STATE OF INDIANA

INDIANA UTILITIES AND REGULATORY COMMISSION

IN THE MATTER OF THE	**§**	
COMMISSION'S INVESTIGATION,	**§**	
UNDER IC 8-1-2-58 AND 59, INTO THE	**§**	
PROPOSED TERMINATION OF THE	**§**	
OPERATING AGREEMENT BETWEEN	**§**	
PSI ENERGY, INC. AND CINCINNATI	**§**	**CAUSE NO. 41954**
GAS & ELECTRIC COMPANY	**§**	
APPROVED BY THE COMMISSION		
MARCH 29, 1994		

DIRECT TESTIMONY

OF

ROBERT M. FAGAN

ON BEHALF OF THE

CITIZENS ACTION COALITION OF INDIANA

APRIL 21, 2005

DIRECT TESTIMONY OF
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BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

DIRECT TESTIMONY OF ROBERT M. FAGAN

ON BEHALF OF CITIZENS ACTION COALITION OF INDIANA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am an energy economics analyst and mechanical engineer with 19 years of experience in the energy industry. My work has focused primarily on electric power industry issues, especially economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, and assessment and implementation of demand-side resource alternatives. I hold an M.A. from Boston University in Energy and Environmental Studies and a B.S. from Clarkson University in Mechanical Engineering. Details of my experience are provided in Exhibit RMF-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE INDIANA UTILITY REGULATORY COMMISSION?

A. No.

Q. HAVE YOU TESTIFIED BEFORE OTHER REGULATORY BODIES ON RELATED WHOLESALE MARKET ISSUES?

A. Yes. I testified before the Texas Public Utilities Commission on stranded cost issues, which encompassed both wholesale and retail market considerations during the transition to a competitive market. I have submitted testimony on Open Access Transmission Tariff issues in Nova Scotia, and I have submitted joint testimony in Maine on transmission capacity reservation needs. I testified on transmission tariff and transmission system code issues in Ontario and Alberta. In all of those jurisdictions, the structure of the impending (Ontario, Nova Scotia) and existing (Alberta, Maine) competitive wholesale and retail markets was germane to my testimony.

Q. WHAT SPECIFIC EXPERIENCE DO YOU HAVE WITH RESPECT TO JGDA ISSUES?

A. I understand the structure of centralized dispatch approaches to power system operation. Between 1996 and December 2004, my work focused in large part on the evolving nature of ISO and RTO structures, and the way in which spot locational energy markets and centralized energy dispatch shaped the development of competitive generation markets. I have experience with the modeling of security-constrained centralized dispatch; I was part of a team of consultants using the industry-standard GE MAPS security-constrained production cost modeling tool to estimate locational marginal prices using a centralized dispatch approach. Lastly, I have followed the development of the Midwest ISO from its original "Day 1" responsibilities, through its development of the MISO Energy Markets Tariff and the planned introduction of locational spot energy markets next month.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is twofold.

First, to gauge the efficacy and equity of the Cinergy Joint Generation and Dispatch Agreement ("JGDA") from the perspective of PSI ratepayers, I review the inter-company energy transactions under the JGDA and assess the impacts on PSI revenues arising from Cinergy's interpretation and implementation of the agreement.

Second, I address the feasibility of the JGDA in a post MISO Day 2 world. I examine the case for prospectively terminating, amending or maintaining the JGDA in light of the recent commencement of spot locational electric energy markets administered by the Midwest Independent System Operator ("MISO"). These markets ("MISO Day 2") began operation on April 1, 2005. I explore the different mechanisms available to sell surplus PSI energy to off-system purchasers and to determine the appropriate price for any energy supplied by PSI for ultimate use by CG&E to meet native load. I address the fundamental distinction between PSI, whose generation assets remain regulated, and CG&E, whose generation assets are unregulated, and what this implies for inter-company energy transfer pricing. I also address the impact on PSI ratepayers of the absence of either installed capacity or ancillary service market structures (in particular, regulation and operating reserve) at the commencement of MISO Day 2 operation.

In the context of each of these purposes, I provide specific recommendations concerning the efficacy and equitableness of the JGDA, its impact on PSI revenues since its inception, and whether it best serves PSI ratepayers to terminate or amend the agreement.

Q. PLEASE SUMMARIZE YOUR MAIN CONCLUSIONS AND RECOMMENDATIONS.

A. My main conclusions and recommendations may be grouped in two broad areas: 1) a retrospective analysis of JGDA implementation, and impacts on PSI ratepayers; and 2) based on this retrospective analysis, a prospective evaluation of the JGDA within the context of MISO Day 2 implementation.

My analysis of JGDA Implementation addresses the following specific issues and is summarized as follows:

1. Data deficiencies limit my ability to thoroughly examine the impact of JGDA transactions, particularly transactions occurring between April 1, 2002 and December 31, 2002, and those after October 31, 2004. Cinergy has indicated that data on JGDA transactions is not available for the earlier time period, in contrast to agreed-upon language present in the JGDA Settlement Agreement.[1]
2. Cinergy's use of the incremental cost cap provision of the JGDA for transfers serving off-system sales has resulted in $3.500 million in PSI net lost revenues for the period January 1, 2003 through September 30, 2004. This

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[1] Exhibit DFE-3.

amount is in rough agreement with that reported by Cinergy in the testimony of Mr. Jennings and Mr. Esamann.[2]

3. Cinergy's use of an hourly market price ("HMP") metric instead of actual market value for off-system sales has resulted in $6.704 million in PSI net lost revenues for the period January 1, 2003 through September 30, 2004. Cinergy has "bought low" from PSI at HMP and "sold high" at actual market price for 2.748 million MWh (net)[3] of energy transferred from PSI to CG&E under the JGDA for this period. This revenue loss is in addition to the revenue loss arising from the incremental cost cap mechanism described in summary point no. 2.

4. An independent valuation of JGDA energy transfers using the "Into Cinergy" bilateral forward market hub price index would lead to PSI net lost revenues when compared to valuation using HMP. If the "Into Cinergy" independent bilateral hub price indices were used to value JGDA energy transfers instead of the Cinergy-computed HMP, for those hours when the "Into Cinergy" index existed and JGDA off-system sales were made, PSI would see an additional $1.484 million in revenue from JGDA transfers for the January 1, 2003 through September 30, 2004 period. This PSI net lost revenue is included in the $6.704 million noted above in summary point no. 3.

5. The amounts of lost revenue that would be refunded or credited to PSI retail ratepayers depend on interpretation of various tariff provisions and other legal

[2] Exhibit KJJ-1:1-4 and Exhibit DFE at 4:9-12.

[3] Synapse computation based on response to CAC 6.1, roughly equal to values reported by Mr. Jennings in Exhibit KJJ-1.

requirements applicable during the time period the revenue was not being properly booked to PSI. Presumably, these amounts would be determined in Cause No. 38707-FAC61-S1 in accordance with Finding No. 17 of the Commission's order of September 22, 2004 in Cause No. 38707-FAC62.

6. Additional PSI net lost revenues are possible for the periods April 1, 2002 through December 31, 2002 and post-September 30, 2004. These net lost revenues should be computed and addressed in the aforementioned fuel adjustment clause sub-docket.

My post-MISO Day 2 evaluation encompasses the following subjects and is summarized as follows:

7. MISO's operational actions coordinating regional energy dispatch since the April 1, 2005 spot markets start-up represent a dramatic paradigm shift in the way in which generation is brought on-line and continuously maneuvered to meet the hourly variations in load throughout the Midwest. This structural modification to the MISO region electricity markets renders the JGDA physical dispatch provisions somewhat obsolete; the existence of MISO spot energy market prices renders the current pricing provisions obsolete.

8. The current differing regulatory treatment of PSI generation and CG&E generation creates an asymmetric incentive structure for sales of surplus energy. This structure creates a bias for off-system sales through CG&E to fully benefit Cinergy shareholders, rather than off-system sales made by PSI whose profits accrue in part to PSI ratepayers. It encourages Cinergy to act to maximize profits by "buying low" from PSI through the JGDA arrangement

and "selling high" through off-system sales. While the JGDA does not prohibit PSI from selling directly off-system, Cinergy has made a unilateral decision to originate all off-system sales through CG&E.

9. Now that MISO Day 2 spot markets are in existence, PSI should sell its surplus power directly into the MISO spot energy markets. PSI should develop or retain the ability to sell surplus power into the forward bilateral markets in the MISO region, to its own account, and not through sales originating through CG&E.

10. The absence of MISO reserve markets indicates that Cinergy still must designate and schedule, on a daily basis, generation units or portions of generation units required to meet operating reserve needs. A separate operating reserves agreement should be established to properly allocate the costs and benefits of operating reserve provision to PSI and CG&E.

11. Any value attributed to PSI's generation capacity through a future MISO capacity market structure should accrue to PSI ratepayers. Any sale of capacity on the part of PSI should occur at market prices.

12. I make nine specific recommendations, explained more fully in Section IV of my testimony and also addressed in the body of Sections II and III. In short:

    i. The incremental cost cap provision should be used solely for transfers used to meet native load.

    ii. A determination should be made in Cause No. 38707-FAC61-S1 as to the disposition of PSI net lost revenue totaling $10.203 million and consisting of 1) $3.500 million arising from the incremental cost cap issue, plus 2)

$6.704 million arising from the use of HMP instead of actual market value.

iii. A determination should be made in Cause No. 38707-FAC61-S1 as to the disposition of PSI net lost revenue of $1.485 million arising from the use of "Into Cinergy" prices instead of Cinergy-defined HMP. This amount is already accounted for in the $6.704 million noted in ii) 2) above.

iv. Additional lost revenues, if any, arising from the mechanisms noted above should be determined for the period April 1, 2002 through December 31, 2002, and from October 1, 2004 to the termination date of the JGDA, and returned to PSI ratepayers in accordance with the findings in the forthcoming Cause No. 38707-FAC61-S1.

v. The physical dispatch and energy transfer pricing provisions of the JGDA should be terminated as soon as possible now that MISO Day 2 markets have commenced.

vi. Initially, upon commencement of the MISO Day 2 spot energy markets, surplus short-term available energy from PSI resources should be valued at MISO Day 2 day-ahead or real-time spot prices, and should be sold into these markets.

vii. As soon as possible, PSI should retain or obtain the ability to sell surplus capacity and energy on a forward basis at time frames greater than MISO's day-ahead market allows. This ability should be independent of the CG&E wholesale market trading function.

viii. A separate System Regulation and Operating Reserve Agreement should be fashioned between PSI and CG&E reflecting the value of capacity for regulation and operating reserve needs and a fair allocation of the costs of and the benefits derived from regulation and operating reserve resources.

ix. If MISO establishes an installed capacity requirement, all PSI generation resource capacity benefits should accrue solely to PSI and its ratepayers.

II. CRITIQUE OF CINERGY'S INTERPRETATION AND IMPLEMENTATION OF PRICING ASPECTS OF THE JGDA

1. Data Deficiencies and Summary of JDGA Focus

Q. HAVE YOU REVIEWED THE JGDA AND THE PREFILED TESTIMONY AND EXHIBITS SUBMITTED IN THIS CAUSE BY CINERGY?

A. Yes. I reviewed the testimony and exhibits of Mr. Esamann, Mr. Jennings, and Ms. Weidmann.

Q. HAVE YOU REVIEWED THE INTER-COMPANY ENERGY TRANSFER TRANSACTION DATA PROVIDED BY CINERGY?

A. Yes. In a partial response to discovery request CAC 6.1, Cinergy provided hourly JGDA energy transfer transaction data for the period January 1, 2003 through October 2004. The data provided included all energy interchange transactions between PSI and CG&E for the period January 1, 2003 through October 31, 2004. The data also included transactions associated with post-merger, pre-JGDA contracts for the same period.

Q. WHY WAS THIS ONLY A "PARTIAL RESPONSE" TO THE DATA REQUEST?

A. In response to data request CAC 10.1, Cinergy indicated that it had computed hourly market prices for every hour since the JGDA was implemented, on April 1, 2002. However, Cinergy did not provide JGDA energy transaction data for all hours since April 1, 2002 in its response to CAC 6.1.

Q. WHAT REASON WAS GIVEN FOR THE PARTIAL RESPONSE TO DATA REQUEST CAC 6.1?

A. Cinergy stated that data for 2002 transactions (i.e., April 1 through December 31, 2002) was "in an earlier and different data base format, making it much more difficult to respond [to the request]"[4], even though the Settlement Agreement indicates that such information is to be maintained and provided to the Settlement parties in a reasonable and usable form[5].

Q. WHAT DOES THE SETTLEMENT AGREEMENT SAY ABOUT MAKING SUCH DATA AVAILABLE TO THE SETTLEMENT PARTIES, INCLUDING CAC?

A. The Settlement Agreement states,

> "In order to facilitate such assessment, PSI agrees to maintain and provide to the other Parties information relating to the days, hours, and amounts of system energy transfers made pursuant to the JGDA, the Market Prices applied to those transfers per the JGDA, and any independently audited price quotes obtained pursuant to the JGDA, in a reasonable and usable form and format and including necessary support documentation".[6]

Q. IN WHAT WAY HAS THIS LIMITED YOUR ANALYSIS?

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[4] Cinergy response to CAC 6.1.

[5] Esamann Exhibit DFE-3, page 4 (F). This is the Settlement Agreement in Cause 41954 entered into August 9, 2001.

[6] *Ibid*.

A. I have not been able to assess the efficacy and equity of the JGDA implementation for April 1 through December 31, 2002. I have also not been able to assess the efficacy and equity of the JGDA implementation for any hours since October 31, 2004. For comparative purposes, I limited my analysis to the period January 1, 2003 through September 30, 2004, consistent with the time period over which Mr. Esamann and Mr. Jennings reported JGDA energy transaction information.

Q. PLEASE DESCRIBE YOUR DATA ANALYSIS FOR THE PERIOD IN WHICH DATA WAS PROVIDED.

A. I analyzed the post-JGDA energy transfer data to confirm the fundamental energy transfer quantity, price, and revenue information provided by Mr. Jennings in his testimony[7] and attached Exhibit KJJ-1 and referenced by Mr. Esamann in his testimony.[8] I also analyzed the data to assess Cinergy's interpretation and implementation of the JGDA, in particular the way in which pricing terms are generated and used, and revenue amounts are computed.

Q. WHICH ASPECTS OF THE JGDA'S INTERPRETATION AND IMPLEMENTATION HAVE YOU FOCUSED ON?

A. I have focused on three aspects of JGDA interpretation and implementation.

First, I reviewed Cinergy's interpretation and implementation of the "incremental cost cap" provisions of the JGDA.

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[7] Jennings 6:1 through 7:14.

[8] Esamann 4: 1-12

Second, I have examined the way in which Cinergy applied hourly market prices to energy transfers between the companies during times when CG&E made simultaneous off-system sales, and how those prices and realized revenue compared with the actual prices and actual realized revenue received for the associated off-system sales.

Third, I analyzed the revenue impacts associated with using the independent "Into Cinergy" bilateral market hub price indices instead of using the Cinergy-derived hourly market price.

I address each of these in turn below.

2. Impact of Using the Incremental Cost Cap for Pricing Off-System Sales

Q. WHAT IS THE "INCREMENTAL COST CAP" AND HOW ARE PSI'S REVENUES FROM JGDA TRANSFERS TO CG&E IMPACTED BY IT?

A. The incremental cost cap refers to Cinergy's JGDA implementation practice of pricing certain energy transfers sourced at PSI and sunk at CG&E (to meet off-system sales obligations) at CG&E's "incremental cost cap", or the production cost of the next MWh of the receiving party.[9] As noted in Mr. Esamann's testimony[10], Cinergy interpreted the JGDA such that for hours when market prices are higher than the receiving company's incremental costs, incremental cost caps are applied to all energy transferred between the companies, whether the energy is destined to meet the

[9] As will be shown in Exhibit RMF-2, most of the incremental cost cap pricing of transfers used for off-system sales is associated with PSI-sourced generation. A small amount of CG&E sourced generation (destined for PSI) was priced at PSI's incremental cost, and my analysis reflects the net impact of these transfers.

[10] Esamann 9: 15-17.

receiving company's native load, or is resold on the wholesale market as an off-system sale.

Q. IS THERE AN ALTERNATIVE JGDA IMPLEMENTATION PRACTICE CONCERNING THE INCREMENTAL COST CAP?

A. Yes. The JGDA contains a pricing term ambiguity, in that the incremental cost cap could be applied to either all energy transfers between companies, or only to transfers used to serve native load. Cinergy has chosen the former interpretation, but has acknowledged the logic and validity of the latter.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY A "PRICING TERM AMBIGUITY" CONCERNING THE INCREMENTAL COST CAP PROVISION OF THE JGDA.

A. Section 4.01(b) of the agreement states that irrespective of any other provision of the agreement, energy transferred between companies will not be priced higher than the receiving party's incremental cost of using its own generation resources. Comparatively, section 4.04(a) states that "<u>any</u> transfer to CG&E or CPI, as applicable, will occur at Market Price" (emphasis added). These two statements are seemingly inconsistent with regards to how incremental cost cap pricing is to be implemented. I am advised by CAC counsel that his understanding from the 2001 negotiations was that this seeming inconsistency had been resolved by an express, oral understanding among the parties to the Indiana settlement relating to the JGDA that the incremental cost cap would apply only to transfers used to serve native load. However, the inclusion of the 4.01(b) clause has been interpreted by Cinergy to allow "at cap" pricing for transfers to CG&E even when the energy is ultimately used for an off-system sale.[11] This has resulted in lower revenue for PSI for energy transferred to CG&E and subsequently sold at market price, compared to the revenue PSI would have received if it were priced at hourly market price or if it were sold directly to an off-system purchaser.

Q. PLEASE EXPLAIN THE ALTERNATIVE INCREMENTAL COST CAP IMPLEMENTATION METHOD.

A. Energy transfers between the companies can be priced at the incremental cost cap of the receiving company only when the energy is used to meet the receiving company's native load. Mr. Esamann acknowledges this more logical interpretation of the JGDA, in his testimony at page 9, lines 18-21:

> "We agree that logically PSI should receive hourly market value for its system energy transfers except when those system energy transfers are being used to serve CG&E native load customers and the incremental cost cap comes into play".

Q. WHAT IMPACT DOES THIS HAVE ON REVENUES BOOKED ON BEHALF OF PSI?

A. When the incremental cost cap is applied to all transfers instead of only those transfers used to serve the receiving company's native load, it lowers the revenues received by PSI. Mr. Esamann and Mr. Jennings estimated that PSI received $2.4 million less in 2003 revenues, and $1 million less in 2004 revenues, due to the impact

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[11] Esamann 9: 15-17. "We have interpreted the JGDA according to its terms and have applied the incremental

of applying the incremental cost cap in this fashion.[12] As shown in Exhibt RMF-2, using the transaction data provided by Cinergy I computed a net PSI revenue loss of $2.521 million and $0.979 million, in 2003 and 2004, respectively, or a total of $3.500 million.

Q. DOES THIS REFLECT THE IMPACT OF THE INCREMENTAL COST CAP ON TRANSFERS ORIGINATING AT CG&E AND SENT TO PSI, AS WELL AS THOSE ORIGINATING AT PSI AND SENT TO CG&E?

A. Yes. Transfers to PSI from CG&E are minimal in 2004, and are zero in 2003. The impact of the 2004 transfers is reflected in this computation.

Q. HOW SHOULD DISPOSTION OF THIS NET LOST REVENUE BE DETERMINED?

A. The disposition of this net lost revenue should be determined in the forthcoming Cause No. 38707-FAC61-S1 in accordance with Finding No. 17 of the Commission's order of September 22, 2004 in Cause No. 38707-FAC62. The amounts of lost revenue that would be refunded or credited to PSI retail ratepayers depend on interpretation of various tariff provisions and other legal requirements applicable during the time period the revenue was not being properly booked to PSI.

Q. ARE THERE ADDITIONAL NET LOST REVENUES ASSOCIATED WITH THIS MECHANISM?

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cap to both transfers for native load purposes and transfers for trading purposes."

[12] Jennings 7: 11-14; Esamann 4: 9-12.

A. Yes, it is likely that there are additional net lost revenues. The $3.5 million in lost revenue described above is for the period January 1, 2003 through September 30, 2004. Additional net lost revenue for April 1, 2002 through December 31, 2002 and for October 1, 2004 through the present has not been computed for this mechanism due to a lack of data.

Q. PLEASE DESCRIBE HOW YOU COMPUTED THIS NET LOST REVENUE.

A. I used the data provided by Cinergy in response to CAC 6.1, which asked for JGDA energy interchange transaction quantities and prices; and the data provided in response to CAC 10.1 a), which asked for a file with Cinergy's "hourly market price" index by hour. Using a cross-tabulation approach, I summed up the revenues associated with "post-JGDA" transaction types across each of 2003 and 2004 (through September 30, 2004, to enable comparison with Mr. Jennings' exhibit). I isolated those transactions with a pricing method of "at cap" from those with a pricing method of either "at cost" or "at HMP". I also tabulated the revenue loss on the basis of company of origin and the company destined to receive the transferred energy. These computations are summarized in Exhibit RMF-2. I note that generally these values agree with the values reported by Mr. Jennings and Mr. Esamann, with differences which I presume are due to rounding protocols used by Mr. Jennings. I have computed lost revenues to the penny, based on Cinergy's data; I rounded to the nearest dollar in Exhibit 2, and to the nearest thousand dollars in my text above.

3. Impact of Using Hourly Market Price vs. Actual Market Price for JGDA Energy Transfers

Q. ARE THERE OTHER SOURCES OF PSI NET LOST REVENUE ARISING FROM CINERGY'S INTERPRETATION AND IMPLEMENTATION OF THE JGDA?

A. Yes. Cinergy has priced at "hourly market price" ("HMP") the energy transferred between the companies to meet off-system sales obligations. As a result, Cinergy earns revenue for these off-system sales that is greater than the revenue provided to PSI for the energy used to meet these obligations. Cinergy effectively "buys low" – at Cinergy-computed hourly prices from PSI resources -- and "sells high" – to off-system purchasers at actual market value. While PSI has received HMP, the off-system sales receive actual market price.

Q. HOW DOES THE JGDA DEFINE MARKET PRICE?

A. The JGDA defines "Market Price" as "the applicable hourly energy price at which the supplier could have sold the energy into the wholesale market if the exchange of energy between the Operating Companies did not take place". The JGDA proceeds to state that "Market Price will be determined by reference to actual sales quotes of hourly energy with similar characteristics to unaffiliated third parties".

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN HMP AND ACTUAL MARKET PRICE.

A. HMP is a Cinergy-defined and Cinergy-computed term used to value energy transfers between the companies. It is constructed in a fairly complex manner, one that is difficult to audit in a comprehensive and consistent manner. It is premised on the average price quote for off-system hourly sales received by Cinergy wholesale market traders.

Market price is the actual market price paid in any given hour for energy that is transferred between the companies and is delivered off-system to meet Cinergy sales obligations.

Q. PLEASE EXPLAIN HOW THE HMP IS CONSTRUCTED IN A COMPLEX MANNER AND WHY IT IS DIFFICULT TO AUDIT COMPREHENSIVELY AND CONSISTENTLY.

A. Cinergy provided an example and a set of "raw data" files in response to CAC 7.4, which asked specifically for the formulas used to compute the "index per Cinergy". The "index per Cinergy" is the HMP.[13] In the example provided in the response, a fairly simple diagram of a single off-system sale is given, which does not reflect the method used to compute the HMP and is not of value to anyone seeking to audit the HMP computation process (although it does indicate how transmission losses are accounted for). The HMP computation process involves averaging prices from several or many sales price quotes. The remainder of the response to CAC 7.4 was in the form of attached spreadsheets, with multiple worksheets in each file and no clear description of how the HMP was computed. For example, the worksheet entitled "JGDA index" contains a link to a cell on another worksheet, entitled "Trades". The linked cell contains a numerical value labeled as a "JGDA Index", but it does not contain a formula for how the value was arrived at.

Q. IN WHAT OTHER WAYS IS THE HMP A DIFFICULT PRICE FORMULATION TO AUDIT?

A. Based on the response to data request CAC 9.9 and CAC 9.10, which asked about how inter-company energy transfer valuation under the JGDA has changed over time, Cinergy provided a list of changes and referenced the JGDA Operating Committee minutes. In that response and in those minutes, Cinergy describes a number of changes to the methods used to compute HMP. For example, a new software system was implemented to account for transfers beginning January 1, 2003. Also, changes were made to the way in which the incremental cost cap was implemented; and there were changes to the way in which price quotes were used to compute the hourly index.

Q. WHAT DO YOU CONCLUDE ABOUT THE METHOD USED TO COMPUTE HMP?

A. At best, the method used requires more detailed documentation to allow an independent auditor to accurately assess the computational process. At worst, the structure invites computational error and leaves open the possibility for price manipulation. The creation of HMP's is purely internal to Cinergy, as it does not depend on any independent market price data, such as the current market indices for next-day power at the "Into Cinergy" hub or the actual market prices for off-system energy sales.

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[13] Response to discovery request CAC 10.1 b).

Q. WHAT IS THE DIFFERENCE IN REVENUES TO PSI WHEN ENERGY TRANSFERS ARE PRICED AT ACTUAL MARKET PRICE COMPARED TO BEING PRICED AT CINERGY-COMPUTED HMP?

A. PSI net lost revenues due to this implementation mechanism amount to a total of $4.769 million in 2003 and $1.934 million in 2004 (through September), for a total of $6.704 million.

Q. PLEASE DESCRIBE HOW YOU COMPUTED THIS PSI NET LOST REVENUE.

A. As with my earlier computation, I started with the data provided by Cinergy in response to CAC 6.1, which asked for JGDA energy interchange transaction quantities and prices.

I then first established the actual market prices for JGDA-transferred energy by reviewing the “Description of Sale Served” data, which was provided on an hourly basis for all transactions. For approximately 80% of the “post-JGDA” transaction records (i.e., those pertaining to JGDA energy transactions associated with off-system sales during the period January 1, 2003 through September 30, 2004) a market price was included in this data field. I extracted that price and created a new data field with this price level. For those transactions that did not report market price, I used the transaction price directly reported as “ICT Price” in the data set. I then computed actual market revenues based on this extracted price and the corresponding energy quantities associated with each transaction.

Using a similar cross-tabulation approach as the method used to examine the incremental cost cap impact, I summed up the revenues associated with “post-JGDA” transaction types across each of 2003 and 2004 (through September 30, 2004). These computations are summarized in Exhibit RMF-3.

Q. HOW SHOULD DISPOSTION OF THIS NET LOST REVENUE BE DETERMINED?

A. In the same manner as that described above for lost revenues arising from the “incremental cost cap” provisions, the disposition of this lost revenue should also be determined in the forthcoming Cause No. 38707-FAC61-S1 in accordance with Finding No. 17 of the Commission's order of September 22, 2004 in Cause No. 38707-FAC62.

Q. ARE ADDITIONAL PSI NET LOST REVENUES ASSOCIATED WITH THIS MECHANISM?

A. Yes, it is likely that there are additional net lost revenues. The $6.704 million in lost revenue described above is for the period January 1, 2003 through September 30, 2004. Additional lost revenue associated with this mechanism for April 1, 2002 through December 31, 2002 and for October 1, 2004 through the present has not been computed due to a lack of data.

Q. WILL HMP COMPUTATION BE REQUIRED AFTER THE START OF MISO DAY 2 MARKETS?

A. Fortunately, no. Any requirement to determine an hourly market price can and should depend upon regional hourly market prices as determined by MISO in its day-ahead or real-time markets. I address this in Section III of this testimony.

4. Impact of Using Into Cinergy Hub Prices to Value JGDA Energy Transfers Used for Off-System Sales

Q. IS THERE A MARKET PRICE INDEX OTHER THAN HMP THAT COULD HAVE BEEN USED TO VALUE INTERCOMPANY ENERGY TRANSFERS?

A. Yes. The “Into Cinergy” bilateral hub price index is an independently computed market index for energy delivered at the Cinergy hub.

Q. PLEASE DESCRIBE MARKET INDICES ASSOCIATED WITH THE “INTO CINERGY” BILATERAL HUB PRICES.

A. Commercial information services such as MW Daily publish forward price indices for power delivery at a number of hubs around the country, with the “Into Cinergy” hub being one of more liquid market locations. These reported prices are based upon an independent survey of transacted bilateral trades for power delivered “Into Cinergy”. In particular, prices are published for next-day delivery of power for blocks of on-peak hours or off-peak hours. While these prices are not hourly prices, but rather an average of prices across 16 or 8 hours, they do represent the market value of power and they are based upon a truly independent process of price quote collection.

Q. WOULD THE “INTO CINERGY” HUB PRICES BE A BETTER MARKET INDEX THAN “HMP” TO USE TO VALUE CINERGY INTERCOMPANY ENERGY TRANSFERS?

A. Yes. But I note that they still are not the most appropriate prices to use; the actual prices for the off-system sales associated with the inter-company transfers are the most appropriate because they perfectly capture the value of the off-system sale.

The "Into Cinergy" hub price is an independently derived price – compared to the Cinergy-computed HMP - that in comparison to HMP better represents actual market price not only because it is based on transaction prices from a competitive market, but also because it lessens even the perception of any possible price manipulation that could benefit Cinergy shareholders at the expense of captive PSI ratepayers.

Q. WHAT ARE THE INCREMENTAL NET LOST REVENUES IF THE "INTO CINERGY" HUB PRICES ARE USED INSTEAD OF THE HMP?

A. As summarized in Exhibit RMF-4, I calculate increased incremental net revenues for PSI of $0.310 million in 2003 and $1.175 million in 2004, for a total of $1.485 million.

Q. HOW DID YOU ARRIVE AT THESE VALUES?

A. In a manner similar to what I've described for the impact of using actual market prices instead of HMP, I summarized the net PSI lost revenue from using the "Into Cinergy" hub prices in place of the HMP. I calculated this lost revenue for those days when an "Into Cinergy" hub price was published, for hours during those days when JGDA energy transactions occurred to meet off-system sales obligations. Using the data supplied by Cinergy in response to CAC 6.3, which asked for "Into Cinergy" hub prices, and using the "post-JGDA" transaction data received in response to CAC 6.1, I substituted the "Into Cinergy" on-peak price for the HMP for each of the sixteen on-peak hours in each day with "Into Cinergy" prices and JGDA energy transactions used to meet off-system sales obligations. I substituted the off-peak "Into Cinergy" prices for HMP for the eight off-peak hours. For weekend days or any other days with no reported "Into Cinergy" hub prices, I carried over in the database the HMP (thus for transactions on these days, there are no incremental PSI lost revenues for this mechanism). I then computed revised revenues for all "post-JGDA" energy transaction types for the period January 1, 2003 through September 30, 2004. I compared these revenues to the revenues seen when using HMP.

Q. HOW SHOULD DISPOSTION OF THIS NET LOST REVENUE BE DETERMINED?

A. The disposition of this lost revenue should also be determined in the forthcoming Cause No. 38707-FAC61-S1.

Q. IS THERE ADDITIONAL NET LOST REVENUE ASSOCIATED WITH THIS MECHANISM THAT YOU HAVE NOT ACCOUNTED FOR IN YOUR ANALYSIS?

A. Yes, it is likely there is. As has been seen with my earlier analyses, this calculation also excludes lost revenues through this mechanism for the periods April 2002 through December 2002, and for post-October 1, 2004.

Q. SINCE "INTO CINERGY" HUB PRICES ARE FOR NEXT-DAY MULTI-HOUR BLOCKS OF ENERGY, ISN'T IT INCONSISTENT TO CONSIDER THEM TO VALUE ENERGY THAT IS TRANSFERRED ON AN HOURLY BASIS?

A. No, it is not. While "Into Cinergy" hub prices are not as good a valuation metric as the actual market prices, it is not inconsistent to consider them for valuing the inter-company energy transfers.

Physical energy transfers between PSI and CG&E occur continuously. Daily scheduling processes and daily unit commitment decisions frame much of the complex operational process in large power systems and control areas such as Cinergy. While dispatch, tracking and settlement are often done on an hourly basis, the ultimate value of inter-company exchanges is directly tied to the bilateral market in which off-system sales are made, and many of those are for multiple-hour blocks. In the MISO region, the bilateral market is relatively liquid for daily block sales; yet relatively illiquid for hourly sales, evidenced by the lack of an index for hourly trades. This is noted by Mr. Esamann; thus a "proxy" method was created to value hourly transfers.[14] The JGDA hourly pricing construct is thus primarily an accounting vehicle, as indicated by Cinergy's use of an after-the-fact mechanism – the PACE tool[15] – to allocate hourly energy, and not an explicit market valuation tool.

Much of the energy sold off-system in the MISO region is sold under bilateral contracting structures using industry-standard multi-hour energy blocks as a unit of sale. In Cinergy's case, these sales are made forward, and energy is either generated, procured or transferred between sister companies – mostly from PSI to CGE – to meet the forward obligation. Thus the ultimate value of the off-system sales is the price paid for the forward-sold energy.

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[14] Exhibit DFE 8:12-18.

[15] Exhibit KJJ 2:12 – 4:13.

5. Relationship of Retrospective Analysis to Prospective JGDA Interpretation and Implementation

Q. IS THERE A RELATIONSHIP BETWEEN YOUR ANALYSIS OF JGDA INTERPRETATION AND IMPLEMENTATION PRE-MISO DAY 2 AND YOUR ANALYSIS OF THE ALTERNATIVES OF RETAINING, MODIFYING OR TERMINATING THE JGDA POST-MISO DAY 2?

A. Yes, there is.

Q. PLEASE EXPLAIN THAT RELATIONSHIP.

A. Cinergy has proposed in this Cause[16] and filed a petition with FERC[17] to continue the JGDA post-MISO Day 2. In addition, PSI generation will continue to be regulated and CG&E generation will continue to be unregulated at the state level post-MISO Day 2. Consequently, Cinergy interpretation and implementation of the JGDA will continue to be quite relevant post-MISO Day 2. It is thus important to understand and evaluate how Cinergy has interpreted and implemented the JGDA and the consequences of those actions for PSI customers pre-MISO Day 2 (as well as to understand and evaluate the ways in which PSI proposes to change its prior interpretation and implementation) in order to properly anticipate and assess Cinergy's post-MISO Day 2 JGDA interpretation and implementation.

I address post-MISO Day 2 issues in the following section.

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[16] Cinergy filing to IURC, "Confirmation of Intent to Use Hourly Market Clearing Price", January 31, 2005.

[17] Cinergy filing to FERC, Docket No. ER05-640, February 23, 2005.

III. ASSESSMENT OF THE FEASIBILITY, EFFICIENCY AND EQUITY OF CONTINUING THE JGDA AND ITS ASSOCIATED SYSTEM ENERGY TRANSFERS

1. MISO Day 2 Energy Market Summary Impact On JGDA Energy Transfers

Q. HOW WILL COMMENCEMENT OF MISO DAY 2 MARKETS IMPACT THE DISPATCH OF PSI AND OTHER CINERGY GENERATION?

A. Prior to April 1, 2005, PSI, CG&E and CPI generation units were committed and dispatched by Cinergy under the JGDA. Neighboring utilities in the MISO region also conduced their own commitment and dispatch. Simultaneously, all of the utilities traded power, somewhat continuously, and bilaterally, based on the marginal economics of buying or selling power to meet expected and unexpected patterns of demand, and constrained by the realities of transmission system capacities and planned and unplanned equipment outages. That system of trade, in place until just recently, had evolved from a rich history of bilateral transactions among these entities, and involved complex systems of exchange between defined regions. That exchange, or “interchange”, used the shared transmission system to economically flow power from regions or systems with lower cost energy to regions or systems that would have otherwise depended on higher cost power.

Upon startup of the MISO Day 2 markets, Cinergy units, along with much of the approximately 132,000 MW of generation within the MISO region footprint[18] are centrally dispatched by MISO. MISO also commits MISO-region units in its day-ahead and RAC processes, or recognizes the self-commitment of units by individual

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[18]Midwest ISO, at www.midwestmarket.org.

generation owners.[19] These centralized operational actions to coordinate energy dispatch by MISO represent a dramatic paradigm shift in the way in which generation is brought on-line and continuously maneuvered to meet the hourly variations in load throughout the Midwest.

This has effectively created a single system supply curve of generation units in the broader Midwest region, which are committed and dispatched against the aggregate load of the utilities in MISO, subject to the locational considerations inherent in the security-constrained commitment and dispatch approach used by MISO. The intended effect will be to increase the overall commitment and dispatch efficiency in the region (thereby lowering the overall production costs to meet load) compared to independent commitment and dispatch procedures previously in use by utilities in the MISO region.

Q. DOES THIS PARADIGM SHIFT RENDER INDIVIDUAL UTILITY OR INDEPENDENT POWER PRODUCER COMMITMENT AND DISPATCH OBSOLETE?

A. No. However, it does offer each utility or independent power producer the option of participating in a centralized unit commitment and dispatch process. While utilities could choose to self-commit and "self-dispatch" or "self-schedule" energy with the MISO, doing so independent of the economics of MISO's commitment and dispatch could prove uneconomic to any given utility or power producer, particularly when applied to generation units that might sometime be on the system margin, i.e., intermediate and peaking units.

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[19] Generation units with long lead times may be self-committed outside the MISO commitment processes.

Q. HOW MIGHT IT BE UNECONOMIC TO NOT PARTICIPATE IN MISO'S COMMITMENT AND DISPATCH PROCESS?

A. MISO in effect offers a centralized exchange for physical power in the very-short term periods of day-ahead, and real-time. If MISO has power available at a lower cost than an individual utility or generator, it would be uneconomic to generate power to meet any given obligation if the power can be procured through MISO at a lower cost. The presence of the MISO short-term markets provides a new means to "bring to delivery" all longer-term obligations for sales and purchases.

Q. DOES MISO'S CENTRALIZED ENERGY EXCHANGE OFFER A VIABLE ALTERNATIVE MECHANISM FOR THE MARKET-PRICING OF SURPLUS PSI POWER?

A. Yes, it is an alternative for pricing short-term spot sales. I discuss this alternative in the following section.

2. Alternative Arrangements for Pricing PSI Surplus Energy

Q. ARE THERE ALTERNATIVE ARRANGEMENTS AVAILABLE FOR PRICING PSI SURPLUS ENERGY?

A. Yes, there are arrangements that could be used in place of the JGDA mechanism.

One alternative is for all surplus energy from PSI units to be sold into the MISO Day 2 spot markets, either the day-ahead or the real-time spot market, when economical to do so. This sales mechanism would allow for true and transparent market-based pricing of surplus energy without reliance on a Cinergy-generated hourly market price index.

A second, sometimes competing alternative is for some portion of PSI surplus energy to be sold in longer-term forward bilateral markets.

Deciding which market is best to sell surplus energy into – i.e., is likely to fetch the highest price - would depend on the status of PSI generation availability, projections of load requirements and the need to ensure adequate reserves for native load obligations, and the relative risks and rewards of making short-term or longer-term sales. Selling surplus power through forward bilateral markets would potentially allow for capture of additional benefits for PSI ratepayers to the extent that the risks inherent in selling forward outweigh the risks of waiting to sell in the short-term day-ahead or real-time MISO markets.

Q. WHAT IS THE INTERRELATIONSHIP BETWEEN THESE ALTERNATIVES FOR SURPLUS POWER: SALES INTO MISO'S SPOT MARKETS, OR SALES THROUGH BILATERAL, FORWARD MARKETS?

A. Ultimately, all physical power will need to be bilaterally scheduled through the MISO, or sold into/purchased from the clearing spot markets. However, the value of energy physically flowing as a result of the scheduling and clearing processes of MISO's operations is not necessarily equal to the spot market prices. While the spot price indicates the marginal price to sell or buy, market participants can still agree on a forward price for power independent of the price in the spot markets. This temporal dimension is a fundamental quality of electricity markets. Such transactions may be conducted because parties – sellers and buyers – may wish to avoid the volatility that can accompany spot electricity markets.

Q. WHAT DOES THIS MEAN FOR PSI SURPLUS POWER?

A. PSI surplus power could be sold at greater value in either the MISO spot markets, or in the bilateral forward markets, depending on market conditions. In electricity markets, the volatility of spot market prices can lead to decisions by sellers and buyers to transact in forward time frames, to avoid the exposure of having to sell and buy at spot prices that are different than buyers and sellers may be prepared to pay or be paid.

Q. IF PSI WAS TO SELL INTO THE MISO SPOT MARKETS, WHICH MARKETS AND AT WHAT LOCATION(S) WOULD THE ENERGY BE SOLD INTO?

A. PSI could economically sell its surplus into both the day-ahead and the real-time market, depending on system conditions. It could sell at each generator's bus location, or it could arrange to sell at any other delivery point on the MISO grid, including locations external to MISO's region if an external pricing point is computed by MISO.

Q. PLEASE EXPLAIN HOW PSI COULD SELL INTO THE DAY-AHEAD MARKET.

A. The day-ahead market structure allows for PSI to participate in MISO's security-constrained unit commitment process, and then enter into a binding financial commitment to sell energy into the day-ahead market based on PSI's start-up, no-load, and energy block offer prices. PSI energy offerings would clear in the MISO day-ahead market if it were economical to operate and run the units – i.e., the revenue received by PSI from its sales would equal or exceed production costs, including the start-up and no-load costs. Whether or not PSI offerings would clear in the MISO day-ahead market would depend on the price and quantity of the remaining MISO supply offerings and the overall level of bids to purchase energy by market participants. Fundamentally, the level of PSI sales into this market will depend on supply and demand balance and the degree of competitiveness of the PSI units.

Q. PLEASE EXPLAIN HOW PSI COULD ALSO SELL INTO THE REAL TIME MARKET.

A. Subsequent to the close of the financially binding day-ahead market, PSI would make its final physical offerings into the MISO real-time market, including participation in the MISO's reliability assessment commitment ("RAC") process. This process allows all market participants to offer into the real time market even if they did not clear in the day-ahead market. As with the day-ahead market, PSI would submit offers based on the start-up, no-load and operating costs of its units. PSI energy offerings into the real-time market would clear based on economics, again only if the prices received were adequate to cover start-up, no-load and operating costs.[20]

PSI's net sales (or purchases) into (from) the MISO market would depend solely on the day-to-day operating economics of PSI's units and the MISO regional market.

Q. PLEASE EXPLAIN HOW PSI COULD SELL INTO LONGER-TERM BILATERAL FORWARD MARKETS.

A. PSI could sell surplus power in the bilateral forward markets in the same manner as wholesale sellers and buyers currently do throughout the North American electricity market, agreeing on price and quantity terms. The mechanism for physical delivery of such sales would change relative to recent physical delivery options, since the MISO spot markets are now in place. PSI would meet the obligations such sales would convey by either physically scheduling its own resources, or buying energy on the MISO spot markets when doing so would be cheaper than using its own resources to meet the obligation.

Q. WITH THE INTRODUCTION OF MISO SPOT MARKETS, WOULD THERE BE A NEED FOR INTERCOMPANY ENERGY TRANSFERS?

A. No. The MISO market would become the new physical "balancing market" to sell surplus power for either PSI or CG&E, or to purchase economy energy if PSI or CG&E unit output were more costly than MISO market purchases.

Q. WOULD THERE BE A NEED TO TRACK EACH COMPANY'S INCREMENTAL COST TO DETERMINE TRANSFER PRICING FOR INTER-COMPANY SALES USED TO MEET NATIVE LOAD?

A. No. All native load requirements not met by each company's own generation would be sourced through MISO and priced at the MISO day-ahead or real-time market price; or sourced and priced under longer-term bilateral contracts executed by each company on behalf of its own native load.

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[20] In both the day-ahead and the real-time markets, there will likely be some need to commit and/or dispatch energy "out of merit" by the MISO, to ensure reliability in some areas.

Q. WHAT IS SERVICE SCHEDULE A OF THE JGDA?

A. Service schedule A describes the hourly energy transfer price arrangements of the JGDA. It includes language that would allow for its survival for a period not to exceed 180 days if agreed to by the parties to the JGDA.

Q. SHOULD "SERVICE SCHEDULE A" OF THE JGDA BE RETAINED AFTER TERMINATION OF THE JGDA?

A. No. Service schedule A contains the same pricing ambiguity I described earlier, where transfer value is capped at the incremental cost of the receiving party's generation resource. With the alternative pricing options available for PSI surplus power, service schedule A is unnecessary.

Q. HOW SHOULD PSI DETERMINE WHETHER OR NOT TO SELL ANY SURPLUS ENERGY OUTSIDE OF THE MISO DAY 2 MARKETS?

A. PSI should obtain or retain the ability to sell surplus power in the forward bilateral markets, to its own account, and not through sales originating through CG&E. PSI should then uphold its obligation to customers to maximize its revenues from off-system sales and obtain the greatest value in utilizing its generation assets. This in turn will provide customers with least-cost electricity service, to the greatest extent possible. It should do this through careful analysis of the risks of selling forward vs. selling into the MISO spot markets for surplus energy.

Q. WHY SHOULD PSI DEVELOP OR RETAIN SUCH ABILITY, WHEN CINERGY CURRENTLY HAS THAT ABILITY THROUGH THE CG&E WHOLESALE TRADING OPERATIONS?

A. As I describe in the next section, the current differing regulatory treatment of PSI generation and CG&E generation creates an asymmetric incentive structure for sales of surplus energy. This structure creates a bias for sales through CG&E to benefit Cinergy shareholders, compared to sales made by PSI that benefit PSI ratepayers.

3. Different Regulatory Treatment of PSI and CG&E Generation Assets

Q. PLEASE DESCRIBE THE REGULATORY STATUS OF THE GENERATION FUNCTIONS OF PSI AND CG&E.

A. PSI remains a fully regulated integrated utility, with 7,055 MW of rate-based generation assets whose revenue requirements are guaranteed by Indiana consumers.[21] CG&E remains regulated, but only for transmission and distribution functions; its generation assets, and those of its subsidiary, Cinergy Power Investments ("CPI"), remain unregulated. CG&E and CPI have 6,276 MW of generation assets.[22]

Q. HOW DOES THE REGULATORY STATUS OF PSI AND CG&E'S GENERATION FUNCTION IMPACT CONSIDERATION OF THE JGDA?

A. CG&E sells all of its power on the competitive market, after first meeting its obligation to sell at a fixed-price tariff to Ohio customers who have not switched to an alternative retail supplier. CG&E is no longer guaranteed a regulated return on their generation assets. PSI is guaranteed cost recovery for its generation assets, and sells to their native load at IURC-approved rates.

[21] Cinergy SEC 10K, February 25, 2005, page 19.

[22] *Ibid*., page 17.

All off-system wholesale sales of Cinergy system power are originated with CG&E, and PSI's exposure to the competitive market is solely via the transfer pricing mechanism described in the JGDA. This arrangement encourages CG&E in particular, as an unregulated entity, to act to maximize profits by "buying low" and "selling high" where possible. As I described in the previous section reviewing the implementation of the JGDA, CG&E has been doing just that – buying low from PSI, and selling high on the marketplace, for the benefit of Cinergy shareholders. Conversely, PSI does not actively participate in selling its surplus power to the market[23], although the JGDA does not prohibit this.

This asymmetric regulatory treatment between the two generation entities does not create the proper incentive for PSI to maximize the value of ratepayer-funded generation assets, on behalf of ratepayers, from sales of surplus power. If that were the case, PSI would be selling off-system directly, at least for some portion of its surplus.

To maximize the value of PSI's assets on behalf of ratepayers, the regulated PSI generation function needs to maximize revenues for sales of off-system PSI power while retaining a reliable level of service for its customers. This can only be accomplished if there is a separation between sales of surplus PSI power, and that of surplus power from CG&E assets.

Q. DOES THE JGDA AS IMPLEMENTED BY CINERGY RESULT IN A SYMMETRIC ARRANGEMENT FOR PRICING POWER FLOWS BEWEEN

[23] *Ibid*., page 9, "In April 2002, CG&E and PSI executed a new joint operating agreement whereby new power marketing and trading contracts since April 2002 are originated on behalf of CG&E only. Historically,

PSI AND CG&E WHEN THE ULTIMATE DESTINATION OF THE POWER IS AN OFF-SYSTEM SALE?

A. No. The pricing arrangement is asymmetric, since all off-system sales originate from CG&E, even if the power is sourced from PSI generation. As I've noted, there is nothing in the JGDA which requires or authorizes all off-system sales to originate from CG&E; this decision apparently was a unilateral action on Cinergy's part.

4. MISO Region Operating Reserve and Capacity Structure Impact on the JGDA

Q. WILL THE MISO DAY 2 MARKET START ALSO INCLUDE OPERATING RESERVE MARKETS?

A. No. Individual control areas, such as Cinergy, will be responsible for providing their own operating reserve requirements. MISO is expected to develop centralized operating reserve markets at some point in the future.

Q. WILL THE MISO DAY 2 MARKETS ADDRESS INSTALLED CAPACITY REQUIREMENTS?

A. Not directly. Unlike the Northeast region RTOs and ISOs, MISO will not have a functional "installed capacity" market or similar clearing mechanism in place at the commencement of its energy market.

Q. HOW DOES THE ABSENCE OF MISO OPERATING RESERVE OR INSTALLED CAPACITY MARKETS INFLUENCE THE NEED FOR A JGDA?

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such contracts were executed on behalf of CG&E and PSI jointly."

A. The absence of MISO reserve markets indicates that Cinergy still must designate and schedule, on a daily basis, generation units or portions of generation units required to meet operating reserve needs. In the future, MISO will likely administer centrally-run operating reserve markets, as is currently done in the other RTOs and ISO in the northeast. In the interim, Cinergy must still act on its own to secure required reserves from the PSI and CG&E units.

The absence of a MISO installed capacity construct does not influence the need for a JGDA, since PSI and CG&E conduct capacity planning outside of the parameters of the JGDA.

Q. HOW SHOULD REGULATION AND OPERATING RESERVES BE HANDLED AFTER MISO DAY 2 MARKETS COMMENCE?

A. A separate agreement is required to address regulation and operating reserves. This agreement would address the physical dispatch issues present between the companies. The current JGDA does not provide any clear direction on how regulation and operating reserves costs and benefits should be shared between the companies. Once regulation and operating reserve markets are established by MISO, this agreement could sunset.

Q. HOW SHOULD THE COSTS FOR OPERATING RESERVES BE ALLOCATED BETWEEN PSI AND CG&E?

A. The overall costs to provide operating reserves for the Cinergy control area should be allocated proportionately between PSI and CG&E. A tabulation of daily regulation and operating reserve costs should be maintained. For any imbalance between proportional obligation and physical plant provision, each company should pay the other.

Q. HOW SHOULD THE OVERALL COSTS TO PROVIDE CINERGY SYSTEM REGULATION AND OPERATING RESERVES BE DETERMINED?

A. Operating reserve and regulation service provided by generation capacity is unit-specific. An accurate accounting of the commitment and dispatch costs, including opportunity costs – e.g., the costs associated with posturing generation capacity for spinning reserve provision, and not selling energy - should be maintained on at least a daily basis, and preferably an hourly basis for all units providing operating reserves and regulation.

Q. ON WHAT BASIS SHOULD A "PROPORTIONAL OBLIGATION" BE DETERMINED?

A. Daily peak load is the most obvious candidate for assigning operating reserves obligation between PSI and CG&E. ECAR operating reserve rules tied to daily peak load guide MISO requirements for operating reserve provision, and those rules specify a daily operating reserves requirement[24] to maintain regulation, spinning and non-spinning operating reserve capacity.

Q. WHAT DO YOU RECOMMEND ONCE (OR IF) MISO DEVELOPS REGULATION AND OPERATING RESERVES MARKETS?

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[24] See the response to discovery request CAC 9.1.

A. I recommend that the inter-company agreement sunset, and that PSI and CG&E independently provide their own regulation and operating reserve requirements, sell surplus regulation and operating reserve through the MISO regulation and reserve markets when economic to do so, or purchase required regulation or operation reserves from the MISO markets when that is more economical than self-provision.

Q. HOW IS INSTALLED CAPACITY IN THE MISO REGION CURRENTLY VALUED?

A. Installed capacity is not explicitly valued in a consistent manner across the MISO region; there are no MISO-region wide "installed capacity" markets. Some capacity is subject to regulated revenue recovery; and other capacity must obtain required returns through the marketplace. Capacity requirements vary across the region and are based on either State-level or NERC region requirements, or both. There is no explicit short-term transparent market price for incremental capacity available to meet any obligations imposed by individual States or NERC regions.

Q. WHAT WOULD A MISO-ADMINISTERED INSTALLED CAPACITY MARKET LOOK LIKE?

A. A MISO-administered capacity market could take any number of forms; though I suspect it will likely look similar to the installed capacity markets in place in PJM, New York or New England, since the MISO has looked to the approaches used in those regions when formulating its detailed energy market tariff provisions. However, I have no specific knowledge of any mechanisms planned by the MISO, nor do I take a position in this testimony on the merits of any potential approaches.

Q. IF SOME FORM OF AN INSTALLED CAPACITY MARKET STRUCTURE IS IMPLEMENTED IN THE MISO REGION, HOW SHOULD PSI AND CG&E'S GENERATION CAPACITY PARTICIPATE IN SUCH A MARKET?

A. Any value attributed to PSI's generation capacity through a MISO capacity market structure should accrue to PSI ratepayers. Any sale of capacity on the part of PSI should occur at market prices.

5. Conclusions on Efficiency and Equity of JGDA Continuance

Q. IS IT EFFICACIOUS FOR THE DISPATCH AND TRANSFER PRICING PROVISIONS OF THE JGDA TO CONTINUE AFTER COMMENCEMENT OF MISO DAY 2 MARKETS?

A. No. It is no longer efficacious to have the physical dispatch and transfer pricing provisions of the joint generation dispatch agreement, because of the paradigm shift taking place with the introduction of MISO centralized unit commitment and dispatch for energy, and the establishment of MISO spot market prices. Jointly dispatching PSI and CG&E generation separate from the economics of the MISO market structure would likely lead to inefficiencies in the production of energy for PSI and CG&E native load obligations, and inefficiencies in determining the economic level of off-system sales and purchases. An alternative, independent spot price administered by MISO renders obsolete the transfer pricing scheme of the JGDA.

Q. IS IT EQUITABLE FOR PSI TO CONTINUE THE JGDA?

A. No. Equity arrangements between PSI, CG&E and Cinergy can be best addressed through termination of the dispatch and transfer pricing provisions of the agreement and recognition that with the introduction of MISO spot markets, a transparent, liquid market alternative exists to sell the excess energy from PSI's system resources. Any remaining efficiencies and opportunities for forward sale of PSI surplus energy should be coordinated by PSI.

IV. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I have nine recommendations:

1. All system energy transfers between PSI and CG&E from April 1, 2002 to the date of termination of the JGDA should be priced on a market basis, unless the energy was used to meet native load requirements of either PSI or CG&E. The incremental cost of the receiving company's generation should be used as a cap only if the transfers were/are to be used to meet the receiving company's native load requirements.

2. A determination should be made in Cause No. 38707-FAC61-S1 as to the disposition of PSI net lost revenue totaling $10.203 million arising from:

   i) The current JGDA implementation method, whereby incremental cost caps were/are in place even for inter-company energy transfers not destined to meet native load. For transactions occurring between January 1, 2003 and September 30, 2004, I calculate that "at cap" inter-company transactions used for off-system sales resulted in a total of $3.500 million in net lost revenues.

   ii) The use of hourly market price methods that inconsistently account for actual transaction prices. For transactions occurring between January 1, 2003 and September 30, 2004, I calculate that such price computation inconsistencies for inter-company transactions used for off-system sales resulted in a total of $6.704 million in PSI net lost revenues.

3. A determination should be made in Cause No. 38707-FAC61-S1 as to the disposition of PSI net lost revenue arising from the use of hourly market price methods instead of using independently-computed "Into Cinergy" indices when appropriate, if not

already included by using the actual market value to price JGDA transfers. For transactions occurring between January 1, 2003 and September 30, 2004, I calculate that substituting “Into Cinergy” indices when appropriate for the HMP results in a total of $1.484 million in PSI net lost revenues.

4. Additional PSI net lost revenues, if any, arising from the mechanisms noted above should be determined for the period April 1, 2002 through December 31, 2002, and from October 1, 2004 to the termination date of the JGDA. The disposition of any additional net lost revenues accruing over these periods should also be determined in Cause No. 38707-FAC61-S1.
5. The physical dispatch and energy transfer pricing provisions of the JGDA should be terminated as soon as possible, since MISO Day 2 spot markets have commenced. The MISO Day 2 market structure and the presence of MISO hourly spot prices render obsolete these aspects of the JGDA.
6. Initially, upon commencement of the MISO Day 2 spot energy markets, surplus short-term available energy from PSI resources should be valued at MISO Day 2 day-ahead or real-time spot prices, and should be sold into these markets.
7. As soon as possible, PSI should retain or obtain the ability to sell surplus capacity and energy on a forward basis at time frames greater than MISO’s day-ahead market allows. This ability should be independent of the CG&E wholesale market trading function. The asymmetrical incentive structure for off-system sales currently present between CG&E and PSI due to the deregulation of CG&E generation and the ongoing regulation of PSI generation creates a bias against PSI ratepayer interests. Once this ability is in place, PSI should make arrangements to prudently sell a portion of PSI

surplus energy in forward bilateral markets, and the remaining in the MISO spot markets.

8. A separate System Regulation and Operating Reserve Agreement should be fashioned between the Companies reflecting the value of capacity for operating reserve needs and a fair allocation of the costs of and the benefits derived from regulation and operating reserve resources.

9. If MISO establishes an installed capacity requirement, all PSI generation resource capacity benefits should accrue solely to PSI and its ratepayers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Robert M. Fagan

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SUMMARY

Mechanical engineer and energy economics analyst with over 19 years experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission pricing structures, wholesale electricity market development, and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.

Additional expertise in:

- Expert witness testimony preparation.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based, GE MAPS and online DOE-2 residential).

Proficient in:

- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Senior Associate
Responsibilities including consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management.

- Provided expert witness testimony before the Texas Public Utility Commission on stranded cost recovery and excess mitigation credits in Texas.
- Submitted expert witness testimony to the Nova Scotia Utilities and Review Board on the Open Access Transmission Tariff proposal by Nova Scotia Power.
- Submitted joint testimony to the Maine Public Utilities Commission on a proposal by Maine Public Service to purchase long-term transmission capacity from New Brunswick Power.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training
Completed coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).
Completed Illuminating Engineering Society courses in lighting design (1989).

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

TESTIMONY

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB and on behalf of the UARB In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. April 14, 2005.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

MAJOR PROJECT WORK – BY CATEGORY

Electric Utility Industry Restructuring

For TransAlta Energy Corporation, developed an issues and information paper on recent Ontario and Alberta market development efforts, focusing on the likely high-level impacts associated with day-ahead and capacity market mechanisms considered in each of those regions. (2004)

For a wholesale energy market stakeholder, participate in New England and PJM RTO markets and market implementation committee meetings, review and summarize material, and advocate on behalf of client on selected market design issues. (2004) Performed similar activities for separate client in New England. (2001)

For a group of potential generation investors in Ontario, analyzed the government's proposed wholesale and retail market design changes and produced an advocacy report for submission to the Ontario Ministry of Energy. The report emphasized, among other things, the importance of retaining a competitive wholesale market structure. (2004)

For a large midwestern utility, supported multiple rounds of direct and rebuttal testimony to the US FERC by Dr. Richard Tabors on the proposed start-up of LMP markets in the Midwest ISO utility service territories. Testimony substance included PJM-MISO seams concerns, FTR allocation options, grandfathered transactions incorporation, FTR and energy market efficiency impacts, and other wholesale market and MISO transmission tariff design issues. Testimony also included quantitative analysis using GE MAPS security-constrained dispatch model runs. (2003-2004)

For the Independent Power Producers Society of Ontario, with TCA Director Seabron Adamson, developed a position paper on resource adequacy mechanisms for the Ontario electricity market. (2003)

For TransAlta Energy Corp., provided direct and reply testimony to the Ontario Energy Board on the Transmission System Code review process. Analyzed and reported on transmission “bypass” and network cost responsibility issues. (2002-2003)

For a commercial electricity marketer in Ontario, with TCA staff, analyzed Ontario market rules for interregional transactions, focusing primarily on the Michigan and New York interties, and assessed the current Ontario electricity market policy related to “failed intertie transactions”. (2002)

For ESBI Alberta Ltd., then Transmission Administrator (TA) of Alberta, served as a key member of the TCA team exploring congestion management issues in the Province, and providing guidance to the TA in presenting congestion management options to Alberta stakeholders, with a particular focus on new transmission expansion pricing and cost allocation issues. (2001)

For a coalition of power producers and marketers in Alberta, filed joint expert witness testimony with Dr. Tabors on the nature of certain transmission access charges associated with supply transmission service. (2001)

For a prospective market participant, served as a core member of the project team that developed summary reports on the New York, New England and PJM wholesale electricity spot market structures. The reports focused on market structure fundamentals, historical transmission flow patterns, forecasted transmission congestion and costs, transmission availability and FTR valuation and market results. (2001)

For the ERCOT ISO, served as a key TCA team member helping to develop and assemble a set of protocols to guide the principles, operation and settlement of the forthcoming Texas competitive wholesale electricity market. (2000)

For the Independent Power Producer’s Society of Ontario, served as expert witness and filed evidence with the Ontario Energy Board supporting an alternative transmission tariff design, and critiquing Ontario Hydro Networks Company’s (OHNC) proposed rate structure. Also a member of OHNC’s Advisory Team on net versus gross billing issues and a leading proponent of a progressive, embedded-generation-friendly tariff structure. (1999-2000)

For a large midwestern utility, designed transmission tariff and wholesale market structures consistent with the proposed establishment of an Independent Transmission Company paradigm for transmission operations. (1999-2000)

For a coalition of independent power producers and marketers in Alberta, helped develop evidence submitted by Dr. Tabors and Dr. Steven Stoft with the Alberta Energy and Utilities Board supporting an alternative to ESBI's proposed transmission tariff. The evidence critiqued the fairness and efficiency of ESBI's proposed tariff, and offered a simple alternative to deal with Alberta's near-term southern supply shortage. (1999)

For Enron Canada Corp., provided ongoing technical support and policy advice during the tenure of the Ontario Market Design Committee (MDC). Presented material on congestion pricing before the committee, and submitted technical assessments of most wholesale market development issues. (1998-1999)

Member of the Ontario Wholesale Market Design Technical Panel. The panel's responsibilities included refinement of the wholesale market design as specified by the Market Design Committee, and specification of the market's initial operating requirements. Also served on two sub-panels: bidding and scheduling; and ancillary services. (1998-1999)

For Enron Canada Corp, assessed the generation markets in Ontario and Alberta and recommended policies for maximizing competitive market mechanisms and minimizing stranded cost burdens. Authored reports on stranded costs in Ontario, and on the legislated hedges structure in Alberta. (1997 - 1998)

For an independent power producer, assessed New England markets for electricity and assisted in valuation of generation assets for sale. (1997)

In support of testimony filed by CCEM (Coalition for Competitive Electric Markets) with the FERC, assessed alternative transmission pricing and wholesale market structures proposed for the NY, NE and PJM regions. The filings proposed market mechanisms to produce competitive wholesale electric energy markets and zonal-based transmission pricing structures. (1996-1997)

Electric Utility Mergers and Market Power Analysis

In support of FERC-filed testimony by Dr. Richard Tabors, conducted a detailed examination of the accessibility of transmission service for wholesale energy market participants on the American Electric Power and Central and Southwest transmission systems. This included evaluating all transmission service requests made over the OASIS for the first six months of 1998 for the two utility systems, and a subsequent, more detailed assessment of AEP's transmission system use during all of 1998. (1998-1999)

For a US western electric utility, served as a member of the team that conducted detailed production cost modeling and strategic market assessment to determine the extent or absence of market power held by the client. (1998)

For an independent power producer, supported FERC-filed testimony on market power issues in the New York State energy and capacity markets. This included detailed supply-curve assessment of existing generation assets within the New York Power Pool. (1997)

Worked with a local economic consulting firm for a Western State public agency in conducting an analysis of the projected savings of a series of proposed electric and gas utility mergers. (1997)

For a southwestern utility company, supported CRA in conducting an analysis of the competitive effects of a proposed electric utility merger. For a northwestern utility company, analyzed the competitive effects of a proposed electric utility merger. (1995-1996)

For the Massachusetts Attorney General's Office, conducted a study of the potential for market power abuse by generators in the NEPOOL market area. (1996)

DSM Competitive Procurement and DSM Evaluation

For two separate large New England utilities, conducted impact evaluations of large commercial and industrial sector DSM programs. (1994-1996)

For a New England utility, worked on the project team developing a set of DSM evaluation master plans for incentive-type and third-party-contracting type DSM programs (1994)

For EPRI, wrote an overview of the status of DSM information systems and the potential effects of an increasingly competitive utility environment. (1993)

For two separate large New England utilities, helped to develop competitive procurement documents (DSM RFPs) for filing before the Massachusetts Department of Public Utilities. (1993, 1994)

For a midwestern utility, conducted a trade ally study designed to determine the influence of trade allies on the market for energy efficient lighting and motor equipment. (1992-1993)

DSM Implementation

Conducted detailed site visits and suggested efficiency improvement strategies for over 1,000 commercial, industrial and institutional buildings in Rhode Island. Performed end-use energy analysis and coordinated implementation of improvements. Worked with local utility DSM program personnel to educate building owners on DSM program opportunities. (1987-1992)

Energy Modeling

For various clientele, worked closely with the TCA GE MAPS modeling group on various facets of security-constrained dispatch modeling of electric power systems across the US and Canada. Specific tasks included assisting in designing MAPS model run parameters (e.g., base case and alternative scenarios specification); proposing modeling designs to clients; supporting input data gathering; interpreting model results; and writing summary reports, memos & testimony describing the results. (2002-2004)

For a group of potential electricity supply investors in Ontario, modeled the impact of proposed generation plant phaseout trajectories on investment requirements for new supply in Ontario. (2004)

For the Independent Power Producer's Society of Ontario, conducted a retrospective quantitative analysis of the Ontario market energy and ancillary service prices during the 15 months of the new wholesale market to determine the extent of infra-marginal rents available that could have supported entry for new generation. (2003)

In support of proposals to the US Dept. of Defense for military housing privatization, performed DOE-2 model runs using an online tool; and created a spreadsheet modeling tool to analyze the efficiency and cost effectiveness of new and renovated residential construction for base housing. Performed life-cycle utility cost analysis and prepared energy plans specifying building shell, equipment and appliance efficiency measures at 15 separate Army, Navy, and Air Force installations around the nation. (2001-2003)

For the Independent Power Producer's Society of Ontario, conducted a rate impact analysis of Ontario Hydro Networks Company proposed transmission tariff. (1999-2000)

For the University of Maryland at Baltimore, conducted a life-cycle cost analysis of alternative proposals for district-type thermal energy provision, comparing existing steam delivery systems to new hot-water systems. (1998)

For the UMass Medical Center (Worcester), conducted an energy use and cost allocation analysis of a large hospital complex to assist in choosing among electric and thermal energy supply options. (2000)

For an independent power producer, developed a spreadsheet-based tool to assess the rate impact of a clean coal facility in Maryland compared to alternative gas-fired supply options. (1996-1997)

For a private consulting firm, examined electric end-use and generation capacity information in seven industry energy models and reported the sensitivities of each model to varying levels of input aggregation. (1995)

For a private industrial firm in Virginia, developed a Monte-Carlo simulation-based spreadsheet model to solve a capital budgeting problem involving long-term choice of industrial boiler equipment. (1995)

For a New England utility, developed a spreadsheet model to help determine economic decision-making processes used by energy service companies when delivering third-party procured DSM. (1995)

Petroleum and Natural Gas Industry Analysis

For a private independent power producer, conducted an analysis of the rate impacts of the Warrior Run clean coal (fluidized bed combustion) power plant in Maryland under various assumptions of natural gas prices and environmental regulation scenarios. (1996-1997)

For a British consulting firm, researched and presented findings on the current status of natural gas restructuring efforts in the US and their impact on regional US markets for power generation. (1996)

For a Canadian law firm representing Native Canadian interests, conducted a detailed analysis of natural gas netback pricing for Alberta gas into US Midwest and West Coast markets over a thirty-year period. (1995)

For a US natural gas pipeline consortium, performed an econometric analysis of the demand for natural gas in the state of Florida. (1992-1993)

PAPERS, PUBICATIONS AND PRESENTATIONS

SMD and RTO West: Where are the Benefits for Alberta? Keynote Paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, with Dr. Richard D. Tabors, March 7, 2003.

A Progressive Transmission Tariff Regime: The Impact of Net Billing, presentation at the Independent Power Producer Society of Ontario annual conference, November 1999.

Tariff Structure for an Independent Transmission Company, with Richard D. Tabors, Assef Zobian, Narasimha Rao, and Rick Hornby, TCA Working Paper 101-1099-0241, November 1999.

Transmission Congestion Pricing Within and Around Ontario, presentation at the Canadian Transmission Restructuring Infocast Conference, Toronto, June 2-4, 1999.

The Restructured Ontario Electricity Generation Market and Stranded Costs. An internal company report presented to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Alberta Legislated Hedges Briefing Note. An internal company report presented to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Generation Market Power in New England: Overall and on the Margin. Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets, Boston, June 1997.

The Market for Power in New England: The Competitive Implications of Restructuring. Prepared for the Office of the Attorney General, Commonwealth of Massachusetts, by Tabors Caramanis & Associates with Charles River Associates, April 1996. R. Fagan was a key member of the team that produced the report.

Estimating DSM Impacts for Large Commercial and Industrial Electricity Users. Lead investigator and author, with M. Gokhale, D.S. Levy, P.J. Spinney, G.C. Watkins. Presented at

The Seventh International Energy Program Evaluation Conference, Chicago, Illinois, August 1995, and published in the Conference Proceedings.

Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric. Prepared with G.C. Watkins, Charles River Associates. Report for COM/Electric System, filed with the MA Dept. of Public Utilities (MDPU), April 28, 1995, Docket # DPU 95-2/3-CC-l.

Demand-side Management Information Systems (DSMIS) Overview. Electric Power Research Institute Technical Report TR-104707. Robert M. Fagan and Peter S. Spinney, principal investigators, prepared by Charles River Associates for EPRI, January 1995.

Impact Evaluation of Commonwealth Electric's Customized Rebate Program. With P.J. Spinney and G.C. Watkins. Charles River Associates, Initial and Updated Reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April28, 1995, Docket # DPU 95-2/3-CC-I. The initial report filed with the MDPU, April 1, 1994.

Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports. With Peter S. Spinney (CRA) and Abbe Bjorklund (Energy Investments). Charles River Associates Reports prepared for Northeast Utilities, June and July 1994.

The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation, Paper authored by Peter J. Spinney (Charles River Associates) and John Peloza (Wisconsin Electric Power Corp.). Presented by Bob Fagan at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

Resume dated April 2005.

Differences in PSI Revenues due to Pricing Using HMP vs. Incremental Cost Cap for All "Post-JGDA" Transfers

		RecvOpCo	SendOpCo	ICT_Type	2003 Pricing Method At Cap	2003 Pricing Method At HMP	2003 Total	2004 Pricing Method At Cap	2004 Pricing Method At HMP	2004 Total	Grand Total
	Pre-May 24, 2004										
1		CGE	PSI	Post-JGDA Sale	$2,521,146	-$5	$2,521,141	$774,137	$0	$774,137	$3,295,278
2		PSI	CGE	Post-JGDA Sale	$0	$0	$0	$1,096	$0	$1,096	$1,096
3		Net Transfers, PSI to CG&E (line 1-2)			$2,521,146	-$5	$2,521,141	$773,041	$0	$773,041	$3,294,182
	Post-May 23, 2004										
4		CGE	PSI	Post-JGDA Sale	$0	$0	$0	$253,331	$2	$253,332	$253,332
5		PSI	CGE	Post-JGDA Sale	$0	$0	$0	$47,760	$0	$47,760	$47,760
6		Net Transfers, PSI to CG&E (line 4-5)			$0	$0	$0	$205,571	$1	$205,572	$205,572
7	Total Net Transfers, All Periods 1/1/2003 - 9/30/2004 (line 3+6)				$2,521,146	-$5	$2,521,141	$978,612	$1	$978,613	$3,499,754

Source: Cinergy JGDA Transaction data in response to discovery request CAC 6.1.

Differences in PSI Revenues due to Pricing Using Actual Market Price vs. HMP for All "Post-JGDA" Transfers

	RecvOpCo	SendOpCo	ICT_Type	2003 Pricing Method At Cap	2003 Pricing Method At HMP	2003 Total	2004 Pricing Method At Cap	2004 Pricing Method At HMP	2004 Total	Grand Total
	Pre-May 24, 2004									
1	CGE	PSI	Post-JGDA Sale	$2,179,253	$2,590,072	$4,769,325	$773,806	$19,357	$793,163	$5,562,488
2	PSI	CGE	Post-JGDA Sale	$0	$0	$0	-$1,096	$0	-$1,096	-$1,096
3	Net Transfers, PSI to CG&E (line 1-2)			$2,179,253	$2,590,072	$4,769,325	$774,902	$19,357	$794,259	$5,563,583
	Post-May 23, 2004									
4	CGE	PSI	Post-JGDA Sale	$0	$0	$0	-$25,340	$1,117,723	$1,092,383	$1,092,383
5	PSI	CGE	Post-JGDA Sale	$0	$0	$0	-$47,751	$0	-$47,752	-$47,752
6	Net Transfers, PSI to CG&E (line 4-5)			$0	$0	$0	$22,411	$1,117,723	$1,140,134	$1,140,134
7	Total Net Transfers, All Periods 1/1/2003 - 9/30/2004 (line 3+6)			$2,179,253	$2,590,072	$4,769,325	$797,313	$1,137,079	$1,934,393	$6,703,717

Source: Cinergy JGDA Transaction data in response to discovery requests CAC 6.1 and 10.1A.

Differences in PSI Revenues due to Pricing Using "Into Cinergy" Hub Prices vs. HMP for All "Post-JGDA" Transfers

		RecvOpCo	SendOpCo	ICT_Type	2003 Pricing Method At Cap	2003 Pricing Method At HMP	2003 Total	2004 Pricing Method At Cap	2004 Pricing Method At HMP	2004 Total	Grand Total
	Pre-May 24, 2004										
1		CGE	PSI	Post-JGDA Sale	-$1,207	$311,310	$310,102	$192,051	$204,113	$396,164	$706,266
2		PSI	CGE	Post-JGDA Sale	$0	$0	$0	$1,515	$224	$1,739	$1,739
3		Net Transfers, PSI to CG&E (line 1-2)			-$1,207	$311,310	$310,102	$190,536	$203,889	$394,425	$704,527
	Post-May 23, 2004										
4		CGE	PSI	Post-JGDA Sale	$0	$0	$0	-$73,809	$822,050	$748,240	$748,240
5		PSI	CGE	Post-JGDA Sale	$0	$0	$0	-$27,589	-$4,476	-$32,065	-$32,065
6		Net Transfers, PSI to CG&E (line 4-5)			$0	$0	$0	-$46,221	$826,526	$780,305	$780,305
7	Total Net Transfers, All Periods 1/1/2003 - 9/30/2004 (line 3+6)				-$1,207	$311,310	$310,102	$144,315	$1,030,415	$1,174,730	$1,484,833

Source: Cinergy JGDA Transaction data in response to discovery requests CAC 6.1, 6.3 and 10.1A.