NON-CONFIDENTIAL REDACTED VERSION

REDACTED INTERVENOR TESTIMONY OF DAVID A. SCHLISSEL

On Behalf of the Sierra Club

Docket No. E-01345A-10-0474

May 31, 2011

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 the Sierra Club.

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 38 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included 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 filed expert testimony 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, Mississippi, Maryland, Virginia, Arkansas, Louisiana, Colorado, New Mexico, Oregon and West Virginia and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is included as Exhibit DAS-1. Additional information about my work is available at www.schlissel-technical.com.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified in Commission Dockets Nos. U-1345-85, U-1345-90-007, U-1551-93-272, E-01345A-01-0822, E-01345A-03-0437, and E-01345A-05-0816.

Q. Please summarize your testimony.

A. Schlissel Technical Consulting was retained to investigate the reasonableness of Arizona Public Service Company's ("APS" or "the Company") proposed acquisition of Southern California Edison's ("SCE") share of Four Corners Units 4-5. This testimony presents the results of my analyses.

Q. What information did you review as part of your analysis?

A. I reviewed APS's Application and supporting testimony. I also reviewed the Company's data request responses. Relevant non-confidential data responses are included as Exhibit DAS-2. Relevant confidential data responses are included in Confidential Exhibit DAS-3. As part of my review, I also examined the output data and files from APS's PROMOD computer model. APS used PROMOD to simulate its electric system operations in order to evaluate the economics of the three alternative resource options it considered. Finally, I reviewed the testimony that I filed concerning APS in ACC Dockets Nos. E-01345A-03-437 and E-01345A-05-0816.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. APS's modeling analyses show that retirement of Four Corners Units 1, 2 and 3 is a significantly less expensive option than retrofitting those units with new emissions controls. This is true whether APS replaces the capacity from Four Corners Units 1, 2 and 3 with SCE's share of Four Corners Units 4-5 or with natural gas-fired combined cycle capacity.

2. However, the results of the Company's modeling analyses are biased in favor of the proposal to purchase SCE's share of Four Corners Units 4-5 by the following:

   a. APS has not presented any evidence, beyond its speculation, that Four Corners Units 4-5 actually would be retired if it does not purchase SCE's share of the units.

   b. The Company fails to fully consider a wide range of potential alternatives for replacing Four Corners such as:

      - Converting one or more of its existing turbines to a combined cycle unit.
      - Extending an existing or entering into a new Power Purchase Agreement ("PPA") for the capacity and energy from an existing merchant combined cycle unit.
      - Including additional renewable resources as part of a portfolio of alternatives.

   c. Although APS repeatedly emphasizes the risks posed by natural gas price volatility, it ignores the risks associated with the continued operation of the Four Corners Units 4-5 that are currently over 40 years old, having entered commercial service in 1969-1970. In particular, without any supporting evidence, the Company very optimistically assumes that Units 4-5 will continue to operate at very high levels of performance as they age up to and beyond the age of sixty.

3. APS significantly overstates the potential risk posed by natural gas price volatility.

4. APS fails to address the significant economic risks associated with the continued operation of Four Corners Units 4-5.

5. The Commission should not rely on APS's life cycle levelized cost analysis as evidence that purchasing Southern California Edison's share of Four Corners Units 4-5 would be the lowest cost option.

Q. What are your recommendations?

A. I am recommending that the Commission:

1. Order APS to begin planning to retire Four Corners Units 1-3 in 2012 or 2014.
2. Reject APS's proposed acquisition of SCE's share of Four Corners Units 4-5 with leave to refile the Application to include analyses of the technical feasibility and economic viability of (a) obtaining replacement combined cycle capacity from the competitive wholesale market; (b) converting one or more of APS's existing combustion turbines to combined cycle technology; and (c) including the additional renewable resources in an alternative portfolio with natural gas combined cycle capacity.

Q. Do the Company's PROMOD modeling analyses show that retrofitting Four Corners Units 1, 2 and 3 is a more expensive alternative than retiring the Units in 2012 or 2014?

A. Yes. As shown in Table 1, below, APS's PROMOD modeling analyses show that retrofitting Four Corners Units 1-3 with new emissions controls is the most expensive option (in cumulative present worth) as compared to either (1) retiring the Units at the end of 2014 and replacing them with natural gas or (2) retiring the Units at the end of 2012 and replacing them with SCE's share of Four Corners Units 4-5. This is true for all three periods considered by APS: 2010-2019, 2010-2029, and 2010-2039.

Table 1: Cumulative Present Worth of APS Alternatives 1, 2 and 3 - Base Gas Prices and \$20/ton CO_2. [CONFIDENTIAL]

	2010-2019	2010-2029	2010-2039
	CPW(Millions$		
Alternative 1 (FC 1-5 Retired and Replaced by Gas)	[REDACTED]		
Alternative 2 (FC 1-3 Retired, APS acquires SCE share of FC 4-5)			
Alternative 3 (FC 1-3 Retrofitted, FC 4-5 Retired)			

Q. Does retrofitting Four Corners Units 1-3 continue to be the most expensive alternative if a $0/ton cost is assumed for CO_2?

A. Yes, as can be seen in Table 2, below, retrofitting Four Corners Units 1-3 remains the most expensive alternative even if you assume no cost for CO_2:

Table 2: Cumulative Present Worth of APS Alternatives 1, 2 and 3 – Base Gas Prices and $0/ton CO_2. [CONFIDENTIAL]

	2010-2019	2010-2029	2010-2039
	CPW(Millions$		
Alternative 1 (FC 1-5 Retired and Replaced by Gas)	[REDACTED]		
Alternative 2 (FC 1-3 Retired)			
Alternative 3 (FC 1-3 Retrofitted, FC 4-5 Retired)			

Q. What action should APS take on the basis of these modeling results?

A. APS should begin immediately planning for the retirement of Four Corners Units 1-3.

Q. Does your conclusion regarding Units 1-3 change depending on whether APS would purchase SCE's share of Four Corners Units 4-5?

A. No. It is not economical to retrofit and continue to operate Four Corners Units 1-3 whether APS ultimately replaces the units by purchasing SCE's of Four Corners 4-5 or with a portfolio of existing and new gas generation.

Q. Should the Commission rely on the results of APS's PROMOD modeling as showing that Four Corners Units 1-3 should be replaced by the purchasing of SCE's share of Four Corners Units 4-5?

A. No. The results of the Company's PROMOD modeling analyses are biased in favor of the proposal to purchase SCE's share of Four Corners Units 4-5 in the following ways:

1. APS has not presented any evidence, beyond its speculation, that Four Corners Units 4-5 actually would be retired if it does not purchase SCE's share of the units.
2. The Company fails to fully consider a wide range of potential alternatives for replacing Four Corners such as:
   - Converting one or more of its existing turbines to a combined cycle unit.
   - Extending an existing or entering into a new Power Purchase Agreement ("PPA") for the capacity and energy from an existing merchant combined cycle unit.
   - Including additional renewable resources as part of a portfolio of alternatives.
3. Although APS repeatedly emphasizes the risks posed by natural gas price volatility, it ignores the risks associated with the continued operation of the Four Corners Units 4-5, which entered commercial service in 1969-1970 and are currently over 40 years old. In particular, without any supporting evidence, the Company very optimistically assumes that Units 4-5 will continue to operate at very high levels of performance as they age up to and beyond the age of sixty.

Q. What generating options does APS consider in its PROMOD modeling analyses as alternatives to its purchase of SCE's share of Four Corners Units 4-5?

A. APS includes two alternatives to its preferred purchase of SCE's share of Four Corners 4-5 (which it calls "Alternative 2"). In Alternative 1, APS adds new combined cycle generating capacity while Four Corners Units 1-3 would be retired at the end of 2014 and Four Corners Units 4-5 would be retired at the beginning of July 2016. APS also models increased generation at its existing combined cycle units in this Alternative.

In Alternative 3, APS models the retrofitting of Four Corners Units 1-3 and the retiring of Four Corners 4-5.

Q. Are there other, potentially lower cost, replacement alternatives that APS did not thoroughly consider as alternatives to the purchase of SCE's share of Four Corners Units 4-5?

A. Yes. For example, APS did not evaluate converting one or more of its existing combustion turbines into combined cycle units or entering into a long-term PPA from a merchant generator.

Q. What are the potential benefits of converting one or more existing combustion turbines into combined cycle facilities?

A. Existing combustion turbines can be converted into combined cycle units at lower cost by using existing site equipment such as the combustion turbines and transmission facilities. In this way, a peaking combustion turbine that had a 12-14,000 btu/kwh heat rate can be repowered as a baseload or intermediate combined cycle unit with a heat rate of 7,000 btu/kwh.

Q. Has APS provided any analyses or assessments of the technical feasibility or economic viability of converting any of its existing simple cycle combustion turbines to combined cycle units?

A. No.[1]

[1] Exhibit DAS-2, APS Response to Data Request SC 1.4.

Q. Has APS adequately considered the availability of natural gas resources in the competitive wholesale market?

A. No. APS states that it "looked at what exists in the competitive wholesale market, but rejects this approach without providing support in its Application or testimony.[2]

Q. What explanation has APS given for its failure to consider obtaining of new gas-fired capacity in the competitive wholesale market as an alternative to purchasing SCE's share of Four Corners Units 4-5?

A. APS dismisses the option of obtaining of new combined cycle generation from the wholesale market for several reasons: (1) the risk of exposing its customers to uncertain gas prices; (2) the claim that it would require that new transmission be built to bring any new gas-fired power to the Company's primary load center in the Metropolitan Phoenix area and (3) the claim that such new gas capacity "will likely be more expensive to APS customers in the end."[3]

Q. What analysis has APS presented to support its claim that obtaining gas-fired capacity in the competitive wholesale market "will likely be more expensive to APS customers in the end?"

A. APS has presented a sensitivity scenario in which the capital cost of new combined cycle capacity has been reduced from $1,253/kW to $750/kW. The Company explained that this $750/kW prices represents what it believes it would cost to obtain gas-fired capacity from the competitive wholesale market.[4]

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[2] Application, at page 25, lines 10-21; Direct Testimony of Patrick Dinkel, at page 12, line 26, to page 13, line 9.

[3] Application, at page 25, lines 10-21.

[4] Exhibit DAS-2, APS Response to Data Request SC 1.21.

Q. Has APS provided any analyses or assessments showing that this $750/kW capital cost fairly represents the cost of obtaining gas-fired combined cycle capacity from the wholesale competitive market?

A. No.

Q. Has APS provided any analyses or assessments showing that this $750/kW capital cost fairly represents the cost of converting one or more of its existing combustion turbines to combined cycle technology?

A. No.

Q. What insights does the $750/kW combined cycle capital cost sensitivity provide concerning the relative economics of the proposed purchase of SCE's share of Four Corners Units 4-5?

A. Even accepting APS's assumptions, the $750/kW combined cycle capital cost sensitivity shows that:

- Purchasing SCE's share of Four Corners Units 4-5 would not be any less expensive through 2019 than obtaining gas capacity in the competitive wholesale market.
- Purchasing SCE's share of Four Corners Units 4-5 would have only a minor economic advantage (approximately 0.6%) over the remaining 20 years of the study period (2020-2039).

Q. Do you have any concerns about the reasonableness of this sensitivity?

A. Yes. This sensitivity analysis uses the same very optimistic assumption as APS's Base Case about the future performance of Four Corners Units 4-5 by projecting high annual capacity factors throughout the extended life of the plants. As I will discuss below, APS has no evidence or analyses to support this assumption.

Q. Should the Commission be concerned that APS would be overly dependent on natural gas if it replaced its existing Four Corners coal-fired capacity with increased generation at existing and new combined cycle units?

A. The Commission should be concerned about any utility becoming overly dependent on any single fuel source. However, replacing the Four Corners generating capacity with natural gas resources would not create undue risk. In its Application and testimony, APS repeatedly raises the threat of gas price volatility. As I will discuss in more detail below, I believe that APS overstates the risk that natural gas prices pose to its generating portfolio. The risk of price volatility does not, by itself, justify the Company's request to purchase additional coal-fired capacity. I also will discuss below several risks that APS faces by relying so heavily on a fleet of aging coal-fired generating units.

Q. What evidence should the Commission consider as it evaluates the potential risk that APS's customers would face if all five Four Corners units were retired?

A. If all five Four Corners units were retired, APS could obtain replacement generation from its existing gas-fired units and either build new gas-fired combined cycle capacity or enter into long-term PPAs for power from merchant combined cycle facilities, or a combination thereof. APS's primary argument against relying on natural gas as an alternative is the volatility and risk of natural gas prices. There are a number of reasons why I believe that APS significantly overstates the potential threat of a gas alternative to its purchase of SCE's share of Four Corners Units 4-5.

First, APS's own analysis, as presented in Graph 4 in the Application, shows that APS would only be dependent on natural gas for just 40 percent of its energy even if all of its capacity from Four Corners were retired.[5] This energy mix does not create an overdependence on natural gas.

[5] Application, Graph 4 at page 17.

Second, there are actions that a prudent utility can and should take to mitigate the risk of gas price volatility. These include entering into some long-term gas contracts and other physical and financial hedging.

Third, the recent discovery of substantial recoverable shale gas reserves and the rapid growth in gas production from these reserves have led to a fundamental change in the market that many anticipate will mean lower natural gas prices for the foreseeable future and a dampening in price volatility. For example, Xcel Energy explained in its 2010 Resource Plan that it filed with the Minnesota Public Utility Commission:

> Economically recoverable shale gas has been a major contributor to increasing reserves and declining natural gas prices…..
>
> * * * *
>
> A long-term lower price for natural gas will produce significant benefits to our customers. It will reduce the production cost at both current and new resources. In addition to lowering the cost of energy from our natural gas-fired facilities, the lower cost of energy is expected to put downward pressure on wind prices, which are a close competitor. Lower natural gas production costs also reduce the integration costs of wind on our system since our ability to follow the wind with flexible gas generation becomes less expensive. Today's natural gas forecasts also predict reduced price volatility.
>
> The Commission has expressed concern in the past that more extensive use of natural gas for electric generation would hamper the supply and increase the cost of natural gas for residential heating customers. The substantial increase in supply due to the ability to economically recover shale gas may result in the ability to expand natural gas-fired generation while reducing the cost to all users of natural gas. Still, natural gas is a commodity that comes with some price volatility and the impacts of federal regulations on shale extraction will be a key factor in whether the same level of volatility that we have seen in the past decade returns.[6]

A recent report from the Bipartisan Policy Center and American Clean Skies Foundation's Task Force on Ensuring Stable Natural Gas Markets has similarly noted that:

[6] Xcel Energy Minnesota 2010 Resource Plan, at pages 2-5 to 2-7.

> Recent developments allowing for the economic extraction of natural gas from shale formations reduce the susceptibility of gas markets to price instability and provide an opportunity to expand the efficient use of natural gas in the United States.[7]

And:

> The currently understood and projected shale gas resource has allowed the United States to project a significant increase in economically recoverable gas resources for the first time in the last 15 years. And for the first time since the 1990s, it now appears that deliverability (i.e., available production) could be adequate to meet increasing gas demand, meaning that the United States will no longer be in the tight supply/demand regime that has historically made natural gas markets vulnerable to price instability.[8]

Q. Has APS provided any actual analysis or assessment of the level of the risk that having 40 percent of its generation dependent on natural gas would pose for its ratepayers?[9]

A. No. When asked to provide any such analysis or assessment, the Company merely responded by claiming that there are any number of documents that reveal gas price volatility.[10] APS did not provide any specific analyses or assessments that quantified that risk.

Q. Are you aware of any utilities that are replacing existing coal-fired capacity with new gas-fired combined cycle units?

A. Yes. A substantial number of utilities around the nation are replacing existing coal-fired units with new combined cycle facilities. These include, but are not limited to, such large utilities as Xcel Energy (Public Service Company of Colorado and Northern States Power), Progress Energy and Duke Energy Carolinas.

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7 At page 67 of 76. Available at http://www.cleanskies.org/wp-content/uploads/2011/05/63704_BPC_web.pdf

8 Id, at page 45 of 76.

9 Direct Testimony of Patrick Dinkel, at page 10, lines 24-27.

10 Exhibit DAS-2, APS Response to Data Request SC 1.19.

For example, Xcel Energy has replaced three of its coal-fired power plants with efficient new combined cycle capacity since 2002 and is now seeking permission from the Minnesota Public Utility Commission to repower another two coal units with combined cycle technology.[11]

Q. Is the potential for volatility in gas prices the only risks that the Commission should consider?

A. No. There are a number of significant risks that APS would face if it continues to operate the aging Four Corners units instead of replacing them with natural gas or renewable energy resources.

Q. What are these significant risks for the Four Corners coal-fired units?

A. Although the Company does not mention them in its Application or testimony, there are a number of potentially significant risks associated with APS's proposed purchase of SCE's share of Four Corners Units 4-5.

First, the actual costs for adding emissions controls on Four Corners Units 4-5 could be higher than APS currently estimates. Although APS is not requesting that the Commission pre-approve recovery of pollution control costs at this time, the present request to guarantee recovery of the purchase price and associated costs of SCE's share of Four Corners Units 4-5 commits the utility and its ratepayers to operate these units for many years into the future. In order to continue to operate any of the Four Corners units, and thereby recoup the ratepayers' investment, APS admits that it will need to install pollution controls in the very near future to meet the pending regional haze pollution control requirements. APS is therefore exposing itself, and its ratepayers, to substantial risk related to the ultimate cost of the pollution control retrofits that will be required.

[11] Xcel Energy Minnesota 2010 Resource Plan, at pages 6-2 and 6-3.

Second, environmental regulations will likely become increasingly stringent over time, requiring additional controls on existing coal plants which could lead to increased capital investments, higher O&M costs and/or reduced operating performance. APS's continued operation of the Four Corners plant exposes it to greater regulatory uncertainty, as well as greater risk from future liabilities such as groundwater contamination, coal-ash cleanup, or other unidentified environmental hazards.

Third, the future costs of CO_2 could be higher than the Base Case figures assumed by APS. Relying on coal as a fuel source therefore includes significant risk because any future increases in CO_2 costs would have substantially greater impacts on coal-fired power plants compared to other resources.

Fourth, it is possible that the aging of plant equipment, structures and components will lead to increased capital investments and/or operating costs. Plant aging also could lead to diminished operating performance. APS currently assumes that Four Corners Units 4-5 will continue to operate as efficient baseload units through 2038 at which time each unit will be 68 years old. However, APS has no studies or analyses that specifically evaluate the impact of aging coal equipment, components and structures on unit operating performance, annual operating costs and annual capital expenditures.[12] In fact, given the large number of older, less efficient coal plants being retired around the nation (many of which are less than 60 years old); it is possible that Four Corners Units 4-5 might be retired before 2038.

Unfortunately, other than scenarios with higher CO_2 costs, APS did not consider any of these potentially adverse risks or impacts of plant aging in any of its sensitivity analyses.

[12] Exhibit DAS-2, APS Response to Data Requests Nos. SC2.8, SC 2.9 and SC 2.11.

Q. In your work around the nation, have you seen any other instances where a utility has sought to replace retired coal-fired capacity through the purchase of other (and almost equally old) coal units?

A. No. Even though a large number of utilities are retiring or are planning to retire existing coal units, this is the only instance that I can recall where a utility is seeking to replace retired coal capacity with another aging coal facility. In fact, if you set aside the small number of new coal units that are under construction around the nation, I don't believe that any large utility company other than APS is seeking to increase its commitment to coal.

Q. Do you believe that the proposal to purchase SCE's share of Four Corners Units 4-5 is a prudent investment by APS?

A. No. The substantial costs related to the pending pollution control retrofits for all five Four Corners units illustrates the increasing difficulties that coal plants face in meeting ever more stringent environmental regulations. In these uncertain times, APS is proposing an unreasonable investment in aging and risky coal units when it could invest, at worst at a relatively comparable cost, in newer and cleaner natural gas and/or renewable energy generation.

Q. Did APS consider the potential for additional renewable resources and/or energy efficiency as part of a portfolio with gas as an alternative to the purchase of SCE's share of Four Corners Units 4-5?

A. It appears not. APS has dismissed several renewable energy alternatives without providing any analysis as to the feasibility of developing those resources.[13] For example,

[13] Direct Testimony of Patrick Dinkel, at page 3, line 18, to page 4, line 22.

APS completely dismisses any consideration of solar and wind generation solely on the basis that such resources are intermittent.

Q. Do you agree with APS's conclusion that solar and wind generation are not adequate resources for replacing any of the Four Corners units?

A. No. It is being increasingly recognized that renewable resources, such as solar and wind, can provide reliable baseload energy when included in a fuel mix with flexible combined cycle capacity. Intermittency issues from solar and wind can be addressed by wider distribution of resources, by balancing loads across geographic areas, or by compensating with increased generation from natural gas resources. Indeed, APS has a substantial amount of underutilized baseload natural gas generation which could be used to offset any intermittency from solar or wind resources.

For all of APS's stated concerns about the volatility of natural gas prices, it ignores in this proceeding the fact that renewable energy resources, such as solar and wind, are not susceptible to fuel price volatility because they do not require commodity fuel.

Q. Do you agree with APS's analysis of the life cycle levelized costs of its proposed purchase of SCE's share of Four Corners Units 4-5?

A. No. APS relies on the comparison shown in Graph 2 on page 13 of its Application to support the conclusion that, on a dollar per megawatt hour basis, the total cost of Four Corners Units 4-5 is lower than combined cycle capacity. The Commission should not rely on this life cycle levelized cost comparison, as presented in Graph 2, because it is biased in several key ways.

<u>First</u>, APS assumes extremely high annual capacity factors for Four Corners Units 1-3 and Units 4-5 that are inconsistent with the results of its PROMOD modeling analyses. This assumption leads to unreasonably low levelized costs for the Four Corners Units.

Second, the comparison in Graph 2 assumes that if Four Corners Units 1-5 were retired all of the replacement energy would come from new combined cycle units. This assumption is inconsistent with the results of APS's PROMOD modeling analyses. In fact, natural gas replacement generation would likely include both new combined cycle capacity and increased generation at currently underutilized gas-fired facilities. APS's assumption that all replacement combined cycle generation would come from new plants improperly increases the initial capital investment required for those resources and, therefore, leads to an unreasonably high levelized cost for the CC alternative.

Q. What annual capacity factors does APS assume in its levelized cost analysis for Four Corners Units 1-3 and 4-5?

A. APS assumes an average capacity factor of [REDACTED] percent for the Four Corners Units for the years 2015 through 2038.

Q. How old will Four Corners Units 1-3 be during the period that APS uses to analyze life cycle levelized costs?

A. Four Corners Units 1-3 began commercial service in 1963-64. If they continue to operate, Units 1-3 will be approximately 52 years old in 2015 and 75 years old by 2038.

Q. How old will Four Corners Units 4-5 be during the period the APS uses to analyze the life cycle levelized costs?

A. Four Corners Units 4-5 began commercial operations in 1969 and 1970. If they continue to operate, they will be 45 years old in 2015 and 68 years old by the currently scheduled end of their service lives in 2038.

Q. Does APS have any analyses that support the assumption that the Four Corners Units will continue to operate at [REDACTED] percent average annual capacity factors as they age past 50 or 60?

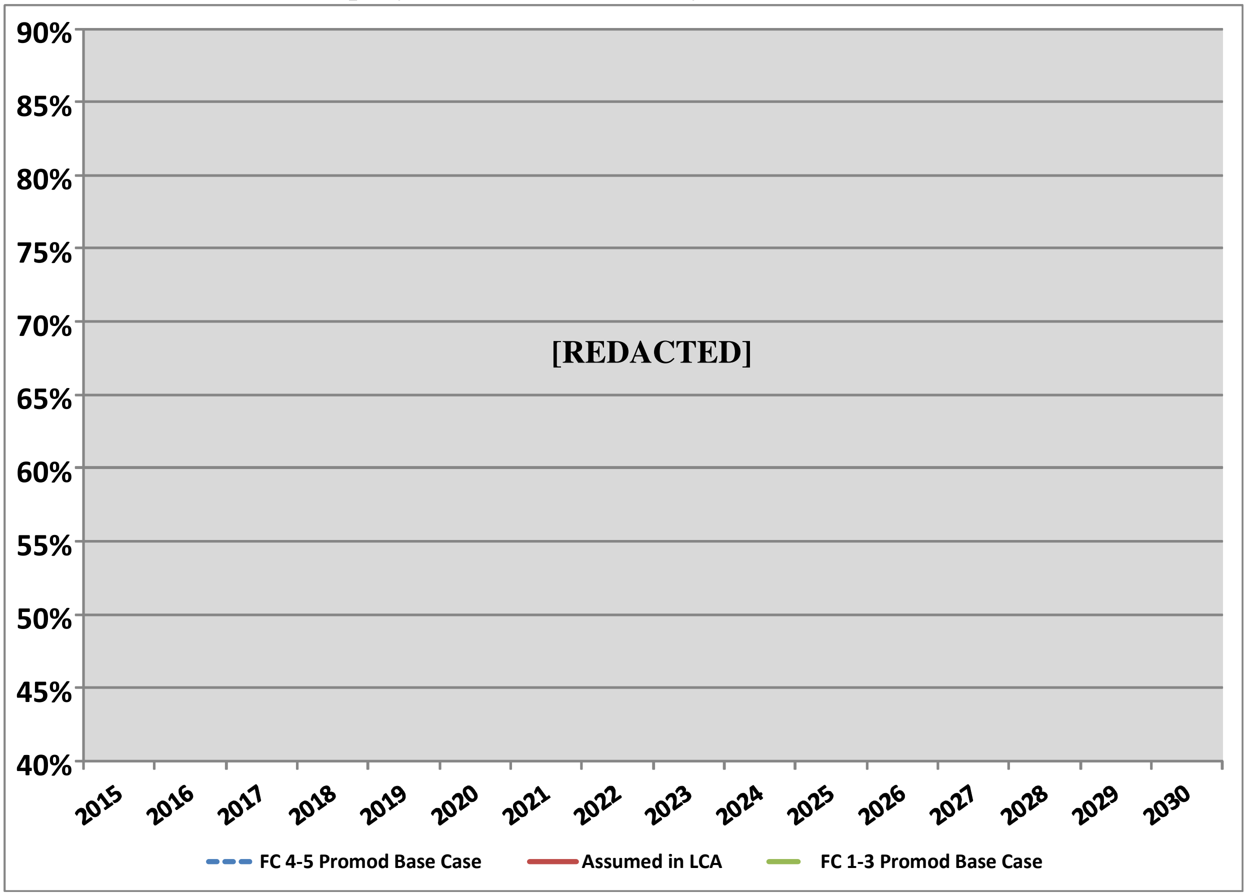
A. No.[14]

Q. Are the [REDACTED] percent average annual capacity factors that APS has assumed for Four Corners Units 1-3 and 4-5 in its levelized cost analysis consistent with the results of APS's PROMOD modeling analyses?

A. No. As shown in Confidential Figure 1, below, the capacity factors projected for Four Corners Units 1-3 and 4-5 in APS's Base Case PROMOD modeling analyses are [REDACTED] percent capacity factor assumed in APS's levelized cost analysis.

[14] Exhibit DAS-2, APS Response to Data Request SC 2.9.

Figure 1: Four Corners Capacity Factors – APS PROMOD Modeling Analysis vs. the Company's Levelized Cost Analysis [CONFIDENTIAL]



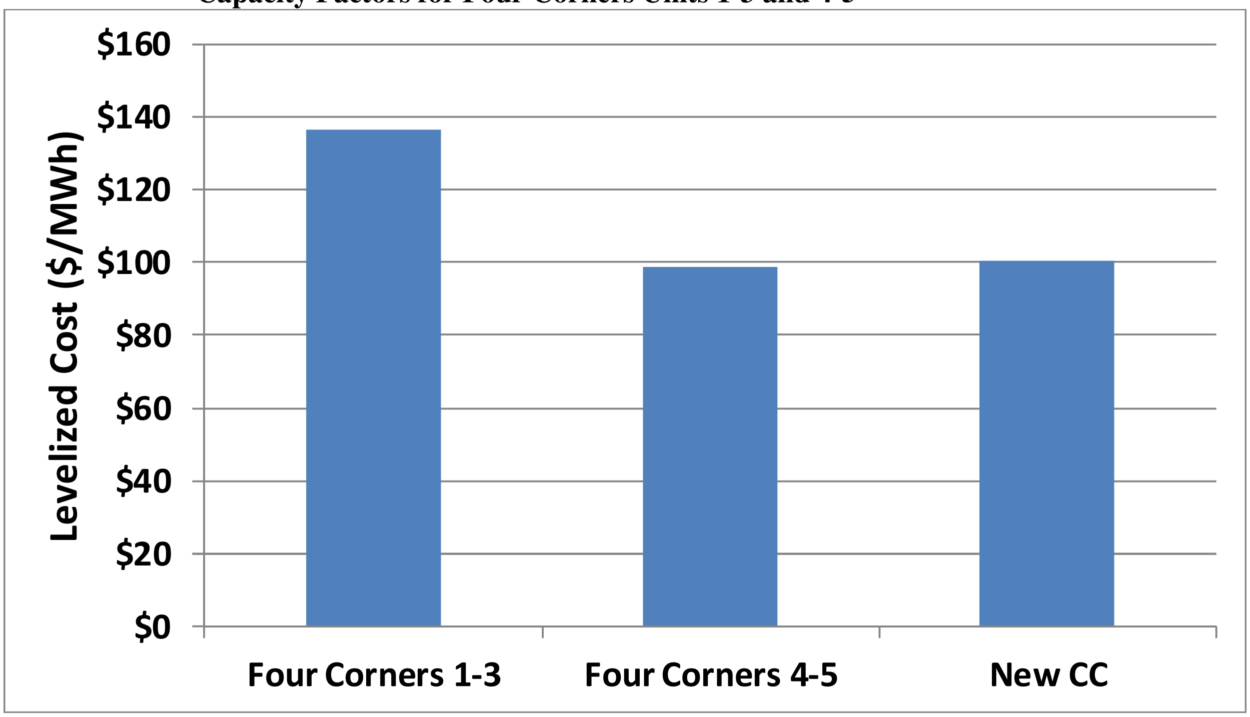
Thus, the average annual capacity factors for the Four Corners Units shown in APS's Base Case PROMOD modeling are [REDACTED] percent for Units 1-3 and [REDACTED] percent for Units 4-5.[15]

15 Exhibit DAS-3, APS Confidential Response to Data Request SC 1.2.

Q. What impact would these capacity factors have on the levelized cost analysis shown in Graph 2 of APS's Application?

A. As shown in Figure 2, below, when the results of APS's Base Case PROMOD modeling are used, the levelized cost of Four Corners Units 4-5 increases by a significant amount and becomes almost the same as the CC alternative.

Figure 2: Graph 2 from Application Revised to Reflect PROMOD Base Case Unit Capacity Factors for Four Corners Units 1-3 and 4-5



As can be seen, the levelized cost of Four Corners 4-5 is only very slightly less (that is $1/MWh) than the levelized cost of power from a new combined cycle unit.

Q. Are there any adjustments that need to be made to the combined cycle alternative in APS's levelized cost analysis to reflect the results of APS's PROMOD modeling?

A. Yes. Figure 2, above, assumes that all of the natural gas resources would come from new combined cycle units. In fact, the results of APS's PROMOD modeling show that a significant portion (an average [REDACTED] percent) of the replacement generation that

APS would need every year if Four Corners Units 4-5 were retired in 2016 would come from APS's existing, and underutilized, gas-fired combined cycle generating units.

Q. What evidence forms the basis for your observation that APS already has a significant amount of underutilized gas-fired combined cycle capacity?

A. APS has approximately 1,600 MW of efficient new gas-fired combined cycle capacity at the RedHawk and West Phoenix sites. Although new combined cycle plants can be expected to provide baseload and intermediate power at up to 60 to 75 percent annual capacity factors, APS's RedHawk CC Units 1 and 2 and West Phoenix CC Units 4-5 have been operating at significantly lower capacity factors in recent years, as is shown in Table 3, below.

Table 3: APS Combined Cycle Units Capacity Factors 2007-2010[16]

	RedHawk CC 1-2	West Phoenix CC5	West Phoenix CC4
2007	49%	33%	19%
2008	48%	31%	16%
2009	47%	23%	18%
2010	39%	30%	11%

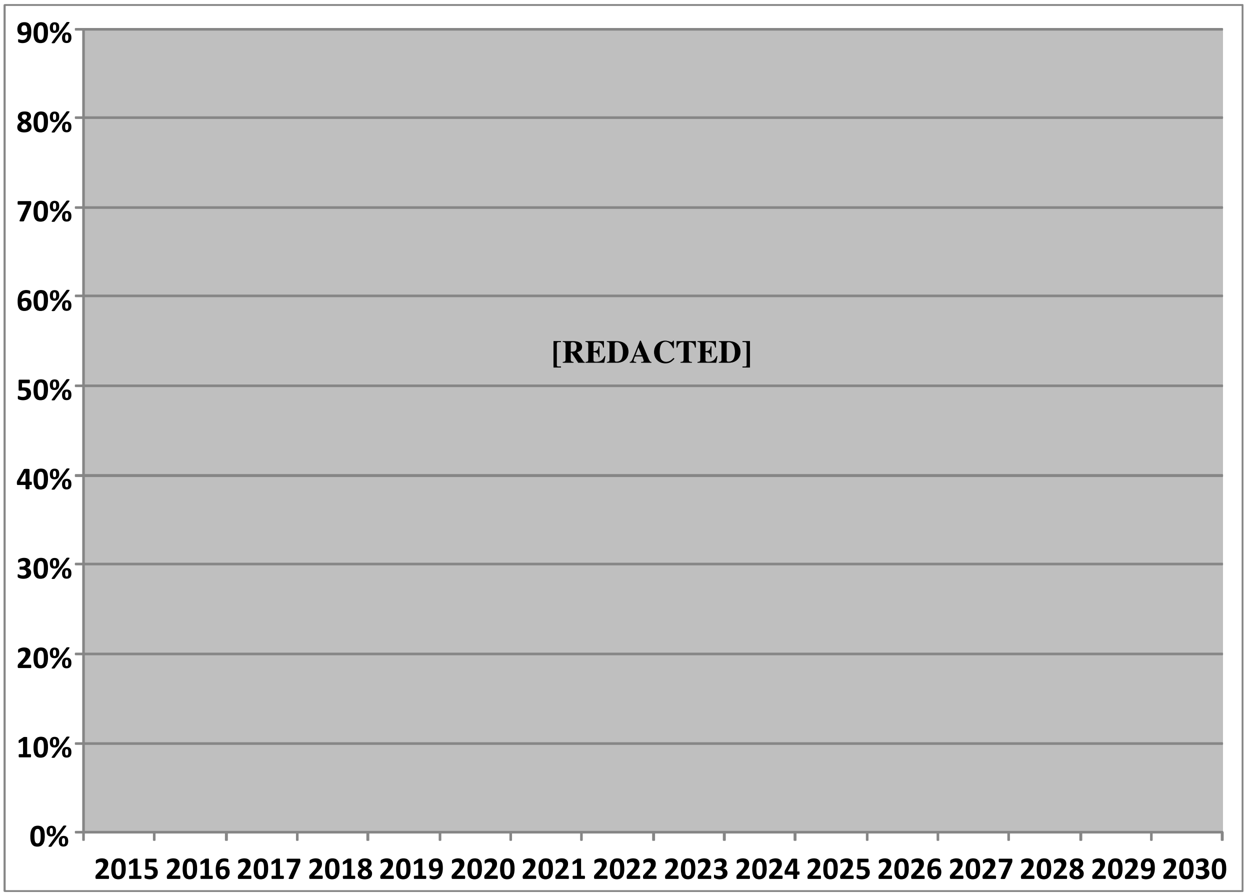
Q. How did you determine the amounts of replacement energy that would come from the Company's existing gas-fired combined cycle units if all of the Four Corners Units were retired by 2016?

A. I compared the annual generation at each of the Company's units in its PROMOD modeling of Alternative 1 (with Four Corners Units 1-3 retired in 2012 and Four Corners 4-5 retired in 2016) and Alternative 2 (with Four Corners Units 1-3 retired in 2014 and APS acquisition of SCE's share of Four Corners Units 4-5).

16 Exhibit DAS-2, APS Response to Data Request SC 1.1.

The results from this comparison are presented in Confidential Figure 3, below, as a percentage of the replacement generation that would be needed if Four Corners Units 4-5 were retired in 2016.

Figure 3: Percentage of Replacement Energy from Existing APS Combined Cycle Units [CONFIDENTIAL]

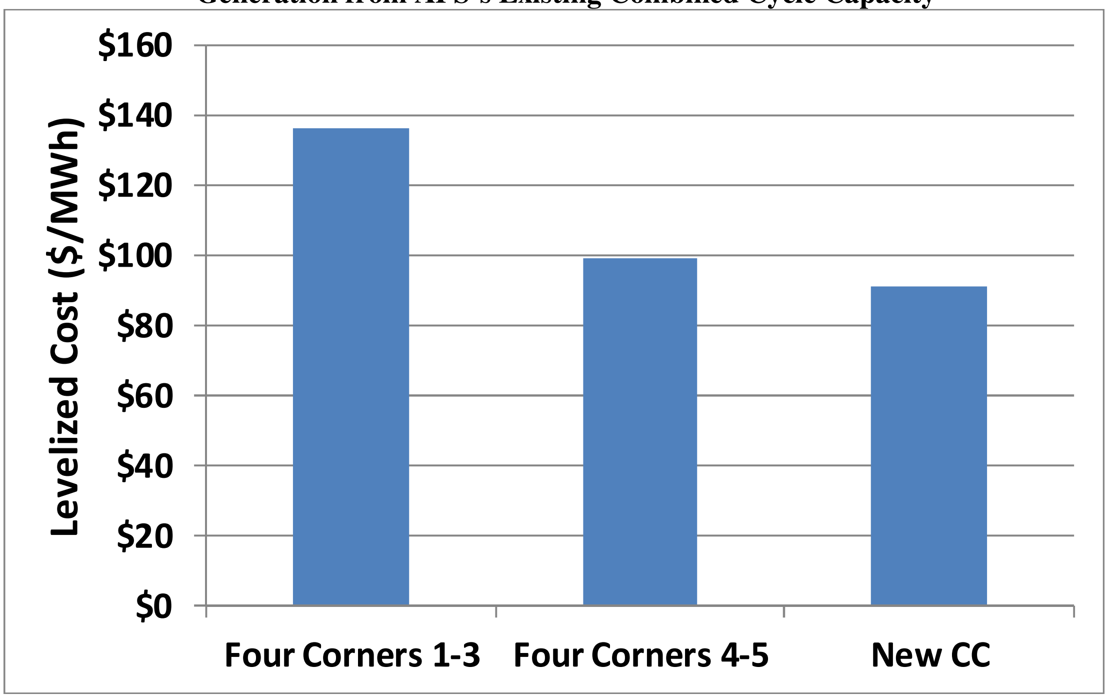


On average, APS's Base Case PROMOD modeling shows that [REDACTED] percent of the replacement energy that would be needed each year if Four Corners Units 4-5 were retired in 2016 would come from existing combined cycle units.

Q. How do the results of APS's levelized cost analysis change if this information is incorporated?

A. As shown in Figure 4, below, the combined cycle option (which now reflects generation from both a new combined cycle plant and APS's existing combined cycle units) becomes the lowest cost alternative.

Figure 4: Graph 2 from Application Revised to Reflect PROMOD Base Case Unit Capacity Factors for Four Corners Units 1-3 and 4-5 and Replacement Generation from APS's Existing Combined Cycle Capacity



Q. Do you have any comments on Graph 1 on page 12 of APS's Application which compares the capital costs of the three alternatives of (1) purchasing SCE's share of Four Corners Units 4-5; (2) retrofitting Four Corners Units 1-3; and (3) building a new combined cycle unit?

A. Yes. This Graph is distorted by APS's assumption that it would have to build a new combined cycle unit by 2016 if it does not purchase SCE's share of Four Corners Units 4-5. The capital cost of the combined cycle alternative would be significantly lower if APS had assumed that it would either (a) obtain combined cycle capacity from the competitive wholesale market or (b) convert one or more of its existing combustion turbines to combined cycle capacity. For example, APS has said that its $750/kW combined cycle capacity capital cost sensitivity was based on its efforts to obtain capacity from the wholesale market.[17] If this $750/kW cost were used in Graph 1 in the Application instead of the $1,253/kW cost for construction of a new combined cycle unit, the capital cost of the CC alternative would not appear so much higher than the other two alternatives.

Q. Does this same assumption that APS would have to build an entirely new combined cycle unit (as opposed to converting an existing combustion turbine or obtaining combined cycle capacity from the wholesale competitive market) also distort the rate impacts presented by APS witness Guldner?[18]

A. Yes. The workpapers for the rate impacts presented by Mr. Guldner show that the alternative in which Four Corners Units 1-3 are retired at the end of 2014 and Units 4-5 are retired on July 6, 2016 (Scenario B) has the lowest rate impact through 2016.[19] The rate impact of this alternative only jumps in 2017 due to the addition of an expensive new combined cycle unit to rate base. Again, this rate impact would be significantly lower if APS assumed that it will be able to convert an existing combustion turbine to combined cycle capacity or obtain combined cycle capacity from the competitive wholesale market at a rate somewhere around $750/kW.

Q. Does this complete your testimony?

A. Yes.

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17 Exhibit DAS-2, APS Response to Data Request SC 1.21.

18 Direct Testimony of Jeffrey B. Guldner, at page 4, lines 10-21.

19 Exhibit DAS-2, APS Response to Data Request SC 1.22.

Exhibit DAS-1

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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

Public Utility Commission of Colorado (Docket No. 10M-245E) – September, October and November 2010
The reasonableness of Public Service of Colorado's proposed Emissions Reduction Plan.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – July and November 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 and August 2010
Comments and Reply 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

The Economics of Existing Coal-Fired Power Plants, Presentation at EUCI Conference in St. Louis, MO, November 2010.

Presentation to the Indiana Utility Regulatory Commission on the Need for the Proposed Duke Energy Indiana Edwardsport IGCC Project, November 2010.

Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan, September 2010.

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

Comments on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on the Facility Cost Report for Tenaska's Proposed Taylorville IGCC Plant, April 2010.

Comments on City of Holland Board of Public Work's 2010 Power Supply Plan, April 2010.

Phasing Out Federal Subsidies for Coal, April 2010.

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

The Economic Impact of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia, August 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.

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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

Exhibit DAS-2

SIERRA CLUB'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
MARCH 24, 2011

SC 1.1: Provide the annual capacity factors and generation achieved by all of the generating units in APS's portfolio for each of the years 2007 through 2010.

Response: Attached as APS13958 is a document that shows the generation and capacity factors for the resources in APS's portfolio.

Witness: Mark Schiavoni

Generation - GWH

APS's Existing Generation Portfolio

2007 - 2010

	Palo Verde	Four Corners 1-2-3	Four Corners 4-5	Cholla 1-2-3	Navajo 1-2-3	Gila River CC	Redhawk CC 1-2	Arlington CC	W. Phoenix CC 5	W. Phoenix CC 4	W. Phoenix CC 1-2-3	Ocotillo Stm 1-2	Saguaro Stm 1-2	Ocotillo CT 1-2	Saguaro CT 1-3	W. Phoenix CT 1-2	Douglas CT	Yucca CT 1-4	Yucca CT 5-6	Sundance CT 1-10
2007	7,929	4,384	1,525	5,058	2,376		4,202		1,445	196	393	168	98	9	18	9	0	16		137
2008	8,478	4,358	1,548	4,893	2,367	2,137	4,151		1,397	161	253	67	40	2	37	4	1	8	38	188
2009	8,922	4,338	1,708	4,365	2,100	1,713	4,006		1,006	182	332	79	66	2	25	1	0	4	61	167
2010	9,080	4,214	1,465	4,500	2,204	1,697	3,376	1,155	1,322	110	285	52	0	4	8	3	0	5	84	108

Capacity Factor

APS's Existing Generation Portfolio

2007 - 2010

	Palo Verde	Four Corners 1-2-3	Four Corners 4-5	Cholla 1-2-3	Navajo 1-2-3	Gila River CC	Redhawk CC 1-2	Arlington* CC	W. Phoenix CC 5	W. Phoenix CC 4	W. Phoenix CC 1-2-3	Ocotillo Stm 1-2	Saguaro Stm 1-2	Ocotillo CT 1-2	Saguaro CT 1-3	W. Phoenix CT 1-2	Douglas CT	Yucca CT 1-4	Yucca CT 5-6	Sundance CT 1-10
2007	79%	4,384	1,525	90%	86%		49%		33%	19%	18%	9%	5%	<1%	1%	<1%	<1%	<1%		4%
2008	84%	4,358	1,548	87%	86%	49%	48%		31%	16%	11%	3%	2%	<1%	2%	<1%	<1%	<1%	8%	5%
2009	89%	4,338	1,708	77%	76%	39%	47%		23%	18%	15%	4%	4%	<1%	1%	<1%	<1%	<1%	4%	5%
2010	90%	4,214	1,465	79%	80%	39%	39%	26%	30%	11%	13%	3%	<1%	<1%	<1%	<1%	<1%	<1%	10%	3%

Notes: * Based on 6 months.

SIERRA CLUB'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
MARCH 24, 2011

SC 1.4: Provide copies of any analyses or assessments of the technical feasibility and economic viability of converting any of APS's existing simple cycle combustion turbine units into combined cycle facilities.

Response: APS has not conducted any such analysis or assessment.

Witness: N/A

SIERRA CLUB'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
MARCH 24, 2011

SC 1.19: Reference page 10, lines 24-27, of the Direct Testimony of Patrick Dinkel. Provide a copy of any analysis or assessment that APS conducted regarding the statement that the level of risk related to having 40% of the Company's generation dependent on natural gas would pose for APS's ratepayers.

Response: There are any number of documents that reveal gas price volatility. To that point, see the diagrams on pages 9 and 10 of Patrick Dinkel's testimony. Sierra Club has already been provided workpapers for these diagrams.

Witness: Pat Dinkel

SIERRA CLUB'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
MARCH 24, 2011

SC 1.21: Reference page 12, lines 26-27 of the Direct Testimony of Patrick Dinkel. Provide the analyses, assessments and reports that APS looked at related to the competitive wholesale market.

Response: The long-term capacity resources available in the competitive wholesale markets at the present time are natural gas fired combined cycle generation resources. These resources are not considered an appropriate replacement for the Four Corners units because natural gas combined cycle resources carry the risk of fuel price volatility as compared with stably-priced coal resources and would expose customers to increased rate volatility.

APS has maintained an awareness of market conditions in the competitive wholesale markets through a number of different sources. APS has participated in solicitations with merchant gas generators in the recent past with the intent of replacing gas generation that will be lost when long-term contracts for gas generation expire. APS was not successful in acquiring any gas generation in these solicitations. The data generated from those solicitations formed the basis for the estimated $750/kW combined cycle capital cost assumed in the cost analysis presented in the application. See chart on page 10 of the testimony of Patrick Dinkel for a graphic demonstration of why those costs do not reasonably compare to that of the proposed transaction.

Witness: Pat Dinkel

SIERRA CLUB'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
MARCH 24, 2011

SC 1.22: Reference page 4, lines 10-21 Direct Testimony of Jeffrey B. Guldner. Provide the workpapers for the rate increase percentages referenced by Mr. Guldner for each of the following scenarios:

a. If the proposed transaction moves forward.

b. If the plant owners shut down all five units of Four Corners in 2016.

c. If the plant owners retire Units 4 and 5 in 2016, but APS continues to operate Units 1-3.

Response: Attached, in Excel, is the workpaper (APS 13943_Q1.22 Customer Bill Impact) that calculates the rate increase percentages addressed in Mr. Guldner's direct testimony.

Witness: Jeff Guldner

Four Corners Acquisition
Revenue Requirement Impact
Scenario A (Shut Down Units 1-3, Acquire SCE Portion of 4-5)
(FC 1-3 Out 9/30/2012, SCE 4-5 In 10/1/2012)
($ Millions)

		2013	2014	2015	2016	2017
A.	**Rate Base**					
	1 Gross Plant (Acquisition)	$ 294	$ 294	$ 294	$ 294	$ 294
	2 Less: Accumulated Depreciation	-	11	22	33	44
	3 Cumulative Routine Plant Investment	11	32	60	125	162
	4 Cumulative Compliance Plant Investment w/AFUDC	-	-	-	168	371
	5 Total Rate Base	305	315	332	554	783
	6 Embedded Cost of Capital with Income Taxes	12.21%	12.21%	12.21%	12.21%	12.21%
	7 Revenue Requirement for Capital Investment	37	38	41	68	96
B.	**Operating Expenses**					
	8 Fuel and Purchased Power Impact	$ (43)	$ (24)	$ (47)	$ (31)	$ (51)
	9 Incremental O&M for Compliance	-	2	2	2	8
	10 Net Increase/Decrease O&M	5	11	18	29	19
	11 Operating Expenses	28	29	30	39	49
	12 Total Operating Expenses	(10)	18	3	39	25
C.	**Total Revenue Requirement**	$ 28	$ 57	$ 44	$ 107	$ 120
D.	**Forecasted 2010 Base Retail Revenues**	$ 2,877				
E.	**% Annual Revenue Requirement Impact to Retail Customer to 2010 Base Retail Revenues**	0.96%	1.97%	1.52%	3.72%	4.17%
F.	**% Increase Revenue Requirement Increase from prior year**	0.96%	1.00%	-0.44%	2.16%	0.44%

Notes:

Normal depreciation on Units 1-3 (no write--off cost)
Data taken from Resource Planning document dated 10-12-2010 and Fuel Forecast October 2010 (excludes carbon tax)

Note that fuel and purchase power impact is lower during plant maintenance outage
Revenue recovery for routine investment lags by one year
Revenue recovery for compliance expense lags by one year
Revenue recovery for compliance investment lags by one year after in-service date
SCE 500 kV Transmission Line excluded

Four Corners Acquisition
Revenue Requirement Impact
Scenario B (Shut Down Units 1-5, Replace with Natural Gas)
(FC 1-3 Out in 12/31/2014, FC 4-5 Out in 7/6/2016)
($ Millions)

		2013	2014	2015	2016	2017
A.	**Rate Base**					
1	Construction Expenditures w/AFUDC					750
2	Routine Plant Investment	7	4			
3	Compliance Plant Investment	4	13	5	1	
4	Total Annual Plant Investment	11	17	5	1	750
5	Plant Investment Balance	11	28	33	34	784
6	Annual Depreciation - based on 26 yr depr rate		(0.4)	(1.3)	(1.3)	(30.2)
7	Accumulated Depreciation		(0.4)	(1.7)	(3.0)	(33.2)
8	Total Rate Base	11	28	31	31	751
9	Embedded Cost of Capital with Income Taxes	12.21%	12.21%	12.21%	12.21%	12.21%
10	Revenue Requirement for Capital Investment	1	3	4	4	92
B.	**Operating Expenses**					
11	Fuel and Purchased Power	-	-	108	130	146
12	Incremental O&M for Compliance	-	-	-	-	-
13	Net Increase/Decrease O&M	(21)	(22)	(43)	(54)	(57)
14	Operating Expenses				12	27
15	Depreciation Expense		0	1	1	30
15	Total Operating Expenses	(21)	(22)	66	89	146
C.	**Total Revenue Requirement**	(20)	(18)	70	93	238
D.	**Forecasted 2010 Base Retail Revenues**	2,877				
E.	**% Annual Revenue Requirement Impact to Retail Customer to 2010 Base Retail Revenues**	-0.68%	-0.63%	2.44%	3.24%	8.27%
F.	**% Increase Revenue Requirement Increase from prior year**	-0.68%	0.05%	3.09%	0.78%	4.87%

Notes:

Normal depreciation on Units 1-3 (no write--off cost)

Data taken from Resource Planning document dated 10-12-2010 and Fuel Forecast October 2010 (excludes carbon tax)

Note that fuel and purchase power impact is lower during plant maintenance outage

Revenue recovery for routine investment lags by one year

Revenue recovery for compliance investment lags by one year after in-dervice date

SCE 500 kV Transmission Line excluded

Four Corners Acquisition
Revenue Requirement Impact
Scenario C (Shut Down Units 4-5, Operate 1-3)
(FC 4-5 Out 7/6/2016)
($ Millions)

		2013	2014	2015	2016	2017
A.	**Rate Base**					
1	Gross Plant	$ -	$ -	$ -	$ -	$ -
2	Less: Accumulated Depreciation	-	-	-	-	-
3	Cumulative Routine Plant Investment	30	92	140	167	175
4	Cumulative Compliance Plant Investment w/AFUDC	-	-	357	542	597
5	Total Rate Base	30	92	497	709	772
6	Embedded Cost of Capital with Income Taxes	12.21%	12.21%	12.21%	12.21%	12.21%
7	Revenue Requirement for Capital Investment	4	11	61	87	94
B.	**Operating Expenses**					
8	Fuel and Purchased Power	-	-	-	24	47
9	Incremental O&M for Compliance	-	2	2	2	4
10	Net Increase/Decrease O&M	9	13	20	26	23
11	Operating Expenses	1	4	19	27	30
12	Total Operating Expenses	10	19	41	79	104
C.	**Total Revenue Requirement**	$ 14	$ 30	$ 102	$ 166	$ 198
D.	**Forecasted 2010 Base Retail Revenues**	$ 2,877				
E.	**% Annual Revenue Requirement Impact to Retail Customer to 2010 Base Retail Revenues**	0.48%	1.03%	3.54%	5.76%	6.88%
F.	**% Increase Revenue Requirement Increase from prior year**	0.48%	0.55%	2.48%	2.15%	1.06%

Notes:

Normal depreciation on Units 1-3 (no write--off cost)
Data taken from Resource Planning document dated 10-12-2010 and Fuel Forecast October 2010 (excludes carbon tax)

Note that fuel and purchase power impact is lower during plant maintenance outage
Revenue recovery for routine investment lags by one year
Revenue recovery for compliance expense lags by one year
Revenue recovery for compliance investment lags by one year after in-service date
SCE 500 kV Transmission Line excluded

SIERRA CLUB'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
April 18, 2011

SC 2.8: Reference APS's response to SC 1.27. Specify the evidence, studies and analyses that form the basis for the assumption that the full load heat rates for Four Corners Units 4 and 5 will remain relatively constant for the duration of each unit's life.

Response: Since Units 4 and 5 commenced operating in 1969 and 1970, the heat rate has remained relatively constant. We have no studies, data or information to suggest that this long-standing trend will reverse in the future.

Witness: Mark Schiavoni

SIERRA CLUB'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
April 18, 2011

SC 2.9: Provide any studies or analyses prepared by or for APS, or which APS's witnesses in this case have seen, that examine the impact that the aging of coal unit equipment, components and structures can be expected to have on the following:

a. each unit's operating performance (that is, its heat rate, availability, planned or forced outage rate, gross or net output, generation or capacity factor);

b. annual operating costs; and

c. annual capital expenditures.

Response: APS objects to this question as vague and ambiguous, overly broad, and as seeking information irrelevant to the issues in this proceeding. Notwithstanding those objections, APS responds that it has no studies or analyses that specifically evaluate the impact of aging coal equipment, components and structures on unit operating performance, annual operating cost and annual capital expenditures. To the extent the documents produced in response to SC 2.10 may provide the information sought, please refer to them.

Witness: Mark Schiavoni

SIERRA CLUB'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING AUTHORIZATION FOR THE PURCHASE OF GENERATING ASSETS FROM SOUTHERN CALIFORNIA EDISON AND FOR AN ACCOUNTING ORDER
DOCKET NO. E-01345A-10-0474
April 18, 2011

SC 2.11: Provide any studies, analyses or evidence that supports the Company's conclusion that Four Corners will be able to achieve the annual capacity factors presented on page 2 of 2 of the attachment to APS's response to SC 1.2 after the year 2020, at which point the units will each be approximately 50 years old.

Response: Please see APS's response to Sierra Club questions 2.8, 2.9 and 2.10.

Witness: Mark Schiavoni

Confidential Exhibit DAS-3

PROOF OF SERVICE

I hereby certify that I have this day served the foregoing non-confidential documents on the following parties in this proceeding by mailing a copy thereof, properly addressed with first class postage prepaid to:

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Dated at San Francisco, California this 31st day of May, 2011.

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