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INFORMATION SHEET

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Application of Dominion North Carolina Power to Join PJM as PJM South

APPEARANCES

PUBLIC STAFF:

ATT. GEN.

COMM. STAFF:

APPLICANT-COMPLAINANT-RESPONDENT PROTESTANT-RESPONDENT-INTERVENOR

See Attached

WITNESSES

Robert B. Stoddard

~~[illegible]~~

Mathew J. Morey

EXHIBITS

Public Staff Cross Exs. 5 & 6

Dominion Direct Stoddard-1

Dominion Direct Stoddard-2

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estimony Data Request No. 1

PUBLIC STAFF
CROSS-EXAMINATION
EXHIBIT NO. 5
I/A PB 1/21/05

Annual Data for North Carolina Retail Customers

(Dollar figures are nominal)

Base Case		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
(M$)	Fuel	47.1	48.8	50.5	51.4	53.1	54.9	57.8	60.9	63.9	66.9
(M$)	Variable O&M	9.0	9.1	8.9	8.8	9.4	10.0	10.5	11.0	11.5	12.0
(M$)	Total Purchased Power[1]	27.3	28.6	29.9	31.4	32.8	34.3	38.3	42.4	46.4	50.5
(M$)	Congestion - Base Rates	-	-	-	-	-	-	-	-	-	-
(M$)	FTRs	-	-	-	-	-	-	-	-	-	-
(GWh)	Owned Generation[2]	3,316	3,326	3,337	3,306	3,274	3,243	3,286	3,329	3,372	3,415
(GWh)	Purchases[2,3]	994	1,013	1,032	1,030	1,028	1,026	1,073	1,121	1,168	1,215

Change Case		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
(M$)	Fuel	43.2	45.1	47.0	47.9	49.6	51.4	54.[illegible]	[illegible]	60.0	62.9
(M$)	Variable O&M	8.5	8.5	8.3	8.3	8.9	9.5	10.[illegible]			
(M$)	Total Purchased Power[1]	30.9	32.0	33.1	35.0	36.8	38.7	43.[illegible]			
(M$)	Congestion - Base Rates	4.9	5.2	5.5	5.8	6.1	6.3	6.[illegible]			
(M$)	FTRs	6.8	7.3	7.7	7.9	8.0	8.1	8[illegible]			
(GWh)	Owned Generation[2]	3,180	3,199	3,217	3,192	3,167	3,143	3,1[illegible]			
(GWh)	Purchases[1,2,3]	1,097	1,108	1,120	1,119	1,118	1,117	1,1[illegible]			

[1] Includes purchases from NUGS.

[2] GWh reported at production level.

[3] Sales are NOT netted out from Purchases.

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Response to Nos. 15 & 16

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Table 1 CRA's Table V-3 Rearranged
(millions of dollars; present value at 7/1/03)
(positive numbers are net costs; negative numbers are net benefits)

Line No.	Line Operations	**Production/Generation Costs**				
		Fuel Factor Impacts				
1		Energy Purchases - Fuel Factor	20.1	(with $2.8 million Congestion Costs Removed)		
2		Fuel Costs	(20.5)			
3		NUG Energy- Fuel Factor	(0.4)			
4	1+2+3	**Sub-total Fuel Factor**	(0.8)			
		Base Rate Impacts				
5		NUG Energy - Base Rates	(12.7)			
6		Energy Purchases - Base Rates	13.0			
7		VOM Reduction - Reduced Output	(2.3)			
8	5+6+7	**Sub-Total Base Rate Energy**	(2.1)			
9	4+8	**Total Production/Generation Costs (Energy)**	(2.9)			
10		**Total Production Revenues**	4.1			
11	9+10	**Net Production Costs (Energy)**		**1.2**		<--- Loss to North Carolina from PJM
12		**Purchased Power Capacity**		**(2.30)**		<--- Gain to North Carolina from PJM
13		Congestion Costs Base Rates	28.4			
14		Congestion Costs Fuel Factor	2.8			
15	13+14	**Total Congestion Costs**	31.2			
16		FTR Revenues Base Rates	(35.80)			
17		FTR Revenues Fuel Factor	(2.80)			
18	16+17	**Total FTR Revenues**	(38.60)			
19	15+18	**Net FTR Revenues**		**(7.40)**		
20		**RTO Admin Fees**		**10.2**		
21	20+19+12+11	**Net Cost to North Carolina Customers**			**1.8**	
22	20+12+11	**Net Cost without Excess FTR Revenues**			**9.2**	

Dominion Stoddard
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Tables A-16 through A-31 follow Table A-15.

I. INTRODUCTION

I.A. Study Overview

This is a study of the benefits and costs of Dominion North Carolina Power ("Dominion") joining the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization ("RTO").[1] This study was commissioned by Dominion and conducted by Charles River Associates, and this report describes the study, its context, methods and results.[2]

The study assesses the net benefits of Dominion joining PJM for North Carolina jurisdictional retail customers ("North Carolina Retail Customers"). These net benefits are measured over a 10-year study period, from 2005 to 2014, presuming that Dominion, along with American Electric Power ("AEP"), Commonwealth Edison ("ComEd") and Dayton Power & Light ("DP&L" and, collectively with Dominion, AEP and ComEd, the "New PJM Entrants"), will be integrated into the PJM market structure by January 2005. The study is based on a pair of scenarios—a Base Case and a Change Case. In the Base Case, Dominion and the other New PJM Entrants are viewed as not being in PJM for the duration of the study period. In the Change Case, Dominion and the other New PJM Entrants are viewed as being in PJM for the duration of the study period. The difference between the two cases is used to quantify the benefits and costs to North Carolina Retail Customers of Dominion joining PJM.

Our approach to cost-benefit analysis is conservative, inasmuch as it quantifies all the costs, necessarily, while omitting from the quantified benefits many of the most valuable benefits, such as enhanced reliability. Previous studies of the benefits of RTO formation have considered a wide range of potential benefits, ranging from benefits that can be achieved quickly after market integration to longer-term, dynamic benefits of a broader marketplace. There is ample evidence that substantial "seams" issues exist between non-integrated wholesale electricity markets, even those that have adopted similar underlying market systems such as PJM and New York.[3] Elimination of

[1] PJM currently acts as the system operator for two control zones: PJM East (which includes all of New Jersey, Delaware and the District of Columbia as well as eastern Maryland and most of eastern and central Pennsylvania) and PJM West (the control zone of Allegheny Power spanning portions of Maryland, Ohio, Pennsylvania, Virginia and West Virginia). Throughout this study, the term "PJM" is used to mean either the RTO itself or the combined PJM East and West control zones that it operates.

[2] CRA has previously conducted a cost-benefit study of RTOs in the southeast on behalf of the Southeastern Association of Regulatory Utility Commissioners ("SEARUC"). That study is available at the website of SEARUC (Go to http://www.state.va.us/scc/searuc/'. The SEARUC study did not include the Dominion control zone within the geographic area under consideration, which instead focused on the GridSouth, SeTrans and GridFlorida areas. This study and the SEARUC study have been conducted using the same modeling approaches appropriately revised to reflect the economic conditions in the expanded PJM area. A further discussion of this study compared to the SEARUC study is contained in Appendix E.

[3] *See*, for example, *2002 State of the Market Report, NYISO*, by David B. Patton, Independent Market Advisor (April 2003), pp. 93-98.

these inter-market seams is the most easily quantifiable benefit from integrating the New PJM Entrants into a common market, and the one most readily and accurately quantified. Consequently, these near-term benefits are the only benefits quantified in this study.

Other benefits of Dominion joining PJM are no less real, but their value is difficult to model or measure. For example, coordinated operation of the transmission grid over a wider area will enhance system reliability, as system operators control more resources to respond to changing system conditions. System planning can take advantage of the greater load diversity of a broader resource pool to ensure the same or higher standards of system reliability with less capital investment. Integration into a broader market will bring many of the benefits of wholesale competition to North Carolina markets, will promote more efficient investment in transmission and demand-side management and will lead to better siting of new generation.[4] Other researchers have linked development of competitive wholesale electricity markets to a material increase in generating unit availability or efficiency.[5] While these longer-term benefits are significant, we find that there is not yet sufficient information to allow us to quantify these benefits with reasonable certainty. Consequently, we discuss these benefits qualitatively only, realizing that the benefits we measure in this study are likely to be conservatively low.

Considering the quantitative and qualitative benefits together, it is clearly a net benefit to the North Carolina Retail Customers for the Company to join PJM. After netting out PJM administrative costs, we see a small quantifiable net cost to North Carolina Retail Customers of $1.8 million net present value over the ten-year study period. This cost is more than justified by the qualitative benefits described herein.

I.B. Overview of the Models

This study uses the General Electric ("GE") Multi-Area Production Simulation ("MAPS") model as the primary analytical tool in the analysis. MAPS is a production simulation model with a detailed transmission representation. Assessing transmission conditions is an important objective of the study, and the MAPS model is well known to be highly capable in such matters. The MAPS model used for this study includes substantially all of the generation and transmission in the Eastern Interconnection, with more detailed transmission monitoring of the combined control areas of PJM East, PJM West, Dominion, AEP, DP&L and ComEd ("Expanded PJM"). To avoid potential confusion with the parallel filing in Virginia, the physical modeling assumptions are unchanged from that

[4] *See*, for example, William W. Hogan, "Transmission Investment and Competitive Electricity Markets," Center for Business and Government, Harvard University, April 1998; and William W. Hogan, "FERC Policy On Regional Transmission Organizations: Comments In Response To The Notice Of Proposed Rulemaking," FERC Docket No. RM99-2-000, pp. 41-44.

[5] See *2003 State of the Market Report, PJM* (March 2004), pp. 131–133.

study. Although there have been some changes in market conditions since these assumptions were cast, the long-term outlook has not changed materially. Consequently, CRA believes that the results from the physical model and the sensitivity cases still reflect likely future conditions with sufficient confidence to serve as a basis for regulatory decisions.

The study has prepared detailed MAPS model runs for the years 2005, 2007, 2010, and 2014, and has interpolated between the results for the remaining years in the study period. The results from the MAPS model are detailed hour-by-hour prices, generation and load at each location in the model. These results are processed by a post-processor SAS model, the output of which is summarized by a Financial Evaluation Model ("FEM") that analyzes the effect of these changes in the wholesale market operation on rates to Dominion's North Carolina Retail Customers. In both the Base Case and the Change Case, the study assumes that North Carolina Retail Customers will remain on cost-of-service rate regulation. Therefore, the FEM analyzes only the *changes* of those portions of North Carolina retail rates that would be affected by PJM integration. It does not estimate the *level* of the cost-of-service rates in either the Base Case or Change Case.

This study explicitly accounts for Financial Transmission Rights ("FTRs") that will be used to hedge transmission congestion costs under PJM. The proposed set of FTRs have been evaluated by PJM to ensure that the studied set is simultaneously feasible—a requirement under the PJM rules. These FTRs are an important component in any risk mitigation strategy undertaken by market participants in the PJM market structure.

I.C. Structure of the Report

The remainder of the report is organized into six main sections. The next section, Section II, provides an overview of the benefits and costs associated with Dominion joining PJM, as well as a discussion of certain issues that are addressed quantitatively. Section III contains a discussion of issues not fully quantified in the study. Section IV describes the analytical approach of the study, including the use of the MAPS model and the subsequent financial modeling. Section V presents the estimates of benefits and compares these to the administrative costs of participating in the RTO. The final section, Section VI, provides our conclusions. In addition, there are five technical appendices:

- Appendix A describes the GE MAPS model of the physical operation of the Eastern Interconnection grid operation and detailed results.
- Appendix B describes the capacity additions and pricing models.
- Appendix C discusses the financial model used to compute the rate effects on North Carolina Retail Customers.
- Appendix D presents detailed results of the sensitivity cases.

Introduction

- Appendix E reviews methods and results of the SEARUC study of RTO costs and benefits and discusses differences in modeling techniques between this study and the SEARUC study.

II. OVERVIEW OF BENEFITS AND COSTS

II.A. Overview of Benefits

This study, similar to other RTO cost-benefit studies, focuses on short-run benefits of Dominion joining PJM. Certain short-run benefits, such as enhanced system reliability, optimized system planning and improved resource adequacy, as well as longer-term benefits that can be expected from the establishment of competitive wholesale markets, cannot be easily identified and quantified for purposes of this type of study. These other benefits, while real and likely to be substantial, are difficult to model.

There are two major sources of the short-run benefits studied and presented here: production cost savings and savings from the pooling of regional capacity markets.

Given that North Carolina Retail Customers will pay cost-of-service rates, the quantifiable benefit to PJM integration is focused on the reduction in the purchase costs of energy and capacity not supplied from Dominion's generation fleet. Lower cost generation becomes more readily available as markets become more transparent and barriers to trade are reduced and Dominion is integrated into a regional capacity market.

This study measures the energy benefit of PJM integration as the difference in generation production costs between a Change Case and a Base Case as estimated using the GE MAPS model. The MAPS model used in this study incorporates a detailed representation of the Eastern Interconnection transmission grid, along with the dispatch and start-up costs of substantially all interconnected generating units. Because of the size of this model, more transmission constraints have been monitored in and around PJM, given the focus of this study, than in the remainder of the Eastern Interconnection. However, major transmission limits are monitored throughout the East. Transmission rates are assumed to be de-pancaked within the Expanded PJM when Dominion joins PJM.[6] Otherwise, transmission rates are assumed to continue as a charge to power movements between RTOs, in particular. Outside of the Expanded PJM, we assume RTOs exist in both the Base and Change Cases in most areas of the country, including SeTrans, GridFlorida, MISO, SPP, and the northeast ISOs.[7] In this way, the study focuses on the incremental impact of Dominion joining PJM, as opposed to the more general implementation of RTOs in other regions.

The MAPS model is a single system optimization model. Among other things, this means that MAPS will find the economically efficient unit commitment and generation dispatch to supply

6 *See* Testimony of Harold W. Payne, Jr., filed concurrently with this study.

7 The exception to this is the Carolinas, which we modeled as three control areas (Duke, Progress Energy, and South Carolina Electric & Gas), with capacity reserve sharing within the region only. Although there is no longer an active SeTrans proposal, whether SeTrans is formed is not material to our study results.

load throughout the study area. The current trading patterns in the Eastern Interconnection cannot be as efficient as this because the various control areas are independently conducting their own dispatch operations. These separate dispatch operations create loop flow on one another's transmission systems that contributes to transmission congestion. Such congestion cannot be managed efficiently in real-time under today's dispatch and trading arrangements. Instead, the utilities have developed other approaches, such as Transmission Line Relief ("TLRs"), to manage congestion. These approaches have served the industry well in the past, but are under additional stress with the development of merchant power producers and competitive wholesale power markets. Moreover, current arrangements for the trading of energy between control areas are based on incomplete bilateral markets that cannot be transparent, given the local management of regional congestion problems. The congestion costs created by transactions can only be partially accounted for under current grid operations in most areas. In contrast, PJM's market structure is based on LMP, which is designed to manage such congestion problems in real-time and to help markets become more efficient and transparent.

MAPS is well suited as a model of the generation dispatch that would take place after the New PJM Entrants are integrated into PJM. However, it cannot depict, without adjustment, the base-case trading arrangements prevailing under local management of congestion in which transactions do not pay the price that reflects the cost of the congestion they create. Accordingly, it is necessary to create a Base Case in MAPS by adding certain elements of inefficiency. In this study, like other studies of RTO benefits conducted previously, we have done this in two ways. First, we modeled individual control areas as having separate unit commitment and dispatch to meet internal load and reserves. Second, net transfers between regions were allowed, but limited by the use of "hurdle" rates. In effect, a hurdle rate is an impediment to trade between control areas, which is modeled as an adder to the transmission rate for transactions between control areas. In part, this hurdle rate reflects direct charges for losses and transmission tariffs; additionally, we assess an additional hurdle to reflect various inefficiencies and costs associated with bilateral trading across control areas. This additional hurdle rate is not actually part of any financial settlement, so it never is actually paid to anyone. Instead, it (together with the wheeling charge) is an input to the unit commitment and dispatch logic of MAPS that represents impediments to trading between control areas. The definition of the hurdle rates for this study is discussed in more detail in Section IV.

These base-case hurdles were chosen so as to calibrate the Base Case to reflect historical patterns of trade between Dominion and its neighbors. In the Change Case in which the New PJM Entrants join PJM, the import hurdle is eliminated for the four New PJM Entrants, but is retained for the Expanded PJM as a whole; that is, trade between the Expanded PJM and neighboring control areas is subject to continuing trade hurdles.[8] The import hurdle continues to apply to the pre-

[8] FERC has recently reaffirmed its order that PJM and the Midwest Independent System Operator ("MISO") work to eliminate out-and-through wheeling charges between them by December 2004. MISO is a net exporting region,

existing RTOs and control areas that are not reconfigured in the Change Case. Similarly, the trade hurdles within the Expanded PJM are eliminated in the Change Case, aside from a small charge to reflect incremental transmission losses.

Production costs, including the costs of starting a plant and the variable costs of running it, will be lower in the Change Case than in the Base Case with hurdles. The difference between the two cases is used as the measurement of the production cost benefits due to the expansion of PJM.

In addition to potential savings in the energy markets, North Carolina Retail Customers benefit from PJM integration through lowered capacity costs. As Dominion's load grows, it will need to rely increasingly on purchases of capacity to meet reliability standards. The cost of these purchases of incremental generation depends on the availability of deliverable capacity. As a general matter, when there is capacity in excess of reliability requirements, the cost of capacity is low; conversely, when new capacity must be built to maintain sufficient installed capacity reserves, prices rise to reflect the levelized cost of new capacity.

By joining the Expanded PJM market, Dominion will become part of a regional, integrated capacity market, bringing with it two benefits on the capacity side. First, two sub-regions of the Expanded PJM currently have fairly substantial amounts of excess capacity reserves: PJM (East and West) and AEP. Second, the Expanded PJM area has greater load diversity than its constituent parts. Taking advantage of this load diversity decreases the total megawatts of installed capacity required across the region while still maintaining the current high standards of reliability. These two effects work together to reduce the pressure on the capacity market, as the need to build new capacity in the Dominion control zone is delayed and reduced. Consequently, the price at which Dominion must purchase incremental capacity is lower as part of PJM than it would be otherwise.

We do not quantify potentially important benefits of joining PJM that should follow from becoming part of a wholesale market with excellent liquidity and transparent price formation. We assume, both in the Base and Change Cases, that all energy is traded at prices consistent with the spot market price of energy, even though most energy is traded bilaterally rather than in spot markets.[9] In markets where trading is thin and prices are not readily observable, market participants manage market risk through greater reliance on self-scheduling, firm transactions, and other relatively blunt tools; in a given hour, this may lead to some higher cost units operating instead of lower-cost units. By contrast, in a well-developed market such as PJM, there is greater convergence between bilateral and spot prices, and the consequent flexibility of unit commitment and dispatch means that customers can be served at lower total cost. Our study, though, focuses solely on the

however, so tighter integration with PJM should increase the net supply of lower-cost resources available to supply North Carolina. Consequently, our modeling choice is conservative.

[9] *See* Testimony of Gregory J. Morgan, filed concurrently with this study.

potential benefits to trade *between* areas, and so it understates potential benefits from improved utilization of resources *within* each control area.

II.B. Calculation of Benefits

Our Financial Evaluation Model processed the output from the physical modeling supported by MAPS in order to assess the benefits for North Carolina Retail Customers. The Financial Evaluation Model does several things:

- Accounts for imports and exports of power in and out of the Dominion control zone and ascribes the trade benefits equally between the buying and selling control zones for trade supported by point-to-point transmission service, such as between Dominion and CP&L.
- Accounts for the price of purchased power needed to serve North Carolina Retail Customers, including power purchased off-system in the Base Case and under the PJM LMP system.
- Accounts for the sale of power both to off-system customers in the Base Case and into the PJM LMP market structure.
- Accounts for the cost of producing power separately for each Dominion generating unit, including the cost of fuel, emissions allowances, start up costs and O&M costs.
- Accounts for the Fuel Factor formula applicable to North Carolina Retail Customers.
- Accounts for FTRs expected to be allocated to Dominion and its jurisdictional retail customers by PJM.

A more detailed description of the Financial Evaluation Model is provided in Section IV and Appendix C.

It should be noted that the results of this study are subject to a margin of error due to various assumptions that must always be made in any modeling study. Possible sources of error include incomplete monitoring of transmission constraints, incomplete data on generation characteristics, fuel price forecast margin of error, uncertainty as to actual FTR allocations and payments in the future and errors in forecasting RTO costs. The net effect of these sources of error cannot be quantified. In modeling these complex matters, however, we have attempted to make conservative assumptions, that is, towards understating the potential net benefits of PJM membership to consumers. Moreover, the two of the three sensitivity cases discussed below help to bracket the likely range of outcomes for two key assumptions: fuel prices and load growth.

Overview of Benefits and Costs

II.C. Overview of Costs

The cost of Dominion joining PJM is assumed to be the average administrative costs of PJM following the integration of the New PJM Entrants. This administrative charge is estimated by PJM to be lower than the current per-unit charge as a result of the four New PJM Entrants being integrated into the PJM market structure. This study has relied on estimated PJM administrative charges from PJM's 2002 budget.

These administrative costs are assumed to be paid by customers on a load-ratio share basis, consistent with the remainder of the load in the Expanded PJM area. These costs are increased at a 2.5 percent annual rate, to reflect inflation.

III. ISSUES NOT FULLY QUANTIFIED

The issues and impacts associated with Dominion joining PJM are numerous and complex. While this study has quantified the major impacts, particularly those in the short-term, it has not been possible to address all of the issues through formal quantitative analysis. This section discusses the qualitative aspects of several issues that have not been modeled explicitly, but nonetheless may bear on the costs and benefits of Dominion's PJM participation.

III.A. Ongoing Protection of Native Load

Membership in PJM will continue native load protections in place today. Most importantly, FTRs or the corresponding Auction Revenue Rights ("ARRs") will be available under PJM to offset the congestion costs that occur on an LMP system.[10] PJM has conducted a simultaneous feasibility test of Dominion FTRs and has determined that adequate transmission capacity exists to support a full allocation of FTRs to Dominion's load throughout the study period. This FTR allocation is a key factor in ensuring that delivered prices in Dominion's service territory remain hedged against the congestion that can occur between generation buses and load buses.

PJM business rules ensure that the load-serving entities of network customers (such as North Carolina Retail Customers) have a right to FTRs that hedge congestion costs to those customers. As discussed in more detail in Appendix C, PJM has determined that Dominion can obtain sufficient FTRs throughout the study period to hedge congestion risk fully. While changes at some future date may materially alter how FTRs are allocated, we have no way to assess this risk. We believe, however, that the PJM review process will continue to provide substantial protection for native load even if the PJM business practices are revised.

For the purposes of this study, we assume that Dominion will receive a pro rata share of the surplus value of the FTRs that are not allocated under current PJM practice. A representative from PJM has estimated that the surplus value in PJM's FTR auctions is likely to be about $50 million per year after PJM is expanded to include all four New PJM Entrants. Dominion's load ratio share of this amount would be about $6 million per year.

Apart from these FTR considerations, it is important to recognize that PJM has agreed that load will not be shed within PJM South (that is, the Dominion control zone) in order to address capacity deficiencies in other parts of PJM. This means that North Carolina Retail Customers will not be placed at risk for capacity shortages occurring elsewhere in PJM.

[10] Under PJM rules, holders of ARRs can self-schedule that right into the FTR auction, thereby converting each ARR into a matching FTR.

Issues Not Fully Quantified

III.B. Reliability

Membership in PJM offers the opportunity for Dominion to ensure improved reliability. Dominion will maintain its own transmission control center to address local reliability problems that will not be monitored by PJM. Moreover, by joining PJM, customers in the current Dominion control zone will have the benefit of an enlarged scope of geographic control of generation that can be used to address transmission system emergencies. The larger scope for generation redispatch in emergency conditions will expand the resources available to PJM operators beyond those currently available to the Dominion control zone operator. [11]

III.C. Integrated Transmission Planning

PJM offers the opportunity for Dominion to participate in a larger regional planning process that will blend Dominion's local expertise with the regional views provided by PJM of other transmission owners and stakeholders. [12] Much of this interaction occurs today on an informal basis. Joining PJM will help to formalize this process and improve the regional transmission planning process by focusing new investment to projects that realize the greatest net benefit. This coordination is particularly important for North Carolina since the transmission upgrades most needed to reduce prices in the state are located outside the Dominion control zone.

III.D. Enhanced Wholesale Competition and Generation Technology Improvements

Improvements to generation technology may be facilitated generally by the development of a competitive wholesale electricity market. Adding Dominion into PJM would enhance wholesale competition both by providing merchant generators with greater integration into a large and liquid wholesale market, and by providing clear locational prices that signal the need for new resources in particular places. Expanded wholesale competition can be expected to propel improvements in technology and unit efficiencies over time. The steady march of technological improvements is a significant source of consumer benefits over time. PJM and the other northeast markets, where vigorous competition in a locational pricing system have been adopted, have seen marked improvement in unit availability and increased investment in existing units to increase their competitiveness.[13] While the importance of this advancement could hardly be overstated, it has not been addressed in this study because of the difficulty in quantifying the long-term benefits of these investments.

[11] *See* Testimony of William L. Thompson, filed concurrently with this study.
[12] *See* Testimony of Ronnie Bailey, filed concurrently with this study.
[13] See *2003 State of the Market, PJM,* (March 2004), pp. 131-133.

Issues Not Fully Quantified

III.E. Demand Response Benefits

A critical component in the development of competitive electricity markets is allowing the demand side of the market to participate fully in spot markets.[14] This issue has not been quantified in this study because, in part, of the difficulty of quantifying such benefits in a pure production-cost model.[15] An important element of a successful demand response program is the ability to provide customers with price information that is directly linked to the incremental cost of providing their power. Further, this information needs to be available both in real-time, to allow for automated price response (such as commercial reductions in air-conditioning load), and day-ahead, to allow industrial users to revise production schedules in response to energy prices, for example. Our Base Case, however, does not include the costs that would be needed to create the independent market system necessary to create and post these real-time and day-ahead prices for a stand-alone Dominion region; rather, North Carolina Retail Customers would continue to be served on an average-cost basis that suppresses price signals to customers and, consequently, provides a poor basis for developing effective demand-side management. Our estimates of the benefits of joining PJM are, therefore, conservative in excluding from the Change Case the benefits from such demand-side management programs or, alternatively, excluding from the Base Case the costs of developing day-ahead and real-time incremental prices in the Dominion control zone. Demand management programs provide material benefits in enhancing grid reliability and reducing the price spikes that lead to high retail prices.

III.F. Improved Generation Siting and Transmission Investment

Over the longer term, the price signals provided by LMP can be expected to promote more efficient siting decisions on the part of developers both of generation and transmission. This effect is not explicitly studied here, but we expect that it will be an important source of benefits over the long term. Under the LMP signals provided in the PJM market structure, generators will have a direct and observable incentive to locate where the generator price is high. In today's market, this price signal is averaged over a wide area, and any locational differences in such average prices are highly muted, at best. In contrast, LMP has the effect of disaggregating the price signals given to each individual generator so that market participants can evaluate the advantages and disadvantages of various locations. Such locational prices are a key to improved siting decisions on the part of future generation and transmission developers that can be expected to benefit North Carolina Retail Customers, as well as others in the Expanded PJM.

[14] *See* Testimony of David F. Koogler, filed concurrently with this study.

[15] Production-cost models such as MAPS do not capture well the hourly volatility created by unexpected surges in demand, unit outages, or loss of critical transmission facilities. It is these spikes, however, that are best addressed by demand-side measures.

Issues Not Fully Quantified

III.G. Installed Capacity Market

In this study, we have used the concept of an Installed Capacity ("ICAP") market, more or less as it has been developed in the original PJM area in both the Base and Change Cases. Regardless of the precise administrative design, we believe that the developer of any new generation built in the future to meet a long-term resource adequacy requirement would have to be paid for the capacity costs of the facilities. This may not take the form of a conventional ICAP payment, but we believe that the economic effect would be effectively the same if new capacity were to be attracted into the market to meet reserve requirements. Therefore, we have not considered alternative versions of the ICAP concept, such as the forward market proposal currently under consideration by the Resource Adequacy Market working group of the ISOs of PJM, New York and New England.

Accordingly, in this study we use the term ICAP market and ICAP price as a proxy for the payments needed by new generation (when such generation is required to meet installed capacity requirements) to recover the capital costs of entry not otherwise recovered through the energy market. As such, other mechanisms could be considered as equivalent to the function of the ICAP market in this study, which is to create a mechanism whereby native load pays for certain investments if they are needed by native load in the first instance.

III.H. Benefits From Integration With an Established Market

It is appropriate to note that this study contrasts the net economic benefits of a Change Case that is fully consistent with federal regulatory directions, versus a Base Case that is not. Although FERC has not yet issued any final order regarding implementation of wholesale market standards, nor has it yet been tested whether FERC has the authority to mandate such standards on jurisdictional utilities, there is clear federal intent that all utilities join an established RTO or join together with neighboring utilities to create one. Dominion is interconnected with only one approved RTO: PJM. While Dominion could conceivably work with other utilities to its south to build a new RTO, there are large costs to designing, implementing and securing regulatory approvals for a new RTO. We have, conservatively, not included such costs in our Base Case.

IV. ANALYTICAL APPROACH

In order to quantify the likely costs and benefits of the proposed integration of Dominion into PJM, CRA needed to develop and refine several analytic models. To model the change in system operations that would result from the market integration, we used GE MAPS running with CRA's proprietary database, discussed in Section IV.A and Appendix A. Interacting with GE MAPS was a model of capacity additions and resulting capacity pricing, which we discuss in Section IV.B and Appendix B. Finally, CRA developed a Financial Evaluation Model to assess the incidence of costs and benefits flowing from these two models of the physical system, which we discuss in Section IV.C and Appendix C.

IV.A. Model of Physical System Operations

In order to assess the operational benefits of expanding PJM to include Dominion and the other New PJM Entrants, CRA used the GE MAPS model to determine the unit commitment and dispatch in the Base and Change Cases. The GE MAPS model is a security-constrained dispatch model that simulates the hourly chronological operation of an electricity market. It assumes marginal cost bidding, performs a least-cost dispatch subject to thermal and contingency constraints, and calculates hourly, locational-based marginal prices for electricity. The GE MAPS simulation is consistent with the congestion management scheme currently utilized in PJM and the other Northeast ISOs. The model's locational spot price calculation algorithm has been successfully benchmarked against the market price algorithm used in the PJM market.[16]

Models are only as reliable as their data, so CRA has taken extra measures to ensure that the assumptions regarding generation characteristics, transmission representation and limitations, fuel costs, emissions rates and regulations, planned additions and retirements, and NUG contracts are accurate and consistent. To avoid potential confusion with the parallel filing in Virginia, the physical modeling assumptions are unchanged from that study. Details of these model inputs are discussed in Appendix A. Although there have been some changes in market conditions since these assumptions were cast, the long-term outlook has not changed materially. Consequently, CRA believes that the results from the physical model and the sensitivity cases still reflect likely future conditions with sufficient confidence to serve as a basis for regulatory decisions.

CRA modeled four years of the ten-year study period: 2005, 2007, 2010 and 2014. We chose 2005 as the earliest full year when Dominion could be integrated into PJM. The year 2014

16 The actual PJM transmission representation for an individual hour was input into MAPS, along with actual loads, imports and exports and generator bids. The locational prices calculated by the GE MAPS program matched those produced by the PJM LMP system for those conditions.

bounds the ten-year study period, and 2007 and 2010 provide mid-point assessments to improve interpolation.

The principal challenge in modeling commitment and dispatch with a tool as powerful as MAPS is not, surprisingly, finding the security-constrained least-cost dispatch. Instead, the challenge is to find a reasonable representation of the inefficiencies that inevitably exist in real-world markets and, more particularly, how these inefficiencies change when moving from one market system to another. Left to its own devices, MAPS will find and execute all possible trades throughout the entire Eastern Interconnection to minimize total system production cost, subject to meeting all load reliably. Because the current market does not capture all these beneficial trades between market participants and, in particular, across market seams, we have set up our model to add inefficiencies through the use of selective barriers to trade, or "hurdles."

We used financial hurdles to approximate inefficiency in the Base Case stemming from several sources, including:

- Biases toward the use of local control zone resources due to uncertainty and resulting reliability concerns;
- Lack of full coordination among the commitment and dispatch processes of control areas;
- Imperfect economic management of congestion between and within control areas due to loop flows and less-efficient congestion management tools than LMP;
- The lack of market transparency in bilateral markets;
- Transaction costs; and
- Inefficient scheduling of transmission.

For this study, we employed four types of hurdle rates. These are discussed in greater detail in Appendix A. In the unit commitment phase of MAPS, we imposed a $10 per MWh hurdle between control areas in order to reflect the self-commitment practices prevailing today. In the dispatch phase of MAPS, we employed two hurdle rates:

First, an "import hurdle" rate of $3 per MWh is imposed on each control area for any imported power during peak periods ($1 per MWh in off-peak periods). The purpose of this hurdle is to mimic the self commitment that is the basis for current operational practices within each control area, transactions costs associated with searching out and executing bilateral trades, and other impediments to trade that bias dispatch towards internal resources. The import hurdle applies only once to any transaction, regardless of how many control areas were involved in wheeling the power.

The second type of dispatch hurdle used in this study is a "trade hurdle" rate of $3 per MWh, which is imposed on power transfers between control areas or RTOs in peak periods ($1 per MWh in off-peak periods). This trade hurdle rate reflects impediments to move power between control areas separately from the self-commitment logic embodied in the import hurdle. The trade hurdle is intended to represent both wheeling rates and trade impediments that become pancaked as power is wheeled across multiple control areas. Consequently, this charge is assessed for each control area through which a transaction moves.

Finally, a $1 per MWh fee is imposed at the dispatch phase for line losses for each inter-control area transfer. These three dispatch hurdles are additive, so a trade involving a single wheel would be subject to a total of a $7 per MWh peak-period dispatch hurdle rate—$3 per MWh to be imported, and $3 per MWh to be transferred to an adjoining control area, plus $1 per MWh for line losses. A trade involving a second transfer would be subject to a total hurdle rate of $11 per MWh—the $3 per MWh import hurdle, plus two transfer hurdles of $3 per MWh each and two losses charges of $1 per MWh each.

These hurdles were implemented in MAPS as economic contracts between zones, rather than as incremental line charges or restrictions on the transmission system. This approach has two distinct benefits in interpreting the results. First, the hurdles do not directly affect the locational prices in the model. The only influence the hurdle rates have is through their effect on the commitment and dispatch of the system. Second, the contracts track transfers between zones, rather than physical flows on lines. This feature aligns our contract transfers with the real bilateral contracts we see in today's electricity markets. It also makes tracking of costs and benefits materially more accurate than tracking only physical flows.

To model the integration of the New PJM Entrants into the PJM market system, we eliminated from the Change Case the commitment, trade and import hurdles among the five control zones in the Base Case that comprise the Expanded PJM market area, namely PJM, Dominion, AEP, DP&L and ComEd. The $1 per MWh line-loss fee remained as the only hurdle, reflecting our view that PJM will implement some version of a distance-dependent transmission loss charge. Commitment and dispatch hurdles from these zones to zones outside the Expanded PJM market were not changed.

IV.B. Model of Capacity Prices

An integral part of the PJM market design is its capacity market, through which PJM ensures that there will be sufficient capacity resources offering to supply energy into the PJM energy markets to ensure reliable system operations. Units selected through the capacity auction are required either to bid into the PJM day-ahead market or to self-schedule that capacity. In return, these capacity resources are paid the auction-clearing price for each kilowatt of supply, regardless of whether the resource is actually called upon to supply energy or ancillary services. These payments allow units that never run, or operate infrequently, to cover their fixed costs; otherwise, generation owners might find it more profitable to mothball or close marginal generation resources, reducing the overall reliability of the system.

For North Carolina Retail Customers, capacity market pricing affects only those purchases of capacity needed to supplement those customers' share of the Dominion generation fleet. The capacity costs of the Dominion generation fleet are included in rate base and, consequently, are unaffected by the transition to the PJM market.

In modeling this capacity market, we first developed the pattern of new entry by location and time. Secondly, we used this pattern of capacity additions to estimate future capacity prices. Appendix B details our modeling assumptions and techniques regarding capacity prices. In summary, CRA modeled first the requirements for new capacity in each area and then the resulting market price for capacity.

In determining new builds for the first year of the study period, 2005, CRA assumed that only those units that are under construction currently would be commercially available. New projects that have been halted were not included among the 2005 builds. Although additional projects might conceivably be tabled, other projects not counted may be completed by Summer 2005. Overall, we believe that this is a reasonable and conservative forecast of 2005 resources.

For subsequent years, we assumed that additional capacity resources are brought on-line to maintain required capacity reserves in each control zone.[17] We allowed trades of capacity between directly interconnected zones provided that two conditions were met. First, the imported capacity could not exceed the transfer capability between the two zones. Second, each zone was required to carry internally enough capacity to meet forecast peak load plus a 2.5 percent operating reserve requirement.

[17] We modeled both MISO and SeTrans as having two separate areas, east and west, to reflect the geographic and electrical separation within those two areas. MISO East corresponds to those areas of MISO in ECAR; MISO West includes those parts in MAIN and MAPP. SeTrans is split between the Southern and Entergy areas. The New York Control Area was modeled consistent with its capacity market design as two sub-regions (New York City and Long Island) and an overall New York region.

Analytical Approach

To estimate the market price of PJM capacity, we developed a probabilistic model, which reflects the uncertainty about whether new capacity will, in fact, be needed in any given year. The model starts from the premise that capacity prices in the PJM auction will be set either at \$20/kW-year if there is a capacity surplus, or at \$50/kW-year if there is not a capacity surplus. We then estimate the probability of each of these two states of the world, assuming that the capacity requirement is centered at our forecast value but has some uncertainty, with a normal random distribution. The forecast uncertainty was assumed to be 0.5 percent in 2003 and to increase by 0.2 percentage points in each subsequent year, so that the standard deviation in 2007 was taken to be 1.3 percent, and in 2014 to be 2.7 percent. These values, in our judgment, reasonably reflect the level of uncertainty intrinsic in long-term load forecasts. Using this model, we estimate the capacity price in each year of the study period for the overall PJM market, defined either with the current footprint in the Base Case or the Expanded PJM area in the Change Case.

IV.C. Model of Financial Effects

North Carolina Retail Customers are assumed to remain under current capped rates through the end of 2005 and under traditionally regulated cost-of-service rates throughout the remainder of the study period. In this study we have not attempted to project actual cost-of-service rates. Instead, we study only those rate components that would be affected by PJM integration. Therefore, only those costs, and offsetting revenue items, that differ between the Base and Change Cases are captured in this study. Fuel Factor costs are captured in all years, and those cost items captured in this study that impact base rates are reflected in North Carolina Retail Customer costs beginning in 2006, the year after the rate cap ends.

Fuel Factor Charges

Fuel Factor charges are calculated as the North Carolina Retail Customer share of the fuel cost of the Dominion generating units, the North Carolina Retail Customer share of post-1992 Dominion NUG energy costs, and 61 percent of the cost of additional off-system energy purchases needed to meet North Carolina Retail Customer load. Other production-related costs considered in the dispatch decision for Dominion generating units, but not considered in the Dominion Fuel Factor, include emission allowances and variable O&M. These costs are captured under base rate impacts.

Analytical Approach

In the Change Case, purchases made on behalf of North Carolina Retail Customers are based on Dominion Load Zone LMP.[18] A portion of Dominion FTRs is allocated through the North Carolina Fuel Factor, based on the percentage of purchases to total load, to offset the congestion charges embedded in these energy purchase prices.[19] The remaining FTRs attributable to North Carolina Retail Customers are allocated as a base rate item.

Costs that Impact Base Rates

Cost items affected by PJM integration that impact North Carolina base rates are included in this study beginning in 2006. These include 39 percent of the energy purchase costs needed to meet North Carolina Retail Customer load, and the North Carolina Retail Customer share of 1) pre-1992 Dominion NUG energy costs, 2) generating unit variable O&M and emission costs, 3) credits for non-requirements energy sales profits, and 4) capacity purchases.

In the Change Case, congestion costs are incurred and flow through base rates. Congestion costs are based on the difference between Dominion Load Zone LMP and Dominion Generation LMP.[20] North Carolina Retail Customers' share of Dominion FTRs, net of the FTR value included in the North Carolina Fuel Factor, are included as an offset to these congestion costs. In addition, PJM administrative charges are assessed to North Carolina Retail Customers in the Change Case. However, the 2005 charges are deferred and recovered with interest during 2006.[21]

[18] Under Dominion's PJM integration proposal, the energy price paid by loads in its control zone would be the weighted average price across the Dominion control zone. *See* Testimony of Gregory J. Morgan, filed concurrently with this study.

[19] *See* Testimony of Andrew J. Evans, filed concurrently with this study.

[20] Dominion Generation LMP is computed as average hourly LMPs at each Dominion generator bus, weighted by the generators' output in that hour.

[21] The study assumes that the deferrals will accrue interest at a rate of 7 percent, consistent with the interest rate for deferrals in recent FERC filings. This assumption is intended as a placeholder for whatever actual interest might be used later.

Analytical Approach

Ancillary Services Impacts and Other Impacts

The total cost of ancillary services has been assumed to not change as Dominion joins PJM because the required quantity of ancillary services that must be procured within the control zone is unchanged between the Base and Change Cases, and the costs remain the same.[22]

Transmission costs and revenues are assumed to be identical in the Base and Change Case. Dominion has assumed that there is no change between cases in such costs and revenues because Dominion's zonal base rate will be the same in the Base and Change Case for each year of the study period. As a result, no impact is computed for these costs and revenues.[23]

[22] *See* Testimony of Gregory J. Morgan and Testimony of Harold W. Payne, Jr., filed concurrently with this study.
[23] *See* Testimony of Harold W. Payne, Jr., filed concurrently with this study.

V. RESULTS OF THE BENEFIT-COST STUDY

Dollar amounts presented in the tables and text below are in nominal dollars for each year, while summary ten-year results are the net present value to July 1, 2003. A 10 percent discount rate is used to calculate the net present values.

V.A Base and Change Case Effects

Shown in Table V-1 are the annual costs and offsetting revenues for North Carolina Retail Customers under the Base Case for each Fuel Factor and relevant base rate component, separated into the following categories: 1) Production/Generation Costs, 2) Production Revenues, 3) Transmission Rights Revenues (FTRs), and 4) RTO Administrative Fees. The individual line items within each of these four categories are discussed after Table V-2. On Table V-1, negative numbers reflect credits to costs, and base rate line items are zero in 2005 because of the cap on base rates in effect in that year.

Results of the Benefit-Cost Study

Table V-1: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Base Case

(Millions of dollars; negative values are credits to cost)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	73.6	10.6	11.0	11.4	12.0	12.6	13.2	14.8	16.3	17.8	19.4
Fuel Costs	285.0	44.0	45.7	47.3	49.0	50.6	52.2	55.1	58.1	61.1	64.1
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	14.6	2.7	2.5	2.3	2.4	2.4	2.5	2.7	2.9	3.1	3.3
Sub-Total Fuel Factor	389.2	60.3	62.3	64.2	65.8	68.1	70.6	75.3	80.1	84.9	89.6
Base Rate Impacts:											
NUG Energy - Base Rates	50.2	0.0	8.1	9.0	9.3	9.7	10.1	11.4	12.7	14.0	15.4
Energy Purchases - Base Rates	41.5	0.0	7.0	7.3	7.7	8.1	8.4	9.4	10.4	11.4	12.4
Sub-Total Base Rate Energy	91.7	0.0	15.1	16.2	17.0	17.8	18.6	20.9	23.2	25.5	27.8
Purchased Power Capacity	16.0	0.0	0.5	1.0	1.4	1.5	2.5	4.1	6.6	8.9	10.7
Total Prod/Gen Costs	496.8	60.3	77.9	81.5	84.2	87.3	91.7	100.3	109.8	119.2	128.1
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(8.2)	(1.6)	(1.6)	(1.6)	(1.5)	(1.4)	(1.2)	(1.3)	(1.4)	(1.4)	(1.5)
Base Rate Impacts:											
VOM on Sales - Base Rates	(1.2)	0.0	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
Profit on Sales - Base Rates	(0.3)	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Sub-Total Base Rate Energy	(1.5)	0.0	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.4)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(9.7)	(1.6)	(1.9)	(2.0)	(1.8)	(1.7)	(1.5)	(1.6)	(1.7)	(1.8)	(1.8)
Transmission Rights Revenues											
Transmission Rights Revenues (FTRs)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RTO Admin Fees											
RTO Admin Fees	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs to Customers	487.1	58.7	76.0	79.5	82.3	85.7	90.2	98.7	108.2	117.5	126.2
********											
Fuel Factor	381.0	58.7	60.7	62.6	64.3	66.7	69.4	74.0	78.7	83.4	88.2

Results of the Benefit-Cost Study

Table V-2 summarizes the annual costs and offsetting revenues for North Carolina Retail Customers under the Change Case. Similarly, on Table V-2, negative numbers reflect credits to costs, and base rate line items are zero in 2005 because of the cap on base rates in effect in that year.

Table V-2: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case

(Millions of dollars; negative values are credits to costs)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	96.5	13.8	14.1	14.5	15.5	16.5	17.5	19.6	21.8	23.9	26.1
Fuel Costs	264.6	40.1	42.0	43.8	45.4	47.1	48.7	51.5	54.4	57.2	60.1
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	14.2	2.5	2.4	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0
Sub-Total Fuel Factor	391.2	59.5	61.7	63.8	65.8	68.5	71.4	76.5	81.7	86.8	92.0
Base Rate Impacts:											
NUG Energy - Base Rates	37.5	0.0	6.4	7.0	7.2	7.4	7.6	8.4	9.1	9.9	10.7
Energy Purchases - Base Rates	54.5	0.0	9.0	9.3	9.9	10.5	11.2	12.5	13.9	15.3	16.7
VOM Reduction - Reduced Output	(2.3)	0.0	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.4)
Sub-Total Base Rate Energy	89.6	0.0	14.9	15.8	16.6	17.4	18.2	20.4	22.6	24.8	26.9
Purchased Power Capacity	13.6	0.0	0.5	1.0	1.4	1.5	2.3	3.1	4.8	7.3	9.7
Congestion - Base Rates	28.4	0.0	5.2	5.5	5.8	6.1	6.3	6.4	6.4	6.5	6.6
Total Prod/Gen Costs	522.9	59.5	82.3	86.1	89.5	93.4	98.3	106.3	115.4	125.4	135.3
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(4.7)	(0.7)	(0.7)	(0.7)	(0.8)	(0.9)	(1.0)	(1.0)	(1.0)	(0.9)	(0.9)
Base Rate Impacts:											
VOM on Sales - Base Rates	(0.8)	0.0	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Profit on Sales - Base Rates	(0.2)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Sub-Total Base Rate Energy	(1.0)	0.0	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(5.6)	(0.7)	(0.9)	(0.9)	(1.0)	(1.1)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(2.8)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.7)	(0.7)
Other FTRs - Base Rates	(35.8)	0.0	(6.9)	(7.3)	(7.4)	(7.5)	(7.6)	(7.7)	(7.9)	(8.0)	(8.1)
Transmission Rights Revenues (FTRs)	(38.6)	(0.4)	(7.3)	(7.7)	(7.9)	(8.0)	(8.1)	(8.3)	(8.5)	(8.7)	(8.8)
RTO Admin Fees											
RTO Admin Fees	10.2	0.0	3.8	1.8	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Costs to Customers	488.9	58.3	77.9	79.3	82.5	86.2	90.8	98.7	107.6	117.4	127.2
********											
Fuel Factor	383.8	58.3	60.5	62.7	64.5	67.1	69.9	74.9	80.1	85.2	90.4

Results of the Benefit-Cost Study

1. Production/Generation Costs
Fuel Factor Impacts:
"Energy Purchases – Fuel Factor" reflects the North Carolina Retail Customers' share of the 61% of Dominion energy purchases that are included in the Fuel Factor. "Fuel Costs" reflects the North Carolina share of Dominion generating unit fuel costs included in the Fuel Factor. "Other Fuel Costs" includes the North Carolina Retail Customers' share of gas pipeline demand and nuclear decommissioning charges included in the Fuel Factor. "NUG Energy – Fuel Factor" reflects the North Carolina share of the post-1992 Dominion NUG energy costs that are included in Fuel Factor charges.

Base Rate Impacts:
"NUG Energy – Base Rates" reflects the North Carolina Retail Customers' share of the pre-1992 Dominion NUG energy costs that are included in base rates. "Energy Purchases – Base Rates" reflects the North Carolina Retail Customers' share of the 39 percent of Dominion energy purchases that are included in base rates. "Purchased Power Capacity" reflects the North Carolina Retail Customers' share of the cost of Dominion capacity purchases included in base rates.

There are two additional Production/Generation Costs line items in the Change Case results shown in Table V-2. "VOM Reduction – Reduced Output" reflects the reduction in variable O&M and emissions costs as a result of the decrease in the amount of generation from the Dominion generating units in the Change Case. "Congestion – Base Rates" reflects the North Carolina Retail Customers' share of the congestion charges associated with the differential between the Dominion Load Zone LMP and Dominion Generation LMP.

2. Production Revenues
Fuel Factor Impacts:
"Sales Costs – Fuel Factor" reflects the North Carolina Retail Customers' share of the fuel cost associated with non-requirements energy sales made from Dominion generating units that are credited to the Fuel Factor.

Base Rate Impacts:
"VOM on Sales – Base Rates" reflects the North Carolina Retail Customer share of the variable O&M associated with non-requirements sales made from Dominion generating units, which are credits to base rates. "Profit on Sales – Base Rates" reflects the North Carolina Retail Customer share of the profit on non-requirements sales made from Dominion generating units, which are also credits to base rates. "Capacity Sales" reflects the North Carolina Retail Customer share of any sales of Dominion capacity, which would be credits to base rates.

Results of the Benefit-Cost Study

3. Transmission Rights Revenues
Fuel Factor Impacts:
FTRs are associated with the Change Case only. "FTRs Attributable to Purchases – Fuel Factor" reflects the value of FTRs allocated through the North Carolina Fuel Factor to offset congestion costs included in "Energy Purchases – Fuel Factor" under the Fuel Factor Impacts discussed above.

Base Rate Impacts:
"Other FTRs – Base Rates" reflects the value of the North Carolina Retail Customers' share of the remaining Dominion FTR value included in base rates.

4. RTO Administrative Fees. These fees are associated with the Change Case only. Fees in 2005 are deferred and recovered with interest in 2006.

There are two total lines on these three tables. "Costs to Customers" reflects the total of the line items discussed above. "Fuel Factor" reflects the total of all of the Fuel Factor related items discussed above.

Results of the Benefit-Cost Study

Table V-3 summarizes the annual differences in these line items between the Base and Change Cases. On Table V-3, positive numbers represent additional net costs to North Carolina Retail Customers as a result of moving from the Base to the Change Case. Negative numbers represent net benefits.

Table V-3: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case Minus Base Case

(Millions of dollars; negative numbers are net benefits)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	22.9	3.1	3.1	3.1	3.5	3.9	4.2	4.9	5.5	6.1	6.7
Fuel Costs	(20.5)	(3.8)	(3.7)	(3.5)	(3.5)	(3.5)	(3.5)	(3.6)	(3.8)	(3.9)	(4.0)
"Other Fuel" Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUG Energy - Fuel Factor	(0.4)	(0.2)	(0.1)	(0.0)	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.3)
Sub-Total Fuel Factor	2.0	(0.9)	(0.6)	(0.4)	0.0	0.4	0.8	1.2	1.6	2.0	2.4
Base Rate Impacts:											
NUG Energy - Base Rates	(12.7)	0.0	(1.6)	(2.0)	(2.2)	(2.3)	(2.5)	(3.1)	(3.6)	(4.1)	(4.6)
Energy Purchases - Base Rates	13.0	0.0	2.0	2.0	2.2	2.5	2.7	3.1	3.5	3.9	4.3
VOM Reduction - Reduced Output	(2.3)	0.0	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.4)
Sub-Total Base Rate Energy	(2.1)	0.0	(0.2)	(0.5)	(0.4)	(0.4)	(0.3)	(0.4)	(0.6)	(0.7)	(0.8)
Purchased Power Capacity	(2.3)	0.0	0.0	0.0	0.0	0.0	(0.2)	(1.1)	(1.8)	(1.6)	(0.9)
Congestion - Base Rates	28.4	0.0	5.2	5.5	5.8	6.1	6.3	6.4	6.4	6.5	6.6
Total Prod/Gen Costs	26.1	(0.9)	4.4	4.6	5.4	6.1	6.6	6.1	5.6	6.2	7.2
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	3.6	0.9	0.9	0.9	0.7	0.5	0.3	0.3	0.4	0.5	0.5
Base Rate Impacts:											
VOM on Sales - Base Rates	0.5	0.0	0.1	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1
Profit on Sales - Base Rates	0.1	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
Sub-Total Base Rate Energy	0.5	0.0	0.2	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	4.1	0.9	1.0	1.1	0.9	0.6	0.3	0.4	0.5	0.6	0.6
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(2.8)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.7)	(0.7)
Other FTRs - Base Rates	(35.8)	0.0	(6.9)	(7.3)	(7.4)	(7.5)	(7.6)	(7.7)	(7.9)	(8.0)	(8.1)
Transmission Rights Revenues (FTRs)	(38.6)	(0.4)	(7.3)	(7.7)	(7.9)	(8.0)	(8.1)	(8.3)	(8.5)	(8.7)	(8.8)
RTO Admin Fees											
RTO Admin Fees	10.2	0.0	3.8	1.8	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Costs to Customers	1.8	(0.4)	1.9	(0.2)	0.1	0.5	0.6	(0.0)	(0.5)	(0.0)	0.9
********											
Fuel Factor	2.8	(0.4)	(0.2)	0.1	0.3	0.4	0.6	1.0	1.4	1.8	2.2

Results of the Benefit-Cost Study

V.B. Summary of Benefits and Costs

Table V-4 summarizes the benefits and costs to North Carolina Retail Customers of Dominion joining PJM. On this table, net benefits are reported as positive numbers, and net costs are reported as negative numbers. Benefits are reported in two basic categories: 1) energy savings, including the impact on the Fuel Factor; and 2) capacity savings. These benefits are taken directly from the more detailed information shown in Table V-3 above. Namely, "Fuel Factor Savings" in Table V-4 below reflects the total change across all of the fuel factor-related items in Table V-3. "Energy – Base Rate Savings" in Table V-4 below reflects the total of energy-related items that impact base rates, and represents the sum of the two "Sub-Total Base Rate Energy" lines in Table V-3 above. "Congestion – Base Rate Savings" and "FTR Value – Base Rate Savings" in Table V-4 below are taken directly from Table V-3 above. Thus, "Total Energy Savings" in Table V-4 below includes not only the impact on the Fuel Factor, but, beginning in 2006, other energy-related items that impact base rates. "Capacity Savings" is also taken directly from Table V-3 above. The cost of joining PJM is reflected in the "Net PJM Admin Charge" in the Change Case and is taken from Table V-3 above, except that the impact of the "Deferral/Recovery" is separately broken out. It is assumed that no costs are incurred in the Base Case, even though it is possible that Dominion might be pressured to form an RTO even if it does not join PJM and such an RTO would likely have equal or greater administrative fees.

Table V-4: Annual Benefits of Dominion Joining PJM for North Carolina Retail Customers
(in millions of $, positive numbers denote benefits)

North Carolina Retail Customers	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Factor Savings	(2.8)	0.4	0.2	(0.1)	(0.3)	(0.4)	(0.6)	(1.0)	(1.4)	(1.8)	(2.2)
Energy - Base Rates Savings	1.5	-	0.0	0.3	0.3	0.3	0.3	0.4	0.5	0.6	0.7
Congestion - Base Rates Savings	(28.4)	-	(5.2)	(5.5)	(5.8)	(6.1)	(6.3)	(6.4)	(6.4)	(6.5)	(6.6)
FTR Value - Base Rates Savings	35.8	-	6.9	7.3	7.4	7.5	7.6	7.7	7.9	8.0	8.1
Total Energy Savings	6.1	0.4	1.8	2.0	1.6	1.3	1.0	0.8	0.5	0.3	0.1
Capacity Savings	2.3	-	-	-	-	-	0.2	1.1	1.8	1.6	0.9
Benefit	8.4	0.4	1.8	2.0	1.6	1.3	1.2	1.8	2.4	2.0	1.0
PJM Admin Charge	(10.2)	(1.8)	(1.8)	(1.8)	(1.7)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)
Deferral/Recovery	-	1.8	(1.9)	-	-	-	-	-	-	-	-
Net PJM Admin Charge	(10.2)	0.0	(3.8)	(1.8)	(1.7)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)
Net Benefit	(1.8)	0.4	(1.9)	0.2	(0.1)	(0.5)	(0.6)	0.0	0.5	0.0	(0.9)

Overall, we see that the benefits over the 10-study period for North Carolina Retail Customers are $8.4 million. However, these benefits and the associated reductions in rates to North Carolina Retail Customers are essentially offset by PJM administrative costs. While there is no short-run, quantifiable gain to these customers, neither is there a material increase in costs. As previously stated, the long-run benefits that are less readily quantifiable but no less real, however, must be considered as well.

V.B.1. Energy Cost Impacts

Given our assumption that North Carolina Retail Customers remain under regulated rates throughout the study period, their benefits from Dominion joining PJM are limited to reductions in the cost of energy and capacity purchased from third-party generation.

The Total Energy Savings of $6.1 million net present value over the ten-year study period is driven by improved opportunities to import power into the Dominion zone. As shown in Table V-5 below, in the Base Case in 2007, Dominion is a net importer of an average of 1,338 MWh in each hour. In the Change Case, Dominion is a net importer of an average of 1,857 MWh in each hour. Note that Dominion is interconnected with AEP, PJM (East and West) and CP&L. Expanding PJM lowers the trade barriers among the zones in the Expanded PJM (including Dominion) with the result that more low-cost energy from those regions can be imported economically into Dominion. As described in more detail in Appendix C, this increased level of trade between and among PJM (East and West), AEP and Dominion results in lower prices in the Dominion area, and it also changes trade opportunities between Dominion and CP&L.

Although there are Total Energy Savings of $6.1 million, the Fuel Factor is negative $2.8 million. This is caused by the fact that not all energy costs flow through the Fuel Factor Savings. As Dominion imports more in the Change Case, Dominion's NUG units generate less. Since some NUG energy expenses are recovered in base rates, any decreased generation from these units results in lower base rate energy costs and higher purchases, for which a portion flows through the Fuel Factor.

Table V-5: Average Hourly Net Imports Into Dominion

	2005	2007	2010	2014
Base Case				
From AEP	1,233	1,200	1,096	921
From PJM (East & West)	55	93	111	253
From CP&L	63	45	22	(25)
TOTAL	1,350	1,338	1,229	1,149
Change Case				
From AEP	1,727	1,647	1,490	1,245
From PJM (East & West)	133	214	345	544
From CP&L	(2)	(4)	(20)	(45)
TOTAL	1,858	1,857	1,815	1,744

Results of the Benefit-Cost Study

V.B.2. Capacity Cost Impacts

The cost of the capacity provided from Dominion's generation fleet to serve North Carolina Retail Customers is recovered through base rates. This component of base rates is assumed to be unchanged between the Base and Change Cases. This rate-base generation, however, is not sufficient to meet the full capacity requirements of the North Carolina Retail Customers. Consequently, Dominion purchases this incremental generation from the market, at market prices that are passed through in cost-of-service rates. In the Expanded PJM market of the Change Case, capacity prices are consistently lower than in the Base Case. See Table B-2 in Appendix B. Consequently, the cost of Dominion's market capacity purchases is lower in the Change Case, reducing cost-of-service rates by $2.3 million dollars in a net present value over the ten-year study period.

V.B.3. PJM Administrative Charge

The cost of being a member of PJM is reflected in the PJM administrative charge. These costs are charged to load in all years of the Change Case, when Dominion is in PJM. These costs have a ten-year present value of $10.2 million.

V.C. Sensitivity Case Results – High Fuel Price Case

To address some of the uncertainty with respect to long-term natural gas and oil prices, a sensitivity case is analyzed in which natural gas and oil prices are increased 25 percent above those that are used in the results from the Base Case ("Base Results"). Not surprisingly, the higher fuel costs translate directly into higher electricity costs in both the Base and Change Case. When Dominion is integrated into a broader market, with better access to diverse generating facilities, this price increase is less than if Dominion is an isolated market. The higher gas prices provide more benefit from substitution of cheaper coal-fired generation when Dominion joins PJM. This provides higher benefits for North Carolina Retail Customers.

As shown in Table V-6, the total benefits to North Carolina Retail Customers are $11.2 million over the 10-year study period. The net benefits are $1.0 million over the 10-year study period. The total and net benefits reflect an increase of almost $3 million compared to the net benefits in the Base Results (see Table V-4). The difference is entirely attributable to increased energy savings (capacity savings and PJM administrative charges are identical to those in the Base Results). The higher fuel costs of natural gas-fired units increase the marginal cost difference between those units and coal-fired units. In the Change Case, when Dominion is part of PJM, Dominion customers are better able to take advantage of lower cost imports from within PJM. See Appendix D for detail.

Table V-6: Summary Benefits of Dominion Joining PJM for North Carolina Retail Customers (High Fuel Price Sensitivity Case)

(Millions of $, positive numbers denote benefits)

North Carolina Retail Customers	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Factor Savings	(0.9)	1.5	0.8	(0.0)	(0.1)	(0.2)	(0.2)	(0.8)	(1.3)	(1.9)	(2.4)
Energy - Base Rates Savings	(0.5)	-	(0.5)	0.1	(0.0)	(0.1)	(0.2)	(0.1)	(0.1)	(0.0)	0.0
Congestion - Base Rates Savings	(37.0)	-	(7.0)	(7.2)	(7.6)	(8.0)	(8.3)	(8.3)	(8.2)	(8.2)	(8.1)
FTR Value - Base Rates Savings	47.4	-	9.2	9.6	9.8	10.0	10.3	10.3	10.4	10.4	10.5
Total Energy Savings	8.9	1.5	2.4	2.5	2.1	1.8	1.5	1.1	0.7	0.4	(0.0)
Capacity Savings	2.3	-	-	-	-	-	0.2	1.1	1.8	1.6	0.9
Benefit	11.2	1.5	2.4	2.5	2.1	1.8	1.7	2.2	2.6	2.0	0.9
PJM Admin Charge	(10.2)	(1.8)	(1.8)	(1.8)	(1.7)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)
Deferral/Recovery	-	1.8	(1.9)	-	-	-	-	-	-	-	-
Net PJM Admin Charge	(10.2)	0.0	(3.8)	(1.8)	(1.7)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)
Net Benefit	1.0	1.5	(1.4)	0.7	0.4	0.0	(0.1)	0.4	0.7	0.1	(1.0)

V.D. Sensitivity Case Results – High Load Case

A second sensitivity case is analyzed with demand higher than included in the capacity requirements forecast. In this case, peak load is 5 percent higher than that used in the Base Results and total demand is 2 percent higher. As shown in Table V-7, the total benefits to North Carolina Retail Customers are $5.6 million over the 10-year study period. The net benefits are ($4.7) million over the 10-year study period. The total and net benefits reflect a decrease of about $3 million compared to the net benefits in the Base Results (see Table V-4). The increased load increases prices generally. Higher-cost units are forced to generate to meet the increased load. As the higher load is unexpected, (that is, not included in the planned reserve margins) the available capacity is closer to reserve margins so that joining PJM does not moderate prices as much. Dominion customers also incur higher PJM administrative charges as this cost has been modeled on a dollar per MWh of load basis. It is possible that the rate would be reduced if load were higher than expected, thus minimizing any cost difference with respect to the PJM administrative charge. See Appendix D for further detail.

Table V-7: Summary Benefits of Dominion Joining PJM for North Carolina Customers (High Load Sensitivity Case)

(in millions of $, positive numbers denote benefits)

North Carolina Retail Customers	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Factor Savings	(5.9)	0.4	(0.0)	(0.5)	(0.6)	(0.7)	(0.8)	(1.7)	(2.6)	(3.5)	(4.3)
Energy - Base Rates Savings	0.9	-	0.2	0.6	0.5	0.4	0.3	0.1	(0.1)	(0.3)	(0.5)
Congestion - Base Rates Savings	(33.7)	-	(5.5)	(5.9)	(6.3)	(6.7)	(7.2)	(7.8)	(8.5)	(9.2)	(9.9)
FTR Value - Base Rates Savings	41.2	-	7.2	7.8	8.0	8.2	8.4	9.1	9.9	10.7	11.5
Total Energy Savings	2.4	0.4	2.0	2.1	1.5	1.1	0.7	(0.3)	(1.3)	(2.3)	(3.3)
Capacity Savings	3.2	-	-	-	-	-	0.3	1.5	2.5	2.2	1.2
Benefit	5.6	0.4	2.0	2.1	1.5	1.1	0.9	1.2	1.2	(0.1)	(2.0)
PJM Admin Charge	(10.4)	(1.9)	(1.9)	(1.8)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)	(2.0)
Deferral/Recovery	-	1.9	(2.0)	-	-	-	-	-	-	-	-
Net PJM Admin Charge	(10.4)	0.0	(3.8)	(1.8)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)	(2.0)
Net Benefit	(4.7)	0.4	(1.9)	0.2	(0.2)	(0.7)	(0.9)	(0.7)	(0.7)	(2.1)	(4.0)

V.E. Sensitivity Case Results – Bedington-Black Oak Case

A third sensitivity case is analyzed in which the normal rating of the Bedington-Black Oak 345kV line is increased from 1,700 MW to 1,850 MW both in the Base and the Change Cases. All other model inputs and assumptions remain the same. Bedington-Black Oak is an Allegheny transmission facility in the eastern arm of West Virginia. This key "west-to-east" electricity highway operates at full capacity much of the time. Discussions early this year with PJM operations staff lead to the conclusion that 1,850 MW reasonably reflects a conservative operating limit on this transmission facility under new PJM protocols implemented early in 2003. As shown in Table V-8, the total benefits to North Carolina Retail Customers are $8.0 million over the 10-year study period. The net benefits are ($2.2) million over the 10-year study period. The total and net benefits reflect a decrease of about $0.5 million compared to the net benefits in the Base Results (see Table V-4). This result does not mean that the higher rating on Bedington-Black Oak is not beneficial—it is. The benefits to North Carolina Retail Customers are greater under the Base Case, however, than under the Change Case, despite the fact that the average wholesale price of energy declines by more over the study period. This beneficial effect of lower purchase prices is offset, however, by greater reliance on energy purchases rather than energy from Dominion's owned generation or NUGs. See Appendix D for further detail.

Table V-8: Summary Benefits of Dominion Joining PJM for North Carolina Customers (Bedington-Black Oak Case)

(in millions of $, positive numbers denote benefits)

North Carolina Retail Customers	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Factor Savings	(3.5)	0.4	(0.0)	(0.4)	(0.5)	(0.5)	(0.6)	(1.0)	(1.4)	(1.9)	(2.3)
Energy - Base Rates Savings	1.9	-	0.1	0.6	0.4	0.3	0.2	0.3	0.5	0.6	0.8
Congestion - Base Rates Savings	(35.7)	-	(6.8)	(7.1)	(7.4)	(7.6)	(7.9)	(7.9)	(7.9)	(7.9)	(7.8)
FTR Value - Base Rates Savings	43.0	-	8.7	9.1	9.1	9.2	9.2	9.1	9.0	8.9	8.9
Total Energy Savings	5.7	0.4	2.0	2.1	1.7	1.3	0.9	0.6	0.2	(0.1)	(0.5)
Capacity Savings	2.3	-	-	-	-	-	0.2	1.1	1.8	1.6	0.9
Benefit	8.0	0.4	2.0	2.1	1.7	1.3	1.1	1.7	2.1	1.5	0.5
PJM Admin Charge	(10.2)	(1.8)	(1.8)	(1.8)	(1.7)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)
Deferral/Recovery	-	1.8	(1.9)	-	-	-	-	-	-	-	-
Net PJM Admin Charge	(10.2)	0.0	(3.8)	(1.8)	(1.7)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)
Net Benefit	(2.2)	0.4	(1.8)	0.4	(0.0)	(0.5)	(0.7)	(0.2)	0.2	(0.4)	(1.5)

VI. CONCLUSIONS

Integration into an established and respected RTO such as PJM will provide North Carolina Retail Customers with a range of important, but difficult to quantify, benefits. Among these are:

- Enhanced reliability in the Dominion service territory through efficient congestion management, restrictions on load shedding in PJM South and a continuation of a local control center to address local reliability.
- Optimized regional transmission planning process that focuses new investment to projects that realize the greatest net economic and reliability benefits. The study also finds that the key transmission constraints that result in locational price differences in the Dominion control zone are located outside of the control zone. Although these constraints do not pose reliability concerns, they impose substantial economic costs. Dominion's membership in PJM would assure that these costs are fully considered in regional transmission planning processes that can address these constraints in the future. In the interim, congestion charges in the Dominion control zone under PJM's LMP congestion management system are fully hedged by the FTR value received by Dominion customers.
- Improved resource adequacy through the Expanded PJM market created by the addition of the New PJM Entrants allowing for greater load diversity, improved reserve sharing across the region, and participation in a larger integrated regional transmission planning process.
- The potential for improvements to the efficiency of installed capacity markets, reflecting investment in generation to enhance its productivity, beyond those that have been incorporated into the formal modeling.
- Enhanced investment and participation in demand-side management programs, in response to clear and time-specific price signals.
- The potential for improved siting decisions on the part of future generation and transmission developers, allowing more efficient investment based on transparent and independent pricing.
- Potential cost savings from joining an established, proven RTO, rather than incurring the costs and uncertainties of developing an alternate response to regulatory requirements.

Conclusions

This study indicates that there are near-term energy and capacity savings that benefit North Carolina Retail Customers:

- Reduced wholesale energy prices will save North Carolina Retail Customers $6.1 million through 2014.
- Reduced capacity prices will save North Carolina Retail Customers $2.3 million through 2014.

Considering the quantitative and qualitative benefits together, it is clearly a net benefit to North Carolina Retail Customers for Dominion to join PJM. After netting out PJM administrative costs, we see a small quantifiable net cost to North Carolina Retail Customers of $1.8 million net present value over the study period. This cost is more than justified by the benefits described, but not quantified herein.

In conclusion, after a comprehensive examination of the comparative costs and benefits of Dominion joining PJM, we find that PJM membership will offer substantial and continuing net benefits to North Carolina Retail Customers.

APPENDIX A: GE MAPS DESCRIPTION

A.1. Description of the GE MAPS Model

An overview of the GE MAPS model was provided in Section IV of this report. Here we provide more detail about how the model combines its inputs to project hourly locational prices and unit generation, and we list some of the key input assumptions used in the model. The first section of this appendix describes some assumptions implicit in the GE MAPS modeling approach (*e.g.*, how maintenance is scheduled, how operating reserve requirements are imposed), while the second details some of the fundamental input assumptions, such as fuel prices and loads.

Basic Model Representation

The GE MAPS model is a security-constrained dispatch model that simulates the hourly chronological operation of an electricity market. Based on unit-level marginal cost bids, the model performs a least-cost dispatch subject to thermal and contingency constraints and calculates hourly, locational-based marginal prices for electricity. Nodal prices and unit level generation data can be aggregated to whatever level is desired (utility, region, state, *etc.*). Zonal load prices can be calculated either as load-weighted averages or as simple averages of locational prices. The GE MAPS simulation is consistent with the congestion management scheme currently utilized in PJM and the other Northeast ISOs. The model's locational spot price calculation algorithm has been successfully benchmarked against the market price algorithm used in the PJM market.[24]

CRA used the Eastern Interconnection version of the MAPS model in our analysis.[25] All modeling and analyses were done at the greatest level of detail possible (*e.g.*, individual company/control zone), given the limitations of our input data.[26] We combined companies into

[24] The actual PJM transmission representation for an individual hour was input into MAPS, along with actual loads, imports and exports and generator bids. The locational prices calculated by the GE MAPS program matched those produced by the PJM LBMP system for those conditions.

[25] The Eastern Interconnection includes all NERC regions, except the Western Systems Coordinating Council (WSCC) and the Electric Reliability Council of Texas (ERCOT). The electrical operations of all areas in the Eastern Interconnection are electrically synchronized with each other (except Hydro Québec), but are not synchronized with those in either ERCOT or the WSCC. Transmission ties with ERCOT, the WSCC and Hydro Québec are through DC ties. The GE MAPS Model of the Eastern Interconnection does not individual generators and loads for the interconnected and synchronized Canadian regions (Ontario, Manitoba, Saskatchewan, and New Brunswick), but rather includes supply curves that captures exports from these regions into the U.S. markets.

[26] Traditional transmission modeling and data reporting arrangements form the basis for all modeling efforts. For example, if an individual company/organization traditionally reports its loads as part of a larger control area, we use that designation in our analyses. Similarly for transmission related information, the control areas in the AC power flow (which is a key input to MAPS) provide the only basis available for aggregating transmission related outputs from the model. If the individual buses of a company/organization are considered as part of a larger control area in typical load flow modeling, we model those buses as part of the larger control area.

pools for commitment and dispatch, where each pool represents either an RTO or independent control zone. RTOs were modeled to correspond to existing ISOs, proposed RTOs as defined in current filings, and public announcements regarding RTO membership plans by individual utilities. Companies without existing definitive plans about their RTO membership were modeled as independent control zones.

Table A-16 at the end of this appendix shows how companies were grouped into RTOs and control zones. The three northeast ISO markets, namely ISO-NE, NYISO, and PJM, were modeled as individual RTOs. In our Base Case, PJM was modeled with its current footprint; in the Change Case, the PJM footprint was expanded to include Dominion, AEP, DP&L, and ComEd. The remaining ECAR and MAIN companies, along with the MAPP companies, were combined to form the Midwest ISO RTO (MISO). The SeTrans and GridFlorida RTOs were also assumed to go forward.[27] SPP and TVA were each assumed to maintain their current composition, but function as RTOs.

Duke Power, Carolina Power & Light (CP&L), and South Carolina Electric & Gas (SCE&G) were treated as individual control areas, with Santee Cooper also included in the SCE&G area. In the Base Case in which Dominion, AEP, DP&L, and ComEd were not integrated into PJM, each of these companies was treated as an individual control zone.

Least-Cost Commitment and Dispatch

The GE MAPS model commits and dispatches generation units to minimize production costs on a system-wide basis, but allows constraints on pool-to-pool transactions to be specified in order to capture pool-level commitment and dispatch and other impediments to trade.[28] As a result, unless constraints that impede trade are specified, all physically feasible, economically beneficial transactions will take place among various entities in the Eastern Interconnection. Because the current market does not capture all economically beneficial trades between utilities, and since trade across RTO seams is not perfectly coordinated, we implemented hurdle rates to restrict commitment and dispatch efficiencies inherent in the model's operation.

These hurdles must be met before either an RTO or a company (operating outside an RTO) will rely on generation from outside its area to meet internal load. Hence, each pool's unit commitment and dispatch will only reflect the availability of economic external generation if the resulting cost-savings from utilizing that capacity exceeds the hurdle. Hurdles apply to pool-to-pool transactions in both the Base and Change Cases. However, because the PJM pool expands in the Change

[27] *See* footnote 7.
[28] "System-wide" commitment and dispatch encompasses the entire Eastern Interconnect.

Appendix A: GE MAPS Description

Case to include Dominion, ComEd, DP&L, and AEP, the hurdles among these companies and the existing PJM companies are removed.

We imposed two types of hurdles and the level of each varies between peak and off-peak periods and between the commitment and dispatch phases. The first type of hurdle, which we have termed "trade hurdles," applies to each trade between directly interconnected pools and therefore becomes larger as the number of transmission wheels increases. Trade hurdles reflect the cost of obtaining firm transmission and impediments associated with securing transmission rights. Trade hurdles apply in both commitment and dispatch and were set to $3/MWh on-peak and $1/MWh off-peak.

We refer to hurdles of the second type as "import hurdles." Import hurdles are an additional penalty assessed to each pool on positive net imports. The penalty is assessed for each MWh by which a pool's load exceeds its internal generation, and hence is a fixed hurdle on pool-to-pool trades that does not pancake with the number of wheels required for the transfer. The effect of these hurdles is to require an additional amount of savings, even after the trade hurdles have been satisfied, before a pool will utilize external generation. These hurdles capture the margin on trades that must be available before the parties are willing to execute a deal.

In order to capture a bias toward committing local resources for meeting peak loads, in commitment we set import hurdles to $10/MWh on-peak and $1/MWh off peak. Each pool is assumed to commit generation to serve its own load except in those instances where a savings of $10 per MWh can be achieved through imports from another control area. If attractive purchases or sales are available, the requisite units are committed (or decommitted) and made available for (or excluded from) the hourly dispatch. In order to allow the export of available, low-cost capacity that has been committed but is not fully utilized to occur with relatively less trading friction, we imposed import hurdles in dispatch of $3/MWh on-peak and $1/MWh off-peak.

We also imposed penalties on trades to simulate the effect of incremental losses. The loss charges were applied to transfers out of or through a pool.[29] We implemented the charges by assess-

[29] GE MAPS can model incremental transmission losses in one of two ways. First, it has the capability to use a set of fixed loss factors based on the specified load flow case and scales these factors up or down as the load increases or decreases with respect to the base case (i.e., it assumes a linear relationship between transmission losses and load on the system). As long as the power flows on transmission lines do not change direction, this is a reasonable approximation, but in much of the study region, flows can reverse direction depending on the season, the time of day, and unit availability. Second, GE has recently added the ability to MAPS to compute incremental loss factors hourly, based on the solved powerflow. CRA has not yet satisfied itself that the new algorithm produces credible results in large-scale studies; nor was this option available at the time the Virginia report was prepared. As a result, neither GE MAPS logic to calculate marginal losses was used, and the impact on market clearing prices of changing physical losses was not determined. Rather, a financial fee for losses was incorporated into the Production Cost Analysis, which provides a reasonable proxy for marginal losses across control zones.

ing a $1/MWh trade hurdle on all transfers between directly connected pools. Even though other hurdles are removed, loss charges among the PJM subregions are maintained in the Change Case to reflect losses within the Expanded PJM.

Table A-1 summarizes the level of all the hurdles by type and time period.

Table A-1: Hurdle Rates on Pool-to-Pool Transactions

	Commitment		**Dispatch**	
	Peak	Off-Peak	Peak	Off-Peak
Trade Hurdles	3	1	3	1
Penalty for Losses	1	1	1	1
Import Hurdles	10	1	3	1

Operating Reserves

MAPS accounts for spinning and non-spinning reserve requirements in its commitment and dispatch. The spinning reserve market affects the energy market prices because the units that provide spinning reserve cannot produce electricity under normal conditions.[30] As a result, energy prices in MAPS are higher when reserve markets are modeled.

In both the Base and Change Case, operating reserve requirements were specified for each pool as 2.5 percent of hourly load, all of which must be met with spinning resources. Additionally, in the Change Case, we imposed locational operating reserve requirements. PJM (East and West combined), ComEd, AEP, DP&L, and Dominion were each required to provide operating reserves internally. The methodology implicitly maintains the Base Case reserve requirements and precludes benefits from reserve sharing across the Expanded PJM.

We assumed that only a limited percentage of generation units' capacity can provide spinning reserves due to ramp-up constraints that prevent units from reaching their full capacity for delivering energy within the ten minutes period required for operating reserves. We specified a ramp rate for each unit and allowed it to hold operating reserves equal to amount the unit can ramp in ten minutes. The ramp rate varies by unit type, as listed in Table A-2.

30 Non-spinning reserve requirements rarely influence MAPS energy prices in areas like the eastern U.S., with a reasonably large supply of quick-starting gas turbines.

Table A-2: Generator Ramp Rates by Unit Type

Unit Type	Ramp Rate (MW/Minute)
Coal	6
Combined Cycle	25
Gas Turbines	9
Nuclear	0
Other	0
Peaking Units	0
Steam Gas/Oil	6
Steam Other	6

Maintenance Scheduling for Thermal Generation Units

The GE MAPS feature of scheduling maintenance of thermal generation units was used to levelize the reserve margin across the weeks of each year.[31] We assumed that maintenance within each pool (*i.e.*, RTO or independent control zone) is scheduled such that reserves within the pool are levelized on an annual basis. For example, if a region's load peaks in the summer, it will schedule little or no maintenance in that season; similarly, if a company's load peaks in the summer and winter, it will schedule no maintenance in these two seasons.

Generation from Conventional Hydro and Pumped Storage Units

Hourly generation levels for each hydro unit were determined by the GE MAPS model for each of the scenarios and years modeled. The GE MAPS model takes monthly generation totals for each hydro unit together with limits on their maximum and minimum generation levels and schedules hydro generation against the load shape for the pool in which the unit is located. The GE MAPS model generally does not dispatch hydro generation to relieve transmission congestion. However, if the locational price at the generation unit is very low (less than $5/MWh), then MAPS backs down generation from that unit to relieve congestion; under these circumstances, backing down the hydro unit is the most economic and may be the only alternative to relieving congestion. Also, GE MAPS does not increase generation from hydro resources to relieve congestion. This modeling assumption impacts each of the scenarios equally because only thermal units are used for congestion management in all scenarios.

GE MAPS dispatches pumped storage units based on load and committed thermal generation in the surrounding region. The model approximates the price elasticity for each hour over the course of a week using the stack of available generating units in the surrounding region and finds the corre-

[31] The weekly reserve margin is capacity available during that week minus the week's peak load.

sponding operating pattern for pumped storage units that minimizes total production cost. The model honors the physical characteristics of each unit, including pumping and generating capacities, pumping efficiency, and reservoir storage limits. When developing the schedule, the model does not directly account for transmission limits, but rather restricts the set of generators it considers to be available to ramp up for pumping or ramp down when the pumped storage units generate to those in the local region of each unit. Once the pumping and generating pattern has been developed, the model does honor all transmission constraints when meeting the schedule as part of the dispatch process. However, because the scheduling algorithm does not directly account for the availability of transmission in each hour, the optimization is only an approximation and as a result contains some noise.

In order to avoid potentially spurious benefits or costs between the Base and Change Cases stemming from the optimization of Bath County Pumped Storage unit operations, CRA used a stylized schedule for this unit and held it constant among all cases.[32] Based on initial runs with various pumping and generating schedules for the unit, a schedule was developed that performed reasonably well in all cases, but was not biased towards either case. The schedule honors all physical operating characteristics of the unit and balances pumping requirements with energy output. All other pumped storage hydro units were optimized using the standard GE MAPS algorithm.

Key Input Assumptions

As inputs to the model, CRA began with GE's complete database for the Eastern Interconnection power system, which is based in part on data from RDI. We have modified this database based on our analysis of public data and model results to ensure data integrity, validity, and consistency of plant operations with historical market data. In addition, we have incorporated data provided by Dominion North Carolina Power.

The following is a list of the major components of the model. The list is followed by a description of each component and the associated data sources.

(1) Load Inputs

(2) Thermal Unit Characteristics

(3) Planned Additions and Retirements

(4) Fuel Price Forecasts

[32] Bath County is a 2,520 MW pumped storage facility located in western Virginia. Dominion owns two-thirds of this facility, with the remainder owned by Allegheny.

(5) Transmission System Representation

(6) Environmental Regulations

(7) Hydro Unit Output

(8) NUG Contracts

Load Inputs

Peak loads and annual energy demands were based on forecasts reported in the 2001 NERC ES&D. Since published data do not extend to the end of our study period (i.e., 2014), forecasts were extended based on the projected growth over the reported forecast period (2002-2011). Table A-3 shows the regional peak load and annual energy totals assumed in each of the years modeled.

Table A-3: Peak Loads and Annual Energy Demand, by Region

	2005		2007		2010		2014	
Control Zone/RTO	Peak Load (MW)	Annual Energy (GWh)	Peak Load (MW)	Annual Energy (GWh)	Peak Load (MW)	Annual Energy (GWh)	Peak Load (MW)	Annual Energy (GWh)
DVP Zone	18,156	92,845	18,911	96,784	19,914	102,289	21,378	110,705
AEP	20,506	124,204	21,217	128,794	22,236	135,212	23,805	144,228
DP&L	3,169	17,227	3,285	17,697	3,374	18,203	3,602	19,277
ComEd	23,250	102,350	24,200	105,250	25,700	109,650	27,543	115,695
PJM (MAAC+APS)	66,920	348,582	69,284	359,149	72,776	375,148	77,681	398,385
MISO	133,005	724,968	137,630	745,573	144,284	782,171	155,288	835,104
CP&L	13,033	66,506	13,353	69,367	14,191	73,647	15,367	79,606
DUKE + CEPCI	22,492	112,912	23,042	117,770	24,490	125,035	26,518	135,154
SCE&G+Santee Cooper	8,586	45,464	8,796	47,420	9,349	50,346	10,123	54,420
TVA	31,779	176,641	33,335	183,091	35,662	192,701	38,540	205,865
SETRANS	75,077	408,431	78,770	426,494	84,358	455,481	92,406	495,010
SPP	42,550	210,934	44,004	217,065	47,119	233,001	50,930	251,219
GFL	42,536	209,759	44,344	221,485	47,316	237,493	51,693	262,592
ISO-NE	25,685	132,085	26,408	136,162	27,529	142,242	29,337	149,743
NYISO	32,300	162,160	33,050	165,880	34,090	171,600	35,520	179,340

Individual company load shapes are based on actual 1997 hourly load data as reported by the companies. The GE MAPS model adjusts each company's historical hourly load shape to fit the peak and annual energy numbers specified for that company for the year being modeled. The hourly load data created by that process for each company is then used as an input for the GE MAPS hourly simulation.

Appendix A: GE MAPS Description

Thermal Unit Characteristics

GE MAPS models generation units in detail, in order to accurately simulate their operational patterns and thereby project realistic hourly prices. The following characteristics are modeled:

- Unit type (steam, combined-cycle, combustion turbine, cogeneration, *etc.*)
- Full load heat rates and heat rate curves.
- Summer and winter capacities.
- Operation and maintenance costs.
- Forced and planned outage rates.
- Minimum up and down times.
- Quick start and spinning reserve capabilities.
- Startup costs.

Sources for thermal unit data include the EIA-411, EIA-867, and EIA-412 forms, the FERC Form 1, and the REA-12 forms. When unit-specific data were unavailable, we developed generic heat rate curves for different unit types based on available data for similar units. CRA specified unit forced and planned outage rates for each type based on an analysis of NERC's "Generating Availability Data System" data set. Table A-4 shows the outages our outage rate assumptions for each unit type.

Table A-4: Outage Rate Assumptions

Unit Type	Size	Forced Outage Rate	Planned Outage Rate
Coal	0 - 100 MW	5.0%	7.2%
Coal	100 - 500 MW	7.0%	7.2%
Coal	500 MW +	7.0%	7.2%
Steam Gas/Oil	0 - 100 MW	5.0%	6.7%
Steam Gas/Oil	100 - 500 MW	7.0%	6.7%
Steam Gas/Oil	500 MW +	7.0%	6.7%
Combined Cycle	0 - 100 MW	3.5%	4.8%
Combined Cycle	100 - 500 MW	3.5%	4.8%
Combined Cycle	500 MW +	3.5%	4.8%
Nuclear	0 - 100 MW	7.0%	7.0%
Nuclear	100 - 500 MW	7.0%	7.0%
Nuclear	500 MW +	7.0%	7.0%
Gas Turbines	0 - 100 MW	5.0%	1.5%
Gas Turbines	100 - 500 MW	2.5%	1.5%
Gas Turbines	500 MW +	2.5%	1.5%
Other Peaking Units	0 - 100 MW	4.0%	1.5%
Other Peaking Units	100 - 500 MW	4.0%	1.5%
Other Peaking Units	500 MW +	4.0%	1.5%
Other	0 - 100 MW	5.0%	6.7%
Other	100 - 500 MW	5.0%	6.7%
Other	500 MW +	5.0%	6.7%

A listing of all generators in the Dominion control zone is provided in Table A-17 at the end of this appendix.

Planned Additions and Retirements

Planned entries and retirements impact the fuel mix of installed capacity and the composition of plants on the margin. Most retirements are oil or steam gas plants, which are likely to be replaced by combined-cycle gas plants.[33] We added new capacity to the model in the years through 2005 based only on existing projects that are currently under construction.[34] Additional generic new capacity was added in the years after 2007 only as needed to meet regional reserve requirements in each case.

We assumed all new capacity would take the form of either gas-fired combined-cycle (CC) or simple-cycle gas turbines (GT), based on the relative economics of their entry. We balanced the entry of CC and GT units in each region consistent with an equilibrium in which each new unit earns

[33] Planned retirements were specified based on information in RDI's BaseCase Database.
[34] As reported in RDI's NewGen Database.

a sufficient margin from energy and capacity sales to cover its capital costs over a 30-year period. We assumed that a new CC would require a margin (energy revenues plus capacity revenues minus variable O&M, fuel, and emissions allowance costs) of $85 per kW in each year in order to cover its capital costs and its annual fixed O&M costs and that a new GT would require a margin of $50 per kW per year. These were derived based on an assumed cost of $560 per kW for CC units and $365 per kW for GTs, excluding interest during construction.

Unit additions and retirements modeled are summarized in Tables A-18 and A-19 at the end of this appendix.

Fuel Price Forecasts

The opportunity cost of fuel consumed for generation (i.e., the current spot price of fuel) is generally the largest component of a unit's marginal cost bid. To project these variable fuel costs, we used forecasts of spot fuel prices at regional hubs, and further refined these based on historical differentials between price points around each hub. For oil and gas, we used estimates of the price delivered to generators on a regional basis, while for coal, we used plant specific price forecasts.

Appendix A: GE MAPS Description

Coal Prices

CRA specified coal prices on the plant-level coal prices using forecasts of the fuel costs for each plant from RDI. RDI's forecasts are based on the historical and expected fuel type used at each plant and regional, delivered price of each type of coal. The forecasts account for potential fuel switch in response to environmental regulations. Where plant-level forecasts were not available, we used RDI's regional coal price forecast. Table A-5 shows the default regional annual coal-prices used in the study.

Table A-5: RDI-Based Regional Coal Forecast ($2002/mmBtu)

Region	2005	2007	2010	2014
East Central Area Reliability Coord Agrmn	1.18	1.17	1.16	1.16
Entergy	1.23	1.22	1.17	1.17
Florida Reliabilty Coordinating Council	1.71	1.69	1.65	1.65
MAIN Sub Region	1.13	1.11	1.06	1.06
Mid-Continent Area Power Pool	0.87	0.88	0.85	0.85
New Brunswick	1.76	1.72	1.66	1.66
New England Power Pool	1.76	1.72	1.66	1.66
New York Power Pool	1.48	1.45	1.44	1.44
SPP Northern Subregion	0.89	0.89	0.86	0.86
PJM Interconnect PA-NJ-MD	1.32	1.30	1.28	1.28
SPP South Subregion	1.13	1.12	1.08	1.08
Southern Subregion	1.50	1.48	1.43	1.43
Tennessee Valley Authority	1.26	1.24	1.21	1.21
Virginia/Carolinas Subregion	1.47	1.44	1.43	1.43

Appendix A: GE MAPS Description

Gas and Oil Prices

The key underlying forecasts are projected prices for crude oil and for natural gas (Henry Hub). All other forecasts are derived from these two basic forecasts using projected basis differentials.

To derive #2 fuel oil prices for electric generation, we used state-specific basis differentials developed based on EIA Form 423 data and assumed the price follows the same trajectory as crude oil prices. Our # 6 fuel oil forecast is based on historic New York Harbor prices. Because residual oil is a close substitute for natural gas in many dual-fuel electric generators and industrial facilities, we trended future #6 oil prices based on the price of natural gas. Table A-6 presents CRA forecasts for #6 and #2 fuel oil.

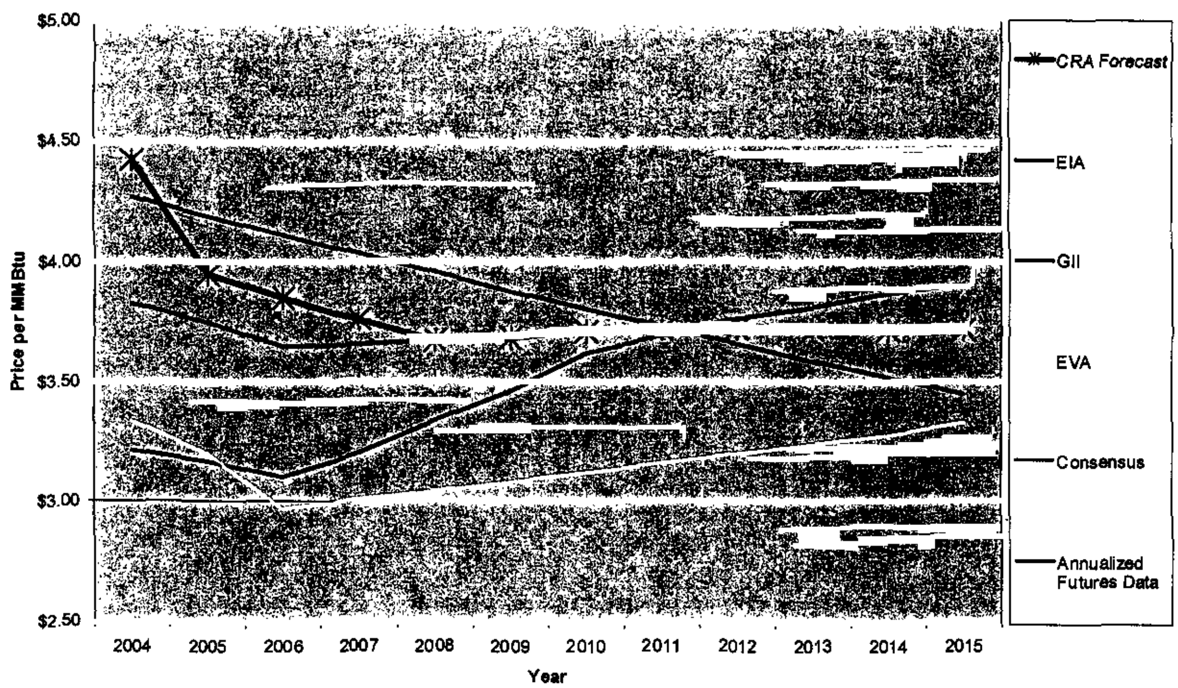
Table A-6: Fuel Oil Prices

	FO2 Prices				FO6 Prices			
	2005	**2007**	**2010**	**2014**	**2005**	**2007**	**2010**	**2014**
ECAR	4.83	4.63	4.57	4.58	3.20	3.06	3.03	3.03
FRCC	4.75	4.55	4.49	4.50	3.20	3.06	3.03	3.03
MAAC	4.69	4.49	4.44	4.45	3.20	3.06	3.03	3.03
MAIN	4.62	4.64	4.66	4.73	3.20	3.06	3.03	3.03
MAPP	5.01	5.03	5.06	5.14	3.20	3.06	3.03	3.03
NPCC	4.97	4.99	5.02	5.10	3.20	3.06	3.03	3.03
SERC	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03
SPP	4.82	4.84	4.87	4.94	3.20	3.06	3.03	3.03
SOUTHERN	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03
TVA	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03
VACAR	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03

Appendix A: GE MAPS Description

Figure A-1 shows CRA's forecast for the spot price of natural gas at Henry Hub. The forecast is a composition of NYMEX futures prices in the short term, and an average among various, publicly available long-term forecasts in the remaining year.

Figure A-1: Comparison of Natural Gas Price Forecasts



Appendix A: GE MAPS Description

The burner-tip price for natural gas is a sum of two components—regional price and local delivery charges (which reflect unavoidable LDC and/or lateral charge). CRA's forecasted regional gas prices are derived from the Henry Hub forecast and projected basis differentials for each region derived from historical regional price data. Our natural gas regions and their corresponding price points are identified in Tables A-7 and A-8. Basis differentials and regional delivered gas prices are shown in Table A-20 at the end of this appendix.

Table A-7: Definition of Gas Price Regions

	Regional Mapping						
	1	**2**	**3**	**4**	**5**	**6**	**7**
New England	MA	ME	NH	VT	RI	CT	
Eastern NY	NY						
NYC[1]	NY						
Eastern PA/NJ[2]	PA	NJ					
Western NY/PA	NY	PA					
DC, DE, MD	DC	DE	MD				
WV, KY	WV	KY	VA				
NC, VA	NC	VA					
SC, GA	SC	GA					
Southeast[3]	LA	AL	TN	KY	MS	AR	FL
Florida	FL						
Midcontinent	IA	MT	NE	OK	KS	MO	
Midwest	MI	OH	IN	IL			
Upper Midwest	MN	WI	ND	SD			
Rockies	MT	WY	CO	UT			
Southwest	NM	AZ	NV				
East Texas	TX						
West Texas	TX						
PNW	WA	ID	OR	NV			
Northern CA	CA						
Southern CA	CA						
Western Canada	CN						

[1]*Con Ed, Long Island Lighting*
[2]Includes PP&L, Exelon, UGI, GPU's Portland Gilbert, Sayerville and Titus areas
[3]Includes Southern Co. plants in the FL panhandle

Table A-8: Sources for Historical Regional Gas Price Data

Region	Price Point
Henry Hub	Bloomberg Natural Gas Henry Hub Spot Price
New England	Algonquin Gates (Bloomberg)
Eastern NY	Avg of Transco Z6 non NY and Iroquois Wright station (2/3 weighting on Z6 due to location of gen stations)
NYC	Bloomberg Tmasco Zone 6
Eastern PA/NJ	Average between NYC [4] and Leidy
Western NY/PA	Bloomberg Dominion Leidy Pa. Natural gas Spot Price
DC, DE, MD	Tetco M3
WV, KY	Platts Gas Daily, COLUMBIA, APP, MONTHLY AVERAGE OF DAILY AVERAGE SPOT GAS PRICE
NC, VA	Priced as a discount to Tetco M3
SC, GA	Platts SOUTHEAST, AVERAGE, DELIVERED TO PIPELINE, SPOT GAS PRICE
Southeast	Platts FLORIDA GATES VIA FGT, MONTHLY AVERAGE OF DAILY AVERAGE SPOT GAS PRICE
Florida	Bloomberg Mid-Continent Natural Gas Spot Price Average
Midcontinent	Bloomberg Mid-Continent Natural Gas Spot Price/Chicago City Gate
Midwest	Average between Chicago [13] and AECO [22]
Upper Midwest	Mixed sources. Bloomberg Colorado Interstate Gas North System Natural Gas Daily Spot Price; Nat Gas Week Colorado Interstate Kanda WY
Rockies	Mixed sources. Bloomberg Natural Gas San Juan Basin Spot Price. Post 1998 Nat Gas Week Blanco NM
Southwest	Bloomberg Natural Gas Katy Spot Price
East Texas	Bloomberg Natural Gas Waha Hub Spot Price
West Texas	Bloomberg Spot Natural Gas Price Huntingdon BC/Sumas WA USD
PNW	Mixed sources. Platts MALIN, OREGON, PG&E LINE 400, AVG, CITY-GATE, SPOT GAS PRICE. Post 2001 Nat Gas week PGT Malin
Northern CA	Platts Gas Daily, SOUTHERN CALIFORNIA LARGE PACKAGES, MONTHLY AVERAGE OF DAILY AVERAGE SPOT GAS PRICE
Southern CA	Bloomberg Spot Natural Gas Price/AECO C Hub USD
Western Canada	Priced at a discount to NC, VA

Appendix A: GE MAPS Description

Transmission System Representation

GE MAPS honors designated transmission constraints in its commitment and dispatch of generating units. We used a combination of GE's standard transmission representation for the Eastern Interconnection, transmission constraints from publicly available regional studies, and specific transmission information provided by Dominion. Constraints included:

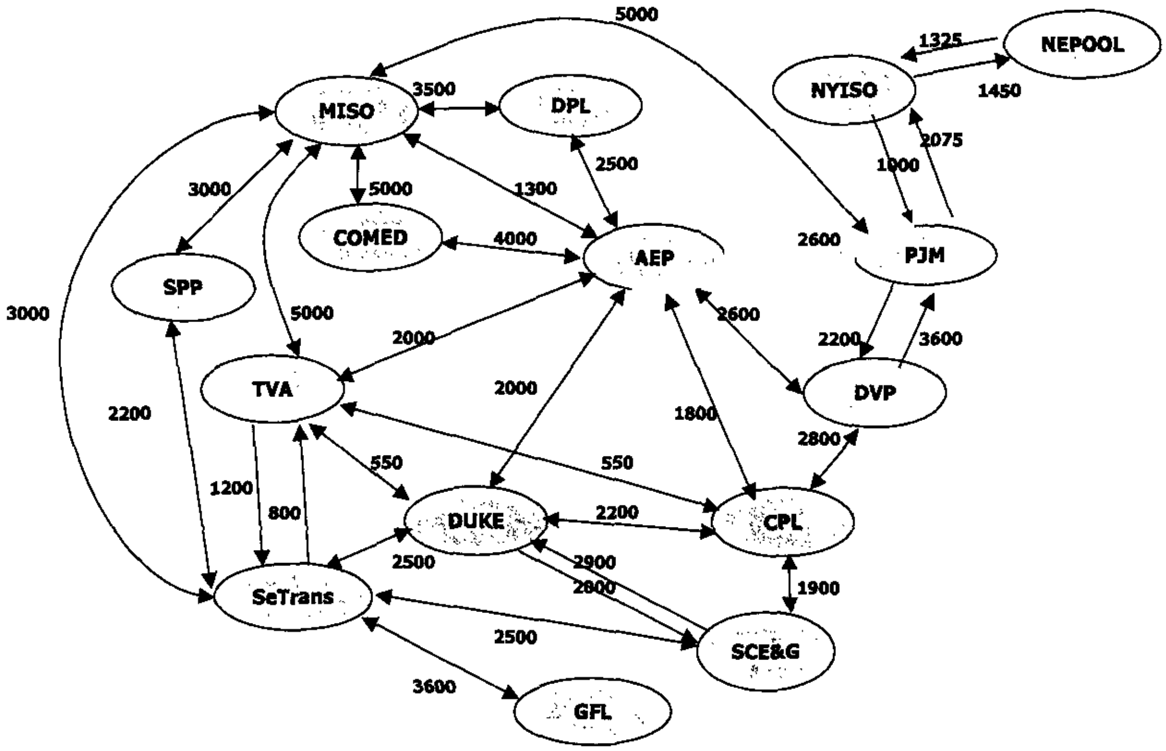
- Thermal limits on all 500 kV lines in the study region.
- NERC flowgates throughout the Eastern Interconnect.
- Contingencies and thermal limits identified by GE's contingency processor as potentially problematic.
- Contingencies listed in the VACAR-TVA-SOUTHERN Study Group's 2003 Summer Study published in February 2000.
- Contingencies listed in the June 1998 VACAR-ECAR-MAAC Study Committee's Interregional Transmission System Reliability Assessment.
- Binding transmission constraints posted on the PJM website.
- Other important constraints identified by Dominion.

We also accounted for several voltage and stability constraints within PJM by limiting the flow on selected interfaces to levels below their thermal ratings. The Bedington-Black Oak line, AP South Interface, and the East, West, and Central Interfaces of PJM were all monitored with limits set to levels consistent with PJM historical operations.

In order to restrict trade between regions to commercially feasible levels, we also limited pool-to-pool transfers. Based on TTC limits reported on OASIS, transfer limits reported in regional transmission studies, NERC reliability assessments, and guidance from Dominion, we imposed the transfer limits shown in Figure A-2. Note that pool-to-pool transfers are also limited by the physical transmission limits described above. However, the MAPS model may in some hours use physically available transmission capacity more efficiently than can generally be accomplished in current markets, even with the hurdles we have implemented. Hence, these additional transfer limits were intended to capture practical commercial limits on the amount of power that can be moved across seams during periods in which physical limits do not bind.

Appendix A: GE MAPS Description

Figure A-2: Maximum Economic Transfers Between Adjacent RTOs or Control Areas in MW



Appendix A: GE MAPS Description

Environmental Regulations

The opportunity cost of tradable SO_2 and NO_X allowances were added to the variable costs of all affected units, based on their current emission rates, and projected emission allowance prices.[35] We assumed the prices of SO_2 and NO_X allowances as shown in Table A-9. These allowance prices are based on current trading prices and projections of allowance prices in future years that are consistent with our fuel price forecasts and the continuation of current emissions limits.[36]

Table A-9: NOX and SO2 Allowance Prices

Market	2003	2004	2005	2007	2010	2014
SO2[1]	$157	$134	$110	$135	$180	$194
SIP Call[2]	$0	$4,800	$4,800	$3,332	$3,741	$4,230
OTR[3]	$7,170	$4,800	$4,800	$3,332	$3,741	$4,230

[1]2003-2007 RDI BaseCase
[2]2004 - 2005 from March 2003 Airtrends. Post 2006 price from RDI BaseCase
[3]Cantor Fitzgerald 3/24/03. OTR assumed to fully merge with SIP call market starting in 2004

Projected Hydro Output

CRA used the basic MAPS modeling approach for conventional hydro units, which accounts for environmental and operating constraints, such as maximum and minimum river flows. Monthly maximum and minimum generation and total energy are supplied to GE MAPS, and the model schedules the units to meet these requirements and shave peak loads. We used historical seasonal patterns for each individual hydro unit as a proxy for future seasonal generation (monthly GWh). The historical data were taken from EIA-759 form information as reported in the RDI database.

For pumped storage units, we used the generating and pumping capacities, reservoir sizes, and efficiency levels as specified in the standard GE MAPS database. Where appropriate, CRA refined the specified capacity and operating characteristic assumptions for the Bath County facility based on input from Dominion. As note above, the operation of the Bath County unit followed a pre-specified, stylized schedule, and the standard MAPS procedure determined the dispatch for all other pumped storage units.

[35] NO_X adders were applied to units in regions affected by the NO_X SIP (State Implementation Plan) Call. Adders were included only during the NO_X season (May through September).

[36] In particular, the NO_X SIP Call, the Title IV national SO_2 cap, and Title V unit-level NO_X emissions limits.

Appendix A: GE MAPS Description

NUG Contracts

Based on guidance from Dominion, CRA modeled certain contractual details for NUGs within Dominion control zone. We modeled all must-take NUGs as fully dispatched, up to capacity factors consistent with historical operation. Also, the operation of dispatchable NUGs reflected specified contract energy prices rather than the plants' variable operating costs. In other words, the NUGS were dispatched whenever the contract energy price fell below the market price of energy, making them economic sources of power for Dominion. We assumed that NUG contracts scheduled to expire during the study period would not be renewed and that the plants would operate on a merchant basis following the expiry.

A.2. MAPS Modeling Results

As discussed in Section IV of the report, the benefits to North Carolina that stem from joining the PJM RTO are driven by increased ability access lower cost generation from neighboring regions without substantial impediments to trades, along with the offset to congestion costs provided by FTR revenue. Several modeling results illustrate the changes in the unit dispatch and trade patterns that occur that occur between the Base and Change Cases in North Carolina and other areas throughout the Eastern Interconnection.

This section present several key outputs from the GE MAPS wholesale market model including:

- Dominion area net imports.
- Average pool-to-pool transfers.
- Generation by unit type and region.
- LMPs for each regional market.
- Binding transmission constraints and congestion.

Pattern of Dominion Imports and Regional Transfers

Table A-10 shows net transfers into the Dominion control zone from each neighboring region. The net imports follow a consistent pattern. The Dominion control zone is a net importer of power, with the largest portion of imports coming from (or through) the AEP area.[37] Net imports increase during off-peak hours, as inexpensive power for pumping the Bath County units can be provided by low cost generators that are otherwise not fully utilized during lower load periods and imported into the Dominion area. During peak hours, flows into the Dominion control zone decrease as Bath County switches from pumping to generating and more of the low cost generation to the west is needed to meet local load.

Table A-10: Average Dominion Zone Net Imports, by Source (MW)

Period	Imports/Transfers	2005 Base Case	2007 Base Case	2010 Base Case	2014 Base Case	2005 Change Case	2007 Change Case	2010 Change Case	2014 Change Case
Off-Peak	Average Net Imports to DVP Zone	1,783	1,842	1,933	2,021	2,104	2,164	2,214	2,280
	Average Transfers from AEP	1,583	1,602	1,693	1,601	1,963	1,911	1,928	1,803
	Average Transfers from PJM	82	130	159	375	109	227	268	505
	Average Transfers from CPL	118	110	81	45	32	26	19	(28)
On-Peak	Average Net Imports to DVP Zone	874	784	455	190	1,587	1,519	1,376	1,154
	Average Transfers from AEP	847	758	438	173	1,467	1,357	1,009	632
	Average Transfers from PJM	25	53	59	120	159	200	428	587
	Average Transfers from CPL	2	(27)	(43)	(103)	(39)	(37)	(62)	(64)
All-Hours	Average Net Imports to DVP Zone	1,350	1,338	1,229	1,149	1,858	1,857	1,815	1,744
	Average Transfers from AEP	1,233	1,200	1,096	921	1,727	1,647	1,490	1,245
	Average Transfers from PJM	55	93	111	253	133	214	345	544
	Average Transfers from CPL	63	45	22	(25)	(2)	(4)	(20)	(45)

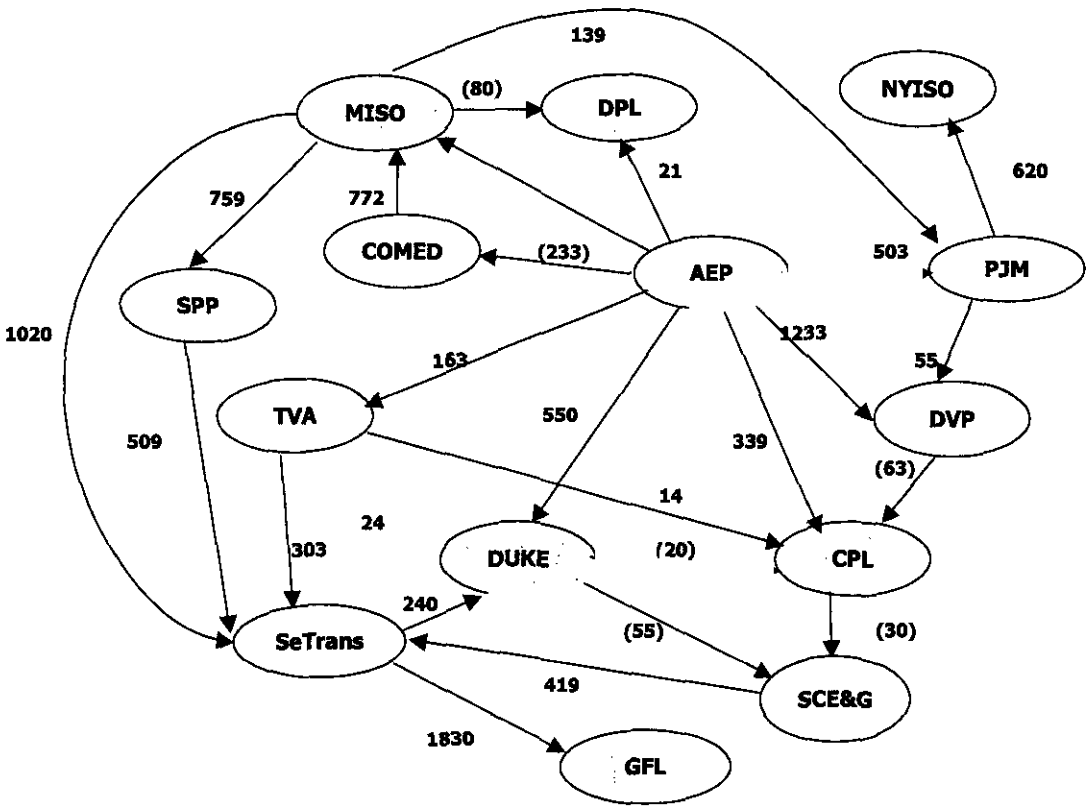
Removing impediments to trade between the Dominion area and the other companies in the Expanded PJM makes imports more attractive, and as a result flows into the Dominion control zone increase by approximately 40 percent. The increase is greatest during peak hours, when the initial trade barriers were the highest.

Removing the internal PJM hurdles causes exporting sub-regions of Expanded PJM to export more, on average, and to refocus existing exports to other PJM sub-regions. Figures A-3 and A-4 show the pattern of net transfers throughout the Eastern Interconnection. Within the Expanded PJM, the AEP area is the largest net exporter, and as expected, lowering the costs of exporting to other parts of Expanded PJM causes AEP net exports to increase. In both the Base and Change Cases, the Expanded PJM region is a combined net exporter, but net exports are lower in the Change Case. In the Change Case when trade barriers between areas within Expanded PJM are removed, the exporting sub-areas of Expanded PJM both export more overall and redirect some of the exports previously sent to areas outside Expanded PJM to internal destinations.

[37] All transfers were modeled as being between first-tier control areas. For example, as shown in Figures A-3 and A-4, flows from ComEd to AEP increase following PJM expansion, but these flows are, in effect, wheeled through to Dominion and PJM.

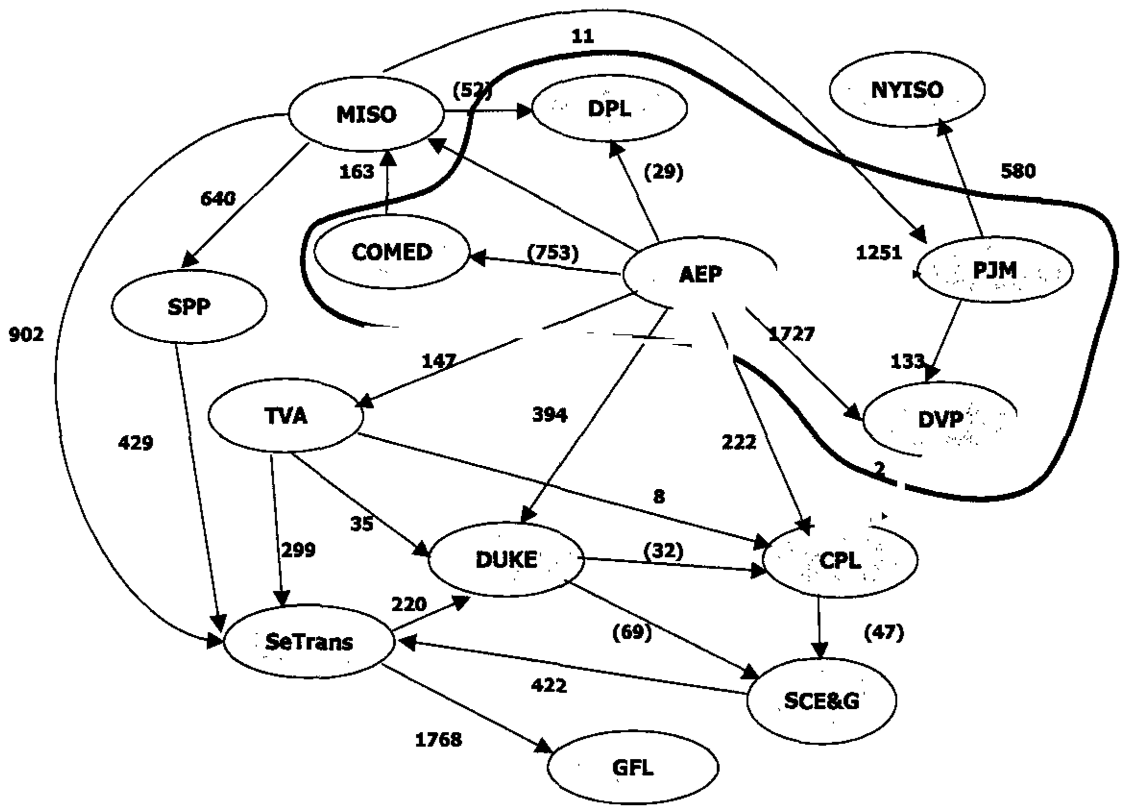
Appendix A: GE MAPS Description

Figure A-3: Pool to Pool All-Hour Average Transfers (MW) – 2005 Base Case



Appendix A: GE MAPS Description

Figure A-4: Pool to Pool All-Hour Average Transfers (MW) – 2005 Change Case



Generation by Unit Type and Region

Table A-11 shows generation by unit type both within the Expanded PJM footprint and the rest of the Eastern Interconnection. Consistent with the shift in pool-to-pool transfers between the Base and Change Cases shown in Figures A-3 and A-4, total generation decreases in the Expanded PJM region and increases elsewhere. Throughout the Eastern Interconnection, coal generation increases when intra-PJM hurdles are removed, displacing generation among mid-merit combined cycle units and gas- and oil-fired steam generators.

Appendix A: GE MAPS Description

Table A-11: Generation by Type (GWh)

		2005			2007			2010			2014		
Capacity Pool	**TYPE**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**
Non-PJM	CC	205,293	208,194	2,901	239,935	242,690	2,755	308,407	311,457	3,050	395,371	396,340	968
	Coal	1,319,544	1,323,220	3,676	1,345,791	1,349,415	3,624	1,368,591	1,372,031	3,439	1,382,225	1,384,345	2,120
	Hydro	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-
	New CC	-	-	-	-	-	-	6,435	6,472	37	23,415	23,445	30
	New CT	-	-	-	254	282	28	4,845	4,838	(8)	36,014	36,930	916
	Nuke	*411,993*	*411,988*	(5)	*411,866*	*411,869*	*3*	*412,234*	*412,259*	*25*	*412,095*	*412,102*	*7*
	Other	61,995	61,996	1	62,011	62,012	2	61,987	61,991	4	61,971	61,985	13
	Peaker	9,241	9,245	4	15,487	15,624	137	25,853	26,304	451	30,834	31,095	261
	PSH	16,333	16,343	9	16,021	16,068	47	15,010	14,976	(34)	12,366	12,609	243
	ST/G/O/D	102,143	103,120	976	113,000	114,197	1,198	126,968	127,646	678	155,009	156,339	1,330
Non-PJM Total		2,227,498	2,235,060	7,563	2,305,320	2,313,113	7,792	2,431,287	2,438,928	7,642	2,610,256	2,616,145	5,889
PJM (Expanded)	CC	25,336	21,748	(3,588)	31,475	27,455	(4,020)	42,721	39,789	(2,932)	63,638	63,002	(637)
	Coal	411,478	408,872	(2,606)	424,429	422,018	(2,411)	441,217	439,105	(2,112)	453,020	451,925	(1,095)
	Hydro	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	498	16	(483)	3,729	1,744	(1,985)
	Nuke	239,973	239,975	2	239,971	239,968	(3)	239,948	239,944	(4)	239,860	239,857	(3)
	Other	9,356	9,308	(48)	9,502	9,481	(22)	9,510	9,500	(10)	9,540	9,528	(12)
	Peaker	1,201	1,125	(77)	1,947	1,883	(63)	3,406	3,355	(50)	5,209	5,180	(29)
	PSH	7,893	7,886	(7)	7,855	7,850	(4)	8,138	8,153	15	7,827	7,848	21
	ST/G/O/D	13,347	12,225	(1,122)	18,607	17,470	(1,138)	26,051	24,093	(1,959)	36,447	34,785	(1,661)
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
PJM Total		716,998	709,546	(7,452)	742,200	734,532	(7,668)	779,902	772,364	(7,538)	827,690	822,285	(5,405)
Eastern Interconnection	CC	230,629	229,942	(687)	271,411	270,145	(1,265)	351,128	351,246	118	459,010	459,341	332
	Coal	1,731,022	1,732,092	1,070	1,770,220	1,771,433	1,212	1,809,808	1,811,135	1,327	1,835,245	1,836,269	1,025
	Hydro	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-
	New CC	-	-	-	-	-	-	6,435	6,472	37	23,415	23,445	30
	New CT	-	-	-	254	282	28	5,344	4,853	(491)	39,743	38,674	(1,069)
	Nuke	651,966	651,963	(3)	651,837	651,838	0	652,181	652,203	22	651,955	651,959	4
	Other	71,350	71,304	(47)	71,513	71,493	(20)	71,497	71,491	(7)	71,511	71,513	1
	Peaker	10,442	10,370	(72)	17,433	17,507	74	29,259	29,660	401	36,043	36,275	231
	PSH	24,226	24,229	2	23,876	23,918	42	23,148	23,129	(19)	20,193	20,457	264
	ST/G/O/D	115,490	115,345	(145)	131,607	131,667	60	153,020	151,739	(1,281)	191,456	191,124	(332)
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
EI Total		2,944,496	2,944,606	111	3,047,520	3,047,644	124	3,211,188	3,211,293	104	3,437,946	3,438,430	484

Within the Expanded PJM, the removal of trade barriers leads to a substantial decrease in the amount of generation among mid-merit combined cycle units and gas- and oil-fired steam generators. Coal-fired generation within Expanded PJM also decreases. To help illustrate the shifts in generation behind this result Table A-12 shows the output by each type of generator within the individual PJM areas. In the areas with surplus low cost coal-fired generation, AEP, DP&L, and ComEd, coal-fired generation increases, while in PJM (East and West) and Dominion, some coal-fired generation is displaced by lower-cost sources during off-peak periods. Outside of PJM, generation among coal, combined cycle, and steam units increases substantially to make up for the decreased transfers from the Expanded PJM areas. Table A-21 at the end of this appendix shows generation by unit type for each pool in the Eastern Interconnect.

Appendix A: GE MAPS Description

Table A-12: Generation by Type and Expanded PJM Region (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	CC	195	707	511	257	912	655	1,304	2,928	1,624	3,510	7,179	3,669
	Coal	130,287	132,465	2,178	135,631	137,062	1,431	141,082	140,863	(219)	144,530	144,637	107
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,888	15,888	-	15,913	15,913	-	15,885	15,885	-
	Other	214	214	(0)	214	214	(0)	214	214	-	213	214	0
	Peaker	-	-	-	-	0	0	20	19	(0)	61	88	27
	PSH	730	728	(2)	710	711	1	620	619	(1)	481	481	0
	ST/G/O/D	0	0	(0)	0	1	0	1	3	1	1	4	3
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		148,595	151,282	2,687	153,984	156,071	2,087	160,438	161,842	1,404	165,965	169,771	3,806
COMED	CC	1,666	1,109	(557)	2,227	1,465	(762)	2,929	2,430	(498)	3,906	3,696	(211)
	Coal	27,944	28,588	644	29,975	30,816	840	33,144	34,154	1,010	35,142	35,704	562
	Nuke	80,330	80,332	2	80,364	80,364	-	80,299	80,296	(4)	80,280	80,278	(3)
	Peaker	177	78	(99)	345	165	(179)	539	364	(175)	1,080	447	(633)
	ST/G/O/D	1,093	335	(758)	1,783	565	(1,218)	3,922	1,021	(2,901)	6,824	3,647	(3,178)
	New CT	-	-	-	-	-	-	106	16	(90)	835	241	(594)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		111,211	110,443	(768)	114,695	113,376	(1,319)	120,939	118,280	(2,658)	128,068	124,012	(4,056)
DP&L	Coal	17,682	17,874	192	18,560	18,727	166	19,712	20,046	334	20,765	20,886	121
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	-	-	-	11	-	(11)	25	22	(4)	128	48	(81)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		17,727	17,919	192	18,616	18,772	155	19,782	20,112	330	20,938	20,979	41
PJM	CC	17,950	16,345	(1,605)	21,890	20,245	(1,644)	28,772	27,699	(1,074)	41,889	41,252	(637)
	Coal	194,502	190,457	(4,045)	198,190	194,756	(3,435)	203,688	201,286	(2,402)	207,748	206,384	(1,364)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,393	117,393	-	117,470	117,467	(3)	117,419	117,419	-	117,446	117,446	-
	Other	6,907	6,907	-	6,913	6,912	(0)	6,907	6,907	-	6,914	6,911	(3)
	Peaker	306	352	45	651	736	84	1,100	1,345	245	1,838	2,654	816
	PSH	4,663	4,659	(5)	4,645	4,639	(6)	4,701	4,717	16	4,528	4,549	20
	ST/G/O/D	7,512	8,031	519	11,026	11,998	972	15,112	16,849	1,737	21,283	23,453	2,171
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
	New CT	-	-	-	-	-	-	-	-	-	942	-	(942)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		355,173	350,075	(5,098)	366,724	362,685	(4,038)	383,637	382,156	(1,482)	408,533	408,590	57
DVP Zone	CC	5,525	3,587	(1,938)	7,102	4,833	(2,268)	9,716	6,733	(2,983)	14,332	10,875	(3,458)
	Coal	41,062	39,488	(1,574)	42,071	40,657	(1,414)	43,592	42,757	(835)	44,834	44,313	(521)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,189	2,142	(47)	2,330	2,309	(21)	2,344	2,334	(10)	2,367	2,358	(9)
	Peaker	718	695	(23)	940	982	42	1,721	1,605	(116)	2,103	1,943	(159)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	4,741	3,859	(882)	5,797	4,905	(892)	7,016	6,220	(795)	8,339	7,682	(657)
	New CT	-	-	-	-	-	-	393	-	(393)	1,952	1,503	(449)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DVP Sum		84,292	79,827	(4,465)	88,180	83,628	(4,553)	95,106	89,974	(5,132)	104,187	98,934	(5,253)

As illustrated in Table A-13, the more efficient commitment and dispatch that is facilitated by removing trade barriers leads to lower overall production costs for the Eastern Interconnection. On the pool level, changes in generation costs mirror the shift in energy production, with production costs increasing in regions with lower-cost generation, and falling in areas where generators run less. Within the Expanded PJM, Change Case production costs are substantially lower in the Dominion and PJM East and PJM West areas, as companies in these areas purchase more of their energy from external sources and generate less. Table A-13 cannot be interpreted to indicate a rise or fall in retail rates for any particular region. This chart shows the total cost of output of generation in the control zone, not the cost to serve the load in a zone, which would need to include purchase costs and deduct sales revenues, at a minimum.

Table A-13: Generation Production Costs by Zone ($M)

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	2,099	2,180	80	2,133	2,195	61	2,305	2,368	64	2,495	2,638	142
COMED	1,102	1,046	(56)	1,148	1,071	(77)	1,298	1,179	(119)	1,525	1,363	(162)
CPL	957	984	28	998	1,021	23	1,117	1,142	25	1,370	1,395	25
DP&L	338	341	2	332	334	2	368	375	7	405	404	(1)
DUKE	1,133	1,150	17	1,182	1,195	13	1,340	1,351	11	1,611	1,634	23
GFL	4,814	4,829	15	5,111	5,115	4	5,576	5,586	10	6,535	6,542	7
MISO E	5,546	5,578	32	5,618	5,654	36	6,227	6,277	50	7,100	7,115	15
MISO W	4,310	4,327	17	4,452	4,467	15	4,930	4,945	15	5,674	5,711	37
ISO-NE	2,483	2,483	(0)	2,544	2,542	(2)	2,738	2,738	1	3,010	3,011	0
NYC	839	848	9	835	843	8	875	885	10	951	963	12
NYL	383	385	2	386	387	1	423	423	0	485	487	1
NYO	1,646	1,654	8	1,667	1,663	(4)	1,803	1,796	(7)	1,986	1,977	(10)
PJM	5,025	4,919	(106)	5,178	5,103	(75)	5,770	5,767	(3)	6,663	6,692	29
SCE&G	828	840	12	845	860	15	911	924	13	1,034	1,048	15
SETRANS E	4,465	4,525	60	4,681	4,761	80	5,209	5,281	72	6,065	6,096	31
SETRANS W	2,245	2,223	(22)	2,469	2,450	(19)	2,871	2,841	(30)	3,465	3,462	(3)
SPP	3,018	3,028	10	3,159	3,169	10	3,597	3,606	9	4,212	4,223	10
TVA	2,267	2,275	9	2,331	2,342	11	2,603	2,612	9	3,016	3,015	(1)
DVP Zone	1,331	1,186	(146)	1,409	1,263	(146)	1,628	1,448	(180)	1,969	1,776	(192)
Total	44,831	44,800	(31)	46,478	46,435	(43)	51,587	51,544	(43)	59,573	59,551	(21)

Locational Spot Prices and Congestion

The change in the pattern of generation between the Base and Change Cases is also reflected in locational prices throughout the Eastern Interconnection. Table A-14 reports each pool's all-hours average LMP. Prices decrease substantially in the importing areas of the Expanded PJM, and prices increase in AEP, reflecting its additional exports. Outside of the Expanded PJM, prices are generally higher, as net imports decrease and higher cost local generation is relied upon more.

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Table A-14: All-Hours Average Load Zone Prices

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	20.98	21.79	0.81	21.14	22.10	0.95	23.85	24.83	0.98	28.21	28.31	0.10
COMED	20.62	20.56	(0.06)	20.87	20.87	(0.01)	23.33	23.63	0.30	27.30	27.22	(0.08)
CPL	27.69	28.23	0.55	28.58	29.35	0.77	31.67	32.59	0.92	36.30	36.78	0.48
DP&L	21.05	21.34	0.28	20.82	21.52	0.70	23.20	24.24	1.03	27.19	27.58	0.39
DUKE	27.83	28.38	0.55	28.71	29.37	0.66	31.78	32.48	0.70	36.49	36.84	0.35
GFL	34.31	34.38	0.07	40.80	40.84	0.05	36.50	36.56	0.06	38.03	38.06	0.02
MISO E	22.14	22.30	0.16	22.37	22.60	0.23	24.98	25.30	0.31	28.77	28.91	0.15
MISO W	23.67	23.78	0.11	24.54	24.66	0.12	29.23	29.36	0.12	31.25	31.35	0.10
ISO-NE	33.10	33.09	(0.01)	32.62	32.63	0.01	33.21	33.17	(0.04)	34.20	34.21	0.01
NYC	34.30	34.34	0.04	33.09	33.17	0.09	34.09	34.15	0.07	35.75	35.85	0.10
NYL	36.58	36.53	(0.05)	35.48	35.47	(0.01)	36.86	36.85	(0.00)	38.25	38.22	(0.04)
NYO	30.14	29.93	(0.21)	29.50	29.35	(0.15)	30.44	30.34	(0.11)	31.55	31.45	(0.09)
PJM	26.91	26.64	(0.27)	26.93	26.79	(0.14)	29.14	29.33	0.19	31.96	32.86	0.90
SCE&G	26.70	27.19	0.49	27.44	28.02	0.57	30.16	30.75	0.59	33.96	34.33	0.37
SETRANS E	28.86	28.98	0.13	29.42	29.55	0.13	31.53	31.62	0.08	34.89	34.95	0.06
SETRANS W	29.41	29.42	0.01	29.77	29.79	0.02	31.15	31.20	0.05	32.69	32.66	(0.03)
SPP	26.64	26.73	0.09	27.10	27.22	0.12	29.11	29.23	0.11	31.52	31.60	0.08
TVA	25.98	26.10	0.13	26.26	26.46	0.20	28.74	28.90	0.16	31.85	31.83	(0.02)
DVP Zone	30.61	29.10	(1.51)	31.09	29.60	(1.49)	33.62	32.65	(0.98)	37.11	36.39	(0.72)
Total	27.08	27.10	0.02	27.77	27.84	0.08	29.85	30.00	0.15	32.53	32.68	0.15

The regional prices shown in Table A-14 also help illustrate the typical pattern of power flows and congestion within the Expanded PJM area. As power flows from the lower cost coal-fired sources in the west to load in the eastern part of the region, the east-west transmission capacity becomes fully utilized, resulting in congestion and separation among LMPs. In particular, transmission facilities in the western portion of PJM East and PJM West are fully more utilized, with substantial congestion on the Bedington-Black Oak and AP South interfaces, over which flows need to be constrained due to voltage and stability limits.

The Bedington-Black Oak and AP South constraints are also the greatest source of congestion costs and the primary cause of price separations within the Dominion control zone. In fact, flows on transmission lines with Dominion are rarely at their limits and contribute very little to congestion costs. Table A-15 shows the transmission constraints that contribute most to differences among the LMPs within the Dominion control zone. Prices are shown for a collection of locations throughout the Dominion area, along with the contribution of each constraint to the price differential between that location's LMP and the area-wide average LMP. Locations in the western part of the control zone have much lower LMPs on average than locations in the east, and congestion on Bedington-Black Oak and AP South are the primary sources of the price difference.

Appendix A: GE MAPS Description

Table A-15: Effect of Transmission Constraints on Dominion LMPs

	Hours Limited	Mount Storm	Bath County	Clover	Possum Point	North Anna	Yorktown	Surry
Average Price Across Generator Set		28.67	28.67	28.67	28.67	28.67	28 67	28.67
Average Generator Bus Price		25.52	27.22	28.28	31.07	30.17	29.26	29.18
Total Congestion		**(3.15)**	**(1.45)**	**(0.39)**	**2.40**	**1.50**	**0.59**	**0.51**
Congestion from Constraints in Virginia Power Area								
Lexington-Cloverdale for Outage of Pruntytown-Mt. Storm	820	0.04	0.15	(0.08)	(0.02)	(0.02)	(0.03)	(0.03)
FG 1710 Chesterfiled-Tyler 230	64	(0.00)	(0.00)	0.01	(0.00)	(0.00)	(0.00)	0.00
Lexington-Cloverdale for Outage of Mt. Storm-Valley	202	(0.01)	0.04	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)
FG 1718 Chuchatuk-Suffolk 230 kV	36	0 00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Total Impact of DVP Constraints		***0.02***	***0.19***	***(0.09)***	***(0.03)***	***(0.02)***	***(0.04)***	***(0.03)***
Congestion from Constraints Outside Virginia								
APS South Interface	1,284	(1.47)	(0 43)	0.15	0.62	0.55	0.30	0.29
Black Oak Beddington Voltage Interface	6,652	(1 49)	(1.20)	(0.59)	1.84	0.98	0.27	0.19
Kanawa-Matt Funk for Outage of Broadford-J Ferry	560	(0.04)	0.06	0.02	(0.03)	(0.01)	0.00	0.00
FG 5 PJM Western Interface	484	(0.02)	(0.01)	(0 00)	0.01	0 01	0.00	0.00
Kanawa-Matt Funk for Outage of Baker-Broadford	164	(0.01)	0.02	0.01	(0.01)	(0.00)	0.00	0.00
Other Contraints		(0 14)	(0.07)	0.12	(0.01)	0.00	0.05	0.06
Total Impact of Outside Constraints		**(3.18)**	**(1.64)**	**(0.30)**	**2.43**	**1.52**	**0.63**	**0.54**

Table A-16: RTOs and Control Zones

RTO/Control Zone	Abbreviation	Companies/Zones
Carolina Power & Light	CP&L	Carolina Power & Light Co.
Duke Control Zone	Duke	Central Electric Power Coop.
		Duke Energy Corp.
Grid Florida	GFL	Florida Power Corp.
		Florida Power & Light Co.
		Florida Municipal Power Agency
		Gainesville Regional Utilities
		Kissimmee Utility Authority
		Lakeland Electric & Water
		Orlando Utilities Comm.
		Seminole Electric Coop.
		Tampa Electric Co.
Midwest ISO	MISO	American Municipal Power
		AmerenUE
		Basin Electric Power Coop.
		Big Rivers Electric Corp.
		Buckeye Power Co.
		Consumers Energ Co.
		Central Illinois Light Co.
		Central Illinois PSC
		Cincinnati Gas & Electric Co.
		Detroit Edison Co.
		Dairyland Power Coop.
		Electric Energy, Inc.
		East Kentucky Power Coop.
		FirstEnergy Corp.
		Great River Energy
		Hoosier Energy Rural Electric Coop.
		Hutchinson Utilities Comm.
		Central Iowa Power Coop.
		Illinois Power Co.
		Indianapolis Power & Light Co.
		Interstate Power Co.
		Kentucky Utilities Co.
		Lansing Board of Water and Light
		Lincoln Electric System
		Louisville Gas & Electric Co.
		Madison Gas & Electric Co.
		Montana-Dakota Utilities Co.
		Municipal Energy Agency Of Nebraska
		MidAmerican Energy Co.
		Minnkota Power Coop.
		Minnesota Power Inc.
		Muscatine Power & Water
		Northern Indiana Public Service Co.
		Nebraska Public Power District
		Northern States Power Co.
		Northwestern Public Service Co.
		Omaha Public Power District

Table A-16: RTOs and Control Zones

RTO/Control Zone	Abbreviation	Companies/Zones
		Otter Tail Power Co.
		Ohio Valley Electric Corp.
		PSI Energy, Inc.
		Southern Indiana Gas & Electric Co.
		Southern Minnesota Municipal Power Agency
		Southern Illinois Power Coop.
		Springfield Water, Light & Power Dept.
		St. Joseph Light & Power Co.
		Union Electric Co.
		Upper Peninsula Power
		Western Area Power Association
		Wisconsin Public Service Co.
		Wisconsin Electric Power Co.
		Wisconsin Power & Light Co.
		Wisconsin Public Power Inc.
		Wolverine Power Supply Coop.
		Wabash Valley Power Assoc.
ISO-New England	ISO-NE	Boston Edison Co.
		Bangor Hydro-Electric Co.
		Cambridge Electric Light Co.
		Central Maine Power Co.
		Commonwealth Electric Co.
		Central Vermont Public Service Corp.
		Eastern Utilities Associates
		Green Mountain Power Corp.
		Massachusetts Municipal Wholesale Electric Co.
		National Grid USA
		Northeast Utilities
		United Illuminating Co.
New York ISO	NYISO	NYISO - Capital Zone
		NYISO - Central Zone
		NYISO - Dunwoodie Zone
		NYISO - Hudson Valley
		NYISO - Long Island
		NYISO - Millwood Zone
		NYISO - Genesee Zone
		NYISO - Mohawk Valley
		NYISO - North Zone
		NYISO - NY City
		NYISO - West Zone
PJM Interconnection	PJM	American Electric Coop. Inc.
		Atlantic City Electric Co.
		Allegheny Energy, Inc.
		Baltimore Gas & Electric Co.
		Commonwealth Electric Co.
		Dayton Power & Light Co.
		Delmarva Power & Light Co.
		Duquesne Light Co.
		GPU Corp. East

Table A-16: RTOs and Control Zones

RTO/Control Zone	Abbreviation	Companies/Zones
		GPU Corp. West
		Old Dominion Electric Coop.
		Peco Energy Co.
		Potomac Electric Power Co.
		PPL Electric Utility
		Public Service Electric & Gas Co.
		Virginia Electric & Power Co.
	SCE&G	South Carolina Electric & Gas Co.
SeTrans RTO	SETRANS	Associated Electric Coop.
		Alabama Electric Coop.
		Cajun Electric Power Coop.
		Entergy Corp.
		Jacksonville Electric Authority
		Oglethorpe Power Corp.
		South Carolina Public
		South Mississippi Electric Power Assoc.
		Southern Company
		Sam Rayburn G&T Inc.
		Tallahassee Electric Operations
		Walton Electric M. Co.
Southwest Power Pool	SPP	Arkansas Electric Coop. Corp.
		Central LA Electric Co.
		Central & South West Corp.
		Empire District Electric Co.
		Grand River Dam Authority
		Independence Power & Light Dept.
		Kansas City Board of Public Utilities
		Kansas City Power & Light Co.
		Lafayette Utilities System
		Louisiana Energy & Power Authority
		Midwest Energy, Inc.
		Missouri Public Service Co.
		Northeast Texas Electric Coop.
		Oklahoma Gas & Electric Co.
		Public Service Co. of Oklahoma
		Springfield City Utilities
		Sunflower Electric Power Corp.
		Southwestern Power Administration
		Southwestern Public Service Co.
		Western Farmers Electric Coop.
		WestPlains Energy
		Western Resources, Inc.
Tennessee Valley Authority	TVA	Tennessee Valley Authority

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
	New Units in VAP						
MANASSAS	MANASSAS IC LUMP		VA	Peaking Units	30	30	1/1/2000
FAUQUIC1	REMINGTON 1	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
FAUQUIC2	REMINGTON 2	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
FAUQUIC3	REMINGTON 3	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
FAUQUIC4	REMINGTON 4	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
DOSWELL1	DOSWELL COMBINED CYCLE FACI	HANOVER	VA	Peaking Units	153.9	171	6/7/2001
CAROLNE1	CAROLINE COUNTY II (DOMGEN)	CAROLINE	VA	Peaking Units	145	178	7/1/2001
CAROLNE2	CAROLINE COUNTY II (DOMGEN)	CAROLINE	VA	Peaking Units	145	178	7/1/2001
POSSUMG3	POSSUM POINT (Conversion to Gas)	PRINCE WILLIAM	VA	Steam Gas/Oil	101	105	5/1/2003
POSSUMG4	POSSUM POINT (Conversion to Gas)	PRINCE WILLIAM	VA	Steam Gas/Oil	221	221	5/1/2003
POSSUMP6	POSSUM POINT 6	PRINCE WILLIAM	VA	Combined Cycle	405	450	5/1/2003
BOSWTAV1	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV2	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV3	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV4	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV5	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	150	170	6/1/2003
FLUVANN1	TENASKA VIRGINIA PARTNERS 1	FLUVANNA	VA	Combined Cycle	300	300	6/1/2004
FLUVANN2	TENASKA VIRGINIA PARTNERS 2	FLUVANNA	VA	Combined Cycle	300	300	6/1/2004
FLUVANN3	TENASKA VIRGINIA PARTNERS 3	FLUVANNA	VA	Combined Cycle	300	300	6/1/2004
REMINGM1	REMINGTON MARSH RUN 1	FAUQUIER	VA	Peaking Units	150	170	10/1/2004
REMINGM2	REMINGTON MARSH RUN 2	FAUQUIER	VA	Peaking Units	150	170	10/1/2004
REMINGM3	REMINGTON MARSH RUN 3	FAUQUIER	VA	Peaking Units	150	170	10/1/2004
REMINGM4	REMINGTON MARSH RUN 4	FAUQUIER	VA	Peaking Units	150	170	1/1/2014
	New Units in AEP						
RIVERSD1	RIVERSIDE	LAWRENCE	KY	Peaking Units	186.5	186.5	1/1/2001
RIVERSD2	RIVERSIDE	LAWRENCE	KY	Peaking Units	186.5	186.5	1/1/2001
RIVERSD3	RIVERSIDE	LAWRENCE	KY	Peaking Units	186.5	186.5	1/1/2001
WOLFHIL1	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL2	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL3	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL4	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL5	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
BIGSANDY	Big Sandy (CPI)		WV	Peaking Units	300	300	8/10/2001
WASHNGT1	WASHINGTON (DUPC)	WASHINGTON	OH	Combined Cycle	558	620	6/1/2002
BUCHANN1	BUCHANAN COUNTY (ALLEGHENY)	BUCHANAN	VA	Peaking Units	81	90	6/25/2002
VANWERT1	VAN WERT COUNTY	VAN WERT	OH	Peaking Units	153	170	8/1/2002
VANWERT2	VAN WERT COUNTY	VAN WERT	OH	Peaking Units	153	170	8/1/2002
VANWERT3	VAN WERT COUNTY	VAN WERT	OH	Peaking Units	153	170	8/1/2002
WATERFD1	WATERFORD (PSEGP)	WASHINGTON	OH	Combined Cycle	270	300	5/1/2003
WATERFD2	WATERFORD (PSEGP)	WASHINGTON	OH	Combined Cycle	270	300	5/1/2003
WATERFD6	WATERFORD (PSEGP)	WASHINGTON	OH	Combined Cycle	270	300	5/1/2003
HANGING1	HANGING ROCK	LAWRENCE	OH	Combined Cycle	558	620	6/1/2003
HANGING2	HANGING ROCK	LAWRENCE	OH	Combined Cycle	558	620	6/1/2003
LAWRENB1	LAWRENCEBURG	DEARBORN	IN	Combined Cycle	508.5	565	6/1/2003
LAWRENB2	LAWRENCEBURG	DEARBORN	IN	Combined Cycle	508.5	565	6/1/2003
ROLLING1	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING2	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING3	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING4	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING5	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
DRESDEC1	DRESDEN ENERGY CENTER	MUSKINGUM	OH	Combined Cycle	601.2	668	9/1/2003
FREMONT1	FREMONT ENERGY CENTER	SANDUSKY	OH	Combined Cycle	630	700	3/1/2005
	New Units in DPL						

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
GREENVI1	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
GREENVI2	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
GREENVI3	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
GREENVI4	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
MADISON1	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON2	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON3	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON4	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON5	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON6	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON7	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON8	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
CHESTER1	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
CHESTER2	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
CHESTER3	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
CHESTER4	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
DARBYGE1	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE2	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE3	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE4	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE5	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	6/1/2002
DARBYGE6	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	6/1/2002
TAITDT01	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
TAITDT02	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
TAITDT03	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
TAITDT04	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
	New Units in ComEd						
MORRISC1	*MORRIS COGENERATION PLANT*	*GRUNDY*	*IL*	*Combined Cycle*	*159.28*	*176.98*	*3/30/2000*
LINCOLE1	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE2	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE3	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE4	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE5	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE6	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE7	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE8	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
ROCKFOR1	ROCKFORD (INDOPE)	WINNEBAGO	IL	Peaking Units	180	200	6/1/2000
ROCKFOR2	ROCKFORD (INDOPE)	WINNEBAGO	IL	Peaking Units	90	100	6/1/2000
ROCKYRP1	ROCKY ROAD POWER, LLC	KANE	IL	Peaking Units	90	100	7/15/2000
LEEGENS1	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS2	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS3	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS4	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS5	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS6	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS7	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS8	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
RELIAUR1	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR2	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR3	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR4	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR6	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
RELIAUR7	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
RELIAUR8	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
RELIAUR9	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
RELIAR10	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
CHICAGC1	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC2	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC3	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC4	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC5	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC6	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
COOKCOU1	COOK COUNTY	COOK	IL	Peaking Units	136.8	152	3/1/2002
RELIAUR5	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	3/1/2002
COOKCOU2	COOK COUNTY	COOK	IL	Peaking Units	136.8	152	3/20/2002
KENDALC1	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	4/15/2002
KENDALC2	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	4/15/2002
KENDALC3	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	4/15/2002
CRETEEP1	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
CRETEEP2	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
CRETEEP3	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
CRETEEP4	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
ROCKFD23	ROCKFORD II	WINNEBAGO	IL	Peaking Units	149.4	166	6/1/2002
ZIONENC1	ZION ENERGY CENTER	LAKE	IL	Peaking Units	150	165	6/25/2002
ZIONENC2	ZION ENERGY CENTER	LAKE	IL	Peaking Units	150	165	6/25/2002
ELGINGT2	ELGIN	COOK	IL	Peaking Units	105.3	117	7/1/2002
STHCHIC1	SOUTH CHICAGO	COOK	IL	Peaking Units	151.2	168	7/1/2002
STHCHIC2	SOUTH CHICAGO	COOK	IL	Peaking Units	151.2	168	7/1/2002
UNIVPAR1	UNIVERSITY PARK	WILL	IL	Peaking Units	158.4	176	7/25/2002
UNIVPAR2	UNIVERSITY PARK	WILL	IL	Peaking Units	158.4	176	7/25/2002
UNIVPAR3	UNIVERSITY PARK	WILL	IL	Peaking Units	158.4	176	7/25/2002
ELGINGT3	ELGIN	COOK	IL	Peaking Units	105.3	117	8/1/2002
KENDALC4	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	8/15/2002
ELGINGT4	ELGIN	COOK	IL	Peaking Units	105.3	117	9/1/2002
ELGINGT1	ELGIN	COOK	IL	Peaking Units	105.3	117	10/1/2002
ZIONENC3	ZION ENERGY CENTER	LAKE	IL	Peaking Units	150	150	6/1/2003
	New Units in PJM						
BURLNGT1	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
BURLNGT2	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
BURLNGT3	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
BURLNGT4	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
COMMNCH1	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	1/1/2000
COMMNCH2	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	1/1/2000
COMMNCH3	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	1/1/2000
DELWREC5	DELAWARE CITY	NEW CASTLE	DE	Combined Cycle	113.75	113.75	1/1/2000
DELWREC6	DELAWARE CITY	NEW CASTLE	DE	Combined Cycle	113.75	113.75	1/1/2000
DELWREC7	DELAWARE CITY	NEW CASTLE	DE	Combined Cycle	5.48	5.48	1/1/2000
GREENMO8	GREEN MOUNTAIN WIND FARM	SOMERSET	PA	Other	10	10	1/1/2000
HUNLOCK1	HUNLOCK CREEK	LUZERNE	PA	Peaking Units	44	44	1/1/2000
LINDENG5	LINDEN (PSEG)	UNION	NJ	Peaking Units	80	80	1/1/2000
LINDENG6	LINDEN (PSEG)	UNION	NJ	Peaking Units	80	80	1/1/2000
AESWARR1	AES WARRIOR RUN INC.	ALLEGANY	MD	Coal	180	180	2/1/2000
ALLEGHE1	ALLEGHENY ENERGY 8 & 9	FAYETTE	PA	Peaking Units	44	44	8/15/2000
ALLEGHE2	ALLEGHENY ENERGY 8 & 9	FAYETTE	PA	Peaking Units	44	44	8/15/2000
ARCHIBD1	ARCHIBALD COGENERATION PLAN	LACKAWANNA	PA	Peaking Units	45	45	1/1/2001
GREENKN1	GREEN KNIGHT ENERGY CENTER	NORTHAMPTON	PA	Peaking Units	9.5	9.5	1/1/2001
KEARNY01	KEARNY (PSEG)	HUDSON	NJ	Peaking Units	85.4	85.4	1/1/2001
KEARNY02	KEARNY (PSEG)	HUDSON	NJ	Peaking Units	85.4	85.4	1/1/2001
MILLRUN1	MILL RUN WINDPOWER	FAYETTE	PA	Other	15	15	1/1/2001
ROCKLAN1	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ROCKLAN2	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
ROCKLAN3	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
ROCKLAN4	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
ROCKLAN5	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
SOMERST1	SOMERSET WIND PROJECT	SOMERSET	PA	Other	9	9	1/1/2001
WILMING1	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001
WILMING2	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001
COMMNCH4	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	6/15/2001
COMMNCH5	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	6/15/2001
COMMNCH6	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	6/15/2001
KRAFTFO1	KRAFT FOODS COGENERATION	KENT	DE	Peaking Units	44	44	7/17/2001
KRAFTFO2	KRAFT FOODS COGENERATION	KENT	DE	Peaking Units	44	44	7/17/2001
WILMING3	WILMINGTON	NEW CASTLE	DE	Peaking Units	112	112	7/31/2001
HANDSOM1	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM2	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM3	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM4	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM5	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
COMMNCH7	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	8/17/2001
GUILFORD	Guilford Township		PA	Peaking Units	88	88	11/30/2001
LINDNCO1	LINDEN COGEN PLANT (ECOAST)	UNION	NJ	Peaking Units	153	170	1/1/2002
IRONWOD1	IRONWOOD PROJECT	LEBANON	PA	Combined Cycle	700	700	1/31/2002
HAZELTN1	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
HAZELTN2	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
HAZELTN3	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
HAZELTN4	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
HAZELTO1	HAZELTON	LUZERNE	PA	Peaking Units	90	100	2/1/2002
PLEASNT1	PLEASANTS COUNTY	PLEASANTS	WV	Peaking Units	153	170	2/1/2002
PLEASNT2	PLEASANTS COUNTY	PLEASANTS	WV	Peaking Units	153	170	2/1/2002
SMYRNA01	SMYRNA			Peaking Units	40.5	45	2/1/2002
LIBERTY1	LIBERTY ELECTRIC PROJECT	DELAWARE	PA	Combined Cycle	450	500	5/1/2002
WILMNGT1	WILMINGTON	NEW CASTLE	DE	Combined Cycle	450	500	5/17/2002
ARMSTRN1	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
ARMSTRN2	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
ARMSTRN3	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
ARMSTRN4	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
BERGEN02	BERGEN	BERGEN	NJ	Combined Cycle	450	500	6/1/2002
REDOAK01	RED OAK	MIDDLESEX	NJ	Combined Cycle	747	830	9/15/2002
ONTELAU1	ONTELAUNEE ENERGY CENTER	BERKS	PA	Combined Cycle	490.5	545	10/1/2002
MNT_WIND	Mountaineer Wind Energy Center		WV	Wind	66	66	12/31/2002
BETHLEC1	BETHLEHEM (CIV)	NORTHAMPTON	PA	Peaking Units	333	333	1/1/2003
LAKEWDC1	LAKEWOOD COGENERATION L/P	OCEAN	NJ	Peaking Units	149.94	166.6	1/30/2003
LAKEWDC2	LAKEWOOD COGENERATION L/P	OCEAN	NJ	Peaking Units	149.94	166.6	1/30/2003
LAKEWDC3	LAKEWOOD COGENERATION L/P	OCEAN	NJ	Peaking Units	149.94	166.6	1/30/2003
ROCKSPR1	Rock Springs		MD	Peaking Units	170	170	2/28/2003
ROCKSPR2	Rock Springs		MD	Peaking Units	170	170	2/28/2003
BETHLEC2	BETHLEHEM (CIV)	NORTHAMPTON	PA	Peaking Units	333	333	3/1/2003
MOOSICM1	MOOSIC MOUNTAIN	WAYNE	PA	Other	50	50	3/1/2003
BETHLEH1	BETHLEHEM (CIV)	NORTHAMPTON	PA	Combined Cycle	495	550	5/1/2003
LINDENP1	LINDEN (PSEGF)	UNION	NJ	Combined Cycle	533.7	593	5/1/2003
LINDENP2	LINDEN (PSEGF)	UNION	NJ	Combined Cycle	533.7	593	5/1/2003
ESSEXENE	Essex Energy		NJ	Peaking Units	5.6	5.6	6/1/2003
GERMANCC	German		PA	Combined Cycle	640	640	6/1/2003
HUNTERS1	HUNTERSTOWN	ADAMS	PA	Combined Cycle	720	800	6/1/2003
LOWERMB1	LOWER MOUNT BETHEL	NORTHAMPTON	PA	Combined Cycle	540	600	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ROCKSPR3	Rock Springs		MD	Peaking Units	170	170	6/1/2003
ROCKSPR4	Rock Springs		MD	Peaking Units	170	170	6/1/2003
SPRINGD1	SPRINGDALE	ALLEGHENY	PA	Combined Cycle	486	540	10/1/2003
FALLSTW1	FALLS TOWNSHIP	BUCKS	PA	Combined Cycle	495	550	3/1/2004
MARCUSR1	MARCUS HOOK REFINERY COGEN	DELAWARE	PA	Combined Cycle	216.9	241	3/1/2004
MARCUSR2	MARCUS HOOK REFINERY COGEN	DELAWARE	PA	Combined Cycle	216.9	241	3/1/2004
MARCUSR3	MARCUS HOOK REFINERY COGEN	DELAWARE	PA	Combined Cycle	216.9	241	3/1/2004
FALLSTW2	FALLS TOWNSHIP	BUCKS	PA	Combined Cycle	495	550	6/1/2004
SEWARD01	SEWARD (RELIANT)	INDIANA	PA	Coal	520	520	9/1/2004
	New Units in CP&L						
ASHEVLE1	ASHEVILLE	BUNCOMBE	NC	Peaking Units	144	160	3/1/2000
WAYNECT1	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	180	200	6/2/2000
WAYNECT2	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	180	200	6/2/2000
WAYNECT3	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	180	200	6/2/2000
WAYNECT4	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	83.7	93	6/2/2000
RICHMND1	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
RICHMND2	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
RICHMND3	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
RICHMND4	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
ROWANGT1	ROWAN	ROWAN	NC	Peaking Units	155	155	5/29/2001
ROWANGT2	ROWAN	ROWAN	NC	Peaking Units	155	155	5/29/2001
ROWANGT3	ROWAN	ROWAN	NC	Peaking Units	155	155	5/29/2001
RICHMND5	RICHMOND PLANT (CPLC)	RICHMOND	NC	Combined Cycle	423	470	5/30/2002
RICHMND6	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/30/2002
ROWANCC4	ROWAN	ROWAN	NC	Combined Cycle	423	470	1/1/2003
	New Units in Duke						
BROADRE1	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	180	200	6/1/2000
BROADRE2	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	180	200	6/1/2000
BROADRE3	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	45	50	6/1/2000
ROCKGHM1	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	180	200	7/12/2000
ROCKGHM2	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	180	200	7/12/2000
ROCKGHM3	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	72	80	7/12/2000
ROCKGHM4	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	180	200	7/17/2000
ROCKGHM5	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	108	120	7/17/2000
BROADRE4	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	157.5	175	6/15/2001
BROADRE5	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	157.5	175	6/15/2001
JOHNSRN1	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Combined Cycle	450	500	1/1/2002
JOHNSRN2	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	135	150	3/1/2002
JOHNSRN3	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	135	150	5/1/2002
MILLCRK1	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK2	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK3	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK4	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK5	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
MILLCRK6	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
MILLCRK7	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
MILLCRK8	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
JOHNSRN4	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	72	80	1/1/2004
JOHNSRN5	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	72	80	1/1/2004
JOHNSRN6	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	72	80	1/1/2004
	New Units in SCE&G						
URQUHAR1	URQUHART - SCEG	AIKEN	SC	Combined Cycle	202.5	225	6/3/2002
URQUHAR2	URQUHART - SCEG	AIKEN	SC	Combined Cycle	202.5	225	6/3/2002
COLUMBE1	COLUMBIA ENERGY CENTER	CALHOUN	SC	Combined Cycle	450	500	6/1/2003
JASPERC1	JASPER COUNTY	JASPER	SC	Combined Cycle	787.5	875	6/1/2004

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
	New Units in MISO (ECAR)						
491E48T9	491 E. 48TH STREET	OTTAWA	MI	Peaking Units	80	80	6/1/2000
ASHTABU1	ASHTABULA (TRCISO)	ASHTABULA	OH	Peaking Units	28	28	2/28/2001
BELLERR3	BELLE RIVER	ST. CLAIR	MI	Peaking Units	144	160	8/1/2002
BELLERR4	BELLE RIVER	ST. CLAIR	MI	Peaking Units	144	160	8/1/2002
BOWLINA1	BOWLING GREEN (AMP)	WOOD	OH	Peaking Units	32	32	7/11/2000
BOWLING1	BOWLING GREEN (USGECO)	WOOD	OH	Peaking Units	33	33	1/1/2000
BOWLING2	BOWLING GREEN (USGECO)	WOOD	OH	Peaking Units	16.5	16.5	1/1/2000
BROWNKU4	BROWN (KUC)	MERCER	KY	Peaking Units	133	133	1/1/2001
BROWNSG1	BROWN (SIGE)	POSEY	IN	Peaking Units	72	80	7/30/2002
CARBONL1	CARBON LIMESTONE LANDFILL	MAHONING	OH	Combined Cycle	20.8	20.8	1/1/2001
CEREDOG1	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG2	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG3	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG4	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG5	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG6	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CLAUDEV7	CLAUDE VANDYKE (BURNIPS)	ALLEGAN	MI	Peaking Units	24	24	8/28/2001
COVERT01	COVERT	VAN BUREN	MI	Combined Cycle	360	400	6/1/2003
COVERT02	COVERT	VAN BUREN	MI	Combined Cycle	360	400	6/1/2003
COVERT03	COVERT	VAN BUREN	MI	Combined Cycle	360	400	6/1/2003
DEARBOC1	DEARBORN INDUSTRIAL GENERAT	WAYNE	MI	Combined Cycle	550	550	1/1/2001
DEARBOR1	DEARBORN DIST GEN FACILITY	WAYNE	MI	Peaking Units	37.7	37.7	1/1/2001
DTECHIN1	DTE East China		MI	Peaking Units	80	80	6/1/2002
DTECHIN2	DTE East China		MI	Peaking Units	80	80	6/1/2002
DTECHIN3	DTE East China		MI	Peaking Units	80	80	6/1/2002
DTECHIN4	DTE East China		MI	Peaking Units	80	80	6/1/2002
DYNEGYB1	DYNEGY - BLUEGRASS	OLDHAM	KY	Peaking Units	180	186	6/1/2002
DYNEGYB2	DYNEGY - BLUEGRASS	OLDHAM	KY	Peaking Units	180	186	6/1/2002
DYNEGYB3	DYNEGY - BLUEGRASS	OLDHAM	KY	Peaking Units	100.8	186	6/1/2002
FOOTHIL1	FOOTHILLS GENERATING PROJEC	LAWRENCE	KY	Peaking Units	144	160	4/1/2002
FOOTHIL2	FOOTHILLS GENERATING PROJEC	LAWRENCE	KY	Peaking Units	153	170	4/1/2002
GALIONG1	GALION	CRAWFORD	OH	Peaking Units	33	33	1/1/2000
GALIONG2	GALION	CRAWFORD	OH	Peaking Units	16.5	16.5	1/1/2000
GAYLORDW	Gaylord [WPSC]		MI	Peaking Units	75	75	6/1/2001
GEORGEJ1	GEORGE JOHNSON	OSCEOLA	MI	Peaking Units	25	25	1/1/2000
GEORGEJ2	GEORGE JOHNSON	OSCEOLA	MI	Peaking Units	25	25	1/1/2000
GEORGET1	GEORGETOWN	MARION	IN	Peaking Units	88	88	1/1/2000
GEORGET2	GEORGETOWN	MARION	IN	Peaking Units	88	88	1/1/2000
GEORGET3	GEORGETOWN	MARION	IN	Peaking Units	88	88	1/1/2000
GEORGET4	GEORGETOWN	MARION	IN	Peaking Units	80	80	1/1/2001
HAMILTON	HAMILTON (AMP)	BUTLER	OH	Peaking Units	32	32	1/1/2000
HARDING8	HARDING STREET		IN	Peaking Units	155	155	5/31/2002
HAWESVI1	HAWESVILLE MILL	HANCOCK	KY	Steam Gas/Oil	60	60	1/1/2001
HENRYGT1	HENRY	HENRY	IN	Peaking Units	45	45	1/1/2001
HENRYGT2	HENRY	HENRY	IN	Peaking Units	45	45	1/1/2001
HENRYGT3	HENRY	HENRY	IN	Peaking Units	45	45	1/1/2001
HOOSFAIR	Hoosier Energy Fairview		IN	Peaking Units	16.43	16.43	6/15/2001
HOOSMIDW	Hoosier Energy Midway		IN	Peaking Units	16	16	6/15/2001
IRONSIDE	Ironside Energy		IN	Peaking Units	50	50	1/1/2002
JACKSON1	JACKSON	JACKSON	MI	Combined Cycle	338.4	376	6/1/2002
JACKSON2	JACKSON	JACKSON	MI	Peaking Units	162	180	6/1/2002
JKSMITG2	J.K. SMITH	CLARK	KY	Peaking Units	85.4	85.4	1/1/2001
JKSMITG3	J.K. SMITH	CLARK	KY	Peaking Units	85	85	1/1/2001
LAFARGE1	LAFARGE GYPSUM	CAMPBELL	KY	Peaking Units	5.2	5.2	1/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
LORAINL1	LORAIN LANDFILL	LORAIN	OH	Combined Cycle	7.8	7.8	1/1/2001
MACKINA1	MACKINAW CITY	EMMET	MI	Other	3.3	3.3	12/3/2001
NAPOLEO1	NAPOLEON	HENRY	OH	Peaking Units	33	33	1/1/2000
NAPOLEO2	NAPOLEON	HENRY	OH	Peaking Units	16.5	16.5	1/1/2000
NOBLEVL1	NOBLESVILLE	HAMILTON	IN	Combined Cycle	270	300	6/1/2003
OHIOAMP1	OHIO (AMP)	NOT APPLICABLE	OH	Peaking Units	21.6	21.6	1/1/2000
OHIOAMP2	OHIO (AMP)	NOT APPLICABLE	OH	Peaking Units	16.2	16.2	1/1/2000
PADDYS13	PADDYS RUN	JEFFERSON	KY	Peaking Units	151	151	1/1/2001
RENAIS10	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RENAISS7	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RENAISS8	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RENAISS9	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RICHLAN1	RICHLAND PEAKING	DEFIANCE	OH	Peaking Units	130	130	1/1/2000
RICHLAN2	RICHLAND PEAKING	DEFIANCE	OH	Peaking Units	130	130	1/1/2000
RICHLAN3	RICHLAND PEAKING	DEFIANCE	OH	Peaking Units	130	130	1/1/2000
SPURLCK1	SPURLOCK	MASON	KY	Coal	250	250	4/1/2005
SUGARCK1	SUGAR CREEK	VIGO	IN	Combined Cycle	450	500	6/1/2003
SUGARCK3	SUGAR CREEK	VIGO	IN	Peaking Units	153	170	6/1/2002
SUGARCK4	SUGAR CREEK	VIGO	IN	Peaking Units	153	170	6/1/2002
SUMPTER1	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
SUMPTER2	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
SUMPTER3	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
SUMPTER4	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
TRAVERS1	TRAVERSE CITY	GRAND TRAVERSE	MI	Peaking Units	45	50	11/1/2002
TRIMBLC4	TRIMBLE COUNTY	TRIMBLE	KY	Peaking Units	135	150	6/1/2002
TRIMBLC5	TRIMBLE COUNTY	TRIMBLE	KY	Peaking Units	135	150	6/1/2002
VERMILL1	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL2	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL3	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL4	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL5	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL6	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL7	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL8	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
WAYNECA1	WAYNE COUNTY AIRPORT	WAYNE	MI	Peaking Units	15.3	17	3/1/2002
WHITINR1	WHITING REFINERY (PRIENE)	LAKE	IN	Combined Cycle	490.5	545	1/31/2002
WOODCOU1	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WOODCOU2	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WOODCOU3	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WOODCOU4	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WORTHIN1	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WORTHIN2	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WORTHIN3	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WORTHIN4	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WSTFORK1	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTFORK2	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTFORK3	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTFORK4	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTLORG1	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG2	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG3	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG4	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG5	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
ZEELAND1	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001
ZEELAND2	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ZEELND01	ZEELAND (MIR)	OTTAWA	MI	Combined Cycle	478.8	532	8/12/2002
ZEELND02	ZEELAND (MIR)	OTTAWA	MI	Combined Cycle	360	400	6/1/2002
ZEELND03	ZEELAND (MIR)	OTTAWA	MI	Combined Cycle	387	430	6/1/2002
ZILWAUK1	ZILWAUKEE	SAGINAW	MI	Peaking Units	29	29	1/1/2000
ZILWAUK2	ZILWAUKEE	SAGINAW	MI	Peaking Units	12.12	12.12	1/1/2000
	New Units in MISO (MAIN)						
AESMEDV1	AESMEDINA VALLEY	TAZEWELL	IL	Combined Cycle	36	40	6/20/2001
AESMEDV2	AESMEDINA VALLEY	TAZEWELL	IL	Peaking Units	28.35	31.5	6/1/2001
ALSEYGT1	ALSEY	SCOTT	IL	Peaking Units	18.9	21	6/1/2000
APPLETN1	APPLETON PAPER-LOCKS MILL	OUTAGAMIE	WI	Peaking Units	43.2	48	4/1/2002
AUDRAIN1	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN2	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN3	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN4	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN5	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN6	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN7	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN8	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
COLUMSS1	COLUMBIA SUBSTATION	BOONE	MO	Peaking Units	80	80	9/4/2001
COLUMSS2	Columbia Substation		MO	Peaking Units	80	80	9/4/2001
ELWOOGT5	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT6	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT7	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT8	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT9	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
GERMNTW1	GERMANTOWN	WASHINGTON	WI	Peaking Units	76.5	85	5/1/2000
GERMNTW2	GERMANTOWN	WASHINGTON	WI	Peaking Units	45	50	8/1/2000
GIBSON1	Gibson		IL	Peaking Units	117	135	6/30/2000
GIBSON2	Gibson		IL	Peaking Units	117	135	6/30/2000
GOOSECR1	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	1/30/2003
GOOSECR2	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR3	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR4	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR5	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR6	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GRANDTW1	GRAND TOWER	JACKSON	IL	Combined Cycle	238.5	265	12/1/2001
GRANDTW2	GRAND TOWER	JACKSON	IL	Combined Cycle	258.3	287	6/29/2001
GRANDTW3	GRAND TOWER	JACKSON	IL	Peaking Units	12.24	13.6	12/1/2001
GRANDTW4	GRAND TOWER	JACKSON	IL	Peaking Units	8.1	9	6/29/2001
GREATRE1	GREAT RIVER ENERGY - PLEASA	MOWER	MN	Peaking Units	137.2	140	5/1/2001
GREATRE2	GREAT RIVER ENERGY - PLEASA	MOWER	MN	Peaking Units	137.2	140	5/1/2001
GREATRE3	GREAT RIVER ENERGY - PLEASA	MOWER	MN	Peaking Units	111.6	124	5/1/2002
HOLLAND1	HOLLAND ENERGY	SHELBY	IL	Combined Cycle	603	670	6/1/2002
INDIATW1	INDIANTOWN WINDPOWER PROJEC			Other	50	50	12/1/2002
LAKEFLJ1	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ2	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ3	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ4	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ5	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ6	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
MARION01	MARION (SIPC)	WILLIAMSON	IL	Coal	18	18	3/1/2003
MEPIGTF1	MEPI GT FACILITY	MASSAC	IL	Peaking Units	64.8	72	8/1/2000
MEPIGTF2	MEPI GT FACILITY	MASSAC	IL	Peaking Units	64.8	72	8/1/2000
MEPIGTF3	MEPI GT FACILITY	MASSAC	IL	Peaking Units	64.8	72	8/1/2000
MEPIGTF4	MEPI GT FACILITY	MASSAC	IL	Peaking Units	45.9	51	8/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
MEPIGTF5	MEPI GT FACILITY	MASSAC	IL	Peaking Units	45.9	51	8/1/2000
MERAMC01	MERAMEC	ST. LOUIS	MO	Peaking Units	43.2	48	6/1/2000
MONTFRW1	MONTFORT WIND FARM	IOWA	WI	Other	25.5	25.5	5/15/2001
NEENAH01	NEENAH	WINNEBAGO	WI	Peaking Units	135	150	5/8/2000
NEENAH02	NEENAH	WINNEBAGO	WI	Peaking Units	135	150	5/8/2000
PATOKA01	PATOKA	MARION	IL	Peaking Units	105.3	117	4/10/2001
PATOKA02	PATOKA	MARION	IL	Peaking Units	105.3	117	5/25/2001
PENOCREK	Peno Creek		MO	Peaking Units	192	192	5/24/2002
PINCKNV1	PINCKNEYVILLE	PERRY	IL	Peaking Units	158.4	176	6/30/2000
PINCKNV2	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	6/18/2001
PINCKNV3	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	6/26/2001
PINCKNV4	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	6/27/2001
PINCKNV5	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	8/28/2001
PULLIAM9	PULLIAM	BROWN	WI	Peaking Units	83	83	6/1/2003
RACCOON1	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	6/1/2002
RACCOON2	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	6/1/2002
RACCOON3	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	7/1/2002
RACCOON4	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	8/13/2002
RELIAES1	RELIANT ENERGY SHELBY COUNT	SHELBY	IL	Peaking Units	180	200	7/14/2000
RELIAES2	RELIANT ENERGY SHELBY COUNT	SHELBY	IL	Peaking Units	126	140	7/14/2000
RIVEREC1	RIVERSIDE ENERGY CENTER	ROCK	WI	Combined Cycle	540	600	6/1/2004
ROCKGEC1	ROCKGEN ENERGY CENTER	DANE	WI	Peaking Units	153	170	5/1/2001
ROCKGEC2	ROCKGEN ENERGY CENTER	DANE	WI	Peaking Units	153	170	5/1/2001
ROCKGEC3	ROCKGEN ENERGY CENTER	DANE	WI	Peaking Units	153	170	5/1/2001
STELMO01	ST ELMO	FAYETTE	IL	Peaking Units	40.5	45	6/1/2000
TOPIOWA1	TOP OF IOWA WIND FARM	WORTH	IA	Other	80	80	12/4/2001
UNIVMIS1	UNIVERSITY OF MISSOURI-COLU	BOONE	MO	Peaking Units	23.4	26	4/15/2002
VENICE01	VENICE (AUEP)	MADISON	IL	Peaking Units	43.2	48	6/1/2002
WSTMARN1	WEST MARINETTE (MGE)	MARINETTE	WI	Peaking Units	74.7	83	6/1/2000
	New Units in MISO (MAPP)						
BLACKDG3	BLACK DOG	DAKOTA	MN	Combined Cycle	261	290	6/15/2002
BROADWAY	Broadway Generation Plant		MN	Peaking Units	12	12	6/1/2003
CASCADE2	Cascade Creek		MN	Peaking Units	50	50	5/23/2002
CASSCNTY	Cass County		NE	Peaking Units	330	330	6/1/2003
CORDENG1	CORDOVA ENERGY	ROCK ISLAND	IL	Combined Cycle	483.39	537.1	6/14/2001
CWBURDP1	C.W. Burdick		NE	Peaking Units	40	40	3/15/2003
CWBURDP2	C.W. Burdick		NE	Peaking Units	40	40	3/15/2003
ELKMNDS1	ELK MOUND STATION	CHIPPEWA	WI	Peaking Units	36.9	41	5/30/2001
ELKMNDS2	ELK MOUND STATION	CHIPPEWA	WI	Peaking Units	36.9	41	6/6/2001
FREMNT_1	Fremont 1		NE	Peaking Units	42	42	6/1/2003
GREADES2	GREATER DES MOINES ENERGY C	POLK	IA	Peaking Units	180	200	6/1/2003
GREADES3	GREATER DES MOINES ENERGY C	POLK	IA	Peaking Units	126	140	6/1/2003
KIMBALL1	KIMBALL WIND	KIMBALL	NE	Other	14	14	9/1/2002
KNOXVLI1	KNOXVILLE INDUSTRIAL (MIDAM	MARION	IA	Peaking Units	16	16	6/1/2000
LUNDQUS1	LUNDQUIST	NOT APPLICABLE	IA	Peaking Units	20	20	6/1/2000
MANKAT01	MANKATO	BLUE EARTH	MN	Peaking Units	10.53	11.7	1/31/2002
MARKETS1	MARKET STREET ENERGY COMPAN	RAMSEY	MN	Other	25	25	12/1/2002
MNRIVERS	Minnesota River Station		MN	Peaking Units	43	43	1/1/2002
NTHHOME1	NORTHOME WOOD PLANT	KOOCHICHING	MN	Other	20	20	11/1/2002
POTLACC1	POTLATCH CLOQUET COGEN	CARLTON	MN	Combined Cycle	21.6	24	5/31/2001
POWERIO1	POWER IOWA 1	NOT APPLICABLE	IA	Combined Cycle	450	500	6/1/2004
SALTVAL2	SALT VALLEY GENERATING STAT	LANCASTER	NE	Peaking Units	41.5	45	5/1/2004
SALTVAL3	SALT VALLEY GENERATING STAT	LANCASTER	NE	Peaking Units	90	90	6/1/2003
SARPYGT1	SARPY	SARPY	NE	Peaking Units	90	100	5/26/2000
SHENAND1	SHENANDOAH	PAGE	VA	Peaking Units	20	20	6/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
SHENANDO	Shenandoah		IA	Peaking Units	20	20	6/1/2000
SOLWAYP1	SOLWAY POWER PLANT	BELTRAMI	MN	Peaking Units	39.6	44	6/1/2003
TACONTH1	TACONITE HARBOR POWER PLANT	COOK	MN	Coal	62.5	67.5	2/7/2002
TACONTH2	TACONITE HARBOR POWER PLANT	COOK	MN	Coal	62.5	67.5	4/1/2002
TACONTH3	TACONITE HARBOR POWER PLANT	COOK	MN	Coal	62.5	67.5	6/5/2002
	New Units in FRCC						
ELDORAD1	EL DORADO (FPL)			Combined Cycle	114	114	1/1/2000
MCINTSL1	MCINTOSH (LALW)	POLK	FL	Coal	120	120	1/1/2000
WINSTON1	WINSTON DISTRIBUTED GEN	POLK	FL	Peaking Units	52	52	1/1/2000
HARDEEP1	HARDEE POWER STATION - SEC1	HARDEE	FL	Peaking Units	72	90	5/20/2000
SOPURDM1	S.O. PURDOM	WAKULLA	FL	Combined Cycle	233	262	8/1/2000
POLKGT02	POLK	POLK	FL	Peaking Units	160	180	8/15/2000
FORTMY10	FORT MYERS	LEE	FL	Peaking Units	150	170	11/1/2000
FORTMY11	FORT MYERS	LEE	FL	Peaking Units	300	340	12/1/2000
INTERCC1	INTERCESSION CITY	OSCEOLA	FL	Peaking Units	80	94	12/13/2000
INTERCC2	INTERCESSION CITY	OSCEOLA	FL	Peaking Units	80	94	12/14/2000
INTERCC3	INTERCESSION CITY	OSCEOLA	FL	Peaking Units	80	94	12/17/2000
INTERCC4	INTERCESSION CITY P15	OSCEOLA	FL	Peaking Units	154	184	12/17/2000
FORTMY12	FORT MYERS	LEE	FL	Peaking Units	150	170	2/1/2001
FORTMY13	FORT MYERS	LEE	FL	Peaking Units	150	170	3/1/2001
FORTMYR9	FORT MYERS	LEE	FL	Peaking Units	150	170	4/1/2001
MCINTSL4	MCINTOSH (LALW)	POLK	FL	Peaking Units	180	200	4/16/2001
MCINTSL5	MCINTOSH (LALW)	POLK	FL	Peaking Units	44.1	49	4/16/2001
JOHNRKL1	JOHN R. KELLY	ALACHUA	FL	Combined Cycle	104.4	116	5/31/2001
FIELDST1	FIELD STREET	VOLUSIA	FL	Peaking Units	36	40	6/1/2001
CANEIPP5	CANE ISLAND POWER PARK	OSCEOLA	FL	Peaking Units	153	170	6/6/2001
MARTINF5	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001
MARTINF6	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001
CRYSTRV1	CRYSTAL RIVER	CITRUS	FL	Coal	100	100	10/1/2001
FORTMYR2	FORT MYERS	LEE	FL	Combined Cycle	651	652	10/1/2001
FORTMYR3	FORT MYERS	LEE	FL	Combined Cycle	901	904	10/1/2001
RELEOSC2	RELIANT ENERGY OSCEOLA	OSCEOLA	FL	Peaking Units	159	170	12/1/2001
RELEOSC3	RELIANT ENERGY OSCEOLA	OSCEOLA	FL	Peaking Units	159	170	12/1/2001
PAYNECK1	PAYNE CREEK GENERATING FACI	HARDEE	FL	Combined Cycle	488	572	1/1/2002
CANEIPP1	CANE ISLAND POWER PARK	OSCEOLA	FL	Combined Cycle	225	250	1/25/2002
PASCOPR1	PASCO POWER PROJECT	PASCO	FL	Peaking Units	158	158	3/1/2002
PASCOPR2	PASCO POWER PROJECT	PASCO	FL	Peaking Units	158	158	3/1/2002
PASCOPR3	PASCO POWER PROJECT	PASCO	FL	Peaking Units	158	158	3/1/2002
RELEOSC1	RELIANT ENERGY OSCEOLA	OSCEOLA	FL	Peaking Units	159	170	3/1/2002
POLKGT03	POLK	POLK	FL	Peaking Units	160	180	5/1/2002
VANDOLH2	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
VANDOLH3	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
DESOTGC1	DESOTO GENERATING CO. (PREN	DE SOTO	FL	Peaking Units	150	170	6/1/2002
DESOTGC2	DESOTO GENERATING CO. (PREN	DE SOTO	FL	Peaking Units	150	170	6/1/2002
OLEANDP1	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
OLEANDP2	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
OLEANDP3	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
OLEANDP4	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
VANDOLH1	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
VANDOLH4	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
SANFRDF3	SANFORD (FPL)	VOLUSIA	FL	Combined Cycle	1030	1116	6/15/2002
AUBURDP1	AUBURNDALE POWER PARTNERS L	POLK	FL	Peaking Units	121.5	135	7/31/2002
FORTMYR5	FORT MYERS	LEE	FL	Peaking Units	170	170	1/1/2003
FORTMYR6	FORT MYERS	LEE	FL	Peaking Units	170	170	1/1/2003
GANNONC1	GANNON	HILLSBOROUGH	FL	Combined Cycle	737	742	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
SANFRDF4	SANFORD (FPL)	VOLUSIA	FL	Combined Cycle	1030	1116	6/1/2003
OSPREYE1	OSPREY ENERGY CENTER	POLK	FL	Combined Cycle	486	540	10/1/2003
STANTN01	STANTON	ORANGE	FL	Combined Cycle	700	700	10/1/2003
HINESCC2	Hines Energy Complex	POLK	FL	Combined Cycle	516	582	11/1/2003
GANNONC2	GANNON	HILLSBOROUGH	FL	Combined Cycle	1042	1072	6/1/2004
MCINTSL2	MCINTOSH (LALW)	POLK	FL	Combined Cycle	332.1	369	1/1/2005
	New Units in ISO-NE						
ANDROEC3	ANDROSCOGGIN ENERGY CENTER	FRANKLIN	ME	Peaking Units	54.46	54.46	1/1/2000
BERKSHP1	BERKSHIRE POWER	HAMPDEN	MA	Combined Cycle	252	252	1/1/2000
BUKSPTE1	BUCKSPORT ENERGY	HANCOCK	ME	Peaking Units	174	174	1/1/2000
FALLRIV1	FALL RIVER COGEN PLANT	BRISTOL	MA	Combined Cycle	6.7	6.7	1/1/2000
MAINEIN1	MAINE INDEPENDENCE STATION	PENOBSCOT	ME	Combined Cycle	519	519	1/1/2000
NEWENGW1	NEW ENGLAND WIND ENERGY STA	CUMBERLAND	ME	Other	20	20	1/1/2000
TIVERTN1	TIVERTON POWER PLANT	NEWPORT	RI	Combined Cycle	88.72	88.72	1/1/2000
BLACKST1	BLACKSTONE (AMNAPO)	WORCESTER	MA	Combined Cycle	290	290	1/1/2001
BLACKST2	BLACKSTONE (AMNAPO)	WORCESTER	MA	Combined Cycle	290	290	1/1/2001
WALLNGF1	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF2	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF3	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF4	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF5	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF6	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WSTBROK1	WESTBROOK POWER PLANT	CUMBERLAND	ME	Combined Cycle	540	540	1/1/2001
MILLENN1	MILLENNIUM POWER PARTNERS,	WORCESTER	MA	Combined Cycle	360	360	4/5/2001
WALLING1	WALLINGFORD	NEW HAVEN	CT	Peaking Units	180	200	1/15/2002
MILFORD3	MILFORD (EPPSCO)	NEW HAVEN	CT	Combined Cycle	489.6	544	3/1/2002
NEWING01	NEWINGTON (COEDDE)	ROCKINGHAM	NH	Combined Cycle	472.5	525	3/1/2002
LAKEROA4	LAKE ROAD	WINDHAM	CT	Combined Cycle	237.6	264	5/1/2002
LAKEROA5	LAKE ROAD	WINDHAM	CT	Combined Cycle	237.6	264	5/1/2002
KENDLSQ1	KENDALL SQUARE	MIDDLESEX	MA	Combined Cycle	210.6	234	6/1/2002
RIHOPEE1	RI HOPE ENERGY	PROVIDENCE	RI	Combined Cycle	522	535	6/1/2002
WESTSPR1	WEST SPRINGFIELD	HAMPDEN	MA	Peaking Units	45	45	6/7/2002
WESTSPR2	WEST SPRINGFIELD	HAMPDEN	MA	Peaking Units	45	45	6/7/2002
LAKEROA6	LAKE ROAD	WINDHAM	CT	Combined Cycle	237.6	264	6/14/2002
FORERIV1	FORE RIVER	NORFOLK	MA	Combined Cycle	450	500	8/1/2002
FORERIV2	FORE RIVER	NORFOLK	MA	Combined Cycle	225	250	8/1/2002
BELLINC1	BELLINGHAM	NORFOLK	MA	Combined Cycle	261	290	11/1/2002
BELLINC2	BELLINGHAM	NORFOLK	MA	Combined Cycle	261	290	12/31/2002
LONDOND1	AES LONDONDERRY	ROCKINGHAM	NH	Combined Cycle	648	720	2/28/2003
MERIDEN1	MERIDEN POWER	NEW HAVEN	CT	Combined Cycle	489.6	544	3/1/2003
MYSTICC1	MYSTIC	MIDDLESEX	MA	Combined Cycle	750	750	4/1/2003
MYSTICC2	MYSTIC	MIDDLESEX	MA	Combined Cycle	750	750	4/1/2003
	New Units in NYISO						
MADISNW1	MADISON WINDPOWER PROJECT	MADISON	NY	Other	11.5	11.5	1/1/2000
UPNYWF11	UPPER NEW YORK WIND FARM	WYOMING	NY	Other	6.6	6.6	1/1/2000
23RDSTR1	23RD STREET	KINGS	NY	Peaking Units	39.95	39.95	1/1/2001
23RDSTR2	23RD STREET	KINGS	NY	Peaking Units	39.95	39.95	1/1/2001
CANASTO1	CANASTOTA	MADISON	NY	Other	30	30	1/1/2001
CARLSON1	CARLSON	CHAUTAUQUA	NY	Peaking Units	43	43	1/1/2001
HARLEMR1	HARLEM RAIL	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
HARLEMR2	HARLEM RAIL	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
HELLGTE1	HELL GATE	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
HELLGTE2	HELL GATE	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
LINDENC9	LINDEN COGEN PLANT (ECOAST)	UNION	NJ	Peaking Units	180	180	1/1/2001
PILGRMS1	PILGRIM STATE HOSPITAL			Peaking Units	44	44	1/1/2001

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
RIVERST1	RIVER STREET (NYPA)	KINGS	NY	Peaking Units	44	44	1/1/2001
VERNONB1	VERNON BOULEVARD	QUEENS	NY	Peaking Units	39.95	39.95	1/1/2001
VERNONB2	VERNON BOULEVARD	QUEENS	NY	Peaking Units	39.95	39.95	1/1/2001
VIRGNAA1	VIRGINIA AVENUE	NEW YORK	NY	Peaking Units	44	44	1/1/2001
CARLSNN1	CARLSON	CHAUTAUQUA	NY	Peaking Units	63.9	71	1/15/2002
BETHPAG1	BETHPAGE (TBG - GRUMMAN)	NASSAU	NY	Peaking Units	39.6	44	5/1/2002
EFBARRE1	E.F. BARRETT	NASSAU	NY	Peaking Units	71.1	79	5/1/2002
PORTJFF1	PORT JEFFERSON	SUFFOLK	NY	Peaking Units	71.1	79	5/1/2002
SHOREHA1	SHOREHAM			Peaking Units	71.91	79.9	5/1/2002
BAYSWAT1	BAYSWATER CLEAN ENERGY CENT	QUEENS	NY	Peaking Units	39.6	44	6/1/2002
GLENWOO1	GLENWOOD	NASSAU	NY	Peaking Units	35.1	39	6/1/2002
GLENWOO2	GLENWOOD	NASSAU	NY	Peaking Units	35.1	39	6/1/2002
EDGEWEG1	EDGEWOOD ELECTRIC GENERATIN	SUFFOLK	NY	Peaking Units	71.1	79	7/24/2002
RAVENSW1	RAVENSWOOD	KINGS	NY	Combined Cycle	225	250	6/1/2003
ATHENGP1	ATHENS GENERATING PLANT	GREENE	NY	Combined Cycle	328.5	365	7/1/2003
ATHENGP2	ATHENS GENERATING PLANT	GREENE	NY	Combined Cycle	328.5	365	7/1/2003
ATHENGP3	ATHENS GENERATING PLANT	GREENE	NY	Combined Cycle	328.5	365	7/1/2003
EASTRIV1	EAST RIVER	NEW YORK	NY	Peaking Units	162	180	1/1/2004
EASTRIV2	EAST RIVER	NEW YORK	NY	Peaking Units	162	180	1/1/2004
ALBANSS1	ALBANY STEAM STATION	ALBANY	NY	Combined Cycle	241	267	6/1/2005
ALBANSS2	ALBANY STEAM STATION	ALBANY	NY	Combined Cycle	241	267	6/1/2005
ALBANSS3	ALBANY STEAM STATION	ALBANY	NY	Combined Cycle	241	267	6/1/2005
	New Units in SETRANS (Entergy)						
ACADIA01	ACADIA	ST. LANDRY	LA	Combined Cycle	558	620	6/1/2002
ACADIA02	ACADIA	ST. LANDRY	LA	Combined Cycle	558	620	8/5/2002
ATTALAE1	ATTALA ENERGY CENTER	ATTALA	MS	Combined Cycle	459	510	6/1/2001
BAYOUCV1	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
BAYOUCV2	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
BAYOUCV3	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
BAYOUCV4	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
BIGCJN11	BIG CAJUN 1	POINTE COUPEE	LA	Peaking Units	108	120	6/6/2001
BIGCJN12	BIG CAJUN 1	POINTE COUPEE	LA	Peaking Units	108	120	6/6/2001
BRANDBG4	BRANDY BRANCH GENERATING ST	DUVAL	FL	Peaking Units	158	191	5/31/2001
BRANDBG5	BRANDY BRANCH GENERATING ST	DUVAL	FL	Peaking Units	158	191	5/31/2001
BRANDBG6	BRANDY BRANCH GENERATING ST	DUVAL	FL	Peaking Units	158	191	10/12/2001
CALCASU1	CALCASIEU GENERATION PROJEC	CALCASIEU	LA	Peaking Units	139.5	155	5/31/2000
CALCASU2	CALCASIEU GENERATION PROJEC	CALCASIEU	LA	Peaking Units	148.5	165	5/15/2001
CARVILE1	CARVILLE ENERGY CENTER	IBERVILLE	LA	Combined Cycle	234.9	261	5/1/2003
CARVILE2	CARVILLE ENERGY CENTER	IBERVILLE	LA	Combined Cycle	234.9	261	5/1/2003
CARVILE3	CARVILLE ENERGY CENTER	IBERVILLE	LA	Combined Cycle	109.8	122	5/1/2002
CHOUTEU1	CHOUTEAU (AECI)	MAYES	OK	Combined Cycle	477	530	7/21/2000
COTTONW1	COTTONWOOD ENERGY	NEWTON	TX	Combined Cycle	555.75	617.5	2/1/2003
COTTONW2	COTTONWOOD ENERGY	NEWTON	TX	Combined Cycle	555.75	617.5	2/1/2003
CROSSEC1	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	6/30/2002
CROSSEC2	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	6/30/2002
CROSSEC3	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	7/31/2002
CROSSEC4	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	7/31/2002
HINDSEF1	HINDS ENERGY FACILITY	HINDS	MS	Combined Cycle	450	500	6/1/2001
HOLDENP1	HOLDEN POWER PLANT	JOHNSON	MO	Peaking Units	96.3	107	5/31/2002
HOLDENP2	HOLDEN POWER PLANT	JOHNSON	MO	Peaking Units	96.3	107	5/31/2002
HOLDENP3	HOLDEN POWER PLANT	JOHNSON	MO	Peaking Units	96.3	107	5/31/2002
HOTSPRF2	HOT SPRING ENERGY FACILITY	HOT SPRING	AR	Combined Cycle	558	620	5/31/2002
HOTSPRP1	HOT SPRINGS POWER	GARLAND	AR	Combined Cycle	648	720	7/1/2004
JDKENND1	J.D. KENNEDY	DUVAL	FL	Peaking Units	158	191	4/1/2000
LOUISI21	LOUISIANA 2	EAST BATON ROUGE	LA	Steam Gas/Oil	140	140	7/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
NROCCGF1	NROC COGEN FACILITY	JEFFERSON	TX	Combined Cycle	72	80	8/1/2001
OUACHIT1	OUACHITA POWER PLANT	OUACHITA	LA	Combined Cycle	720	800	11/1/2002
PERRYVP1	PERRYVILLE POWER STATION	OUACHITA	LA	Peaking Units	153	170	6/15/2001
PERRYVP3	PERRYVILLE POWER STATION	OUACHITA	LA	Combined Cycle	502.2	558	7/1/2002
PINEBLF1	PINE BLUFF ENERGY CENTER (S	JEFFERSON	AR	Combined Cycle	198	220	9/24/2001
RSCOGEN1	RS COGEN	CALCASIEU	LA	Combined Cycle	403.2	448	8/1/2002
SABINEC1	SABINE COGENERATION FACILIT	ORANGE	TX	Combined Cycle	90	100	1/15/2000
SABINER1	SABINE RIVER WORKS (COGLPO)	ORANGE	TX	Combined Cycle	378	420	11/28/2001
SHELLGM1	SHELL GEISMAR	ASCENSION	LA	Combined Cycle	36	40	8/1/2002
SHELLGM2	SHELL GEISMAR	ASCENSION	LA	Combined Cycle	36	40	8/1/2002
STERGT10	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	17	17	6/15/2000
STERLGT1	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	6/15/2000
STERLGT2	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	6/15/2000
STERLGT3	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	7/15/2000
STERLGT4	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	8/15/2000
STERLGT5	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	3/1/2001
STERLGT6	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	3/1/2001
STERLGT7	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	7/15/2001
STERLGT8	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	7/15/2001
STERLGT9	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	17	17	7/15/2001
STFRANS1	ST FRANCIS	DUNKLIN	MO	Combined Cycle	234	260	6/1/2001
STHAVEN1	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN2	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN3	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN4	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN5	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN6	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN7	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN8	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHHAVN1	SOUTHAVEN (COGENT)	DE SOTO	MS	Combined Cycle	240.3	267	6/1/2003
STHHAVN2	SOUTHAVEN (COGENT)	DE SOTO	MS	Combined Cycle	240.3	267	6/1/2003
STHHAVN3	SOUTHAVEN (COGENT)	DE SOTO	MS	Combined Cycle	239.4	266	6/1/2003
TAFTPRO1	TAFT PROJECT	ST. CHARLES	LA	Combined Cycle	700.2	778	9/1/2002
UNIONPP2	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	1/27/2003
UNIONPP3	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	4/1/2003
UNIONPP4	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	6/1/2003
UNIONPP5	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	8/1/2003
WARRNPP1	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WARRNPP2	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WARRNPP3	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WARRNPP4	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WASHPAR1	WASHINGTON PARISH ENERGY CE	WASHINGTON	LA	Combined Cycle	253.8	282	7/1/2004
WASHPAR2	WASHINGTON PARISH ENERGY CE	WASHINGTON	LA	Combined Cycle	253.8	282	7/1/2004
WRIGHTV1	WRIGHTSVILLE POWER FACILITY	PULASKI	AR	Combined Cycle	322.2	358	6/25/2002
WRIGHTV2	WRIGHTSVILLE POWER FACILITY	PULASKI	AR	Combined Cycle	172.8	192	6/25/2002
	New Units in SETRANS (SOCO)						
AUTAUGA1	AUTAUGAVILLE	AUTAUGA	AL	Combined Cycle	567	630	6/1/2003
AUTAUGA2	AUTAUGAVILLE	AUTAUGA	AL	Combined Cycle	567	630	6/1/2003
BACONTO1	BACONTON	MITCHELL	GA	Peaking Units	126.9	141	6/1/2000
BACONTO2	BACONTON	MITCHELL	GA	Peaking Units	42.3	47	7/1/2000
BARRYAL1	BARRY (ALAP)	MOBILE	AL	Combined Cycle	483.3	537	5/31/2000
BARRYAL2	BARRY (ALAP)	MOBILE	AL	Combined Cycle	483.3	537	5/1/2001
CALHOUN1	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003
CALHOUN2	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003
CALHOUN3	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
CALHOUN4	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003
DAHLBRG1	DAHLBERG	JACKSON	GA	Peaking Units	180	200	6/1/2000
DAHLBRG2	DAHLBERG	JACKSON	GA	Peaking Units	180	200	6/1/2000
DAHLBRG3	DAHLBERG	JACKSON	GA	Peaking Units	72	80	6/1/2000
DAHLBRG4	DAHLBERG	JACKSON	GA	Peaking Units	72	80	6/20/2000
DAHLBRG5	DAHLBERG	JACKSON	GA	Peaking Units	72	80	7/1/2000
DAHLBRG6	DAHLBERG	JACKSON	GA	Peaking Units	144	160	11/1/2001
DOYLEPT1	DOYLE PLANT	WALTON	GA	Peaking Units	180	200	6/15/2000
DOYLEPT2	DOYLE PLANT	WALTON	GA	Peaking Units	81	90	6/15/2000
DOYLEPT3	DOYLE PLANT	WALTON	GA	Peaking Units	72	80	7/30/2000
EFFINGH1	EFFINGHAM COUNTY	EFFINGHAM	GA	Combined Cycle	480	530	6/1/2003
ENTERPE1	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE2	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE3	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE4	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE5	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE6	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE7	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE8	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
GOATRCK1	GOAT ROCK (GPCO)	HARRIS	GA	Combined Cycle	513	570	6/1/2005
GOATRCK3	GOAT ROCK (GPCO)	HARRIS	GA	Combined Cycle	513	570	6/1/2002
GOATRCK4	GOAT ROCK (GPCO)	HARRIS	GA	Combined Cycle	513	570	6/1/2003
HEARDCP1	HEARD COUNTY POWER PLANT	HEARD	GA	Peaking Units	150.3	167	6/1/2001
HEARDCP2	HEARD COUNTY POWER PLANT	HEARD	GA	Peaking Units	150.3	167	6/1/2001
HEARDCP3	HEARD COUNTY POWER PLANT	HEARD	GA	Peaking Units	149.4	166	6/1/2001
HILLABE1	HILLABEE ENERGY CENTER	TALLAPOOSA	AL	Combined Cycle	693	770	12/1/2003
HOGBAYU1	HOG BAYOU ENERGY CENTER	MOBILE	AL	Combined Cycle	198	220	7/15/2001
LANSINS1	LANSING SMITH (GUPC)	BAY	FL	Combined Cycle	450	500	4/22/2002
MONROEC1	MONROE (CPLC)	MONROE	GA	Peaking Units	135	150	6/6/2001
MONROEC2	MONROE (CPLC)	MONROE	GA	Peaking Units	135	150	6/6/2001
MONROEC3	MONROE (CPLC)	MONROE	GA	Peaking Units	135	150	6/6/2001
MONROEM1	MONROE (MONPOW)	WALTON	GA	Peaking Units	144	160	3/31/2001
MURRAYE1	MURRAY ENERGY FACILITY (DUK	MURRAY	GA	Combined Cycle	540	600	3/1/2003
MURRAYE2	MURRAY ENERGY FACILITY (DUK	MURRAY	GA	Combined Cycle	540	600	3/1/2003
SANDERV1	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV2	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV3	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV4	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV5	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV6	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV7	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV8	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANTARS1	SANTA ROSA (SKYSER)	SANTA ROSA	FL	Combined Cycle	216	240	9/1/2002
SEGENCP1	SE GENERATING CORP	DECATUR	GA	Peaking Units	72	80	7/1/2000
SEWELLC1	SEWELL CREEK ENERGY CENTER	POLK	GA	Peaking Units	180	200	7/1/2000
SEWELLC2	SEWELL CREEK ENERGY CENTER	POLK	GA	Peaking Units	117	130	7/1/2000
SEWELLC3	SEWELL CREEK ENERGY CENTER	POLK	GA	Peaking Units	117	130	9/15/2000
SYLVARE1	SYLVARENA	SMITH	MS	Peaking Units	38.7	43	6/1/2003
SYLVARE2	SYLVARENA	SMITH	MS	Peaking Units	38.7	43	6/1/2003
SYLVARE3	SYLVARENA	SMITH	MS	Peaking Units	38.7	43	6/1/2003
TALBOTE1	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	5/15/2002
TALBOTE2	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	5/15/2002
TALBOTE3	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/1/2002
TALBOTE4	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/6/2002
TALBOTE5	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
TALBOTE6	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/1/2003
TENASCA1	TENASKA CENTRAL ALABAMA GEN	AUTAUGA	AL	Combined Cycle	765	850	6/1/2003
TENASGG1	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2001
TENASGG2	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2001
TENASGG3	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	8/15/2001
TENASGG4	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2002
TENASGG5	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2002
TENASGG6	*TENASKA GEORGIA*	*HEARD*	*GA*	*Peaking Units*	*140.4*	*156*	*6/1/2002*
TENASLH1	TENASKA LINDSAY HILL GENERA	AUTAUGA	AL	Combined Cycle	761.4	846	5/1/2002
TENASLH2	TENASKA LINDSAY HILL GENERA	AUTAUGA	AL	Combined Cycle	311.4	346	5/15/2002
THEODRC1	THEODORE COGEN	MOBILE	AL	Combined Cycle	216	240	12/23/2000
VANNPWP1	VANN POWER PLANT	COVINGTON	AL	Combined Cycle	450	500	1/1/2002
VICTORJ1	VICTOR J. DANIEL	JACKSON	MS	Combined Cycle	450	500	4/1/2001
VICTORJ2	VICTOR J. DANIEL	JACKSON	MS	Combined Cycle	450	500	4/1/2001
WANSLE01	WANSLEY	HEARD	GA	Combined Cycle	509.4	566	6/1/2002
WANSLE02	WANSLEY	HEARD	GA	Combined Cycle	509.4	566	6/1/2002
WANSLEM1	*WANSLEY (MEAG)*	*HEARD*	*GA*	*Combined Cycle*	*452.7*	*503*	*5/1/2004*
WANSLEO1	WANSLEY [OGLE]	HEARD	GA	Combined Cycle	468.9	521	3/1/2003
WASHCPP1	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WASHCPP2	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WASHCPP3	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WASHCPP4	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WSTGERG1	WEST GEORGIA GENERATING FAC	UPSON	GA	Peaking Units	180	200	6/7/2000
WSTGERG2	WEST GEORGIA GENERATING FAC	UPSON	GA	Peaking Units	180	200	6/7/2000
WSTGERG3	WEST GEORGIA GENERATING FAC	UPSON	GA	Peaking Units	180	200	6/7/2000
WSTGERG4	*WEST GEORGIA GENERATING FAC*	*UPSON*	*GA*	*Peaking Units*	*72*	*80*	*6/7/2000*
	New Units in SPP						
GORDONE1	GORDON EVANS	SEDGWICK	KS	Peaking Units	132.66	147.4	6/1/2000
HAWTHRN3	HAWTHORN	JACKSON	MO	Peaking Units	69.3	77	6/30/2000
HAWTHRN2	HAWTHORN	JACKSON	MO	Combined Cycle	242.1	269	7/11/2000
HAWTHRN5	HAWTHORN	JACKSON	MO	Peaking Units	31.5	35	7/11/2000
HORSESL1	HORSESHOE LAKE	OKLAHOMA	OK	Peaking Units	85.5	95	7/30/2000
MUSTNG01	MUSTANG	OKLAHOMA	OK	Steam Gas/Oil	115	115	7/30/2000
MASSEGL1	MASSENGALE	LUBBOCK	TX	Combined Cycle	55.8	62	9/7/2000
ANADRK11	*ANADARKO I*	*CADDO*	*OK*	*Peaking Units*	*81*	*90*	*5/8/2001*
ONEOKLC1	ONEOK - LOGAN COUNTY PEAKIN			Peaking Units	180	200	5/16/2001
ONEOKLC2	ONEOK - LOGAN COUNTY PEAKIN			Peaking Units	90	100	5/16/2001
FULTONA1	FULTON (AEC)	HEMPSTEAD	AR	Peaking Units	137.7	153	5/26/2001
MCCLAIN1	MCCLAIN ENERGY FACILITY	MCCLAIN	OK	Combined Cycle	450	500	6/1/2001
GORDONE2	GORDON EVANS	SEDGWICK	KS	Peaking Units	135.45	150.5	6/12/2001
HAWTHRN1	HAWTHORN	JACKSON	MO	Coal	540	540	6/30/2001
STATLNE1	STATELINE (EMDE)	JASPER	MO	Combined Cycle	451.8	502	7/2/2001
NTHEST01	NORTHEASTERN	ROGERS	OK	Combined Cycle	420.3	467	7/15/2001
ARIESGT1	*ARIES*	*CASS*	*MO*	*Peaking Units*	*180*	*200*	*7/16/2001*
ARIESGT2	ARIES	CASS	MO	Peaking Units	154.8	172	7/16/2001
GRAYCNT1	GRAY COUNTY	GRAY	KS	Other	110	110	12/17/2001
LLANOEC1	LLANO ESTACADO	CARSON	TX	Other	80	80	12/28/2001
EASTEXC1	EASTEX COGENERATION FACILIT	HARRISON	TX	Combined Cycle	396	440	12/30/2001
GREENCE1	GREEN COUNTRY ENERGY PROJEC	TULSA	OK	Combined Cycle	239.4	266	2/10/2002
GREENCE2	GREEN COUNTRY ENERGY PROJEC	TULSA	OK	Combined Cycle	240.3	267	2/10/2002
GREENCE3	GREEN COUNTRY ENERGY PROJEC	TULSA	OK	Combined Cycle	240.3	267	2/10/2002
ARIESCC3	ARIES	CASS	MO	Combined Cycle	531.9	591	3/1/2002
ARIESGT6	*ARIES*	*CASS*	*MO*	*Combined Cycle*	*36.9*	*41*	*3/1/2002*
RUSSIDP1	RUSSELL INDUSTRIAL PARK	RUSSELL	KS	Combined Cycle	13.5	15	3/1/2002
MCCARTN1	MCCARTNEY GENERATING STATIO	GREENE	MO	Peaking Units	90	100	4/1/2002

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ONETAGS1	ONETA GENERATING STATION	WAGONER	OK	Combined Cycle	513	570	7/15/2002
ONETAGS2	ONETA GENERATING STATION	WAGONER	OK	Combined Cycle	513	570	3/1/2003
THOMFIT1	THOMAS FITZHUGH	FRANKLIN	AR	Peaking Units	153	170	4/1/2003
EMPIREE1	EMPIRE ENERGY CENTER	JASPER	MO	Peaking Units	45	50	5/1/2003
EMPIREE2	EMPIRE ENERGY CENTER	JASPER	MO	Peaking Units	45	50	5/1/2003
PITTSBP1	PITTSBURG POWER PLANT	PITTSBURG	OK	Combined Cycle	330.3	367	6/1/2003
PITTSBP2	PITTSBURG POWER PLANT	PITTSBURG	OK	Combined Cycle	119.7	133	6/1/2003
KIAMICH1	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
KIAMICH2	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
KIAMICH3	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
KIAMICH4	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
REDBUD01	REDBUD	OKLAHOMA	OK	Combined Cycle	1080	1200	6/1/2003
PAOLAGT1	PAOLA	MIAMI	KS	Peaking Units	75.6	84	6/1/2003
HARRISC1	HARRISON COUNTY POWER PROJE	HARRISON	TX	Combined Cycle	468	520	6/1/2003
DOWPALQ1	DOW PLAQUEMINE (AEP)	IBERVILLE	LA	Combined Cycle	810	900	8/15/2003
	New Units in TVA						
ACKERMN1	ACKERMAN	CHOCTAW	MS	Combined Cycle	450	500	1/1/2005
ACKERMN2	ACKERMAN	CHOCTAW	MS	Combined Cycle	180	200	1/1/2005
ASHLAND1	ASHLAND [MAGNEN]	BENTON	MS	Combined Cycle	810	900	6/1/2003
BATESVL1	BATESVILLE GENERATION FACIL	PANOLA	MS	Combined Cycle	450	500	8/15/2000
BATESVL2	BATESVILLE GENERATION FACIL	PANOLA	MS	Combined Cycle	303.3	337	8/15/2000
BOLIVAR1	BOLIVAR	HARDEMAN	TN	Peaking Units	18	20	6/30/2001
CALEDN01	CALEDONIA	LOWNDES	MS	Combined Cycle	240.3	267	6/1/2003
CALEDN02	CALEDONIA	LOWNDES	MS	Combined Cycle	240.3	267	6/1/2003
CALEDN03	CALEDONIA	LOWNDES	MS	Combined Cycle	239.4	266	6/1/2003
CALVECT1	CALVERT CITY PLANT - APC	MARSHALL	KY	Peaking Units	23.4	26	4/6/2000
DECATEC1	DECATUR ENERGY CENTER	MORGAN	AL	Combined Cycle	450	500	6/1/2002
DECATEC2	DECATUR ENERGY CENTER	MORGAN	AL	Combined Cycle	715	794	6/1/2003
GALLATN1	GALLATIN (TVA)	SUMNER	TN	Peaking Units	180	200	6/1/2000
GALLATN2	GALLATIN (TVA)	SUMNER	TN	Peaking Units	90	100	6/1/2000
GLEASN01	GLEASON	WEAKLEY	TN	Peaking Units	180	200	6/1/2000
GLEASN02	GLEASON	WEAKLEY	TN	Peaking Units	180	200	6/1/2000
GLEASN03	GLEASON	WEAKLEY	TN	Peaking Units	99	110	6/1/2000
HAYWOEC1	HAYWOOD ENERGY CENTER	HAYWOOD	TN	Combined Cycle	450	500	6/1/2004
JOHNSNV1	JOHNSONVILLE (TVA)	HUMPHREYS	TN	Peaking Units	180	200	6/1/2000
JOHNSNV2	JOHNSONVILLE (TVA)	HUMPHREYS	TN	Peaking Units	90	100	6/1/2000
LAGONC10	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGONC11	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGONC12	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC1	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC2	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC3	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC4	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC5	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC6	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC7	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC8	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC9	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
MARSHCN1	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN2	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN3	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN4	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN5	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN6	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN7	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
MARSHCN8	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MEMPHRF1	MEMPHIS REFINERY	SHELBY	TN	Combined Cycle	71.1	79	6/1/2003
MIDDLEP1	MIDDLEPOINT LANDFILL	NOT APPLICABLE	TN	Peaking Units	4.68	5.2	4/9/2001
MISSISF1	MISSISSIPPI FUEL CELL PLANT	NOT APPLICABLE	MS	Combined Cycle	12	12	6/1/2003
MORGANE1	MORGAN ENERGY CENTER	MORGAN	AL	Combined Cycle	711	790	5/1/2003
PADUCAH1	PADUCAH			Peaking Units	180	200	1/1/2005
PADUCAH2	PADUCAH			Peaking Units	180	200	1/1/2005
PADUCAH3	PADUCAH			Peaking Units	180	200	1/1/2005
REDHILL1	RED HILLS GENERATION FACILI	CHOCTAW	MS	Coal	440	440	3/15/2002
RELECHO1	RELIANT ENERGY CHOCTAW COUN	CHOCTAW	MS	Combined Cycle	720	800	11/1/2003
SCOOBAP1	SCOOBA PEAKER	KEMPER	MS	Peaking Units	153	170	6/1/2002
SCOOBAP2	SCOOBA PEAKER	KEMPER	MS	Peaking Units	153	170	6/1/2002

Table A-18: Retirements 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
	Retirements in VAP							
POSSUMP1	POSSUM POINT 1	PRINCE WILLIAM	VA	Steam Gas/Oil	74	74	1/1/1948	5/1/2003
POSSUMP2	POSSUM POINT 2	PRINCE WILLIAM	VA	Steam Gas/Oil	69	71	1/1/1951	5/1/2003
POSSUMP3	POSSUM POINT 3	PRINCE WILLIAM	VA	Coal	101	105	1/1/1955	5/1/2003
POSSUMP4	POSSUM POINT 4	PRINCE WILLIAM	VA	Coal	221	221	1/1/1962	5/1/2003
	Retirements in AEP							
SEARSLO3	SEARS LOGISTICS SERVICES	FRANKLIN	OH	Peaking Units	17.05	18.46	1/1/1972	1/8/2000
GLENLYN5	GLEN LYN	GILES	VA	Coal	90	95	1/1/1944	12/31/2004
	Retirements in Duke							
BUCKNC07	BUCK (NC)	ROWAN	NC	Peaking Units	31	31	1/1/1970	12/1/2004
BUCKNC08	BUCK (NC)	ROWAN	NC	Peaking Units	31	31	1/1/1970	12/1/2004
BUCKNC09	BUCK (NC)	ROWAN	NC	Peaking Units	31	31	1/1/1970	12/1/2004
LEESC05	LEE (SC)	ANDERSON	SC	Peaking Units	30	30	1/1/1968	12/1/2004
LEESC06	LEE (SC)	ANDERSON	SC	Peaking Units	30	30	1/1/1968	12/1/2004
LINCOLN1	LINCOLN COMBUSTION	LINCOLN	NC	Peaking Units	75	99	1/1/1995	12/1/2004
RIVERB10	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
RIVERB11	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
RIVERBE8	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
RIVERBE9	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
BUZZARD6	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
BUZZARD7	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
BUZZARD8	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
BUZZARD9	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
	Retirements in PJM							
BURLNGT7	BURLINGTON (PSEG)	BURLINGTON	NJ	Steam Gas/Oil	180	185	1/1/1955	3/1/2000
DELWREC1	DELAWARE CITY	NEW CASTLE	DE	Coal	28.5	28.5	1/1/1956	4/30/2000
DELWREC2	DELAWARE CITY	NEW CASTLE	DE	Coal	28.5	28.5	1/1/1956	4/30/2000
LINDEN05	LINDEN (PSEG)	UNION	NJ	Peaking Units	46	60	1/1/1970	6/1/2000
LINDEN06	LINDEN (PSEG)	UNION	NJ	Peaking Units	46	60	1/1/1970	6/1/2000
RINGGOL1	RINGGOLD	JEFFERSON	PA	Peaking Units	15	15	1/1/1990	9/1/2000
WILMING1	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001	5/31/2002
WILMING2	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001	5/31/2002
WILMING3	WILMINGTON	NEW CASTLE	DE	Peaking Units	112	112	7/31/2001	5/31/2002
LINDEN01	LINDEN (PSEG)	UNION	NJ	Steam Gas/Oil	168	180	1/1/1957	5/1/2003
LINDEN02	LINDEN (PSEG)	UNION	NJ	Steam Gas/Oil	247	250	1/1/1957	5/1/2003
AESBVPA3	AES BV PARTNERS BEAVER VALL	BEAVER	PA	Coal	100.26	107	1/1/1987	5/31/2003
BETHLEC1	BETHLEHEM (CIV)	NORTHAMPTON	PA	Peaking Units	333	333	1/1/2003	6/1/2003
SEWARD04	SEWARD (RELIANT)	INDIANA	PA	Coal	60	62	1/1/1950	9/30/2003
SEWARD05	SEWARD (RELIANT)	INDIANA	PA	Coal	136	137	1/1/1957	9/30/2003
RIEGEL01	RIEGEL	HUNTERDON	NJ	Peaking Units	21	21	1/1/1970	7/1/2004
HUNLOCK3	HUNLOCK CREEK	LUZERNE	PA	Coal	48	48	1/1/1959	12/1/2004
DICKRSN4	DICKERSON	MONTGOMERY	MD	Peaking Units	13	13	1/1/1967	12/31/2004
DICKRSN5	DICKERSON	MONTGOMERY	MD	Peaking Units	139	167	1/1/1992	12/31/2004
DICKRSN6	DICKERSON	MONTGOMERY	MD	Peaking Units	139	167	1/1/1993	12/31/2004
ELRAMA01	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	97	100	1/1/1952	12/31/2004
ELRAMA02	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	97	100	1/1/1953	12/31/2004
ELRAMA03	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	109	112	1/1/1954	12/31/2004
ELRAMA04	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	171	175	1/1/1960	12/31/2004
	Retirements in MISO (ECAR)							
BLACKDO1	BLACK DOG	DAKOTA	MN	Coal	75	64	1/1/1952	1/1/2000
MORRIGT1	MORRIS COGENERATION PLANT	GRUNDY	IL	Peaking Units	78	78	1/1/1990	6/1/2000
MORRIGT2	MORRIS COGENERATION PLANT	GRUNDY	IL	Peaking Units	78	78	1/1/1990	6/1/2000
MORRIGT3	MORRIS COGENERATION PLANT	GRUNDY	IL	Peaking Units	78	78	1/1/1990	6/1/2000
WYANDOT4	WYANDOTTE (WYAN)	WAYNE	MI	Steam Gas/Oil	10.5	11.5	1/1/1948	10/1/2000
WYANDOT6	WYANDOTTE (WYAN)	WAYNE	MI	Coal	7.5	7.5	1/1/1969	10/1/2000

Table A-18: Retirements 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
GRANDTO3	GRAND TOWER	JACKSON	IL	Coal	82	82	1/1/1951	6/29/2001
AESMEDV2	AESMEDINA VALLEY	TAZEWELL	IL	Peaking Units	28.35	31.5	6/1/2001	7/15/2001
GRANDTO4	GRAND TOWER	JACKSON	IL	Coal	104	104	1/1/1958	12/1/2001
MIAMIWA1	MIAMI WABASH	WABASH	IN	Peaking Units	16	17	1/1/1968	12/31/2001
MIAMIWA2	MIAMI WABASH	WABASH	IN	Peaking Units	16	17	1/1/1968	12/31/2001
MIAMIWA3	MIAMI WABASH	WABASH	IN	Peaking Units	15	17	1/1/1968	12/31/2001
MIAMIWA4	MIAMI WABASH	WABASH	IN	Peaking Units	15	17	1/1/1968	12/31/2001
MIAMIWA5	MIAMI WABASH	WABASH	IN	Peaking Units	15	18	1/1/1969	12/31/2001
MIAMIWA6	MIAMI WABASH	WABASH	IN	Peaking Units	16	18	1/1/1969	12/31/2001
MITCHE11	MITCHELL (NIPS)	LAKE	IN	Coal	110	110	1/1/1970	12/31/2001
MITCHEL4	MITCHELL (NIPS)	LAKE	IN	Steam Gas/Oil	125	125	1/1/1956	12/31/2001
MITCHEL5	MITCHELL (NIPS)	LAKE	IN	Coal	125	125	1/1/1959	12/31/2001
MITCHEL6	MITCHELL (NIPS)	LAKE	IN	Coal	125	125	1/1/1959	12/31/2001
MITCHEL9	MITCHELL (NIPS)	LAKE	IN	Peaking Units	17	17	1/1/1966	12/31/2001
WABASH07	WABASH RIVER	VIGO	IN	Peaking Units	8	8	1/1/1967	12/31/2001
VERMIGT1	VERMILION	VERMILION	IL	Peaking Units	10	12	1/1/1967	1/1/2002
ZEELAND1	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001	6/1/2002
ZEELAND2	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001	6/1/2002
BLACKDO2	BLACK DOG	DAKOTA	MN	Coal	101	88	1/1/1954	6/15/2002
LAKERDM3	LAKE ROAD (MO)	BUCHANAN	MO	Steam Gas/Oil	11	8	1/1/1962	12/1/2002
BEMORROA	B.E. MORROW	KALAMAZOO	MI	Peaking Units	14	17	1/1/1968	12/31/2002
BEMORROB	B.E. MORROW	KALAMAZOO	MI	Peaking Units	14	17	1/1/1969	12/31/2002
CAMPBELA	CAMPBELL (CEC)	OTTAWA	MI	Peaking Units	13	17	1/1/1968	12/31/2002
GAYLORD1	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD2	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD3	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD4	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD5	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1968	12/31/2002
STRAITS1	STRAITS	EMMET	MI	Peaking Units	16	21	1/1/1969	12/31/2002
THETFOR1	THETFORD	GENESEE	MI	Peaking Units	30	37	1/1/1970	12/31/2002
THETFOR2	THETFORD	GENESEE	MI	Peaking Units	29	37	1/1/1970	12/31/2002
THETFOR3	THETFORD	GENESEE	MI	Peaking Units	30	37	1/1/1970	12/31/2002
THETFOR4	THETFORD	GENESEE	MI	Peaking Units	30	37	1/1/1970	12/31/2002
THETFOR5	THETFORD	GENESEE	MI	Peaking Units	15	17	1/1/1971	12/31/2002
THETFOR6	THETFORD	GENESEE	MI	Peaking Units	15	17	1/1/1971	12/31/2002
THETFOR7	THETFORD	GENESEE	MI	Peaking Units	14	17	1/1/1971	12/31/2002
THETFOR8	THETFORD	GENESEE	MI	Peaking Units	15	18	1/1/1971	12/31/2002
THETFOR9	THETFORD	GENESEE	MI	Peaking Units	14	17	1/1/1971	12/31/2002
WEADOCKA	WEADOCK	BAY	MI	Peaking Units	13	17	1/1/1968	12/31/2002
WHITINGA	WHITING (CEC)	MONROE	MI	Peaking Units	13	17	1/1/1968	12/31/2002
EDWARDS6	EDWARDSPORT	KNOX	IN	Coal	40	40	1/1/1944	12/31/2003
EDWARDS7	EDWARDSPORT	KNOX	IN	Coal	45	45	1/1/1949	12/31/2003
EDWARDS8	EDWARDSPORT	KNOX	IN	Coal	75	75	1/1/1951	12/31/2003
NOBLESV1	NOBLESVILLE	HAMILTON	IN	Coal	45	45	1/1/1950	5/31/2004
NOBLESV2	NOBLESVILLE	HAMILTON	IN	Coal	45	45	1/1/1950	5/31/2004
CONNEVL1	CONNERSVILLE	FAYETTE	IN	Peaking Units	42	49	1/1/1972	12/31/2004
CONNEVL2	CONNERSVILLE	FAYETTE	IN	Peaking Units	43	49	1/1/1972	12/31/2004
SALTVAL3	SALT VALLEY GENERATING STAT	LANCASTER	NE	Peaking Units	90	90	6/1/2003	5/1/2004
PORTWAS1	PORT WASHINGTON	OZAUKEE	WI	Coal (Scrubbed)	80	80	1/1/1935	1/1/2005
PORTWAS2	PORT WASHINGTON	OZAUKEE	WI	Coal	83	83	1/1/1943	1/1/2005
PORTWAS3	PORT WASHINGTON	OZAUKEE	WI	Coal	83	84	1/1/1948	1/1/2005
PORTWAS4	PORT WASHINGTON	OZAUKEE	WI	Coal (Scrubbed)	80	80	1/1/1949	1/1/2005
HOOTLAK1	HOOT LAKE	OTTER TAIL	MN	Coal	7.55	7.55	1/1/1948	5/1/2005
	Retirements in SETRANS (Entergy)							
HMOSES01	HAMILTON MOSES	ST. FRANCIS	AR	Steam Gas/Oil	72	72	1/1/1951	12/1/2001
HMOSES02	HAMILTON MOSES	ST. FRANCIS	AR	Steam Gas/Oil	72	72	1/1/1951	12/1/2001
DELTA01	DELTA (MS)	BOLIVAR	MS	Steam Gas/Oil	99	99	1/1/1953	12/1/2003
LKCATHE3	LAKE CATHERINE	HOT SPRING	AR	Steam Gas/Oil	100	100	1/1/1953	12/1/2003
CLYNCH01	CECIL LYNCH	PULASKI	AR	Steam Gas/Oil	110	110	1/1/1954	12/1/2004

Table A-18: Retirements 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
HCOUCH02	HARVEY COUCH	LAFAYETTE	AR	Steam Gas/Oil	125	125	1/1/1954	12/1/2004
NINEMIL3	NINEMILE POINT	JEFFERSON	LA	Steam Gas/Oil	125	125	1/1/1955	12/1/2005
MABELVA3	MABELVALE	PULASKI	AR	Peaking Units	16	16	1/1/1970	12/31/2005
	Retirements in SETRANS (SOCO)							
KENNED10	J.D. KENNEDY	DUVAL	FL	Steam Gas/Oil	129	129	1/1/1961	4/1/2000
STHSIDE4	SOUTHSIDE	DUVAL	FL	Steam Gas/Oil	67	67	1/1/1958	10/26/2001
STHSIDE5	SOUTHSIDE	DUVAL	FL	Steam Gas/Oil	142	142	1/1/1964	10/26/2001
SWEATT0A	SWEATT	LAUDERDALE	MS	Peaking Units	35	43.5	1/1/1971	1/1/2002
ARKWRI03	ARKWRIGHT	BIBB	GA	Coal	44.3	44.3	1/1/1948	1/1/2003
ARKWRI04	ARKWRIGHT	BIBB	GA	Coal	43.2	43.2	1/1/1948	1/1/2003
ARKWRI5A	ARKWRIGHT	BIBB	GA	Peaking Units	15.47	18.02	1/1/1969	1/1/2003
ARKWRI5B	ARKWRIGHT	BIBB	GA	Peaking Units	15.47	18.02	1/1/1969	1/1/2003
ARKWRST1	ARKWRIGHT	BIBB	GA	Coal	41.9	41.9	1/1/1941	1/1/2003
ARKWRST2	ARKWRIGHT	BIBB	GA	Coal	40.9	40.9	1/1/1942	1/1/2003
ATKINS03	ATKINSON	COBB	GA	Steam Gas/Oil	62.8	62.8	1/1/1945	1/1/2003
ATKINS04	ATKINSON	COBB	GA	Steam Gas/Oil	59.9	59.9	1/1/1948	1/1/2003
ATKINS5A	ATKINSON	COBB	GA	Peaking Units	34.55	42.56	1/1/1970	1/1/2003
ATKINS5B	ATKINSON	COBB	GA	Peaking Units	34.55	42.56	1/1/1970	1/1/2003
ATKINST2	ATKINSON	COBB	GA	Steam Gas/Oil	57.2	57.2	1/1/1941	1/1/2003
CRIST01	CRIST	ESCAMBIA	FL	Steam Gas/Oil	25.6	25.6	1/1/1945	1/1/2003
EATON02	EATON	FORREST	MS	Steam Gas/Oil	25	25	1/1/1947	1/1/2003
MITCHLS1	MITCHELL (GPCO)	DOUGHERTY	GA	Coal	21.2	21.2	1/1/1948	1/1/2003
MITCHLS2	MITCHELL (GPCO)	DOUGHERTY	GA	Coal	20.1	20.1	1/1/1949	1/1/2003
EATON03	EATON	FORREST	MS	Steam Gas/Oil	24.4	24.4	1/1/1949	1/1/2005
RIVERSS4	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	19.3	19.3	1/1/1926	1/1/2005
RIVERSS5	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	9	9	1/1/1936	1/1/2005
RIVERSS6	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	16.3	16.3	1/1/1949	1/1/2005
RIVERSS7	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	21	21	1/1/1954	1/1/2005
RIVERSS8	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	40.4	40.4	1/1/1956	1/1/2005
	Retirements in SPP							
LOVINGT1	NORTH LOVINGTON	LEA	NM	Steam Gas/Oil	16	16	1/1/1962	1/1/2000
LOVINGT2	NORTH LOVINGTON	LEA	NM	Steam Gas/Oil	33	33	1/1/1966	1/1/2000
MUSTSTN2	MUSTANG STATION	YOAKUM	TX	Peaking Units	261	290	6/1/1999	4/20/2000
HAWTHOR6	HAWTHORN	JACKSON	MO	Peaking Units	142	162	1/1/1997	7/15/2000
STATELI2	STATELINE (MO)	JASPER	MO	Peaking Units	152	152	1/1/1997	6/20/2001
NTHESTN1	NORTHEASTERN	ROGERS	OK	Steam Gas/Oil	157	157	1/1/1961	7/14/2001
TUCULUMP	TUCUMCARI	QUAY	NM	Peaking Units	13	13	1/1/1975	8/1/2001
RUSSLUMP	RUSSELL	RUSSELL	KS	Peaking Units	26.6	26.6	1/1/1956	9/2/2001
NATCLUMP	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	8.6	8.6	1/1/1972	12/1/2001
SOUTHWE2	SOUTHWESTERN	CADDO	OK	Steam Gas/Oil	80	80	1/1/1954	12/1/2001
ARIESGT1	ARIES	CASS	MO	Peaking Units	180	200	7/16/2001	3/1/2002
ARIESGT2	ARIES	CASS	MO	Peaking Units	154.8	172	7/16/2001	3/1/2002
NATCHI10	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	24	24	1/1/1972	4/1/2002
NATCHIT8	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	7	7	1/1/1962	4/1/2002
NATCHIT9	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	11	11	1/1/1966	4/1/2002
NICHOTX2	NICHOLS STATION	POTTER	TX	Steam Gas/Oil	106	106	1/1/1962	8/1/2002
KNOXLEE2	KNOX LEE	GREGG	TX	Steam Gas/Oil	25	25	1/1/1950	12/1/2002
KNOXLEE3	KNOX LEE	GREGG	TX	Steam Gas/Oil	25	25	1/1/1952	12/1/2002
MCPH2GT1	MCPHERSON 2	MCPHERSON	KS	Peaking Units	52.9	60	1/1/1973	12/1/2002
MCPH2GT2	MCPHERSON 2	MCPHERSON	KS	Peaking Units	50.9	60	1/1/1976	12/1/2002
MCPH2GT3	MCPHERSON 2	MCPHERSON	KS	Peaking Units	52	60	1/1/1979	12/1/2002
PLANTX01	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	48	48	1/1/1952	12/1/2002
FITZHUGH	THOMAS FITZHUGH	FRANKLIN	AR	Steam Gas/Oil	59	59	1/1/1963	5/31/2003
LONESTAR	LONE STAR	MORRIS	TX	Steam Gas/Oil	50	50	1/1/1954	12/1/2003
PLANTX02	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	102	102	1/1/1953	1/1/2004
PLANTX04	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	191	191	1/1/1964	1/1/2004
LIEBER03	LIEBERMAN	CADDO	LA	Steam Gas/Oil	112	112	1/1/1957	12/1/2004
LIEBER04	LIEBERMAN	CADDO	LA	Steam Gas/Oil	110	110	1/1/1959	12/1/2004
NTHESTN2	NORTHEASTERN	ROGERS	OK	Steam Gas/Oil	480	480	1/1/1970	12/1/2004

Table A-18: Retirements 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
WELEETK4	WELEETKA	OKFUSKEE	OK	Peaking Units	55	55	1/1/1975	12/1/2004
WILKES02	WILKES	MARION	TX	Steam Gas/Oil	357	357	1/1/1970	12/1/2004
PLANTX03	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	103	103	1/1/1955	1/1/2005
CUNGHAM2	CUNNINGHAM	LEA	NM	Steam Gas/Oil	196	196	1/1/1965	8/1/2005
KNOXLEE4	KNOX LEE	GREGG	TX	Steam Gas/Oil	77	77	1/1/1956	12/1/2005
LIEBER01	LIEBERMAN	CADDO	LA	Steam Gas/Oil	25	25	1/1/1947	12/1/2005
MCPHER21	MCPHERSON 2	MCPHERSON	KS	Steam Gas/Oil	26.6	26.6	1/1/1963	12/1/2005
WELEETK5	WELEETKA	OKFUSKEE	OK	Peaking Units	54	54	1/1/1976	12/1/2005
WELEETK6	WELEETKA	OKFUSKEE	OK	Peaking Units	54	54	1/1/1976	12/1/2005
WILKES03	WILKES	MARION	TX	Steam Gas/Oil	348	348	1/1/1971	12/1/2005
	Retirements in TVA							
ELIZABE1	ELIZABETHTON PLANT	CARTER	TN	Coal	24	24	1/1/1988	4/1/2000
DECATEC1	DECATUR ENERGY CENTER	MORGAN	AL	Combined Cycle	450	500	6/1/2002	6/1/2003
	Retirements in GFL							
TSMITHS4	TOM G SMITH	PALM BEACH	FL	Steam Gas/Oil	32	33	1/1/1971	4/1/2000
CANEIPP5	CANE ISLAND POWER PARK	OSCEOLA	FL	Peaking Units	153	170	6/6/2001	8/15/2001
FTMYST01	FORT MYERS	LEE	FL	Steam Gas/Oil	141	142	1/1/1958	9/1/2001
FTMYST02	FORT MYERS	LEE	FL	Steam Gas/Oil	391	394	1/1/1969	9/1/2001
MCINTSL4	MCINTOSH (LALW)	POLK	FL	Peaking Units	180	200	4/16/2001	9/15/2001
MCINTSL5	MCINTOSH (LALW)	POLK	FL	Peaking Units	44.1	49	4/16/2001	9/15/2001
FORTMY10	FORT MYERS	LEE	FL	Peaking Units	150	170	11/1/2000	10/1/2001
FORTMY11	FORT MYERS	LEE	FL	Peaking Units	300	340	12/1/2000	10/1/2001
FORTMY12	FORT MYERS	LEE	FL	Peaking Units	150	170	2/1/2001	10/1/2001
FORTMY13	FORT MYERS	LEE	FL	Peaking Units	150	170	3/1/2001	10/1/2001
FORTMYR9	FORT MYERS	LEE	FL	Peaking Units	150	170	4/1/2001	10/1/2001
SANFORD4	SANFORD (FPL)	VOLUSIA	FL	Steam Gas/Oil	384	390	1/1/1972	12/31/2001
SANFORD5	SANFORD (FPL)	VOLUSIA	FL	Steam Gas/Oil	390	394	1/1/1974	12/31/2001
HOOKERS5	HOOKERS POINT	HILLSBOROUGH	FL	Steam Gas/Oil	67	67	1/1/1955	1/1/2003
LARSEN07	LARSEN MEMORIAL	POLK	FL	Steam Gas/Oil	49.2	51.2	1/1/1966	3/1/2003
GANNON05	GANNON	HILLSBOROUGH	FL	Coal	227	232	1/1/1965	1/1/2004
GANNON06	GANNON	HILLSBOROUGH	FL	Coal	362	372	1/1/1967	1/1/2004
AVNPARK1	AVON PARK	HIGHLANDS	FL	Peaking Units	25	30	1/1/1968	12/1/2004
AVNPARK2	AVON PARK	HIGHLANDS	FL	Peaking Units	25	30	1/1/1968	12/1/2004
BAYBORO1	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
BAYBORO2	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
BAYBORO3	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
BAYBORO4	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
TURNER01	G.E. TURNER	VOLUSIA	FL	Peaking Units	13	16	1/1/1970	12/1/2004
TURNER02	G.E. TURNER	VOLUSIA	FL	Peaking Units	13	16	1/1/1970	12/1/2004
GANNON01	GANNON	HILLSBOROUGH	FL	Coal	119	119	1/1/1957	1/1/2005
GANNON02	GANNON	HILLSBOROUGH	FL	Coal	98	98	1/1/1958	1/1/2005
GANNON03	GANNON	HILLSBOROUGH	FL	Coal	145	145	1/1/1960	1/1/2005
GANNON04	GANNON	HILLSBOROUGH	FL	Coal	159	169	1/1/1963	1/1/2005
MARTINF5	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001	6/1/2005
MARTINF6	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001	6/1/2005
	Retirements in ISO-NE							
SOMERSJ1	SOMERSET	BRISTOL	MA	Peaking Units	19.7	22	1/1/1970	5/1/2000
REFERBUS	REFERENCE BUS			Other	1	1	1/1/1999	12/31/2000
WSTSPRF1	WEST SPRINGFIELD	HAMPDEN	MA	Steam Gas/Oil	51	51.5	1/1/1949	9/1/2001
WSTSPRF2	WEST SPRINGFIELD	HAMPDEN	MA	Steam Gas/Oil	51	51.5	1/1/1952	9/1/2001
MYSTIC04	MYSTIC	MIDDLESEX	MA	Steam Gas/Oil	135	135	1/1/1957	3/1/2002
MYSTIC05	MYSTIC	MIDDLESEX	MA	Steam Gas/Oil	115	115	1/1/1959	3/1/2002
MYSTIC06	MYSTIC	MIDDLESEX	MA	Steam Gas/Oil	138	138.28	1/1/1961	3/1/2002
KENDALL1	KENDALL SQUARE	MIDDLESEX	MA	Steam Gas/Oil	18	17	1/1/1949	6/1/2002
KENDALL2	KENDALL SQUARE	MIDDLESEX	MA	Steam Gas/Oil	19	21	1/1/1951	6/1/2002
KENDALL3	KENDALL SQUARE	MIDDLESEX	MA	Steam Gas/Oil	26	26	1/1/1958	6/1/2002
CANALSN2	CANAL (SENENG)	BARNSTABLE	MA	Steam Gas/Oil	551.38	586	1/1/1976	12/31/2002

Table A-18: Retirements 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
	Retirements in NYC							
WATERS16	WATERSIDE (CONED)	NEW YORK	NY	Steam Gas/Oil	69	69	1/1/1992	12/31/2001
WATERSD8	WATERSIDE (CONED)	NEW YORK	NY	Steam Gas/Oil	47	47	1/1/1949	12/31/2001
WATERSD9	WATERSIDE (CONED)	NEW YORK	NY	Steam Gas/Oil	47	47	1/1/1949	12/31/2001
ASTOGSO2	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	171	175	1/1/1954	12/31/2003
ASTOGSO3	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	353	361	1/1/1958	12/31/2003
ASTOGSO4	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	361	369	1/1/1961	12/31/2004
ASTOGSO5	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	361	369	1/1/1962	12/31/2004
	Retirements in NYO							
ALBANYS1	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	96.7	100.7	1/1/1952	12/31/2002
ALBANYS2	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	96.5	100.75	1/1/1952	12/31/2002
ALBANYS3	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	97.25	100	1/1/1953	12/31/2002
ALBANYS4	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	98.25	100	1/1/1954	12/31/2002
	Retirements in SCE&G							
URQUAHA1	URQUHART - SCEG	AIKEN	SC	Coal	245	265	1/1/1953	5/31/2002
URQUAHA1	URQUHART - SCEG	AIKEN	SC	Coal	245	265	1/1/1953	5/31/2002

Table A-19: Basis Differentials and Regional Natural Gas Prices

		Plant Gate Prices New England		Eastern NY		NYC		Eastern PA/NJ		Western NY/PA		DC, DE, MD		WV, KY		NC,VA		SC, GA		Southeast		Florida		Midcontinent		Midwest		Upper Midwest		East Texas	
Month	Henry Hub	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price	Basis & Plant Gate Deliv. Cost	Dlvrd Price
Jan 2005	4.11	1.27	5.38	0.80	4.91	1.64	5.75	0.97	5.08	0.60	4.72	0.93	5.04	0.27	4.38	0.76	4.87	0.68	4.80	0.23	4.34	0.20	4.31	(0.04)	4.07	0.08	4.19	(0.19)	3.92	(0.11)	4.00
Feb 2005	4.10	1.28	5.38	0.81	4.91	1.64	5.75	0.98	5.08	0.61	4.72	0.94	5.04	0.27	4.37	0.77	4.87	0.69	4.80	0.24	4.34	0.21	4.31	(0.04)	4.07	0.09	4.19	(0.18)	3.92	(0.10)	4.00
Mar 2005	3.94	0.61	4.55	0.51	4.45	0.51	4.45	0.30	4.24	0.31	4.25	0.41	4.34	0.29	4.23	0.37	4.30	0.30	4.24	0.20	4.14	0.19	4.13	0.01	3.95	0.12	4.06	(0.16)	3.78	0.02	3.96
Apr 2005	3.93	0.62	4.55	0.52	4.45	0.52	4.45	0.31	4.24	0.32	4.25	0.41	4.34	0.29	4.22	0.37	4.30	0.31	4.24	0.21	4.14	0.19	4.13	0.02	3.95	0.13	4.06	(0.15)	3.78	0.03	3.96
May 2005	3.92	0.62	4.55	0.53	4.45	0.53	4.45	0.32	4.24	0.32	4.25	0.42	4.34	0.29	4.21	0.38	4.30	0.31	4.24	0.22	4.14	0.20	4.13	0.03	3.95	0.14	4.06	(0.14)	3.78	0.04	3.96
Jun 2005	3.88	0.51	4.39	0.39	4.26	0.42	4.29	0.70	4.58	0.23	4.11	0.33	4.21	0.24	4.12	0.31	4.18	0.24	4.12	0.18	4.06	0.39	4.27	0.02	3.90	0.08	3.96	(0.27)	3.61	0.05	3.93
Jul 2005	3.88	0.51	4.39	0.39	4.26	0.42	4.29	0.70	4.58	0.23	4.11	0.33	4.21	0.24	4.12	0.31	4.18	0.24	4.12	0.18	4.06	0.39	4.27	0.02	3.90	0.08	3.96	(0.27)	3.61	0.05	3.93
Aug 2005	3.87	0.52	4.39	0.39	4.26	0.42	4.29	0.71	4.58	0.24	4.11	0.34	4.21	0.24	4.11	0.31	4.18	0.25	4.12	0.19	4.06	0.40	4.27	0.02	3.90	0.09	3.96	(0.26)	3.61	0.06	3.93
Sep 2005	3.90	0.65	4.55	0.55	4.45	0.55	4.45	0.34	4.24	0.35	4.25	0.44	4.34	0.29	4.19	0.41	4.30	0.34	4.24	0.24	4.14	0.23	4.13	0.05	3.95	0.16	4.06	(0.12)	3.78	0.06	3.96
Oct 2005	3.89	0.66	4.55	0.56	4.45	0.56	4.45	0.35	4.24	0.36	4.25	0.45	4.34	0.29	4.18	0.41	4.30	0.34	4.24	0.25	4.14	0.23	4.13	0.06	3.95	0.17	4.06	(0.11)	3.78	0.07	3.96
Nov 2005	3.88	0.59	4.48	0.50	4.38	0.58	4.46	0.41	4.30	0.47	4.35	0.44	4.32	0.29	4.17	0.40	4.29	0.33	4.22	0.29	4.17	0.22	4.10	(0.10)	3.78	(0.00)	3.88	(0.19)	3.70	(0.06)	3.82
Dec 2005	4.03	1.31	5.34	0.90	4.93	1.45	5.48	0.76	4.79	0.40	4.43	0.93	4.95	0.26	4.29	0.76	4.79	0.68	4.71	0.22	4.25	0.21	4.24	0.21	4.23	0.31	4.34	(0.11)	3.92	0.13	4.16
Jan 2007	3.92	1.25	5.17	0.79	4.71	1.60	5.52	0.95	4.87	0.60	4.51	0.92	4.83	0.27	4.18	0.75	4.67	0.67	4.59	0.23	4.15	0.30	4.22	(0.04)	3.88	0.11	4.02	(0.19)	3.73	(0.10)	3.81
Feb 2007	3.91	1.26	5.17	0.80	4.71	1.61	5.52	0.96	4.87	0.60	4.51	0.92	4.83	0.27	4.18	0.76	4.67	0.68	4.59	0.24	4.15	0.31	4.22	(0.03)	3.88	0.11	4.02	(0.18)	3.73	(0.10)	3.81
Mar 2007	3.75	0.61	4.37	0.51	4.27	0.52	4.28	0.31	4.07	0.31	4.07	0.41	4.16	0.29	4.04	0.37	4.12	0.30	4.06	0.20	3.96	0.28	4.04	0.01	3.76	0.14	3.89	(0.16)	3.59	0.02	3.78
Apr 2007	3.75	0.62	4.37	0.52	4.27	0.53	4.28	0.32	4.07	0.32	4.07	0.42	4.16	0.29	4.04	0.38	4.12	0.31	4.06	0.21	3.96	0.29	4.04	0.02	3.76	0.15	3.89	(0.15)	3.59	0.03	3.78
May 2007	3.74	0.63	4.37	0.53	4.27	0.54	4.28	0.33	4.07	0.33	4.07	0.43	4.16	0.29	4.03	0.39	4.12	0.32	4.06	0.22	3.96	0.30	4.04	0.03	3.76	0.16	3.89	(0.15)	3.59	0.04	3.78
Jun 2007	3.70	0.52	4.22	0.39	4.09	0.43	4.13	0.69	4.39	0.24	3.93	0.34	4.04	0.24	3.94	0.31	4.01	0.25	3.94	0.18	3.88	0.48	4.18	0.02	3.71	0.10	3.80	(0.26)	3.43	0.05	3.75
Jul 2007	3.70	0.52	4.22	0.39	4.09	0.43	4.13	0.69	4.39	0.24	3.93	0.34	4.04	0.24	3.94	0.31	4.01	0.25	3.94	0.18	3.88	0.48	4.18	0.02	3.71	0.10	3.80	(0.26)	3.43	0.05	3.75
Aug 2007	3.69	0.53	4.22	0.40	4.09	0.44	4.13	0.70	4.39	0.24	3.93	0.35	4.04	0.24	3.93	0.32	4.01	0.25	3.94	0.19	3.88	0.49	4.18	0.02	3.71	0.11	3.80	(0.26)	3.43	0.06	3.75
Sep 2007	3.72	0.65	4.37	0.55	4.27	0.56	4.28	0.35	4.07	0.35	4.07	0.45	4.16	0.29	4.00	0.41	4.12	0.34	4.06	0.24	3.96	0.32	4.04	0.05	3.76	0.18	3.89	(0.12)	3.59	0.06	3.78
Oct 2007	3.71	0.66	4.37	0.56	4.27	0.57	4.28	0.36	4.07	0.36	4.07	0.46	4.16	0.29	4.00	0.42	4.12	0.35	4.06	0.25	3.96	0.33	4.04	0.06	3.76	0.19	3.89	(0.12)	3.59	0.07	3.78
Nov 2007	3.70	0.60	4.30	0.50	4.20	0.58	4.29	0.42	4.12	0.46	4.16	0.44	4.14	0.29	3.99	0.40	4.11	0.34	4.04	0.28	3.99	0.31	4.02	(0.10)	3.61	0.02	3.72	(0.19)	3.51	(0.06)	3.64
Dec 2007	3.84	1.29	5.13	0.89	4.73	1.43	5.27	0.75	4.59	0.40	4.24	0.91	4.75	0.26	4.10	0.75	4.59	0.67	4.51	0.22	4.06	0.31	4.15	0.20	4.04	0.32	4.16	(0.12)	3.73	0.13	3.97
Jan 2010	3.83	1.28	5.11	0.83	4.65	1.63	5.46	0.99	4.82	0.63	4.46	0.95	4.78	0.26	4.09	0.79	4.62	0.71	4.54	0.27	4.10	0.34	4.17	(0.00)	3.83	0.15	3.97	(0.15)	3.68	(0.06)	3.76
Feb 2010	3.83	1.28	5.11	0.83	4.65	1.63	5.46	0.99	4.82	0.63	4.46	0.95	4.78	0.26	4.09	0.79	4.62	0.71	4.54	0.27	4.10	0.34	4.17	(0.00)	3.83	0.15	3.97	(0.15)	3.68	(0.06)	3.76
Mar 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.34	4.02	0.44	4.12	0.29	3.97	0.39	4.08	0.33	4.01	0.23	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.05	3.73
Apr 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.34	4.02	0.43	4.12	0.29	3.97	0.39	4.08	0.33	4.01	0.23	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.05	3.73
May 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.33	4.02	0.43	4.12	0.29	3.97	0.39	4.08	0.33	4.01	0.22	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.04	3.73
Jun 2010	3.65	0.52	4.17	0.39	4.04	0.43	4.08	0.69	4.34	0.24	3.89	0.34	3.99	0.24	3.89	0.31	3.96	0.25	3.90	0.18	3.83	0.48	4.13	0.02	3.67	0.10	3.75	(0.26)	3.39	0.05	3.70
Jul 2010	3.65	0.52	4.17	0.39	4.04	0.43	4.08	0.69	4.34	0.24	3.89	0.34	3.99	0.24	3.89	0.31	3.96	0.25	3.90	0.18	3.83	0.48	4.13	0.02	3.67	0.10	3.75	(0.26)	3.39	0.05	3.70
Aug 2010	3.65	0.52	4.17	0.39	4.04	0.43	4.08	0.69	4.34	0.24	3.89	0.34	3.99	0.24	3.89	0.31	3.96	0.25	3.90	0.18	3.83	0.48	4.13	0.02	3.67	0.10	3.75	(0.26)	3.39	0.05	3.70
Sep 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.33	4.02	0.43	4.12	0.29	3.97	0.39	4.08	0.32	4.01	0.22	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.04	3.73
Oct 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.33	4.02	0.43	4.12	0.29	3.97	0.39	4.08	0.32	4.01	0.22	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.04	3.73
Nov 2010	3.69	0.57	4.26	0.47	4.16	0.56	4.24	0.39	4.07	0.43	4.11	0.41	4.10	0.29	3.97	0.37	4.06	0.31	3.99	0.25	3.94	0.28	3.97	(0.12)	3.56	(0.01)	3.68	(0.22)	3.47	(0.09)	3.60
Dec 2010	3.83	1.24	5.08	0.85	4.68	1.38	5.21	0.71	4.54	0.36	4.19	0.87	4.70	0.26	4.10	0.70	4.53	0.63	4.46	0.18	4.01	0.27	4.10	0.15	3.99	0.28	4.11	(0.16)	3.68	0.08	3.92
Jan 2014	3.84	1.28	5.12	0.82	4.66	1.63	5.47	0.99	4.83	0.63	4.47	0.95	4.79	0.26	4.10	0.79	4.62	0.71	4.55	0.27	4.10	0.34	4.18	(0.00)	3.83	0.14	3.98	(0.15)	3.69	(0.07)	3.77
Feb 2014	3.84	1.28	5.12	0.82	4.66	1.63	5.47	0.99	4.83	0.63	4.47	0.95	4.79	0.26	4.10	0.79	4.62	0.71	4.55	0.27	4.10	0.34	4.18	(0.00)	3.83	0.14	3.98	(0.15)	3.69	(0.07)	3.77
Mar 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98	0.39	4.08	0.32	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
Apr 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98	0.39	4.08	0.32	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
May 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98	0.39	4.08	0.32	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
Jun 2014	3.66	0.52	4.18	0.39	4.05	0.43	4.09	0.69	4.35	0.24	3.89	0.34	4.00	0.24	3.90	0.31	3.97	0.25	3.91	0.18	3.84	0.48	4.13	0.02	3.67	0.10	3.76	(0.26)	3.39	0.05	3.71
Jul 2014	3.66	0.52	4.18	0.39	4.05	0.43	4.09	0.69	4.35	0.24	3.89	0.34	4.00	0.24	3.90	0.31	3.97	0.25	3.91	0.18	3.84	0.48	4.13	0.02	3.67	0.10	3.76	(0.26)	3.39	0.05	3.71
Aug 2014	3.66	0.52	4.18	0.39	4.05	0.43	4.09	0.69	4.35	0.24	3.89	0.34	4.00	0.24	3.90	0.31	3.97	0.25	3.91	0.18	3.84	0.48	4.13	0.02	3.67	0.10	3.76	(0.26)	3.39	0.05	3.71
Sep 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98	0.39	4.08	0.33	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
Oct 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98	0.39	4.08	0.33	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.05	3.74
Nov 2014	3.69	0.57	4.26	0.47	4.16	0.56	4.25	0.39	4.08	0.43	4.12	0.41	4.10	0.29	3.98	0.38	4.07	0.31	4.00	0.25	3.94	0.29	3.98	(0.12)	3.57	(0.01)	3.69	(0.22)	3.47	(0.09)	3.60
Dec 2014	3.84	1.25	5.08	0.85	4.69	1.38	5.22	0.71	4.55	0.37	4.20	0.87	4.71	0.26	4.10	0.71	4.54	0.63	4.47	0.18	4.02	0.27	4.11	0.16	3.99	0.28	4.12	(0.15)	3.68	0.09	3.92

Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
BELLMEAD	Dominion	BELL MEADE	CC	230.26	250	1/1/1991	12/31/2100	
CHESTFD7	Dominion	CHESTERFIELD 7	CC	197	232	1/1/1990	12/31/2100	
CHESTFD8	Dominion	CHESTERFIELD 8	CC	200	235	1/1/1992	12/31/2100	
POSSUMP6	Dominion	POSSUM POINT 6	CC	405	450	5/1/2003	12/31/2100	
BREMOBL3	Dominion	BREMO BLUFF 3	Coal	71	74	1/1/1950	12/31/2100	
BREMOBL4	Dominion	BREMO BLUFF 4	Coal	156	160	1/1/1958	12/31/2100	
CHESAST1	Dominion	CHESAPEAKE ENERGY CENTER 1	Coal	111	111	1/1/1953	12/31/2100	
CHESAST2	Dominion	CHESAPEAKE ENERGY CENTER 2	Coal	111	111	1/1/1954	12/31/2100	
CHESAPE3	Dominion	CHESAPEAKE ENERGY CENTER 3	Coal	156	162	1/1/1959	12/31/2100	
CHESAST4	Dominion	CHESAPEAKE ENERGY CENTER 4	Coal	217	221	1/1/1962	12/31/2100	
CHESTFD3	Dominion	CHESTERFIELD 3	Coal	100	105	1/1/1952	12/31/2100	
CHESTFD4	Dominion	CHESTERFIELD 4	Coal	166	171	1/1/1960	12/31/2100	
CHESTFD5	Dominion	CHESTERFIELD 5	Coal	310	312	1/1/1964	12/31/2100	
CHESTFD6	Dominion	CHESTERFIELD 6	Coal	658	671	1/1/1969	12/31/2100	
CLOVER01	Dominion	CLOVER 1	Coal	441	441	1/1/1995	12/31/2100	50% ODEC
CLOVER02	Dominion	CLOVER 2	Coal	441	441	1/1/1996	12/31/2100	50% ODEC
LGEALTAV	Dominion	LG&E WESTMORELAND-ALTAVISTA	Coal	62.7	62.7	1/1/1992	12/31/2100	
LGEHOPEW	Dominion	LG&E WESTMORELAND-HOPEWELL	Coal	62.7	62.7	1/1/2006	12/31/2100	
LGESOUTH	Dominion	LG&E WESTMORELAND-SOUTHAMPTN	Coal	62.7	62.7	1/1/1992	12/31/2100	
MTSTORM1	Dominion	MOUNT STORM 1	Coal	524	545	1/1/1965	12/31/2100	
MTSTORM2	Dominion	MOUNT STORM 2	Coal	533	545	1/1/1966	12/31/2100	
MTSTORM3	Dominion	MOUNT STORM 3	Coal	521	536	1/1/1973	12/31/2100	
POSSUMG3	Dominion	POSSUM POINT 3	Coal	101	105	1/1/1955	5/1/2003	Converted to Gas
POSSUMG4	Dominion	POSSUM POINT 4	Coal	221	221	1/1/1962	5/1/2003	Converted to Gas
YORKTOW1	Dominion	YORKTOWN 1	Coal	159	163	1/1/1957	12/31/2100	
YORKTOW2	Dominion	YORKTOWN 2	Coal	167	172	1/1/1959	12/31/2100	
NTHBRANC	Dominion	NORTH BRANCH PROJECT	Waste Coal	74	77	1/1/1992	12/31/2100	
BATHCVAP	Dominion	BATH COUNTY	PSH	2520	2520	1/1/1990	12/31/2100	60% Dominion, 40% APS
CUSHAWPD	Dominion	CUSHAW	Hydro	2	2	1/1/1990	12/31/2100	
GASTONPD	Dominion	GASTON (NC)	Hydro	225	225	1/1/1990	12/31/2100	
NTHANNAH	Dominion	NORTH ANNA HYDRO	Hydro	1	1	1/1/1990	12/31/2100	
ROANOKPD	Dominion	ROANOKE RAPIDS	Hydro	99	99	1/1/1990	12/31/2100	
NTHANNA1	Dominion	NORTH ANNA 1	Nuke	925	925	1/1/1978	4/1/2018	11.6% ODEC
NTHANNA2	Dominion	NORTH ANNA 2	Nuke	917	917	1/1/1980	8/21/2020	11.6% ODEC
SURRY01	Dominion	SURRY 1	Nuke	810	810	1/1/1972	5/25/2012	
SURRY02	Dominion	SURRY 2	Nuke	815	815	1/1/1973	1/29/2013	
CAROLNE1	Dominion	LADYSMITH 1	Peaker	145	178	7/1/2001	12/31/2100	
CAROLNE2	Dominion	LADYSMITH 2	Peaker	145	178	7/1/2001	12/31/2100	
CHESAGT1	Dominion	CHESAPEAKE GT01	Peaker	15	19	1/1/1967	12/31/2100	
CHESAGT2	Dominion	CHESAPEAKE GT02	Peaker	15	18	1/1/1969	12/31/2100	
CHESAGT4	Dominion	CHESAPEAKE GT04	Peaker	15	18	1/1/1969	12/31/2100	
CHESAPE6	Dominion	CHESAPEAKE GT06	Peaker	15	18	1/1/1969	12/31/2100	
CHESAPE7	Dominion	CHESAPEAKE GT07	Peaker	21	29	1/1/1969	12/31/2100	
CHESAPE8	Dominion	CHESAPEAKE GT08	Peaker	21	29	1/1/1969	12/31/2100	
CHESAPE9	Dominion	CHESAPEAKE GT09	Peaker	21	29	1/1/1970	12/31/2100	

Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
CHESAP10	Dominion	CHESAPEAKE GT10	Peaker	21	29	1/1/1970	12/31/2100	
DARBYTO1	Dominion	DARBYTOWN 1	Peaker	72	92	1/1/1990	12/31/2100	
DARBYTO2	Dominion	DARBYTOWN 2	Peaker	72	92	1/1/1990	12/31/2100	
DARBYTO3	Dominion	DARBYTOWN 3	Peaker	72	92	1/1/1990	12/31/2100	
DARBYTO4	Dominion	DARBYTOWN 4	Peaker	72	92	1/1/1990	12/31/2100	
FAUQUIC1	Dominion	REMINGTON 1	Peaker	145	178	7/5/2000	12/31/2100	
FAUQUIC2	Dominion	REMINGTON 2	Peaker	145	178	7/5/2000	12/31/2100	
FAUQUIC3	Dominion	REMINGTON 3	Peaker	145	178	7/5/2000	12/31/2100	
FAUQUIC4	Dominion	REMINGTON 4	Peaker	145	178	7/5/2000	12/31/2100	
GRAVELN1	Dominion	GRAVEL NECK 1	Peaker	15	17	1/1/1970	12/31/2100	
GRAVELN2	Dominion	GRAVEL NECK 2	Peaker	22	28	1/1/1970	12/31/2100	
GRAVELN3	Dominion	GRAVEL NECK 3	Peaker	73	92	1/1/1989	12/31/2100	
GRAVELN4	Dominion	GRAVEL NECK 4	Peaker	73	92	1/1/1989	12/31/2100	
GRAVELN5	Dominion	GRAVEL NECK 5	Peaker	73	92	1/1/1989	12/31/2100	
GRAVELN6	Dominion	GRAVEL NECK 6	Peaker	73	92	1/1/1989	12/31/2100	
KITTYGT1	Dominion	KITTY HAWK 1	Peaker	22	28	1/1/1971	12/31/2100	
KITTYGT2	Dominion	KITTY HAWK 2	Peaker	22	28	1/1/1971	12/31/2100	
LOWMOOR1	Dominion	LOW MOOR 1	Peaker	15	18	1/1/1971	12/31/2100	
LOWMOOR2	Dominion	LOW MOOR 2	Peaker	15	18	1/1/1971	12/31/2100	
LOWMOOR3	Dominion	LOW MOOR 3	Peaker	15	18	1/1/1971	12/31/2100	
LOWMOOR4	Dominion	LOW MOOR 4	Peaker	15	18	1/1/1971	12/31/2100	
MTSTOJF1	Dominion	MOUNT STORM GT1	Peaker	12	16	1/1/1967	12/31/2100	
NTHNECK1	Dominion	NORTHERN NECK 1	Peaker	16	19	1/1/1971	12/31/2100	
NTHNECK2	Dominion	NORTHERN NECK 2	Peaker	16	19	1/1/1971	12/31/2100	
NTHNECK3	Dominion	NORTHERN NECK 3	Peaker	16	19	1/1/1971	12/31/2100	
NTHNECK4	Dominion	NORTHERN NECK 4	Peaker	16	19	1/1/1971	12/31/2100	
POSSUGT1	Dominion	POSSUM POINT GT1	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT2	Dominion	POSSUM POINT GT2	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT3	Dominion	POSSUM POINT GT3	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT4	Dominion	POSSUM POINT GT4	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT5	Dominion	POSSUM POINT GT5	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT6	Dominion	POSSUM POINT GT6	Peaker	13	16	1/1/1968	12/31/2100	
POSSUMP1	Dominion	POSSUM POINT 1	ST/G/O/D	74	74	1/1/1948	5/1/2003	Retired w new CC
POSSUMP2	Dominion	POSSUM POINT 2	ST/G/O/D	69	71	1/1/1951	5/1/2003	Retired w new CC
POSSUMP3	Dominion	POSSUM POINT 3	ST/G/O/D	101	105	5/1/2003	12/31/2100	Converted to Gas
POSSUMP4	Dominion	POSSUM POINT 4	ST/G/O/D	221	221	5/1/2003	12/31/2100	Converted to Gas
POSSUMP5	Dominion	POSSUM POINT 5	ST/G/O/D	786	801	1/1/1975	12/31/2100	
YORKTOW3	Dominion	YORKTOWN 3	ST/G/O/D	818	820	1/1/1974	12/31/2100	
DOSWECC1	NUG	DOSWELL COMBINED CYCLE FACILITY CC 1	CC	302.5	363	1/1/1992	12/31/2100	5/5/2017 Term End
DOSWECC2	NUG	DOSWELL COMBINED CYCLE FACILITY CC 2	CC	302.5	363	1/1/1992	12/31/2100	5/5/2017 Term End
GORDONCC	NUG	GORDONSVILLE ENERGY L.P.	CC	217	288	1/1/1994	12/31/2100	5/31/2024 Term End
HOPEWECC	NUG	HOPEWELL COGENERATION	CC	337	400	1/1/1993	12/31/2100	7/30/2015 Term End
BIRCHWO1	NUG	BIRCHWOOD POWER FACILITY 1	Coal	238	242	1/1/1996	12/31/2100	11/14/2021 Term End
CGNHOPEW	NUG	COGENTRIX HOPEWELL 1	Coal	92.5	92.5	1/1/1987	12/31/2100	1/9/2008 Term End

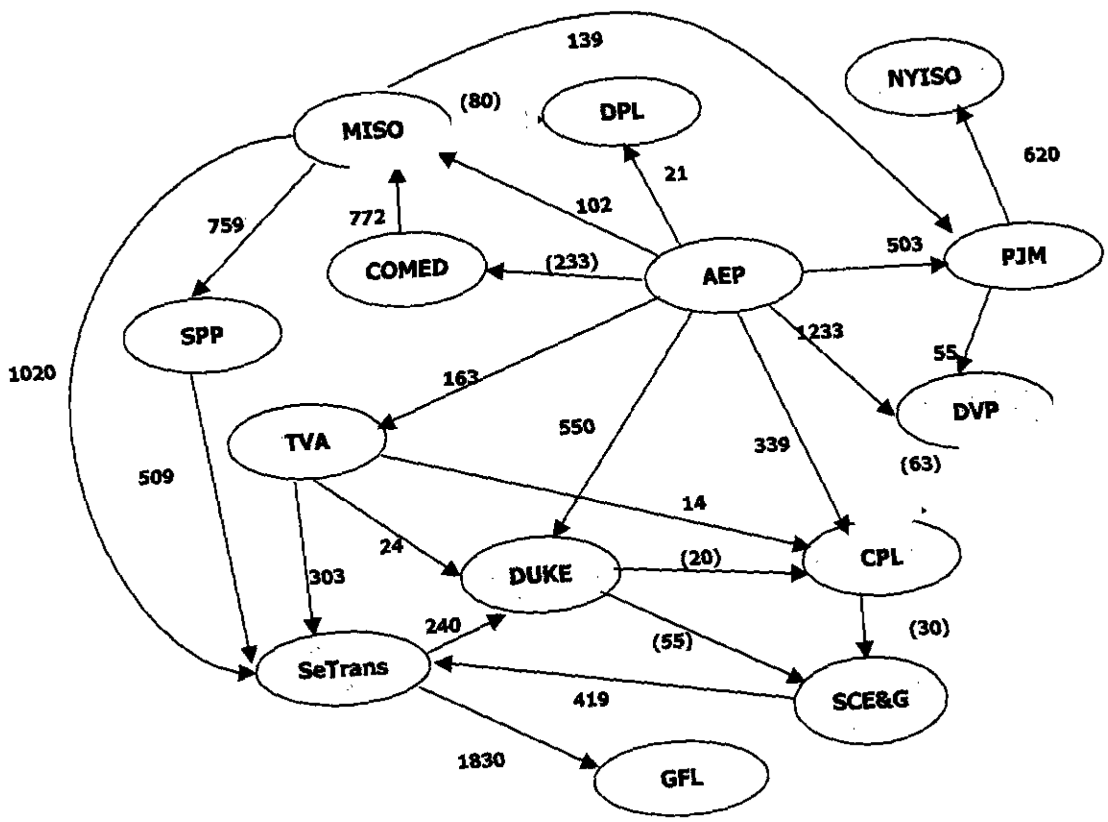
Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
CGNRICH1	NUG	COGENTRIX RICHMOND 1	Coal	115.5	115.5	1/1/1992	12/31/2100	7/31/2017 Term End
CGNRICH2	NUG	COGENTRIX RICHMOND 2	Coal	93.5	93.5	1/1/1992	12/31/2100	7/31/2017 Term End
DCBATTL1	NUG	DC BATTLE (COG ROCKY MT) 1	Coal	57.5	57.5	1/1/1990	12/31/2100	10/14/2015 Term End
DCBATTL2	NUG	DC BATTLE (COG ROCKY MT) 2	Coal	57.5	57.5	1/1/1990	12/31/2100	10/14/2015 Term End
MECKLEN1	NUG	MECKLENBURG 1	Coal	66	66	1/1/1992	12/31/2100	11/5/2017 Term End
MECKLEN2	NUG	MECKLENBURG 2	Coal	66	66	1/1/1992	12/31/2100	11/5/2017 Term End
PARK5002	NUG	PARK 500 DIVISION 1	Coal	6	6	1/1/1984	12/31/2100	12/30/2003 Term End
PARK5001	NUG	PARK 500 DIVISION 2	Coal	6	6	1/1/1983	12/31/2100	12/30/2003 Term End
PORTSMO1	NUG	COGENTRIX PORTSMOUTH 1	Coal	57.5	57.5	1/1/1988	12/31/2100	6/8/2008 Term End
PORTSMO2	NUG	COGENTRIX PORTSMOUTH 2	Coal	57.5	57.5	1/1/1988	12/31/2100	6/8/2008 Term End
ROANOKVP	NUG	ROANOKE VALLEY PROJECT	Coal	165	167.21	1/1/1994	12/31/2100	5/28/2019 Term End
ROANOKV1	NUG	ROANOKE VALLEY II	Coal	44	45.1	1/1/1995	12/31/2100	5/31/2020 Term End
ALEXARL1	NUG	ALEXANDRIA/ARLINGTON MSW 1	Other	10	10	1/1/1988	12/31/2100	1/28/2023 Term End
ALEXARL2	NUG	ALEXANDRIA/ARLINGTON MSW 2	Other	10	10	1/1/1988	12/31/2100	1/28/2023 Term End
APPOMAT1	NUG	APPOMATTOX COGEN-STONE CONT	Other	38	38	1/1/1981	12/31/2100	10/25/2004 Term End
COVINGT1	NUG	WESTVACO COVINGTON 1	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT2	NUG	WESTVACO COVINGTON 2	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT3	NUG	WESTVACO COVINGTON 3	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT4	NUG	WESTVACO COVINGTON 4	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT5	NUG	WESTVACO COVINGTON 5	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT6	NUG	WESTVACO COVINGTON 6	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
I95ENER1	NUG	I-95 ENERGY-COVANTA FAIRFAX	Other	79	79	1/1/1990	12/31/2100	5/31/2015 Term End
MULTITR1	NUG	MULTITRADE OF PITTSYLVANIA	Other	39.8	39.8	1/1/1994	12/31/2100	6/14/2019 Term End
MULTITR2	NUG	MULTITRADE OF PITTSYLVANIA	Other	39.8	39.8	1/1/1994	12/31/2100	6/14/2019 Term End
SPSAPOW1	NUG (Netted from VAP Load Forecast)	NORFOLK NAVAL SHIPYARD 1	Other	18.6	20	1/1/1987	12/31/2100	
SPSAPOW2	NUG (Netted from VAP Load Forecast)	NORFOLK NAVAL SHIPYARD 2	Other	18.6	20	1/1/1987	12/31/2100	
SPSAPOW3	NUG (Netted from VAP Load Forecast)	NORFOLK NAVAL SHIPYARD 3	Other	18.6	20	1/1/1987	12/31/2100	
PLYMOUT4	NUG	WEYERHAUSER PLYMOUTH NC 4	Other	4.73	4.73	1/1/1949	12/31/2100	7/26/2004 Term End
PLYMOUT6	NUG	WEYERHAUSER PLYMOUTH NC 6	Other	4.73	4.73	1/1/1956	12/31/2100	7/26/2004 Term End
PLYMOUT7	NUG	WEYERHAUSER PLYMOUTH NC 7	Other	4.73	4.73	1/1/1952	12/31/2100	7/26/2004 Term End
PLYMOUT8	NUG	WEYERHAUSER PLYMOUTH NC 8	Other	4.73	4.73	1/1/1964	12/31/2100	7/26/2004 Term End
PLYMOUT9	NUG	WEYERHAUSER PLYMOUTH NC 9	Other	4.73	4.73	1/1/1976	12/31/2100	7/26/2004 Term End
PLYMOU10	NUG	WEYERHAUSER PLYMOUTH NC 10	Other	4.73	4.73	1/1/1978	12/31/2100	7/26/2004 Term End
CHESAPP6	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 06	Other	5.7	5.7	1/1/1937	12/31/2100	
CHESAPP8	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 08	Other	5	5	1/1/1954	12/31/2100	
CHESAPP9	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 09	Other	9.6	10	1/1/1960	12/31/2100	
CHESPP10	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 10	Other	24	25	1/1/1968	12/31/2100	
CHESAP11	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 11	Other	14.4	15	1/1/1977	12/31/2100	
CHESAP12	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 12	Other	42.7	46	1/1/1985	12/31/2100	
COMMONA1	NUG	COMMONWEALTH ATLANTIC LIMIT 1	Peaker	104	125	1/1/1992	12/31/2100	6/4/2017 Term End
COMMONA2	NUG	COMMONWEALTH ATLANTIC LIMIT 2	Peaker	104	125	1/1/1992	12/31/2100	6/4/2017 Term End
COMMONA3	NUG	COMMONWEALTH ATLANTIC LIMIT 3	Peaker	104	125	1/1/1992	12/31/2100	6/4/2017 Term End
DOSWELL1	NUG	DOSWELL COMBINED CYCLE FACILITY 1	Peaker	155	182	6/7/2001	12/31/2100	12/31/2005 Term End
FRANKLI1	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 1	Other	5	5	1/1/1937	12/31/2100	
FRANKLI6	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 6	Other	9.01	9.38	1/1/1950	12/31/2100	

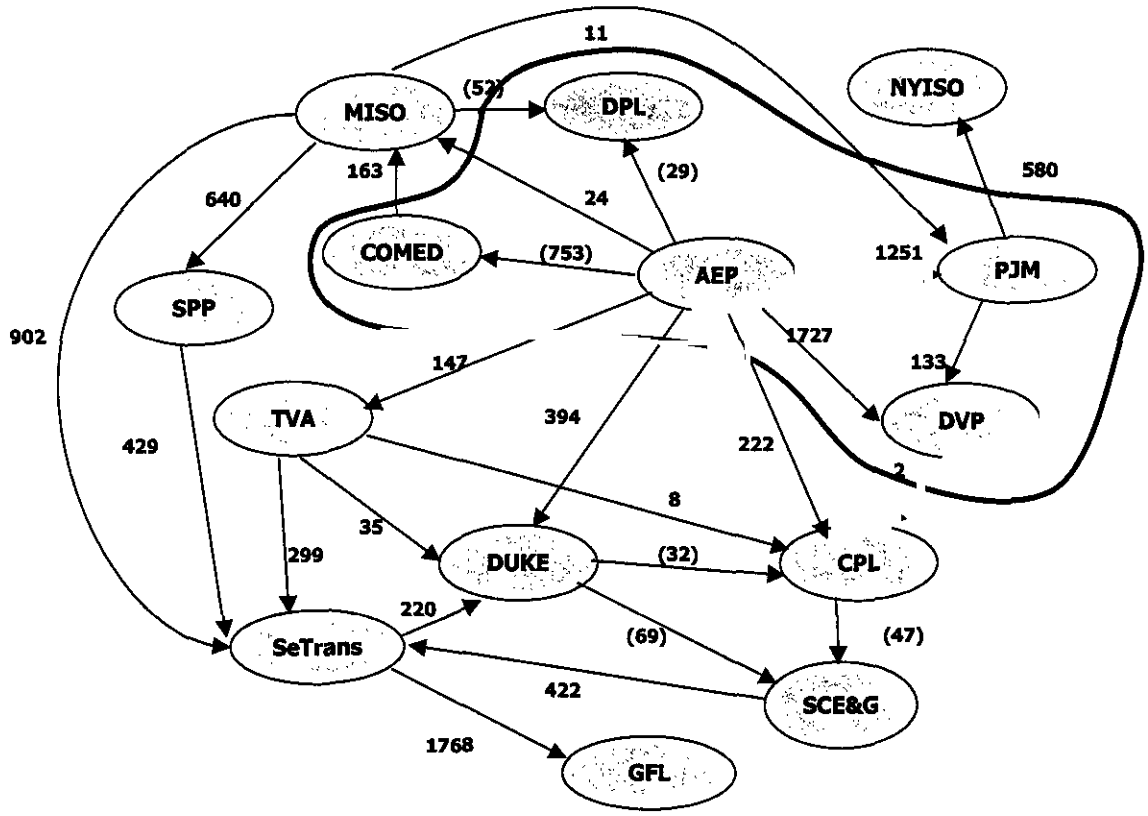
Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
FRANKLI7	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 7	Other	15.02	15.63	1/1/1958	12/31/2100	
FRANKLI8	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 8	Other	31.14	32.4	1/1/1970	12/31/2100	
FRANKLI9	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 9	Other	26.91	28	1/1/1977	12/31/2100	
PANDARCC	NUG	PANDA-ROSEMARY	CC	165	198	1/1/1990	12/31/2100	12/26/2015 Term End
ROANOST1	NUG	INTL PAPER ROANOKE RAPIDS	Coal	14	14	1/1/1966	12/31/2100	8/26/2006 Term End
I95LNDFL	NUG	I-95 LANDFILL	Other	3.2	3.2	3/1/1993	12/31/2100	12/31/2011 Term End
I95LNDF2	NUG	I-95 LANDFILL PHASE II	Other	3.2	3.2	1/1/1992	12/31/2100	2/9/2013 Term End
SCOTTENE	NUG	SCOTT ENERGY	Other	2.5	2	12/1/1989	12/31/2100	12/28/2015 Term End
SUFFLKLF	NUG	SUFFOLK LANDFILL	Other	3.2	3.28	11/1/1994	12/31/2100	11/3/2014 Term End
WPP3RICH	NUG	WPP 3 RICHMOND PLANT	Other	2.93	3	7/1/1991	12/31/2100	8/26/2013 Term End
BRASFLDD	NUG	BRASFIELD DAM	Hydro	3	3	1/1/1990	12/31/2100	10/11/2013 Term End
EMPORIAH	NUG	EMPORIA HYDRO	Hydro	1	1	1/1/1990	12/31/2100	3/30/2006 Term End
SCHOOLFD	NUG	SCHOOLFIELD DAM	Hydro	3	3	1/1/1990	12/31/2100	11/30/2015 Term End
FLUVANN1	Merchant	TENASKA VIRGINIA PARTNERS 1	CC	300	300	6/1/2004	12/31/2100	
FLUVANN2	Merchant	TENASKA VIRGINIA PARTNERS 2	CC	300	300	6/1/2004	12/31/2100	
FLUVANN3	Merchant	TENASKA VIRGINIA PARTNERS 3	CC	300	300	6/1/2004	12/31/2100	
BOSWTAV1	ODEC	BOSWELL'S TAVERN (LOUISA CO) 1	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV2	ODEC	BOSWELL'S TAVERN (LOUISA CO) 2	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV3	ODEC	BOSWELL'S TAVERN (LOUISA CO) 3	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV4	ODEC	BOSWELL'S TAVERN (LOUISA CO) 4	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV5	ODEC	BOSWELL'S TAVERN (LOUISA CO) 5	Peaker	150	170	6/1/2003	12/31/2100	
REMINGM1	ODEC	REMINGTON MARSH RUN 1	Peaker	150	170	10/1/2004	12/31/2100	
REMINGM2	ODEC	REMINGTON MARSH RUN 2	Peaker	150	170	10/1/2004	12/31/2100	
REMINGM3	ODEC	REMINGTON MARSH RUN 3	Peaker	150	170	10/1/2004	12/31/2100	
REMINGM4	ODEC	REMINGTON MARSH RUN 4	Peaker	150	170	1/1/2014	12/31/2100	
PLEASANV	Harrisonburg Electric	PLEASANT VALLEY (HARRISNBRG)	Peaker	14	14	1/1/1998	12/31/2100	
MTCLINT1	Harrisonburg Electric	MT. CLINTON (HARRISONBURG)	Peaker	14	14	1/1/1999	12/31/2100	
MANASSAS	Manassas Electric Dept.	AGGREGATED MANASSAS ICs	Peaker	30	30	1/1/2000	12/31/2100	
JKERRVAP	SEPA	JOHN H. KERR	Hydro	146	146	1/1/1990	1/1/2100	

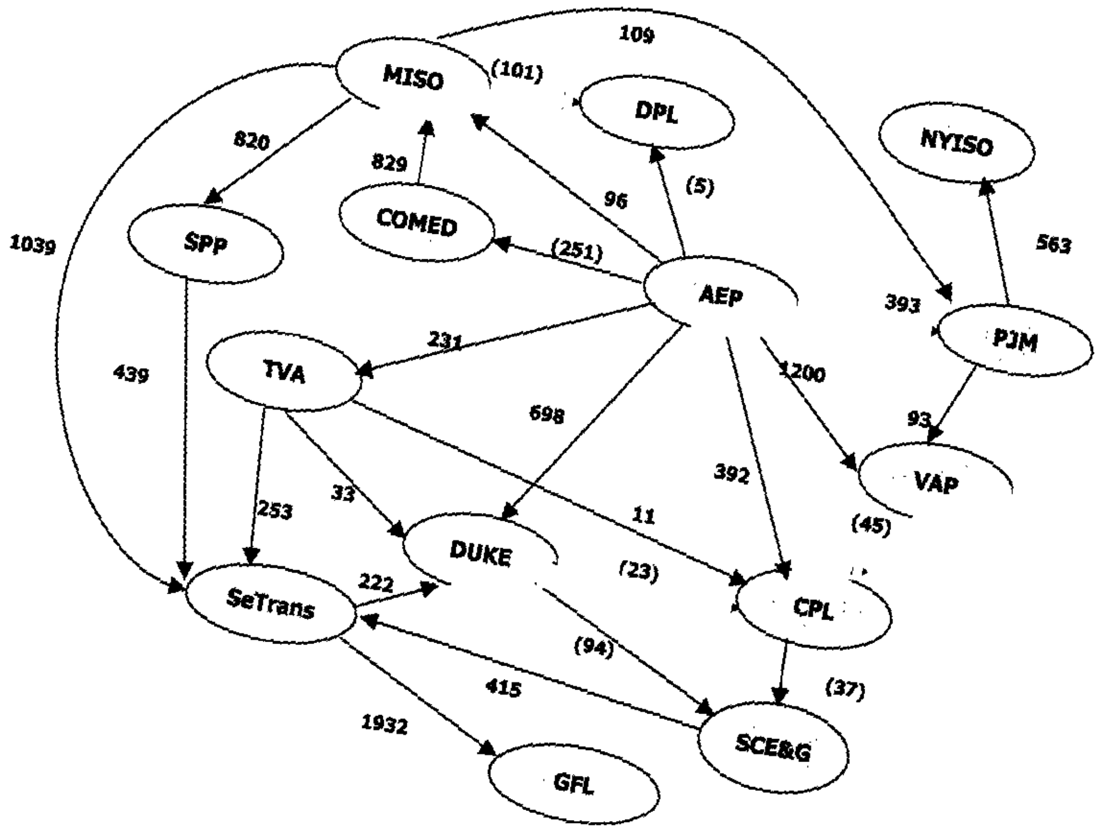
Pool to Pool All-Hour Average Transfers (MW)
2005 Base Case



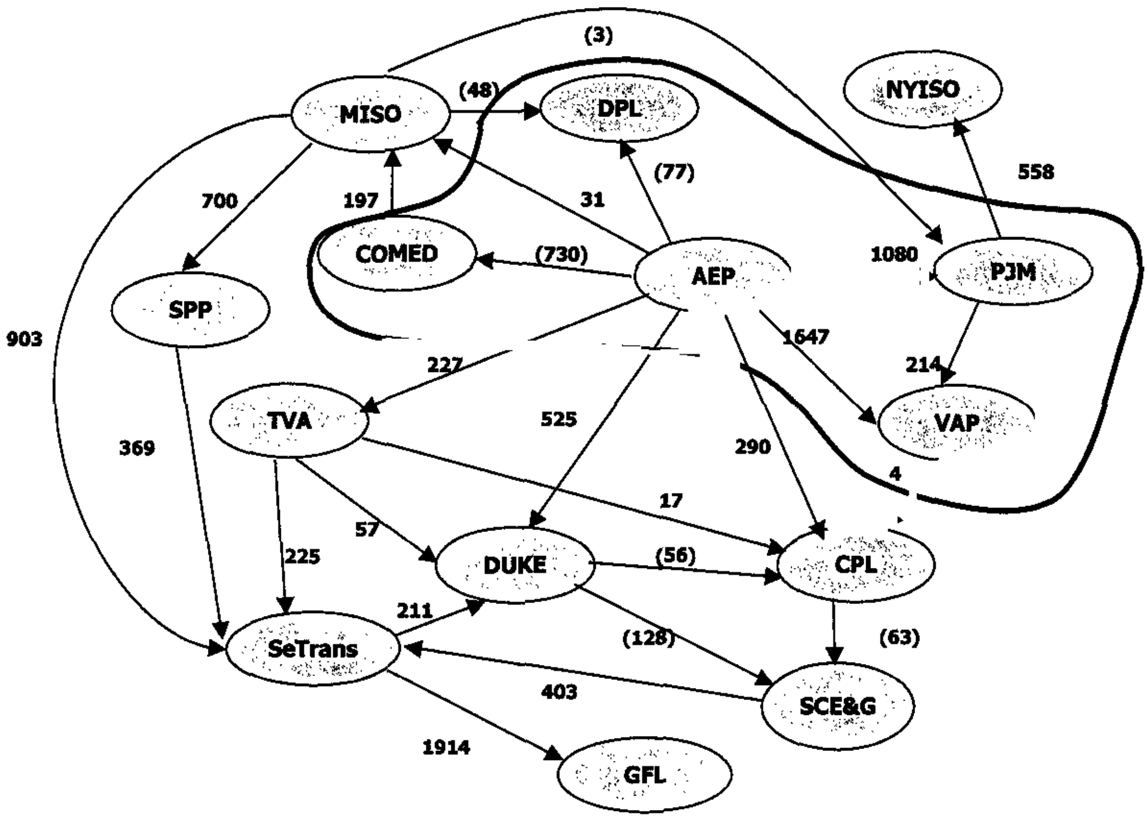
Pool to Pool All-Hour Average Transfers (MW)
2005 Change case



Pool to Pool All-Hour Average Transfers (MW)
2007 Base Case



Pool to Pool All-Hour Average Transfers (MW)
2007 Change Case



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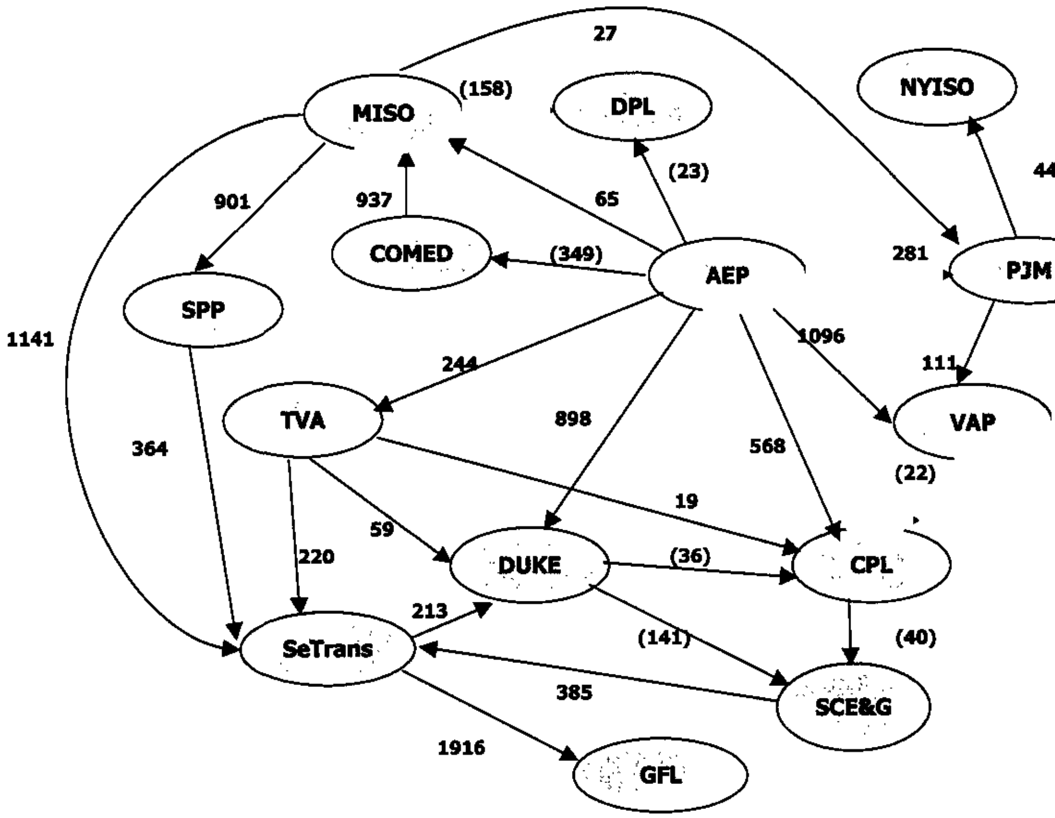
2010 Base Case



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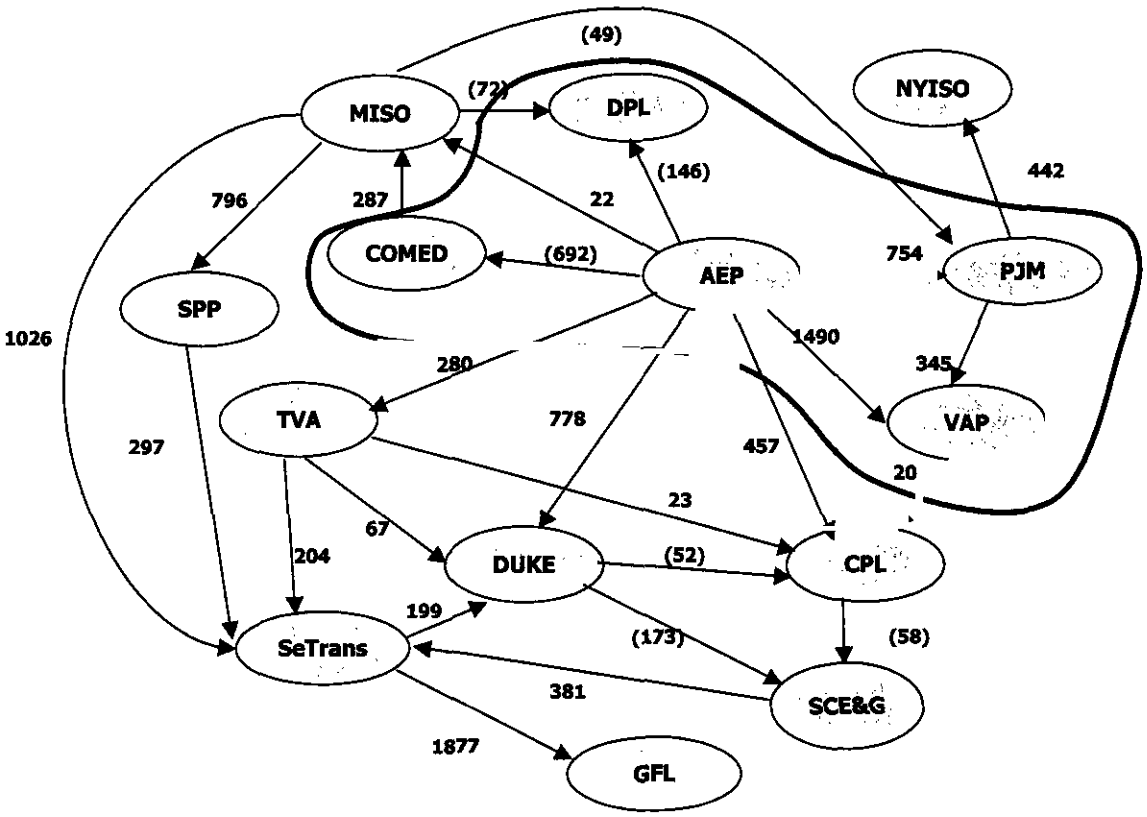
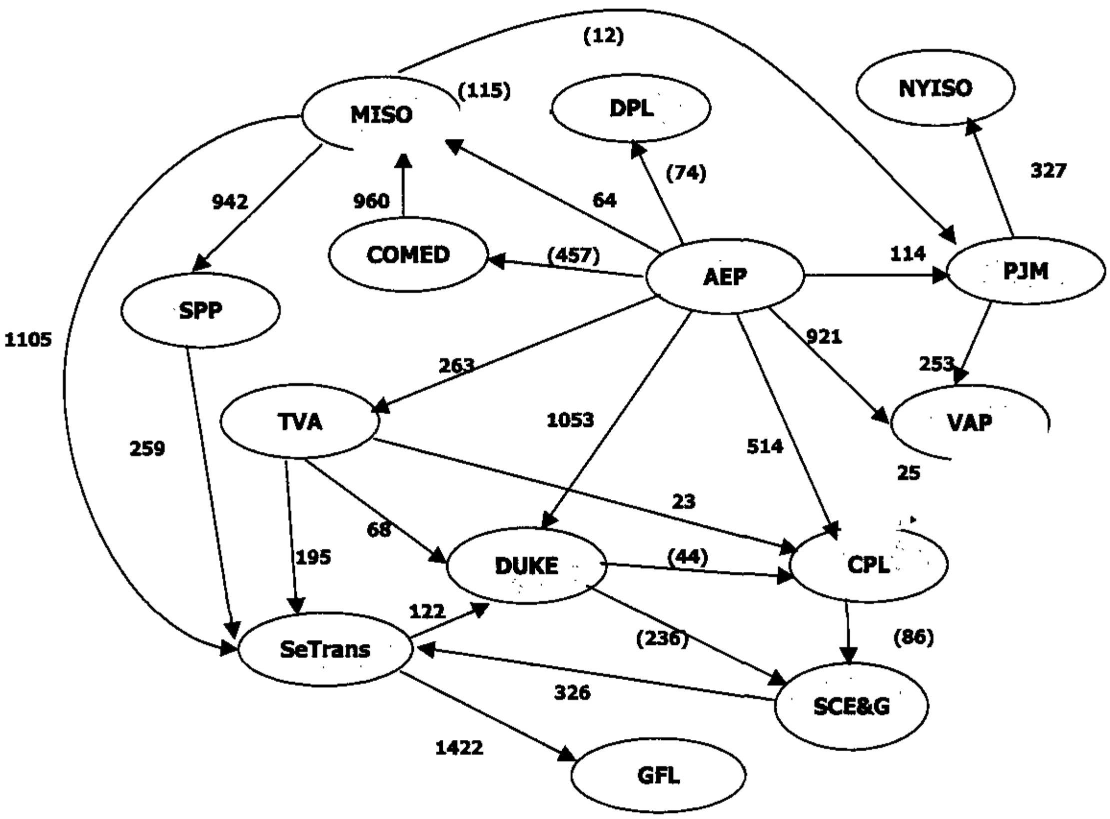
2010 Change Case



Pool to Pool All-Hour Average Transfers (MW)
2014 Base Case



Pool to Pool All-Hour Average Transfers (MW)
2014 Change Case

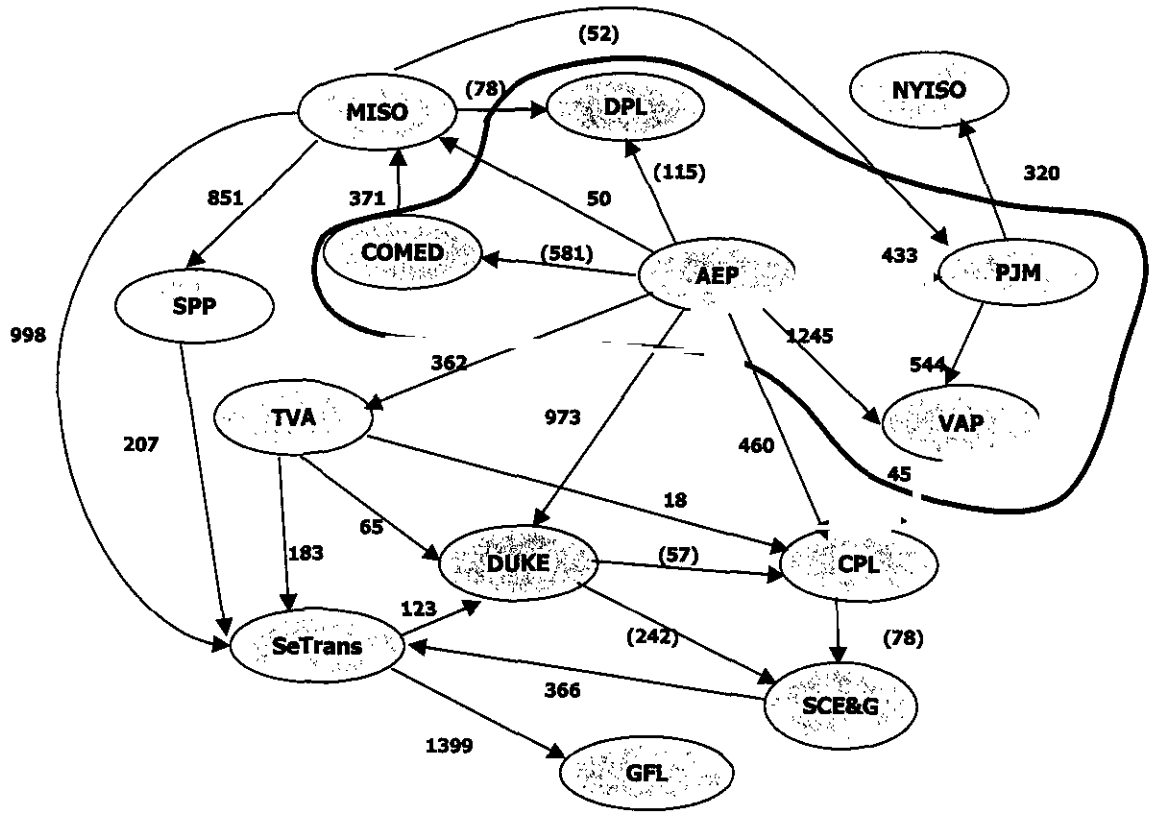


Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
AEP	CC	195	707	511	257	912	655	1,304	2,928	1,624	3,510	7,179	3,669
	Coal	130,287	132,465	2,178	135,631	137,062	1,431	141,082	140,863	(219)	144,530	144,637	107
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,888	15,888	-	15,913	15,913	-	15,885	15,885	-
	Other	214	214	(0)	214	214	(0)	214	214	-	213	214	0
	Peaker	-	-	-	-	0	0	20	19	(0)	61	88	27
	PSH	730	728	(2)	710	711	1	620	619	(1)	481	481	0
	ST/G/O/D	0	0	(0)	0	1	0	1	3	1	1	4	3
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		*148,595*	*151,282*	*2,687*	*153,984*	*156,071*	*2,087*	*160,438*	*161,842*	*1,404*	*165,965*	*169,771*	*3,806*
COMED	CC	1,666	1,109	(557)	2,227	1,465	(762)	2,929	2,430	(498)	3,906	3,696	(211)
	Coal	27,944	28,588	644	29,975	30,816	840	33,144	34,154	1,010	35,142	35,704	562
	Nuke	80,330	80,332	2	80,364	80,364	-	80,299	80,296	(4)	80,280	80,278	(3)
	Peaker	177	78	(99)	345	165	(179)	539	364	(175)	1,080	447	(633)
	ST/G/O/D	1,093	335	(758)	1,783	565	(1,218)	3,922	1,021	(2,901)	6,824	3,647	(3,178)
	New CT	-	-	-	-	-	-	106	16	(90)	835	241	(594)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		111,211	110,443	(768)	114,695	113,376	(1,319)	120,939	118,280	(2,658)	128,068	124,012	(4,056)
CPL	CC	1,530	2,087	557	2,152	2,570	418	3,044	3,395	351	4,259	4,376	117
	Coal	34,977	35,155	178	36,738	36,916	178	37,848	38,006	159	39,383	39,497	114
	Hydro	949	949	-	949	949	-	949	949	-	949	949	-
	Nuke	24,491	24,491	-	24,494	24,494	-	24,519	24,519	-	24,507	24,507	-
	Other	2,512	2,512	-	2,504	2,504	-	2,509	2,509	(1)	2,509	2,509	0
	Peaker	379	415	36	668	747	78	1,137	1,357	221	1,531	1,618	87
	New CT	-	-	-	-	-	-	560	498	(62)	3,537	3,814	277
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
CPL Sum		64,838	65,610	772	67,504	68,179	675	70,566	71,233	667	76,675	77,269	594
DP&L	Coal	17,682	17,874	192	18,560	18,727	166	19,712	20,046	334	20,765	20,886	121
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	-	-	-	11	-	(11)	25	22	(4)	128	48	(81)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		17,727	17,919	192	18,616	18,772	155	19,782	20,112	330	20,938	20,979	41

Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
DUKE	CC	990	1,276	287	1,465	1,627	162	2,034	2,132	98	2,851	2,903	53
	Coal	50,497	50,731	233	52,169	52,373	203	53,477	53,618	142	54,954	55,040	85
	Hydro	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-
	Nuke	53,021	53,021	-	52,958	52,958	-	53,031	53,031	-	53,054	53,054	-
	Other	56	56	-	56	56	-	56	56	-	57	57	0
	Peaker	536	569	33	786	827	41	1,588	1,645	57	3,307	3,432	125
	PSH	3,665	3,677	12	3,494	3,547	53	3,236	3,231	(5)	2,332	2,308	(24)
	ST/G/O/D	4	6	1	2	4	1	8	9	2	10	11	1
	New CT	-	-	-	205	233	28	1,460	1,497	38	3,795	4,047	251
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DUKE Sum		113,035	113,601	566	115,401	115,890	489	119,156	119,486	331	124,624	125,116	491
GFL	CC	63,040	63,319	280	67,521	67,571	51	72,380	72,507	127	79,002	79,071	69
	Coal	55,677	55,778	101	56,264	56,313	49	56,513	56,572	58	57,107	57,120	13
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	214	214	-	214	214	-	214	214	-	214	214	-
	Nuke	29,964	29,964	-	29,897	29,897	-	29,929	29,929	-	29,886	29,886	-
	Other	3,147	3,147	-	3,150	3,150	-	3,147	3,147	-	3,148	3,148	-
	Peaker	2,067	2,050	(17)	4,897	4,884	(13)	4,424	4,473	49	3,178	3,205	27
	ST/G/O/D	39,627	39,812	185	42,647	42,712	65	44,974	45,023	49	49,240	49,300	60
	New CT	-	-	-	-	-	-	2,699	2,710	12	7,958	7,960	2
	New CC	-	-	-	-	-	-	6,435	6,472	37	20,370	20,407	37
GFL Sum		193,737	194,284	548	204,590	204,742	152	220,716	221,048	332	250,104	250,311	207
MISO E	CC	3,654	3,689	34	5,369	5,471	103	10,497	10,938	441	19,597	19,749	152
	Coal	317,718	319,634	1,916	326,664	328,666	2,002	340,013	342,181	2,169	351,778	353,087	1,308
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-
	Nuke	29,335	29,335	-	29,324	29,324	-	29,279	29,279	-	29,334	29,334	-
	Other	2,456	2,456	-	2,451	2,451	-	2,454	2,454	-	2,455	2,456	1
	Peaker	416	399	(16)	771	762	(9)	1,343	1,332	(10)	2,704	2,478	(226)
	PSH	5,234	5,234	(0)	5,072	5,084	12	4,718	4,715	(3)	3,846	3,829	(17)
	ST/G/O/D	1,076	1,128	53	1,830	1,850	20	3,843	3,898	55	8,404	8,387	(17)
	New CT	-	-	-	-	-	-	-	-	-	765	737	(28)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO E Sum		362,546	364,532	1,986	374,138	376,266	2,128	394,805	397,456	2,651	421,541	422,715	1,174

Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
MISO W	CC	6,582	6,722	139	8,558	8,686	128	13,140	13,247	106	18,334	18,417	83
	Coal	283,317	284,023	706	288,503	289,180	677	292,908	293,582	674	301,069	301,556	487
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-
	Nuke	56,909	56,903	(6)	56,946	56,950	4	56,941	56,967	26	56,905	56,915	9
	Other	10,576	10,577	1	10,584	10,586	2	10,559	10,564	4	10,566	10,578	12
	Peaker	3,927	3,919	(8)	5,161	5,174	13	10,951	11,015	64	10,135	10,327	191
	PSH	661	660	(2)	670	673	3	672	674	2	673	669	(5)
	ST/G/O/D	277	295	18	455	468	12	1,290	1,294	5	1,663	1,700	37
	New CT	-	-	-	-	-	-	-	-	-	11,811	12,189	378
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO W Sum		377,707	378,557	850	386,336	387,175	839	401,919	402,800	881	426,615	427,808	1,193
ISO-NE	CC	25,943	25,968	24	28,074	27,992	(82)	34,313	34,329	16	38,941	38,652	(290)
	Coal	21,568	21,550	(18)	21,810	21,776	(34)	22,067	22,062	(4)	22,102	22,103	1
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-
	Nuke	33,909	33,909	-	33,884	33,883	(1)	33,963	33,963	-	33,989	33,989	-
	Other	14,314	14,314	-	14,322	14,322	-	14,317	14,317	-	14,311	14,311	-
	Peaker	-	-	-	-	-	-	-	-	-	-	-	-
	PSH	1,125	1,122	(3)	1,053	1,046	(7)	1,019	1,010	(9)	867	884	17
	ST/G/O/D	16,801	16,771	(30)	18,701	18,794	93	18,148	18,145	(3)	20,603	20,952	350
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Sum		120,921	120,894	(27)	125,104	125,073	(31)	131,087	131,087	(0)	138,074	138,151	77
NYC	CC	6,174	6,304	130	6,429	6,533	105	6,819	6,944	124	7,297	7,381	84
	Other	179	179	-	179	179	-	179	179	-	179	179	-
	Peaker	342	338	(5)	219	225	6	274	265	(9)	483	493	9
	ST/G/O/D	18,223	18,367	144	19,237	19,403	165	20,157	20,393	236	21,505	21,785	281
	New CT	-	-	-	29	29	(0)	58	59	1	157	165	8
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYC Sum		24,918	25,188	269	26,094	26,369	276	27,488	27,840	352	29,620	30,002	381
NYL	CC	1,502	1,508	7	1,530	1,544	14	1,608	1,608	0	1,690	1,690	0
	Other	992	992	-	991	991	-	991	991	-	988	988	-
	Peaker	152	150	(3)	128	128	(0)	226	221	(5)	303	311	8

Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
	ST/G/O/D	8,199	8,237	37	8,790	8,802	12	9,605	9,607	2	10,862	10,887	24
	New CT	-	-	-	20	20	0	70	73	3	206	204	(2)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYL Sum		10,845	10,886	41	11,460	11,486	26	12,500	12,501	1	14,050	14,080	31
NYO	CC	10,934	11,204	271	11,898	11,711	(187)	13,800	13,772	(28)	15,957	15,798	(159)
	Coal	26,150	25,821	(330)	26,643	26,384	(259)	27,290	27,053	(237)	27,558	27,406	(152)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-
	Nuke	37,813	37,813	1	37,718	37,718	(0)	37,741	37,740	(1)	37,718	37,715	(2)
	Other	2,408	2,408	(0)	2,403	2,403	(0)	2,402	2,402	(0)	2,398	2,398	0
	Peaker	1	1	0	0	0	0	2	2	0	5	5	0
	PSH	2,008	2,014	6	2,013	2,017	4	1,861	1,846	(15)	1,693	1,699	6
	ST/G/O/D	7,858	8,119	261	9,373	9,713	340	10,200	10,298	98	12,456	12,490	33
	New CT	-	-	-	-	-	-	-	-	-	59	99	40
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYO Sum		115,795	116,003	208	118,670	118,569	(102)	121,918	121,736	(183)	126,466	126,232	(234)
PJM	CC	17,950	16,345	(1,605)	21,890	20,245	(1,644)	28,772	27,699	(1,074)	41,889	41,252	(637)
	Coal	194,502	190,457	(4,045)	198,190	194,756	(3,435)	203,688	201,286	(2,402)	207,748	206,384	(1,364)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,393	117,393	-	117,470	117,467	(3)	117,419	117,419	-	117,446	117,446	-
	Other	6,907	6,907	-	6,913	6,912	(0)	6,907	6,907	-	6,914	6,911	(3)
	Peaker	306	352	45	651	736	84	1,100	1,345	245	1,838	2,654	816
	PSH	4,663	4,659	(5)	4,645	4,639	(6)	4,701	4,717	16	4,528	4,549	20
	ST/G/O/D	7,512	8,031	519	11,026	11,998	972	15,112	16,849	1,737	21,283	23,453	2,171
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
	New CT	-	-	-	-	-	-	-	-	-	942	-	(942)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		355,173	350,075	(5,098)	366,724	362,685	(4,038)	383,637	382,156	(1,482)	408,533	408,590	57
SCE&G	CC	1,935	2,180	245	2,617	2,987	370	3,749	4,081	331	5,263	5,466	202
	Coal	36,724	36,867	143	37,938	38,070	132	38,746	38,854	108	39,534	39,595	61
	Hydro	875	875	-	875	875	-	875	875	-	875	875	-
	Nuke	7,611	7,611	-	7,610	7,610	-	7,609	7,609	-	7,650	7,650	-
	Other	1,004	1,004	-	1,007	1,007	-	1,008	1,008	-	1,006	1,006	-

Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
	Peaker	9	10	1	31	33	2	59	69	10	24	31	7
	PSH	948	941	(7)	886	884	(2)	803	793	(10)	504	520	16
	ST/G/O/D	6	9	3	28	29	1	40	44	4	59	64	4
	New CT	-	-	-	-	-	-	-	-	-	766	889	124
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SCE&G Sum		49,113	49,498	386	50,991	51,495	504	52,890	53,333	443	55,681	56,095	414
SETRANS E	CC	18,168	19,452	1,284	23,209	25,276	2,067	36,790	38,971	2,181	55,618	56,530	912
	Coal	186,069	186,481	412	191,153	191,474	321	190,531	190,758	227	181,389	181,500	111
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-
	Nuke	45,935	45,935	-	46,039	46,039	-	46,072	46,072	-	46,029	46,029	-
	Other	8,842	8,842	-	8,847	8,847	-	8,856	8,856	-	8,840	8,840	-
	Peaker	381	390	10	1,488	1,517	28	3,254	3,281	28	4,632	4,672	40
	PSH	315	312	(3)	298	288	(10)	272	273	1	145	144	(0)
	ST/G/O/D	4,560	4,658	98	4,815	4,957	142	5,853	5,925	72	6,427	6,491	64
	New CT	-	-	-	-	-	-	-	-	-	5,373	5,331	(42)
	New CC	-	-	-	-	-	-	-	-	-	3,045	3,038	(7)
SETRANS E Sum		273,448	275,249	1,801	285,029	287,577	2,548	300,806	303,315	2,510	320,675	321,753	1,077
SETRANS W	CC	31,610	30,898	(713)	39,824	39,064	(760)	50,547	49,502	(1,045)	64,096	63,520	(576)
	Coal	56,497	56,586	89	56,517	56,531	14	57,393	57,397	5	58,095	58,086	(9)
	Hydro	581	581	-	581	581	-	581	581	-	581	581	-
	Nuke	38,906	38,906	-	38,920	38,920	-	39,055	39,055	-	39,016	39,016	-
	Other	1,608	1,608	-	1,610	1,610	-	1,606	1,606	-	1,606	1,606	-
	Peaker	634	612	(22)	702	694	(9)	993	1,012	19	1,410	1,420	10
	ST/G/O/D	1,815	1,936	121	2,218	2,431	213	4,879	4,906	27	9,781	10,147	366
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SETRANS W Sum		*131,651*	*131,126*	*(525)*	*140,372*	*139,830*	*(542)*	*155,054*	*154,059*	*(995)*	*174,586*	*174,376*	*(210)*
SPP	CC	26,796	27,017	221	33,017	33,223	206	45,171	45,296	124	58,991	59,146	154
	Coal	146,368	146,403	35	143,750	143,858	109	142,381	142,456	76	138,289	138,337	48
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-
	Nuke	9,358	9,358	-	9,337	9,337	-	9,381	9,381	-	9,337	9,337	-
	Other	11,249	11,249	-	11,252	11,252	-	11,245	11,245	-	11,254	11,254	-

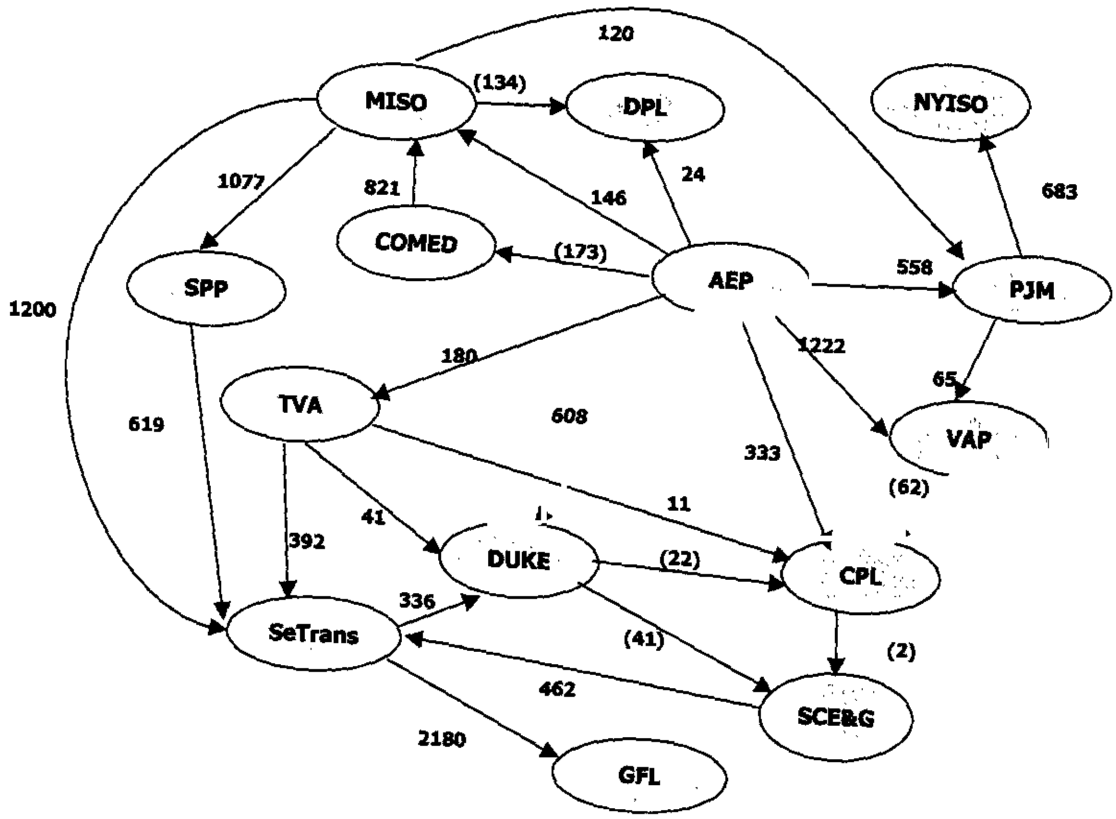
Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
	Peaker	263	266	2	415	386	(29)	1,118	1,118	(0)	1,969	2,003	34
	ST/G/O/D	3,696	3,782	86	4,903	5,035	132	7,973	8,103	131	14,000	14,126	126
	New CT	-	-	-	-	-	-	-	-	-	329	320	(9)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SPP Sum		208,770	209,115	344	213,714	214,131	418	228,309	228,639	330	245,208	245,562	354
TVA	CC	6,435	6,570	134	8,275	8,436	162	14,514	14,735	222	23,475	23,643	168
	Coal	103,982	104,192	210	107,644	107,874	230	109,426	109,490	64	110,966	111,020	54
	Hydro	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-
	Nuke	44,740	44,740	-	44,738	44,738	-	44,713	44,713	-	44,671	44,671	-
	Other	2,653	2,653	-	2,655	2,655	-	2,656	2,656	-	2,655	2,655	0
	Peaker	133	127	(6)	219	247	28	485	514	29	1,152	1,101	(52)
	PSH	2,377	2,383	6	2,536	2,529	(7)	2,428	2,435	6	2,306	2,556	250
	ST/G/O/D	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	-	-	-	1,259	1,176	(83)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
TVA Sum		180,173	180,517	343	185,918	186,332	413	194,074	194,395	321	206,337	206,675	338
VAP	CC	5,525	3,587	(1,938)	7,102	4,833	(2,268)	9,716	6,733	(2,983)	14,332	10,875	(3,458)
	Coal	41,062	39,488	(1,574)	42,071	40,657	(1,414)	43,592	42,757	(835)	44,834	44,313	(521)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,189	2,142	(47)	2,330	2,309	(21)	2,344	2,334	(10)	2,367	2,358	(9)
	Peaker	718	695	(23)	940	982	42	1,721	1,605	(116)	2,103	1,943	(159)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	4,741	3,859	(882)	5,797	4,905	(892)	7,016	6,220	(795)	8,339	7,682	(657)
	New CT	-	-	-	-	-	-	393	-	(393)	1,952	1,503	(449)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
VAP Sum		84,292	79,827	(4,465)	88,180	83,628	(4,553)	95,106	89,974	(5,132)	104,187	98,934	(5,253)

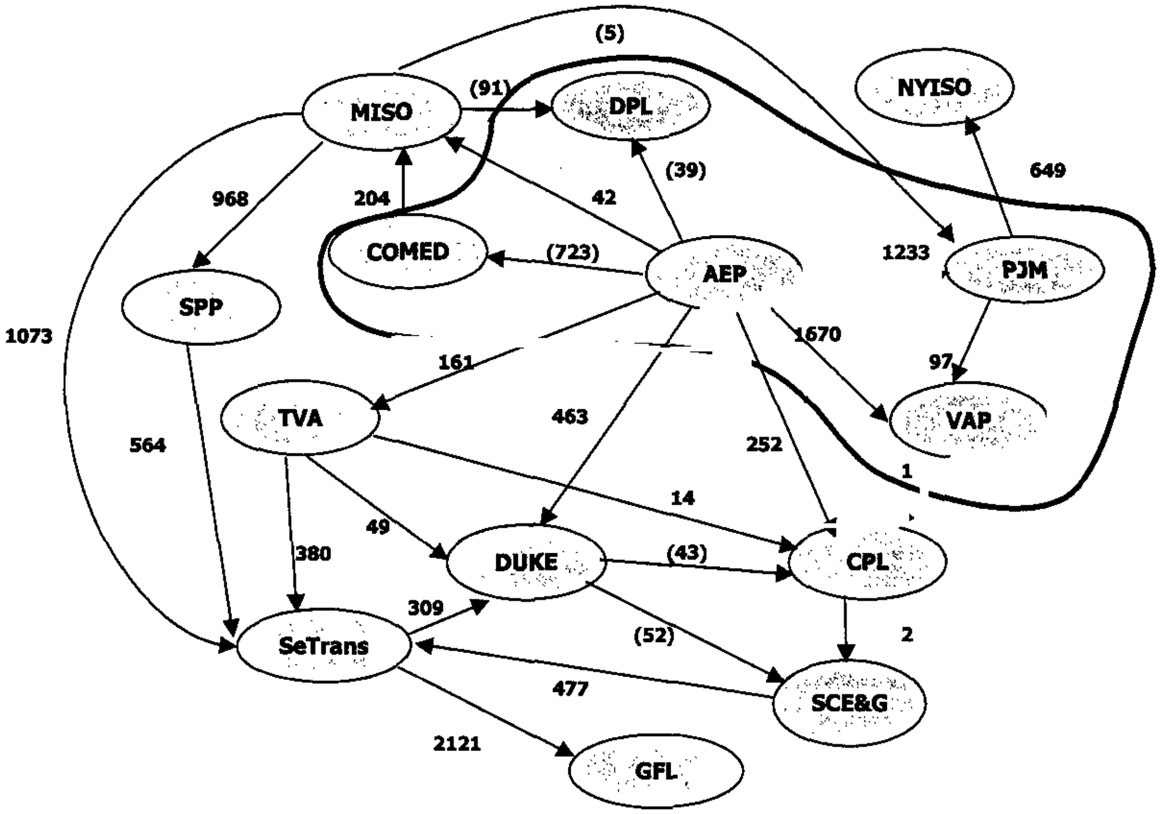
Table A-22: Average VAP Net Imports by Source (MW) 2005-2014, High Fuel Prices

Period	Imports/Transfers	2005 Base Case	2007 Base Case	2010 Base Case	2014 Base Case	2005 Change Case	2007 Change Case	2010 Change Case	2014 Change Case
Off-Peak	Average of VAP Net Imports	1,764	1,805	1,954	2,015	2,061	2,095	2,173	2,226
	Average Transfers from AEP	1,566	1,551	1,705	1,558	1,935	1,847	1,906	1,739
	Average Transfers from PJM	85	155	183	413	89	227	271	525
	Average Transfers from CPL	112	100	66	44	37	21	(3)	(38)
On-Peak	Average of VAP Net Imports	893	760	493	233	1,440	1,373	1,235	1,043
	Average Transfers from AEP	843	733	445	200	1,378	1,275	865	524
	Average Transfers from PJM	43	58	103	175	105	169	464	675
	Average Transfers from CPL	7	(31)	(55)	(142)	(43)	(70)	(95)	(156)
All-Hours	Average of VAP Net Imports	1,349	1,307	1,258	1,166	1,765	1,751	1,726	1,662
	Average Transfers from AEP	1,222	1,161	1,105	911	1,670	1,575	1,410	1,160
	Average Transfers from PJM	65	108	145	300	97	199	363	597
	Average Transfers from CPL	62	37	9	(45)	(1)	(22)	(47)	(94)

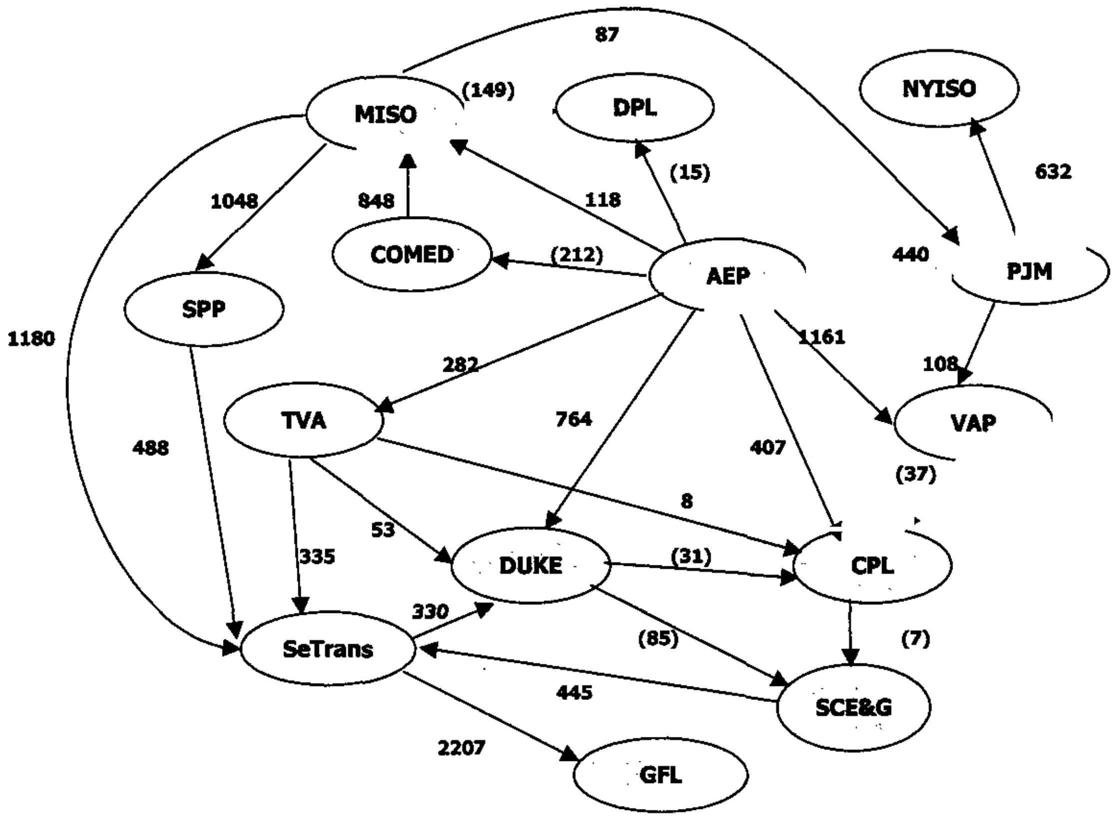
Pool to Pool All-Hour Average Transfers (MW)
2005 High Fuel/Base



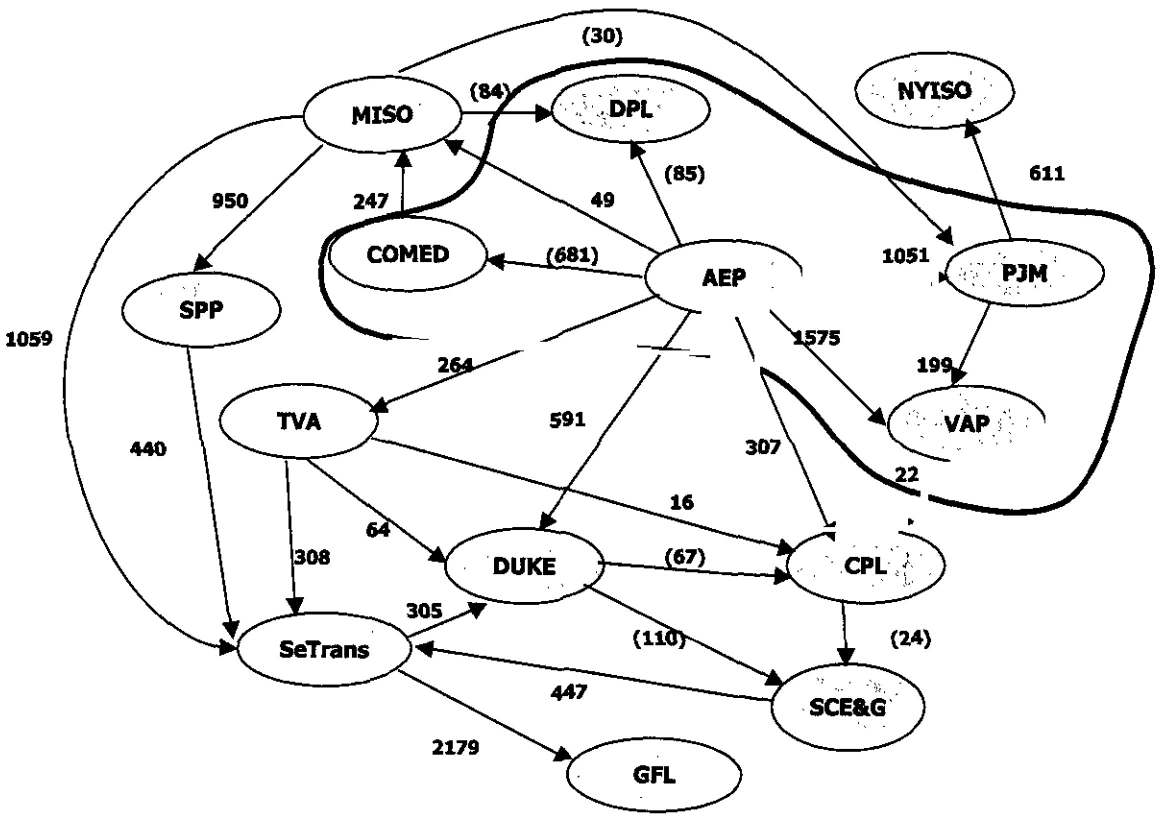
Pool to Pool All-Hour Average Transfers (MW)
2005 High Fuel/Change



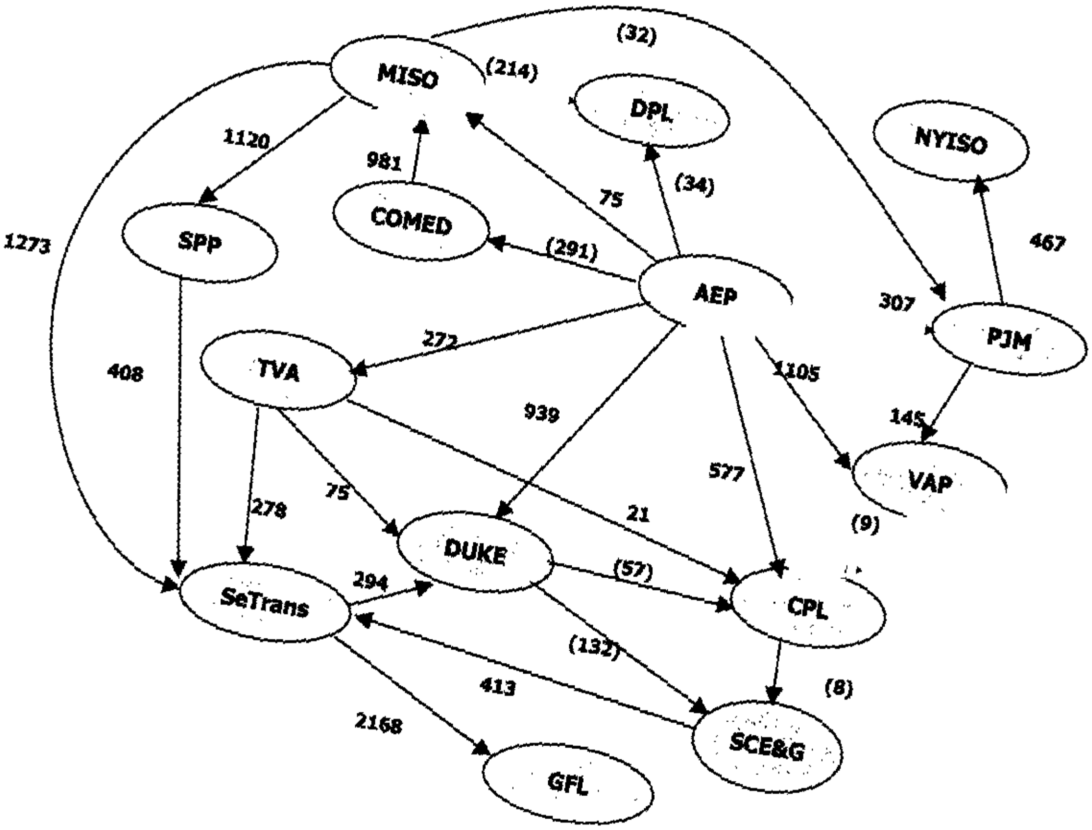
Pool to Pool All-Hour Average Transfers (MW)
2007 High Fuel/Base



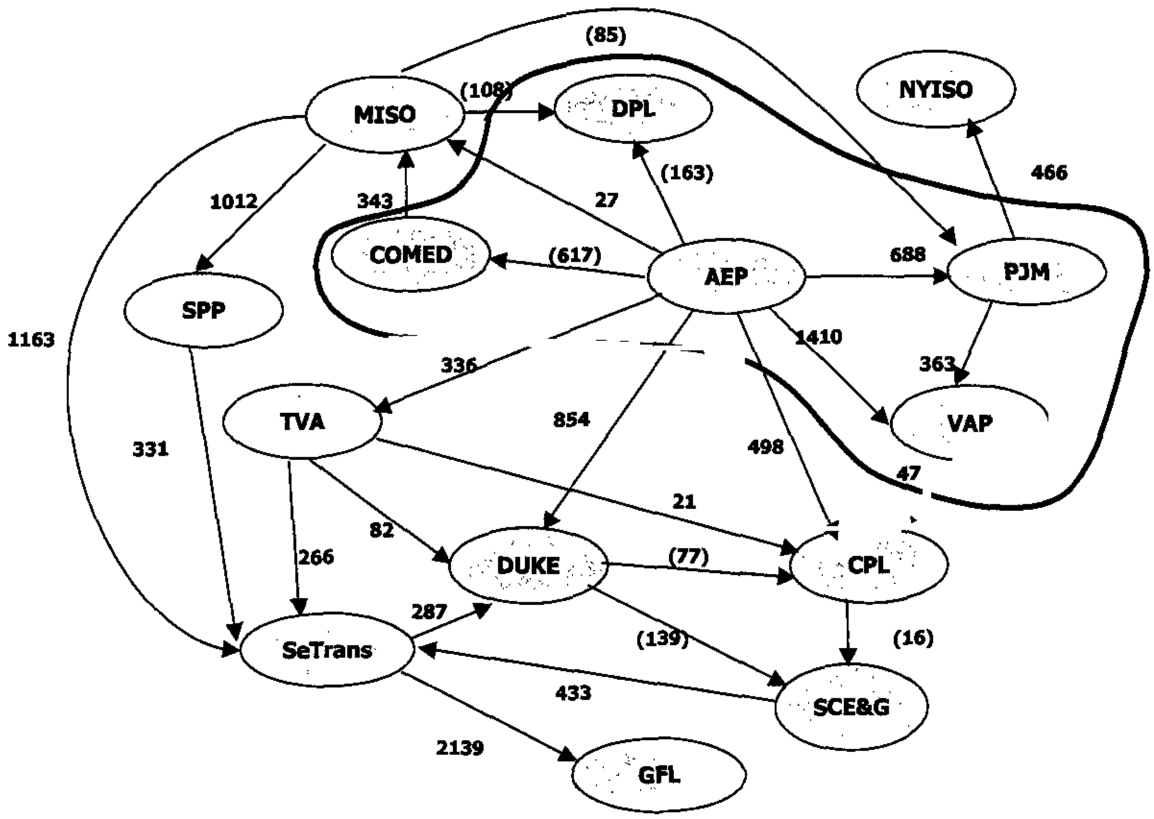
Pool to Pool All-Hour Average Transfers (MW)
2007 High Fuel/Change



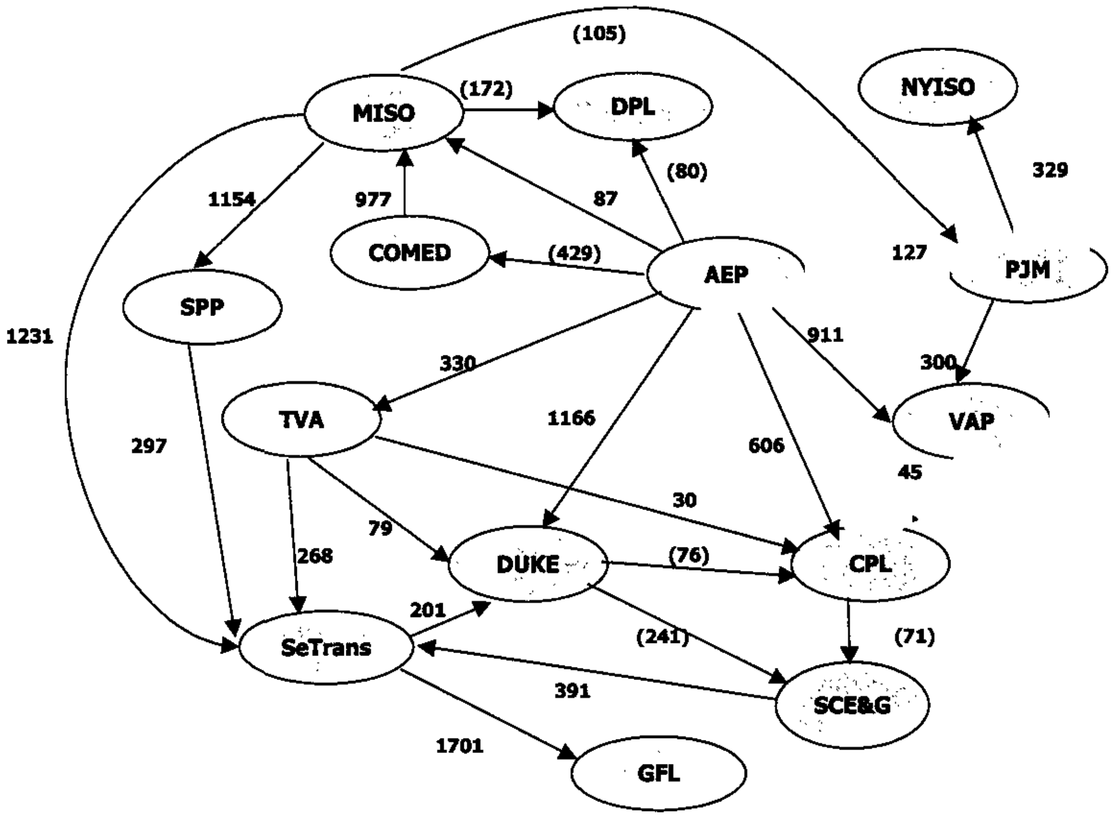
Pool to Pool All-Hour Average Transfers (MW)
2010 High Fuel/Base



Pool to Pool All-Hour Average Transfers (MW)
2010 High Fuel/Change



Pool to Pool All-Hour Average Transfers (MW)
2014 High Fuel/Base



Pool to Pool All-Hour Average Transfers (MW)
2014 High Fuel/Change

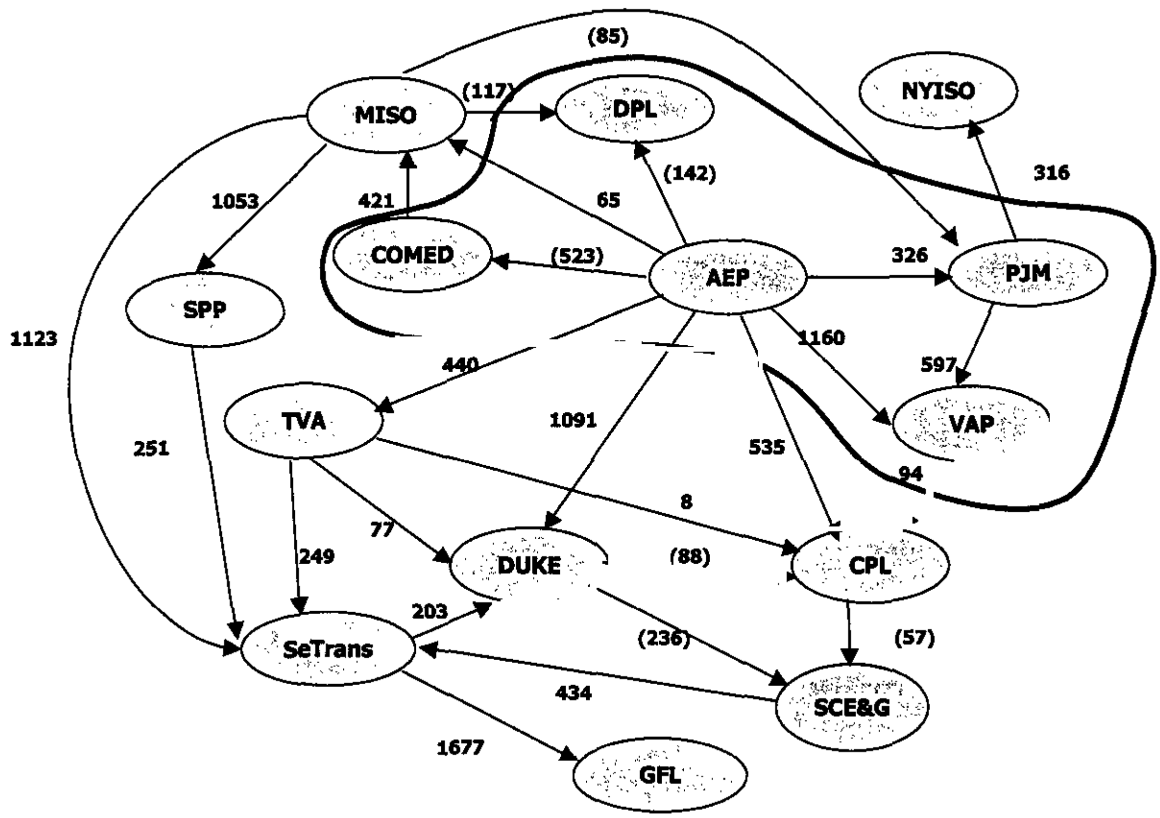


Table A-23: Generation by Type and Pool (GWh), High Fuel Prices

		2005			*2007*			*2010*			*2014*		
Capacity Pool	**TYPE**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**
Non-PJM	CC	193,665	196,743	3,078	229,789	232,917	3,128	298,980	301,730	2,750	387,043	388,281	1,238
	Coal	1,331,021	1,334,905	3,884	1,354,481	1,358,170	3,688	1,377,395	1,380,625	3,230	1,391,696	1,393,401	1,705
	Hydro	100,956	100,956	-	100,956	100,956	(0)	100,956	100,956	-	100,956	100,956	-
	New CC	-	-	-	-	-	-	6,432	6,446	14	23,299	23,334	35
	New CT	-	-	-	252	257	4	4,731	4,710	(21)	33,499	34,642	1,142
	Nuke	411,921	411,926	5	411,791	411,808	18	412,133	412,153	20	412,004	412,010	6
	Other	61,990	61,992	2	61,999	62,001	2	61,970	61,971	1	61,953	61,963	10
	Peaker	8,201	8,180	(21)	14,511	14,552	40	24,324	24,600	276	28,385	28,942	557
	PSH	17,069	17,094	25	16,771	16,853	82	15,421	15,426	5	13,841	13,807	(34)
	ST/G/O/D	100,103	100,771	668	111,532	112,421	889	125,567	126,277	710	153,581	154,648	1,067
Non-PJM Total		2,224,925	2,232,567	7,642	2,302,081	2,309,933	7,852	2,427,909	2,434,895	6,987	2,606,256	2,611,982	5,726
PJM (Expanded)	CC	22,164	19,224	(2,940)	29,113	26,026	(3,087)	40,086	38,412	(1,674)	62,621	61,564	(1,057)
	Coal	416,816	413,175	(3,641)	429,065	425,807	(3,258)	446,002	443,393	(2,609)	458,180	456,631	(1,549)
	Hydro	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	481	15	(466)	3,670	1,796	(1,874)
	Nuke	239,971	239,975	4	239,971	239,971	1	239,946	239,941	(5)	239,858	239,857	(2)
	Other	9,372	9,340	(32)	9,514	9,506	(7)	9,522	9,519	(3)	9,554	9,546	(7)
	Peaker	1,127	1,044	(83)	1,888	1,831	(57)	3,285	3,233	(52)	4,709	5,018	308
	PSH	8,157	8,163	6	8,033	8,012	(21)	8,313	8,333	20	7,967	7,995	29
	ST/G/O/D	13,962	13,187	(775)	19,235	18,003	(1,232)	26,586	24,487	(2,099)	37,162	35,625	(1,537)
	Wind	337	329	(8)	336	330	(6)	337	333	(3)	343	340	(3)
PJM Total		719,981	712,512	(7,469)	745,229	737,561	(7,667)	782,633	775,741	(6,892)	832,139	826,447	(5,691)
Eastern Interconnection	CC	215,829	215,967	138	258,901	258,943	42	339,066	340,142	1,076	449,664	449,845	181
	Coal	1,747,836	1,748,080	243	1,783,546	1,783,976	430	1,823,398	1,824,018	621	1,849,876	1,850,032	157
	Hydro	109,030	109,030	-	109,030	109,030	(0)	109,030	109,030	-	109,030	109,030	-
	New CC	-	-	-	-	-	-	6,432	6,446	14	23,299	23,334	35
	New CT	-	-	-	252	257	4	5,212	4,725	(487)	37,169	36,438	(731)
	Nuke	651,892	651,901	9	651,761	651,779	18	652,078	652,094	15	651,862	651,866	4
	Other	71,362	71,333	(30)	71,513	71,508	(5)	71,492	71,490	(2)	71,507	71,509	2
	Peaker	9,328	9,224	(104)	16,400	16,383	(17)	27,609	27,833	224	33,094	33,959	865
	PSH	25,226	25,257	31	24,803	24,865	61	23,734	23,759	25	21,807	21,802	(5)
	ST/G/O/D	114,065	113,958	(107)	130,767	130,424	(343)	152,154	150,765	(1,389)	190,743	190,273	(470)
	Wind	337	329	(8)	336	330	(6)	337	333	(3)	343	340	(3)
EI Total		2,944,906	2,945,079	173	3,047,310	3,047,495	185	3,210,541	3,210,636	95	3,438,394	3,438,429	35

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	*Delta* (Change - Base)	Base Case	Change Case	*Delta* (Change - Base)	Base Case	Change Case	*Delta* (Change - Base)	Base Case	Change Case	*Delta* (Change - Base)
AEP	CC	167	514	347	264	789	526	1,380	2,673	1,293	4,793	7,091	2,298
	Coal	132,267	133,331	1,065	137,298	137,869	571	142,526	141,915	(611)	146,128	145,833	(295)
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,888	15,888	-	15,913	15,913	-	15,885	15,885	-
	Other	213	213	(0)	214	213	(0)	214	214	-	214	213	(0)
	Peaker	-	-	-	1	3	2	19	21	2	31	90	59
	PSH	786	784	(2)	752	750	(1)	674	676	2	528	525	(3)
	ST/G/O/D	0	0	0	1	1	0	1	3	2	2	4	2
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		150,602	152,012	1,410	155,700	156,797	1,097	162,010	162,698	688	168,864	170,925	2,061
COMED	CC	1,201	674	(528)	1,943	1,209	(734)	2,758	2,134	(624)	3,767	3,363	(405)
	Coal	28,526	29,144	618	30,360	31,111	751	33,599	34,408	809	35,600	36,041	441
	Nuke	80,328	80,332	4	80,363	80,364	1	80,297	80,292	(5)	80,278	80,277	(2)
	Peaker	163	86	(77)	301	168	(133)	470	356	(114)	919	421	(498)
	ST/G/O/D	884	292	(592)	1,564	539	(1,026)	3,610	897	(2,713)	6,677	3,586	(3,090)
	New CT	-	-	-	-	-	-	90	15	(74)	726	248	(477)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		111,103	110,528	(575)	114,532	113,391	(1,141)	120,824	118,103	(2,721)	127,967	123,937	(4,030)
CPL	CC	1,236	1,737	501	1,841	2,337	496	2,847	3,149	302	4,024	4,139	115
	Coal	35,577	35,676	99	37,176	37,301	125	38,369	38,471	102	39,960	40,021	60
	Hydro	949	949	-	949	949	-	949	949	-	949	949	-
	Nuke	24,491	24,491	-	24,494	24,494	-	24,519	24,519	-	24,507	24,507	-
	Other	2,512	2,512	-	2,504	2,504	-	2,509	2,509	(1)	2,509	2,509	0
	Peaker	299	310	11	573	630	57	1,048	1,162	114	1,174	1,290	117
	New CT	-	-	-	-	-	-	477	400	(77)	2,853	3,196	344
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
CPL Sum		65,064	65,675	610	67,537	68,215	678	70,719	71,160	441	75,976	76,611	636
DP&L	Coal	18,137	18,305	168	19,062	19,106	44	20,311	20,512	201	21,373	21,469	96
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	-	-	-	11	1	(10)	19	23	4	77	40	(37)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		18,182	18,350	168	19,118	19,152	34	20,375	20,581	206	21,495	21,554	59

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
DUKE	CC	776	1,033	257	1,242	1,513	271	1,855	1,957	102	2,702	2,804	102
	Coal	51,256	51,411	154	52,870	53,002	132	54,112	54,180	68	55,566	55,584	19
	Hydro	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-
	Nuke	53,021	53,021	-	52,958	52,958	-	53,031	53,031	-	53,054	53,054	-
	Other	56	56	-	56	56	-	56	56	-	57	57	0
	Peaker	409	429	20	677	718	41	1,390	1,444	54	2,625	2,851	226
	PSH	3,791	3,794	3	3,618	3,680	63	3,322	3,332	9	2,558	2,509	(49)
	ST/G/O/D	3	4	1	2	2	0	7	8	1	4	10	6
	New CT	-	-	-	206	210	4	1,442	1,475	33	3,447	3,696	249
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DUKE Sum		113,577	114,012	436	115,894	116,404	510	119,483	119,749	266	124,277	124,830	553
GFL	CC	61,644	61,806	162	66,268	66,372	105	71,415	71,429	14	78,343	78,372	29
	Coal	55,811	55,896	85	56,289	56,373	84	56,545	56,617	71	57,113	57,118	5
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	214	214	-	214	214	-	214	214	-	214	214	-
	Nuke	29,964	29,964	-	29,889	29,897	9	29,929	29,929	-	29,886	29,886	-
	Other	3,147	3,147	-	3,148	3,150	2	3,147	3,147	-	3,148	3,148	-
	Peaker	1,833	1,832	(1)	4,726	4,690	(36)	4,045	4,074	29	3,044	3,063	19
	ST/G/O/D	38,064	38,318	254	41,665	41,743	78	44,083	44,196	113	48,622	48,661	40
	New CT	-	-	-	-	-	-	2,691	2,713	21	7,040	7,138	98
	New CC	-	-	-	-	-	-	6,432	6,446	14	20,269	20,288	19
GFL Sum		190,678	191,179	501	202,199	202,441	241	218,502	218,765	263	247,679	247,889	209
MISO E	CC	3,019	3,220	201	4,911	5,077	166	9,902	10,295	393	18,966	19,234	268
	Coal	321,465	323,678	2,213	329,611	331,721	2,110	343,140	345,250	2,110	354,919	356,109	1,190
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-
	Nuke	29,335	29,335	-	29,324	29,324	-	29,279	29,279	-	29,334	29,334	-
	Other	2,456	2,456	-	2,451	2,451	-	2,454	2,454	-	2,455	2,456	1
	Peaker	357	325	(32)	706	674	(32)	1,156	1,176	20	2,185	2,060	(125)
	PSH	5,498	5,501	3	5,207	5,200	(7)	4,951	4,942	(9)	4,047	4,036	(11)
	ST/G/O/D	794	736	(58)	1,498	1,463	(35)	3,405	3,508	103	7,977	7,980	3
	New CT	-	-	-	-	-	-	-	-	-	730	753	22
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO E Sum		365,581	367,908	2,327	376,367	378,568	2,202	396,946	399,562	2,616	423,272	424,620	1,347

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
MISO W	CC	5,872	6,061	189	8,085	8,221	136	12,442	12,621	179	17,806	17,982	176
	Coal	284,524	285,350	826	289,244	289,968	724	293,767	294,485	718	302,179	302,516	337
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-
	Nuke	56,836	56,841	5	56,881	56,890	9	56,844	56,864	20	56,813	56,820	7
	Other	10,571	10,573	2	10,575	10,575	1	10,542	10,543	2	10,548	10,557	9
	Peaker	3,405	3,412	7	4,673	4,687	14	10,419	10,429	10	9,713	9,881	168
	PSH	673	674	1	692	690	(2)	681	683	2	688	680	(8)
	ST/G/O/D	252	261	9	430	444	14	1,280	1,277	(2)	1,652	1,684	32
	New CT	-	-	-	-	-	-	-	-	-	11,492	11,776	284
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO W Sum		377,590	378,630	1,039	386,038	386,933	896	401,433	402,361	928	426,348	427,353	1,005
ISO-NE	CC	24,838	24,878	40	26,500	26,481	(20)	33,071	33,084	13	37,666	37,316	(350)
	Coal	21,593	21,568	(25)	21,866	21,841	(25)	22,059	22,059	0	22,130	22,131	1
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-
	Nuke	33,909	33,909	-	33,884	33,884	-	33,963	33,963	-	33,989	33,989	-
	Other	14,314	14,314	-	14,322	14,322	-	14,317	14,317	-	14,311	14,311	-
	Peaker	-	-	-	-	-	-	-	-	-	-	-	-
	PSH	1,047	1,046	(1)	1,061	1,062	0	853	855	1	790	806	16
	ST/G/O/D	17,048	17,025	(23)	19,124	19,188	64	18,469	18,457	(12)	20,988	21,382	395
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Sum		120,009	120,000	(9)	124,018	124,039	20	129,993	129,995	2	137,134	137,196	62
NYC	CC	6,186	6,270	84	6,384	6,491	107	6,792	6,882	90	7,319	7,365	45
	Other	179	179	-	179	179	-	179	179	-	179	179	-
	Peaker	330	330	1	198	202	4	247	246	(1)	441	452	11
	ST/G/O/D	18,355	18,335	(19)	19,000	19,184	184	20,131	20,276	145	21,473	21,684	211
	New CT	-	-	-	28	27	(1)	58	58	1	158	160	3
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYC Sum		25,050	25,115	65	25,790	26,083	293	27,407	27,642	234	29,569	29,840	270
NYL	CC	1,504	1,506	3	1,546	1,552	6	1,609	1,610	1	1,686	1,691	5
	Other	992	992	-	991	991	-	991	991	-	988	988	-
	Peaker	144	140	(3)	124	122	(2)	203	202	(1)	273	274	1

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	**TYPE**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**
	ST/G/O/D	8,214	8,250	36	8,787	8,804	17	9,639	9,620	(19)	10,923	10,929	6
	New CT	-	-	-	18	20	2	63	64	1	180	185	5
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYL Sum		10,853	10,889	36	11,466	11,489	23	12,505	12,487	(18)	14,051	14,068	17
NYO	CC	10,272	10,569	297	11,149	11,259	110	13,115	13,085	(29)	15,289	15,191	(98)
	Coal	26,608	26,284	(324)	27,075	26,803	(271)	27,834	27,610	(224)	28,310	28,171	(139)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	28,623	28,623	-	28,623	28,623	(0)	28,623	28,623	-	28,623	28,623	-
	Nuke	37,813	37,814	1	37,716	37,717	1	37,737	37,737	0	37,719	37,718	(2)
	Other	2,408	2,408	0	2,403	2,403	-	2,402	2,402	-	2,398	2,398	-
	Peaker	1	1	(0)	0	0	(0)	1	1	0	4	4	0
	PSH	2,068	2,080	11	2,063	2,069	6	1,935	1,932	(3)	1,778	1,782	3
	ST/G/O/D	7,505	7,896	391	9,395	9,586	190	10,193	10,368	175	12,352	12,424	72
	New CT	-	-	-	-	-	-	-	-	-	63	107	45
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYO Sum		115,298	115,674	376	118,424	118,461	36	121,840	121,759	(81)	126,536	126,417	(119)
PJM	CC	15,943	14,572	(1,371)	20,249	19,233	(1,016)	26,850	26,772	(78)	40,187	40,290	103
	Coal	196,141	192,132	(4,010)	199,585	196,220	(3,365)	205,507	203,160	(2,346)	209,701	208,341	(1,360)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,393	117,393	-	117,470	117,470	-	117,419	117,419	-	117,446	117,446	-
	Other	6,907	6,907	-	6,913	6,913	-	6,907	6,907	-	6,914	6,911	(3)
	Peaker	312	343	30	662	706	44	1,158	1,320	162	1,800	2,606	806
	PSH	4,871	4,879	8	4,781	4,762	(19)	4,822	4,840	18	4,620	4,651	31
	ST/G/O/D	8,289	8,831	541	11,825	12,433	608	15,976	17,261	1,285	22,142	24,199	2,057
	Wind	337	329	(8)	336	330	(6)	337	333	(3)	343	340	(3)
	New CT	-	-	-	-	-	-	-	-	-	1,023	-	(1,023)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		355,794	350,984	(4,810)	367,422	363,668	(3,754)	384,575	383,613	(963)	409,775	410,384	609
SCE&G	CC	1,827	1,961	134	2,495	2,812	317	3,542	3,810	267	5,346	5,512	166
	Coal	36,943	37,090	147	38,105	38,261	156	38,978	39,063	85	39,881	39,912	31
	Hydro	875	875	-	875	875	-	875	875	-	875	875	-
	Nuke	7,611	7,611	-	7,610	7,610	-	7,609	7,609	-	7,650	7,650	-
	Other	1,004	1,004	-	1,007	1,007	-	1,008	1,008	-	1,006	1,006	-

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
	Peaker	7	7	(0)	24	28	5	64	72	9	27	32	5
	PSH	964	978	14	901	911	11	849	853	4	627	616	(11)
	ST/G/O/D	8	9	1	24	28	5	49	54	5	50	64	15
	New CT	-	-	-	-	-	-	-	-	-	1,049	1,080	31
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SCE&G Sum		49,240	49,536	296	51,040	51,533	493	52,976	53,346	370	56,511	56,748	237
SETRANS E	CC	16,530	17,638	1,108	22,388	24,036	1,648	35,867	37,503	1,636	54,571	55,511	940
	Coal	188,144	188,573	429	192,465	192,779	314	191,518	191,754	236	182,305	182,385	80
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-
	Nuke	45,935	45,935	-	46,039	46,039	-	46,072	46,072	-	46,029	46,029	-
	Other	8,842	8,842	-	8,847	8,847	-	8,856	8,856	-	8,839	8,839	(1)
	Peaker	428	416	(12)	1,436	1,444	8	3,246	3,273	27	4,785	4,859	74
	PSH	433	423	(10)	355	369	14	294	290	(4)	163	163	-
	ST/G/O/D	4,592	4,662	70	4,843	4,930	87	6,086	5,992	(94)	6,628	6,699	71
	New CT	-	-	-	-	-	-	-	-	-	5,110	5,144	34
	New CC	-	-	-	-	-	-	-	-	-	3,030	3,045	16
SETRANS E Sum		274,083	275,668	1,584	285,552	287,623	2,071	301,118	302,918	1,800	320,639	321,854	1,215
SETRANS W	CC	29,993	29,697	(295)	38,525	37,871	(654)	49,871	49,219	(651)	63,661	63,267	(394)
	Coal	56,062	56,120	58	56,110	56,171	61	57,136	57,111	(25)	57,927	57,928	1
	Hydro	581	581	-	581	581	-	581	581	-	581	581	-
	Nuke	38,906	38,906	-	38,920	38,920	-	39,055	39,055	-	39,016	39,016	-
	Other	1,608	1,608	-	1,610	1,610	-	1,606	1,606	-	1,606	1,606	-
	Peaker	656	644	(12)	775	762	(13)	985	988	3	1,392	1,405	13
	ST/G/O/D	1,829	1,695	(135)	2,155	2,269	115	4,609	4,814	205	9,352	9,390	38
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SETRANS W Sum		129,635	129,251	(384)	138,676	138,184	(491)	153,841	153,373	(468)	173,535	173,193	(342)
SPP	CC	25,178	25,437	259	31,616	31,777	160	43,954	44,069	114	58,007	58,212	205
	Coal	146,482	146,559	78	143,904	144,043	139	142,535	142,614	79	138,426	138,480	54
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-
	Nuke	9,358	9,358	-	9,337	9,337	-	9,381	9,381	-	9,337	9,337	-
	Other	11,249	11,249	-	11,252	11,252	-	11,245	11,245	-	11,254	11,254	-

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
	Peaker	206	202	(4)	370	343	(27)	1,033	1,015	(18)	1,787	1,823	36
	ST/G/O/D	3,439	3,579	140	4,608	4,779	170	7,615	7,706	91	13,560	13,739	179
	New CT	-	-	-	-	-	-	-	-	-	288	296	8
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SPP Sum		206,952	207,425	473	212,128	212,571	443	226,804	227,070	266	243,699	244,181	482
TVA	CC	4,791	4,930	139	6,837	7,116	279	12,697	13,018	321	21,657	21,686	29
	Coal	106,556	106,700	145	109,766	109,905	140	111,401	111,411	9	112,979	113,046	67
	Hydro	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-
	Nuke	44,740	44,740	-	44,738	44,738	-	44,713	44,713	-	44,671	44,671	-
	Other	2,653	2,653	-	2,655	2,655	-	2,656	2,656	-	2,655	2,655	0
	Peaker	126	131	5	231	252	21	487	518	31	936	949	13
	PSH	2,596	2,599	3	2,873	2,870	(3)	2,535	2,540	4	3,190	3,215	25
	ST/G/O/D	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	-	-	-	1,090	1,110	20
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
TVA Sum		181,314	181,607	292	186,952	187,389	437	194,342	194,708	366	207,030	207,183	153
VAP	CC	4,853	3,464	(1,388)	6,657	4,794	(1,862)	9,098	6,833	(2,265)	13,874	10,820	(3,054)
	Coal	41,745	40,263	(1,482)	42,761	41,501	(1,259)	44,060	43,397	(662)	45,377	44,946	(431)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,206	2,175	(32)	2,342	2,335	(7)	2,356	2,353	(3)	2,381	2,377	(4)
	Peaker	652	616	(36)	914	954	40	1,620	1,513	(107)	1,882	1,861	(21)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	4,788	4,064	(724)	5,844	5,030	(815)	6,999	6,326	(673)	8,342	7,837	(506)
	New CT	-	-	-	-	-	-	392	-	(392)	1,922	1,548	(374)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
VAP Sum		84,300	80,638	(3,663)	88,458	84,555	(3,903)	94,849	90,747	(4,102)	104,037	99,647	(4,390)

Table A-25: Generation Cost ($k), High Fuel

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	2,152,216	2,201,423	49,207	2,174,579	2,215,008	40,430	2,351,521	2,403,291	51,770	2,619,628	2,718,016	98,388
COED	1,108,962	1,053,096	(55,866)	1,165,885	1,084,256	(81,629)	1,341,785	1,196,294	(145,492)	1,608,930	1,415,169	(193,761)
CPL	971,802	999,776	27,974	1,013,408	1,040,625	27,217	1,151,828	1,170,810	18,982	1,398,797	1,432,658	33,861
DP&L	349,812	353,424	3,611	342,903	343,497	594	381,822	386,922	5,100	419,636	419,626	(10)
DUKE	1,148,830	1,165,325	16,495	1,204,323	1,220,565	16,242	1,380,280	1,390,844	10,564	1,651,434	1,684,779	33,345
GFL	5,515,566	5,533,680	18,114	5,909,656	5,915,765	6,109	6,481,555	6,491,597	10,042	7,642,129	7,652,451	10,322
MISO E	5,643,742	5,685,392	41,650	5,709,443	5,749,788	40,345	6,376,537	6,432,344	55,806	7,363,701	7,390,981	27,280
MISO W	4,366,728	4,389,203	22,475	4,536,743	4,554,301	17,557	5,104,385	5,121,042	16,657	5,982,797	6,020,467	37,669
ISO-NE	2,808,023	2,808,515	493	2,885,796	2,885,707	(89)	3,126,949	3,127,074	125	3,455,234	3,455,988	754
NYC	1,036,892	1,040,310	3,418	1,015,608	1,026,537	10,929	1,074,106	1,082,635	8,529	1,165,409	1,175,844	10,435
NYL	468,178	470,467	2,289	472,529	473,677	1,149	517,806	516,858	(949)	593,292	594,319	1,026
NYO	1,769,810	1,792,930	23,121	1,823,211	1,825,313	2,102	1,981,478	1,979,805	(1,673)	2,202,679	2,198,882	(3,797)
PJM	5,224,665	5,124,655	(100,010)	5,432,629	5,365,272	(67,358)	6,116,894	6,145,587	28,694	7,190,830	7,254,348	63,519
SCE&G	844,834	853,855	9,021	865,596	882,677	17,080	939,723	953,100	13,377	1,116,618	1,126,218	9,600
SETRANS E	4,613,851	4,672,872	59,021	4,871,900	4,949,744	77,844	5,520,836	5,583,171	62,335	6,596,703	6,640,607	43,904
SETRANS W	2,431,892	2,410,698	(21,194)	2,720,684	2,697,497	(23,186)	3,226,171	3,211,210	(14,962)	3,961,933	3,950,995	(10,937)
SPP	3,148,178	3,165,538	17,361	3,342,461	3,358,038	15,577	3,894,867	3,903,052	8,185	4,665,475	4,683,400	17,925
TVA	2,321,835	2,330,848	9,013	2,386,493	2,400,950	14,457	2,694,341	2,707,600	13,259	3,166,439	3,171,888	5,449
VAP	1,419,034	1,283,605	(135,429)	1,528,822	1,382,388	(146,434)	1,765,262	1,591,656	(173,606)	2,174,809	1,984,186	(190,623)
Total	47,344,848	47,335,611	(9,237)	49,402,670	49,371,607	(31,063)	55,428,146	55,394,890	(33,256)	64,976,472	64,970,820	(5,652)

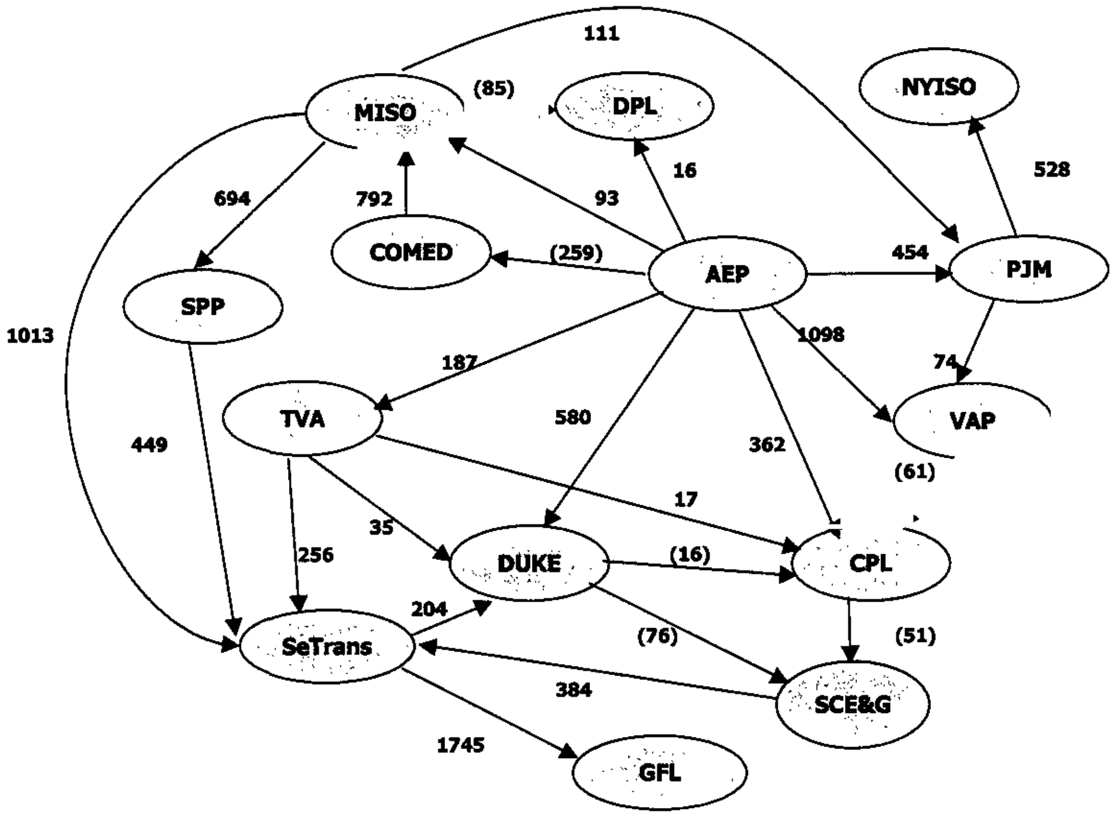
Table A-26: Average Spot Prices ($/MWh), High Fuel

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	22.51	23.16	0.65	23.21	23.97	0.76	26.71	27.37	0.66	31.99	32.17	0.18
COED	21.88	21.65	(0.23)	22.61	22.38	(0.23)	25.90	25.80	(0.10)	30.96	30.75	(0.20)
CPL	30.67	31.09	0.42	32.02	32.73	0.71	35.88	37.08	1.20	41.83	42.35	0.52
DP&L	22.31	22.63	0.32	22.63	23.28	0.65	25.82	26.65	0.84	30.83	31.27	0.44
DUKE	30.71	31.16	0.45	32.08	32.74	0.66	35.92	36.71	0.80	42.02	42.43	0.40
GFL	39.66	39.73	0.07	46.75	46.77	0.02	42.64	42.67	0.03	44.79	44.81	0.02
MISO E	23.45	23.67	0.22	24.05	24.32	0.27	27.46	27.74	0.28	32.29	32.52	0.23
MISO W	25.64	25.80	0.16	27.00	27.13	0.13	33.05	33.12	0.08	35.89	36.01	0.13
ISO-NE	38.47	38.45	(0.02)	37.96	37.96	0.00	38.50	38.48	(0.02)	39.86	39.94	0.08
NYC	40.00	39.97	(0.04)	38.54	38.65	0.10	39.65	39.69	0.04	41.92	42.01	0.09
NYL	42.88	42.82	(0.06)	41.72	41.70	(0.02)	43.25	44.08	0.84	45.06	45.04	(0.02)
NYO	34.16	33.82	(0.34)	33.45	33.27	(0.17)	34.66	34.49	(0.17)	36.25	36.15	(0.10)
PJM	29.89	29.51	(0.38)	30.15	29.95	(0.21)	32.99	33.26	0.27	36.69	37.57	0.88
SCE&G	30.01	30.39	0.39	31.11	31.74	0.63	34.66	35.27	0.61	39.90	40.28	0.38
SETRANS E	32.25	32.40	0.15	33.23	33.40	0.17	36.05	36.31	0.26	40.64	40.70	0.06
SETRANS W	33.16	33.19	0.03	33.87	33.95	0.07	35.74	35.80	0.06	38.13	38.14	0.02
SPP	29.83	29.85	0.02	30.68	30.75	0.07	33.38	33.46	0.08	36.57	36.67	0.10
TVA	28.52	28.63	0.11	29.31	29.54	0.23	32.59	32.79	0.20	36.75	36.77	0.02
VAP	34.24	32.37	(1.87)	35.07	33.56	(1.50)	38.30	37.61	(0.69)	42.97	42.28	(0.69)
Total	30.14	30.12	(0.02)	31.18	31.23	0.06	33.96	34.13	0.17	37.53	37.70	0.17

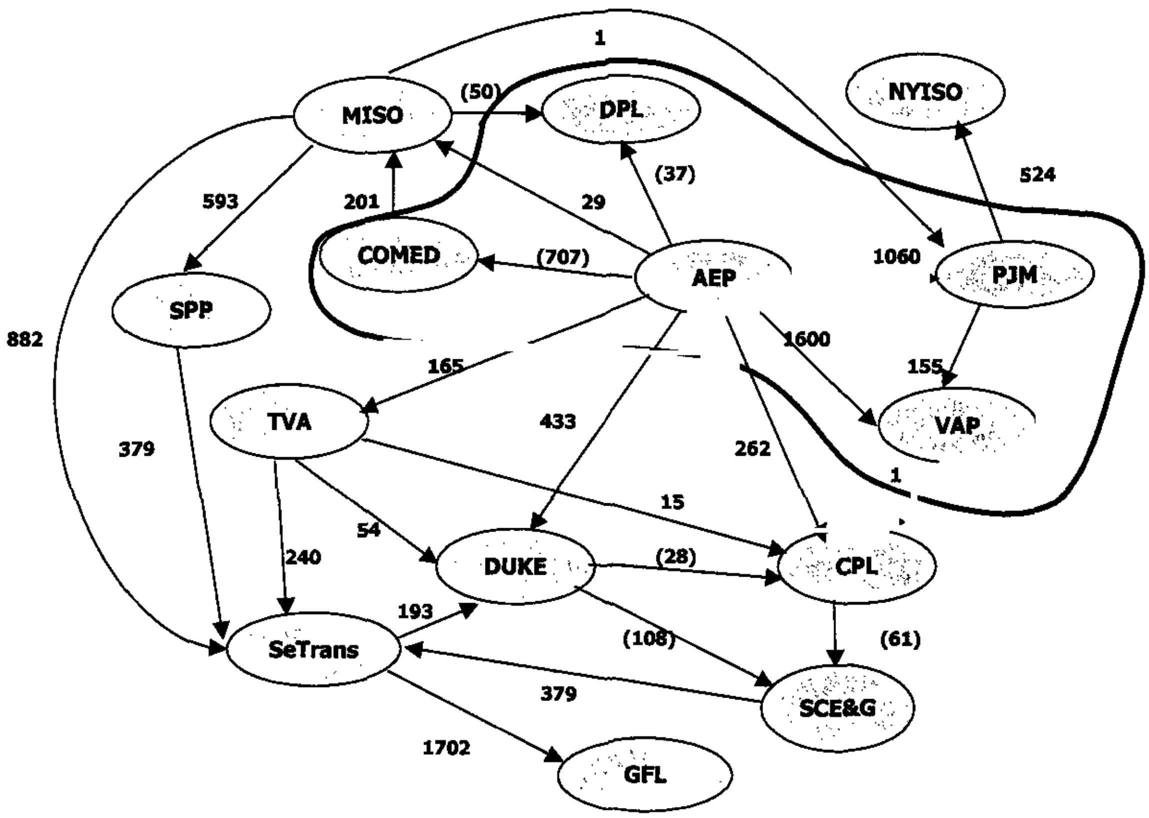
Table A-27: Average VAP Net Imports by Source (MW) 2005-2014, High Load

Period	Imports/Transfers	2005 Base Case	2007 Base Case	2010 Base Case	2014 Base Case	2005 Change Case	2007 Change Case	2010 Change Case	2014 Change Case
Off-Peak	Average of VAP Net Imports	1,722	1,770	1,906	1,980	2,063	2,106	2,197	2,259
	Average Transfers from AEP	1,494	1,521	1,624	1,526	1,918	1,862	1,882	1,750
	Average Transfers from PJM	100	154	191	432	98	224	313	553
	Average Transfers from CPL	128	96	90	22	46	20	2	(43)
On-Peak	Average of VAP Net Imports	697	584	346	137	1,413	1,303	1,238	1,068
	Average Transfers from AEP	663	555	334	140	1,249	1,071	729	544
	Average Transfers from PJM	45	68	95	109	218	282	622	576
	Average Transfers from CPL	(12)	(39)	(83)	(112)	(54)	(50)	(114)	(52)
All-Hours	Average of VAP Net Imports	1,234	1,206	1,163	1,102	1,753	1,723	1,740	1,692
	Average Transfers from AEP	1,098	1,061	1,010	866	1,600	1,485	1,333	1,176
	Average Transfers from PJM	74	113	145	278	155	252	460	564
	Average Transfers from CPL	61	32	8	(42)	(1)	(13)	(53)	(48)

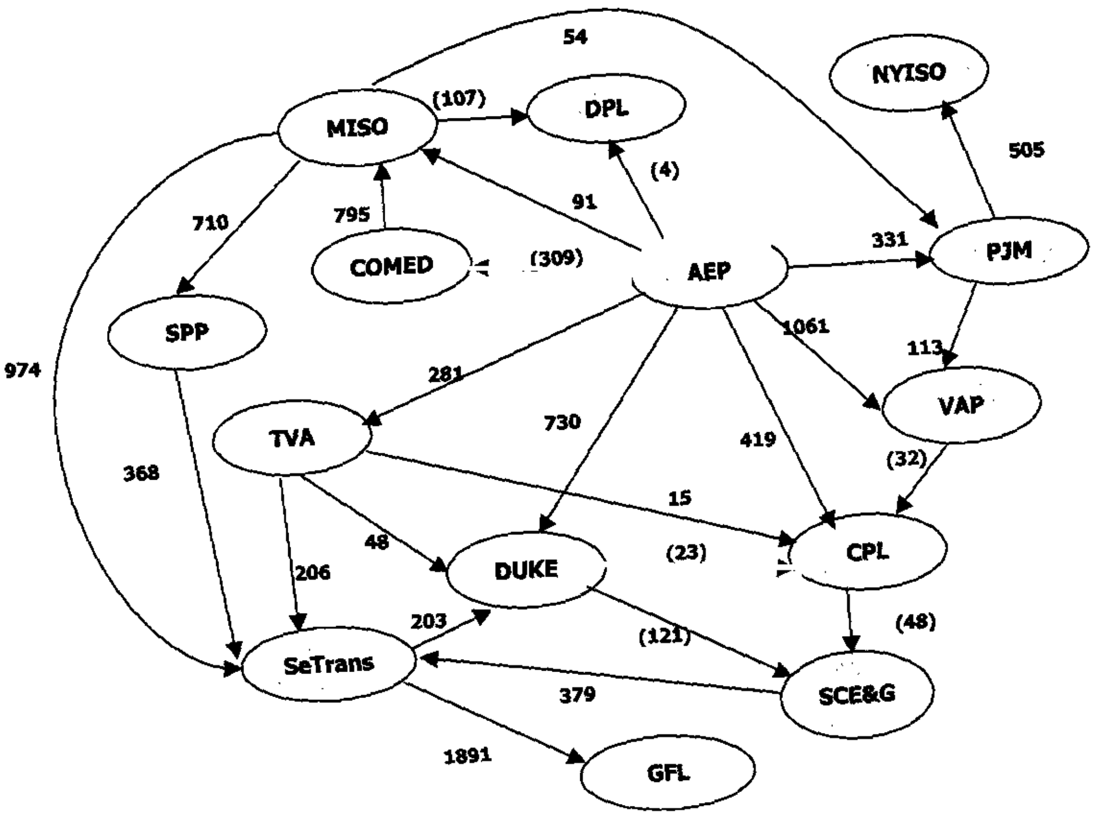
Pool to Pool All-Hour Average Transfers (MW)
2005 High Load/Base



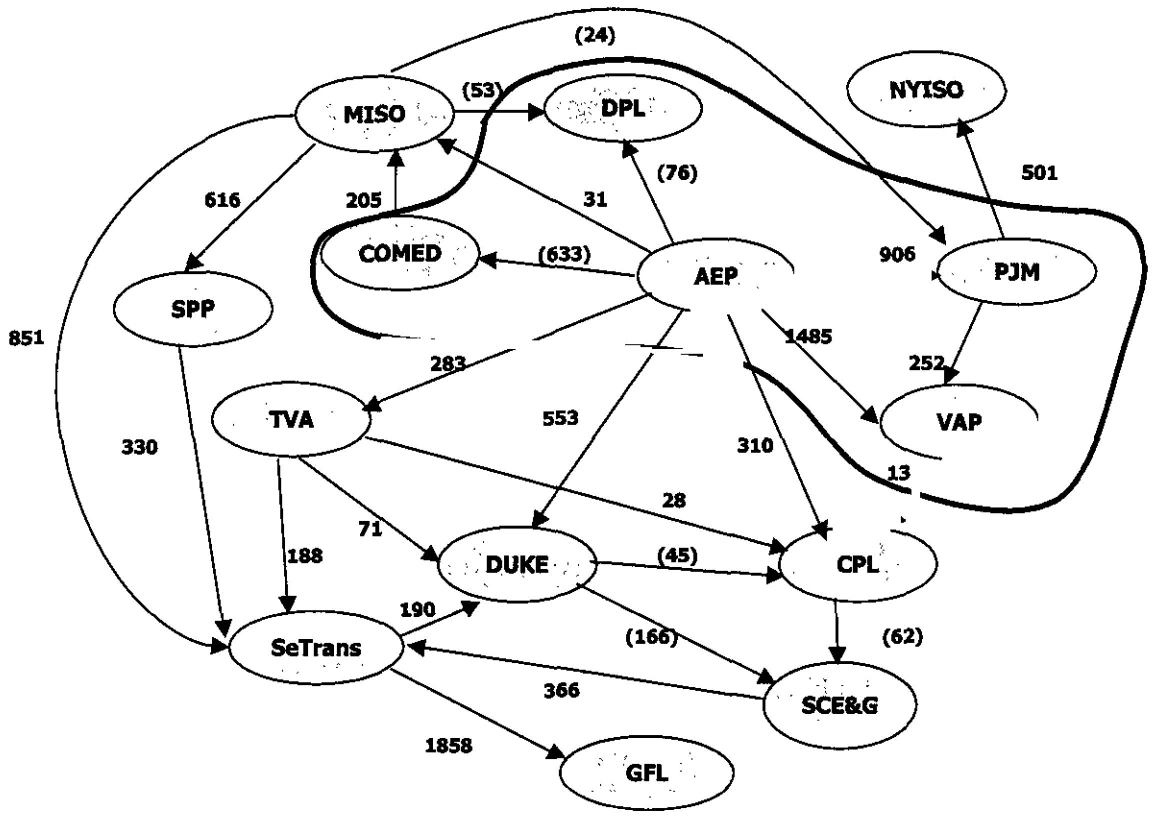
Pool to Pool All-Hour Average Transfers (MW)
2005 High Load/Change



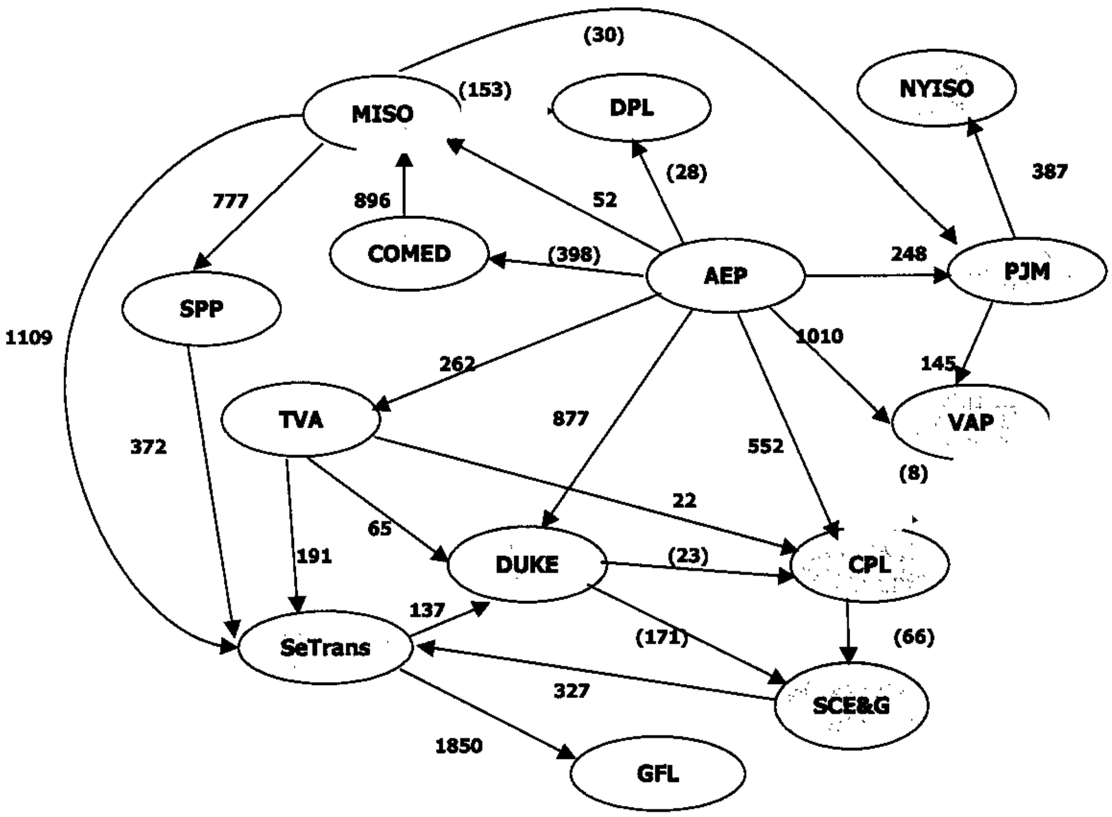
Pool to Pool All-Hour Average Transfers (MW)
2007 High Load/Base



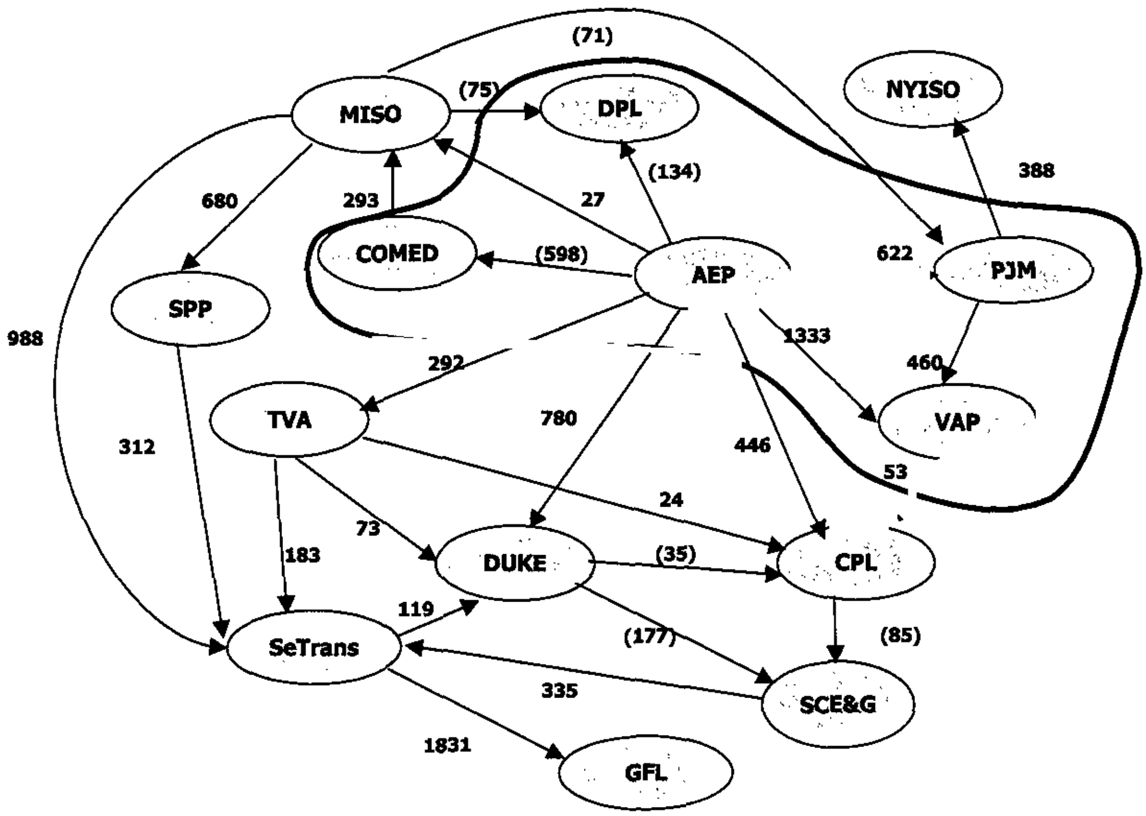
Pool to Pool All-Hour Average Transfers (MW)
2007 High Load/Change



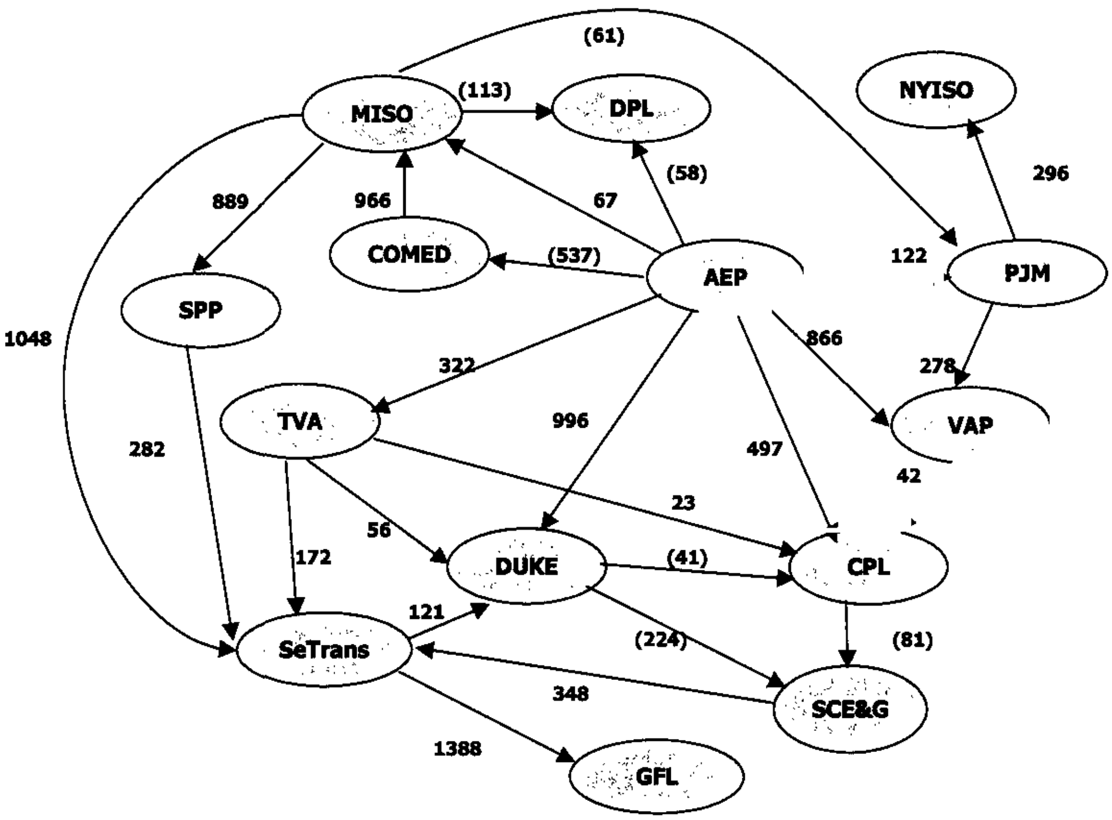
Pool to Pool All-Hour Average Transfers (MW)
2010 High Load/Base



Pool to Pool All-Hour Average Transfers (MW)
2010 High Load/Change



Pool to Pool All-Hour Average Transfers (MW)
2014 High Load/Base



Pool to Pool All-Hour Average Transfers (MW)
2014 High Load/Change

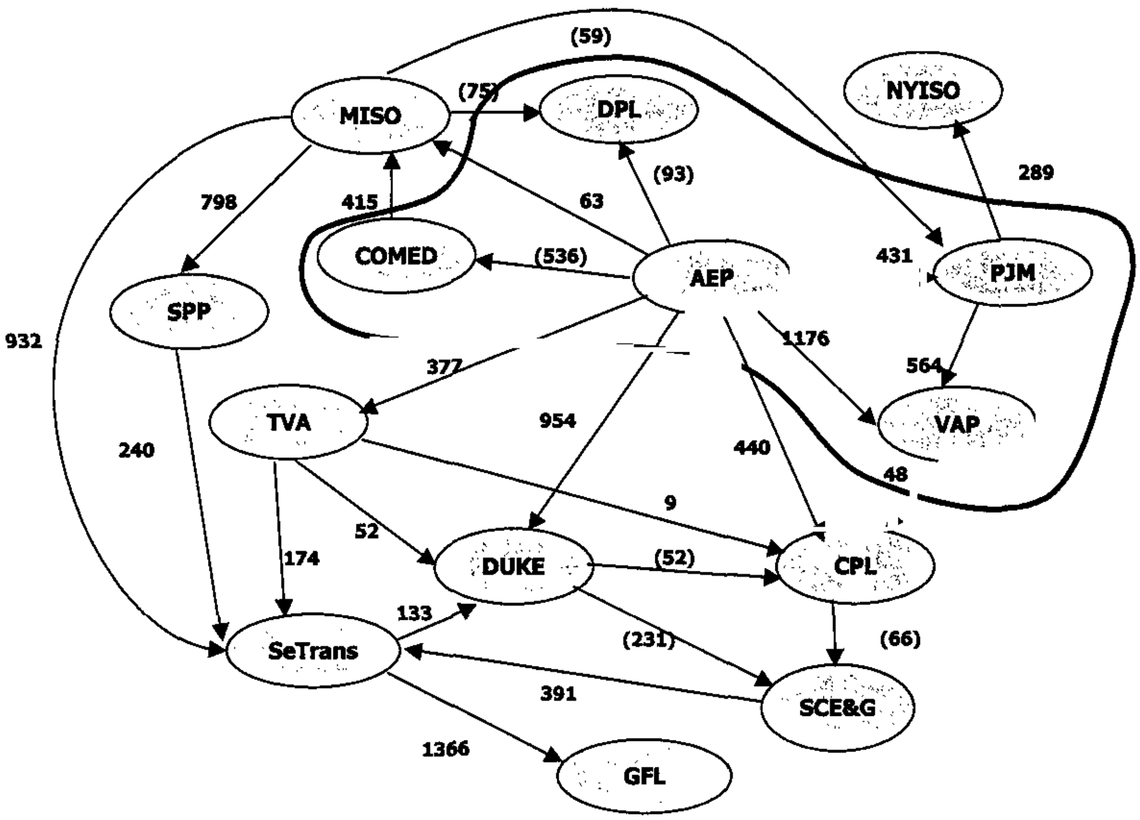


Table A-28: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	**TYPE**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**
	CC	231,512	234,109	2,597	266,969	269,759	2,791	335,612	338,144	2,532	414,807	415,943	1,135
	Coal	1,323,143	1,326,698	3,555	1,346,190	1,349,580	3,390	1,365,218	1,368,522	3,303	1,376,704	1,378,545	1,841
	Hydro	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-
	New CC	-	-	-	-	-	-	6,411	6,417	6	23,675	23,708	33
	New CT	-	-	-	466	484	18	6,562	6,349	(214)	47,583	49,149	1,565
	Nuke	411,983	411,981	(2)	411,822	411,827	5	412,078	412,084	6	412,037	412,038	1
	Other	61,952	61,954	2	61,997	61,998	1	61,979	61,985	5	61,973	61,982	9
	Peaker	15,033	15,094	61	23,998	24,336	338	38,020	38,474	454	44,519	44,969	450
	PSH	17,082	17,107	25	16,673	16,687	13	15,921	15,910	(10)	13,637	13,609	(28)
	ST/G/O/D	112,055	112,831	776	123,343	124,495	1,152	140,166	140,971	805	169,515	170,224	709
Non-PJM Total		2,273,717	2,280,731	7,014	2,352,414	2,360,121	7,707	2,482,922	2,489,811	6,888	2,665,407	2,671,122	5,715
PJM (Expanded)	CC	32,117	28,792	(3,325)	38,673	35,420	(3,253)	51,448	50,210	(1,237)	71,923	72,724	801
	Coal	412,848	410,874	(1,974)	425,047	423,079	(1,967)	439,957	437,718	(2,238)	450,656	448,949	(1,706)
	Hydro	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	612	22	(590)	5,373	2,289	(3,085)
	Nuke	239,964	239,968	4	239,953	239,951	(2)	239,872	239,868	(4)	239,780	239,777	(4)
	Other	9,359	9,329	(29)	9,502	9,491	(11)	9,511	9,503	(7)	9,536	9,525	(11)
	Peaker	2,048	1,866	(182)	3,283	3,020	(263)	5,355	5,068	(287)	8,294	7,792	(502)
	PSH	7,893	7,899	6	7,899	7,899	0	8,143	8,156	13	7,804	7,849	45
	ST/G/O/D	18,274	16,888	(1,386)	24,372	22,302	(2,070)	30,803	28,360	(2,443)	41,869	40,778	(1,091)
	Wind	339	332	(7)	335	329	(6)	333	329	(4)	344	341	(3)
PJM Total		730,917	724,023	(6,893)	757,138	749,566	(7,572)	794,107	787,310	(6,797)	843,655	838,099	(5,555)
Eastern Interconnection	CC	263,629	262,901	(728)	305,641	305,179	(462)	387,059	388,355	1,295	486,731	488,667	1,937
	Coal	1,735,991	1,737,572	1,581	1,771,237	1,772,659	1,422	1,805,175	1,806,240	1,065	1,827,359	1,827,494	135
	Hydro	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-
	New CC	-	-	-	-	-	-	6,411	6,417	6	23,675	23,708	33
	New CT	-	-	-	466	484	18	7,174	6,370	(804)	52,957	51,437	(1,519)
	Nuke	651,947	651,950	2	651,775	651,778	3	651,950	651,951	2	651,818	651,815	(2)
	Other	71,311	71,284	(27)	71,500	71,489	(10)	71,490	71,488	(2)	71,509	71,507	(2)
	Peaker	17,082	16,961	(121)	27,281	27,356	75	43,375	43,542	167	52,813	52,761	(52)
	PSH	24,975	25,006	31	24,572	24,586	14	24,064	24,067	3	21,441	21,458	17
	ST/G/O/D	130,329	129,719	(610)	147,715	146,797	(918)	170,968	169,331	(1,637)	211,384	211,002	(382)
	Wind	339	332	(7)	335	329	(6)	333	329	(4)	344	341	(3)
EI Total		3,004,633	3,004,754	121	3,109,552	3,109,687	135	3,277,030	3,277,120	91	3,509,061	3,509,221	160

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	CC	579	1,485	906	830	1,930	1,099	2,278	4,240	1,962	5,586	10,454	4,868
	Coal	131,081	132,571	1,491	136,231	137,403	1,171	140,841	140,490	(351)	144,074	143,882	(191)
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,885	15,885	-	15,913	15,913	-	15,884	15,884	-
	Other	214	214	(0)	213	213	(0)	214	214	-	214	214	-
	Peaker	-	-	-	24	34	10	176	233	57	251	304	54
	PSH	729	731	2	718	718	(1)	618	618	0	465	463	(2)
	ST/G/O/D	1	1	0	2	2	0	3	5	2	4	8	4
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		149,772	152,170	2,398	155,188	157,468	2,280	161,326	162,995	1,670	167,760	172,493	4,732
COMED	CC	2,258	1,776	(482)	2,656	2,113	(543)	3,261	3,015	(246)	4,344	4,079	(265)
	Coal	28,550	29,565	1,015	30,245	31,190	946	33,231	34,166	935	34,991	35,473	482
	Nuke	80,327	80,331	4	80,342	80,340	(2)	80,249	80,245	(4)	80,282	80,277	(6)
	Peaker	323	178	(145)	487	263	(224)	857	587	(270)	2,031	844	(1,188)
	ST/G/O/D	2,184	557	(1,627)	3,281	846	(2,435)	5,434	1,649	(3,785)	7,958	5,254	(2,704)
	New CT	-	-	-	-	-	-	160	22	(139)	1,527	391	(1,136)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		113,641	112,407	(1,235)	117,011	114,753	(2,257)	123,192	119,683	(3,509)	131,134	126,318	(4,816)
CPL	CC	2,194	2,612	419	2,768	3,110	342	3,578	3,797	219	4,600	4,664	64
	Coal	35,098	35,242	143	36,736	36,913	177	37,687	37,814	127	39,110	39,209	99
	Hydro	949	949	-	949	949	-	949	949	-	949	949	-
	Nuke	24,491	24,491	-	24,494	24,494	-	24,476	24,476	-	24,507	24,507	-
	Other	2,511	2,511	-	2,506	2,506	-	2,508	2,513	5	2,506	2,506	(1)
	Peaker	847	873	26	1,278	1,442	165	1,857	2,084	227	2,258	2,426	168
	New CT	-	-	-	-	-	-	853	647	(206)	4,585	5,109	524
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
CPL Sum		66,090	66,678	588	68,730	69,414	685	71,907	72,279	372	78,514	79,369	855
DP&L	Coal	18,106	18,260	155	18,920	19,091	171	19,957	20,202	245	20,794	20,903	109
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	8	-	(8)	38	17	(20)	150	162	13	334	208	(126)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		18,159	18,306	147	19,003	19,153	151	20,152	20,409	257	21,173	21,157	(17)

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
DUKE	CC	1,454	1,636	181	1,756	1,915	158	2,287	2,337	50	2,980	3,037	56
	Coal	50,666	50,859	193	52,325	52,551	226	53,456	53,593	137	54,821	54,889	67
	Hydro	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-
	Nuke	53,021	53,021	-	52,958	52,958	-	53,031	53,031	-	53,054	53,054	-
	Other	57	57	-	56	56	-	56	56	-	57	57	0
	Peaker	980	1,023	43	1,371	1,438	67	2,368	2,593	225	4,770	4,778	8
	PSH	3,789	3,807	17	3,579	3,595	16	3,292	3,312	20	2,447	2,440	(7)
	ST/G/O/D	9	10	2	9	10	1	13	13	0	15	18	2
	New CT	-	-	-	386	403	16	2,059	2,064	5	5,571	5,775	204
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DUKE Sum		114,240	114,677	437	116,706	117,192	486	120,829	121,265	436	127,981	128,312	331
GFL	CC	64,622	64,809	187	68,828	68,960	132	73,812	73,848	36	79,783	79,862	79
	Coal	55,142	55,209	66	55,793	55,874	82	56,219	56,285	66	56,804	56,823	19
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	214	214	-	214	214	-	214	214	-	214	214	-
	Nuke	29,966	29,966	-	29,896	29,896	-	29,953	29,953	-	29,885	29,885	-
	Other	3,147	3,147	-	3,150	3,150	-	3,147	3,147	-	3,147	3,147	-
	Peaker	3,563	3,566	2	7,173	7,171	(2)	6,424	6,476	52	4,883	4,892	9
	ST/G/O/D	42,002	42,123	121	44,295	44,363	68	46,349	46,363	14	50,247	50,260	12
	New CT	-	-	-	-	-	-	3,447	3,434	(14)	10,032	10,100	68
	New CC	-	-	-	-	-	-	6,411	6,417	6	20,603	20,606	3
GFL Sum		198,657	199,035	377	209,349	209,629	280	225,978	226,138	160	255,600	255,790	190
MISO E	CC	6,314	6,410	96	8,816	9,201	385	14,889	15,224	335	22,470	22,570	101
	Coal	319,766	321,577	1,812	327,778	329,588	1,809	339,242	341,278	2,036	349,941	351,213	1,272
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-
	Nuke	29,319	29,319	-	29,323	29,323	-	29,290	29,290	-	29,334	29,334	-
	Other	2,454	2,454	-	2,455	2,455	-	2,457	2,457	-	2,454	2,455	1
	Peaker	695	663	(32)	1,122	1,143	21	2,199	2,289	90	4,976	4,843	(133)
	PSH	5,229	5,232	3	5,085	5,076	(10)	4,669	4,654	(15)	4,025	3,999	(27)
	ST/G/O/D	2,133	2,273	140	3,282	3,351	70	5,971	6,149	178	10,648	10,548	(101)
	New CT	-	-	-	-	-	-	-	-	-	1,891	1,901	10
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO E Sum		368,567	370,586	2,019	380,520	382,796	2,276	401,374	403,999	2,625	428,397	429,520	1,123

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
MISO W	CC	9,163	9,411	248	11,217	11,299	82	15,298	15,358	60	19,876	19,948	72
	Coal	286,340	286,944	604	289,929	290,585	657	293,571	294,201	630	301,110	301,509	399
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-
	Nuke	56,845	56,845	0	56,919	56,924	5	56,805	56,812	7	56,886	56,883	(2)
	Other	10,566	10,567	1	10,571	10,572	1	10,560	10,561	1	10,555	10,564	9
	Peaker	5,796	5,800	4	7,863	7,908	45	15,554	15,482	(73)	13,696	14,000	304
	PSH	671	668	(3)	678	685	8	688	686	(2)	678	674	(4)
	ST/G/O/D	605	608	3	859	866	6	1,862	1,873	11	2,148	2,193	45
	New CT	-	-	-	-	-	-	-	-	-	14,912	15,475	564
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO W Sum		385,444	386,302	858	393,494	394,298	804	409,796	410,431	635	435,318	436,704	1,386
ISO-NE	CC	27,926	27,908	(18)	30,153	29,989	(165)	36,218	36,236	18	41,117	41,071	(46)
	Coal	21,345	21,352	7	21,557	21,540	(17)	21,862	21,859	(2)	21,908	21,901	(7)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-
	Nuke	33,909	33,909	-	33,883	33,882	(1)	33,963	33,963	-	33,979	33,979	-
	Other	14,300	14,300	-	14,314	14,314	-	14,319	14,319	-	14,309	14,309	-
	Peaker	-	-	-	-	-	-	-	-	-	0	1	1
	PSH	1,361	1,368	7	1,284	1,287	3	1,251	1,258	7	1,076	1,071	(5)
	ST/G/O/D	17,582	17,641	59	19,475	19,633	158	19,267	19,286	19	21,680	21,819	138
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Sum		123,684	123,739	55	127,927	127,906	(21)	134,140	134,181	42	141,331	141,412	81
NYC	CC	6,434	6,523	89	6,594	6,690	96	6,998	7,058	60	7,453	7,543	91
	Other	179	179	-	179	179	-	179	179	-	179	179	-
	Peaker	469	467	(3)	355	361	6	486	480	(6)	683	702	20
	ST/G/O/D	18,867	19,044	176	19,819	19,990	171	21,006	21,164	158	22,319	22,503	184
	New CT	-	-	-	45	45	1	104	106	2	221	225	4
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYC Sum		25,950	26,212	263	26,992	27,266	274	28,773	28,987	214	30,854	31,153	299
NYL	CC	1,483	1,492	9	1,527	1,526	(0)	1,606	1,606	0	1,661	1,660	(1)
	Other	988	988	-	991	991	-	987	987	-	989	989	-
	Peaker	211	208	(3)	203	204	1	281	279	(2)	430	428	(2)

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
	ST/G/O/D	8,779	8,783	4	9,429	9,475	46	10,278	10,287	9	11,492	11,506	15
	New CT	-	-	-	35	35	1	100	98	(1)	274	274	(1)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYL Sum		11,461	11,471	10	12,185	12,232	47	13,252	13,258	6	14,847	14,858	11
NYO	CC	12,127	12,094	(33)	13,178	13,027	(151)	14,758	14,748	(10)	17,427	17,342	(85)
	Coal	25,891	25,700	(190)	26,387	26,200	(187)	27,074	26,870	(204)	27,296	27,129	(167)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-
	Nuke	37,819	37,817	(2)	37,706	37,707	1	37,729	37,728	(1)	37,706	37,710	4
	Other	2,401	2,402	1	2,402	2,402	-	2,402	2,402	(0)	2,397	2,397	(0)
	Peaker	3	3	(1)	2	2	0	4	4	(1)	25	23	(2)
	PSH	2,037	2,040	3	2,046	2,050	4	1,899	1,896	(3)	1,806	1,815	9
	ST/G/O/D	9,704	9,734	30	10,919	11,141	222	11,658	11,753	95	13,416	13,415	(0)
	New CT	-	-	-	-	-	-	-	-	-	101	151	50
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYO Sum		118,604	118,413	(192)	121,263	121,152	(111)	124,147	124,024	(123)	128,797	128,605	(192)
PJM	CC	22,225	20,731	(1,494)	26,386	25,068	(1,318)	34,747	34,673	(74)	46,545	45,939	(605)
	Coal	194,000	190,797	(3,203)	197,444	194,514	(2,930)	202,406	200,211	(2,195)	206,032	204,540	(1,492)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,388	117,388	-	117,476	117,476	-	117,393	117,393	-	117,365	117,367	2
	Other	6,902	6,902	-	6,908	6,908	-	6,904	6,904	-	6,907	6,904	(2)
	Peaker	619	665	45	1,249	1,305	56	1,857	2,132	275	2,947	3,937	990
	PSH	4,664	4,668	4	4,681	4,682	1	4,709	4,722	13	4,521	4,568	46
	ST/G/O/D	10,452	11,452	1,001	14,574	15,574	1,000	17,759	19,610	1,851	25,287	27,326	2,038
	Wind	339	332	(7)	335	329	(6)	333	329	(4)	344	341	(3)
	New CT	-	-	-	-	-	-	-	-	-	1,240	-	(1,240)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		362,187	358,534	(3,653)	374,652	371,455	(3,197)	391,707	391,573	(134)	416,787	416,521	(266)
SCE&G	CC	2,476	2,738	262	3,132	3,495	363	4,311	4,585	274	5,510	5,700	189
	Coal	36,508	36,660	153	37,705	37,812	107	38,514	38,600	86	39,282	39,328	46
	Hydro	875	875	-	875	875	-	875	875	-	875	875	-
	Nuke	7,611	7,611	-	7,610	7,610	-	7,609	7,609	-	7,650	7,650	-
	Other	1,004	1,004	-	1,007	1,007	-	1,007	1,007	-	1,005	1,005	-

Table A-29: Generation by Type and Pool (GWh), High Load

Capacity Pool	TYPE -	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
	Peaker	35	41	6	79	83	4	128	143	15	55	74	19
	PSH	987	983	(5)	912	898	(13)	822	810	(12)	565	572	7
	ST/G/O/D	25	27	2	65	69	4	105	102	(3)	82	84	1
	New CT	-	-	-	-	-	-	-	-	-	1,255	1,340	85
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SCE&G Sum		49,522	49,940	418	51,383	51,848	465	53,372	53,732	360	56,279	56,627	348
SETRANS E	CC	22,051	23,961	1,910	28,225	30,078	1,853	40,635	42,679	2,045	58,235	59,217	982
	Coal	185,268	185,740	472	190,095	190,377	282	189,214	189,493	278	180,095	180,186	91
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-
	Nuke	45,953	45,953	-	46,039	46,039	-	46,072	46,072	-	46,029	46,029	-
	Other	8,841	8,841	-	8,851	8,851	-	8,852	8,852	(0)	8,842	8,842	-
	Peaker	1,062	1,056	(6)	2,581	2,603	21	4,268	4,219	(49)	6,142	6,172	30
	PSH	430	430	0	363	369	5	594	595	1	369	363	(6)
	ST/G/O/D	4,888	5,044	156	5,396	5,523	127	6,345	6,401	56	7,022	7,073	51
	New CT	-	-	-	-	-	-	-	-	-	6,547	6,544	(3)
	New CC	-	-	-	-	-	-	-	-	-	3,072	3,102	30
SETRANS E Sum		277,671	280,204	2,532	290,730	293,019	2,289	305,159	307,490	2,331	325,531	326,706	1,175
SETRANS W	CC	36,277	35,252	(1,025)	43,415	42,526	(889)	55,230	54,154	(1,076)	66,373	65,634	(739)
	Coal	56,613	56,662	49	56,667	56,680	13	57,236	57,234	(2)	57,830	57,834	5
	Hydro	581	581	-	581	581	-	581	581	-	581	581	-
	Nuke	38,950	38,950	-	38,919	38,919	-	39,054	39,054	-	39,016	39,016	-
	Other	1,606	1,606	-	1,606	1,606	-	1,606	1,606	-	1,608	1,608	-
	Peaker	671	662	(9)	779	777	(2)	1,298	1,326	27	1,809	1,793	(15)
	ST/G/O/D	2,611	2,609	(1)	3,637	3,678	40	6,936	7,144	208	13,428	13,659	231
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SETRANS W Sum		137,309	136,323	(986)	145,604	144,767	(838)	161,942	161,099	(843)	180,645	180,126	(519)
SPP	CC	30,338	30,438	100	36,786	36,962	177	48,337	48,630	293	61,446	61,718	272
	Coal	145,769	145,860	91	143,151	143,216	64	141,824	141,884	60	137,590	137,587	(3)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-
	Nuke	9,358	9,358	-	9,337	9,337	-	9,381	9,381	-	9,337	9,337	-
	Other	11,247	11,247	-	11,252	11,252	-	11,245	11,245	-	11,271	11,271	-

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	**TYPE -**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**	**Base Case**	**Change Case**	**Delta (Change - Base)**
	Peaker	413	427	14	650	655	5	1,914	1,852	(62)	2,750	2,764	14
	ST/G/O/D	4,851	4,935	83	6,157	6,396	239	10,373	10,434	60	17,014	17,145	130
	New CT	-	-	-	-	-	-	-	-	-	442	448	6
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SPP Sum		213,017	213,305	288	218,375	218,859	484	234,116	234,467	351	250,890	251,309	418
TVA	CC	8,653	8,825	172	10,575	10,981	406	17,654	17,883	229	25,877	25,977	100
	Coal	104,738	104,892	154	108,067	108,243	176	109,319	109,409	91	110,918	110,939	21
	Hydro	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-
	Nuke	44,740	44,740	-	44,738	44,738	-	44,713	44,713	-	44,655	44,655	(0)
	Other	2,652	2,652	-	2,655	2,655	-	2,653	2,653	-	2,653	2,653	(0)
	Peaker	287	305	18	542	549	6	1,239	1,248	10	2,042	2,072	30
	PSH	2,578	2,580	2	2,727	2,727	-	2,706	2,699	(7)	2,670	2,674	4
	ST/G/O/D	-	-	-	-	-	-	3	3	-	3	3	(0)
	New CT	-	-	-	-	-	-	-	-	-	1,753	1,808	54
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
TVA Sum		183,501	183,847	346	189,157	189,745	588	198,139	198,461	322	210,423	210,633	210
VAP	CC	7,055	4,800	(2,255)	8,800	6,309	(2,491)	11,162	8,283	(2,879)	15,449	12,252	(3,197)
	Coal	41,112	39,681	(1,432)	42,207	40,882	(1,325)	43,521	42,650	(871)	44,765	44,151	(615)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,197	2,168	(29)	2,336	2,325	(11)	2,348	2,341	(7)	2,370	2,362	(8)
	Peaker	1,098	1,024	(74)	1,486	1,400	(86)	2,315	1,954	(362)	2,731	2,499	(232)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	5,638	4,878	(760)	6,515	5,880	(635)	7,608	7,097	(511)	8,619	8,191	(429)
	New CT	-	-	-	-	-	-	451	-	(451)	2,606	1,898	(708)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
VAP Sum		87,156	82,606	(4,550)	91,284	86,737	(4,548)	97,730	92,649	(5,081)	106,800	101,611	(5,188)

Table A-30: Generation Cost ($k), High Load

Capacity Pool	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
AEP	2,144,573	2,226,788	82,215	2,175,404	2,245,632	70,228	2,353,124	2,428,550	75,426	2,579,007	2,753,606	174,599
COED	1,189,850	1,110,059	(79,791)	1,235,062	1,126,569	(108,493)	1,380,978	1,233,999	(146,979)	1,650,963	1,452,103	(198,859)
CPL	1,012,142	1,033,292	21,150	1,054,118	1,078,016	23,898	1,187,803	1,200,919	13,116	1,466,794	1,506,597	39,803
DP&L	349,677	350,954	1,277	341,363	343,352	1,989	379,726	386,085	6,359	416,230	413,610	(2,619)
DUKE	1,178,378	1,190,219	11,841	1,233,939	1,247,844	13,904	1,420,263	1,436,235	15,972	1,771,795	1,786,734	14,939
GFL	5,024,318	5,034,683	10,365	5,327,473	5,334,811	7,338	5,807,643	5,812,144	4,501	6,787,905	6,795,172	7,267
MISO E	5,765,006	5,800,346	35,340	5,857,312	5,903,418	46,107	6,485,398	6,538,782	53,384	7,416,760	7,430,092	13,332
MISO W	4,557,034	4,574,338	17,304	4,708,783	4,723,090	14,307	5,266,119	5,270,964	4,845	6,063,481	6,112,092	48,612
ISO-NE	2,583,826	2,583,887	62	2,643,879	2,639,984	(3,895)	2,841,106	2,841,505	399	3,128,981	3,131,623	2,642
NYC	881,396	889,326	7,931	870,256	878,705	8,449	925,601	932,011	6,409	1,002,387	1,012,286	9,898
NYL	410,505	410,983	478	416,062	417,984	1,921	454,862	455,055	193	521,240	521,870	629
NYO	1,756,947	1,749,662	(7,285)	1,766,646	1,761,792	(4,853)	1,886,662	1,881,737	(4,925)	2,068,199	2,061,425	(6,774)
PJM	5,302,495	5,231,085	(71,410)	5,484,139	5,425,745	(58,394)	6,093,667	6,135,571	41,905	7,025,441	7,047,366	21,924
SCE&G	848,664	862,232	13,567	866,379	880,433	14,054	933,026	943,703	10,677	1,062,654	1,076,103	13,449
SETRANS E	4,640,401	4,722,865	82,464	4,904,012	4,972,946	68,933	5,378,776	5,444,578	65,802	6,261,722	6,293,860	32,138
SETRANS W	2,437,053	2,400,814	(36,239)	2,640,737	2,613,308	(27,429)	3,108,879	3,086,356	(22,523)	3,680,816	3,667,319	(13,497)
SPP	3,178,786	3,187,179	8,393	3,332,837	3,345,622	12,784	3,816,567	3,823,932	7,365	4,435,765	4,448,181	12,416
TVA	2,371,574	2,381,176	9,602	2,434,342	2,450,133	15,791	2,737,170	2,747,373	10,203	3,157,283	3,164,881	7,598
VAP	1,452,510	1,302,389	(150,122)	1,533,235	1,387,915	(145,321)	1,738,333	1,558,351	(179,982)	2,085,664	1,897,900	(187,764)
Total	47,085,135	47,042,278	(42,858)	48,825,979	48,777,298	(48,681)	54,195,703	54,157,852	(37,851)	62,583,086	62,572,821	(10,265)

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Table A-31: Average Spot Prices ($/MWh), High Load

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	22.07	22.97	0.90	22.31	23.34	1.03	25.25	26.02	0.77	29.23	29.31	0.08
COED	21.76	21.87	0.11	22.06	22.11	0.05	24.58	24.74	0.15	28.41	28.18	(0.23)
CPL	29.19	29.75	0.56	30.38	31.18	0.80	33.72	34.54	0.82	37.48	38.54	1.05
DP&L	22.02	22.47	0.45	22.05	22.71	0.66	24.48	25.41	0.93	28.33	28.50	0.16
DUKE	29.22	29.78	0.56	30.55	31.29	0.75	33.74	34.35	0.61	37.50	38.21	0.70
GFL	36.71	36.74	0.03	49.02	49.07	0.05	43.35	43.19	(0.16)	38.82	39.11	0.29
MISO E	23.29	23.47	0.19	23.56	23.82	0.26	26.09	26.32	0.24	29.96	30.07	0.11
MISO W	25.56	25.66	0.10	26.35	26.46	0.12	34.34	34.13	(0.22)	33.85	33.99	0.14
ISO-NE	33.03	33.06	0.03	32.48	32.56	0.08	33.05	32.99	(0.07)	34.11	34.00	(0.11)
NYC	35.24	35.36	0.12	33.32	33.36	0.04	34.57	34.61	0.04	37.40	37.67	0.27
NYL	37.14	37.22	0.07	35.37	35.36	(0.02)	36.64	36.60	(0.04)	39.25	39.23	(0.03)
NYO	30.08	30.00	(0.07)	29.49	29.38	(0.11)	30.44	30.32	(0.12)	31.79	31.65	(0.14)
PJM	27.68	27.49	(0.19)	27.74	27.70	(0.04)	30.07	30.22	0.15	33.20	34.77	1.57
SCE&G	27.99	28.50	0.51	29.22	29.83	0.61	32.41	33.11	0.70	34.88	35.65	0.77
SETRANS E	29.40	29.50	0.10	30.29	30.40	0.11	32.35	32.38	0.03	35.57	35.61	0.03
SETRANS W	29.70	29.74	0.04	29.90	29.95	0.05	31.32	31.38	0.05	32.76	32.69	(0.07)
SPP	27.14	27.25	0.11	27.56	27.63	0.07	30.04	30.08	0.04	32.28	32.29	0.01
TVA	26.77	26.90	0.13	27.12	27.27	0.14	29.69	29.84	0.14	32.81	32.81	0.00
VAP	31.58	30.23	(1.35)	32.38	31.05	(1.33)	35.02	33.99	(1.03)	38.43	38.69	0.27
Total	28.11	28.16	0.06	29.20	29.30	0.10	31.79	31.83	0.04	33.68	33.96	0.29

APPENDIX B: CAPACITY MODEL

B.1. *Determining New Build Requirements*

The existing fleet of generation resources cannot meet future needs indefinitely. In order to forecast both future energy and capacity prices, CRA needed to project what new generation resources would be built, where, and when.

For the first year of the study period, 2005, CRA assumed that only those units that are under construction currently would be commercially available. New projects that have been halted were not included among the 2005 builds. Although additional projects might conceivably be tabled, other projects not counted may be completed by Summer 2005. Overall, we believe that this is a reasonable and conservative forecast of 2005 resources.

For subsequent years, we assumed that additional capacity resources are brought on-line to maintain required capacity reserves in each control zone.[38] We allowed trades of capacity between directly interconnected zones provided that two conditions were met. First, the imported capacity could not exceed the transfer capability between the two zones. Second, each zone was required to carry internally enough capacity to meet forecast peak load plus a 2.5 percent operating reserve requirement.

This possibility of capacity export means that the location of new builds is not determined unambiguously. In the SEARUC study, we allowed no capacity trading and, consequently, the need for and quantity of new capacity in each zone was deterministic. In this study, we used the following procedure to locate new capacity resources:

1. Build internally to meet load plus operating reserves.

2. Fully utilize trading from resource-long areas. For example, New York can import capacity either from New England or PJM East. New England, however, has no other export markets for its surplus capacity, and more than enough to meet New York's capacity shortfall until after PJM East itself becomes capacity short. PJM East resources, however, can sell to other markets. We therefore first meet New York's shortfall from New England capacity, before considering imports from PJM.

[38] We modeled both MISO and SeTrans as having two separate areas, east and west, to reflect the geographic and electrical separation within those two areas. MISO East corresponds to those areas of MISO in ECAR; MISO West includes those parts in MAIN and MAPP. SeTrans is split between the Southern and Entergy areas. The New York Control Area was modeled consistent with its capacity market design as two sub-regions (New York City and Long Island) and an overall New York region.

3. When available capacity exports cannot meet remaining capacity requirements in interconnected markets, allocate capacity exports so as to equalize the internal capacity margin in each import market. To a first approximation, this procedure equalizes the expected returns to new generators in each affected area.

This departure from the method of the SEARUC study more accurately reflects the dynamics of observed capacity trading, especially in areas like PJM and other RTOs that have formal capacity markets. For example, New York currently obtains about ten percent of its total capacity from external resources. Such realities led CRA to adopt a more cross-regional view of capacity markets.

In the both the Base and Change Cases, we required that each control zone, including those of the New PJM Entrants, carry internally sufficient capacity to meet peak load plus operating reserve. This rule required new builds in Dominion and ComEd, as well as areas outside the Expanded PJM market. Additional capacity needed generically in PJM to meet the pool-wide capacity requirement was also sited in these two zones, since they had the lowest internal reserve margins among the PJM sub-areas and, therefore, could be expected to have higher prices for peaking units.

The critical difference between the Base Case and the Change Case in the capacity market is that, owing to the increased load diversity of the Expanded PJM market, the level of required reserves declines. In the Base Case, PJM (East and West) is modeled to hold a 17 percent capacity margin, consistent with current requirements. Following the integration of the New PJM Entrants, this requirement is lowered to 12.5 percent for the PJM (East and West) market area, resulting in an approximately 15 percent margin above coincident peak for the Expanded PJM area. This reduction in capacity requirements frees approximately 3,000 MW of resources that had been needed in PJM (East and West), making additional capacity available to other areas of the Expanded PJM, including Dominion. Other required capacity margins outside PJM (East and West) are assumed to be unchanged, so Dominion holds a 12.5 percent reserve requirement in both the Base and Change Cases, of which no more than 10 percentage points can be met with external capacity resources.[39]

A second difference between the two cases is that we modify the capacity export rule (#3 above) so that surplus capacity in one area of Expanded PJM is used first to meet capacity shortfalls in other areas of Expanded PJM. Only if Expanded PJM is collectively net long will any PJM zone export to a non-PJM zone, reflecting the higher transactions costs of selling external capacity. The practical effect of this change is to divert exports of capacity from AEP, that had been sold to CP&L, Duke, and TVA, are instead sold to Dominion, Commonwealth Edison and the current PJM companies.

[39] *See* Testimony of Gregory J. Morgan, filed concurrently with this study.

Appendix B: Capacity Model

The pattern of builds across the Eastern Interconnect used in this study is summarized in Table B-1.

Table B-1: Pattern of New Capacity Builds by Region
Cumulative Additions, MW

	2007 Base Case	2007 Change Case	2007 Difference	2010 Base Case	2010 Change Case	2010 Difference	2014 Base Case	2014 Change Case	2014 Difference
PJM	0	0	0	0	0	0	2,069	0	-2,069
DVP	0	0	0	310	0	-310	3,360	1,668	-1,692
AEP	0	0	0	0	0	0	0	0	0
DP&L	0	0	0	0	0	0	0	0	0
ComEd	0	0	0	563	87	-476	4,407	2,250	-2,157
CP&L	0	0	0	763	498	-265	3,078	3,227	149
DUKE	846	846	0	2,875	2,856	-19	6,870	7,128	258
SCE&G	0	0	0	0	0	0	1,621	1,621	0
MISO E	0	0	0	0	0	0	5,564	6,280	716
MISO W	0	0	0	0	0	0	8,285	9,085	800
SPP	0	0	0	0	0	0	1,020	1,020	0
SETRANS E	0	0	0	0	0	0	8,840	8,840	0
SETRANS W	0	0	0	0	0	0	0	0	0
TVA	0	0	0	0	0	0	2,410	2,944	534
GFL	0	0	0	3,046	3,046	0	8,684	8,684	0
NEP	0	0	0	0	0	0	0	0	0
NYC	175	175	0	271	271	0	619	619	0
NYL	175	175	0	307	307	0	670	670	0
NYO	0	0	0	0	0	0	368	368	0
Subtotal New PJM	0	0	0	873	87	-786	9,836	3,918	-5,918
Subtotal Other	1,196	1,196	0	7,262	6,978	-284	48,029	50,486	2,457
Total	1,196	1,196	0	8,135	7,065	-1,070	57,865	54,404	-3,461

B.2. Determining PJM Capacity Market Clearing Prices

Under the current capacity market design, the quantity of capacity purchased by PJM is determined administratively, to reach a capacity margin based on engineering analyses. This approach tends to create prices that tip between one of two values:

If the system has more than enough capacity resources to meet the capacity reserve margin, the capacity price is set by the payment needed to keep existing resources from exiting. Specifically, the marginal unit needs to recover its avoidable fixed costs from its combined net revenues in the energy, ancillary services and capacity markets. Based on the MAPS runs for this study, we determined that the marginal PJM resource would expect to receive insignificant payments in the energy and ancillary service markets. Consequently, the market-clearing price for capacity, when PJM is net long capacity, should be equal to the avoidable fixed costs of marginal capacity resources.[40] Based on previous CRA studies about PJM capacity, we estimate that this cost is $20 per kilowatt-year. This level may be conservatively high, since observed capacity prices in PJM have frequently been below this level. Using a lower level for the cost of capacity during periods of surplus capacity would increase the benefits to customers from Dominion joining PJM.

The other possible state of the capacity markets is that there is an overall shortage of capacity. In order to attract new capacity resources, the capacity price must cover not merely the avoidable fixed costs of the facility, but the fully loaded cost of new entry net of margins the unit could receive in the energy and ancillary services markets. CRA considered, in each market that needed additional capacity resources, whether a combined-cycle unit or a simple gas turbine would require a lower capacity payment. Combined-cycle units have a higher capital cost but are more efficient, allowing them to operate profitable in more hours than a gas turbine. In most markets, including the Expanded PJM area, the extra energy margin that a combined-cycle unit could earn did not offset their higher capital charges. Consequently, the capacity market-clearing price was set to the levelized embedded cost of a new gas turbine, less expected net revenue from the energy and ancillary services markets (which were small). CRA estimated that this levelized cost in PJM is approximately $50 per kilowatt-year, which is substantially in agreement with similar calculations other researchers have made for New York and New England.[41]

Stripped down to these basics, one might expect that the capacity prices can only be at one of two levels: a low price when there is sufficient capacity already installed ($20/kW-year), or a high price when new entry is needed ($50/kW-year). If, for example, in 2013 we foresaw the market as 10 MW deficient in the Base Case, but 10 MW in surplus in the Change Case, the simple "price tipping" model would suggest that the entire capacity purchases made by Dominion area should be repriced from $50/kW-year to $20/kW-year.

Such a knife-edge result does not, in our opinion, reasonably reflect the expected value of integrating capacity markets. There are many uncertain variables in our model, including the load forecast, the level of available capacity from each unit in the system,[42] and the development of

[40] This conclusion sets aside the sale of capacity to other control areas from PJM, which could allow scarcity pricing in other areas to raise the PJM capacity price. At this time, market rules for trading capacity between markets are insufficiently developed to allow full market integration and price formation across RTO seams. We chose, therefore, to model the PJM capacity market as a stand-alone market.

[41] *See* "New York Independent Operator, Inc.'s Filing of Revisions to the ISO Market Administration and Control Area Service Tariff: ICAP Demand Curve," FERC Docket No. ER03-647-000 (March 2003), and "Compliance Filing of ISO New England, Inc.", FERC Docket No. ER03-563-030 (March 2004). The more recent of the two (New England's) proposes a capacity market design based on a $54/kW-year capacity payment when the capacity market is in long-run balance.

[42] Instead of counting each resource at its faceplate capacity rating, PJM computes Available Capacity from a unit, which takes into account its recent historical forced outage rates.

demand-side capacity resources, that could turn a forecast capacity deficit into a surplus, or vice versa. To reflect these uncertainties about the state of the future capacity markets, we developed a simple probabilistic model to forecast capacity prices.

The model starts from the premise that capacity prices in the PJM auction will be set either at \$20/kW-year if there is a capacity surplus, or at \$50/kW-year otherwise. We then estimate the probability of each of these two states of the world, assuming that the capacity requirement is centered at our forecast value but has some uncertainty, with a normal random distribution. The forecast uncertainty was assumed to be 0.5 percent in 2003 and to increase by 0.2 percentage points in each subsequent year, so that the standard deviation in 2007 was taken to be 1.3 percent, and in 2014 to be 2.7 percent. These values, in our judgment, reasonably reflect the level of uncertainty intrinsic in long-term load forecasts.

Using this model, we compute the predicted capacity price as the probability-weighted average of the low-price (\$20) and high-price (\$50) outcomes. If, for example, installed capacity exactly equaled the forecast capacity requirement, there would be a 50 percent chance that the market would be deficient, and a 50 percent chance that the market would be in surplus. We would, therefore, assign a capacity price of \$35/kW-year (half of \$50 plus half of \$20). Table B-2 below shows the modeled capacity prices in PJM for each year of the study period.

Table B-2: ICAP Prices

(\$/kW-year)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	\$21.54	\$22.08	\$22.63	\$23.19	\$23.77	\$26.38	\$37.30	\$51.62	\$61.57	\$66.12
Change Case	\$21.54	\$22.08	\$22.63	\$23.19	\$23.77	\$24.50	\$27.53	\$37.17	\$50.25	\$60.34

An underlying assumption of this price formation methodology is the persistence of prices. Once the existing installed capacity is no longer sufficient to meet capacity requirements, new capacity is induced to enter through higher capacity prices. Economists refer to this higher price as a "trapping state;" once a market needs new capacity, the capacity price remains at the long-term marginal cost of capacity forever. In actual practice, however, we know that investment tends to occur in cycles, with the price correspondingly swinging through extremes. Attempting to model such complex market dynamics is beyond the scope of this study.

Further, we focus solely on the capacity clearing price for the overall PJM market, defined either with the current footprint in the Base Case or the Expanded PJM area in the Change Case. In lieu of an active capacity market in the Base Case, we chose capacity prices in the existing PJM market as the relevant proxy.

APPENDIX C: FINANCIAL MODEL DESCRIPTION

C.1. Overview

The Financial Model is an Excel-based model that relies upon inputs from the MAPS model to measure changes in revenues and costs for North Carolina Retail Customers resulting from Dominion and the other New PJM Entrants joining PJM in 2005. Changes in revenues and costs are calculated by comparing the Change Case results in which the New PJM Entrants are a part of PJM to results from a Base Case (the "Base Results") in which they are not a part of PJM. Since the focus of this analysis is on the *change* in revenues and costs and not the absolute levels in the Base and Change Cases the analysis focuses primarily on *incremental* revenues and costs. As such, items that do not change from the Base Case to the Change Case are not included in the analysis.

The Financial Model measures changes in revenues and costs for North Carolina Retail Customers over a 10-year period commencing in 2005 and continuing through 2014. Annual results for each of the 10 years are calculated in addition to and a 10-year net present value (discounted to July 1, 2003[43]). The Financial Model relies on inputs from MAPS. MAPS simulates the operation of the electricity system in the Eastern Interconnect in the Base and Change Cases to derive hourly generation by unit, hourly unit generation production costs (fuel, variable O&M, start-up costs and emissions trading costs), hourly location-specific prices for each generation and load bus on the transmission system and hourly flows between interconnected control areas. For each case, MAPS model runs were conducted for 2005, 2007, 2010 and 2014. The remaining years in the analysis (2006, 2008, 2009, 2011, 2012 and 2013) are then interpolated from the MAPS model runs in the surrounding years.

C.2. MAPS Outputs Used in the Financial Model

All hourly generation, cost and price data in the Financial Model are outputs from the MAPS model. This data is post-processed using a SAS model to summarize and format the hourly data prior to its inclusion in the Financial Model. The following hourly outputs from the MAPS model are used in the Financial Model:

1. Hourly generation in MWh, separately calculated for Dominion-owned units, units under NUG contracts to Dominion, and other generation from units located in the Dominion control zone.

[43] This date was set based on the parallel Virginia filing in VA SCC Docket No. PUE-2000-00551.

2. Hourly production costs, separately calculated for Dominion-owned units, units under NUG contracts to Dominion[44] and other non-merchant generator units located in the Dominion control zone.

3. Hourly weighted average Dominion energy price, calculated as the weighted average generation bus price of each generating unit in the Dominion control zone, weighted by each unit's generation in a given hour.[45]

4. Hourly load prices, there is a single load price within the Dominion control zone in each hour.

5. Hourly flows into and out of the Dominion control zone, separately calculated for each zone that is interconnected with Dominion.[46]

6. Hourly price differentials on flows into and out of the Dominion control zone, separately calculated for each zone that is interconnected with Dominion.

Additionally, annual capacity is an input into the Financial Model from the MAPS model, with separate annual capacity data for Dominion-owned capacity (including capacity under NUG contracts) and other non-merchant generator capacity located in the Dominion control zone.

C.3. Other Inputs into the Financial Model

The Financial Model also relies upon a number of inputs that do not come from the MAPS model:

1. PJM Administrative Charge, based on PJM budgeted costs and projected load, including the New PJM Entrants. Rates are $0.43 per MWh in 2005, $0.42 per MWh in 2006, $0.41 per MWh in 2007, $0.42 per MWh in 2008 and then held constant at $0.42 per MWh in real dollars thereafter. See Table C-2.

2. Wheeling Rates, based on off-peak Non-Firm OATT energy rates. Rates are as follows: Dominion ($1.46 per MWh), AEP ($1.95 per MWh), CP&L ($1.23 per MWh) and PJM and other New PJM Entrants ($1.50 per MWh). A rate of $0.50 per

[44] Production costs for units under NUG contracts to Dominion are based on the contractual price for must-take units and the contractual fuel cost for dispatchable units, with relevant escalation factors.
[45] Energy prices at hydro units were not included in the weighted average calculation in hours in which they were pumping rather than generating and thus had "negative" generation.
[46] Interconnected areas with Dominion are CP&L, AEP, PJM East and PJM West.

MWh is applied to all trades in off-peak hours.[47] These rates are all in 2002 dollars and apply to both the Base and Change Case. These rates are held constant through 2008 after which the rates grow with inflation.[48] See Table C-1.

3. Load Shares, shares of load by entity within the Dominion control zone are based on energy load forecasts for 2005 through 2012 (2013 and 2014 shares use the load forecast for 2012). Shares of 1CP load are based on actual 2001 load shares for each customer type. Dominion's share of Expanded PJM is based on estimated load in Expanded PJM in 2005.

4. ICAP Prices, ICAP prices for 2005, 2007, 2010 and 2014 are derived from a probabilistic ICAP model. The ICAP prices apply for the entire Dominion control zone. ICAP prices used in the analysis are $20.00 per kW-year (in 2002 dollars) for 2005 through 2009 in both the Base and Change Cases. Beginning in 2010, ICAP prices rise above the $20.00 per kW-year level, with greater increases in the Base Case compared to the Change Case. See Table B-2.

5. Ratemaking Framework, North Carolina Retail Customers are assumed to be assessed current base rates in 2005, and cost of service base rates thereafter. A cost-of-service Fuel Factor is assessed for North Carolina Retail Customers in all study years. Other Dominion customers are assumed to operate under cost of service Fuel Factors throughout the study period. Certain Dominion wholesale customers are assumed to transition to market pricing for energy at the beginning of the study period, January 1, 2005.

6. Inflation and Discount Rate, the assumed inflation rate is 2.5 percent per year and the discount rate used in all net present value calculations is 10.0 percent.

C.4. Annual Calculations – North Carolina Retail Customers

Fuel Factor Calculations

The annual Fuel Factor calculation includes North Carolina Retail Customers' share of the following costs and credits:

[47] Off-peak hours for purposes of this analysis include midnight to 6 am and 10 pm to midnight on Monday through Friday, and all day on Saturday and Sunday.

[48] This methodology was chosen to be consistent with the parallel study for Virginia and is immaterial to the study results.

Appendix C: Financial Model Description

1. Unit Fuel, actual fuel costs for Dominion-owned units.

2. Post-1992 NUG Energy Charges, contract prices multiplied by actual hourly generation for must-take NUG contracts, plus contract fuel costs multiplied by actual hourly generation for dispatchable NUG contracts.

3. Sixty-one percent of Purchases for Load, includes imports and purchases from non-Dominion-owned generation inside the Dominion control zone (*e.g.*, from merchants). In the Base Case, purchases are made at the prevailing spot wholesale energy price in the Dominion control zone. In the Change Case, purchases are made at the Dominion Load Zone LMP and offset by allocated FTRs (based on the percentage of purchases to total load) to compensate for any congestion costs incurred in these purchases. The purchase costs of imports also include a credit for trade savings that is assumed to be one-half of the price difference between the exporting and importing control areas less the prevailing wheeling rate (trade savings are discussed in more detail below).

4. Sales Cost Credit, credit for the cost of energy sales to non-Dominion load (*e.g.*, exports and sales to non-requirements wholesale customers). Calculated as the quantity of sales to non-Dominion load multiplied by the highest marginal cost of generation up to the quantity of sales to non-Dominion load.

5. Other, includes gas pipeline demand charges and nuclear decommissioning charges.

6. Fuel expenses were allocated to North Carolina Retail Customers using the North Carolina fuel allocation methodology

Items that Impact Base Rates

Other costs and credits that impact North Carolina retail base rates beginning in 2006 are North Carolina Retail Customers' share of the following items:

1. 39 percent of Purchases for Load, using the methodology described in the Fuel Factor calculation above.

2. Pre-1992 NUG Energy costs, using the methodology described in the Fuel Factor above for post-1992 NUG Energy.

3. In the Change Case, Congestion Charges in Base Rates, reflecting the difference in LMPs at the generation bus for the Dominion generating units and the zonal load LMP for Dominion load multiplied by the output of the Dominion generating units.

4. In the Change Case, the value of the FTRs (see discussion below) not passed through the Fuel Factor.

5. Market Capacity Purchases. Market Capacity Purchases are calculated by: 1) multiplying the annual peak load of Dominion by one plus the reserve margin, 2) subtracting the capacity of the Dominion generating units, 3) multiplying by the North Carolina Retail Customer demand share, and then 4) multiplying by the prevailing ICAP price.

6. PJM Administrative Fees, applies only to the Change Case, when Dominion is a part of PJM. Calculated as annual load multiplied by the PJM Administrative Charge. Fees for 2005 are deferred and recovered with interest in 2006.

7. Non-fuel clause energy expenses were allocated to North Carolina Retail Customers based on the North Carolina energy allocation methodology. Demand related expenses were allocated to North Carolina Retail Customers based on the summer/winter peak and average allocation methodology.

C.5. Key Assumptions

Allocation of Trade Savings

Cross-seam trades occur because higher prices in one area attract lower cost generation. Such trades benefit the importer, which has access to lower priced generation than is available otherwise, and the exporter, which receives a higher price for its generation. Savings from these purchases and sales are allocated to the importer and exporter using a split-savings approach. In other words, 50 percent of the savings is allocated to the exporter and 50 percent is allocated to the importer.

As it pertains to Dominion, purchase savings on imports are measured using the price difference on contract flows between regions as determined in the MAPS model. The price difference reflects the higher price of generation in the importing area relative to the exporting area. The transmission charge of the exporter is subtracted from the price difference before the purchase savings are split.

Appendix C: Financial Model Description

Sales savings on exports are also measured using the price difference on contract flows. The transmission charge of Dominion is subtracted from the price difference before the sales savings are split.

Exports from the Dominion control zone are assumed to be from Dominion-owned generation and merchant generation. Generation owned by others within the Dominion control zone is assumed to generate only to meet their internal load and hence does not export. The split between Dominion-owned generation and merchant generation is based on their relative share of generation in each hour.

FTR Awards

In the Change Case when Dominion is part of PJM there is a presumption that Dominion and other load in the control area would be awarded FTRs to compensate for any congestion costs incurred in market energy purchases. PJM conducted a preliminary analysis that determined that the full quantity of FTRs from Dominion's generation units to its load could be awarded throughout the study period; that is, these FTRs were simultaneously feasible given existing FTR awards. PJM business rules allow Dominion, on behalf of its network customers, to request FTRs from resources to match its peak load in any given year. Since the total feasible set of FTRs exceeds this peak load, CRA assumed that Dominion would nominate those FTRs that were most valuable. In each modeled year (2005, 2007, 2010 and 2014), FTR nominations were scaled down for all units, with the exception of Bath County and Mount Storm, such that the total FTRs nominated equaled Dominion's peak load.

Appendix C: Financial Model Description

Input Assumptions

This section includes tables showing relevant inputs.

Table C-1: Transmission Rates (Base and Change Cases)

Area	Base Case	Change Case	
DVP	$1.46	$1.46	per MWh in 2002$
Classic PJM	$1.50	NA	per MWh in 2002$
New PJM	NA	$1.50	per MWh in 2002$
CP&L	$1.23	$1.23	per MWh in 2002$
Off-Peak	***$0.50***	***$0.50***	per MWh in 2002$
Assumed to grow with inflation after 2008			

Table C-2: PJM Administrative Charges

	2005	2006	2007	2008
PJM Admin Charge ($/MWh)	$0.43	$0.42	$0.41	$0.42

Appendix C: Financial Model Description

Table C-3: Dominion FTR Quantities by MAPS Unit

DVP Unit	2005 FTR MW Provided	2007 FTR MW Provided	2010 FTR MW Provided	2014 FTR MW Provided	DVP Unit	2005 FTR MW Provided	2007 FTR MW Provided	2010 FTR MW Provided	2014 FTR MW Provided
BATHCVAP	1548.0	1548.0	1548.0	1548.0	COVINGT5	10.1	10.6	11.3	12.3
MTSTORM1	545.0	545.0	545.0	545.0	COVINGT6	10.1	10.6	11.3	12.3
MTSTORM2	545.0	545.0	545.0	545.0	CHESTFD3	91.8	96.6	102.8	112.0
MTSTORM3	536.0	536.0	536.0	536.0	CGNRICH2	81.8	86.0	91.6	99.7
SURRY01	708.4	744.9	793.3	864.0	DARBYTO1	80.5	84.6	90.1	98.1
SURRY02	712.8	749.5	798.2	869.3	DARBYTO2	80.5	84.6	90.1	98.1
YORKTOW3	717.2	754.1	803.1	874.6	DARBYTO3	80.5	84.6	90.1	98.1
CHESTFD6	586.8	617.0	657.1	715.7	DARBYTO4	80.5	84.6	90.1	98.1
NTHBRANC	67.3	70.8	75.4	82.1	ROANOST1	19.7	20.7	22.0	24.0
CLOVER02	192.8	202.8	215.9	235.2	APPOMAT1	33.2	34.9	37.2	40.5
CLOVER01	192.8	202.8	215.9	235.2	KITTYGT1	24.5	25.7	27.4	29.9
MECKLEN1	57.7	60.7	64.6	70.4	KITTYGT2	24.5	25.7	27.4	29.9
GASTONPD	196.8	206.9	220.4	240.0	DOSWECC1	324.6	341.3	363.5	395.9
BREMOBL4	139.9	147.1	156.7	170.7	DOSWECC2	324.6	341.3	363.5	395.9
PANDARCC	173.2	182.1	193.9	211.2	GRAVELN2	24.5	25.7	27.4	29.9
ROANOKVP	146.2	153.8	163.8	178.3	CHESAP10	25.4	26.7	28.4	30.9
LGEALTAV	54.8	57.7	61.4	66.9	CHESAPE7	25.4	26.7	28.4	30.9
COMMONA1	91.0	95.6	101.9	110.9	CHESAPE8	25.4	26.7	28.4	30.9
GORDONCC	251.7	264.7	281.9	307.0	CHESAPE9	25.4	26.7	28.4	30.9
HOPEWECC	346.0	363.8	387.4	422.0	CHESAGT1	16.6	17.5	18.6	20.3
MULTITR1	35.0	36.8	39.2	42.7	CHESAGT2	15.7	16.6	17.6	19.2
MULTITR2	35.0	36.8	39.2	42.7	CHESAGT4	15.7	16.6	17.6	19.2
CHESAST4	193.3	203.2	216.4	235.7	CHESAPE6	15.7	16.6	17.6	19.2
ROANOKPD	84.0	88.3	94.0	102.4	GRAVELN1	14.9	15.6	16.6	18.1
CHESTFD5	272.9	286.9	305.6	332.8	NTHNECK1	16.6	17.5	18.6	20.3
BREMOBL3	64.7	68.0	72.5	78.9	NTHNECK2	16.6	17.5	18.6	20.3
DCBATTL2	50.3	52.9	56.3	61.3	NTHNECK3	16.6	17.5	18.6	20.3
DCBATTL1	50.3	52.9	56.3	61.3	NTHNECK4	16.6	17.5	18.6	20.3
BELLMEAD	218.6	229.9	244.8	266.7	DOSWELL1	149.6	157.2	167.5	182.4
CHESAPE3	141.7	149.0	158.7	172.8	ALEXARL1	8.7	9.2	9.8	10.7
CHESTFD8	205.5	216.1	230.1	250.7	ALEXARL2	8.7	9.2	9.8	10.7
YORKTOW2	150.4	158.2	168.4	183.5	POSSUGT1	14.0	14.7	15.7	17.1
CHESTFD7	202.9	213.3	227.2	247.5	POSSUGT2	14.0	14.7	15.7	17.1
YORKTOW1	142.6	149.9	159.6	173.9	POSSUGT3	14.0	14.7	15.7	17.1
LGESOUTH	54.8	57.7	61.4	66.9	POSSUGT4	14.0	14.7	15.7	17.1
CHESAST1	97.1	102.1	108.7	118.4	POSSUGT5	14.0	14.7	15.7	17.1
CHESAST2	97.1	102.1	108.7	118.4	POSSUGT6	14.0	14.7	15.7	17.1
PORTSMO1	47.2	49.7	52.9	57.6	CAROLNE1	155.7	163.7	174.3	189.9
CHESTFD4	149.6	157.2	167.5	182.4	CAROLNE2	155.7	163.7	174.3	189.9
ROANOKV1	39.4	41.5	44.2	48.1	I95ENER1	69.1	72.6	77.4	84.3
LOWMOOR1	15.7	16.6	17.6	19.2	POSSUMP3	91.8	96.6	102.8	112.0
LOWMOOR2	15.7	16.6	17.6	19.2	BIRCHWO1	211.8	222.7	237.2	258.3
LOWMOOR3	15.7	16.6	17.6	19.2	FAUQUIC3	155.7	163.7	174.3	189.9
LOWMOOR4	15.7	16.6	17.6	19.2	FAUQUIC1	155.7	163.7	174.3	189.9
CGNRICH1	101.0	106.2	113.1	123.2	FAUQUIC2	155.7	163.7	174.3	189.9
CGNHOPEW	76.1	80.0	85.2	92.8	FAUQUIC4	155.7	163.7	174.3	189.9
GRAVELN3	80.5	84.6	90.1	98.1	POSSUMP4	193.3	203.2	216.4	235.7
GRAVELN4	80.5	84.6	90.1	98.1	NTHANNA2	709.0	745.4	793.9	864.6
GRAVELN5	80.5	84.6	90.1	98.1	NTHANNA1	715.1	751.9	800.8	872.2
GRAVELN6	80.5	84.6	90.1	98.1	POSSUMP5	700.5	736.6	784.5	854.4
COVINGT1	10.1	10.6	11.3	12.3	POSSUMP6	393.6	413.8	440.7	480.0
COVINGT2	10.1	10.6	11.3	12.3					
COVINGT3	10.1	10.6	11.3	12.3					
COVINGT4	10.1	10.6	11.3	12.3	**Totals**	10,744	11,134	11,651	12,406

APPENDIX D: DETAILED FINANCIAL RESULTS OF SENSITIVITY CASES

Table D-1: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Base Case (High Fuel Price Sensitivity Case)

(Millions of dollars; negative values are credits to cost)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	82.1	11.5	11.8	12.2	13.1	14.1	15.0	16.9	18.7	20.5	22.4
Fuel Costs	312.2	47.3	49.6	51.8	53.6	55.5	57.3	60.7	64.2	67.6	71.0
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	14.9	2.8	2.5	2.3	2.4	2.5	2.6	2.8	2.9	3.1	3.3
Sub-Total Fuel Factor	425.2	64.7	67.1	69.5	71.6	74.5	77.6	83.0	88.6	94.1	99.6
Base Rate Impacts:											
NUG Energy - Base Rates	50.5	0.0	8.4	9.3	9.5	9.7	10.0	11.3	12.6	14.0	15.3
Energy Purchases - Base Rates	46.4	0.0	7.6	7.8	8.4	9.0	9.6	10.8	12.0	13.1	14.3
Sub-Total Base Rate Energy	96.9	0.0	15.9	17.0	17.9	18.7	19.6	22.1	24.6	27.1	29.6
Purchased Power Capacity	*16.0*	*0.0*	*0.5*	*1.0*	*1.4*	*1.5*	*2.5*	*4.1*	*6.6*	*8.9*	*10.7*
Total Prod/Gen Costs	538.1	64.7	83.6	87.6	90.9	94.7	99.7	109.2	119.8	130.1	139.9
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(11.4)	(1.4)	(1.9)	(2.4)	(2.3)	(2.1)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)
Base Rate Impacts:											
VOM on Sales - Base Rates	(1.5)	0.0	(0.3)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Profit on Sales - Base Rates	(0.9)	0.0	(0.7)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Sub-Total Base Rate Energy	(2.4)	0.0	(1.0)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(13.8)	(1.4)	(2.9)	(2.9)	(2.7)	(2.5)	(2.4)	(2.5)	(2.6)	(2.7)	(2.8)
Transmission Rights Revenues											
Transmission Rights Revenues (FTRs)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RTO Admin Fees											
RTO Admin Fees	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs to Customers	524.3	63.3	80.7	84.7	88.2	92.2	97.3	106.8	117.2	127.5	137.2
********											
Fuel Factor	413.8	63.3	65.2	67.1	69.4	72.4	75.6	80.9	86.4	91.9	97.3

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-2: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case (High Fuel Price Sensitivity Case)

(Millions of dollars; negative values are credits to cost)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	104.2	14.0	14.6	15.1	16.5	17.8	19.2	21.8	24.4	26.9	29.5
Fuel Costs	292.0	43.7	46.0	48.2	50.0	51.9	53.7	57.1	60.5	63.9	67.3
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	14.7	2.6	2.5	2.3	2.4	2.5	2.6	2.7	2.8	3.0	3.1
Sub-Total Fuel Factor	426.8	63.4	66.2	68.9	71.4	74.7	78.2	84.2	90.4	96.6	102.8
Base Rate Impacts:											
NUG Energy - Base Rates	39.3	0.0	6.9	7.5	7.6	7.7	7.8	8.6	9.5	10.3	11.1
Energy Purchases - Base Rates	59.2	0.0	9.3	9.7	10.5	11.4	12.3	13.9	15.6	17.2	18.9
VOM Reduction - Reduced Output	(1.8)	0.0	(0.5)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)
Sub-Total Base Rate Energy	*96.7*	*0.0*	*15.7*	*16.7*	*17.7*	*18.7*	*19.7*	*22.2*	*24.7*	*27.2*	*29.7*
Purchased Power Capacity	13.6	0.0	0.5	1.0	1.4	1.5	2.3	3.1	4.8	7.3	9.7
Congestion - Base Rates	37.0	0.0	7.0	7.2	7.6	8.0	8.3	8.3	8.2	8.2	8.1
Total Prod/Gen Costs	574.2	63.4	89.4	93.9	98.2	102.9	108.6	117.8	128.1	139.2	150.3
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(8.7)	(1.1)	(1.2)	(1.3)	(1.4)	(1.6)	(1.7)	(1.8)	(1.9)	(2.1)	(2.2)
Base Rate Impacts:											
VOM on Sales - Base Rates	(1.2)	0.0	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.4)
Profit on Sales - Base Rates	(0.4)	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Sub-Total Base Rate Energy	(1.6)	0.0	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.5)	(0.5)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(10.3)	(1.1)	(1.5)	(1.6)	(1.7)	(1.9)	(2.0)	(2.2)	(2.4)	(2.5)	(2.7)
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(3.4)	(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.6)	(0.7)	(0.8)	(0.8)	(0.9)
Other FTRs - Base Rates	*(47.4)*	*0.0*	*(9.2)*	*(9.6)*	*(9.8)*	*(10.0)*	*(10.3)*	*(10.3)*	*(10.4)*	*(10.4)*	*(10.5)*
Transmission Rights Revenues (FTRs)	(50.8)	(0.5)	(9.7)	(10.1)	(10.4)	(10.6)	(10.9)	(11.0)	(11.1)	(11.2)	(11.4)
RTO Admin Fees											
RTO Admin Fees	10.2	0.0	3.8	1.8	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Costs to Customers	523.2	61.8	82.1	84.0	87.8	92.1	97.4	106.4	116.5	127.4	138.2
********											
Fuel Factor	414.7	61.8	64.4	67.1	69.4	72.6	75.9	81.7	87.7	93.7	99.7

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-3: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case Minus Base Case (High Fuel Price Sensitivity Case)

(Millions of dollars; negative numbers are benefits)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	22.1	2.5	2.7	3.0	3.4	3.7	4.1	4.9	5.6	6.4	7.2
Fuel Costs	(20.3)	(3.6)	(3.6)	(3.6)	(3.6)	(3.6)	(3.6)	(3.6)	(3.7)	(3.7)	(3.8)
"Other Fuel" Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUG Energy - Fuel Factor	(0.3)	(0.1)	(0.1)	0.0	0.0	0.0	0.1	(0.0)	(0.1)	(0.2)	(0.3)
Sub-Total Fuel Factor	1.6	(1.3)	(0.9)	(0.6)	(0.2)	0.2	0.6	1.2	1.9	2.5	3.1
Base Rate Impacts:											
NUG Energy - Base Rates	(11.2)	0.0	(1.5)	(1.8)	(1.9)	(2.0)	(2.1)	(2.6)	(3.2)	(3.7)	(4.2)
Energy Purchases - Base Rates	12.8	0.0	1.7	1.9	2.1	2.4	2.6	3.1	3.6	4.1	4.6
VOM Reduction - Reduced Output	(1.8)	0.0	(0.5)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)
Sub-Total Base Rate Energy	(0.2)	0.0	(0.2)	(0.3)	(0.1)	0.0	0.2	0.1	0.1	0.1	0.0
Purchased Power Capacity	(2.3)	0.0	0.0	0.0	0.0	0.0	(0.2)	(1.1)	(1.8)	(1.6)	(0.9)
Congestion - Base Rates	37.0	0.0	7.0	7.2	7.6	8.0	8.3	8.3	8.2	8.2	8.1
Total Prod/Gen Costs	36.1	(1.3)	5.9	6.3	7.3	8.2	8.9	8.6	8.4	9.1	10.4
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	2.7	0.2	0.7	1.1	0.8	0.6	0.3	0.2	0.2	0.2	0.1
Base Rate Impacts:											
VOM on Sales - Base Rates	0.3	0.0	0.1	0.2	0.1	0.1	0.0	0.0	(0.0)	(0.0)	(0.0)
Profit on Sales - Base Rates	0.5	0.0	0.6	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Sub-Total Base Rate Energy	0.8	0.0	0.7	0.2	0.1	0.1	0.0	0.0	(0.0)	(0.0)	(0.1)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	3.5	0.2	1.4	1.3	1.0	0.6	0.3	0.2	0.2	0.1	0.0
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(3.4)	(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.6)	(0.7)	(0.8)	(0.8)	(0.9)
Other FTRs - Base Rates	(47.4)	0.0	(9.2)	(9.6)	(9.8)	(10.0)	(10.3)	(10.3)	(10.4)	(10.4)	(10.5)
Transmission Rights Revenues (FTRs)	(50.8)	(0.5)	(9.7)	(10.1)	(10.4)	(10.6)	(10.9)	(11.0)	(11.1)	(11.2)	(11.4)
RTO Admin Fees											
RTO Admin Fees	10.2	0.0	3.8	1.8	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Costs to Customers	(1.0)	(1.5)	1.4	(0.7)	(0.4)	(0.0)	0.1	(0.4)	(0.7)	(0.1)	1.0
********											
Fuel Factor	0.9	(1.5)	(0.8)	0.0	0.1	0.2	0.2	0.8	1.3	1.9	2.4

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-4: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Base Case (High Load Sensitivity Case)

(Millions of dollars; negative values are credits to cost)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	76.3	10.2	10.7	11.1	12.0	12.9	13.9	15.9	17.9	19.9	21.9
Fuel Costs	300.5	47.0	48.7	50.4	51.9	53.3	54.7	57.6	60.5	63.3	66.2
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	15.3	2.9	2.6	2.3	2.4	2.5	2.6	2.8	3.1	3.3	3.5
Sub-Total Fuel Factor	408.0	63.2	65.1	67.0	68.8	71.3	73.9	79.0	84.2	89.3	94.5
Base Rate Impacts:											
NUG Energy - Base Rates	58.2	0.0	9.7	10.8	11.1	11.4	11.7	13.0	14.4	15.7	17.1
Energy Purchases - Base Rates	43.4	0.0	6.8	7.1	7.7	8.3	8.9	10.2	11.5	12.7	14.0
Sub-Total Base Rate Energy	101.6	0.0	16.5	17.9	18.8	19.7	20.5	23.2	25.8	28.5	31.1
Purchased Power Capacity	23.3	0.0	1.6	2.1	2.4	2.5	3.7	5.9	9.0	11.8	13.9
Total Prod/Gen Costs	532.9	63.2	83.2	87.0	89.9	93.4	98.1	108.0	119.0	129.7	139.5
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(8.9)	(1.6)	(1.6)	(1.6)	(1.6)	(1.5)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)
Base Rate Impacts:											
VOM on Sales - Base Rates	(1.4)	0.0	(0.3)	(0.3)	(0.3)	(0.3)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)
Profit on Sales - Base Rates	(0.6)	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)
Sub-Total Base Rate Energy	(1.9)	0.0	(0.3)	(0.4)	(0.4)	(0.4)	(0.3)	(0.4)	(0.4)	(0.5)	(0.5)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(10.8)	(1.6)	(2.0)	(2.0)	(2.0)	(1.9)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)
Transmission Rights Revenues											
Transmission Rights Revenues (FTRs)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RTO Admin Fees											
RTO Admin Fees	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs to Customers	522.0	61.6	81.2	84.9	87.9	91.5	96.3	106.1	117.0	127.5	137.3
********											
Fuel Factor	399.0	61.6	63.5	65.4	67.2	69.7	72.5	77.5	82.6	87.7	92.8

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-5: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case (High Load Sensitivity Case)

(Millions of dollars; negative values are credits to cost)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	102.3	13.5	14.0	14.5	15.9	17.3	18.7	21.6	24.5	27.4	30.3
Fuel Costs	281.5	43.3	45.3	47.2	48.6	50.0	51.3	54.2	57.1	60.0	63.0
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	14.7	2.7	2.5	2.3	2.4	2.5	2.6	2.7	2.8	3.0	3.1
Sub-Total Fuel Factor	414.5	62.6	64.9	67.2	69.4	72.2	75.3	81.2	87.2	93.2	99.2
Base Rate Impacts:											
NUG Energy - Base Rates	43.7	0.0	7.6	8.3	8.4	8.6	8.8	9.7	10.6	11.4	12.3
Energy Purchases - Base Rates	58.3	0.0	8.9	9.3	10.2	11.0	11.9	13.8	15.6	17.5	19.4
VOM Reduction - Reduced Output	(1.9)	0.0	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.4)	(0.4)	(0.3)	(0.3)
Sub-Total Base Rate Energy	100.1	0.0	16.1	17.1	18.2	19.2	20.3	23.1	25.8	28.6	31.4
Purchased Power Capacity	20.2	0.0	1.6	2.1	2.4	2.5	3.4	4.3	6.5	9.7	12.7
Congestion - Base Rates	33.7	0.0	5.5	5.9	6.3	6.7	7.2	7.8	8.5	9.2	9.9
Total Prod/Gen Costs	568.5	62.6	88.1	92.3	96.2	100.7	106.1	116.4	128.0	140.7	153.1
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(6.3)	(1.1)	(1.0)	(1.0)	(1.1)	(1.3)	(1.4)	(1.3)	(1.2)	(1.1)	(1.0)
Base Rate Impacts:											
VOM on Sales - Base Rates	(1.0)	0.0	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Profit on Sales - Base Rates	(0.4)	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Sub-Total Base Rate Energy	(1.4)	0.0	(0.2)	(0.2)	(0.3)	(0.3)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(7.7)	(1.1)	(1.3)	(1.2)	(1.4)	(1.6)	(1.8)	(1.6)	(1.5)	(1.4)	(1.2)
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(3.2)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.7)	(0.8)	(1.0)	(1.1)
Other FTRs - Base Rates	(41.2)	0.0	(7.2)	(7.8)	(8.0)	(8.2)	(8.4)	(9.1)	(9.9)	(10.7)	(11.5)
Transmission Rights Revenues (FTRs)	(44.4)	(0.4)	(7.6)	(8.2)	(8.4)	(8.7)	(8.9)	(9.8)	(10.7)	(11.7)	(12.6)
RTO Admin Fees											
RTO Admin Fees	10.4	0.0	3.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	2.0
Costs to Customers	526.8	61.2	83.0	84.7	88.2	92.2	97.3	106.8	117.7	129.6	141.3
********											
Fuel Factor	405.0	61.2	63.5	65.9	67.8	70.5	73.3	79.2	85.2	91.2	97.1

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-6: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case Minus Base Case (High Load Sensitivity Case)

(Millions of dollars; negative numbers are benefits)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	26.0	3.3	3.3	3.4	3.9	4.3	4.8	5.7	6.6	7.4	8.3
Fuel Costs	(18.9)	(3.7)	(3.5)	(3.2)	(3.3)	(3.4)	(3.4)	(3.4)	(3.3)	(3.3)	(3.2)
"Other Fuel" Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUG Energy - Fuel Factor	(0.6)	(0.2)	(0.1)	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)
Sub-Total Fuel Factor	6.5	(0.6)	(0.2)	0.2	0.6	1.0	1.3	2.2	3.0	3.9	4.7
Base Rate Impacts:											
NUG Energy - Base Rates	(14.4)	0.0	(2.0)	(2.6)	(2.6)	(2.7)	(2.8)	(3.3)	(3.8)	(4.3)	(4.8)
Energy Purchases - Base Rates	14.9	0.0	2.1	2.2	2.5	2.8	3.1	3.6	4.2	4.8	5.3
VOM Reduction - Reduced Output	(1.9)	0.0	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.4)	(0.4)	(0.3)	(0.3)
Sub-Total Base Rate Energy	*(1.4)*	*0.0*	*(0.4)*	*(0.8)*	*(0.6)*	*(0.4)*	*(0.3)*	*(0.1)*	*0.0*	*0.1*	*0.3*
Purchased Power Capacity	(3.2)	0.0	0.0	0.0	0.0	0.0	(0.3)	(1.5)	(2.5)	(2.2)	(1.2)
Congestion - Base Rates	33.7	0.0	5.5	5.9	6.3	6.7	7.2	7.8	8.5	9.2	9.9
Total Prod/Gen Costs	35.6	(0.6)	4.9	5.3	6.3	7.3	8.0	8.4	9.0	11.0	13.6
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	2.6	0.6	0.6	0.7	0.5	0.3	0.0	0.2	0.4	0.6	0.7
Base Rate Impacts:											
VOM on Sales - Base Rates	0.4	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.2
Profit on Sales - Base Rates	0.1	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.1	0.1
Sub-Total Base Rate Energy	0.5	0.0	0.1	0.2	0.1	0.1	(0.0)	0.0	0.1	0.2	0.3
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	3.2	0.6	0.7	0.9	0.6	0.3	0.0	0.3	0.5	0.8	1.0
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(3.2)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.7)	(0.8)	(1.0)	(1.1)
Other FTRs - Base Rates	(41.2)	0.0	(7.2)	(7.8)	(8.0)	(8.2)	(8.4)	(9.1)	(9.9)	(10.7)	(11.5)
Transmission Rights Revenues (FTRs)	(44.4)	(0.4)	(7.6)	(8.2)	(8.4)	(8.7)	(8.9)	(9.8)	(10.7)	(11.7)	(12.6)
RTO Admin Fees											
RTO Admin Fees	10.4	0.0	3.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	2.0
Costs to Customers	4.7	(0.4)	1.9	(0.2)	0.2	0.7	0.9	0.7	0.7	2.1	4.0
********											
Fuel Factor	5.9	(0.4)	0.0	0.5	0.6	0.7	0.8	1.7	2.6	3.5	4.3

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-7: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Base Case (Bedington-Black Oak Case)

(Millions of dollars; negative values are credits to cost)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	78.1	11.5	11.9	12.4	12.9	13.4	13.9	15.4	16.9	18.4	19.9
Fuel Costs	278.0	42.7	44.3	45.9	47.6	49.2	50.9	54.0	57.0	60.1	63.1
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	14.5	2.6	2.4	2.2	2.3	2.4	2.5	2.7	2.9	3.1	3.3
Sub-Total Fuel Factor	386.5	59.8	61.8	63.7	65.3	67.6	70.1	74.8	79.6	84.4	89.3
Base Rate Impacts:											
NUG Energy - Base Rates	47.8	0.0	7.6	8.4	8.8	9.3	9.7	10.9	12.2	13.5	14.8
Energy Purchases - Base Rates	43.9	0.0	7.6	7.9	8.3	8.6	8.9	9.9	10.8	11.8	12.8
Sub-Total Base Rate Energy	91.7	0.0	15.3	16.4	17.1	17.8	18.6	20.8	23.0	25.3	27.5
Purchased Power Capacity	16.0	0.0	0.5	1.0	1.4	1.5	2.5	4.1	6.6	8.9	10.7
Total Prod/Gen Costs	494.2	59.8	77.6	81.1	83.7	86.9	91.1	99.7	109.3	118.6	127.5
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(7.9)	(1.6)	(1.6)	(1.6)	(1.5)	(1.3)	(1.1)	(1.2)	(1.2)	(1.3)	(1.3)
Base Rate Impacts:											
VOM on Sales - Base Rates	(1.1)	0.0	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Profit on Sales - Base Rates	(0.2)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)
Sub-Total Base Rate Energy	(1.3)	0.0	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(9.2)	(1.6)	(1.9)	(1.9)	(1.7)	(1.5)	(1.3)	(1.4)	(1.5)	(1.5)	(1.6)
Transmission Rights Revenues											
Transmission Rights Revenues (FTRs)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RTO Admin Fees											
RTO Admin Fees	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs to Customers	485.1	58.2	75.7	79.2	82.0	85.4	89.8	98.3	107.8	117.1	125.8
********											
Fuel Factor	378.6	58.2	60.2	62.1	63.8	66.3	69.0	73.6	78.4	83.2	87.9

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-8: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case (Bedington-Black Oak Case)

(Millions of dollars; negative values are credits to cost)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	104.5	15.1	15.4	15.8	16.8	17.8	18.8	21.1	23.4	25.7	28.0
Fuel Costs	255.0	38.4	40.4	42.5	44.0	45.4	46.9	49.6	52.4	55.2	57.9
"Other Fuel" Costs	15.9	3.1	3.1	3.2	2.5	2.5	2.7	2.7	2.7	2.8	2.9
NUG Energy - Fuel Factor	14.1	2.4	2.3	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0
Sub-Total Fuel Factor	389.5	59.0	61.4	63.7	65.6	68.1	70.9	76.1	81.3	86.6	91.9
Base Rate Impacts:											
NUG Energy - Base Rates	33.5	0.0	5.8	6.2	6.4	6.7	6.9	7.5	8.2	8.8	9.4
Energy Purchases - Base Rates	58.8	0.0	9.9	10.1	10.7	11.4	12.0	13.5	15.0	16.4	17.9
VOM Reduction - Reduced Output	(2.9)	0.0	(0.7)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)
Sub-Total Base Rate Energy	89.4	0.0	15.0	15.6	16.6	17.4	18.3	20.4	22.5	24.6	26.7
Purchased Power Capacity	13.6	0.0	0.5	1.0	1.4	1.5	2.3	3.1	4.8	7.3	9.7
Congestion - Base Rates	35.7	0.0	6.8	7.1	7.4	7.6	7.9	7.9	7.9	7.9	7.8
Total Prod/Gen Costs	528.2	59.0	83.7	87.5	90.9	94.7	99.5	107.4	116.5	126.3	136.1
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	(3.8)	(0.5)	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)	(0.9)
Base Rate Impacts:											
VOM on Sales - Base Rates	(0.6)	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)
Profit on Sales - Base Rates	(0.2)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)
Sub-Total Base Rate Energy	(0.8)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	(4.5)	(0.5)	(0.7)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.1)
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(3.7)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)
Other FTRs - Base Rates	(43.0)	0.0	(8.7)	(9.1)	(9.1)	(9.2)	(9.2)	(9.1)	(9.0)	(8.9)	(8.9)
Transmission Rights Revenues (FTRs)	(46.6)	(0.6)	(9.3)	(9.7)	(9.7)	(9.8)	(9.9)	(9.8)	(9.8)	(9.7)	(9.7)
RTO Admin Fees											
RTO Admin Fees	10.2	0.0	3.8	1.8	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Costs to Customers	487.2	57.8	77.5	78.8	82.1	85.8	90.5	98.5	107.6	117.5	127.3
********											
Fuel Factor	382.1	57.8	60.2	62.5	64.3	66.8	69.5	74.6	79.8	85.0	90.2

Appendix D: Detailed Financial Results of Sensitivity Cases

Table D-9: Annual Costs and Offsetting Revenues for North Carolina Retail Customers – Change Case Minus Base Case (Bedington-Black Oak Case)

(Millions of dollars; negative numbers are benefits)

North Carolina Retail	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production/Generation Costs											
Fuel Factor Impacts:											
Energy Purchases - Fuel Factor	26.3	3.6	3.5	3.4	3.9	4.4	4.9	5.7	6.5	7.3	8.1
Fuel Costs	(22.9)	(4.3)	(3.8)	(3.4)	(3.6)	(3.8)	(4.0)	(4.3)	(4.6)	(4.9)	(5.2)
"Other Fuel" Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUG Energy - Fuel Factor	(0.4)	(0.2)	(0.1)	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.3)
Sub-Total Fuel Factor	3.0	(0.9)	(0.4)	0.0	0.3	0.6	0.8	1.3	1.7	2.2	2.6
Base Rate Impacts:											
NUG Energy - Base Rates	(14.3)	0.0	(1.8)	(2.3)	(2.4)	(2.6)	(2.8)	(3.4)	(4.1)	(4.7)	(5.4)
Energy Purchases - Base Rates	14.9	0.0	2.2	2.1	2.5	2.8	3.1	3.6	4.1	4.7	5.2
VOM Reduction - Reduced Output	(2.9)	0.0	(0.7)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)
Sub-Total Base Rate Energy	(2.3)	0.0	(0.3)	(0.7)	(0.5)	(0.4)	(0.2)	(0.4)	(0.5)	(0.7)	(0.9)
Purchased Power Capacity	(2.3)	0.0	0.0	0.0	0.0	0.0	(0.2)	(1.1)	(1.8)	(1.6)	(0.9)
Congestion - Base Rates	35.7	0.0	6.8	7.1	7.4	7.6	7.9	7.9	7.9	7.9	7.8
Total Prod/Gen Costs	34.0	(0.9)	6.1	6.4	7.1	7.8	8.4	7.7	7.2	7.7	8.7
Production Revenues											
Fuel Factor Impacts:											
Sales Costs - Fuel Factor	4.2	1.1	1.1	1.0	0.8	0.6	0.4	0.4	0.4	0.5	0.5
Base Rate Impacts:											
VOM on Sales - Base Rates	0.5	0.0	0.2	0.2	0.1	0.1	0.0	0.0	0.1	0.1	0.1
Profit on Sales - Base Rates	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0
Sub-Total Base Rate Energy	0.5	0.0	0.2	0.2	0.1	0.1	0.0	0.0	0.1	0.1	0.1
Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Production Revenue	4.6	1.1	1.3	1.2	0.9	0.7	0.4	0.4	0.5	0.5	0.6
Transmission Rights Revenues											
FTRs Attributable to Purchases - Fuel Factor	(3.7)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)
Other FTRs - Base Rates	(43.0)	0.0	(8.7)	(9.1)	(9.1)	(9.2)	(9.2)	(9.1)	(9.0)	(8.9)	(8.9)
Transmission Rights Revenues (FTRs)	(46.6)	(0.6)	(9.3)	(9.7)	(9.7)	(9.8)	(9.9)	(9.8)	(9.8)	(9.7)	(9.7)
RTO Admin Fees											
RTO Admin Fees	10.2	0.0	3.8	1.8	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Costs to Customers	2.2	(0.4)	1.8	(0.4)	0.0	0.5	0.7	0.2	(0.2)	0.4	1.5
********											
Fuel Factor	3.5	(0.4)	0.0	0.4	0.5	0.5	0.6	1.0	1.4	1.9	2.3

APPENDIX E: COMPARISON TO SEARUC STUDY

CRA and GE Power Systems Engineering Consulting on behalf of the Southeastern Association of Regulatory Utility Commissioners conducted the SEARUC study. That study examined the impacts of forming three RTOs in the southeast—SeTrans, GridSouth and GridFlorida. In designing and executing the study for Dominion North Carolina Power, CRA drew upon its experience of the SEARUC study to adapt and improve the SEARUC study's methodology to address the more focused questions relating to Dominion's applications to join PJM. This Appendix summarizes the SEARUC study methods and findings and discusses why particular methodological changes were made in this study for Dominion.

The SEARUC study assessed the short-run benefits of forming southeastern RTOs. While the financial models used in the SEARUC study and this study are quite different in scope and detail, both studies used similar GE-MAPS models and a trade-hurdle methodology to assess the effects on the physical operation of the system. A base case was calibrated to historical usage patterns of generation using hurdle rates that are similar to those in this study. In particular, the same $10 per MWh hurdle rate was used for the unit-commitment phase of MAPS. The dispatch hurdle rate in the SEARUC study was about $7-$8 per MWh consisting of a $5 per MWh rate to reflect trade impediments, a $1 per MWh rate for line losses, and a $1-$2 per MWh transmission rate. This hurdle rate was pancaked in the SEARUC study. In this study for Dominion, the dispatch hurdle rate has been separated into a pancaked trade hurdle and a non-pancaked import hurdle. As such, the methodology used here is improved over that adopted in the SEARUC study.

The modeled implementation of RTOs in the SEARUC study was similar to that in this study. For example, the hurdle rates do not apply for trades within RTOs (except for line losses), but do impact trades that cross RTOs boundaries (or boundaries between control areas in the base case).

A key difference between the SEARUC study and this study is the financial model. The SEARUC study examined the total net benefits of each control zone and the collective net benefits across the Eastern Interconnection. That study did not address, however, the incidence of the costs or benefits on classes of stakeholders within a control zone, leaving unanswered the question of whether retail customers would receive net benefits. Given the number of utilities covered by the SEARUC study and the difficulty of accurately modeling state and federal regulatory nuances for each, the only practical approach for the SEARUC study was to fold all stakeholders in a control area together. In this study, focused as it is on the customers of a single utility, we were able to parse the effects of changes in the wholesale markets down to the level of changes in relevant parts of the retail rates, thus improving its relevance to regulators.

Both studies include several sensitivity cases, but they are focused on different questions. The SEARUC study examined several sensitivity cases, the most important of which assessed

Appendix E: Comparison to SEARUC Study

alternative regulatory treatments of new investment in transmission and generation capacity. In this study, however, these are not relevant questions.

Consistent with FERC's Order 2003, the cost of new transmission investment in this study is assumed to be borne by those who benefit; moreover, there is no difference in how such costs are treated between the Base and Change Cases, and so there is no effect on the net benefit. Consequently, there was no need to conduct a sensitivity analysis of transmission funding.

The other major sensitivity examined in the SEARUC study was the level of merchant plants deciding to go forward. The Entergy-Southern Company area had about 24,000 MW of excess merchant capacity at the time of the study, much of which was not deliverable to load. Since the study, this level has been reduced slightly, but the remaining excess is still quite large. The uncertainty about the amount of such capacity that might decide to remain in the market versus withdrawing until a later date was addressed through a sensitivity case in which the assumed level of merchant plants was about 7,500 MW smaller. This assumption had a significant impact on the results, with benefits generally being smaller for the reduced level of merchant participation in the market. The regions of interest in this study, however, do not have the issues of a large overhang of deliverability-constrained capacity. As discussed in Appendix B-1, this study dealt carefully with the modeling issues of adding new capacity required for system reliability; the issue of excess regional capacity did not arise.

Capacity pricing is handled differently in the SEARUC model than in this present study. In the SEARUC study, the Change Case allowed greater exports of capacity from Entergy to Southern, thereby delaying the need to build new capacity in the eastern part of SeTrans. The SEARUC model did not include a capacity market, however; the benefit from reduced capacity requirements was valued as though all capacity were built in utilities' rate bases and paid for by native load under cost-of-service rates. Although this modeling choice was appropriate for SEARUC, it would not accurately reflect the likely benefits to North Carolina Retail Customers under the PJM market design, which does include an ICAP market. As discussed in Appendix B-2, capacity prices in PJM reflect the (expected) balance between capacity and load in PJM, so that the price serves as a signal for developers to build new generation needed to support local reliability. Moreover, the existence of active capacity markets in the mid-Atlantic and Northeast region dictated that we explicitly model capacity trading across regions, which was not modeled in the SEARUC study.

The sensitivity cases in this study, by contrast to the SEARUC study, bracket uncertainty with respect to two inputs to the physical model: fuel prices and energy demand. The results of these sensitivity cases provide useful information about the range of likely outcomes, which was absent from the SEARUC study.

Dominion Stoddard
Direct Ex. 2
E-22, Sub 418
I/A PB 1/21/05

Exhibit Stoddard-1

NORTH CAROLINA - BENEFITS AS PERCENTAGE OF COSTS (As Filed and Public Staff Cases)

Annual Benefits (MM$)	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	(1.8)	0.4	(1.9)	0.2	(0.1)	(0.5)	(0.6)	0.0	0.5	0.0	(0.9)
High Fuel Price	1.0	1.5	(1.4)	0.7	0.4	0.0	(0.1)	0.4	0.7	0.1	(1.0)
High Load	(4.7)	0.4	(1.9)	0.2	(0.2)	(0.7)	(0.9)	(0.7)	(0.7)	(2.1)	(4.0)
Bedington-Black Oak	(2.2)	0.4	(1.8)	0.4	(0.0)	(0.5)	(0.7)	(0.2)	0.2	(0.4)	(1.5)
Filed - 5% Cramdown	(3.7)	0.4	(2.3)	(0.2)	(0.5)	(0.9)	(1.0)	(0.4)	0.1	(0.4)	(1.4)
Filed - 10% Cramdown	(5.6)	0.4	(2.7)	(0.6)	(0.9)	(1.3)	(1.4)	(0.8)	(0.3)	(0.8)	(1.8)
Low-Hurdle Base	(2.0)	0.2	(2.0)	0.2	(0.1)	(0.5)	(0.7)	0.0	0.5	0.1	(0.8)
Low-Hurdle Base - 5% Cramdown	(3.9)	0.2	(2.3)	(0.2)	(0.5)	(0.9)	(1.1)	(0.4)	0.1	(0.3)	(1.3)
Low-Hurdle Base - 10% Cramdown	(5.8)	0.1	(2.7)	(0.6)	(0.9)	(1.3)	(1.5)	(0.8)	(0.3)	(0.8)	(1.7)
Expanded PJM Base	(4.1)	0.9	(1.6)	0.4	0.1	(0.2)	(0.5)	(0.9)	(2.1)	(3.1)	(3.2)
Expanded PJM Base -5% Cramdown	(6.0)	0.9	(2.0)	0.0	(0.3)	(0.6)	(0.9)	(1.4)	(2.5)	(3.5)	(3.6)
Expanded PJM Base -10% Cramdown	(7.9)	0.9	(2.3)	(0.3)	(0.7)	(1.0)	(1.3)	(1.8)	(2.9)	(4.0)	(4.1)
Low-Hurdle/Expand PJM	(4.8)	0.7	(1.8)	0.3	0.0	(0.3)	(0.6)	(1.1)	(2.2)	(3.2)	(3.2)
Low-Hurdle/Expand PJM -5% Cramdown	(6.6)	0.7	(2.1)	(0.0)	(0.4)	(0.7)	(1.0)	(1.5)	(2.6)	(3.6)	(3.7)
Low-Hurdle/Expand PJM -10% Cramdown	(8.5)	0.7	(2.5)	(0.4)	(0.7)	(1.1)	(1.4)	(1.9)	(3.0)	(4.0)	(4.1)

Base Rates in NC $0.05072 per kW

		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
NC Retail Sales @ the Meter		3,836	3,911	3,891	3,686	3,748	3,816	3,901	3,984	4,063	4,142
Base Rates x Sales (MM$)		194.6	198.4	197.4	186.9	190.1	193.5	197.9	202.1	206.1	210.1

Fuel Factor Costs - Base Case (MM$)	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	381.0	58.7	60.7	62.6	64.3	66.7	69.4	74.0	78.7	83.4	88.2
High Fuel Price	413.8	63.3	65.2	67.1	69.4	72.4	75.6	80.9	86.4	91.9	97.3
High Load	399.0	61.6	63.5	65.4	67.2	69.7	72.5	77.5	82.6	87.7	92.8
Bedington-Black Oak	378.6	58.2	60.2	62.1	63.8	66.3	69.0	73.6	78.4	83.2	87.9
Low-Hurdle Base	382.5	58.6	60.7	62.7	64.5	67.0	69.7	74.4	79.3	84.1	89.0
Expanded PJM Base	382.8	59.2	61.0	62.8	64.5	67.1	69.8	74.3	79.0	83.7	88.3
Low-Hurdle/Expand PJM	383.5	59.2	61.1	62.9	64.7	67.2	69.9	74.5	79.2	84.0	88.7

Total Costs ($MM)											
Base Case	1,479.4	253.3	259.0	259.9	251.2	256.8	262.9	271.8	280.8	289.5	298.2
High Fuel Price	1,512.2	257.9	263.6	264.4	256.3	262.5	269.2	278.8	288.5	297.9	307.4
High Load	1,497.5	256.2	261.9	262.8	254.1	259.8	266.0	275.3	284.7	293.8	302.9
Bedington-Black Oak	1,477.0	252.8	258.5	259.5	250.8	256.4	262.5	271.5	280.5	289.2	298.0
Low-Hurdle Base	1,480.9	253.2	259.1	260.1	251.4	257.1	263.2	272.3	281.4	290.2	299.0
Expanded PJM Base	1,481.2	253.8	259.4	260.1	251.5	257.2	263.3	272.2	281.1	289.7	298.4
Low-Hurdle/Expand PJM	1,482.0	253.7	259.4	260.3	251.6	257.3	263.4	272.3	281.3	290.0	298.8

Benefits as % of Total Cost	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	-0.12%	0.17%	-0.75%	0.08%	-0.05%	-0.18%	-0.24%	0.00%	0.18%	0.02%	-0.31%
High Fuel Price	0.07%	0.60%	-0.52%	0.27%	0.15%	0.02%	-0.05%	0.13%	0.25%	0.03%	-0.34%
High Load	-0.32%	0.16%	-0.71%	0.09%	-0.09%	-0.27%	-0.34%	-0.24%	-0.24%	-0.70%	-1.33%
Bedington-Black Oak	-0.15%	0.15%	-0.69%	0.14%	-0.01%	-0.18%	-0.27%	-0.07%	0.07%	-0.14%	-0.50%
Filed - 5% Cramdown	-0.25%	0.16%	-0.89%	-0.07%	-0.20%	-0.34%	-0.40%	-0.15%	0.03%	-0.13%	-0.46%
Filed - 10% Cramdown	-0.38%	0.15%	-1.03%	-0.22%	-0.36%	-0.49%	-0.55%	-0.30%	-0.12%	-0.28%	-0.60%
Low-Hurdle Base	-0.14%	0.07%	-0.76%	0.06%	-0.06%	-0.19%	-0.26%	0.00%	0.19%	0.03%	-0.28%
Low-Hurdle Base - 5% Cramdown	-0.26%	0.06%	-0.90%	-0.08%	-0.21%	-0.35%	-0.41%	-0.15%	0.04%	-0.11%	-0.43%
Low-Hurdle Base - 10% Cramdown	-0.39%	0.05%	-1.04%	-0.22%	-0.36%	-0.50%	-0.56%	-0.30%	-0.10%	-0.26%	-0.57%
Expanded PJM Base	-0.27%	0.36%	-0.62%	0.16%	0.05%	-0.06%	-0.18%	-0.34%	-0.73%	-1.07%	-1.07%
Expanded PJM Base -5% Cramdown	-0.41%	0.35%	-0.76%	0.02%	-0.11%	-0.22%	-0.33%	-0.50%	-0.88%	-1.22%	-1.22%
Expanded PJM Base -10% Cramdown	-0.54%	0.35%	-0.90%	-0.13%	-0.26%	-0.37%	-0.49%	-0.65%	-1.03%	-1.37%	-1.37%
Low-Hurdle/Expand PJM	-0.32%	0.29%	-0.68%	0.13%	0.01%	-0.11%	-0.23%	-0.39%	-0.77%	-1.09%	-1.09%
Low-Hurdle/Expand PJM -5% Cramdown	-0.45%	0.28%	-0.81%	-0.01%	-0.14%	-0.26%	-0.38%	-0.54%	-0.91%	-1.24%	-1.23%
Low-Hurdle/Expand PJM -10% Cramdown	-0.57%	0.27%	-0.95%	-0.16%	-0.29%	-0.42%	-0.53%	-0.69%	-1.06%	-1.39%	-1.38%

Exhibit Stoddard-1

NORTH CAROLINA - BENEFITS AS PERCENTAGE OF COSTS (With Joint Offer of Settlement)

Annual Benefits (MM$)	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	1.1	0.4	0.2	0.2	(0.0)	(0.1)	(0.1)	0.5	1.0	0.4	(0.6)
High Fuel Price	0.9	1.5	0.2	0.1	(0.1)	(0.3)	(0.2)	0.2	0.5	(0.2)	(1.4)
High Load	(1.8)	0.4	0.2	0.2	(0.1)	(0.3)	(0.3)	(0.1)	(0.2)	(1.6)	(3.7)
Bedington-Black Oak	0.7	0.4	0.0	0.1	(0.0)	(0.2)	(0.2)	0.4	0.9	0.4	(0.6)
Filed - 5% Cramdown	0.9	0.4	0.1	0.2	(0.0)	(0.2)	(0.1)	0.5	0.9	0.4	(0.6)
Filed - 10% Cramdown	0.8	0.4	0.1	0.1	(0.1)	(0.2)	(0.2)	0.4	0.9	0.4	(0.6)
Low-Hurdle Base	0.4	0.2	0.1	0.1	(0.0)	(0.1)	(0.1)	0.4	0.8	0.1	(1.0)
Low-Hurdle Base - 5% Cramdown	0.3	0.2	0.1	0.1	(0.0)	(0.2)	(0.1)	0.4	0.7	0.1	(1.0)
Low-Hurdle Base - 10% Cramdown	0.1	0.1	0.1	0.1	(0.1)	(0.2)	(0.1)	0.3	0.7	0.1	(1.1)
Expanded PJM Base	(1.2)	0.9	0.5	0.4	0.2	0.2	0.1	(0.4)	(1.6)	(2.7)	(2.8)
Expanded PJM Base -5% Cramdown	(1.4)	0.9	0.5	0.4	0.2	0.1	0.0	(0.5)	(1.6)	(2.7)	(2.9)
Expanded PJM Base -10% Cramdown	(1.5)	0.9	0.5	0.4	0.2	0.1	0.0	(0.5)	(1.7)	(2.8)	(2.9)
Low-Hurdle/Expand PJM	(2.3)	0.7	0.4	0.3	0.1	0.1	(0.0)	(0.7)	(1.9)	(3.1)	(3.4)
Low-Hurdle/Expand PJM -5% Cramdown	(2.5)	0.7	0.3	0.3	0.1	0.0	(0.1)	(0.7)	(2.0)	(3.2)	(3.4)
Low-Hurdle/Expand PJM -10% Cramdown	(2.6)	0.7	0.3	0.3	0.1	0.0	(0.1)	(0.7)	(2.0)	(3.2)	(3.5)

		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Rates in NC		$0.05072 per kW									
NC Retail Sales @ the Meter		3,836	3,911	3,891	3,686	3,748	3,816	3,901	3,984	4,063	4,142
Base Rates x Sales (MM$)		194.6	198.4	197.4	186.9	190.1	193.5	197.9	202.1	206.1	210.1

Fuel Factor Costs - Base Case (MM$)	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	381.0	58.7	60.7	62.6	64.3	66.7	69.4	74.0	78.7	83.4	88.2
High Fuel Price	413.8	63.3	65.2	67.1	69.4	72.4	75.6	80.9	86.4	91.9	97.3
High Load	399.0	61.6	63.5	65.4	67.2	69.7	72.5	77.5	82.6	87.7	92.8
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Low-Hurdle Base	382.5	58.6	60.7	62.7	64.5	67.0	69.7	74.4	79.3	84.1	89.0
Expanded PJM Base	382.8	59.2	61.0	62.8	64.5	67.1	69.8	74.3	79.0	83.7	88.3
Low-Hurdle/Expand PJM	383.5	59.2	61.1	62.9	64.7	67.2	69.9	74.5	79.2	84.0	88.7

Total Costs ($MM)											
Base Case	1,479.4	253.3	259.0	259.9	251.2	256.8	262.9	271.8	280.8	289.5	298.2
High Fuel Price	1,512.2	257.9	263.6	264.4	256.3	262.5	269.2	278.8	288.5	297.9	307.4
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Bedington-Black Oak	1,477.0	252.8	258.5	259.5	250.8	256.4	262.5	271.5	280.5	289.2	298.0
Low-Hurdle Base	1,480.9	253.2	259.1	260.1	251.4	257.1	263.2	272.3	281.4	290.2	299.0
Expanded PJM Base	1,481.2	253.8	259.4	260.1	251.5	257.2	263.3	272.2	281.1	289.7	298.4
Low-Hurdle/Expand PJM	1,482.0	253.7	259.4	260.3	251.6	257.3	263.4	272.3	281.3	290.0	298.8

Benefits as % of Total Cost	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	0.07%	0.17%	0.06%	0.07%	0.00%	-0.06%	-0.04%	0.19%	0.34%	0.16%	-0.19%
High Fuel Price	0.06%	0.60%	0.08%	0.04%	-0.04%	-0.10%	-0.09%	0.06%	0.16%	-0.08%	-0.46%
High Load	-0.12%	0.16%	0.08%	0.06%	-0.05%	-0.13%	-0.11%	-0.04%	-0.07%	-0.55%	-1.21%
Bedington-Black Oak	0.05%	0.15%	0.01%	0.05%	-0.01%	-0.08%	-0.07%	0.16%	0.33%	0.14%	-0.20%
Filed - 5% Cramdown	0.06%	0.16%	0.05%	0.06%	-0.01%	-0.06%	-0.05%	0.17%	0.33%	0.14%	-0.20%
Filed - 10% Cramdown	0.05%	0.15%	0.04%	0.05%	-0.02%	-0.07%	-0.06%	0.16%	0.32%	0.13%	-0.21%
Low-Hurdle Base	0.03%	0.07%	0.06%	0.06%	-0.01%	-0.06%	-0.04%	0.15%	0.27%	0.04%	-0.33%
Low-Hurdle Base - 5% Cramdown	0.02%	0.06%	0.05%	0.05%	-0.02%	-0.07%	-0.05%	0.14%	0.26%	0.03%	-0.34%
Low-Hurdle Base - 10% Cramdown	0.01%	0.05%	0.04%	0.04%	-0.03%	-0.08%	-0.06%	0.13%	0.25%	0.02%	-0.35%
Expanded PJM Base	-0.08%	0.36%	0.19%	0.15%	0.09%	0.06%	0.03%	-0.16%	-0.57%	-0.93%	-0.95%
Expanded PJM Base -5% Cramdown	-0.09%	0.35%	0.18%	0.14%	0.09%	0.05%	0.02%	-0.17%	-0.58%	-0.94%	-0.96%
Expanded PJM Base -10% Cramdown	-0.10%	0.35%	0.18%	0.14%	0.08%	0.04%	0.01%	-0.18%	-0.60%	-0.95%	-0.98%
Low-Hurdle/Expand PJM	-0.16%	0.29%	0.14%	0.12%	0.06%	0.02%	-0.02%	-0.24%	-0.69%	-1.08%	-1.14%
Low-Hurdle/Expand PJM -5% Cramdown	-0.17%	0.28%	0.13%	0.11%	0.05%	0.01%	-0.02%	-0.25%	-0.70%	-1.09%	-1.15%
Low-Hurdle/Expand PJM -10% Cramdown	-0.18%	0.27%	0.12%	0.10%	0.04%	0.00%	-0.03%	-0.26%	-0.71%	-1.10%	-1.16%

Exhibit Stoddard-1

Incremental Change in

NORTH CAROLINA - BENEFITS AS PERCENTAGE OF COSTS (With Joint Offer of Settlement)

Annual Benefits (MM$)	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	2.8	0.0	2.1	(0.0)	0.1	0.3	0.5	0.5	0.4	0.4	0.4
High Fuel Price	(0.2)	0.0	1.6	(0.6)	(0.5)	(0.3)	(0.1)	(0.2)	(0.3)	(0.3)	(0.4)
High Load	2.9	0.0	2.1	(0.1)	0.1	0.4	0.6	0.6	0.5	0.4	0.4
Bedington-Black Oak	2.9	0.0	1.8	(0.2)	(0.0)	0.3	0.5	0.6	0.7	0.8	0.9
Filed - 5% Cramdown	4.6	0.0	2.4	0.3	0.5	0.7	0.9	0.9	0.8	0.8	0.8
Filed - 10% Cramdown	*6.4*	*0.0*	*2.8*	*0.7*	*0.8*	*1.1*	*1.3*	*1.3*	*1.2*	*1.2*	*1.2*
Low-Hurdle Base	2.4	0.0	2.1	(0.0)	0.1	0.4	0.6	0.4	0.2	0.0	(0.1)
Low-Hurdle Base - 5% Cramdown	4.2	0.0	2.5	0.3	0.5	0.7	0.9	0.8	0.6	0.4	0.3
Low-Hurdle Base - 10% Cramdown	5.9	0.0	2.8	0.7	0.8	1.1	1.3	1.2	1.0	0.8	0.6
Expanded PJM Base	2.8	0.0	2.1	(0.0)	0.1	0.3	0.5	0.5	0.4	0.4	0.4
Expanded PJM Base -5% Cramdown	4.6	0.0	2.4	0.3	0.5	0.7	0.9	0.9	0.8	0.8	0.8
Expanded PJM Base -10% Cramdown	6.4	0.0	2.8	0.7	0.8	1.1	1.3	1.3	1.2	1.2	1.2
Low-Hurdle/Expand PJM	2.4	0.0	2.1	(0.0)	0.1	0.4	0.6	0.4	0.2	0.0	(0.1)
Low-Hurdle/Expand PJM -5% Cramdown	4.2	0.0	2.5	0.3	0.5	0.7	0.9	0.8	0.6	0.4	0.3
Low-Hurdle/Expand PJM -10% Cramdown	5.9	0.0	2.8	0.7	0.8	1.1	1.3	1.2	1.0	0.8	0.6

Benefits as % of Total Cost	PV	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	0.19%	0.00%	0.81%	-0.01%	0.04%	0.13%	0.20%	0.18%	0.16%	0.14%	0.12%
High Fuel Price	-0.01%	0.00%	0.60%	-0.22%	-0.19%	-0.12%	-0.04%	-0.07%	-0.09%	-0.11%	-0.12%
High Load	0.19%	0.00%	0.79%	-0.03%	0.04%	0.14%	0.24%	0.21%	0.17%	0.15%	0.12%
Bedington-Black Oak	0.20%	0.00%	0.71%	-0.08%	-0.01%	0.10%	0.20%	0.23%	0.26%	0.28%	0.31%
Filed - 5% Cramdown	0.31%	0.00%	0.94%	0.13%	0.19%	0.27%	0.35%	0.32%	0.30%	0.28%	0.26%
Filed - 10% Cramdown	0.43%	0.00%	1.07%	0.27%	0.34%	0.42%	0.49%	0.47%	0.44%	0.42%	0.39%
Low-Hurdle Base	0.16%	0.00%	0.82%	-0.01%	0.05%	0.14%	0.22%	0.15%	0.08%	0.01%	-0.05%
Low-Hurdle Base - 5% Cramdown	0.28%	0.00%	0.95%	0.13%	0.19%	0.28%	0.36%	0.28%	0.21%	0.15%	0.08%
Low-Hurdle Base - 10% Cramdown	0.40%	0.00%	1.07%	0.26%	0.33%	0.42%	0.50%	0.42%	0.35%	0.28%	0.22%
Expanded PJM Base	0.19%	0.00%	0.81%	-0.01%	0.04%	0.13%	0.20%	0.18%	0.16%	0.14%	0.12%
Expanded PJM Base -5% Cramdown	0.31%	0.00%	0.94%	0.13%	0.19%	0.27%	0.35%	0.32%	0.30%	0.28%	0.26%
Expanded PJM Base -10% Cramdown	0.43%	0.00%	1.07%	0.27%	0.34%	0.42%	0.49%	0.47%	0.44%	0.42%	0.39%
Low-Hurdle/Expand PJM	0.16%	0.00%	0.82%	-0.01%	0.05%	0.14%	0.22%	0.15%	0.08%	0.01%	-0.05%
Low-Hurdle/Expand PJM -5% Cramdown	0.28%	0.00%	0.95%	0.13%	0.19%	0.28%	0.36%	0.28%	0.21%	0.15%	0.08%
Low-Hurdle/Expand PJM -10% Cramdown	0.40%	0.00%	1.07%	0.26%	0.33%	0.42%	0.50%	0.42%	0.35%	0.28%	0.22%