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PUCO EXHIBIT FILING

Date of Hearing: 9/10/2015

Case No. 14-1297-EL-SSO

PUCO Case Caption: In the Matter of the Application of Ohio Edison, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

List of exhibits being filed: Volume VIII

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Reporter's Signature: Karen Sue Gibson

Date Submitted: 10/30/2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the :
Application of Ohio Edison:
Company, The Cleveland :
Electric Illuminating :
Company, and The Toledo :
Edison Company for : Case No. 14-1297-EL-SSO
Authority to Provide for :
a Standard Service Offer :
Pursuant to R.C. 4928.143 :
in the Form of an Electric:
Security Plan. :

- - -

PROCEEDINGS

before Mr. Gregory Price, Ms. Mandy Chiles, and Ms. Megan Addison, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:00 a.m. on Thursday, September 10, 2015.

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VOLUME VIII

- - -

ARMSTRONG & OKEY, INC.
222 East Town Street, Second Floor
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
Fax - (614) 224-5724

- - -

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF SOUTHWESTERN ELECTRIC POWER COMPANY'S PETITION FOR A DECLARATORY ORDER FINDING THAT INSTALLATION OF ENVIRONMENTAL CONTROLS AT THE FLINT CREEK POWER PLANT IS IN THE PUBLIC INTEREST	)	**DOCKET NO. 12-008-U**

DIRECT TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

SOUTHWESTERN ELECTRIC POWER COMPANY

REDACTED

February 9, 2012

TABLE OF CONTENTS

LIST OF ATTACHMENTS

I. INTRODUCTION

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

A. My name is Judah L. Rose. I am a Managing Director of ICF International (ICF). My business address is 9300 Lee Highway, Fairfax, Virginia 22031.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. After receiving a degree in economics from the Massachusetts Institute of Technology and a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University, I joined ICF in 1982. I have worked at ICF for over 29 years and am Managing Director of ICF's wholesale power practice. I also have been a member of the Board of Directors of ICF International and am one of three people (in a consulting firm of more than 3,500 people) to have received ICF's honorary title of Distinguished Consultant.

Q. DOES ICF HAVE PUBLIC SECTOR CLIENTS?

A. Yes. In the United States, ICF has been the principal power consultant to the U.S. Environmental Protection Agency (EPA) continuously for over 35 years, specializing in the analysis of the impact of air emission programs, especially cap and trade programs. ICF currently works for the U.S. Department of Energy (DOE) on Electricity Delivery and Energy Reliability. We also have worked with the Federal Energy Regulatory Commission (FERC) on transmission issues. In addition, we have worked with state regulators and state energy agencies, including those in California, Connecticut, Kentucky, New Jersey, New York, Ohio, Texas, and Michigan, as well as with numerous foreign governments. ICF has also worked on regional CO_2 trading programs such as RGGI and the Midwestern Greenhouse Gas Reduction Accord.

Q. DOES ICF HAVE UTILITY CLIENTS?

A. Yes. For nearly 40 years, ICF has provided forecasts and other consulting services to major United States and Canadian electric utilities. In the U.S., ICF has worked with utilities such as American Electric Power, Allegheny, Arizona Public Service, Dominion Power, Delmarva Power & Light, Duke Energy, FirstEnergy, Entergy, Exelon, Florida Power & Light, Northeast Utilities, National Grid, Nevada Power, Southern California Edison, Otter Tail Power, PacifiCorp, PEPCO, Public Service Electric and Gas, Public Service of New Mexico, Sempra, Southern Company, Tucson Electric, and Xcel Energy.

Q. WHAT OTHER TYPES OF CLIENTS DOES ICF HAVE?

A. ICF also works with Regional Transmission Organizations and similar organizations including the Western Electric Coordinating Council, Midwest Independent Transmission System Operator, the Electric Reliability Council of Texas, and the Florida Regional Coordinating Council. ICF works for Independent Power Producers (IPPs) (such as Calpine, NRG, Kelson, CPV) and the financial community (private equity firms and investment banks). Additionally, ICF works for environmental organizations such as NRDC, Sierra Club, and Greenpeace.

Q. WHAT IS YOUR EXPERIENCE IN ELECTRIC UTILITY PLANNING?

A. I have extensive experience in electric utility planning. I regularly assess the economics of generation investments in existing and new power plants and key drivers of these investments: capital costs, fuel costs, environmental regulations, and the interactions among these factors. My planning analysis is based on computer modeling tools that include proprietary models of utility systems and supply and demand interactions in the wholesale power, natural gas, coal, environmental, transmission, and related markets.

Q. WHAT EXPERT TESTIMONY EXPERIENCE DO YOU HAVE RELATED TO ELECTRIC POWER?

A. I have testified before, filed with, or made presentations to the FERC, an international arbitration tribunal, federal courts, domestic arbitration panels, and state regulators in 21 U.S.

states and Canadian provinces: Arizona, Arkansas, California, Florida, Indiana, Kentucky, Louisiana, Manitoba, Massachusetts, Minnesota, Missouri, New Jersey, Nevada, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Quebec, South Carolina, and Texas. I have testified extensively on the topics of electric power prices and markets, utility planning, the development of new generation resources and transmission, and generation asset valuation.

Q. WHAT OTHER RELEVANT EXPERIENCE DO YOU HAVE?

A. In addition, I have authored numerous articles in industry journals and spoken at scores of industry conferences. For specific details, please see my resume, attached hereto as Attachment JLR-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ARKANSAS?

A. Yes. I have testified on behalf of Southwestern Electric Power Company, Clean Line Energy, and Entergy.

Q. ON WHOSE BEHALF ARE YOU CURRENTLY TESTIFYING?

A. I am testifying on behalf of Southwestern Electric Power Company ("SWEPCO" or "the Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports SWEPCO's petition for a declaratory order finding that installation of environmental controls at the Flint Creek power plant is in the public interest.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized in six sections. The first section (i.e., this section) introduces my testimony. The second section summarizes my testimony including key results. The third section discusses the economic analysis and summarizes key economic assumptions used in my analysis including natural gas prices, delivered coal prices, potential CO_2 regulations and likely future CO_2 prices. The fourth section discusses the higher annual volatility of natural gas prices *compared to coal prices. The fifth section provides a comparison of Flint Creek and other U.S.* coal-fired power plants. The sixth section presents my conclusions.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. SWEPCO jointly owns the coal-fueled Flint Creek plant in northwestern Arkansas together with the Arkansas Electric Cooperative Corporation (AECC), with each company owning a 50% share. The plant's current total capacity is 528 MW, and hence each entity owns 264 MW. The plant has been operating since 1978 and burns coal produced in Wyoming's Powder River Basin (PRB) and delivered via railroad. SWEPCO proposes to retrofit environmental controls at Flint Creek and seeks a declaratory order finding that installation of environmental controls at the Flint Creek power plant is in the public interest. The environmental controls are required if the plant continues to operate using coal and most of the controls are scheduled to come on-line by 2016. With the FGD system and with other environmental upgrades assumed in my analysis, the capacity would decrease to 517 MW or 258.5 MW for each 50% share.

OPTIONS ANALYZED

ICF analyzed five options for the Flint Creek plant and the SWEPCO system. The first two involve continued coal use, and the other three involve replacement natural gas generation. Thus, the principal alternative to the continued operation of the plant is natural gas-fired generation. In the options in which Flint Creek continues to operate, the plant is assumed to install environmental controls including a scrubber or Flue Gas Desulfurization (FGD), a fabric filter (FF), activated carbon injection (ACI), and low NO_x burners with over-fired air (LNB/OFA). The proposed retrofits also include upgrades to the coal combustion residue handling and disposal systems and the water cooling systems. The plant is also assumed to add NO_x SCR system coming on line either in 2020 (Option #1), or in 2016 (Option #2).[1] The total cost of the environmental investment in 2010 real dollars for the entire plant is approximately $535 million or $1,035/kW assuming SCR on-line in 2020. Additionally, potential future CO_2 regulations are assumed to occur. Thus, the analysis ensures a comprehensive treatment of any future environmental costs by including additional (non-FGD) environmental costs associated with potential future requirements.

Three natural gas generation options were considered: (1) a new 528 MW[2] natural gas-fired combined cycle, located on the same site, i.e., the brownfield option (Option #3), (2) a new 528 MW[1] natural gas combined cycle plant built remote from the plant site (within SPP) and augmented with electricity transmission upgrades to deliver the power to the northern section of SWEPCO's territory in which Flint Creek is located, i.e., the greenfield option (Option #4), and (3) conversion of the existing plant to use natural gas (Option #5). In the case in which the plant uses gas at the site or is converted to natural gas (Options #3 and #5), it is assumed to be subject to Reliability Must Run (RMR) requirements for a portion of the year in response to concerns about local power supply shortages. In other words, the plant is assumed to have a minimum operational level due to transmission limitations in the area that require the operation of the plant at least at partial load levels in certain periods of the year, even if the economics would otherwise indicate the plant should not operate. Thus, the benefit of the greenfield option is that the transmission upgrades obviate the need for the natural gas plant to operate when it is otherwise not economic. However, there are additional transmission costs associated with this option and increased costs associated with using a new site.

[1] Environmental control costs also include costs for baghouse, Activated Carbon Injection (ACI), boiler improvement and control, LNB/OFA, landfill expansion, and upgrades to the coal combustion residue handling and disposal systems and water cooling systems.

[2] 528 MW reflects summer capacity; on an annual average basis, capacity of the replacement combined cycle options is 566 MW

METHODOLOGY

ICF uses a four-part assessment to evaluate these options:

- **Base Case PVRR** – The first and most important element is the analysis of the Present Value of SWEPCO's Revenue Requirements (PVRR) for the 2016 to 2045 period for each of the five options under the Base Case outlook. The goal is to identify the least cost option for SWEPCO, i.e., the one with the lowest PVRR. In the Base Case, input assumptions are set equal to their most likely value. PVRR reflects the total going forward recovery requirement for the utility, including (i) recovery of and on future capital expenditures, (ii) future production costs (i.e., fuel costs, operating and maintenance costs, and net emission costs), and (iii) off-system purchases and sales at competitive market prices. The PVRR is measured as of January 1, 2016 in 2010 real dollars for the 2016 to 2045 period. A real discount rate of 4.4 percent is used to discount future costs (i.e., revenue requirements).[3] The detailed modeling analysis was conducted using ICF's IPM® model. This analysis is discussed in greater detail in the attached ICF Report (see Attachment JLR-2). ICF conducts this PVRR analysis for a Base Case and several sensitivity cases, as will be discussed next, but ICF gives most weight and places greatest emphasis on the Base Case and associated conclusions.

- **Sensitivity Case PVRR Analysis** – The second part of the analysis is to analyze the Present Value of Revenue Requirements for each option under six alternative scenarios. The goal of these cases is to examine long-term average uncertainty in key economic drivers, i.e., natural gas, coal, and CO_2 prices. While the principal criterion in determining the optimal option is least cost, i.e., lowest PVRR, in the Base Case,

[3] Revenue requirements reflect future capital costs, future production costs, net exports sold at market prices, and emission allowance costs net of allocation.

secondary consideration is given to the performance of options under uncertainty in long-term average conditions. Robust results, i.e., consistent least cost determination or small variation in multiple scenarios would reinforce the Base Case results.

- **Annual Volatility** – The third part of the approach qualitatively considers year-to-year cost volatility. While the long-term analysis incorporates year-by-year values, it does not examine the full range of uncertainty in each year. Ratepayers are assumed to prefer low annual volatility, all else equal. The principal considerations in determining relative annual volatility are historical levels and contractual options for managing volatility. Low annual volatility could reinforce the Base Case and/or sensitivity case results. This part of the analysis is given less weight than the PVRR analysis.

- **Retrofit Suitability** – The fourth part of the analysis involves a comparison of the Flint Creek plant to other U.S. coal plants in terms of age, site, and other. This component of the analysis is also not quantitatively determinative and does not involve the IPM model. Rather, it is useful to provide perspective on the suitability of the plant for environmental upgrade. This part of the analysis had the least weight in the overall assessment.

BASE CASE – PVRR ANALYSIS

The ICF Base Case analysis concludes that the Flint Creek upgrade is preferred in both SCR scenarios over all three natural gas options (see Exhibit 1). Option #1, the retrofit case with the SCR on-line in 2020, has a PVRR advantage over the three natural gas generation options ranging from $314 million to $750 million (see Exhibit 1). The acceleration of the SCR retrofit from 2020 to 2016 increases the PVRR by $5 million for SWEPCO, and hence, has little effect on the conclusions. The advantage of the coal options over the natural gas option is so large that even if we were to eliminate CO_2 emission allowance allocations, an issue discussed more fully in the accompanying report, we still find the coal options to have lower PVRR than the natural gas options.

EXHIBIT 1
SWEPCO PVRR by Option – Base Case (2010$ million as of January 2016)

Option #	**Option**	**Fuel**	**PVRR**	**PVRR Increase Relative to Option #1**
1	Flint Creek Retrofit – SCR 2020	Coal	23,594	--
2	Flint Creek Retrofit – SCR 2016	Coal	23,599	5
3	New Combined Cycle on Flint Creek Site(Brownfield)	Gas	23,909	314
4	New Combined Cycle at Greenfield Site Remote From Flint Creek With Transmission Upgrades	Gas	23,990	396
5	Conversion of Flint Creek to Natural Gas	Gas	24,345	750

One perspective on the results is gained by a comparison of capital costs. The total capital costs for FGD, SCR (on-line in 2020) and other environmental upgrades are $1,035/kW (2010$). In comparison, the cost of a new coal power plant is estimated to be approximately $3,000/kW (2010$). Therefore, SWEPCO has an option to continue operation of the Flint Creek plant for a cost that is less than one-third the cost of a new coal plant. Thus, even if *new* natural gas-fueled plants were more attractive than *new* coal power plants, in the case of Flint Creek, a new natural gas option is not as attractive when compared with the option of maintaining an *existing* coal plant at a low capital cost.

The capital cost of the coal option (with SCR in 2020) is similar to the capital cost of the brownfield gas combined cycle option (i.e., $1,035/kW for the coal retrofit versus [redacted] in 2010 dollars). The capital cost of the coal option is even lower compared to the greenfield gas combined cycle option due to the greenfield natural gas plant's added transmission and site related costs. In this case, the natural gas option has capital costs that are [redacted], i.e., [redacted] for the greenfield versus $1035/kW in 2010 real dollars. However, the variable costs of Flint Creek are much lower than the variable costs of the natural gas options. This is in contrast to the more typical generation relationship whereby capital and variable costs are inversely correlated. Lower variable costs for the Flint Creek coal option results in much greater dispatch, and hence, the lower capital costs are amortized over greater production, further lowering per unit costs.

Among the three gas options, the most preferred natural gas option is the brownfield natural gas combined cycle (see Exhibit 2) due to its lower capital cost. The next most preferred natural gas option is the new greenfield combined cycle which lacks the capital cost discount of the brownfield combined cycle associated with use of existing transmission and other on-site equipment. The operational flexibility of the greenfield plant which decreases the hours of forced operation (i.e., no RMR) does not offset the higher capital costs.

Despite having the lowest capital cost at $329/kW (2010$), the natural gas conversion option is the least attractive option. The conversion option has very high variable costs because the thermal efficiency for the gas conversion option is much lower at 31% as compared with 48% for a new combined cycle at full load. [redacted].

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EXHIBIT 2
PVRR Ranking – Base Case

Option	Scenario	Ranking – Lowest to Highest PVRR
1	Flint Creek Retrofit – SCR 2020	1
2	Flint Creek Retrofit – SCR 2016	2
3	New Combined Cycle on Flint Creek Site	3
4	New Combined Cycle at Greenfield Site Remote From Flint Creek With Transmission Upgrades	4
5	Conversion of Flint Creek to Natural Gas	5

While the past is not necessarily an indicator of the future, in 2010, the SPP combined cycle average dispatch was only 38 percent.[4] In ICF's modeling, the strong competitiveness of

[4] Source: SNL Financial

coal power plants in eastern SPP and the premium in natural gas pricing in Arkansas relative to other SPP regions (due in large part to an approximately 2.75 percent fuel tax for combined cycle plants),[5] results in a projected capacity factor over the 2016 to 2045 period of 82 percent for the Flint Creek plant using coal, and 24 percent for the new greenfield combined cycle. Thus, not only is the capital cost of the combined cycle higher, but the capital costs of the natural gas options are amortized over less output, decreasing their economic attractiveness. In the case of the brownfield combined cycle and natural gas steam conversion, the operation of these plants is [redacted]. On average, over the 2016 to 2045 period, dispatch averages [redacted] for the brownfield combined cycle and [redacted] for the gas steam conversion option. This is due to natural gas plant operation that is [redacted].

SENSITIVITY CASES – PVRR ANALYSIS

In addition to the Base Case, ICF analyzed six sensitivity cases to capture uncertainty in three key parameters, namely natural gas prices, CO_2 prices, and coal prices. Specifically, we analyzed low and high natural gas price cases, low and high CO_2 price cases, and low and high delivered coal price cases. The sensitivity cases were structured to roughly approximate a 75% confidence interval, e.g., there is a 12.5% or one in eight chance of the natural gas price being at or below the low case level. The CO_2 cases also reflect an integrated view of natural gas prices, i.e. changes in CO_2 pricing result in changes in natural gas demand and natural gas prices.

In all six sensitivity cases examined, the coal option is preferred even over the most economic natural gas option, the brownfield option (see Exhibit 3). This result strongly reinforces the conclusion of the Base Case PVRR analysis that the coal option is preferred. This

[5] This reflects a 6% statewide sales tax; there is an additional 1.5 percent average local tax rate, which varies by city/county, but is subject to rebate.

result is so strong that even if the conservative and unlikely assumption is made that no CO_2 allowances are allocated, the coal option has a lower PVRR in the Base and all sensitivity cases except the Low Gas Case where the brownfield option becomes more economic than the coal option by $22 million (these results are not shown in Exhibit 3 below but can be found in the report, Attachment JLR-2). Thus, in 14 cases (7x2), the coal option has the lowest PVRR in all cases but one. Even in this one case, only one of the three natural gas options is favored over the coal option.

Among the variables examined, the natural gas price has the largest impact. This is in part because of the greater uncertainty about long run average natural gas prices. The range analyzed is more than twice that of delivered coal prices. Nonetheless, unless long run average real (2010$) natural gas prices for 2016 to 2045 are below $5/MMBtu (approximately $4.5/MMBtu), the coal option is preferred.

EXHIBIT 3
Delta in PVRR Relative to the Flint Creek Option (SCR Retrofit in 2020)
(2010$ MM)

Option	Option #	Option						
		Base Case	Low Coal Price	High Coal Price	Low Natural Gas Price	High Natural Gas Price	Low CO_2 Price	High CO_2 Price
Flint Creek Retrofit – SCR 2020	1	NA	NA	NA	NA	NA	NA	NA
Flint Creek Retrofit – SCR 2016	2	5	18	38	21	18	17	18
Brownfield Natural Gas	3	314	500	216	43	600	420	219
Greenfield Natural Gas	4	396	633	293	209	723	509	411
Natural Gas Conversion	5	750	1,001	669	475	1,132	870	754

Positive indicates cost premium over Option #1 and vice versa
[1] Assumes CO_2 allocation based, in part, on SWEPCO emissions in the 2016 to 2019 period.

ANNUAL VOLATILITY OF REVENUE REQUIREMENTS

The PVRR measure does not address the issue of year-to-year variance in revenue requirements. Historically, the year-by-year volatility of utility revenue requirements is higher with natural gas options than coal options. Historical 1995 – 2010 annual natural gas price volatility, measured using the standard deviation of annual prices, is higher than price volatility for minemouth Powder River Basin coal, the type used by the Flint Creek project, by a factor of twelve. Annual U.S. utility delivered natural gas price volatility is also five times higher than U.S. utility delivered coal price volatility. All else equal, the lower volatility of coal pricing also favors the retrofit options as low volatility facilitates planning for SWEPCO's customers. Additionally, it is difficult to lower volatility of natural gas via long-term contracts due to the requirements for mark-to-market collateral. The results of our review of annual volatility also reinforce the conclusion of the Base Case PVRR analysis.

COMPARISON OF FLINT CREEK TO OTHER COAL PLANTS

In addition to the quantitative PVRR analysis performed using ICF's IPM© model, ICF compared Flint Creek with other U.S. coal plants. This comparison finds Flint Creek to be younger and larger than the U.S. coal power plant fleet average. This favors a longer than average remaining useful life for Flint Creek and a higher degree of suitability for retrofit. ICF also reviewed the history of retrofits of similar equipment and found many similarly aged and situated units retrofitting the same environmental controls. Lastly, ICF reviewed announced retirements of coal power plants and found that retiring coal plants are generally smaller and older than Flint Creek on average. This review also supports the conclusion that the Flint Creek retrofit is appropriate.

CONCLUSIONS

In conclusion, the retrofit of the Flint Creek plant is the most economic option for SWEPCO. In the Base Case, the Flint Creek retrofit saves between $314 million and $750 million on a PVRR basis in real 2010 dollars. The Flint Creek FGD retrofit option is preferred in all scenarios, has lower annual volatility, and is consistent with the plant's size and age characteristics. Additionally, because most new plants are natural gas-fueled and incremental supply from the SPP wholesale market is natural gas-based in most hours, retrofitting Flint Creek is likely one of the few options for preventing even faster growth in SWEPCO's reliance on higher priced and more volatile natural gas. Thus, the option provides diversification resulting in decreased reliance on natural gas for incremental supply.

III. ICF'S ECONOMIC ASSESSMENT OF THE FLINT CREEK FGD PROJECT

Q. DID YOU CONDUCT YOUR OWN ECONOMIC ASSESSMENT OF THE OPTIONS?

A. Yes.

Q. HOW DID YOU MODEL SWEPCO'S PVRR?

A. The PVRR analysis was conducted using ICF's IPM® computer model. IPM® is a widely used model, in the US and globally, both by private sector companies such as electric utilities, Independent Power Producers (IPPs) and financial institutions, and public sector entities such as the US Environmental Protection Agency (EPA), state Public Service Commissions, Environment Canada, European Union, , etc. The model seeks to minimize costs for a given scenario by adjusting dispatch, capacity expansion, power sales, and purchases, subject to meeting forecast electricity demand and capacity reserve requirements. The model accounts for key constraints including operational limits on power plants and transmission constraints. ICF's Integrated Planning Model (IPM®) simultaneously, for all selected regions including the SWEPCO region, solves for the following parameters consistent with a least-cost solution:

- Power plant dispatch
- Fuel use, emissions, and environmental compliance
- Capacity expansion, mothballing, and retirement
- Inter-regional transmission flows
- Hourly spot electrical energy prices
- Annual spot pure capacity prices which can heuristically be allocated to super peak demand hours

The model is described in greater detail in the report (Attachment JLR-2).

Q. WHAT DATA SOURCES DID YOU USE?

A. ICF used a combination of data sources. ICF used SWEPCO data for Flint Creek specifications (e.g., capital and O&M costs for coal options and natural gas conversion) and its own system (e.g., SWEPCO demand). For all other data, ICF relied on its internal views and forecasts, e.g., for commodity prices, environmental regulations, and new build costs for natural-gas fired power plant options. Modeling data on power plants and transmission lines and other key elements is in turn a combination of publicly available information and ICF assumptions and refinements.

Q. WHAT DID THE ANALYSIS ASSUME ABOUT CAPITAL COSTS?

A. The analysis assumes the retrofit option would cost approximately $535 million or $1035/kW (2010$). This capital cost includes costs for the FGD, SCR, and other environmental costs as discussed earlier. The brownfield combined cycle capital cost is [redacted], and the greenfield combined cycle cost is [redacted]. The natural gas conversion cost is $156 million ($329/kW) (see Exhibit 4).

EXHIBIT 4
Natural Gas Generation Capital Cost (2010$)

Parameter	Flint Creek Retrofit – 2020 SCR[7,8]	Flint Creek Retrofit – 2016 SCR[7,8]	Brownfield 7FA Combined Cycle	Greenfield[4] 7FA Combined Cycle	Flint Creek Natural Gas Conversion[5]
Total Summer Capacity (MW)	517[6]	517[6]	528	528	475
Natural Gas Pipeline[1,3] ($MM) ($/kW)	NA	NA	[redacted]	[redacted]	54 114
Electricity Transmission[2] ($MM) ($/kW)	NA	NA	[redacted]	[redacted]	NA
Power Plant [3] ($MM) ($/kW)	535 1035	553 1070	[redacted]	[redacted]	102 215
Total Capital Cost ($MM) ($/kW)	535 1035	553 1070	[redacted]	[redacted]	156 329

Source: ICF for most parameters for greenfield and brownfield combined cycle options; SWEPCO for most parameters for natural *gas conversion and Flint Creek*

[1] Natural gas pipeline cost for the brownfield and conversion options estimated as NPV of flat nominal payment of $5.8M/year for the entire plant ($2.9M/year for SWEPCO's share) recovered over 20 years; natural gas costs for the greenfield option reflect ICF generic assumptions for gas interconnection for new facilities

[2] *Electricity transmission cost estimated as NPV of flat nominal payment of $10,726,000/year for the entire plant, half of which* ($5,363,000/year) SWEPCO will recover through the SPP cost allocation methodology. This transmission upgrade will allow Flint Creek to be retired and will obviate the need to obtain replacement capacity locally. The greenfield transmission cost additionally includes transmission interconnection and upgrade costs [redacted]

[3] Includes assumed Allowance for Funds Used During Construction (AFUDC) of approximately 4.4%

[4] Reflects costs for the SWEPCO Arkansas region

[5] *Natural gas conversion cost provided by SWEPCO as $211/kW excluding AFUDC in 2011$*

[6] *Net Capacity of Flint Creek changes from 528 MW to 517 MW after retrofit installation in 2016*

[7] FGD costs include 10% contingency costs

[8] Retrofit costs include costs for baghouse, Activated Carbon Injection (ACI), boiler improvement and control , LNB/OFA, and landfill expansion

Q. WHAT ARE THE KEY ECONOMIC ASSUMPTIONS UNDERLYING YOUR ASSESSMENT?

A. The three key economic assumptions in our analysis are natural gas prices, coal prices, and potential CO_2 regulations.

SECTION III-1 – NATURAL GAS PRICES

Q. WHY ARE NATURAL GAS PRICES IMPORTANT?

A. The natural gas price directly affects the costs and competitiveness of natural gas power plants. Every $1/MMBtu increase or decrease in the natural gas price forecast results in an approximately $7/ to $8/MWh (in real dollars) advantage or disadvantage to Flint Creek coal generation over natural gas generation (combine cycle generation), all else equal. This potential differential is significant relative to the baseline expected delivered coal costs of approximately $22/MWh on a levelized average basis over the 2016 to 2045 period in real 2010 dollars.

Q. WHAT DID YOU ASSUME REGARDING NATURAL GAS PRICES?

A. Exhibit 5 summarizes the Base Case Henry Hub natural gas price forecast in 2010 real dollars and nominal dollars (which incorporates the effect of general inflation assumed to be 2.5 percent per year). The Henry Hub natural gas price for the 2016-2045 period is $6.8/MMBtu on a simple average basis and $6.38/MMBtu on a levelized average basis in real terms (2010$).[6] The simple average in nominal terms is $11.96/MMBtu. This reflects ICF's current forecast of long-term natural gas prices[7] based on ICF's modeling of supply and demand fundamentals including short run and long run costs of production. The forecast includes the effect of developments on shale gas and environmental regulations. Natural gas prices increase over time due to a combination of depletion of existing wells and growing natural gas demand which creates the need to incrementally produce resources with higher production costs, and for prices to reflect full recovery of and on invested capital.

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[6] All assumptions are in 2010 real dollars unless otherwise stated.
[7] As of November 2011

EXHIBIT 5
ICF Henry Hub Gas Price Projection

Year	Henry Hub (2010$/MMBtu)	Henry Hub (Nominal$/MMBtu)
2016	5.15	5.97
2017	5.21	6.19
2018	5.27	6.42
2019	5.33	6.66
2020	5.39	6.90
2021	5.47	7.18
2022	5.56	7.47
2023	5.64	7.77
2024	5.77	8.15
2025	5.89	8.54
2026	6.03	8.95
2027	6.16	9.37
2028	6.30	9.82
2029	6.44	10.29
2030	6.58	10.79
2031	6.75	11.33
2032	6.92	11.91
2033	7.09	12.51
2034	7.27	13.15
2035	7.45	13.82
2036	7.62	14.47
2037	7.78	15.16
2038	7.95	15.87
2039	8.12	16.62
2040	8.44	17.69
2041	8.44	18.14
2042	8.44	18.59
2043	8.44	19.06
2044	8.44	19.53
2045	8.44	20.02
Levelized Average[1] 2016-2035	**5.91**	**8.29**
Levelized Average[1] 2016-2045	**6.38**	**9.59**
Simple Average 2016-2045	**6.80**	**11.96**

[1]ICF uses a real discount rate of 4.4% for levelization

Q. HOW WAS YOUR NATURAL GAS PRICE FORECAST DEVELOPED?

A. ICF's natural gas forecast is based on highly detailed integrated modeling of the North American natural gas sector using ICF's proprietary Gas Market Model (GMM). ICF's GMM projections are based on ICF's assessment of supply and demand fundamentals. Among many other factors, GMM accounts for increased demand for natural gas over time from the power and other sectors, due in part to CO_2 and other environmental regulations. These factors support increasing prices over time. As mentioned, the depletion of existing wells also supports stronger prices over time. Current (i.e., winter 2011-2012) prices are low due to the weak economy, very mild weather that is causing a build-up of natural gas in storage, and disequilibrium in supply and demand resulting in temporary excess capacity.[8] A projected downward adjustment in excess capacity also supports stronger prices over time. ICF's natural gas practice has access to some of the best shale gas resource data in the country by virtue of our work with that industry. On the whole, ICF is very bullish on U.S. natural gas supply. Nonetheless, by the time the retrofits are scheduled to come on-line in 2016, and on average, over the 2016 to 2045 period, natural gas prices are much higher than current levels. This is due, in part, to the eventual need for prices to reflect the long run costs of natural gas including recovery of, and on invested capital. Additional description of GMM and its interaction with ICF's IPM model is provided in the Appendix of our report.

Q. HOW DOES YOUR NATURAL GAS PRICE FORECAST COMPARE TO OTHER NATURAL GAS PRICES?

A. Three comparisons to ICF's natural gas price forecasts are presented, and all support the reasonableness of the ICF forecast. First, NYMEX natural gas futures typically trade liquidly for

[8] In early January, U.S. natural gas in storage was well above historical levels depressing natural gas spot prices: 3,377 Bcf was in storage versus 2,979 Bcf in the previous year, and 2,886 Bcf for the five year average. Drilling rigs were much lower: 791 rigs versus 902 one year earlier, and 1,139 rigs for the 5 year average. This is evident of an on-going adjustment in supply that supports the projection of decreased excess supply. Details from U.S. EIA and Baker Hughes as reported in Argus Coal Weekly, page 7, January 13, 2012.

the next 1-2 years. While less liquid, NYMEX natural gas futures are available for a longer period. *Exhibit 6 summarizes NYMEX futures traded in October 2011 for the 2012-2023 period* as compared with the ICF forecast over the same period. The levelized average NYMEX price for 2012 to 2023 is $4.72/MMBtu in 2010 dollars compared to ICF's forecast of $4.96/MMBtu. Thus, ICF is very similar to the October 2011 futures prices, albeit slightly higher.

EXHIBIT 6

Henry Hub Natural Gas Price Forecasts (2010$/MMBtu)

Year	ICF Nov 2011	NYMEX Oct 2011	EIA[1]
2012	4.14	3.93	4.55
2013	4.23	4.35	4.61
2014	4.32	4.54	4.62
2015	4.73	4.65	4.71
2016	5.15	4.74	4.79
2017	5.21	4.81	4.81
2018	5.27	4.88	4.87
2019	5.33	4.95	4.93
2020	5.39	5.00	5.11
2021	5.47	5.07	5.30
2022	5.56	5.14	5.45
2023	5.64	5.22	5.64
2024	5.77		5.87
2025	5.89		6.04
2026	6.03		6.17
2027	6.16		6.31
2028	6.30		6.38
2029	6.44		6.42
2030	6.58		6.47
2031	6.75		6.56
2032	6.92		6.70
2033	7.09		6.82
2034	7.27		6.95
2035	7.45		7.15
Levelized Average[2]			
2012 – 2023	**4.96**	**4.72**	**4.90**
2016 - 2023	**5.36**	**4.96**	**5.08**
2016 - 2035	**5.91**		**5.75**

[1] Source: EIA Annual Energy Outlook 2011; http://www.eia.gov/oiaf/aeo/tablebrowser/; 2009$ forecast converted to 2010$ assuming 1.15% inflation from 2009 to 2010

[2] *ICF uses a real discount rate of 4.4% for levelization*

Second, the U.S. DOE Energy Information Administration (EIA)[9] Reference Case forecast for Henry Hub natural gas prices for the period of 2016 to 2035[10] averages $5.75/MMBtu (see Exhibit 6) on a levelized basis.[11] This is also very similar to (approximately 3 percent lower than) the average ICF assumption for the same period. As noted, ICF's forecast is $5.91/MMBtu on a levelized average basis in real 2010$ terms for 2016 to 2035.

Third, the 2000-2010 historical average price for Henry Hub was $6.28/MMBtu (2010$), similar to the ICF long-term projection of $6.38/MMBtu for 2016 to 2045. The close correspondence between the historical and forecast prices is shown to provide perspective; historical and future conditions will be different. For example, in the future as compared to the past, natural gas demand, shale gas production, oil prices, etc. are likely to be different. Furthermore, there were no CO_2 controls in this historical period, and thus, natural gas prices would have been even higher had there been some form of $/ton CO_2 controls, all else equal. The only years in which the historical natural gas price was lower than the average ICF projection were years with recessions or years with very poor economic conditions (see Exhibit 7).[12] Reliance on only natural gas prices observed during recessionary or unexpectedly poor economic times biases the prices downward.

[9] Annual Energy Outlook 2011
[10] Forecast years that are available for comparison.
[11] Levelized using 4.4% real discount rate
[12] 2009, 2010, 2002, and 2001 (barely).

EXHIBIT 7
Historical Average Henry Hub Spot Gas Prices (2010 \$/MMBtu)

Year	Price
2000	5.40
2001	4.84
2002	4.04
2003	6.44
2004	6.72
2005	9.83
2006	7.22
2007	7.24
2008	9.02
2009	3.96
2010	4.38
Average 2000-2010	6.28
Standard Deviation (2010 \$/MMBtu)	1.97
Standard Deviation as Percent of Price (%)	31.4%

Source: Bloomberg

SECTION III-2 – POTENTIAL CO_2 ALLOWANCE PRICES

Q. WHY ARE CO_2 ALLOWANCE PRICES IMPORTANT?

A. Potential CO_2 emission costs are important in assessing the Flint Creek project for two reasons. First, CO_2 emission regulations adversely affect fossil fuel generation options, especially coal, by increasing the cost of generation in proportion to the CO_2 emission rate and the emission allowance price. Second, CO_2 regulations affect fuel markets with the primary effect being to increase natural gas demand and natural gas prices, all else equal.

The direct effect of an illustrative \$10/ton CO_2 emission allowance price adds approximately \$10/MWh[13] to the cost of operating a coal-fired unit like the Flint Creek plant compared to the current regulatory situation in which there is no national CO_2 cost. In contrast, a \$10/ton CO_2 price adds approximately \$4/MWh[14] to the cost of a new natural gas-fired

[13] The Flint Creek Plant full load heat rate is approximately 10,000 Btu/kWh.
[14] The heat rate for a new combined cycle is assumed to be 7,100 Btu/kWh.

combined cycle, or \$6/MWh less than the cost add-on for a coal plant. The add-on for a natural gas conversion facility is intermediate between the coal plant and the new combined cycle plant.

Q. WHAT IS YOUR FORECAST OF CO_2 ALLOWANCE PRICES?

A. Exhibit 8 summarizes the ICF Base Case outlook for CO_2 emission allowance prices, reflective of the latest ICF forecast available as of November 2011. Between 2016 and 2045, prices average \$10.7 /ton in levelized real terms (2010\$) and \$16.1/ton in levelized nominal terms assuming 2.5 percent general annual inflation. We estimate the price by multiplying the probability that \$/ton CO_2 controls will occur with the expected CO_2 allowance price. The expected CO_2 price, in turn, reflects the results of ICF's IPM® computer modeling simulation of a utility-only Waxman-Markey cap and trade program. We assume that the probability of \$/ton CO_2 controls in 2033 is [redacted], increasing to [redacted] by the 2040-2045 Period.

EXHIBIT 8
CO_2 Emission Allowance Prices

Year	[redacted]	[redacted]	Base Case Effective Probability Weighted Price (2010$/ton)	
	[redacted]	[redacted]	(2010$/ton)	(Nom$/ton)[1]
2016	[redacted]	[redacted]	0	0
2017	[redacted]	[redacted]	0	0
2018	[redacted]	[redacted]	0	0
2019	[redacted]	[redacted]	0	0
2020	[redacted]	[redacted]	0	0
2021	[redacted]	[redacted]	0	0
2022	[redacted]	[redacted]	0	0
2023	[redacted]	[redacted]	6.2	8.5
2024	[redacted]	[redacted]	7.0	9.9
2025	[redacted]	[redacted]	7.9	11.4
2026	[redacted]	[redacted]	8.9	13.2
2027	[redacted]	[redacted]	9.9	15.1
2028	[redacted]	[redacted]	11.0	17.2
2029	[redacted]	[redacted]	12.3	19.7
2030	[redacted]	[redacted]	13.0	21.4
2031	[redacted]	[redacted]	14.2	23.9
2032	[redacted]	[redacted]	15.5	26.7
2033	[redacted]	[redacted]	16.9	29.8
2034	[redacted]	[redacted]	18.4	33.2
2035	[redacted]	[redacted]	20.0	37.0
2036	[redacted]	[redacted]	21.7	41.2
2037	[redacted]	[redacted]	23.6	45.9
2038	[redacted]	[redacted]	25.6	51.0
2039	[redacted]	[redacted]	27.7	56.7
2040	[redacted]	[redacted]	30.0	63.0
2041	[redacted]	[redacted]	30.0	64.6
2042	[redacted]	[redacted]	30.0	66.2
2043	[redacted]	[redacted]	30.0	67.8
2044	[redacted]	[redacted]	30.0	69.5
2045	[redacted]	[redacted]	30.0	71.3
Simple Ave 2023-2045	[redacted]	[redacted]	19.1	37.6
Levelized Ave *2016 – 2035*[2]	[redacted]	[redacted]	**6.4**	**9.0**
Levelized Ave *2016 – 2045*[2]	[redacted]	[redacted]	**10.7**	**16.1**

[1] Assumes annual general inflation of 2.5 percent
[2] *ICF uses a real discount rate of 4.4% and a nominal discount rate of 7.0% for levelization.*

Q. WHY DO YOU THINK A $/TON CO_2 PROGRAM IS REASONABLE TO INCLUDE IN YOUR BASE CASE?

A. ICF believes the following considerations support $/ton CO_2 regulations in its Base Case outlook:

- First, while cap and trade is currently a political non-starter, there is still the possibility of a legislated program which could be implemented as early as 2023. The most likely case is not the return of a multi-sector climate bill similar to Waxman-Markey. When we have modeled a utility sector only cap, where the utility sector is required to achieve proportional reductions to the Waxman-Markey level cap and the transportation sector is specifically excluded, observed allowance prices are significantly lower. As noted, the Base Case outlook reflects a [redacted] chance of a large stationary sources only CO_2 control program similar to Waxman Markey in 2023 and a [redacted] chance of such a program starting by 2040.

- Second, there is an eventual possibility, albeit small, of a regulated program with trading. Such a program could be based on existing authority under New Source Performance Standards (NSPS) to regulate CO_2. However, as noted earlier, EPA has stated that it does not intend to implement a trading system under NSPS, and there are significant political hurdles to implementing such a program.

- Third, our Base Case price is reasonable because it also gives weight to the possibility that the future may not lead to a $/ton program affecting existing plants, but rather a regulatory program comprised of a suite of what is referred to as "complementary measures" including a federal Clean Energy Standard, energy efficiency requirements (including higher CAFÉ standards for the transportation sector), renewable portfolio standards, conventional pollutant reduction requirements (i.e., Mercury and Air Toxics Standards -- MATS), and CO_2-based NSR and NSPS standards.

In conclusion, we believe it is reasonable to assume there could eventually be national CO_2 emission regulations and CO_2 prices should positive be in the Base Case. More precisely, the probability weighted set of uncertain CO_2 outcomes results in a positive expected CO_2 \$/ton price starting at some point in the future.[15]

Q. HOW DOES YOUR FORECAST OF A DELAY REFLECT RECENT DEVELOPMENTS?

A. As noted, recent developments give weight to a significantly delayed start to any potential program and CO_2 allowance pricing in the lower end of the potential price range. This conclusion reflects the following factors:

- **Recent Federal Developments** – After the passage of the Waxman-Markey Climate Change Bill in June 2009 by the U.S. House of Representatives, the U.S. Senate, even with one party having 60 members, did not pass any bill. Since then, near-term prospects for a bill have become extremely remote due to changes in the U.S. Congress and elsewhere. However, EPA, under existing authority, is establishing New Source Review (NSR) and NSPS for CO_2 emissions. These standards do not have the effect of creating a \$/ton charge for existing plants. NSR involves the application of Best Available Control Technology (BACT) to new or modified units. While some have argued that EPA can establish a trading program under NSPS that would impact existing sources, EPA is not likely to establish a trading program under NSPS in the immediate future, and given the inability to pass cap and trade legislation, any attempt to do so in the current political environment would be a politically contentious move.
- **Near-Term Conditions** –The potential for a national CO_2 cap and trade program, or national \$/ton charge for the emission of CO_2 as early as 2016 is effectively non-existent. This is because the lead time for major new environmental regulations is

[15] Put another way, as long as the probability of \$/ton CO_2 controls is greater than zero, there is an expected positive CO_2 price. This is because CO_2 prices cannot be negative.

approximately five years (based on historical experience and the complexity of potential CO_2 regulations). Additionally, the prospects for the near-term initiation of a major national CO_2 control program leading to a $/ton charge have become very remote in recent months.

- **Regional and International Greenhouse Gas Reduction Accords** – Several regional efforts at CO_2 control have stalled, been delayed, or effectively cancelled. This includes the Midwest Climate Accord and for most western states, the Western Climate Initiative. In the US, only two regional programs are in place or moving forward, i.e., RGGI in the Northeast (although over-allocated) and California. In the recent international talks on the Kyoto Protocol in Durban, South Africa, the U.S. and many other countries undertook to implement a GHG control program by 2015 and initiate controls by 2020. These controls been originally scheduled for 2012. Canada also withdrew from the Kyoto Protocol, although Quebec has stated that it is joining the Western Climate Initiation (WCI) with California.

Q. HOW WAS YOUR CO_2 FORECAST DERIVED?

A. ICF'S CO_2 forecast reflects a utility only Waxman-Markey cap. The forecast is developed using a model-based approach with the IPM® model as referenced earlier. ICF has conducted numerous detailed modeling exercises of proposed CO_2 cap and trade programs, both nationally and regionally, including for the Midwestern Accord. This analysis considers such impacts as:

- Fuel Switching
- Changes in Dispatch
- Increased Use of Renewables
- Nuclear Power
- Energy Efficiency
- Carbon Capture and Sequestration (CCS)

- Offsets from Other Sectors and/or Countries

Q. WHAT DID YOU ASSUME ABOUT ALLOCATIONS?

A. ICF believes it is likely that if there is a $/ton CO_2 control program, it will include allocations of CO_2 emission allowances (i.e., permits to emit a ton of CO_2) to SWEPCO and other utilities. Allocations of emission allowances have been designed to smooth the transition to the new regulatory regime and cushion the impact. Hence, allocations are generally concentrated at the start of the program when the impact is the largest. Allocations are especially important when they depend on future actions, rather than on past actions or factors beyond the control of decision makers.

There is uncertainty not only with respect to the CO_2 $/ton price, but also with the method for allocation. Nonetheless, in ICF's view, the impacts of CO_2 control on fossil fuel options, especially coal options, will be partially mitigated by allocating allowances. Furthermore, the choice of a coal retrofit option results in more total allowances than a natural gas option because allocations will depend on future emissions. This is because in the future, these emissions will then be part of the historical baseline used for determining allocations. This is also because there is such a large expected delay in the program. That is, in 2023, at the beginning of an assumed CO_2 control program, we also assume that the federal government will start to provide emission allowance allocations to utilities – and specifically to the local distribution companies (LDCs).[16] Based on many previous cap and trade programs, we believe the basis for the allocation will be an average of several years' historical baseline. For a program with a significant delay starting no earlier than 2023, this historical baseline may, for example, be based on 2016 to 2019 emissions and sales. This baseline in 2023 will be beyond the control of decision makers, but today it can be managed by picking options with higher emission rates and greater utilization such that emissions are higher.

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[16] The decisions in the model are not made with knowledge of the impact of allowance allocations.

Q. WHAT IS THE NET IMPACT OF ALLOCATIONS?

A. The allocations effectively decrease the impact of the CO_2 price [redacted] (see Exhibit 9) on average over the 2016-2045 period.

EXHIBIT 9
CO_2 Emission Allowance Allocations

Year	Allowance Allocations Factor (%)	CO_2 Price	Net Effective CO_2 Price[1] (After Allocations)
2016	[redacted]	-	[redacted]
2017	[redacted]	-	[redacted]
2018	[redacted]	-	[redacted]
2019	[redacted]	-	[redacted]
2020	[redacted]	-	[redacted]
2021	[redacted]	-	[redacted]
2022	[redacted]	-	[redacted]
2023	[redacted]	6.2	[redacted]
2024	[redacted]	7.0	[redacted]
2025	[redacted]	7.9	[redacted]
2026	[redacted]	8.9	[redacted]
2027	[redacted]	9.9	[redacted]
2028	[redacted]	11.0	[redacted]
2029	[redacted]	12.3	[redacted]
2030	[redacted]	13.0	[redacted]
2031	[redacted]	14.2	[redacted]
2032	[redacted]	15.5	[redacted]
2033	[redacted]	16.9	[redacted]
2034	[redacted]	18.4	[redacted]
2035	[redacted]	20.0	[redacted]
2036	[redacted]	21.7	[redacted]
2037	[redacted]	23.6	[redacted]
2038	[redacted]	25.6	[redacted]
2039	[redacted]	27.7	[redacted]
2040	[redacted]	30.0	[redacted]
2041	[redacted]	30.0	[redacted]
2042	[redacted]	30.0	[redacted]
2043	[redacted]	30.0	[redacted]
2044	[redacted]	30.0	[redacted]
2045	[redacted]	30.0	[redacted]
Levelized 2016 – 2045		**10.7**	[redacted]

[1] Price relevant for SWEPCO's choice among options 1-5.

Q. DID YOU ALSO CONSIDER THE RESULTS OF NO CO_2 ALLOWANCE ALLOCATIONS TO THE COMPARISON OF OPTIONS?

A. Yes, as will be discussed later, we analyzed the impact of the conservative and unlikely assumption of no CO_2 allocations on the range of options.

SECTION III-3 – DELIVERED COAL PRICE FORECAST

Q. WHAT IS YOUR COAL PRICE FORECAST?

A. ICF forecasts that delivered coal prices will average [redacted] on a real 2010 dollar levelized basis ([redacted] in nominal dollars) for the 2016 to 2045 period (see Exhibits 10 and 11). This is equal to [redacted] in real dollars assuming 17.6 MMBtu/ton. This is [redacted] historical coal pricing levels because SWEPCO's recent rail and coal supply contracts are scheduled to expire and prices are higher than when contracts were previously negotiated. Coal prices are discussed further in the accompanying report.

EXHIBIT 10
Flint Creek Coal Prices

Year	2010 ($/ton)				Nominal ($/ton)			
	Mine	Trans	Tax	Delivered	Mine	Trans	Tax	Delivered
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ave 2016-2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Average[1] 2016 – 2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] ICF uses a real discount rate of 4.4% and a nominal discount rate of 7.0% for levelization

EXHIBIT 11
Flint Creek Coal Prices

Year	2010 $/MMBtu				Nominal$/MMBtu			
	Mine	Trans	Tax	Delivered	Mine	Trans	Tax	Delivered
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ave 2016-2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Average[1] 2016 - 2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

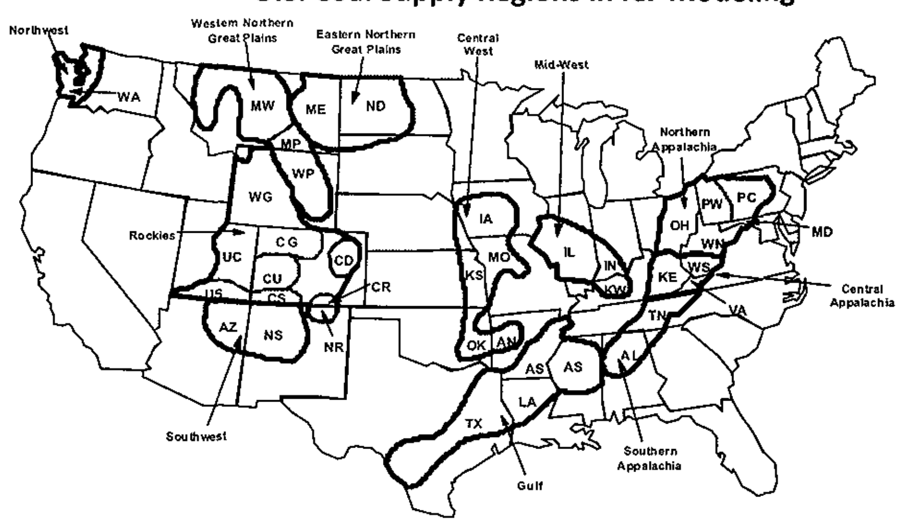
[1] ICF uses a real discount rate of 4.4% and a nominal discount rate of 7.0% for levelization.

Q. HOW WAS THE COAL PRICE FORECAST DEVELOPED?

A. PRB minemouth coal price forecasts were developed using ICF's IPM® model. This model is discussed in detail in the Appendix. The IPM© modeling simultaneously assesses coal resources, production costs, transportation, demand, environmental regulations, international trade, and the competition across coal regions and industries (see Exhibit 12).

In ICF's forecast, the widespread use of SO_2 scrubbers by U.S. coal plants subject to recent federal controls (CSAPR and the proposed MATS rule) decreases the long-term demand for PRB coal relative to a situation in which SO_2 scrubbers are less prevalent. Also, coal mining labor productivity is expected to continue to improve in the PRB and some selected regions. This helps moderate prices.

EXHIBIT 12
U.S. Coal Supply Regions in ICF Modeling



The ICF IPM model assumes 30 billion tons of economically recoverable coal reserves in PRB. This is the same reserve estimate updated by EIA in February 2011. The model assumes that recent real increases in coal transportation costs will cease, although nominal increases are expected. See report for additional information.

SECTION III-4 – SENSITIVITY CASE ASSUMPTIONS

Q. PLEASE SUMMARIZE THE SENSITIVITY CASES YOU CONSIDERED.

A. ICF analyzed six sensitivity cases involving changes to long-term natural gas, coal, and CO_2 emission allowance prices. The sensitivity case assumptions are summarized in Exhibit 13.

EXHIBIT 13
Sensitivity Cases

Variable	Low	Base	High
Natural Gas – Henry Hub (Levelized 2016 to 2045 2010$/MMBtu)[1]	[redacted]	6.38	[redacted]
Coal Price (Levelized 2016 to 2045 2010$/MMBtu)[1]	[redacted]	[redacted]	[redacted]
CO_2 Allowance Price (Levelized 2016 to 2045 2010$/ton)[1]	[redacted]	10.7	[redacted]

[1] ICF uses a real discount rate of 4.4% for levelization, i.e., for creating an annuity value with the same present value

Q. WHAT WERE YOUR CHANGES REGARDING NATURAL GAS PRICES?

A. *In the Base Case, Henry Hub natural gas prices averaged $6.38/MMBtu between 2016 and 2045* on a real basis (2010$). Two sensitivity cases with lower and higher natural gas prices were analyzed:

- **Sensitivity Case #1: Low Natural Gas Price** – In the Low Natural Gas Price Case, Henry Hub prices are [redacted] (in 2010$) throughout the 2016 to 2045 period. This is considered approximately the low end of the 75% confidence interval for long-term average Henry Hub natural gas prices in real dollars. This means there is an approximately 12.5 percent, or one in eight chance that long-term natural gas prices will be at this level or lower. Similarly, there is an approximately 87.5% chance that prices will be higher than this level. As discussed later, annual volatility could cause individual years to be higher or lower in response to short-term factors such as the economy, weather, temporary disequilibrium supply and demand in the natural gas industry, oil and natural gas liquid prices, etc.

- **Sensitivity Case #2: High Natural Gas Price** – In the High Natural Gas Price Case, Henry Hub natural gas prices average [redacted] (on levelized basis) between 2016 and 2045 (in 2010$), and hence, the prices are roughly symmetric in the High and Low natural gas price cases around the Base Case.

Thus, the range of long-term natural gas prices examined is [redacted]. While the $/MMBtu range examined in the natural gas sensitivity cases is roughly 2.5 times higher than in the coal price cases, this is in part related to higher absolute natural gas pricing levels. In addition, natural gas prices were varied in response to changes in CO_2 prices (see discussion below).

Q. WHAT WERE YOUR CHANGES REGARDING CO_2 ALLOWANCE PRICES?

A. In the Base Case, the levelized average CO_2 allowance price equals $10.7/ton (2010$) over the 2016 – 2045 period. Two sensitivity cases with lower and higher CO_2 allowance prices were analyzed:

- **Sensitivity Case #3: Low CO_2 Price** – [redacted]
- **Sensitivity Case #4: High CO_2 Price** – [redacted]

[redacted].

The derivation of the roughly 75% confidence interval and the low and high CO_2 cases are discussed further in the accompanying report.

Q. DID YOU CHANGE THE CO_2 ALLOWANCE ALLOCATIONS IN THE SENSITIVITY CASES?

A. No, the approach to the allocation of CO_2 allowances does not change in the sensitivity cases.

Q. DID YOU ALSO EVALUATE THE OPTIONS IN CASES WITHOUT A CO_2 ALLOCATION EFFECT?

A. Yes. We also analyzed the impact of no CO_2 allocations for the Base Case and all six sensitivity cases. In all these cases except one (i.e. the Low Gas Price Case), even without any CO_2 allocations, the coal options continue to be preferred.

EXHIBIT 14
CO_2 Price Net of Allocations

Year	Allowance Factor	CO_2 Price			Net CO_2 Price After Allocation		
		Low	Base	High	Low	Base	High
2016	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	6.2	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	7.0	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	7.9	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	8.9	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	9.9	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	11.0	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	12.3	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	13.0	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	14.2	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	15.5	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	16.9	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	18.4	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	20.0	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	21.7	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	23.6	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	25.6	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	27.7	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	30.0	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	30.0	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	30.0	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	30.0	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	30.0	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	30.0	[redacted]	[redacted]	[redacted]	[redacted]
Levelized 2016-2045		[redacted]	**10.7**	[redacted]	[redacted]	[redacted]	[redacted]

Q. WHAT WERE THE CHANGES MADE TO DELIVERED COAL PRICES?

A. In the Base Case, the delivered coal price averages [redacted] on a 2016 – 2045 levelized average, real 2010$ basis. This in turn reflects a levelized average cost of [redacted] for minemouth coal and rail transportation costs of [redacted]. Two sensitivity cases with lower and higher delivered coal prices were analyzed:

- **Sensitivity Case #5 – Low Coal Price** – In the Low Coal Price Case, for the 2016 – 2045 period, levelized PRB minemouth prices are assumed to be [redacted] (2010$) and rail transportation costs are assumed to be [redacted], for a total delivered price of [redacted] or [redacted] in 2010$.
- **Sensitivity Case #6 – High Coal Price –** In the High Coal Price Case, the levelized average 2016 – 2045 minemouth PRB price is assumed to be [redacted] and the rail transportation cost is assumed to be [redacted], for a total delivered price of [redacted] or [redacted] (2010$). Therefore, the range of coal prices examined was [redacted] (i.e., from [redacted] to [redacted] – 2010$) in 2010 levelized dollars. The lack of symmetry in coal prices between the Low and High Coal Price cases (i.e., there is a greater differential between the Low and Base Case than between the Base and High Case) reflects several factors: (1) competition between coal sources increases at higher PRB prices and makes high delivered PRB prices less likely, (2) the potential for increased regulatory pressure on railroads to lower rates as prices rise, (3) the fact that current prices already reflect the impacts on mining and rail costs of increases in oil prices that are near the higher end of the sustainable oil price range, (4) lower coal demand due to environmental regulations, and (5) the historical record which has only lower annual delivered coal prices. Nonetheless, even an increase to

\$3/MMBtu to \$3.25/MMBtu (2010\$) would still likely result in Flint Creek being the favorable option over the most economic natural gas alternative.

SECTION IV – ANNUAL FUEL PRICE VOLATILITY AND FUEL DIVERSITY

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING ANNUAL VOLATILITY OF REVENUE REQUIREMENTS?

A. The year-by-year volatility of utility revenue requirements is higher with use of natural gas than with coal. All else equal, this lower volatility favors the environmental retrofits at the plant because it facilitates planning by customers. Thus, this analysis reinforces the results of the PVRR analysis. In addition, because new plant trends favor natural gas relative to the historical fuel mix and incremental supply from the SPP wholesale power market is mostly natural gas-based, retrofitting Flint Creek is one of the few options for preventing an even greater increase in the reliance on higher priced and more volatile natural gas.

Q. WHAT IS THE BASIS FOR THIS CONCLUSION?

A. Historical coal price volatility, especially for Powder River Basin coal, the type used by the Flint Creek project, is lower than natural gas price volatility. Coal prices are relatively stable, in part because long-term coal and rail contracts, unlike natural gas, do not require mark-to-market collateral (see Exhibit 15). The reason why fixed price, long-term natural gas contracts are not widely used to mitigate risk, and hence, are not comparable to coal contracts, is the existence of mark-to-market collateral costs in natural gas contracts. The costs are too high for long-term fixed price gas positions. Under gas contracts, unlike coal contracts, the required level of collateral is determined each day based on the market gas price versus the contract price times the volume. Each night, liquid collateral must be posted. The longer the term of the contract, the larger the collateral requirement swings due to the large volumes of gas involved. Indeed, it is possible to bankrupt companies that cannot obtain the necessary collateral and the collateral requirement can exceed the net worth of medium sized companies. Natural gas contracting is discussed further in the accompanying report.

EXHIBIT 15
Fuel Purchasing and Contracting Favor Coal

Parameter	Coal	Natural Gas
Commodity Contract Type	3 - 5 Year[1]	Spot
Transportation Contract Type	5 – 10 Year	5 – 10 Year, Spot
Mark-to-Market Collateral Hedging	No	Yes

[1]Price fixed for five years on average.
Source: ICF

Coal contracts do not have such collateral requirements due to the lower volatility of price. Over the 1995 to 2010 period, the relative standard deviation of annual spot Henry Hub natural gas prices was 12.1 times higher than for minemouth PRB coal prices (see Exhibit 16). This understates the higher historical volatility since it uses new long-term rail contract prices which are more volatile than average prices which reflect vintage contracts. Delivered PRB coal costs for a rail distance equal to Flint Creek has one-fifth the annual variance (standard deviation) of the Henry Hub natural gas price. A second measure, not based on delivered PRB coal, but on average, U.S. delivered utility costs, also shows high natural gas volatility compared to coal, with volatility 5 times higher (see Exhibit 17). Even if volatility in the short-term was lower with lower natural gas prices, the evidence strongly supports a conclusion of higher long run natural gas price volatility relative to coal.

If natural gas price volatility was low, contracts without mark-to-market collateral requirements would be available. The collateral provisions are designed to ensure that the contract is honored in spite of natural gas price volatility. Indeed, natural gas futures contracts contain the mark-to-market collateral requirements because the market perceives a significant risk of gas price volatility.

EXHIBIT 16

Historical Comparison of PRB Coal Prices with Henry Hub Spot Gas Price

Year	Spot PRB Coal Prices[1] (Nominal$/MMBtu)	Delivered PRB Coal Prices – 1,000 Miles Competitive New Contract-Based Movement (Nominal $/MMBtu)	Henry Hub Spot Gas Price[2] (Nominal$/MMBtu)
1995	0.27	0.73	1.72
1996	0.23	0.71	2.68
1997	0.25	0.70	2.47
1998	0.26	0.71	2.08
1999	0.27	0.71	2.26
2000	0.26	0.70	4.32
2001	0.57	1.01	3.96
2002	0.35	0.79	3.36
2003	0.36	0.80	5.47
2004	0.36	0.81	5.86
2005	0.55	1.21	8.87
2006	0.73	1.70	6.72
2007	0.55	1.52	6.94
2008	0.75	1.81	8.84
2009	0.56	1.64	3.92
2010	0.73	1.92	4.37
Average	**0.44**	1.09	**4.62**
Standard Deviation	**0.19**	**0.46**	**2.30**

Note: PRB = Powder River Basin (8800 Btu/lb)

1. Source: Coal Outlook

2. Source: Bloomberg

EXHIBIT 17

Average Coal Price Delivered To Electric Utilities vs. Henry Hub Gas Price (Nominal $/MMBtu)

Year	US Average Delivered Coal Prices to Utilities[1] (Nominal$/MMBtu)	U.S. Average Delivered Natural Gas Prices to Utilities (Nominal $/MMBtu)	Henry Hub Spot Gas Price[2] (Nominal$/MMBtu)
1999	1.22	2.57	2.27
2000	1.20	4.30	4.30
2001	1.23	4.49	3.96
2002	1.25	3.56	3.37
2003	1.28	5.39	5.49
2004	1.36	5.96	5.90
2005	1.54	8.21	8.89
2006	1.69	6.94	6.73
2007	1.77	7.11	6.97
2008	2.07	9.02	8.89
2009	2.21	4.74	3.94
2010	2.27	5.09	4.37
Average 1999-2010	1.59	5.62	5.42
Standard Deviation	0.41	1.91	2.12

[1] Source: EIA
[2] Bloomberg

SECTION V – COAL POWER PLANT LIFETIMES AND THE OPERATIONAL PROSPECTS OF FLINT CREEK

Q. WHAT DO YOU CONCLUDE FROM YOUR COMPARISON OF FLINT CREEK TO OTHER COAL PLANTS?

A. As Flint Creek is newer than average, Flint Creek has a longer remaining useful life compared to the US fleet average. Flint Creek is also larger than the average plant in the US coal fleet. Both these attributes contribute to the relative suitability of Flint Creek for retrofit and continued operation.

Q. WHAT IS FLINT CREEK'S AGE?

A. The Flint Creek plant came on-line in 1978 and, hence, is 33 years old. The average age of the U.S. coal fleet is 42 years.[17] Hence, the Flint Creek plant is nine years younger than the U.S. average coal plant. Exhibits 18 and 19 show that coal power plants 33 years old or older constitute 64% of U.S. coal capacity, and hence, Flint Creek is younger than most U.S. coal capacity. As Flint Creek is one of the younger plants in the U.S., all else equal, it would have an above average remaining lifetime. This in turn favors the environmental investment, all else equal, as it provides for more years and output over which to amortize the capital costs of the environmental upgrades.

[17] Source: EPA NEEDS database.

EXHIBIT 18

U.S. Coal-Fired Power Plants and Capacity by On-line Dates

On-Line Year	Number of Units	Summer Capacity (MW)	% of Total Capacity
1941-1950	106	3,938	1%
1951-1960	425	46,532	15%
1961-1970	336	69,295	22%
1971-1980	382	117,171	37%
1981-1990	319	60,115	19%
1991-2000	71	7,249	2%
2001-2010	86	15,243	5%
TOTAL	1,725	319,542	100%

Source: Ventyx database

EXHIBIT 19

U.S. Coal-Fired Power Plants and Capacity by On-line Dates

Pre & Post 1978

On-Line Year	Number of Units	Summer Capacity (MW)	% of Total Capacity
Pre- 1978[1]	1,122	206,017	64%
Post- 1978	603	113,525	36%
TOTAL	1,725	319,542	100%

[1] Includes 1978

Source: Ventyx database

Q. WHAT IS FLINT CREEK'S SIZE?

A. The capacity of the Flint Creek coal plant is 528 MW. Only 12% of the coal power plant units in the U.S. are 528 MW or greater (see Exhibits 20 and 21). The larger size of the plant increases the potential for economies of scale in operations, maintenance, retrofit installation costs, and upgrades. Thus, Flint Creek benefits from both longer than average remaining useful life and greater than average economies of scale. This is reflected in our cost assumptions and provides background relevant to developments nationwide concerning the coal fleet.

EXHIBIT 20
U.S. Coal Power Plants by Plant Size

Age Group by On-Line Date	Number of Units					Total
	<100 MW	100 - 200 MW	200 - 500 MW	500-700 MW	>700 MW	
1941-1950	95	11	0	0	0	106
1951-1960	184	160	78	3	0	425
1961-1970	117	82	86	42	9	336
1971-1980	97	66	118	65	36	382
1981-1990	170	40	60	38	11	319
1991-2000	47	8	14	2	0	71
2001-2010	50	10	10	10	6	86
TOTAL	760	377	366	160	62	1,725
% OF TOTAL	**44.1%**	**21.9%**	**21.2%**	**9.3%**	**3.6%**	**100%**

Source: Ventyx database

EXHIBIT 21
U.S. Coal Power Plants by Plant Size

MW Size	Number of Units	% of Total Capacity
> or = 528	209	12%
<528	1,516	88%
TOTAL	1,725	100%

Source: Ventyx database

Q. HOW DOES FLINT CREEK'S HISTORICAL OPERATIONAL PERFORMANCE COMPARE WITH THE U.S. AVERAGE?

A. U.S. coal plants are operating at an average capacity factor of 68% (see Exhibit 22). The Flint Creek plant has been operating on average at a capacity factor[18] of 75 percent for the 2006-2010 period, or 7 percent higher than the U.S. average.

[18] SNL Financial. Note, a multi-year average is shown to correct for the impact of the recession.

EXHIBIT 22
U.S. Coal Plants Utilization by Plant Size

Plant Size (MW)	Capacity (MW)	% Utilization					
		2006	2007	2008	2009	2010	2006 – 2010 Average
>500	264,641	73%	73%	72%	65%	67%	70%
200 - 500	38,556	65%	66%	63%	51%	57%	60%
<200	16,345	60%	62%	59%	49%	51%	56%
Total	319,542	71%	72%	71%	63%	66%	68%

Source: Ventyx Database

Q. WHAT IS THE HISTORICAL PERFORMANCE OF NATURAL GAS COMBINED CYCLES?

A. In contrast to coal, U.S. natural gas-fired combined cycle capacity factors are much lower and averaged 40% in 2010. In SPP, the 2010 average natural gas-fired combined cycle dispatch was 38 percent. As noted, all else equal, an Arkansas combined cycle's competitiveness is lower than other combined cycles due to the Arkansas fuel tax.

Given the likelihood of lower natural gas plant dispatch, the impacts of replacing Flint Creek with a natural gas combined cycle will be dependent on changes in SWEPCO operations and SWEPCO's interaction with neighboring systems – e.g., dispatch, power sales and purchases. Therefore, we model SWEPCO and surrounding systems to capture the system effects and adjustments of the two very different power plant options.

Q. WHAT SO_2 POLLUTION CONTROL IS CURRENTLY INSTALLED AT FLINT CREEK?

A. Flint Creek does not currently have a scrubber for SO2 emissions control.

Q. IS THIS UNCOMMON?

A. No. Flint Creek is similar to many other U.S. coal power plants in terms of pollution controls. Only 59% of U.S. coal power plant capacity is currently scrubbed for SO_2 (see Exhibit 23). Flint Creek is not scrubbed because it uses one of the lowest sulfur coals in the world. Hence, its emissions are currently lower than at many other unscrubbed units. Nonetheless, the plant is required to further decrease SO_2 and other emissions.

Q. IS IT UNCOMMON FOR PLANTS OF FLINT CREEK'S AGE TO RETROFIT SO_2 SCRUBBERS?

A. No. It is not uncommon for coal plants similar in age to Flint Creek to install additional pollution control systems. Approximately 57% of the coal plants in the U.S. that have SO_2 scrubbers were 30 years or older when they retrofitted a SO_2 scrubber at the plant.

EXHIBIT 23
U.S. FGD Capacity by Age Group

Age Group[1]	**Capacity (MW)**	**Percent of Total**
Plant constructed with FGD	72,048	38%
1-5	2,605	1%
6-10	2,790	1%
11-15	4,489	2%
16-20	8,584	4%
21-25	19,176	10%
26-30	13,789	7%
31-35	19,561	10%
36-40	28,862	15%
41-45	9,847	5%
46-50	4,253	2%
51-55	4,081	2%
56-60	1,428	1%
FGD Capacity	**191,513**	**100%**
FGD Capacity - Retrofitted[2]	**119,465**	
FGD Capacity - Retrofitted (30+ Age)[3]	**68,032**	**57%**
Total Coal Capacity	**319,542**	

[1] The age group represents the coal plant's age when it retrofitted to an FGD.

[2] FGD Capacity - Retrofitted represents coal capacity that retrofitted to an FGD *after* its online date.

[3] Represents FGDs installed at plants when they were older than 30 years old. The 57% is based on the capacity that retrofitted to an FGD *after* its online date, not the total FGD capacity in the U.S. of 191.5 GW.

Q. IS THERE A RELATIONSHIP BETWEEN COAL PLANT RETIREMENTS AND PLANT CHARACTERISTICS?

A. There has been an increase in announced coal plant retirements, and hence, it is useful to determine whether this has implications generally for the proposed project. Currently, announced coal plant retirements between 2011 and 2025 total approximately 24 GW. This is approximately 7% of U.S. coal capacity (see Exhibits 24 and 25).

Most of the announced retirements are for smaller and older units than Flint Creek and at sites without FGD environmental controls. In general, smaller, unscrubbed coal units are considered the most at risk for economic retirement. Hence, the Flint Creek Plant does not fit this profile. Only 1.5 GW or 6.5% of the 24 GW of announced coal plant retirements between 2011 and 2025 have an age of 33 years old or less (see Exhibit 25). While more announced coal retirements are expected, they will likely continue to be concentrated at units with a different profile than Flint Creek, e.g., smaller and older and with poorer economics for environmental controls.

EXHIBIT 24
U.S. Announced Coal Retirements by Control Technology, 2011 – 2025

Control Tech	Capacity (MW)	Percent of Total
SNCR	3,167	13%
Scrubber	2,499	10%
SCR	1,914	8%
Fabric Filter	1,400	6%
SNCR & Fabric Filter & ACI	1,166	5%
ACI	697	3%
DSI	482	2%
Scrubber & Fabric Filter	338	1%
Scrubber & SNCR	309	1%
DSI & Fabric Filter	213	1%
SNCR & ACI	165	1%
Other Controls[1]	11,310	47%
No Controls	193	1%
Total	**23,853**	**100%**

Source: Ventyx; As of October 10, 2011. Note, some units have already been retired in the first half of 2011.
[1] Other controls include ESP, Low NO_x burners and Overfire Air technologies.

EXHIBIT 25
U.S. Announced Coal Retirements by Age Group, 2011 – 2025

Age Group	Capacity (MW)	Percent of Total
< 30	0	0%
30-33[1]	1,553	6.5%
34-40	3,441	14.4%
41-50	6,652	27.9%
51-60	11,152	46.8%
60+	1,054	4.4%
Total	**23,852**	**100%**

Source: Ventyx
[1] Flint Creek is 33 years old. Plants equal to our younger than 33 years amounts to 1,553 MW or 6.5% of announced retirements.

SECTION VI - CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS?

A. I conclude that the Flint Creek coal plant FGD retrofit is the most economic option available to SWEPCO as compared to investment in natural gas alternatives. This conclusion reflects the following considerations.

- In the Base Case, the ICF analysis concludes that the Flint Creek upgrade is preferred in both SCR scenarios over all three natural gas options. Option #1, the retrofit case with the SCR on-line in 2020, has a PVRR advantage over the three natural gas generation options ranging from $314 million to $750 million (see Exhibit 3). This advantage is so pronounced that even in the unlikely case of elimination of allowance allocations, the coal options are still preferred. This Base Case PVRR assessment is the primary basis for my conclusion.
- The sensitivity analysis strongly reinforces this conclusion. ICF analyzed six sensitivity cases focused on key elements of uncertainty in the market, namely natural gas prices, coal prices, and national CO_2 program expectations. The coal option is preferred in all cases analyzed. Even when conservative allowance allocation assumptions are made (i.e. no CO2 allocations are assumed), the coal retrofit option is preferred in all cases but one (i.e. the low gas case). Even in this one case, only one of the three gas options evaluated is preferred and the coal option is preferred over the other two gas options.
- ICF also reviewed annual revenue requirement volatility using historical data and assessed contracting differences between coal and natural gas. ICF concludes that coal options have lower volatility than natural gas options. Lower volatility facilitates customer planning and supports the conclusion that the FGD investment is the preferred option.

- In addition to the quantitative PVRR analysis performed using ICF's IPM® model, ICF compared Flint Creek with other U.S. coal plants. This comparison found Flint Creek to be younger and larger than the U.S. coal power plant fleet average. This favors a longer than average remaining useful life for Flint Creek and a higher degree of suitability for retrofit. ICF also reviewed the history of retrofits of similar equipment and found many similarly aged and situated units retrofitting the same environmental controls. Lastly, ICF reviewed announced retirements of coal power plants and found that retiring coal plants are generally smaller and older than Flint Creek on average, and hence, Flint Creek differs from coal plants that are being retired. Thus, this review reinforces the conclusion that the coal retrofit is the most appropriate option.
- With demand growth and incremental need for additional capacity, SWEPCO is likely to have significant opportunities for new plant natural gas options and investment as there are challenges to new coal options due to high capital costs and current environmental regulatory opposition to new coal. SPP wholesale power prices are already heavily affected by higher priced and more volatile natural gas price. As such, incremental coal alternatives to natural gas volatility are hard to come by, and hence, are very valuable. This too supports approval of the investment.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.