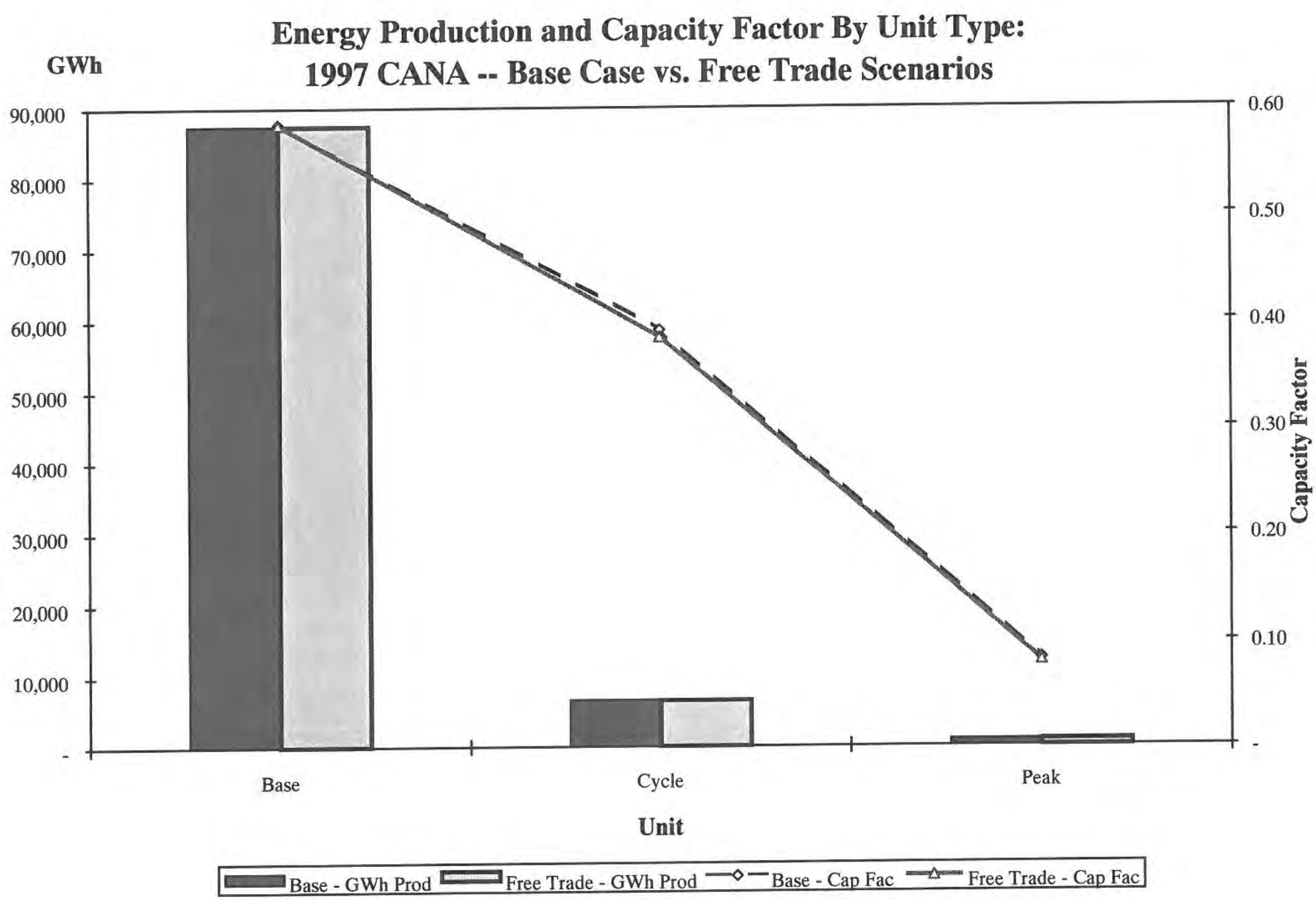



Energy Production and Capacity Factor By Unit Type:
1997 NWP2 -- Base Case vs. Free Trade Scenarios
GWh
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac


Energy Production and Capacity Factor By Unit Type:
1997 SOCA -- Base Case vs. Free Trade Scenarios
GWh
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

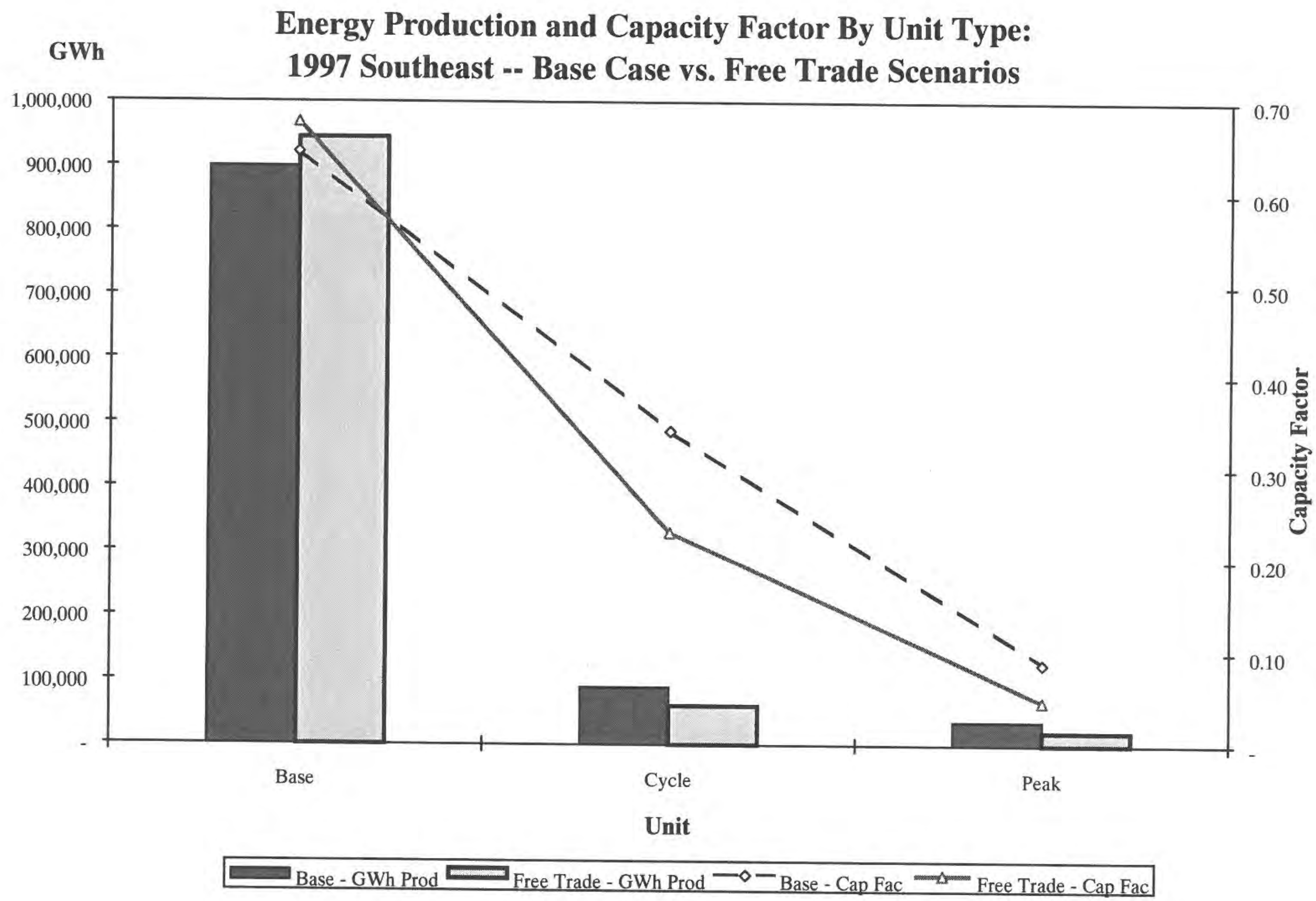

Energy Production and Capacity Factor By Unit Type:
1997 NOCA -- Base Case vs. Free Trade Scenarios
GWh
60,000
50,000
40,000
30,000
20,000
10,000
-
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

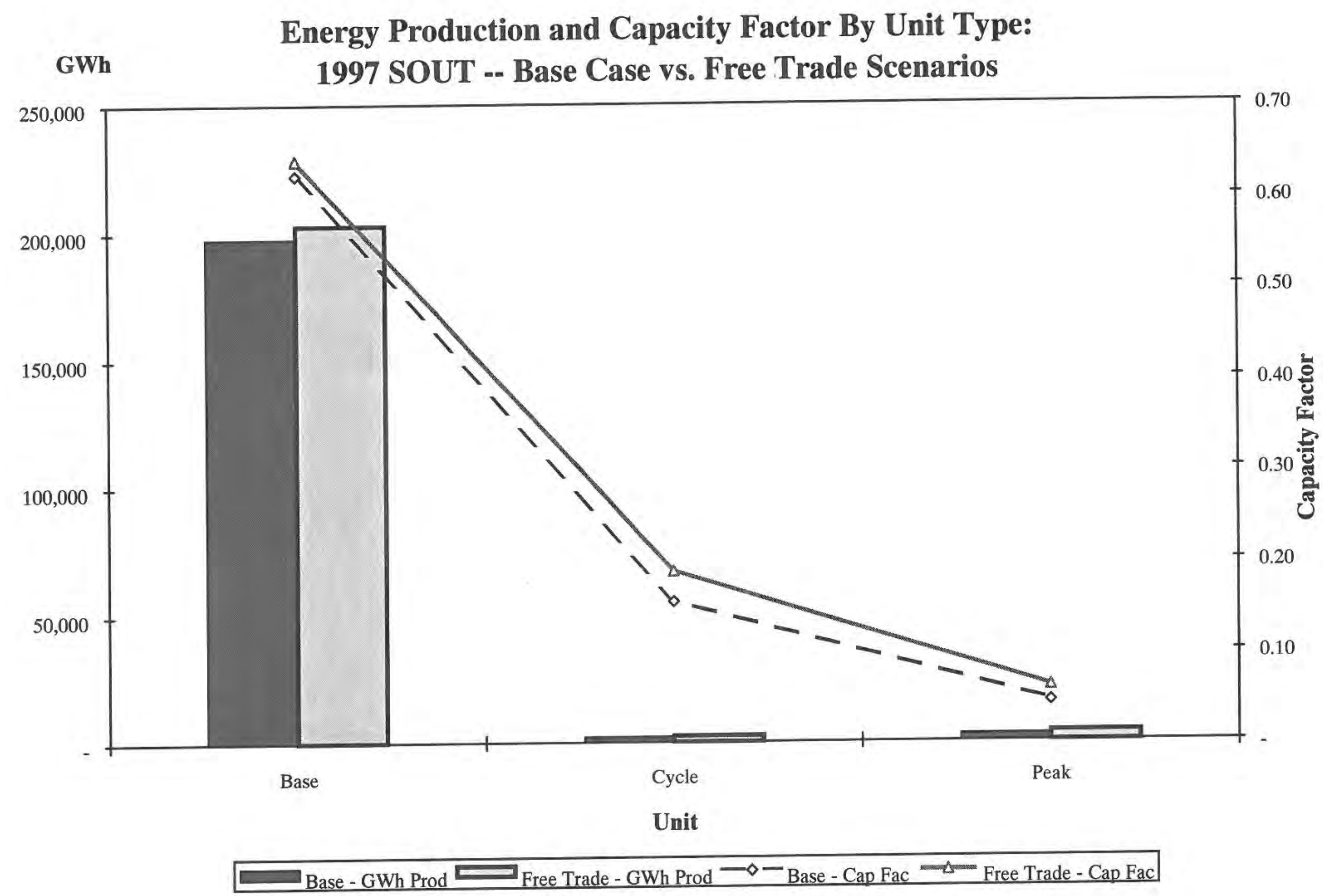

Energy Production and Capacity Factor By Unit Type:
1997 RMPA -- Base Case vs. Free Trade Scenarios
GWh
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

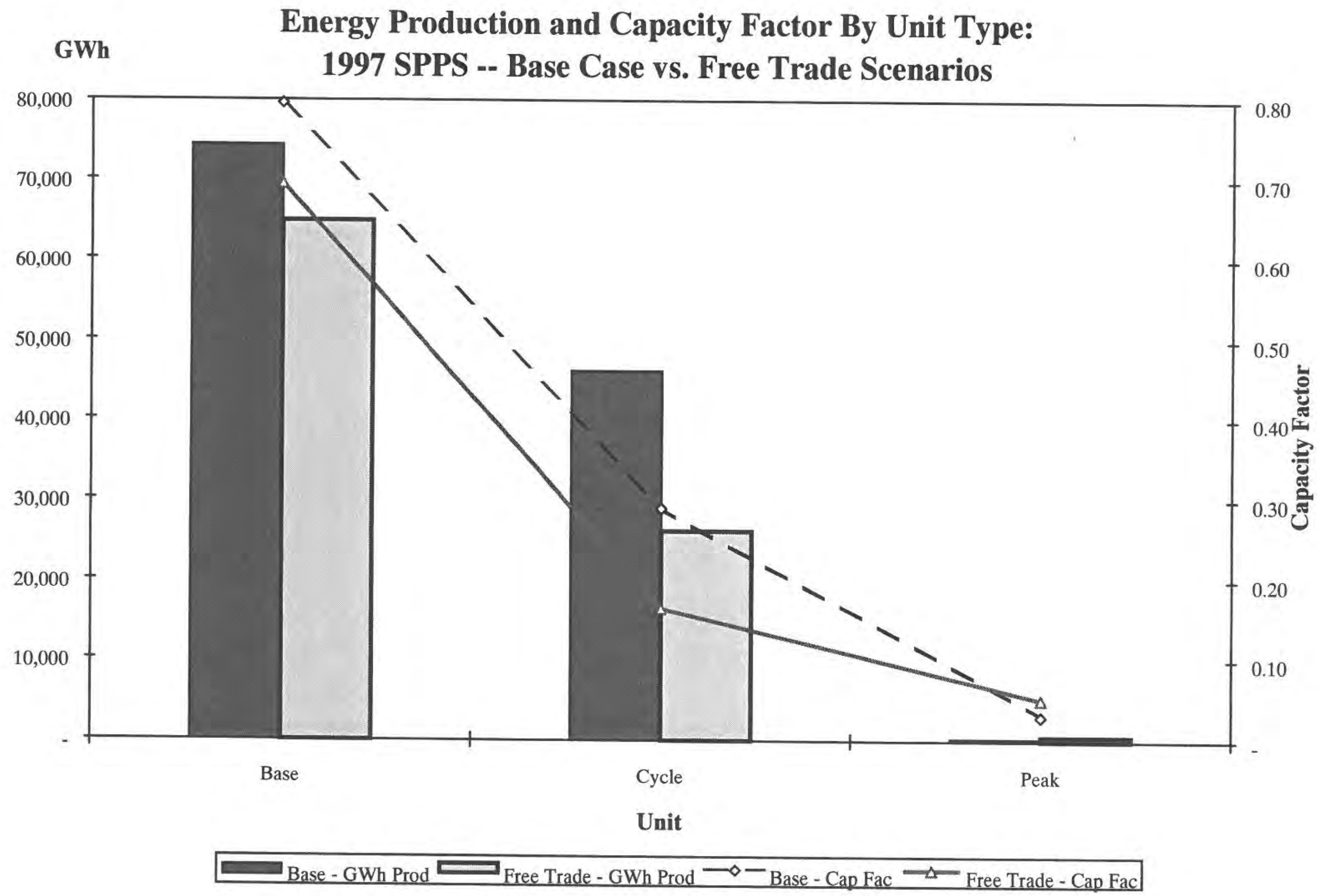

Energy Production and Capacity Factor By Unit Type:
1997 CANA -- Base Case vs. Free Trade Scenarios
GWh
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

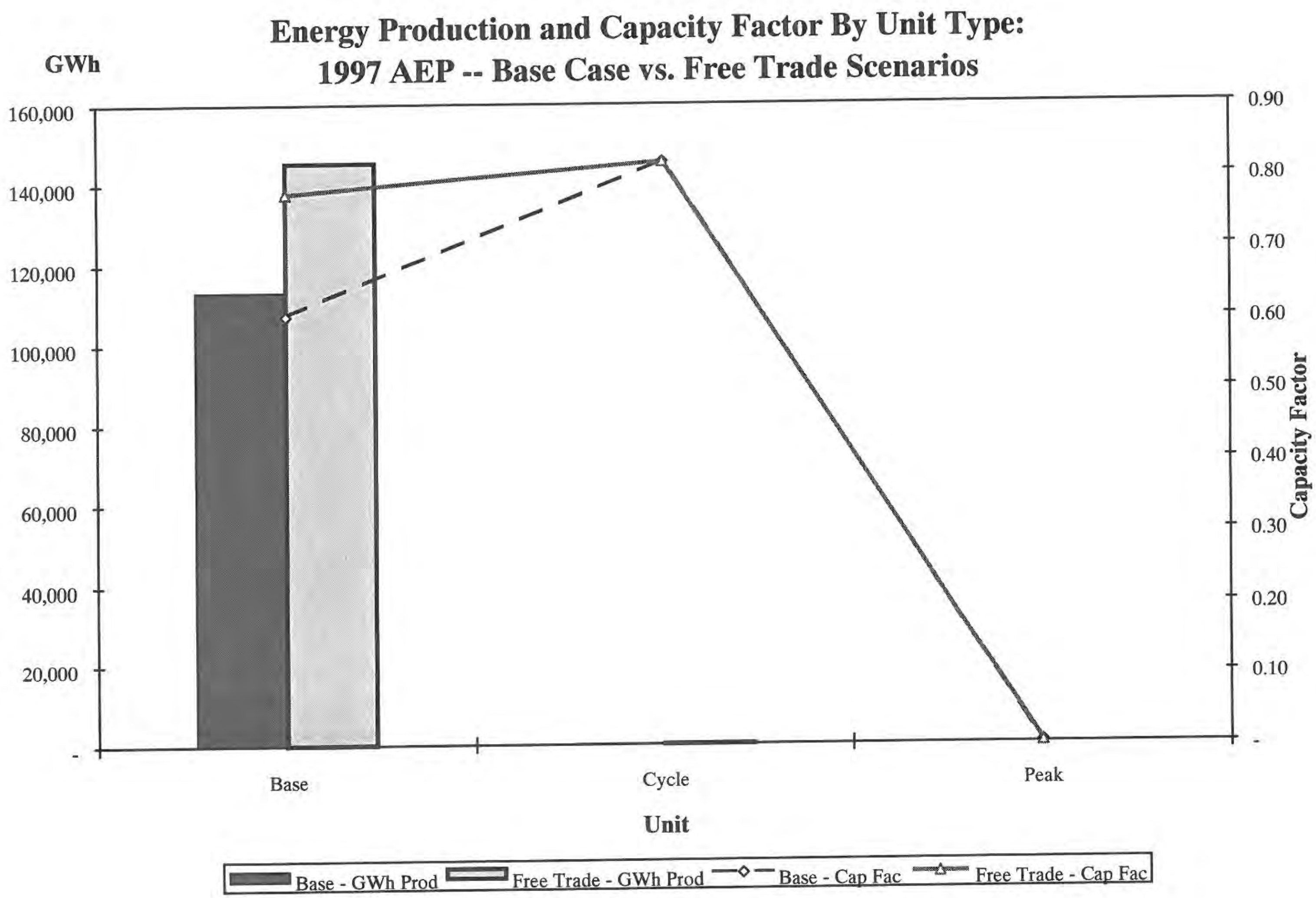
1997 Energy Production and Capacity Factor By Unit Type

Southeast

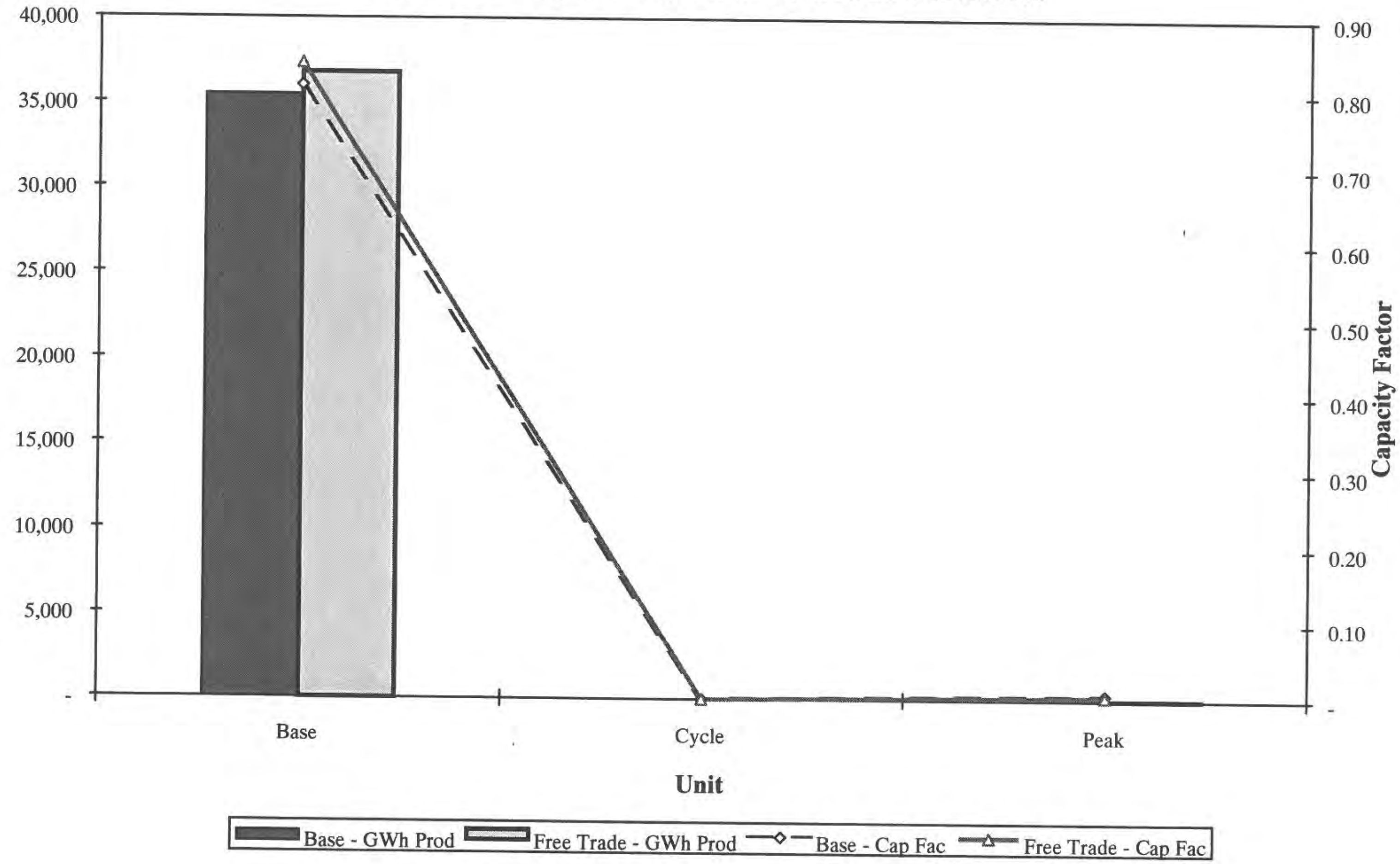

Energy Production and Capacity Factor By Unit Type:
1997 Southeast -- Base Case vs. Free Trade Scenarios
GWh
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

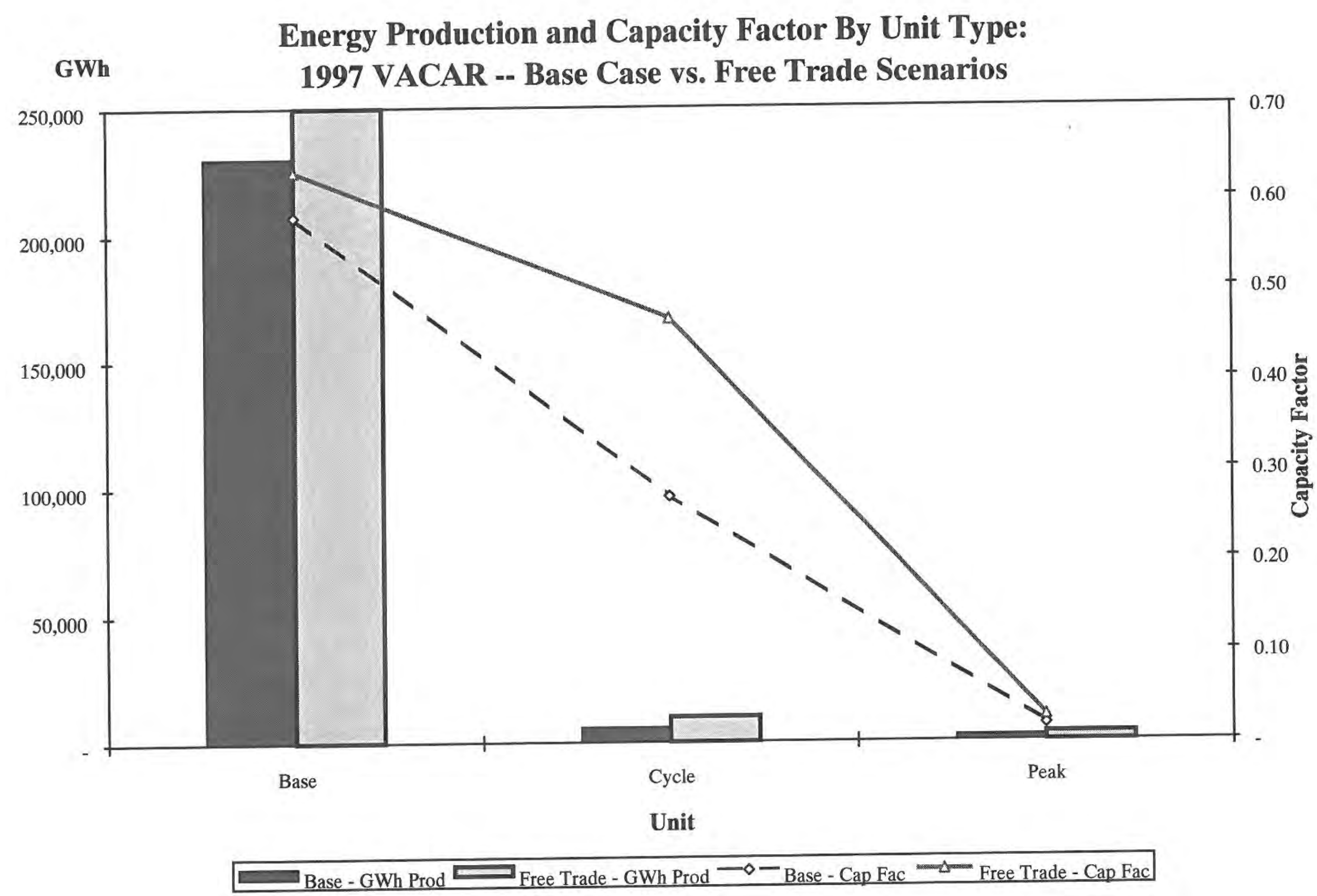

Energy Production and Capacity Factor By Unit Type:
1997 SOUT -- Base Case vs. Free Trade Scenarios
GWh
250,000
200,000
150,000
100,000
50,000
-
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

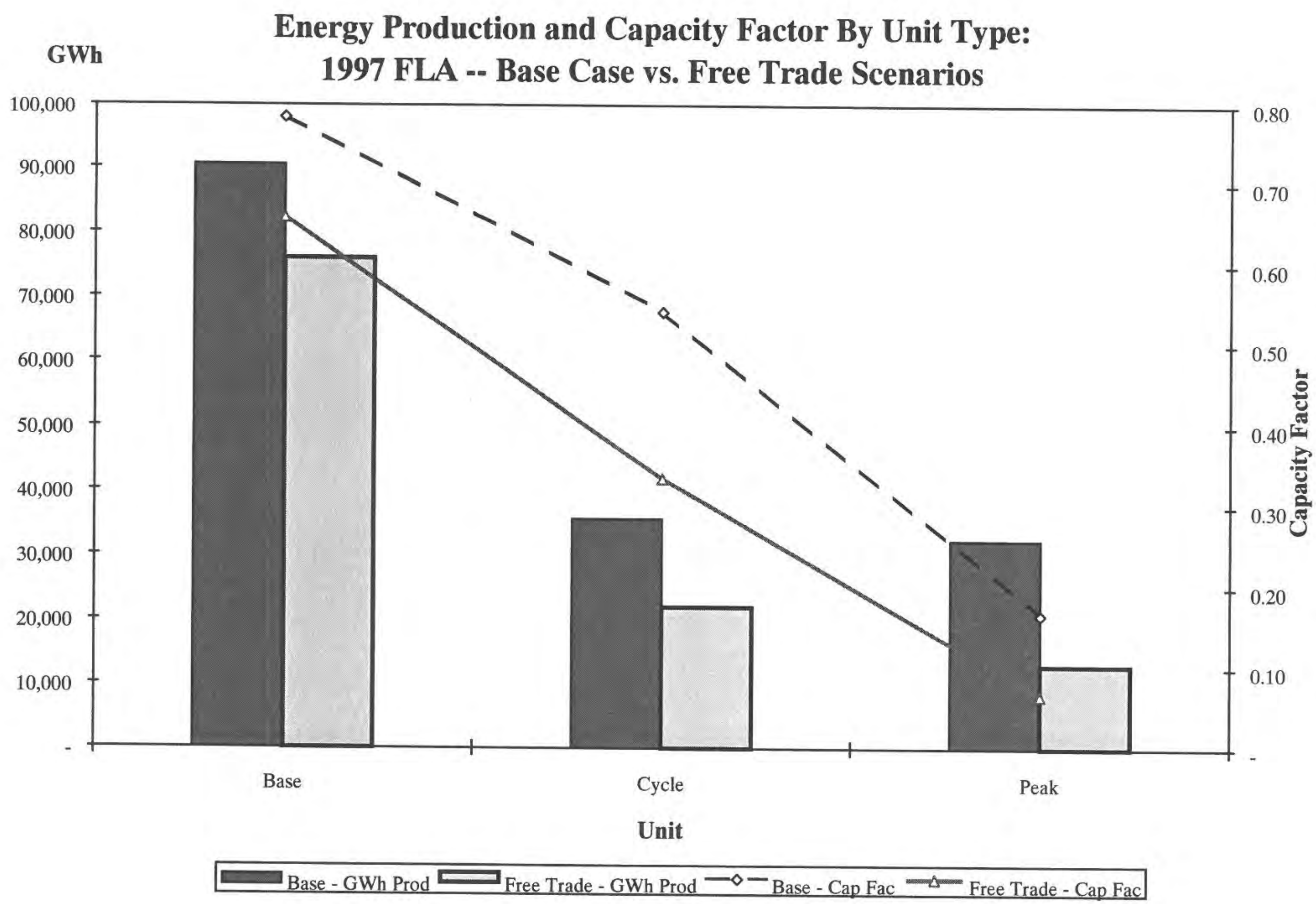

Energy Production and Capacity Factor By Unit Type:
1997 SPPS -- Base Case vs. Free Trade Scenarios
GWh
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

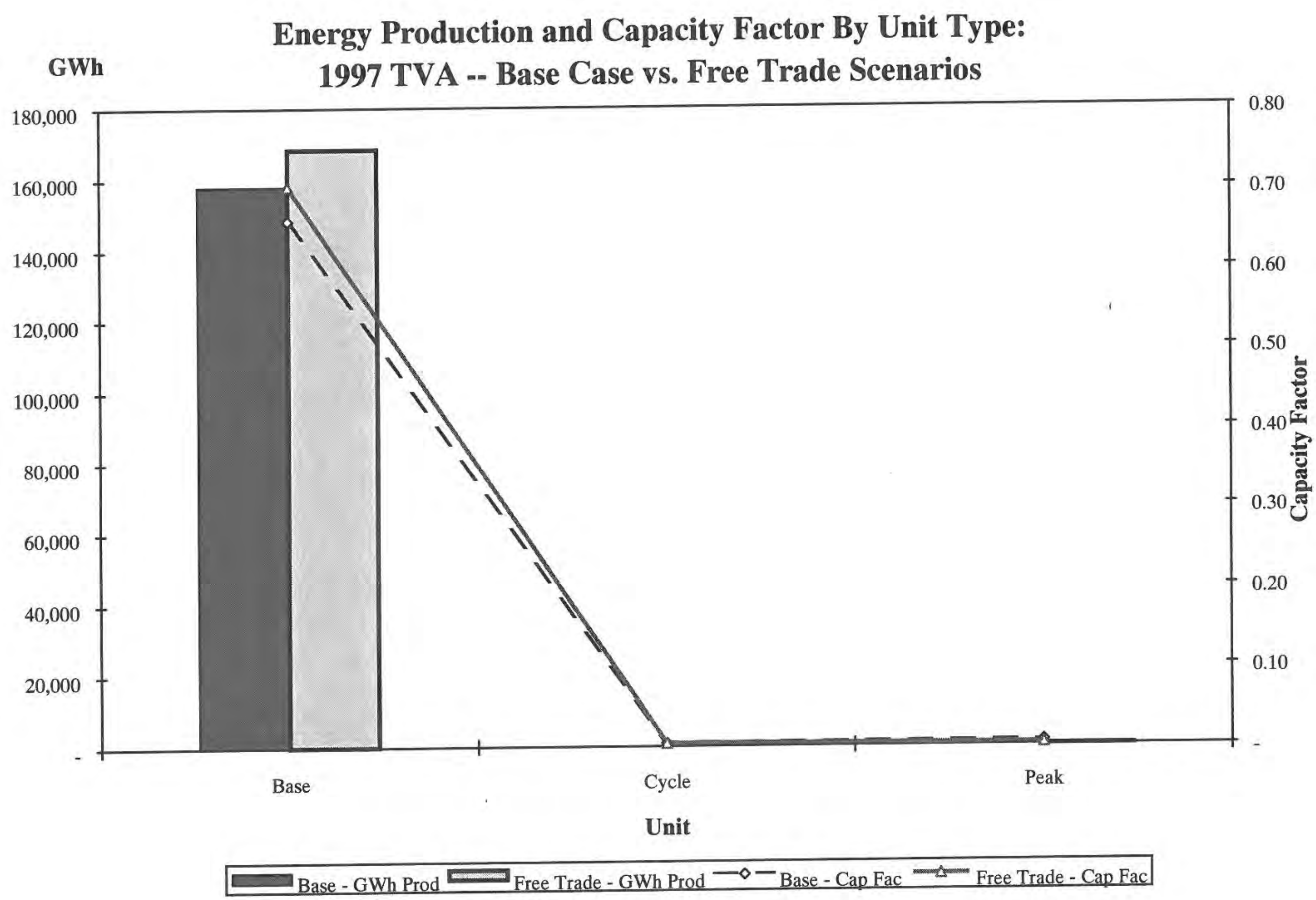

Energy Production and Capacity Factor By Unit Type:
1997 AEP -- Base Case vs. Free Trade Scenarios
GWh
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

Energy Production and Capacity Factor By Unit Type:
1997 APS -- Base Case vs. Free Trade Scenarios




Energy Production and Capacity Factor By Unit Type:
1997 VACAR -- Base Case vs. Free Trade Scenarios
GWh
250,000
200,000
150,000
100,000
50,000
-
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac


Energy Production and Capacity Factor By Unit Type:
1997 FLA -- Base Case vs. Free Trade Scenarios
GWh
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac


Energy Production and Capacity Factor By Unit Type:
1997 TVA -- Base Case vs. Free Trade Scenarios
GWh
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
Capacity Factor
Base
Cycle
Peak
Unit
Base - GWh Prod
Free Trade - GWh Prod
Base - Cap Fac
Free Trade - Cap Fac

Comparisons of Capacity Factor By Fuel Type

Northeast 1997 Base Case, Free Trade, and Fees Only Scenarios

		Base Case		Free Trade		Fees Only	
Market Area	Load	Average Dispatch Cost ($/MWh)	Average Capacity Factor	Average Capacity Factor	Change in CF: Free Trade CF - Base Case CF -	Average Capacity Factor	Change in CF: Fees Only CF- Base Case CF
APS	Gas	NA	NA	NA	NA	NA	NA
QUB	Coal	NA	NA	NA	NA	NA	NA
QUB	Gas	NA	NA	NA	NA	NA	NA
QUB	Oil	NA	NA	NA	NA	NA	NA
APS	Other	-	0.34	0.34	-	0.34	-
QUB	Other	-	0.29	0.29	-	0.29	-
NEPL	Other	2.92	0.43	0.43	0.00	0.43	-
ECAR	Other	3.72	0.49	0.49	0.00	0.49	-
NYPP	Other	3.78	0.54	0.54	(0.00)	0.54	-
VACR	Other	4.22	0.57	0.57	0.00	0.57	-
ONT	Other	4.95	0.66	0.66	0.00	0.66	0.00
MAAC	Other	5.32	0.75	0.75	0.00	0.75	0.00
CAPC	Other	6.09	0.82	0.82	-	0.82	-
APS	Coal	12.62	0.83	0.83	0.00	0.83	(0.00)
CAPC	Coal	13.72	0.69	0.74	0.05	0.72	0.03
ECAR	Coal	13.94	0.66	0.74	0.08	0.72	0.06
MAAC	Coal	14.57	0.73	0.70	(0.03)	0.71	(0.02)
VACR	Coal	15.70	0.55	0.57	0.02	0.53	(0.02)
NYPP	Coal	16.20	0.74	0.68	(0.06)	0.70	(0.04)
ONT	Coal	16.31	0.48	0.52	0.04	0.58	0.10
NEPL	Coal	17.24	0.80	0.64	(0.16)	0.77	(0.03)
ONT	Gas	20.81	0.38	0.40	0.02	0.42	0.05
NEPL	Gas	24.92	0.88	0.61	(0.27)	0.77	(0.11)
ECAR	Gas	28.42	0.12	0.21	0.09	0.18	0.06
NYPP	Gas	28.50	0.72	0.69	(0.03)	0.69	(0.02)
VACR	Gas	28.51	0.20	0.26	0.06	0.23	0.02
MAAC	Gas	30.47	0.41	0.37	(0.04)	0.37	(0.04)
NEPL	Oil	39.83	0.35	0.14	(0.20)	0.21	(0.14)
NYPP	Oil	46.45	0.15	0.08	(0.07)	0.09	(0.06)
CAPC	Gas	46.63	0.05	0.04	(0.01)	0.04	(0.01)
ONT	Oil	55.06	0.02	0.02	0.01	0.02	0.00
MAAC	Oil	55.07	0.05	0.05	(0.01)	0.05	(0.00)
ECAR	Oil	58.21	0.01	0.00	(0.00)	0.01	(0.00)
VACR	Oil	59.88	0.02	0.02	0.00	0.02	0.00
APS	Oil	66.10	0.01	0.01	(0.00)	0.01	(0.00)
CAPC	Oil	76.99	0.01	0.01	(0.00)	0.01	(0.00)
PJM	Coal	14.67	0.66	0.68		0.68	
PJM	Gas	28.99	0.45	0.43		0.44	
PJM	Oil	50.61	0.13	0.07		0.09	
PJM	Other	4.32	0.60	0.60		0.60	
Total		19.08	0.53	0.53		0.53	

WSCC 1997 Base Case, Free Trade, and Fees Only Scenarios

		Base Case		Free Trade		Fees Only	
Market Area	Load	Average Dispatch Cost ($/MWh)	Average Capacity Factor	Average Capacity Factor	Change in CF: Free Trade CF-Base Case CF	Average Capacity Factor	Change in CF: Fees Only CF-Base Case CF
CFE	Coal	NA	NA	NA	NA	NA	NA
NOCA	Coal	NA	NA	NA	NA	NA	NA
CFE	Other	-	0.70	0.70	0.00	0.70	-
CANA	Other	0.04	0.48	0.48	(0.00)	0.48	-
RMPA	Other	0.14	0.22	0.22	0.00	0.22	0.00
NWP1	Other	0.23	0.49	0.49	0.00	0.49	0.00
NWP2	Other	1.04	0.48	0.49	0.01	0.49	0.01
AZNM	Other	1.88	0.60	0.60	0.00	0.60	0.00
SOCA	Other	2.62	0.43	0.43	0.00	0.43	(0.00)
NOCA	Other	3.23	0.55	0.55	-	0.55	-
RMPA	Coal	11.00	0.78	0.82	0.04	0.80	0.02
NWP2	Coal	11.04	0.73	0.79	0.06	0.78	0.05
NWP1	Coal	12.36	0.75	0.82	0.07	0.81	0.06
CANA	Coal	14.11	0.78	0.78	(0.00)	0.79	0.01
SOCA	Coal	15.85	0.78	0.72	(0.06)	0.75	(0.03)
AZNM	Coal	15.99	0.55	0.73	0.18	0.73	0.18
RMPA	Gas	18.65	0.49	0.67	0.18	0.60	0.11
NWP1	Gas	20.61	0.70	0.75	0.05	0.74	0.04
NWP2	Gas	23.39	0.41	0.67	0.26	0.57	0.16
NOCA	Gas	24.59	0.41	0.31	(0.10)	0.34	(0.06)
SOCA	Gas	26.61	0.36	0.24	(0.12)	0.24	(0.12)
CFE	Gas	27.44	-	-	-	-	-
CANA	Gas	27.60	0.34	0.34	(0.00)	0.41	0.06
AZNM	Gas	28.12	0.07	0.39	0.32	0.37	0.30
AZNM	Oil	44.35	0.00	0.03	0.03	0.02	0.02
CFE	Oil	55.40	0.02	0.00	(0.02)	0.00	(0.02)
RMPA	Oil	59.09	0.02	0.13	0.12	0.04	0.02
NWP2	Oil	66.63	0.00	0.06	0.05	0.03	0.03
SOCA	Oil	69.40	0.03	0.00	(0.03)	0.00	(0.03)
NOCA	Oil	72.51	0.02	0.00	(0.02)	0.00	(0.02)
NWP1	Oil	77.12	0.05	0.04	(0.01)	0.03	(0.02)
CANA	Oil	80.19	0.03	0.02	(0.02)	0.02	(0.01)
WSCC	Coal	13.42	0.72	0.77		0.77	
WSCC	Gas	25.67	0.37	0.32		0.33	
WSCC	Oil	67.43	0.03	0.03		0.02	
WSCC	Other	1.15	0.50	0.50		0.50	
Total		15.18	0.47	0.47		0.47	

Southeast 1997 Base Case, Free Trade, and Fees Only Scenarios

		Base Case		Free Trade		Fees Only	
Market Area	Load	Average Dispatch Cost ($/MWh)	Average Capacity Factor	Average Capacity Factor	Change in CF: Free Trade CF-Base Case CF	Average Capacity Factor	Change in CF: Fees Only CF-Base Case CF
APS	Other	-	0.34	0.34	-	0.34	-
SOUT	Other	3.43	0.45	0.45	0.00	0.45	0.00
TVA	Other	4.02	0.56	0.56	-	0.56	-
VACR	Other	4.19	0.57	0.57	0.00	0.57	-
AEP	Other	4.43	0.58	0.58	-	0.58	-
SPPS	Other	6.00	0.77	0.77	-	0.77	-
FLA	Other	6.37	0.79	0.79	0.00	0.79	-
APS	Coal	12.65	0.82	0.85	0.03	0.84	0.02
TVA	Coal	13.34	0.73	0.81	0.08	0.82	0.08
AEP	Coal	13.90	0.61	0.80	0.20	0.75	0.15
SOUT	Coal	15.35	0.70	0.72	0.02	0.78	0.08
VACR	Coal	15.61	0.59	0.68	0.09	0.61	0.02
SPPS	Coal	16.35	0.81	0.63	(0.18)	0.66	(0.15)
FLA	Coal	16.68	0.78	0.60	(0.18)	0.69	(0.09)
FLA	Gas	29.31	0.32	0.19	(0.12)	0.22	(0.10)
SPPS	Gas	29.63	0.29	0.16	(0.13)	0.14	(0.15)
VACR	Gas	31.88	0.10	0.17	0.08	0.15	0.06
SOUT	Gas	33.52	0.09	0.11	0.03	0.13	0.05
TVA	Gas	35.56	-	-	-	-	-
AEP	Gas	36.01	-	-	-	-	-
APS	Gas	36.01	-	-	-	-	-
SPPS	Oil	40.18	0.03	0.05	0.02	0.03	0.00
FLA	Oil	42.79	0.21	0.08	(0.13)	0.11	(0.11)
VACR	Oil	65.72	0.01	0.01	(0.00)	0.01	(0.00)
APS	Oil	66.96	0.01	0.01	(0.00)	0.01	(0.00)
TVA	Oil	67.12	0.01	0.00	(0.00)	0.00	(0.00)
SOUT	Oil	71.84	0.01	0.01	0.00	0.01	0.00
AEP	Oil	87.43	0.00	0.00	(0.00)	0.00	(0.00)
FRCC	Coal	14.92	0.68	0.73		0.73	
FRCC	Gas	30.66	0.23	0.16		0.16	
FRCC	Oil	53.58	0.12	0.05		0.06	
FRCC	Other	4.30	0.58	0.58		0.58	
Total		20.54	0.49	0.49		0.49	

APPENDIX A SUPPLEMENT

COLOR LOAD-LAMBDA PLOTS ON CD-ROM

Attached to the back cover of this report is a CD-ROM holding 67 full color Load-Lambda plots. They are being distributed on this CD-ROM as Portable Document Format (PDF) files.

Getting Started

1. Locate your computer's CD-ROM drive and insert the CD-ROM disk.
2. Install Adobe Acrobat Reader 3.0 from CD-ROM (instructions in next section).
3. Run Adobe Acrobat Reader 3.0
4. Open the file MEFIRST.PDF.

With MEFIRST open you will see three buttons that are linked to other PDF files. The first of these buttons, "Report Summary", brings up a two page Report Summary of this report. The next button, "Derivation of Plots", is linked to a four page write up of "What a Point on the Load-Lambda Plot Represents". The last of these buttons "Go to Plots", opens a list of the plots on this CD-ROM. Grouped geographically, each of the figure captions on these 3 pages is hyperlinked to the plot in question.

Acrobat Reader has document navigation buttons in a toolbar. You may use these buttons to go from plot to plot in alphabetical order. Use the button at bottom of page to return to the list of plots.

Adobe Acrobat Reader 3.0

Adobe Acrobat® Reader, a program developed by Adobe Systems Incorporated to view and print PDF files, is provided on this CD-ROM. The latest version is always available from Adobe via the internet: (http://www.adobe.com/prodindex/acrobat/readstep.html). The following is a list of supported computer platforms for Adobe Acrobat Reader:

Macintosh	Windows	Sun™ Solaris®
SunOS ™	IBM®AIX®	HP-UX
Silicon Graphics® IRIX™	Digital UNIX®	Linux
OS/2®	MS-DOS	

System Requirements

CD-ROM drive, a 13 inch or larger color monitor.

Requirements for Windows

- 486 or later PC processor
- Windows 3.1 or later, Windows 95, or Windows NT® 3.51 or later
- 8MB of RAM (16MB for Windows NT)
- 10 MB of available hard-disk space

Requirements for Macintosh

- Macintosh with a 68020 processor or Power Macintosh® or later processor
- Apple System Software version 7.0 or later
- 8 MB of RAM
- 10 MB of available hard-disk space

Installation Instructions

for Windows 3.1:

From the Windows environment choose Run in the File menu of the Program Manager. When the Run dialog box appears press the Browse button. Choose the drive letter corresponding to your CD-ROM drive. Double click the "ACROREAD" directory, the "WIN" directory, and then the directory "16BIT", where you will find the file INSTALL.EXE. Now choose INSTALL EXE and press the OK button. You will press OK when the Run dialog box reappears. Follow the instructions given by the installation program.

for Windows 95 and NT:

From Windows environment use Windows Explorer to locate the CD-ROM drive. Open the drive by double clicking it and find the folder "Acroread". Double click on the "Acroread" folder, the "Win" folder, and then the folder "32Bit" where you will find the file INSTALL.EXE. Now launch the installation program INSTALL.EXE by double clicking on it. Follow the instructions given by the installation program.

for Macintosh:

From the Finder locate and double click the CD ICON "TR 108999" on your desktop. Double click on the "Acroread" folder, the MAC folder, and then the folder "READER" where you will find the file INSTALL. Now launch this program by double clicking it. Follow the instructions given by the installation program.