BEFORE THE

PUBLIC SERVICE COMMISSION OF ARKANSAS

In the Matter of Southwestern Electric	**)**	
Power Company's Petition for a	**)**	
Declaratory Order Finding that	**)**	**Docket No. 12-008-U**
Installation of Environmental Controls	**)**	
at the Flint Creek Power Plant Is in the	**)**	
Public Interest	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE SIERRA CLUB

Resource Insight, Inc.

JUNE 29, 2012

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 250 times on utility issues before various regulatory, legislative, and judicial bodies, including the utility regulators of thirty states, five Canadian provinces, New Orleans, the District of Columbia, Austin Texas, and two U.S. federal agencies.

Q: Have you testified previously before this Commission?

A: Yes. I testified on lost-revenue recovery and shareholder incentives in Energy Arkansas's 2009 rate proceeding, Docket No. 09-084-U; on fuel switching, program administration and oversight, and programs for large customers in the Energy Efficiency Notice of Inquiry proceeding, Docket No. 10-010-U; on lost contributions to fixed costs, avoided costs, and shareholder incentives for program performance in the Innovative Ratemaking proceeding, Docket No. 08-137-U; and on opt-out and self-direct programs for industrial energy efficiency in Docket No. 10-101-R.

Q: Please summarize your experience in planning of utility resources.

A: I have testified on need, economics and other issues for utility power supply in scores of proceedings since 1978, as well as several proceedings regarding the need for transmission facilities.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Sierra Club.

Q: Please provide a brief summary of this proceeding and your conclusions.

A: In this proceeding, the Southwestern Electric Power Company (SWEPCo or the Company) requests that the Public Service Commission find that the installation of some very expensive environmental controls (the Project) at Flint Creek would be in the public interest. That finding would provide SWEPCo with some assurance of cost recovery, which the Company suggests is necessary for it to proceed with the Project, rather than retire or repower the coal plant.

In order for the Commission to know whether the Project is in the public interest, SWEPCo must derive a realistic estimate of Project costs and compare those costs to the costs of the most attractive alternatives under realistic conditions. The Company has failed to meet any of those standards: it has not provided serious site-specific estimates of the control costs, has ignored the most attractive alternatives (particularly enhanced energy-efficiency programs and the purchase of an existing efficient combined-cycle plant), and used unrealistic cost inputs (including gas prices, SWEPCo's share of transmission costs, and even the need for transmission upgrades).

Hence, the Company has not met its burden and the Commission should not endorse the Project.

Q: What is the scope of your testimony?

A: I review the adequacy of the analysis of the economics of major environmental retrofits of the 518-MW Flint Creek coal-fired power plant by its lead owner, the Southwestern Electric Power Company (SWEPCo or the Company) and its partner, the Arkansas Electric Cooperative Corporation (AECC). I examine the reliability of SWEPCo's estimates of the costs of continued operation of the coal plant, the costs related to transmission constraints, and alternatives to the coal plant not considered by SWEPCo.

In my review, I have concentrated on the analysis offered by SWEPCo, specifically through the direct testimony of Company Witness Scott Weaver. The Company also sponsors a similar parallel analysis by Judah Rose of ICF International, based on similar assumptions. I sometimes refer to the Rose direct testimony and discovery responses, where they describe SWEPCo's assumptions most clearly. My testimony also touches on the direct testimonies of Company Witnesses John Hendricks on environmental requirements, Paul Hassink on transmission issues, and Christian Beam on the environmental controls. My references to discovery responses (in the form "party Data Request set-number," sometimes specifying attachments) are SWEPCo's responses, except where I specifically cite to AECC responses.

Q: What is SWEPCo requesting in this proceeding?

A: The Company has petitioned the Arkansas Public Service Commission (APSC or the Commission) for a declaratory order finding that it would be in the public interest to install environmental controls at the Flint Creek power plant near Gentry, Arkansas. The Company and AECC each own a 50% share of Flint Creek and jointly seek to invest $504 million, including allowance for funds used during construction (AFUDC), to construct, own, and operate the following improvements, to which I will refer to collectively as the Project:

- a dry flue-gas-desulfurization system (DFGD or dry scrubber) to reduce the plant's emissions of sulfur dioxide (SO_2);
- an activated-carbon-injection system to reduce the plant's emissions of mercury;
- low-NOx burners and overfire air to reduce the plant's emissions of oxides of nitrogen;

- a pulse-jet fabric filter (or baghouse) integrated into the scrubber, to capture fine particulates and associated hazardous air pollutants (including the mercury adsorbed onto the activated carbon particles;
- support equipment for the delivery of lime (the chemical reagent used to remove SO_2 in the scrubber) and activated carbon, and the disposal of the scrubber and baghouse wastes;
- various investments associated with the environmental retrofits or general life extension and upgrades, including landfill development work, installation of continuous emission monitoring systems, and improvements to unit controls, steam coils, the balanced-draft system, and materials handling (Petition for Declaratory Order at 7–8).

In addition to the components of the Project, and the normal expenses and investments associated with operating a coal plant, SWEPCo anticipates that continued operation of Flint Creek will require investments for management of coal-combustion-waste materials and for additional NOx control. The Company included estimates of these costs in its economic analyses.

Q: Why is SWEPCo proposing the Project?

A: The Company states that these improvements in air-pollution controls and other systems for Flint Creek are required to meet more stringent emissions limits in order to comply with the Mercury and Air Toxics Standards (MATS) and the Regional Haze Rule. The MATS requirements would take effect in 2016, and would require the baghouse and injection of activated carbon.

The timing and stringency of the Regional Haze Rule are somewhat uncertain, but the U.S. EPA is committed to ensuring compliance with the best-available retrofit-technology (BART) requirements of the Rule by 2018. These will likely require some form of flue-gas desulfurization, as well as reductions in NOx emissions. The low-NOx burners and overfire air would reduce NOx emissions but may not be sufficient, depending on the final BART requirements of that rule (Petition at 5–7; Hendricks Direct at 5, 11, 15–16).

Q: Please describe the Company's analysis.

A: In Mr. Weaver's testimony, SWEPCo presented results for the following four options:

- Investing $721 million ($361 million for SWEPCo's share), in environmental retrofits at Flint Creek and continuing to run the unit on coal.[1] The Company's share of the environmental retrofits would include $252 million for a scrubber, a baghouse, and carbon injection in 2016, to control sulfur, particulate, and mercury emissions, respectively; $72 million for selective catalytic reduction for NOx control in 2020 in the base case (with sensitivities for installations in 2016 and never); and $37 million for control of coal combustion residuals by 2017. This is Option 1.
- Converting Flint Creek to burn natural gas at a cost of $110 million for SWEPCo's share. The Company assumes that the natural-gas plant, which might be economically dispatched at a 10–20% capacity factor, would be forced to run at 70% of full capacity every hour in several months (or about 40% on an annual basis) to back up the transmission system in the northwest Arkansas (NW-AR) region. This is Option 2.
- The Company's Option 3 is retiring Flint Creek and building a new 608-MW combined-cycle plant, plus 116 MW of peaking duct-firing capacity

[1] For simplicity, I cite SWEPCo's share of the costs in my discussion below, except as noted. Mr. Weaver's Table 6 shows SWEPCo's estimate of its share of the costs, and his workpapers show the AFUDC.

(of which SWEPCo would own half, at a cost of $459 million) at or near the Flint Creek site. This "brownfield" combined-cycle option would require increased gas transmission to Flint Creek. The Company assumes that the brownfield combined-cycle would also be operated out of economic order, although the economic burden would be smaller than for the gas steam plant, since a combined-cycle unit has lower running costs.

- Retiring Flint Creek and building a new 610-MW combined-cycle plant, plus 116 MW of peaking duct-firing (of which SWEPCo would own half, at a cost of $509 million), at a greenfield site outside NW-AR. The Company assumes that this option would require a new transmission line, at a cost of $193 million, of which SWEPCo would pay for about $32 million, with the remainder socialized across the Southwest Power Pool's (SPP) transmission region. This is Option 4.[2]

The Company's economic analysis estimates the costs to SWEPCo, recognizing that it jointly plans and dispatches its system with its sister utility Public Service of Oklahoma (PSO), also a subsidiary of American Electric Power (AEP). The Company and PSO are sometimes referred to jointly as the "AEP West" or "AEP SPP" system.

Q: Which aspects of that analysis did you review?

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[2]The $193 million includes about $31 million for lower-voltage local transmission that would be allocated 56% to SWEPCo, with the remainder presumably allocated to other utilities in the load pocket. This may be the same as the [redacted] million in [redacted] estimated in IR Staff 1-03_Attachment 2. The remaining $162 million would be spread across all SPP transmission owners; SWEPCo reports that AEP-SPP's share would be about 17% (from Mr. Weaver's workpapers for his Table 6), and apparently uses this cost in its analysis. The Company's load share would be about 9%. Including Public Service of Oklahoma overstates SWEPCo's share of the investment by about $13 million and its costs in 2016 by about $18 million.

A: My review covered the following issues:

- The validity of assumptions made by SWEPCo in evaluating the three alternatives (Options 2–4) that it proposed to the retrofit project. These include the need for transmission were Flint Creek retired without construction of equivalent-sized generation capacity in Northwest Arkansas (NW-AR), and the need to run any new non-coal generation in Northwest Arkansas out of economic order for transmission support absent additional transmission investment.
- The Company's forecast of natural-gas prices, and the effect of updating those prices to reflect the current market on the economics of alternatives to the continued operation of the Flint Creek coal unit.
- The following potential savings from replacement resource options that SWEPCo did not consider:
  - energy-efficiency programs;
  - purchasing an existing gas combined-cycle plant to replace Flint Creek, rather than building its own new combined-cycle unit;
  - a smaller amount of combined-cycle capacity;
  - a combined-cycle plant at the site of the Company's Harry D. Mattison plant in Tontitown, Arkansas;
- The reliability of the cost estimates for the near-term scrubber and for the selective-catalytic-reduction (SCR) system that SWEPCo assumes will be required in 2020 in its base case.

Q: What are your conclusions?

A: My conclusions are as follows.

First, SWEPCo has seriously exaggerated the effects of the NW-AR load pocket on the cost of retiring the Flint Creek coal plant. It concludes that a new transmission line would be needed were Flint Creek retired and replaced by a greenfield combined-cycle plant (or other resources) outside the load pocket. However, were the transmission line needed under those circumstances, it would also probably be needed with the Flint Creek coal unit in operation. SWEPCo's evaluation of the load pocket also leads it to impose minimum-load requirements on the gas steam plant and the brownfield combined-cycle plant that are clearly excessive and grossly overstate the costs of those resources. The effect is to make Options 2 and 3 appear less economic. As a result, no analysis incorporating the Company's transmission and minimum-load assumptions can be considered reliable.

Second, the costs of all of the alternatives considered in SWEPCo's analysis are highly dependent on natural-gas prices. The gas prices SWEPCo used—even in the supposedly "low band" fuel-price case—are much higher than current forward market prices. The Company's use of overstated gas prices overstates the costs of all the alternatives to continued operation of Flint Creek on coal. Without an analysis of the economics of alternatives under more reasonable gas prices, it is impossible to conclude that the Project is in the public interest.

Third, SWEPCo did not consider the most-attractive alternatives to an extension of Flint Creek's life as a coal plant. The Company did not analyze a variety of attractive options, including combinations of energy-efficiency programs, purchased capacity, and gas-fired generation located at the Mattison site. Until those options are compared to the Flint Creek coal plant, it is impossible to conclude that the Project is in the public interest.

Fourth, the Company's estimates of the cost of the environmental retrofits (both the Project and subsequent SCR installation) necessary to keep the coal plant in operation are of doubtful quality.

Q: How large an effect could correction of the problems you have identified have on SWEPCo's analyses in this proceeding?

A: Correcting those problems could well reverse the net benefit that SWEPCo asserts for the Project. Table 1 summarizes the corrections for which I can estimate a value.

Correction 1 is a simple updating of SWEPCo's analysis to be more consistent with current conditions (a more detailed analysis would require a full production costing model). Correction 2 adds in an estimate of the costs of an alternative SWEPCo overlooked. Correction 3 corrects the inclusion of PSO's costs in SWEPCo's computation. Correction 4 (which subsumes Correction 3) represents a more-realistic view of the incremental need for the transmission upgrades. Correction 5 is a rough adjustment to SWEPCo's low and poorly documented SCR cost estimate. These corrections are derived below.

Table 1: Alternatives Improved by Corrections to SWEPCo's Analysis
(Millions of NPV Dollars)

Correction	Applicable to	Approximate Improvement
1. Update Natural Gas Prices from SWEPCo Low-Band Price Case	Option 2	$104
	Option 3	$95
	Option 4	$81
2. Purchase Existing Combined-Cycle Capacity	Option 4	$220–$300
3. Correct Allocation of Transmission Cost	Option 4	$24
4. Remove Transmission Cost	Option 4	$42
5. Increase SCR Cost by $100/kW	Options 2, 3, and 4	$25

Since SWEPCo estimates that the cumulative present worth of continued operation of the coal plant is less than Options 2–4 by $227 million, $148 million, and $274 million, respectively, these corrections would eliminate all of

SWEPCo's claimed benefit for the Project compared to the greenfield combined-cycle Option 4, the vast majority of the claimed benefit over the brownfield Option 3 ($120 out of $148 million), and over half of the claimed benefit over the gas-steam Option 2 ($106 out of $227 million).

In addition to these roughly quantified adjustments, I have identified four problems in the Company's analysis that I have not been able to quantify:

- the Company's modeling of the gas-steam and combined-cycle resources at Flint Creek (Options 2 and 3) as operating at 70% of their rated capacity in all hours of most months, at a large economic penalty;
- the omission of energy-efficiency programs as a resource to replace part of Flint Creek's energy and capacity and relieve loads in NW-AR;
- the failure to consider replacement capacity at Mattison, which would both allow the conversion of Mattison combustion turbines to combined-cycle operation and avoid any need for the transmission line and a new gas pipeline;
- the poor quality of SWEPCo's estimate of the cost of the scrubber-and-baghouse combination (known as NID).

Q: How do you recommend that the Commission respond to the Company's petition in this docket?

A: I recommend that the Commission decline to find the Project to be in the public interest, unless and until the problems I have raised above are resolved. A detailed review and appropriate revision of cost inputs and a more-realistic consideration of alternatives would most likely show that the Project is not the most cost-effective option for meeting demand in SWEPCo's territory as whole, and the Northwest Arkansas region in particular.

III. The Northwest Arkansas Load Pocket

Q: What does the Company claim about the Northwest Arkansas Load Pocket?

A: The Company asserts that retirement of Flint Creek would require either

- construction of an equivalent amount of capacity in NW-AR, which SWEPCo models as being at least 476 MW (for Flint Creek operating on gas), generating at least 333 MW or more around the clock for months every year, or
- "an incremental bulk transmission investment…to ameliorate those regional (NW-AR) constraints" (Weaver Direct, Table 5).

The Company suggests that the transmission investment can be "proxied" as a 345-kV transmission line running from Fort Smith to Chamber Springs, approximately 70 miles long, at a cost of $193 million, comprising $133 million in 345-kV transmission, $25 million in local equipment, $11 million in overheads, and $24 million in AFUDC. The Company estimates it would pay for about $37 million of this investment, plus overheads and AFUDC, consisting of 17% of SPP-level costs ($23 million) with the remainder socialized across the SPP transmission region and 56% of local costs ($14 million) with the remainder spread over other utilities in the AEP-SPP zone.[3] With the overheads and AFUDC, SWEPCo's share would be about $45 million. The Company reports that cost recovery on that share of the transmission line through 2040 would have a 2011 present value of $42 million.[4]

[3] Weaver Direct, workpaper Ex SCW-6 DETAIL WP (Opt 4_EHV Trans Cost Impact on CPW).

[4] Ibid. The Company appears to include overheads and AFUDC in the 14.65% fixed-charge rate it applies to transmission.

Q: Does SWEPCo assert that these costs represent the least-cost solution for the transmission issues in NW-AR?

A: No. The Company concedes that this plan is only a proxy, rather than a well-developed transmission solution.

> Witness Hassink only suggests the 345kV line from Fort Smith to Chamber Springs is a reasonable proxy for any transmission solution that may ultimately be authorized by SPP to resolve NERC requirements in the NW-AR area if Flint Creek were to be retired without local replacement. (APSC Data Request 4-46)

Were some transmission needed (which is far from clear), the least-cost plan may be less expensive than this proxy.

Q: Did SWEPCo properly estimate its share of the transmission improvements?

A: No. The Company appears to have over-estimated its share of the transmission project, by using the "AEP-SPP" shares of the total costs.[5] SWEPCo's load shares are 8.8% of SPP costs and 38.5% of local costs,[6] which would imply a SWEPCo share (without overhead or AFUDC) of

$$8.8\% \times \$133 + 38.5\% \times \$25 = \$21 \text{ million}^{7}$$

much less than the $37 million that the Company estimates for the same set of costs.

Q: What problems does SWEPCo identify as arising if Flint Creek is retired and the transmission project is not constructed?

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[5]Ex SCW-6 DETAIL WP (Opt 4_EHV Trans Cost Impact on CPW).

[6]Lachowsky's workpaper "P 40 SPP trans allocation."

[7]The present value of cost recovery through 2040 would be about $24 million.

A: As explained in Attachments 1 and 2 to APSC Data Request 1-3, the problem would arise for a second-contingency outage. As SWEPCo explains in its reply to APSC Data Request 5-21,

> The study provided as [Attachment 1] addressed single contingencies…. For the upcoming ten year period, this analysis found that no system upgrades were necessary in order to retire the Flint Creek generator for [these] contingencies.[8] The study provided as [Attachment 2] addressed multiple contingencies…. Since 320 MW of load shed was required in order to be compliant, system upgrades would be required.
>
> ….
>
> Attachment 2…looks at the Flint Creek generation being off and the Mattison generation being on at the 2017 and 2022 summer peak. Then it takes one line out of service. Then it checks to see how much load would have to be shed preemptively, in order to avoid having the next worst contingency overload any transmission facility above 110% of its emergency rating.

Specifically, given the current transmission system and with Flint Creek out of service, if one of the three 345-kV transmission lines serving the load pocket were to go out of service, as much as 320 MW of load in NW-AR would need to be shed to avoid complete collapse if a second 345-kV transmission line or the Mattison generation were to go off line.

While Attachment 2 states that analyses were performed for 2017 and 2022 peak, it does not specify the year for which the 320-MW shortfall is identified. The Company (APSC Data Request 5-21) says, "the result…that 'up to approximately 320 MW of load in the Northwest Arkansas area may have to be shed preemptively' is based upon 2017 summer peak."

[8]Indeed, there is no problem with any one contingency (e.g., line outage), without Flint Creek, even with no generation from any of the four units of Mattison.

Q: Does SWEPCo's treatment of the load pocket affect its analysis of the alternatives?

A: Yes. Each of the options, other than the retrofit of Flint Creek and continued operation as a coal unit, has been burdened with unnecessary costs as a result of the overstated load pocket concerns. The greenfield combined-cycle option includes the $37 million for the additional transmission line, while the brownfield and gas-conversion options are required to operate at a minimum of 70% of capacity in all hours for "several months of the year" (Rose Direct at 9).[9] As a result, ICF's analysis concludes, "On average, over the 2016 to 2045 period, dispatch averages 61% for the brownfield combined cycle and 38% for the gas steam conversion option" (Rose Direct at 10). Rose reports that the greenfield combined-cycle plant would run at a 24% capacity factor (Rose Direct at 10), which would be typical of economic operation of combined-cycle plant in the SPP region. A steam gas unit would typically run at a capacity factor much lower than a modern combined-cycle plant, given the lower efficiency of this type of unit. In interpreting the load-pocket constraints to require a minimum hourly output of 70% of capacity, SWEPCo imposes very large costs of uneconomic operation on the gas options in the load pocket.[10]

Q: Are the Company's claims about the load pocket supported by the record?

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[9]The Company appears to have specified the peak months in which the plants are required to run out of order ([redacted] only in a response classified as highly sensitive protected information (Company response to Sierra Club Data Request 1-165b).

[10]In SWEPCo's analysis (replying to APSC Data Request 5-4), the brownfield combined-cycle plant runs at an average [redacted]% capacity factor. In that analysis, the greenfield combined-cycle plant runs at [redacted]%, while the gas steam plant also runs at [redacted]% capacity factor.

A: No. The Company's principal analysis of the effects of Flint Creek retirement on the NW-AR transmission system is contained in the Hassink attachments to APSC Data Request 1-3, which describe the results of transmission modeling for summer peaks in 2017 and 2022.[11] These analyses display a number of peculiarities and inconsistencies, including the following:

- dismissing the possibility of rearranging dispatch to relieve transmission overloads,
- overstating the number of hours and days on which loads reach levels at which SWEPCo has identified problems,
- imposing more-stringent dispatch requirements on the brownfield combined-cycle than on the gas steam plant, and
- ignoring the similarity in load flows following a forced outage of Flint Creek and retirement of that unit.

Q: Please describe SWEPCo's treatment of the possibility of optimizing dispatch to relieve transmission overloads.

A: The overloading of transmission lines into a constrained area can be exacerbated by the flow of power over the heavily loaded lines to allow power to flow out of the area over other lines. Reducing those exports, or otherwise changing the flow pattern, can reduce the overloading. This procedure is called transmission loading relief (TLR), and it often would require changing dispatch of generation. The Company says that it

[11] These are the dates in Hassink's Attachment 2. Attachment 1 does not specify a date, but APSC Data Request 5-21 clarifies that it was based on loads anticipated for 2022.

> …utilizes TLR [and Congestion Management Event] procedures to control loadings on defined flowgates to maintain loadings within acceptable levels. In some cases, transmission re-configuration options are also available to mitigate thermal / voltage concerns. Re-configuration typically occurs on a post-contingency basis but, depending on system conditions, may also occur pre-contingency. Out of Order Merit Energy (OOME) requests may also be issued to manually re-dispatch units that can assist in facility loading control. If TLR/CME procedures, re-configurations options, or OOME requests do not provide enough relief, AEP would shed load to reduce loadings on the applicable facility until loadings are below the defined emergency rating. (Sierra Club Data Request 1-209)

Hassink's Attachment 2 to APSC Data Request 1-3 says, "[redacted]." However, APSC Data Request 4-8 shows exports from the load pocket that average [redacted]%–[redacted]% of NW-AR load and [redacted]%–[redacted]% of NW-AR imports annually over 2009–2011.[12] The Company seems to have prematurely dismissed the potential for reduced exports from NW-AR to relieve transmission overloads in the load pocket. Dismissing the potential for TLR to alleviate the load pocket problem allows SWEPCo to argue that excessive and uneconomic operation is required for Options 2 and 3, and that the transmission line is required for Option 4, making all three alternatives look less attractive than they would actually be.

I have not been able to locate in the record which of the NW-AR tie lines tend to be importing and which tend to be exporting at peak hours. However the Company says, "Historically the Brookline–Flint Creek 345-kV line exports power out of the area. Under contingency conditions, the line provides a

[12]Unfortunately, the codes used to identify the tielines in APSC Data Request 4-8 are not used in the transmission diagrams or other information that SWEPCo provided, and I have not been able to match the imports and exports with specific lines or interfaces.

minimal level of power import" (Sierra Club Data Request 1-203). This line runs northeast from Flint Creek; increasing generation to the north and east might reduce the export over this line and relieve the overloads on the lines from the west.

To make matters worse, the Company's transmission analysis assumes that retirement of 514 MW at Flint Creek would result in generation increases of 257 MW at Wilkes in Northeast Texas and Oneta Energy Center near Tulsa, Oklahoma, to the west and southwest from NW-AR, which would appear to increase the flows over the lines subject to overloads (APSC Data Request 5-29). This would not a realistic response to retirement of Flint Creek.

The Company has not shown whether generation increases in different locations outside NW-AR would have smaller effects on transmission than would the Wilkes-Oneta combination.

The Company's assumption that additional output at Oneta and Wilkes would replace Flint Creek's is inconsistent with the rest of its analysis, in two ways. First, the potential transmission problems that SWEPCo has identified occur only at high loads and Oneta is a highly efficient gas combined-cycle unit, so Oneta is unlikely to have over 250 MW of capacity sitting idle at peak hours. More importantly for the present proceeding, SWEPCo assumes that retirement of the generation at Flint Creek would result in addition of some new resource (a greenfield combined-cycle plant in the option that the Company asserts would create the need for transmission), so the major difference in peak-hour dispatch due to Flint Creek's retirement would be that the replacement resource would operate. The Company could base its selection of the location of that greenfield combined-cycle plant, in part, to reduce the stress on the transmission system.

Q: Did SWEPCo overstate the number of hours and days on which loads reach levels at which transmission problems might occur?

A: Yes. The problems identified by the Company in Hassink's Attachment 2 to APSC Data Request 1-3 only occur at load levels exceeding the capacity of the existing transmission lines. SWEPCo asserts that a 320-MW shortfall would occur with the loads and generation modeled for 2017 (APSC Data Request 5-21), but does not identify the peak load level that is 320 MW higher than the transmission capacity. Given the discussion of the loads used for 2022 in Hassink's Attachment 1 to APSC Data Request 1-3, and of the loads SWEPCo currently projects for 2018 and 2023, it is my opinion that the 320 MW shortfall was computed for a peak loads around MW. At lower demand levels, less load would need to be shed to bring the load below the carrying capacity of the system with two 345-kV lines out of service. For demands of less than about MW-79% of peak-no load shedding would be needed.[13] In 2009–2011, an average of hours on an average of days had loads greater than 79% of peak. Consequently load-shedding would be needed for only about 7% of the hours or 23% of the days for which SWEPCo requires the gas-steam and brownfield combined-cycle plants to operate. During these high-load hours, the combined-cycle unit would likely run for economic reasons; even the gas-steam plant would run economically at many of these hours. Hence, SWEPCo's estimates of the amount of uneconomic operation of the brownfield and gas-steam plants are greatly overstated.

[13] If the statement refers to any higher peak load, the level at which any shedding might be required would be higher and occur further in the future.

Q: Did the Company impose more-stringent dispatch requirements on the brownfield combined-cycle plant than on the gas steam plant?

A: Yes. The Company requires both the 476-MW gas-steam plant in Option 2 and the 608-MW combined-cycle plant in Option 3 to operate at 70% of capacity, even though that is 333 MW for the gas-steam unit and 426 MW for the combined-cycle unit, and even though the combined-cycle plant would generally be able to ramp up faster after a first contingency than the gas-steam plant. The 70% minimum-dispatch requirement is clearly arbitrary.

Q: Does the Company's position adequately address the similarity in load flows following a forced outage of Flint Creek and retirement of that unit?

A: No. The situation in NW-AR without Flint Creek at a particular load level is the same whether Flint Creek has been retired or is simply offline for a few days of repairs. The Company

> has not designed a Special Protection Scheme for NW Arkansas…because the need to preemptively shed load that witness Hassink describes in his testimony is predicated upon the retirement of Flint Creek Generating Plant. The Flint Creek Generating Plant is presently an in-service plant, therefore, there is no need for a Special Protection Scheme. (Sierra Club Data Request 1-212)

Instead, if Flint Creek is out of service and SWEPCo Arkansas load exceeds [redacted], the Company will [redacted].[14] This is apparently a rare occurrence, since [redacted] in 2009–

[14] Even when Flint Creek is operating, SWEPCo's procedures require it to [redacted] when SWEPCo Arkansas load exceeds [redacted]. (IR AG 2-8, Attachment 1) It is not clear how total load in SWEPCo Arkansas, which includes some of the load in NW-AR and some load elsewhere, relates to total load in NW-AR.

2011. This shows that the absence of Flint Creek capacity, even at peak demand, does not require new transmission lines, 476 MW of additional generation, or the operation of 333 MW in all hours at 70% of full capacity.

If SWEPCo's position on the need for load relief in NW-AR following Flint Creek's retirement were correct, similar investments would be required even with Flint Creek in continued service, probably at current load levels but certainly at loads anticipated over the next several years.

Q: Is SWEPCo's position that the retirement of Flint Creek would require either (1) the transmission additions or (2) the construction of at least 476 MW of new capacity in NW-AR in any way plausible?

A: No. Any capacity or transmission reinforcement required with the retirement of Flint Creek would also be required with Flint Creek remaining in service and cannot be considered a cost of Flint Creek's retirement for the Project alternatives evaluated by the Company.

Q: Given the information that SWEPCo has provided, is it reasonable to expect the NW-AR load pocket would need a minimum of 333 MW of capacity operating in the load pocket for [redacted] the hours of the year?

A: No. That operational requirement would clearly be unnecessary and inconsistent with current practice.

Q: What would be the effect of correcting these overstatements about the need for new transmission and minimum run time have on SWEPCo's analysis of the alternatives to Flint Creek?

A: If the transmission upgrade is not part of the cost of replacing Flint Creek with a greenfield combined-cycle plant, either because the line is not needed without Flint Creek or because the line is needed even with Flint Creek in operation, the investment for the greenfield combined-cycle plant (Option 4) would be reduced by about $173 million, and the present value of the cost of that option would be reduced by about $42 million (Weaver Direct, Exhibit SCW-6 and supporting detail workpaper in APSC Data Request 1-3). Simply correcting SWEPCo's inclusion of PSO's share of the transmission costs would reduce the present value of Option 4 by about $13 million.

For Options 2 and 3, SWEPCo does not include the transmission line in its estimates but does include significant amounts of uneconomic energy generation, most of which would not be necessary, as explained on page 19 above. Estimating the magnitude of those excess costs would require a new modeling run, with more realistic operating constraints.

IV. Overstatement of Natural-Gas Prices

Q: Why are natural-gas prices important in the evaluation of the Project?

A: All three options that SWEPCo considers as alternatives to continued burning of coal at Flint Creek are natural-gas-fired generation. One major factor favoring the selection of the project is the difference in fuel costs per MWh between Option 1 (Flint Creek coal) and the three gas-burning alternatives (Options 2, 3, and 4). All else equal, lower gas fuel costs per MMBtu (and hence per MWh) will shrink the cost differentials among these options. Differences in fuel costs comprise 120% of the difference in present value that SWEPCo reports between Options 1 and 2, more than 200% of the difference between Options 1 and 3, and 90% of the difference between Options 1 and 4. Thus, overstating gas prices will disproportionately inflate the overall costs of gas-fired options compared to coal.

Q: Are the natural-gas prices in SWEPCo's analysis reasonable?

A: No. The Company's natural-gas forecasts might have been reasonable when prepared last summer and fall, but the natural-gas market has shifted substantially in the last several months.

The shifts are due to development of large amounts of non-conventional gas resources and expectations that additional such resources will continue to be available at low cost for many decades. In response to a long-term surplus of domestic natural gas, projects to import liquefied natural gas into North America have been cancelled, existing import facilities are being converted to export gas, and new export projects are under development.

These changes in expected natural-gas prices must be reflected in an updated analysis to provide the Commission with a sound basis on which to base its determination of whether the proposed retrofit is in the public interest.

Q: How did SWEPCo and ICF develop their forecasts?

A: The Company's gas-price forecast was part of a long-term projection of commodity prices developed by the AEP Fundamental Analysis group in September 2011 (Weaver Direct at 41), using the U.S. Energy Information Administration's Annual Energy Outlook forecast from April 2011 and consultant forecasts from May (see APSC Data Request 1-3, workpaper "Ex SCW-4(2) WP (NG-HH Consensus Pricing)"). The market forward prices represent estimates of future costs on which markets are betting actual money. The ICF natural-gas-price forecast was apparently from an internal analysis from 2011benchmarked on Henry Hub forward prices from 2011 (Rose Direct Exhibit JLR-2 at 56–57), although other responses (Sierra Club Data Requests 1-175 and 1-179) suggest that the forecast was prepared in .

The ICF forecast explicitly treats the NYMEX forwards for Henry Hub as an input or benchmark (Rose Direct, Attachment JLR-2 at 56).

Figure 1 shows the Company's base forecast for natural gas at Henry Hub (the "Fleet Transition–CSAPR" case) and its lowest Henry Hub forecast (the "Fleet Transition–CSAPR: Lower Band" case), along with Henry Hub forwards from September 2011, November 2011 and June 19 2012.

Figure 1: Henry Hub Prices, SWEPCo Forecasts and Forwards over Time

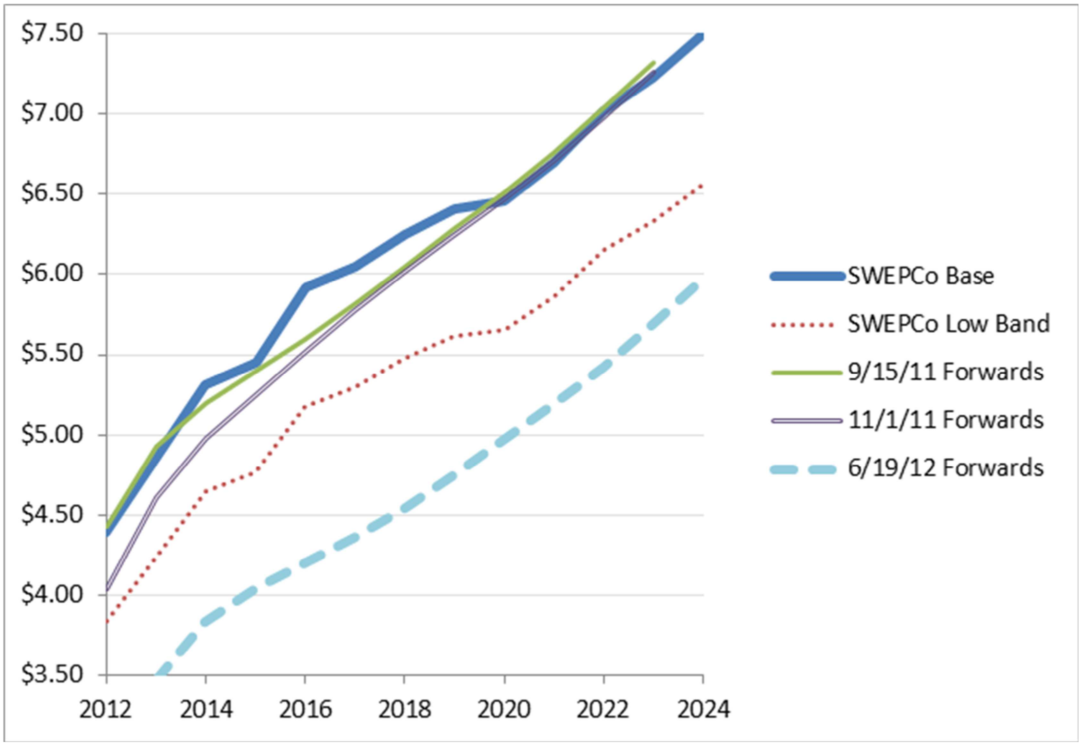

Figure 1 shows that SWEPCo's base case was very similar to the forwards prices from September and November. Current forwards are not just lower than SWEPCo's base case, but also lower than the Company's low-band forecast. Indeed, the current natural-gas forwards average about as far below SWEPCo's low-band case as its low-band case is below the Company's base forecast.

While Mr. Weaver says that his low-band case "bounds the low-end of the BASE case with plausible fuel, emissions and energy pricing varying by approximately −1.0 standard deviation" (Weaver Direct, Table 7), his low forecast only reached half way to reality.

Q: Can you revise SWEPCo's natural-gas-price forecast to reflect current conditions in the long-term market?

A: Yes. From 2016 through 2024, I updated SWEPCo's base forecast of natural gas prices at Henry Hub from the fall-2011 prices SWEPCo used to the annual average of closing NYMEX forward prices on June 19 2012. These prices are shown in Table 2, along with the ratio of current forwards to SWEPCo's base forecast.

Table 2: SWEPCo Base Gas Forecast, Current Forwards, and Extrapolation

.	SWEPCo Base Forecast	6/19/12 Forwards	Price Ratio	Updated Forecast
2013	$4.85	$3.46	71.4%	$3.46
2014	$5.31	$3.84	72.2%	$3.84
2015	$5.45	$4.04	74.1%	$4.04
2016	$5.91	$4.20	71.1%	$4.20
2017	$6.05	$4.37	72.2%	$4.37
2018	$6.25	$4.54	72.7%	$4.54
2019	$6.41	$4.75	74.2%	$4.75
2020	$6.46	$4.98	77.0%	$4.98
2021	$6.70	$5.19	77.5%	$5.19
2022	$7.02	$5.42	77.2%	$5.42
2023	$7.23	$5.69	78.7%	$5.69
2024	$7.49	$5.96	79.6%	$5.96
2025	$7.74		80.7%	$6.24
2026	$7.85		81.8%	$6.41
2027	$8.04		82.8%	$6.66
2028	$8.23		83.9%	$6.91
2029	$8.42		85.0%	$7.15
2030	$8.54		86.0%	$7.34
2031	$8.65		87.1%	$7.53
2032	$8.76		88.2%	$7.73
2033	$8.88		89.2%	$7.92
2034	$9.00		90.3%	$8.13
2035	$9.13		91.4%	$8.34
2036	$9.25		92.4%	$8.55
2037	$9.37		93.5%	$8.76
2038	$9.50		94.5%	$8.98
2039	$9.62		95.6%	$9.20
2040	$9.75		96.7%	$9.43

Note: For those years after the NYMEX Henry Hub forwards end in 2024, I extrapolated the price ratio at the 1.07% average annual increase from 2016 to 2024.

My updated forecast exceeds SWEPCo's low-band forecast in 2032.

This revision is intended to represent current market indications for future prices. It is an update to SWEPCo's base case. An updated low-band case would be even lower than my revised base case.

Q: How would this updated forecast of the cost of natural gas affect the costs of the different options?

A: A comprehensive analysis of the effects of revised natural-gas forecasts on the costs of the different natural-gas-fired alternatives would require rerunning SWEPCo's costing models. Instead I estimated the effect of revising the natural-gas-price forecasts by computing the reduction of fuel costs for each of the natural-gas-fired options, from both SWEPCo's base and low-band natural-gas-price forecasts. For each year, I multiplied the difference in natural-gas price between SWEPCo's forecast and my updated gas-price forecast by the energy output from the option's replacement capacity (Flint Creek converted to natural-gas firing, a brownfield combined-cycle at Flint Creek, or a greenfield combined-cycle outside the NW-AR load pocket) reported in response to APSC Data Request 5-4.[15] I did these computations directly from SWEPCo's base forecast, and indirectly from SWEPCo's low-band natural-gas forecast; for the latter, I compute the difference in costs from the SWEPCo low-band natural-gas price to current prices, add SWEPCo's estimate of the difference in system costs between its base and low-band natural-gas forecasts, and add back the $3 million effect of the reduction in coal prices between SWEPCo's base and low fuel forecasts. The results of these computations are summarized in Table 3.

[15]The Company designated its modeled forecast of the annual energy output by unit as confidential, so I provide only the present-value summary of my results in this testimony.

Table 3: Cost Reductions from Revising Gas Forecast (Millions of NPV Dollars)

Option		Reduction from SWEPCo[a] Base	Reduction from SWEPCo[a] Low Band	SWEPCo Difference from Base to Low Band[b]	Update from Base, via SWEPCo Low Band[c]
2	Flint Creek Gas	$97	$36	$68	$104
3	Brownfield CC	$137	$46	$49	$95
4	Greenfield CC	$92	$31	$50	$81

[a] Base and Low Band from Table 2, Exhibit SCW-4, and APSC Data Request 5-4
[b] Exhibit SCW-6, net of $3M due to coal price change
[c] Sum of low band and SWEPCo difference

Table 3 presents the following two estimates of the cost reduction for each option if the updated gas prices are substituted for SWEPCo's base forecast:

- my estimate of the reduction from SWEPCo base prices to updated prices, using the replacement plant's energy in SWEPCo's base-price case ("Base")
- the sum of the SWEPCo's estimate of the cost reduction from its base to low-band prices and my estimate of reduction from SWEPCo low-band prices to updated prices, using the replacement plant's energy in SWEPCo's low-band case (rightmost column).

The two methods in Table 3 agree fairly closely for Options 2 and 4, suggesting that changes in gas prices mostly affect the cost of running the options' replacement capacity. For Option 3, using SWEPCo's low-band case results in a smaller reduction than does working directly from SWEPCo's base case. That difference probably arises due to a combination of increased economic dispatch of the brownfield combined-cycle plant with lower fuel prices, redispatch of other units, and changes in wholesale transactions.

V. Alternative Resource Options

Q: What additional resource alternatives have you identified, beyond those considered by SWEPCo?

A: I have identified the following additional resource options:

- energy-efficiency programs,
- purchasing an existing gas combined-cycle plant to replace Flint Creek, rather than building its own new combined-cycle unit,
- a smaller amount of combined-cycle capacity,
- a combined-cycle plant at the Mattison site.

I discuss these options in the next three sections.

A. Energy Efficiency

Q: How would increased energy-efficiency programs create an alternative resource for replacing Flint Creek and avoiding the costs of the environmental retrofits?

A: Energy-efficiency programs beneficially reduce the following loads:

- energy consumption and associated line losses, offsetting the reduction in energy produced associated with the retirement of Flint Creek;
- peak loads, associated line losses, and the need for reserves, offsetting the loss in system capacity due to retirement of Flint Creek;
- loads in the NW-AR load pocket, reducing the need for transmission and generation for that area;
- system loads and NW-AR loads more at high-load times (such as extraordinarily hot days), when the reductions are most needed and valuable.

In addition to these benefits related to the specific concerns addressed in SWEPCo's economic analysis, energy-efficiency programs also reduce local transmission-and-distribution costs. Reducing energy requirements can also reduce the cost of meeting environmental constraints, such as the seasonal NOx limits in all three states served by SWEPCo (Arkansas, Louisiana, and Texas) and the annual SO_2 and NOx limits in Texas under the Cross State Air Pollution Rule.

Q: How much energy and peak savings does SWEPCo currently project from its energy-efficiency programs?

A: In Arkansas, SWEPCo is projecting annual incremental demand savings of about 0.77% of peak load in 2012, falling to about 0.5% of peak load from 2013 through 2016, averaging about 0.3% from 2017 to 2020, and falling off to zero by 2026.[16] In the rest of its retail system, SWEPCo projects annual incremental savings of about 0.1% of load in 2013, about 0.2% in 2014 to 2020, falling to near zero thereafter.[17]

Cumulatively, this amounts to about 24 MW of post-2012 savings for SWEPCo Arkansas and another 24 MW for the rest of SWEPCo through 2016, and 35 MW for SWEPCo Arkansas and another 51 MW for the rest of SWEPCo through 2020. About 65% of SWEPCo's Arkansas load is in NW-AR, so a similar share of the energy-efficiency savings should be in the load pocket, as well.

While SWEPCo has not provided as much detail for its projected energy savings (either the breakdown between Arkansas and the rest of the utility or the

[16]The 2012 savings are consistent with the Commission's target of 0.75% savings.

[17]These data are from Weaver's Exhibit SCW-2, the supporting workpapers, and Sierra Club Data Request 1-187. The Company has provided publicly its forecast of Arkansas retail peak load and both retail and system-wide energy-efficiency demand savings, but not its forecast of retail load in the rest of the system. Hence, I describe these projections in only the most general terms.

breakdown between wholesale and retail), they appear to be of similar magnitude.

Q: How much savings are the leading utilities and regulatory jurisdictions achieving from their energy-efficiency programs?

A: The utilities and other program administrators that have seriously invested in energy-efficiency have achieved and are planning to continue achieving annual savings in the range of 1% to 2% of load. See the report from the Green Energy Economics Group, attached as Exhibit PLC-2 (specifically Tables 1, 4, and 6), for more detail.

Q: If SWEPCo ramped up its energy-efficiency programs to those levels, by how much might it reduce its load?

A: Were SWEPCo to increase its annual incremental energy-efficiency savings to

- 1% in 2013, rather than decreasing them,
- 1.25% in 2014, and
- 1.5% for 2015–2020,

and the Texas and Louisiana annual incremental savings to

- 0.25% in 2013,
- 0.5% in 2014,
- another 0.25% increase each year through 1.25% in 2017, and
- 1.5% in 2018–2020,

the Company could reduce its peak load by about 80 MW in 2016 and 280 MW in 2020, of which about 32 MW and 20 MW would be in Arkansas and NW-AR, respectively by 2016, rising to about 84 MW and 55 MW, respectively by 2020. All of these figures are in addition to the energy-efficiency savings in the Company’s forecast.

Q: How much would these savings cost?

A: The experience of other jurisdictions indicates that the costs of achieving savings of this magnitude would be on the order of 4¢–5¢/kWh saved. See Exhibit PLC-2, Table 15, for more detail.

B. Purchase of Natural-Gas Combined-Cycle Capacity

Q: Were SWEPCo to seek the opportunity to purchase an existing gas combined-cycle plant from a merchant owner, would it be likely to find one?

A: Yes. I have identified approximately 6,100 MW of combined-cycle capacity owned by merchant generators in the Southwest Power Pool and well-interconnected neighboring Entergy Arkansas territory. See Table 4 below. This capacity is generally not committed to serving load, and is sold in the spot market or under short-term contracts.

The first four plants in Table 4, Oneta, Dogwood, Eastman, and Green Country (along with the Harrison plant that was sold to Texas coops in December 2010), are listed as being available to meet generation shortfalls in the modeling used to develop the Southwest Power Pool's 2012 Integrated Transmission Plan Near-Term Assessment Report (January 9, 2012; Table 6.3). The two Arkansas plants, Pine Bluff and Union Power, are in the Entergy control area, geographically and electrically adjacent to SWEPCo.

[redacted] Clearly, there are willing sellers.

Table 4: Merchant Combined-Cycle Capacity in SPP or Entergy's Arkansas Territory

Plant and Owner	State	Summer Net MW	2010 Capacity Factor
Oneta Energy Center[a]			
Calpine Central LP	Okla.	886	31%
Dogwood Energy Facility[b]			
Dogwood Energy LLC	Mo.	449	15%
Eastman Cogeneration Facility			
Eastman Cogeneration LP	Tex.	402	55%
Green Country Energy[c]			
Green Country LLC	Okla.	263	32%
Coughlin Power Station			
Cleco Evangeline LLC	La.	732	4%
Kiamichi Energy Facility			
Kiowa Power Partners LLC	Okla.	1,178	31%
Pine Bluff Energy Center			
Pine Bluff Energy LLC	Ark.	192	85%
Union Power Station			
Union Power Partners LP	Ark.	2,020	41%
Total		6,122	32%

[a] The 886 MW at Oneta Energy Center is net of a 200-MW sale to Southwestern Public Service Company (Calpine 2010 Annual Report at 66) through May 2019.

[b] The 449 MW at Dogwood Energy Facility is net of the recent sales of a total of 165 MW to municipal utilities

[c] The 263 MW at Green Country Energy is net of the 520 MW PPA with Public Service Company of Oklahoma that will be in effect from June 2012 through February 2022 (Exelon 10-K at 295).

In addition to the combined-cycle capacity listed above in Table 4, merchant generators also own some 826 MW of modern combustion turbine capacity in Louisiana and Missouri that may be available to provide SWEPCo with peaking energy and reserve capacity. As noted below in Section V.C, SWEPCo's model selects combustion turbines whenever it is allowed to do so.

Q: Have other merchant generators sold combined-cycle plants in SPP and adjacent areas?

A: Yes. About twenty such merchant combined-cycle gas plants have sold in SPP and elsewhere in Texas and Arkansas in recent years, as shown below in Table

5. These past sales provide some indication of the market value of combined-cycle plants.

Table 5: Sales of Combined-Cycle Plants In and Around the Southwest Power Pool

Seller	Plant Name	State	Closing Date	Sold	Summer Capacity (MW)[a]	Acquirer	Purchase Price $M	Purchase Price $/kW
NRG Energy	McClain	Okla.	7/9/04	77%	377	Okla. G&E	$160	$425
CLECo	Perryville	La.	6/30/05	100%	831	Entergy LA	$170	$205
Central Mississippi Generating	Attala	Miss.	3/31/06	100%	500	Entergy MS	$88	$176
Calpine	Aries/Dogwood	Mo.	2/7/07	100%	677	Kelson	$234	$345
Cogentrix Energy	Ouachita	La.	5/4/07	100%	904	Entergy AR	$198	$219
Calpine	Acadia Energy	La.	8/17/07	50%	1,376	Cajun Gas Energy	$189	$137
GE Energy Financial Services	Green Country	Okla.	10/2/07	100%	904	J-Power USA Generation	$240	$265
Cogentrix	Southaven	Miss.	5/9/08	100%	904	TVA	$461	$510
Kelson	Redbud	Okla.	9/30/08	100%	1,338	Okla. G&E	$852	$637
Tennessee Valley Authority	Southaven	Miss.	10/6/08	70%	633	Seven States Power	$345	$545
Acadia Power	Acadia 1	La.	Feb '10	100%	580	CLECo	$304	$524
Kelson	Cottonwood	Texas	Aug '10	100%	1,279	NRG Energy	$525	$410
Entergy	Harrison	Texas	Dec '10	61%	550	East and North Texas Coops	$219	$654
PSEG	Odessa	Texas	1/13/11	100%	1,000	High Plains Diversified Energy	$335	$335
PSEG	Guadelupe	Texas	1/13/11	100%	1,000	Wayzata Investment	$351	$351
Acadia Power	Acadia 2	La.	4/29/11	100%	580	Entergy LA	$300	$517
Sequent	Wolf Hollow	Texas	5/13/11	100%	720	Exelon	$305	$424
Kelson	Magnolia	Miss.	Aug '11	100%	863	TVA	$436	$505
KGen Partners	Hinds	Miss.	2012	100%	520	Entergy AR	$206	$396
KGen Partners	Hot Spring	Ark.	2012	100%	630	Entergy MS	$253	$408
Kelson	Dogwood	Ark.	3/11	8.2%	50	MJMEUC	$46	$613
				12.3%	75	Independence P&L		
				6.6%	40	Kansas Power Pool		
GDF Suez	Hot Spring	Ark.	5/13/11	100%	641	AECC	$240	$374

[a]Summer capacity reported by owner or U.S. EIA.

The average of the transaction prices in 2011 and 2012 was about $420/kW, or about $470/kW excluding the plants in the Electric Reliability Council of Texas territory.

[redacted]

Q: Have the owners of Flint Creek received offers or expressions of interest from the owners of combined-cycle plants for sale of ownership or long-term capacity entitlements in the plants?

A: Yes. Those offers to SWEPCo are discussed in replies to Sierra Club Data Request 1-147 and 1-148 and to AECC in APSC Data Request 7-1 and 7-2.

Q: Does SWEPCo accept that these recent transactions indicate the likely cost of purchasing capacity from one or more of the eight plants in Table 4?

A: No. In response to the Staff's question about the significance of the agreement under which AECC would purchase the Hot Springs Power Plant, SWEPCo disputes the relevance as a market indicator of the price that GDF Suez offered for the Hot Springs plant:

> …the Company does not believe that the recent offer for sale of GDF Suez' Hot Springs Power Plant provides a valid data point for the availability of purchasing merchant CC generation in or near SPP. First, with the exception of the Dogwood plant, the Company is not aware of other owners of merchant CC generation in or near SPP starting any sale processes. The Dogwood facility recently sold 75 MW of capacity for $612/kW to a group of municipal utilities in Kansas. So the Hot Springs plant does not appear to provide a valid data point on what else may be available. Second, the willingness or desire of the owner of merchant CC generation to begin a sale process depends largely on the specific circumstances of the unit, such as whether or not the owner has entered into any long-term contracts for capacity or energy from the unit. GDF Suez' offer reflects the circumstances at the Hot Springs plant; nothing can be inferred about other merchant CC generation from GDF Suez' desire to sell the Hot Springs plant. (APSC Data Request 5-7)[18]

Notwithstanding the Company's preference for referring to the more expensive Dogwood sale and its assertion that the Hot Springs sale is irrelevant, both of these sales were at prices far below SWEPCo's estimate of the cost of a new combined-cycle plant. And despite SWEPCo's implication that the offer from GDF Suez was related to "the specific circumstances of the unit," many merchant generators have sold ownership or long-term capacity contracts (including parts of three plants in Table 4). Others (including some owners of capacity in Table 4) have offered capacity unsuccessfully.

The plants listed in Table 4 and Table 5 are efficient modern combined-cycle units. Dogwood, for example operated at about 7,700 Btu/kWh heat rate in 2010, even though it was running at a disadvantageously low capacity factor of only 16%.[19] Any of those units would be likely to remain in operation much longer than the analysis period used by SWEPCo.

[18]The Company cites only a portion of the Dogwood sale.

[19]Dogwood consists of two Siemens-Westinghouse Model 501F combustion turbines and a steam cycle.

Q: Were SWEPCo to purchase an existing combined-cycle plant, rather than build a new one, how would that change the economics of the greenfield combined-cycle option?

A: The Company estimates costs of the greenfield combined-cycle unit (Option 4), excluding AFUDC, at $1,287/kW without the duct firing and $1,084/kW counting the duct-firing capacity, in 2011 dollars (Weaver Direct, Table 6). With AFUDC, these values would be about $1,468/kW and $1,236/kW, respectively.[20] Since these costs are in 2011 dollars, they should be comparable to recent sales prices.

By comparison, the sales of existing combined cycle capacity since 2010 have ranged from $335/kW to $613/kW, while the average for SPP and other Arkansas sales was $470/kW.

The difference in cost between the greenfield combined-cycle plant and the recent sales is roughly $600–$1,000/kW, depending on whether the reported capacity of recent sales include duct burners, and whether the average or highest price is used in the comparison. For a purchase equal to SWEPCo's share of the greenfield combined-cycle plant, 305 MW without duct burners or 363 MW with, this would represent a savings of $220–$300 million in capital costs, wiping out most or all of the $274 million present-value advantage calculated by

[20]This computation includes $131 million of nominal AFUDC (from Mr. Weaver's workpapers for Table 6). This is $110 million in 2011 dollars (using SWEPCo's 3.5% escalation rate), and thus $181/kW without counting the duct firing and $152/kW with the duct firing. SWEPCo estimates the costs of the greenfield combined-cycle plant in 2016, with AFUDC, to be about $1,650/kW (without duct firing) and $1,386/kW (with duct firing).

SWEPCo for Flint Creek coal versus the greenfield combined-cycle plant under the base commodity-price scenario (Weaver Direct, Exhibit SCW-6).[21]

C. Other Promising Generation Construction Options

Q: What other generation construction options should the Company have considered?

A: The Company should have compared the costs of continued operation of Flint Creek to a smaller amount of combined-cycle capacity and a combined-cycle plant at the Mattison site.

Q: Why should the Company have compared the Flint Creek retrofit with a smaller amount of combined-cycle capacity?

A: In its analysis, SWEPCo compares the economics of its 259-MW share of Flint Creek to 304 MW (Option 3) or 305 MW (Option 4) of a gas combined-cycle plant, plus 58 MW of duct-firing capacity, all in 2016. There are two reasons to believe that this oversized replacement plant would be less economic than one more appropriately sized to replace Flint Creek

First, the Company's modeling runs indicate that the least-cost additions are always combustion turbines. SWEPCo forces the combined-cycle plants into the analysis to replace Flint Creek in 2016, and in 2020, to replace Welsh 2, which must retire in 2015. This is true for all options, all fuel prices, and all carbon prices. Since the economic optimization does not choose additional

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[21] Each dollar of avoided capital cost saves about $1.45 in present value of revenue requirements over thirty years, but this increase is offset by a roughly equal reduction from discounting the costs from 2016 back to 2011.

combined-cycle additions, it is likely that the additional 45 MW of extra combined-cycle capacity is also not economic.

Second, while the extra 45 MW of combined-cycle capacity and the 58 MW of peaking duct-firing are added in 2016, the Company's model does not select any additional capacity (other than the forced combined-cycle in 2020) until 2026 with Flint Creek (Options 1 and 2) or 2027 with the larger replacement combined-cycle options (Options 3 and 4). By over-sizing the combined-cycle plant and adding the duct-firing capacity, SWEPCo has included costs starting in 2016 for capacity that the planning model would not add until 2026.

The Company did not evaluate, or estimate the costs of 200 MW or 400 MW of gas combined-cycle capacity at the Flint Creek site. (Sierra Club Data Request 1-107).

Q: Why should SWEPCo have compared the Flint Creek retrofit with a combined-cycle plant at the Mattison site?

A: The Mattison site has gas supply and is in the NW-AR load pocket. The four existing General Electric Model 7EA combustion turbines at the plant have a total summer capacity of 300 MW. SWEPCo's original 2006 announcement of the plant projected the construction of up to 480 MW of peaking generation.[22] The Company has also said (in Exhibit WMJ-2, PUCT Docket No. 37364, at 161), "The site was designed to have up to eight GE 7E" combustion turbines "but the constructed size was scaled back to four [units] to match forecasted demand," suggesting that additional gas supply is available at the site. In addition, each pair of existing General Electric 7EA combustion turbines can be

[22] "SWEPCo Announces Plans for New Generation" AEP news release, May 31 2006 http://www.aep.com/environmental/news/?id=1286, accessed June 27 2012.

incorporated into a combined-cycle plant, adding about 80 MW of steam-turbine capacity. Converting the two pairs of Mattison combustion turbines to combined-cycle operation would add about 160 MW of capacity in the load pocket, without requiring any gas pipeline capacity beyond that currently dedicated to the Mattison plant.

The Company has completely ignored the possibility of developing generation at Mattison. "No cost estimates of the 'attendant gas supply requirements' for 200 MW, 400 MW or 600 MW of gas combined-cycle capacity at the Mattison site were prepared. These scenarios were not evaluated." (Sierra Club Data Request 1-108)

Q: Other than the Mattison site, are there other locations in NW-AR that have gas supply?

A: Yes. From the map in the Company's response to Sierra Club Data Request 1-109, it appears that three gas pipelines serve parts of NW-AR.

VI. Estimates of Control Costs

Q: For which control costs are SWEPCo's documentation inadequate?

A: The Company has not adequately explained its estimates of the costs of the combined scrubber and integrated baghouse (in a system that the manufacturer Alstom calls "NID") and the SCR.

Q: Is it clear what emission limits these pollution-control systems must meet?

A: No. The Company asserts that the dry flue-gas-desulfurization system and low-NOx burners and overfire air will be needed to meet SO_2 and NOx limits, respectively, under the BART requirements of the Regional Haze Rule (Hendricks Direct at 9). However, as SWEPCo acknowledges (Hendricks Direct at 8), the EPA has not yet finalized the BART requirements that will apply to Flint Creek. EPA partially disapproved the Arkansas State Implementation Plan for regional haze. Specifically, EPA rejected the proposed presumptive emission limits that were the basis for the proposed pollution controls.[23] Hence, the regulatory requirements upon which SWEPCo justifies the economics of the Project are no longer in effect.

The Company acknowledges that the "final NOx and SO_2 emission limits…will be at least as stringent as the [rejected] presumptive limits" (Hendricks Direct at 9). Yet SWEPCo has not demonstrated that the Project would cost-effectively comply with more stringent limits. The Company admits that "the prospect that the final EPA-approved Regional Haze SIP could potentially require further NOx reductions [creates] the potential need for SCR" (Hendricks Direct at 16). Other regulations may also affect SO_2 and NOx emission limits and hence the capital and operating cost of Flint Creek's environmental controls.[24] The Company has not presented the capital and operating costs associated with meeting any specific requirements more stringent than the presumptive BART limits for SO_2 and NOx.

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[23]The EPA disapproved the SO_2 and NOx BART determinations for Flint Creek rejecting Chapter 15 of Arkansas' Air Pollution Control and Ecology Commission Regulation No. 19, the State's Regional Haze Rule. The BART determinations for Flint Creek in the Arkansas SIP were based on the presumptive BART limits established in the Rule instead of a five-factor BART analysis. The EPA rejected that approach and insists on a five-factor BART analysis (77 Fed. Reg. 14604, 14651, Mar. 12, 2012).

[24]Examples of those regulations include rules implementing the 75-ppb National Ambient Air Quality Standard (NAAQS) for ozone set in 2008 but not yet implemented, the still lower ozone NAAQS anticipated in 2013, and the one-hour SO_2 NAAQS, for which EPA is currently developing rules for determining compliance.

Q: What are the implications of this regulatory uncertainty?

A: In the absence of a final BART determination, showing that retrofitting and continuing to operate Flint Creek is in the public interest would require a demonstration that continued operation would be cost-effective under the plausible range of required controls.[25] Other than including an SCR, SWEPCo has not attempted to make that demonstration.

Q: How did the Company estimate the cost of the NID?

A: That is a simple question with a complicated and unsatisfying answer. Company Witness Beam states, "a detailed cost estimate for a DFGD [dry flue-gas desulfurization system] has not been completed for Flint Creek since engineering and design is only in the very early phases"[26] (Beam Direct at 19). Specifically, the cost estimate for the Flint Creek NID system

> was developed from technology evaluations and estimates associated with FGD studies for AEP's Big Sandy and Rockport Plants and AEP's years of experience with environmental system construction and startup execution. Competitive bids were solicited for various removal technologies as part of these studies; however, the pricing was based on highly indicative supplier estimates with little to no site specific detail. The selected bid proposal estimates were converted to $/kW indicative pricing to allow for scaling of pricing associated with Flint Creek's 528 MW unit size…. (Beam Direct at 26–27.)

This description of how these cost estimates were derived is troubling enough, as it states that the estimates were derived by making the following assumptions:

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[25]As I demonstrate in Section II, SWEPCo's claim of cost-effectiveness, even with the control requirements that the EPA rejected, relies on outdated fuel-price forecasts, excessive transmission-related costs, and a constrained set of alternative resources.

[26]The Company uses DFGD to refer to the NID system, which is a proprietary DFGD with an integral baghouse.

- the cost per kilowatt for 528-MW Flint Creek would be the same as for the 800-MW Big Sandy–2 plant and the two 1,300-MW Rockport units (which would be less expensive, all else equal, due to economies of scale);
- the cost of the system for Flint Creek, which burns Power River Basin subbituminous coal, would be the same as for the Big Sandy and Rockport units, which burn high-sulfur eastern bituminous coal;
- "highly indicative supplier estimates with little to no site specific detail" represent unbiased estimates of the actual costs of scrubbers, even at Big Sandy and Rockport.

At least Mr. Beam's testimony suggests that the cost estimate for the NID was based on some sort of estimates (however shaky) for similar systems at other plants (however different). The actual source of the NID cost estimate, however, seems to be even less reliable.

The "Flint Creek $/kW Indicative Pricing Conversion" provided in response to Sierra Club Data Request 1-30(d), Attachment 1, shows that the Company's indicative pricing conversion for the NID was not based on the bids for DFGD at Big Sandy and Rockport. Instead it was derived from the $375/kW actual costs of the 2009 installation of a wet FGD at AEP's 375-MW Conesville 4, which burns high-sulfur eastern bituminous coal. A wet FGD is an entirely different type of scrubber than the dry FGD included in the NID system.

The Company assumed that a NID would cost 80% of a wet FGD, inflated the 2009 costs to year-end 2015, and added a 20% contingency factor. Based on these adjustment factors, SWEPCo estimates 2015 end-of-year in-service costs of $500/kW for installation of a NID at Flint Creek. The Company then apparently applied additional adjustments and added landfill, rail improvements, continuous emission monitoring, and owner's costs to yield the $218 million

($746/kW in 2011 dollars, plus inflation) of Mr. Weaver's Table 6. The Company does not appear to have provided any support for any of its multiple adjustments.

This is an enormous extrapolation, between completely different technologies at plants burning fuels with different sulfur and heat contents, through many levels of adjustment. This back-of-the-envelope calculation is an entirely unreliable basis for SWEPCo's key cost estimates in this proceeding.

Q: Would either of the methods SWEPCo has described for estimating the cost of the NID be sufficient to allow the Commission to find that the proposed project is in the public interest?

A: No. The first method started with unreliable and undocumented estimates (possibly for a similar technology) for much larger units burning different fuels, while the second started with a different technology at a somewhat smaller unit, also burning a different fuel. Neither estimation technique seems to be reasonable or reliable enough to support any pre-approval of the project.

Q: What is SWEPCo's estimate of the cost of the SCR system?

A: While it is not part of the cost of the Project, SWEPCo recognizes that installation of an SCR system would likely be a necessary part of the cost of keeping Flint Creek running on coal over the next several years. The Company estimates its 50% share of total costs for installation of an SCR system on the 528 MW Flint Creek unit by 2020 at $72 million nominal, or about $213/kW in 2011 dollars (Weaver Direct, Table 6 and associated workpapers). The Company's estimate of the variable SCR Operating Costs is $0.56/MWh; curiously, SWEPCo does not escalate these costs over time. ("Ex SCW-5 WP (Fixed Cost Modeling Parameters).xls," workpaper provided as partial response to Data Request 1-3) Since the variable costs of SCR include periodic replacement of the precious-metal catalyst, consumption of ammonia, and use of power to run the system, I would expect these costs to rise roughly with general inflation, making it more expensive to keep Flint Creek in operation.

Q: How were these costs derived?

A: I have not found any documentation of SWEPCo's derivation of the SCR costs. The resulting cost estimate does not appear to take into account any site-specific factors, such as the layout of the site after the installation of the NID and other environmental retrofits.

Q: Is the SCR cost that SWEPCo estimated likely to meet future BART requirements under the Regional Haze Rule?

A: That would be hard to determine, since we do not know the NOx emission levels for which SWEPCo's hypothetical SCR system was designed, and the EPA has partially disapproved the Arkansas State Implementation Plan, so the allowed NOx emissions for Flint Creek under the Regional Haze Rule are not yet known. The cost of the SCR—especially its operating costs—will vary with the stringency of the eventual Arkansas State Implementation Plan.

The Company includes the addition of SCR in 2020 for its base case, with a sensitivity analysis in which SCR is required in 2016. SCR is required under the regional-haze program's Best Available Retrofit Technology ("BART") Requirement, then the 2016 installation date is far more likely. The first regional-haze planning period ends in 2018 (40 CFR 51.308(e)(2)(iii)). EPA made clear in a recent rulemaking (at 17) that "the BART requirements or alternatives to BART must be fully implemented by 2018."[27] This likely implementation date is confirmed by the Company (Hendricks Direct at 15).

[27]The rule, dated May 30 2012 but not yet published in the Federal Register, is entitled "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available

Arkansas has chosen to develop source-specific BART determinations for sources like Flint Creek. The EPA has rejected Arkansas's proposal to set the NOx BART for Flint Creek at the emission rate attainable using only combustion controls (such as low-NOx burners and overfire air), stating it "believes that a proper evaluation of the five statutory factors is likely to demonstrate that emission limits lower than the NOX and SO_2 presumptive emission limits are BART for Flint Creek" (77 Fed. Reg. 14604, 14651 (Mar. 12, 2012)). Such lower-NOx-emission limits are attainable primarily through post-combustion controls such as SCR, which is likely to be required by 2018, rather than 2020. The earlier the SCR is required, the greater its present-value cost.

Q: How does SWEPCo's estimate of the cost of the SCR system compare to other estimates?

A: It is rather low. An analysis of SCR-process-equipment costs in 2010 (Cichanowicz at 6-2) found that the typical capital cost for SCR installed on a coal plant the size of Flint Creek in 2010–2012 would be about \$270/kW in 2008 dollars, and that SCR prices had been rising at about \$15/kW each year.[28] Including civil engineering and other costs, inflation, and the strong upward time trend in SCR costs, this analysis suggests a capital cost on the order of \$300–\$400/kW in 2011 dollars by 2020. An additional \$100/kW would add about \$25 million in SWEPCo investment and about \$25 million to the present value of the costs of the Flint Creek–coal option, depending on the timing of the SCR installation.

Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans."

[28]Cichanowicz, J. Edward. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies." Utility Air Regulatory Group. January 2010.

Q: Does this conclude your testimony?

A: Yes, at this time. At the time that this testimony was prepared, the Company had not responded to several data requests from the parties to this proceeding. Thus, I reserve my right to modify my testimony and to address additional issues in my rebuttal testimony, based on the Company's future responses to data requests.

CERTIFICATE OF SERVICE

I, Jeff Speir, do hereby certify that on the 29th of June, 2012, a true and correct copy of the Direct Testimony and Exhibits of Paul Chernick on Behalf of the Sierra Club was electronically mailed to all parties on the service list for this docket.

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