BEFORE THE PUBLIC UTILITIES COMMISSION OF COLORADO

Docket No. 10M-245E

IN THE MATTER OF COMMISSION CONSIDERATION OF PUBLIC SERVICE COMPANY OF COLORADO PLAN IN COMPLIANCE WITH HOUSE BILL 10-1365, "CLEAN AIR – CLEAN JOBS ACT"

ANSWER TESTIMONY OF DAVID A. SCHLISSEL

September 17, 2010

Q. Please state your name, occupation, and business address.

A. My name is David A. Schlissel. I am the President of Schlissel Technical Consulting, Inc. My business address is 45 Horace Road, Belmont, Massachusetts 02478.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Western Resource Advocates.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 28 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included the New Mexico Public Regulation Commission, the U.S. Department of Justice, the Attorney

General and the Governor of the State of New York, state consumer advocates, and national and local environmental organizations.

I have testified before state regulatory commissions in Arizona, New Jersey, California, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota, Michigan, Florida, North Dakota and Mississippi and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is included as Attachment A. Additional information about my work is available at www.schlissel-technical.com.

Q. Please summarize your testimony.

A. Schlissel Technical Consulting was retained to investigate the reasonableness of Public Service of Colorado's ("PSCo" or "Xcel") proposed Emissions Reduction Plan. This testimony presents the results of our analyses.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. The results of the transmission analyses by KEMA show that PSCo does not need to install a second combined cycle unit at the Cherokee site in order to ensure adequate system reliability. As a result, the retirement of Cherokee Unit 4 can be advanced to the end of 2017.

2. PSCo did not model any scenario in which 903 MW of coal capacity would be retired by the end of 2017. However, the results of the Company's Scenario 6 Strategist modeling show that retiring Cherokee Units 1-4 and Valmont Unit 5 by the end of 2018 would be substantially less expensive for ratepayers than installing environmental controls. Given these results and our analysis, it is reasonable to expect that retiring all of these units by the end of 2017 also would be less expensive for ratepayers.

3. PSCo Replacement Scenario 6H would include 325 MW of new combined cycle capacity at the Fort St. Vrain site and would provide enough new capacity to ensure an adequate level of system reliability.

4. It is unclear whether the addition of that new 325 MW combined cycle unit is the best alternative available to PSCo. It may be that there are lower cost, lower risk alternatives that include additional energy efficiency, more wind, additional solar thermal capacity, additional solar photo voltaic resources, and, perhaps, some additional gas-fired combined cycle or combustion turbine capacity.

5. The Commission need not determine with finality, in this proceeding, the exact mix of resources that would replace Cherokee Unit 4 if it were retired at the end of 2017. That question can and should be addressed in detail in the Company's 2011 Electric Resource Plan. In that proceeding, the economics and reliability impact of adding a new combined cycle unit at Fort St. Vrain should be examined against the economics and reliability consequences of other resource portfolios.

6. However, the Commission should feel reassured that if it determines in the 2011 Electric Resource Plan that PSCo should add a new combined cycle unit at Fort St. Vrain, that unit could be in operation prior to the Company's peak summer period in 2018. Therefore, the Commission would not be risking future electric system reliability by ordering the retirement of Cherokee Units 1-4 and Valmont Unit 5 by the end of 2017.

7. The assumed coal prices in the Company's Strategist modeling appear to be too low.

8. The \$20/ton and \$40/ton CO_2 prices that PSCo has used in its modeling analyses reasonably reflect the uncertainties associated with the timing, stringency and design of federal regulation of greenhouse gas emissions. It is unreasonable to assume a \$0/ton CO_2 price in resource planning analyses.

Q. What materials have you reviewed during the preparation of this testimony?

A. I have reviewed the Company's testimony and exhibits in this docket and its responses to the discovery submitted by the WRA and other active parties. I also have reviewed the Company's filings in Docket Nos. 10A-377E and 10A-554EG, as well as the filings and Commission Orders in Docket No. 07A-447E.

A LOW COST, LOW RISK REPLACEMENT PORTFOLIO FOR CHEROKEE 1-4 AND VALMONT 5

Q. Has PSCo presented a scenario in which the Cherokee 1-4 and Valmont 5 units would all be retired by the end of 2017, the legislated date for full implementation of the Company's NOx Emissions Reduction Plan?

A. No. PSCo presents a number of scenarios in the Emissions Resource Plan in which Cherokee 1-4 and Valmont 5 all would be retired. However, none of these scenarios assumes that all of the units would be retired by the end of 2017. In Scenarios 6 and 7, the last unit, Cherokee 4, would be retired at the end of 2018. In Scenario 6.1, which represents PSCo' Preferred Plan, Cherokee 4 would not be retired until the end of 2022.

Q. What explanation has the Company given for not considering a scenario in which Cherokee 1-4 and Valmont 5 are all retired by the end of 2017?

A. PSCo explains in its Emissions Reduction Plan that under Scenarios 6 and 7, it could not start construction of a second combined cycle unit at Cherokee until Cherokee 3 was retired in 2015. As a result, construction of that second new unit at Cherokee could not be completed until the end of 2018, at which time Cherokee 4 could be retired.[1] In Scenario 6.1, the Company's Preferred Plan, the retirement of Cherokee 3 would be delayed until 2017. Consequently, Cherokee 4 could not be retired until the end of 2022, the date by which the second replacement combined cycle unit could be ready.[2]

[1] Emissions Reduction Plan, at page 36.
[2] Id.

Q. Do you agree with the Company's assessment that the retirement of Cherokee 4 must await the construction of a second new unit at the Cherokee site?

A. No. As explained in the testimony of P. Jeffrey Palermo for WRA, there are other options, besides building a second combined cycle unit at Cherokee, for providing needed reactive power for transmission grid reliability. Without the need to wait for the construction of that second combined cycle unit at Cherokee, there is no reason to delay the retirement of Cherokee 4 beyond 2017. In fact, if there were adequate replacement capacity available at other company-owned generating facilities or from off-system purchases, Cherokee 4 could be retired once the first replacement combined cycle unit was completed at that site at the end of 2015.

Q. What Replacement Portfolios did the Company evaluate in Scenario 6 – the scenario in which Cherokee 1-4 and Valmont 5 would be retired by 2018?

A. As shown in Table 1, below, PSCo evaluated five Replacement Portfolios in Scenario 6:

Table 1: Scenario 6 Replacement Portfolios

	Replacement Portfolio 6E	Replacement Portfolio 6F	Replacement Portfolio 6G	Replacement Portfolio 6H	Replacement Portfolio 6I
	Fuel switch Arapahoe 4 to gas in 2013 Cher 2x1 CC in 2015 Cher 1x1 CC in 2018	Fuel switch Arapahoe 4 to gas in 2013 Cher 2x1 CC in 2015 Cher Peaker Cap in 2018 Pumped Storage in 2017	Fuel switch Arapahoe 4 to gas in 2013 Cher 2x1 CC in 2015 Cher Peaker Cap in 2018 Solar Thermal in 2016	Fuel switch Arapahoe 4 to gas in 2013 Cher 2x1 CC in 2015 Cher Peaker Cap in 2018 FSV CC in 2017	SW Arap 2014 SW Val 2014 Cher 2x1 CC in 2015 Cher Peaker Cap in 2018 300 MW of wind in 2016 60 MW of solar PV in 2016 Solar Thermal in 2016
Total MW of Replacement Capacity	994 MW	1259 MW	952 MW	1072 MW	1122 MW
MW of Coal Retired	903 MW	903 MW	903 MW	903 MW	903 MW

Q. Do the results of the Company's Strategist modeling show that retiring all 903 MW of Cherokee 1-4 and Valmont 5 by 2018 would be a less expensive option than installing controls on some or all of these units?

A. Yes. The results of the Company's modeling of the Scenario 6 Replacement Portfolios show that retiring Cherokee 1-4 and Valmont 5 by the end of 2018 would be much less expensive than installing controls on Cherokee 1-4 and Valmont 5.[3] The same is true for the Replacement Portfolios that PSCo examined in Scenario 7 which also retired Cherokee 1-4 and Valmont 5 by the end of 2018.

[3] Emissions Reduction Plan, Tables 8.1 and 8.2, at pages 59 and 61.

Q. Is it reasonable to expect that retiring Cherokee 1-4 and Valmont 5 by the end of 2017 also would be less expensive than installing emissions controls?

A. Yes. Given the results of the Company's Strategist modeling analyses, it is certainly reasonable to expect that retiring Cherokee 1-4 and Valmont 5 by the end of 2017 would be a lower cost option than installing emissions controls and continuing to operate these units.

Q. Which of the Scenario 6 Replacement Portfolios are you recommending that the Commission adopt?

A. We believe that the Commission should adopt a Revised Replacement Portfolio 6H ("6H-Revised") that would retire Cherokee 4 at the end of 2017. In addition, the 147 MW of peaking combustion turbine capacity that PSCo includes in Replacement Portfolio 6H also would be removed. While this capacity might be needed as part of the Company's generic expansion plan, and should be considered in the 2011 Electric Resource Plan, it is not required as part of the replacement capacity for Cherokee 1-4 and Valmont 5.

Q. How does the PVRR of Replacement Portfolio 6H compare to the Company's Preferred Plan, Replacement Scenario 6.1E?

A. Replacement Portfolio 6H has almost exactly the same PVRR as the Company's preferred Replacement Portfolio 6.1E. For example, as shown in Table 8.1 of the

Emissions Reduction Plan, the 2010-2046 PVRR of Replacement Scenario 6H is $76,430 million versus the PVRR of PSCo's preferred Portfolio 6.1E which is $76,376 million. This is only a $54 million, or seven-hundredths of one percent, of a difference between the two plans over a period of 36 years. As shown in the testimony of WRA witness Dirmeier, retiring Cherokee 4 in 2017 instead of 2018 and eliminating 147 MW of new peaking capacity does affect the PVRR of Replacement Portfolio 6H to some extent. However, as Mr. Dirmeier testifies, WRA's 6H-Revised would be less expensive over time than Replacement Portfolio 6.1E, which is PSCo's Preferred Plan.

Q. What would be the other benefits of WRA's 6H-Revised over the Company's preferred Portfolio 6.1E?

A. There would be several significant benefits to WRA's 6H-Revised:

1. The Commission could be confident that the PVRR of retiring Cherokee 1-4 and Valmont would be lower than the cost of installing environmental controls.

2. Cherokee 4 could be retired five years earlier, at the end of 2017 instead of 2022.

3. There would be significant health benefits due to the earlier retirement of Cherokee 4.

4. Due to the earlier retirement of Cherokee 4, the Company and its ratepayers also would have less of an exposure to the risk that CO_2 prices will be higher than PSCo's $20/ton CO_2 price.

5. Ratepayers also would be protected against the risk that the price of the coal that would be burned by Cherokee 4 will be higher than the Company now projects.

6. The Company would not have to commit to building a replacement combined cycle unit at Fort St. Vrain by the end of 2017. Instead, the question of whether to proceed with the combined cycle unit at Fort St Vrain could be investigated as part of the Company's 2011 Electric Resource Plan. Thus, the Company and the Commission would have the flexibility under WRA's 6H-Revised to delay beyond 2017, or to cancel entirely, the Fort St. Vrain combined cycle unit if it became clear in the 2011 Electric Resource Plan process that there are alternatives to that unit that had lower costs while providing the same or greater environmental benefits.

Q. WRA 6H-Revised (like Portfolio 6H) also advances the retirement of Cherokee 3 from 2017 to 2015. Would you expect similar benefits from an earlier retirement of Cherokee 3 as would be achieved from the earlier retirement of Cherokee 4?

A. Yes. The benefits of an earlier retirement of Cherokee 3 would be generally the same as those from an earlier retirement of Cherokee 4.

Q. What are the relative economics of Replacement Portfolio 6H and the Company's preferred Portfolio 6.1E with PSCo's \$40/ton CO_2 price?

A. As noted above, PSCo's preferred Replacement Portfolio 6.1E shows a slight economic advantage (i.e., lower cost) during the period 2010-2046 with PSCo's \$20/ton CO_2 price. With PSCo's \$40/ton CO2 price, Replacement Portfolio 6H becomes the lower cost alternative, with a more substantial \$312 million PVRR economic advantage over Replacement Portfolio 6.1E during the same 36 year period. Replacement Portfolio 6H also has almost exactly the same PVRR as Portfolio 6.1E during the shorter 2010-2020 period (i.e., \$35,027 million vs. \$35,021 million).[4]

These results are not surprising as Replacement Portfolio 6H retires the higher CO_2 emitting Cherokee 3 and Cherokee 4 several years earlier than these units would be retired in PSCo's preferred Portfolio 6.1E.

Q. Is it reasonable to expect that WRA's 6H-Revised would also have a lower cost than PSCo's preferred Portfolio 6.1E with the Company's \$40/ton CO_2 price?

A. Yes. WRA's modified Portfolio 6H would retire Cherokee 4 in 2017, a year earlier than the unit would be retired in the Company's Portfolio 6H. Therefore, WRA's modified Portfolio 6H would have lower CO_2 emissions in 2018 and, consequently, lower CO_2 costs than either the Company's Portfolio 6H or its preferred Portfolio 6.1E.

[4] See Table 8.11 on page 79 of the Emissions Reduction Plan.

SYSTEM RELIABILITY

Q. Would the WRA's 6H-Revised Replacement Portfolio provide the same level of system reliability as either the Company's preferred Portfolio 6.1E or the continued operation of Cherokee 1-4 and Valmont 5?

A. Yes. WRA 6H-Revised would add at least 925 MW of capacity by the end of 2017 or more than the 903 MW of capacity that PSCo would be retiring at Cherokee 1-4 and Valmont 5. This is true even without the 147 MW of Cherokee peaking capacity that PSCo proposes to install as part of its Replacement Portfolio 6H.

Table 2: Capacity Retired/Added in PSCo Replacement Portfolio 6.1E and WRA's 6H- Revised – with 245 of Additional Capacity from Fort St. Vrain Combined Cycle Unit

Year	Cumulative MW of Coal Capacity Retired in Portfolio 6.1E	Cumulative MW of Replacement Capacity Added in Portfolio 6.1E	Cumulative MW of Coal Capacity Retired in Portfolio WRA 6H-Revised	Cumulative MW of Replacement Capacity Added in Portfolio WRA 6H-Revised
By January 1st of the Year				
2013	213	0	213	0
2014	213	111	213	111
2015	213	111	213	111
2016	213	680	365	680
2017	213	680	365	680
2018	551	680	903	925
2019	551	680	903	925
2020	551	680	903	925
2021	551	680	903	925
2022	551	680	903	925
2023	903	994	903	925

Q. How much additional capacity does Table 2 reflect would be added as part of the Fort St. Vrain combined cycle unit?

A. Table 2 reflects that the conversion of the two most recently installed combustion turbines at Fort St. Vrain into a combined cycle unit would add 245 MW of new capacity. This is the assumption included in the workpaper for Table 5.5 on page 44 of the Emission Reduction Plan.

Q. But don't Tables 8.1 and 8.2 in the Emission Reduction Plan show that the Fort St. Vrain combined cycle unit would increase the Company's available capacity resources by 325 MW, not 245 MW?

A. Yes. That is correct. The assumption in Tables 5.5 regarding how much additional capacity would be provided in Replacement Portfolio 6H by the new combined cycle unit at Fort St. Vrain appears to be different from that in Tables 8.1 and 8.2. To be conservative, Table 2, above, uses the lower 245 MW figure used to prepare Figure 5.5 in the Emissions Reduction Plan.

However, as shown in Table 3, below, the amount of replacement capacity that would be added in WRA's Replacement Portfolio 6H-Revised would be even higher if we assumed that the new Fort St. Vrain combined cycle unit would add 325 MW of new capacity, as shown in Figures 8.1 and 8.2 of the Emission Reduction Plan.

Table 3: Capacity Retired/Added in PSCo Replacement Portfolio 6.1E and WRA's Modified Portfolio 6H – with 325 of Additional Capacity from Fort St. Vrain Combined Cycle Unit

Year	Cumulative MW of Coal Capacity Retired in Portfolio 6.1E	Cumulative MW of Replacement Capacity Added in Portfolio 6.1E	Cumulative MW of Coal Capacity Retired in Portfolio WRA 6H-Revised	Cumulative MW of Replacement Capacity Added in Portfolio WRA 6H-Revised
By January 1st of the Year				
2013	213	0	213	0
2014	213	111	213	111
2015	213	111	213	111
2016	213	680	365	680
2017	213	680	365	680
2018	551	680	903	1005
2019	551	680	903	1005
2020	551	680	903	1005
2021	551	680	903	1005
2022	551	680	903	1005
2023	903	994	903	1005

Q. Is there any reason for the Commission to be concerned that there might be a reliability problem in the years 2013 through 2015 when more coal capacity (that is, Cherokee 1 and 2) would be retired than new capacity added?

A. No. The Company's load-resources table shows that even with the retirement of the 213 MW of capacity from Cherokee 1 and 2 at the end of 2011, PSCo will have enough capacity to achieve its required reserve margins. For example, Emissions Reduction Plan workpaper 5 shows the PSCo would have the following capacity surpluses, on top of its required reserves, in the years 2012 to 2015 even if Cherokee 1 and 2 were retired at the end of 2011.

Table 4: PSCo Capacity Surpluses during the Years 2012-2015 with the Retirements of Cherokee 1 and 2

Year	2012	2013	2014	2015
PSCo Capacity Surplus	685 MW	255 MW	120 MW	15 MW

Consequently, WRA's Replacement Portfolio 6H-Revised should not pose any reliability problems for PSCo.

RENEWABLE RESOURCES

Q. Does the Company examine the impact of adding additional renewable resources to its Replacement Portfolio 6H?

A. Yes. The Company ran two bolt-on scenarios which added 30 MW of solar PV and 100 MW of wind, respectively, to the natural gas-fired capacity already included as part of Replacement Portfolio 6H.

Q. What were the results of these bolt-on scenarios?

A. Adding the 30 MV of solar PV reduced the PVRR of Replacement Portfolio 6H by a small amount, approximately \$23 million.[5] Adding 100 MW of wind increased the PVRR of the Replacement Portfolio by approximately the same amount (\$17 million).

Q. Have you been able to identify why adding the solar PV reduced the PVRR of the Replacement Portfolio by such a relatively small amount while adding the 100 MW of wind actually increased Portfolio's PVRR?

A. No. I do not have available to me the specific information I would need to draw a definitive conclusion. However, it is possible that the fact that PSCo treated them as bolt-on scenarios might have had some impact. As I understand it, in a bolt-on scenario, the generation expansion plan is not re-optimized. Thus Replacement Portfolio 6H had the

[5] Table 8.20, at page 91 of the Emissions Reduction Plan.

same amount of new natural gas-fired capacity (1,072 MW) even when the additional 30 MW of solar PV or the 100 MW of wind were added. Even though the Company gave some capacity credits for the additional solar PV and wind, it is unclear whether this credit was adequate to compensate for the fact that, in essence, the Company possibly was over-building its system in the bolt-on scenarios. Clearly, the economics of adding more solar PV, wind or other renewable resources should be examined in detail in the 2011 Electric Resource Plan process, where the Company's system can be re-optimized.

Q. Regardless of whether new solar PV capacity were to reduce the PVRR of a Replacement Portfolio by a small amount or if the addition of new wind were to increase the PVRR of the Portfolio by a similar slight amount, don't these renewable resources provide other important benefits?

A. Absolutely. The addition of renewable resources, such as solar PV and wind to a Replacement Portfolio would provide significant benefits by reducing the exposure of the Company and its ratepayers to (1) higher natural gas and coal prices and (2) higher CO_2 prices. Of course, adding renewable resources also could provide significant health and environmental benefits by displacing coal and gas-fired generation.

ENERGY EFFICIENCY

Q. Did PSCo analyze Replacement Portfolio 6H to determine the impact of achieving higher energy efficiency savings?

A. No.

Q. The results presented in Table 8.13 of the Emissions Reduction Plan suggest that adding 30 percent more DSM (above the Commission Goals) would actually increase the PVRR of the three Replacement Portfolios in which that change were included. Do you understand the reason for these results?

A. PSCo developed the assumptions for a scenario in which the DSM goals that were established by the Commission in Docket No. 07A-420E were increased by 30 percent on an annual basis (the so-called 130% of Commission Goals). This assumption was modeled in a Strategist sensitivity scenario.

The costs that the Company assumed would be required to achieve these goals are very high because PSCo assumed that it would need to pay 100 percent incentives to reach this level of savings. This assumption appears to be contrary to the testimony of Company witness Sundin in the DSM Strategic Issues Docket 10A-554EG where she concluded that:

> **Rebate Costs in the KEMA Study may be too high**. In its study, KEMA has shown the estimated achievable market potential available at three different customer incentive levels: 50%, 75% and 100% of the incremental cost of the measure. While it is surely true that higher incentives will drive higher customer participation, it may also be true that, for the majority of customers, a higher rebate is more of an incentive than necessary to make them act. Philosophically speaking, the purpose of a rebate is to provide the customer with just enough of an incentive to make them act. When we start speaking of incentives at 75% or 100% of incremental costs, these incentives may be more than is needed by all participants, causing the Company's costs to increase unnecessarily. This is because some customers are willing to implement measures at a lower rebate level than others. Further, if rebate levels are set too high in the early years of a long-term program, then we will lose the opportunity to acquire a certain portion of the total achievable potential for a lower price.

> Therefore, the Company advocates setting goals in such a way as to obtain the greatest level of energy savings at the lowest price thereby minimizing the rate impact to customers unable to participate in the DSM program. Rebate levels should be set lower at the beginning and then increased over time, as needed, to achieve the desired sustainable participation level.[6] (Emphasis in original)

Despite this conclusion, it appears from the workpaper provided by PSCo that the Company assumed in its 130 % DSM Strategist modeling sensitivity that it would have to pay 100 percent incentives for all measures.

Q. Is there any evidence that suggests that additional energy efficiency savings are available beyond those assumed by PSCo as part of the 130% Commission Goal?

A. Yes. Despite assuming that such high incentives would be required to achieve savings, the KEMA study estimated the Total Resource Cost ("TRC") benefit-cost ratio at well over 2 for a wide range of measures except for emerging commercial technologies. Typically, this would suggest that additional energy efficiency is available. However, there is not enough information to evaluate what those measures might be (although Ms. Sundin suggests two possible programs in her testimony in Docket No. 10A-554EG) and, ultimately, these issues are better explored in the DSM Strategic Issues docket or the 2011 Electric Resource Plan process. But the results of the KEMA study should give the Commission comfort that even in the extreme scenario of paying 100 percent incentives, energy efficiency remains cost-effective.

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6 Direct Testimony and Exhibits of Debra L. Sundin, Docket No. 10A-554EG, filed August 10, 2010, at page 13, line 21, to page 14, line 18.

Q. What measures does Ms. Sundin state in her testimony in Docket 10A-554EG might bridge the gap to the 130% of Commission Goals?

A. Because building codes and standards as they relate to energy efficiency are not typically complied with in full in the first several years following their adoption, the Company could "provide training and verification services to the builders and other trades involved in new construction." It could then take credit for the portion of the savings attributed to earlier compliance with new codes.

Also, Ms. Sundin suggests a program in which energy efficiency investments on the utility-side of the meter could be better prioritized among the Company's capital investment choices.[7]

Q. If additional energy efficiency savings, e.g., 130% of Commission Goals, are cost-effective, why then does the Company's Strategist modeling show that additional DSM increases PVRR?

A. My understanding is that the base Replacement Portfolios in the Company's Strategist modeling did not change in the 130% DSM scenarios. In other words, the same new gas plants were built whether or not additional DSM investments and savings were included. The impact of the additional DSM was limited to how it changed the dispatch of generating units. Thus, I believe that the four portfolios that were run with 130% DSM all had higher PVRR (1) due to the very high incentives that I discussed above and (2) because the model only could adjust the portfolio for the energy benefits of the additional

7 Direct Testimony and Exhibits of Debra L. Sundin, Docket No. 10A-554EG, filed August 10, 2010, at page 33, line 1, to page 34, line 18.

DSM and not for the capacity benefits (by reducing capital investments for new generating facilities). I believe that these factors make the additional spending on DSM wrongly appear to be not cost-effective.

Q. What is your recommendation as to how the Commission should address additional energy efficiency savings as part of a portfolio of alternatives to existing coal units?

A. As I have explained above, I do not believe that the Company and the Commission should at this time be locked into building a new combined cycle facility at the Fort St. Vrain site. Instead, the Commission should explore in the 2011 Electric Resource Plan process whether there are more cost-effective and lower risk alternatives to building that new generating unit. The Commission's resolution of the issues being addressed in the DSM Strategic Issues docket should inform its decision as to the timing and the size of the new generating unit that would need to be added as part of the Replacement Portfolio for Cherokee 1-4 and Valmont 5.

MODELING CONCERNS

Q. Do you have any concerns about the Company's Strategist modeling and whether its results may be biased in favor of the continued operation of existing coal units?

A. Yes. I have several concerns.

First, because the model is not reoptimizing the overall expansion plan, the Company appears to be over-building in a number of Replacement Portfolios, especially when additional renewable resources and/or DSM are included. Although PSCo has testified that it gives a capacity credit for excess capacity based on the costs of a generic CT, we have not had time to verify that these credits fully compensate for the costs of the over-building. It would have been better to re-optimize the Replacement Portfolios to see what impacts adding renewable resources and/or additional DSM would have on the timing and sizes of the new gas-fired units being installed in each Portfolio.

Second, the Company has acknowledged that the load forecast used in the Strategist modeling does not reflect the revisions to its load forecasts that were made in early August. At the same time, I am concerned about the Company's treatment of interruptible loads in the Strategist modeling. Traditionally, required reserves (and hence total capacity needs) are based on a company's firm obligation load which is calculated by subtracting any interruptible loads (and other load management) from the native load forecast. The Company has used this methodology in its ERP Workpaper 5, an excerpt from which is presented below:

Table 5: Excerpt from PSCo Emissions Reduction Plan Workpaper 5 Showing Derivation of Annual Firm Obligations in Load-Resources Calculation

A	**PSCo Load**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
B	**2010 Native Load Forecast**	**6,490**	**6,539**	**6,339**	**6,477**	**6,600**	**6,705**	**6,817**	**6,902**	**6,988**	**7,079**	**7,178**	**7,274**	**7,245**
C														
D	Interruptible Load	226	245	250	254	256	257	259	213	215	216	218	219	220
E	Saver's Switch	137	152	163	174	172	160	149	139	130	121	112	105	97
F	**Firm Obligation Load**	**6,128**	**6,142**	**5,926**	**6,048**	**6,172**	**6,288**	**6,409**	**6,549**	**6,644**	**6,743**	**6,848**	**6,950**	**6,927**
G														
H	**Base Reserve Margin %**	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%
I	DSM Above Enhanced DSM (Decision No. C08	0	14	38	68	104	145	187	231	278	331	385	440	494
J	Added Reserve Margin % (Decision No. C08-05	0.0%	0.1%	0.3%	0.5%	0.7%	0.8%	1.0%	1.2%	1.5%	1.7%	2.0%	2.2%	2.5%
K	Reserve Margin % from Phase II Process	16.3%	16.4%	16.6%	16.8%	17.0%	17.1%	17.3%	17.5%	17.8%	18.0%	18.3%	18.5%	18.8%
L	Reserve Margin Requirement (MW)	999	1,009	986	1,018	1,048	1,075	1,110	1,148	1,180	1,214	1,251	1,286	1,302

In the Strategist modeling, however, the Company treats load management as a resource, not a reduction in loads. Consequently, as I understand it, Strategist calculates the required reserves and, hence, the Company's total resource requirements, based on the loads that have not been adjusted (i.e., reduced) to account for load management. Load management is then used as a resource for meeting loads.

This methodology appears to artificially inflate the capacity needs of the Company's system and, consequently, appears to over-build with new capacity. It does so because, in essence, it is including a reserve margin requirement for those load management loads that should have been subtracted from the load forecast. As best as I can tell, this factor, when combined with the difference in the Strategist load forecast due to the August revisions, leads the Strategist model to over-build the Company's system by 18 MW in 2011, with the effect growing to 145 MW in 2017, 193 MW in 2020, 256 MW in 2025, and increasingly larger amounts in subsequent years.

These overstatements of capacity requirements will have a significant impact on the results of the Strategist modeling and the Company's resource needs and plans.

COAL PRICES

Q. Do you have any other concerns about the Company's Strategist modeling?

A. Yes. I am concerned that the Company is using coal prices which appear to be too low and therefore may be biasing the results of the Strategist modeling in favor of the continued operation of its existing coal units.

Q. What are the sources for the coal burned in the Company's power plants?

A. The Company currently burns coal from two supply sources: Colorado (Uintah) and Powder River Basin (PRB) mines.

Q. What coal price escalation does PSCo assume in its Strategist modeling?

A. As shown in Table 2.5 in the Emissions Reduction Plan and Supplemental Attachment J in the Sixth Production of Documents, PSCo has assumed very low escalation of coal prices over the next 36 years. For example, the Company assumes that coal prices will only increase at an average 1.1 percent annual rate between 2010 and 2025 and at an average 1.5 percent annual rate during the entire period 2010 through 2046. This price escalation is lower than the Company's projected 2.5 percent overall rate of inflation.

Q. Do you agree with this view of future coal prices?

A. No. I believe the Company's view of future coal prices is overly optimistic. A number of factors suggest there will be significant upward pressures on PRB and Colorado coal prices in coming years, as well as price volatility .

In particular, there is an increasing emphasis on exporting domestic U.S. coal at the very same time that traditional sources are being depleted. This is expected to lead to upward pressure on coal prices as Central Appalachian reserves are depleted and mining in the PRB is intensified due to rising domestic and international demands and reduced supplies at other sources.[8] A recent coal industry market commentary expressed a concern that appears to be felt by many in the industry: "If the near-term sense of helplessness against the tide of seemingly incurable market dilemmas portends longer-term problems, if a season of wild price volatility truly is a precursor to a more complex and domestically threatening energy environment, we might all be about to catch a falling knife."[9]

For example, there are indications that intensified mining efforts will lead to rising costs of production in the Powder River Basin.[10] In 2008 the USGS issued a study of the PRB's Gillette coal beds. This study, which reflected forty years of USGS research on coal reserve methodology throughout the United States, concluded that the methods used by the United States government to calculate coal reserves had significantly overstated the amount of economically recoverable coal. The study explained that as existing mines and new mines in the area are more intensively exploited, production costs would rise substantially, perhaps to a level that could not be covered by the market price.[11] This is an important observation as the Gillette coal bed contains most of the coal produced in the PRB, and, overall, accounts for 37% of the nation's coal production.

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8 See, for example, Scott Learn, *Mining companies aim to export coal to China through Northwest points,* The Oregonian, September 8, 2010. The most recent reporting on plans to ship PRB coal through the Pacific Northwest.

9 Energy Publishing, In, *Coal and Energy Price Report,* Volume 12, No.88, May 10, 2010.

10 United States Geological Survey, *Assessment of Coal Geology Resources and Reserves in the Gillette Coalfield River Basin, Wyoming,* Open-File Report – 2008-1202.

11 The study offers precise calculations for existing mines in the Gillette coal beds as well as cost curves based on various production levels. These models allow for a dynamic understanding of the relationship between rising costs of production and the need for higher coal prices in the market place.

Q. Are there other factors that indicate that PSCo's coal price assumptions are too low?

A. Yes. There are indications that reduced supplies and higher demands could put upward pressure on future Colorado coal prices.

For example, the two largest mines in Colorado, the West Elk mine under the ownership of Arch Coal and Twentymile owned by Peabody Energy, accounted for 13.8 million of the 32 million tons of coal produced in Colorado,[12] or 43 percent of statewide production. The owners of both mines each have recently acknowledged reserve limitations.[13]

At the same time, because Colorado coal has a low sulfur content and a high BTU value, it will likely become more competitive on the U.S, domestic market. Already in 2008, 65% of Colorado's annual coal production, or 21,561,000 tons, were shipped to twenty-six points outside the borders of the state.[14] This percentage may increase in the future as several utilities in the country with the largest coal fleets dependent on high BTU, low sulfur coal are publicly in the market for new coal suppliers other than those from Central Appalachia.[15]

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[12] Energy Information Administration, *Annual Coal Report, 2008, Major US Coal Mines – 2008, Table 9,* March 2010.

[13] There is no indication in the description of the coal forecast that Colorado's mining capacity could lose up to 20% of annual capacity (West Elk) starting around 2019 (for which no replacement is identified), or what impact this might have on coal prices. The forecast for the period 2019-2025 is relatively flat.

[14] Energy Information Administration, *Domestic Distribution of U.S. Coal by Origin State, Consumer, Destination and Method of Transportation, 2008 – Final,* May 2010, at page 7/67.

[15] Coal and Energy Price Report, *Market Commentary,* March 19 and 30, 2010

Q. What would be effect of using higher coal prices in the Company's Strategist modeling?

A. The PVRR difference between the Company's preferred Replacement Portfolio 6.1E and Replacement Portfolio 6H shown in the Emissions Reduction Plan would be reduced, eliminated entirely or reversed.

CO_2 PRICES

Q. What prices for CO_2 emissions did PSCo assume in its Strategist modeling analyses?

A. PSCo assumed a Base set of CO_2 prices that begins at $20 per ton in 2014 and escalates at 7 percent per year. PSCo also assumed a High set of CO_2 prices that begins at $40/ton, also in 2014, and escalates at 7 percent per year. Finally, PSCo looked at a $0/ton CO2 price sensitivity.

Q. Is it reasonable to use a $0/ton CO_2 price in resource planning analyses?

A. No. It is unreasonable to assume that there will be no regulation of CO_2 emissions at any point during the next 36 years.

Q. Are the $20/ton and $40/ton CO_2 price trajectories that PSCo has used in its Strategist modeling reasonable?

A. Yes. It is important and prudent to consider a wide range of possible CO_2 prices given the uncertainties associated with the timing, stringency and design of federal regulation of greenhouse gas emissions. PSCo has done so in its Strategist modeling.

Q. How do the CO_2 prices that PSCo used in its Strategist modeling compare to other projections of future CO_2 prices?

A. Figure 1, below, compares the CO_2 emissions prices that PSCo used in its Strategist modeling with the results of the independent modeling of the legislation that has been introduced in the U.S. Congress in recent years. These modeling analyses include:

- The U.S. Department of Energy's Energy Information Administration's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007).[16]
- The EIA's October 2007 Supplement to the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*.[17]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008).[18]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008).[19]
- The EIA's assessment of the *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009).[20]
- The U.S. Environmental Protection Agency's ("EPA")' *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007).[21]
- The EPA's *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008).[22]
- The EPA's *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008).[23]
- The EPA's *Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress* (June 2009)[24]

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16 Available at http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf.

17 Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf

18 Available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf

19 Available at http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.

20 Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

21 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

22 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

23 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

24 Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf.

- *Assessment of U.S. Cap-and-Trade Proposals* by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change (April 2007).[25]

- *Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191* by the Joint Program at MIT on the Science and Policy of Global Change (April 2008).[26]

- *The Lieberman-Warner America's Climate Security Act: A Preliminary Assessment of Potential Economic Impacts,* prepared by the Nicholas Institute for Environmental Policy Solutions, PSCo University and RTI International (October 2007)[27]

- *U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways*, prepared by the International Resources Group for the Natural Resources Defense Council (May 2008).[28]

- *The Lieberman-Warner Climate Security Act – S. 2191*, *Modeling Results from the National Energy Modeling System – Preliminary Results,* Clean Air Task Force (January 2008).[29]

- *Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model*, CRA International, April 2008.[30]

- *Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM),* a report by the American Council for Capital Formation and the National Association of Manufacturers, March 2008.[31]

- The EPA's *Supplemental Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress* (January 2009)[32]

- The EPA's *Analysis of the American Power Act of 2010 in the 111th Congress* (June 2010)[33]

- The EIA's assessment of the *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010).[34]

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25 Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf.

26 Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.

27 Available at http://www.nicholas.PSCo.edu/institute/econsummary.pdf.

28 Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf.

29 Available at http://lieberman.senate.gov/documents/catflwcsa.pdf.

30 Available at http://www.nma.org/pdf/040808_crai_presentation.pdf.

31 Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.

32 Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf

33 Available at http://www.epa.gov/climatechange/economics/pdfs/EPA_APA_Analysis_6-14-10.pdf

In total, these modeling analyses examined more than 100 different scenarios. These scenarios reflected a wide range of assumptions concerning important inputs such as: the "business-as-usual" emissions forecasts; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress and the cost of alternatives; and the presence or absence of a "safety valve" price.

In Figure 1:

- S.280 refers to the McCain-Lieberman bill introduced in 2007 in the 110th U.S. Congress
- S.1766 refers to the Bingaman-Specter bill introduced in 2007 in the 110th U.S. Congress
- S. 2191 refers to the Lieberman-Warner bill introduced in 2007 in the 110th U.S. Congress
- HR. 2454 refers to the Waxman-Markey bill introduced in 2009 in the current 111th U.S. Congress
- APA refers to the American Power Act that has been introduced in the current 111th Congress.

[34] Available at http://www.eia.doe.gov/oiaf/servicerpt/kgl/pdf/sroiaf%282010%2901.pdf.

Figure 1: Levelized PSCo CO_2 Prices Compared to Results of Modeling of Proposed Federal Legislation

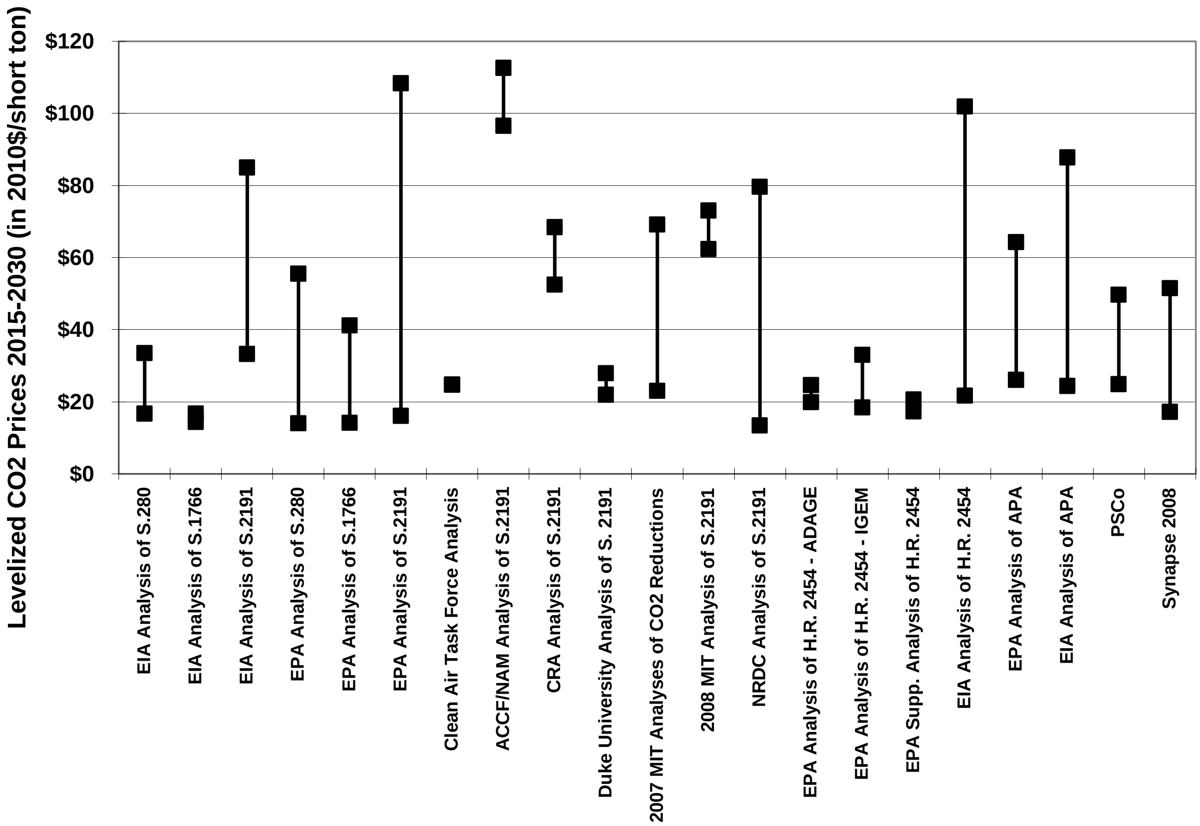


Figure 1 confirms that the \$20/ton to \$40/ton range of CO_2 prices used by PSCo was reasonable given the potential uncertainties associated with the design and stringency of future federal regulation of greenhouse gas emissions. In fact, there are a number of circumstances in which CO_2 prices could be substantially higher than the \$40/ton high end of the range of CO_2 prices assumed by PSCo.

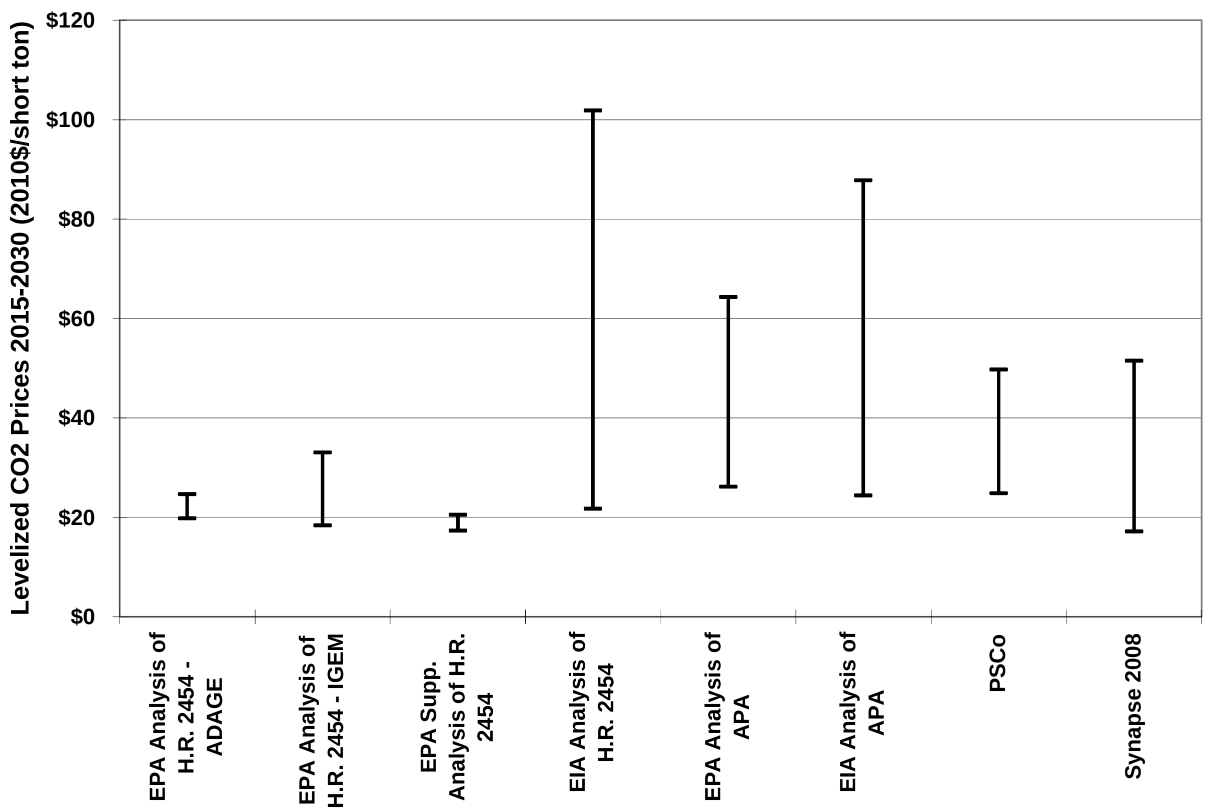
Q. Why do you include the proposed legislation from past sessions of Congress in Figure 1?

A. It is not certain what features a bill that is ultimately passed by the U.S. Congress to reduce greenhouse gas emissions include. For this reason, the results of the modeling of the important climate change legislation that has been introduced in previous U.S. Congresses, as well as the current U.S. Congress, are relevant.

Q. Are PSCo's assumed CO_2 prices reasonable compared just to the results of the recent EPA and EIA analyses of the Waxman-Markey bill and the proposed American Power Act?

A. Yes. Figure 2, below, compares the range of CO_2 prices used by PSCo in its Strategist modeling with the results of the EPA and EIA's recent modeling of the Waxman-Markey bill and the proposed American Power Act.

Figure 2: Levelized PSCo CO_2 Prices Compared to Results of Modeling of Waxman-Markey Bill and Proposed American Power Act



Again, as can be seen from Figure 2, there are a number of circumstances under both the Waxman-Markey bill and the proposed American Power Act in which CO_2 prices could be substantially higher than the $40/ton high end of the range of CO_2 prices assumed in its Strategist modeling.

Q. Did you help develop CO_2 price estimates when you were with Synapse Energy Economics?

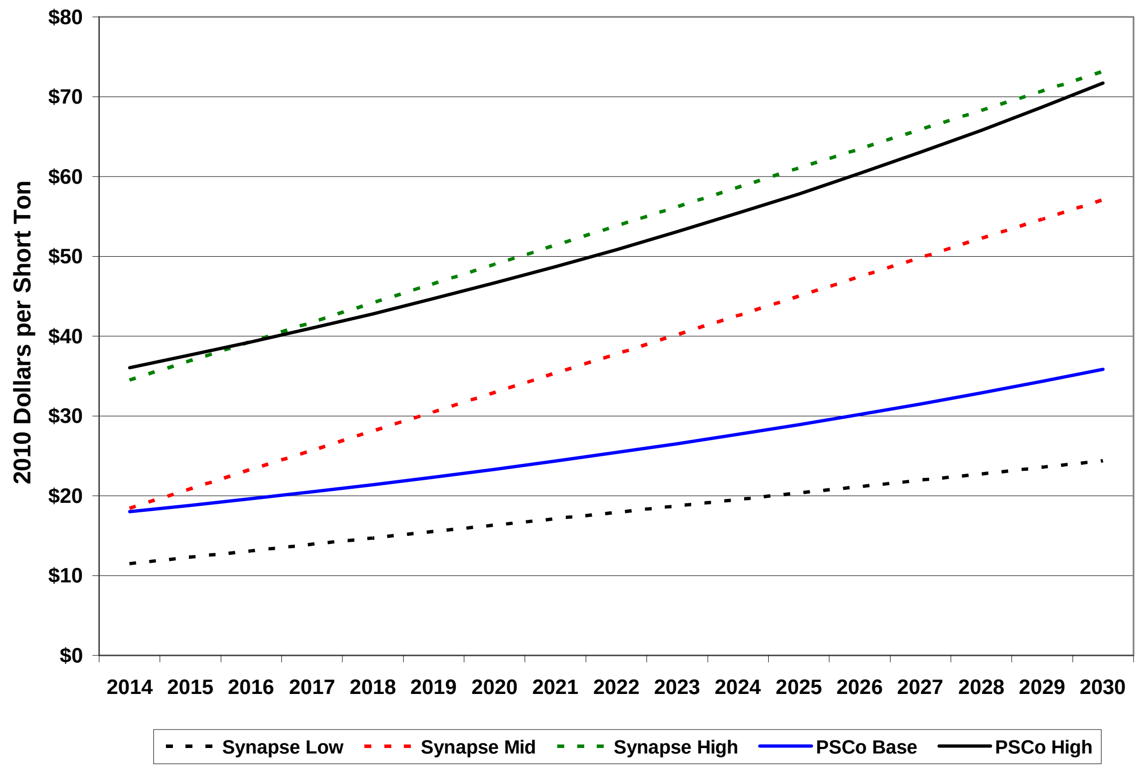
A. Yes, I did.

Q. How do the CO2 prices assumed by PSCo compare to the CO_2 prices that you helped develop when you were with Synapse Energy Economics?

A. Figure 3, below, compares the annual CO_2 prices used by PSCo in its Strategist modeling analyses with the CO_2 price projections that I helped developed in 2008 when I was with Synapse Energy Economics, Inc.[35]

[35] The derivation of the Synapse CO_2 price forecasts is available at http://schlissel-technical.com/docs/reports_34.pdf.

Figure 3: PSCo and Synapse CO_2 Prices in Nominal Dollars



As can be seen in Figure 3, the PSCo $40/ton and the Synapse High CO_2 price trajectories are extremely close. In addition, the PSCo $20/ton CO2 price is approximately mid-way between the Synapse Mid and Low CO_2 price trajectories.

Q. Have the Synapse CO2 prices been accepted for use in electric resource planning?

A. Yes. Utilities and regulatory commissions around the nation (including the New Mexico Public Regulation Commission and the California Public Utilities Commission) have adopted, in whole or in part, the Synapse CO_2 prices in electric resource planning.

Q. Does this conclude your testimony?

A. Yes.

David A. Schlissel

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SUMMARY

I have worked for thirty six years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

PROFESSIONAL EXPERIENCE

Electric Resource Planning - Analyzed the economic costs and benefits of energy supply options. Examined whether there are lower cost, lower risk alternatives than proposed fossil and nuclear power plants. Evaluated the economic and system reliability consequences of retiring existing electric generating facilities. Investigated whether new electric generating facilities are used and useful. Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Assessed the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets.

Coal-fired Generation – Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Analyzed the economic and financial risks of making expensive environmental and other upgrades to existing plants. Investigated whether plant owners had adequately considered the risks associated with building new fossil-fired power plants, the most significant of which are the likelihood of federal regulation of greenhouse gas emissions and construction cost increases.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO_2 and CO_2. Examined whether new state and federal emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proposed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Electric System Reliability - Evaluated whether existing or new generation facilities and transmission lines are needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Nuclear Power – Reviewed recent cost estimates for proposed nuclear power plants. Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Electric Industry Regulation and Markets - Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales, auctions, and power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than 100 proceedings before regulatory boards and commissions in 35 states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC S4) – July 2010
The reasonableness of Duke Energy Indiana's new analyses of the economics of completing the Edwardsport Project as an IGCC plant.

Oregon Public Utility Commission (Docket LC 48) – May 2010
Comments on Portland General Electric Company's 2009 Integrated Resource Plan.

South Dakota Public Service Commission (Docket No. EL-09-018) – April 2010
The reasonableness of Black Hills Power Company's 2007 Integrated Resource Plan and the Company's decision to build the Wygen III coal-fired power plant.

Michigan Public Service Commission (Docket No. U-16077) – April 2010
Comments on the City of Holland Board of Public Works' 2010 Power Supply Study.

Illinois Commerce Commission (Tenaska Clean Coal Facility Analysis) – April 2010
Comments on the Facility Cost Report for the proposed Taylorville IGCC power plant.

North Carolina Utilities Commission (Docket No. E-100, Sub 124) – February 2010
The reasonableness of the 2009 Integrated Resource Plans of Duke Energy Carolinas and Progress Energy Carolinas.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009
The costs and risks associated with the proposed Kemper County IGCC power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009 and January 2010
The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-138) –September and October 2009
The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

Public Service Commission of Michigan (Docket No. U-15996) – July 2009
Comments on Consumer Energy's Electric Generation Alernatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant.

Public Service Commission of Michigan (Docket No. U-16000) – Juy 2009
Comments on Wolverine Power Cooperative's Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant.

Georgia Public Service Commission (Docket No. 27800-U) – December 2008
The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and Sepember 2008
The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008
The estimated cost of Duke Energy Indiana's Edwardsport Project.

Public Service Commission of Maryland (Case 9127) – July 2008
The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007
AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009
The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007
Appalachian Power Company's application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

Iowa Utility Board (Docket No. GCU-07-01) – October 2007
Whether Interstate Power & Light Company's adequately considered the risks associated with building a new coal-fired power plant and whether that Company's participation in the proposed Marshalltown plant is prudent.

Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007
Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

Louisiana Public Service Commission (Docket No. U-30192) – September 2007
The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007
The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008

Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007
The appropriate carbon dioxide ("CO_2") emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana's proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – May and June 2007
Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

Florida Public Service Commission (Docket No. 070098-EI) – March 2007
Florida Light & Power Company's need for and the economics of the proposed Glades Power Park.

Michigan Public Service Commission (Case No. 14992-U) – December 2006
The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007
Duke's need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006
Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006
Whether APS's acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006
Quantification of plaintiff's business losses during an extended power plant outage and plaintiff's business earnings due to the shortening and delay of future plant outages. [Confidential Expert Report]

Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006

South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

Georgia Public Service Commission (Docket No. 22449-U) – May 2006
Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006
The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.
Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005
The siting of a proposed 230 kV transmission line.

Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005
The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005
The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005
Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

Maine Public Utilities Commission (Docket No. 2005-17) – July 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

Maine Public Utilities Commission (Docket No. 2004-771) – March 2005
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company. [Confidential Expert Report]

New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation. [Confidential Expert Report]

California Public Utilities Commission (Application No. AO4-01-009) – August 2004
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004
Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004
Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

Connecticut Siting Council (Docket No. 272) – May 2004
Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004
Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004
Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003
The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – May 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.
Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.
Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales. [Confidential Testimony]

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, April 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - June 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - May 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - November 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and June 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) – December 1985 and January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - January 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

Presentation to the Oregon Public Utility Commission on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on Draft Portland General Electric Company 2009 Integrated Resource Plan, October 2009.

Energy Future: A Green Energy Alternative for Michigan, report, July 2009.

Energy Future: A Green Energy Alternative for Michigan, presentation, July 2009.

Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan, June 2009.

The Financial Risks to Old Dominion Electric Cooperative's Consumer-Members of Building and Operating the Proposed Cypress Creek Power Station, April 2009.

An Assessment of Santee Cooper's 2008 Resource Planning, April 2009.

Nuclear Loan Guarantees: Another Taxpayer Bailout Ahead, Report for the Union of Concerned Scientists, March 2009.

New Hampshire Senate Bill 152: Merrimack Station Scrubber, March 2009.

The Risks of Building and Operating Plant Washington, Presentation to the Sustainable Atlanta Roundtable, December 2008.

The Risks of Building and Operating Plant Washington, Report and Presentation to EMC Board Members, December 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the University of California at Berkeley Energy and Resources Group Colloquium, October 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at Georgia Tech University, October 2008.

Nuclear Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Coal-Fired Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Synapse 2008 CO_2 *Price Forecasts,* Synapse Energy Economics, July 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the NARUC ERE Committee, NARUC Summer Meetings, July 2008.

Are There Nukes In Our Future, Presentation at the NASUCA Summer Meetings, June 2008.

Risky Appropriations: Gambling US Energy Policy on the Global Nuclear Energy Partnership, Report for Friends of the Earth, the Institute for Policy Studies, the Government Accountability Project, and the Southern Alliance for Clean Energy, March 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation to the New York Society of Securities Analysts, February 26, 2008.

*Don't Get Burned,*Report for the Interfaith Center for Corporate Responsibility, February 2008.

The Risks of Participating in the AMPGS Coal Plant, Report for NRDC, February 2008.

Kansas is Not Alone, the New Climate for Coal, Presentation to members of the Kansas State Legislature, January 22, 2008.

The Risks of Building New Nuclear Power Plants, Presentation to the Utah State Legislature Public Utilities and Technology Committee, September 19, 2007.

The Risks of Building New Nuclear Power Plants, Presentation to Moody's and Standard & Poor's rating agencies, May 17, 2007.

The Risks of Building New Nuclear Power Plants, U.S. Senate and House of Representative Briefings, April 20, 2007.

Carbon Dioxide Emissions Costs and Electricity Resource Planning, New Mexico Public Regulation Commission, Case 06-00448-UT, March 28, 2007, with Anna Sommer.

The Risks of Building New Nuclear Power Plants, Presentation to the New York Society of Securities Analysts, June 8, 2006.

Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs. Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities. Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

The 2003 Blackout: Solutions that Won't Cost a Fortune, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability. An Analysis for Riverkeeper, Inc. November 3, 2003.

The Impact of Converting Indian Point Units 2 and 3 to Closed-Cycle Cooling Systems with Cooling Towers on Energy's Likely Future Earnings. An Analysis for Riverkeeper, Inc. November 3, 2003.

Entergy's Lost Revenues During Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems. An Analysis for Riverkeeper, Inc. November 3, 2003.

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, <u>Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company</u>, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2010 - President, Schlissel Technical Consulting, Inc.

2000 - 2009: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 10M-245E

IN THE MATTER OF COMMISSION CONSIDERATION OF PUBLIC SERVICE COMPANY OF COLORADO PLAN IN COMPLIANCE WITH HOUSE BILL 10-1365, "CLEAN AIR –CLEAN JOBS ACT"

AFFIDAVIT OF DAVID A. SCHLISEL

COMES NOW DAVID A. SCHLISSEL, of proper age and duly sworn, and states that the attached Testimony in the above-captioned matter was prepared by *him* or under *his* supervision and control and that it is true and correct to the best of *his* knowledge and belief, and would be the same if given orally under oath.

David A. Schlissel

David A. Schlissel

STATE OF MASSACHUSETTS)
) ss.
COUNTY OF MIDDLESEX)

On this 14th day of September 2010, before me, the undersigned notary public, personally appeared David A. Schlissel, proved to me through satisfactory evidence of identification, which were MA. Driver's Lic., to be the person whose name is signed on the preceding or attached document and acknowledged to me that he signed it voluntarily for its stated purpose.

Takhakal

Notary Public
My commission expires: 9/23/16