Q. HOW DOES THE FRAMEWORK FOR ASSESSING VERTICAL MARKET POWER DIFFER FROM THE HORIZONTAL ANALYSIS FRAMEWORK?

A. For the vertical market power screen, the Commission's focus is on the structural competitiveness of downstream or upstream product markets, as measured by HHIs. The main difference from the horizontal analysis is that in the vertical analysis, the focus is not on the change in HHIs resulting from the merger, but on the structure of those markets where one merging party sells upstream products in a geographic market in which the other merging party sells downstream products.

Q. WHAT ARE THE VERTICAL ISSUES THAT THE COMMISSION HAS FOUND REQUIRE INVESTIGATION IN THE CONTEXT OF MERGERS BETWEEN ELECTRIC UTILITIES AND GAS TRANSPORTATION PROVIDERS?

A. The Commission has indicated that under some circumstances such mergers could give rise to vertical concerns. The Commission has expressed its concern in decisions addressing "convergence mergers" and in Order No. 642, that vertical mergers "may create or enhance the incentive and/or ability for the merged firm to adversely affect prices and output in the downstream electricity market and to discourage entry by new generators."[35] Potential market power arising from a merger between an electric utility and a gas pipeline is discussed by the Commission principally in Order No. 642 and Section 33.4 of the Revised Filing Requirements, and in its orders in *Enova*, *Dominion*, *Brooklyn Union Gas* and *Energy East*.[36]

As already noted, the main areas of Commission concern are: (1) the creation of incentives for the gas-related upstream activities to raise costs for rivals of the electricity generation affiliate; (2) the enhanced ability to facilitate coordination of pricing in upstream or downstream markets; and (3) the enhanced ability to evade regulation,

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[35] III FERC Stats. & Regs. Regs. Preambles, ¶31,111 at 31,904.

[36] See *Enova Corporation and Pacific Enterprises*, 79 FERC ¶ 61,372 (1997) ("Enova"); *Dominion*; *Long Island Lighting Company*, 80 FERC ¶ 61,035 (1997) ("Brooklyn Union Gas"); and *Energy East Corporation and RGS Energy Group, Inc.*, 96 FERC ¶ 61, 322 (2001) ("Energy East").

primarily through self-dealing.[37] The Commission also has expressed concerns that (a) convergence mergers involving an upstream gas supplier serving the downstream merger partner, as well as competitors of that partner, could result in preferential terms of service; and (b) a pipeline serving electric generation could provide commercially valuable information to newly affiliated electricity generating or marketing operations. My analysis considers each of these concerns.

Q. PLEASE ELABORATE ON WHAT IS MEANT BY RAISING RIVALS' COSTS.

A. Foreclosure, or raising rivals' costs, refers to a situation in which a vertically integrated firm withholds inputs produced in its upstream operations (*e.g.*, delivered gas) from rivals in the downstream (*e.g.*, electric generation) market in order to increase the costs of downstream rivals, thereby increasing downstream market prices and creating an opportunity for the integrated firm to achieve increased profits from its downstream operations. It also may refer to a situation in which the price charged to rivals can be profitably increased as a result of a merger with additional generating facilities (*e.g.*, the economics of discounted service are changed by the merger).

If the vertically integrated firm exercises market power in the upstream market after the merger, the costs to rivals in the downstream market could increase. However, if competitors in the downstream market have adequate alternatives to the upstream product, the merged firms cannot exercise market power. Moreover, if conditions in the upstream market are not conducive to the exercise of market power (*i.e.*, the upstream market is competitive), an attempt to raise rivals' cost will be unsuccessful. Similarly, if the upstream or downstream markets are sufficiently competitive, there should be no issue of anti-competitive coordination.

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[37] Because neither of the Applicants own regulated assets that take service from the other Applicant's LDC, the regulatory evasion concern is not present and I do not discuss it further.

Q. ARE THERE ANY OTHER RELEVANT PARAMETERS IN CONSIDERING GAS-ELECTRIC VERTICAL ISSUES?

A. The Commission has stated that a necessary condition for a convergence merger to cause a vertical concern is that both the upstream and downstream markets are highly concentrated.[38] In other words, the screen is passed if the downstream (or upstream) market is not highly concentrated, irrespective of the degree of concentration of the upstream (or downstream) market. A proper analysis of the upstream market requires that the structure of control of transportation capacity be examined, which requires that control of the transportation capacity be allocated to holders of firm capacity rights on the relevant pipelines with any unsubscribed capacity allocated to the pipeline owner.

Q. WHAT ARE THE RELEVANT ISSUES IN CONSIDERING TRANSMISSION-RELATED VERTICAL ISSUES?

A. In the context of a merger in which parties own both generation and transmission, the issue is whether the merger creates any additional ability or incentive to use control over transmission facilities to gain a competitive advantage in wholesale electricity markets.

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[38] "[H]ighly concentrated upstream and downstream markets are necessary, but not sufficient, conditions for a vertical foreclosure strategy to be effective" Revised Filing Requirements, ¶ 31,311 at 31,911. "A vertical merger can create or enhance the incentive and ability of the merged firm to adversely affect electricity prices or output in the downstream market by raising rivals' input costs if market power could be exercised in both the upstream and downstream geographic markets." Order No. 642, *slip op.* at 79. This was confirmed in *Energy East.* ("Applicants correctly conclude that because they have shown that the downstream markets are not highly concentrated, there is no concern about foreclosure or raising rivals' costs in this case.") *Energy East, op. cit.*

IV. DESCRIPTION OF METHODOLOGY

Q. PLEASE SUMMARIZE THE METHODOLOGY THAT YOU USED TO ANALYZE THE COMPETITIVE EFFECTS OF THE MERGER.

A. I evaluated the competitive effects of the merger using the delivered price test outlined in Appendix A and the Revised Filing Requirements. I implemented this analysis using a proprietary CRA model called the "Competitive Analysis Screening Model" ("CASm"). The source and methodology for the data required to conduct the delivered price test in CASm are described in Exhibit J-5. A technical description of CASm is provided in Exhibit J-6. I, and other CRA witnesses, have used CASm in numerous previous analyses submitted to the Commission.

Q. WHAT DESTINATION MARKETS DID YOU CONSIDER?

A. Consistent with the instructions in the Revised Filing Requirements, I identified the relevant geographic markets (i.e., destination markets) that could potentially be impacted by the merger.

In analyzing RTO markets, the Commission historically has taken into consideration transmission constraints into subareas that may define narrower relevant markets. I adopted this approach in my determination of the relevant markets to consider within the MISO-PJM footprint. Thus, in addition to analyzing MISO as a relevant geographic market, I considered two other relevant geographic markets based upon my review of relevant data, discussed below. Exhibit J-5 provides information on transmission constraints that was used to define these markets.

The first market, which is the MISO submarket consists of MISO, excluding WUMS,[39] as well as Iowa, Minnesota and LG&E. The constraints into WUMS are well documented. In order to be conservative, I excluded these additional areas that are often constrained

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[39] Reflecting the frequency of constraints, WUMS is a "Narrow Constrained Area" under the market power mitigation measures in the MISO Tariff. *2004 State of The Market Report Midwest ISO*, Potomac Economics Ltd., June 2005.

away from the portion of MISO in which Cinergy is located. I note however, that these additional areas have not been singled out by the MISO market monitor as either Broad or Narrow Constrained Areas under the tariff.

The second market, which is the MISO-PJM Midwest market, is the smallest relevant market that includes both Cinergy's regulated generation in MISO and Duke Energy's merchant generation in MISO and PJM. The MISO-PJM Midwest market consists of the MISO Submarket plus PJM excluding PJM east of Allegheny Energy.[40] The "carve outs" from the full MISO-PJM combined market are based on a combination of transmission constraints and conservatisms applied to determine the smallest relevant market, and I will describe each of the analyses I conducted and why certain areas are excluded in my MISO-PJM Midwest market. Applicants' generation in this market is summarized in Table 11 below:

Table 11: Applicants' Generation in MISO and PJM Markets

	Duke Energy (MW)	Cinergy (MW)
MISO	420	12,510*
PJM	3,057**	-
Total MISO-PJM	3,477	12,510

* Includes 196 MW of generation located in the OVEC control area for which Cinergy has network service into MISO

** Includes generation in MAIN (Illinois) and ECAR (Ohio, Indiana and Pennsylvania.

With respect to the Duke Power generation, consistent with the Commission's requirements, I examined the Duke Power control area as well as its direct interconnections (that is, its first-tier control area markets), which are Progress Energy

[40] My analysis of the MISO-PJM Midwest market includes Allegheny Energy, but excludes the original PJM participants as well as Dominion Virginia Power. My analysis suggests that Allegheny Energy should be included with PJM Classic; however, since Duke Energy owns a merchant plant interconnected with Allegheny Energy, inclusion of Allegheny Energy in the market is conservative.

Carolinas ("CPL"),[41] South Carolina Electric and Gas Co. ("SCEG"), Santee Cooper ("SC"), Tennessee Valley Authority ("TVA"); and Southern Company ("SOCO").[42] There are two additional control areas to which Duke Power is interconnected – Southeastern Power Administration ("SEPA")[43] and Yadkin, Inc. ("YAD"),[44] but I did not analyze these control areas because they are generation (and transmission)-only control areas, and have essentially no load to be affected by the transaction.

With respect to Applicants' generation in markets other than the MISO, PJM or the DUK control area, the location of the generation is summarized in Table 12 below.

Table 12: Applicants' Generation outside of MISO, PJM and DUK Control Area

	Duke Energy (MW)	Cinergy (MW)
SERC (TVA)	-	894
WECC (CAISO and AZ)	5,238	-
NPCC (ISO-NE)	793	-
Canada (NPCC and WECC)	364	-
Total Other	6,395	894

41 CPL has two control areas (east and west) interconnected to and separated by the DUK control area: CPLE and CPLW. As discussed below, my analysis models each of the two CPL control areas and then combines their presence in each market as a single supplier (termed "CAPO").

42 The former AEP control area (now PJM) also is first tier to Duke. However, AEP already is analyzed as part of the MISO-PJM Midwest market. Since Cinergy's generation is fully included in the MISO-PJM Midwest market, but would be excluded (except for import allocation) from the AEP market, the analysis that I performed is a more conservative treatment of AEP.

43 SEPA is responsible for marketing the energy generated at hydroelectric plants operated by the United States Army Corps of Engineers, and the DUK control area is interconnected to two SEPA control areas (SEHA and SETH, also referred to as Hartwell and Thurmond). This power is marketed to preference customers throughout the Southeast. SEPA has about 1,500 MW of generation in control areas interconnected with the DUK control area, and some of its preference customers are located within the DUK control area. Since the SEPA control area has no load of its own, and I am already analyzing the other control areas first-tier to DUK, no insights would be gained by analyzing a control area such as SEPA with no load. In other words, since the competitive choices faced by the relevant SEPA customers are already considered in my analyses, it should not be necessary to analyze a SEPA control area separately.

44 The generation in the YAD control area consists of the 201 MW of hydroelectric generation formerly used to supply the load of an Alcoa aluminum smelter, but the smelter had been shut down throughout 2003, and is not currently regularly operating. Hence, the relevant control area load is essentially zero, except for about 4-5 MW relating to Alcoa's non-smelting operations. The fact that load in this control area is *de minimis* should be dispositive of the lack of any market power concerns and, therefore, I did not analyze the YAD control area further.

As shown, the only other market in which Cinergy controls capacity is TVA, and the TVA market, as a first-tier interconnection to Duke Power, is being analyzed in any event. It is not necessary to analyze any other markets,[45] since Cinergy controls no capacity in the other markets where Duke Energy controls capacity, and Duke Energy's other generation is at least two wheels away from any relevant market in which Cinergy owns generation.

Q. PLEASE DESCRIBE THE BASIS FOR YOUR GEOGRAPHIC MARKET DEFINITIONS.

A. As noted earlier, it is appropriate to consider MISO as an initial starting point for defining the relevant geographic market. I then analyzed information on, or indicative of, transmission constraints in order to more conservatively define that part of the MISO that faces similar supply options most of the time. In the context of this transaction, the issue is whether transmission constraints within MISO prevent suppliers from competing to serve consumers around Cinergy. On the basis of the information discussed in Exhibit J-5, I subtracted out portions of MISO from the market.[46] Restricting the relevant geographic market only to a subset of the MISO, ignoring other nearby areas in which competing generation is located, is an elevation of form over substance. The fact that AEP, Dayton and Commonwealth Edison are in PJM rather than MISO does not (particularly in view of the elimination of transmission rate pancaking and other actions taken to resolve seams issues) mean that generators located therein cannot provide effective competition to Cinergy. Moreover, restricting the geographic market to a portion of MISO means that Duke Energy's generation in MISO and PJM, located primarily in AEP and Allegheny, would not be included in the market. Hence, it is

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[45] Consistent with the Revised Filing Requirements, I also considered Applicants' historical customer and concluded that no additional markets need be examined. Historical purchases and sales are discussed in Exhibit J-5 and details are included in workpapers.

[46] It is notable that the areas that I subtracted out were, in some instances, areas where the constraint is from Cinergy to the hived-off area, rather than the reverse. Commission policy is that transmission constraints that define markets are those that are into, not out of the market (See *Exelon Corporation and Public Service Enterprise Corporation, Inc.*, 112 FERC ¶ 61,011 (2005), P 124). Hence, the basis that I used to define the geographic market is quite conservative.

arguably more accurate, and certainly more conservative, to also include the western portion of PJM as part of the market in which the bulk of Cinergy's generation is located. As noted, Duke Energy's capacity is located in Indiana, Ohio, Pennsylvania and Illinois. Thus, I included those control areas in which the Duke Energy MISO and PJM plants are located (Cinergy, AEP, Commonwealth Edison and Allegheny Energy) as areas in which generation can compete with the Cinergy generation or, equivalently in which additional customers face similar supply alternatives to those in the portion of MISO containing Cinergy.

While conservatism biased my market definition toward including the control areas containing the Duke MISO and PJM generation, I relied on an analysis of congestion based on Transmission Loading Relief ("TLRs") to identify portions of MISO-PJM to include (or equivalently, to "carve out") for purposes of my analysis. I also considered prices in MISO for the period of time since the MISO energy markets became operational. On the basis of this analysis, which is described in detail in Exhibit J-5, my MISO-PJM Midwest market can be described as follows:

Table 13: MISO Submarket and MISO-PJM Midwest Market Definition

RTO	Excluded Region or Utility
MISO	LG&E
	WUMS
	Minnesota
	Iowa
PJM	Classic
	Dominion Virginia Power

Q. WHAT TIME PERIODS DID YOU ANALYZE?

A. For each relevant market, I examined ten time periods for both the Economic Capacity and Available Economic Capacity measures, selected to reflect a broad range of system conditions. Broadly, I evaluated hourly load data to aggregate similar hours. I defined periods within three seasons (Summer, Winter and Shoulder) to reflect the differences in unit availability, load and transmission capacity. Hours were first separated into seasons to reflect differences in generating availability and then further differentiated by load levels during each season.[47] For each season, hours were segmented into peak- and off-peak periods.[48] The periods evaluated (and the designations used to refer to these periods in exhibits) are:

SUMMER (June-July-August)

Super Peak 1 (S_SP1):	Top load hour
Super Peak 2 (S_SP2):	Top 10% of peak load hours
Peak (S_P):	Remaining peak hours
Off-peak (S_OP):	All off-peak hours

WINTER (December-January-February)

Super Peak (W_SP):	Top 10% of peak load hours
Peak (W_P):	Remaining peak hours
Off-peak (W_OP):	All off-peak hours

SHOULDER (March-April-May-September-October-November)

Super Peak (SH_SP):	Top 10% of peak load hours
Peak (SH_P):	Remaining peak hours
Off-peak (SH_OP):	All off-peak hours

Q. WHAT "COMPETITIVE" PRICE LEVELS DID YOU ANALYZE?

A. For each destination market, I evaluated conditions assuming destination market prices ranging from about $30/MWh in an Off-Peak period to $250/MWh in the Summer Super Peak period. In Order No. 642, the Commission indicated that sub-periods should be

47 Appendix A requires applicants to evaluate the merger's impact on competition under different system conditions. For example, aggregating summer peak and shoulder peak conditions may mask important differences in unit availability and, therefore, a merger could potentially affect competition differently in these seasons. Thus, applicants are directed to evaluate enough sufficiently different conditions to show the merger's impact across a range of system conditions. On the other hand, the DOJ/FTC *Horizontal Merger Guidelines* discuss the ability to "sustain" a price increase, and a finding that a structural test (like the HHI statistic) violates the safe harbor for some small subset of hours during the year may not be indicative of any market power problems.

48 Peak and off-peak hours were defined according to NERC's definition, except that I did not consider Saturdays to be peak days. *See* ftp://www.nerc.com/pub/sys/all_updl/oc/opman/apdx1f.doc.

determined by load levels rather than by time periods. As discussed below, I analyzed each market at prices that range from the levels that would apply at the lowest load levels to those consistent with the highest load levels. Using a broad range of prices allows me to analyze the impact of the merger during all market conditions. That is, the selected prices allow me to investigate if the merger raises competitive concerns during (1) low load/price time periods, when baseload units are likely setting the market price; (2) mid load/price time periods when more efficient gas-fired generation (e.g., CCs) is likely setting the market price; and (3) high load/price time periods when peaking capacity is required to serve load. In addition, I have conducted sensitivity analyses using slightly higher and lower prices.

For my review of the markets in which Cinergy operates, the initial prices (shown in Table 14 below) are based on a review of historical bilateral prices "into Cinergy", as reported by Platts. These 2004 prices were then escalated to 2006[49] using an escalation factor calculated as the difference between actual 2004 fuel prices and forecast 2006 fuel prices for the fuel setting the market price.[50] I then reviewed actual unit operation to ensure that the periods reflect the various types of generation setting the price during different periods. For example, peaking capacity in MISO, including Duke Energy's Vermillion plant, typically operate at about a 2 percent capacity factor.[51] This implies that combustion turbines ("CTs") are dispatched less than 200 hours (2 percent times 8,760 hours).[52] Given the 2006 market prices that I have used and the incremental cost of

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49 As noted below, my analysis is based on 2006 market conditions, consistent with the requirement that the analysis be forward looking.

50 Gas prices at Henry Hub were used as the basis for determining the escalation factor, as forecast by NYMEX. For the off-peak periods, a similar methodology was used, but based on coal prices as reported by Platts' CoalDat. Finally, the values were adjusted in order to better reflect different price points over the 10 time periods (*e.g.*, rather than evaluating two periods at $70/MWh, prices were adjusted such that different pricing points were modeled).

Note that the assumed dispatch costs for gas-fired combined cycle capacity in the region is about $55/MWh, while the dispatch cost of coal units range from the high teens to around $30/MWh. A complete listing of the units in the model and their dispatch costs by season is provided in workpapers.

51 Vermillion's capacity factor in 2003 and 2004 was less than 0.5 percent.

52 2004 was a leap year, therefore the total hours in the various periods shown in the table is 8,784 versus 8,760.

Vermillion and other similar peaking units, my selection of prices that makes CTs economic in the Summer and Winter Super Peak periods is consistent with this operating pattern (i.e., there are about 210 hours in the three periods where peaking facilities are economic).[53] I conducted a similar analysis for combined-cycle ("CC") capacity as well, and determined that capacity factors in MISO averaged about 12 percent in 2003 to 2004. This implies that CCs are dispatched about 1,000 hours per year (12 percent times 8,760 hours). A recent MISO report indicates that CCs are expected to be dispatched about 1,000 hours during the summer of 2005.[54] My selection of prices makes CCs economic in all the seasonal Super Peak periods, as well as the Summer and Winter Peak periods.

Table 14: Market Prices for MISO Markets

Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Price	$250	$80	$60	$30	$85	$65	$40	$75	$50	$35
Hours	1	104	951	1152	104	936	1144	209	1887	2296

Price data for the DUK control area are not similarly available, although historical bilateral prices are reported for nearby entities, such as into Southern and into TVA. Therefore, I again have reviewed historical unit operation of mid-merit (CC) and peaking facilities to inform my selection of prices for each time period. In VACAR (Virginia - Carolinas Reliability Agreement), the historical capacity factor for CCs ranges from about 4 to 20 percent. CTs in VACAR have historical capacity factors of between 1 and 4 percent. I have estimated that the incremental dispatch costs of new CC and CT capacity in VACAR is around $54/MWh and $78/MWh, respectively. Coal-fired generation is between $35-50/MWh. On the basis of the incremental cost data and nearby bilateral prices, I used the prices in Table 15 below for the DUK control area as well as its first-tier markets:

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[53] The other Duke facilities in MISO-PJM are Lee County (PJM), a CT with an assumed dispatch cost of approximately $79/MWh; Fayette (PJM), a CC with an assumed dispatch cost of about $57/MWh; and two units, Washington and Hanging Rock, (PJM), both CCs with estimated dispatch costs of about $55/MWh.

[54] *Midwest ISO 2005 Summer Evaluation Report*, May 25, 2005, page 9. http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-7f250a48324a/2005%20Summer%20Evaluation_v1.1_TH.pdf?action=download&_property=Attachment

Table 15: Market Prices for DUK Control Area and First-Tier Markets

Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Price	$ 250	$ 85	$ 50	$ 40	$ 80	$ 60	$ 45	$ 75	$ 65	$ 35
Hours	1	104	951	1152	104	936	1144	209	1887	2296

The fact that I used the same prices for MISO markets as for the DUK control area market is not to suggest that at any given season/time period, prices will be the same. My analysis is intended to look at a broad range of reasonable prices. Conducting a sensitivity analysis around these prices further demonstrates that the results of my analysis are not sensitive to the specific price levels analyzed.

Q. PLEASE DESCRIBE THE BASIC MODEL ARCHITECTURE YOU USED IN ANALYZING THIS MERGER.

A. I used CRA's proprietary model, CASm, to perform the analysis. CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test. The model includes each potential supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic element of the delivered price test (*e.g.*, 105 percent of the market price) than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface.

Q. HOW DID YOU ALLOCATE LIMITED TRANSMISSION CAPACITY?

A. Appendix A notes that there are various methods for allocating transmission, and that applicants should support the method used.[55] I allocated transmission based on a prorata,

[55] See Order No. 592, ¶ 31,044 at 30,133: "In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated

"squeeze down" method based on relative ownership shares of capacity at a transmission interface, rather than on the basis of economics, which would allocate limited transmission first to the least expensive generation. The prorata "squeeze-down" method, so-named because it seeks to prorate capacity at each node, is the closest approximation to what the Commission applied in *FirstEnergy*[56] that is computationally feasible. Under this method, shares of available transmission are allocated at each interface, diluting the importance of distant capacity as it gets closer to the destination market. When there is economic supply (*i.e.*, having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

Shares on each transmission path are based on the shares of deliverable energy at the source node for the particular path being analyzed. The calculations start at the outside of a network, defined with the destination market as its center, and end at the destination market itself. A series of decision rules are required to accomplish this proration. The purpose of these decision rules is limited to assigning a unique power flow direction to each link for any given destination market analysis. Once the links are given a direction, the complex network can be solved. CASm implements a series of rules to determine the direction of the path. The first rule (and the one expected to be applied most frequently) is based on the direction of the flow under an economic allocation of transmission capacity. Other options take into consideration the predominant flow on the line based on desired volume (the amount of economic capacity seeking to reach the destination market, the number of participants seeking to use a path in a particular direction, and the path direction that points toward the destination market).

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among the potential suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used."

[56] *Ohio Edison Company, et al.*, 80 FERC ¶ 61,039 at 61,107: "When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface." This Commission recently reiterated its acceptance of this method. *Exelon Corporation and Public Service Enterprise Corporation, Inc.* 112 FERC ¶ 61,011 (2005), P 129.

The model proceeds to assign suppliers at each node a share equal to their maximum supply capability. At each node, "new" suppliers (those located at the node outside of the next interface) are given a share equal to their supply capability, and the shares of more distant suppliers (those who have had to pass through interfaces more remote from the destination market in order to reach the node) are scaled down to match the line capacity into the node. Ultimately, the shares at the destination market represent the prorated shares of Economic Capacity (or Available Economic Capacity) that is economically and physically feasible.

This is the same modeling architecture that I have used to analyze numerous previous mergers in testimony relied upon by the Commission. A summary of the transmission architecture used in analyzing the relevant markets is included in Exhibit J-7.

Q. HOW DID YOU TREAT IMPORTS IN YOUR ANALYSIS?

A. For my analysis of the MISO and PJM markets, I relied on a transmission study provided by Cinergy that determined the simultaneous import limit into the three relevant markets I examined. The analysis relies on the NERC 2006 summer base case. The import limits, as measured by First Contingency Incremental Transfer Capacity ("FCITC") are summarized in the table below.[57]

Table 16: Simultaneous Import Capability into MISO and PJM Markets

Market	FCITC (MW)
MISO	15,766
MISO Submarket	11,032
MISO-PJM Midwest	9,705

[57] The First Contingency Total Transfer Capability ("FCTTC") is higher than the FCITC, reflecting the fact that there is a significant level of base imports assumed in the NERC model. FCITC is the correct measure to use in this context. I note, however, that the results of my analysis are only modestly sensitive to the assumed simultaneous import capability: whatever the import level, Applicants' share of imports will remain essentially the same.

For imports from PJM to MISO, I used PJM's OASIS postings that report PJM's Total Transfer Capability ("TTC") to the former MISO control areas. I eliminated paths that appear to be duplicative.

I modeled the area around DUK based on a control-area-to-control-area representation. For imports into DUK, supply from Cinergy or Duke Energy merchant generation will compete with other supply in the MISO market to be prorated into the DUK control area market. For the control-area-to-control-area interconnections around the DUK control area, I used the most recent postings available on OASIS, combined with the simultaneous import capability calculated by Duke Power in connection with its market-based rate, Section 205 compliance filing.[58] For some of the surrounding control area markets, I supplemented these data with other parties' calculations of simultaneous import capability.[59] I used OASIS postings for both TTC and Available Transfer Capability ("ATC"). Since ATCs are not universally available for all the potential exporting markets, I used TTCs for my base case.[60] Since I am using control area-to-control area limits in conjunction with simultaneous limits, the total amount of imports is determined by the simultaneous limit.

Q. WHAT YEAR DID YOUR ANALYSIS COVER?

A. I analyze 2006 market conditions, consistent with the Order No. 642 requirement that the analysis be forward looking.

Even though my analysis approximates 2006 market conditions, the primary source of data on generation and transmission is current and recent historical data. Where appropriate, I adjusted relevant data to approximate 2006 conditions. As described in

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58 *Duke Power*, Docket No. ER96-110-013, compliance filing dated August 11, 2004.

59 For example, in addition to the Duke Power simultaneous import studies conducted in the reference docket, I also relied on simultaneous import capability studies submitted in AEP's Section 205 filing (See Affidavit of Joe Pace in Docket No. ER96-2495-020, *et al*). A full listing of the SILs into each control area is provided in workpapers.

60 The specific values used for each path are provided in workpapers. I also completed a sensitivity using ATCs, where available.

Exhibit J-5, this includes load and generation dispatch (*i.e.*, fuel) costs. With respect to new generation, I only included generation already under construction and expected to be on-line by 2006; I did not include any additional planned generation not yet under construction. With respect to retirements, I included units already retired or already approved for retirement prior to 2006.[61]

For purposes of my analysis, I assumed that Cinergy controls the Wheatland facility, the purchase of which was approved by the Commission in June.[62]

Q. HOW DO YOU ACCOUNT FOR LONG-TERM PURCHASES AND SALES?

A. In the past, I have treated long-term power arrangements as resulting in a transfer of ownership and control to the purchaser. Order No. 642 discusses two criteria for determining control: operational control (*i.e.*, "the party that has the authority to decide when generating resources are available for operation"),[63] and economic or beneficial interest (*i.e.*, "the party for whose economic benefit the…unit is operated").[64] In the

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[61] I relied on Form 411s, EIA Form 860 and information in Platt's "Basecase" database for my review of new entry and retirements.

[62] It is relevant to note that I have not reflected in my analysis the merger of Exelon and PSEG recently approved by the Commission, which will alter the composition of generation ownership in PJM. Until that merger's mitigation proposal is implemented, it is not sensible to try to reflect the impact of that merger in my analysis of relevant markets here. However, the effect of that merger on market concentration would not be material with respect to my conclusions here.

[63] *Revised Filing Requirements*, Section 33.3(c)(4)(i)(A).

> Economic capacity means the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. Prior to applying the delivered price test, the generating capacity meeting this definition must be adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts (*i.e.*, contracts with a remaining commitment of more than one year). <u>The capacity associated with any such adjustments must be attributed to the party that has authority to decide when generating resources are available for operation.</u> Other generating capacity may also be attributed to another supplier based on operational control criteria as deemed necessary, but the applicant must explain the reasons for doing so. (emphasis added)

[64] *Order No. 642*, footnote 39.

> The starting point for calculating economic capacity is the supplier's own generation capacity with low enough variable costs that energy can be delivered to a market (after paying all necessary transmission and ancillary service costs, including losses) at a price that is five percent or less above the pre-merger market price. Capacity must be decreased to reflect any portion committed

Revised Filing Requirements and in subsequent orders concerning market rate authority, the Commission has emphasized the first of these criteria.[65] For most purchases and sales, I am unable to determine whether the seller or buyer has control[66] and in those cases I assigned control to the buyer. I note, however, that the treatment of purchases and sales is inconsequential in terms of the results of my analysis, except with respect to Applicants' contracts.

With respect to the Applicants' contracts, I have made conservative assumptions regarding control. Duke Power has long-term (more than one-year) contracts to purchase a portion of the output of two merchant plants in its control area: 458 MW from Progress Energy Venture's Rowan gas-fired CT facility[67] and 165 MW from Dynegy's 800 MW Rockingham gas-fired CT facility. I also included 169 MW of purchases from QFs and, as I described earlier, the SEPA allocation to entities in the DUK control area. In my analysis, I conservatively treated the generation subject to these contracts as if under Duke Power's control. I also included some recent minor reratings of Duke Power's generation.

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to long-term firm sales; and it must be increased to reflect any portion acquired by long-term firm purchases. In addition, any capacity under the operational control of a party other than the owner must be attributed to the party for whose economic benefit the related unit is operated. The result of these calculations is the supplier's "economic capacity." (Emphasis added)

65 In the context of the Commission's new, interim generation market power analysis in connection with market-based rates, the Commission focuses on operational control ("if an applicant has control over certain capacity such that the applicant can affect the ability of that capacity to reach the relevant market, then that capacity should be attributed to the applicant when performing the screens."). *AEP Power Marketing, Inc. et al.*, Order on Rehearing, 108 FERC ¶ 61,026 (2004), P 65.

66 This uncertainty arises both from ambiguity in the Commission's guidance and a lack of access to contract terms. A common example is a unit contingent contract (tolling or otherwise) in which the buyer has the right to nominate output from the unit. However, the seller controls whether the unit is made available (typically subject to penalties for non-availability). Moreover, if the buyer does not nominate the output, the seller frequently has the right to dispatch the plant for its own account. Given this mixture of circumstances, it is not wholly clear which party has "control" in the sense relevant to the Commission's market power tests.

67 Rowan also has a combined-cycle facility, which is not under contract to Duke Power.

I am not aware of any long-term sales contracts for the output of any of the relevant Duke Energy or Cinergy merchant plants, so I assume that they are controlled by Applicants and that they are available to make sales into the markets that I study.[68]

[68] A Duke Energy affiliate has a contract to purchase 50 percent of the output of the St. Francis plant interconnected with the Associated Electric Cooperative ("AECI") control area in Missouri. Because AECI has operational control of the facility, I did not include the contract as part of Duke Energy's generation portfolio. Notably, the conclusions from my analysis would not change had I considered this energy as under Duke Energy's control.

V. IMPACT OF THE MERGER ON COMPETITION

Q. WHAT SPECIFIC ANALYSES DID YOU CONDUCT TO EVALUATE THE POTENTIAL COMPETITIVE EFFECTS ARISING FROM THE COMBINATION OF GENERATION ASSETS?

A. Consistent with the guidance in the *Merger Policy Statement*, I analyzed Economic Capacity and Available Economic Capacity. I also considered whether there were any other relevant product markets (e.g., ancillary services and capacity) and determined there were no such other relevant markets, as described below. As already described, I examined the following relevant destination markets: MISO, MISO Submarket, MISO-PJM Midwest, DUK, and DUK first-tier control area markets. I also considered other geographic markets in which Applicants own generation outside of these markets.

In the sections below, I first look at each of the relevant markets for Economic Capacity. Second, I consider the relevant Available Economic Capacity analyses. Third, I evaluate any other relevant geographic and product markets.

Economic Capacity

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN MISO?

A. The Economic Capacity analysis for MISO reflects the combination of generation owned by Applicants in MISO, plus a portion of Applicants' generation owned in PJM, DUK and TVA.[69] In the analysis here, I also included an assumed 250 MW firm transmission path from DUK to MISO as part of the post-merger market, which, as I described earlier, is a worst case scenario. My exhibits also show the results with no firm path and with a 100 MW path. In this market, the Competitive Analysis Screen is readily passed in all time periods, as shown below in Table 17 (same as Table 3) and in Exhibit J-8. Pre-Merger, Cinergy's market share ranges from 8 to 10 percent, and Duke Energy's is well less than one percent. The market is unconcentrated post-merger, with a combined

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[69] As discussed earlier, the analyses reflect the allocation of a portion of the interface into MISO to Applicants' generation located outside of MISO.

market share of no more than about 10 percent and HHI changes of no more than 14, even with consideration of the 250 MW path from Duke Power to MISO. Without a firm path, or with a 100 MW firm path, the HHI changes are slightly lower, as shown in Exhibit J-8.

Table 17: Economic Capacity, MISO

		Pre-Merger						Post-Merger with 250 MW Integration Path			
Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
S_SP1	$250	11,676	8.4%	635	0.5%	138,877	510	12,561	9.0%	521	11
S_SP2	$80	10,594	8.3%	689	0.5%	128,335	509	11,533	9.0%	521	12
S_P	$60	9,500	8.7%	341	0.3%	109,407	516	10,090	9.2%	526	10
S_OP	$30	7,967	8.5%	185	0.2%	94,006	566	8,402	8.9%	574	8
W_SP	$85	10,850	8.3%	789	0.6%	130,281	508	11,889	9.1%	522	14
W_P	$65	9,591	8.8%	267	0.2%	109,342	513	10,108	9.2%	521	8
W_OP	$40	9,577	9.7%	94	0.1%	98,934	556	9,921	10.0%	563	7
SH_SP	$75	7,509	7.5%	347	0.4%	99,672	480	8,106	8.1%	489	9
SH_P	$50	7,491	9.1%	206	0.3%	82,702	517	7,948	9.6%	527	10
SH_OP	$35	6,998	8.7%	234	0.3%	80,309	515	7,482	9.3%	526	11

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN MISO-SUBMARKET?

A. This market reflects the combination of Cinergy generation and Duke Energy's Vermillion plant, as well as the share of imports allocated to the Duke Energy merchant plants in PJM and Duke Power. The Competitive Analysis Screen is readily passed in all time periods, as shown below in Table 18 (same as Table 4) and in Exhibit J-8. The market is unconcentrated post-merger, with HHI changes no more than 25 points. Without a firm path, or with a 100 MW firm path, the HHI changes are slightly lower, with a maximum HHI change of 21, as shown in Exhibit J-8.

Table 18: Economic Capacity, MISO Submarket

		Pre-Merger						Post-Merger with 250 MW Integration Path			
Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
S_SP1	$250	11,664	12.2%	570	0.6%	95,778	814	12,483	13.0%	835	21
S_SP2	$80	10,582	11.8%	602	0.7%	89,513	809	11,433	12.8%	832	23
S_P	$60	9,500	12.5%	199	0.3%	75,947	814	9,948	13.1%	829	15
S_OP	$30	7,967	12.3%	107	0.2%	64,998	920	8,325	12.8%	934	14
W_SP	$85	10,837	11.9%	709	0.8%	91,331	806	11,795	12.9%	831	25
W_P	$65	9,591	12.6%	204	0.3%	76,218	813	10,045	13.2%	828	15
W_OP	$40	9,577	13.9%	120	0.2%	69,164	901	9,947	14.4%	916	15
SH_SP	$75	7,502	10.9%	241	0.4%	68,815	766	7,993	11.6%	782	16
SH_P	$50	7,491	13.0%	80	0.1%	57,664	833	7,821	13.6%	848	15
SH_OP	$35	6,998	12.5%	151	0.3%	55,901	825	7,399	13.2%	843	18

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN MISO-PJM MIDWEST?

A. As noted earlier, this is the smallest relevant market that encompasses Cinergy's generation and Duke Energy's generation located in the MISO and PJM. Cinergy's share of this market is about 6 to 7 percent. This also includes a portion of Cinergy's generation located in TVA and pro rated into the MISO-PJM Midwest market. Duke Energy's market share, consisting of its merchant generation located in the MISO and PJM and a share of Duke Power's generation located in the DUK control area, ranges from one to about 3 percent. The Competitive Analysis Screen is readily passed in all time periods, as shown below in Table 19 (same as Table 5) and in Exhibit J-8. The market remains unconcentrated post-merger, with HHI changes ranging from about 13 to 37 points. Without a firm path, or with a 100 MW firm path, the HHI changes are slightly lower, as shown in Exhibit J-8.

Table 19: Economic Capacity, MISO-PJM Midwest

		Pre-Merger						Post-Merger with 250 MW Integration Path			
Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
S_SP1	$250	11,715	6.5%	4,387	2.5%	179,158	587	16,352	9.1%	622	35
S_SP2	$80	10,637	6.2%	4,442	2.6%	171,479	603	15,329	8.9%	638	35
S_P	$60	9,500	6.6%	3,234	2.2%	145,113	664	12,984	8.9%	696	32
S_OP	$30	7,967	6.9%	849	0.7%	115,961	718	9,067	7.8%	731	13
W_SP	$85	10,897	6.3%	4,830	2.8%	174,443	602	15,978	9.2%	639	37
W_P	$65	9,591	6.6%	3,373	2.3%	146,015	665	13,214	9.0%	698	33
W_OP	$40	9,577	7.3%	950	0.7%	130,911	743	10,777	8.2%	757	14
SH_SP	$75	7,529	5.7%	3,314	2.5%	131,770	620	11,094	8.4%	652	32
SH_P	$50	7,491	6.9%	1,168	1.1%	108,290	693	8,909	8.2%	712	19
SH_OP	$35	6,998	6.6%	856	0.8%	105,618	705	8,104	7.7%	719	14

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN THE DUK CONTROL AREA?

A. The results for the DUK control area presented below in Table 20 (same as Table 6) and in Exhibit J-8 reflect the fact that Duke Energy has a relatively high market share, consisting of Duke Power generation and a share of imports allocated to Duke Energy's merchant generation in MISO and PJM. Cinergy's market share, however, is no more than one-tenth of one percent (no more than 14 MW), including a portion of Cinergy's generation located in TVA and pro rated into the DUK control area market. The Competitive Analysis Screen is passed in all time periods, even though the market is highly concentrated, because the HHI increases are well below 50 points (indeed, the highest change is 10 points). As I noted previously, if I had assumed that a firm path from DUK to MISO was being used to deliver capacity from Duke Power into Cinergy, it would have had the effect of deconcentrating the market.

Table 20: Economic Capacity, DUK Market

		Pre-Merger						Post-Merger			
Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
S_SP1	$250	6	0.0%	17,747	75.0%	23,677	5,709	17,752	75.0%	5,713	4
S_SP2	$80	6	0.0%	16,357	73.5%	22,268	5,497	16,363	73.5%	5,501	4
S_P	$60	6	0.0%	13,060	71.3%	18,311	5,223	13,066	71.4%	5,228	5
S_OP	$30	11	0.1%	9,041	63.2%	14,312	4,220	9,052	63.3%	4,229	9
W_SP	$85	5	0.0%	16,856	76.1%	22,138	5,897	16,862	76.2%	5,901	4
W_P	$65	5	0.0%	12,938	73.7%	17,558	5,574	12,942	73.7%	5,578	4
W_OP	$40	6	0.0%	11,977	72.1%	16,614	5,364	11,983	72.1%	5,370	6
SH_SP	$75	9	0.0%	14,022	66.7%	21,025	4,561	14,031	66.7%	4,567	6
SH_P	$50	14	0.1%	10,366	61.9%	16,738	4,005	10,379	62.0%	4,015	10
SH_OP	$35	14	0.1%	9,295	59.3%	15,667	3,724	9,309	59.4%	3,734	10

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY IN THE DESTINATION MARKETS FIRST-TIER TO THE DUK CONTROL AREA?

A. Applicants' market share ranges from one to less than 20 percent in these markets, consisting of their shares of import capability prorated into these markets, plus, in the TVA market, Cinergy's merchant generation located within that market. The Competitive Analysis Screen is readily passed in all time periods, as shown in Exhibit J-8. In most of the first-tier markets, the HHI changes were in the single digits. The only market with material HHI changes was the CPLW market, but even there the HHI changes were well below 50 points during periods when the market was moderately concentrated, or below 20 points during periods when the market was highly concentrated. Clearly, the effect of the merger on first-tier markets is small.

Available Economic Capacity

Q. HAVE YOU ALSO ANALYZED THE EFFECTS OF THE MERGER ON AVAILABLE ECONOMIC CAPACITY?

A. Yes, although I note that developing a comprehensive Available Economic Capacity analysis is quite difficult in the MISO and PJM markets, given the status of retail access in MISO and PJM. Under conditions of full retail access, the Available Economic Capacity analysis becomes identical to Economic Capacity. However, despite full retail access in some portions of MISO and PJM (*e.g.*, Ohio, Pennsylvania, New Jersey and Illinois), Cinergy has continuing load obligations: PSI, since there is no retail access in Indiana, and CG&E has continuing load obligations in Kentucky and in the form of a requirement to provide POLR service to its customers in Ohio. Additionally, there is no retail access in North Carolina or South Carolina, so Duke Power has continuing load obligations. Thus, Available Economic Capacity continues to be a relevant measure of market conditions and the impact of the merger, and my analysis of Available Economic Capacity takes into consideration Applicants' commitments to serve customer loads.

CG&E continues to have load responsibility for its non-switching pre-retail access customer load, and CG&E remains the default service provider for returning customers. I based my analysis of Available Economic Capacity on the switching rates that utilities in Ohio, Illinois and Michigan have experienced most recently.[70] Utilities in other states are assumed to continue to have full native load responsibility. Merchant generation in the market, by definition, is assumed to be "uncommitted" (*i.e.*, not required to meet any

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[70] I included a sensitivity in which I assumed an additional 5 percentage points of load switched for utilities in these states. The results, which show no material difference, are included in my workpapers.

specific load).[71] This includes utility-affiliated merchant generation, such as Cinergy's merchant generation in TVA. For purposes of my analysis, I have further assumed that Wheatland remains uncommitted, which is a conservative assumption because I understand it was purchased by Cinergy to serve retail load.

Q. WHAT ARE THE RESULTS OF YOUR AVAILABLE ECONOMIC CAPACITY ANALYSES?

A. Exhibit J-9 presents a series of results for Available Economic Capacity. For MISO (see Table 7 in my summary), Cinergy's Available Economic Capacity ranges from less than 100 MW to about 3,100 MW, depending on the time period considered, and Duke Energy's ranges from zero to about 1,400 MW. Their combined shares of Available Economic Capacity in MISO range from 4 to 10 percent. The market is unconcentrated and the HHI changes are no more than 39 points. Thus, the Competitive Analysis Screen is easily passed.

For MISO Submarket (see Table 8 in my summary), Applicants' combined share of Available Economic Capacity are no more than 12 percent. The market is unconcentrated and the HHI changes are no more than about 50 points.

For MISO-PJM Midwest, Applicants' combined shares of Available Economic Capacity are no more than about 11 percent (see Table 9 in my summary). The market is unconcentrated and the HHI changes are well below 100 points.

For the DUK control area market, Duke Energy's share of Available Economic Capacity ranges from zero to more than 50 percent, but Cinergy has a very small share of the market (less than one percent), as shown in Table 21 below (same as Table 10) and Exhibit J-9. Because of Cinergy's small share, the HHI changes are below 50 points in all but one instance (and well below 50 points in most time periods), although the market is highly concentrated in some time periods. As I noted earlier, there is one time period

[71] To the extent I could identify non-utility generation as under long-term contract to third parties, including load-serving entities, I took such contracts into consideration.

when 39 MW of Cinergy supply results in an HHI_change of 65 points in a highly concentrated market. Notably, there is no systematic pattern of large HHI changes in the DUK market, and, in any event, Cinergy generally is allocated less than 50 MW of Available Economic Capacity in the DUK market.

Table 21: Available Economic Capacity, DUK Market

		Pre-Merger						Post-Merger			
Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
S_SP1	$250	34	0.7%	1,194	23.0%	5,193	1,065	1,228	23.7%	1,095	30
S_SP2	$80	31	0.6%	1,555	28.1%	5,539	1,269	1,586	28.6%	1,301	32
S_P	$60	9	0.2%	1,289	27.7%	4,654	1,106	1,299	27.9%	1,118	12
S_OP	$30	32	0.9%	-	0.0%	3,663	1,058	32	0.9%	1,058	-
W_SP	$85	18	0.2%	4,160	55.7%	7,472	3,285	4,179	55.9%	3,312	27
W_P	$65	11	0.2%	2,552	48.3%	5,287	2,522	2,563	48.5%	2,543	21
W_OP	$40	39	0.7%	2,522	46.0%	5,482	2,376	2,561	46.7%	2,441	65
SH_SP	$75	7	0.1%	2,312	30.1%	7,676	1,264	2,319	30.2%	1,270	6
SH_P	$50	48	0.9%	824	14.7%	5,624	889	873	15.5%	914	25
SH_OP	$35	61	0.9%	1,575	23.9%	6,578	1,102	1,636	24.9%	1,146	44

Finally, for destination markets first-tier to the DUK market, as shown in Exhibit J-9, Applicants' shares of Available Economic Capacity range from just a few percentage points to up to about 25 percent, but the Competitive Analysis screen is easily passed. Most of the markets are unconcentrated in most time periods. In the few instances where the market is moderately concentrated, the HHI changes are generally small. In only one instance, in one time period, is the market highly concentrated, and there the HHI change is trivial.

Other Geographic Markets

Q. ARE THERE ANY OTHER RELEVANT GEOGRAPHIC MARKETS IN WHICH APPLICANTS CONTROL GENERATION?

A. Other than the markets I have already analyzed, Applicants "do not currently operate in the same geographic markets or...the extent of the business transactions is *de minimis*"[72]

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72 Section 33(a)(2) of the Revised Filing Requirements. The Commission established an exemption from the requirement to file a horizontal Competitive Analysis Screen if the applicant:

and, therefore, no further analysis is required. As I discussed previously, the only additional markets in which Applicants own generation is Duke Energy's ownership of generation in the Northeast (ISO-NE and Canada) and the West (CAISO and Arizona). Since only one of the merging parties owns generation in these markets, Applicants "do not currently operate in the same geographic markets" with respect to this generation.

Other Product Markets

Q. ARE THERE ANY OTHER PRODUCT MARKETS RELEVANT TO YOUR INQUIRY OF THE EFFECT ON COMPETITION?

A. No. Under the Merger Policy Statement, the Commission requires that Applicants consider the impact of a merger on markets for ancillary services, specifically reserves and imbalance energy "when the necessary data are available." The Merger Policy Statement does not explicitly require consideration of capacity markets, but where relevant, I have examined such markets in the past. Here, MISO does not operate centralized ancillary services or resource adequacy (i.e., capacity) markets, and ancillary services remain a cost-based service under the MISO OATT. As such, the requisite data to analyze the market are not available.

Moreover, the addition of Duke Energy's Vermillion plant to Cinergy generation does not materially affect the supply alternatives for providing ancillary services in MISO. This is only a single unit and of a type that has very modest ancillary services capability.[73]

(i) Affirmatively demonstrates that the merging entities do not currently operate in the same geographic markets or that the extent of the business transactions in the same geographic market is *de minimis*; and

(ii) No intervenor has alleged that one of the merging entities is a perceived potential competitor in the same geographic market as the other.

[73] The type of turbine used at Vermillion cannot start quickly enough to count as quick start capability. Peakers generally cannot be used to provide regulation or real time imbalance energy due to their on-or-off operating characteristics. Even for supplemental reserves they will rarely be economic providers of reserves due to their high running cost.

Customers requiring regulation or spinning reserves may self-supply, or procure such services from third-parties or through MISO. Customers may secure some ancillary services (regulation, operating reserves and supplemental reserves) anywhere in MISO, subject to meeting technical requirements. If MISO requires ancillary services to be provided by Cinergy, Cinergy is obligated to do so. As a result, Cinergy is effectively a default supplier of ancillary services to MISO for load in its control area and, as such, has no ability to withhold such services from the market.

With respect to resource adequacy, MISO members are subject to requirements of their respective NERC or reliability councils. Based on my analysis of MISO energy markets at super peak conditions, which approximates total capacity, it is clear that the merger has no effect on capacity markets in MISO.

There are market-based ancillary services and capacity markets in PJM, where Duke Energy owns capacity. However, the only capacity Cinergy owns that even arguably is in PJM is includable as a PJM ancillary services provider is its share of the CCD plants, which represent only a very small share of PJM capacity (1,432 MW relative to PJM capacity in excess of 160,000 MW). As I described earlier, Cinergy has a pseudo-tie configuration to deliver its ownership interest in these CCD plants into MISO, and I correctly treated them as such in my analysis of energy markets. While, theoretically, Cinergy also could use its share of the CCD units located in PJM to provide ICAP and ancillary services within PJM, it cannot "double-count" by, for example, counting this CCD capacity as meeting its reserve obligations in its jurisdictional states (i.e., in MISO) while simultaneously selling capacity or ancillary services from its CCD units into PJM. In any event, PJM ancillary services markets cannot be materially affected by this merger. The relevant market for regulation in the context of Applicants' supply consists of the Western Region of PJM (Allegheny, ComEd, AEP, and Dayton), which market has more than twice as much regulation supply as required.[74] To the extent Applicants' units offer modest amounts of ancillary services capability, it follows from the fact that their

[74] *2004 State of the Market*, Market Monitoring Unit, PJM, page 5.

shares of installed capacity are small that their shares of ancillary services capability also will be relatively small. Applicants' units are not uniquely positioned to provide ancillary services and hence the merger will have not have a material effect on ancillary services markets. Similarly, for capacity markets in PJM. Duke Energy is a small participant in PJM (3,057 MW, or less than 2 percent of the more than 160,000 MW of PJM capacity), and its units clearly represent a small share of installed capacity (ICAP or UCAP). Even considering Cinergy's share of the CCD units, its share of capacity (less than one percent) is so small that the combination of Applicants' shares has an immaterial effect on market consideration. The only possible additional effect of the merger is that a share of imports from Cinergy in MISO might be able to supply ICAP. But, the total simultaneous import capability into PJM is only about 7,500 MW, or less than 5 percent of installed capacity in PJM. Clearly, Cinergy's theoretic ability to sell into the PJM capacity market does not raise any market power concerns.

In sum, I cannot identify any concern about the impact of the merger on either the ancillary services or capacity markets in PJM or MISO.

Vertical Market Power

Q. WHAT ARE THE VERTICAL MARKET POWER ISSUES THAT POTENTIALLY COULD AFFECT COMPETITION IN THE RELEVANT MARKETS?

A. The remaining potential market power issue is vertical market power -- control over electric transmission, generating sites or fuels supplies.

Q. ARE THERE ANY TRANSMISSION MARKET POWER ISSUES?

A. No. The merger does not increase any of the Applicants' ability or incentive to use control over transmission facilities to gain a competitive advantage in wholesale electricity markets. Duke Power's transmission system is remote from Cinergy-owned generation. The vast majority of Duke Energy's generation in MISO and PJM is not within the footprint of Cinergy's transmission system. The only Duke Energy plant within the former Cinergy control area is Vermillion, and there is nothing unique about the location of that plant that provides Cinergy with any new ability or incentive to exercise vertical market power. Moreover, in any event, the Cinergy electric transmission systems are controlled by MISO, and Duke Power's transmission is subject to a Commission-approved OATT.

Q. WHAT IS THE ISSUE CONCERNING AN APPLICANT'S CONTROL OVER ESSENTIAL FUELS OR DELIVERY SYSTEMS?

A. In the context of long-term capacity markets, the issue is whether the merging parties can foreclose or impede the entry of competing generators. There also is a shorter-term issue of whether the merger might increase the incentive or ability to raise rivals' costs.

Q. WHAT CONTROL DO APPLICANTS HAVE OVER FUELS OR FUEL DELIVERY SYSTEMS?

A. As described earlier, Duke Energy's Texas Eastern pipeline serves a portion of the MISO market where the Cinergy-owned generation competes. Duke's Texas Eastern pipeline delivers into the states of Kentucky, Ohio, Illinois, Missouri, West Virginia and Pennsylvania. Cinergy's KO pipeline also serves a portion of the market where Duke Energy's merchant generation competes. The KO pipeline delivers into Kentucky and Ohio. While KO does not serve any competing gas-fired generation either directly or indirectly, Texas Eastern directly serves less than 1,700 MW of competing generation (excluding Cinergy generation), which represents well less than 10 percent of gas-fired generation in MISO and only a little more than 1 percent of total generation.. See Exhibit J-10.

Q. HOW MUCH INTERSTATE PIPELINE CAPACITY SERVING THE MISO DO APPLICANTS OWN?

A. There are a large number of interstate pipelines serving the MISO market, including the Texas Eastern and KO pipelines, as detailed in Exhibit J-11. I included two market definitions for this purpose: MISO market (including the states of Ohio, Illinois, Michigan, Indiana, Missouri, Kentucky, Wisconsin, and Minnesota) and a subset of the MISO market (excluding Kentucky, Wisconsin and Minnesota). These are similar, but not identical, to the MISO and MISO Submarket market definitions I used for analyzing electricity markets, as shown in Table 22 below.[75] For purposes of analyzing gas transportation markets, it is easier, perhaps even necessary, to define the markets by the state borders since the data reported for pipeline capacity are based on delivering capacity into states.

Table 22: States Partially or Fully Represented in Analysis

	Electric Markets			Transportation Markets	
State	MISO	MISO-PJM Midwest	MISO Submarket	MISO	MISO Submarket
IA	x				
IL	x	x	x	x	x
IN	x	x	x	x	x
KY	x			x	
MD		x			
MI	x	x	x	x	x
MN	x			x	
MO	x	x	x	x	x
MT	x				
ND	x				
OH	x	x	x	x	x
PA	x	x	x		
SD	x				
WI	x			x	

As shown, the state coverage of the MISO submarket in my gas transportation analysis differs from the MISO-PJM Midwest market only by the exclusion of Maryland and Pennsylvania, both states that are only partially represented in my analysis of electricity markets. (Both FirstEnergy, a MISO member, and Allegheny Energy, a PJM member, have operating subsidiaries in Pennsylvania, and Allegheny Energy has an operating subsidiary in Maryland, but their generation in these states is relatively small.)

[75] I did not perform a vertical analysis for the MISO-PJM Midwest market because it is difficult to include partial states, and inclusion of additional states (Pennsylvania, for example) would expand the market well beyond the MISO-PJM Midwest to eastern PJM. In any event, inclusion of additional states would not alter my conclusions, because of the large number of pipelines and contract customers already included in the MISO market.

As shown on Exhibit J-11, Texas Eastern represents less than 10 percent of capacity on pipelines entering into MISO or MISO Submarket.[76]

Q. WHAT FIRM TRANSMISSION RIGHTS DO APPLICANTS HAVE ON INTERSTATE GAS PIPELINES SERVING THE MISO?

A. I examined Applicants' firm transmission reservations on each of these pipelines (excluding those expiring prior to 2006 with no rollover rights) into states covering MISO. I considered contracts with upstream receipt points (that is, outside of the relevant states) and delivery points within the relevant states as well as contracts with either upstream or in-market receipt points.[77] With respect to the former, both Duke Energy's and Cinergy's total firm transmission reservations for delivery into states within MISO total about 700 mmcf/day. Duke Energy's contracts with upstream or in-market receipt points total about 1,300 mmcf/day and Cinergy's about 800 mmcf/day. See Exhibit J-12.[78]

Both Duke Power and Cinergy must comply with applicable FERC codes of conduct and Order No. 2004 standards of conduct, which govern affiliate relationships. In any event, the amount of generation served is small relative to the market totals such that knowledge of customers' operations is of relatively little commercial value to electric generation. In short, none of the vertical concerns that the Commission focused upon in prior vertical mergers exist in this merger and the transaction does not create or enhance vertical market power.

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[76] Even if I considered a region consisting solely of Ohio and Indiana, where Cinergy's generating capacity is located, Texas Eastern supplies less than 15 percent of pipeline capacity into those two states. However, since Cinergy's generating capacity competes in the larger Midwest markets, the use of these markets is relevant in the context of my vertical analysis as well.

[77] In conducting the market concentration analysis for upstream markets, I focus on contracts with upstream receipt points and delivery points within the relevant states. This avoids double-counting delivery capacity in the relevant markets.

[78] Exhibit J-12 also shows the amount of transportation capacity actually attributed to Applicants in my upstream analysis. As I describe below, this allocation is necessary when the sum of firm contracts exceeds the capacity into a market.

Q. WHAT STEPS DID YOU FOLLOW IN PERFORMING YOUR ANALYSIS OF VERTICAL COMPETITIVE IMPACTS?

A. My analysis is consistent with the Commission's analytic framework set forth in Section 33.4 of the Revised Filing Requirements. That framework requires that relevant upstream (delivered gas) and downstream (electricity) geographic markets be defined. The structure of downstream markets is analyzed using the same delivered price test methodology as the Commission has mandated for horizontal market power analysis, with two modifications. First, gas-fired generation is deemed to be controlled by (*i.e.*, is assigned to) its gas supplier rather than its owner. Second, whereas the focus of the horizontal screening analysis is on the change in market structure, the focus of the downstream portion of the vertical screen is not directly concerned with the concentrating effects of the merger *per se* but with the post-merger structure of those markets in which one of the merging parties sells upstream products and the other sells downstream products.

In analyzing downstream markets, I focused on Economic Capacity and did not analyze Available Economic Capacity.[79] I attributed gas-fired generation to the upstream suppliers, *i.e.*, the pipeline that serves it.

The analysis of the upstream market requires that the structure of control of transportation capacity be examined. For this purpose, I allocated control of gas transportation pipelines to holders of firm capacity rights with any unsubscribed capacity allocated to the pipeline owner. Details of this approach are provided below and in Exhibit J-5.

The Commission has stated that a necessary condition for a convergence merger to cause a vertical concern is that both the upstream and downstream markets are highly

[79] An analysis of Available Economic Capacity would add little in the context of evaluating this transaction. To the extent downstream markets are highly concentrated, additional review (*e.g.*, of upstream markets) would be required in any event. To the extent downstream markets are not highly concentrated, which is the case here, there is the additional difficulty of measuring Available Economic Capacity that I described earlier.

concentrated.[80] In other words, the screen is passed if the downstream (or upstream) market is not highly concentrated, irrespective of the degree of concentration of the upstream (or downstream) market. While I considered both the downstream market and upstream market, it is not necessary to do so once one of these markets is proven not to be highly concentrated.

Q. PLEASE COMMENT FURTHER ON YOUR APPROACH TO EXAMINING THE DOWNSTREAM MARKET.

A. The basic sources for identifying transportation providers for gas-fired generation include Energy Planning, Inc.'s *Directory of Natural Gas Customers*, Platts' *POWERdat* and *POWERmap* databases and other public sources.

There are a series of decision rules necessary to determine the pipeline company to which the gas-fired units are attributed. The decision rules I have employed are as follows. If a power plant is directly connected to a single-owner pipeline, the entire capacity of the plant is attributed to the pipeline. If the pipeline is jointly owned, the generating capacity is divided among the pipelines' owners proportionate to their ownership share. If there are more than four owners, the capacity is attributed to the owner with the largest ownership share.

For power plants directly connected to multiple pipelines, the plant's capacity is divided into equal shares and attributed to the pipelines that are connected. If a pipeline

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80 "[H]ighly concentrated upstream and downstream markets are necessary, but not sufficient, conditions for a vertical foreclosure strategy to be effective" Revised Filing Requirements, ¶ 31,311 at 31,911. "A vertical merger can create or enhance the incentive and ability of the merged firm to adversely affect electricity prices or output in the downstream market by raising rivals' input costs if market power could be exercised in both the upstream and downstream geographic markets." Order No. 642, *slip op.* at 79. This was confirmed in *Energy East*. ("Applicants correctly conclude that because they have shown that the downstream markets are not highly concentrated, there is no concern about foreclosure or raising rivals' costs in this case.") *Energy East*, *op. cit.*

connection cannot be determined by the mapping process, or the plant is served by an LDC that is fed by multiple pipelines, the capacity is assigned to the electricity owner.[81]

Q. PLEASE DESCRIBE FURTHER YOUR APPROACH TO EXAMINING THE UPSTREAM MARKET FOR NATURAL GAS TRANSPORTATION.

A. For a given geographic market definition, there are three primary steps required to determine market concentration. The first is to identify the physical pipeline assets serving the market. The second is to identify the entities that own or control that capacity. The third is to allocate the regional pipeline capacity to its rights holders and calculate market concentration.

The EIA database of interstate pipeline capacity and flows "at state borders" is the starting point for identifying pipelines serving each market. Broadly, for each market, I identified pipelines flowing from outside the target region into the market area. To the extent the geographic market definition involves control areas or destination markets rather than states, I used pipeline and service territory maps to refine the definition of pipelines to be included. The aggregate capacity of the pipelines so identified represents the total supply for the market. Exhibit J-5 describes this approach further.

Next, pipeline capacity is allocated to pipeline customers who have firm capacity rights under long-term agreements. These firm customers have the first call on the pipeline capacity into a region and retain the option of selling their rights to a third party (*e.g.*, through capacity release) should conditions warrant. These customers are the suppliers of gas to that market (or are customers buying gas upstream of the pipeline) and thus direct or indirect competitors selling delivered gas into downstream markets. The primary source of information for identifying shippers with firm contractual rights is the

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[81] This attribution implicitly assumes that Applicants could foreclose gas service to these rivals or otherwise raise their delivered gas costs, but, as the Commission recognized in its *Dominion* order, while the screen calls for attributing capacity to the serving gas transportation carrier, this does not imply a degree of control of, or economic interest in, the output of the generator remotely on a par with actual ownership. In *Dominion*, the Commission noted "Applicants have no operational control over generation owned exclusively by others pre- or post-merger, regardless of the fuel supply arrangements." *Dominion, op. cit.*

Index of Customers (Form 549b) filed with the Commission by interstate pipeline companies. Platts compiles a database of these filings, which provide a list of customers, contract volumes, rate schedule and delivery points. For this portion of the analysis, there were a number of analytical steps required to assign firm rights within a market to customers. These steps are detailed in Exhibit J-5.

Broadly, I used both receipt and delivery point information to identify shippers with upstream receipt points and (i) delivery points in the market; (ii) delivery points downstream of the market; and (iii) delivery points upstream of the market. I excluded shippers that fell into the third category.

I next allocated the total pipeline capacity into a market to firm customers with upstream receipt points and delivery points either in the market or downstream of the defined market. Customers downstream of the defined market may be relevant because they may, in effect, "use up" capacity on the pipeline that otherwise would have been available for delivery into the defined market. On many pipelines, such customers also can "drop off" gas at upstream delivery points; nominating more downstream points adds flexibility, often at little additional cost.

In some instances, my analysis showed that the sum of firm contracts is in excess of capacity into a market. It is not entirely clear why this result occurs. It could be because of overlapping receipt and delivery points, but I generally was able to take different delivery points into account. To the extent capacity was in excess of that which could enter a market, capacity was allocated to parties with the largest amount of capacity under contract, resulting in a conservative (*i.e.*, more highly concentrated) estimate of market concentration. To the extent firm entitlements within and downstream of the market were less than capacity on a given pipeline, the remaining capacity was assumed to be controlled by the pipeline owner.[82]

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[82] The index of customers provides a snapshot of long-term firm contracts at a given point in time. I included all contracts that were included in the second quarter 2005 filings at the Commission as reported in the April 2005 release of GASDat (a publication of Platts), the most recent data available at the time of my analysis. While some contracts might have termination dates within a one-year period, it was not possible to evaluate any rights

Q. WHAT RELEVANT DOWNSTREAM PRODUCTS AND MARKETS DID YOU CONSIDER?

A. The relevant downstream product for purposes of this portion of my analysis is wholesale electric energy. I used the same market definitions for my analysis of downstream markets in the MISO and PJM as for energy markets, namely MISO, MISO Submarket, and MISO-PJM Midwest.

Q. WHAT DID YOUR ANALYSIS OF DOWNSTREAM MARKETS IN THE THESE MARKETS SHOW?

A. The relevant downstream product markets are not highly concentrated, and Applicants' share of these markets, calculated pursuant to the attribution methodology, is generally quite small (less than 15 percent), not really much different than in my Economic Capacity analysis. (See Exhibit J-13.) Within these markets, I attributed less than 2,000 MW of competing gas-fired generation to Applicants, as shown in Exhibit J-10.

Gas-fired generation represents only 16 percent of total installed generation in MISO,[83] and has only recently begun to play a more substantial role in the relevant energy markets, which remain dominated by nuclear and coal-fired generation. In any case, the relatively small share of gas-fired generation should further mitigate any concerns that the merger will create or enhance the ability of Applicants to pursue a vertical foreclosure or raising rivals' cost strategy.

Despite the results that these markets are not highly concentrated, I also examined competitive conditions in the upstream market to support my conclusion that the market is not conducive to the exercise of vertical market power. This is discussed below.

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to continue these contracts. However, I did conduct a sensitivity analysis that eliminated contracts apparently expiring within the next twelve months. The results, which are included in my workpapers, did not alter any of my conclusions.

[83] *2004 State of The Market Report Midwest ISO*, Potomac Economics Ltd., June 2005, page 18.

Q. IN EXAMINING COMPETITIVE CONDITIONS IN UPSTREAM MARKETS, WHAT PRODUCTS DID YOU CONSIDER?

A. I considered commodity gas, long-haul natural gas transportation services, LDC operations and gas storage services. I do not mean to imply that each of these necessarily is a separate product. For example, gas storage competes with flowing gas and LDCs may compete with transmission pipelines.

Q. DO APPLICANTS HAVE POTENTIAL MARKET POWER IN THE COMMODITY GAS MARKET?

A. No. Because the Commission has found that the commodity gas market is competitive,[84] I have not examined this market further, and the remainder of my analysis focuses on transportation and storage. Further, Cinergy's LDC operations do not raise any competitive concerns since they do not deliver gas to any rival generators, and new generators seeking gas deliveries are likely to bypass the LDC and locate directly on the pipelines.

Q. WHAT IS THE RELEVANT UPSTREAM PRODUCT?

A. The relevant upstream product is delivered gas. Since the provision of delivered gas is not vertically integrated, an upstream analysis must be broken down into component products and services. These are: (a) commodity gas supplies, (b) transportation of these supplies from gas-producing regions and remote storage facilities into the market area (including transportation to and from remote or market-area storage facilities), and (c) (for gas not delivered directly from an interstate pipeline transportation system to an end-use customer) the local distribution of these supplies to gas-fired electric generating facilities.

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[84] *See*, for example, Order No. 436.

The Commission has found that the gas commodity market is structurally competitive.[85] As a result, I do not consider this market further. Since Applicants control a number of gas pipelines and gas storage facilities, as well as rights to use capacity on interstate gas transportation pipelines and gas storage facilities owned by others, I focused on the transportation and storage of natural gas as relevant products.

Q. WHAT ARE THE RELEVANT UPSTREAM GEOGRAPHIC MARKETS WITH RESPECT TO THE TRANSPORTATION OF NATURAL GAS?

A. In concept, the relevant upstream geographic market for gas transportation is the area in which electricity to serve the relevant downstream markets (defined above) is generated. There are no bright lines around this area, but my market definition broadly matches the markets analyzed for energy. I focused on two markets, approximating the MISO and MISO Submarket used in both my horizontal analysis and my downstream vertical analysis. As noted above, the market "approximates" these market definitions because, as noted earlier, in my upstream analysis, I used state borders as the boundary of the markets analyzed whereas the MISO and MISO Submarket markets are defined by the control areas in which the market participants operate.

These market definitions are intended to encompass an area in which Applicants' generation competes with other generation and where there exists a potential overlap with Duke Energy's Texas Eastern pipeline. Pipeline capacity into these markets is shown in Exhibit J-11.

Q. PLEASE DESCRIBE THE FIRM TRANSPORTATION CAPACITY HELD BY APPLICANTS INTO MISO MARKETS.

A. In each of these markets, Applicants combined have a modest amount of firm transmission rights, in the 4-5 percent range, as shown in Exhibit J-14.[86]

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[85] Order No. 436.

[86] Their share would be slightly higher had I not had to allocate limited capacity among market participants.

Q. DOES THE FACT THAT APPLICANTS HOLD GAS TRANSMISSION RIGHTS RAISE VERTICAL MARKET POWER CONCERNS?

A. Not in and of itself. Firm pipeline transportation rights, such as those held by Applicants, while certainly relevant to an analysis of the competitive structure of the transportation market, do not on their own create a potential vertical market power issue. Executing the vertical market power abuses of the type with which the Commission has expressed concerned in Order No. 642, *Enova* and *Dominion* implicitly requires that the upstream affiliate have operational control of the pipeline. In any event, Duke Energy's potential ability to withhold capacity as an owner is small since currently Texas Eastern is largely fully subscribed to holders of long-term firm transportation contracts.

Q. DID YOU FIND RELEVANT UPSTREAM MARKETS TO BE HIGHLY CONCENTRATED?

A. No. Both of the markets I analyzed are unconcentrated (and, as noted above, Applicants have relatively small shares), as shown in Exhibit J-14. Therefore, the competitive conditions for a vertical foreclosure strategy are not present.

Q. IS THERE ANY VERTICAL ISSUE RAISED IN CONNECTION WITH NATURAL GAS STORAGE CAPACITY?

A. No. Duke Energy's existing market area storage, primarily its storage facility at Dawn, Ontario, across the U.S. border from Detroit, competes with a large number of storage facilities, particularly in Michigan and, to a lesser extent, New York, to serve relevant market areas. The geographic scope of the storage market is slightly different than for energy or gas transportation, because storage located outside of MISO is used for customers located in MISO. My analysis of storage markets includes storage located such that the facilities serve customers in MISO, PJM and the northeast.[87] The relevant storage market is not highly concentrated. See Exhibit J-15.

Q. DOES DUKE ENERGY'S OWNERSHIP OF ALGONQUIN LNG RAISE ANY RELEVANT CONCERNS IN THIS TRANSACTION?

A. No. Algonquin's LNG facility serves New England, not MISO, and in any event its capacity is small relative to storage capacity in New England.[88]

Q. DO APPLICANTS EXERCISE CONTROL OVER THE AVAILABLE GENERATION SITES?

A. No. I was unable to identify any special barriers to entry in this regard. Merchant generation development activity of electric generation has been robust in the areas where the Applicants have gas transportation facilities, and the service areas of these Applicants are small relative to the relevant geographic markets that include many possible generating sites. Entrants who could compete in areas potentially affected by this merger would not need to locate new facilities in Applicants' service areas or connect to Applicants' transmission systems. In any event, MISO controls the interconnection process for new generation connecting to the Cinergy transmission system, and, if approved, a new independent entity will be responsible for requests from new generation seeking to connect to the Duke Power system. This should moot any concerns in this regard.

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87 My analysis includes storage located in Indiana, Maryland, Michigan, New York, Ohio, Pennsylvania, Virginia and West Virginia.

88 http://www.nega.com/industry_trends/about_lng0901.html

Q. DO THESE APPLICANTS HAVE THE ABILITY TO FRUSTRATE ENTRY INTO ELECTRICITY GENERATION MARKETS DUE TO THEIR CONTROL OVER FUELS OR FUEL DELIVERY SYSTEMS?

A. No. As noted earlier, the Commission has found that the wellhead gas and gas gathering market is competitive. An entrant into generation in the region in which Applicants are located would have no difficulty in purchasing commodity gas from any number of sellers. While Applicants control long distance gas transmission facilities that theoretically might be used to disadvantage entrants, the circumstances of this transaction do not change the ability and/or incentives to frustrate competition. In MISO, the number of pipelines is so numerous that there is no ability to frustrate entry. New gas generators of sufficient scale to affect electricity prices routinely connect directly to pipelines and, indeed, to improve bargaining leverage, usually select locations with access to multiple pipelines.

Q. EARLIER, YOU STATED THAT THE COMMISSION HAS FOUND LONG-TERM MARKETS TO BE PRESUMPTIVELY COMPETITIVE. PLEASE ELABORATE.

A. In Order No. 888, the Commission in referring to a decision in *Entergy Services, Inc.*, noted that "after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets."[89] In the Merger NOPR, the Commission stated that "[a]s restructuring in the wholesale and retail electricity markets progresses, short-term markets appear to be growing in importance. The role of long-term capacity markets appears to be diminishing."[90] While the Commission has indicated its intent to review the presumption that long-term markets are competitive, there is no evidence to overcome that presumption. Certainly, the entry of new generation into the relevant geographic markets and its ownership by numerous independent entities shows that entry is not constrained.

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[89] Order No. 888 at 31,649 n.86 (citation omitted).

Q. IS THERE ANY EVIDENCE THAT THERE WILL BE ENTRY INTO MISO OR PJM WITHIN THE NEXT FEW YEARS?

A. Yes. In MISO, there is about 12,000 MW of generation in the generation interconnection queue with executed interconnection agreements and service dates between 2004 and 2009 inclusive, plus an additional 17,000 MW of generation without an interconnection agreement.[91] Although PJM has been capacity-long in the past few years, its reserve margin is expected to decline relatively quickly given planned retirements and load growth. PJM also has 17,000 MW of generation in its queue.[92]

VI. SAFETY NET CONCERNS

Q. IN SOME RECENT SECTION 203 CASES CONCERNING ACQUISITIONS, THE COMMISSION HAS STATED THAT MOVING GENERATION FROM A MERCHANT ACTIVITY TO A REGULATED FRANCHISE UTILITY CREATES REGULATORY CONCERNS. IN PARTICULAR, THE CONCERN HAS BEEN EXPRESSED THAT THE "SAFETY NET" ARISING FROM POTENTIALLY TRANSFERRING UNREGULATED GENERATING ASSETS TO THE RATEBASE OF A CONVENTIONALLY REGULATED UTILITY WILL HAVE POTENTIAL CHILLING COMMERCIAL AND ADVERSE EFFICIENCY EFFECTS. AS PART OF THIS TRANSACTION, APPLICANTS INTEND TO COMBINE CG&E'S EXISTING GENERATION PORTFOLIO WITH DUKE ENERGY'S GENERATION IN PJM AND MISO. DOES THIS COMBINATION RAISE THE SAFETY NET ISSUES DESCRIBED BY THE COMMISSION IN ITS *CINERGY SERVICES* AND *AMEREN* ORDERS?

A. No. The kernel of the concern is that state regulatory oversight might not adequately police the ability of a parent of a franchised, rate-of-return regulated utility to bail out

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90 Merger NOPR, *op. cit.*, at 20.

91 *Midwest ISO Transmission Expansion Plan, 2005,* page 37. http://www.midwestiso.org/plan_inter/documents/expansion_planning/MTEP05_Report_061605.pdf

92 ftp://ftp.pjm.com/pub/reports/planning/rto/20050621-RTO.pdf

unsuccessful market assets by transferring them to ratebase at a price that exceeds their true value. This free put option arguably will make affiliated merchant generators less risky than unaffiliated merchants, creating a non-level playing field. A related concern is that a franchise utility might preferentially transact with its affiliate rather than buying the assets of, or power from, non-affiliates. This could cause uneconomic exit of non-affiliated assets from the market (an unlikely prospect) or chill entry (more likely). Further, the theory postulates that a franchised utility might prefer to run the now-ratebased assets in preference to buying power from merchants, though the motive for doing so or its relationship to the acquisition is somewhat questionable.[93]

In this case, however, the core concern is missing. While CG&E is a utility, the generating assets that it owns are not subject to ratebase treatment.[94] To state the matter somewhat more precisely, putting the former DENA Midwest assets into CG&E's generating portfolio will not cause the generation component of CG&E's retail and wholesale rates to increase, nor will it change the value of the Duke Energy assets (other than via any synergies arising from asset consolidation). My understanding is that the generation component of CG&E's regulated prices (separate from a fuel and purchased power adjustment) is not cost-of-service based, nor will it be in the future. In short, there would be no safety net, even if the assets in question had previously been owned by a merchant affiliate of CG&E, which they were not.

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[93] The fact that previously merchant assets now are in ratebase creates no obvious reason to run them when purchases are less expensive. One possible such reason would be that the utility might fear that state regulators might find little-used assets to not be "used and useful" and remove them from ratebase. This concern, to the extent valid, is not strictly related to the acquisition, since it could also apply to any ratebase asset. Indeed, it would seem more likely that the utility would over-employ inefficient old assets to make them appear to be used and useful than the modern assets that likely would have been owned by a merchant affiliate. This concern does not apply to CG&E, since it does not have a ratebase used to determine the prices it receives. Moreover, the fact that dispatch is now controlled by MISO further undermines this argument.

[94] CG&E generation is part of CG&E, which also has POLR responsibilities in Ohio. Through 2008, CG&E's existing (*i.e.*, exclusive of the acquired Duke Energy merchant assets) generation is dedicated to meeting this POLR responsibility. The terms upon which it does so were negotiated with the Ohio PUC and will not be affected in any way by the acquisition of the Duke Energy merchant assets. Cinergy's other two utility subsidiaries, which are subject to rate of return regulation, each have their own generation ratebase. Their rates also will be wholly unaffected by this acquisition. Subsequent to the expiry of the existing arrangement in 2008, Cinergy expects that CG&E's POLR responsibilities will be meet from the market without reference to CG&E's generation assets.

Indeed, the most accurate way to think about this aspect of the transaction is that CG&E's non-ratebased merchant generating activity is acquiring a small fleet of previously unaffiliated generation. Such an acquisition raises potential market power issues (shown not to be present in this case) but does not raise a safety net question.

Q. ONE ASPECT OF THE CONCERNS EXPRESSED IN *CINERGY SERVICES* AND *AMEREN* WAS THE CHILLING EFFECT OF THE ACQUISITION ON COMPETITION. IS THAT CONCERN MEANINGFUL IN THIS INSTANCE?

A. No. I should note first that the "chilling effect" concern is not really related to any specific transaction, but to the Commission's policy concern that a pattern of such transactions could adversely affect the willingness of non-affiliated generators to invest in new generation. That is, once a utility buys its distressed merchant assets, there is no materially increased risk to new merchants with respect to that particular utility, since the utility is unlikely to be in a position to do so again.

In any event, in this case, CG&E is acquiring unaffiliated assets. It is doing so as part of a merger, but could have bought the same assets separately. Such a purchase might be seen as "disadvantaging" others who might have wanted to sell their assets (or contract away their output to CG&E). However, this is not an issue of harming competition, merely individual competitors.

Q. WILL CG&E HAVE INCENTIVES TO DISPATCH THE ACQUIRED ASSETS UNECONOMICALLY?

A. No. The acquired assets will not be dedicated to CG&E's affiliated load-serving distribution activity, but rather will be competitive merchant plants. It will have no incentive to dispatch the plants uneconomically, any more that Duke Energy would have had.

Moreover, CG&E is a part of MISO. The assets being transferred to it are located either in the MISO or in PJM. They, rather than CG&E, determine which plants are dispatched.

Q. WILL CG&E HAVE THE ABILITY AND INCENTIVE TO USE THE ACQUIRED GENERATING ASSETS TO EXERCISE MONOPSONY POWER IN ORDER TO SUPPRESS THE REVENUES OF MERCHANT GENERATORS?

A. No. First of all, CG&E's load serving arm must meet the loads of its customers. The exercise of monopsony power generally requires the ability to artificially suppress demand in order to decrease prices. It has no such ability. Second, CG&E simply is not large enough, within the relevant market, to exercise monopsony power. Third, while it is theoretically possible for CG&E to reduce the residual demand faced by other generators by using its own generation to generate uneconomically large amounts of energy, as noted previously, it is PJM and MISO, not CG&E, who determines the dispatch of its generation. CG&E could bid at levels below its variable cost in order to reduce prices. However, this is a doubly adverse action to take. Manifestly, selling power at below variable cost is a money-losing proposition. Further, lowering prices also would reduce the revenues that CG&E generation would receive from its sales into the market from its other generation.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission determine that this merger will not have an adverse effect on competition in markets subject to its jurisdiction.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

EXHIBITS

Exhibit J-1	Testimony
Exhibit J-2	Resume of William H. Hieronymus
Exhibit J-3	Combined North American Asset Map
Exhibit J-4	Applicants' Generation
Exhibit J-5	Data and Methodology
Exhibit J-6	Description of CASm Model
Exhibit J-7	Schematic of Transmission Assumptions for Relevant Markets
Exhibit J-8	Economic Capacity
Exhibit J-9	Available Economic Capacity
Exhibit J-10	Gas-Fired Plants in Midwest Served by Duke Energy
Exhibit J-11	Pipelines Serving Midwest Markets
Exhibit J-12	Downstream Economic Capacity
Exhibit J-13	Applicants' Firm Transmission Reservations in the Midwest
Exhibit J-14	Upstream Market
Exhibit J-15	Midwest Storage Market

Tables

Exhibit J-2

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William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last seventeen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his thirty years of consulting to this sector, he also has performed a number of more specific functional tasks, including analyzing potential investments; assisting in negotiation of power contracts, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States the United Kingdom and Australia. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus serves as an advisor to the senior executives of electric utilities on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. Related to some of these assignments, he has testified before state agencies on regulatory policies and on contract and asset valuation.

- For utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers on which he has testified are EEG (Exelon and PSE&G), Sempra (Enova and Pacific Enterprises), Xcel (New Century Energy and Northern States Power), Exelon (Commonwealth Edison and Philadelphia Electric), AEP (American Electric Power and Central and Southwest), Dynegy-Illinois Power, Con Edison-Orange and Rockland, Dominion-Consolidated Natural Gas, NiSource-Columbia Energy, E-on-PowerGen/LG&E and NYSEG-RG&E and Exelon-PSE&G. He also submitted testimony in mergers that were terminated for unrelated reasons, including Entergy-Florida Power and Light, Northern States Power and Wisconsin Energy, KCP&L and Utilicorp and Consolidated Edison-Northeast Utilities. Testimony on similar topics has been filed for a number of smaller utility mergers and for asset acquisitions. Dr Hieronymus has also assisted numerous clients in the pre-merger screening of potential acquisitions and merger partners.

- For utilities seeking to establish or extend market rate authority, Dr. Hieronymus has provided numerous analyses concerning market power in support of submissions under Sections 205 of the Federal Power Act.

- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For generators and marketers, Dr. Hieronymus has testified extensively in the regulatory proceedings concerning the electricity crisis in the WECC that occurred during May 2000 and May 2001. His testimony concerned, inter alia, the economics of long term contracts entered into during that period the behavior of market participants during the crisis period and the nexus between purportedly dysfunctional spot markets and forward contracts.

- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC and in ISO-New England's market power mitigation rules.

- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.

- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation and more recently before FERC in connection with transactions related to PG&E's bankruptcy and on the contracts signed between merchant generators and various buyers.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

- He has testified concerning the value of terminated long term contracts in connection with contract defaults by bankrupt power marketers and merchant generators.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- He has made numerous presentations to U.S. utility managements regarding overseas electricity systems.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that were then under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders. For the senior managements and boards of utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.

- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system.

- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional distribution and retail supply companies focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing commercial capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.

- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted one of the Regional Electricity Companies in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus testified before the federal court of Australia concerning the market power implications of acquisition of a share of a large coal-fired generating facility by a large retail and distribution company.

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that inter alia requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command- and-control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.

- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.

- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.

- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.

- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.

- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section l33.

- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.

- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed a basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.

- For state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.

- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus assists clients in Hart-Scott-Rodino investigations by the Antitrust Division of the U.S. Department of Justice and the Federal Trade Commission. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality. In two Surface Transportation Board proceedings, he testified on the sufficiency of product market competition to inhibit the exercise of market power by railroads transporting coal to power plants.

- For a landholder, Dr. Hieronymus examined the feasibility and value of an energy conversion project that sought a long-term lease. The analysis was used in preparing contract negotiation strategies.

- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.

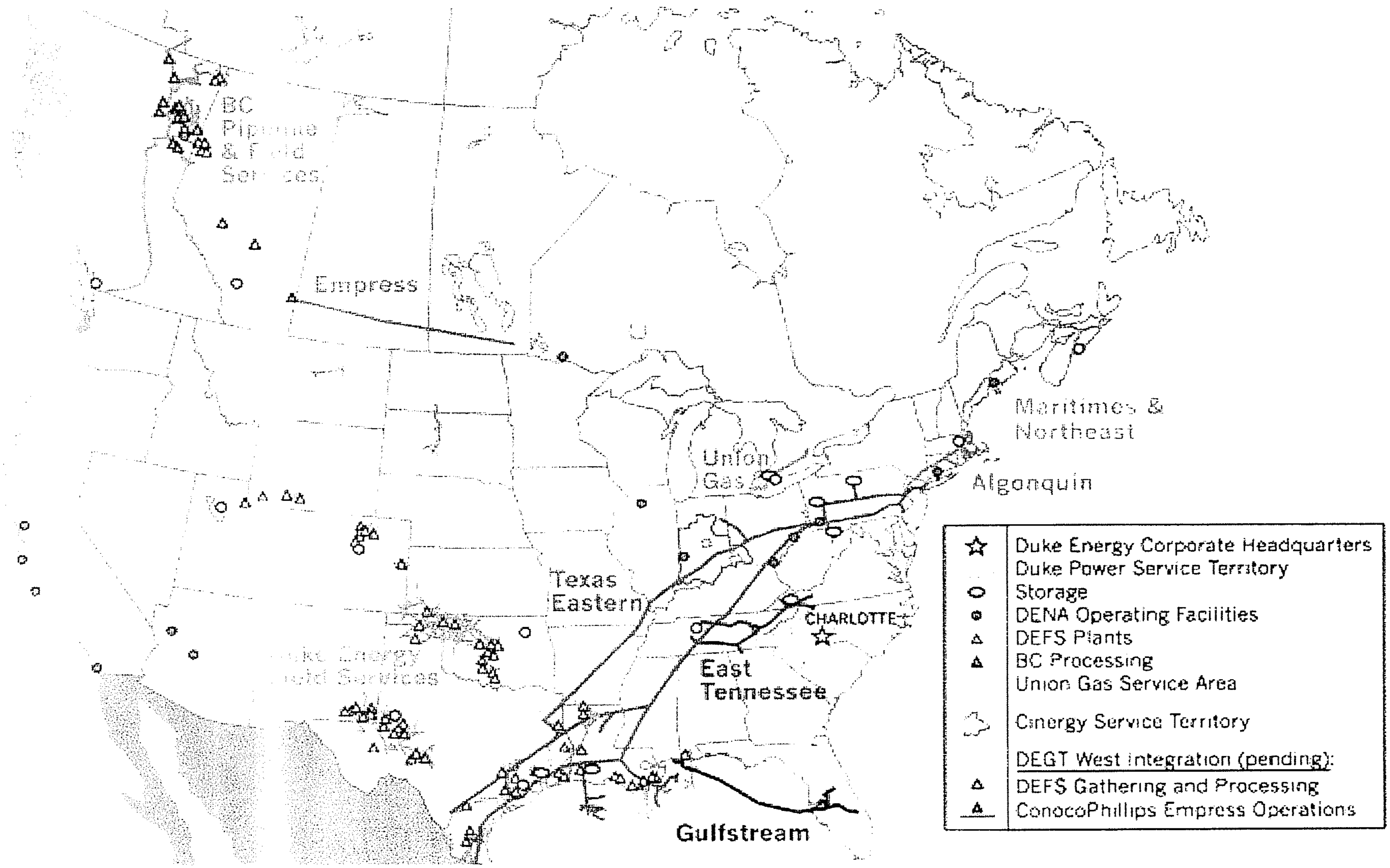
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has been an invited speaker at numerous conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervener strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.

Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate and Program Manager for Energy Market Analysis at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army.

Exhibit J-3

Combined North American Asset Map



Summary of Generation Owned or Controlled by Applicants

NERC	Control Area	Duke (MW)	Cinergy (MW)		Combined (MW)
ECAR	MISO	420.0	12,313.4	1/	12,733.4
ECAR	PJM	2,488.5	-		2,488.5
MAIN	PJM	568.0	-		568.0
ECAR	OVEC	-	196.3		196.3
SERC	DUK	19,275.9	-		19,275.9
SERC	TVA	-	894.0		894.0
NPCC	ISO-NE	792.7	-		792.7
WECC	CAISO	4,364.0	-		4,364.0
WECC	Arizona	874.0	-		874.0
NPCC	Canada	305.0	-		305.0
WECC	Canada	58.5	-		58.5
Total		29,146.5	13,403.7		42,550.3

1/ Includes Cinergy's shares of jointly-owned capacity that is phyisically located in the former AEP and DPL control areas, but for which Cinergy has grandfathered transmission rights for delivery into MISO.

Generation Owned or Controlled by Duke Energy and its Affiliates

Control Area	Unit Name	Unit No.	Primary Fuel	Unit Type	Summer Capacity (MW)	% Ownership	Net Summer Capacity (MW)
DUK	Belews Creek	1-2	COAL	ST	2,270.0	100%	2,270.0
DUK	Buck	3-6	COAL	ST	369.0	100%	369.0
DUK	Cliffside	1-5	COAL	ST	760.0	100%	760.0
DUK	Dan River	1-3	COAL	ST	276.0	100%	276.0
DUK	G G Allen	1-5	COAL	ST	1,145.0	100%	1,145.0
DUK	Marshall	1-4	COAL	ST	2,110.0	100%	2,110.0
DUK	Riverbend	4-7	COAL	ST	454.0	100%	454.0
DUK	W S Lee	1-3	COAL	ST	370.0	100%	370.0
DUK	McGuire	1-3	NUCLEAR	ST	2,200.0	100%	2,200.0
DUK	Catawba	1	NUCLEAR	ST	1,129.0	25.0%	282.3
DUK	Oconee	1-3	NUCLEAR	ST	2,538.0	100%	2,538.0
DUK	Bad Creek	1-4	WATER	PS	1,360.0	100%	1,360.0
DUK	Cowans	1-4	WATER	HYDRO	325.0	100%	325.0
DUK	Jocassee	1-4	WATER	PS	680.0	100%	680.0
DUK	Other Hydro		WATER	HYDRO	804.0	100%	804.0
DUK	Buck	7-9	DFO	GT	93.0	100%	93.0
DUK	Buzzards Roost	6-15	DFO	GT	196.0	100%	196.0
DUK	Dan River	4-6	DFO	GT	85.0	100%	85.0
DUK	Lincoln Combustion	1-16	NG	GT	1,267.2	100%	1,267.2
DUK	Mill Creek	1-8	NG	GT	595.4	100%	595.4
DUK	Riverbend	8-11	DFO	GT	120.0	100%	120.0
DUK	W S Lee	4-6	DFO	GT	90.0	100%	90.0
	Subtotal, Owned Generation				19,236.6		18,389.9
	Purchases						
DUK	Purchase from Rockingham						165.0
DUK	Purchase from Rowan						458.0
DUK	Purchases from QFs						169.0
DUK	SEPA Allocations						94.0
	Subtotal, Purchases						886.0
	Subtotal DUK Control Area				38,473		19,275.9
MISO (CIN)	Vermillion Energy Facility		NG	CT	560.0	75%	420.0

Generation Owned or Controlled by Duke Energy and its Affiliates

Control Area	Unit Name	Unit No.	Primary Fuel	Unit Type	Summer Capacity (MW)	% Ownership	Net Summer Capacity (MW)
PJM (ComEd)	Lee Energy Facility		NG	CT	568.0	100%	568.0
PJM (AEP)	Washington Energy Facility		NG	CC	600.0	100%	600.0
PJM (APS)	Fayette Energy Facility		NG	CC	600.5	100%	600.5
PJM (AEP)	Hanging Rock Energy Facility		NG	CC	1,288.0	100%	1,288.0
ISO-NE	Bridgeport Energy Project	1-3	NG	CT	454.0	67%	302.7
ISO-NE	Maine Independence Station	1-3	NG	CT	490.0	100%	490.0
MAR (Canada)	Bayside Power Project		NG	CC	260.0	75%	195.0
IMO (Canada)	Fort Frances Cogeneration		NG	Cogen	110.0	100%	110.0
CAISO (ZP-26)	Morro Bay	1-4	NG	ST	999.0	100%	999.0
CAISO (NP-15)	Moss Landing		NG	ST, CT	2,498.0	100%	2,498.0
CAISO (NP-15)	Oakland		DFO	GT	160.0	100%	160.0
CAISO (SP-15)	South Bay		NG	ST, CT	707.0	100%	707.0
AZ	Griffith				588.0	50%	294.0
AZ	Arlington		NG	CT	580.0	100%	580.0
BCHA (Canada)	McMahon Cogen				117.0	50%	58.5
	Subtotal DENA				10,580		9,871
TOTAL	**Duke Energy**				49,053		29,147

Generation Owned or Controlled by Cinergy and its Affiliates

Control Area	Unit Name	Unit No.	Primary Fuel	Unit Type	Summer Capacity (MW)	% Ownership	Net Summer Capacity (MW)
MISO	Dicks Creek	1	NG	JE	92.0	100.0%	92.0
MISO	Dicks Creek	3-5	NG	GT	44.2	100.0%	44.2
MISO	East Bend	2	COAL	ST	600.0	69.0%	414.0
MISO	Miami Fort	5-6	COAL	ST	243.0	100.0%	243.0
MISO	Miami Fort	7-8	COAL	ST	1,000.0	64.0%	640.0
MISO	Miami Fort	GT3-6	FO2	GT	56.8	100.0%	56.8
MISO	Walter C Beckjord	1-5	COAL	ST	704.0	100.0%	704.0
MISO	Walter C Beckjord	6	COAL	ST	414.0	37.5%	155.3
MISO	Walter C Beckjord	GT1-4	FO2	GT	186.4	100.0%	186.4
MISO	Woodsdale	GT1-6	NG	GT	462.0	100.0%	462.0
MISO	Cayuga	1-2	COAL	ST	995.0	100.0%	995.0
MISO	Cayuga	4	NG	GT	99.0	100.0%	99.0
MISO	Cayuga	3a-d	FO2	IC	10.0	100.0%	10.0
MISO	Connersville	1-2	FO2	GT	86.0	100.0%	86.0
MISO	Edwardsport	6	FO2	ST	40.0	100.0%	40.0
MISO	Edwardsport	7-8	COAL	ST	120.0	100.0%	120.0
MISO	Gibson	1-4	COAL	ST	2,512.0	100.0%	2,512.0
MISO	Gibson	5	COAL	ST	620.0	50.1%	310.3
MISO	Markland	1-3	WAT	HY	45.0	100.0%	45.0
MISO	Miami Wabash	1-6	FO2	GT	96.0	100.0%	96.0
MISO	Noblesville	3	NG	ST	285.0	100.0%	285.0
MISO	R Gallagher	1-4	COAL	ST	560.0	100.0%	560.0
MISO	Wabash River	1-6	COAL	ST	753.0	100.0%	753.0
MISO	Wabash River	7a-c	FO2	IC	8.0	100.0%	8.0
MISO	Wabash River	1a			175.0	100.0%	175.0
MISO	W H Zimmer	ST1	COAL	ST	1,300.0	46.5%	604.5
MISO	Madison	1-8	NG	GT	576.0	100.0%	576.0
MISO	Henry County	1-3	NG	GT	136.5	100.0%	136.5
MISO	Wheatland		NG	CT	472.0	100.0%	472.0
Subtotal, MISO							10,881.0
PJM	Conesville	4	COAL	ST	780.0	40.0%	312.0
PJM	J M Stuart	1-4	COAL	ST	2,340.0	39.0%	912.6
PJM	J M Stuart	D1-D4	DFO	GT	10.0	39.0%	3.9
PJM	Killen Station	2	COAL	ST	600.0	33.0%	198.0
PJM	Killen Station	GT1	FO2	GT	18.0	33.0%	5.9
Subtotal, PJM							1,432.4
OVEC	Kyger Creek		COAL	ST	985.7	9.0%	88.7
OVEC	Clifty Creek		COAL	ST	1,195.8	9.0%	107.6

Generation Owned or Controlled by Cinergy and its Affiliates

Control Area	Unit Name	Unit No.	Primary Fuel	Unit Type	Summer Capacity (MW)	% Ownership	Net Summer Capacity (MW)
TVA	Brownsville				450.0	100.0%	450.0
TVA	Caledonia				444.0	100.0%	444.0
Subtotal, Other							1,090.3
TOTAL							13,403.7

Data and Methodology

The Delivered Price Test specified in Appendix A ("DPT" or "Appendix A") requires estimating the generating resources for each of the potential suppliers in the model, specifying the transmission network that these suppliers can use to reach the relevant destination market and the destination market price. Below, a description of the data inputs used in the DPT is provided. In addition, I also provide additional information on defining the relevant core geographic markets around Cinergy that I have evaluated, and on the review that I conducted on overlap between Applicants' historical purchases and sales for the most recent two year period (2003 and 2004). Finally, I describe the data and methodology used for the vertical analyses that I have conducted.

I have implemented the DPT analysis using a proprietary CRA model called the "Competitive Analysis Screening Model" ("CASm").[1] CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test. The model includes each potential supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic facet of the delivered price test than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface. The model incorporates simultaneous transmission import capability, consistent with the Commission's approach outlined in *FirstEnergy*,[2] and, as appropriate, consistent with the Commission's approach in the current, interim screens for market-based rates.[3]

I conducted the Appendix A competitive screening test assuming the existing market structure and using publicly available data on generation (from the EIA-411 reports or their

1 A technical description of the model is provided in Exhibit J-6.

2 *Ohio Edison Company, et al.*, 80 FERC ¶ 61,039 (1997).

3 *AEP Power Marketing, Inc., et al.*, Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, 107 FERC ¶ 61,018 (2004); *order on reh'g*, 108 FERC ¶ 61,026 (2004).

equivalent). The data inputs were adjusted to reflect 2006 conditions as a representative year (i.e., to reflect updated fuel prices, load, and generation).

I. DATA INPUTS AND MODELING ASSUMPTIONS

A. Regions Included

The specific list of utilities (and corresponding abbreviations used in other exhibits) is included in workpapers. The model includes all significant generation and load sources, including traditional utilities, Qualifying Facilities ("QFs"), merchant generators, municipal utilities and cooperatives. These entities are generally modeled as individual "nodes" in the model.[4] Outside of Commission-approved RTOs, control areas were used to aggregate generation and transmission assets. For RTOs, I aggregated suppliers into each of the relevant RTOs (or, in the case of the MISO Submarket and MISO-PJM Midwest markets, I aggregated load and resources into these defined "nodes".) I included generators in MRO, MISO, SERC and PJM in the model and also restricted suppliers to be within four wheels of the destination market.[5] This list of candidate suppliers does not pre-judge the question of the geographic scope of the specific destination market, which is determined via the delivered price test.

B. Generating Resources

The main source for data on generating plant capability are the EIA-411 publications dated April 2004, supplemented by later editions where available or earlier editions as necessary, as well as by the EIA-860 Annual Generator Report. These publications provide data on summer and winter capacity, planned retirements and additions, and jointly-owned units.

4 The term "Nodes" is used in CASm to denote regions where load, generation or transmission assets are aggregated.

5 This restriction was selected in recognition of the Commission's guidance regarding the number of wheels a potential supplier can realistically travel and still be considered a player in the destination market. For example, in FirstEnergy, the Commission limited the number of wheels "a supplier could reasonably travel to reach the destination market," recognizing that "[m]ore distant suppliers would face considerable losses and transmission costs." 80 FERC ¶61,039 at 61,104. In FirstEnergy, the Commission limited the potential suppliers to those within four wheels. Ibid.

Also, the request for comments on the use of computer models in merger analysis suggests that "three wheels has been deemed adequate." Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis, Notice of Request for Written Comments and Intent to Convene a Technical Conference, Docket No. PL98-6-000, April 16, 1998, page 24. Including a broader geographic region implies adding additional potential suppliers not controlled by the Applicants; thus, defining the set of potential suppliers in this manner is conservative.

For jointly-owned plants, shares were assigned to each of the respective owners. Summer ratings were used for the summer and shoulder periods and winter ratings for the winter period. The capacity representing shares of jointly-owned units typically are represented as if they were physically located in the owner's control area, reflecting the fact that utilities typically will have transmission or network service from their generation to their load.[6] In addition, I took into account data available from the MISO regarding the deliverability of generators within MISO.[7]

Each supplier's generating resources were adjusted to reflect long-term capacity purchase and sales where such information was available, and to the extent control is assumed to be transferred.[8] Such information was identified from publicly-available information, such as FERC Form 1 and EIA Form 412 filings (or databases based on these forms), Form EIA-411, individual utility resource plans and NERC's Electricity Supply and Demand ("ES&D") database. The capacity representing firm purchases and sales, analogous to the treatment of jointly-owned units, was assumed to be moved from its actual physical location to the geographic location of the buyer.

To the extent a utility has sold energy rights under a long-term agreement, ownership over that resource was assumed to pass to the buyer.[9,10] Accordingly, as with jointly-owned units, generation ownership was adjusted to reflect the transfer of control by assuming that the sale resulted in a decrease in capacity for the seller and a corresponding increase in capacity for the buyer. Consistent with guidance provided in Appendix A, it was assumed that system power sales were comprised of the lowest-cost supply for the seller unless a

6 This includes Cinergy's shares of jointly-owned generation located in PJM. I also treated Cinergy's share of OVEC generation similarly, because Cinergy has network service back to MISO. I also applied this same assumption to the other owners of OVEC (i.e., I included the capacity associated with their ownership or rights in OVEC as part of the owners stack of resources in their home regions).

7 See http://www.midwestiso.org/plan_inter_gen_deliver_test_results.shtml.

8 Requirements contracts are treated as the equivalent of native load, and Economic Capacity was not adjusted to reflect them.

9 Consistent with this assumption, QFs or non-utility generation ("NUGs") was assumed to be under the control of the purchasing utility.

10 The Revised Filing Requirements direct applicants to consider whether operational control of a unit is transferred to the buyer. Such information generally is not readily available for non-applicants. Therefore, I treated long-term sales as being under the control of the purchaser.

more representative price could be identified.[11] To the extent that long-term sales could be identified specifically as unit sales, the capacity of the specific generating unit was adjusted to reflect the sale, and the variable element of the purchase price attributed to the sale was the variable cost of the unit. The dispatch price for system purchases was based on the energy price reported for long-term purchases where such purchases could be identified and a variable cost price determined, or an estimate made.

Since the delivered price test is intended to evaluate energy products, the summer and winter capacity ratings were de-rated to approximate the actual availability of the units in each period. That is, it was assumed that generation capacity would be unavailable during some hours of the year for either (planned) maintenance or forced (unplanned) outages. Data reported in the NERC "Generating Availability Data System" ("GADS") was used to calculate the "average equivalent availability factor" to estimate total outages, and the "average equivalent forced outage rate" to estimate forced outages for fossil and nuclear plants.[12] Scheduled maintenance was assumed to occur only during the non-peak

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11 "[T]he lowest running cost units are used to serve native load and other firm contractual obligations" (Appendix A, p. 11). The lowest-cost supply that was available year-round (i.e., excluding hydro) was used.

12 These data were supplemented, where necessary, by data from other public sources such as NERC and EPRI. In addition to thermal unit availability, hydro unit availability and generation are specified for each time period. For each of the time periods analyzed, hydro capacity factors have been assigned to each unit based on historical operation. Capacity factors for hydro units were based on five years of EIA Form 759 and EIA Form 920 monthly generation data and reported maximum capacities (from Platts). I assumed hydro units were operated in order to "peak shave" by spreading the historical energy values (in MWh) first to the peak periods in the analysis and then allocating the remaining energy to the off-peak periods. In instances where this resulted in insufficient energy for each period (defined as times when the calculated off-peak capacity factor was less than 5 percent), I assumed that the unit operated on a run-of-river basis and spread the reported historical energy equally over each time period.

For pumped storage units, I rated the units during each period using the following methodology. For super peak periods, I assumed that pumped storage units were fully available, while for off-peak periods, I assumed that pumped storage units were not producing energy. For the peak periods, I rated the units based on an analysis of the historical energy production at each facility by calculating for each season the remaining MWh available to serve the peak period and adjusting the facilities capacity factor to match. Historical energy production values were again retrieved from Platts (EIA Form's 759 and 906). For pumped storage units, the Form 906 reports net generation (calculated as gross generation less pumping energy) and pumping energy, which were used to derive monthly gross generation values used to rate the units during the peak periods. In instances where data for specific units were not available, an average based on the analysis described above was applied.

For wind units, I used historical capacity factors based on energy produced at each facility (as reported by Platts). In instances where no data were available, I assumed a 30 percent capacity factor.

(shoulder) seasons and forced outages were assumed to occur uniformly throughout the year.

Supply curves were developed for each potential supplier in the model, based on estimates of each unit's incremental costs. The incremental cost is calculated by multiplying the fuel cost for the unit by the unit's efficiency (heat rate) and adding any additional variable costs that may apply, such as costs for variable operations and maintenance and costs for environmental controls.[13]

Data used to derive incremental cost estimates for each unit were taken from the following sources:

- Heat Rates – EIA Form 860, supplemented by data reported in Platts' PowerDat database. (Note that the most recently available data from the Form 860 date back to 1995.)

- Fuel Costs - Futures prices and Regional Projections. Regional dispatch costs for natural gas and oil units were derived from futures market data and spot price history. For gas-fired units, I relied on 2006 NYMEX Henry Hub natural gas futures contract prices and regional basis differentials. I used these data to estimate regional delivered commodity prices for all gas-fired units modeled. Basis differentials were estimated from a review of regional market center and Henry Hub prices. The NYMEX Henry Hub price, plus each region's basis differential equals my estimated regional price. For oil-fired units, I relied on the NYMEX futures contract for light sweet crude oil. I estimated delivered residual and distillate oil prices based on a multi year analysis of delivered refined products versus spot crude oil prices. I used plant specific forecasts of coal prices from Platts as the basis for my coal unit dispatch cost. In instances where no forecast was available for a given unit, I used Platts' regional average price estimate as my default. While my methodology for all three fuels is slightly different than what I historically used for the DPT (primarily relying on actual historical fuel costs, by unit, plus an escalation factor), the recent dramatic run up in commodity fuel prices make it increasingly difficult to rely on historical fuel costs to generate reasonable input price assumptions.

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13 For NUGs, the incremental costs were estimated on the basis of the energy price reported in relevant regulatory filings, if available. Otherwise, NUGs were assumed to be must-run and the variable costs set to zero. New merchant and utility capacity included in the analysis was priced assuming an average full-load heat rate of 10,000 Btu/kWh for combustion turbines ("CT") and 7,000 Btu/kWh for combined cycle ("CC") plants. These values were derived from an evaluation of existing technology. Variable O&M costs for new units were assumed to be the same as for existing units.

- Variable O&M – $1/MWh for gas and oil steam units, $3/MWh for scrubbed coal-fired units and $2/MWh for other coal-fired units (generic estimates based on trade and industry sources).[14] Additional Variable O&M adders for other unit types are shown in my workpapers.

- Environmental Costs – All units covered by Phase II of the Clean Air Act Amendments of 1990 (CAAA) are assessed a variable dispatch adder to cover costs associated with SO2 emissions. This unit-specific cost is calculated using the SO2 content of fuel burned at the unit as reported in FERC Form 423 (adjusting for emissions reduction equipment at the facility) and an SO2 allowance cost of $720/ton for 2006.[15] In addition to SO2, the unit dispatch costs also reflect the impact of existing NOx trading programs in the Northeast (OTR). Unit-specific data on NOx rates (lbs/mmBtu) were taken from the EPA's "2000 Acid Rain Program Emission Scorecard."[16] The NOx allowance price for the OTR was assumed to be $3,525/ton.[17]

C. Transmission

The Commission's Appendix A analysis specifies that the transmission system be modeled on the basis of inter-control area limits (i.e., ATCs or TTCs) using transmission prices based on transmission providers' maximum non-firm OATT rates, except where lower rates can be clearly documented. This dictates a transportation representation of the transmission network, and the structure of CASm was designed to conform to Appendix A. This representation remains appropriate for many portions of the United States where transmission service is generally provided under each transmission provider's OATT. Basing tariffs on OATT rates is increasingly modified by RTO transmission pricing

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14 As noted, these variable O&M costs are generic estimates by plant type and do not necessarily match actual individual unit O&M costs. Notably, variable O&M accounts for a minor portion of the dispatch costs used in the analysis, and, importantly, the specific O&M assumption tends not to alter the merit order of the generic types of generation.

15 Consistent with my methodology for estimating coal prices, I used plant specific forecasts of SO2 emissions from Platts as the basis for my coal unit dispatch cost. When there was no forecast for a given unit, I defaulted to Platts' regional average SO_2 estimate. SO_2 costs of $720 was taken from Evolution Markets LLC's Monthly Market Update - SO2 Markets, March 2005.

16 In cases where unit-specific data were not available, such as for new capacity, the following boiler level assumptions were applied, based on the unit's fuel type: Coal – 0.4; Oil – 0.2; Natural Gas – 0.1.

17 NOx rates and allowance price ($3,525/ton) were derived from EPA's 2000 Acid Rain Program Emission Scorecard and Evolution Markets LLC's Monthly Market Update - NOx Markets, March 2005.

arrangements, however, and the Commission has instructed applicants to account for them.[18]

As noted in Exhibit J-1, my modeling of the transmission system incorporates both the MISO and PJM RTOs' structure, as well as the more traditional control-area-to-control-area representation in the Southeast. Limits were placed on the amount of capacity that could be transferred over the transmission network by both non-simultaneous control area to control area limits and simultaneous interface limits. For example, I have used Duke Power's non-simultaneous TTC postings along with an overall simultaneous limit into Duke Power when analyzing the DUK destination market.[19] Similarly, I have used non-simultaneous limits into the different MISO configurations, and then applied the overall simultaneous limit calculated by Cinergy's transmission group, as described in Exhibit J-1.[20]

For my base case analysis, I have assumed zero transmission costs across the model. This assumption allows Duke and Cinergy to compete more economically against capacity located in the intervening markets and is, therefore, conservative. Losses, which are assumed to be 2.8 percent, are assessed for each wheel incurred along the path to deliver power to the destination market but are not added for the final wheel into the destination market.

I also have conducted a sensitivity analysis in which I apply Order 888 rates, where available, and analyzed Duke Power and its first-tier destination markets. Consistent with Order No. 592, the ceiling rates in Schedule 8 (Non-Firm Point-to-Point Transmission Service) of each utility's Order No. 888 filings were used for utilities that are not part of

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18 *See* Revised Filing Requirements.

19 I have assumed a simultaneous import limit into the DUK market of 3,400 MW in the Summer, 2,700 MW in the Winter and 4,800 MW in the Shoulder (the average of Duke's Fall (4,000 MW) and Spring (5,600 MW) SILs), based on Duke's recent market-based rate compliance filing.

20 For regions to the West of the MISO (including the MRO region), transmission availability is calculated on the basis of flowgates and, therefore, there are no recent publicly available postings on a control area to control area basis. For these regions, I have used TTC data from the most recent historical control area to control area postings.

RTO arrangements.[21] The results of this sensitivity are shown in workpapers and are not materially different then my base case analysis. This is not surprising, since transmission costs make up a relatively insignificant part of the overall delivered cost to reach a market and impact the different potential suppliers in the analysis generally in a symmetric manner.

D. Market Prices and Time Periods

As discussed in Exhibit J-1, I selected the market prices used in my base case after evaluating a number of different data sources, including historical bilateral prices, expected changes in fuel costs and analyzing historical unit operation (i.e., capacity factors of CC and CT units). Below, I provided additional details on the market price data that I have used in order to conduct the analyses.

A summary of historical bilateral prices for Cinergy, Southern and TVA, as reported by Platts, is provided in workpapers. I escalated the historical data to 2006 using publicly available information on futures prices for natural gas and coal. These data points provided the initial basis for selecting a market price to review for each period. A summary of the capacity factors for CC and CTs in MISO and VACAR is also provided in workpapers. While the peaking facilities match well with the historical data, strict use of the historical data would result in mid-merit (CC) facilities operating at much higher levels than suggested by their historical operations. Therefore, I adjusted the Shoulder Peak price such that the implied capacity factors for mid-merit units are consistent with the historical data. I note also that by analyzing a broad range of prices, I ensure that there are no gaps in the various price segments to be analyzed. Further, I include in my workpapers a sensitivity analysis where prices are plus or minus 10 percent of my base case assumptions.

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21 Each entities tariff rate was retrieved from Platts. If an entity reported both on and off-peak prices, the on-peak rate was used. In instances where no data was available and in regions that no longer use control area to control area pricing, such as MRO, then a generic assumption of $2/MWh was applied.

In implementing transmission rates into the analysis, regardless of the transmission regime, it has been assumed that transmission charges would be incurred for the transmission system where the generator is located and for wheeling the power through intermediate systems, but not for the destination market. No transmission charge is included for the transmission system in which the load is located. This has no impact on the analysis, since including this charge (the transmission charge included in the bundled rate of the transmission provider in the area where the customer is located, or the "zonal" or postage stamp charges in the case of an RTO) would symmetrically raise the delivered cost for each supply to reach the destination market by the same amount. Thus, the relative economics would not be impacted.

II. DEFINING THE CORE GEOGRAPHIC MARKET

As described in Exhibit J-1, my base case analysis defines markets around the existing RTOs (MISO and PJM), and I evaluated alternative market definitions around Cinergy based on an analysis of congestion, market information provided by MISO, and the formal reports of the market monitors.[22] The relevant markets I analyzed include MISO, MISO Submarket and MISO-PJM Midwest. As detailed below, my analysis of congestion patterns suggests that the actual market is more expansive than MISO and includes much of the PJM RTO during most market conditions.

My analysis of the preliminary information from MISO and the MISO's State of the Market reports suggests that the minimum relevant geographic market is the MISO Submarket, that is a subset of the MISO that excludes the WUMS region (constrained away on the "high" side) and the Minnesota/Iowa region (constrained away on the "low" side).[23] Specifically, the MISO market monitor has identified two Narrowly Constrained Areas, WUMS and Northern WUMS, that are often constrained from the rest of MISO, and preliminary MISO price and constraint data appear to confirm this finding. The IMM used as a standard that the transmission flowgate or flowgates experience binding transmission constraints for at least 500 hours during a given year. While the evidence regarding constraints around the Minnesota/Iowa region does not rise to the same level as those around WUMS, my exclusion of these regions is conservative. In addition, a recent presentation by the IMM reports preliminary price data showing price separation between Minnesota, Cinergy, and WUMS (the IMM did not present comparable data for Iowa).[24]

I considered the extent of transmission congestion within MISO and PJM by examining TLRs called around Cinergy and MISO/PJM more generally. NERC is the official

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22 See, e.g., *2004 State of the Market Report, Midwest ISO,* June 2005.

23 That is, the data suggests that during the periods when WUMS is constrained away from the rest of MISO, the region is importing power and, therefore, has a higher price. The opposite is true for Minnesota/Iowa. Note that excluding WUMS from the broader market definition is conservative in that if an entity attempted to raise prices within the MISO market, suppliers selling into WUMS could respond and help to defeat any such attempt.

24 *Highlights of Midwest ISO: 2004 State of the Market Report and Day-2 Energy Markets*, June 22, 2005. Note that the IMM's report presented a limited amount of data, covering only the May 15 to June 8, 2005 period.

repository of information on TLRs called throughout the Eastern Interconnection.[25] The TLR procedure can be used to mitigate potential or actual transmission limits. Any transmission provider or control area that operates the relevant transmission element may request a TLR to be called by their reliability coordinator. TLR calls can be made at different levels, ranging from level 1, where the reliability coordinator foresees a potential operating problem within their reliability area, to level 6, which is considered an emergency situation.[26] TLR level 3a is the first stage at which transactions, non-firm in this case, are potentially curtailed.

I reviewed TLR events called by the various reliability coordinators from January 1, 2004 through April 2005. The NERC TLR database contains information that allows me to map each TLR event to the flowgate at issue and the control area(s) where the flowgates are located. A summary of the data, which reflects TLR events at levels 3a and above, is provided in workpapers.[27]

The TLR data are consistent with the finding of the MISO market monitor that there are non-trivial (*i.e.*, over 500 hours) amounts of transmission constraints around the WUMS region.[28] The data also reports less significant amounts of TLR calls in Minnesota and Iowa, some of which are related to the WUMS flowgates.[29]

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25 See https://www.nerc.net/crc/; user id and password required.

26 Level 1 notifies security coordinators of potential operating security limit violations. Level 2 places a hold in interchange transactions at current levels. Levels 3a and 3b implement curtailments of non-firm transactions in priority order. Level 4 calls for reconfiguring the transmission system to allow firm point-to-point service to continue. Level 5 requires curtailments of firm point-to-point service. Level 6 calls for implementing emergency procedures such as load shedding.

27 More specifically, NERC's website contains a historical database that includes all TLR events and lists the flowgate name and number, reliability coordinator, duration and level (for all TLRs level 3a and higher). NERC also maintains a "Book of Flowgates" that lists additional information on the defined flowgates, including the control area, transmission provider and reliability coordinator. These two databases can be combined to extract TLR events by reliability coordinator and control area.

The data in my workpapers is organized by the relevant reliability coordinator and the control area where the flowgate is located. For each flowgate, I have categorized the total number of calls and related duration of each call by month by peak and off-peak hours (assuming a 5X16 peak period). I have then summarized the data by the seasonal definitions used in the Delivered Price Test analysis (i.e., Summer, Winter and Shoulder seasons). The same data is also provided sorted by duration.

28 Most of the calls appear related to the Eau Claire-Arpin 345 kV element (listed as Eau-Claire-Arpin 345 KV and MWSI flowgate names). There are also significant amounts of TLR calls related to Paddock in

In other portions of MISO, however, the TLR data do not show a consistent pattern of TLR calls, particularly with respect to the broad area encompassing Missouri, Illinois, Indiana, Ohio, Michigan and parts of Kentucky and Pennsylvania. .[30]

In addition, the TLR data also allow for a review of constraints between MISO and the PJM, TVA and IMO regions. It appears that there were insignificant amounts of TLR calls between MISO and PJM. These limited and sporadic TLR calls support the assertion that a more narrowly defined market, such as former control areas, is not a separate relevant geographic market insofar as transmission constraints define markets. The TLR data do show more significant transmission constraints between MISO and the TVA and IMO regions (which are not included as part of the core geographic market in any of my analyses).

Thus, on the basis of these TLR data, the geographic market within the MISO and PJM RTOs appears to include the broad area extending from Missouri in the west to eastern Pennsylvania and down to Kentucky in the south during most system conditions.

Additional evidence on transmission constraints is contained in the MISO's daily market reports that list, for the day-ahead and real-time markets, binding constraints during the day.[31] The report provides the constraint name, start and end times, and the control area in

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southern Wisconsin and on the Flow South flowgate (in northern WUMS related to the Morgan-Plains elements).

29 For example, the Arnold-Hazelton 345 path in Alliant West is defined with respect to the loss of Wempletown-Paddock 345 in WUMS. The other MISO region that reported more than about 250 hours of TLR calls between January 2004 and April 2005 was LGE, which is also excluded from my alternative market definitions.

30 The exceptions are largely around Lake Michigan in northern Indiana (Dune Acres-Michigan City and Crete-St. Johns Tap 345 kV) and southern Missouri (St. Francis - Bland). According to the 2004 IMM report, the TLRs around Lake Michigan were due largely to the initial integration of AEP and ComEd into PJM, while the St. Francis – Lutesville calls all occurred during September and October in 2004. The data also show a number of TLR calls in 2004 within Cinergy, most of which are related to the Miami Fort 345 for the loss of East Bend–Terminal 345 flowgate. It is my understanding that these TLRs were related to a temporary transformer outage that has since been fixed and, therefore, I do not consider them evidence of systematic transmission constraints within the region. I do not have information if outages or other temporary issues may be driving the other TLR calls in the database. However, given the location and duration/nature of the other calls noted above, it appears that the broad area noted above is largely unaffected by TLR calls.

31 See http://www.midwestmarket.org/publish/Folder/10b1ff_101f945f78c_-75e70a48324a

which the constraint is located. I have reviewed the real-time data, which I believe is the most directly comparable to the NERC TLR data noted above, and found that the reported constraints are consistent with the historical TLR calls discussed noted above. A summary is provided in workpapers.

III. HISTORICAL PURCHASES AND SALES

My workpapers include a summary of Duke Power and Cinergy's historical purchases and sales as reported in their respective FERC Form 1s for 2003 and 2004.[32] I considered this data in order to determine whether there are other relevant geographic markets that should be examined. In brief, my analysis of the MISO, MISO Submarket, MISO-PJM Midwest markets, PJM, Duke Power and Duke Power's first-tier entities covers all of the relevant markets where both Cinergy and Duke Power have historically made more than a *de minimis* amount of sales. To the extent Cinergy or Duke Power individually had sales to additional customers, I determined that the markets I analyzed provided reasonably proxies for the impact of the merger on these customers.

For the FERC Form 1 data, the MWh reported in Cinergy's FERC Form 1 (for purchases and sales) are extremely large and appear to represent many buy and sell transactions. Therefore, I have calculated a "net" sales position for Cinergy and used this in my review of overlap between the two entities.[33] Sales data are reported in MWh in the FERC Form 1 and I also have calculated the average MW sold by each entity by dividing the MWh by hours (assuming 100 percent load factor).

I also have reviewed sales made by Duke Power and Cinergy (and their respective affiliates) as reported in the EQR. Specifically, in addition to the operating companies, the EQR data include sales made by affiliates, such as Cinergy Services and Duke Energy Marketing and Trading. I combined the sales reported by each of the affiliates and, again, calculated the average MW sold be each entity to each counter-party.[34]

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[32] For Cinergy, I have aggregated the data reported by Cinergy's three operating companies.

[33] All of the relevant FERC Form 1 data, however, are included in my workpapers.

[34] Note that I excluded Duke Energy's affiliates located in the Western Electricity Coordinating Council ("WECC") as well as sales from projects that are no longer owned by the companies.

IV. DOWNSTREAM VERTICAL ANALYSIS

A. Attributing Natural Gas-Fired Generating Units

Gas connections for generating units in the regions that I have modeled that use natural gas as their primary fuel source are determined in one of three ways:[35]

- Energy Planning, Inc.'s ("EPI") Directory of Natural Gas Customers provides the natural gas transportation information for over half of the electric generating units.
- Platts POWERdat and POWERmap databases provide the locations of the power plants, pipelines, and local distribution companies. In some cases, the locations of the gas generating units that are not included in Platts' database are determined from other public sources.
- The Applicants provide the connection information for the generating units to which their pipelines directly connect.

This information is used to attribute the generation of the natural gas units to the pipeline companies. The following set of rules determines the pipeline to which the units are attributed:

- If a power plant is directly connected to a pipeline, the capacity of the plant is attributed to the pipeline, unless the pipeline is jointly owned. If the pipeline is jointly owned, the capacity is conservatively attributed to the owner with the largest ownership share.
- If the power plant is directly connected to multiple pipelines owned by other companies (as determined from EPI), the plant's capacity is divided up in equal shares to the pipelines that are connected.
- If the power plant's most likely connection is determined by the mapping process, the entire capacity of the plant is attributed to that pipeline. If the pipeline connection cannot be determined by the mapping process, the capacity is assigned to the electricity owner.
- If the power plant is directly connected to a local distribution company, and there is a single pipeline connection to the LDC as listed in Brown's Directory of North American Gas Companies, the entire capacity of the plant is attributed to the pipeline serving the LDC. If there is no information on the pipeline(s) serving the LDC or if there are multiple pipelines listed, the capacity is assigned to the electricity owner.

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35 This is the same methodology that I have used in previous analyses accepted by the Commission, including the Duke–Westcoast merger.

Once the natural gas-fired units are attributed to the pipeline companies, the Economic Capacity analysis proceeds in a similar fashion to the horizontal (generation) analysis.

V. UPSTREAM VERTICAL ANALYSIS

For a given market definition, there are three broad steps required to develop market concentration statistics. The first step is to identify the physical pipeline assets serving the market. The second step is to identify the entities that potentially have ownership rights and control of that capacity. The final step is to allocate the total regional pipeline capacity to its owners and calculate market concentration statistics as measured by the HHI. Each step is described below.

A. Pipelines Serving Markets

The basic data for identifying pipelines serving each market comes from the EIA database of interstate pipeline capacity and flows at state borders.

For each market, I identified all pipelines flowing from outside the target region into the market area. Pipelines wholly contained within a market were excluded. In cases where a single pipeline flowed into a target market, exited the target market and re-entered the target market, I used a pipeline and service territory map to determine the border crossing that best represents the capacity provided to the market. Finally, I eliminated pipelines that had capacities of under 50 MMcf/d. These smaller pipelines often are laterals and gathering lines that do not provide substantial additional supplies to the market.

The total influent capacity into a target market was thus defined by the final set of pipelines serving that market. This capacity represents the total supply for the market.

B. Ownership Rights into a Market

Market shares for the HHI calculation are a function of this total regional capacity and how it is spread across suppliers to the region. The suppliers of capacity to a market are the companies that control capacity on those pipelines. Pipeline companies generally sell capacity rights to firm customers under long-term agreements. These firm customers have the first call on the pipeline capacity into a region and retain the option of selling their rights to a third party should conditions warrant. For the purposes of a market concentration analysis, shippers with firm capacity on the pipelines serving a market are the suppliers of gas to that market as it is those capacity holders that compete in the delivery of gas into downstream markets.

The primary source of data for identifying capacity holders is the FERC's Index of Customers, Form 549b, as reported by Platts. The Index includes key information for the analysis, including the customer names, the rate schedule associated with the contract, the quantity under contract and the delivery points associated with the contract volumes.

Identifying the holders of firm rights into a specific market, however, requires consolidating customers based on their corporate affiliations. I based this on Platt's data, *The Directory of Corporate Affiliations*, company websites and other public information.

Some interstate pipelines span long distances and, as a result, may sell firm rights for delivery to a number of different locations. Some customers hold capacity with delivery points upstream of the target market. Others may hold capacity downstream of the target market. I used the delivery point information included in the Index of Customers to identify the set of shippers that represent primary suppliers into the market.

I identified the location of each Index of Customer delivery point by state and county. Customers were classified into three categories: (i) those with delivery points in the market; (ii) those with delivery points downstream of the market and (iii) those with delivery points only upstream of the market.

The index of customers provides a snapshot of long-term firm contracts at a given point in time. While some contracts might have termination dates within a one-year period, it was not possible to evaluate any rights to continue these contracts. However, I did conduct a sensitivity analysis that eliminated contracts apparently expiring within the next twelve months. The results, which are included in my workpapers, did not alter any of my conclusions.

Shippers with only upstream reservations were excluded from the set of suppliers into the target market. The total capacity in a market was then allocated to firm customers - scarce pipeline capacity was allocated according to the rank order of capacity under contract with largest customers being served first. This provides a conservative ranking of customers' market share. In the cases where total firm entitlements inside and downstream of the market were less than the physical capacity on a given pipeline, the unclaimed capacity reverted back to the pipeline owner.

Market share is calculated as the total regional capacity entitlements divided by the total regional influent pipeline capacity.

COMPETITIVE ANALYSIS SCREENING MODEL (CASm)

Charles River Associate's Competitive Analysis Screening model ("CASm") is designed to perform the calculations required in order to conduct a market power analysis under Appendix A of the FERC Merger Policy Statement ("Order No. 592" or "Appendix A").[1] The delivered price test specified in Appendix A requires an analysis of market concentration for a large number of markets under a number of different conditions. CASm facilitates this process by performing the required calculations.

The primary requirement of Appendix A is to assess potential suppliers to a market using a "delivered price test". This test involves comparing variable generation costs plus delivery costs (transmission rates, transmission losses and ancillary services) to a "market price." If the delivered cost of generation is less than 105 percent of the market price, the generation is considered economic. Economic generation is further limited to the amount that can be delivered into the market, given transmission capability and constraints.

CASm implements the prescribed delivered price test by determining -- for each destination market, for each relevant time period, and for each relevant supply measure -- potential supply to the destination market both pre- and post-merger. In effect, CASm determines the relevant geographic market by applying the delivered price test, based on the economics of production and delivery (transmission rates, transmission losses and ancillary services), and also based on the physical transmission capacity available to the competing suppliers on an open access basis. This requires a delivery route for the energy on the established transmission paths, each of which has a capability, transmission rate and transmission losses associated with it. CASm finds the supply that can be delivered to the destination market consistent with cost minimization and the delivered price test.

As a formal matter, CASm minimizes the production and transmission costs of supplying demand in the destination market. Any shortfall in demand is filled by a hypothetical generator located in the destination market that can produce an unlimited amount of energy at 105 percent of the market price. On this basis, any supplier who can profitably supply energy to the destination market will do so, to the maximum extent that their cost structure and the transmission system allow. This formulation ensures that no supplied generation is uneconomic; the hypothetical generator will undercut all such suppliers.

CASm determines pre- and post-merger market shares and calculates concentration (as measured by the Herfindahl-Hirschman Index, or HHI) and the change in HHIs.

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[1] CASm was developed under the direction of CRA employees while employed by Putnam, Hayes & Bartlett and PHB-Hagler Bailly, and has been used in analyzing numerous mergers and power plant acquisitions in proceedings before the Commission.

To undertake these analyses, CASm solves a series of scenarios involving a network of interconnected suppliers. By limiting suppliers based on the economics of generation and delivery, or by limiting the interconnections between those suppliers based on the transmission capability, each Appendix A analysis can be completed. CASm includes a simplified depiction of the transmission system, essentially a system of "pipes" with independent, fixed capacity between and among utilities.

The following sections describe:

- What data inputs are required to operate CASm
- How different analyses are undertaken in CASm
- What outputs CASm produces; and
- How CASm is implemented.

INPUT DATA

Market Participants

The largest element of the required data for CASm relates to individual market participants, which generally are utilities with both generating capacity and load obligations. In addition, some market participants may have load obligations but no generating capacity (e.g., transmission dependent utilities, or TDUs) or have generating capacity but no load obligations (e.g., merchant capacity). CASm regards all distinct market participants as having the ability to both supply and consume electricity. The particular circumstances of each analysis will determine the extent to which each activity is possible.

Nodes

In CASm, a node is a location where electricity is generated or consumed, or where it may "split" or change direction. All market participants are defined as having a unique node, and hence unique location in the transportation network. Total simultaneous import limits can be imposed at each node to mirror reliability restrictions.

Output Capability

Each market participant may have generating ability, which is defined generically in terms of any number of "tranches" of generation having both a quantity (MW) and dispatch cost ($/MWh). This output capability and cost may differ over time, for example because of planned and unplanned outage rates and fuel prices. CASm has a number of data inputs available for modifying the underlying physical availability of generating assets to get the relevant "supply curve" for any given model period.

Destination Market Prices

For each destination market, a prevailing market price is defined. The destination market price is used to calculate a threshold price that potential suppliers must meet to be included in the market for economic-based analyses (that is, the "delivered price test").

Interconnections

Interconnections represent the network that links market participants together. These interconnections are represented as a "transportation" network, where flows are specifically directed.

Lines

A line between two nodes in CASm may represent either a single line, or the combined effect of a number of lines. Each line has an upper limit on the flow, and losses may occur on the line. Since capacity on the line may represent physical limits less firm commitments, limits are allowed to be different, depending on the direction of the flow. Limits on the simultaneous flow on combinations of lines can be imposed to simulate the effect of loopflow or reliability constraints either by specifying a set of lines to jointly limit or by limiting the overall amount of supply that can be injected into a Node (a "nomogram" limit).

Scenarios

The final input area for CASm is related to scenario definition. Scenarios define which parties are considering merging, which load periods are relevant, and so on. In effect, the scenarios define a number of individual analyses to be performed, and how they should be compared to each other for reporting purposes.

Accounting for Ownership

It is sometimes necessary to merge the results for several nodes, or to split them, based on ownership changes between scenarios. CASm has a "report as" function that will merge the results of several nodes into a single one to correctly account for ownership. Also, CASm may "impute" all or part of any tranche in the supply curve of a node to any other node to account for shared ownership. This feature is used by CASm for vertical market analysis.

REQUIRED CALCULATIONS

Appendix A's delivered price test defines two different supply measures to evaluate:

- **Economic Capacity** is the amount of capacity that can reach a market at a cost (including transmission rates, transmission losses and ancillary services) no more than 105 percent of the destination market price.

- **Available Economic Capacity** is the amount of Economic Capacity that is available after serving native load and other net firm commitments with the lowest cost units.

For every analysis, the following process is undertaken:

First, a Linear Programming (LP) problem is solved. The LP construction is slightly different, depending on the underlying assumptions of each of the supply measures. CASm includes two options for allocating scarce transmission capacity. CASm has a "proration" option, which is called "squeeze-down". This is discussed in detail below. Another option is an economic allocation of limited transfer capability. Under this option, where available supply exceeds the ability of the network to deliver that capacity to the destination market, the least-cost supply is allocated the available transmission capacity.[2] Since this analysis assumed no import capacity, there is no need to allocate scarce transmission capacity and the economic allocation methodology was used.

The final step involves calculating what can be delivered to the destination market, after accounting for line losses. CASm allocates total system losses amongst suppliers on the basis on how much they injected, and how far away (how many wheels) they are from the destination market.

Economic Capacity

For the Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity[3], for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

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[2] CASm can be modified to apply different proration methods when appropriate for some analyses.

[3] Available quantity may be modified. See discussion in the Output Capacity section.

sum over lines (flow * simultaneous factor) <= simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) <= flowgate limit, for all limits

The objective is slightly different when transmission capacity is to be prorated. The objective then becomes:

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

And, where ownership imputation is being used, the following constraints are added:

sum over economic[4] tranches <= imputed share of economic tranches, for all owners at each imputed node

Available Economic Capacity

For the Available Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity (less native load), for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

sum over lines (flow * simultaneous factor) <= simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) <= flowgate limit, for all limits

This is different from the economic capacity analysis only to the extent that potential suppliers are required to meet their load obligations prior to participating in the market.

When transmission capacity is to be prorated the objective becomes:

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4 Economic tranches are those that can deliver to the destination within 105% of the market price.

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

And, where ownership imputation is being used, the following constraints are added:

> sum over economic tranches <= imputed share of economic tranches, for all owners at each imputed node

OUTPUTS

The primary output from CASm is a report that summarizes the results of different analyses. For each destination market, load period and FERC analysis type, CASm reports the following for both pre- and post-merger:

- Supplied MW
- Market Share
- HHIs

This report also shows the change in HHIs post-merger compared to pre-merger.

CASm also produces a transmission report that shows the detail of each node, and the injections and flows between them. Finally, a summary of the results for each market is also produced.

"SQUEEZE-DOWN" PRORATION

In the "squeeze-down" proration algorithm, prorated shares on each line are based on the weighted shares of deliverable energy at the source node for that line. As discussed more fully below, weighted shares at the destination market node are calculated by a recursive algorithm that starts at the "outside" of the network, then calculating shares on each line until it reaches the "middle". Specifically, where available supply exceeds the ability of the network to deliver that capacity to the destination market, suppliers are allocated shares at each node, and hence each outgoing line, based on the results of an algorithm that considers both supply and transfer capability at each node. Starting at the "outside" of the network, CASm calculates a share at each node that is based on a proportion of the incoming transfer capability (and the share of that capability allocated to each supplier), and the maximum economic supply available at that node. When the algorithm reaches the destination market, a total share of the incoming transfer capability has been determined.

This algorithm requires that all possible paths are simultaneously feasible, which, in turn, requires that each line be assigned a unique "direction". The steps of the proration algorithm include:

1. A C++ program enumerates all possible paths to the destination, the cost of transmission on each path and the maximum possible flow on the path. A "wheel limit", or maximum number of point-to-point links, may be imposed on paths.

2. The minimum "entry cost" for each supplier is calculated. This cost is the injection cost of the cheapest generator that has capacity for possible delivery to the destination.

3. Paths for which the entry cost plus the transmission cost are higher than 105% of the destination market price are rejected as being uneconomic.

4. To the extent remaining paths are not simultaneously feasible (because, for example, suppliers can seek to use the paths in both directions), a series of decision rules for determining the direction of the line are undertaken (in the following order):

    - Instructions can be manually input as to the chosen direction of a line.

    - Merger-case decisions should be consistent with base-case decisions.

    - The direction of the line as determined in an economic allocation of available transmission is applied.

    - The direction heading toward a destination market, if it is clear, is chosen.

    - The direction that retains the maximum potential volume-weighted flow on the line (calculated from the paths that depend on this line) is chosen.

    - The direction on which the maximum number of economic paths depend is chosen.

If these other options fail to reach a feasible solution, manual input will be required.

5. If there are simultaneous limits, they are checked for feasibility. All lines that have a worsening effect on a simultaneous constraint, given their defined flow direction, are checked against the simultaneous limit. If they would exceed the simultaneous limit if fully utilized, then their maximum capacity is prorated downwards in proportion to their respective limit participation factors. In this way, no set of targets will be produced that could not be delivered in a way that is feasible with the simultaneous limits.

6. Proration begins at nodes furthest from the destination market (where only exports, and no imports are being attempted). Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability.

7. Proration continues at the next set of nodes, that should consist only of nodes with inflows from "resolved" nodes from step 5. Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability. Suppliers from the "resolved" nodes have their shares scaled down to match the transmission capacity into the node.

8. To the extent an iteration of the algorithm does not resolve any additional nodes and the destination market has not yet been reached (i.e., a loop is detected), flow is disallowed from any unresolved node to the furthest and smallest node affected by a loop.

9. The proration has been completed when the destination market node has been resolved. At that point, the "shares" at the destination market represent the prorated shares of deliverable energy.

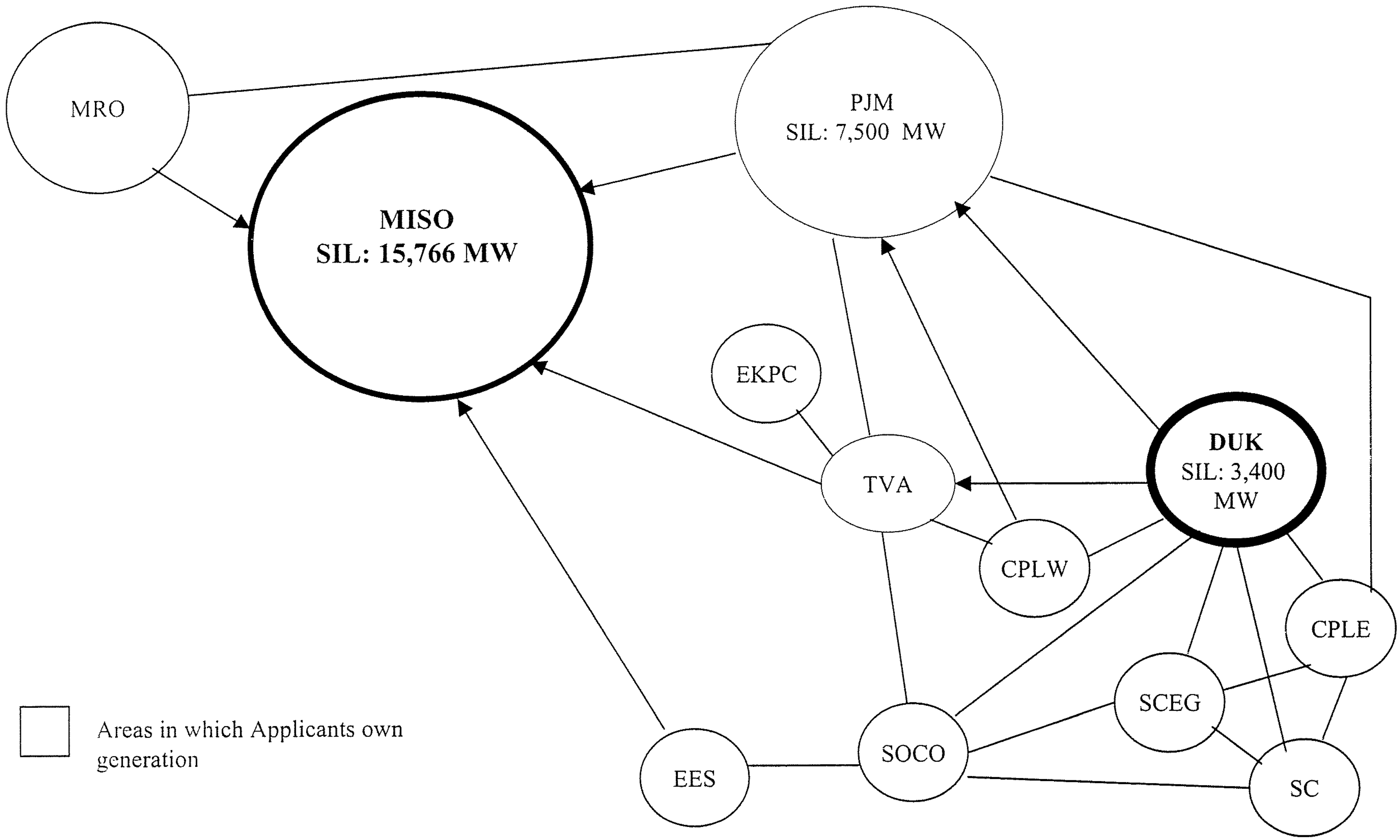
10. If ownership at a node is to be "imputed", or credited to another node, further proration targets are calculated. First, only those tranches that can deliver to the destination within 105% of the market price are considered. A factor representing the share each owner has of these economic tranches is calculated. For each owner, a constraint is calculated that limits the sum of injections attributed to that owner to be not more than that owner's "share" of the target calculated above. In this way, the proportion of ownership of economic capacity at a node is fairly reflected in the final solution outcome.

11. Injections for each supplier are "capped" at the calculated shares, and these injections are then checked for economic feasibility. While suppliers need not deliver their energy to the destination in exactly the way that their share was calculated, the solution is still both economically and physically feasible. The final solution represents the least-cost method of delivering these supplies.

CASM IMPLEMENTATION

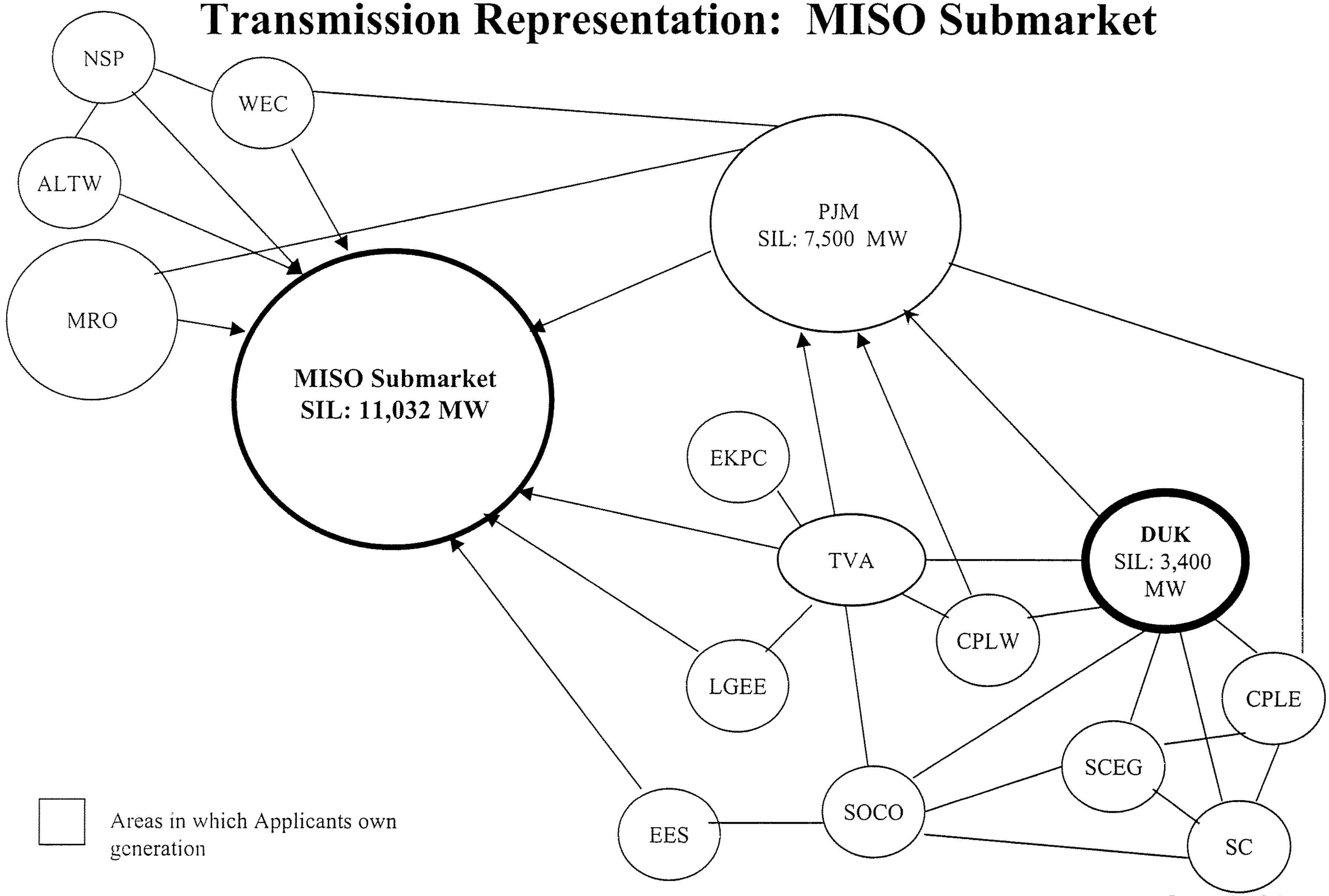
CASm has been implemented using GAMS (Generalized Algebraic Modeling System). GAMS is a programming language which supports both data manipulation and calls to many mainstream mathematical modeling systems. The linear programming problems generated by CASm are solved by BDMLP. The path enumeration program has been written in Microsoft Visual C++ version 5.

Transmission Representation: MISO Market



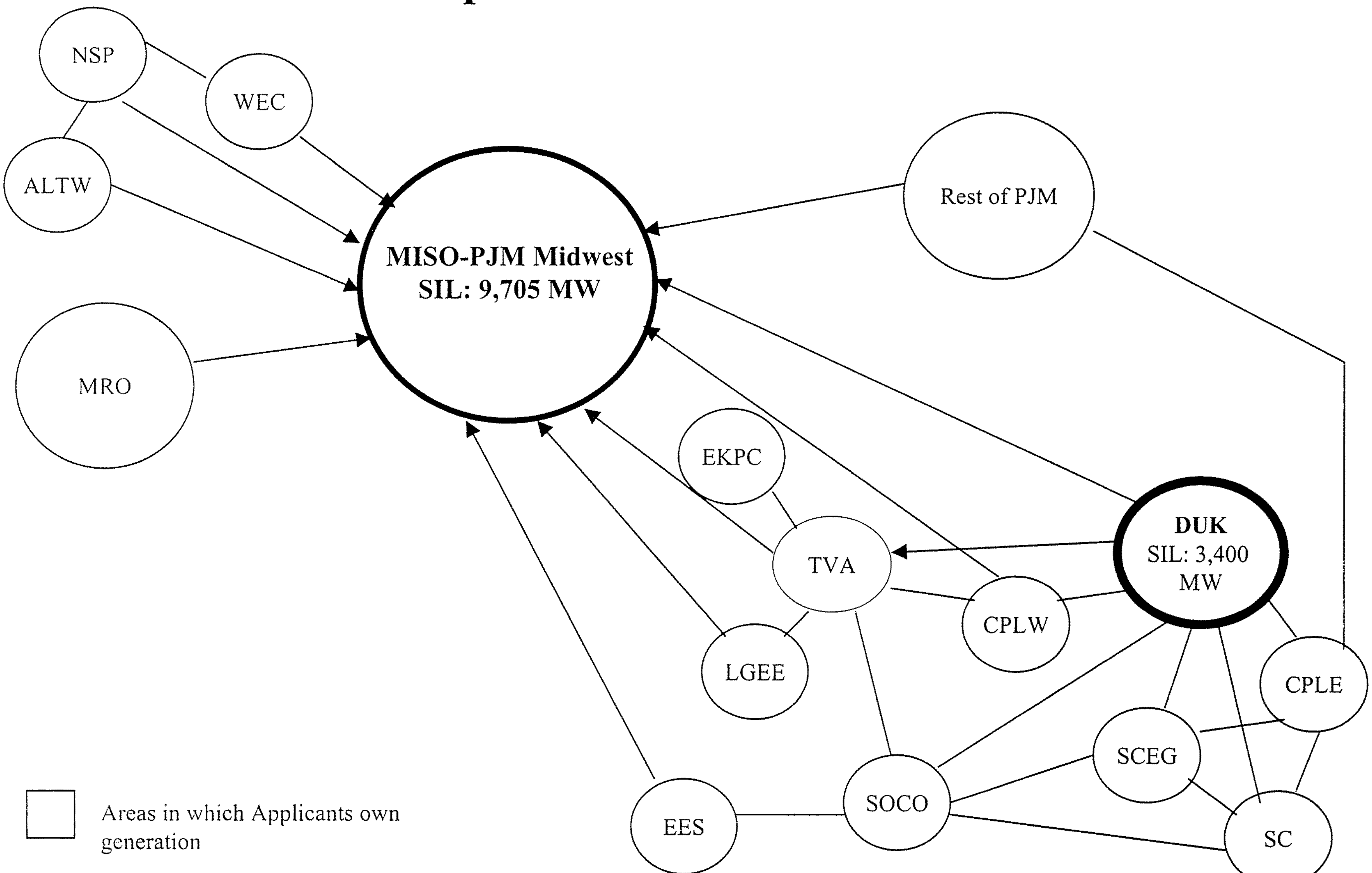
SILs are summer ratings. Not all interconnections/SILs shown.

Transmission Representation: MISO Submarket



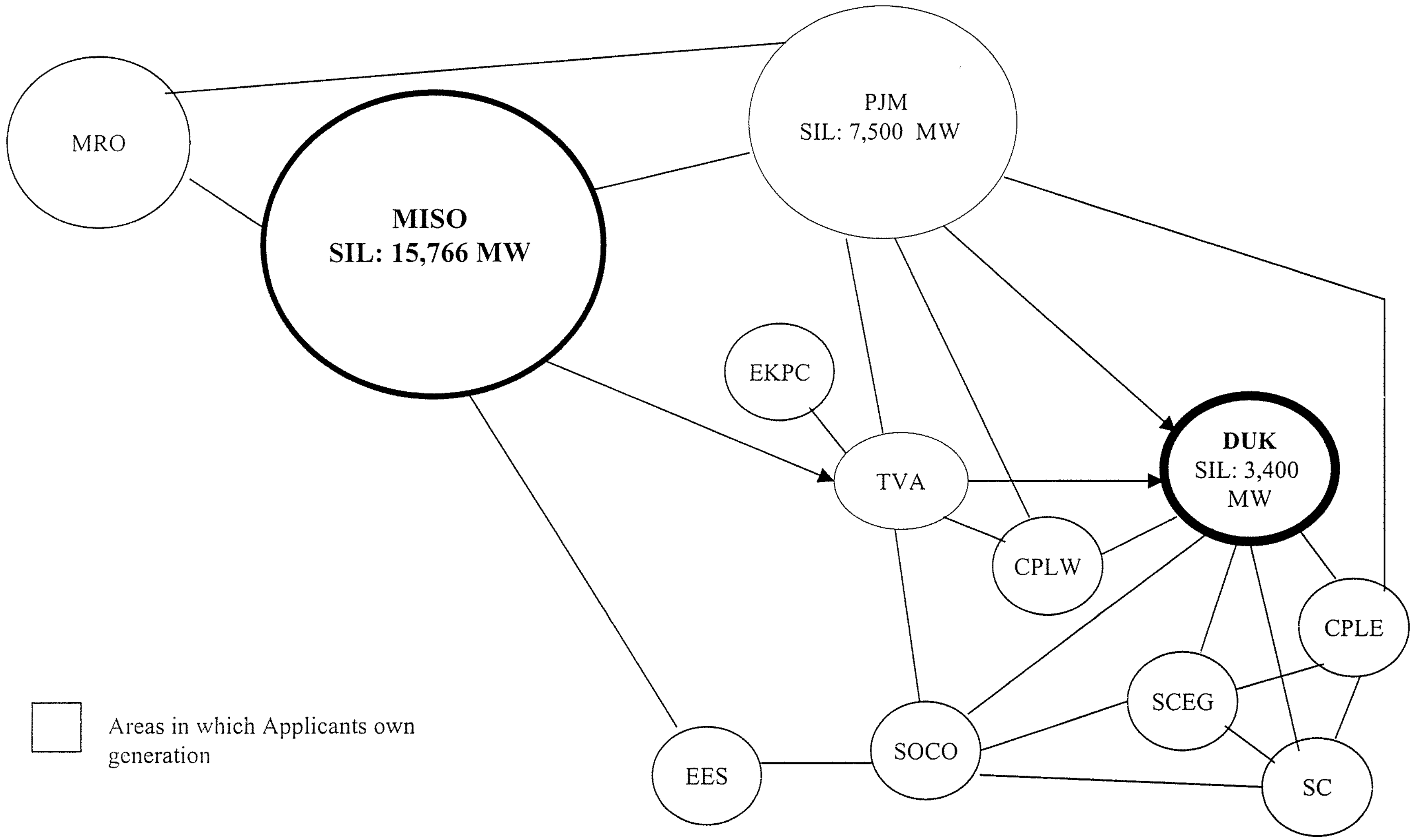
SILs are summer ratings. Not all interconnections/SILs shown..

Transmission Representation: MISO-PJM Midwest Market



SILs are summer ratings. Not all interconnections/SILs shown.

Transmission Representation: DUK Market



Areas in which Applicants own generation

SILs are summer ratings. Not all interconnections/SILs shown.

Economic Capacity

MISO

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
MISO	S_SP1	$250	11,676	8.4%	635	0.5%	138,877	510	12,311	8.9%	518	8
MISO	S_SP2	$80	10,594	8.3%	689	0.5%	128,335	509	11,283	8.8%	518	9
MISO	S_P	$60	9,500	8.7%	341	0.3%	109,407	516	9,840	9.0%	521	5
MISO	S_OP	$30	7,967	8.5%	185	0.2%	94,006	566	8,152	8.7%	569	3
MISO	W_SP	$85	10,850	8.3%	789	0.6%	130,281	508	11,639	8.9%	518	10
MISO	W_P	$65	9,591	8.8%	267	0.2%	109,342	513	9,858	9.0%	517	4
MISO	W_OP	$40	9,577	9.7%	94	0.1%	98,934	556	9,671	9.8%	557	1
MISO	SH_SP	$75	7,509	7.5%	347	0.4%	99,672	480	7,856	7.9%	485	5
MISO	SH_P	$50	7,491	9.1%	206	0.3%	82,702	517	7,698	9.3%	522	5
MISO	SH_OP	$35	6,998	8.7%	234	0.3%	80,309	515	7,232	9.0%	520	5

			Pre-Merger						Post-Merger with 100 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO	S_SP1	$250	11,676	8.4%	635	0.5%	138,877	510	12,411	8.9%	519	9
MISO	S_SP2	$80	10,594	8.3%	689	0.5%	128,335	509	11,383	8.9%	519	10
MISO	S_P	$60	9,500	8.7%	341	0.3%	109,407	516	9,940	9.1%	523	7
MISO	S_OP	$30	7,967	8.5%	185	0.2%	94,006	566	8,252	8.8%	571	5
MISO	W_SP	$85	10,850	8.3%	789	0.6%	130,281	508	11,739	9.0%	519	11
MISO	W_P	$65	9,591	8.8%	267	0.2%	109,342	513	9,958	9.1%	519	6
MISO	W_OP	$40	9,577	9.7%	94	0.1%	98,934	556	9,771	9.9%	560	4
MISO	SH_SP	$75	7,509	7.5%	347	0.4%	99,672	480	7,956	8.0%	487	7
MISO	SH_P	$50	7,491	9.1%	206	0.3%	82,702	517	7,798	9.4%	524	7
MISO	SH_OP	$35	6,998	8.7%	234	0.3%	80,309	515	7,332	9.1%	522	7

			Pre-Merger						Post-Merger with 250 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO	S_SP1	$250	11,676	8.4%	635	0.5%	138,877	510	12,561	9.0%	521	11
MISO	S_SP2	$80	10,594	8.3%	689	0.5%	128,335	509	11,533	9.0%	521	12
MISO	S_P	$60	9,500	8.7%	341	0.3%	109,407	516	10,090	9.2%	526	10
MISO	S_OP	$30	7,967	8.5%	185	0.2%	94,006	566	8,402	8.9%	574	8
MISO	W_SP	$85	10,850	8.3%	789	0.6%	130,281	508	11,889	9.1%	522	14
MISO	W_P	$65	9,591	8.8%	267	0.2%	109,342	513	10,108	9.2%	521	8
MISO	W_OP	$40	9,577	9.7%	94	0.1%	98,934	556	9,921	10.0%	563	7
MISO	SH_SP	$75	7,509	7.5%	347	0.4%	99,672	480	8,106	8.1%	489	9
MISO	SH_P	$50	7,491	9.1%	206	0.3%	82,702	517	7,948	9.6%	527	10
MISO	SH_OP	$35	6,998	8.7%	234	0.3%	80,309	515	7,482	9.3%	526	11

Exhibit J-8

Economic Capacity

MISO Submarket

			Pre-Merger							Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger		Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
MISO Submarket	S_SP1	$250	11,664	12.2%	570	0.6%	95,778	814		12,233	12.8%	828	14
MISO Submarket	S_SP2	$80	10,582	11.8%	602	0.7%	89,513	809		11,183	12.5%	824	15
MISO Submarket	S_P	$60	9,500	12.5%	199	0.3%	75,947	814		9,698	12.8%	821	7
MISO Submarket	S_OP	$30	7,967	12.3%	107	0.2%	64,998	920		8,075	12.4%	924	4
MISO Submarket	W_SP	$85	10,837	11.9%	709	0.8%	91,331	806		11,545	12.6%	824	18
MISO Submarket	W_P	$65	9,591	12.6%	204	0.3%	76,218	813		9,795	12.9%	820	7
MISO Submarket	W_OP	$40	9,577	13.9%	120	0.2%	69,164	901		9,697	14.0%	906	5
MISO Submarket	SH_SP	$75	7,502	10.9%	241	0.4%	68,815	766		7,743	11.3%	774	8
MISO Submarket	SH_P	$50	7,491	13.0%	80	0.1%	57,664	833		7,571	13.1%	836	3
MISO Submarket	SH_OP	$35	6,998	12.5%	151	0.3%	55,901	825		7,149	12.8%	832	7

			Pre-Merger							Post-Merger with 100 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger		Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO Submarket	S_SP1	$250	11,664	12.2%	570	0.6%	95,778	814		12,333	12.9%	831	17
MISO Submarket	S_SP2	$80	10,582	11.8%	602	0.7%	89,513	809		11,283	12.6%	828	19
MISO Submarket	S_P	$60	9,500	12.5%	199	0.3%	75,947	814		9,798	12.9%	824	10
MISO Submarket	S_OP	$30	7,967	12.3%	107	0.2%	64,998	920		8,175	12.6%	928	8
MISO Submarket	W_SP	$85	10,837	11.9%	709	0.8%	91,331	806		11,645	12.8%	827	21
'ISO Submarket	W_P	$65	9,591	12.6%	204	0.3%	76,218	813		9,895	13.0%	823	10
.ISO Submarket	W_OP	$40	9,577	13.9%	120	0.2%	69,164	901		9,797	14.2%	910	9
MISO Submarket	SH_SP	$75	7,502	10.9%	241	0.4%	68,815	766		7,843	11.4%	777	11
MISO Submarket	SH_P	$50	7,491	13.0%	80	0.1%	57,664	833		7,671	13.3%	841	8
MISO Submarket	SH_OP	$35	6,998	12.5%	151	0.3%	55,901	825		7,249	13.0%	836	11

			Pre-Merger							Post-Merger with 250 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger		Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO Submarket	S_SP1	$250	11,664	12.2%	570	0.6%	95,778	814		12,483	13.0%	835	21
MISO Submarket	S_SP2	$80	10,582	11.8%	602	0.7%	89,513	809		11,433	12.8%	832	23
MISO Submarket	S_P	$60	9,500	12.5%	199	0.3%	75,947	814		9,948	13.1%	829	15
MISO Submarket	S_OP	$30	7,967	12.3%	107	0.2%	64,998	920		8,325	12.8%	934	14
MISO Submarket	W_SP	$85	10,837	11.9%	709	0.8%	91,331	806		11,795	12.9%	831	25
MISO Submarket	W_P	$65	9,591	12.6%	204	0.3%	76,218	813		10,045	13.2%	828	15
MISO Submarket	W_OP	$40	9,577	13.9%	120	0.2%	69,164	901		9,947	14.4%	916	15
MISO Submarket	SH_SP	$75	7,502	10.9%	241	0.4%	68,815	766		7,993	11.6%	782	16
MISO Submarket	SH_P	$50	7,491	13.0%	80	0.1%	57,664	833		7,821	13.6%	848	15
MISO Submarket	SH_OP	$35	6,998	12.5%	151	0.3%	55,901	825		7,399	13.2%	843	18

Economic Capacity

MISO-PJM Midwest Market

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO-PJM Midwest	S_SP1	$250	11,715	6.5%	4,387	2.5%	179,158	587	16,102	9.0%	619	32
MISO-PJM Midwest	S_SP2	$80	10,637	6.2%	4,442	2.6%	171,479	603	15,079	8.8%	635	32
MISO-PJM Midwest	S_P	$60	9,500	6.6%	3,234	2.2%	145,113	664	12,734	8.8%	693	29
MISO-PJM Midwest	S_OP	$30	7,967	6.9%	849	0.7%	115,961	718	8,817	7.6%	728	10
MISO-PJM Midwest	W_SP	$85	10,897	6.3%	4,830	2.8%	174,443	602	15,728	9.0%	637	35
MISO-PJM Midwest	W_P	$65	9,591	6.6%	3,373	2.3%	146,015	665	12,964	8.9%	696	31
MISO-PJM Midwest	W_OP	$40	9,577	7.3%	950	0.7%	130,911	743	10,527	8.0%	753	10
MISO-PJM Midwest	SH_SP	$75	7,529	5.7%	3,314	2.5%	131,770	620	10,844	8.2%	649	29
MISO-PJM Midwest	SH_P	$50	7,491	6.9%	1,168	1.1%	108,290	693	8,659	8.0%	708	15
MISO-PJM Midwest	SH_OP	$35	6,998	6.6%	856	0.8%	105,618	705	7,854	7.4%	715	10

			Pre-Merger						Post-Merger with 100 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO-PJM Midwest	S_SP1	$250	11,715	6.5%	4,387	2.5%	179,158	587	16,202	9.0%	620	33
MISO-PJM Midwest	S_SP2	$80	10,637	6.2%	4,442	2.6%	171,479	603	15,179	8.9%	636	33
MISO-PJM Midwest	S_P	$60	9,500	6.6%	3,234	2.2%	145,113	664	12,834	8.8%	694	30
MISO-PJM Midwest	S_OP	$30	7,967	6.9%	849	0.7%	115,961	718	8,917	7.7%	729	11
MISO-PJM Midwest	W_SP	$85	10,897	6.3%	4,830	2.8%	174,443	602	15,828	9.1%	638	36
MISO-PJM Midwest	W_P	$65	9,591	6.6%	3,373	2.3%	146,015	665	13,064	8.9%	697	32
MISO-PJM Midwest	W_OP	$40	9,577	7.3%	950	0.7%	130,911	743	10,627	8.1%	755	12
MISO-PJM Midwest	SH_SP	$75	7,529	5.7%	3,314	2.5%	131,770	620	10,944	8.3%	650	30
MISO-PJM Midwest	SH_P	$50	7,491	6.9%	1,168	1.1%	108,290	693	8,759	8.1%	709	16
MISO-PJM Midwest	SH_OP	$35	6,998	6.6%	856	0.8%	105,618	705	7,954	7.5%	717	12

			Pre-Merger						Post-Merger with 250 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO-PJM Midwest	S_SP1	$250	11,715	6.5%	4,387	2.5%	179,158	587	16,352	9.1%	622	35
MISO-PJM Midwest	S_SP2	$80	10,637	6.2%	4,442	2.6%	171,479	603	15,329	8.9%	638	35
MISO-PJM Midwest	S_P	$60	9,500	6.6%	3,234	2.2%	145,113	664	12,984	8.9%	696	32
MISO-PJM Midwest	S_OP	$30	7,967	6.9%	849	0.7%	115,961	718	9,067	7.8%	731	13
MISO-PJM Midwest	W_SP	$85	10,897	6.3%	4,830	2.8%	174,443	602	15,978	9.2%	639	37
MISO-PJM Midwest	W_P	$65	9,591	6.6%	3,373	2.3%	146,015	665	13,214	9.0%	698	33
MISO-PJM Midwest	W_OP	$40	9,577	7.3%	950	0.7%	130,911	743	10,777	8.2%	757	14
MISO-PJM Midwest	SH_SP	$75	7,529	5.7%	3,314	2.5%	131,770	620	11,094	8.4%	652	32
MISO-PJM Midwest	SH_P	$50	7,491	6.9%	1,168	1.1%	108,290	693	8,909	8.2%	712	19
MISO-PJM Midwest	SH_OP	$35	6,998	6.6%	856	0.8%	105,618	705	8,104	7.7%	719	14

Economic Capacity

DUK Market

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
DUK	S_SP1	$250	6	0.0%	17,747	75.0%	23,677	5,709	17,752	75.0%	5,713	4
DUK	S_SP2	$80	6	0.0%	16,357	73.5%	22,268	5,497	16,363	73.5%	5,501	4
DUK	S_P	$60	6	0.0%	13,060	71.3%	18,311	5,223	13,066	71.4%	5,228	5
DUK	S_OP	$30	11	0.1%	9,041	63.2%	14,312	4,220	9,052	63.3%	4,229	9
DUK	W_SP	$85	5	0.0%	16,856	76.1%	22,138	5,897	16,862	76.2%	5,901	4
DUK	W_P	$65	5	0.0%	12,938	73.7%	17,558	5,574	12,942	73.7%	5,578	4
DUK	W_OP	$40	6	0.0%	11,977	72.1%	16,614	5,364	11,983	72.1%	5,370	6
DUK	SH_SP	$75	9	0.0%	14,022	66.7%	21,025	4,561	14,031	66.7%	4,567	6
DUK	SH_P	$50	14	0.1%	10,366	61.9%	16,738	4,005	10,379	62.0%	4,015	10
DUK	SH_OP	$35	14	0.1%	9,295	59.3%	15,667	3,724	9,309	59.4%	3,734	10

			Pre-Merger						Post-Merger with 100 MW Integration Path to MISO			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
DUK	S_SP1	$250	6	0.0%	17,747	75.0%	23,677	5,709	17,652	74.6%	17,693	(59)
DUK	S_SP2	$80	6	0.0%	16,357	73.5%	22,268	5,497	16,263	73.0%	16,302	(61)
DUK	S_P	$60	6	0.0%	13,060	71.3%	18,311	5,223	12,966	70.8%	12,993	(73)
DUK	S_OP	$30	11	0.1%	9,041	63.2%	14,312	4,220	8,952	62.5%	8,973	(79)
DUK	W_SP	$85	5	0.0%	16,856	76.1%	22,138	5,897	16,762	75.7%	16,798	(64)
DUK	W_P	$65	5	0.0%	12,938	73.7%	17,558	5,574	12,842	73.1%	12,863	(79)
DUK	W_OP	$40	6	0.0%	11,977	72.1%	16,614	5,364	11,883	71.5%	11,902	(81)
DUK	SH_SP	$75	9	0.0%	14,022	66.7%	21,025	4,561	13,931	66.3%	13,974	(57)
DUK	SH_P	$50	14	0.1%	10,366	61.9%	16,738	4,005	10,279	61.4%	10,315	(64)
DUK	SH_OP	$35	14	0.1%	9,295	59.3%	15,667	3,724	9,209	58.8%	9,244	(65)

			Pre-Merger						Post-Merger with 250 MW Integration Path to MISO			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
DUK	S_SP1	$250	6	0.0%	17,747	75.0%	23,677	5,709	17,502	73.9%	17,599	(153)
DUK	S_SP2	$80	6	0.0%	16,357	73.5%	22,268	5,497	16,113	72.4%	16,204	(159)
DUK	S_P	$60	6	0.0%	13,060	71.3%	18,311	5,223	12,816	70.0%	12,878	(188)
DUK	S_OP	$30	11	0.1%	9,041	63.2%	14,312	4,220	8,802	61.5%	8,843	(209)
DUK	W_SP	$85	5	0.0%	16,856	76.1%	22,138	5,897	16,612	75.0%	16,695	(167)
DUK	W_P	$65	5	0.0%	12,938	73.7%	17,558	5,574	12,692	72.3%	12,739	(203)
DUK	W_OP	$40	6	0.0%	11,977	72.1%	16,614	5,364	11,733	70.6%	11,773	(210)
DUK	SH_SP	$75	9	0.0%	14,022	66.7%	21,025	4,561	13,781	65.5%	13,880	(151)
DUK	SH_P	$50	14	0.1%	10,366	61.9%	16,738	4,005	10,129	60.5%	10,206	(173)
DUK	SH_OP	$35	14	0.1%	9,295	59.3%	15,667	3,724	9,059	57.8%	9,132	(177)

Exhibit J-8

Economic Capacity

First-Tier Control Area Markets

Market	Period	Price	Pre-Merger Cinergy MW	Pre-Merger Cinergy Mkt Share	Pre-Merger Duke MW	Pre-Merger Duke Mkt Share	Pre-Merger Market Size	Pre-Merger HHI Pre-Merger	Post-Merger Combined MW	Post-Merger Combined Mkt Share	Post-Merger HHI Post-Merger	Post-Merger HHI Change
CPLE	S_SP1	$250	34	0.2%	830	5.5%	15,023	5,331	864	5.8%	5,334	3
CPLE	S_SP2	$80	38	0.3%	819	5.8%	14,073	5,074	857	6.1%	5,077	3
CPLE	S_P	$60	46	0.4%	801	6.7%	12,009	4,410	848	7.1%	4,415	5
CPLE	S_OP	$30	67	0.9%	761	9.8%	7,773	2,435	828	10.7%	2,452	17
CPLE	W_SP	$85	61	0.4%	1,411	8.1%	17,430	3,639	1,473	8.5%	3,645	6
CPLE	W_P	$65	77	0.5%	1,367	9.1%	15,110	2,973	1,444	9.6%	2,982	9
CPLE	W_OP	$40	98	0.7%	1,393	9.2%	15,090	2,979	1,491	9.9%	2,991	12
CPLE	SH_SP	$75	48	0.4%	860	6.9%	12,491	4,256	909	7.3%	4,261	5
CPLE	SH_P	$50	67	0.6%	819	7.5%	10,860	3,624	887	8.2%	3,633	9
CPLE	SH_OP	$35	66	0.6%	838	8.0%	10,433	3,445	904	8.7%	3,455	10

Market	Period	Price	Pre-Merger Cinergy MW	Pre-Merger Cinergy Mkt Share	Pre-Merger Duke MW	Pre-Merger Duke Mkt Share	Pre-Merger Market Size	Pre-Merger HHI Pre-Merger	Post-Merger Combined MW	Post-Merger Combined Mkt Share	Post-Merger HHI Post-Merger	Post-Merger HHI Change
CPLW	S_SP1	$250	10	0.6%	238	13.3%	1,796	2,428	249	13.9%	2,443	15
CPLW	S_SP2	$80	11	0.6%	230	12.8%	1,796	2,419	242	13.5%	2,435	16
CPLW	S_P	$60	10	0.7%	215	15.8%	1,360	1,290	225	16.6%	1,313	23
CPLW	S_OP	$30	14	1.5%	167	16.9%	990	740	182	18.4%	790	50
CPLW	W_SP	$85	9	0.6%	171	11.1%	1,534	3,061	179	11.7%	3,073	12
CPLW	W_P	$65	7	0.7%	160	14.2%	1,125	1,690	168	14.9%	1,708	18
CPLW	W_OP	$40	9	0.8%	150	13.3%	1,125	1,684	159	14.2%	1,706	22
CPLW	SH_SP	$75	10	0.6%	226	13.6%	1,660	1,842	236	14.2%	1,859	17
CPLW	SH_P	$50	15	1.1%	203	15.1%	1,345	1,055	218	16.2%	1,088	33
CPLW	SH_OP	$35	14	1.1%	203	15.1%	1,344	1,065	218	16.2%	1,097	32

Market	Period	Price	Pre-Merger Cinergy MW	Pre-Merger Cinergy Mkt Share	Pre-Merger Duke MW	Pre-Merger Duke Mkt Share	Pre-Merger Market Size	Pre-Merger HHI Pre-Merger	Post-Merger Combined MW	Post-Merger Combined Mkt Share	Post-Merger HHI Post-Merger	Post-Merger HHI Change
SCEG	S_SP1	$250	4	0.1%	547	7.4%	7,364	4,118	551	7.5%	4,119	1
SCEG	S_SP2	$80	6	0.1%	478	6.7%	7,116	3,962	484	6.8%	3,963	1
SCEG	S_P	$60	6	0.1%	492	7.7%	6,351	4,082	498	7.8%	4,084	2
SCEG	S_OP	$30	13	0.5%	353	14.5%	2,434	1,238	366	15.0%	1,253	15
SCEG	W_SP	$85	6	0.1%	479	6.7%	7,155	3,986	485	6.8%	3,987	1
SCEG	W_P	$65	7	0.1%	383	6.1%	6,246	4,000	390	6.3%	4,001	1
SCEG	W_OP	$40	8	0.2%	426	9.6%	4,423	3,744	433	9.8%	3,748	4
SCEG	SH_SP	$75	9	0.2%	386	6.2%	6,194	3,622	395	6.4%	3,624	2
SCEG	SH_P	$50	8	0.2%	463	11.5%	4,022	3,306	471	11.7%	3,310	4
SCEG	SH_OP	$35	11	0.3%	528	13.9%	3,795	3,081	538	14.2%	3,088	7

Economic Capacity

First-Tier Control Area Markets

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
SC	S_SP1	$250	4	0.1%	296	4.6%	6,421	4,365	300	4.7%	4,366	1
SC	S_SP2	$80	5	0.1%	308	5.0%	6,129	4,257	313	5.1%	4,258	1
SC	S_P	$60	6	0.1%	314	6.1%	5,135	3,499	320	6.2%	3,500	1
SC	S_OP	$30	14	0.4%	280	8.1%	3,451	3,378	295	8.5%	3,385	7
SC	W_SP	$85	5	0.1%	311	4.9%	6,314	4,382	315	5.0%	4,383	1
SC	W_P	$65	5	0.1%	398	7.8%	5,137	3,512	403	7.9%	3,514	2
SC	W_OP	$40	9	0.2%	380	7.4%	5,137	3,520	389	7.6%	3,523	3
SC	SH_SP	$75	7	0.1%	309	6.0%	5,125	3,778	316	6.2%	3,780	2
SC	SH_P	$50	8	0.2%	409	9.4%	4,357	3,090	417	9.6%	3,093	3
SC	SH_OP	$35	11	0.3%	307	7.2%	4,251	2,957	318	7.5%	2,960	3

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
SOCO	S_SP1	$250	39	0.1%	1,522	2.7%	57,078	4,421	1,561	2.7%	4,421	-
SOCO	S_SP2	$80	46	0.1%	1,495	2.7%	54,800	4,250	1,541	2.8%	4,251	1
SOCO	S_P	$60	22	0.1%	1,459	3.3%	44,168	4,825	1,481	3.4%	4,825	-
SOCO	S_OP	$30	38	0.2%	1,422	6.1%	23,473	3,500	1,459	6.2%	3,502	2
SOCO	W_SP	$85	45	0.1%	1,485	2.7%	55,051	4,270	1,531	2.8%	4,270	-
SOCO	W_P	$65	12	0.0%	1,428	3.2%	44,325	4,873	1,440	3.3%	4,873	-
SOCO	W_OP	$40	33	0.1%	1,720	5.0%	34,285	4,979	1,753	5.1%	4,980	1
SOCO	SH_SP	$75	36	0.1%	1,499	3.2%	47,166	4,181	1,535	3.3%	4,181	-
SOCO	SH_P	$50	21	0.1%	1,604	5.3%	30,482	4,695	1,626	5.3%	4,696	1
SOCO	SH_OP	$35	41	0.1%	1,173	3.9%	29,897	4,692	1,213	4.1%	4,693	1

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
TVA	S_SP1	$250	934	2.6%	154	0.4%	36,395	5,971	1,088	3.0%	5,973	2
TVA	S_SP2	$80	932	2.7%	168	0.5%	34,569	5,794	1,099	3.2%	5,796	2
TVA	S_P	$60	110	0.4%	167	0.6%	28,864	5,826	277	1.0%	5,826	-
TVA	S_OP	$30	114	0.5%	208	0.9%	23,212	5,966	322	1.4%	5,967	1
TVA	W_SP	$85	1211	3.0%	302	0.7%	40,628	4,362	1,513	3.7%	4,366	4
TVA	W_P	$65	270	0.8%	314	0.9%	34,989	4,226	584	1.7%	4,227	1
TVA	W_OP	$40	304	1.0%	297	1.0%	30,813	4,522	601	2.0%	4,524	2
TVA	SH_SP	$75	816	2.4%	281	0.8%	33,960	4,110	1,097	3.2%	4,114	4
TVA	SH_P	$50	278	1.0%	341	1.2%	27,739	4,168	619	2.2%	4,171	3
TVA	SH_OP	$35	266	1.0%	353	1.4%	25,940	3,893	618	2.4%	3,896	3

Available Economic Capacity

MISO

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
MISO	S_SP1	$250	1,074	2.8%	1,177	3.0%	39,120	463	2,251	5.8%	479	16
MISO	S_SP2	$80	788	2.0%	1,204	3.0%	39,532	454	1,992	5.0%	466	12
MISO	S_P	$60	1,690	4.6%	743	2.0%	36,805	499	2,433	6.6%	517	18
MISO	S_OP	$30	1,898	5.2%	-	0.0%	36,625	759	1,898	5.2%	759	0
MISO	W_SP	$85	2,430	4.7%	1,357	2.6%	51,996	418	3,787	7.3%	442	24
MISO	W_P	$65	2,284	5.5%	743	1.8%	41,351	468	3,027	7.3%	488	20
MISO	W_OP	$40	3,109	7.7%	562	1.4%	40,619	599	3,671	9.0%	620	21
MISO	SH_SP	$75	65	0.2%	884	2.9%	30,279	537	949	3.1%	538	1
MISO	SH_P	$50	1,053	4.0%	361	1.4%	26,096	758	1,413	5.4%	769	11
MISO	SH_OP	$35	1,686	5.5%	731	2.4%	30,756	640	2,417	7.9%	666	26

			Pre-Merger						Post-Merger with 100 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO	S_SP1	$250	1,074	2.8%	1,177	3.0%	39,120	463	2,351	6.0%	482	19
MISO	S_SP2	$80	788	2.0%	1,204	3.0%	39,532	454	2,092	5.3%	469	15
MISO	S_P	$60	1,690	4.6%	743	2.0%	36,805	499	2,533	6.9%	521	22
MISO	S_OP	$30	1,898	5.2%	-	0.0%	36,625	759	1,998	5.5%	762	3
MISO	W_SP	$85	2,430	4.7%	1,357	2.6%	51,996	418	3,887	7.5%	445	27
MISO	W_P	$65	2,284	5.5%	743	1.8%	41,351	468	3,127	7.6%	491	23
MISO	W_OP	$40	3,109	7.7%	562	1.4%	40,619	599	3,771	9.3%	625	26
MISO	SH_SP	$75	65	0.2%	884	2.9%	30,279	537	1,049	3.5%	540	3
MISO	SH_P	$50	1,053	4.0%	361	1.4%	26,096	758	1,513	5.8%	773	15
MISO	SH_OP	$35	1,686	5.5%	731	2.4%	30,756	640	2,517	8.2%	671	31

			Pre-Merger						Post-Merger with 250 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO	S_SP1	$250	1,074	2.8%	1,177	3.0%	39,120	463	2,501	6.4%	487	24
MISO	S_SP2	$80	788	2.0%	1,204	3.0%	39,532	454	2,242	5.7%	473	19
MISO	S_P	$60	1,690	4.6%	743	2.0%	36,805	499	2,683	7.3%	527	28
MISO	S_OP	$30	1,898	5.2%	-	0.0%	36,625	759	2,148	5.9%	767	8
MISO	W_SP	$85	2,430	4.7%	1,357	2.6%	51,996	418	4,037	7.8%	450	32
MISO	W_P	$65	2,284	5.5%	743	1.8%	41,351	468	3,277	7.9%	497	29
MISO	W_OP	$40	3,109	7.7%	562	1.4%	40,619	599	3,921	9.7%	632	33
MISO	SH_SP	$75	65	0.2%	884	2.9%	30,279	537	1,199	4.0%	544	7
MISO	SH_P	$50	1,053	4.0%	361	1.4%	26,096	758	1,663	6.4%	780	22
MISO	SH_OP	$35	1,686	5.5%	731	2.4%	30,756	640	2,667	8.7%	679	39

Available Economic Capacity

MISO Submarket

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
												0
MISO Submarket	S_SP1	$250	1,015	3.2%	762	2.4%	31,561	514	1,778	5.6%	530	16
MISO Submarket	S_SP2	$80	760	2.3%	919	2.8%	32,505	502	1,680	5.2%	515	13
MISO Submarket	S_P	$60	1,690	5.7%	443	1.5%	29,565	577	2,134	7.2%	594	17
MISO Submarket	S_OP	$30	1,898	6.7%	-	0.0%	28,395	894	1,898	6.7%	894	0
MISO Submarket	W_SP	$85	2,386	5.8%	995	2.4%	41,431	525	3,380	8.2%	553	28
MISO Submarket	W_P	$65	2,284	6.9%	583	1.8%	32,890	580	2,867	8.7%	605	25
MISO Submarket	W_OP	$40	3,109	9.8%	513	1.6%	31,616	772	3,622	11.5%	804	32
MISO Submarket	SH_SP	$75	32	0.1%	572	2.4%	24,191	555	604	2.5%	555	0
MISO Submarket	SH_P	$50	1,053	5.1%	243	1.2%	20,822	794	1,296	6.2%	806	12
MISO Submarket	SH_OP	$35	1,686	7.1%	410	1.7%	23,922	711	2,095	8.8%	735	24

			Pre-Merger						Post-Merger with Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO Submarket	S_SP1	$250	1,015	3.2%	762	2.4%	31,561	514	1,878	6.0%	533	19
MISO Submarket	S_SP2	$80	760	2.3%	919	2.8%	32,505	502	1,780	5.5%	519	17
MISO Submarket	S_P	$60	1,690	5.7%	443	1.5%	29,565	577	2,234	7.6%	599	22
MISO Submarket	S_OP	$30	1,898	6.7%	-	0.0%	28,395	894	1,998	7.0%	899	5
MISO Submarket	W_SP	$85	2,386	5.8%	995	2.4%	41,431	525	3,480	8.4%	557	32
MISO Submarket	W_P	$65	2,284	6.9%	583	1.8%	32,890	580	2,967	9.0%	610	30
MISO Submarket	W_OP	$40	3,109	9.8%	513	1.6%	31,616	772	3,722	11.8%	811	39
MISO Submarket	SH_SP	$75	32	0.1%	572	2.4%	24,191	555	704	2.9%	558	3
MISO Submarket	SH_P	$50	1,053	5.1%	243	1.2%	20,822	794	1,396	6.7%	812	18
MISO Submarket	SH_OP	$35	1,686	7.1%	410	1.7%	23,922	711	2,195	9.2%	743	32

			Pre-Merger						Post-Merger with 250 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO Submarket	S_SP1	$250	1,015	3.2%	762	2.4%	31,561	514	2,028	6.4%	539	25
MISO Submarket	S_SP2	$80	760	2.3%	919	2.8%	32,505	502	1,930	5.9%	524	22
MISO Submarket	S_P	$60	1,690	5.7%	443	1.5%	29,565	577	2,384	8.1%	607	30
MISO Submarket	S_OP	$30	1,898	6.7%	-	0.0%	28,395	894	2,148	7.6%	907	13
MISO Submarket	W_SP	$85	2,386	5.8%	995	2.4%	41,431	525	3,630	8.8%	563	38
MISO Submarket	W_P	$65	2,284	6.9%	583	1.8%	32,890	580	3,117	9.5%	619	39
MISO Submarket	W_OP	$40	3,109	9.8%	513	1.6%	31,616	772	3,872	12.2%	823	51
MISO Submarket	SH_SP	$75	32	0.1%	572	2.4%	24,191	555	854	3.5%	562	7
MISO Submarket	SH_P	$50	1,053	5.1%	243	1.2%	20,822	794	1,546	7.4%	822	28
MISO Submarket	SH_OP	$35	1,686	7.1%	410	1.7%	23,922	711	2,345	9.8%	754	43

Available Economic Capacity

MISO-PJM Midwest Market

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
MISO-PJM Midwest	S_SP1	$250	1,593	2.5%	4,710	7.3%	64,356	424	6,304	9.8%	460	36
MISO-PJM Midwest	S_SP2	$80	1,327	2.0%	4,908	7.3%	66,947	447	6,234	9.3%	476	29
MISO-PJM Midwest	S_P	$60	1,690	2.8%	3,432	5.7%	60,749	532	5,122	8.4%	563	31
MISO-PJM Midwest	S_OP	$30	1,898	4.3%	-	0.0%	43,690	812	1,898	4.3%	812	0
MISO-PJM Midwest	W_SP	$85	2,773	3.3%	5,411	6.5%	82,954	434	8,184	9.9%	477	43
MISO-PJM Midwest	W_P	$65	2,284	3.5%	4,778	7.4%	64,766	520	7,062	10.9%	572	52
MISO-PJM Midwest	W_OP	$40	3,109	5.5%	2,430	4.3%	56,942	696	5,539	9.7%	743	47
MISO-PJM Midwest	SH_SP	$75	234	0.5%	3,721	8.0%	46,698	501	3,955	8.5%	509	8
MISO-PJM Midwest	SH_P	$50	1,053	3.8%	665	2.4%	27,709	865	1,718	6.2%	883	18
MISO-PJM Midwest	SH_OP	$35	1,686	4.3%	1,326	3.4%	38,902	782	3,012	7.7%	812	30

			Pre-Merger						Post-Merger with 100 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO-PJM Midwest	S_SP1	$250	1,593	2.5%	4,710	7.3%	64,356	424	6,404	10.0%	463	39
MISO-PJM Midwest	S_SP2	$80	1,327	2.0%	4,908	7.3%	66,947	447	6,334	9.5%	479	32
MISO-PJM Midwest	S_P	$60	1,690	2.8%	3,432	5.7%	60,749	532	5,222	8.6%	566	34
MISO-PJM Midwest	S_OP	$30	1,898	4.3%	-	0.0%	43,690	812	1,998	4.6%	814	2
MISO-PJM Midwest	W_SP	$85	2,773	3.3%	5,411	6.5%	82,954	434	8,284	10.0%	480	46
SO-PJM Midwest	W_P	$65	2,284	3.5%	4,778	7.4%	64,766	520	7,162	11.1%	575	55
ISO-PJM Midwest	W_OP	$40	3,109	5.5%	2,430	4.3%	56,942	696	5,639	9.9%	746	50
MISO-PJM Midwest	SH_SP	$75	234	0.5%	3,721	8.0%	46,698	501	4,055	8.7%	513	12
MISO-PJM Midwest	SH_P	$50	1,053	3.8%	665	2.4%	27,709	865	1,818	6.6%	888	23
MISO-PJM Midwest	SH_OP	$35	1,686	4.3%	1,326	3.4%	38,902	782	3,112	8.0%	816	34

			Pre-Merger						Post-Merger with 250 MW Integration Path			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
MISO-PJM Midwest	S_SP1	$250	1,593	2.5%	4,710	7.3%	64,356	424	6,554	10.2%	468	44
MISO-PJM Midwest	S_SP2	$80	1,327	2.0%	4,908	7.3%	66,947	447	6,484	9.7%	483	36
MISO-PJM Midwest	S_P	$60	1,690	2.8%	3,432	5.7%	60,749	532	5,372	8.8%	571	39
MISO-PJM Midwest	S_OP	$30	1,898	4.3%	-	0.0%	43,690	812	2,148	4.9%	817	5
MISO-PJM Midwest	W_SP	$85	2,773	3.3%	5,411	6.5%	82,954	434	8,434	10.2%	484	50
MISO-PJM Midwest	W_P	$65	2,284	3.5%	4,778	7.4%	64,766	520	7,312	11.3%	581	61
MISO-PJM Midwest	W_OP	$40	3,109	5.5%	2,430	4.3%	56,942	696	5,789	10.2%	751	55
MISO-PJM Midwest	SH_SP	$75	234	0.5%	3,721	8.0%	46,698	501	4,205	9.0%	518	17
MISO-PJM Midwest	SH_P	$50	1,053	3.8%	665	2.4%	27,709	865	1,968	7.1%	895	30
MISO-PJM Midwest	SH_OP	$35	1,686	4.3%	1,326	3.4%	38,902	782	3,262	8.4%	822	40

Available Economic Capacity

DUK Market

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
DUK	S_SP1	$250	34	0.7%	1,194	23.0%	5,193	1,065	1,228	23.7%	1,095	30
DUK	S_SP2	$80	31	0.6%	1,555	28.1%	5,539	1,269	1,586	28.6%	1,301	32
DUK	S_P	$60	9	0.2%	1,289	27.7%	4,654	1,106	1,299	27.9%	1,118	12
DUK	S_OP	$30	32	0.9%	-	0.0%	3,663	1,058	32	0.9%	1,058	-
DUK	W_SP	$85	18	0.2%	4,160	55.7%	7,472	3,285	4,179	55.9%	3,312	27
DUK	W_P	$65	11	0.2%	2,552	48.3%	5,287	2,522	2,563	48.5%	2,543	21
DUK	W_OP	$40	39	0.7%	2,522	46.0%	5,482	2,376	2,561	46.7%	2,441	65
DUK	SH_SP	$75	7	0.1%	2,312	30.1%	7,676	1,264	2,319	30.2%	1,270	6
DUK	SH_P	$50	48	0.9%	824	14.7%	5,624	889	873	15.5%	914	25
DUK	SH_OP	$35	61	0.9%	1,575	23.9%	6,578	1,102	1,636	24.9%	1,146	44

			Pre-Merger						Post-Merger with 100 MW Integration Path to MISO			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
DUK	S_SP1	$250	34	0.7%	1,194	23.0%	5,193	1,065	1,128	21.7%	1,171	(57)
DUK	S_SP2	$80	31	0.6%	1,555	28.1%	5,539	1,269	1,486	26.8%	1,517	(69)
DUK	S_P	$60	9	0.2%	1,289	27.7%	4,654	1,106	1,199	25.8%	1,195	(104)
DUK	S_OP	$30	32	0.9%	-	0.0%	3,663	1,058	0	0.0%	31	(1)
DUK	W_SP	$85	18	0.2%	4,160	55.7%	7,472	3,285	4,079	54.6%	4,059	(120)
JK	W_P	$65	11	0.2%	2,552	48.3%	5,287	2,522	2,463	46.6%	2,404	(159)
JK	W_OP	$40	39	0.7%	2,522	46.0%	5,482	2,376	2,461	44.9%	2,460	(101)
DUK	SH_SP	$75	7	0.1%	2,312	30.1%	7,676	1,264	2,219	28.9%	2,247	(72)
DUK	SH_P	$50	48	0.9%	824	14.7%	5,624	889	773	13.7%	846	(27)
DUK	SH_OP	$35	61	0.9%	1,575	23.9%	6,578	1,102	1,536	23.4%	1,607	(29)

			Pre-Merger						Post-Merger with 250 MW Integration Path to MISO			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Integration	HHI Change
DUK	S_SP1	$250	34	0.7%	1,194	23.0%	5,193	1,065	978	18.8%	1,054	(174)
DUK	S_SP2	$80	31	0.6%	1,555	28.1%	5,539	1,269	1,336	24.1%	1,379	(207)
DUK	S_P	$60	9	0.2%	1,289	27.7%	4,654	1,106	1,049	22.5%	1,040	(259)
DUK	S_OP	$30	32	0.9%	-	0.0%	3,663	1,058	0	0.0%	31	(1)
DUK	W_SP	$85	18	0.2%	4,160	55.7%	7,472	3,285	3,929	52.6%	3,844	(335)
DUK	W_P	$65	11	0.2%	2,552	48.3%	5,287	2,522	2,313	43.7%	2,148	(415)
DUK	W_OP	$40	39	0.7%	2,522	46.0%	5,482	2,376	2,311	42.2%	2,222	(339)
DUK	SH_SP	$75	7	0.1%	2,312	30.1%	7,676	1,264	2,069	27.0%	2,138	(181)
DUK	SH_P	$50	48	0.9%	824	14.7%	5,624	889	623	11.1%	780	(93)
DUK	SH_OP	$35	61	0.9%	1,575	23.9%	6,578	1,102	1,386	21.1%	1,506	(130)

Available Economic Capacity

First-Tier Control Area Markets

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
CPLE	S_SP1	$250	55	1.3%	340	8.3%	4,116	620	395	9.6%	642	22
CPLE	S_SP2	$80	40	1.0%	393	9.5%	4,116	589	433	10.5%	607	18
CPLE	S_P	$60	49	1.2%	458	11.1%	4,116	578	507	12.3%	604	26
CPLE	S_OP	$30	64	1.6%	-	0.0%	4,116	829	64	1.6%	829	-
CPLE	W_SP	$85	80	1.0%	1,111	13.9%	7,981	667	1,191	14.9%	695	28
CPLE	W_P	$65	100	1.3%	922	11.9%	7,754	608	1,021	13.2%	639	31
CPLE	W_OP	$40	163	2.0%	1,180	14.7%	8,041	711	1,343	16.7%	770	59
CPLE	SH_SP	$75	11	0.3%	272	6.1%	4,430	568	283	6.4%	571	3
CPLE	SH_P	$50	63	1.4%	285	6.4%	4,430	793	348	7.9%	811	18
CPLE	SH_OP	$35	71	1.4%	569	11.4%	5,000	717	640	12.8%	749	32

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
CPLW	S_SP1	$250	22	2.3%	69	7.1%	972	525	91	9.4%	557	32
CPLW	S_SP2	$80	19	1.8%	92	8.9%	1,030	525	110	10.7%	557	32
CPLW	S_P	$60	14	1.5%	82	8.5%	964	462	97	10.0%	487	25
CPLW	S_OP	$30	24	2.5%	-	0.0%	964	781	24	2.5%	781	-
CPLW	W_SP	$85	18	2.3%	120	14.8%	807	644	138	17.1%	711	67
CPLW	W_P	$65	10	1.4%	93	13.1%	714	537	103	14.4%	572	35
CPLW	W_OP	$40	22	3.1%	90	12.6%	714	610	112	15.7%	688	78
CPLW	SH_SP	$75	4	0.4%	58	5.7%	1,026	516	62	6.1%	520	4
CPLW	SH_P	$50	22	2.2%	95	9.4%	1,014	765	118	11.6%	806	41
CPLW	SH_OP	$35	24	2.4%	134	13.2%	1,014	683	158	15.6%	746	63

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
SCEG	S_SP1	$250	6	0.2%	98	3.5%	2,809	1,743	104	3.7%	1,744	1
SCEG	S_SP2	$80	34	1.2%	213	7.5%	2,826	1,677	247	8.8%	1,696	19
SCEG	S_P	$60	14	0.5%	222	8.0%	2,786	1,067	236	8.5%	1,076	9
SCEG	S_OP	$30	29	1.6%	-	0.0%	1,800	1,018	29	1.6%	1,018	-
SCEG	W_SP	$85	22	0.6%	469	13.6%	3,447	1,539	491	14.2%	1,557	18
SCEG	W_P	$65	21	0.7%	214	6.5%	3,302	1,344	235	7.1%	1,352	8
SCEG	W_OP	$40	29	1.6%	264	14.7%	1,800	732	293	16.3%	779	47
SCEG	SH_SP	$75	4	0.2%	93	3.5%	2,680	1,430	97	3.6%	1,431	1
SCEG	SH_P	$50	20	1.1%	241	13.4%	1,800	893	261	14.5%	923	30
SCEG	SH_OP	$35	24	1.3%	323	18.0%	1,800	835	347	19.3%	883	48

Available Economic Capacity

First-Tier Control Area Markets

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
SC	S_SP1	$250	14	1.0%	81	5.4%	1,500	916	96	6.4%	926	10
SC	S_SP2	$80	15	1.0%	125	8.5%	1,480	724	140	9.5%	741	17
SC	S_P	$60	12	0.8%	203	13.5%	1,500	588	215	14.4%	610	22
SC	S_OP	$30	27	1.8%	-	0.0%	1,500	907	27	1.8%	907	-
SC	W_SP	$85	16	1.0%	222	14.5%	1,532	657	237	15.5%	687	30
SC	W_P	$65	12	0.8%	268	17.9%	1,500	782	280	18.7%	810	28
SC	W_OP	$40	2	0.2%	264	17.6%	1,500	1,084	266	17.8%	1,089	5
SC	SH_SP	$75	3	0.2%	86	5.7%	1,500	638	89	5.9%	640	2
SC	SH_P	$50	16	1.1%	171	11.4%	1,500	676	187	12.5%	700	24
SC	SH_OP	$35	1	0.0%	217	14.5%	1,500	999	218	14.5%	1,001	2

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
SOCO	S_SP1	$250	158	1.2%	575	4.3%	13,242	720	733	5.5%	730	10
SOCO	S_SP2	$80	155	1.2%	746	5.7%	13,006	752	900	6.9%	765	13
SOCO	S_P	$60	28	0.3%	731	7.1%	10,365	607	759	7.3%	610	3
SOCO	S_OP	$30	50	0.8%	-	0.0%	6,176	1,245	50	0.8%	1,245	-
SOCO	W_SP	$85	168	0.9%	1,284	6.5%	19,741	1,438	1,452	7.4%	1,449	11
SOCO	W_P	$65	28	0.2%	1,011	6.3%	16,112	1,899	1,039	6.5%	1,901	2
SOCO	W_OP	$40	91	1.1%	1,218	15.3%	7,987	851	1,309	16.4%	886	35
SOCO	SH_SP	$75	111	0.9%	545	4.6%	11,966	672	656	5.5%	680	8
SOCO	SH_P	$50	50	0.8%	404	6.3%	6,457	872	454	7.0%	881	9
SOCO	SH_OP	$35	72	1.0%	417	6.0%	6,941	764	489	7.0%	776	12

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
TVA	S_SP1	$250	870	10.8%	220	2.7%	8,047	515	1,091	13.6%	574	59
TVA	S_SP2	$80	858	10.7%	277	3.5%	8,040	519	1,135	14.1%	593	74
TVA	S_P	$60	53	0.8%	314	4.7%	6,741	512	367	5.4%	519	7
TVA	S_OP	$30	95	1.8%	-	0.0%	5,207	622	95	1.8%	622	-
TVA	W_SP	$85	1,108	8.1%	370	2.7%	13,623	390	1,478	10.9%	434	44
TVA	W_P	$65	174	1.4%	297	2.5%	12,129	412	471	3.9%	419	7
TVA	W_OP	$40	337	3.4%	422	4.3%	9,899	504	759	7.7%	533	29
TVA	SH_SP	$75	653	5.6%	284	2.4%	11,644	462	936	8.0%	489	27
TVA	SH_P	$50	164	1.9%	89	1.1%	8,453	715	253	3.0%	719	4
TVA	SH_OP	$35	241	2.5%	395	4.1%	9,678	580	636	6.6%	600	20

Exhibit J-10

Gas-Fired Generators in MISO and MISO-PJM Midwest Customers of Texas Eastern

Owner	Plant	State	Control Area	Region	MW
Cinergy	Madison	OH	MISO	ECAR	576.0
Cinergy	Woodsdale	OH	MISO	ECAR	462.0
Duke Energy	Hanging Rock	OH	PJM	ECAR	1,288.0
Duke Energy	Fayette	OH	PJM	ECAR	600.5
Duke Energy	Washington	OH	PJM	ECAR	600.0
Duke Energy	Vermillion	IN	MISO	ECAR	560.0
Dynegy	Rolling Hills	OH	PJM	ECAR	825.0
AEP	Waterford	OH	PJM	ECAR	821.0
Borough of Chambersburg	Chambersburg	PA	PJM	ECAR	7.3
Total					5,739.8
Unaffiliated with Duke Energy					2,691.3
Unaffiliated with Applicants					1,653.3

Pipelines Flowing into MISO

Route	Pipeline Name	Owner	From	To	Capacity at end of 2004 (MMCF/day)
	ALLIANCE PIPELINE CO	Enbridge and Fort Chicago Partners	IA	IL	1,800
ML-SW, ML-LA	ANR PIPELINE CO	El Paso Corp.	IA, TN	IL, KY	2,051
	BLUEWATER PIPELINE CO	Southern Union	ON	MI	250
OM-1	CENTERPOINT ENERGY GAS TRANS CO	CenterPoint Energy Inc.	AR	MO	100
ML	CENTRA PIPELINE CO	Terasen Inc (formerly BC Gas)	MB	MN	63
R701+	COLUMBIA GAS TRANS CORP	NiSource	WV	OH	764
ML-1	COLUMBIA GULF TRANS CO	NiSource	TN	KY	2,317
LN2535, TL-404, TL-377	DOMINION TRANSMISSION CO	Dominion	PA, WV	OH	1,099
ML1	ENBRIDGE PIPELINES (KPC)	Enbridge, Inc.	KS	MO	50
	GREAT LAKES GAS TRANS LTD	Great Lakes Gas	MB	MN	2,412
DIST	INTERSTATE POWER CO	Alliant Energy	IA	IL	75
PONY2	KM INTERSTATE GAS CO	Kinder Morgan, Inc.	KS	MO	255
ML	MIDWESTERN GAS TRANS CO	Center Point Energy	TN	KY	665
ML-123	MISSISSIPPI RIVER TRANS CORP	Reliant Energy	AR	MO	730
109MAR, T307MA	NAT GAS P L CO OF AMERICA	Kinder Morgan	IA, AR	IL, MO	3,351
ML	NORTHERN BORDER PIPELINE CO	Northern Border Partners	SD	MN	2,355
IAM742, ABCD&J, IM6MM8	NORTHERN NATURAL GAS CO	MidAmerican Energy Holdings	IA	IL, MN	2,285
ML-WST	PANHANDLE EASTERN P L CO	Southern Union	KS	MO	1,559
LAT-E5, LAT-1E, LAT-E6, LAT-I	SOUTHERN STAR CENTRAL GAS PL CO	AIG Highstar	KS	MO	1,325
ML-W1	TENNESSEE GAS PIPELINE CO	El Paso Corp.	TN	KY	2,771
ML-S1, ML-N1`	TEXAS EASTERN TRANS CORP	Duke Energy	TN, AR	KY, MO	2,524
ML1	TEXAS GAS TRANSMISSION CO	Loews Corp.	TN	KY	1,660
ML-LA	TRUNKLINE GAS CO	Southern Union	TN	KY	1,570
MICHCO	VECTOR PIPELINE CO	Enbridge, DTE Energy	ON	MI	1,000
ML-1	VIKING GAS TRANSMISSION CO	Northern Border Partners/TransCanada	MB	MN	516
					33,547

Notes:

Includes pipelines into OH, IL, MI, IN, MO, KY, WI, and MN.

Excluded Alliance capacity as it enters MN from SD to avoid double counting volume with portion that enters IL

Excluded ANR as it enters MO from NE to avoid double counting with segment that enters IL from IA. MO portion is very short. IA to IL better represents capacity delivered into market.

Excluded IA to IL segment of Northern Border to avoid double counting with SD to MN segment.

Pipelines Flowing into MISO Submarket

Route	Pipeline Name	Owner	From	To	Capacity at end of 2004 (MMCF/day)
	ALLIANCE PIPELINE CO	Enbridge and Fort Chicago Partners	IA	IL	1,800
ML-SW, LAT-W2, ML-LA, LAT-M	ANR PIPELINE CO	El Paso Corp.	IA, WI, KY	IL, IN MI	2,887
ML-SW	ANR PIPELINE CO	El Paso Corp.	IA	IL	653
	BLUEWATER PIPELINE CO	Southern Union	ON	MI	250
OM-1	CENTERPOINT ENERGY GAS TRANS CO	CenterPoint Energy Inc.	AR	MO	100
R701+	COLUMBIA GAS TRANS CORP	NiSource	WV	OH	764
LN2535, TL-404, TL-377	DOMINION TRANSMISSION CO	Dominion	PA, WV	OH	1,099
ML1	ENBRIDGE PIPELINES (KPC)	Enbridge, Inc.	KS	MO	50
	GREAT LAKES GAS TRANS LTD	Great Lakes Gas	WI	MI	2,226
DIST	INTERSTATE POWER CO	Alliant Energy	IA	IL	75
PONY2	KM INTERSTATE GAS CO	Kinder Morgan, Inc.	KS	MO	255
AM-4	KO TRANSMISSION CO	Cinergy (and Columbia Gas)	KY	OH	219
ML	MIDWESTERN GAS TRANS CO	Center Point Energy	KY	IN	664
ML-123	MISSISSIPPI RIVER TRANS CORP	Reliant Energy	AR	MO	730
109MAR, T307MA	NAT GAS P L CO OF AMERICA	Kinder Morgan	IA, AR	IL, MO	3,351
ML	NORTHERN BORDER PIPELINE CO	Northern Border Partners	IA	IL	858
IAM742, MIM101	NORTHERN NATURAL GAS CO	MidAmerican Energy Holdings	IA, WI	IL, MI	657
ML-WST	PANHANDLE EASTERN P L CO	Southern Union	KS	MO	1,559
LAT-E5, LAT-1E, LAT-E6, LAT-I	SOUTHERN STAR CENTRAL GAS PL CO	AIG Highstar	KS	MO	1,325
ML-W1	TENNESSEE GAS PIPELINE CO	El Paso Corp.	KY	OH	1,777
ML-N1`, ML-S1	TEXAS EASTERN TRANS CORP	Duke Energy	AR, KY	MO, OH	2,390
LAT1, LATN5, ML1	TEXAS GAS TRANSMISSION CO	Loews Corp.	KY	IN	1,502
ML-LA	TRUNKLINE GAS CO	Southern Union	KY	IL	1,544
MICHCO	VECTOR PIPELINE CO	Enbridge, DTE Energy	ON	MI	1,000
					27,082

Notes:

Includes pipelines into OH, IL, MI, IN, and MO.

Excluded ANR as it enters MO from NE to avoid double counting with segment that enters IL from IA. MO portion is very short. IA to IL better represents capacity delivered into market.

Applicants' Firm Capacity Rights on Pipelines into the MISO (MMcf/d)

	Contracts with Upstream Receipt	Contracts with Upstream or In Market Receipts	Allocated Capacity [1/]
MISO Market			
Firm Contracts for Duke Energy Affiliates			
Alliance Pipeline Co	238	238	238
ANR Pipeline Co.	-	7	-
Dominion Transmission Co	11	11	-
Great Lakes Gas Transmission, L.P.	-	7	-
Nat Gas P L Co Of America	2	42	-
Panhandle Eastern Pipe Line Co.	-	58	-
Texas Eastern Trans Corp	258	545	584 [2/]
Texas Gas Transmission Co	133	133	133
Trunkline Gas Co	66	66	66
Viking Gas Transmission Co	5	5	5
Vector Pipeline, L.P.	-	245	-
Total Duke	714	1,359	1,026
Firm Contracts for Cinergy Affiliates			
Columbia Gas Trans Corp	262	262	-
Columbia Gulf Trans Co	190	190	190
Midwestern Gas Transmission	54	220	54
Tennessee Gas Pipeline Co	48	48	48
Texas Eastern Trans Corp	12	12	12
Texas Gas Transmission Co	104	104	104
Total Cinergy	670	836	409
Total, Applicants	1,384	2,195	1,435

Applicants' Firm Capacity Rights on Pipelines into the MISO (MMcf/d)

	Contracts with Upstream Receipt	Contracts with Upstream or In Market Receipts	Allocated Capacity [1/]
MISO Submarket			
Firm Contracts for Duke Energy Affiliates			
Alliance Pipeline Co	238	238	238
ANR Pipeline Co.	7	7	-
Dominion Transmission Co	11	11	-
Great Lakes Gas Trans Ltd	7	7	-
Nat Gas P L Co Of America	2	42	-
Panhandle Eastern Pipe Line Co.	-	58	-
Texas Eastern Trans Corp	258	545	437 [2/]
Texas Gas Transmission Co	133	133	133
Trunkline Gas Co	66	66	66
Vector Pipeline, L.P.	-	245	-
Total Duke	723	1,354	874
Firm Contracts for Cinergy Affiliates			
Columbia Gas Trans Corp	221	221	-
KO Transmission Co	447	447	219 [3/]
Midwestern Gas Transmission	54	220	54
Texas Eastern Trans Corp	12	12	12
Texas Gas Transmission Co	104	104	104
Total Cinergy	839	1,004	389
Total, Applicants	1,561	2,358	1,263

1/ The analysis included all contracts with delivery points downstream or in market AND receipt points upstream of the market. Scarce pipeline capacity is allocated to the largest customers first.

2/ Unsubscribed Texas Eastern capacity is allocated to the Duke Energy as owner of the pipeline.

3/ 100% of KO Transmission's into market capacity is allocated to the Applicants (no Index of Customers).

Economic Capacity, Downstream Results

MISO

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
MISO	S_SP1	$250	9,950	7.2%	2,771	2.0%	138,877	448	12,721	9.2%	476	28
MISO	S_SP2	$80	9,500	7.4%	2,101	1.6%	128,335	455	11,601	9.0%	480	25
MISO	S_P	$60	9,500	8.7%	640	0.6%	109,407	490	10,140	9.3%	501	11
MISO	S_OP	$30	7,967	8.5%	185	0.2%	94,006	559	8,153	8.7%	562	3
MISO	W_SP	$85	9,591	7.4%	2,710	2.1%	130,281	449	12,301	9.4%	480	31
MISO	W_P	$65	9,591	8.8%	617	0.6%	109,342	488	10,208	9.3%	498	10
MISO	W_OP	$40	9,577	9.7%	94	0.1%	98,934	550	9,671	9.8%	552	2
MISO	SH_SP	$75	7,491	7.5%	680	0.7%	99,672	454	8,171	8.2%	464	10
MISO	SH_P	$50	7,491	9.1%	207	0.3%	82,702	512	7,698	9.3%	516	4
MISO	SH_OP	$35	6,998	8.7%	234	0.3%	80,309	509	7,233	9.0%	515	6

MISO Submarket

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
MISO Submarket	S_SP1	$250	9,950	10.4%	1,917	2.0%	95,778	709	11,867	12.4%	750	41
MISO Submarket	S_SP2	$80	9,500	10.6%	1,460	1.6%	89,513	726	10,960	12.2%	761	35
MISO Submarket	S_P	$60	9,500	12.5%	419	0.6%	75,947	798	9,919	13.1%	812	14
MISO Submarket	S_OP	$30	7,967	12.3%	108	0.2%	64,998	916	8,075	12.4%	920	4
MISO Submarket	W_SP	$85	9,591	10.5%	1,763	1.9%	91,331	712	11,353	12.4%	753	41
MISO Submarket	W_P	$65	9,591	12.6%	432	0.6%	76,218	795	10,022	13.2%	809	14
MISO Submarket	W_OP	$40	9,577	13.9%	120	0.2%	69,164	898	9,697	14.0%	903	5
MISO Submarket	SH_SP	$75	7,491	10.9%	457	0.7%	68,815	738	7,948	11.6%	753	15
MISO Submarket	SH_P	$50	7,491	13.0%	80	0.1%	57,664	829	7,572	13.1%	833	4
MISO Submarket	SH_OP	$35	6,998	12.5%	151	0.3%	55,901	822	7,150	12.8%	829	7

MISO-PJM Midwest Market

			Pre-Merger						Post-Merger			
Market	Period	Price	Cinergy MW	Cinergy Mkt Share	Duke MW	Duke Mkt Share	Market Size	HHI Pre-Merger	Combined MW	Combined Mkt Share	HHI Post-Merger	HHI Change
MISO-PJM Midwest	S_SP1	$250	9,950	5.6%	6,861	3.8%	179,158	541	16,811	9.4%	583	42
MISO-PJM Midwest	S_SP2	$80	9,500	5.5%	6,505	3.8%	171,479	558	16,005	9.3%	600	42
MISO-PJM Midwest	S_P	$60	9,500	6.6%	4,142	2.9%	145,113	621	13,642	9.4%	658	37
MISO-PJM Midwest	S_OP	$30	7,967	6.9%	849	0.7%	115,961	696	8,817	7.6%	706	10
MISO-PJM Midwest	W_SP	$85	9,591	5.5%	6,873	3.9%	174,443	555	16,464	9.4%	598	43
MISO-PJM Midwest	W_P	$65	9,591	6.6%	4,294	2.9%	146,015	622	13,885	9.5%	661	39
MISO-PJM Midwest	W_OP	$40	9,577	7.3%	950	0.7%	130,911	723	10,527	8.0%	734	11
MISO-PJM Midwest	SH_SP	$75	7,491	5.7%	3,681	2.8%	131,770	575	11,172	8.5%	607	32
MISO-PJM Midwest	SH_P	$50	7,491	6.9%	1,168	1.1%	108,290	674	8,659	8.0%	689	15
MISO-PJM Midwest	SH_OP	$35	6,998	6.6%	856	0.8%	105,618	684	7,854	7.4%	695	11

MISO Delivered Gas Transportation Market

Customer	Capacity (MMcf/d)	Market Share	HHI
NiSource Inc	2,568	8%	59
Great Lakes Gas Transmission, L.P.	2,412	7%	52
MidAmerican Energy Holdings Co.	2,402	7%	51
Duke/Cinergy	**1,435**	**4%**	**18**
Nicor, Inc.	1,354	4%	16
Southern Union Co.	1,173	3%	12
Enbridge, Inc.	1,171	3%	12
Dominion Resources, Inc.	1,138	3%	12
Laclede Group, The	950	3%	8
Northern Border Partners	744	2%	5
ProLiance Energy, LLC	679	2%	4
Ameren Corp.	674	2%	4
BP plc	664	2%	4
Oneok Inc	623	2%	3
EnCana Corp	576	2%	3
Peoples Energy Corp.	539	2%	3
All Others	14,443	43%	30
Total	**33,547**	**100%**	**296**

MISO Submarket Delivered Gas Transportation Market

Customer	Capacity (MMcf/d)	Market Share	HHI
Transcanada Corp. [1/]	1,622	6%	36
NiSource Inc	1,617	6%	36
Nicor, Inc.	1,371	5%	26
Dominion Resources, Inc.	1,266	5%	22
Duke/Cinergy	**1,263**	**5%**	**22**
Enbridge, Inc.	1,171	4%	19
Southern Union Co.	1,120	4%	17
Laclede Group, The	950	4%	12
Peoples Energy Corp.	910	3%	11
MidAmerican Energy Holdings Co.	802	3%	9
BP plc	685	3%	6
ProLiance Energy, LLC	678	3%	6
Ameren Corp.	674	2%	6
CMS Energy Corp.	668	2%	6
Oneok Inc	619	2%	5
eCORP Marketing L.L.C.	500	2%	3
All Others	11,163	41%	33
Total	**27,082**	**100%**	**276**

[1/] Note that the largest TransCanada contract on Great Lakes has a receipt point in Minnesota and a delivery in the MISO Submarket. However, when analyzing the MISO market, this contract is excluded since the receipt point is in MISO.

Exhibit J-15

Storage Market for Customers in MISO

Storage Ownership	Working Capacity (BCF)	Market Share
Duke Energy [1/]	217	13%
Dominion Resources, Inc.	363	21%
El Paso Corp.	259	15%
NiSource Inc	251	15%
CMS Energy Corp.	157	9%
DTE Energy Co.	130	8%
National Fuel Gas Co.	96	6%
Washington 10 Storage	42	2%
Equitable Resources, Inc.	26	2%
The Williams Companies, Inc.	23	1%
Other	138	8%
TOTAL	1,701.6	100%

Storage Ownership by Contract	Working Capacity (BCF)	Market Share	HHI
Duke Energy/Cinergy [1/]	203	12%	143
Dominion Resources, Inc.	165	10%	94
CMS Energy Corp.	157	9%	85
NiSource Inc	152	9%	80
DTE Energy Co.	131	8%	60
National Fuel Gas Co.	86	5%	26
The Williams Companies, Inc.	72	4%	18
El Paso Corp.	71	4%	17
Washington 10 Storage	42	2%	6
WGL Holdings, Inc.	36	2%	5
KeySpan Corp.	36	2%	4
Public Service Enterprise Group, Inc.	35	2%	4
Wisconsin Energy Corp.	32	2%	4
Energy East Corp.	27	2%	2
National Grid Transco Plc	25	1%	2
Other	430	25%	15
TOTAL	1,701.6	100%	565

1/ Conservatively includes 150 bcf of storage capacity at Dawn. Dawn does not publish an Index of Customers report.

Exhibit K: Maps

Maps of the properties owned by the Applicants are attached hereto in the non-public version of this Application. Applicants request that the maps of their jurisdictional facilities remain confidential because they contain Critical Energy Infrastructure Information (CEII).

Exhibit K

Redacted in the Public Version

Exhibit L: Status of Regulatory Actions and Orders

Approvals from the following state and federal agencies are required for the Transaction. As of the date of this Application, no such approvals have been obtained.

State Approvals

1. North Carolina Utilities Commission.

2. Public Service Commission of South Carolina.

3. Public Utility Commission of Ohio.

4. Kentucky Public Service Commission.

5. Indiana Utility Regulatory Commission ("IURC"). Although the IURC will not approve the Transaction itself, the IURC does have jurisdiction to approve certain aspects of the Transaction, and the transfer of the Vermillion Energy Facility, as explained in Section III.A and Appendix 1.

Federal Approvals

1. Nuclear Regulatory Commission.

2. Clearance from either the Department of Justice or Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act.

3. Approval by the Securities and Exchange Commission under the Public Utility Holding Company Act to engage in various transactions associated with the Transaction.

4. Approval from the Federal Communications Commission for the transfer of certain licenses.