BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	
AUTHORIZING APPLICANT TO MODIFY ITS	)	CAUSE NO. PUD 201700496
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Direct Testimony

of

Leon Howell

on behalf of

Oklahoma Gas and Electric Company

January 16, 2018

Q. **Please state your name, your employer, and your business address.**

A. My name is Leon Howell. I am employed by Oklahoma Gas and Electric Company ("OG&E" or "Company") and my business address is 321 N. Harvey, Oklahoma City, Oklahoma 73102.

Q. **What position do you hold with OG&E?**

A. I hold the position of Director, Resource Planning and Investment. I am responsible for OG&E's resource planning group and for all of its activities including the preparation of integrated resource plan submittals and frequent resource planning analyses that are performed on an ongoing basis as needs arise. I am also responsible for analyzing the business case for all capital expenditures the company makes that exceed one million dollars.

Q. **Would you please summarize your professional and educational background?**

A. I have been employed by OG&E since 1996. In 1985, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Oklahoma and in 2000 I earned a Master’s Degree in Business Administration from Oklahoma City University. I am a registered Professional Engineer (#16018) in the State of Oklahoma. Prior to joining OG&E in 1996, I was employed by Western Farmers Electric Cooperative as a Senior Transmission Planning Engineer. Since joining OG&E, I have held various operations and engineering positions. I have been responsible for leading OG&E’s resource planning efforts since 2003.

Q. **Have you previously testified or appeared before the Oklahoma Corporation Commission ("Commission")?**

A. Yes, I have filed testimony at the Commission on several occasions and have appeared before the Commission for numerous IRP public meetings. In 2008, I submitted testimony in OG&E’s application to acquire a 51% interest in the approximately 1200

MW Redbud combined cycle generating plant (Cause No. 200800086). Later that same year, I submitted testimony in OG&E's application to construct the 345 kV Windspeed transmission line to deliver wind resources from western Oklahoma to OG&E's load centers (Cause No. PUD 200800148). In addition, I also testified in the Company's Environmental Compliance Filing, Cause No. PUD 201400229. I have also submitted testimony before the Arkansas Public Service Commission and the Federal Energy Regulatory Commission.

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to explain how the new Mustang units are needed by next summer to comply with the Southwest Power Pool, Inc. ("SPP") planning reserve margin requirements. The SPP tariff requires load serving entities like OG&E to have at least a 12% planning reserve margin to ensure resource adequacy. This amount was previously 13.8% but was lowered by the SPP in 2017, to reflect the benefit of the SPP Integrated Market. I also explain how OG&E management approached its decision to replace the retiring Mustang capacity and why a combination of factors show that the addition of quick-start CTs at the Mustang site was a reasonable and prudent action from a resource planning perspective.

Q. **How does the retirement of the old Mustang units impact OG&E's SPP planning reserve margin?**

A. OG&E retired Mustang Units 1 & 2 in December 2015 and will retire Mustang Units 3 & 4 in December 2017. These units needed to be retired for operational reasons as discussed by Company witness Burch. The 2014 IRP Update focuses on the resources needed to meet capacity obligations as specified by the Southwest Power Pool ("SPP") capacity margin criteria. In order to continue to meet the SPP capacity margin criteria, OG&E will replace the approximate 480 MW of summer capacity gas-fired steam units to be retired at the Mustang facility with approximately 462 MW of nameplate capacity new combustion turbine generation by the summer of 2018. OG&E's system peak occurs in the summer and the contribution of each generating resource must be measured at its capability during ambient conditions expressed during the summer months as opposed to the nameplate capacity.

Q. **Please briefly describe the Company's approach to the 2014 IRP Update.**

A. The 2014 IRP identifies the resource plan that will allow OG&E to meet its capacity obligations at the lowest reasonable cost. OG&E updated its IRP in 2014 to reflect the impact of the EPA Regional Haze compliance requirement. The Company evaluated the best environmental compliance alternatives and generation resource options after performing a comprehensive update of its resource planning assumptions.

The 2014 IRP analysis is similar to the Company's prior IRPs with one significant difference: the incorporation of the impact of the SPP Integrated Marketplace ("IM") implementation.

Q. **Please describe the process that OG&E uses to develop its resource plan.**

A. OG&E's resource planning team employs a multi-step process that culminates in the development of a draft presentation to interested Stakeholders, and final IRP report. The submission of the final IRP report considers input received during meetings with our stakeholders in both Oklahoma and Arkansas.

The modeling process requires an update to all of the model assumptions including the load forecast, fuel prices, and operational attributes for each of OG&E's units and all units across the SPP footprint. We then perform an extensive number of computer simulations. These computer models use Monte Carlo simulation technology considering multiple scenarios of future conditions and sensitivities to various assumptions.

The IRP process concludes by applying OG&E's set of objectives to the collection of alternative portfolios and developing a specific 5 Year Action Plan, to meet the capacity requirement.

Q. **Did OG&E include any generating unit retirements in the 2014 IRP?**

A. Yes. The retirement date for all of OG&E's Mustang units were assumed to be by the end of 2017 and retirement dates for other gas steam generation units are reflected in Figure 5 in the attached Direct Exhibit LCH-1.

Q. **Can OG&E rely on the SPP Integrated Marketplace to cover its capacity needs?**

A. No. The SPP IM is an energy market only and not a capacity market. Thus, OG&E cannot rely on the SPP IM to cover its capacity needs should it fall short in any year. OG&E remains responsible for ensuring that it has adequate capacity either from OG&E units or from firm contracts for capacity from other resources to meet its projected peak load requirements, including a reserve margin of 12%.

Q. **When OG&E retires the existing Mustang units, does the Mustang capacity need to be replaced?**

A. Yes. Table 17 on page 39 of OG&E's 2014 IRP Update shows that the retirement of the existing Mustang units creates a capacity need. This need was evident in the 2014 and 2015 IRP updates and it continues to be true today. The capacity being retired at Mustang must be replaced pre summer of 2018 in order for OG&E to comply with the SPP planning reserve margin requirement.

Q. **How did OG&E approach the decision on how to replace the old Mustang units from a resource planning perspective?**

A. When OG&E made its decision to move forward with the CTs at the Mustang site, I had investigated other existing generation in and around OG&E's service territory, but none of those alternatives were available to serve the need in 2018 or consistent with the needs identified above. From my perspective, there were no generating units capable of providing the reliability and other benefits provided by CTs at Mustang.

The 2014 IRP Update indicated that quick-starting CTs were the lowest cost option compared with adding combined cycle units, those CTs were also highly desirable for several reliability and operational reasons. Quick start CTs can respond quickly to market signals in the SPP Integrated Marketplace ("IM"), are capable of multiple starts per day and can save operating costs by coming off-line quickly when not needed. Most importantly, with the growth of highly variable renewable generating resources in the SPP and OG&E's service territory, quick-starting CTs are able to respond quickly to fill resource needs caused by changing conditions inherent with variable generation resources like wind and solar.

Of OG&E's approximately 7000 MW of generating capacity, quick start CTs currently only constitute about one (1) percent of OG&E's current generation fleet. As discussed by OG&E Witness Nickell, Vice President of Engineering at the SPP, in a region that has seen wind generation reaching 54% of the total generation in the SPP and representing about 20% of the total SPP capacity, it is concerning for transmission system operators when that wind generation is being relied on and the wind stops blowing. The SPP needs quick starting generation to step in and replace the wind generation when the wind suddenly stops. Adding 462 MW of nameplate capacity that is flexible, such as quick start CTs, in a market containing high levels of wind and solar improves reliability. Since reliability is one of the key objectives in every decision that OG&E makes, the Company believes that additional CTs are essential to ensure reliability on the grid.

Q. **Are there any SPP studies that confirmed the need for CTs and specifically at the Mustang site?**

A. Yes. Most recently, the SPP conducted a voltage stability study to investigate the impact of variable wind generation levels on voltage stability on the SPP transmission system. The results of the study showed that even at wind generation levels much lower than those levels currently being experienced, the Oklahoma City area (the Company's largest load center) could experience system overloads and voltage collapse under certain circumstances (like the loss of a key transmission line). As testified to by Witness Lanny Nickell, , quick start CTs at the Mustang site are critical to mitigate those overloads and limit exposure to any voltage collapse situations, especially in an environment of fluctuating wind generation. This study, and the testimony of witness Nickell, validates OG&E's view that the location of the CTs at Mustang is important for system reliability reasons. In his testimony, witness Nickell concludes that "the availability of generation at Mustang is critical to reliable system operations in the Oklahoma City area. The generation OG&E has chosen, quick-start CTs, provides a valuable reliability tool to more quickly respond to system loading and voltages in the largest load center of Oklahoma."

Q. **Why did OG&E focus on installing its new generation only at the Mustang site?**

A. There were several reasons why OG&E decided to install the CTs at the Mustang site. The largest benefit of utilization of the Mustang site is the value that the site brings from a reliability perspective. As testified by OG&E Witness McAuley, CTs at the Mustang site would be the perfect solution for managing increases or decreases in voltage to stabilize the transmission system. Further, the site's connection to both the 138kV and 69kV transmission systems on the west side of Oklahoma City provides specific operational and reliability benefits including reduced line losses, reduced line congestion and cost, voltage control support, and support for the Company's system restoration plan[1].

Moreover, it is extremely rare to have a site that is both favorably situated near a load center and has many of the necessary attributes that are required to operate the facility and transmit the electricity that is produced. The Mustang location already has the necessary infrastructure in place to support a generating facility, including a secure property, roads, facilities to support operations and maintenance, water supply and rights, fuel supply facilities, and most importantly, existing electrical switchyard interconnections to both the 138kV and 69kV transmission systems. As discussed by OG&E Witness Burch, in addition to the transmission infrastructure savings, utilizing this existing infrastructure at the Mustang site is estimated to save OG&E customers between $45 and $50 million compared to replicating that same infrastructure at a new greenfield facility.

[1] As discussed in greater detail by Company witness McAuley on page 10, lines 3-26.

Q. **Does OG&E believe that its decision to replace the retiring Mustang capacity with quick-start CTs is reasonable and consistent with the public interest?**

A. Yes. While the need to retire the Mustang units was clear and difficult to rationally dispute, the Company's operational team strongly believed that the capacity needed to be located in close proximity to our largest load center, which is Oklahoma City. The Mustang plant site had unique benefits to the security of the transmission grid, a significant amount of the necessary infrastructure already in place, a trained and skilled workforce and, importantly, the support of the community in which it is located. As mentioned above, Witnesses McAuley and Nickell explain in greater detail why the Mustang site is so valuable. Selecting CTs also made sense. These quick start units accommodate greater amounts of variable generation such as wind and solar power and add dynamic, next generation technology to the new regional market. Given these factors, OG&E believes that the decision was reasonable and consistent with the public interest.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

Oklahoma Gas and
Electric Company

INTEGRATED RESOURCE PLAN

Prepared 2014 by:
OKLAHOMA GAS AND ELECTRIC COMPANY
321 N. Harvey Ave.
Oklahoma City, OK 73101

OG+E®

EXECUTIVE SUMMARY

OG&E submits its Integrated Resource Plan ("IRP") in both the Oklahoma and Arkansas jurisdictions in compliance with the IRP requirements that have been established pursuant to the Oklahoma Corporation Commission's ("OCC") Electric Utility Rules and the Arkansas Public Service Commission's ("APSC") Resource Planning Guidelines for Electric Utilities. This IRP is submitted in response to material changes in planning assumptions that have occurred since the Company's regular triennial IRP, submitted in accordance with the Commissions' rules in 2012.

The material change in planning assumptions that has occurred since the 2012 submittal involves specific environmental rules with which OG&E must now comply. Those rules include the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standards Rule ("MATS"), the Oklahoma Regional Haze State Implementation Plan ("SIP") and the EPA's Regional Haze Federal Implementation Plan ("FIP").

OG&E and the State of Oklahoma appealed the EPA's FIP in federal court. On May 27, 2014, the United States Supreme Court denied a petition to review a July, 2013 decision by the 10th Circuit Court of Appeals. That 10th Circuit decision upheld the EPA's rejection of the SO_2 emission provisions of the Oklahoma Regional Haze SIP and the implementation of the EPA FIP related to SO_2 emissions instead. With the Supreme Court order, the State of Oklahoma and OG&E have now exhausted all legal avenues in their effort to gain approval from the EPA for a less costly compliance plan that was used as one of the planning assumptions in the 2012 submittal.

The issuance of the Supreme Court decision also re-establishes Oklahoma's (and OG&E's) time to comply with the Regional Haze rule that had been suspended during the legal appeal process. OG&E must comply with those requirements by January 2019, a short deadline given the long development lead times required for compliance.

Before discussing the compliance alternatives available to the Company, it is instructive to review OG&E's efforts to dramatically reconfigure its resource portfolio since announcing its "2020 Goal" in October 2007. The 2020 Goal established the objective of deferring the addition of new fossil fuel capacity until at least 2020 and maintaining flexibility to address future environmental regulations in the manner most beneficial to our customers. OG&E's strategy for meeting the 2020 goal included new wind energy, additional transmission in western Oklahoma to enhance the delivery of wind energy, new customer energy efficiency programs, smart grid supported demand response, and terminating wholesale electricity sales contracts. Over time, OG&E has retired 237 MW of aging and less efficient power plants, added 671 MW of wind energy and constructed multiple transmission lines that support wind energy development in the region. OG&E also restructured existing demand reduction programs, added a combination of new energy efficiency and demand response programs, including the technology enabled SmartHours program, and announced the termination of 300MW of wholesale contracts by 2015. As a result of these actions, OG&E's customers have benefited in the short term through lower costs and the Company is better positioned to address an uncertain environmental future.

For this IRP, OG&E must now determine which of several alternatives meets the requirements of the EPA FIP and MATS obligations, while serving the best long-term interests of our customers in light of future environmental uncertainties.

This IRP identifies the best environmental compliance alternative based on a calculation of the lowest, reasonable cost to our customers. In order to do so, the Company performed an extensive update of its IRP models and planning assumptions in order to produce an IRP that reflects the current operating and regulatory environment. This included updates to its load forecast, demand-side resources, existing unit characteristics, retirement plan, new unit costs and generating characteristics, emission control costs, fuel prices, CO_2 cost assumptions and Southwest Power Pool ("SPP") Integrated Marketplace ("IM") prices.

As further described in Section V. of the IRP, OG&E evaluated five alternative environmental compliance plans that capture the range of possibilities including unit replacement, installation of scrubber technology, and conversion of existing generation from coal to natural gas. Each of these alternatives has been subjected to scenario and sensitivity analyses to assess the impact of uncertainties associated with key input assumptions including fuel prices and the potential impacts of future carbon regulation. The results were evaluated against a set of portfolio objectives that included the projected cost to our customers over a 30-year period and other important customer objectives including fuel diversity and future regulatory risks.

This analysis indicated that the "Scrub/Convert" alternative is the best approach. The "Scrub/Convert" alternative involves the installation of dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. It is the lowest cost alternative in the base case and provides a compromise between the "Scrub" alternative with its high CO_2 risk and the "Convert" alternative that exposes customers to high natural gas price risk. After considering all of the possibilities, OG&E selected the "Scrub/Convert" alternative which is, in OG&E's view, the lowest reasonable cost with due consideration to the uncertainty associated with fuel and carbon prices.

This IRP also reflects the recently implemented SPP IM, which went live on March 1, 2014. The SPP IM includes a Day Ahead market and several other features that will commit and dispatch resources and transmission flows to serve electricity loads across the multi-state SPP footprint. While OG&E is still required to own or control sufficient generation capacity to meet SPP planning reserve requirements, the Company now obtains all of its energy through the SPP IM rather than relying on its own resources. As a consequence, the evaluation of OG&E's prospective resource needs incorporates an analysis of generation resources, transmission constraints and market conditions for the entire SPP region.

In the context of environmental concerns, the SPP IM and the need to meet capacity requirements, OG&E began to focus more closely on its Mustang plant. OG&E concluded that retirement of the Mustang steam units in late 2017 and replacement with new, efficient combustion turbines ("CTs") at the existing Mustang site in 2018 and 2019 is the best course of action. The initial Mustang unit was built in 1950 and each of the Mustang units has already operated well beyond the retirement age of nearly all units in the United States of similar type and size. A significant failure could render the existing units unavailable to meet load requirements for an extended period of time and/or indefinitely.

OG&E chose the existing Mustang site as the location for the new CTs for several reasons. Since it is close to OG&E's largest load center, the site provides valuable reliability support and voltage control functions. The site is also beneficial because of existing infrastructure such as secure property, electric transmission and interconnection facilities, a gas pipeline connection, roads, buildings, water lines, water rights to support operation and maintenance of the plant, an existing workforce and community support. In addition, retiring and replacing the capacity of the Mustang steam units on the aforementioned schedule allows OG&E to take advantage of existing site-specific environmental permits. Delaying replacement of these units will limit or eliminate OG&E's ability to permit the capacity that OG&E needs to meet SPP planning capacity margin requirements at the Mustang site. The addition of new CTs at Mustang will also enhance the development of additional wind in Oklahoma.

OG&E believes the IRP accomplishes a number of key objectives:

- Places the Company in compliance with Regional Haze and MATS requirements within the prescribed deadlines.
- Provides a balanced approach of cost and risk while preserving fuel diversity and ensures SPP capacity requirements are met.
- Preserves the strategic Mustang site, enhances the availability of Oklahoma wind, preserves jobs, and provides reliability benefits in the SPP IM.
- Provides the best opportunity to hold down customers' costs in a variety of future circumstances.

OG&E takes very seriously its responsibility to provide reliable, reasonably priced power produced in an environmentally responsible way. This IRP reflects OG&E's plan to meet federal mandates in a way that minimizes the impact on customers. Unfortunately, all alternatives available to the Company increase customer costs. After carefully considering all these factors, OG&E has decided to convert two coal-fired units at the Muskogee Power Plant to natural gas, add scrubbers to the coal-fired units at the Sooner power plant, and other pollution control equipment to other units, and replace vintage natural gas steam units at the Mustang Power Plant with modern combustion turbines.

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List of Acronyms

Acronym	Phrase Represented	Reference
ACI	Activated Carbon Injection	Technology
APSC	Arkansas Public Service Commission	Agency
BART	Best Available Retrofit Technology	Technology
CAA	Clean Air Act	EPA
CC	Combined Cycle electricity generating unit	Technology
CCR	Coal Combustion Residuals Rule	EPA
CSAPR	Cross-State Air Pollution Rule	EPA
CT	Combustion Turbine electricity generating unit	Technology
DG	Distributed Generation	Technology
DR	Demand Response	OG&E
DSM	Demand Side Management	Industry
EE	Energy Efficiency	OG&E
EHV	Extra High Voltage	Technology
EIA	Energy Information Administration	Agency
EIS	Energy Imbalance Services	SPP
EPA	Environmental Protection Agency	Agency
FERC	Federal Energy Regulatory Commission	Agency
FIP	Federal Implementation Plan	EPA
IM	Integrated Marketplace	SPP
IRP	Integrated Resource Plan	Industry
ITP	Integrated Transmission Planning	SPP
ITP10	Integrated Transmission Planning 10 Year Assessment	SPP
ITP20	Integrated Transmission Planning 20 Year Assessment	SPP
ITPNT	Integrated Transmission Planning Near-Term Assessment	SPP
IVVC	Integrated Volt Var Control	OG&E
LMP	Locational Marginal Price	SPP
MATS	Mercury and Air Toxics Standards Rule	EPA
NAAQS	National Ambient Air Quality Standards	EPA
NERC	North American Electric Reliability Corporation	Agency
NPV	Net Present Value	General
NPVCC	Net Present Value of Customer Cost	OG&E
OCC	Oklahoma Corporation Commission	Agency
PPA	Purchase Power Agreement	Industry
PV	Photovoltaic	Technology
RFI	Request for Information	General
RFP	Request for Proposals	General
SIP	State Implementation Plan	OK
SPP	Southwest Power Pool	SPP
STEP	SPP Transmission Expansion Plan	SPP

I. INTRODUCTION

A. Purpose of the IRP Submittal

OG&E submits this IRP pursuant to the OCC Electric Utility Rules and the APSC Resource Planning Guidelines for Electric Utilities. OG&E submitted its last IRP in both jurisdictions in October 2012. This submittal is being made primarily in response to the EPA Mercury and Air Toxics Standards Rule ("MATS"), the US Supreme Court's May 27, 2014 order that affirmed the EPA's rejection of Oklahoma's proposed SIP and implementation of a FIP. As a result, in order to comply with the Regional Haze requirements of the Clean Air Act ("CAA"), OG&E must now comply with the EPA's FIP. As indicated in Figure 1, our 2012 IRP assumed that Oklahoma's SIP would ultimately be accepted by the EPA.

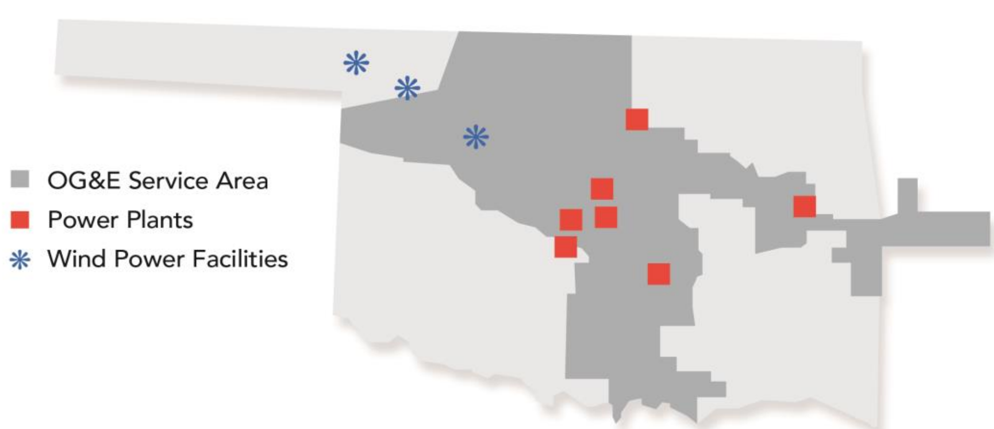
Figure 1: IRP Compliance assumption

2012 IRP assumed compliance with SIP for SO_2	→	2014 IRP update assumes compliance with FIP for SO_2

B. Description of OG&E Service Territory

OG&E serves more than 800,000 retail customers in Oklahoma and western Arkansas, as well as a number of wholesale customers throughout the region. The service territory covers approximately 30,000 square miles, includes 268 communities and surrounding areas, and has a population of approximately 2 million. OG&E serves Oklahoma City, which is the largest city in Oklahoma, as well as Ft. Smith, Arkansas. Of the 268 communities served by OG&E, 242 are in Oklahoma, and 26 are in Arkansas. OG&E's retail service area is shown in Figure 2.

Figure 2: OG&E Service Area



C. Outline of the Report

This IRP Report and Appendices comply with OCC Electric Utility Rules and APSC Resource Planning Guidelines for Electric Utilities. The organization of the report is similar to prior reports except that OG&E has included a new section immediately following this Introduction that describes the new SPP IM and OG&E's environmental compliance obligations, and provides context as to how each of these developments relates to OG&E's 2020 Goal.

The balance of the analysis is organized like previous IRPs. Section III presents the IRP objectives and process. Section IV offers the demand and energy forecast and modeling assumptions and inputs used in the analysis. Section V explains the analysis methodology and results. Section VI summarizes the five-year action plan. Section VII concludes the report with the following schedules as required by Oklahoma Corporation Commission rule OAC 165:35-37-4(c):

A. Electric demand and energy forecast
B. Forecast of capacity and energy contributions from existing and committed supply- and demand-side resources
C. Description of transmission capabilities and needs covering the forecast period
D. Assessment of the need for additional resources
E. Description of the supply, demand-side and transmission options available to the utility to address the identified needs
F. Fuel procurement plan, purchased power procurement plan, and risk management plan
G. Action plan identifying the near-term (i.e., across the first five (5) years) actions
H. Proposed RFP(s) documentation, and evaluation
I. Technical appendix for the data, assumptions and descriptions of models
J. Description and analysis of the adequacy of its existing transmission system
K. Assessment of the need for additional resources to meet reliability, cost and price, environmental or other criteria
L. An analysis of the utility's proposed resource plan
M. Description and analysis of the utility's consideration of physical and financial hedging to determine the utility's ability to mitigate price volatility

The report also includes several Appendices. Appendix A presents OG&E's 2013 Load Forecast. Appendix B presents the annual customer costs for the resource portfolios discussed in the plan. Appendix C presents the annual emissions for the resource portfolios. Appendix D presents the CO_2 cost calculation used in the development of sensitivities. Appendix E presents the technical conference minutes for Oklahoma.

II. THE 2020 GOAL, SPP'S INTEGRATED MARKETPLACE, AND OG&E'S ENVIRONMENTAL COMPLIANCE CHALLENGES

This section reviews the actions that OG&E has taken to reconfigure its portfolio since 2007, SPP's new Integrated Marketplace ("IM") and its impact on OG&E's resource planning process, and the environmental challenges that must be addressed by OG&E.

The 2020 Goal and OG&E's prior actions to meet that goal provide the foundation for this IRP. OG&E's customers are already using electricity more efficiently and shifting their usage from peak to non-peak hours. OG&E will continue investments and programs that achieve further gains on the customer side of the meter. The generation fleet also is more efficient and produces far fewer emissions than it did in 2007. Through the additions of wind energy, OG&E's generation portfolio is more diverse than it has ever been.

A. OG&E's 2020 Goal Progress

The 2020 Goal established the objective to defer the addition of new, incremental fossil fuel capacity until at least 2020 through a combination of wind energy, new energy efficiency programs, smart grid-enabled demand response, and termination of wholesale contracts and by doing so, defer the construction of new incremental fossil fuel generation until 2020 despite the retirement of 237MW of aging and less efficient generation. The specific changes undertaken by OG&E since the goal was announced in the fall of 2007, including demand-side management ("DSM") actions to date are presented in Table 1.

Table 1: 2020 Goal Actions to Date (MW)

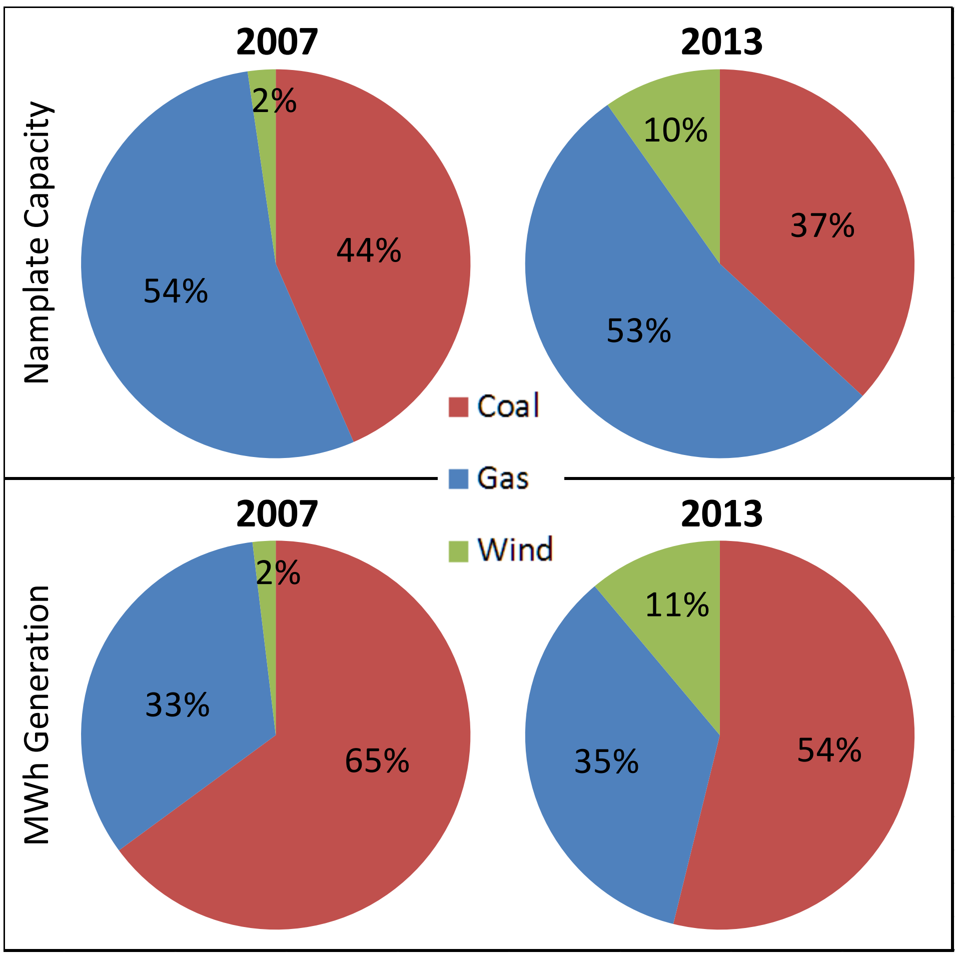
Year	Wind	DSM	Wholesale
2008		2	18
2009	OU Spirit – 101	13	
2010	Keenan – 152	12	5
2011	Taloga – 130 Crossroads – 228	22	
2012	Cowboy – 60	118	14
2013		99	50
Total	**671 MW**	**266 MW**	**87 MW**

As shown in Table 1, OG&E added 671 MW of wind generation over this period bringing OG&E's total nameplate wind capacity to 841 MW. Load reduction from demand-side resources increased by 266 MW and OG&E terminated 87 MW of wholesale contracts over this period, further offsetting the amount of capacity that OG&E would otherwise need in its portfolio. Additionally by May of 2015, OG&E will complete its exit from the wholesale market with the remaining 300 MW of wholesale contracts being terminated. Also, by 2015, over 300 MW of demand-side resources will be utilized through a combination of energy efficiency and demand response programs, including the technology-enabled SmartHours program.

In addition to the actions taken to support the 2020 Goal, OG&E also retired several units over this period without replacement: four circa-1965 combustion turbines with a total capacity of 56 MW at Enid, a 10 MW CT at Woodward, and a 171 MW gas steam plant at Muskogee. Continued operation of the Enid and Woodward CTs, as discussed in the 2012 IRP, would have required the installation of Selective Catalytic Reduction technology to bring NOx emissions within required limits.

These actions have significantly changed OG&E's capacity and generation mix as shown in Figure 3. Wind capacity represents nameplate capacity and does not represent planning capacity margin.

Figure 3: Nameplate Capacity and Generation Mix Changes



B. SPP's Integrated Marketplace

SPP launched its IM on March 1, 2014 after a decade of planning and development efforts. The IM is designed to improve the efficiency of the electricity system across the

SPP footprint and to share those benefits with SPP members and their customers. The IM represents the next step in the evolution of SPP from a regional reliability organization at its founding in 1941 to becoming a Regional Transmission Organization in 2004 to operating an Energy Imbalance Services ("EIS") market in 2007.

The IM is a major enhancement to the market functions initiated by SPP in March 2014. In designing the IM, SPP has worked with stakeholders in an effort to benefit from the experiences of other regional market designs, while reflecting the specific circumstances of the SPP region, including the existing and potential resource base and the objectives of the region's state regulators. The IM is expected to contribute to more efficient transmission and generation capacity development, enhance the ability for both buyers and sellers to hedge risk, and enhance reliability across the SPP footprint through a regional balancing of supply and demand. SPP has projected that the IM will generate approximately $45M to $100M of savings per year, to be shared among the members. OG&E represents approximately 13% of the total load in SPP and expects to realize a similar percentage of the overall market savings.

The IM will accomplish these various objectives through the following capabilities:
(1) a Day-Ahead Market with Transmission Congestion Rights;
(2) a Reliability Unit Commitment process;
(3) a Real-Time Balancing Market that supplants SPP's EIS Market;
(4) a price-driven Operating Reserve Market; and
(5) a single SPP-wide Balancing Authority.

The IM does not operate a capacity market or conduct an annual regional process to obtain incremental capacity, as is the case in certain other regions. OG&E will remain responsible for ensuring that it has planning capacity sufficient to serve its peak load requirements. It must meet these capacity obligations through OG&E-owned generation or contracts for capacity.

OG&E's minimum capacity planning reserve margin continues to be established pursuant to Section 4.3.5 of the SPP Criteria as follows:

> Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities.

Thus, OG&E is required to maintain capacity levels that allow for a minimum of 12% margin between capacity and demand. This calculation is explained in Section 2.1 of the SPP Criteria as represented in the following equation:

$$\text{Capacity Margin \%} = \frac{(\text{Total Net Capability}) - (\text{Net On System Demand})}{(\text{Total Net Capability})}$$

This obligation has not changed under the IM and is identical to the capacity planning assumption that was reflected in OG&E's 2012 IRP. However, OG&E and all other Load Serving Entities now obtain all of their energy through the IM and pay hourly locational marginal prices established by the market, rather than relying on owned or contracted assets for energy. Also, OG&E sells all of its energy generated by its assets, including contracted assets, into the IM so the IM will have a direct impact on (1) the degree to which OG&E's generation resources will be called upon to provide electricity and (2) on the revenues that will result from SPP market compensation mechanisms that establish hourly locational prices to be paid to each generation source.

As a result, in order to evaluate new generation resources in the IRP, it is necessary to forecast the market prices for the region that will apply to electricity generated by OG&E units and to purchases from the market to serve OG&E's load. As described in Section IV E, OG&E utilizes Ventyx PROMOD IV, an electric market simulation tool which incorporates generating unit operating characteristics, transmission grid topology and constraints, to estimate future energy prices in the SPP IM. Further, market conditions such as availability of diverse generation resources, fuel pricing and emission costs will impact market pricing and this is reflected in the design of scenario analyses that capture the uncertainty in these areas.

C. Environmental Compliance Obligations

The electricity production activities of OG&E are subject to a stringent, complex and interrelated set of existing Federal, state and local laws and regulations, especially those governing environmental protection. These laws and regulations can restrict or impact OG&E's business activities in many ways including requiring remedial action to mitigate certain emissions and discharges, restricting the way OG&E handles or disposes of its wastes, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of emission control equipment.

Existing and potential environmental obligations have a major impact on OG&E's resource plan and have been examined in several prior IRP submittals. OG&E's 2014 IRP is designed to meet the existing environmental obligations while at the same time also considering the potential of future environmental regulations, even though certainty of these rules, including the potential regulation of greenhouse gas emissions, are not settled.

1. Compliance with the MATS and Regional Haze Rules

The focus of OG&E's existing environmental obligations is on the emissions of SO_2, NOx, and certain hazardous air pollutants. Of immediate concern are the MATS and Regional Haze rules, which combine to impact OG&E's coal and gas steam units.

a) Mercury and Air Toxics Standards Rule

The final MATS rule, published on February 16, 2012 and effective April 16, 2012, includes numerical standards for particulate matter (as a surrogate for metals), hydrogen chloride (acid gases) and mercury emissions from coal-fired boilers. The regulations also include work practices for dioxins and furans. Compliance is required by April 16, 2015 unless extended for one year by the state environmental regulatory agency. OG&E requested and has received a one-year extension for compliance to April 16, 2016 from the Oklahoma Department of Environmental Quality.

OG&E plans to comply with MATS by installing activated carbon injection ("ACI") at five coal-fired units. The cost of installing ACI on all five of OG&E's coal units is estimated to be $24 million. OG&E does not believe any retrofits are necessary at its five coal-fired generating units to comply with the particulate matter and acid gas emission limits.

Because of the relatively low cost of the ACI systems and the three-year difference in the compliance timeframes for MATS and Regional Haze, OG&E determined that installing ACI at the five coal-fired units was the least-cost choice irrespective of a subsequent decision with respect to its coal units under the Regional Haze compliance plan. In order to comply with the April 16, 2016 MATS compliance deadline, OG&E has begun the engineering and design process to support ACI installation and is currently scheduled to finish the construction and installation by January 2016.

b) Regional Haze and the Federal Implementation Plan

On July 6, 2005, the EPA published final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. These regulations are intended to protect visibility in certain national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains is the only area covered under the regulation. However, Oklahoma's impact on national parks in other states must also be evaluated.

As required by the Federal regional haze rule, the State of Oklahoma evaluated the installation of Best Available Retrofit Technology ("BART") to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. Certain units at the Horseshoe Lake, Seminole, Muskogee and Sooner generating stations were evaluated for BART. On February 17, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The Oklahoma SIP included requirements for reducing emissions of NO_X and SO_2 from OG&E's seven BART-eligible units: Seminole Units 1, 2 & 3, Muskogee Units 4 & 5, and Sooner Units 1 & 2.[1] The SIP also included an approved waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP was subject to the EPA's review and approval.

[1] Muskogee Unit 6 was not in existence prior to August 7, 1977; therefore, Unit 6 is not a BART-eligible source. Unit 6 commenced commercial operation in mid-1984.

On December 28, 2011, the EPA rejected portions of the Oklahoma SIP and published a FIP related to Regional Haze SO_2 emission requirements. While the EPA accepted Oklahoma's BART determination for NO_X in the SIP, it rejected the SO_2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. In its place, the EPA implemented its FIP requiring that OG&E meet an SO_2 emission rate of 0.06 pounds per MMBtu within five years. OG&E can meet the proposed standard by either installing and operating Flue Gas Desulfurization equipment (scrubbers) or fuel switching to natural gas at the four affected units.

The State of Oklahoma and OG&E challenged the FIP at the 10th Circuit Court of Appeals and the 10th Circuit Court of Appeals upheld the EPA's rejection of the SO_2 emission portion of Oklahoma SIP and the EPA's implementation of the FIP in July 2013. Review by the United States Supreme Court of the 10th Circuit's decision was sought and denied by the Supreme Court on May 27, 2014, causing the 10th Circuit's decision to become final. One positive of these various legal proceedings is that OG&E received a stay of the FIP, which extended the compliance deadline for the SO_2 portion of the FIP.[2] The Court's stay was lifted on May 30, 2014 making the FIP compliance deadline January 4, 2019.

As explained in Section V, OG&E has modeled several scenarios that would meet the Regional Haze FIP SO_2 emission limits, including scrubbing all four affected units, converting or replacing all such units to natural gas and a combination of scrubbing and conversion/replacement.

c) Initial Actions to Comply with the MATS and Regional Haze Rules

OG&E has already taken certain actions to address these existing requirements by installing emission control equipment at eight of its units. Specifically, OG&E is installing low NOx burners at seven units (Muskogee 4 & 5, Sooner 1 & 2, and Seminole 1, 2 & 3) and ACI at its five coal-fired units. These investments are shown in Table 2.

Table 2: Environmental Equipment Installation Plans

Equipment	Begin Construction	Completion	Approximate Investment Cost*
Low NO_X Burners on 7 Units	Feb-13	Jan-17	$100 million
Activated Carbon Injection on 5 Units	Apr-15	Apr-16	$24 million

**Includes both past and future investment.*

2 The compliance deadline for the NOx portion of the Oklahoma SIP remains January 2017, as this portion of the Oklahoma SIP was approved by the EPA and was not subject to the stays granted by the 10th Circuit while the FIP was being challenged.

2. Future Environmental Compliance Risks

Environmental regulations are expected to become ever more stringent, requiring increased capital expenditures for control equipment and increased costs to operate the control equipment and to report compliance. Many of the new and more stringent requirements are focused on coal-fired generation. Some environmental advocacy organizations have a stated goal of ending the generation of electricity with coal by mid-century to address climate change.

With respect to new or proposed environmental rules or actions by the EPA that would affect OG&E's generation portfolio, they are numerous and include: (i) EPA's Cross-State Air Pollution Rule ("CSAPR") that restricts NO_x emissions during the ozone season from May 1 through September 30, (ii) EPA's proposed Coal Combustion Residuals Rule ("CCR") that will affect the disposal of coal ash from coal plants, (iii) EPA's new rule under Section 316(b) of the Clean Water Act regulating intakes of water used as a coolant in the power production process, (iv) EPA's proposed standards for greenhouse gas emissions from existing power plants, (v) EPA's adoption in the future of more stringent standards for pollutants covered by the National Ambient Air Quality Standards, and (vi) additional reviews by the EPA of future SIPs by Oklahoma to comply with regional haze provisions of the CAA. In addition, OG&E could be impacted by the Endangered Species Act and New Source Review Litigation.

a) Cross-State Air Pollution Rule

On August 8, 2011, the EPA published CSAPR to replace the former Clean Air Interstate Rule that was remanded by a federal court as a result of legal challenges. The final rule would require 27 states to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. On December 27, 2011, the EPA published a supplemental rule ("Supplemental Rule"), which would make five additional states, including Oklahoma, subject to CSAPR for NO_X emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E would have been required to reduce ozone-season NO_X emissions from its electrical generating units within the state beginning in 2012. Both rules were challenged in court by numerous states and utilities. On December 30, 2011, the D.C. Circuit Court of Appeals stayed the applicability of both rules. On August 21, 2012, the D.C. Circuit Court vacated CSAPR and ordered the EPA to promulgate a replacement rule. The Supplemental rule was not vacated with the original rule but remained stayed at the D.C Circuit Court of Appeals pending briefing of the merits. After further appeal of the original CSAPR to the U.S Supreme Court, the Supreme Court, on April 29, 2014, reversed and remanded the case to the D.C Circuit Court to resolve a number of outstanding technical issues. Until the outcome of the court process including the briefing of the merits on the Supplemental Rule is known, the CSAPR requirements remained stayed but not vacated for the State of Oklahoma. The low NOx combustion equipment being installed for regional haze also will help meet the CSAPR requirements contained in the Supplemental Rule. At this point, it is not clear if those measures by themselves will be enough to satisfy CSAPR or if OG&E will have to consider installing additional controls or purchasing emission credits.

b) Coal Combustion Residuals

The EPA published the proposed CCR rule in June 2010, establishing standards for the management and disposal of byproducts of coal combustion in power plants (coal ash, etc.). EPA has a December 2014 deadline to finalize the rule. As proposed, the rule contains three primary options, including one program to regulate CCRs as hazardous waste, and two options to regulate CCRs as non-hazardous solid wastes. The CCR rule could require additional investment in the existing coal plants depending on the option that is included in the final rule. The CCR rule could restrict OG&E's ability to manage its coal ash through beneficial re-use, thus increasing the cost of managing coal ash.

c) Section 316(b) of the Clean Water Act

The EPA published a proposed cooling water intake rule in April 2011 under Section 316(b) of the Clean Water Act. A final rule was released on May 19, 2014. This rule establishes technological standards for the design and operation of cooling water intake structures at existing electric generating facilities to lessen their impacts on fish and other aquatic life. Facilities have the ability to choose one of seven options for meeting best technology available requirements for reducing impacts but may also be required to conduct further biological studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms entrained by cooling water systems. This decision process would include public input. OG&E is still evaluating the final rule to determine the impact on OG&E facilities.

d) Greenhouse Gas Regulations

The EPA proposed emissions standards for greenhouse gas emissions from new electric utility fossil-fuel steam generating units and combustion turbines on January 8, 2014. The EPA has determined that partial carbon capture and storage is the "best system of emission reduction" for new coal plants and that new natural gas combined cycle technology will suffice for natural gas turbines, specifying limits for emissions of CO_2 for each fuel source. The EPA is expected to issue a final rule by the end of 2014. On June 18, 2014, the EPA published a rule for existing power plants. This proposed rule would require the State of Oklahoma to propose a plan to reduce CO_2 emissions in the state by 43% in 2030 compared to 2012, with an interim requirement for an average 40% reduction between 2020 and 2029. OG&E is still reviewing the details of this important rule. EPA has stated that it anticipates finalizing the rule by June 1, 2015. OG&E's plan to convert two coal units to natural gas will reduce CO_2 emissions from OG&E's generation fleet, positioning the Company to provide a meaningful contribution to any state CO_2 reductions ultimately required by the EPA.

OG&E has accounted for the considerable uncertainty regarding regulation of greenhouse gas emissions by including a carbon tax in its sensitivity analyses.

e) National Ambient Air Quality Standards ("NAAQS")

The EPA is required to set NAAQS designed to be protective of human health and the environment for six specific pollutants. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. For example, in 2010, the EPA revised the NAAQS for SO_2 and NO_2, establishing new one-hour standards that are significantly more stringent than the prior standards. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, OG&E could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS.

In addition to tightening standards, the EPA has proposed new ways to determine whether areas are in attainment with the NAAQS. This new process uses computer modeling instead of actual monitored emissions to determine whether violations of the standards may occur. If EPA implements such a process, such computer models may be used to move areas of Oklahoma into non-attainment status. As of the end of 2013, no areas of Oklahoma had been designated as non-attainment for pollutants that are likely to affect OG&E's operations. However, in recent years, monitored ozone levels in Oklahoma have been close to a NAAQS exceedance level and this assessment is reviewed each year and measured against the standard that is currently in effect.

f) Future Requirements under Regional Haze

When EPA disapproved Oklahoma’s BART determinations under Regional Haze for OG&E’s four coal-fired units, it said it was taking no action on whether the state had satisfied the reasonable progress requirements of the regional haze provisions in the Clean Air Act. Environmental groups have now sued EPA to force it to take action on this aspect of Oklahoma’s regional haze plan. Subject to court approval, EPA has agreed to issue a proposed rule by Nov. 15, 2014 and a final rule by Sep. 4, 2015. The rule could be used to adopt emission limits that are more stringent than BART or to apply emission limits to sources that were not subject to BART, although the impact on OG&E, if any, cannot be determined until there is a specific proposal.

The Regional Haze Rule provides for several planning periods prior to the 2064 deadline for achieving the national goal of natural visibility conditions in Class I Federal areas. States are required to develop a SIP for each planning period. The second planning period commences in 2019. It is anticipated that, during the second planning period, additional reductions of emissions affecting visibility may be required, or reductions may be required from additional sources, beyond those regulated in the first planning period.

g) Endangered Species Act and other Federal Laws

Certain federal laws, including the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unauthorized activities that result in harm to or, harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which OG&E conducts operations, or if additional species in those areas become subject to protection, OG&E’s operations and development projects, particularly transmission or wind projects, could be restricted or delayed, or OG&E could be required to implement expensive mitigation measures.

The U.S. Fish and Wildlife Service announced a proposed rule to list the Lesser Prairie Chicken as threatened on November 30, 2012. The decision applies to a 5-state area including parts of Oklahoma where OG&E has undertaken the development of certain large transmission projects. On March 10, 2014, OG&E enrolled in the Western Association of Fish and Wildlife Agencies' Range-Wide Conservation Plan for the Lesser Prairie Chicken. This Range-Wide Conservation Plan consists of industry-specific conservation practices that apply to new and existing projects and activities in the impacted area. The Range-Wide Conservation Plan has been approved by the U.S. Fish and Wildlife Service and incorporated as part of the agency's final decision on March 27, 2014 to list the lesser prairie chicken as a threatened species. More than 32 companies have enrolled in the Range-Wide Conservation Plan.

h) New Source Review Litigation

On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. On July 8, 2013, the Department of Justice at the request of the EPA, filed a complaint for declaratory relief against OG&E in U.S District Court for the Western District of Oklahoma (Case No. CIV-13-690-D) alleging that OG&E did not follow the Clean Air Act procedures for projecting emission increases attributable to eight projects that occurred between 2003 and 2006. This complaint seeks to have OG&E submit a new assessment of whether the projects were likely to result in a significant emissions increase. The Sierra Club has intervened in this proceeding and has asserted claims for declaratory relief that are similar to those requested by the United States. The United States has filed a motion for summary judgment against OG&E, and OG&E has filed a motion to dismiss the claims by the United States and the Sierra Club. These motions have been briefed and are waiting for a decision from the court.

If OG&E does not ultimately prevail in these proceedings, the EPA and the Sierra Club could seek to require OG&E to install additional pollution control equipment, including scrubbers, baghouses and selective catalytic reduction systems.

On August 12, 2013, the Sierra Club filed a separate complaint against OG&E in the U.S District Court for the Eastern District of Oklahoma (Case No. 13-CV-00356) alleging that OG&E's modifications made at Unit 6 of the Muskogee generating plant in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant has exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. On November 4, 2013, OG&E filed a Motion to Dismiss and on March 4, 2014, the District Court issued an Order dismissing the prevention of significant deterioration claim but allowing the claim relating to opacity and particulate matter emissions to continue. On May 21, 2014, OG&E filed a motion for summary judgment on the remaining opacity and particulate matter claims. At the same time, Sierra Club issued a notice of intent to assert additional opacity and particulate matter claims monitoring and emission limit claims not only against Muskogee 6, but also against Muskogee Units 4 and 5.

If OG&E does not prevail in these proceedings, the Sierra Club could seek penalties and could seek to require OG&E to install additional pollution control equipment, including baghouses.

III. IRP OBJECTIVES AND PROCESS

A. IRP Objectives

OG&E strives to develop a lowest reasonable cost resource plan that will allow it to meet its capacity obligations over the 30-year planning horizon at the lowest reasonable cost (as represented by the Net Present Value of Customer Cost or "NPVCC") with due consideration to the uncertainties attributable to many of the planning assumptions including fuel prices and future environmental regulations. Every generation technology has a differing set of capital costs, O&M costs, and operating characteristics (i.e., the ability to start quickly or run at less than full loading) and these differences are captured in the IRP modeling and reflected in NPVCC calculations.

A primary planning objective that OG&E relies on to address the uncertainties in fuel and emission prices is fuel diversity. Fuel diversity helps to ensure stability in prices and reliability in electric supply, protecting the company and customers from short term contingencies such as fuel unavailability. Natural gas may have limited availability during times of extreme cold weather when well heads can freeze, impacting both the amount of flowing gas and the ability of pipelines to reach carrying capacities. Coal can also have delivery issues which threaten supply, including production problems at the mine site and railroad transportation issues. Catastrophic weather events such as floods, tornado, and weather extremes can impact both fuels.

Fuel diversity also provides protection from fuel price fluctuations caused by market conditions as well as longer term contingencies such as changes in regulatory practices that can drive up the cost of a particular fuel.

OG&E's goal is to meet SPP's planning capacity margin requirements with a fuel diverse generation fleet. The sensitivity of portfolio NPVCCs to price forecasts depends to a considerable degree on the nature of the generation mix. For example, the NPVCC of a portfolio that is heavily weighted toward natural gas plants will be relatively insulated from the impact of carbon prices but will swing widely in response to volatility in natural gas prices. Similarly, the NPVCC of a portfolio that is heavily dependent on coal resources will be relatively sensitive to carbon prices and also be at risk should regulation of CO_2 take a less flexible form than a market-based approach. Finally, wind energy provides very little capacity value (and may not generate energy when it is most needed and most valuable).

Thus, while a portfolio with a lower NPVCC is clearly preferred, a portfolio with the lowest NPVCC in any scenario may not represent the lowest reasonable cost portfolio, even if all portfolios are equally reliable. A portfolio that mitigates risks may be preferred to a portfolio that has moderately lower NPVCC but exposes customers to greater risks that actual costs will end up being much higher under a different set of plausible assumptions. The most desirable portfolio can be characterized as a "robust" portfolio because it will produce an acceptable NPVCC outcome under a wide range of plausible assumptions.

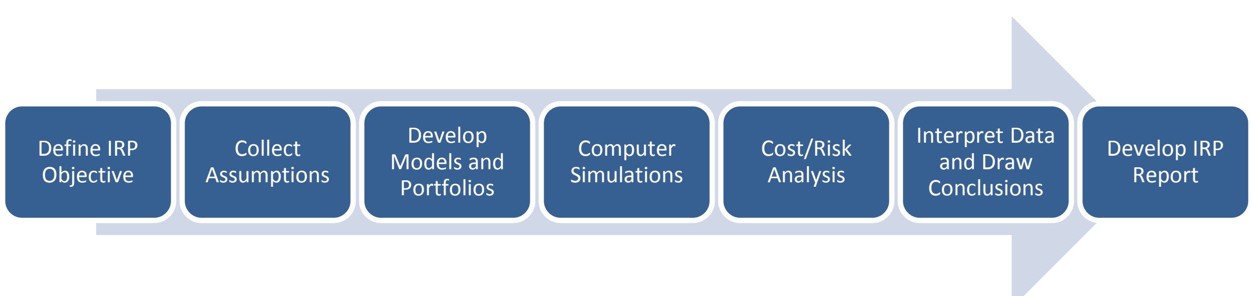
To identify the robust portfolio, OG&E is guided by the following objectives:

(1) Reliability: satisfy SPP's planning capacity margin requirements throughout the 30-year planning horizon;
(2) Compliance with Existing Environmental Rules: satisfy the requirements of MATS and the Regional Haze FIP;
(3) Expected Cost to Consumers: lowest reasonable NPVCC subject to satisfying other IRP objectives;
(4) Fuel Diversity: maintain a reasonable balance among natural gas, coal, and wind, and other economically viable renewable resources;
(5) Operational Flexibility: maintain or increase the ability of OG&E's portfolio to respond at SPP's direction to localized reliability issues (through quick-start peaking units, for example);
(6) Portfolio Age: maintain a reasonable balance of capacity as measured by expected remaining asset life;
(7) Demand-Side Resources: maximize the reliance on economic demand-side resources;
(8) Exposure to Fuel and Emissions Prices: consider the sensitivity of NPVCC based on different assumptions regarding fuel and emissions prices;
(9) Exposure to Future Environmental Regulation: consider the potential that future environmental regulations (particularly regulations intended to address greenhouse gases) may result in costly environmental compliance solutions.

B. IRP Process

The IRP "process" also remains largely unchanged although it is now necessary to estimate the operation of SPP's IM by forecasting the market prices for the region that will apply to electricity generated by OG&E units and to purchases from the market to serve OG&E load. A seven-step process is used to accomplish the IRP objective, illustrated in Figure 4.

Figure 4: Integrated Resource Planning Seven Step Process



IV. ASSUMPTIONS AND INPUTS

OG&E performed an extensive update of its IRP models and assumptions in order to produce an IRP that is "current". This section describes the major assumptions: (A) OG&E's 2013 load forecast including demand-side resources, (B) Supply-Side resources from existing units and their transition to new resources and environmental control alternatives, (C) SPP transmission additions, (D) Fuel price forecast and CO_2 price forecast used in sensitivity analysis, and (E) SPP Market Price forecast under several scenarios and sensitivities.

A. 2013 Load Forecast and Demand Side Resources

OG&E prepared the September 2013 load forecast that is presented in Appendix A. The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of electricity prices for price-sensitive customer classes. The final energy and demand forecast includes Federal Energy Regulatory Commission ("FERC") jurisdictional wholesale contracts as adjustments to the forecast on top of the load forecasting modeling results. All OG&E wholesale contracts are scheduled to expire by mid-2015.

Estimates of demand-side resources, incremental to those already reflected in the econometric-based forecast, are developed based on the continued growth in existing OG&E programs and new programs. Growth in Distributed Generation ("DG") is not currently included in the load forecast but is considered in the market price sensitivity section of this report. A more complete discussion of the topic is presented there.

1. Load Forecast – Energy and Peak Demand

Load forecasting includes projections of annual energy sales and peak demand.

a) Energy Sales Forecast Methodology

The retail energy forecast is based on retail sector-level econometric models representing weather, growth and economic conditions in OG&E's Oklahoma and Arkansas service territories. Historical and forecast economic variables (drivers) used in the models are provided by the Center for Applied Economic Research at Oklahoma State University.

b) Peak Demand Forecast Methodology

The load responsibility forecast relies on an hourly econometric model reflecting the:

- Impact of different weekdays on hourly system load;
- Impact of different summer months on hourly system load;
- Influence of heat buildup during heat waves;
- Impact of the combined effects of humidity and warm temperatures; and
- Non-linearity in the load and temperature relationships at very high temperatures;

Historical and forecast weather-adjusted retail energy sales are the main driver for the peak demand forecast projections.

c) Energy Sales Forecast

The energy sales forecast adds FERC wholesale sales contracts and line losses to the retail econometric model forecast. The forecast is based on normal weather in both Oklahoma and Arkansas. The energy sales forecast is shown in Table 3. The declines shown between 2015 and 2016 are attributable to the expiration of wholesale contracts.

Table 3: OG&E Energy Sales Forecast (GWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Wholesale	511	0	0	0	0	0	0	0	0	0
Retail	27,708	28,062	28,410	28,668	28,973	29,258	29,474	29,678	29,920	30,144
Total	28,219	28,062	28,410	28,668	28,973	29,258	29,474	29,678	29,920	30,144
Losses	1,973	1,962	1,986	2,004	2,025	2,045	2,060	2,075	2,091	2,107
Total with Losses	30,192	30,023	30,396	30,671	30,998	31,303	31,534	31,753	32,011	32,251
Energy Efficiency	396	496	638	793	873	995	1,132	1,095	1,061	1,027
Demand Response	89	94	98	102	102	104	104	104	104	103
Load Responsibility	29,707	29,433	29,661	29,777	30,023	30,204	30,298	30,554	30,847	31,121
Sales Growth		-0.92%	0.77%	0.39%	0.83%	0.60%	0.31%	0.84%	0.96%	0.89%

d) Peak Demand Forecast

Table 4 shows the final load responsibility forecast, adjusted for wholesale loads[3] and line losses. The peak demand forecast is also based on normal weather conditions.

Table 4: OG&E Peak Demand Forecast (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Wholesale	0	0	0	0	0	0	0	0	0	0
Retail	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605	6,651
Total	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605	6,651
Energy Efficiency	83	104	134	167	183	209	238	230	223	216
Demand Response	272	293	309	328	332	336	340	344	348	348
Load Responsibility	5,850	5,855	5,892	5,882	5,921	5,924	5,950	5,988	6,034	6,087
Peak Demand Growth		0.09%	0.63%	-0.18%	0.67%	0.05%	0.43%	0.64%	0.78%	0.87%

The Energy Efficiency ("EE") and Demand Response ("DR") forecasts reflected in the previous tables represent incremental demand-side resources, resulting from increased

[3] This forecast reflects the termination of all wholesale contracts by June of 2015.

participation in existing programs and the addition of new programs. The impact of prior years' energy efficiency and demand response efforts is assumed to be captured in the econometric forecast of retail requirements. These incremental contributions are described in the following paragraphs.

2. Demand Side Management

OG&E is required to periodically propose, administer and implement a demand portfolio of energy efficiency and demand response programs.[4] Programs implemented after 2012 are not embedded in OG&E's annual load forecast and are subtracted from the baseline forecast to calculate the final energy and peak demand forecasts.

While EE programs do provide some demand reduction, EE programs are designed to educate and encourage customers to make behavioral changes and purchasing decisions that will provide long-term benefits in managing their energy usage. DR programs are designed to send customers price signals encouraging them to reduce their demand during system peak.

a) Energy Efficiency

For more than 30 years, OG&E has successfully managed several DSM programs such as: Positive Energy Home, Geothermal Home, Heat Pumps, Rate Tamer and Power Factor Correction. A renewed focus on energy efficiency in the last ten years targeted areas such as: weatherization of homes for low and fixed income customers, residential air conditioner tune-ups and duct seals, commercial lighting, and incentive payments to commercial and industrial customers who reduce peak demand. The benefits of the programs are reported annually to the OCC and the APSC. Collectively, these programs have reduced energy by more than 160,000 MWh and demand by more than 40MW.[5] As noted above, these historical reductions have been captured in the econometric load forecast models and therefore are embedded in OG&E's annual load forecast.

Table 5 and Table 6 present the 2012 combined Oklahoma and Arkansas demand portfolio estimates of the impact of energy efficiency programs on the load forecast. OG&E will continue promoting and monitoring these programs and will revise future estimates as appropriate.

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[4] OG&E presented the 2013-2015 Demand Portfolio in PUD 201200134. An overview can be found at: http://imaging.occeweb.com/AP/Orders/03048227.pdf

[5] The OG&E 2012 Oklahoma Demand Programs Annual Report can be found at: http://occeweb.com/pu/DSM%20Reports/2012_OGE_Demand%20_Programs_Annual_Report%2006-01-2013.pdf

The OG&E 2012 Arkansas Energy Efficiency Program Portfolio Annual Report can be found at: http://www.apscservices.info/pdf/07/07-075-TF_196_1.pdf

Table 5: Forecasted Energy Reduction from Energy Efficiency (GWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 Programs	396	396	396	396	376	358	340	323	307	291
2015 Programs	-	100	242	396	396	396	396	376	358	340
2018 Programs	-	-	-	-	100	242	396	396	396	396
Total	396	496	638	793	873	995	1,132	1,095	1,061	1,027

Table 6: Forecasted Peak Demand Reduction from Energy Efficiency (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 Programs	83	83	83	83	79	75	71	68	64	61
2015 Programs	-	21	51	83	83	83	83	79	75	71
2018 Programs	-	-	-	-	21	51	83	83	83	83
Total	83	104	134	167	183	209	238	230	223	216

b) Demand Response

DR programs are designed to encourage customers to reduce their load during peak loading periods. OG&E offers a Real Time Pricing option which communicates hourly prices for the next day to encourage customers to shift their energy usage to non-peak periods. The seasonally and time-differentiated Time-of-Use program communicates varying prices to customers promoting them to shift their energy use habits. These reductions have been captured in the econometric load forecast models and therefore are embedded in OG&E's annual load forecast.

The demand response of OG&E's 2013-2015 demand portfolio continues efforts to expand the SmartHours and Integrated Volt Var Control ("IVVC") programs[6]. The SmartHours program integrates technology and pricing to help customers reduce energy usage at peak times. The program utilizes the Advanced Metering Infrastructure (AMI) to securely send price signals across the network and through the smart meter, directly to the Programmable Communicating Thermostat. The Programmable Communicating Thermostat allows customers to set a temperature schedule in addition to receiving and responding to price changes automatically while maintaining full control of their thermostat settings and overall usage at all times. IVVC is a system of devices, controls, software and communications products used to manage OG&E's distribution system reactive power and voltage level.

In Cause No. PUD 200800398, OG&E restructured the event-based programs to offer the Load Reduction Rider. This pricing schedule replaced previous event based tariffs while lowering the customers' annual on-peak period maximum demand requirement from 500 kW to 200 kW and above. The customer enrollment period starts in January and ends March 31st. OG&E plans to steadily grow this program for the next several years.

[6] OG&E Demand Portfolio Technology-enabled Demand Responses program overview can be found at: http://imaging.occeweb.com/AP/CaseFiles/03034DFA.pdf

SmartHours, IVVC and the Load Reduction Rider impacts are not reflected in the annual load forecast and are subtracted from the baseline forecast to calculate the final energy and peak demand forecasts. Table 7 and
Table 8 show OG&E's system-wide estimate of energy and demand reductions possible for the next ten years. OG&E continues to evaluate these programs to look for more demand reduction opportunities but believes the current programs aggressively reduce system peak demand.

Table 7: DR Energy Reduction (GWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SmartHours	66	67	67	66	67	68	68	68	67	67
IVVC	21	25	29	33	33	33	33	33	33	33
Load Reduction Rider	2	2	2	2	3	3	3	3	3	3
Total Reduction	89	94	98	102	102	104	104	104	104	103

Table 8: DR Peak Demand Reduction (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SmartHours	189	194	194	194	194	194	194	194	194	194
IVVC	41	54	67	82	82	82	82	82	82	82
Load Reduction Rider	41	45	49	53	56	60	64	68	71	71
Total Reduction	272	293	309	328	332	336	340	344	348	348

As shown in
Table 8, the potential contribution of SmartHours is significant in 2015, illustrating the success of actual and projected customer enrollments and performance. Once these programs are fully implemented, OG&E will be able to assess the potential for additional customers and reductions through SmartHours. The growth in SmartHours from 2016 on is based on an anticipated enrollment from customer growth on OG&E's system.

B. Supply-Side Resources

As described in Section II, OG&E remains obligated to maintain capacity sufficient to serve its peak load requirements, either through OG&E-owned generation or contracts for capacity. OG&E's capacity planning reserve margin is 12% and must be satisfied by existing resources (net of any planned retirements) or new capacity resources. OG&E's existing resources and potential new resources (by technology) are presented in this section.

1. Existing Resources

OG&E owns generation and obtains capacity and energy from several purchase power agreements ("PPAs"). OG&E's generation resources include coal-fired units, gas-fired steam units, gas-fired combined cycle ("CC") units, quick start gas-fired combustion turbine ("CT") units, and wind facilities. OG&E owns 51% of the Redbud CC plant and 77% of the McClain CC plant. All other fossil plants are fully owned by OG&E. OG&E is the operator of all of its fossil plants, including McClain and Redbud. OG&E also owns three wind facilities: Centennial, OU Spirit and Crossroads. Following SPP Criteria 12, OG&E's December 30, 2013 net peak capacity is 6,347 MW. By 2015 OG&E will complete efficiency improvements at McClain and Redbud realizing an increase of approximately 55 MW of capacity.

OG&E's PPAs include 320 MW from the qualifying facility AES plant at Shady Point that burns coal and 120 MW from the natural gas fired combined cycle PowerSmith plant. OG&E currently has four wind energy PPAs: Sooner Wind at 50 MW, Keenan at 151.8 MW, Taloga at 130 MW and Blackwell at 60 MW. OG&E's fossil fuel PPAs contribute 440 MW of peak capacity while PPAs from wind contribute 13MW due to their non-dispatchable qualities. OG&E's portfolio of electric generating facilities is presented in Table 9.

Table 9: 2015 OG&E Existing Generation Resources – Peak Capacity*

Unit Type	Unit Name	First Year In Service	Capacity (MW)
Coal Fired Steam (2540 MW)	Muskogee 4	1977	492
	Muskogee 5	1978	506
	Muskogee 6	1984	500
	Sooner 1	1979	520
	Sooner 2	1980	522
Gas Fired Steam (2483 MW)	Horseshoe Lake 6	1958	169
	Horseshoe Lake 8	1968	394
	Mustang 1	1950	50
	Mustang 2	1951	50
	Mustang 3	1955	121
	Mustang 4	1959	242
	Seminole 1	1971	486
	Seminole 2	1973	482
	Seminole 3	1973	489
Combined Cycle (1195 MW)	Horseshoe Lake 7	1963	193
	McClain	2001	380**
	Redbud	2004	622**
Quick Start Combustion Turbine (176 MW)	Horseshoe Lake 9	2000	45
	Horseshoe Lake 10	2000	45
	Mustang 5A	1971	36
	Mustang 5B	1971	34
	Seminole 1GT	1971	16
Purchase Power - Thermal (440 MW)	AES Shady Point	1991	320
	PowerSmith	1998	120
Purchase Power - Wind (13 MW)	FPL Wind	2003	2
	Keenan	2010	5
	Taloga	2011	4
	Blackwell	2012	2
Owned Wind (11 MW)	Centennial	2007	2
	OU Spirit	2009	2
	Crossroads	2012	7
Total Net Capability			**6,858**

**See steam gas unit retirement dates in Figure 5. OG&E does not assume retirement dates that are outside the 30-year study period.*

*** Represents OG&E owned interest.*

2. Retirement Assumptions

Historically, OG&E assumed for planning purposes that each generating unit in its fleet would perform for the entire study period. However, the aging of OG&E's fleet necessitated a change in this approach and the 2012 IRP contained end of life dates for the units located at the Mustang, Horseshoe Lake and Seminole plants.

Subsequent to the 2012 submittal, OG&E focused more closely on the Mustang plant. This was in large part because these units are some of the oldest generation units of their type and size operating in the US.[7] In addition, OG&E expects the operation of Mustang units in the SPP IM to evolve even further from their original purpose resulting in a seasonal role with increased cycling for short periods. Operating older steam units in a manner not consistent with the purpose for which they were originally designed will, as a practical matter, tend to shorten the estimated useful life for those units.

OG&E's more specific analysis of the Mustang units' age as compared to their peers in the industry and their anticipated future operations caused the company to conclude that the risk of significant failure for these units is substantial and increasing every year. Moreover, if failure occurs in any one of several critical components of a Mustang unit, including but not limited to the turbine, boiler headers, external high energy piping, or a generator step up transformer, the units could be unavailable to meet load requirements for an extended time or even permanently. This is, in part, because replacement parts for units of this age are often no longer supported by manufacturers and, if they can be reproduced at all, must be specially made at a significant expense and lead time. Taking into account the probability and potential impact of equipment failure, as well as the associated safety issues for our members OG&E concluded that, while the Mustang units should remain operational in the near term, retiring all of the Mustang units by the end of 2017 is the prudent course of action. This date represents the earliest generation can be designed, permitted, procured and installed at the Mustang location.

OG&E believes that utilizing the existing Mustang site to replace the 463 MW of reserve planning capacity being retired is prudent for a variety of operational reasons. First, the Mustang plant serves a crucial reliability support function because of its location within the load area. Mustang is located only 9 miles from downtown Oklahoma City, within OG&E's largest load center. Under extreme conditions such as those identified in the Department of Homeland Security report Terrorism and Electric Power Delivery System[8] and recently reported in the Wall Street Journal[9], the Mustang units are available to supply power to a load "island" that could include the critical national security site of Tinker Air Force Base. The Mustang site plays an especially important role in the

[7] For example, according to SNL, Mustang unit 4 is the oldest gas steam unit of its size in the United States. Also, there is only one unit in the U.S. older than Mustang Units 1 and 2 of similar size and only six units in the U.S. older than Mustang 3 of similar size. All of the Mustang steam units are already well beyond the average life for this type of unit (52 years).

[8] National Research Council. Terrorism and the Electric Power Delivery System. Washington, DC: The National Academies Press, 2012.

[9] Smith, R. (2014, March 12). *U.S. Risks National Blackout From Small-Scale Attack*. Wall Street Journal

service restoration process. The Company's service restoration plan designates Mustang as a key contributor in re-energizing the system in black start situations and helping get our other units back on-line in those events. Locating quick-starting combustion turbines at Mustang would speed up the system restoration process and allow OG&E to restore the system faster in the event of black start situation. Having generation close to OG&E's largest load center also mitigates OG&E's exposure to prolonged storm-related outages on the transmission system.

Mustang also provides valuable voltage control on the transmission system. Given the close proximity of the Mustang plant to Oklahoma City, and since the Mustang plant is configured to flow power into both the 69 kV and 138 kV transmission systems, it serves a critical role as a dynamic resource to stabilize voltage on the part of our transmission system that directly serves the majority of our customers. The Mustang location allows the transmission system operators the ability to operate within North American Electric Reliability Corporation ("NERC") and regionally-mandated criteria, and mitigates the prospect for sudden, substantial voltage collapses on the system.

In addition, Mustang has an existing infrastructure in place to support operation and maintenance of the plant including: secure property, electric transmission and interconnection facilities, a gas pipeline connection, available water supply with water rights, roads and buildings.

Mustang's existing environmental air permits provide the opportunity to use the permitting process for gas-fired generation on OG&E's system. This opportunity is based on a "netting analysis" whereby the emissions from replacement generation are "netted" against the historical emissions from the existing units. Since operation of the existing Mustang units is expected to decline in the IM market, permitting the new units in the near term will maximize the amount of replacement generation capacity that can be installed at the Mustang site.

The company concluded that CTs, with their ability to start quickly and react faster to SPP market signals, will be dispatched more hours in the SPP market and produce more revenue (to the benefit of OG&E customers). Similarly, with the growing amount of intermittent wind generation within the SPP footprint, these new CT units will be able to react quicker to changes in wind patterns and will complement the growing wind generation in the state and region. As the amount of wind generation and solar energy in the SPP market grows, this type of agile gas generation is expected to be even in more demand. The need for additional quick start CT capacity has been identified in several of SPP's Integrated Transmission Plans including the latest plan. OG&E also determined that no CT's are available for acquisition in the region.

For all of these reasons, OG&E believes that retirement of the Mustang steam units at the end of 2017 and the replacement of those units with CT's at the existing site is the best course of action. These assumptions are used in the IRP analysis. In addition, OG&E has performed an analysis comparing this approach to other options for retiring the four Mustang units and replacing the capacity. The results of that analysis are discussed in Section V. The assumed retirement dates for the remaining gas-fired steam units are reflected in Figure 5.

Figure 5: Assumed Gas-Fired Steam Unit Retirements

Horseshoe Lake Plant	Seminole Plant
Unit 6 (169 MW) – 2024	**Unit 1 (486 MW) – 2037**
Unit 7 (209 MW) – 2029	**Unit 2 (482 MW) – 2039**
Unit 8 (394 MW) – 2035	**Unit 3 (489 MW) – 2041**

As with the Mustang Units, these dates are assumptions that may be adjusted over time to reflect contemporary conditions.

3. Emission Control Technologies

Several existing generation units will require emission control equipment to comply with federal and state emissions regulations. Compliance with Regional Haze requirements under the EPA's FIP will require either the installation at Sooner 1 and 2 and Muskogee Units 4 and 5 of Dry Scrubber technology or conversion to natural gas. Several coal and gas-fired units will require installation of Low NOx Burners to comply with Regional Haze and potentially for CSAPR rules that are soon to be finalized. Activated Carbon Injection will be utilized to address MATS. Estimates for natural gas transportation fees to support the potential conversion from coal to natural gas at both Muskogee and Sooner plants have also been developed to capture the complete cost associated with this environmental compliance alternative. OG&E anticipates that a competitive bidding process will be necessary to construct new pipeline capacity to serve Muskogee to support the conversion. Cost estimates for emission control technologies considered in this IRP are based on information provided by Sargent & Lundy, shown in Table 10.

Table 10: Emission Control Technologies (2014 Dollars)

Control	Units	Overnight Capital Cost ($Millions)	Fixed O&M Cost ($Millions)	Variable O&M Cost ($/MWh)
Dry Scrubber	All Coal per unit	$247.9	$7.88	$2.72
Low NO_x Burners	Muskogee 4	$11.0	$0.24	-
Low NO_x Burners	Sooner 1	$10.6	$0.24	-
Low NO_x Burners	Seminole 1&2	$41.3	$1.30	-
Low NO_x Burners	Seminole 3	$19.0	$0.64	-
Activated Carbon Injection	All Coal	$24.3	$0.80	$2.50
Conversion to Gas	Muskogee per unit	$35.7	-$5.57*	-$0.12
Conversion to Gas	Sooner per unit	$35.7	-$5.75*	$0.39

**Represents the incremental cost decrease due to conversion from coal to gas*

4. New Build Supply-Side Resources

OG&E utilized the 2014 Energy Information Administration ("EIA") Annual Energy Outlook Early Release to identify proxy supply side resources. The proxy units are meant to represent a generic type of unit and not the specific manufacturer or technology to be placed into service. The EIA data was used only to screen viable generation technologies to consider. Two requirements were established for selecting new resources to analyze: (1) whether the technology was proven, and (2) whether the cost was economically viable. Resources had to satisfy both requirements in order to be subject to further analysis. The supply-side resource options and screening requirements are presented below in Table 11.

Table 11: New Resource Screening Requirements (2014 Dollars)

Type	Technology	Capacity (MW)	Overnight Capital Cost ($/kW)	Proven Technology	Cost
Coal	Single Unit Advanced PC	650	3,319	Yes	
	Dual Unit Advanced PC	1,300	3,000	Yes	
	Single Unit Advanced PC w/ CCS	650	5,345		
	Dual Unit Advanced PC w/ CCS	1,300	4,831		
	Single Unit IGCC	600	4,499		
	Dual Unit IGCC	1,200	3,869		
	Single Unit IGCC with CCS	520	6,748		
Natural Gas	Conventional NGCC	620	938	Yes	Yes
	Advanced NGCC	400	1,046		Yes
	Advanced NGCC with CCS	340	2,142		Yes
	Conventional CT	85	995	Yes	Yes
	Advanced CT	210	691	Yes	Yes
	Fuel Cells	10	7,269		
Uranium	Dual Unit Nuclear	2,234	5,655	Yes	
Biomass	Biomass CC	20	8,365	Yes	
	Biomass BFB	50	4,207	Yes	
Wind	Onshore Wind	100	2,263	Yes	Yes
	Offshore Wind	400	6,371	Yes	
Solar	Solar Thermal	100	5,181	Yes	
	Small Photovoltaic	20	4,277	Yes	*Table 12
	Large Photovoltaic	150	3,960	Yes	
Geo-thermal	Geothermal - Dual Flash	50	6,384	Yes	
	Geothermal - Binary	50	4,461	Yes	
MSW	Municipal Solid Waste	50	8,500	Yes	
Hydro	Hydro-electric	500	3,002	Yes	
	Pumped Storage	250	5,407	Yes	

**Updated Overnight Capital Cost is less than $2,500/kW as shown in Table 12*

a) Proven Technology

In addition to providing construction and operating costs associated with the new resources, the Annual Energy Outlook also discusses how some technologies are more developed than others. For example, while carbon capture and sequestration is discussed as a solution to reduce CO_2 emissions, repeated utility scale facilities have not been developed and operated. Therefore this technology is not considered proven and is not included in a resource portfolio. The advanced units in the Annual Energy Outlook are typically not technologies proven on a commercial scale.

b) Cost

The second requirement considers the cost of the new resource option. For example, the Biomass CC unit has a cost of $8,365/kW. This is significantly more expensive than other renewable or base load resource options; therefore it would not be a reasonable addition to a portfolio. For purposes of the cost/scale criterion, technologies that have overnight capital costs of less than $2,500/kW are assumed to pass the test.

As described in the following paragraphs, OG&E supplemented the EIA data for both wind and central solar facilities through a Request for Information ("RFI") in the case of wind energy and further research with respect to central solar facilities. In both cases, the costs are lower than suggested by the EIA analysis.

c) 2013 OG&E Wind Energy RFI

To gain market intelligence of wind energy pricing and availability, in 2013, OG&E issued a Wind Energy RFI. Respondents were "encouraged to be creative with the size and terms" of agreements. Due to uncertainties associated with wind energy in the SPP IM the RFI stated "OG&E has a preference for terms that reflect the wind energy suppliers incur all curtailment risk, including those for economic purpose". Responses were received from nine (9) companies that offered twenty (20) locations throughout Oklahoma and Kansas. Although some responses were structured such that suppliers took a small amount of curtailment risk, none accepted all curtailment risk. Responses that offered to accept some level of curtailment risk required additional compensation for accepting the risk, accepted only a very small amount of the risk or both. In contrast, all of the offers included take-or-pay provisions that would also make the developer whole on production tax credits in the event of a curtailment other than force majeure and beyond the amount of curtailment acceptable to the respondent. Base pricing averaged approximately $22/MWh and is less than that provided in previous RFI's with respondents citing improved technology resulting in increased capacity factors and reductions in turbine prices.

d) Central Solar Photovoltaic

Central solar Photovoltaic ("PV") requires 10-15 acres per MW. Two types of Solar PV systems were evaluated[10] to estimate potential costs. The first type of system was a fixed tilt system that has an estimated cost of about $2.25 per watt and 18.5% capacity

[10] The overall cost per watt taken from the publically available documentation provided by Arizona Public Service Company. The capacity factors were derived using load data provided from a solar vendor's engineering model using Oklahoma City location characteristics.

factor. This unit also had less coincidence with peak so the capacity value was estimated at 50%. The second unit evaluated, a single axis tracking system, is more expensive at nearly $2.50 per watt but appears to be more beneficial to customers since it operates with an estimated capacity factor of 24% and has a higher coincident capacity value of 70%. The estimated maintenance cost is $25 - $40 per kW-year and includes an inverter replacement once every 10 years. These assumptions are summarized in Table 12. There are numerous considerations that still need to be analyzed before wide-scale implementation can be achieved. As more information becomes available, OG&E will conduct a more in-depth analysis to test the viability of central solar PV.

Table 12: Central Solar Photovoltaic (2014 Dollars)

	Cost ($/kW)	Size (MW)	Capacity Factor	Energy (MWh)	Fixed O&M ($/kW-yr.)
Fixed Single Axis	$ 2,498	10	23.9%	20,971	$40
Fixed Tilt	$ 2,229	10	18.5%	16,246	$25

e) Sargent & Lundy estimates

A select group of practicable technologies was selected for more in depth study. The new supply side resources utilized for detailed analysis were provided in the IRP Technology Assessment: New Gas Generating Options by Sargent & Lundy. A summary is shown in Table 13.

Table 13: New Supply Side Resources (2014 Dollars)

Type	Technology	Net Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost ($/kW)	Fixed O&M Cost ($/kW)	Variable O&M Cost ($/MWh)
Natural Gas	Combined Cycle	281	6,120	$1,475	$22.50	$2.56
	Combined Cycle	562	6,120	$1,227	$16.36	$2.56
	Combustion Turbine	39	8,904	$1,002	$26.59	$1.81
	Combustion Turbine	75	10,733	$1,084	$22.50	$18.41
	Combustion Turbine	86	8,309	$1,657	$16.36	$4.50
	Combustion Turbine	237	9,040	$985	$8.18	$16.36

5. Transmission to Connect New Supply-Side Resources

Supply side resource options often require transmission investments depending on location and the configuration of existing transmission facilities. In an effort to develop a more comprehensive estimate of the costs of new generation, OG&E has identified proxy sites and estimated the transmission expansion costs that would be associated with these sites. These sites were chosen for analysis purposes only and no determination has been made on future specific locations.

a) Thermal Generation

A Transmission Service study was performed by OG&E for the purpose of analyzing the transmission constraints associated with the addition of one 562 MW generating unit to the McClain generation plant. The McClain plant is located in McClain County near Newcastle, Oklahoma. The addition of the unit will require expansion of the McClain substation to include a 345kv Bus. The estimated expansion cost is $20 million as detailed in Table 14.

Table 14: Estimated Expansion Cost at McClain Substation

Description	Estimated Cost
345kV Substation w/ Cimarron & Draper lines looped	$12,000,000
345/138kV Bus tie transformer & low side w/2 line terminals	$3,000,000
Rebuild McClain 138kV for Breaker & 1/2 to accommodate 2 new lines from new McClain Extra High Voltage sub	$4,000,000
Lines between McClain 138kV & McClain Extra High Voltage Sub	$1,000,000
Total 345 kV Expansion Cost	$20,000,000

Contingency Analysis was performed to determine if any overloads were present due to new generation. One overload was detected in the Western Farmers Electric Cooperative area and transmission network upgrades will be required to correct the overload. There may be additional cost that will be determined in the SPP study process.

OG&E also examined the potential of adding CTs at the Mustang site and determined that this would not require any additional transmission capacity beyond what is already located at Mustang to allow for transmission service.

C. New Transmission Facilities

OG&E's transmission system is directly interconnected to seven other utilities' transmission systems at over 50 interconnection points. Indirectly, OG&E is connected to the entire Eastern interconnection through the SPP regional transmission organization. The SPP footprint covers 370,000 square miles and its 74 members serve over 6 million customers across all of Kansas and Oklahoma and parts Arkansas, Louisiana, Mississippi, Missouri, New Mexico, Nebraska, and Texas. In compliance with FERC Order 890 for transmission planning, SPP performs annual expansion planning for the entire SPP footprint. OG&E provides input to the SPP planning process, and SPP is ultimately responsible for the planning of the OG&E system.

The 2014 SPP Transmission Expansion Plan[11] ("STEP") summarizes Integrated Transmission Planning ("ITP") efforts including regional reliability, local reliability, generation interconnection, and long-term tariff studies due to transmission service

[11] 2014 STEP http://www.spp.org/publications/2014_STEP_Report_Final_20140205.pdf

requests. The purpose of the ITP process is to maintain reliability, provide economic benefits and meet public policy needs in both the near and long-term to create a cost-effective, flexible and robust transmission grid with improved access to the SPP region's diverse resources. The ITP is a three-phase iterative three-year process that includes a long-term 20-year assessment, a 10-year assessment and a near-term assessment.

The first phase, the ITP 20 Year Assessment ("ITP20") is used as a roadmap for the development of a long-term transmission plan over a 20-year horizon. The ITP20 focuses on the continued development of the SPP region's extra high voltage ("EHV") transmission system to reduce congestion and enable low cost generation access to SPP's members. SPP will not issue any Notifications to Construct as a result of the ITP20. The ITP20 plan process is repeated every three years.

The second phase of the ITP process is the ITP 10-Year Assessment ("ITP10"), which analyzes the transmission grid over a 10-year time frame. The ITP10 utilizes economic and reliability analysis to find solutions for local reliability upgrades, mitigate congestion, improve access to markets and eliminate potential criteria violations.

The third phase of the ITP process is the annual ITP Near-Term Assessment ("ITPNT"). The goals of the ITPNT are to preserve SPP transmission grid reliability and to create an effective near-term plan for the SPP footprint. ITPNT will identify potential problems under normal and first contingency scenarios in compliance with NERC Reliability Standards, SPP Criteria, and local planning criteria. Mitigation plans to meet regional reliability needs will be developed and necessary reliability upgrades will be identified for approval and construction.

Transmission improvements identified in the 2014 STEP were included in the transmission models for this IRP. Some of the benefits provided by these improvements include reliability and the capacity for expansion of Oklahoma's wind energy. Transmission system expansion provides benefits to members throughout SPP; therefore, the costs of all projects constructed in SPP are shared through various cost allocation methods, depending on the type of project.

The Balanced Portfolio and Priority Projects include transmission upgrades of 345 kV projects with regional benefits that exceed project costs.[12] These projects provide benefits through production cost savings, reduced congestion, and integration of SPP's East and West regions, among others. The costs associated with these projects are spread broadly across the SPP footprint because they benefit the entire region. The 2014 STEP included the following major 345 kV transmission projects for OG&E to construct. A more descriptive list of those projects can be found in Schedule J.

[12]http://www.spp.org/publications/2009%20Balanced%20Portfolio%20-%20Final%20Approved%20Report.pdf

http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf

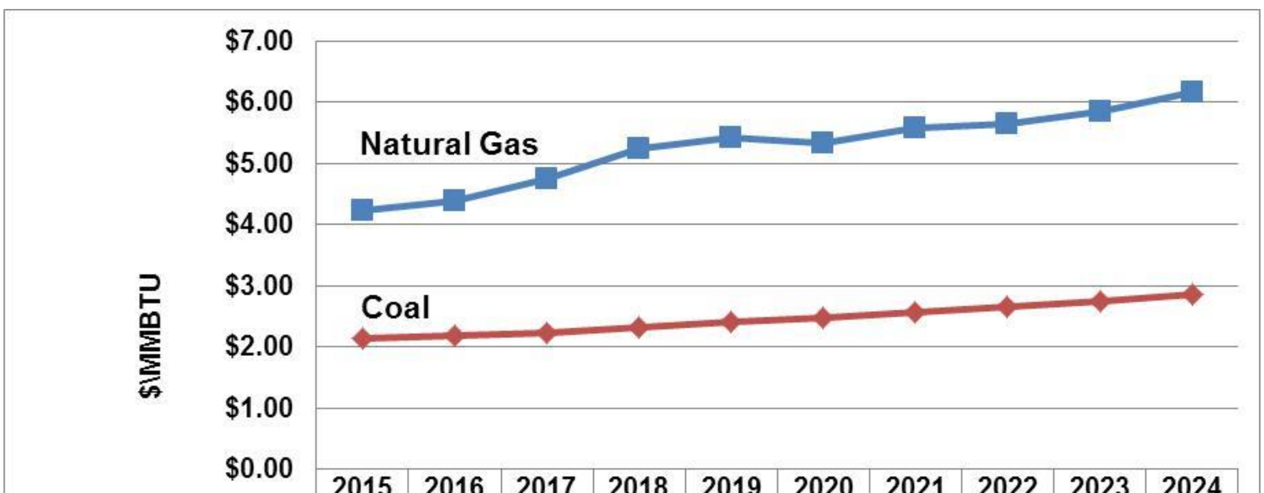
Table 15: Major 345 kV Transmission Projects

Project Type	Project	Expected In Service Year
High Priority	110 miles of double circuit 345 kV transmission line from Thistle to Woodward District EHV in northwest Oklahoma and southwest Kansas	2014
Balanced Portfolio	250 miles of 345 kV transmission line from Woodward District EHV in west Oklahoma to Oklahoma/Texas Stateline to Tuco in west Texas	2014
High Priority	122 miles of double circuit 345 kV transmission line from Hitchland to Woodward EHV in northwest Oklahoma	2014
ITP 10	30 miles of 345 kV transmission line from Chisholm to Gracemont in western Oklahoma	2018
Transmission Service	5 miles of 345 kV transmission line from Arcadia to Redbud in central Oklahoma	2019
ITP 10	126 miles of 345 kV transmission line from Woodward District EHV to Tatonga to Mathewson to Cimarron in northwestern Oklahoma	2021

D. Fuel and CO_2 Assumptions

The Fuel Price forecast for this IRP is from the Energy Information Agency's (EIA) 2014 Annual Energy Outlook Early Release and is shown in Figure 6.

Figure 6: EIA Fuel Forecast (Annual Average)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
NG ($/MMBTU)	$4.23	$4.38	$4.74	$5.26	$5.42	$5.33	$5.58	$5.66	$5.84	$6.17
Coal ($/MMBTU)	$2.14	$2.18	$2.24	$2.33	$2.41	$2.49	$2.57	$2.66	$2.76	$2.85

The 2014 Annual Energy Outlook Early Release assumes that there are no explicit federal regulations to limit greenhouse gas emissions, therefore CO_2 emission costs were only included in the analysis as a sensitivity.

OG&E developed its CO_2 cost forecast by calculating, for each year from 2020 on, the CO_2 cost that would equate the marginal cost of generation from a natural gas combined cycle power plant and a scrubbed coal-fired power plant, given their relative CO_2 emission rates. This price forecast was developed to create price parity between efficient gas generation and emission controlled coal generation. OG&E based this analysis on its forecasted natural gas and coal fuel prices, typical plant heat rates, and typical plant variable non-fuel O&M costs. The resulting CO_2 cost forecast shown in Table 16.

Table 16: CO_2 Price Forecast ($/ton)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
$/ton	$0	$0	$0	$0	$0	$15	$16	$16	$16	$18

E. Integrated Marketplace Prices

OG&E and the other members of SPP are now participating in the SPP IM which has implications for the way OG&E plans for generation resources. Since OG&E will sell its generation into the market and buy all of its load requirements from the market, it is necessary to calculate future market prices to reflect in the modeling process. OG&E utilizes Ventyx PROMOD IV®, an Electric Market Simulation tool which incorporates generating unit operating characteristics, transmission grid topology and constraints, to determine future energy prices in the SPP IM.

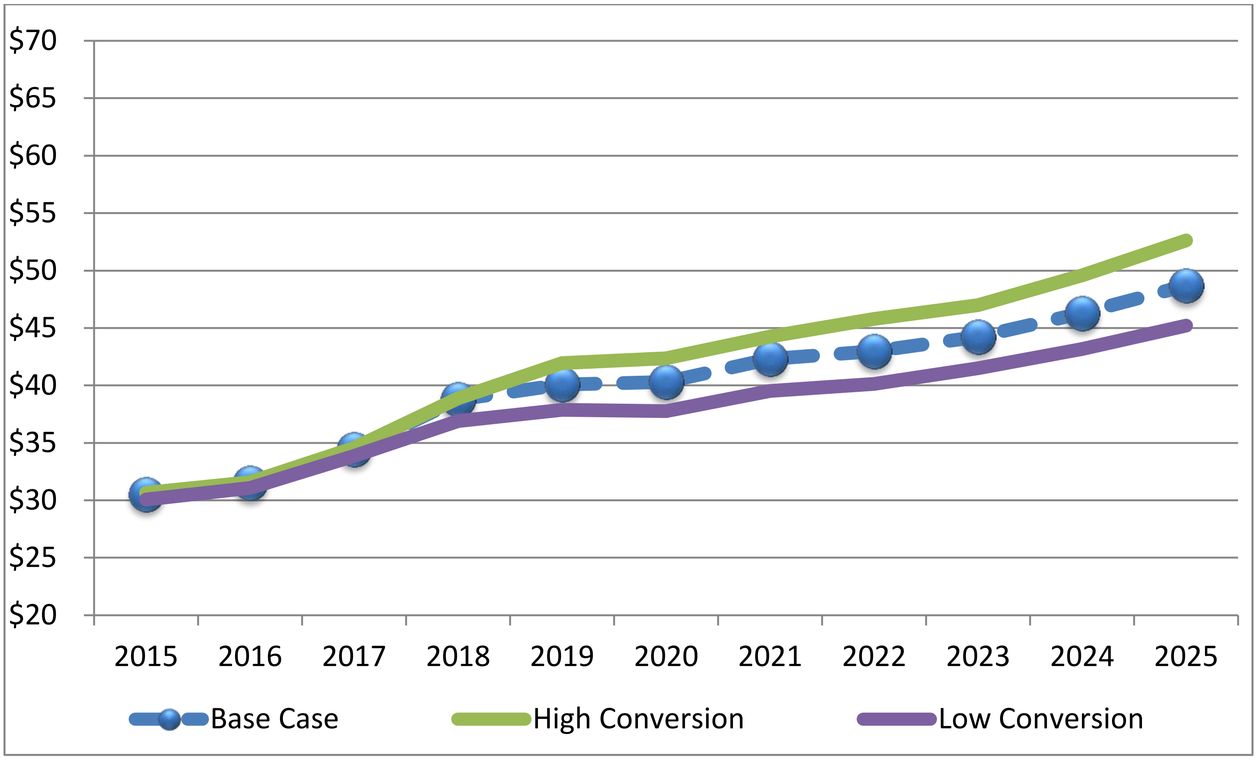
1. Market Price Scenarios

Market conditions such as availability of diverse generation resources, fuel pricing and emission costs will impact market pricing. To capture the uncertainties associated with these market drivers, OG&E has developed three market scenarios that it believes are plausible outcomes. The likelihood that SPP members will be required to control emissions on their coal plants was used to define the three scenarios:

- Base Case – All announced plans to control emissions on SPP coal units are included in the models. Also, it is assumed all coal units in SPP smaller than 200 MW and all units older than 1977 that do not have emission controls will be converted to natural gas. All other coal units with and without emission control are assumed to be available in the IM.
- High Conversion – Starting with the Base Case scenario, all coal units in SPP that have not announced plans to control emission are assumed to be converted to natural gas.
- Low Conversion – All announced plans to control emission on SPP units are included in the models. All other coal units with and without emission control are assumed to be available in the IM.

The resulting average annual Locational Marginal Prices (“LMPs”) for the three scenarios are shown in Figure 7.

Figure 7: SPP Market Scenarios (Annual Average $/MWh)



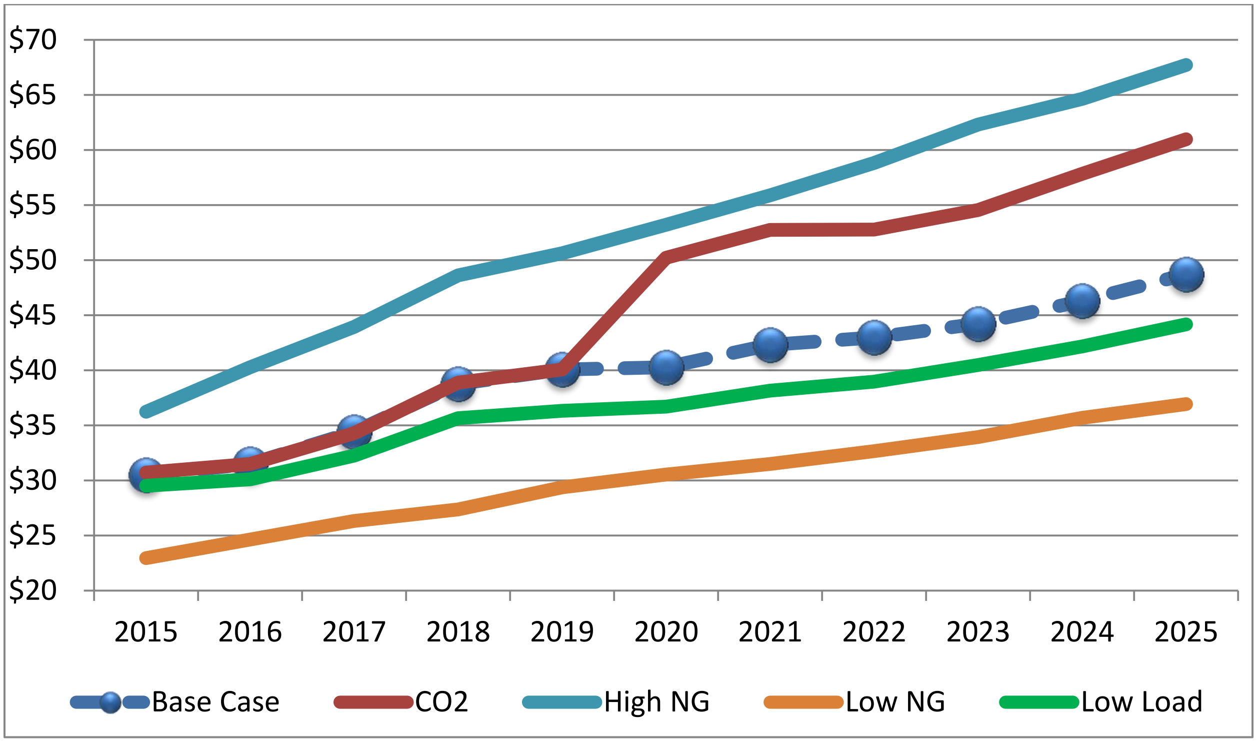
2. Market Price Sensitivities

Potential market prices due to the uncertainty of natural gas prices, the potential for a CO_2 tax and load requirements were considered through the development of sensitivities. These sensitivities were developed by changing each assumption associated with the uncertainties listed below one at a time in the model. The result was four sets of market prices that reflect these uncertainties.

- High Natural Gas - Natural gas prices 1.5 times as much as the Base Case gas price
- Low Natural Gas - Natural gas prices 0.75 times as much as the Base Case gas price
- CO_2 – CO_2 tax is included in 2020
- Low Load - Load across the SPP footprint declines by 10% over the next 10 years because of the increased prevalence of distributed generation

The prices define a range of possible prices in the IM. The resulting average annual LMPs of the Base Case scenario versus the four sensitivities are shown in Figure 8.

Figure 8: Market Prices for Sensitivity Analysis (Annual Average $/MWh)



a) Discussion of Distributed Generation

DG is defined as electricity production that is on premise or close to the customer load and is interconnected to the utility distribution system. The most common DG technologies currently being adopted include solar photovoltaic, fuel cells and micro-turbines. In most applications, DG can be a substitute product for grid-supplied electricity.

DG growth is increasing in certain states due to policies favorable to DG, tax incentives, state-level equipment rebates and relatively high electricity prices. Since these conditions are not prevalent throughout the SPP footprint, the near term impacts of DG on SPP load and energy prices are not estimated to be material.

However, suppliers of DG systems are structuring their product financing to be more affordable. Additionally, technological advancements and market dynamics are expected to reduce the overall costs of DG systems over the next decade. As a result DG systems will likely become more attractive to customers within OG&E's service territory and SPP. Given these factors, there is potential for the adoption of DG systems to grow more rapidly in five to ten years.

In modeling the market price sensitivity, OG&E considered the impact to SPP market prices if energy from DG systems reduced total SPP load by an incremental 1% per year over the next ten years for a total of 10% reduction by 2024.

V. RESOURCE PLANNING MODELING AND ANALYSIS

This section describes the resource planning analysis that OG&E has performed by applying the process described in Section III. All analyses begin with the assumption that OG&E is obligated to acquire capacity to meet its SPP capacity planning margin requirement of 12% as described in Section II.

OG&E relies on the Ventyx PROMOD IV® software to model the SPP IM. OG&E performed base case, sensitivity and scenario analyses based on the assumptions that are described in Section IV. These model runs produce an estimate of the 30-year NPVCC which represents one of the most important IRP objectives – producing the lowest reasonable cost for OG&E's customers. The sensitivity and scenario analysis results contribute to the assessment of the portfolio's ability to satisfy other IRP objectives, including the value of fuel diversity. Overall, the model results inform OG&E's judgment as to the lowest reasonable cost resource portfolio.

A. OG&E's Capacity Planning Obligation

As described in section II, the SPP capacity planning margin is 12% and considers all resources currently owned or under contract. If expected resources do not reach the level of customer demand plus the minimum 12% margin, additional resources or a reduction in load responsibility is required. The results are presented in Table 17.

Table 17: Planning Capacity Margin (MW unless noted)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Resources	Total Owned Capacity	6,405	6,355	6,355	5,942	5,942	5,942	5,942	5,942	5,942	5,773
	Purchase Contracts	453	453	453	453	451	331	331	331	11	11
	Total Net Dependable Capability	6,858	6,808	6,808	6,395	6,393	6,273	6,273	6,273	5,953	5,784
Demand	Load Forecast	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605	6,651
	Energy Efficiency	83	104	134	167	183	209	238	230	223	216
	Demand Response	272	293	309	328	332	336	340	344	348	348
	Net On System Demand	5,850	5,855	5,892	5,882	5,921	5,924	5,950	5,988	6,034	6,087
Capacity Needs	Capacity Margin	1,008	953	916	513	472	349	323	285	-81	-303
	Percent Capacity Margin (%)	14.7	14.0	13.4	8.0	7.4	5.6	5.2	4.5	-1.4	-5.2
	Needed Capacity	-	-	-	289	336	460	488	532	905	1,134

As shown in Table 17, OG&E's initial year of need is 2018 due to the prior retirement of Muskogee 3, Enid and Woodward plants and the planned retirement of Mustang. Also, needs increase each year as load continues to grow.

B. Environmental Compliance Analysis

This section presents the multi-step process used to analyze various environmental compliance alternatives. These steps include the identification of potential portfolios to meet both environmental compliance and longer-term capacity needs followed by detailed modeling analyses including scenario and sensitivity analyses. The final step is the application of IRP objectives and judgment to the set of model analyses to identify the lowest reasonable cost plan.

1. Development of Portfolios

Although the EPA has specified in the FIP that OG&E should limit emissions to comply with Regional Haze, there are several alternatives that should be considered before deciding on the lowest reasonable cost plan. Since the compliance plans do not result in an increase in capacity, it is necessary to combine each plan with a capacity expansion plan before determining which combined compliance/expansion plan will be the best plan for OG&E and its customers. As described below, OG&E has identified five potential Regional Haze compliance alternatives and three potential expansion plans for a total of 15 portfolios to subject to the Ventyx modeling analysis.

a) Regional Haze Compliance Alternatives

OG&E identified five alternatives for controlling SO_2 emissions and complying with the Regional Haze rule as established in the FIP by the 2019 compliance year. Each alternative uses different technologies to achieve required levels of emission reductions, as outlined in Figure 9 that represent variations of three fundamental alternatives: installation of dry scrubbers, conversion of the coal units to natural gas, and replacement of the coal units with new combined cycle plants.

Figure 9: Regional Haze Compliance Alternatives

Scrub/Convert	• Scrub Sooner 1 by 2018 and Sooner 2 by 2019 • Convert two Muskogee units by 2019
Scrub	• Scrub Muskogee 4 by 2018 and Muskogee 5 by 2019 • Scrub Sooner 1 by 2018 and Sooner 2 by 2019
Convert	• Convert four coal units to gas by 2019
Scrub/Replace	• Scrub Sooner 1 by 2018 and Sooner 2 by 2019 • Replace two Muskogee coal units with new CCs by 2019
Replace	• Replace four coal units with new CCs by 2019

Each of these compliance plan alternatives assume that Low NO_x Burners are installed on the 7 Regional Haze impacted units (the four coal units and the three gas steam

Seminole units) by 2017 and that ACI is installed on the coal units by the April 2016 MATS deadline to achieve compliance with respect to mercury standards.[13]

b) Expansion Plan Options

Three expansion plans were developed by considering the SPP 12% planning capacity criteria. As explained in the Retirement Assumptions section, the Mustang units will be retired and options for replacement are analyzed as part of the overall future expansion plan. All expansion plans examined are consistent with OG&E's "2020 Goal" with no incremental fossil fuel generation added to the resource portfolio until 2020.

OG&E utilizes a screening process as described in Section IV to narrow the options to those that are feasible to OG&E. In this screening process, Combined Cycle units and Combustion Turbine units met all the screening criteria for consideration. OG&E obtained more specific unit data from Sargent and Lundy in order to model the expansion units in the SPP IM. The CCs and CTs were then distributed across the 30-year forecast period with in-service dates as necessary to meet OG&E's projected capacity needs. Each of the three primary options adds capacity beginning in 2018 to meet the capacity need that will result from the retirement of the Mustang units. They represent an all CC-option ("CC"), a CT followed by CCs ("CT"), and an option that reflects the flexibility offered by smaller sized CT's by spreading them out over 2 years along with a mix of CTs and CCs "(Spread CT"). These options are presented in Table 18.

Table 18: Expansion Plans

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2031
CC	560 MW CC					560 MW CC		560 MW CC					560 MW CC
CT	400 MW CTs		560 MW CC				560 MW CC					560 MW CC	
Spread CT	280 MW CTs	120 MW CTs	560 MW CC				560 MW CC					560 MW CC	

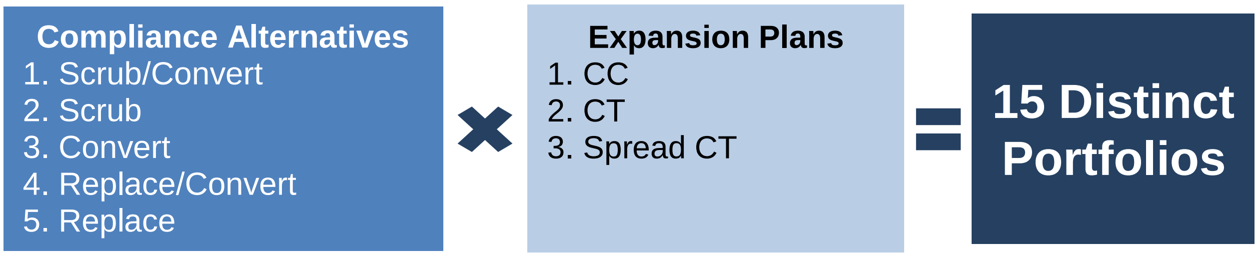
c) Portfolio Identification

The five Regional Haze compliance alternatives were combined with the three expansion plan options to form 15 distinct portfolios. This collection of portfolios allows OG&E to compare the compliance alternatives while also offering insights on the

13 Specific installation dates for emission controls must be assumed for modeling purposes and are based on current OG&E plans although the actual installation dates may change somewhat as the development plans are finalized.

benefits of each expansion option. This also allowed OG&E to determine if or how expansion plan options impact the Regional Haze compliance alternatives. These 15 portfolios are shown in Figure 10.

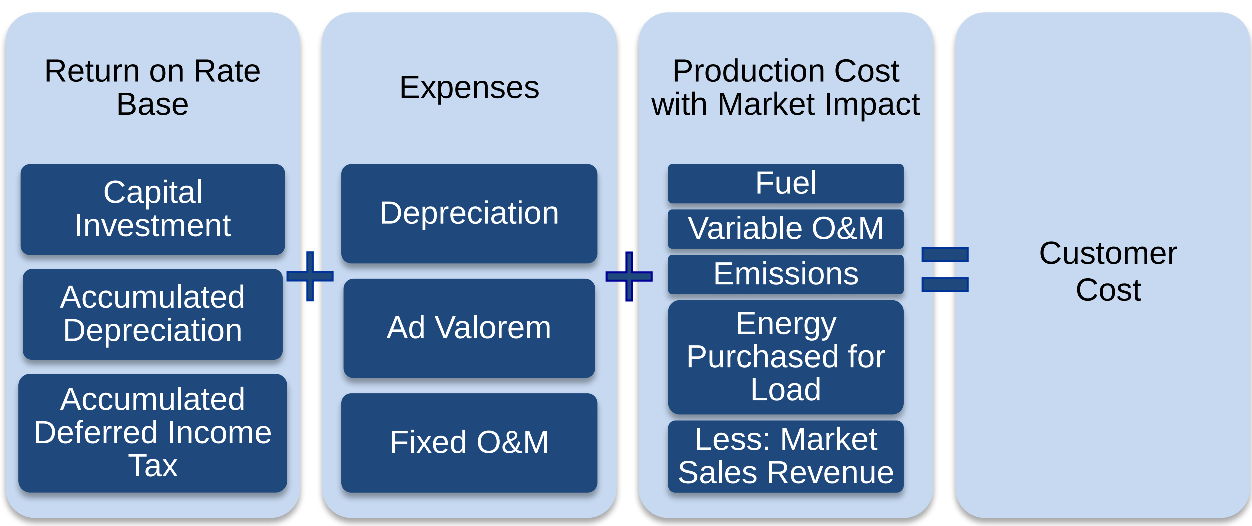
Figure 10: Portfolio Development



2. Portfolio Modeling Analysis

The modeling analysis determines customer costs as measured over the 30-year forecast period. The portfolios are first analyzed using the "Base Case" set of forecast assumptions, before testing the impacts of alternative sets of assumptions by performing scenario and sensitivity analyses. The production cost with market impact of each portfolio is determined utilizing PCI GenTrader® software with a model set-up that represents OG&E's generating unit characteristics and operating constraints. The OG&E generators are dispatched against the IM price forecast to simulate operations in the SPP IM. The return on rate base and non-production expenses associated with each portfolio is then added to production costs with market impacts to determine the customer costs as shown in Figure 11.

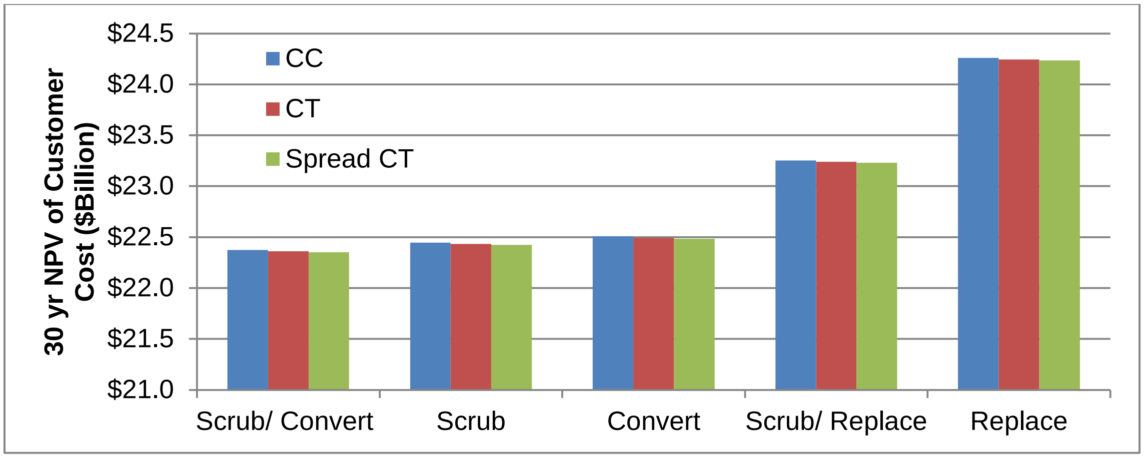
Figure 11: Customer Cost Components



a) Compliance Alternative and Expansion Plan Analysis

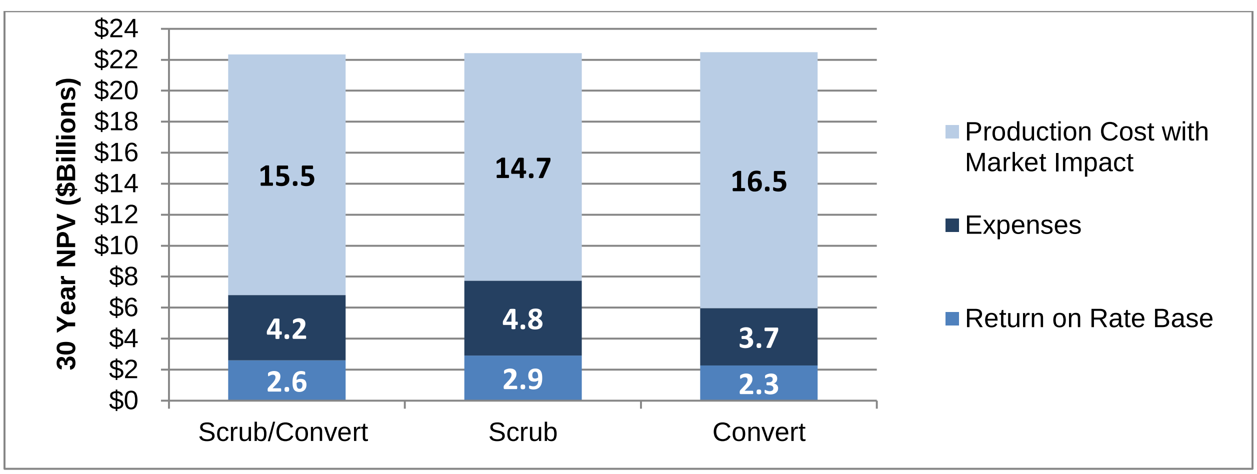
The results of the modeling are provided in a 30-year Net Present Value ("NPV") of customer costs format for each compliance alternative and expansion plan in Figure 12.

Figure 12: Compliance Alternative and Expansion Plan Comparison ($Billions)



As shown in this figure, the "Replace" alternatives are considerably more expensive than the "Convert" alternatives. The "Scrub" and "Convert" alternatives are relatively close (as well as the combined "Scrub/Convert" alternative). There is also minimal difference among the three expansion options although they are consistently ranked from lowest cost to highest cost as follows: Spread CT, CT, and CC. The expansion options do not appear to influence the comparison among environmental compliance alternatives. For the remaining analysis shown in this report, the Spread CT expansion plan will be used since it is the least cost option. To better understand the dynamics between compliance alternatives it is helpful to consider the customer cost components of the three lowest cost compliance alternatives as identified in Figure 13.

Figure 13: Cost Component Comparison for Select Compliance Alternatives ($Billions)



As shown, the alternatives that include scrubbing have higher return on rate base and expenses but lower production cost with market impact. The lower production cost with market impact reflects the margins that customers receive from OG&E selling coal generation into the market. The alternatives that include converting coal to natural gas have lower return on rate base and expenses but higher production cost with market impacts because OG&E has less coal generation to sell into the market. Comparing the production cost with market impact of the three compliance alternatives illustrates the value of coal generation as compared to market prices.

The next step in the analysis is to consider how these portfolios perform when subject to different IM price scenarios and sensitivity analyses around fuel prices, carbon prices, load forecast and capital costs.

b) Scenario Analysis

As described in Section III, OG&E developed three market scenarios that were defined to capture the uncertainty of other SPP IM participant responses to environmental compliance requirements with respect to their coal units. OG&E's compliance alternatives were tested in each market scenario to determine the impact that other market participants could have on decisions made by OG&E. The Spread CT expansion plan is used with each compliance alternative for the market scenario combinations illustrated in Figure 14.

Figure 14: Compliance Alternatives and Market Scenario Combinations

Compliance Alternatives
1. Scrub/Convert
2. Scrub
3. Convert
4. Replace/Convert
5. Replace

×

Market Scenarios
1. High Coal to Gas Conversions
2. Base Case
3. Low Coal to Gas Conversions

=

15 Cases

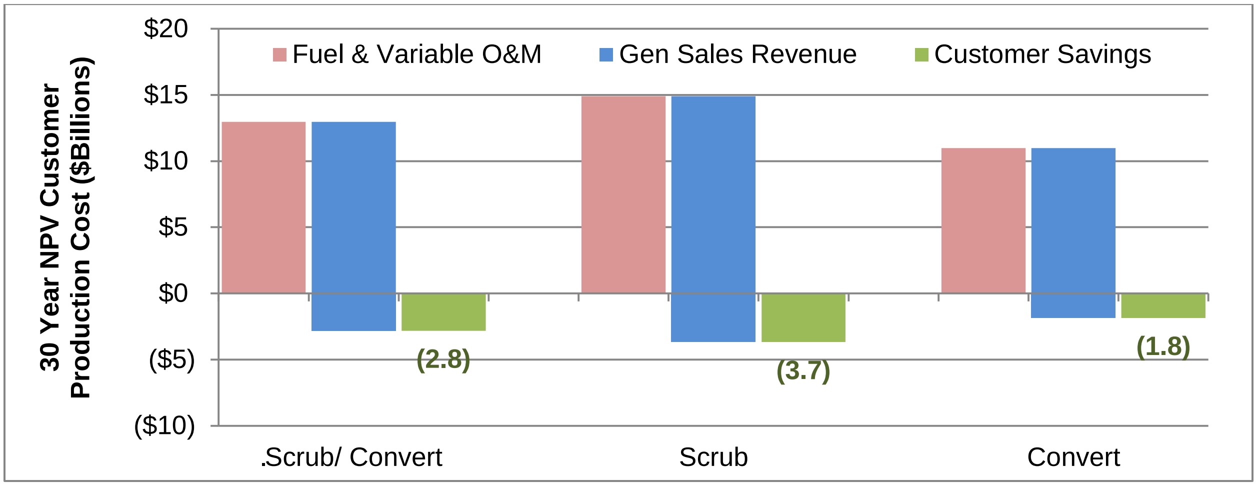
The 30-year NPV of customer costs for each compliance alternative in the scenario analysis is provided in Table 19.

Table 19: Market Scenario 30-year NPVCC Values ($Billions)

	Scrub/ Convert	Scrub	Convert	Scrub/ Replace	Replace
High Conversion	$22.4	$22.3	$22.7	$23.0	$24.0
Base Case	$22.4	$22.4	$22.5	$23.2	$24.2
Low Conversion	$22.2	$22.4	$22.2	$23.3	$24.3

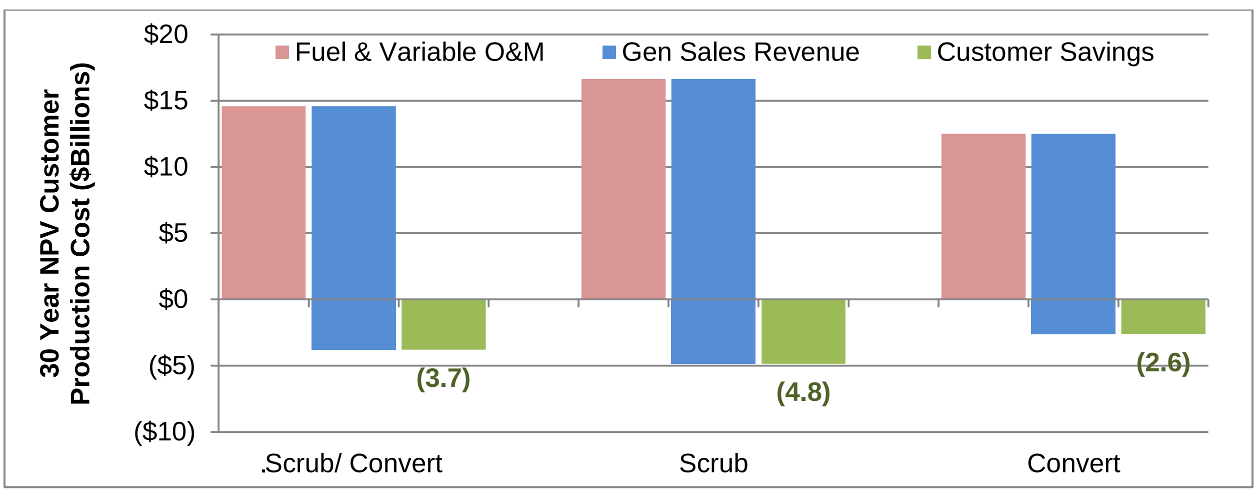
The "Convert" compliance alternative is impacted by a change in market prices by about $0.5 billion ($22.2 to $22.7 billion) and is more than the other alternatives. Again, this is due to OG&E having less coal generation to sell into the SPP market or to hedge market prices due to diversification. This analysis has no impact on the return on rate base or fixed costs making it possible to focus more narrowly on production costs and generation revenue to compare the scenarios. The difference in production cost and generation revenue is the savings customers realize from owning low cost coal generation and is shown in Figure 15.

Figure 15: Customers Production Cost in Base Case Market Scenario ($Billions)



In the Base Case market scenario the 30 year NPV customer production cost savings associated with the "Scrub" compliance alternative is $1.9 billion more than the savings associated with the "Convert" compliance alternative. To demonstrate the impact of market prices on the NPV savings associated with compliance alternatives, the customer production cost in the High Conversion market scenario is shown in Figure 16.

Figure 16: Customers Production Cost in High Conversion Market Scenario ($Billions)



In the high conversion market scenario the 30-year NPV customer production cost savings associated with the "Scrub 4" compliance alternative jumps to $2.2 billion more than the savings associated with the "Convert 4" compliance alternative. Comparing the two charts it is clear that the scrub alternatives offer increased savings as market prices increase and thus provide a hedge against higher market prices due to diversification.

c) Sensitivity Analyses

Sensitivity analysis involves changing a single input variable of the Base Case and measures the impact of the change in that specific variable. The variables changed in the sensitivity analyses are the Natural Gas Prices, Load for SPP members, CO_2 Prices and capital cost of emission control technologies as described in section III. The Spread CT expansion plan is used with each compliance alternative for sensitivities illustrated in Figure 17.

Figure 17: Sensitivity Development

Compliance Alternatives
1. Scrub/Convert
2. Scrub
3. Convert
4. Replace/Convert
5. Replace

×

Sensitivities
1. Gas Price (+50%)
2. Gas Price (-25%)
3. CO_2 Cost
4. Load (-10%)
5. Capital Cost (+30%)
6. Capital Cost (-30%)

=

30 Cases

The 30-year NPV of customer costs for each case in the sensitivity analysis is provided in Table 20.

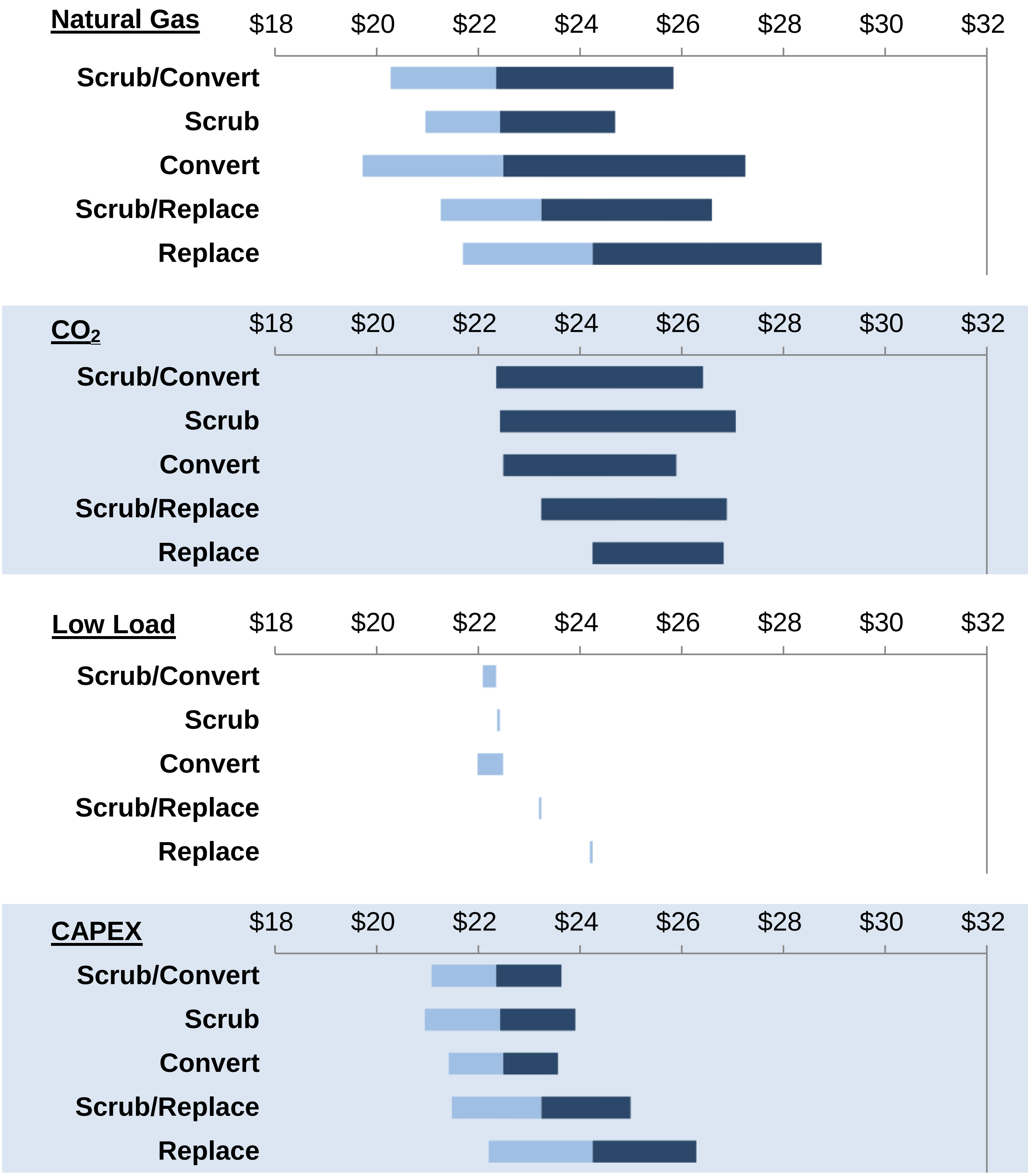
Table 20: Sensitivity 30-year NPVCC Values ($Billions)

	Scrub/ Convert	Scrub	Convert	Scrub/ Replace	Replace
High Gas	$25.8	$24.7	$27.2	$26.6	$28.7
Low Gas	$20.3	$21.0	$19.7	$21.3	$21.7
CO_2	$26.4	$27.0	$25.9	$26.9	$26.8
Low Load	$22.1	$22.4	$22.0	$23.2	$24.2
High Capital Cost	$23.6	$23.9	$23.6	$25.0	$26.3
Low Capital Cost	$21.1	$21.0	$21.4	$21.5	$22.2

As expected, compliance alternatives that rely on converting from coal to natural gas are impacted by gas price sensitivity the most and compliance alternatives that rely on scrubbing coal units are impacted by gas price sensitivity the least. The reverse is true for CO_2 price sensitivity as a carbon tax would hit coal unit costs the hardest. Low load has very little impact on all compliance alternatives though the largest impact is on the convert alternative since lower load in SPP would free up low cost generation in the market resulting in reduced load costs. Sensitivity to capital costs has a relatively low impact as compared to natural gas and CO_2 price sensitivity but it does have the greatest impact on the scrub compliance alternatives as they have a higher capital cost.

The tornado charts in Figure 18 present the range of customer costs for each compliance alternative using the base case scenario as a starting point.

Figure 18: Sensitivity Analysis NPVCC ($Billions)



3. Lowest Reasonable Cost Plan

Given the relatively modest differences among the three lower-cost environmental compliance alternatives and the varying results of the CO_2 and gas price sensitivities, OG&E concludes that the Scrub/Convert alternative offers the lowest reasonable cost. This determination was based on the least cost/risk plan that best meets the comprehensive list of objectives identified by OG&E. This is an appropriate conclusion despite the fact that the Scrub/Convert is not the lowest cost plan in any of the six sensitivity cases presented in Table 20. Rather, it is the second lowest cost option in all six cases, whereas the Scrub and Convert options have a lower cost than the Replace options in all of the cases. In order to operate Muskogee 4 and 5 as gas units a natural gas pipeline into the Muskogee plant will need to be constructed. OG&E expects that through a competitive bidding process a third party would construct the pipeline and charge a transportation fee for the service.

It should also be noted that acquisition of an existing 500 MW combined-cycle plant could be an alternative to the conversion of a Muskogee unit. OG&E has acquired two existing combined-cycle plants over the past decade (McClain and Redbud) and continues to monitor CC plants across the SPP region. However, it should also be noted that our analysis indicates that the acquisition cost of this alternative would have to be very aggressive in order to compete with the “Convert” alternative, less than $250/kW for a new highly efficient plant. Older CC plants with higher heat rates would make sense only at lower acquisition costs. Thus, it appears that it isn’t a viable alternative as OG&E believes no combined cycle plants are available at the acquisition cost necessary make this alternative economical.

Overall, the lowest reasonable cost plan is the Scrub/Convert compliance alternative with Spread CT expansion plan. This portfolio provides the best overall performance when measured against the set of IRP objectives.

C. Wind Energy Analysis

OG&E considered including wind generation as an element of the environmental compliance plan analysis but determined that it would not add any incremental insights that would affect the analysis or recommendation. The primary objective of the environmental compliance plan is the absolute requirement that OG&E replace the capacity provided by the existing coal units with a like amount of capacity in order to meet its load obligations. SPP only recognizes approximately 5% of nameplate wind generation capability for capacity margin purposes, implying that 10,000 MW of wind would be needed to replace just one of OG&E’s 500 MW coal units. Therefore, wind generation would not serve as an effective resource to address the planning capacity needs in OG&E’s environmental compliance plan.

Additionally, OG&E considered wind energy from a customer savings perspective. Prior to the SPP IM, OG&E either generated wind energy or purchased wind energy through purchased power agreements. This energy was used to directly serve OG&E’s customers and the cost of the wind energy was passed through to customers. In the

SPP IM, the entire pool (including OG&E customers) proportionately pays the market price for each individual wind facility as determined by the SPP economic dispatch model regardless of the wind energy provider's cost. The wind energy provider (or its customers) bears the price risk between its costs and the market price as determined by SPP.

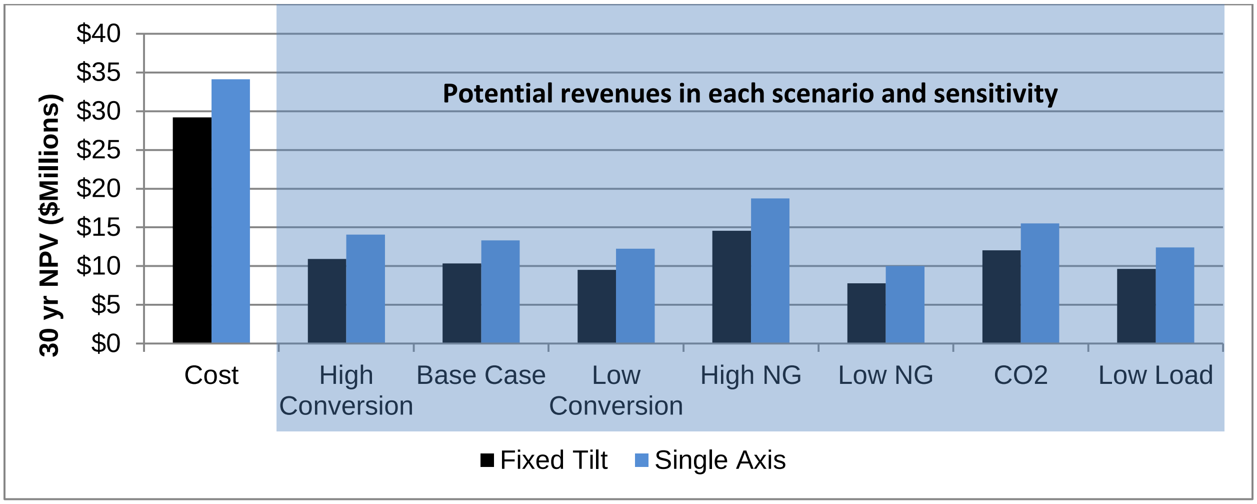
Another change created by the SPP IM is that wind developers may now construct wind farms and sell the energy output directly into the SPP IM without an agreement with OG&E. While analysis indicates that wind energy may provide energy cost savings over a 25 year period, these savings are dependent on assumed SPP IM prices. Based on recent experience with wind energy there is considerable SPP IM price risk and the respondents to our 2013 RFI declined to assume this risk. We expect that this price risk will diminish as new transmission capacity is placed in service and will monitor this risk. However, given this risk, OG&E has made a decision not to pursue additional wind generation at this time. In the interim, we are supportive of wind developers constructing new wind farms and selling the energy directly into the SPP IM.

This does not imply that wind energy will not continue to serve a critical role in OG&E's portfolio and indeed it is likely that OG&E will increase its reliance on wind energy over the coming decade, particularly after transmission constraints are relieved. The fact is that wind technology and associated capital costs are continuing to improve and may indeed reach levels where wind energy tax credits are no longer necessary to support growth in wind energy. OG&E will continue to monitor the market and revisit its decision as more is understood of the uncertainties.

D. Central Solar Analysis

Combining the costs of the investment and future maintenance expenses, the 30-year net present value of the cost of 10 MW of central solar is around $35 million. This cost can then be compared to the expected revenues from the solar unit operating in the various market price scenarios and sensitivities. As shown in Figure 19, the cost of solar is about twice the amount of the potential revenues, confirming that central solar is not a viable option for OG&E at this time.

Figure 19: Potential Revenue and Cost ($Millions)



E. Conclusions from Resource Planning Analysis

Based on this resource planning analysis, OG&E has determined that the following strategy will provide the greatest benefits to OG&E's customers:

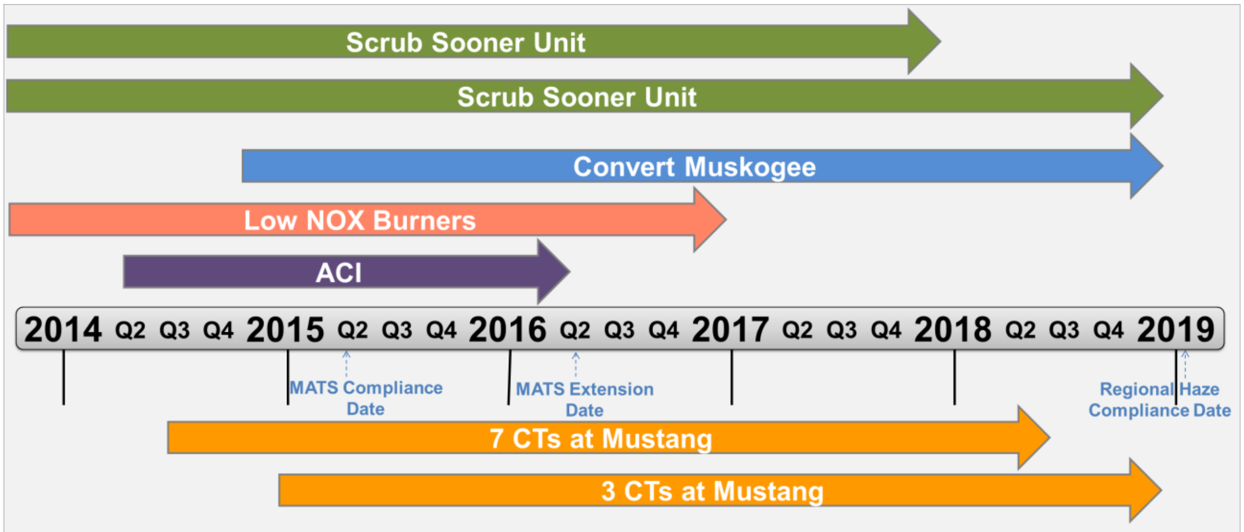
(1) Continue to aggressively pursue demand-side resources;
(2) Scrub Sooner Units 1 and 2;
(3) Convert Muskogee 4 and 5 to natural gas;
(4) Defer expanding wind energy for at least two years, or until transmission constraints are relieved and there is greater certainty as to the value of wind in the SPP IM; and
(5) Replace Mustang Units 1-4 (463MW) with ten net 40MW (net 400MW) natural-gas fired combustion turbine units over the course of two years, beginning in 2018.

When considered as a comprehensive resource plan, this combination of actions addresses OG&E's future requirements in a lowest reasonable cost manner and leverages prior OG&E actions that have been made while it implemented the 2020 Goal.

VI. RESOURCE STRATEGY AND ACTION PLAN

The Five-Year Action Plan addresses the years from 2014 to 2018. Within this time frame, OG&E will be making modifications to a number of units to maintain compliance with environmental regulations.

Figure 20: Action Plan Timeline



A. Environmental Controls

1. Activated Carbon Injection

The installation of ACI equipment for mercury removal is planned to be complete on all coal units by April 2016.

2. Low NO_x Burners

By early 2017, OG&E plans to complete installation of Low NO_x burners with overfire air on 7 units (Muskogee 4 & 5, Sooner 1 & 2, Seminole 1, 2 & 3) to reduce emissions that cause or contribute to regional haze. Installation has been completed on Muskogee unit 5 and Sooner units 1 and 2.

3. Dry Scrubbers at Sooner

Dry scrubbers for SO_2 removal will be installed on Sooner 1 by 2018 and Sooner 2 by 2019. OG&E believes the installation of dry scrubbers will keep the Sooner plant in compliance with the federal requirements for SO_2 emissions.

4. Convert Muskogee 4 & 5 to Natural Gas

Muskogee 4 & 5 will be converted to natural gas by 2019. OG&E believes the conversion from coal to natural gas will satisfy the federal requirements for SO_2 emissions.

B. Mustang Unit Retirement and Replacement Units

OG&E plans to retire the existing Mustang plant in 2017 and replace with ten 40MW natural-gas fired combustion turbine units over the course of two years. The first of the replacement units are planned to come online in 2018.

C. Demand Side Management Plan

OG&E plans to continue to expand Energy Efficiency programs and expects growth in Demand Response programs. OG&E depends on the Demand Side Management plan to maintain an adequate planning capacity margin in SPP and to achieve the “2020 Goal.”

D. Future Generation Options

OG&E will continue to monitor market conditions and implementation feasibility of generation options. In the spring of 2015, OG&E will seek market information by issuing an RFI for fossil fuel generation capacity along with renewable (solar and wind) generation. The findings from the RFI will be considered in OG&E’s 2015 IRP.

VII. SCHEDULES

This section is intended to provide a tabular summary of each section as described in the OCC's Electric Utility Rules, Subchapter 37 of Chapter 35, section 4 (c).

Schedule A – Electric Demand and Energy Forecast

Details of this forecast can be found starting on page 21 and also in Appendix A – OG&E 2013 Load Forecast. Also included is the Demand Side Resources which can be found starting on page 23.

OG&E Energy Sales Forecast (GWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Wholesale	511	0	0	0	0	0	0	0	0	0
Retail	27,708	28,062	28,410	28,668	28,973	29,258	29,474	29,678	29,920	30,144
Total	28,219	28,062	28,410	28,668	28,973	29,258	29,474	29,678	29,920	30,144
Losses	1,973	1,962	1,986	2,004	2,025	2,045	2,060	2,075	2,091	2,107
Total with Losses	30,192	30,023	30,396	30,671	30,998	31,303	31,534	31,753	32,011	32,251
Energy Efficiency	396	496	638	793	873	995	1,132	1,095	1,061	1,027
Demand Response	89	94	98	102	102	104	104	104	104	103
Load Responsibility	29,707	29,433	29,661	29,777	30,023	30,204	30,298	30,554	30,847	31,121
Sales Growth		-0.92%	0.77%	0.39%	0.83%	0.60%	0.31%	0.84%	0.96%	0.89%

OG&E Peak Demand Forecast (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Wholesale	0	0	0	0	0	0	0	0	0	0
Retail	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605	6,651
Total	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605	6,651
Energy Efficiency	83	104	134	167	183	209	238	230	223	216
Demand Response	272	293	309	328	332	336	340	344	348	348
Load Responsibility	5,850	5,855	5,892	5,882	5,921	5,924	5,950	5,988	6,034	6,087
Peak Demand Growth		0.09%	0.63%	-0.18%	0.67%	0.05%	0.43%	0.64%	0.78%	0.87%

Forecasted Energy Reduction from Energy Efficiency (GWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 Programs	396	396	396	396	376	358	340	323	307	291
2015 Programs	-	100	242	396	396	396	396	376	358	340
2018 Programs	-	-	-	-	100	242	396	396	396	396
Total	396	496	638	793	873	995	1,132	1,095	1,061	1,027

Forecasted Peak Demand Reduction from Energy Efficiency (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 Programs	83	83	83	83	79	75	71	68	64	61
2015 Programs	-	21	51	83	83	83	83	79	75	71
2018 Programs	-	-	-	-	21	51	83	83	83	83
Total	83	104	134	167	183	209	238	230	223	216

DR Energy Reduction (GWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SmartHours	66	67	67	66	67	68	68	68	67	67
IVVC	21	25	29	33	33	33	33	33	33	33
Load Reduction Rider	2	2	2	2	3	3	3	3	3	3
Total Reduction	89	94	98	102	102	104	104	104	104	103

DR Peak Demand Reduction (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SmartHours	189	194	194	194	194	194	194	194	194	194
IVVC	41	54	67	82	82	82	82	82	82	82
Load Reduction Rider	41	45	49	53	56	60	64	68	71	71
Total Reduction	272	293	309	328	332	336	340	344	348	348

Schedule B – Existing Resources

This schedule provides a summary of existing supply side resources. Details on this data can be found in the Resource Options section starting on page 25.

2015 OG&E Existing Generation Resources – Peak Capacity

Unit Type	Unit Name	First Year In Service	Capacity (MW)
Coal Fired Steam (2540 MW)	Muskogee 4	1977	492
	Muskogee 5	1978	506
	Muskogee 6	1984	500
	Sooner 1	1979	520
	Sooner 2	1980	522
Gas Fired Steam (2483 MW)	Horseshoe Lake 6	1958	169
	Horseshoe Lake 8	1968	394
	Mustang 1	1950	50
	Mustang 2	1951	50
	Mustang 3	1955	121
	Mustang 4	1959	242
	Seminole 1	1971	486
	Seminole 2	1973	482
	Seminole 3	1973	489
Combined Cycle (1195 MW)	Horseshoe Lake 7	1963	193
	McClain	2001	380*
	Redbud	2004	622*
Quick Start Combustion Turbine (176 MW)	Horseshoe Lake 9	2000	45
	Horseshoe Lake 10	2000	45
	Mustang 5A	1971	36
	Mustang 5B	1971	34
	Seminole 1GT	1971	16
Purchase Power - Thermal (440 MW)	AES Shady Point	1991	320
	PowerSmith	1998	120
Purchase Power - Wind (13 MW)	FPL Wind	2003	2
	Keenan	2010	5
	Taloga	2011	4
	Blackwell	2012	2
Owned Wind (11 MW)	Centennial	2007	2
	OU Spirit	2009	2
	Crossroads	2012	7
Total Net Capability			**6,858**

** Represents OG&E owned interest.*

Emission Control Technologies (2014 dollars)

Control	Units	Overnight Capital Cost ($Millions)	Fixed O&M Cost ($Millions)	Variable O&M Cost ($/MWh)
Dry Scrubber	All Coal per unit	$247.9	$7.88	$2.72
Low NO_x Burners	Muskogee 4	$11.0	$0.24	-
Low NO_x Burners	Sooner 1	$10.6	$0.24	-
Low NO_x Burners	Seminole 1&2	$41.3	$1.30	-
Low NO_x Burners	Seminole 3	$19.0	$0.64	-
Activated Carbon Injection	All Coal	$24.3	$0.80	$2.50
Conversion to Gas	Muskogee	$35.7	-$5.57*	-$0.12
Conversion to Gas	Sooner	$35.7	-$5.75*	$0.39

**Represents the incremental cost decrease due to conversion from coal to gas*

Schedule C – Transmission Capability and Needs

Section IV.C on page 33 provides a description of OG&E transmission system. The table below shows how many miles of transmission OG&E has for each transmission voltage.

Transmission Lines by Voltage (Miles)

Voltage	69 kV	138kV	161 kV	345 kV	500 kV	Total
Miles	1,413	1,910	252	1,087	47	4,709

Schedule D – Needs Assessment

This schedule provides the needs assessment for new generating resources for the next 10 years. A further description of these needs is found on page 39.

Planning Capacity Margin (MW unless noted)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Resources	Total Owned Capacity	6,405	6,355	6,355	5,942	5,942	5,942	5,942	5,942	5,942	5,773
	Purchase Contracts	453	453	453	453	451	331	331	331	11	11
	Total Net Dependable Capability	6,858	6,808	6,808	6,395	6,393	6,273	6,273	6,273	5,953	5,784
Demand	Load Forecast	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605	6,651
	Energy Efficiency	83	104	134	167	183	209	238	230	223	216
	Demand Response	272	293	309	328	332	336	340	344	348	348
	Net On System Demand	5,850	5,855	5,892	5,882	5,921	5,924	5,950	5,988	6,034	6,087
Capacity Needs	Capacity Margin	1,008	953	916	513	472	349	323	285	-81	-303
	Percent Capacity Margin (%)	14.7	14.0	13.4	8.0	7.4	5.6	5.2	4.5	-1.4	-5.2
	Needed Capacity	-	-	-	289	336	460	488	532	905	1,134

Schedule E – Resource Options

This schedule provides a description of the supply side options available to OG&E to address the needs identified in Schedule D and further explained starting on page 30.

New Supply Side Resources (2014 Dollars)

Type	Technology	Net Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost ($/kW)	Fixed O&M Cost ($/kW)	Variable O&M Cost ($/MWh)
Natural Gas	Combined Cycle	281	6,120	$1,475	$22.50	$2.56
	Combined Cycle	562	6,120	$1,227	$16.36	$2.56
	Combustion Turbine	39	8,904	$1,002	$26.59	$1.81
	Combustion Turbine	75	10,733	$1,084	$22.50	$18.41
	Combustion Turbine	86	8,309	$1,657	$16.36	$4.50
	Combustion Turbine	237	9,040	$985	$8.18	$16.36

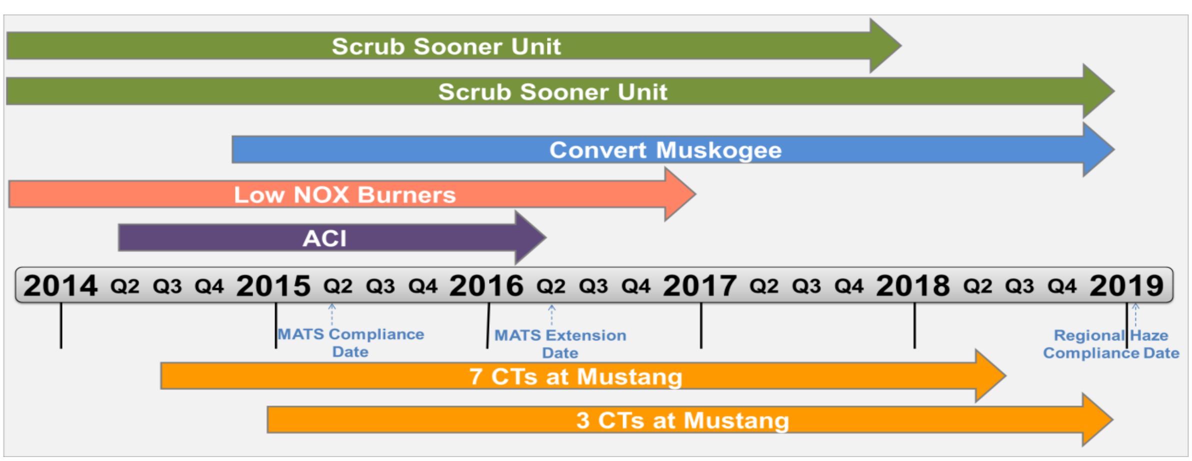
Schedule F – Fuel Procurement and Risk Management Plan

On May 15, 2014, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC.

Schedule G – Action Plan

This schedule outlines the proposed actions for the next five years. These actions are in accord with this IRP, and will position OG&E to complete the plan as described in this report. The Five-Year Action Plan addresses the years from 2014 to 2018. Within this time frame, OG&E will be making modifications to a number of units to maintain compliance with environmental regulations.

Action Plan Timeline



Environmental Controls

Activated Carbon Injection

The installation of Activated Carbon Injection (ACI) equipment for mercury removal is planned to be complete on all coal units by April 2016.

Low NOx Burners

By early 2017, OG&E plans to complete installation of Low NO_x burners with overfire air on 7 units (Muskogee 4 & 5, Sooner 1 & 2, Seminole 1, 2 & 3) to reduce emissions that cause or contribute to regional haze. Installation has been completed on Muskogee unit 5 and Sooner units 1 and 2.

Dry Scrubbers at Sooner

Dry scrubbers for SO_2 removal will be installed on Sooner 1 by 2018 and Sooner 2 by 2019. OG&E believes the installation of dry scrubbers will keep the Sooner plant in compliance with the federal requirements for SO_2 emissions.

Convert Muskogee 4 & 5 to Natural Gas

Muskogee 4 & 5 will be converted to natural gas by 2019. OG&E believes the conversion from coal to natural gas will satisfy the federal requirements for SO_2 emissions.

Mustang Unit Retirement and Replacement Units

OG&E plans to retire the existing Mustang plant in 2017 and replace with ten 40MW natural-gas fired combustion turbine units over the course of two years. The first of the replacement units are planned to come online in 2018.

Demand Side Management Plan

OG&E plans to continue to expand Energy Efficiency programs and expects growth in Demand Response programs. OG&E depends on the Demand Side Management plan to maintain an adequate planning capacity margin in SPP and to achieve the "2020 Goal."

Renewable Generation

OG&E will continue to monitor market conditions and implementation feasibility for renewable generation options. We will consider new projects with reasonable and manageable price and risk characteristics that satisfy our generation needs.

Schedule H – Requests for Proposals

OG&E has already conducted Requests for Proposals ("RFPs") for all control equipment associated Low NOx burners and is in the process of conducting RFPs for dry scrubber and ACI equipment. OG&E plans to conduct RFPs for the installation of the remaining low NOx burners and is in the process of conducting RFPs for the installation of dry scrubbers and ACI. In addition, OG&E intends to conduct RFPs for the equipment and work associated with both the conversion of the Muskogee Units and the installation of the new Mustang units. OG&E will make the RFP documents and procedures for the low NOx burners, scrubbers and ACI available upon request and subject to the Protective Order issued in Cause No. PUD201400137.

Schedule I – Modeling Methodology and Assumptions

This schedule is a technical appendix for the data, assumptions, and descriptions of models needed to understand the derivation of the resource plan. The table below explains who supplied each assumption and provides a reference for where this information is found in the IRP. Since the load forecast is provided in Appendix A, the remaining was provided in Schedule A, it has not been repeated here.

Assumption	Source	Page
Load	OG&E	21
Energy Efficiency	OG&E	23
Demand Response	OG&E	24
Existing Unit Characteristics	OG&E	25
Emission Control Technologies	OG&E, S&L	29
New Resource Screening Requirements	OG&E, EIA	30
New Unit Characteristics	OG&E, S&L	32
Natural Gas	EIA	35
Coal	EIA	35
CO_2	OG&E	35
Market Prices	OG&E	36

Descriptions of Software Tools

OG&E utilizes two software programs for production cost modeling.

GenTrader®

The GenTrader ® software provided by Power Costs, Inc. is designed to model complex portfolios of power and fuel resources, including generators, contracts, options, and ancillary services in great detail. Some of the functionalities include: multiple and concurrent fuel and emission limits, multi-stage combined-cycle modeling, ancillary services like regulations and spinning reserve as well as energy limited contracts. GenTrader® is used to simulate OG&E owned or contracted units serving OG&E's load

PROMOD IV®

The PROMOD IV® software provided by Ventyx is the industry-leading Fundamental Electric Market Simulation software, incorporating extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations. PROMOD IV® is used to model the SPP Integrated Marketplace.

Schedule J – Transmission System Adequacy

This schedule is a description of the transmission system adequacy over the next 10 years. SPP evaluates system adequacy and develops a transmission expansion plan to determine what improvements are necessary to ensure reliable transmission service. The 2014 SPP Transmission Expansion Plan[14] describes improvements necessary for regional reliability, local reliability, generation interconnection, long-term tariff studies due to transmission service requests and transmission owner sponsored improvements. Included in below is a subset of the 2014 STEP, which OG&E has committed to construct.

Estimated Capital Expenditures for OG&E Committed Projects

	Year	Description	Type of Upgrade	Cost Allocation	Cost ($Million)
1	2014	Fort Smith - Colony 161 kV 2	Reconductor Line	Regional Reliability	$1.8
2	2014	Dover-Twin Lake-Crescent-Cottonwood conversion 138 kV	Reconductor Line and Substation Work	Regional Reliability	$9.6
3	2014	Pecan Creek - Five Tribes 161 kV Ckt 1	Reconductor Line and Substation Work	Regional Reliability	$2.6
4	2014	Tuco - Woodward 345 kV (OG&E)	New Line and Substation Work	Balanced Portfolio	$120.0
5	2014	Cushing Area 138 kV	Reconductor Line and Substation Work	Regional Reliability	$15.0
6	2014	Hitchland - Woodward 345 kV dbl Ckt	New Line and Substation Work	High Priority	$165.0
7	2014	Thistle - Woodward 345 kV dbl Ckt	New Line and Substation Work	High Priority	$145.0

14 2014 STEP: http://www.spp.org/publications/2014_STEP_Report_Final_20140205.pdf

	Year	Description	Type of Upgrade	Cost Allocation	Cost ($Million)
8	2014	Classen - Southwest 5 Tap 138 kV	Substation Work	Regional Reliability	$0.2
9	2014	Shidler 138KV - Osage Sub work	Line and Substation Work	Generation Interconnection	$0.4
10	2014	Renfrow 345/138 kV Transformer Ckt 1	New 345/138 kV Transformer	Regional Reliability	$3.1
11	2014	Renfrow Substation	New Substation	Regional Reliability	$11.7
12	2014	Grant County Substation	New Substation	Regional Reliability	$5.0
13	2014	Grant County 138/69 kV Transformer	New 138 / 69 KV Transformer	Regional Reliability	$1.2
14	2014	Renfrow - Grant County 138 kV line	New Line and Substation Work	Regional Reliability	$4.5
15	2014	Koch Substation Voltage Conversion	Substation Voltage Conversion to 138 KV	Regional Reliability	$0.6
16	2014	Medford Tap - Renfrow 138 kV	New Line and Substation Work	Regional Reliability	$3.2
17	2014	Medford Tap 138 kV	Substation Work	Regional Reliability	$0.2
18	2015	Doolin - Medford Tap 138 kV	New Line and Substation Work	Regional Reliability	$13.8
19	2015	Chikaskia - Doolin 138 kV	New Line and Substation Work	Regional Reliability	$8.2
20	2015	Doolin 138 kV Switching Station	New Substation	Regional Reliability	$3.0
21	2017	Northwest Substation	Install 3rd 345 / 138 KV Transformer	Transmission Service	$15.0
22	2017	Ft. Smith Substation	Install 3rd 500 / 161 KV Transformer	Transmission Service	$14.0
23	2017	VBI - VBI North 69 kV	Substation Upgrade	Transmission Service	$0.1
24	2017	El Reno - Service PL El Reno 69 kV CKT 1	Substation Work	Transmission Service	$0.0
25	2018	Chisholm - Gracemont 345 kV	New Line and Substation Work	ITP10	$75.5

	Year	Description	Type of Upgrade	Cost Allocation	Cost ($Million)
26	2019	Bryant - Memorial 138 kV	Line and Substation Work	Transmission Service	$0.2
27	2019	Arcadia - Redbud 345 kV Ckt 3	New Line and Substation Work	Transmission Service	$18.0
28	2021	Tatonga - Woodward District EHV 345 kV Ckt 2	New Line and Substation Work	ITP10	$59.5
29	2021	Matthewson - Tatonga 345 kV Ckt 2	New Line and Substation Work	ITP10	$65.8
30	2021	Cimarron - Matthewson 345 kV Ckt 2	New Line and Substation Work	ITP10	$32.9
31	2021	Matthewson 345 kV	New Substation	ITP10	$20.0

Transmission system expansion provides benefits to members throughout the SPP; therefore, the costs of all projects constructed in the SPP are shared through various cost allocation methods, depending on the type of project.

Schedule K – Resource Plan Assessment

This IRP assessed the need for additional resources to meet reliability, cost and price, environmental, and other criteria established by the OCC, the State of Oklahoma, the APSC, SPP, NERC, and FERC. All criteria were met by all portfolios considered in this IRP, in the base line condition. These criteria were also met in scenarios and uncertainties which included variations in load growth, fuel prices, emissions prices, environmental regulations, technology improvements, demand side resources, and fuel supply, among others. This plan provides a comprehensive analysis of the proposed options.

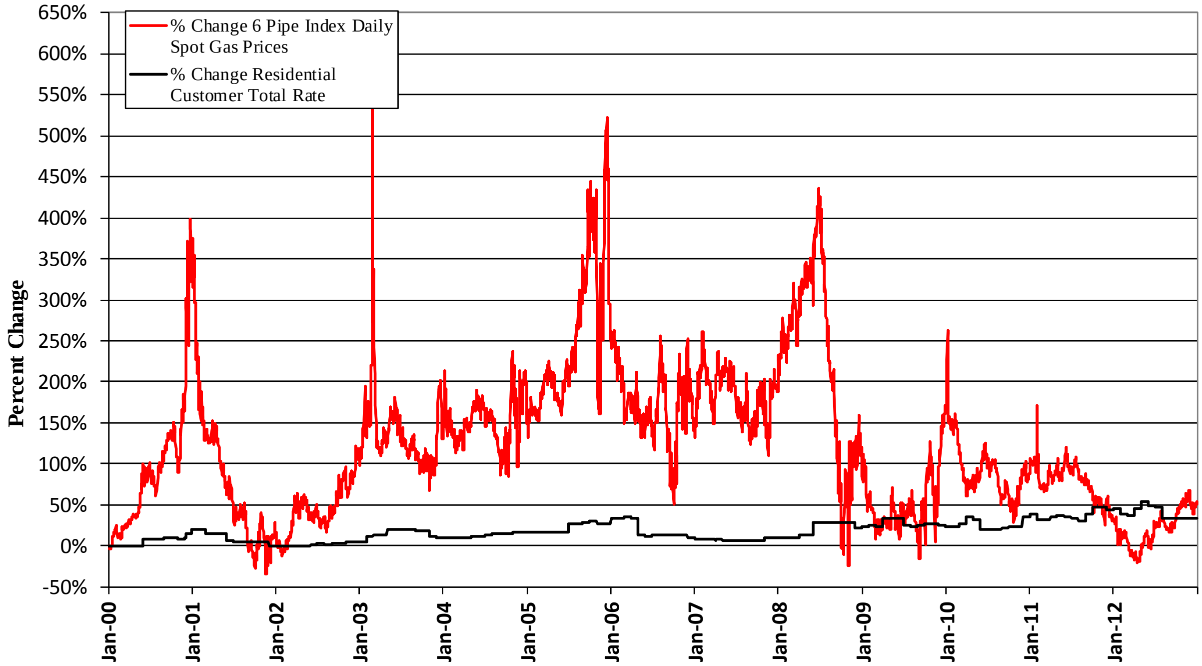
Schedule L – Proposed Resource Plan Analysis

This IRP demonstrates that all proposed alternatives meet all planning criteria as outlined in Schedule K. The proposed action plan outlined in Schedule G best meets these criteria. Documentation of the planning analysis and assumptions used in preparing this analysis are described in Schedule I.

Schedule M - Physical and Financial Hedging

Currently, OG&E's Fuel Cost Adjustment tariff provides OG&E customers' effective protection against fuel price volatility as shown in Chart 1. Additionally, OG&E has a diverse mix of generation assets as outlined in Section IV of this report. The sensitivity analysis in Section V illustrates the advantages of generation diversity and the impact of the fuel volatility.

Daily Gas Price Volatility Compared with Residential Rate Volatility



Note: 1. Base value for percentage changes is: 1/1/2000
2. Fuel Adjustment Factors moved to coincide with operations

Financial Hedging of a commodity such as power plant fuel is aimed at reducing the volatility in price. Financial hedging comes at a cost in the form of transaction costs, margin calls and premiums required to lock in pricing. OG&E's customers have been protected to a large extent from the historic volatility in natural gas prices by OG&E's portfolio approach to fuel and purchased power. As a result, the Company does not believe it to be prudent at this time to incur the additional costs associated with financial hedging.

On May 15, 2014, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC.

VIII. APPENDICES

Appendix A – OG&E 2013 Load Forecast

Final Report

2013 OG&E Load Forecast Report

Prepared by:
OGE Resource Planning Department

Revised June 2014

Table of Contents

Executive Summary

This report presents Oklahoma Gas & Electric Services' (OG&E) 2013 Load Forecasts. It describes both energy and peak demand forecasting models developed by OG&E with input from OG&E's Load Forecasting Team.

The 2013 retail sales forecast utilized the revenue class-based econometric modeling framework that has been in place for over a decade. The 2013 load responsibility peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility series. The hourly modeling approach has been used since the 2000 forecast.

The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of OG&E electricity prices for price-sensitive customer classes. The load forecast contains the energy efficiency impact expected from the anticipated future implementation of national energy efficiency standards for appliances, lighting products and equipment. The final energy and demand forecast includes Federal Energy Regulatory Commission (FERC) jurisdictional wholesale contracts as post-modeling adjustments. (All OG&E wholesale contracts are scheduled to expire by mid-2015.) OG&E Demand Side Management Programs are now included in the final energy and demand forecasts as post-modeling adjustments.

The economic data, on which the forecast relies, indicates the economy in OG&E's service territory has experienced a strong recovery since the Great Recession. Regional economic indicators have outpaced those at the national level over the past few years. Economic activity has moderated somewhat recently, but the economic forecast shows that growth is expected to accelerate again in the near term. A primary reason for the expected uptick is an anticipated increase in oil & gas drilling and pipeline activity over the next 2 years.

The energy and demand forecasts through 2023 are shown in tables on the next pages. The retail energy forecast is anticipated to grow at an average annual rate of 1.12%. The final energy sales forecast, after adjusting for OG&E DSM programs, projects an average annual growth at 0.52%. Retail peak demand is anticipated to grow at an average annual rate of 0.92% over the next decade. The final demand forecast after adjustments is nearly flat across the 10 year forecast horizon.

2013 Energy Forecast

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FERC	AVEC[1]	946,007	1,007,181	511,201	-	-	-	-	-	-	-	-
MWH Sales	SPA[2]	21,221	10,305	-	-	-	-	-	-	-	-	-
Without	OMPA[3]	219,000	-	-	-	-	-	-	-	-	-	-
Losses	MDEA[4]	61,320	20,440	-	-	-	-	-	-	-	-	-
	Total FERC Sales	1,247,549	1,037,926	511,201	-	-	-	-	-	-	-	-
			-16.80%	-50.75%	-100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Retail	Residential	9,114,402	9,255,993	9,355,271	9,436,621	9,530,650	9,573,518	9,632,811	9,665,510	9,635,237	9,587,179	9,564,471
MWH Sales	Commercial	7,038,163	7,159,631	7,280,760	7,402,484	7,492,217	7,552,977	7,628,098	7,704,192	7,782,821	7,867,416	7,962,220
Without	Industrial	3,949,581	3,969,431	3,976,535	3,991,491	3,999,874	4,010,761	4,027,394	4,047,964	4,071,446	4,096,226	4,119,268
Losses or	Petroleum	3,356,420	3,541,919	3,602,539	3,640,935	3,699,291	3,754,359	3,812,699	3,870,984	3,917,493	3,963,274	4,005,883
OG&E DSM	Street Lighting	65,336	65,999	66,835	67,680	68,495	69,294	70,103	70,935	71,811	72,727	73,666
	Public Authority	3,237,332	3,320,825	3,426,197	3,522,540	3,619,937	3,706,604	3,801,442	3,898,472	3,995,356	4,091,677	4,194,541
	Total Retail Sales	26,761,233	27,313,798	27,708,137	28,061,750	28,410,463	28,667,514	28,972,546	29,258,056	29,474,164	29,678,498	29,920,048
			2.06%	1.44%	1.28%	1.24%	0.90%	1.06%	0.99%	0.74%	0.69%	0.81%
Total	Total Retail + FERC	28,008,782	28,351,724	28,219,338	28,061,750	28,410,463	28,667,514	28,972,546	29,258,056	29,474,164	29,678,498	29,920,048
MWH	Losses[5]	1,957,814	1,981,786	1,972,532	1,961,516	1,985,891	2,003,859	2,025,181	2,045,138	2,060,244	2,074,527	2,091,411
With Losses	Energy Subtotal	29,966,596	30,333,510	30,191,869	30,023,267	30,396,355	30,671,373	30,997,727	31,303,194	31,534,408	31,753,025	32,011,460
			1.22%	-0.47%	-0.56%	1.24%	0.90%	1.06%	0.99%	0.74%	0.69%	0.81%
OG&E DSM	Energy Efficiency	100,026	241,603	396,266	496,292	637,869	792,532	872,745	995,499	1,132,280	1,095,479	1,060,519
MWH Reduction	Demand Response	30,866	68,023	88,907	94,129	97,663	102,028	102,294	103,684	103,775	104,005	103,763
Load Responsibility MWH	**Load Responsibility = Total Sales with Losses and DSM Reduction**	**29,835,703**	**30,023,884**	**29,706,697**	**29,432,846**	**29,660,823**	**29,776,813**	**30,022,688**	**30,204,012**	**30,298,353**	**30,553,541**	**30,847,178**
			0.63%	-1.06%	-0.92%	0.77%	0.39%	0.83%	0.60%	0.31%	0.84%	0.96%

[1] AVEC Contract can expire on June 30, 2015
[2] Paris Contract expired on May 31, 2012 and Vance Contract has been extended to May 31, 2014
[3] OMPA PSA Contract terminates on December 31, 2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.
[4] MDEA Contract 2 expired on December 31, 2012 and MDEA Contract 1 can expire on April 30, 2014
[5] The energy loss factor is 0.0699

2013 Peak Demand Forecast

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FERC Demand (MW) Without Losses	AVEC[1]	215	229	-	-	-	-	-	-	-	-	-
	SPA[2]	5	-	-	-	-	-	-	-	-	-	-
	OMPA[3]	25	-	-	-	-	-	-	-	-	-	-
	MDEA[4]	10	-	-	-	-	-	-	-	-	-	-
	Total FERC w/o Losses	255	229	-	-	-	-	-	-	-	-	-
	Losses	22	20	-	-	-	-	-	-	-	-	-
	Total FERC w/ Losses	277	248	-	-	-	-	-	-	-	-	-
			-10.26%	-100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Total Retail Demand	6,027	6,137	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605
			1.83%	1.10%	0.77%	1.33%	0.64%	0.94%	0.51%	0.90%	0.53%	0.66%
Pre OG&E DSM Load Responsibility (MW)	Demand Subtotal = FERC + Retail (Losses Included)	6,303	6,385	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605
			1.30%	-2.83%	0.77%	1.33%	0.64%	0.94%	0.51%	0.90%	0.53%	0.66%
Pre OG&E DSM Load Factor	Energy(MWH) Subtotal	29,966,596	30,333,510	30,191,869	30,023,267	30,396,355	30,671,373	30,997,727	31,303,194	31,534,408	31,753,025	32,011,460
	Pre DSM Load Factor	54.27%	54.23%	55.55%	54.82%	54.77%	54.91%	54.98%	55.23%	55.15%	55.24%	55.33%
OG&E DSM Reduction (MW)	Energy Efficiency	21	51	83	104	134	167	183	209	238	230	223
	Demand Response	171	232	272	293	309	328	332	336	340	344	348
Net Load Responsibility (MW)	**Load Responsibility = Total Load with Losses and DSM Reduction**	**6,112**	**6,103**	**5,850**	**5,855**	**5,892**	**5,882**	**5,921**	**5,924**	**5,950**	**5,988**	**6,034**
			-0.14%	-4.15%	0.09%	0.63%	-0.18%	0.67%	0.05%	0.43%	0.64%	0.78%
DSM Adjusted Load Factor	Total Net Energy MWh	29,835,703	30,023,884	29,706,697	29,432,846	29,660,823	29,776,813	30,022,688	30,204,012	30,298,353	30,553,541	30,847,178
	Load Factor	55.73%	56.16%	57.97%	57.38%	57.46%	57.79%	57.88%	58.20%	58.13%	58.25%	58.35%

[1] AVEC Contract can expire on June 30, 2015
[2] Paris Contract expired on May 31, 2012 and Vance Contract has been extended to May 31, 2014
[3] OMPA PSA Contract terminates on December 31, 2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.
[4] MDEA Contract 2 expired on December 31, 2012 and MDEA Contract 1 can expire on April 30, 2014

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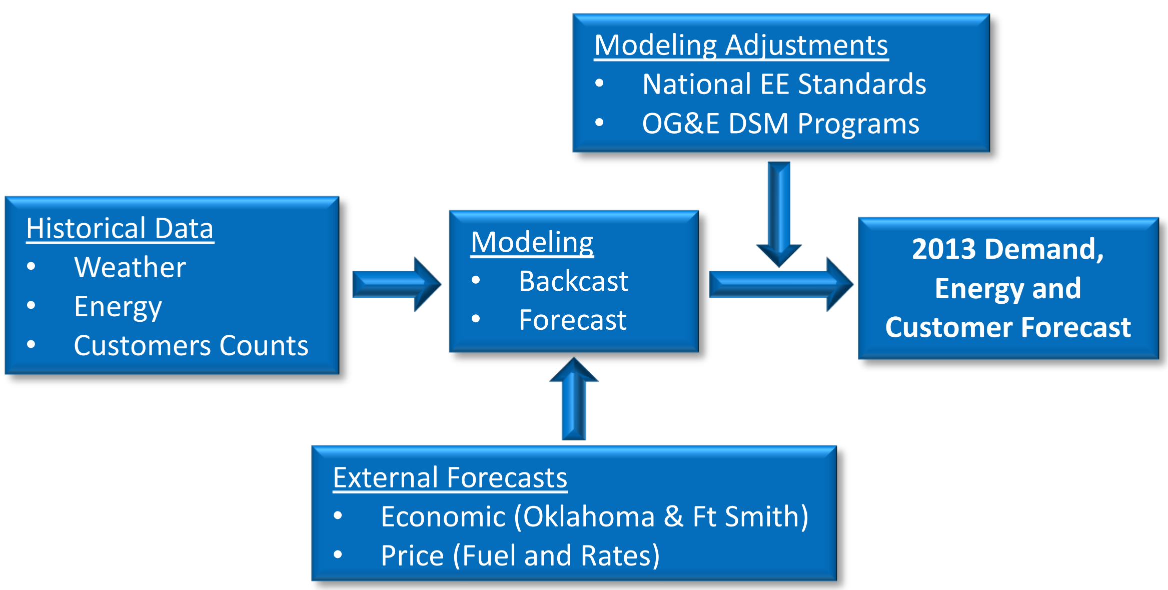
1 Introduction

The 2013 load forecast offers a ten year projection for energy, peak demand and customer growth. The 2013 retail sales (energy) forecast utilized the revenue class-based econometric modeling framework that has been in place for over a decade. The 2013 load responsibility peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility series. The econometric model used for customer growth relies heavily on population growth projections in OG&E's service territories.

The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of OG&E electricity prices for price-sensitive customer classes. The final energy and demand forecast includes Federal Energy Regulatory Commission (FERC) jurisdictional wholesale contracts as post-modeling adjustments. (All OG&E wholesale contracts are scheduled to expire by mid-2015.) OG&E Demand Side Management Programs are now included in the final energy and demand forecasts as post-modeling adjustments.

A simplified process map, as shown in Figure 1, shows how historical data is integrated with external forecasts of the future. This modeling step first tests previous assumptions in a regression analysis to historical performance (this is also called the backcast). Assumptions are adjusted as needed to produce the future forecast for each revenue class. Modeling adjustments are made to the forecast to incorporate additional changes before the final forecast is produced.

Figure 1 – Load Forecast Process



2 Economic Outlook

KEY TAKEAWAYS:

- ***Oklahoma economic activity has leveled off recently, but it is expected to pick up in 2014 due to growth in the Energy Sector.***
- ***Consumers' spending has increased and is expected to modestly increase in the near term.***
- ***Employment growth in Oklahoma has outpaced the nation, and is expected to show continued strength in the next few years.***

2.1 Economic Summary

Oklahoma entered the Great Recession behind most of the country, and it has been recovering slightly ahead of the rest of the nation. Recently, economic activity in the state has leveled off, but it is expected to resume adding gains in the near future. A modest national recovery has led to increasing demand for products that are typically exported from the region (energy, aerospace, manufacturing, agriculture, etc.). Relatively healthy activity in the energy sector continues to drive the Oklahoma economy and should provide continued momentum for gains in income and employment across all sectors of the state economy.

2.2 Underlying Economic Fundamentals

Consumer spending has risen in the past year and has been especially strong among restaurants and hotels, while showing little change among retailers and auto dealers. Manufacturing activity has improved somewhat with additional, but moderated gains expected in the near future. Transportation activity has been relatively flat, while sales in the high-tech services sector have risen slightly. The residential real estate market continues to improve with increased sales, construction, and prices, while the commercial real estate sector has continued to slow. Banks have reported slightly higher loan demand and improved loan quality, although non-performing loan problems exist throughout the state. The Agricultural sector has seen substantial easing of drought conditions, leading to higher yields, corresponding lower crop and cattle prices and higher land values. However, the sector has been restrained by lower farm income levels in 2013, as well as higher interest rates on farmland real-estate. The energy sector remains sound, but off from highs of the previous two years. Most sectors reported higher input prices, but final goods prices and wages have remained stable, which is consistent with national trends.

2.2.1 Oklahoma Employment

Oklahoma's employment has risen back above pre-recession levels and overall employment growth continues to outpace the nation in most areas of the state. Employment growth in the Natural Resources and Mining sector is expected to remain at historic levels in the next few years, although at a more moderated pace when compared to the two previous years. Any significant deviation in energy prices will greatly affect employment in this sector. Employment in both Manufacturing and Construction is forecast to continue growing over the next two years. State and Local Government employment is forecast to rise slightly as the state budget continues to recover, but this is highly dependent on the political process. Federal Government employment in the state is anticipated to continue declining due to spending cuts at the federal level.

2.2.2 Oklahoma Energy Sector

Overall energy activity remains fairly stable at high levels in Oklahoma. Oklahoma drilling activity has slipped somewhat as growth in the number of active crude oil rigs offset steep declines in natural gas drilling. Drilling activity is expected to grow at a consistent pace in coming months, even as activity continues to shift away from natural gas to oil. A slowdown in natural gas drilling is expected to put upward pressure on natural gas prices. Crude oil prices have been influenced by the conflicting pressures of declines in U.S. crude oil inventory and concerns over softening global demand. However, later this year, China is projected to exceed the US in oil imports, which is expected to ease any remaining global demand concerns.

2.2.3 Manufacturing Sector

Manufacturing production and hiring have continued to increase, but at a more moderated pace when compared to the previous two years. Manufacturers expect activity in the near term to be substantially moderated from gains seen in 2011 and 2012. Manufacturing production in the OG&E service territory is closely related to oil and natural gas drilling activity.

2.2.4 Real Estate and Construction

Real estate activity continues to improve, and construction activity has strengthened. Residential home sales and prices have risen, and home inventories continue to fall. The housing market is expected to continue to improve in the near term, with storm recovery construction expected to provide further positive influence in the sector. Even before the May 2013 storm/tornado impact, which the Oklahoma Department of Insurance estimates could top $1 billion; builders were reporting an increase in housing starts and a rise in new home prices as well as improvement in the traffic of potential buyers. Commercial real estate conditions have moderated. Construction and sales of commercial real estate properties have slowed slightly, real estate prices and rents have remained flat but vacancy rates continue to fall. Views are mixed on the near-term impact rising interest rates will have on the real estate sector.

2.3 Role of Economic Data in 2013 Energy Sales Forecast

The 2013 retail energy forecast is based on retail sector-level econometric models representing OG&E's Oklahoma and Arkansas service territories. Historical and forecast economic variables (drivers) are provided by the Center for Applied Economic Research at Oklahoma State University (OSU). The historical economic data is compared to actual retail sales to determine a correlation. Then the economic forecast parameters are used to predict retail energy based on historically-defined correlations.

2.4 Economic Drivers for Energy Forecast

The 2013 Economic Forecast calls for modest increases in economic growth in Oklahoma and Ft. Smith over the next five years relative to the previous decade. The economic drivers for Ft. Smith show higher growth rates over the next five years in comparison to the previous decade due to relatively poor economic conditions during the previous decade. The growth rates for

2019 to 2023 are still expected to remain at strong levels as the prolonged economic recovery continues nationally. Table 1 shows the historical and projected annual average growth rates of the primary economic drivers utilized in the retail energy forecast.

Table 1 - Economic Driver Growth Rates

Economic Drivers and Models			Economic Driver Average Annual Growth Rates		
			2002 - 2012	2013-2018	2019-2023
Oklahoma	Residential	OKC Real Personal Income (Ex-Energy)	2.38%	2.88%	1.38%
Oklahoma	Commercial	OKC Real Gross Metro Product (Ex-Energy)	2.25%	3.39%	3.05%
Oklahoma	Industrial	OKC Transportation & Public Utility Employment	-4.24%	0.79%	1.98%
Oklahoma	Petroleum	Natural Resources & Mining Personal Income	12.71%	3.42%	3.25%
Oklahoma	Street Lighting	OKC Population	1.42%	1.32%	1.33%
Oklahoma	Public Authority	Oklahoma Real Gross State Product	1.84%	2.96%	2.71%
Arkansas – Ft. Smith	Residential	Real Gross Metro Product	0.75%	2.16%	1.95%
Arkansas – Ft. Smith	Commercial	Real Personal Income	1.79%	4.12%	3.57%
Arkansas – Ft. Smith	Industrial	Mining, Logging, Construction Employment	0.68%	4.08%	1.46%
Arkansas – Ft. Smith	Petroleum	Mining, Logging, Construction Employment	0.68%	4.08%	1.46%
Arkansas – Ft. Smith	Street Lighting	Population	0.83%	0.78%	0.96%
Arkansas – Ft. Smith	Public Authority	Real Gross Metro Product	0.75%	2.16%	1.95%

3 OG&E Demand Side Management Summary

KEY TAKEAWAYS:

- ***Energy Efficiency (EE) and Demand Response (DR) reduce the load requirements on the system.***
- ***Historical savings from previously implemented EE programs are already embedded in the load forecast.***

OG&E Demand Side Management includes both Energy Efficiency and Demand Response programs. While EE programs do provide some demand reduction, EE is designed to educate and encourage customers to make behavioral changes and purchasing decisions that will provide long-term benefits in managing their energy usage. DR programs are designed to encourage customers to reduce their demand during system peak. Detailed descriptions of current programs can be found in Appendix B – Expected DSM Program Impacts.

The impact of EE programs implemented between 2009 and 2011 is embedded in the baseline energy and peak demand forecasts. However, the expected impacts of more recent and future programs, as well as the expected impact of DR programs have been subtracted from the baseline forecast to calculate the final energy and peak demand forecasts. Table 2 and Table 3 show the expected impacts of these programs.

Table 2 – Expected *Energy* Reduction from OG&E DSM Programs

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Efficiency	100	242	396	496	638	793	873	995	1,132	1,095	1,061
2012 Programs	100	242	396	396	396	396	376	358	340	323	307
2015 Programs	-	-	-	100	242	396	396	396	396	376	358
2018 Programs	-	-	-	-	-	-	100	242	396	396	396
Demand Response	31	68	89	94	98	102	102	104	104	104	104
Smart Hours	25	58	66	67	67	66	67	68	68	68	67
IVVC	5	9	21	25	29	33	33	33	33	33	33
LRR	1	2	2	2	2	2	3	3	3	3	3
Total GWH	131	310	485	590	736	895	975	1,099	1,236	1,199	1,164

Table 3 – Expected *Peak Demand* Reduction from OG&E DSM Programs

Demand (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Efficiency	21	51	83	104	134	167	183	209	238	230	223
2012 Programs	21	51	83	83	83	83	79	75	71	68	64
2015 Programs	-	-	-	21	51	83	83	83	83	79	75
2018 Programs	-	-	-	-	-	-	21	51	83	83	83
Demand Response	171	232	272	293	309	328	332	336	340	344	348
Smart Hours	118	165	189	194	194	194	194	194	194	194	194
IVVC	18	29	41	54	67	82	82	82	82	82	82
LRR	35	38	41	45	49	53	56	60	64	68	71
Total MW Reduction	192	282	355	397	443	495	515	545	578	574	571

4 Energy Forecast

KEY TAKEAWAYS:

- ***Total retail energy increases by an average of 1.12% per year***
- ***Total retail energy for 2023 is expected to be 29,920,048 MWh***

4.1 Econometric Modeling Process - Energy

The retail energy forecast is generated from a regression analysis of historical energy, economic growth patterns and annual weather. OG&E's retail energy is divided into six market segments (residential, commercial, industrial, petroleum, street lighting and public authority) for both states (Oklahoma and Arkansas). Within each segment, a variety of different models is prepared and tested against actual historical sales to determine which model provides the highest quality forecast for that market segment. The models test a range of variable combinations (i.e. model specifications), each with separate intercept and slope coefficients.

The dependent variable is OG&E's retail energy sales by market segment. Key independent variables include:

- Electricity price paid by the customer.
- Economic conditions as reflected through various economic indicators.
- Cooling degree days, base 65. This cooling degree day variable effectively represents temperature impacts when daily average temperatures (average of the daily minimum and daily maximum temperatures) exceed 65 degrees.
- Heating degree days, base 65. This heating degree day variable effectively represents temperature impacts when daily average temperatures fall below 65 degrees.
- Monthly or seasonal variables, used to capture the highly seasonal nature of energy sales.

The monthly energy consumption analysis for each market segment follows a three-step process:

Step 1. Set up models for each market segment with different variable groups and generate estimates using the 2012 model specifications as a starting point

Step 2. Inspect goodness-of-fit and other important statistics (e.g., R-squared, t-statistics, multicollinearity statistics); compare actual versus predicted values of the dependent variable over the historical period.

Step 3. Adjust variables repeat steps 1 and 2 as needed until a final model specification is generated.

Between 10 and 50 models were estimated for each segment. The final model was not always the one with the "best fit." The overriding selection criterion was the model providing the best forecast. For example, if a model with an R-square of 0.95 had a larger error in the out-of-sample period than an alternative model with an R-square of 0.93, the latter model was selected. Table 4 and Table 5 detail the final model variables used for Oklahoma and Arkansas, respectively.

Table 4 – Oklahoma Energy Model Drivers

	Primary Economic Drivers Oklahoma Economic Outlook	Other Drivers
Residential	OKC Real Personal Income (Ex-Energy)	Real Residential electric price, Heating-Degree Days (HDD), Cooling-Degree Days (CDD)
Commercial	OKC Real Gross Metro Product (Ex-Energy)	OKC Population, Real Commercial electric price, HDD, CDD
Industrial	OKC Transportation & Public Utility Employment	OKC Non-Durable Goods Manufacturing Employment
Petroleum	Natural Resources & Mining Personal Income	Nominal Energy GSP
Street lighting	OKC Population	Free Street Lighting Service Variable
Public Authority	Oklahoma Real Gross State Product	Real Public Authority electric price, HDD, CDD

* Some models also have monthly-specific intercept and interaction terms.

Table 5 – Arkansas Energy Model Drivers

	Primary Economic Drivers Arkansas Economic Outlook – Ft. Smith	Other Drivers
Residential	Real Gross Metro Product	Ft. Smith Population, Real Residential electric price, HDD, CDD
Commercial	Real Personal Income	Real Commercial electric price, HDD, CDD
Industrial	Mining, Logging, Construction Employment	Fort Smith Real Manufacturing Gross Product
Petroleum	Mining, Logging, Construction Employment	N/A
Street lighting	Population	N/A
Public Authority	Real Gross Metro Product	Real Public Authority electric price, HDD, CDD

* Some models also have monthly-specific intercept and interaction terms.

4.2 2013 Energy Forecast Adjustments

The regression analysis cannot predict external changes that will occur in the future. Therefore, adjustments must be made to the model before the final forecast is generated.

4.2.1 National Energy Efficiency Adjustment

The residential and commercial sectors for Oklahoma and Arkansas were adjusted for energy efficiency that is expected as a result of the anticipated implementation of national energy efficiency standards for appliances, lighting products and equipment. The adjustments were made by utilizing state-level energy efficiency impact data from the "Appliance Standards

Awareness Project"[1] and applying a ratio based on the relationship of OG&E's service territory to the state. Existing codes and standards are assumed to be included in the baseline forecast. The energy efficiency adjustments include standards expected to be implemented in the future. The results of these calculations are shown in Table 6.

Table 6 – Energy Efficiency Adjustments

Oklahoma Residential Energy Efficiency

Year	Oklahoma Residential Baseline MWh	Oklahoma Res. Energy Efficiency MWh Adjustment	Final Oklahoma Residential Model MWh
2013	8,375,887	-	8,375,887
2014	8,512,599	1,028	8,511,571
2015	8,607,290	6,947	8,600,344
2016	8,685,546	16,490	8,669,055
2017	8,785,271	31,681	8,753,590
2018	8,846,530	61,701	8,784,830
2019	8,936,685	101,650	8,835,036
2020	9,011,918	153,166	8,858,752
2021	9,061,074	237,192	8,823,882
2022	9,092,928	321,218	8,771,710
2023	9,152,722	405,244	8,747,479

Oklahoma Commercial Energy Efficiency

Year	Oklahoma Commercial Baseline MWh	Oklahoma Com. Energy Efficiency MWh Adjustment	Final Oklahoma Commercial Model MWh
2013	6,279,102	-	6,279,102
2014	6,382,666	-	6,382,666
2015	6,486,543	-	6,486,543
2016	6,591,832	1,450	6,590,382
2017	6,690,335	23,883	6,666,452
2018	6,776,717	65,989	6,710,728
2019	6,878,278	108,229	6,770,049
2020	6,987,577	158,128	6,829,449
2021	7,105,040	210,319	6,894,721
2022	7,230,213	262,510	6,967,702
2023	7,368,167	314,701	7,053,466

Arkansas Residential Energy Efficiency

Year	Arkanas Residential Baseline MWh	Arkansas Res. Energy Efficiency MWh Adjustment	Final Arkansas Residential Model MWh
2013	738,515	-	738,515
2014	744,512	91	744,421
2015	755,548	620	754,928
2016	769,039	1,474	767,566
2017	779,893	2,833	777,059
2018	794,166	5,477	788,688
2019	806,788	9,013	797,775
2020	820,341	13,583	806,758
2021	832,419	21,064	811,355
2022	844,014	28,545	815,469
2023	853,018	36,026	816,992

Arkansas Commercial Energy Efficiency

Year	Arkansas Commercial Baseline MWh	Arkansas Com. Energy Efficiency MWh Adjustment	Final Arkansas Commercial Model MWh
2013	759,061	-	759,061
2014	776,965	-	776,965
2015	794,217	-	794,217
2016	812,244	143	812,102
2017	828,068	2,304	825,764
2018	848,896	6,647	842,249
2019	869,049	11,000	858,049
2020	891,073	16,330	874,743
2021	910,135	22,035	888,100
2022	927,453	27,740	899,714
2023	942,199	33,445	908,754

4.2.2 FERC Wholesale Load Adjustments

OG&E utilized historical wholesale sales data and the expiration dates for current contracts to produce the forecasts of FERC wholesale sales. Using an econometric forecasting approach

[1]Potential Oklahoma state-level benefits: http://www.appliance-standards.org/sites/default/files/fedappl_ok.pdf
Potential Arkansas state-level benefits: http://www.appliance-standards.org/sites/default/files/fedappl_ar.pdf

similar to what was used for the retail energy forecast models; OG&E produced separate forecasts of wholesale sales for all of the wholesale contracts. Out of model adjustments were then made to those forecasts to reflect current expiration dates.

4.3 Retail Energy Forecast and Load Responsibility

Table 7 summarizes the 2013 retail energy forecast (excluding line losses) by state and for the company as a whole before OG&E DSM program reductions. Weather-normalized annual retail sales are expected to grow from 26,761 GWh in 2013 to 29,920 GWh in 2023, which translates into an 11.8% increase over OG&E's planning horizon, or an average annual increase of 1.12%.

Table 7 – 2013 Retail Energy Forecast (MWh)

	Year	Residential	Commercial	Industrial	Petroleum	Street Lighting	Public Authority	Total
Oklahoma	2013	8,375,887	6,279,102	2,891,303	3,345,727	56,268	3,101,294	24,049,582
	2014	8,511,571	6,382,666	2,903,297	3,531,227	56,934	3,183,264	24,568,959
	2015	8,600,344	6,486,543	2,905,070	3,591,847	57,725	3,285,338	24,926,866
	2016	8,669,055	6,590,382	2,914,668	3,630,243	58,511	3,378,503	25,241,363
	2017	8,753,590	6,666,452	2,917,668	3,688,598	59,261	3,472,790	25,558,359
	2018	8,784,830	6,710,728	2,923,143	3,743,667	59,994	3,556,292	25,778,655
	2019	8,835,036	6,770,049	2,934,338	3,802,007	60,738	3,647,949	26,050,117
	2020	8,858,752	6,829,449	2,949,443	3,860,292	61,507	3,742,122	26,301,565
	2021	8,823,882	6,894,721	2,967,432	3,906,801	62,320	3,836,479	26,491,635
	2022	8,771,710	6,967,702	2,986,692	3,952,581	63,176	3,930,232	26,672,094
	2023	8,747,479	7,053,466	3,004,187	3,995,190	64,055	4,030,655	26,895,031
Arkansas	2013	738,515	759,061	1,058,277	10,693	9,067	136,038	2,711,651
	2014	744,421	776,965	1,066,134	10,693	9,064	137,562	2,744,839
	2015	754,928	794,217	1,071,465	10,693	9,109	140,859	2,781,270
	2016	767,566	812,102	1,076,822	10,693	9,169	144,036	2,820,388
	2017	777,059	825,764	1,082,207	10,693	9,234	147,148	2,852,105
	2018	788,688	842,249	1,087,618	10,693	9,300	150,312	2,888,859
	2019	797,775	858,049	1,093,056	10,693	9,365	153,492	2,922,429
	2020	806,758	874,743	1,098,521	10,693	9,428	156,350	2,956,492
	2021	811,355	888,100	1,104,014	10,693	9,490	158,878	2,982,529
	2022	815,469	899,714	1,109,534	10,693	9,551	161,445	3,006,404
	2023	816,992	908,754	1,115,081	10,693	9,611	163,886	3,025,017
Total OG&E	2013	9,114,402	7,038,163	3,949,581	3,356,420	65,336	3,237,332	26,761,233
	2014	9,255,993	7,159,631	3,969,431	3,541,919	65,999	3,320,825	27,313,798
	2015	9,355,271	7,280,760	3,976,535	3,602,539	66,835	3,426,197	27,708,137
	2016	9,436,621	7,402,484	3,991,491	3,640,935	67,680	3,522,540	28,061,750
	2017	9,530,650	7,492,217	3,999,874	3,699,291	68,495	3,619,937	28,410,463
	2018	9,573,518	7,552,977	4,010,761	3,754,359	69,294	3,706,604	28,667,514
	2019	9,632,811	7,628,098	4,027,394	3,812,699	70,103	3,801,442	28,972,546
	2020	9,665,510	7,704,192	4,047,964	3,870,984	70,935	3,898,472	29,258,056
	2021	9,635,237	7,782,821	4,071,446	3,917,493	71,811	3,995,356	29,474,164
	2022	9,587,179	7,867,416	4,096,226	3,963,274	72,727	4,091,677	29,678,498
	2023	9,564,471	7,962,220	4,119,268	4,005,883	73,666	4,194,541	29,920,048

Projected growth rates associated with these data are comparable to those observed over the last decade. Weather-normalized sales grew by approximately 1.3% annually from 2002 through 2012. Average annual growth is projected to be similar from 2013 to 2018 (1.39%), Average annual sales growth in the last half of the forecast, the 2019–2023 period, will be lower (0.86%). This is consistent with economic growth rates noted in the Economic Outlook section of this report. The retail energy growth rates by state and sector and shown in Table 8 below.

Table 8 – Retail Energy Growth Rates

	Year	Residential	Commercial	Industrial	Petroleum	Street Lighting	Public Authority	Total
Oklahoma	2014	1.62%	1.65%	0.41%	5.54%	1.18%	2.64%	2.16%
	2015	1.04%	1.63%	0.06%	1.72%	1.39%	3.21%	1.46%
	2016	0.80%	1.60%	0.33%	1.07%	1.36%	2.84%	1.26%
	2017	0.98%	1.15%	0.10%	1.61%	1.28%	2.79%	1.26%
	2018	0.36%	0.66%	0.19%	1.49%	1.24%	2.40%	0.86%
	2019	0.57%	0.88%	0.38%	1.56%	1.24%	2.58%	1.05%
	2020	0.27%	0.88%	0.51%	1.53%	1.27%	2.58%	0.97%
	2021	-0.39%	0.96%	0.61%	1.20%	1.32%	2.52%	0.72%
	2022	-0.59%	1.06%	0.65%	1.17%	1.37%	2.44%	0.68%
	2023	-0.28%	1.23%	0.59%	1.08%	1.39%	2.56%	0.84%
Arkansas	2014	0.80%	2.36%	0.74%	0.00%	-0.03%	1.12%	1.22%
	2015	1.41%	2.22%	0.50%	0.00%	0.50%	2.40%	1.33%
	2016	1.67%	2.25%	0.50%	0.00%	0.65%	2.26%	1.41%
	2017	1.24%	1.68%	0.50%	0.00%	0.71%	2.16%	1.12%
	2018	1.50%	2.00%	0.50%	0.00%	0.71%	2.15%	1.29%
	2019	1.15%	1.88%	0.50%	0.00%	0.70%	2.12%	1.16%
	2020	1.13%	1.95%	0.50%	0.00%	0.67%	1.86%	1.17%
	2021	0.57%	1.53%	0.50%	0.00%	0.66%	1.62%	0.88%
	2022	0.51%	1.31%	0.50%	0.00%	0.64%	1.62%	0.80%
	2023	0.19%	1.00%	0.50%	0.00%	0.64%	1.51%	0.62%
Total OG&E	2014	1.55%	1.73%	0.50%	5.53%	1.01%	2.58%	2.06%
	2015	1.07%	1.69%	0.18%	1.71%	1.27%	3.17%	1.44%
	2016	0.87%	1.67%	0.38%	1.07%	1.26%	2.81%	1.28%
	2017	1.00%	1.21%	0.21%	1.60%	1.20%	2.76%	1.24%
	2018	0.45%	0.81%	0.27%	1.49%	1.17%	2.39%	0.90%
	2019	0.62%	0.99%	0.41%	1.55%	1.17%	2.56%	1.06%
	2020	0.34%	1.00%	0.51%	1.53%	1.19%	2.55%	0.99%
	2021	-0.31%	1.02%	0.58%	1.20%	1.23%	2.49%	0.74%
	2022	-0.50%	1.09%	0.61%	1.17%	1.28%	2.41%	0.69%
	2023	-0.24%	1.21%	0.56%	1.08%	1.29%	2.51%	0.81%

Table 9 combines the forecasts of wholesale sales with the retail energy forecast from Table 7 and expected OG&E DSM energy reductions, yielding the 2013 energy forecast.

Table 9 – 2013 *Energy* Forecast including Wholesale, Losses and Planned OG&E DSM Programs

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FERC	AVEC[1]	946,007	1,007,181	511,201	-	-	-	-	-	-	-	-
MWH Sales	SPA[2]	21,221	10,305	-	-	-	-	-	-	-	-	-
Without	OMPA[3]	219,000	-	-	-	-	-	-	-	-	-	-
Losses	MDEA[4]	61,320	20,440	-	-	-	-	-	-	-	-	-
	Total FERC Sales	1,247,549	1,037,926	511,201	-	-	-	-	-	-	-	-
			-16.80%	-50.75%	-100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Retail	Residential	9,114,402	9,255,993	9,355,271	9,436,621	9,530,650	9,573,518	9,632,811	9,665,510	9,635,237	9,587,179	9,564,471
MWH Sales	Commercial	7,038,163	7,159,631	7,280,760	7,402,484	7,492,217	7,552,977	7,628,098	7,704,192	7,782,821	7,867,416	7,962,220
Without	Industrial	3,949,581	3,969,431	3,976,535	3,991,491	3,999,874	4,010,761	4,027,394	4,047,964	4,071,446	4,096,226	4,119,268
Losses or	Petroleum	3,356,420	3,541,919	3,602,539	3,640,935	3,699,291	3,754,359	3,812,699	3,870,984	3,917,493	3,963,274	4,005,883
OG&E DSM	Street Lighting	65,336	65,999	66,835	67,680	68,495	69,294	70,103	70,935	71,811	72,727	73,666
	Public Authority	3,237,332	3,320,825	3,426,197	3,522,540	3,619,937	3,706,604	3,801,442	3,898,472	3,995,356	4,091,677	4,194,541
	Total Retail Sales	26,761,233	27,313,798	27,708,137	28,061,750	28,410,463	28,667,514	28,972,546	29,258,056	29,474,164	29,678,498	29,920,048
			2.06%	1.44%	1.28%	1.24%	0.90%	1.06%	0.99%	0.74%	0.69%	0.81%
Total	Total Retail + FERC	28,008,782	28,351,724	28,219,338	28,061,750	28,410,463	28,667,514	28,972,546	29,258,056	29,474,164	29,678,498	29,920,048
MWH	Losses[5]	1,957,814	1,981,786	1,972,532	1,961,516	1,985,891	2,003,859	2,025,181	2,045,138	2,060,244	2,074,527	2,091,411
With Losses	Energy Subtotal	29,966,596	30,333,510	30,191,869	30,023,267	30,396,355	30,671,373	30,997,727	31,303,194	31,534,408	31,753,025	32,011,460
			1.22%	-0.47%	-0.56%	1.24%	0.90%	1.06%	0.99%	0.74%	0.69%	0.81%
OG&E DSM	Energy Efficiency	100,026	241,603	396,266	496,292	637,869	792,532	872,745	995,499	1,132,280	1,095,479	1,060,519
MWH Reduction	Demand Response	30,866	68,023	88,907	94,129	97,663	102,028	102,294	103,684	103,775	104,005	103,763
Load Responsibility MWH	**Load Responsibility = Total Sales with Losses and DSM Reduction**	**29,835,703**	**30,023,884**	**29,706,697**	**29,432,846**	**29,660,823**	**29,776,813**	**30,022,688**	**30,204,012**	**30,298,353**	**30,553,541**	**30,847,178**
			0.63%	-1.06%	-0.92%	0.77%	0.39%	0.83%	0.60%	0.31%	0.84%	0.96%

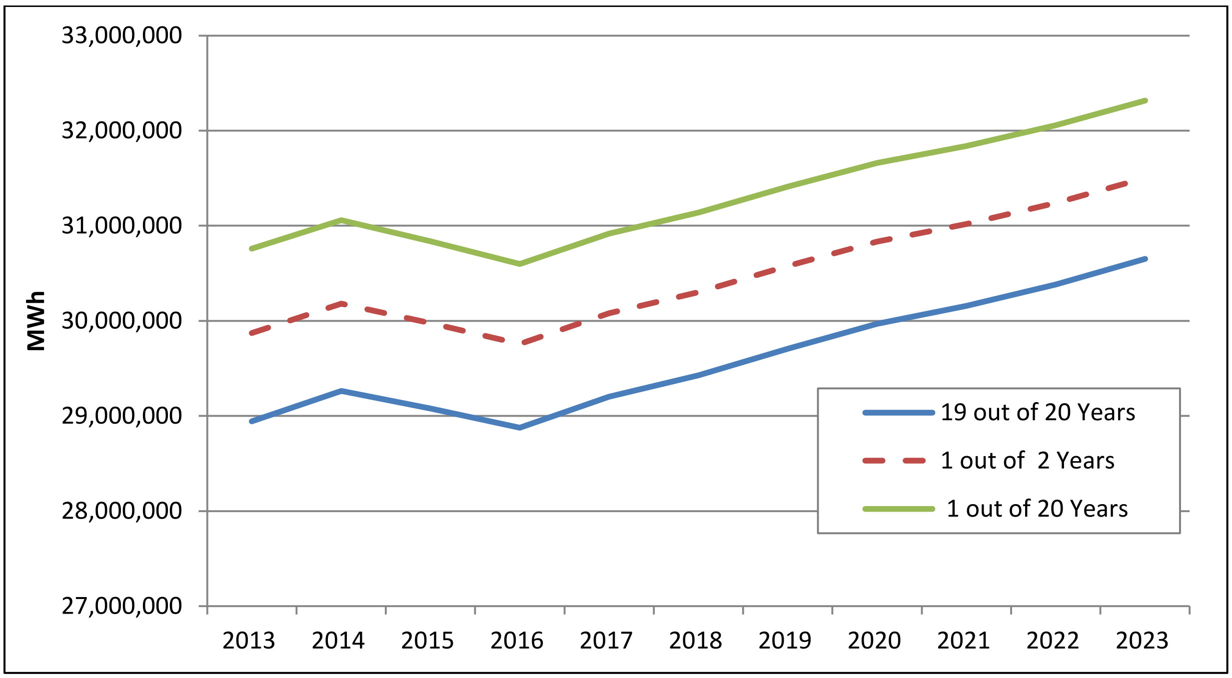
[1] AVEC Contract can expire on June 30, 2015
[2] Paris Contract expired on May 31, 2012 and Vance Contract has been extended to May 31, 2014
[3] OMPA PSA Contract terminates on December 31, 2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.
[4] MDEA Contract 2 expired on December 31, 2012 and MDEA Contract 1 can expire on April 30, 2014
[5] The energy loss factor is 0.0699

4.4 Energy Forecast Uncertainty

Weather uncertainty in the energy models is represented through a Monte Carlo modeling approach where the last three decades of weather are systematically entered into the various energy models to produce a distribution of possible sales outcomes.

The weather-year Monte Carlo approach essentially runs all weather years from 1981 to 2012 through the weather-sensitive energy models and the peak demand model to develop a probability distribution of possible outcomes. Figure 2 shows the results directly from this modeling process for energy sales and includes FERC adjustments.

Figure 2 – Energy Model Forecast Outcomes by Weather Probability



The *1 out of 2 years* average weather line indicates there is a 50% probability that energy sales will reach this level or higher.

Now, consider the *1 out of 20 years* forecast. This line shows energy sales under more extreme weather events occurring just 5% of the time. Finally, the lower bound forecast (*19 out of 20 year* case) shows sales may fall below the normal weather forecast by approximately 900,000 MWh if weather is milder than normal given expected economic performance.

5 Peak Demand Forecast

KEY TAKEAWAYS:

- ***Retail peak demand increases by an average of 0.92% per year***
- ***The expected peak demand in 2023 after OG&E DSM programs is 6,032MW***

5.1 Econometric Modeling Process – Peak Demand

The econometric modeling framework has been in place at OG&E since 2000. The modeling structure consists of 24 separate hourly equations, one for each hour of the day, with separate intercept and slope coefficients in the various models. The hourly equations are estimated over the May through September period.

The dependent variable is OG&E's normalized load responsibility, less the fixed 25 MW Oklahoma Municipal Power Authority (OMPA) Power Sales Agreement (PSA) load, and includes line losses. Key independent variables include:

- Cooling degree hours, base 72. This cooling degree hour variable is calculated in a manner similar to cooling degree days and effectively represents temperature impacts when temperatures exceed 72 degrees.
- A second temperature variable, defined as temperature—103°, which addresses the "topping off" effect in which there is a reduction in the *rate* of load increases at very high temperatures.
- National Oceanic and Atmospheric Administration's (NOAA) misery index reflecting the combined effects of humidity and warm temperatures. The misery build-up or duration of the misery index is captured through the weighted average of past hourly values of the misery index.[1]
- Wind speed.
- Economic growth as reflected through weather-adjusted retail energy sales, which represents the aggregate impact of economic conditions on the OG&E system. The sales are also normalized by the number of days in each month.

[1] The lag structure is designed to pick up the effects of a heat wave lasting a few days or more. More electricity is demanded later (vs. earlier) in a heat wave, even when temperatures decline slightly. The implication is that "design temperature" is not sufficient for peak forecasting purposes. The temperature of the building is the result of the accumulated outdoor temperatures, less the impact of the HVAC system. The weighted average is capable of capturing the effects of both duration and nighttime cooling since high daytime temperatures and lower nighttime temperatures are reflected in the average.

Relevant weather stations are shown below in Table 10, along with the OG&E population estimates from the 2010 census used to weigh data from each station:

Table 10 – Weather Station Weights

Weather Station	Population in OG&E Territory	Weight (% of OG&E population)
Oklahoma City (Will Rogers)	1,322,249	63.8%
Fort Smith	298,592	14.4%
Guthrie	159,111	7.7%
Stillwater	179,197	8.6%
Muskogee	112,690	5.4%

The peak demand forecast is generated via a probabilistic approach by using the last 32 available years of actual weather data. This Monte Carlo modeling approach runs all weather years from 1981 to 2012 through the peak demand model, while alternating the weather year "starting day" seven times for each day of the week. Since loads are much lower on weekends, alternating the starting day allows the model to determine the demand impact of actual weather events as if they had occurred on any day of the week.

This results in a matrix of 32 weather years by seven days, or a total of 224 simulations given the historical hourly weather data available to OG&E. The peak demand forecast is constructed by calculating a range of weather-feasible load forecasts for each year over the forecast horizon from the regression model results. As described above, this step generates 224 weather-feasible forecasts. These 224 annual load forecasts were ranked from highest to lowest and assigned probabilities to the occurrence of each forecast under the assumption of a uniform distribution (i.e., each weather has an equal chance of occurrence).

All of the highest values (peaks) in the resulting forecast distribution occur between 3:00 p.m. and 7:00 p.m. (Central Daylight Time), with the majority occurring at 5:00 p.m.

5.2 Peak Demand Forecast Adjustments and Load Responsibility

FERC wholesale load adjustments are conducted in two steps based on known and verifiable events. First, the OMPA wholesale load Power Sales Agreement (PSA) contract is added to the normalized load responsibility forecast from the model. Second, expiring contracts are subtracted to obtain final Load Responsibility forecasts. Table 11 reflects the 2013 Load Responsibility forecast after planned OG&E DSM Programs.

Table 11 – 2013 *Peak Demand* Forecast including Wholesale, Losses and Planned OG&E DSM Programs

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FERC Demand (MW) Without Losses	AVEC[1]	215	229	-	-	-	-	-	-	-	-	-
	SPA[2]	5	-	-	-	-	-	-	-	-	-	-
	OMPA[3]	25	-	-	-	-	-	-	-	-	-	-
	MDEA[4]	10	-	-	-	-	-	-	-	-	-	-
	Total FERC w/o Losses	255	229	-	-	-	-	-	-	-	-	-
	Losses	22	20	-	-	-	-	-	-	-	-	-
	Total FERC w/ Losses	277	248	-	-	-	-	-	-	-	-	-
			-10.26%	-100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Total Retail Demand	6,027	6,137	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605
			1.83%	1.10%	0.77%	1.33%	0.64%	0.94%	0.51%	0.90%	0.53%	0.66%
Pre OG&E DSM Load Responsibility (MW)	Demand Subtotal = FERC + Retail (Losses Included)	6,303	6,385	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605
			1.30%	-2.83%	0.77%	1.33%	0.64%	0.94%	0.51%	0.90%	0.53%	0.66%
Pre OG&E DSM Load Factor	Energy(MWH) Subtotal	29,966,596	30,333,510	30,191,869	30,023,267	30,396,355	30,671,373	30,997,727	31,303,194	31,534,408	31,753,025	32,011,460
	Pre DSM Load Factor	54.27%	54.23%	55.55%	54.82%	54.77%	54.91%	54.98%	55.23%	55.15%	55.24%	55.33%
OG&E DSM Reduction (MW)	Energy Efficiency	21	51	83	104	134	167	183	209	238	230	223
	Demand Response	171	232	272	293	309	328	332	336	340	344	348
Net Load Responsibility (MW)	**Load Responsibility = Total Load with Losses and DSM Reduction**	**6,112**	**6,103**	**5,850**	**5,855**	**5,892**	**5,882**	**5,921**	**5,924**	**5,950**	**5,988**	**6,034**
			-0.14%	-4.15%	0.09%	0.63%	-0.18%	0.67%	0.05%	0.43%	0.64%	0.78%
DSM Adjusted Load Factor	Total Net Energy MWh	29,835,703	30,023,884	29,706,697	29,432,846	29,660,823	29,776,813	30,022,688	30,204,012	30,298,353	30,553,541	30,847,178
	Load Factor	55.73%	56.16%	57.97%	57.38%	57.46%	57.79%	57.88%	58.20%	58.13%	58.25%	58.35%

[1] AVEC Contract can expire on June 30, 2015
[2] Paris Contract expired on May 31, 2012 and Vance Contract has been extended to May 31, 2014
[3] OMPA PSA Contract terminates on December 31, 2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.
[4] MDEA Contract 2 expired on December 31, 2012 and MDEA Contract 1 can expire on April 30, 2014

5.3 Peak Demand Forecast Uncertainty

Table 12 illustrates mapping between event (peak demand) occurrence and the occurrence probability. The median load projections come from the 50th percentile of the distribution. This means that half of the time the peak load would be expected to exceed this level and half of the time the peak load would be below this level.

Table 12 – Probability Assignments

Event Occurrence	Occurrence Probability
1 out of 30 years	3%
1 out of 10 years	10%
1 out of 4 years	25%
1 out of 2 years	50%
3 out of 4 years	75%
9 out of 10 years	90%
29 out of 30 years	97%

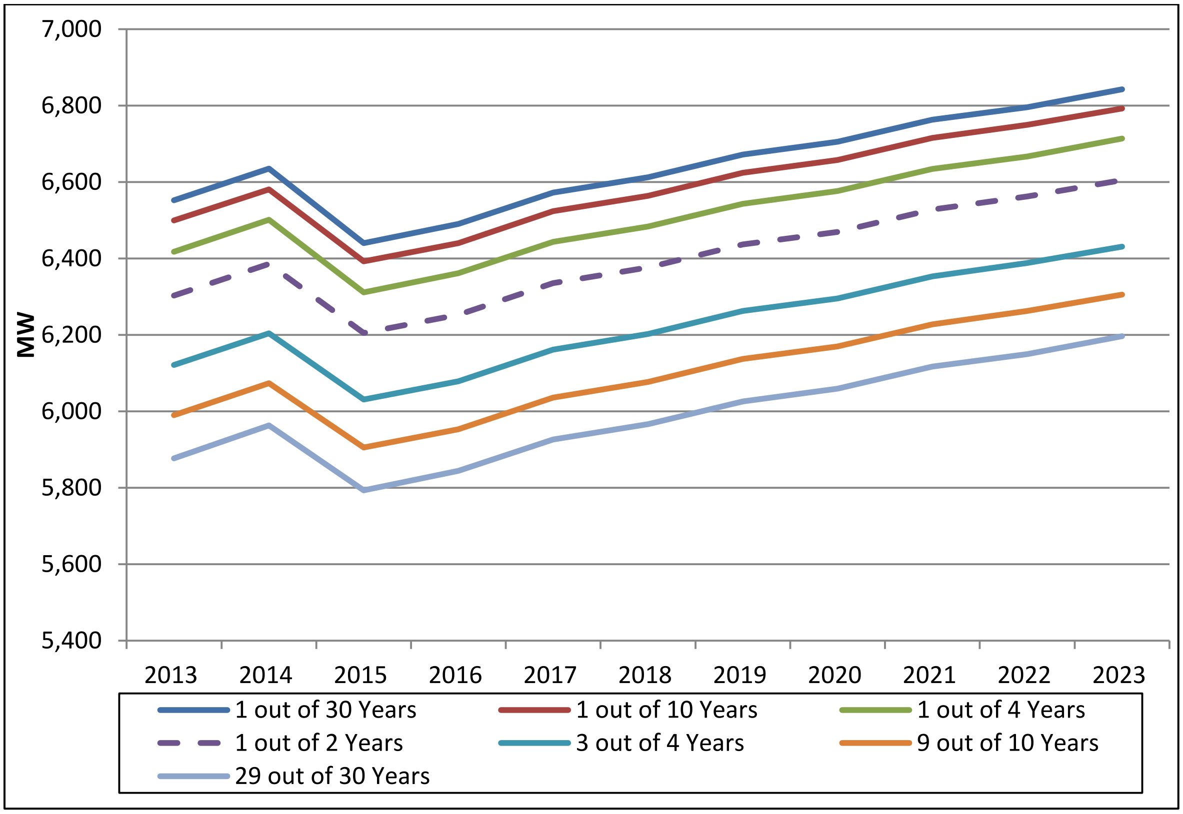
Table 13 and Figure 3 summarize the peak load model forecasts with a 97% confidence interval around potential weather events, assuming no changes in the expected economic outlook. These estimates include wholesale loads and the assumption of expiring wholesale contracts. Following the probability assignments in Table 12, the interpretation of these results is as follows. The *1 out of 2 years* or "expected" forecast shows the peak demand level given the 50th percentile of the load forecast distribution, using all available historical weather data. In this case, there is a 50% probability the peak load will reach this load level or higher.

Table 13 – Peak Demand (MW) Model Forecasts by Weather Probability

Year	1 out of 30 Years	1 out of 10 Years	1 out of 4 Years	1 out of 2 Years	3 out of 4 Years	9 out of 10 Years	29 out of 30 Years
2013	6,553	6,500	6,418	6,303	6,121	5,990	5,877
2014	6,635	6,581	6,501	6,385	6,204	6,074	5,963
2015	6,440	6,393	6,311	6,205	6,031	5,905	5,794
2016	6,491	6,440	6,362	6,252	6,078	5,953	5,844
2017	6,572	6,524	6,443	6,336	6,162	6,036	5,926
2018	6,613	6,564	6,484	6,377	6,202	6,077	5,966
2019	6,672	6,624	6,543	6,437	6,262	6,137	6,025
2020	6,705	6,657	6,576	6,470	6,295	6,170	6,059
2021	6,763	6,715	6,634	6,528	6,353	6,228	6,117
2022	6,796	6,750	6,667	6,562	6,388	6,262	6,150
2023	6,843	6,793	6,714	6,605	6,431	6,305	6,196

The *1 out of 10 years* forecast, which is approximately 200 MW higher than the *1 out of 2 years* case, shows the estimated peak demand under a more extreme weather event that occurs just 10% of the time. Put differently, over a 10-year planning horizon, it is likely that OG&E will reach a summer peak consistent with the *1 out of 10 years* forecast at least once.

Figure 3 – Peak Demand Model Forecasts by Weather Probability



Weather conditions will vary markedly from one year to the next. Consequently, the weather impact on peak demand will also vary considerably from year to year. Dramatic weather condition changes have much more impact on year-to-year differences in demand than do economic growth. Overall, the 97% confidence interval associated with weather conditions represents a significant source of risk responsible for approximately 640 MW of potential peak load variability in 2023.

6 Retail Customer Forecast

KEY TAKEAWAYS:

- ***Total retail customers increases by an average of 1.08% per year***
- ***The forecasted total number of retail customers in 2023 is 894,805***

The retail customer forecast is generated from a regression analysis of historical customer growth and economic growth patterns. Approximately five to ten models were estimated for each segment, with 2012 data held as an "out-of-sample" forecasting test period. During the initial model specification phase, attempts were made at specifying models with a variety of different economic drivers. Table 14 illustrates the final model variables used for the Oklahoma and Arkansas retail customer forecasts, respectively.

Table 14 – Customer Model Drivers

Economic Drivers and Models			Economic Driver Average Annual Growth Rates		
			2002 - 2012	2013-2018	2019-2023
Oklahoma	Residential	OKC Population	1.42%	1.32%	1.33%
Oklahoma	Commercial	OKC Population	1.42%	1.32%	1.33%
Oklahoma	Industrial	OKC Manufacturing Employment	-2.72%	3.63%	0.77%
Oklahoma	Petroleum	2013 EIA Nominal Natural Gas Forecast	8.62%	4.13%	4.36%
Oklahoma	Street Lighting	OKC Population	1.42%	1.32%	1.33%
Oklahoma	Public Authority	OKC Population	1.42%	1.32%	1.33%
Arkansas – Ft. Smith	Residential	Population	0.83%	0.78%	0.96%
Arkansas – Ft. Smith	Commercial	Population	0.83%	0.78%	0.96%
Arkansas – Ft. Smith	Industrial	Manufacturing Employment	-3.91%	0.42%	-0.34%
Arkansas – Ft. Smith	Petroleum	2013 EIA Nominal Natural Gas Forecast	8.62%	4.13%	4.36%
Arkansas – Ft. Smith	Street Lighting	Population	0.83%	0.78%	0.96%
Arkansas – Ft. Smith	Public Authority	Government Employment	1.95%	2.34%	2.11%

Table 15 summarizes the 2013 annual retail customer forecast by sector and state, and for the company as a whole.

Table 15 – Retail Customer Forecast

	Year	Residential	Commercial	Industrial	Petroleum	Street Lighting	Public Authority	Total
Oklahoma	2013	633,169	80,559	2,642	6,364	226	15,509	738,470
	2014	640,983	81,606	2,701	6,336	227	15,986	747,839
	2015	648,547	82,590	2,740	6,312	228	16,435	756,852
	2016	655,818	83,553	2,764	6,292	228	16,882	765,537
	2017	662,632	84,469	2,776	6,276	229	17,308	773,689
	2018	669,221	85,366	2,782	6,262	229	17,724	781,584
	2019	675,849	86,275	2,787	6,250	230	18,145	789,537
	2020	682,674	87,214	2,790	6,241	230	18,581	797,731
	2021	689,876	88,209	2,793	6,233	231	19,042	806,383
	2022	697,440	89,254	2,795	6,226	232	19,526	815,473
	2023	705,205	90,328	2,797	6,220	232	20,023	824,805
Arkansas	2013	54,522	8,947	360	50	26	1,511	65,417
	2014	54,604	9,005	361	55	26	1,550	65,601
	2015	54,848	9,092	363	56	27	1,590	65,974
	2016	55,175	9,202	364	56	27	1,631	66,455
	2017	55,534	9,323	364	56	27	1,672	66,976
	2018	55,898	9,445	363	57	27	1,711	67,501
	2019	56,259	9,566	363	57	27	1,751	68,022
	2020	56,609	9,683	363	57	27	1,791	68,529
	2021	56,954	9,798	363	57	27	1,828	69,026
	2022	57,289	9,910	362	57	28	1,866	69,512
	2023	57,625	10,022	362	57	28	1,905	69,999
Total OG&E	2013	687,691	89,507	3,002	6,414	253	17,020	803,887
	2014	695,587	90,611	3,062	6,391	254	17,535	813,440
	2015	703,395	91,681	3,103	6,368	254	18,025	822,827
	2016	710,993	92,755	3,128	6,348	255	18,513	831,992
	2017	718,166	93,792	3,139	6,332	256	18,979	840,664
	2018	725,119	94,811	3,145	6,318	256	19,435	849,084
	2019	732,108	95,840	3,150	6,307	257	19,896	857,559
	2020	739,282	96,897	3,154	6,297	258	20,372	866,260
	2021	746,830	98,006	3,156	6,289	258	20,870	875,409
	2022	754,729	99,164	3,157	6,282	259	21,392	884,984
	2023	762,830	100,350	3,159	6,277	260	21,928	894,805

Table 16 summarizes the 2013 annual retail customer growth rate forecast by sector and state, and for the company as a whole.

Table 16 – Customer Growth Rates

	Year	Residential	Commercial	Industrial	Petroleum	Street Lighting	Public Authority	Total
Oklahoma	2014	1.23%	1.30%	2.24%	-0.45%	0.32%	3.07%	1.27%
	2015	1.18%	1.21%	1.45%	-0.37%	0.25%	2.81%	1.21%
	2016	1.12%	1.17%	0.87%	-0.32%	0.25%	2.72%	1.15%
	2017	1.04%	1.10%	0.43%	-0.26%	0.24%	2.52%	1.06%
	2018	0.99%	1.06%	0.22%	-0.22%	0.23%	2.41%	1.02%
	2019	0.99%	1.06%	0.18%	-0.18%	0.23%	2.38%	1.02%
	2020	1.01%	1.09%	0.13%	-0.15%	0.24%	2.40%	1.04%
	2021	1.06%	1.14%	0.09%	-0.13%	0.25%	2.48%	1.08%
	2022	1.10%	1.19%	0.07%	-0.11%	0.27%	2.54%	1.13%
	2023	1.11%	1.20%	0.06%	-0.09%	0.27%	2.54%	1.14%
Arkansas	2014	0.15%	0.64%	0.41%	8.78%	0.48%	2.57%	0.28%
	2015	0.45%	0.96%	0.35%	2.31%	0.41%	2.58%	0.57%
	2016	0.60%	1.22%	0.28%	0.72%	0.52%	2.61%	0.73%
	2017	0.65%	1.31%	0.01%	0.24%	0.57%	2.47%	0.78%
	2018	0.65%	1.31%	-0.04%	0.10%	0.57%	2.37%	0.78%
	2019	0.65%	1.28%	-0.04%	0.05%	0.56%	2.32%	0.77%
	2020	0.62%	1.22%	-0.06%	0.04%	0.54%	2.28%	0.74%
	2021	0.61%	1.19%	-0.08%	0.04%	0.53%	2.06%	0.73%
	2022	0.59%	1.14%	-0.10%	0.06%	0.51%	2.11%	0.70%
	2023	0.59%	1.13%	-0.10%	0.07%	0.51%	2.10%	0.70%
Total OG&E	2014	1.15%	1.23%	2.02%	-0.37%	0.34%	3.03%	1.19%
	2015	1.12%	1.18%	1.32%	-0.35%	0.27%	2.79%	1.15%
	2016	1.08%	1.17%	0.80%	-0.31%	0.28%	2.71%	1.11%
	2017	1.01%	1.12%	0.38%	-0.26%	0.27%	2.52%	1.04%
	2018	0.97%	1.09%	0.19%	-0.22%	0.27%	2.40%	1.00%
	2019	0.96%	1.09%	0.15%	-0.18%	0.27%	2.37%	1.00%
	2020	0.98%	1.10%	0.11%	-0.15%	0.27%	2.39%	1.01%
	2021	1.02%	1.15%	0.07%	-0.13%	0.28%	2.44%	1.06%
	2022	1.06%	1.18%	0.05%	-0.11%	0.29%	2.50%	1.09%
	2023	1.07%	1.20%	0.04%	-0.09%	0.30%	2.51%	1.11%

Appendix A – Data Sources

OG&E's service territory encompasses approximately half of Oklahoma and a small area in western Arkansas, including and surrounding Ft. Smith. Historical data sources used to estimate the econometric equations and prepare the 2013 forecast fall into the following categories:

- OG&E company data (energy sales, revenue, load responsibility peak demand and weather-normal degree days);
- Constructed variables for the models (usually binary variables);
- Weather information;
- Economic and demographic data from the Center for Applied Economic Research at Oklahoma State University; and
- Energy Efficiency impacts based on expected national standards for appliances and equipment from the Appliance Standard Awareness Project (ASAP).

This section describes each of these categories and the types of variables used in the econometric models.

Internal Information

Sales, Revenue and Customers

OG&E's Accounting Department provides sales (MWh), revenue, and customer data by revenue class. This information is recorded in the monthly energy sales report for both Oklahoma and Arkansas jurisdictions. The monthly energy sales report (by state) contains information from the 1970s to the present. The six revenue classes are: Residential, Commercial, Industrial, Petroleum, Street Lighting and Public Authority.

Retail Electric Prices

In the econometric models with statistically significant electric price variables, the historical values of the variables are defined as "average" prices (energy revenues divided by energy sales). The retail electric prices used in the (forward-looking) forecast include the revised cost of operations along with riders for various other projects. Overall, the expected increases in retail prices are similar to those in the 2012 forecast. The cumulative increase in price over ten years in the 2013 forecast is 17%. Annually, this breaks down to approximately a 1.5% increase in the average price per kWh.

Load Responsibility

The peak load forecasts are obtained based on historical "Normalized Load Responsibility" data (defined as the System Load minus OMPA Total Load plus OMPA PSA[1] plus Load Curtailment plus real-time pricing (RTP) induced self-generation). The normalized load responsibility series was further adjusted for peak demand modeling purposes by subtracting variable OMPA PSA loads and forecasting these directly as wholesale FERC loads.

[2] OMPA PSA contract terminates 12/31/2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.

Weather Normalized Cooling Degree Days and Heating Degree Days

OG&E's Pricing Department provides the weather-normal monthly Cooling Degree Days and Heating Degree Days (see definitions below), which are factors in developing the energy forecast for future years. The weather-normalized CDD and HDD values are based on 30 rolling years of weather history from selected weather stations in the OG&E service territory.

Information Obtained from External Sources

Weather Data

OG&E obtained the following information from the Department of Commerce, NOAA:

- Cooling-degree days (CDD).
- Heating-degree days (HDD).
- A variety of hourly weather indicators, including temperature, humidity, dew point, precipitation, wind speed, and cloud cover.

NOAA's definition of HDD is 65° minus the average of the high and low temperatures of the day (or zero if the average of the high and low temperatures is greater than 65°). The definition of CDD is the average of the high and low temperatures of the day minus 65° (or zero if the average of the high and low temperatures of the day is less than 65°). HDD and CDD for Ft. Smith and Oklahoma City have been used in weather-sensitive sales forecasting equations. Hourly weather data from these stations, and from Guthrie, Stillwater, and Muskogee, were used to model and forecast peak loads.

Economic and Demographic Data

OG&E purchases economic and demographic data from Oklahoma State University. The data include historical and forecasted time series used in the econometric models; these data include population, real income, wages and salaries, price deflators, various production and output series, including industrial production, gross state product, natural gas prices, and employment.

In 2007 the Oklahoma economic driver series were adjusted for structural changes in the state's economy. OSU's research had revealed a "billionaire" effect that inflates the real income and gross state product series that are critically important in forecasting OG&E's energy sales.

The table below compares the growth rates of 2013 and 2012 forecast drivers. The "ex-energy" variables, where the "billionaire" effect is removed, are compared to their unadjusted counterparts. The comparison reveals that the difference in growth rates between the ex-energy series and their counterpart is still a significant factor, and is in fact increasing for several of the series compared to the forecasts from 2012.

Economic Driver Growth Rate Comparison

Economic Drivers	Drivers Average Growth Rate					
	Current Forecast 2013 to 2023	Last Year 2013 to 2023	Current Forecast 2013 to 2018	Last Year 2013 to 2018	Current Forecast 2019 to 2023	Last Year 2019 to 2023
Real Personal Income OKC	3.86%	2.95%	4.14%	3.29%	3.53%	2.54%
Real Personal Income *Ex Energy* OKC	2.20%	2.70%	2.88%	3.06%	1.38%	2.26%
Difference	**1.67%**	**0.25%**	**1.26%**	**0.23%**	**2.15%**	**0.28%**
Real Gross State Product (GSP)	3.14%	2.75%	3.22%	3.43%	3.04%	2.74%
Real GSP *Ex Energy*	2.85%	3.84%	2.96%	3.23%	2.71%	2.43%
Difference	**0.29%**	**-1.09%**	**0.26%**	**0.20%**	**0.33%**	**0.32%**

National Energy Efficiency Codes and Standards Impact Data

The Appliance Standard Awareness Project (ASAP) compiles energy efficiency information about expected appliance and equipment codes and standards, including expected implementation dates and expected energy efficiency impacts. OG&E downloaded state-level data from the ASAP website, http://www.appliance-standards.org/, and scaled the expected state-level impacts for the OG&E service territory. The scaled energy efficiency impacts have been included in the baseline retail energy forecast.

Appendix B – Expected DSM Program Impacts

Demand Side Management (DSM) is designed to reduce the load requirements on the system. OG&E utilizes two different areas to achieve load reduction. These areas are Energy Efficiency (EE) and Demand Response (DR).

Energy Efficiency Programs

EE programs are designed to educate and encourage customers to make behavioral changes and purchasing decisions that will provide long term benefits in managing their energy usage. Inducements currently are provided through a portfolio of demand programs that encourage customers to make thermal and equipment upgrades.

Historical Energy Efficiency Programs

Over the past 30 years, OG&E has successfully managed several DSM programs such as: Positive Energy Home, Geothermal Home, Heat Pumps, Rate Tamer and Power Factor Correction. The demand reduction and kWh reduction have been captured in the econometric load forecast models and therefore are embedded in OG&E's annual load forecast.

Recent EE Programs in Arkansas expanded the work that began with the Quick Start Program as described in Docket No. 07-075-TF. In Order No. 25 in Docket No. 07-075-TF, the Arkansas Public Service Commission ordered OG&E to submit for approval a revised Comprehensive Plan for Energy Efficiency, (CPEE) to reduce their kWh sales by 0.25% in 2011, 0.50% in 2012; and 0.75% in 2013 incremental over the baseline year of 2010 that was weather normalized. On September 30, 2011, OG&E proposed a revised CPEE that was accepted by the Arkansas Commission on December 30, 2011. These programs are embedding in OG&E's annual load forecast.

Current and Future Oklahoma Energy Efficiency Programs

According to OAC 165:35-41-4(a), utilities are required to propose, at least once every three years, a demand portfolio of EE and DR Programs. Working with Frontier Associates LLC, OG&E chooses programs based upon customer benefit, market potential and budget criteria. OG&E estimates similar programs will also be effective in future EE filings. Below is a summary of the current[1] and future filings.

a. <u>Weatherization Residential Assistance</u>

This program is designed to provide assistance to both lower and fixed income customers by engaging licensed contractors to make improvements to the thermal envelope and to inspect and

[1] Cause No. PUD 200900200 and PUD 201200134

tune up mechanical equipment in their homes. This work allows customers to better manage energy usage, improve their comfort and makes the living space safer.

b. Commercial Lighting

Commercial Lighting will be expanded to include inducements focused on lighting controls and light emitting diode (LED) lamps as well as replacement of total lighting systems. The inducements offered for replacement of inefficient fluorescent lamps will continue.

c. Home Energy Efficiency

This consists of a comprehensive home energy survey targeted to residential customers who need assistance in identifying areas to improve in both thermal and technology efficiencies. Assistance is offered for air conditioning tune ups, duct repair and inducements offered for additional attic insulation installed.

d. Positive Energy-New Home Construction

This program encourages builders and homeowners to utilize energy efficient Positive Energy-New Home Construction practices by installing higher level than required thermal packages in the construction of new homes. Builders will be paid inducements to bring new homes to the higher standards. These homes will be rated and certified by OG&E. This certification allows homebuilders to apply for available tax credits as a result of these upgrades.

e. Geothermal Heating, Cooling & Water Heating

This program provides inducements to customers who choose to install geothermal heat pumps into their new or existing homes.

f. Commercial Energy Efficiency

This program is targeted to medium and large commercial customers for the purpose of allowing them to pursue EE projects unique to their business. Inducements will be paid for kW reduced by these customers.

g. Education

This program provides consistent energy information to all levels of customers including elementary and secondary students with custom presentations at the Energy Technology Center. OG&E will provide energy surveys to commercial customers targeting churches, non-profits and schools to provide them with knowledge on quick, low or no cost options to reduce their electric bills.

h. Industrial Energy Efficiency

This program offers financial inducements for the installation of a wide range of measures but is primarily targeted to industrial processes that reduce customer energy costs, for the Power and Light rate or Large Power and Light rate customers

Oklahoma Energy Efficiency Forecast

Historical savings from previous EE Programs are already imbedded in the load forecast. New programs need to be subtracted from the load forecast. The Oklahoma Comprehensive Energy Efficiency Programs and the Arkansas Comprehensive Plan for Energy Efficiency Programs are not yet included in the load forecast and need to be subtracted along with any future EE plans.

OK Forecasted Energy Reduction from Energy Efficiency

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2012 Programs	100	242	396	396	396	396	376	358	340	323	307
2015 Programs	-	-	-	100	242	396	396	396	396	376	358
2018 Programs	-	-	-	-	-	-	100	242	396	396	396
Total Energy	100	242	396	496	638	793	873	995	1,132	1,095	1,061

OK Forecasted Peak Demand Reduction from Energy Efficiency

Demand (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2012 Programs	21	51	83	83	83	83	79	75	71	68	64
2015 Programs	-	-	-	21	51	83	83	83	83	79	75
2018 Programs	-	-	-	-	-	-	21	51	83	83	83
Total Peak Demand	21	51	83	104	134	167	183	209	238	230	223

Demand Response Programs

DR programs are designed to encourage customers to reduce their load during peak loading periods. OG&E has used Real Time Pricing in the past which provides hourly prices for the next day to allow customers the ability to shift their energy usage. The seasonally and time-differentiated Time-of-Use (TOU) program communicates varying prices to customers signaling them to shift their energy use habits. OG&E has recently added more DR programs. These programs include the technology-enabled DR program (SmartHours), the Integrated Volt Var Control Program (IVVC) and the Load Reduction Rider.

a. <u>SmartHours</u>

The SmartHours program integrates technology and pricing to help customers reduce energy usage at peak times. The program utilizes the Advanced Metering Infrastructure (AMI) to securely send price signals across the network and through the smart meter, directly to the Programmable Communicating Thermostat (PCT). Signals are also sent via text message and email. Customers respond to these price signals between the weekday hours of 2:00 p.m. and 7:00 p.m. over the four summer months of June, July, August and September and help reduce the peak demand on the system. By the year 2020, the Company’s goal is to enroll and maintain approximately 20% of residential customers into the SmartHours program. Likewise, commercial and industrial customers will be able to take advantage of more price response programs in the future with an estimated peak demand reduction of 15 MW over the next 10 years.

b. IVVC

The IVVC Program is a system of devices, controls, software and communication products used to manage OG&E's distribution system reactive power flow and voltage level. This technology is used to minimize losses and reduce energy demand during peak periods, while ensuring acceptable customer voltage levels. During non-peak periods, Volt Var Optimization (VVO) will normally operate in loss reduction mode. In loss reduction mode VVO compensates for inefficiencies caused by reactive loads such as electric motors. As a result, energy loss reductions (i.e. energy savings) are expected to be realized during non-peak periods. VVO will be placed in demand reduction or combined loss/demand reduction mode when needed to help reduce system peak energy demand. Demand reduction mode reduces voltage in order to achieve a corresponding reduction in peak energy consumption. Based on study results achieved to date, a peak demand reduction of approximately 2% has been achieved across the circuits on which this technology has been deployed. Over the next 10 years, IVVC is expected to reduce OG&E's load requirement by 82 MW.

c. Load Reduction Rider

In Cause No. PUD 200800398, OG&E restructured the event based programs to offer the Load Reduction Rider. This pricing schedule replaced previous event based tariffs while lowering the customers' annual on-peak period maximum demand requirement from 500 kW to 200 kW and above.

OG&E Demand Response Energy Reduction Forecast

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
SmartHours - PCT	20	35	38	38	38	37	37	38	38	38	38
SmartHours - VPP Web Only	3	18	20	20	19	19	19	20	20	20	19
SmartHours - myOGEpower	2	5	6	6	6	6	6	6	6	6	6
SmartHours - C&I	-	-	2	4	4	4	4	4	4	4	4
IVVC	5	9	21	25	29	33	33	33	33	33	33
Load Reduction Rider	1	2	2	2	2	2	3	3	3	3	3
Demand Response Total Energy	31	68	89	94	98	102	102	104	104	104	104

OG&E Demand Response Peak Demand Reduction Forecast

Demand (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
SmartHours - PCT	99	131	141	141	141	141	141	141	141	141	141
SmartHours - VPP Web Only	15	27	29	29	29	29	29	29	29	29	29
SmartHours - myOGEpower	4	7	9	9	9	9	9	9	9	9	9
SmartHours - C&I	-	-	9	14	14	14	14	15	15	15	15
IVVC	18	29	41	54	67	82	82	82	82	82	82
Load Reduction Rider	35	38	41	45	49	53	56	60	64	68	71
Demand Response Total Demand	171	232	272	293	309	328	332	336	340	344	348

Appendix B – Portfolio Annual Cost Components

Portfolio Annual Cost Components

	Scrub/ Convert				Scrub				Convert			
($Millions)	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	17	282	864	1,163	21	283	864	1,168	13	282	864	1,158
2016	38	254	905	1,197	55	256	905	1,216	23	252	905	1,181
2017	76	263	947	1,286	105	265	947	1,317	51	260	947	1,258
2018	136	273	998	1,407	175	283	1,009	1,466	99	260	986	1,345
2019	193	272	1,156	1,622	242	322	1,080	1,643	144	231	1,233	1,607
2020	212	322	1,152	1,687	264	391	1,078	1,733	162	260	1,230	1,652
2021	210	352	1,194	1,757	258	424	1,115	1,797	162	297	1,277	1,736
2022	223	345	1,225	1,793	269	421	1,150	1,840	178	276	1,305	1,758
2023	254	344	1,262	1,860	297	428	1,188	1,913	211	275	1,347	1,833
2024	267	373	1,300	1,941	308	452	1,217	1,977	227	303	1,393	1,924
2025	259	406	1,356	2,020	297	490	1,269	2,056	220	337	1,457	2,015
2026	255	407	1,428	2,090	291	486	1,335	2,112	218	339	1,528	2,085
2027	268	467	1,480	2,216	302	539	1,382	2,223	234	416	1,597	2,247
2028	302	473	1,557	2,331	333	540	1,454	2,328	270	414	1,664	2,348
2029	313	463	1,602	2,378	342	543	1,483	2,368	283	398	1,725	2,406
2030	298	481	1,693	2,472	325	571	1,564	2,461	271	403	1,837	2,511
2031	287	510	1,836	2,633	311	577	1,708	2,597	261	463	1,974	2,699
2032	283	489	1,921	2,693	305	568	1,772	2,645	260	420	2,086	2,766
2033	302	517	2,043	2,862	322	592	1,882	2,796	281	461	2,211	2,954
2034	352	513	2,153	3,018	370	597	1,988	2,954	333	441	2,329	3,103
2035	401	526	2,237	3,164	416	628	2,056	3,100	384	445	2,451	3,280
2036	448	546	2,356	3,350	462	644	2,150	3,255	434	460	2,576	3,471
2037	495	596	2,417	3,507	506	705	2,215	3,426	482	511	2,631	3,624
2038	541	583	2,556	3,680	550	687	2,343	3,580	531	491	2,793	3,814
2039	589	646	2,625	3,861	596	743	2,411	3,750	581	569	2,875	4,025
2040	639	657	2,801	4,097	644	765	2,581	3,991	632	562	3,029	4,223
2041	691	690	2,905	4,287	695	803	2,654	4,153	686	603	3,165	4,454
2042	759	741	3,077	4,577	762	845	2,814	4,420	755	649	3,367	4,771
2043	824	770	3,262	4,856	826	846	3,134	4,805	821	676	3,533	5,030
2044	819	821	3,361	5,001	820	840	3,346	5,006	817	728	3,682	5,227
30 Yr NPVRR	2,596	4,216	15,540	22,351	2,919	4,821	14,683	22,423	2,276	3,699	16,509	22,484

($Millions)	Scrub/ Replace				Replace			
	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	27	284	864	1,174	32	284	864	1,180
2016	62	257	905	1,223	70	258	905	1,232
2017	138	269	947	1,354	175	275	947	1,397
2018	263	284	998	1,545	352	285	986	1,624
2019	353	297	1,100	1,750	463	284	1,120	1,866
2020	365	380	1,093	1,838	466	378	1,113	1,957
2021	355	402	1,133	1,891	452	397	1,155	2,003
2022	362	404	1,164	1,931	454	395	1,183	2,033
2023	386	402	1,201	1,988	475	392	1,224	2,090
2024	394	433	1,238	2,064	478	424	1,269	2,170
2025	379	462	1,289	2,130	460	450	1,325	2,235
2026	369	465	1,362	2,196	447	454	1,396	2,296
2027	377	504	1,413	2,294	451	489	1,462	2,402
2028	405	515	1,487	2,407	475	499	1,525	2,500
2029	410	508	1,529	2,447	478	489	1,578	2,544
2030	390	542	1,612	2,544	454	526	1,675	2,654
2031	373	540	1,755	2,668	433	525	1,812	2,770
2032	364	538	1,838	2,739	420	518	1,920	2,858
2033	377	550	1,960	2,887	431	529	2,044	3,003
2034	422	563	2,070	3,055	471	543	2,162	3,176
2035	464	584	2,148	3,196	511	560	2,272	3,342
2036	506	608	2,268	3,382	549	585	2,399	3,534
2037	547	652	2,325	3,524	586	624	2,447	3,658
2038	588	647	2,467	3,701	623	618	2,616	3,857
2039	632	690	2,535	3,857	665	656	2,694	4,015
2040	679	720	2,716	4,115	711	690	2,859	4,259
2041	729	748	2,822	4,299	759	720	2,998	4,477
2042	793	798	2,993	4,584	822	764	3,199	4,785
2043	856	846	3,185	4,887	883	809	3,380	5,072
2044	848	916	3,282	5,045	874	878	3,524	5,276
30 Yr NPVRR	3,602	4,623	15,005	23,229	4,282	4,515	15,439	24,237

Appendix C – Portfolio Annual Emissions

Portfolio Annual Emissions

	Scrub/ Convert			Scrub			Convert		
	CO_2 (ktons)	SO_2 (tons)	Annual NOx (tons)	CO_2 (ktons)	SO_2 (tons)	Annual NOx (tons)	CO_2 (ktons)	SO_2 (tons)	Annual NOx (tons)
2015	18,113	43,677	17,686	18,113	43,677	17,686	18,113	43,677	17,686
2016	15,949	37,615	13,286	15,949	37,615	13,286	15,949	37,615	13,286
2017	17,775	42,282	14,746	17,775	42,282	14,746	17,775	42,282	14,746
2018	19,532	36,703	15,777	19,385	28,962	15,672	19,675	45,257	15,879
2019	12,207	11,126	10,830	18,476	13,156	15,210	6,289	9,208	6,706
2020	13,957	10,980	11,298	20,826	13,190	16,126	7,219	8,802	6,589
2021	14,101	10,908	11,229	21,281	13,230	16,251	7,605	8,790	6,726
2022	14,300	11,722	11,616	21,310	13,983	16,531	7,434	9,522	6,779
2023	14,759	11,199	11,502	21,758	13,431	16,458	7,135	8,770	6,103
2024	15,916	10,872	11,430	23,338	13,248	16,668	8,397	8,474	6,111
2025	16,060	12,846	12,282	23,206	15,116	17,362	8,789	10,534	7,124

	Scrub/ Replace			Replace		
	CO_2 (ktons)	SO_2 (tons)	Annual NOx (tons)	CO_2 (ktons)	SO_2 (tons)	Annual NOx (tons)
2015	18,113	43,677	17,686	18,113	43,677	17,686
2016	15,949	37,615	13,286	15,949	37,615	13,286
2017	17,775	42,282	14,746	17,775	42,282	14,746
2018	19,532	36,703	15,777	19,675	45,257	15,879
2019	13,975	11,149	10,710	9,826	9,253	6,467
2020	16,070	11,007	11,238	11,411	8,855	6,424
2021	16,282	10,936	11,114	11,925	8,845	6,441
2022	16,403	11,748	11,525	11,692	9,575	6,664
2023	17,294	11,230	11,541	12,205	8,832	6,181
2024	18,361	10,902	11,420	13,312	8,534	6,125
2025	18,253	12,873	12,336	13,164	10,588	7,218

Appendix D – CO_2 Cost Calculation

CO2 Cost Calculation

Assumptions		
CC Gas Unit Heat Rate	7.400	MMBtu/MWh
Coal Unit Heat Rate	10.500	MMBtu/MWh
CC Gas Unit Variable O&M	$ 2.50	$/mwh
Coal Unit Variable O&M	$ 6.14	$/mwh
CO2 Rate Gas	118.86	lb/MMBtu
CO2 Rate Coal	209.58	lb/MMBtu
CC Gas Unit CO2 Ton per MWh	0.440	Short Tons/MWh
Coal Unit CO2 Ton per MWh	1.100	Short Tons/MWh

Nominal Fuel Price Forecast $/MMBtu	2020	2021	2022	2023	2024
Natural Gas Price	$ 5.33	$ 5.58	$ 5.66	$ 5.84	$ 6.17
Coal Price	$ 2.49	$ 2.57	$ 2.66	$ 2.76	$ 2.85

Year: 2020

$$\frac{[(\text{Natural Gas Price} * \text{CC Gas Unit Heat Rate}) + \text{CC Gas Unit Variable O\&M}] - [(\text{Coal Price} * \text{Coal Unit Heat Rate}) + \text{Coal Unit Variable O\&M}]}{\text{Coal Unit CO2 Ton per MWh} - \text{CC Gas Unit CO2 Ton per MWh}} = \text{CO2 Price per Ton}$$

$$\frac{[(\$5.3273 * 7.400) + \$2.500] - [(\$2.4863 * 10.500) + \$6.1400]}{1.1003 - 0.4398} = \$\ 14.65$$

$$\frac{41.9220 - 32.2462}{0.6605}$$

Calculated CO2 Price Forecast $/Ton	2020	2021	2022	2023	2024
CO2 $/Ton	$ 14.65	$ 16.05	$ 15.50	$ 16.11	$ 18.26

Appendix E – OG&E 2014 IRP Oklahoma Collaborative Technical Conference

OG&E 2014 IRP Update

Oklahoma Technical Conference

June 24, 2014, Oklahoma City

Meeting Minutes

The OG&E 2014 Integrated Resource Plan ("IRP") Update Technical Conference was held on June 24, 2014 in OG&E's offices from 9:15 AM to 12:30 PM.[1] A list of participants is presented in Attachment A. The meeting began with an introduction by Jerry Peace, OG&E's Chief Generation Planning and Procurement Officer.

The majority of the meeting was organized around a slide presentation of the Draft IRP that was made by three members of OG&E's resource planning team (Leon Howell, Zac Hager, and Kelly Riley). Stakeholders asked clarifying questions throughout the presentation. The second part of the meeting was devoted to stakeholder feedback on OG&E's draft IRP. A copy of the slides presented is included as Attachment B.

Part I: OG&E Presentation & Stakeholder Questions

The slide presentation was divided into sections that corresponded to the organization of the Draft IRP Report. The <u>first section</u> provided an overview of the IRP Update. OG&E began by providing a summary of progress that has been made in diversifying the portfolio since OG&E announced its 2020 Goal in 2007. A summary of the environmental compliance obligations (Regional Haze and the Mercury and Air Toxics Rules) and deadlines was presented. OG&E reviewed the process used to develop the IRP and introduced the one significant change from prior years: the need to reflect the implementation of SPP's Integrated Marketplace on March 1, 2014. Finally, OG&E concluded the overview by presenting a slide with the 5-Year Action Plan.

The <u>second section</u> of the presentation was devoted to a review of the IRP assumptions, starting with the load forecast. OG&E presented a slide that reviewed the historical and projected contributions from four demand side management ("DSM") programs: Energy Efficiency, SmartHours, Integrated Volt Var Control ("IVVC") and the Load Reduction Rider. In response to a comment, OG&E agreed to update the DSM forecast in the final IRP to correspond to a more recent submittal.

OG&E described the Capacity Margin calculation and presented a slide showing OG&E would have a capacity need beginning in 2018 as a result of the planned retirement of

[1] As required by the IRP rules, OG&E secured the services of a facilitator, Robert C. Yardley, Jr. In addition to facilitating the meeting, Mr. Yardley prepared these meeting notes.

460 MW at its Mustang Unit. OG&E also presented a slide that showed how its capacity and energy mix has changed since 2007 and what it is expected to look like in 2020, based on the IRP.

The balance of this section was devoted to tables and graphs of key assumptions including the costs of potential environmental control technologies (scrub, convert, Low NOx burners, and Activated Carbon Injection), coal and natural gas fuel prices, and SPP market prices. OG&E explained that the resource planning team had developed the SPP market prices using PROMOD under three scenarios: the base case and two other cases that were defined assuming "high" and "low" conversion of coal plants across the SPP.

The <u>third section</u> of the presentation focused on the quantitative analyses and results. It began with identification of the three components of customer costs: (1) return on rate base, (2) fixed expenses, and (3) "production cost with market impact." OG&E explained that the third component reflects the fact that OG&E is compensated at the SPP market price when its generation units are dispatched (and incurs fuel and variable costs to run them), and purchases all of its load requirements from the SPP. The market price assumptions are thus key inputs to this calculation.

OG&E identified the five environmental compliance plans that were analyzed (combinations of scrub, convert, and replace). Since OG&E will need new capacity beginning in 2018, it developed three expansion cases that were added on to each of the five environmental compliance plans and presented the results of these fifteen cases. The results indicated that the expansion options did not have a significant impact on which of the environmental compliance plans might be preferred. They also indicated that the three plans that included only scrub and convert options were preferred to the two plans that included replace options and by a significant margin.

OG&E described the impact of each of the three customer cost components on the total 30-year net present value of customer costs ("NPVCC") and the extent to which dispatch of OG&E's units into the SPP market contributes to lower NPVCC.

Next, OG&E presented the results of the three market price scenarios when applied to each of the five environmental compliance plans. Finally, OG&E presented the results of six sensitivity cases that each varied one of four assumptions: two natural gas sensitivities (high and low), a carbon price sensitivity (the Base Case did not assume a carbon price), two environmental compliance plan capital cost cases (high and low), and a low SPP load growth forecast.

The <u>fourth section</u> of the presentation examined three specific issues: (1) retirement and replacement of the capacity provided by Mustang, (2) an OG&E decision to pause for at least a year on adding wind energy to the portfolio, and (3) a decision not to consider central solar generation at this time due to economic factors.

The <u>fifth and final section</u> of the presentation focused on the Action Plan, beginning with a discussion of the nine objectives OG&E applied to identify the best cost resource plan.

Part II: Stakeholder Feedback

Stakeholders provided feedback in several areas. OG&E responses are also presented if they were offered.

1. Environmental Compliance Plans
    - Question as to whether OG&E had considered consolidating all of its coal operations at Muskogee where it will still have one operating coal unit rather than scrub Sooner and convert Muskogee
        - *OG&E indicated the Sooner plant had a lower heat rate, lower O&M, and better performance than Muskogee.*
    - Question as to why OG&E had installed ACI on Muskogee 4 and 5 if units will be converted to natural gas in the future
        - *OG&E indicated it will install ACI on Muskogee 4 and 5 to be compliant with MATS by 2016. Analysis indicates customers are projected to realize savings if OG&E adds ACI allowing the coal units to run for the next three years as opposed to converting them to natural gas in 2016.*
    - Question as to where energy will come from if Muskogee 4 and 5 are converted to natural gas and don't run as often and whether wind energy could make up this gap
        - *OG&E indicated that all energy for load will be provided by the SPP IM. It could come from any resource in the SPP, including wind.*
    - Question as to why OG&E was no longer considering DSI, a compliance option that had been included in its 2012 IRP
        - *OG&E indicated that DSI was considered in the 2012 IRP as an option to comply with the MATS acid gas requirements. OG&E has determined that acid gases are within the compliance requirements so DSI is no longer needed to comply with the acid gas control requirements of MATS.*
    - Suggestion that IRP more clearly indicate how carbon and other environmental emissions costs are incorporated into the analyses
    - Suggestion that at least one of the environmental compliance plans should reflect a portfolio approach that includes wind
        - *OG&E indicated that all of the alternatives consider how the portfolio impacts customers cost. Wind was not considered a Regional Haze alternative because it was not a viable capacity alternative, but wind energy was considered separately to determine if it offered customer savings.*

- Suggestion that OG&E consider asking EPA for an extension of time to comply with Regional Haze

2. Future Environmental Regulation
   - Question as to whether OG&E would consider including the emissions as calculated in the IRP
     - *OG&E indicated it would include the annual SO_2, NOx and CO_2 annual emissions from the analysis in the appendix of the IRP.*
   - Question as to whether OG&E could include its methodology for calculating a CO_2 price in the IRP
     - *OG&E indicated it would include the calculation of a CO_2 price in the appendix of the IRP.*
   - Concern expressed that OG&E's plan may not be addressing the recently announced potential carbon regulations and that the carbon sensitivity case may not capture the range of impacts of such regulation
     - *OG&E indicated that it is very uncertain as to how the final regulation on carbon may look. OG&E included a carbon tax sensitivity analysis beginning in 2020 to capture one potential outcome of carbon regulation.*
     - *The High Conversion market price scenario is another way OG&E captured carbon regulation by assuming approximately 1/3 of all coal units in the SPP would be converted to natural gas, reducing the SPP's CO_2 footprint.*

3. Water Impacts
   - Concern expressed that there may not be an adequate water supply to support scrubbing of the Sooner plants
     - *OG&E indicated that Sooner Lake was built to support up to 6 coal units and is expected to have adequate water to support scrubbing the existing units.*

4. DSM
   - Expression of interest in OG&E making its load reduction program more attractive to customers
   - Suggestion that DSM costs be more clearly presented in the IRP

5. Mustang Retirement and Replacement
   - Question as to why the Mustang retirement dates had been moved up from the dates included in the 2012 IRP
     - *OG&E indicated that it recently determined Mustang needed to be retired for operational reasons.*
   - Question as to whether OG&E could add the estimated retirement dates to the IRP
     - *OG&E indicated the estimated retirement dates were included in the 2012 IRP and it would include them in this update.*

- Question as to whether OG&E would issue an RFP for replacement capacity
    - *OG&E indicated that it would competitively bid all major components for Mustang CT's but did not plan to issue an RFP for replacement capacity.*

6. Wind Energy
    - Question as to whether OG&E installation of scrubbers might preclude OG&E from adding wind energy next year
        - *OG&E indicated that additional wind energy is considered by determining whether or not it offers customers savings. Adding scrubbers will have little to no impact on the savings calculation.*
    - Question as to whether OG&E might invest in transmission capacity to contribute to easing transmission delivery constraints and congestion price impacts
        - *OG&E indicated that SPP is responsible for its members' transmission planning and, consequently, whether transmission capacity is added. OG&E developed the Windspeed 345 kV transmission line early on to facilitate the development of wind energy but has no plans to propose another sponsored upgrade line. Also, OG&E is about to complete three major 345kV lines to improve the deliverability of wind energy resources in Western Oklahoma.*
    - Suggestion that acquiring wind energy and rate-basing this option may be a low cost option and a similar comment was made with respect to acquiring new gas-fired capacity

7. Natural Gas Purchasing
    - Question as to whether OG&E will engage in gas price hedging if the portfolio is going to be increasingly reliant on natural gas
        - *OG&E indicated that gas supply volumetric needs in the SPP's Integrated Marketplace are highly variable and unpredictable. As a result, a price hedging program would be very difficult to implement.*

8. Potential Rate Impacts
    - Concern expressed that the potential rate impact will be too high
    - Concern expressed that the rate impact would harm high load factor customers disproportionately as lower energy cost units were being replaced with higher cost energy
    - Question as to whether the undepreciated portion of converted units will be recovered in future rates
        - *OG&E indicated that it was assumed existing assets would be recovered in future rates.*

Appendix A - Attendee List

June 24, 2014 - Oklahoma IRP

Name:	Representing:
Tom Schroedter	OIEC
Scott Norwood	OIEC
MARK GARRETT	OIEC
John Riesenberg	Devon
Jeff Riles	OK Energy Results
Cheryl Vaught	OK Energy Results
Jim Roth	OK Energy Results
Nicole King	OCC-PUD
Tonya Hinex-Ford	OCC-PUD
Sharon Fisher	OCC-PUD
Chip Clark	OG&E Shareholder Assn.
Jerry Sanger	AG
Tessa Hager	AG
Ed Farrar	
Aaron Pupa	LS Power
Joel Rodriguez	OCC-PUD
Jason Chaplin	OCC-PUD
Mike Knapp	OCC-PUD
GEOFFREY RUSH	OCC-PUD
BOB THOMPSON	OCC-PUD
Paul Renfrow	OG&E
CRAIG SUNDSTROM	SOEE
Emily Shuart	PSO
MARK BECKER	AEP/PSO
Allen Gould	OG&E

Oklahoma IRP

Attendee List 6/24/14

Name:	Representing:
JOHN WENDLING	OG&E
Usha Turner	OG&E
Bill Wylie	Univ. of Oklahoma
DAVID DYKE	OG&E
Stephanie Rumbaugh	OGE
Bill Wilkinson	OGE
BOB KOENIG	OGE
JOAN WALKER-RATLIFF	PHILLIPS 66
Chris Knapp	Apex Clean Energy
LEE PADEN	QOSC
Montelle Clark	OSN
Rick Chamberlain	
RON STAKEM	OG&E Shareholder
Lundy Kiger	AES
Kendall Parrish	AES
Carisa Kent	OGE
Bob Vandewater	Corporation Comm
Herbert Bergman	Oklahoma Cogeneration, LLC
[illegible] Brandt	"
JAMES R BEERS	"
Al Armendariz	Sierra Club
Kristin Henry	Sierra Club
Eddie Terrill	DEQ
Rob Singletary	DEQ

Name	Representing
Dong Shanedy	OG+E
Pat Shore	OG+E
Stephanie Houle	OGE
Jerry Peace	OGE

Appendix B - Presentation

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2014 Integrated Resource Plan

Oklahoma Collaborative Technical Conference

June 24, 2014

WITH ALL YOUR POWER WHAT WOULD YOU DO?

2014 Integrated Resource Plan

INTRODUCTION

Presentation Outline

- **Summary**
- **Assumptions**
- **Analysis**
- **Other Considerations**
- **Action Plan**

In 2007 OG&E announced its "2020 Goal"

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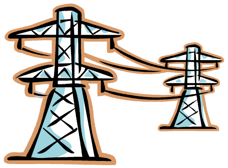
- 2020 Goal is no new incremental fossil fuel generation until the year 2020
- OG&E developed a three-pronged plan to accomplish the goal while preparing for potential environmental legislation and/or regulation

1) Construct Transmission Lines to Deliver Wind to OG&E Load



2) Add up to 640 MW of Wind Generation

3) Manage load by terminating wholesale contracts and increasing demand side management programs

Progress has been made toward achieving the 2020 Goal and plans are in place to continue the success

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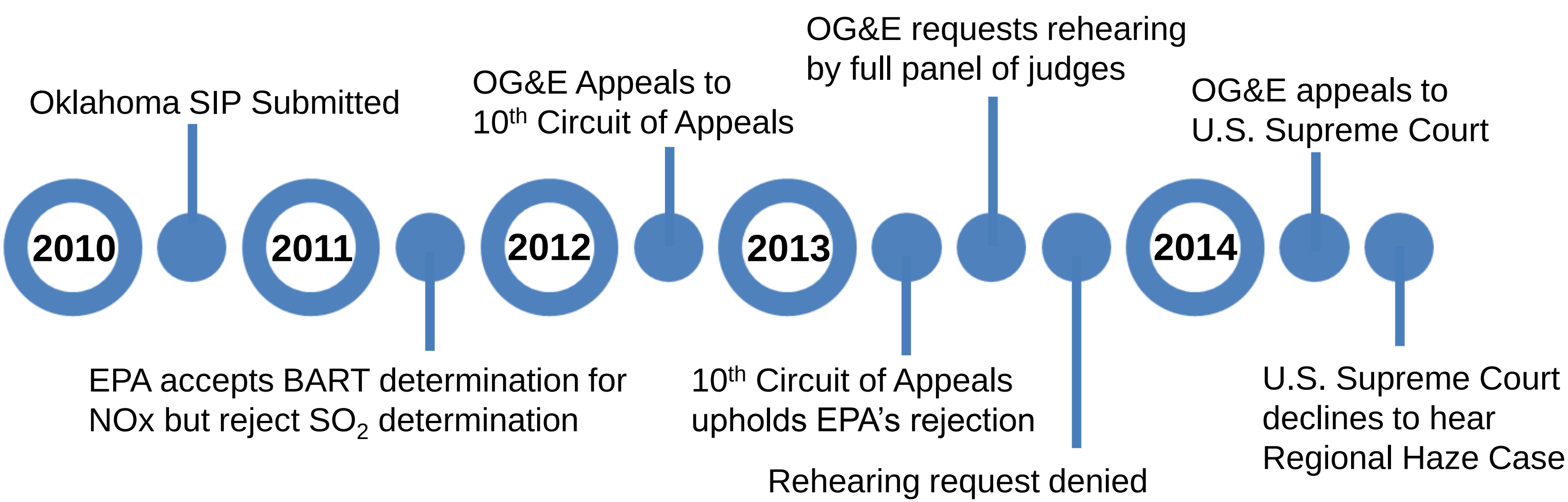
Year	Wind	DSM	Wholesale
2008		2	18
2009	OU Spirit – 101	13	
2010	Keenan – 152	12	5
2011	Taloga – 130 Crossroads – 228	22	
2012	Cowboy – 60	118	14
2013		99	50
Total	671 MW	266 MW	87 MW

Crossroads Wind Farm

Environmental challenges and deadlines

- **Regional Haze** – Legal measures have been exhausted so OG&E now must comply with the Environmental Protection Agency (EPA) Federal Implementation Plan (FIP) by **January 4, 2019**

- **Mercury Air Toxics Rules (MATS)** - OG&E requested and has received a one-year extension for compliance to **April 16, 2016** from the Oklahoma Department of Environmental Quality



IRP Update process is similar to the past

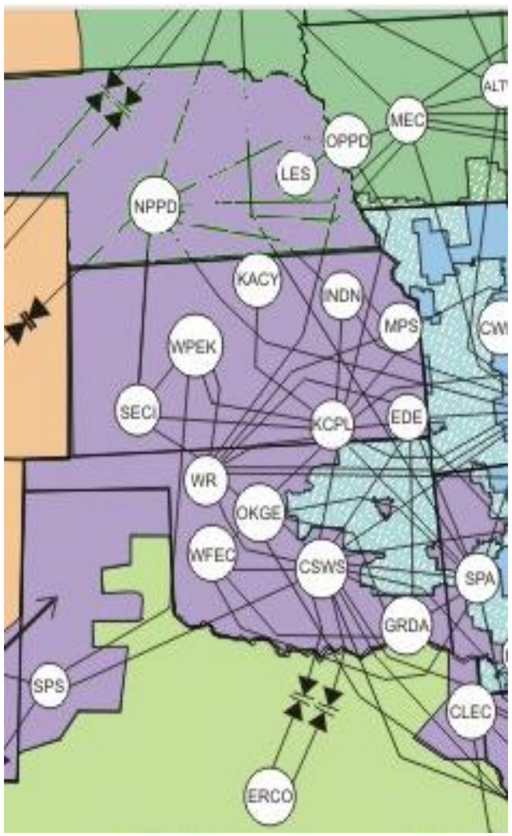
- Each one of the plans since 2010 has included an analysis of regional haze compliance alternatives
- The main change to the process is the inclusion of the SPP IM in generation optimization

Define IRP Objective → Collect Assumptions → Develop Models and Portfolios → Computer Simulations → Cost/Risk Analysis → Interpret Data and Draw Conclusions → Develop IRP Report

2009 2010 2011 2012

SPP implemented the IM on March 1, 2014

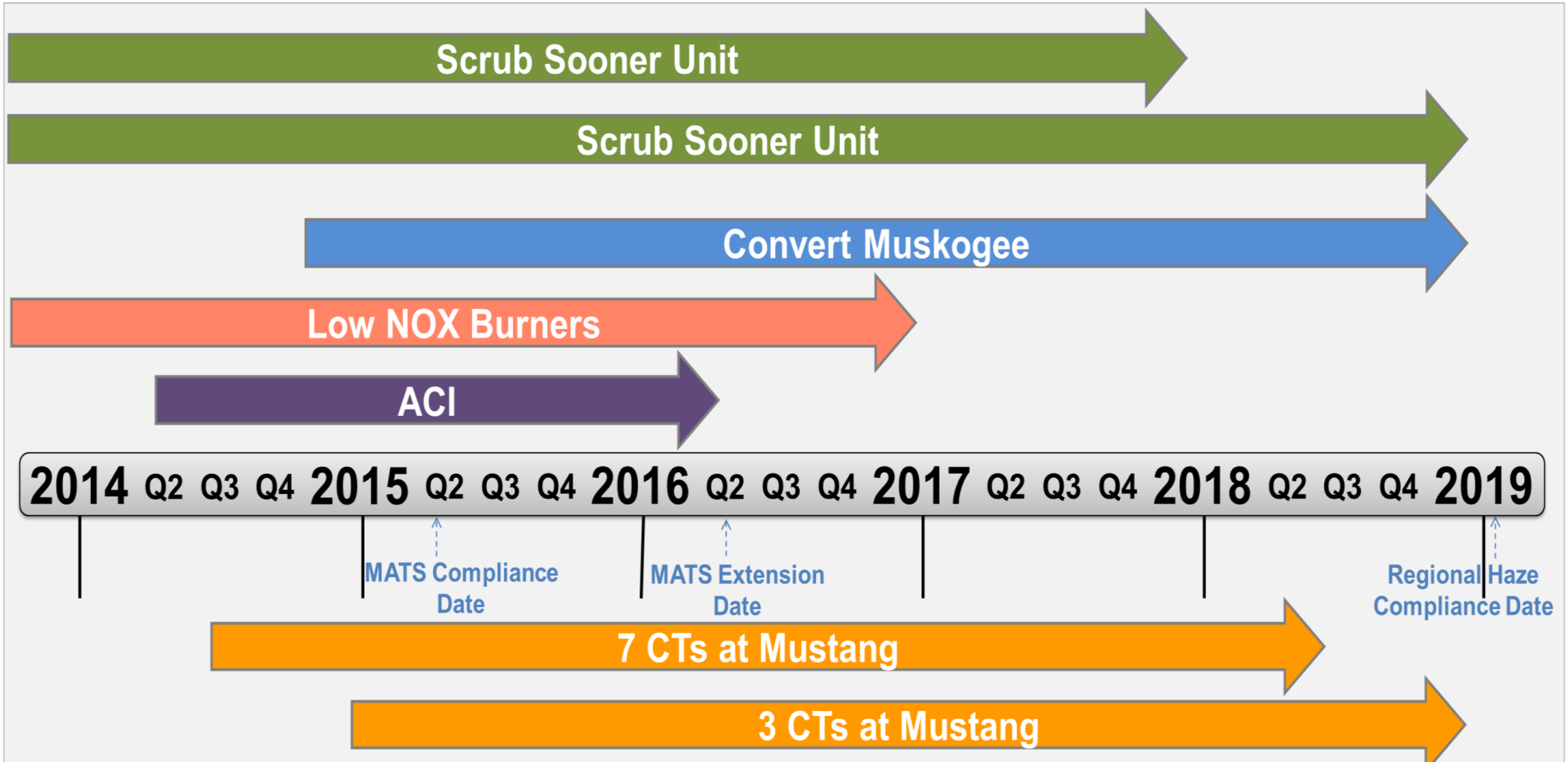
- OG&E now sells all of its generated energy into the market and buys all of its energy for load from the market



- **OG&E unit commitment and dispatch**
- **16 Balancing Authorities**
- **OG&E optimizes generation to serve load**

- **SPP unit commitment and dispatch**
- **1 Balancing Authority (SPP)**
- **SPP optimizes generation to serve load**

The 5 year Action Plan



Regional Haze compliance date is set 55 months from US Supreme Court decision. Clock restarted 5/29/2014 + 55 months = 1/4/2019.

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ASSUMPTIONS

DSM programs will reduce Peak Demand by approximately 10% by 2020

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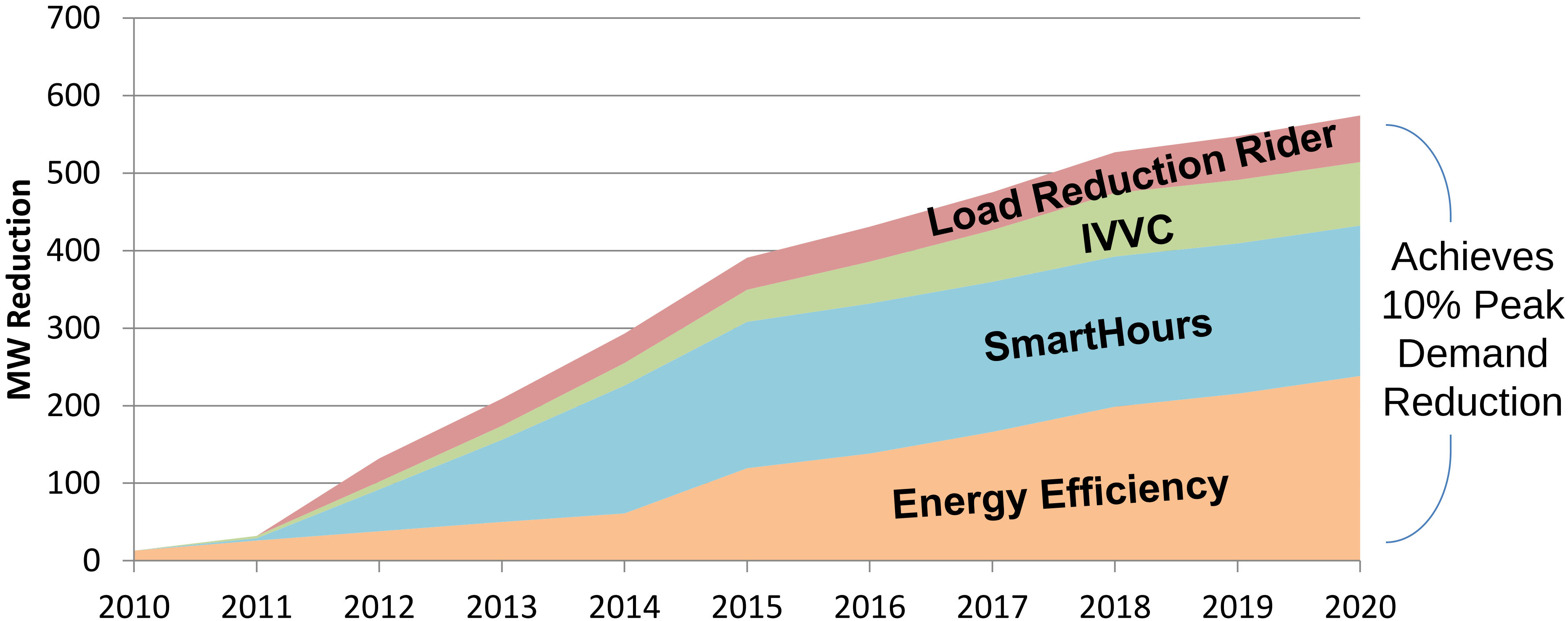
	2015	2016	2017	2018	2019	2020
Load Responsibility	5,850	5,855	5,892	5,882	5,921	5,924
Peak Demand Growth		0.09%	0.63%	-0.18%	0.67%	0.05%



Planning Capacity Margin

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		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Resources	Total Owned Capacity	6,405	6,355	6,355	5,942	5,942	5,942	5,942	5,942	5,942	5,773
	Purchase Contracts	453	453	453	453	451	331	331	331	11	11
	Total Net Dependable Capability	**6,858**	**6,808**	**6,808**	**6,395**	**6,393**	**6,273**	**6,273**	**6,273**	**5,953**	**5,784**
Demand	Load Forecast	6,205	6,252	6,336	6,377	6,437	6,470	6,528	6,562	6,605	6,651
	Energy Efficiency	83	104	134	167	183	209	238	230	223	216
	Demand Response	272	293	309	328	332	336	340	344	348	348
	Net On System Demand	**5,850**	**5,855**	**5,892**	**5,882**	**5,921**	**5,924**	**5,950**	**5,988**	**6,034**	**6,087**
Capacity Needs	Capacity Margin	1,008	953	916	513	472	349	323	285	-81	-303
	Capacity Margin (%)	14.7	14.0	13.4	8.0	7.4	5.6	5.2	4.5	-1.4	-5.2
	Needed Capacity	**-**	**-**	**-**	**289**	**336**	**460**	**488**	**532**	**905**	**1,134**

$$\textbf{Capacity Margin \% =} \frac{\textbf{(Total Net Capability) - (Net On System Demand)}}{\textbf{(Total Net Capability)}}$$

OG&E is gradually shifting generation resources while maintaining fuel diversity

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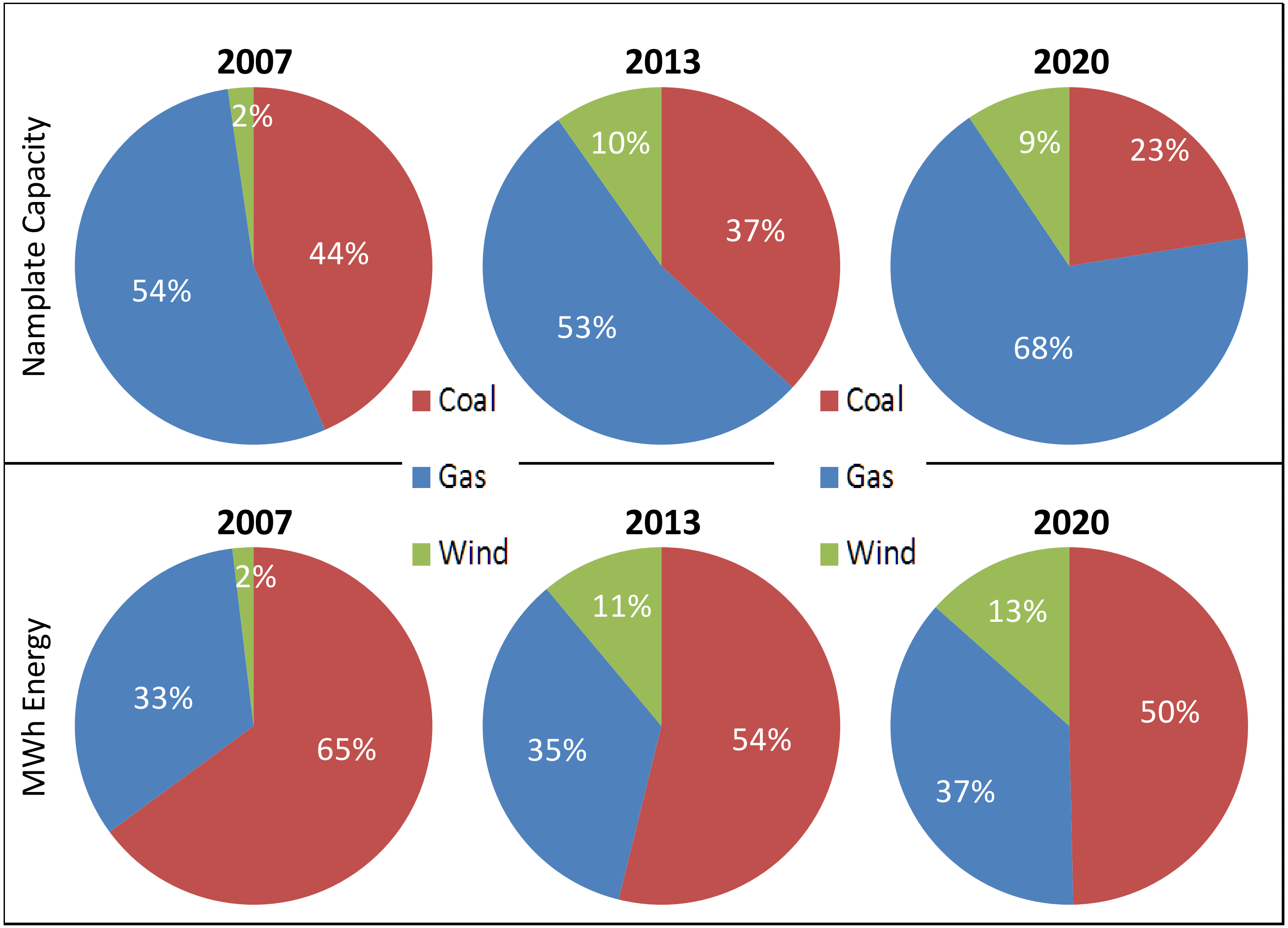

Emission Control Technology Cost Assumptions

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Control	Units	Overnight Capital Cost (2014$ in Millions)	Fixed O&M Cost (2014$ in Millions)	Variable O&M Cost (2014$ /MWh)
Dry Scrubber	All Coal per unit	$239.0	$7.88	$2.72
Low NO_x Burners	Muskogee 4	$11.0	$0.24	-
Low NO_x Burners	Sooner 1	$10.6	$0.24	-
Low NO_x Burners	Seminole 1&2	$41.3	$1.30	-
Low NO_x Burners	Seminole 3	$19.0	$0.64	-
Activated Carbon Injection	All Coal	$24.3	$0.80	$2.50
Conversion to Gas	Muskogee per unit	$35.7	-$5.57*	-$0.12
Conversion to Gas	Sooner per unit	$35.7	-$5.75*	$0.39

**Represents the incremental cost decrease due to conversion from coal to gas*

EIA forecast projects gradual increases in both coal and natural gas prices over the next decade

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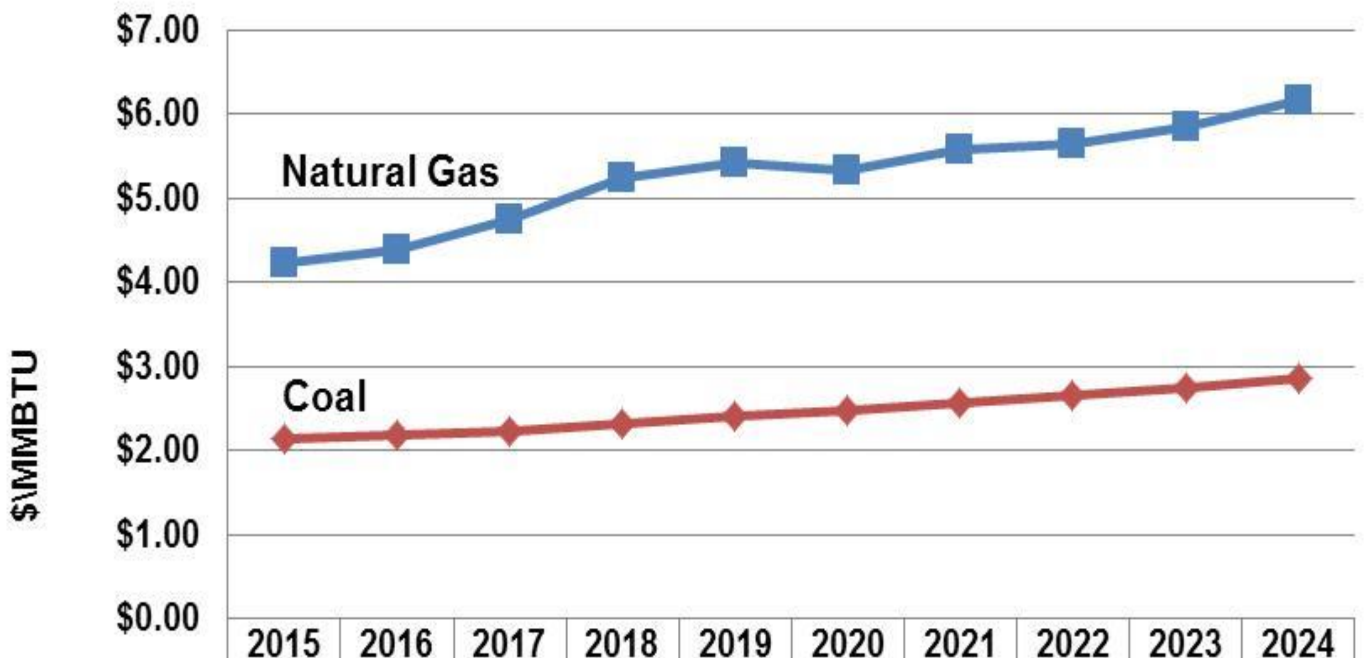

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
NG ($/MMBTU)	$4.23	$4.38	$4.74	$5.26	$5.42	$5.33	$5.58	$5.66	$5.84	$6.17
Coal ($/MMBTU)	$2.14	$2.18	$2.24	$2.33	$2.41	$2.49	$2.57	$2.66	$2.76	$2.85

PROMOD was used to project future market energy prices under various scenarios

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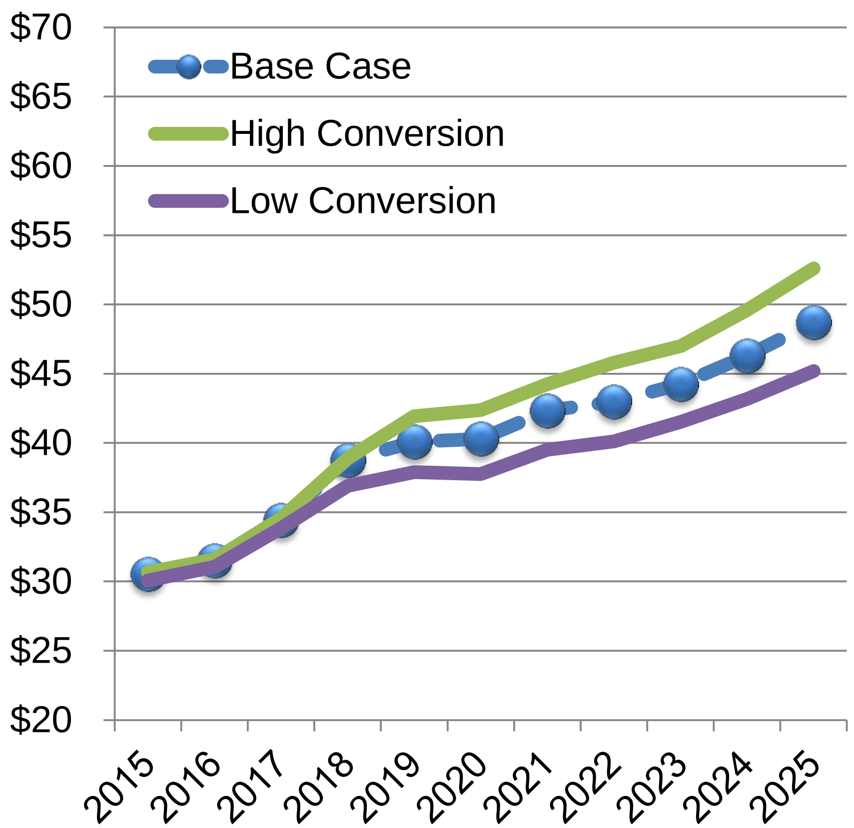
Average Annual Market Price ($/MWh)



Scenarios

- <u>Base Case</u> – Coal units in SPP smaller than 200 MW and coal units built before 1977 currently without emission controls are assumed to be converted to natural gas
- <u>High Conversion</u> – All coal units in SPP that have not announced plans to control emissions are assumed to be converted to natural gas.
- <u>Low Conversion</u> – Only coal units with announced plans to convert

Market price sensitivity to assumption changes

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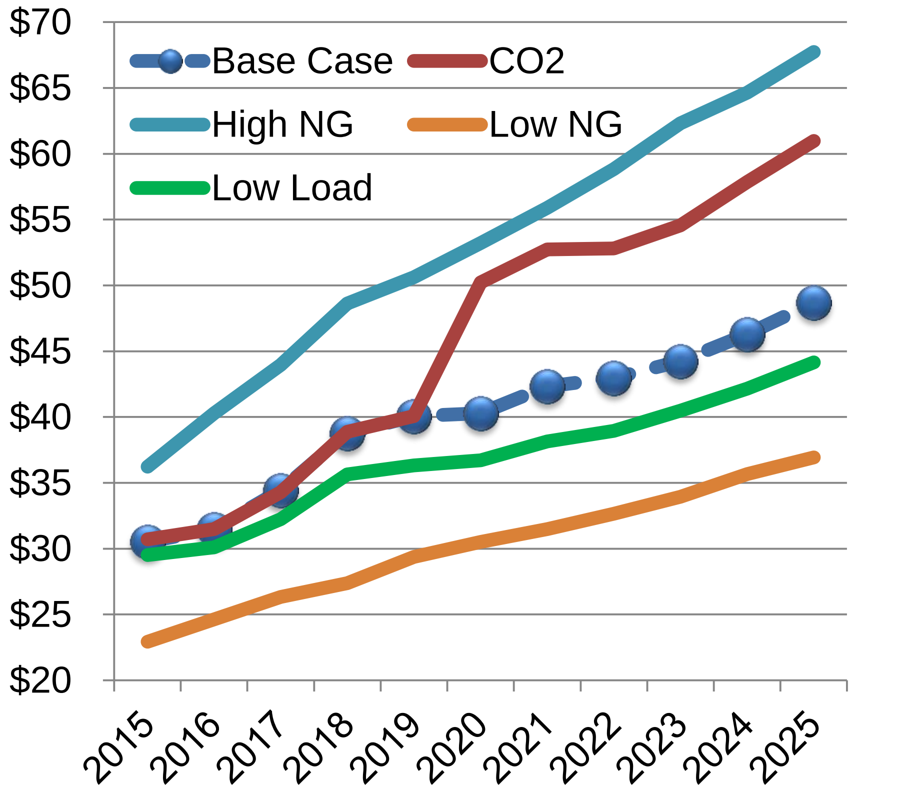
Sensitivities

- High NG Price (+50% Base)
- Low NG Price (-25% Base)
- Low Load (-10% Base)
- CO_2 Cost

Sensitivity	2020	2021	2022	2023	2024
CO2 $/ton	$15	$16	$16	$16	$18

Average Annual Market Price ($/MWh)



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ANALYSIS

Participation in the market adds two components to the traditional customer cost calculation

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Return on Rate Base
- Capital Investment
- Accumulated Depreciation
- Accumulated Deferred Income Tax

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Expenses
- Depreciation
- Ad Valorem
- Fixed O&M

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Production Cost with Market Impact
- Fuel
- Variable O&M
- Emissions
- Load Cost
- Less: Market Sales Revenue

=

Customer Cost

OG&E evaluated five alternative environmental compliance plans

Scrub/Convert	• Scrub Sooner 1 by 2018 and Sooner 2 by 2019 • Convert two Muskogee units by 2019
Scrub	• Scrub Muskogee 4 by 2018 and Muskogee 5 by 2019 • Scrub Sooner 1 by 2018 and Sooner 2 by 2019
Convert	• Convert four coal units to gas by 2019
Scrub/Replace	• Scrub Sooner 1 by 2018 and Sooner 2 by 2019 • Replace two Muskogee coal units with new CCs by 2019
Replace	• Replace four coal units with new CCs by 2019

Environmental compliance alternatives are not impacted by expansion plan options

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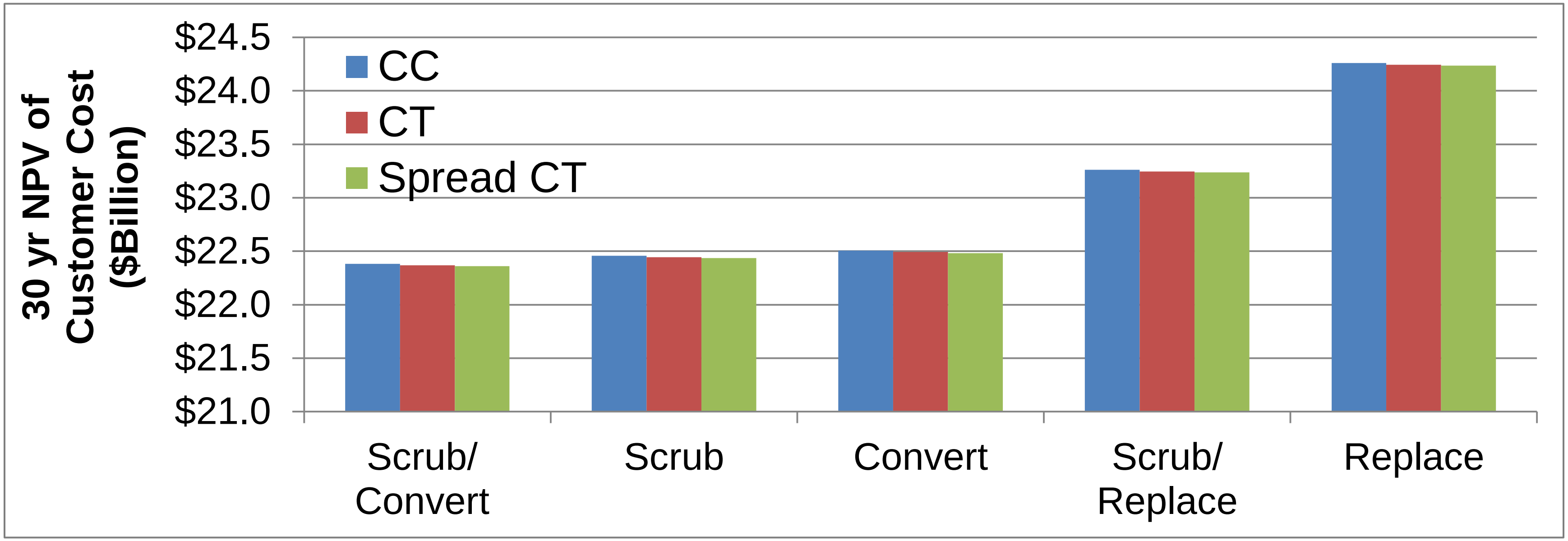

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2031
CC	560 MW CC					560 MW CC		560 MW CC					560 MW CC
CT	400 MW CTs		560 MW CC				560 MW CC					560 MW CC	
Spread CT	280 MW CTs	120 MW CTs	560 MW CC				560 MW CC					560 MW CC	

Cost components have different magnitudes but result in similar 30-yr NPVCC

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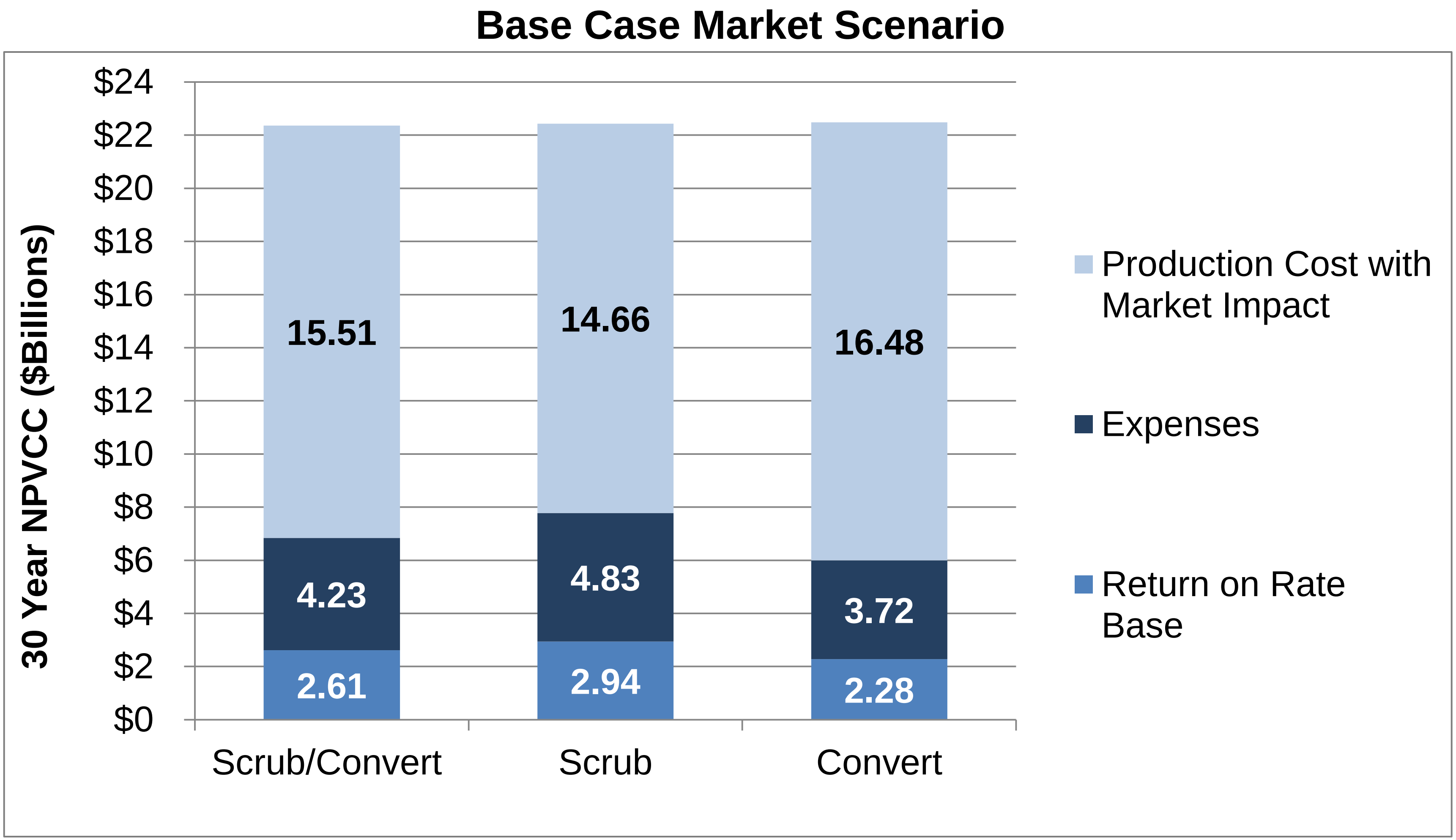

Market Revenue has a significant impact on production cost

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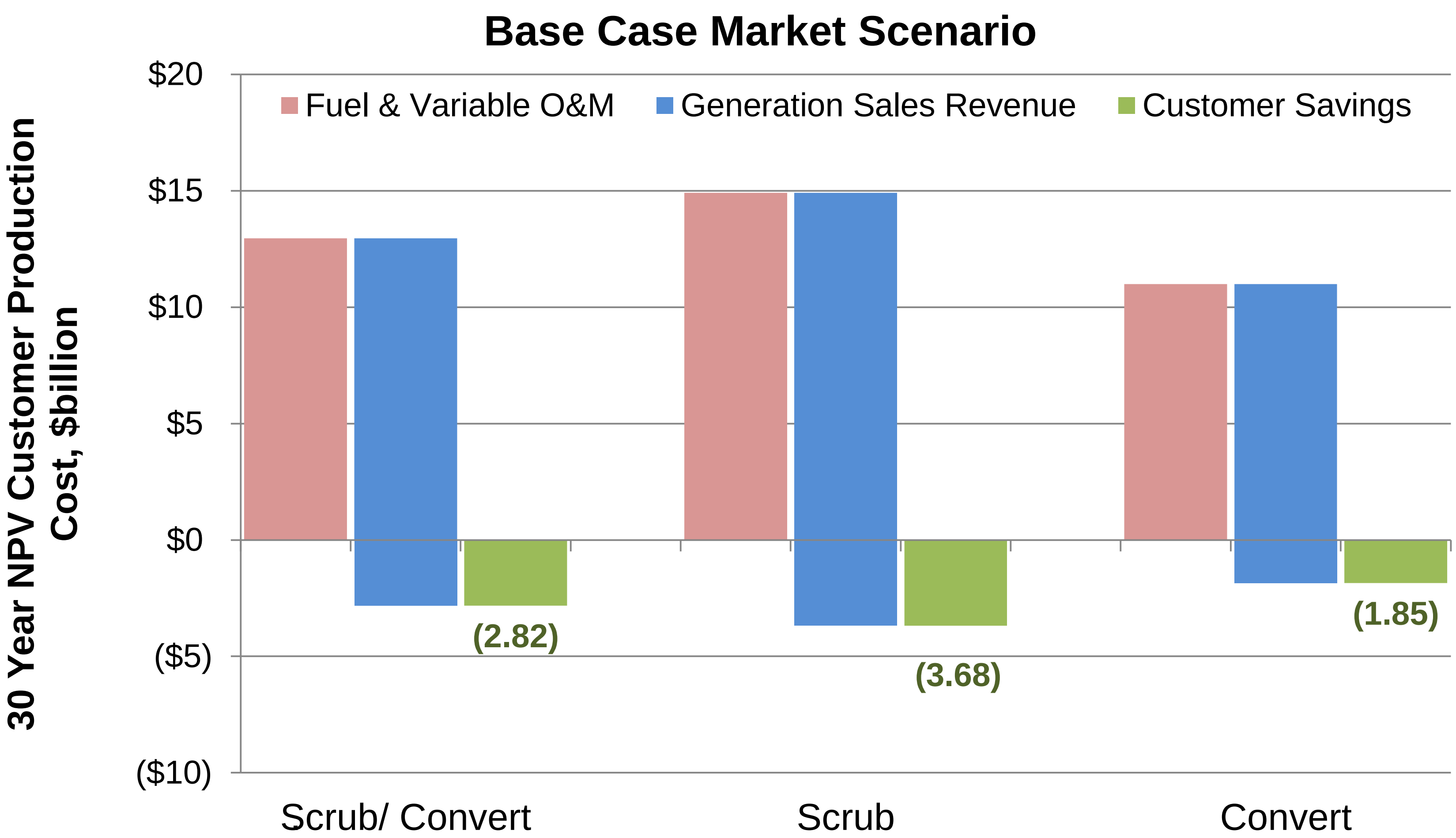

WITH ALL YOUR POWER WHAT WOULD YOU DO?

Performance of alternatives was considered in each market scenario

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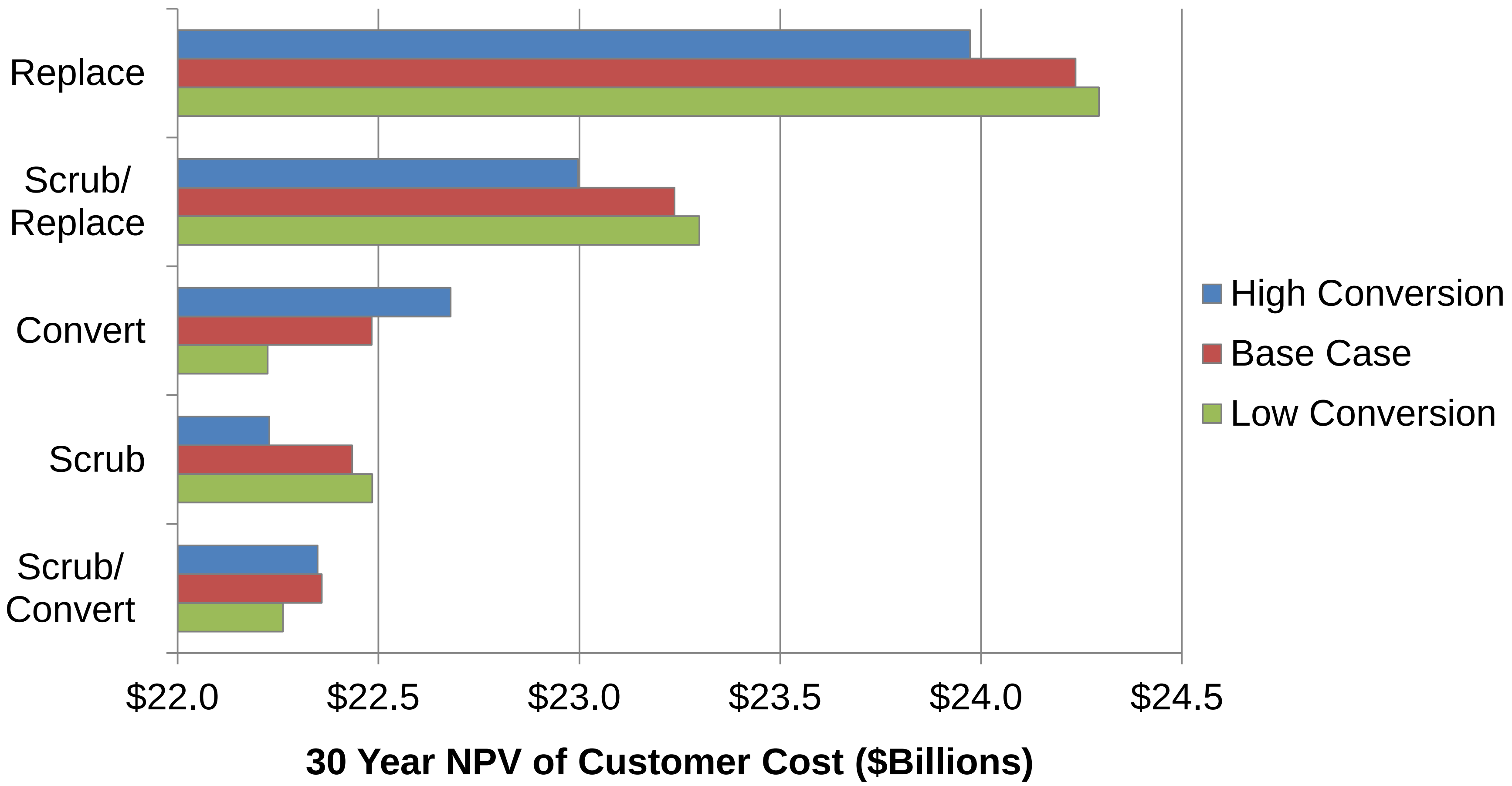

Sensitivity Analysis projects risk across multiple assumptions

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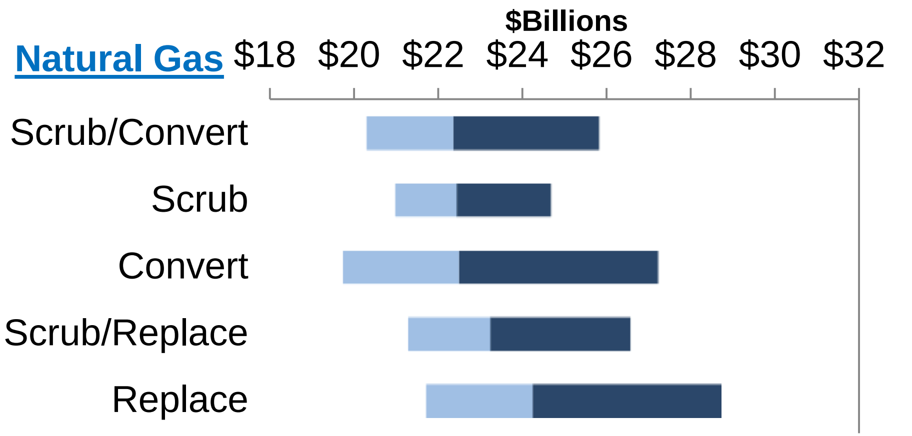

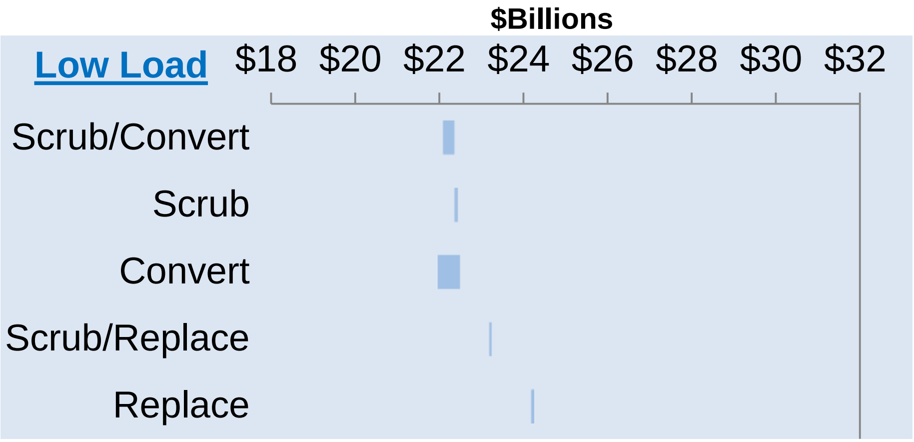

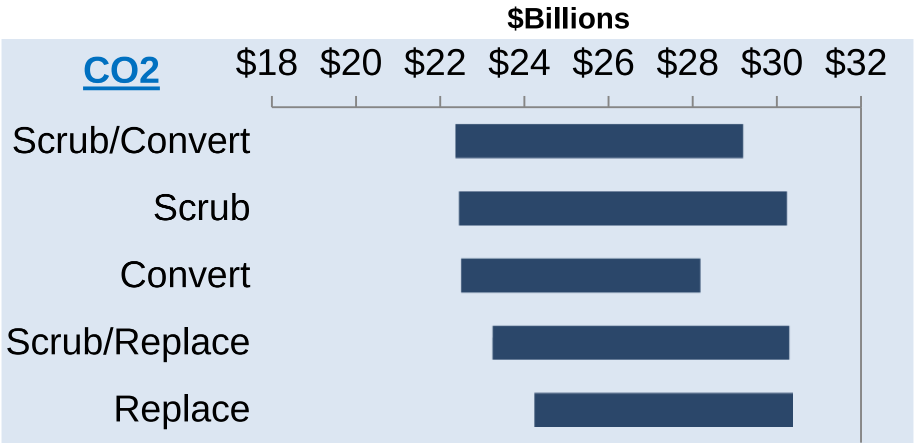

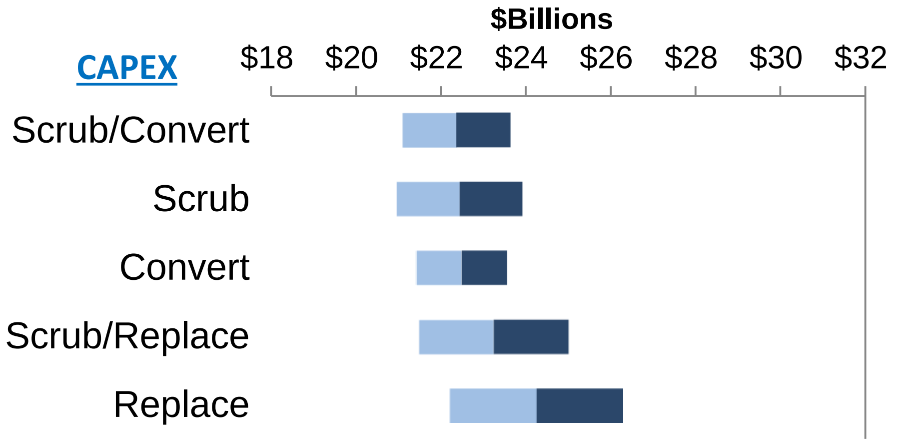

2014 Integrated Resource Plan

OTHER CONSIDERATIONS

Mustang Retirement and Replacement

- **Plant has reached the end of its useful life**
  - When retired the unit age ranges from 58 to 67 years
  - Units of this age are at a greater risk of catastrophic failure
  - Component failure due to age creates a greater safety risk for employees
  - Parts for units of this age are often non-existent
- **Existing site has a number of benefits**
  - Located near Oklahoma's largest load center, Oklahoma City
  - Provide reliability support function due to location within the load area
    - System restoration
    - Voltage support
  - Existing infrastructure
    - Transmission interconnection
    - Water supply with water rights
    - Gas pipeline connection
    - Property and roads
  - Existing environmental air permit
- **CT's offer reliability benefits**
  - Quick start, smaller units offer flexibility
  - Support the intermittency of wind
  - Support the growth of distributed generation

Why not more wind at this time?

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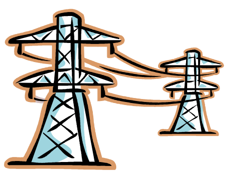
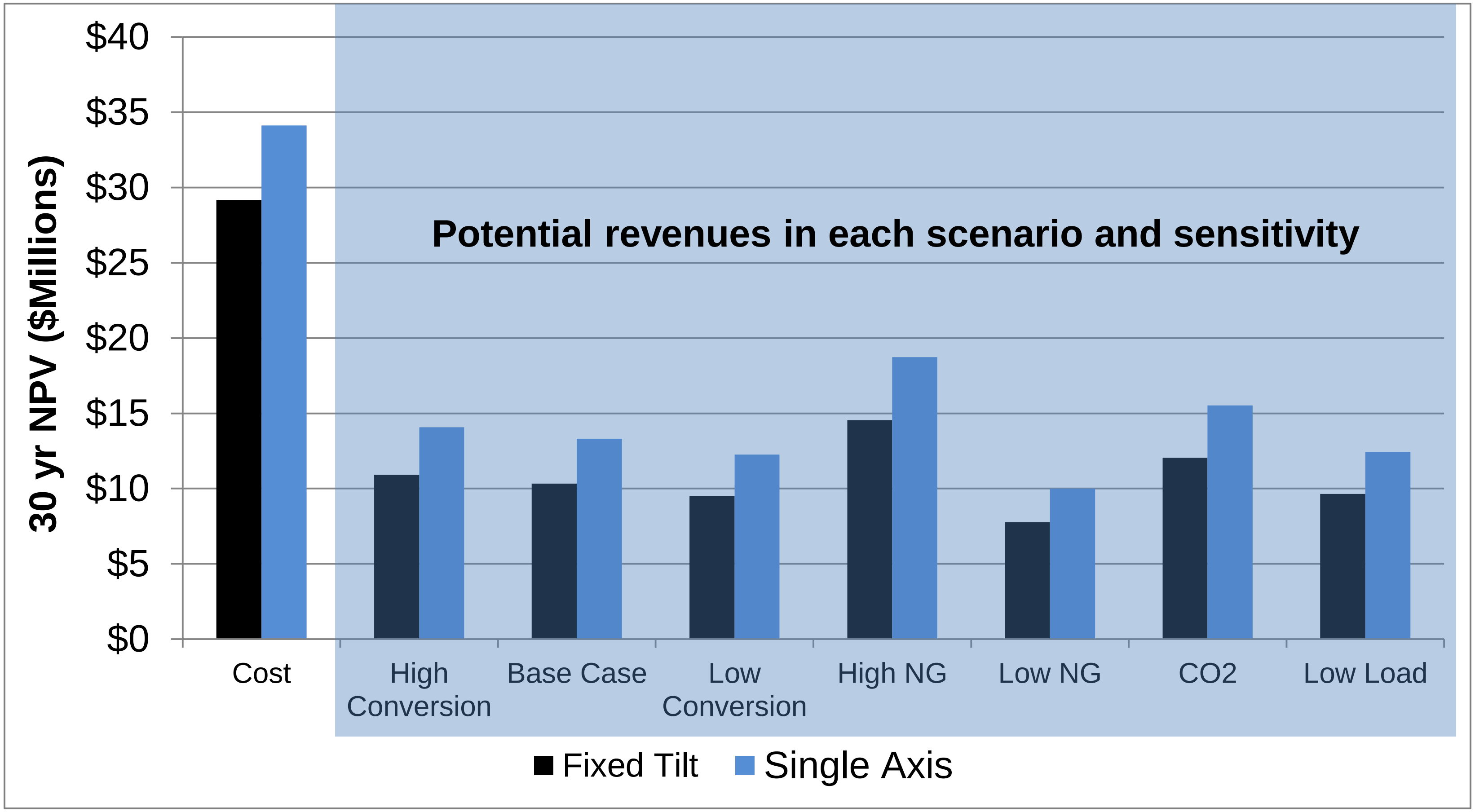
- **OG&E is committed to renewable generation**
  - OG&E is not saying no more wind; it's saying not now
  - Continue to monitor the situation to determine when the time is right
- **Wind is not a viable solution to Regional Haze**
  - Wind does not reduce the emission rate of coal units
  - OG&E must maintain its planning capacity margin requirements
  - Only 5% of nameplate wind generation can be counted towards capacity margin requirements
  - It takes 10,000MW of wind to replace 500MW of fossil fuel capacity



- **Delivery of wind to the market is a concern**
  - 2013 RFI respondents unwilling to accept economic curtailment risk
  - Curtailments due to transmission constraints occur
  - Congestion charges reduce the value of wind energy
  - More than 2000MW of additional wind generation will soon come on line depressing energy prices and increasing congestion

Central solar is not yet economical

POSITIVE ENERGY TOGETHER®



2014 Integrated Resource Plan

ACTION PLAN

Objectives were developed to guide OG&E to the most robust portfolio

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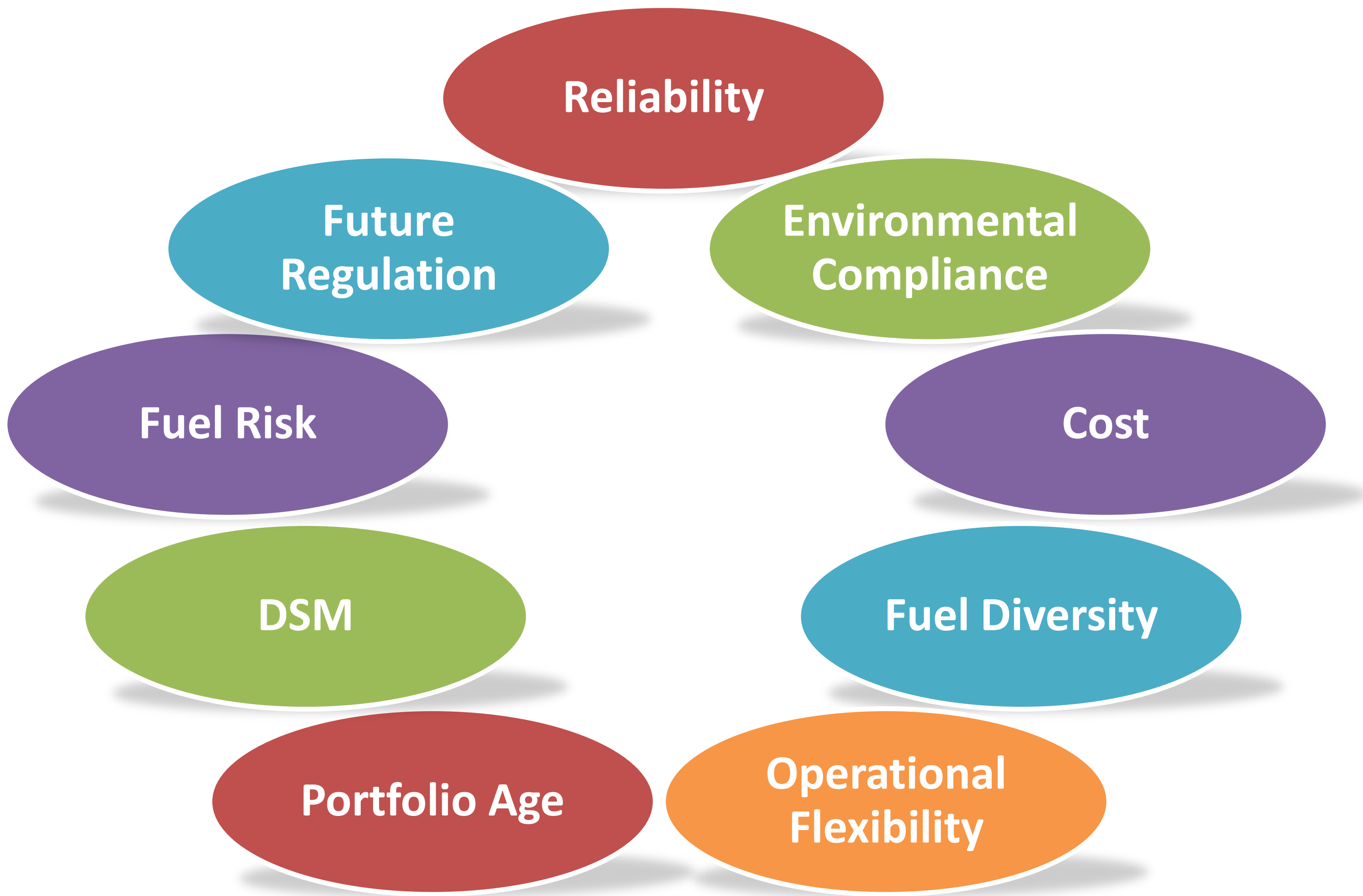

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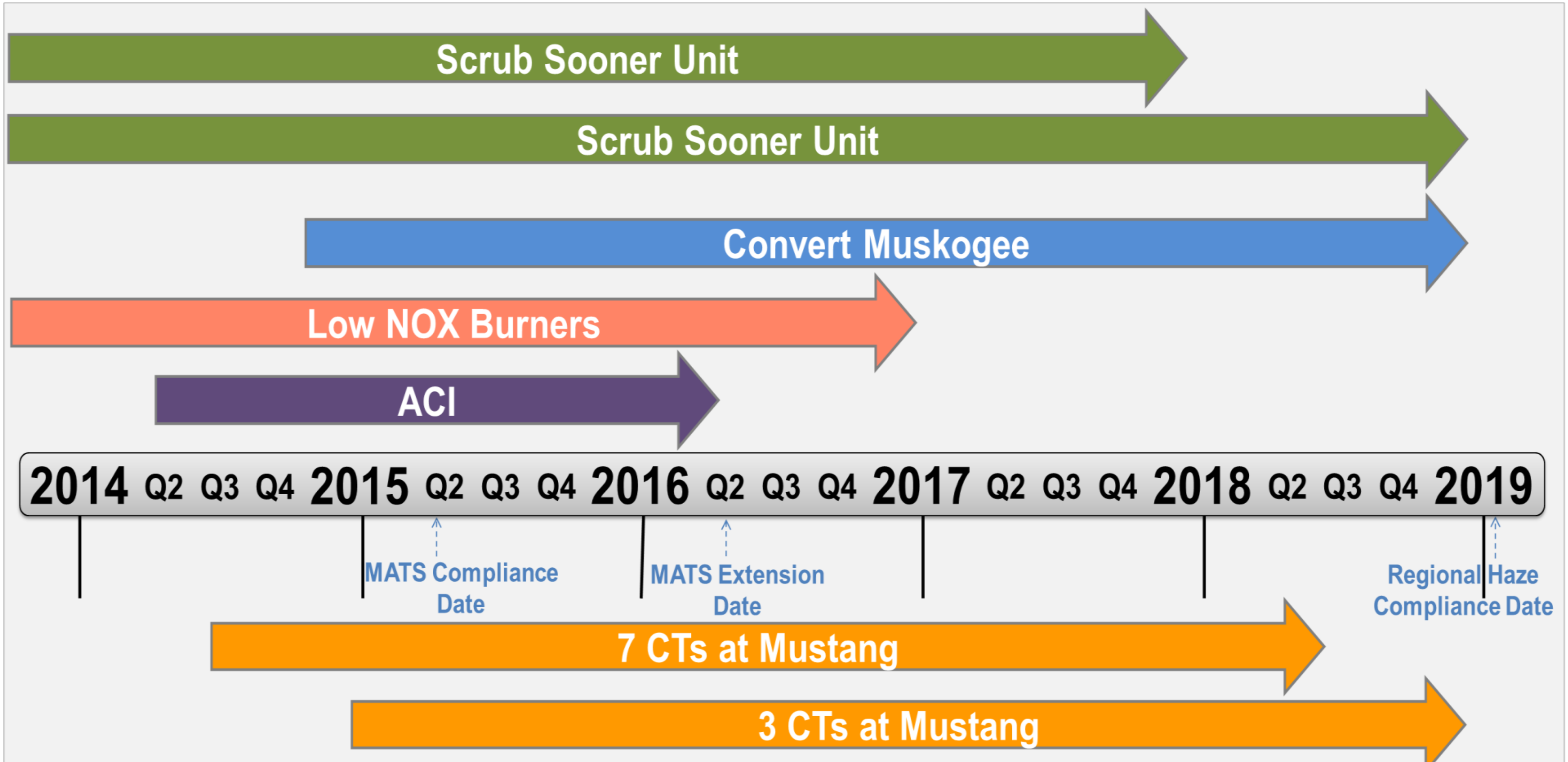
The 5 year Action Plan



Regional Haze compliance date is set 55 months from US Supreme Court decision. Clock restarted 5/29/2014 + 55 months = 1/4/2019.

Feedback