

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF PSI ENERGY, INC FOR)
AUTHORITY TO INCREASE ITS RATES AND)
CHARGES FOR ELECTRIC SERVICE; FOR)
APPROVAL OF NEW SCHEDULES OF RATES)
AND CHARGES AND OF RULES AND)
REGULATIONS APPLICABLE TO SUCH RATES)
AND CHARGES; FOR THE AUTHORITY TO)
REFLECT ITS QUALIFIED POLLUTION)
CONTROL PROPERTY AND OTHER NEW PLANT)
AND EQUIPMENT IN ITS RATES AND)
CHARGES; FOR APPROVAL OF ITS)
IMPLEMENTATION OF THE FEDERAL ENERGY)
REGULATORY COMMISSION'S SEVEN-FACTOR) CAUSE NO. 42359
TEST; FOR APPROVAL OF VARIOUS RATE)
TRACKING MECHANISMS, INCLUDING A)
PROPOSED MIDWEST INDEPENDENT)
TRANSMISSION SYSTEM OPERATOR)
MANAGEMENT COST ADJUSTMENT RIDER)
AND CONTINUED USE OF A PURCHASED)
POWER TRACKING MECHANISM; AND FOR)
APPROVAL OF RELATED ACCOUNTING)
TREATMENT AND DEPRECIATION RATES AND)
OTHER ACCOUNTING RELIEF RELATIVE TO)
ITS BUSINESS.)

Testimony of

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Synapse Energy Economics, Inc.

Prepared on Behalf of

THE CITIZENS ACTION COALITION OF INDIANA

PUBLIC VERSION

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I. INTRODUCTION

7

8 **Q. PLEASE STATE YOUR NAME, BUSINESS POSITION AND ADDRESS.**

9 A. My name is Bruce Edward Biewald. I am president of Synapse Energy
10 Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

11 **Q. PLEASE DESCRIBE YOU EMPLOYMENT, QUALIFICATIONS, AND
12 EXPERIENCE?**

13 A. I am president and owner of Synapse Energy Economics, Inc., a consulting
14 company specializing in economic and policy analysis of the electricity industry,
15 particularly issues of restructuring, market power, electricity market prices,
16 consumer protection, stranded costs, efficiency, renewable energy, environmental
17 quality, and nuclear power. I graduated from the Massachusetts Institute of
18 Technology in 1981, where I studied energy use in buildings. I was employed for
19 15 years at the Tellus Institute, where I was Manager of the Electricity Program,
20 responsible for studies on a broad range of electric system regulatory and policy
21 issues. I have testified on energy issues in more than eighty regulatory
22 proceedings in twenty-five states and two Canadian provinces. I have co-
23 authored more than one hundred reports, including studies for the Electric Power
24 Research Institute, the U.S. Department of Energy, the U.S. Environmental
25 Protection Agency, the Office of Technology Assessment, the New England
26 Governors' Conference, the New England Conference of Public Utility
27 Commissioners, and the National Association of Regulatory Utility
28 Commissioners. My papers have been published in the *Electricity Journal*,
29 *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and numerous
30 conference proceedings, and I have made presentations on the economic and
31 environmental dimensions of energy throughout the U.S. and internationally. I
32 also have consulted for federal agencies, including the Department of Energy, the

1 Department of Justice, the Environmental Protection Agency, and the Federal
2 Trade Commission. Details of my experience are provided in Exhibit BEB-1.

3 **Q. HAVE YOU TESTIFIED PREVIOUSLY IN INDIANA?**

4 A. Yes. I most recently testified before the Commission in July, 2002, regarding a
5 proposed settlement of a pending NIPSCO rate investigation. Previously, I
6 testified before the Commission regarding NIPSCO system reliability and excess
7 capacity in Cause No. 38405 in November, 1986. I made a presentation regarding
8 stranded costs in the Commission's Forum on Electric Industry Competition in
9 November, 1996. I also made presentations regarding various aspects of electric
10 utility restructuring before the Indiana Energy Conference in October, 1996 and
11 the Regulatory Flexibility Committee of the Indiana General Assembly in
12 September, 1997. I also prepared and filed testimony regarding the proposed
13 termination of the operating agreement between PSI Energy, Inc. and Cincinnati
14 Gas & Electric Company in Cause No. 41952 in June, 2001, but the case was
15 settled before my testimony was admitted.

16 **Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?**

17 A. On behalf of the Citizens Action Coalition of Indiana, Inc.

18 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

19 A. The Citizens Action Coalition has asked me to review aspects of the Company's
20 rate proposal that may unfairly allocate risk to its customers.

21 **Q. PLEASE SUMMARIZE YOUR KEY CONCLUSIONS AND**
22 **RECOMMENDATIONS.**

23 A. My conclusions are as follows:

- 24 • The scope and number of the Company's existing and proposed rate
25 adjustment trackers is large in comparison to similar regulated utilities. These
26 trackers provide significant risk reduction benefits to the Company.

- 1 • Based on the information that the Company has provided, I project the net
2 cost or credit to customers of the Summer Reliability Tracker and conclude
3 that, contrary to the Company’s claims, the tracker is likely to result in a net
4 cost to customers beginning in 2004.
- 5 • The system for accounting and tracking of transactions is complex and prone
6 to abuse.
- 7 • The Company’s proposed NOx Emission Allowance (EA) tracker differs from
8 its existing SO2 tracker in that it allows the Company to retain a portion of
9 any profits it receives through its NOx EA transactions. This represents a
10 potentially inappropriate incentive for the Company, as PSI should not be
11 allowed to gain from EA sales made possible through NOx compliance costs
12 that it is fully recovering from customers.
- 13 • The trackers reduce or eliminate the incentive for the Company to manage
14 costs and risks associated with the tracked costs, even though the Company is
15 in a better position than its customers to manage those costs and risks.
- 16 • The inclusion of the previously unregulated merchant plants into PSI’s rate
17 base provides additional risk reduction benefits to Cinergy’s shareholders by
18 assuring them of recovering through PSI’s retail rates the cost of its holding
19 company’s unprofitable unregulated investments.
- 20 • Cinergy actively analyzes and manages risks to shareholders, but neither PSI
21 nor Cinergy adequately analyzes or manages risks to regulated customers.
- 22 • Cinergy and PSI have made some, but very limited progress toward managing
23 environmental risks, diversifying the resource mix, and realizing attractive
24 opportunities to invest in efficiency and renewable generating sources.

25 Based on these conclusions, my recommendations to the Commission are as
26 follows:

- 27 • The Commission should disallow the Summer Reliability Tracker’s off-
28 system sales profit sharing mechanism and require the Company to credit all
29 such profits to customers. The Company should also establish a monitoring
30 process independent of its holding company to verify that PSI’s off-system
31 sales activity is optimized for the benefit of its customers.

- 1 • The Commission should open a sub-docket to more carefully review and
2 thoroughly audit the Company's use of the Post Analysis Cost Evaluation
3 model and the corresponding issues pertaining to the Joint Generation
4 Dispatch Agreement.
- 5 • The Commission should reject the net revenue allocation scheme of the
6 Company's proposed NOx Emission Allowance tracker and require the
7 Company to allocate 100 percent of net gains and losses from allowance
8 transactions to customers.
- 9 • The Commission should consider the risk reduction effects of the Company's
10 existing and proposed trackers and of the inclusion of merchant plants in the
11 Company's base rates in determining an appropriate return on equity.
- 12 • PSI should be required to conduct an analysis of options to further mitigate its
13 environmental risks, by diversifying its resource mix, by retrofitting additional
14 emission controls to existing facilities, by increasing its supply-side
15 efficiency, by investing in a comprehensive set of demand-side management
16 programs, and by developing renewable generating resources in its service
17 territory. The Company should be required to pursue those resource options
18 that are found to be attractive in that analysis.

19 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

20 A. I begin my testimony with a general discussion of risk exposure and rate of return
21 on common equity. I present the results of my rate adjustment tracker analysis
22 and relate them to the Company's risk exposure and proposed rate of return on
23 equity. In the following section, I examine the Company's proposed Summer
24 Reliability Tracker and provide a projection of the tracker's cost to customers that
25 contradicts the Company's expectation that the tracker will result in a credit to
26 customers in the initial years of its existence. I also examine the reasonableness
27 of the profit-sharing mechanism of the tracker, and provide my opinion about the
28 overall equity of the tracker. I follow this with a discussion of the issues
29 surrounding the Company's Post Analysis Cost Evaluation and their implications
30 for the Company's Joint Generation Dispatch Agreement.

1 Next, I examine how the Company’s proposed NOx Emission Allowance
2 tracker may improperly allocate net gains and losses from EA transactions
3 between the Company and its customers. I also observe that the tracker will
4 further reduce the Company’s exposure to environmental compliance risks. I then
5 proceed to a discussion of the declining value of Cinergy’s merchant plants prior
6 to their transfer to PSI, and the risk allocation implications of their inclusion in
7 PSI’s rate base. Finally, I examine whether PSI may have imprudently managed
8 its environmental risks and discuss the value of energy efficiency and renewable
9 energy investments in reducing PSI’s vulnerability to these risks.

10 **II. RISK EXPOSURE AND RETURN ON EQUITY**

11 **Q. TO WHAT FORMS OF RISK IS A REGULATED UTILITY COMPANY**
12 **TYPICALLY EXPOSED TO?**

13 A. Regulated utility companies are exposed to many different forms of risk,
14 including weather, financial, economic, environmental, and regulatory risks.

15 **Q. HOW ARE THE COMMON SHAREHOLDERS OF A REGULATED**
16 **UTILITY COMPENSATED FOR EXPOSURE TO THESE RISKS?**

17 The Return on Equity (ROE) is intended to reasonably compensate common
18 shareholders for exposure to these risks. The Company is requesting a Return on
19 Equity of 11.5 percent.¹ In determining whether the Company’s requested ROE is
20 excessive, the Commission should consider the following:

- 21 • The risk reduction effect of the Company’s existing and proposed
22 trackers and pre-approved costs; and
- 23 • If the Commission’s pre-approval of the Company’s merchant plant
24 acquisition has effectively shifted from Cinergy to PSI customers most of
25 the risks associated with the investment in those plants.

¹ Prefiled Case-in-Chief testimony of Roger A. Morin, page 4, line 10.

1 **Q. WHAT RATE ADJUSTMENT TRACKERS ARE CURRENTLY**
2 **INCLUDED IN THE COMPANY’S REVENUES?**

3 A. The following table presents a list of the riders that were in effect in April 2003²,
4 along with the per books jurisdictional revenue attributable to each during the test
5 year ending September 30, 2002. The information in this table was obtained from
6 Schedule C-3.4 in Mr. Farmer’s Petitioner’s Exhibit X-8.

Rider No.	Description	Per Books Amount (000s)
60	Fuel Cost Adjustment	-
62	Qualified Pollution Control Property	\$4,752
63	Emission Allowance	\$16,111
66	DSM Recovery of On- Going Expense	\$8,806
67	Recovery of Pre-approved Purchased Power Costs	\$22,365
Total		\$52,034

7
8 In addition to these trackers, the Company also has an environmental
9 Construction Work in Progress (CWIP) Tracker that generated \$27.8 million in
10 the test year.³ Including this amount to the total tracker revenue in Table A would
11 increase the total revenue to \$79.8 million.

12 **Q. HOW DOES THE COMPANY’S TOTAL TRACKER REVENUE**
13 **COMPARE TO ITS RETAIL OPERATING REVENUES DURING THE**
14 **TEST YEAR?**

15 A. The Company’s pro forma operating revenues under current rates, exclusive of all
16 trackers, is \$1,251.2 million.⁴ Netting out fuel costs, which the Company is
17 allowed to fully recover, and adding in the \$79.8 million tracker revenue, results

² Petitioner’s Exhibit BB-1 (Bailey). The rate adjustment mechanisms under consideration in this proceeding are sometimes referred to as “riders” and sometimes as “trackers.” I will use the two terms interchangeably.

³ Petitioner’s Exhibit C-5 (JPS-5) (Steffen), line 2, column G.

⁴ Petitioner’s Exhibit C-5 (JPS-5) (Steffen), line 2, column F.

1 in operating revenues of \$952.7 million. Thus, the Company’s total tracker
2 revenue is equivalent to 8.4% of its operating revenue during the test year.

3 If we include the Company’s pro forma fuel costs in the calculation of
4 tracked revenue, then \$378.3 million of the Company’s \$1,331.0 million of
5 operating revenues, or 34.4%, are “tracked” under the Company’s current rates.

6 These numbers, while significant, do not paint the full picture of the
7 Company’s ability to recover its costs. The vast majority of the Company’s
8 “untracked” operating expenses are not subject to the high levels of volatility and
9 uncertainty that characterize its “tracked” expenses. The Company is virtually
10 assured of recovering these more predictable expenses through the return on its
11 rate base. As explained in greater detail below, the Company’s trackers enhance
12 its ability to recover all of its costs by greatly reducing the possibility that it will
13 not be able to recover costs of a volatile nature in a timely manner.

14 **Q. WHAT ADDITIONAL TRACKERS IS THE COMPANY REQUESTING**
15 **APPROVAL FOR IN THIS RATE CASE?**

16 A. In addition to the above trackers, the Company is seeking approval for the
17 following proposed trackers, which are described in the prefiled testimonies of
18 Kent K. Freeman (Exhibit Z) and Stephen M. Farmer (Exhibit CC):

19 Rider No. 68

20 MISO Tracker to track Midwest Independent Transmission System Operator
21 related management costs.

22 Rider No. 69

23 NOx Emission Allowance Tracker to track the sales and purchases of NOx
24 Emission Allowances.

25 Rider No. 70

26 Summer Reliability Tracker to track summer purchased power costs, PowerShare
27 costs, and off-system sales profits. This tracker is intended to effectively replace
28 Rider No. 67.

29 **Q. HOW DO THE COMPANY’S TRACKERS AFFECT ITS EXPOSURE TO**
30 **RISK?**

1 A. By passing through a substantial portion of its operating costs to retail rates, the
2 Company's rate tracking mechanisms effectively reduce its shareholders'
3 exposure to risk in that they (1) reduce regulatory lag; (2) allow certain significant
4 categories of costs (e.g. environmental costs) that increase to be put into rates
5 without consideration of other, related categories of costs (e.g. cost of capital) that
6 decrease; (3) tend to defer general rate cases, with their attendant risks and costs;
7 (4) tend to decrease the scope and detail of regulatory review of tracked costs
8 compared to a general rate case.

9 Furthermore, such riders can, in many situations, greatly reduce volatility
10 of net earnings on a monthly, quarterly and annual basis, by virtue of the fact that
11 they eliminate or significantly reduce the likelihood of failing to recover the costs
12 associated with particularly volatile line items. Such a reduction of volatility in
13 net earnings, *per se*, can constitute a material reduction in the financial risk of the
14 firm as a whole from the perspective of shareholders and is of significant value to
15 them, more generally.

16 **Q. WHAT ARE THE POTENTIAL BENEFITS TO RATEPAYERS OF THE**
17 **COMPANY'S REDUCED VOLATILITY AND RISK EXPOSURE?**

18 A. As the Company has noted several times in its testimony, reduced volatility and
19 risk exposure may have a positive impact on the Company's credit rating, hence
20 reducing the cost of capital for both equity and debt. This will tend to reduce
21 retail electric rates. However, several other factors also affect electricity rates,
22 including the Company's approved return on equity. If the Company's approved
23 ROE does not account for the risk reduction effects of its trackers and other risk
24 reduction measures which I discuss later in my testimony, then customers may be
25 required to subsidize excessive shareholder earnings by paying inordinately high
26 rates.

27 **Q. HOW DO THE NUMBER AND SCOPE OF THE COMPANY'S EXISTING**
28 **AND PROPOSED TRACKERS COMPARE WITH THOSE OF OTHER**
29 **ELECTRIC UTILITY COMPANIES?**

30 A. Roger A. Morin's prefiled testimony explains how he calculated the company's
31 proposed return on equity by reference to a peer group of 13 comparable

1 investment-grade vertically integrated electric utilities. These utilities are listed in
2 Petitioner's Exhibit G-11 (RAM-11). Exhibit BEB-2 presents a comparison of
3 the rate adjustment trackers included in the general rate schedules of each of the
4 13 utilities in Petitioner's Exhibit G-11, as well as PSI's existing and proposed
5 trackers. These 14 utilities own 26 regulated electric generation, transmission,
6 and distribution companies in 16 separate states with varying degrees of
7 deregulation and regulatory oversight. The average number of trackers employed
8 by each of the 26 companies is 2.12.⁵ Across the 14 utilities, the average is 2.35
9 trackers per utility. With six trackers,⁶ PSI has the highest number among the 26
10 utility companies, and is one of only two companies (Alabama Power is the other)
11 that have trackers for perhaps the four most significant cost categories that are
12 commonly tracked: fuel adjustment, purchased power, environmental cost
13 recovery, and emission allowances.

14 **Q. WHAT DOES THIS SUGGEST ABOUT PSI'S EXPOSURE TO RISK**
15 **RELATIVE TO ITS INDUSTRY PEERS?**

16 A. The large number of PSI's rate adjustment trackers relative to its industry peers
17 suggests that the Company is relatively well protected against many risks to
18 which other utilities are often exposed.

19 **Q. DON'T THE UNIQUE REGULATORY AND BUSINESS**
20 **CIRCUMSTANCES OF EACH UTILITY HINDER THE USEFULNESS**
21 **OF SUCH A COMPARISON?**

22 A. Although regulatory conditions do differ from state to state, there are a number of
23 risks that are almost universally applicable to regulated utilities. As mentioned
24 above, perhaps the most significant of these are fuel costs, purchased power
25 capacity costs, and environmental compliance costs, including the cost of

⁵ Rather than base my comparison on the absolute number of trackers that each company has, I have chosen to identify trackers by category. Hence, the absolute number of trackers that Company has does not necessarily match its categorical number. In the case of PSI, the Company has an existing SO₂ emission allowance tracker and has proposed a NO_x emission allowance tracker. Because these two trackers both address emission allowances, I have grouped them together and counted them as a single tracker for the purposes of my analysis.

⁶ Again, this is the categorical, rather than absolute, number of trackers that PSI currently employs and is proposing.

1 purchasing emission allowances. These are the uncertainties that rate adjustment
2 trackers are intended to account for and minimize,⁷ and I believe that a tracker-
3 based comparison can serve as an indicative measure of a company's protection
4 against risk.

5 **Q. IN YOUR VIEW, WOULD THE COMPANY'S PROPOSED RETURN ON**
6 **EQUITY BE APPROPRIATE IF ITS PROPOSED TRACKERS ARE**
7 **APPROVED?**

8 A. The magnitude and number of PSI's existing trackers and the magnitude of its
9 proposed trackers, particularly the Summer Reliability Tracker which I will
10 discuss later in my testimony, greatly reduce the Company's exposure to several
11 different types of risk. A reasonable return on equity for PSI would account for
12 the risk reduction effect of the Company's rate tracking mechanisms.

13 **III. SUMMER RELIABILITY TRACKER**

14 **Q. UNDER THE COMPANY'S PROPOSED SUMMER RELIABILITY**
15 **TRACKER, HOW ARE THE COSTS OF PURCHASED POWER AND**
16 **THE PROFITS FROM OFF-SYSTEM SALES SHARED BETWEEN THE**
17 **COMPANY AND ITS CUSTOMERS?**

18 A. As explained in the pre-field Case-in-Chief testimony of Douglas F. Esamann,
19 under the proposed tracker, 100 percent of summer purchased power costs are
20 borne by customers. Off-system sales profits are assigned to customers in the
21 following manner: 100 percent of off-system sales profits during the summer, and
22 25 percent of profits during the non-summer months (October to May). During
23 the non-summer months, 75 percent of profits from off-system sales are retained
24 by the Company. Assuming replication of test-year experience, this arrangement
25 would result in a 50/50 sharing of profits between PSI customers and its holding
26 company.

⁷ In Page 25, Line 22, of Steven M. Fetter's Prefiled Case-in-Chief testimony, Mr. Fetter states, in reference to fuel and purchased power trackers, "These mechanisms mitigate a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations."

1 **Q. HAS THE COMPANY PROVIDED PROJECTIONS FOR SUMMER**
2 **PURCHASED POWER COSTS?**

3 A. Yes. The Company provided data request response NUCOR/PSI-2.7-A, which
4 contains projected summer purchased power costs from 2003 to 2007 (see
5 attached Exhibit BEB-3).

6 **Q. WHAT AMOUNT DOES THE COMPANY EXPECT TO SPEND ON**
7 **PURCHASED POWER?**

8 A. NUCOR/PSI-2.7-A indicates that, between 2003 and 2007, the Company projects
9 that it will need to purchase 1,237,264 MWh at a total cost of \$97,763,843.

10 **Q. DOES THE COMPANY INDICATE THE PORTION OF THESE COSTS**
11 **THAT ARE INCLUDED IN THE SUMMER RELIABILITY TRACKER?**

12 Yes. The same data request response indicates that the Tracker portion of these
13 costs is \$81,012,312. Averaged over the five-year projection period, this is
14 equivalent to approximately \$16.2 million per year.

15 **Q. ARE THE COMPANY'S PURCHASED POWER PROJECTIONS**
16 **REASONABLE?**

17 A. There is reason to believe that the Company's purchased power projections are
18 conservatively low. PSI has contracts with a number of large wholesale
19 customers that are due to expire between 2003 and 2007. The Company's Base
20 Case Load Forecast upon which the above purchased power projections are based
21 assume that these wholesale customers do not enter into new supply contracts
22 with PSI. As noted in page 12 of Diane L. Jenner's prefiled case-in-chief
23 testimony, this assumption provides a conservatively low view of PSI's future
24 load. If PSI continues to serve all of its current wholesale load, the Tracker
25 portion of summer purchased power costs would be approximately \$65.6 million
26 in 2007 – compared to about \$13.6 million using the assumption that PSI does not
27 renegotiate any new wholesale contracts.⁸ This serves to illustrate that the
28 projected cost of purchased power during the summer months is heavily
29 dependent on the Company's expected load.

⁸ From NUCOR/PSI-2.7-A

1 **Q. WHAT OTHER UNCERTAINTIES AFFECT PSI'S PROJECTED LOAD**
2 **AND PURCHASED POWER REQUIREMENTS?**

3 A. As identified by the Company, the other primary uncertainties with respect to
4 PSI's projected load and purchased power requirements are whether: PSI can
5 cost-effectively implement new and enhanced DSM programs; PSI will be able to
6 increase customer participation in PowerShare programs; PSI's interruptible
7 customers will switch back to firm service once their current contracts expire; and
8 PSI's reserve margin criteria should be changed to 17% rather than 15%.⁹

9 **Q. HOW DOES EACH OF THESE UNCERTAINTIES AFFECT THE**
10 **COMPANY'S PROJECTED LOAD AND PURCHASED POWER**
11 **REQUIREMENTS?**

12 A. Increases in demand-side resources and customer participation in peak load
13 management programs will have the effect of decreasing the actual load relative
14 to the Base Case Load forecast, thus reducing the Company's need for purchased
15 power. If the Company's interruptible contracts are not renewed, the actual load
16 will be higher relative to the Base Case, and the Company's purchased power
17 needs will be greater. Under a 17 percent reserve margin requirement, the actual
18 load does not change relative to the forecast, but purchased power requirements
19 increase by 43 percent over the eight-year period from 2003 to 2010.

20 **Q. WHAT ARE THE LOW AND HIGH-END ESTIMATES OF THE**
21 **COMPANY'S PROJECTIONS FOR PURCHASED POWER**
22 **REQUIREMENTS?**

23 A. Data from Petitioner's Exhibit W-2 (DLJ-2) indicate that the Company's
24 projected total purchased power requirements between 2003 to 2010, inclusive,
25 range from a low of 1,658 MW to a high of 5,202 MW. The low-end estimate
26 represents a 31 percent reduction from the Base Case and is based on the
27 aggressive assumption that RTP/CallOption demand-side resources remain at high
28 2001 levels. The high-end estimate, which exceeds the Base Case level by 117

⁹ The uncertainty over PSI's reserve margin criteria, particularly the component for unscheduled outages, is discussed on pages 14-15 of Ms. Jenner's pre-filed testimony.

1 percent, assumes that PSI continues meeting all of its current wholesale customer
2 load through 2010.

3 **Q. IN YOUR OPINION, DOES THE COMPANY’S BASE CASE LOAD**
4 **FORECAST PROVIDE A REASONABLE AND ACCURATE ESTIMATE**
5 **FOR DETERMINING PURCHASED POWER REQUIREMENTS?**

6 A. I believe that the Company’s Base Case load forecast may be unreasonably low.
7 The forecast assumes that PSI does not renegotiate any new wholesale customer
8 contracts after its current contracts expire, and it assumes that *all* of its current
9 interruptible load contracts are renewed. These are very conservative
10 assumptions, and in my view, it is more likely that the Company would continue
11 to meet at least some portion of its existing wholesale customer load and would
12 find that some interruptible load customers fail to renew their contracts and
13 become firm customers. For instance, Ms. Jenner’s pre-filed Case-in-Chief
14 testimony states that “recent experience in other regions has shown that actual
15 interruption has caused some interruptible customers to switch back to firm
16 service” (page 14, line 10).

17 Based on these factors, it appears that the Company’s Base Case load
18 forecast should be adjusted to reflect less conservative assumptions about its
19 projected load for purposes of projecting summer purchased power. This would
20 result in a higher level of projected summer purchased power.

21 **Q. HAS THE COMPANY PROVIDED PROJECTIONS FOR PROFITS**
22 **FROM OFF-SYSTEM SALES?**

23 A. Yes. Page 5 of Ms. Jenner’s pre-filed Case-in-Chief testimony contains a chart
24 with estimated monthly off-system sales profits from re-dispatch analyses from
25 October 2002 through September 2003. The total profits for the one-year period
26 are approximately \$17.9 million.

27 **Q. HAS THE COMPANY PROVIDED OFF-SYSTEM SALES PROFITS**
28 **PROJECTIONS BEYOND SEPTEMBER 2003?**

29 A. To my knowledge, the Company has not provided any such projections in its pre-
30 filed testimony or in response to data requests.

1 to make [REDACTED] of summer power purchases.¹⁰ In 2005, the cost of
2 projected summer power purchases rises to just under [REDACTED]. The credit to
3 retail customers from off-systems sales profits in Ms. Jenner's redispach analysis
4 was [REDACTED]. [REDACTED]

5 [REDACTED]
6 [REDACTED]
7 [REDACTED] This data is presented in graphical form in confidential Exhibit
8 BEB-5.

9 **Q. IN HIS TESTIMONY, MR. ESAMANN STATES THAT THE PROPOSED**
10 **PROFIT SHARING MECHANISM IN WHICH PSI RETAINS 75% OF**
11 **NON-SUMMER OFF-SYSTEM SALES PROFITS WOULD PROVIDE**
12 **THE COMPANY WITH INCENTIVE TO MAXIMIZE ITS OFF-SYSTEM**
13 **SALES PROFITS. PLEASE COMMENT ON THE APPROPRIATENESS**
14 **OF THIS INCENTIVE.**

15 A. I do not believe that such a profit sharing mechanism as proposed in the
16 Company's tracker is either proper or necessary. As a regulated utility, PSI is
17 bound to provide quality electricity service at the lowest possible cost to its
18 customers. In exchange, it receives a state-sanctioned monopoly within its
19 service territory and charges state-sanctioned rates which provide it with the
20 opportunity to earn a reasonable rate of return on its investment in providing
21 service. As a result, the Company should not require any other motive to
22 optimize its operations for the benefit of its customers other than its legal mandate
23 to do so. In claiming that additional profit in the form of an incentive is necessary
24 to maximize the cost efficiency of its resources, the Company is subverting its
25 responsibility to its customers as a regulated utility.

26 **Q. IS THERE A SINGLE IDEAL APPROACH TO UTILITY INCENTIVES?**

27 A. No. In many situations utility rates are set simply to recover prudently incurred
28 costs, and regulators hope or assume or enforce through prudence reviews that the
29 regulated utility will fulfill its obligations to provide reliable service at the lowest

¹⁰ Based on wholesale forwards from 3/19/03.

1 reasonable cost. A utility subject to this sort of “traditional regulation” would,
2 presumably, attempt to minimize its overall costs of providing service, subject to
3 various constraints and risk-related considerations. This would involve
4 dispatching the system economically, minimizing fuel and purchased power costs,
5 and maximizing net revenue from off-system sales.

6 In some regulatory contexts explicit performance incentive systems are
7 put in place to specifically penalize (or, conversely, reward) particularly poor (or
8 good) utility performance. Synapse Energy Economics, Inc. prepared a report
9 entitled “Performance-Based Regulation in a Restructured Electric Industry” for
10 the National Association of Regulatory Utility Commissioners. In that report, we
11 analyzed experience with existing performance-based regulation (PBR) programs
12 and potential designs of future PBR programs. We concluded that the specifics of
13 a PBR approach should naturally depend upon the context and the objectives in
14 any particular situation. In other words, there is no single ideal approach to
15 incentives. But such approaches should not result in windfall profit opportunities
16 for investors at the expense of customers.

17 **Q. DO THE TRACKERS REDUCE UTILITY INCENTIVES TO REDUCE**
18 **COSTS?**

19 A. Yes. “Traditional rate regulation” involves occasional rate cases with cost
20 increases or decreases between rate cases borne by the shareholders. To the
21 extent that trackers and adjustment clauses eliminate the regulatory lag between
22 rate cases, they also reduce the associated incentives to the Company to increase
23 revenues or reduce costs during those periods.

24 **Q. CAN YOU COMMENT SPECIFICALLY ON PSI’S PROPOSED**
25 **INCENTIVE APPROACH FOR OFF-SYSTEM SALES?**

26 A. Yes. The Company’s proposal is for 100% of off-system sales profits in the
27 summer to be credited to customers, and for 25% of off-system sales profits in
28 other months to be credited to customers, with shareholders benefiting from 75%
29 of the off-system sales profits in the non-summer months. In my view the 75%
30 “incentive” to the Company for non-summer off-system sales is excessive. It is
31 unreasonable and unjustified.

1 Moreover, incentive approaches can have unintended consequences, and
2 incentive frameworks with large discontinuities are particularly prone to
3 problems. PSI (or its affiliates hopefully acting on its behalf) makes decisions
4 that influence PSI's summer resource balance and costs. They also make
5 decisions that influence PSI's annual resource balance and costs. If a resource
6 decision (e.g., to add a baseload resource rather than a peaking resource) will
7 result in a large increase in PSI's non-summer off-system sales revenue (which
8 shareholders would keep 75% of under the Company's proposal) but would
9 increase costs that are passed through to customers, how would that be
10 evaluated? A very specific targeted incentive of this type could serve to
11 undermine the overall objective of low net costs of serving regulated customers.

12 **Q. DID MR. ESAMANN ADEQUATELY ADDRESS THIS ISSUE IN HIS**
13 **ORAL TESTIMONY BEFORE THE COMMISSION?**

14 A. No. Under cross-examination during his testimony before the Commission on
15 June 9, 2003, Mr. Esamann failed to adequately address concerns regarding the
16 issue of PSI's split incentive approach to off-system sales profits. Instead, Mr.
17 Esamann chose to refocus attention on how the profit-sharing mechanism is
18 intended to produce an equal sharing of off-system sales profits. Exhibit BEB-6
19 presents the relevant excerpt from the transcript of the June 9, 2003 hearing.

20 **Q. IN YOUR OPINION, DOES THE SUMMER RELIABILITY TRACKER**
21 **EQUITABLY DISTRIBUTE THE COSTS OF PURCHASED POWER AND**
22 **THE PROFITS FROM OFF-SYSTEM SALES BETWEEN THE**
23 **COMPANY AND ITS CUSTOMERS?**

24 A. I do not believe that the Summer Reliability Tracker would equitably distribute
25 the costs and profits from these off-system sales and purchases. Even taking the
26 Company's estimates at face value, the proposed tracker requires customers to
27 bear 100 percent of summer purchased power costs while crediting them with
28 only 50 percent of off-system sales profits. Contrary to the Company's claims,
29 the tracker's cost/profit distribution mechanism will likely result in a net cost to
30 customers starting in 2004. Furthermore, the problematic split incentive

1 mentioned above raises the possibility that off-system sales profits will be more
2 likely to arise at times when the ratepayers benefit the least.

3 **Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION**
4 **CONCERNING THE APPROVAL OF THE PROPOSED SUMMER**
5 **RELIABILITY TRACKER?**

6 A. I recommend that the Commission reject the tracker as it is currently proposed.
7 As I note elsewhere in my testimony, rate adjustment trackers such as the Summer
8 Reliability Tracker often confer handsome benefits to shareholders while
9 providing little or no tangible benefits to customers. I recommend that the
10 Commission approve a modified version of the Summer Reliability Tracker that
11 allows customers to retain 100 percent of off-system sales profits in all months of
12 the year. Given the Company's failure to justify its need for such a significant
13 profit incentive and given the magnitude of the Company's proposed rate
14 increase, it stands to reason that customers should receive all of the off-system
15 sales profits. Modifying the tracker in this manner would also greatly increase the
16 probability that customers would indeed receive a net credit from the tracker, as
17 Mr. Esamann has claimed.

18 Confidential Exhibit BEB-7 presents my analysis of the tracker's
19 estimated net cost to customers under a scenario in which 100 percent of off-
20 system sales profits are allocated to customers. [REDACTED]

21 [REDACTED]

22 [REDACTED]

23 [REDACTED]. Averaged over the
24 five-year period from 2003 to 2007, the rate impact of the tracker would be
25 essentially revenue neutral, equaling an annual credit of [REDACTED].

26 **Q. WHAT PROCEDURES DEFINE HOW PSI AND OTHER CINERGY**
27 **COMPANIES ENTER INTO TRANSACTIONS WITH ONE ANOTHER**
28 **AND HOW ARE SUCH TRANSACTIONS ACCOUNTED FOR AMONG**
29 **THE CINERGY COMPANIES?**

30 A. The Joint Generation Dispatch Agreement (JGDA) and Joint Transmission
31 Agreement (JTA) were negotiated during 2001 in the context of FERC Docket

1 Nos. ER01-200-000 and ER01-200-001 and IURC Cause No. 41954. The IURC
2 approved the settlement agreement containing the terms of the JGDA and JTA on
3 September 11, 2001. The agreement sets out the manner in which Cinergy's
4 generating and transmission assets are dispatched, and the manner in which
5 system energy transfers, off-system purchase and sales, transmission system costs,
6 and other transactions are allocated among the Cinergy companies.

7 Cinergy established an Administrative Operating Committee (AOC) to
8 implement the JDGA. The minutes of that Committee are confidential. The
9 topics that it deals with include specifics of how to implement the JDGA,
10 including the treatment of various types of generating resources, the treatment of
11 various types of loads, and the treatment of various types of transactions. The
12 "Post Analysis Cost Exchange Program" (PACE) is used in implementing the
13 JDGA. There are algorithms in PACE which determine the allocation and
14 treatment of dispatch costs and transactions. These details can be complex, and
15 they can have large impacts upon how costs are allocated among the Cinergy
16 companies. There is a strong incentive for Cinergy to maximize the net revenues
17 that are allocated to the deregulated business units and away from PSI, where they
18 would be credited to regulated customers.

19 **Q. ACCORDING TO THE TERMS OF THE SETTLEMENT AGREEMENT,**
20 **WHEN WILL THE NEXT COMMISSION PROCEEDING ASSESSING**
21 **THE JGDA OCCUR?**

22 A. Section II.(F) of the settlement agreement provides for a 2004 process to "assess
23 the feasibility, efficacy, and equity of continuing joint system dispatch and
24 associated system energy transfers." Unless all the parties to the settlement
25 agreement concur otherwise, PSI is required to file a petition with the
26 Commission by March 15, 2004 to initiate an IURC assessment of the functioning
27 of the JGDA.

28 **Q. WHAT DO YOU RECOMMEND THAT THE IURC DO WITH RESPECT**
29 **TO THE JGDA, THE AOC, AND PACE?**

30 A. The interpretation and implementation of the JGDA and JTA are extremely
31 complex, subject to manipulation, occurring in a context in which the decision-

1 makers have conflicting or problematic incentives, and important to the
2 determination of the appropriate level of costs to be allocated to PSI for purposes
3 of this rate case. The Company has provided some information on the AOC and
4 PACE, but it was not in the Company's filing and it was obtained late in the
5 discovery process. The Company's rate case filing was voluminous, but there
6 was no witness who identified the issues in interpreting and implementing the
7 JGDA, the implications of various transactions upon PSI, and the accounting
8 procedures for those transactions. I believe that a more thorough review is
9 required than has been possible in the rate case, and that such a review will take
10 considerable time. I recommend that a sub-docket be initiated to address issues
11 related to the JGDA, the AOC, and PACE. The issues would include:

- 12 (1) review of the implementation decisions made with respect to the JGDA;
- 13 (2) examination of the logic behind the PACE system to determinate whether it is
14 logical, consistent, and fair;
- 15 (3) auditing of the methods and calculations of cost allocations associated with
16 O&M, emissions, and transmission;
- 17 (4) consideration of the status of and adequacy of hourly market price data for use
18 in the pricing of transactions;
- 19 (5) review of the transactions entered into and the basis for entering into
20 particular transactions;
- 21 (6) examination of the timing of various decisions, e.g., when a contract is entered
22 into, compared with when its treatment within PACE is determined (since
23 time lags could create opportunities for risks to be shifted, as they were with
24 the transfer of the merchant plants to regulated rates);
- 25 (7) assessment of the role of individuals on the AOC to determine whether and to
26 what extent PSI's interests as a regulated utility and entity separate from
27 Cinergy are being effectively are being effectively represented; and
- 28 (8) consideration of reserve margin requirements in the context of the
29 implementation of the JGDA and PACE, to make sure that PSI's reserve
30 requirement is determined on the basis of its customers' needs.

31

1 In effect, PSI should not be permitted to increase its rates based on the
2 decisions of the AOC and the allocations of PACE until the Commission can
3 verify that PSI manages its operations and transactions (including off-system
4 power purchase sales activity) in the interests of its customers. The IURC should
5 fully understand the processes, and the documentation and explanation should be
6 sufficient to provide some confidence that PSI customers are not subsidizing the
7 other Cinergy legal entities, or bearing risks that are not appropriately placed on
8 the regulated entity.

9 **Q. HOW WOULD THIS SUB-DOCKET RELATE TO THE 2004 PROCESS?**

10 A. The sub-docket would provide a great deal of information and education with
11 regard to the workings of the JGDA, the AOC, and PACE. It would focus on
12 setting appropriate rates for PSI. The 2004 process would focus on whether to
13 continue, amend, or terminate the JGDA. So the sub-docket would provide a
14 great deal of useful background on how the JGDA has been implemented, which
15 would help to inform the 2004 process.

16

17 **IV. NOX EMISSION ALLOWANCE TRACKER**

18 **Q. WHAT ENVIRONMENTAL COMPLIANCE COSTS DOES PSI FACE?**

19 A. Because of its high level of reliance on coal-fired generation, PSI faces significant
20 environmental compliance costs. The Company has spent approximately \$540
21 million for equipment and \$53.6 million for SO₂ emission allowances in order to
22 meet 1990 Clean Air Act Amendment regulations.¹¹ According to its own
23 estimates, the Company faces \$600 million or more in costs for additional
24 pollution control measures.¹²

25 **Q. WHAT MUST PSI DO TO COMPLY WITH THE NO_x SIP CALL?**

26 A. To comply with the SIP call, PSI needs to reduce its NO_x emissions by 63%, or
27 about 21,000 tons per year. The Company's NO_x Compliance Plan includes

¹¹ William F. Tyndall prefiled Case-in-Chief testimony, page 3.

¹² Douglas F. Esamann prefiled Case-in-Chief testimony, page 34.

1 installation of selective catalytic reduction and selective non-catalytic reduction
2 controls, low NOx burners, and boiler optimization equipment at multiple
3 generating units.¹³

4 **Q. WHICH OF THE COMPANY’S ENVIRONMENTAL COMPLIANCE**
5 **COSTS ARE CURRENTLY RECOVERABLE THROUGH RATES?**

6 A. The Company has received approval for deferred ratemaking treatment for its
7 NOx Construction Work in Progress (CWIP) projects, allowing the Company to
8 recover the costs of its NOx Compliance Plan. Rider No. 63 also allows the
9 Company to recover its costs associated with the acquisition of SO2 emission
10 allowances. In a separate SB 29 proceeding, the Company is requesting approval
11 for an additional tracker which would allow it to concurrently recover
12 depreciation and operation and maintenance expenses of its CWIP rather than
13 defer the costs for future recovery.

14 **Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF THE NOx CWIP**
15 **AND SB 29 TRACKERS?**

16 A. Stephen Farmer testified under cross-examination that the revenues from NOx
17 CWIP would increase base rates by approximately 3 percent, or about \$33 million
18 (\$27.8 million of annualized CWIP revenue from Line 2, Column G of
19 Petitioner’s Exhibit C-5 plus \$4.8 million of revenues from Rider No. 62 from
20 Petitioner’s Exhibit X-8). These costs are reflected in the test year period.
21 Beyond the test year, Mr. Farmer approximated that the CWIP tracker would
22 generate an additional \$18 million in annual revenues on top of the 3 percent rate
23 increase.¹⁴ Adding this to the \$33 million that is being included in base rates
24 yields a total rate increase of about \$51 million, or a 4 percent increase over
25 current rates.

26 On an annualized basis, the rate impact of the SB 29 tracker is estimated
27 to be between \$12 and \$13 million.¹⁵ This would bring the cost to customers of
28 PSI’s NOx compliance plan to well over \$60 million each year.

¹³ Esamann prefiled Case-in-Chief testimony page 34.

¹⁴ Stephen M. Farmer’s cross examination by Michael Mullett, page 45, line 15.

¹⁵ Stephen M. Farmer’s cross-examination by Michael Mullett, page L-48, line 11.

1 **Q. WHAT PROJECTIONS HAS THE COMPANY PROVIDED WITH**
2 **REGARD TO THE RATE IMPACT OF THE NO_x EMISSION**
3 **ALLOWANCE TRACKER?**

4 A. To my knowledge, the Company has not provided any projections predicting the
5 rate impacts of the NO_x Emission Allowance Tracker.

6 **Q. HOW MANY NO_x EMISSION ALLOWANCES WILL THE**
7 **ENVIRONMENTAL PROTECTION AGENCY (EPA) ALLOCATE TO PSI**
8 **IN FUTURE YEARS?**

9 A. The Company estimates that, beginning in 2004, the EPA will allocate
10 approximately [REDACTED] of NO_x emission allowances to PSI each year.¹⁶

11 **Q. HOW DOES THE EPA'S ALLOCATION OF EMISSION ALLOWANCES**
12 **COMPARE TO THE COMPANY'S PROJECTIONS OF FUTURE NO_x**
13 **EMISSIONS?**

14 A. According to its confidential estimates, PSI expects to emit more than [REDACTED] tons
15 of NO_x each year through 2007. The Company's projected emissions exceed its
16 EPA EA allocation by an average of [REDACTED] tons per year between 2004 and 2007.¹⁷
17 However, because of the Early Reduction Credits that PSI has earned and expects
18 to earn through 2003, the Company does not anticipate the need to obtain
19 additional NO_x EAs or install additional NO_x reduction equipment until
20 approximately 2007 (see page 11 of John J. Roebel's pre-filed Case-in-Chief
21 testimony).

22 **Q. UNDER WHAT CIRCUMSTANCES MIGHT THE COMPANY BE**
23 **REQUIRED TO PURCHASE NO_x EMISSION ALLOWANCES PRIOR TO**
24 **2007?**

25 A. If the Company's planned NO_x reduction projects are delayed or experience
26 operational problems, the Company's NO_x emissions may exhaust its balance of
27 EAs. Also, if the Company's electricity generation exceeds anticipated levels,
28 NO_x emissions may also increase and potentially require the Company to obtain

¹⁶ Confidential Data Response OUCC/PSI-9-234-A.

¹⁷ Ibid.

1 EAs prior to 2007. In the previous section of my testimony I noted that the
2 Company's load forecast may be unreasonably low. This increases the probability
3 that PSI will need to acquire more EAs than it has projected.

4 Furthermore, the NOx SIP Call's flow control mechanism could restrict
5 the Company's ability to use its banked EAs, and increase the likelihood that the
6 Company will need to purchase additional EAs.¹⁸

7 **Q. WHAT UNCERTAINTIES EXIST CONCERNING THE MARKET FOR**
8 **NOx EMISSION ALLOWANCES?**

9 A. It is extremely difficult to predict the future cost of NOx emission allowances.
10 Like wholesale electricity markets, the market for EAs is subject to considerable
11 volatility and price risk. Unexpected plant outages and high summer temperatures
12 can cause sudden and dramatic increases in NOx EA prices. Likewise,
13 "overinvestment" in NOx reduction measures by affected utilities can cause
14 significant reductions in NOx EA prices. Publicly available data from the Cantor
15 Environmental Brokerage Market Price Index indicates that NOx Early Reduction
16 Credits were recently trading for approximately \$5,500 per ton per year in
17 Indiana.¹⁹

18 **Q. HOW DOES THE PROPOSED NOx EA TRACKER MITIGATE THE**
19 **RISKS OF ENVIRONMENTAL COMPLIANCE?**

20 A. The Company's proposed NOx EA tracker assigns the majority (80 percent) of
21 NOx EA acquisition costs related to serving native load to retail rates. Although
22 the Company does not currently forecast the need to acquire additional EAs
23 before 2007, changes in load, plant operations and other unforeseen circumstances
24 could change the Company's NOx EA position. Beyond 2007, the Company's
25 NOx EA situation is highly unknown. By allocating the principal share of NOx
26 EA acquisition costs to retail customers, the proposed tracker serves to further
27 reduce the environmental compliance risks that PSI faces. Adding the NOx EA
28 tracker to its existing NOx program CWIP and SO2 EA trackers puts the

¹⁸ See William F. Tyndall's cross-examination hearing transcript, page I-53.

¹⁹ Data as of June 2, 2003. Available at http://www.emissionstrading.com/index_mpi.htm, accessed 6/30/03.

1 Company in a position of very little risk exposure to the costs of complying with
2 current environmental regulations.

3 **Q. ARE THERE ANY SIGNIFICANT DIFFERENCES BETWEEN THE NO_x**
4 **AND SO₂ EA TRACKERS?**

5 A. Yes. Whereas the NO_x EA tracker allocates 80 percent of net gains or losses
6 from NO_x transactions related to serving its native load obligations to customers,
7 the SO₂ EA tracker allocates 100 percent of such gains or losses to customers. I
8 find this difference questionable because the Company appears to be supporting
9 two otherwise entirely similar tracking mechanisms that have different cost
10 allocation schemes. It would seem more appropriate for both trackers to allocate
11 the same percentage of net gains and losses to customers. The disparate
12 allocation schemes grant the Company the ability to profit where such opportunity
13 exists (in the case where the Company has opportunity to sell some of its banked
14 NO_x EAs), while requiring customers to bear fully the costs of environmental
15 compliance where profitable opportunities do not exist (in the case of the
16 Company's continuing to be a net buyer of SO₂ EAs).

17 Furthermore, the opportunity for gains from NO_x EA sales has been
18 created by the Company's pre-approved NO_x compliance measures. The
19 Company is already allowed to earn a return on these expenditures via the NO_x
20 CWIP tracker. Permitting the Company to profit from NO_x EA sales when it
21 already earns a return on the NO_x compliance expenditures that create the sales
22 opportunity would provide an inappropriate incentive for the Company and would
23 prevent customers from realizing all of the potential economic benefits created by
24 the NO_x pollution controls which customers are fully funding through higher
25 rates.

26 **Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION**
27 **CONCERNING THE COMPANY'S PROPOSED NO_x EA TRACKER?**

28 A. I recommend that PSI's NO_x EA tracker be amended to allocate 100 percent of
29 net gains and losses from NO_x EA transactions to customers. The Company's
30 proposal to retain 20 percent of potential gains from its NO_x EA transactions
31 constitutes an inappropriate profit incentive and does not appear to be in the best

1 interest of its ratepaying customers. Allocating 100 percent of net gains and
2 losses from NOx EA transactions to customers would also be consistent with the
3 Company's existing SO2 EA tracker.

4 **Q. IN YOUR VIEW, DO THE COMPANY'S PROPOSED TRACKERS**
5 **PROVIDE EQUAL BENEFIT TO ITS RETAIL CUSTOMERS AND**
6 **SHAREHOLDERS?**

7 A. In my opinion, the Company's proposed trackers assign the majority of risks to its
8 retail customers. The proposed Summer Reliability Tracker requires customers to
9 bear 100 percent of summer purchased power costs, which are one of the
10 Company's most significant risks. The proposed NOx EA Tracker likewise
11 assigns 80 percent of EA acquisition costs to retail rates. The cumulative effect of
12 these trackers is to shield PSI's shareholders from a large portion of the
13 Company's most significant risks – at the expense of retail customers.

14 **Q. MR. ESAMANN'S TESTIMONY (PAGE 5, LINES 1-2) STATES THAT**
15 **PSI'S "TRACKER PROPOSALS...ALIGN CUSTOMER AND**
16 **SHAREHOLDER INTERESTS IN A BALANCED MANNER." IN YOUR**
17 **VIEW, IS THIS AN ACCURATE STATEMENT?**

18 A. No. I believe that the proposed Summer Reliability and NOx Emission
19 Allowance trackers require PSI customers to bear a disproportionate amount of
20 the Company's exposure to risk. The trackers serve to further protect shareholder
21 earnings and also include inappropriate profit incentives. Because the proposed
22 trackers require customers to bear the significant and volatile costs of the
23 Company's reliability purchases and environmental compliance, it is fair to
24 expect that these same customers be entitled to the full benefits of off-system
25 sales and NOx EA sales, where such opportunities exist. I encourage the
26 Commission to consider the asymmetrical risk distribution of the Company's
27 trackers when determining their appropriateness. I further encourage the
28 Commission to consider the risk reduction and earnings protection afforded to
29 shareholders by all of the Company's existing and proposed trackers when
30 determining the appropriateness of the Company's requested ROE.

1 **V. MERCHANT PLANT ACQUISITIONS**

2
3 **Q. WHEN WERE THE HENRY COUNTY AND MADISON GENERATING**
4 **PLANTS CONSTRUCTED?**

5 A. The application for the Henry County construction permit was received in
6 December of 1998. Construction was suspended by the IURC in March, 2000,
7 and resumed in April, 2001. The plant began operating in the summer of 2001.
8 The construction of the Madison/Butler County plant was announced in July of
9 1999, and the plant began commercial operation in May and June of 2000.

10 **Q. WHEN DID CINERGY SEEK TO TRANSFER THE OWNERSHIP OF**
11 **THESE PLANTS TO PSI?**

12 A. In December of 2001, Cinergy proposed to transfer the plants to PSI in Cause No.
13 42145.

14 **Q. WHAT WERE THE MARKET PRICE PROJECTIONS AT THE TIME**
15 **THAT CINERGY INVESTED IN THE PLANTS?**

16 A. In 1998 and 1999, the wholesale electricity market in the Midwest experienced
17 unprecedented price spikes. The uncertain nature of the incipient market pushed
18 forward price projections upward through the first half of 2001. For example, in
19 the first four months of 2001, on-peak electricity for the Calendar 2002 period
20 was routinely being traded for more than \$50 per MWh, and throughout 2000 the
21 market for Summer 2002 on-peak power rarely dropped below \$90 per MWh.

22 **Q. WHAT WERE THE ACTUAL MARKET PRICES DURING 2002?**

23 A. According to day-ahead trading reported by Energy Argus, spot market, on-peak
24 electricity in 2002 averaged well under \$30 per MWh, and on-peak summer
25 electricity averaged less than \$35 per MWh. In other words, market price
26 expectations in 2000 and 2001 exceeded actual prices by up to 150 percent.
27 Exhibit BEB-8 presents a graph of actual 2002 (as indicated by day-ahead
28 forward trades) prices compared against forward trades from 2000 and 2001.

1 **Q. WHEN DID MARKET PRICE EXPECTATIONS BEGIN TO FALL MORE**
2 **IN LINE WITH ACTUAL PRICES?**

3 A. Beginning in the spring of 2001, 2002 forwards experienced a significant price
4 decline. Graphs of 2002 summer and calendar forwards are presented in Exhibits
5 BEB-9 and BEB-10. In April 2001, 2002 calendar forwards were routinely being
6 traded for more than \$50 per MWh. By late June, prices rarely exceeded \$40 per
7 MWh, and by October, they were trading at prices close to \$30 per MWh.
8 Summer forward prices experienced a similar decline – from about \$90 per MWh
9 in April to about \$50 per MWh by late September.

10 **Q. WHAT WAS THE CONDITION OF THE WHOLESALE MARKET**
11 **WHEN CINERGY/PSI FILED ITS PETITION IN DECEMBER 2001?**

12 A. In December 2001, 2002 forward electricity prices dropped to their lowest levels
13 since these products began trading in 2000. Calendar forwards were trading for
14 little more than \$30 per MWh and summer forwards had dropped below \$50 per
15 MWh.

16 **Q. HOW DID THE CHANGED MARKET CONDITIONS AFFECT THE**
17 **PROFITABILITY OF THE MERCHANT PLANTS?**

18 A. The value of new peaking units such as the Henry County and Madison plants is
19 heavily dependent on wholesale market prices, particularly prices prevailing at
20 times when additional generation is needed to meet peak system demand.
21 Unregulated electric generating companies are likely to invest in peaking
22 combustion turbine plants if they believe that such plants will recoup their
23 investment through sufficiently high wholesale electricity prices. In 2001, the
24 wholesale electricity market in the Midwest shifted from a period of price spikes
25 and extreme volatility to one characterized by much reduced prices and volatility.
26 These shifting market conditions would make it increasingly difficult for
27 merchant peaking units such as the Henry County and Madison plants to be
28 profitable to Cinergy's unregulated business.

1 **Q. DID CINERGY ACKNOWLEDGE THAT THE PLANTS WERE**
2 **UNPROFITABLE AT THE TIME THAT PSI REQUESTED APPROVAL**
3 **FOR THEIR PURCHASE?**

4 A. Yes. Cinergy acknowledged that the plants were not profitable in the initial years
5 of their operation, but claimed to believe that the plants would still recover their
6 costs in the long run.²⁰

7 **Q. DOES ANY EVIDENCE EXIST TO SUGGEST HOW CINERGY VIEWED**
8 **THE MERCHANT PLANTS AS FINANCIAL INVESTMENTS AT THE**
9 **TIME OF THE PROPOSED TRANSFER TO PSI?**

10 A. Yes. Presentations given at several of Cinergy's Board meetings in 2001 allude to
11 the importance of Cinergy's ability to recover its stranded merchant power plant
12 costs. Confidential Exhibit BEB-11 presents a slide from a presentation of 2001
13 Cinergy financial results by R. Foster Duncan at a board meeting in January 2002.

14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]

18 **Q. HOW DID THE APPROVAL OF THE MERCHANT PLANT TRANSFER**
19 **AFFECT CINERGY'S ANTICIPATED STOCK PERFORMANCE?**

20 A. Information presented at the January 2002 Cinergy board meeting suggests that
21 the merchant plant transfer had a significant impact on Cinergy's expected
22 earnings per share. Confidential Exhibit BEB-13 presents a slide from Mr.
23 Duncan's presentation showing the estimated impact of the merchant plant
24 transfer at cost-based rates on Cinergy's 2002 Energy Merchant EPS plan. [REDACTED]

25 [REDACTED]
26 [REDACTED]
27 [REDACTED]
28 [REDACTED]
29 [REDACTED]

²⁰ See, for instance, Section II(B) of Petitioner's Reply Brief in Cause No. 42145, submitted November 28, 2002.

1 **Q. HAVE ANY CONCERNS BEEN RAISED WITH RESPECT TO THE**
2 **PRICE THAT PSI PAID FOR THE MERCHANT PLANTS?**

3 A. Yes. The price that PSI paid Cinergy for the Madison and Henry County plants
4 was one of the most contentious issues in the merchant plant transfer proceeding,
5 Cause No. 42145. Several intervenors, including the OUCC, PSI Industrial
6 Group (PSI-IG), and the Midwest Independent Power Suppliers (MWIPS), argued
7 that the proposed sale price was unreasonably high. After Cinergy and PSI agreed
8 to a slightly lower price in their settlement agreement with the OUCC, PSI-IG and
9 MWIPS continued to argue that the plants were significantly overpriced.

10 The intervenors raised concerns over PSI's failure to obtain an
11 independent assessment of the market value of the facilities and the relatively
12 high cost per kilowatt of the plants in comparison to other merchant and utility
13 plant sales and construction in the region. In particular, both PSI-IG and the
14 OUCC compared the cost of Cinergy's merchant plants to the cost of a
15 combustion turbine constructed by Indianapolis Power & Light (IPL). Per the
16 terms of the settlement agreement in Cause No. 42145, PSI paid \$528/kW for the
17 merchant plants,²¹ while IPL received approval in Cause No. 42033 to construct
18 its combustion turbine plant at a cost of \$341/kW.²²

19 The evidence presented by the intervenors and the contentiousness
20 surrounding the value of the Madison and Henry County plants further support the
21 implication that the plants' value had significantly diminished since their
22 inception, and that their transfer to PSI at book value constituted a boon to
23 Cinergy shareholders at the expense of regulated ratepayers.

24 **Q. DID PSI CHALLENGE THE ARGUMENTS CONCERNING THE**
25 **DIMINISHED MARKET VALUE OF THE MERCHANT PLANTS?**

26 A. Yes. PSI vigorously challenged the assertion that the merchant plants were worth
27 less than their book value, and provided several counterarguments that attempted

²¹ PSI purchased the plants for \$376 million (Mr. Esamann's prefiled testimony, page 37). Dividing this by their combined capacity of 712 MW yields \$528/kW.

²² Redacted Prefiled Testimony of OUCC witness Robert M. Endris in Cause No. 42145, page 30, line 17.

1 to justify the reasonableness of their purchased price. However, the confidential
2 information in Exhibits BEB-11 and BEB-13 concerning the plants' impact on
3 EMBU earnings per share provides indisputable evidence that their transfer to
4 cost-based rates generated significant earnings protection for Cinergy
5 shareholders.

6 **Q. IN LIGHT OF THE SETTLEMENT AGREEMENT APPROVED BY THE**
7 **COMMISSION IN CAUSE NO. 42145, WHY ARE THESE ISSUES**
8 **PERTINENT TO THE CURRENT PROCEEDING?**

9 A. I acknowledge that the profitability and value of the plants and Cinergy's motives
10 for seeking their transfer were addressed at length in Cause No. 42145 and
11 ultimately settled in an agreement that was approved by the Commission. By
12 briefly revisiting these issues, I do not intend to cast doubt upon the terms of the
13 settlement agreement. Rather, the purpose of my discussion of these issues is to
14 examine how PSI's holding company benefits prospectively from reduced
15 exposure to risk as a result of the merchant plant transfer and the implications of
16 this reduced risk exposure on the Company's proposed rate of return on equity in
17 this current rate case

18 The plants' lack of profitability in the initial years of their operation had a
19 negative impact on Cinergy's earnings per share and posed similar risks for the
20 future. Their transfer to a regulated affiliate operating under cost-based rates
21 allows Cinergy to recover essentially all of the plants' capital costs and to earn a
22 regulated rate of return on those investments. In effect, this represented a transfer
23 of risk from Cinergy, who became protected from the risks of recovering the costs
24 of its highly speculative merchant plant investment, to PSI's customers, who will
25 now bear the economic risks of the plants priced at embedded cost.

26 **Q. WHAT ARE THE REGULATORY IMPLICATIONS OF MERCHANT**
27 **PLANT TRANSACTIONS BETWEEN THE UNREGULATED AND**
28 **REGULATED AFFILIATES OF THE SAME HOLDING COMPANY?**

29 A. Because of the potential for market abuse, such transactions have come under
30 increasing scrutiny from regulatory agencies. For example, the Federal Energy
31 Regulatory Commission (FERC) recently ordered an administrative review of

1 long-term power purchase contracts between Southern Co.'s unregulated
2 subsidiary and its regulated affiliates Georgia Power Co. and Savannah Electric
3 and Power Co., over concerns regarding whether the agreements adversely affect
4 wholesale competition.²³

5 While it approved without hearing Cinergy's request to transfer its
6 merchant plants to PSI, FERC also acknowledged the ramifications of such
7 transactions on electricity market competitiveness and fairness, noting, "The
8 ability of a franchised utility to assume its affiliated merchant's generation when
9 market demand declines gives the affiliated merchant a safety net that merchant
10 generators not affiliated with a franchised utility lack."²⁴

11 Since Cinergy's merchant plant transfer, FERC has set a hearing for the
12 proposed transfer of generating and interconnection facilities from Amergen
13 Energy Generating Co. to its regulated affiliate, Ameren Union Electric. The
14 Illinois Commerce Commission, which has pre-approval authority over the
15 transfer, recommended to FERC that it reject the transaction.²⁵

16 **Q. HOW DOES THE MERCHANT PLANT TRANSFER TO THE**
17 **REGULATED COMPANY AFFECT THE RISK BORNE BY PSI**
18 **RATEPAYERS AND ITS ONLY SHAREHOLDER, CINERGY?**

19 A. There are two important considerations relevant to risk allocation.

20 First, the fact that the IURC pre-approved this transfer on the terms that it
21 did indicates that PSI is operating in a *very* favorable regulatory climate for
22 shareholders. That is, the regulated utility business, PSI, is not only being
23 protected from many risks attendant to its own business by its tracker mechanisms
24 – it has also been used to transfer risk to PSI customers associated with the
25 activities of Cinergy's unregulated subsidiaries that would have otherwise been
26 borne by Cinergy's shareholders. From the perspective of current and prospective
27 Cinergy shareholders, this risk transfer is quite valuable. From the perspective of

²³ Dow Jones Business News, "FERC Orders Review of Southern Power Deals," July 9, 2003.

²⁴ Foster Electric Report, "Concerned About the Effect on Competition, FERC Sets for Hearing the Proposed Transfer of Generation and Interconnection Assets of Ameren's Subsidiaries." Report No. 306, May 14, 2003.

1 PSI ratepayers, however, there is a problematic asymmetry with the situation,
2 unless the risk transfer is reflected in the ROE allowed Cinergy on the plant
3 investment, i.e. by lowering the ROE relative to what would otherwise be
4 allowed. If there is no such adjustment to the allowed ROE for Cinergy's
5 investment, then PSI's ratepayers will have been subjected to a "heads I win, tails
6 you lose" proposition.

7 Second, there is the PSI business and regulatory risk reduction normally
8 attendant to pre-approval of generating facilities. Pre-approval is intended to
9 eliminate the risk of unnecessary plant, as well as plant that is excessively costly
10 to construct or acquire. Similarly, it is intended to eliminate the risk of regulatory
11 disallowance for unnecessary or excessively costly plant. The merchant plants, as
12 well as the Noblesville Repowering Project, have been pre-approved by the
13 Commission. This means, *a fortiori*, that the risks of their plant capacity being
14 unnecessary or excessively costly, and the associated risks of partial or total
15 regulatory disallowance, have been eliminated as far as these three plants are
16 concerned. This risk reduction should also be reflected in a lower required ROE
17 with respect to the investment in these three plants than would be the case in the
18 absence of pre-approval.

19 **VI. MANAGING RISKS, RESOURCE DIVERSITY, AND AIR EMISSIONS**

20

21 **Q. DOES CINERGY ACTIVELY MANAGE ITS RISKS?**

22 A. Yes. Cinergy appears to actively analyze and manage its risks, focusing on the
23 risks to shareholders. The following is an excerpt from its 2002 annual report.

24 We manage, on a portfolio basis, the market risks in our
25 energy marketing and trading transactions subject to
26 parameters established by our Risk Policy Committee. Our
27 market and credit risks are monitored by the Global Risk
28 Management function to ensure compliance with stated risk
29 management policies and procedures. The Global Risk
30 Management function operates independently from the

25

Ibid.

1 business units and other corporate functions, which
2 originate and actively manage the market risk exposures.
3 Policies and procedures are periodically reviewed to ensure
4 their responsiveness to changing market and business
5 conditions. Credit risk mitigation practices include
6 requiring parent company guarantees, various forms of
7 collateral, and the use of mutual netting/closeout
8 agreements.²⁶
9

10 Cinergy's presentations to its Board of Directors also focus upon risks to
11 shareholders and the role of favorable regulation in securing shareholder earnings.
12 Confidential Exhibit BEB-14 presents a slide from the February 6, 2003 Cinergy
13 Board Meeting presentation given by Cinergy's CEO of Regulated Businesses,
14 Jim Turner. [REDACTED]
15 [REDACTED]. Confidential Exhibit BEB-
16 15 is an excerpt from an internal memo from Jim Rogers to the Cinergy Board of
17 Directors, dated October 1, 2002. [REDACTED]
18 [REDACTED]
19 [REDACTED]

20 **Q. DOES PSI ACTIVELY MANAGE RISKS TO REGULATED**
21 **CUSTOMERS?**

22 A. No. PSI and Cinergy appear to be relatively passive in analyzing and managing
23 risks to PSI customers. There is a notable contrast between the Company's focus
24 on the projected effects of regulatory proposals on shareholder earnings, as
25 referenced above, and its relative lack of inquiry and analysis concerning the rate
26 impacts of its trackers on its customers in future years. The Company's heavy
27 reliance on trackers effectively shifts PSI's risk exposure to its customers, yet the
28 Company has demonstrated little concern in attempting to quantify these
29 ratepayer risks beyond the test year period.

30 **Q. SHOULD PSI MANAGE THE RISKS TO ITS CUSTOMERS?**

31 A. Yes, of course PSI should analyze and manage the risks to which its customers
32 are exposed. For example, PSI should monitor and analyze various uncertainties

²⁶ Cinergy Corp. 2002 Annual Report, "The Faces of Leadership," page 58.

1 that bear upon its future costs of providing service, including fuel prices, power
2 market prices, and environmental compliance costs – and take affirmative steps to
3 mitigate those risks and their impact on customers. The Company is clear that
4 there is uncertainty in the components of those costs, but the trackers appear to
5 give PSI sufficient confidence that fluctuations in those costs will not have a
6 detrimental effect upon PSI’s shareholder (Cinergy). The result appears to be a
7 situation in which neither PSI nor Cinergy believes that the costs and risks
8 covered under trackers need to be thoroughly analyzed and mitigated precisely
9 because they are being tracked.

10 **Q. WHAT EFFECT DO THE TRACKERS HAVE UPON RISKS TO**
11 **SHAREHOLDERS?**

12 A. Relative to traditional regulation, the trackers shift risk from shareholders to
13 customers. Because the earnings are based upon the difference between two large
14 numbers (total costs and total revenues), shareholders under traditional rate
15 regulation (without trackers) are exposed to risks associated with volatility on the
16 cost side (e.g., power costs could be higher than anticipated) and on the revenue
17 side (e.g., sales could be lower than expected). With the trackers, earnings
18 become relatively quite stable and predictable. Shareholders are protected from
19 volatility in those components that are tracked. With trackers covering costs that
20 are volatile or rising (e.g., fuel, purchased power, environmental compliance)
21 PSI’s shareholder is exposed to very little risk (e.g., stable items such as
22 depreciation, or unlikely findings of imprudence with associated disallowances
23 for costs such as transmission and distribution investment and wage and salary or
24 tax expense). The result of the trackers is to reduce volatility and risk in
25 shareholder returns, putting that volatility into the prices that customers pay.

26 **Q. ARE THERE ACTIONS THAT PSI COULD TAKE TO REDUCE ITS**
27 **EXPOSURE TO ENVIRONMENTAL RISKS?**

28 A. Yes. PSI could more actively address its environmental risks. PSI has made
29 some effort to diversify its generation mix, to reduce emissions from its existing
30 plants, and to implement demand-side management programs. These efforts,
31 however, are quite limited and reflect an approach of doing the minimum

1 required. PSI should serve its customers with low cost, reliable power in a way
2 that also diversifies the resource mix, cleans up the existing fleet of plants, and
3 expands energy efficiency programs.

4 **Q. YOU MENTIONED PSI RESOURCE MIX, AND THE NEED FOR FUEL**
5 **DIVERSITY AND EMISSIONS REDUCTIONS. WHAT IS THE**
6 **CURRENT SITUATION AND WHAT SHOULD PSI DO?**

7 A. According to EPA data (“eGRID”) Cinergy’s generation mix in the year 2000 was
8 98% coal. Cinergy’s emissions of CO₂, SO₂, and NO_x in 2000 were 67 million
9 tons, 560 thousand tons, and 154 thousand tons, respectively. It was the nation’s
10 fourth largest emitter of CO₂ and SO₂ (after AEP, Southern, and Xcel Energy)
11 and the third largest emitter of NO_x (after AEP and Southern). According to
12 Cinergy’s “Environmental, Health and Safety Progress Report 2002” its emissions
13 of SO₂ and NO_x decreased between 2000 and 2002, while its CO₂ emissions
14 stayed level, and its particulate emissions increased.

15 PSI’s share, relative to the Cinergy totals is about 59% of the 2000 amount
16 of generation. PSI’s share of CO₂ emissions is also 59% of the total. For SO₂,
17 PSI’s share is higher (66% of total) and for NO_x PSI’s share is lower (53% of
18 total). These shares are based upon EPA’s eGRID data.

19 Cinergy has made investments in selective catalytic reduction (SCR) to control
20 NO_x emissions (the “Environmental, Health and Safety Progress Report 2002,”
21 p.4, reports four out of nine planned SCR units to have been completed).

22 In addition, the repowering of Noblesville has increased the station’s
23 capacity and switched its fuel from coal to gas. This represents progress toward
24 improving the efficiency of Cinergy’s generating mix, and diversity of its fuel
25 supply, but Noblesville represents just 300 MW of capacity in a system of about
26 12,000 MW.

27 Cinergy and PSI are making some progress in reducing some important
28 types of air emissions and diversifying the fuel mix to include a small slice of gas
29 in addition to coal. However, this progress is very gradual, and appears to be the
30 minimum required to comply with regulations. Carbon dioxide emissions, fine
31 particulates, and toxics such as mercury will be important for Cinergy to address.

1 Demand side programs and renewable generating resources will be essential
2 components of a low cost and prudent strategy to manage these emissions and
3 associated risks.

4 **Q. YOU MENTIONED ENERGY EFFICIENCY PROGRAMS. WHAT IS**
5 **THE CURRENT SITUATION WITH REGARD TO PSI'S DSM**
6 **PROGRAMS AND WHAT SHOULD PSI DO?**

7 A. PSI's investments in demand-side management (DSM) programs during the
8 1990s are plotted in Exhibit BEB-16. PSI's annual spending on DSM peaked in
9 1994 at \$40 million per year of spending (with incremental energy savings of 172
10 GWh/year), declining to less than \$2 million per year in the late 1990s (with
11 incremental energy savings of less than 20 GWh/year). DSM programs and
12 investments in renewable generating technologies provide benefits in reducing
13 exposure to environmental risks. For a Company that is heavily dependent upon
14 coal-fired generating facilities in a policy context of increasingly comprehensive
15 and stringent air emissions regulations (including likely future restrictions on
16 emissions of carbon dioxide in order to address global climate change), the role of
17 efficiency and renewables can be particularly important.

18 **Q. HOW DID THE COMPANY EXPLAIN ITS MARKED DECLINE IN DSM**
19 **INVESTMENTS IN THE LATE 1990s?**

20 A. Richard G. Stevie, under cross-examination in this case, explained the Company's
21 decreased DSM investments as follows:

22 They [DSM investments] were greater in the early '90s up
23 until about 1996 or 1997, somewhere in there, when I think
24 it became – it became evident that for the larger customers,
25 they felt that it would – it was very easy for them to go out
26 into the marketplace and obtain energy efficiency services
27 on their own rather than paying for it through the utility and
28 having the utility provide those services.²⁷
29

30 The data reported by the Company to EIA show PSI spending on DSM peaking in
31 1994 at \$40 million (see Exhibit BEB-16). The notion that large customers can

²⁷ Richard G. Stevie cross-examination by Michael Mullett, page J-127, line 11.

1 obtain energy efficiency on their own is a poor reason to discontinue cost-
2 effective programs to encourage efficient use of electricity. Other companies
3 have found ways to provide cost-effective programs to large and small customers.

4 **Q. DO PSI'S DSM COST EFFECTIVENESS SCREENING MECHANISMS**
5 **SUFFICIENTLY ACCOUNT FOR THE AVOIDED ENVIRONMENTAL**
6 **COMPLIANCE COSTS THAT RESULT FROM INCREASED ENERGY**
7 **EFFICIENCY?**

8 A. I am concerned that the Company's DSM cost effectiveness screening
9 mechanisms do not sufficiently account for the avoided environmental
10 compliance costs of energy efficiency programs. The following is an excerpt
11 from Michael Mullett's cross examination of Mr. Stevie:

12 Q. Could you explain how environmental risk is factored into the
13 various tests that are employed to evaluate the cost effectiveness of
14 the demand side management program?

15 A. The programs that we have pass the cost effectiveness test without
16 including any potential environmental benefits. What you see is
17 once these programs are passed on to the integrated resource
18 planning process, that any reductions in environmental costs would
19 be captured within the analysis of the integrated resource plan. We
20 don't specifically identify a particular environmental savings for
21 these programs here. They already pass the cost effectiveness
22 test.²⁸

23
24 This suggests that PSI's DSM cost screening mechanism does not address the
25 environmental risks posed by future regulatory regulatory compliance costs (e.g.
26 CO2 and mercury emissions). Given the Company's heavy reliance on coal
27 generation and its pronounced vulnerability to new environmental regulations,
28 aggressively pursuing DSM would seem a prudent environmental risk
29 management policy that the Company can ill afford to overlook.

30 **Q. HAVE YOU ANALYZED THE POTENTIAL FOR PSI TO INCREASE ITS**
31 **INVESTMENT IN EFFICIENCY AND RENEWABLES?**

32 A. I have not conducted an analysis specific to PSI. I have, however, done an
33 analysis of the broader region – the ten states ranging from the Dakotas in the

²⁸ Richard G. Stevie cross examination by Michael Mullett, page J-119, line 17.

1 west to Ohio in the east. The results specific to Indiana are summarized on a two-
2 page document provided here as Exhibit BEB-17. The executive summary of the
3 regional analysis is provided as Exhibit BEB-18.

4 For this region, we found that a “clean energy development plan”
5 compared with the “business as usual” scenario could reduce electric system
6 carbon dioxide emissions by 51 percent in 2020. This would be a 36 percent
7 reduction relative to actual electric sector carbon dioxide emissions in the year
8 2000.

9 The cost of the clean energy plan, which emphasized efficiency programs
10 and renewable electricity generating resources, was estimated to be only 3.4
11 percent higher than total electricity costs in the business as usual case. The details
12 of this analysis are available in the report “Repowering the Midwest: The Clean
13 Energy Development Plan for the Heartland,” available online at
14 <http://www.repowermidwest.org>.

15 For PSI to implement a utility system portion of the energy efficiency
16 programs included in the regional clean energy plan would serve to reduce its
17 exposure to the environmental compliance risks of dependence on coal, while
18 actually reducing total costs to its customers. An aggressive and cost-effective set
19 of demand-side management programs can cut demand growth to less than half of
20 what it would otherwise be.

21 For PSI to implement its share of the renewable generating capacity would
22 also serve to reduce its exposure to environmental risks, at costs that could
23 reasonably be borne by customers. Based upon this regional study, and the state-
24 specific results from the study, it is reasonable to conclude that PSI could and
25 should aggressively develop and implement cleaner generating resources and
26 energy efficiency programs, in order to better serve its customers.

27 In contrast with the clean energy plan, Cinergy’s approach is minimal.
28 The Company chooses to do what is required, but does not go beyond that
29 minimum to anticipate future regulations, to proactively reduce its environmental
30 footprint, or to significantly diversify its predominantly coal resource mix.

1 **Q. IN YOUR OPINION, DOES CINERGY’S CURRENT APPROACH**
2 **REPRESENT PRUDENT MANAGEMENT OF PSI’S ENVIRONMENTAL**
3 **RISK?**

4 A. No, it does not. There is a definite difference between managing environmental
5 risk and managing environmental compliance risk. Cinergy’s approach equates
6 the two approaches. For Cinergy, global warming and climate change are not
7 risks worth managing for PSI because they have yet to be reflected in
8 environmental regulations or court orders legally requiring particular emissions to
9 be reduced to particular levels.

10 But, the international scientific community has concluded that global
11 warming and climate change are real phenomena with real costs and
12 consequences to people and the planet—and the emissions from coal-fired power
13 plants unquestionably contribute significantly to those phenomena. Moreover,
14 Cinergy is making decisions today regarding PSI investments in technology, plant
15 and equipment which will continue to have consequences 20, 40 even 60 years or
16 more in the future.

17 Given those two factors—the reality of climate change and its
18 consequences and the certainty that Cinergy’s decisions today regarding PSI
19 investments can and will affect that reality in the future—Cinergy must have a
20 strategy for managing PSI’s greenhouse emissions that is reasonably calculated to
21 be least cost in the long run to be prudently managing PSI’s environmental risk.
22 A least cost plan to comply with only the most current environmental regulations
23 is simply not enough in this day and age.

1 Most worrisome, Cinergy top management knows this, but has heretofore
2 done nothing about it beyond running alternately hot and cold on the necessity for
3 enactment of “four pollutant” legislation at the national level. But, with or
4 without national legislation, Cinergy top management has an obligation to PSI
5 customers to develop and propose to this Commission a strategy for managing
6 PSI’s greenhouse emissions that is reasonably calculated to be least cost in the
7 long run. Until they have done that, in my opinion, Cinergy is not prudently
8 managing PSI’s environmental risk.

9 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

10 **A. Yes, it does.**