INTEGRATED RESOURCE PLAN

Oklahoma Gas & Electric

PREPARED 2024

OGE ENERGY CORP

OG&E submits this Integrated Resource Plan (IRP) in compliance with requirements established pursuant to the Oklahoma Corporation Commission's (OCC) Electric Utility Rules OAC 165:35-37 and the Arkansas Public Service Commission's (APSC) Resource Planning Guidelines for Electric Utilities.

EXECUTIVE SUMMARY

OG&E plans to meet future capacity needs through a balanced portfolio of solar resources and hydrogen-capable combustion turbines that provides affordable costs for customers while satisfying IRP objectives. OG&E will also seek market opportunities for immediate capacity needs.

Over the next five years, load growth, unit retirements, and changes in Resource Adequacy policy will result in the need for additional generation capacity to meet OG&E's planning reserve requirements. OG&E has significant generation capacity needs in the near term, as shown in the table below.

OG&E Planning Reserve Margin and Needed Capacity (MW unless noted)

	2024	2025	2026	2027	2028
Total Capacity	7,027	7,002	6,495	6,630	6,030
Net Demand	6,073	6,001	6,229	6,237	6,295
Reserve Margin	16%	17%	4%	6%	-4%
Needed Capacity*	0	0	556	431	1,096

**Indicates the capacity needed to meet planning reserve margin requirements.*

OG&E's prior IRP, prepared in 2021, demonstrated the projected need for additional capacity resources at that time. Since 2021, OG&E's capacity needs have grown further due to increased capacity requirements specified by the Southwest Power Pool (SPP) and load growth in the OG&E service area. Looking forward, the need for investment in generation resources could continue to grow as SPP further enhances policies addressing Resource Adequacy, electrification contributes to expanding load growth in the region, and environmental regulations change.

The IRP analysis contained in this report evaluates a range of potential generation portfolios to meet the capacity needs and determines a balanced portfolio of solar resources and combustion turbines is the preferred plan to satisfy expected capacity needs. This plan helps maintain system resiliency and reliability, advances fuel and technology diversity of the generation fleet, improves operational flexibility, is scalable, and expands OG&E's renewable generation portfolio. Adding zero-emitting technologies along with high-efficiency combustion turbines that enable and support renewable generation growth are important building blocks to meet expectations for cleaner energy in the future. Additionally, advances in combustion turbine technology are expected to further expand the capability to utilize hydrogen as a fuel, providing future emission and fuel diversity benefits.

OG&E's 2024 IRP is designed to meet existing environmental obligations while also considering future updates to environmental regulations and addressing, to the extent possible, uncertainties in the environmental regulatory landscape. In particular, OG&E's fleetwide compliance obligations under the recent Good Neighbor Plan, which revises the Cross State Air Pollution Rule (CSAPR) ozone-season Nitrogen Oxides (NOx) trading program for Electric Generating Units (EGUs), are uncertain due to pending litigation. Depending on the outcome of litigation, compliance may require a range of potential modifications to existing units and other necessary actions. OG&E retained the services of 1898 & Co., a part of Burns & McDonnell (1898 & Co.), to assist with the analysis and modeling of the 2024 IRP. OG&E and 1898 & Co. analyzed resource portfolios and various fleet-wide compliance plans consistent with the current understanding of this rule.

OG&E will issue a Request(s) for Proposals (RFP) for resources to meet the capacity requirements and other IRP objectives of the company and to seek future generation that increases efficiency, diversifies our fuel mix by advancing cleaner generation, and maintains affordability and reliability for OG&E's customers. OG&E will also continue to monitor environmental regulation developments, including those from litigation, and take actions if deemed necessary.

OG&E Action Plan

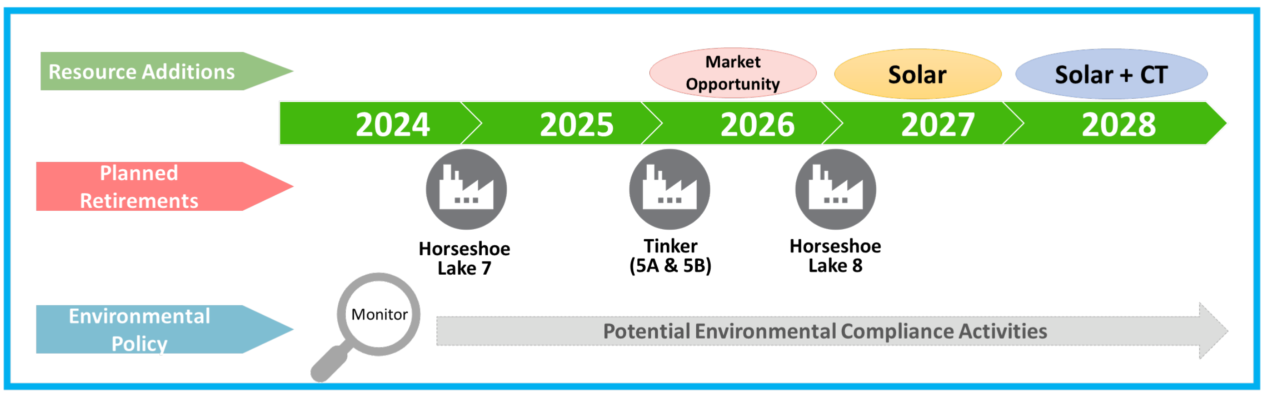


Table of Contents

List of Figures

List of Tables

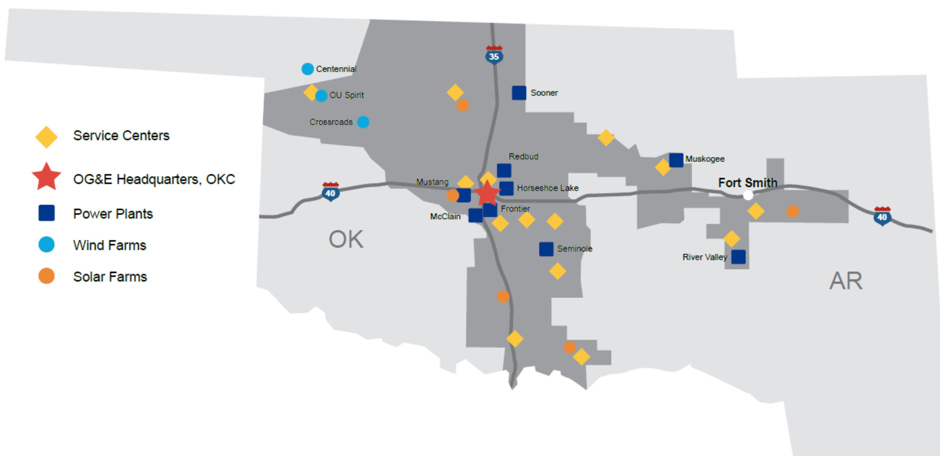
List of Acronyms

Acronym	Phrase Represented	Reference
APSC	Arkansas Public Service Commission	Agency
CAA	Clean Air Act	Environmental
CO_2	Carbon Dioxide	Environmental
CC	Combined Cycle electricity generating unit	Technology
CSAPR	Cross-State Air Pollution Rule	Environmental
CT	Combustion Turbine electricity generating unit	Technology
DSM	Demand Side Management	Industry
EGU	Electricity Generating Unit	Technology
ELCC	Effective Load Carrying Capacity	SPP
EIA	Energy Information Administration	Agency
EPA	U.S. Environmental Protection Agency	Agency
FERC	Federal Energy Regulatory Commission	Agency
FIP	Federal Implementation Plan	Environmental
IM	Integrated Marketplace	SPP
GHG	Greenhouse Gas	Environmental
HH	Henry Hub	Industry
ITP	Integrated Transmission Planning	SPP
IRP	Integrated Resource Plan	Industry
LMP	Locational Marginal Price	Industry
LOLE	Loss of Load Expectation	SPP
MATS	Mercury and Air Toxics Standards	Environmental
NAAQS	National Ambient Air Quality Standards	Environmental
NOx	Nitrogen Oxides	Environmental
NPVCC	Net Present Value of Customer Cost	OG&E
NREL	National Renewable Energy Laboratory	Agency
O&M	Operations & Maintenance	General
OCC	Oklahoma Corporation Commission	Agency
ODEQ	Oklahoma Department of Environmental Quality	Agency
OG&E	Oklahoma Gas & Electric	Agency
PBA	Performance Based Accreditation	SPP
PPA	Power Purchase Agreement	Industry
PRM	Planning Reserve Margin	SPP
RFP	Request for Proposal	General
RSC	Regional State Committee	SPP
SCR	Selective Catalytic Reduction	Industry
SIP	State Implementation Plan	Environmental
SMR	Small Modular Reactor	Technology
SNCR	Selective Non-Catalytic Reduction	Industry
SPP	Southwest Power Pool	SPP
STEP	SPP Transmission Expansion Plan	SPP

I. Introduction

OG&E was formed in 1902 and is Oklahoma's oldest and largest investor-owned electric utility. OG&E serves more than 894,000 customers in 267 towns and cities in an approximately 30,000 square mile area of Oklahoma and western Arkansas. OG&E's service area is shown in Figure 1.

Figure 1 – OG&E Service Area



This IRP Report and Appendices have been completed following the Oklahoma Corporation Commission (OCC) Electric Utility Rules and APSC Resource Planning Guidelines for Electric Utilities. Sections I – VII present the IRP objectives and process, assumptions, resource planning modeling and analysis, and five-year action plan. Section VIII concludes the report with the following schedules as prescribed 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, purchased power procurement, and risk management plans
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

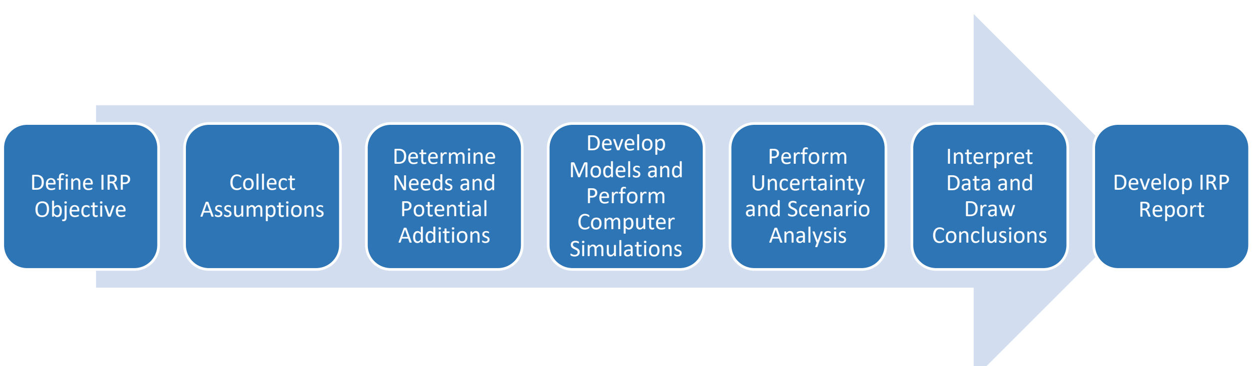
II. IRP Objectives and Process

OG&E strives to develop a resource plan that meets its capacity obligations in the most reasonable and affordable manner over the planning horizon while considering the uncertainties attributable to many of the planning assumptions and other items of value to OG&E customers. The objectives below are relied upon to identify the best future portfolio.

1. Capacity Obligation: satisfy Southwest Power Pool (SPP) Resource Adequacy Requirements to support reliability
2. Expected Cost to Customers: lowest reasonable Net Present Value of Customer Cost (NPVCC) subject to satisfying other IRP objectives
3. Exposure to Risks: consider the sensitivity of NPVCC related to risks that affect customer cost and benefits, including uncertain future prices of fuel and emissions, as well as other potential risks
4. Fuel and Technology Diversity: maintain a reasonable balance among technologies and fuel sources such as natural gas, renewable, coal, energy storage, and demand-side resources
5. Reliability and Resiliency Benefits: maintain generation capability and dispatchability to support SPP system reliability, respond to localized reliability issues, and minimize customer disruptions
6. Adaptability: Consider a range of capacity options with varying degrees of scalability and differing implementation timelines
7. Portfolio Age: maintain a reasonable balance of resources as measured by expected remaining asset life
8. Environmental Stewardship: consistent with OG&E's expectation to reduce CO_2 emissions by 2030

OG&E's seven-step Integrated Resource Planning process remains largely unchanged from previous IRPs and is illustrated in Figure 2.

Figure 2 – Integrated Resource Planning Seven Step Process



III. Current and Future Risks

There are a number of policy and operational risks facing OG&E that are emerging from a rapidly changing landscape. Although they vary in maturity and probability, each has the potential to require substantial investments in new or existing generation resources for the continued support of reliability and compliance. These risks, some of which are created by conflicting policies and regulations, make both compliance and execution timelines challenging and unclear.

III. A. Current Resource Adequacy Policy Risks

III. A. 1. Resource Adequacy Policy Risk Overview

As a member of SPP, OG&E is required to comply with a range of policies and regulations specified by SPP's Open Access Transmission Tariff (OATT), Business Practices, Operating Criteria, and Planning Criteria. Since OG&E's last IRP, SPP has been developing new policies to enhance Resource Adequacy in its footprint. As the Regional Balancing Authority, SPP is required by the Federal Energy Regulatory Commission (FERC) to balance electric supply and demand, ensuring there is sufficient generation to reliably meet the demand for electricity within its region. Two of the most important factors to determining needed capacity are the Planning Reserve Margin (PRM) level set by SPP and the capacity accreditation of resources. SPP is planning changes to both of these important factors within the next three years. These policy changes have been incorporated into the Expected Future Case analysis for this IRP due to their advanced stage of development.

III. A. 1. a) Expected Change to the SPP Planning Reserve Margin (PRM)

SPP performs a biennial study to project the generation needed to reliably serve load. The preliminary results of the most recent study recommend a range of potential increases to the PRM, which are being further evaluated through the SPP stakeholder process. All Load Responsible Entities (LREs) in SPP, including OG&E, are required to maintain generation capacity equal to their forecasted seasonal Net Peak Demand plus the seasonal PRM requirement. SPP's PRM was increased from 12% to 15% starting in the summer of 2023, based on the prior biennial study. In this 2024 IRP, OG&E has assumed an additional incremental increase in the PRM based on the latest study results, which showed summer PRM values ranging from 16% to 21% for studied summer seasons. Details on assumptions are discussed in Section IV.

III. A. 1. b) SPP Resource Accreditation Methodologies

SPP policy changes in this section affect the capacity accreditation of all thermal and renewable generation resources in SPP. SPP will seek FERC approval of these policies in 2024 and plans to make them effective in 2026. Implementation of these policies could further impact OG&E capacity needs.

III. A. 1. b) (i) Performance Based Accreditation (PBA) for conventional resources

SPP's Regional State Committee (RSC) and Board of Directors approved the PBA policy[1] in October 2023. This policy was submitted toFERC for approval on February 23, 2024. With this policy, generating resources will be required to perform periodic capability tests, just as they are currently, then SPP will adjust the accredited capacity of each thermal generation resource by the unit's historical performance. Although, the net impact of PBA on OG&E's capacity position is not known with clarity. OG&E believes implementation of the PBA policy will result in an increase to OG&E's generation capacity needs. In this 2024 IRP, OG&E has assumed PBA is implemented as planned in 2026. Specific details on assumptions are discussed in Section IV.

III. A. 1. b) (ii) Effective Load Carrying Capability (ELCC) for renewable resources

In October 2023, SPP's RSC and Board of Directors approved the ELCC policy, which will utilize annual ELCC studies to calculate the accredited capacity of renewable resources within SPP, based on the amount of incremental load these resources can reliably serve. SPP projects that, as more renewable resources come onto the SPP system, the percentage of accredited capacity compared to nameplate capacity of renewable resources will decrease[2]. The ELCC policy also requires approval by FERC. In this 2024 IRP, OG&E has assumed ELCC is implemented as planned in 2026. Specific details on assumptions are discussed in Section IV.

III. B. Future Resource Adequacy Policy Risks

Future Policy Risks identified in this section are not currently incorporated into the analysis in this IRP, however, these policies have the potential to further expand capacity needs or other investments in OG&E's generation fleet.

III. B. 1. Winter Resource Adequacy Requirement

SPP's RSC and Board of Directors has approved policy implementing a Resource Adequacy Requirement (RAR) similar to the Summer RAR, which would require deficiency payments for non-compliance. OG&E's winter peak demand is substantially below its summer peak demand, therefore, a Winter PRM equal to the Summer PRM does not increase total generation capacity needs. SPP filed the Winter RAR policy with FERC on September 8, 2023[3] and it was rejected on November 30, 2023[4]. With the rejection, FERC recommended SPP prioritize the development of a robust Winter Resource Adequacy requirement. SPP has begun studying the winter season specifically to determine the appropriate Winter PRM. Initial study results indicate the Winter PRM

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[1] https://www.spp.org/Documents/69255/RR554.zip

[2] SPP (2019), *Solar and Wind ELCC Accreditation*, https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf

[3] SPP (2023), *Submission of Tariff Revisions to attachment AA to Add the Winter Season Resource Adequacy Requirement*, https://www.spp.org/documents/70094/20230908_revisions%20to%20add%20winter%20season%20resource%20adequacy%20requirement_er23-2781-000.pdf

[4] FERC (2023), *Order Rejecting Tariff Revisions re Southwest Power Pool, Inc. under ER23-2781*, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231130-3093&optimized=false

could be set higher than the Summer PRM and could result in incremental capacity needs for OG&E, as well as for other SPP members.

III. B. 2. Demand Response Program Accreditation

SPP's RSC and Board of Directors approved a policy in October 2023 that is expected to lead to adjustments in the capacity accreditation for Demand Response programs in SPP. SPP Staff and members are currently developing detailed tariff revisions. OG&E's current Load Reduction Program is tested annually and is considered a reduction to the peak load forecast for Resource Adequacy planning purposes. OG&E will continue to participate in tariff language development discussions related to the details of this policy.

III. B. 3. Fuel Assurance Policy

Fuel Assurance policy is being developed by SPP with a focus on fuel security during critical periods in SPP. The precise impacts of this policy have not been fully developed, however, SPP is currently evaluating additional impacts to accreditation in order to address this.

III. B. 4. Ramping Capability Requirement

SPP is developing a potential requirement for LREs to maintain a certain level of rampable, or dispatchable, capacity to reliably serve load under fast changing conditions.

III. C. Environmental Compliance Risk

OG&E's electric generation is 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.

Both existing and potential future environmental regulations can impact OG&E's resource plan. OG&E analyzes final environmental regulations as part of its IRP process. OG&E's 2024 IRP is designed to meet the existing environmental obligations while also recognizing future potential environmental regulations. For instance, OG&E's fleetwide compliance obligations under the recent Good Neighbor Plan, which revises the Cross State Air Pollution Rule (CSAPR) for Electric Generating Units (EGUs), are uncertain due to ongoing litigation. Depending on the outcome of litigation, compliance may require a range of potential modifications to existing units and other necessary actions. While the Good Neighbor Plan is not currently in effect for Oklahoma EGUs, the OCC approved a stipulation in OG&E's 2021 Rate Case Final Order (Cause No. PUD 202100164) requiring OG&E to include analysis of the potential impacts of revisions to the CSAPR rule. In accordance with this stipulation, this IRP evaluates various resource portfolios consistent with fleet-wide compliance under the current understanding of the rule.

III. C. 1. Compliance with Current Environmental Regulations

As noted, past IRPs have included important planning elements related to imminent compliance obligations for final federal environmental regulations such as the Mercury and Air Toxics Standards (MATS) and Regional Haze rules. OG&E has complied with these requirements by installing emission control equipment and converting two coal-fired generating units at the Muskogee Power Plant to natural gas, among other measures. OG&E's operations are in substantial compliance with current federal, state, and local environmental standards.

III. C. 2. Potential Environmental Compliance Risk

Environmental regulations are expected to become increasingly stringent, requiring increased expenditures for installing and operating control equipment and to monitor and report compliance. The current administration has targeted a 50 to 52 percent reduction in economy wide net greenhouse gas emissions from 2005 levels by 2030 with full decarbonization of the electric power industry by 2035. Many new, upcoming or potential requirements are focused on coal-fired generation.

OG&E has identified several proposed or anticipated environmental rules and actions by the Environmental Protection Agency (EPA) that, if implemented, could affect OG&E's generation portfolio, including: (i) revisions to the CSAPR program for EGUs; (ii) proposed revisions to the MATS rule; (iii) proposed Effluent Limitation Guidelines under the Federal Clean Water Act; (iv) proposed standards for greenhouse gas emissions from new and existing power plants; (v) anticipated adoption of more stringent standards for pollutants covered by the National Ambient Air Quality Standards (NAAQS); and (vi) review of Oklahoma's State Implementation Plan (SIP), submitted in August 2022, addressing Regional Haze requirements under Section 169A of the Clean Air Act (CAA) for the second planning period. ("A State Implementation Plan (SIP) is a collection of regulations and documents used by a state, territory, or local air district to implement, maintain, and enforce the National Ambient Air Quality Standards, or NAAQS, and to fulfill other requirements of the Clean Air Act."[5])

III. C. 2. a) CAA Good Neighbor Provision and CSAPR

The EPA revised the NAAQS for ozone in 2015. Section 110(a)(2)(D) of the CAA requires states to submit SIPs for addressing interstate transport of pollutants by prohibiting in-state ozone sources from contributing significantly to nonattainment or interfering with maintenance of the ozone NAAQS in another state. In accordance with this mandate, Oklahoma submitted a SIP addressing these "Good Neighbor" requirements on October 28, 2018. On January 31, 2023, the EPA disapproved in whole or in part the SIPs of 21 states, including Oklahoma. In March 2023, the Oklahoma Attorney General and the Oklahoma Department of Environmental Quality (ODEQ)—joined by several industry petitioners, including OG&E—filed suits challenging the EPA's SIP disapproval for Oklahoma in the U.S. Court of Appeals for the Tenth Circuit (Tenth Circuit). On June 6, 2023, OG&E and the other Oklahoma petitioners jointly filed a motion with the Tenth

[5] *"About Air Quality Implementation Plans,"* United State Environmental Protection Agency, https://www.epa.gov/air-quality-implementation-plans/about-air-quality-implementation-plans

Circuit requesting a stay of the Oklahoma SIP disapproval. The Tenth Circuit granted the stay on July 27, 2023. On February 27, 2024, the Tenth Circuit issued a decision transferring the challenges of the Oklahoma SIP disapproval to the D.C. Circuit court but did not vacate the Tenth Circuit's stay of the disapproval granted on July 27, 2023.

After disapproving the Oklahoma SIP, the EPA finalized a Federal Implementation Plan (FIP) addressing the "Good Neighbor" requirements for Oklahoma, and 22 other states. ("A Federal Implementation Plan (FIP) is an air quality plan developed by EPA under certain circumstances to help states or tribes attain and/or maintain the National Ambient Air Quality Standards (NAAQS) for criteria air pollutants and fulfill other requirements of the Clean Air Act."[6]) The June 5, 2023 FIP includes revisions to the CSAPR ozone-season NOx trading program for EGUs. These changes would result in a revision to the Oklahoma NOx emissions budget for EGUs, including OG&E's units, beginning in May 2023. Under the terms of the FIP, the emissions budget will decline over time based on the level of reductions the EPA has determined is achievable through particular emissions controls. The EPA has published unit-level allowance allocations for the 2023, 2024, and 2025 ozone seasons; starting in 2026, unit-level allowances will be determined based on the rolling average heat input for the previous three years, capped by maximum ozone emissions (referred to as dynamic budgeting).[7] The FIP also moderates the ability to bank unused allowances. While there is inherent uncertainty in determining the quantity of emission allowances OG&E units will receive after 2025 or the availability of allowances in the market, OG&E anticipates that all future (i.e., new) and existing thermal resources will likely require a high level of emission control with equipment such as Selective Catalytic Reduction (SCR).

After the EPA finalized the FIP, OG&E began evaluating various control strategies to reduce emissions at its generating units. Compliance strategies can range from some combination of installation of selective catalytic reduction or selective non-catalytic reduction controls, conversion of coal-fired units to gas-fired units along with installation of SCRs, retirement and replacement of coal-fired generating resources, or purchase of emission allowances,

On July 7, 2023, the Attorney General of Oklahoma and other petitioners filed a motion with the Tenth Circuit to stay EPA's Final FIP for Oklahoma. Subsequently, on July 27, 2023, the Tenth Circuit granted a stay of EPA's SIP Disapproval for Oklahoma in a related challenge. After the court granted this stay, EPA no longer had authority to enforce the FIP in Oklahoma. Therefore, on July 31, 2023, the petitioners filed a joint, unopposed motion requesting that the court abate further proceedings regarding the FIP pending resolution of the Oklahoma SIP disapproval challenges. The court granted this motion

[6] *Ibid.*

[7] Unit-level allowances are allocated based on an overall state-wide allowance budget for each covered state. State budgets are predetermined for the 2023-2025 ozone seasons, using heat input data and known fleet changes at the time the FIP was finalized. Starting in 2026, EPA will also calculate state budgets using dynamic budgeting, based on a rolling average heat input for covered EGUs within each state. For the 2026 – 2029 ozone seasons, the FIP established a pre-set allowance floor for state budgets which could potentially be increased by dynamic budgeting. After the 2029 ozone season there will be no pre-set allowance floor and annual allowance allocations will be determined solely by dynamic budgeting.

on August 2, 2023. The petitioners will be required to notify the court within five days after the SIP disapproval challenge is resolved. EPA issued an Interim Final Rule on September 29, 2023, that prevents its FIP from going into effect in Oklahoma. Enforcement of the FIP will remain stayed until after the SIP disapproval challenge is resolved.

III. C. 2. b) Mercury and Air Toxics Standards (MATS)

On April 24, 2023, the EPA published a proposed revision to the MATS rule in the Federal Register. The proposed rule included an updated technology review and would change certain emission standards and compliance measures for the coal- and oil-fired EGU source category, including lowering the emission limit for filterable particulate matter (fPM), requiring the use of continuous emissions monitoring systems to demonstrate compliance with the filterable particulate matter standard, and lowering the mercury emission limit for lignite-fired EGUs. EPA has indicated it anticipates publishing a final rule by April 2024. It is unknown what potential impacts to OG&E, if any, will result from this action by the EPA.

III. C. 2. c) Federal Clean Water Act

On March 29, 2023, the EPA published a proposed rule to revise the effluent limitation guidelines for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. The proposed rule would prohibit any discharge from bottom ash transport water systems and has a compliance date of December 31, 2029. OG&E is installing dry bottom ash handling technology that will comply with the rule.

III. C. 2. d) Greenhouse Gas (GHG) Regulations

On May 23, 2023, the EPA proposed several actions to address greenhouse gas emissions from fossil fuel-fired electric generating units under Clean Air Act Section 111. The proposal encompasses both Section 111(b) and 111(d) rulemakings for new units and existing units, respectively. In particular, the proposed rules would (i) strengthen the current New Source Performance Standards for newly built, modified, or reconstructed fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establish emission guidelines for states to follow in limiting carbon pollution from existing fossil fuel-fired steam electric generating units (including coal and natural gas-fired units); and (iii) establish emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired). Among other emission reduction measures, EPA proposed the following requirements for certain classes of new and existing units beginning as early as 2030: capacity factor limitations; the use of carbon capture, utilization and storage systems; and/or the combustion of fuel comprised of hydrogen blended with natural gas. EPA has indicated it anticipates finalizing the regulations in April 2024. At this point, it is unknown what the outcome will be from the final action by the EPA.

III. C. 2. e) More Stringent National Ambient Air Quality Standards (NAAQS)

The CAA requires EPA to set NAAQS for six “criteria” pollutants, which are designed to be protective of human health and the environment. EPA must review each NAAQS every five years, and revise the NAAQS as needed. Based on these reviews, EPA has periodically taken action to adopt more stringent NAAQS for criteria pollutants including ozone and PM. EPA then sets an attainment deadline for states to comply with the NAAQS and make air quality designations for areas in each state based on whether they are attaining the NAAQS for a particular pollutant. Emission sources in areas that have been designated as nonattainment may be required to install additional controls to help the state attain the NAAQS.

As of the end of 2023, no areas of Oklahoma were designated as non-attainment for pollutants likely to affect OG&E's operations. However, in recent years, monitored ozone levels in Oklahoma have been close to a NAAQS exceedance level; ambient monitoring data for NAAQS pollutants is reviewed each year and evaluated against the standard that is currently in effect.

In August 2023, EPA began a review of the ozone NAAQS. EPA has indicated it intends to complete this review as expeditiously as possible. It is unknown at this time what, if any, potential impacts to OG&E may result from final EPA actions.

On February 7, 2024, the EPA issued a final rule resulting from its reconsideration of the primary (health-based) and secondary (welfare-based) NAAQS for PM. The final rule lowers the primary annual PM2.5 NAAQS from 12.0 $\mu g/m^3$ to 9.0 $\mu g/m^3$. The final rule retains the other PM standards at their current levels, including the 24-hour PM2.5 NAAQS. Within two years of the effective date of the rule, ODEQ will evaluate attainment with the revised standard and EPA will then make attainment designations for areas in Oklahoma. If an area in Oklahoma is not in attainment, ODEQ will develop and submit attainment plans no later than 18 months after the EPA finalizes the designation. It is unknown at this time what, if any, potential impacts to OG&E may result from final EPA actions.

III. C. 2. f) Future Requirements under Regional Haze

Section 169A of the Clean Air Act sets a national goal of eliminating anthropogenic impairment of visibility in Class I Federal Areas by 2064. Under the Regional Haze Rule, states are required to develop a SIP for each of several planning periods before the 2064 deadline, assessing sources of visibility impairment and potential controls.

Oklahoma submitted a Regional Haze SIP for the second planning period to the EPA on August 9, 2022, which EPA deemed administratively complete on August 18, 2022. EPA is currently reviewing Oklahoma’s SIP. When review of the SIP is completed, EPA will issue a proposed approval or disapproval, which will be available for public comment before being finalized. EPA may call for additional reductions of emissions affecting visibility from sources that were previously regulated or may require reductions from additional sources, beyond those regulated in the first planning period. However, the additional impact on OG&E, if any, cannot be determined until EPA’s review of the Oklahoma SIP is final. A response from the EPA is expected in 2024.

III. C. 2. g) Endangered Species Act (ESA) and other Federal Laws

Certain federal laws, including the ESA, 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 areas in which OG&E conducts operations or if additional species in those areas become subject to protection, OG&E's operations and development projects could be restricted, delayed, or be required to implement mitigation measures.

IV. Assumptions

OG&E's resource planning process includes collecting information regarding material assumptions used in the modeling and analysis of potential resource additions.

IV. A. Load Forecast

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. The peak demand forecast relies on an hourly econometric model. Historical and forecast weather-adjusted retail energy sales are the main driver for the peak demand forecast projections. The peak demand forecast is reduced by planned OG&E Demand Side Management (DSM) programs to determine the net demand used for planning purposes. Energy and Peak Demand forecasts are provided in Table 1 and Table 2.

Table 1 – Energy Forecast (GWh)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Forecast[8]	34,133	35,905	39,768	40,472	41,382	42,307	43,249	44,641	46,087	47,585	47,823
OG&E DSM[9]	185	371	468	565	678	789	889	988	1,094	1,319	1,184
Net Energy	33,947	35,534	39,300	39,908	40,703	41,518	42,360	43,653	44,993	46,266	46,639

Table 2 – Peak Demand Forecast (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Demand Forecast[8]	6,632	6,754	7,217	7,264	7,343	7,403	7,497	7,623	7,755	7,861	7,917
OG&E DSM[9]	559	753	988	1,027	1,049	1,074	1,098	1,119	1,141	1,159	1,160
Net Demand	6,073	6,001	6,229	6,237	6,295	6,330	6,400	6,504	6,614	6,701	6,757

The baseline Energy and Demand Forecasts include the impacts of historical programs such as Energy Efficiency and the SmartHours Program. Historically, OG&E's Energy Efficiency programs in Oklahoma and Arkansas have achieved between 30 MW and 40 MW of incremental demand reduction each year. The SmartHours Program integrates technology and pricing to help customers reduce energy usage at peak times. Customers respond to price signals between the non-holiday weekday hours of 2:00 p.m. and 7:00 p.m. over the summer months to help reduce the peak demand on the system by approximately 90 MW and is expected to grow to over 140 MWs.

OG&E DSM programs are shown in the energy and peak demand forecast tables (Table 1 and Table 2). On top of the significant strides made in historical Energy Efficiency and Demand Response programs, OG&E forecasts additional incremental program growth in

[8] Includes SmartHours and Historical Energy Efficiency programs.
[9] Represents estimates for incremental Energy Efficiency programs in Oklahoma and Arkansas, incremental growth of SmartHours, and the Load Reduction Program.

the future, which demonstrates its ongoing commitment to engaging customers to reduce energy and demand requirements. OG&E's Energy Efficiency programs in Oklahoma and Arkansas include, but are not limited to, efforts to improve weatherization, lighting, heating, ventilation, and air conditioning systems. OG&E's Energy Efficiency programs are projected to add nearly 40 MW of demand reduction each year. OG&E's Load Reduction Rider offers rate incentives to commercial and industrial customers that can reduce their electrical load when notified by OG&E, which offsets some capacity needs. Table 1 and Table 2 include significant forecasted growth in OG&E's Load Reduction Rider program.

IV. B. Planning Reserve Margin

For purposes of this IRP, OG&E has estimated the PRM will be 18% starting in the summer of 2026 and the revised resource accreditation policies described in Section III. A. 1. b) will also be in place in 2026. The assumed PRM is based on SPP study results that show a range of potential increases to the PRM ranging from 16% to 21% between years 2026 and 2029. The 18% PRM estimate serves to develop capacity needs consistent with a change to the PRM and implementation of other SPP Resource Adequacy policies that are still in development. Section III. A. 1. a) of this report provides a description of study and policy development.

IV. C. Generation Resources

OG&E is obligated to satisfy SPP Resource Adequacy Requirements by maintaining capacity sufficient to serve its peak load plus a planning reserve. This is accomplished through OG&E-owned generation, power purchase agreements (PPAs), and if necessary, potential new resources.

IV. C. 1. Existing Resources

OG&E's existing portfolio of electric generating facilities consists of owned thermal generation, owned renewable resources and PPAs, shown in Table 3 through Table 6.

Table 3 – OG&E Existing Thermal Resources

Unit Type	Unit Name	First Year In Service	Summer Capability (MW)
Gas-Fired Steam (3,085 MW)	Horseshoe Lake 7	1963	211
	Horseshoe Lake 8	1969	375
	Seminole 1	1971	500
	Seminole 2	1973	513
	Seminole 3	1975	509
	Muskogee 4	1977	489
	Muskogee 5	1978	488
Combined Cycle (1,111 MW)	Frontier	1989	121
	McClain[10]	2001	373
	Redbud[10]	2004	617
Combustion Turbine (552 MW)	Tinker (Mustang 5A)	1971	33
	Tinker (Mustang 5B)	1971	31
	Horseshoe Lake 9	2000	45
	Horseshoe Lake 10	2000	43
	Mustang 6	2018	57
	Mustang 7	2018	56
	Mustang 8	2018	58
	Mustang 9	2018	57
	Mustang 10	2018	57
	Mustang 11	2018	58
	Mustang 12	2018	57
Coal-Fired Steam (1,878 MW)	Sooner 1	1979	516
	Sooner 2	1980	520
	Muskogee 6	1984	521
	River Valley[11]	1990	321

Table 4 – OG&E Existing Renewable Resources

Unit Type	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capability (MW)
Wind (61 MW)	Centennial	2006	120	19
	OU Spirit	2009	101	9
	Crossroads	2012	228	33
Solar (22 MW)	Mustang	2015	3	2
	Covington	2018	9	8
	Chickasaw Nation	2020	5	4
	Choctaw Nation	2020	5	4
	Butterfield	2022	5	2
	Branch	2021	5	3

[10] Represents OG&E owned interest: 77% of McClain and 51% of Redbud.
[11] River Valley is primarily a coal-fired steam unit but can also utilize natural gas and tire-derived fuel in the combustion process.

Table 5 – Existing Power Purchase Agreements

	Unit Name	Contract Start date	Nameplate Capacity (MW)	Summer Capability (MW)
Power Purchase (55 MW)	Keenan	2010	152	22
	Taloga	2011	130	14
	Blackwell	2012	60	12
	Southwestern Power Administration	1979	7	7

In early 2023, OG&E conducted an RFP for Bridge Capacity. As a result of that RFP, the Company secured agreements for generation capacity over the summer months (June – September) of the years 2024, 2025, 2026, and 2027. The Bridge Capacity agreements were put in place to address near-term capacity requirements.

Table 6 – Existing Capacity Purchase Agreements

Agreement Type	Name	Contract Year	Summer Capability (MW)
Capacity Purchase	Bridge Capacity	2024	450
	Bridge Capacity	2025	450
	Bridge Capacity	2026	600
	Bridge Capacity	2027	600

IV. C. 2. Resource Changes in the Ten-Year Planning Horizon

Eight units in OG&E's owned generation resource fleet are planned for retirement over the next 10 years. In addition, two wind PPAs will expire before 2032.

IV. C. 2. a) Resource Retirements and Contract Expirations

IV. C. 2. a) (i) Horseshoe Lake Retirements

Horseshoe Lake Unit 6 was a 170 MW natural gas-fired steam turbine unit originally commissioned in 1958. Unit 6 was the oldest unit in OG&E's current generation fleet and depreciation studies prepared for OG&E have shown probable retirement dates for Horseshoe Lake 6 as early as 2013. The 2022 EIA-860[12] shows that similarly sized natural gas-fired steam generators have reached retirement after an average of 54 years of operation. OG&E ceased operation of Horseshoe Lake unit 6, as planned, at the end of 2023, after 65 years of operation.

Horseshoe Lake Unit 7 was originally commissioned in 1963 as an early combined cycle unit with a gas turbine and a natural gas-fired steam turbine. Unit 7's 26 MW gas turbine retired in 2015. OG&E maintained the remaining 211 MW steam unit without the legacy gas turbine. Previous depreciation studies have shown Horseshoe Lake unit 7's probable retirement date as early as 2019. The 2022 EIA-860 shows that similarly sized natural

[12] EIA. (2023). 2022 EIA-860 3_1_Generator_Y2022.xlsx. U.S. Energy Information Administration (EIA). https://www.eia.gov/electricity/data/eia860/xls/eia8602022.zip

gas-fired steam generators have reached retirement after an average of 54 years of operation. Horseshoe Lake Unit 7 is planned for retirement at the end of 2024.

Horseshoe Lake Unit 8 is a 375 MW natural gas-fired steam turbine unit originally commissioned in 1969. Previous depreciation studies have shown a probable retirement date as early as 2024. The 2022 EIA-860 shows that similarly sized natural gas-fired steam generators have reached retirement after an average of 45 years of operation. OG&E plans to retire Horseshoe Lake unit 8 in 2027, after 58 years.

IV. C. 2. a) (ii) Tinker Retirements

Mustang Units 5A and 5B are two aero-derivative simple-cycle combustion turbines (CTs) that were originally installed at OG&E's Mustang power plant site in 1971. In 1990, OG&E moved these two units to Tinker Air Force Base. These units have a net capacity of approximately 64 MW and support all customers while providing islanding and resiliency benefits to Tinker. Previous depreciation studies have shown a probable retirement date as early as 2018 for the Tinker units. The 2022 EIA-860 shows that other natural gas-fired simple cycle combustion turbines in the United States have reached retirement after an average of 38 years of operation. The two units located at Tinker are planned to be retired in late 2025 or early 2026 after 54 years of service.

IV. C. 2. a) (iii) Seminole Retirements

Seminole Units 1, 2 and 3 are natural gas-fired steam generators located at the Seminole power plant in Konawa, Oklahoma. These units were placed in service in the early to mid-1970s. Previous depreciation studies showed these three units' probable retirement dates in 2030. The 2022 EIA-860 shows that similarly sized natural gas-fired steam generators in the United States have historically been retired after an average of 42 years of operation. OG&E currently anticipates retiring Seminole Units 1, 2, and 3 at the end of 2030, 2032, and 2034, respectively, after each unit achieves 59 years of service. The three Seminole units represent approximately 1,500 MWs of OG&E's current generating capacity.

IV. C. 2. a) (iv) Owned Wind Retirements

OG&E's Centennial Wind farm was commissioned in 2006 and is scheduled for retirement in late 2031, after 25 years of service to OG&E's customers. OG&E is exploring alternatives to retirement, including potential repower and life extension.

IV. C. 2. a) (v) Wind Purchase Power Agreements

OG&E entered into 20-year PPAs with the Keenan and Taloga Wind facilities starting in 2010 and 2011, respectively. Those agreements are expected to end on schedule in 2030 and 2031. The Blackwell Wind 20-year PPA began in 2012 and will end in 2032.

IV. C. 2. b) Planned Resource Additions

IV. C. 2. b) (i) Horseshoe Lake

Horseshoe Lake Units 11 and 12 are planned to go into service in late 2026. These units include two identical GE 7FA.05 natural gas-fired combustion turbines selected from

OG&E's 2022 Flexible Resource RFP. Horseshoe Lake Units 11 and 12 were unanimously approved by OCC in Order number 738566 in Cause number PUD2023-00038 in October 2023. They will bring a total of 448 MW of accredited capacity, quick starting capability, modernization, and improved reliability to OG&E's generation fleet.

IV. C. 2. b) (ii) Tinker

Tinker units 1 and 2 will be located at Tinker Air Force Base and are planned to go into service in 2026. The Tinker Air Force Base site is close to Oklahoma City, OG&E's largest load center. The proximity to the load center reduces the effect of congestion on the transmission system and provides reliable energy to all OG&E's retail customers. The new Tinker CT units will have the ability to be turned on and off quickly, which allows them to supply power during peak times, to serve changing demand in real-time, and to supply ancillary services to the grid.

The new units are two identical 48 nameplate MW GE LM6000 natural gas-fired combustion turbines. They will bring a total of 88 MW of accredited capacity, quick starting capability, modernization, and improved reliability to OG&E's generation fleet and will be hydrogen capable. The units will not only address part of OG&E's overall capacity need, but they will also be able to be dispatched by SPP to serve all customers and will provide the added benefit of providing islanding and resiliency benefits to Tinker Air Force Base, in the event of a national security emergency.

The new Tinker CTs are aligned with the preferred plan from OG&E's 2021 IRP, which included detailed analysis of different generating technologies and their costs and risks.

IV. C. 3. Future Resource Options

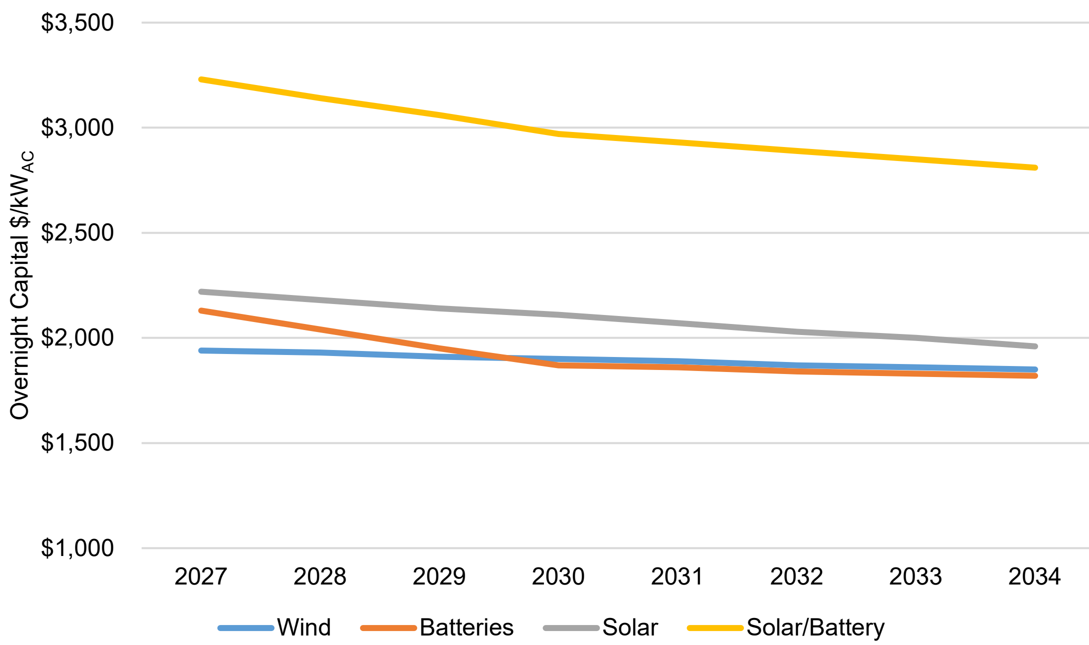
OG&E contracted with the engineering firm Burns & McDonnell to provide cost and performance estimates for Combined Cycle (CC), simple cycle technologies like Combustion Turbines (CT) and Reciprocating Internal Combustion Engines (RICE), Solar, Wind, Battery Storage, and Small Modular Reactor (SMR). Potential additional resource options evaluated are shown in Table 7.

Table 7 – Resource Options in 2023$

Technology	Model	Nameplate Capacity (MW)	Up-front Capital Cost ($/kW)	Summer Capability (MW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)
Wind	Land-Based	250	$1,940	50	$42.40	N/A
Batteries	Lithium Ion	100	$2,130	100	$30.00	N/A
Solar	Photovoltaic Single Axis	150	$2,220	90	$17.40	N/A
Solar/Battery Combo	Single Axis/Lithium Ion	150	$3,230	150	$36.00	N/A
RICE	Reciprocating Engine 3x	55	$1,800	55	$15.40	$4.60
	Reciprocating Engine 6x	110	$1,420	110	$15.10	$4.60
CT Aero	1x LM2500 SCGT	32	$3,200	29	$9.10	$1.70
	12x LM2500 SCGT	389	$2,660	352	$9.20	$1.70
	1x LM6000 SCGT	54	$2,190	50	$5.60	$1.40
	8x LM6000 SCGT	428	$1,870	399	$5.30	$1.40
	1x LMS100 SCGT	102	$2,200	87	$3.10	$1.20
	4x LMS100 SCGT	406	$1,940	347	$3.90	$1.20
CT Frame	1x "E" Class SCGT	86	$2,030	78	$7.50	$7.50
	1x "F" Class SCGT	221	$1,130	211	$3.30	$2.10
	1x "G/H" Class SCGT	280	$930	264	$3.70	$2.20
Combined Cycle (CC)	1x1 J Class	531	$1,180	503	$4.10	$1.50
	1x1 J Class Duct Fired	637	$990	613	$4.10	$2.30
	2x1 G/H Class Duct Fired	1001	$870	944	$2.90	$2.30
	2x1 F Class	729	$1,130	662	$2.70	$1.50
	2x1 F Class Duct Fired	880	$960	828	$2.80	$2.30
	1x1 F Class Duct Fired	441	$1,250	411	$4.90	$2.40
Nuclear	Small Modular Reactor (SMR)	320	$11,720	320	$234.40	Unknown

Capital costs for renewable resources have risen in recent years, however, they are expected to decline modestly over the next decade due to expected improvements in technology. OG&E utilized National Renewable Energy Laboratory (NREL)[13] price projections to develop an estimated price reduction curve for wind, solar and battery resources in the IRP, which is shown in Figure 3.

Figure 3 – Renewables Nameplate Overnight Cost Projections in 2023$ (\$/kW$_{AC}$)



IV. C. 4. Resource Location Considerations

SPP's long-term Integrated Transmission Planning (ITP) assessment[14] anticipates continued growth in renewable energy resources throughout the SPP system. Additionally, SPP's ITP model assumes retiring thermal generators are primarily replaced by combustion turbines at existing generation sites to meet resource adequacy requirements. Existing generation facilities can provide opportunities for re-development of new generation by providing benefits such as land, water rights, and emission permits. Also, these facilities are already strategically connected to the existing electric transmission infrastructure which can minimize both cost and time required to connect to the SPP transmission system. OG&E utilized these opportunities for the future Horseshoe Lake and Tinker Units. Other OG&E sites also have the potential to provide these re-development opportunities. Additionally, locations near OG&E's load centers offer opportunities to maintain the locational reliability these sites have provided to

[13] NREL. (2023). *Electricity annual Technology Baseline data download*. NREL. https://atb.nrel.gov/electricity/2023/data

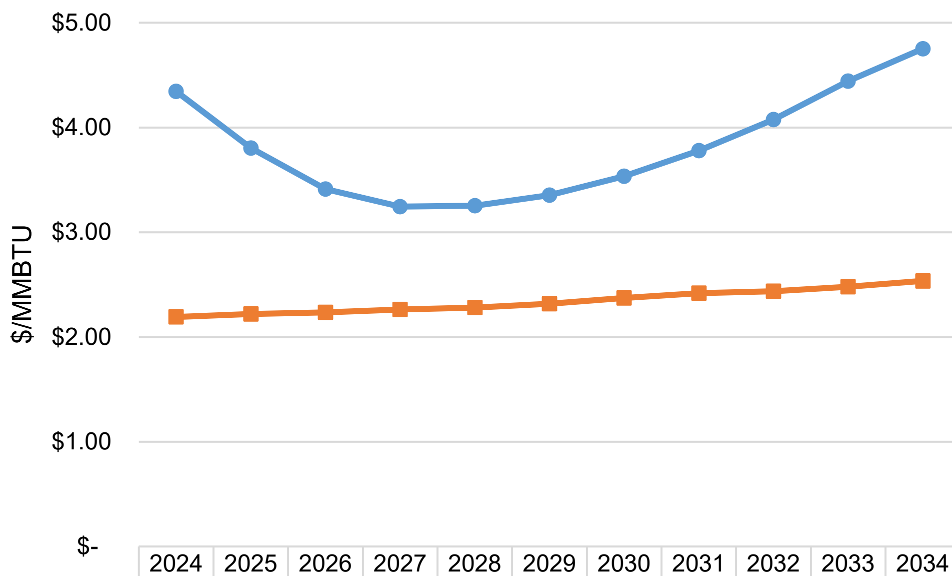
[14] SPP. (2023). *2023 Integrated Transmission Planning Assessment Report*. SPP. https://www.spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf

OG&E's system for many years. OG&E will consider these factors for existing sites in the future.

IV. D. Fuel Price Projections

OG&E utilizes fuel price projections provided in the EIA 2023 Annual Energy Outlook (AEO)[15]. EIA's models consider macroeconomic conditions, world oil prices, technological developments, and energy policies to provide fuel price projections for the U.S. The AEO "Reference Case" reflects current laws, regulations, and market conditions, and is the foundation for OG&E's Base Case in this IRP. The following figure provides the Henry Hub (HH) Natural Gas price assumption and the projected U.S. average coal price assumption for the next ten years from the 2023 AEO.

Figure 4 – EIA 2023 Annual Energy Outlook Fuel Projections (Nominal $)



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Natural Gas - HH	$4.34	$3.80	$3.41	$3.24	$3.25	$3.35	$3.54	$3.78	$4.07	$4.44	$4.75
Coal	$2.19	$2.22	$2.24	$2.26	$2.28	$2.32	$2.37	$2.42	$2.44	$2.48	$2.54

IV. E. Risk Assessment

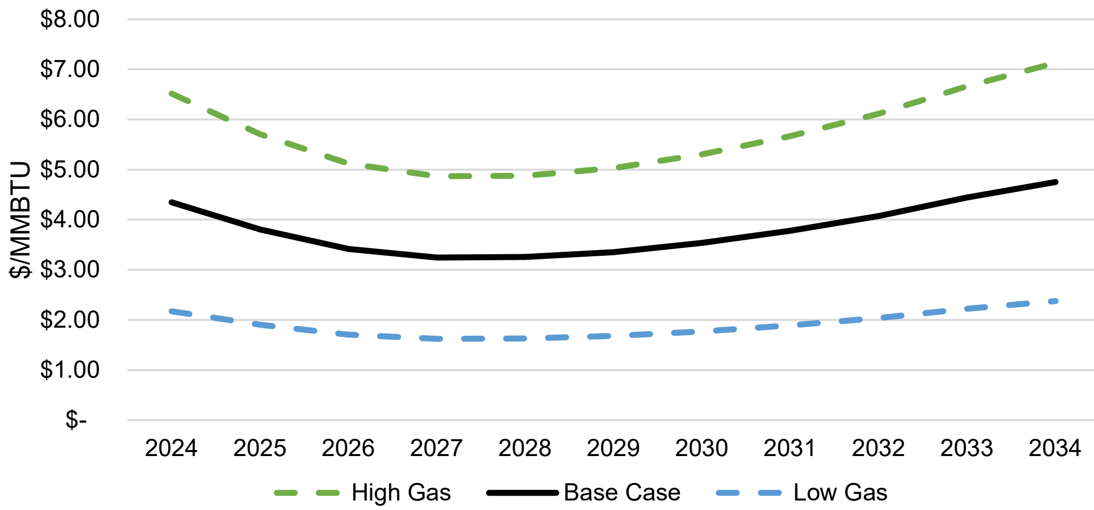
In addition to conducting the resource planning analysis under Base Case conditions, assumptions are varied to develop a range of hypothetical future conditions. Sensitivities involve adjusting a single assumption and measuring the impact of that specific variable on potential resource plans. Scenarios are designed by modifying more than one assumption. The analysis using the sensitivities and scenarios are provided in Section V of this report to assess risk.

[15] EIA. (2023, March 16). U.S. Energy Information Administration. *Annual Energy Outlook 2023.* https://www.eia.gov/outlooks/aeo/

IV. E. 1. Sensitivities

The variables considered in the sensitivity analysis are natural gas prices, solar capital costs, and the potential future implementation of a CO_2 tax. The High and Low natural gas prices used in this analysis represent a 50% increase and a 50% reduction, respectively, to the base natural gas price assumptions as shown in Figure 5.

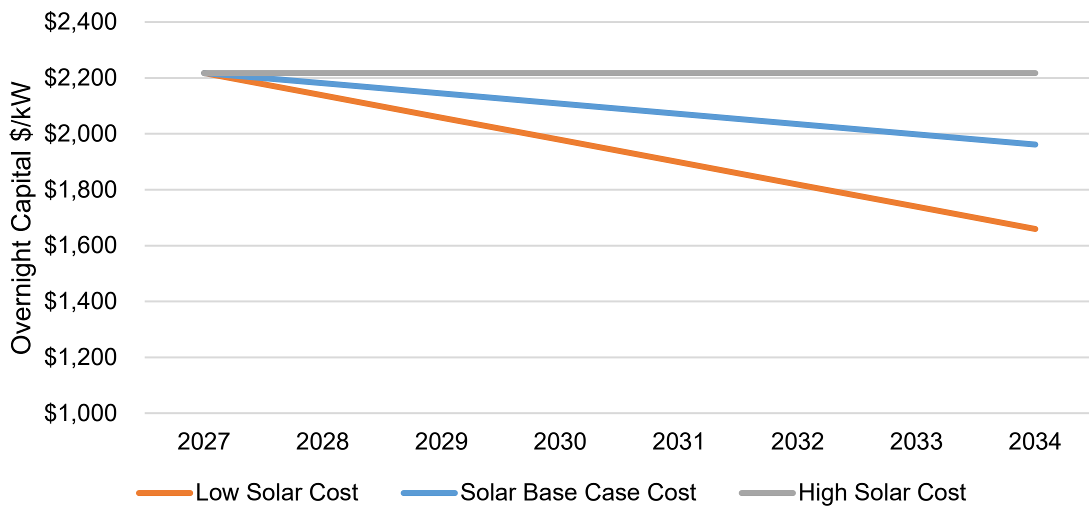
Figure 5 – Natural Gas Sensitivities



NREL provides varying projections for future solar capital costs. Figure 6 illustrates OG&E's solar capital cost sensitivities based on the current expected capital cost shown in Table 7. Both the base case and the low solar cost sensitivity rely on projected capital cost trajectories provided by NREL[16] while the high solar cost sensitivity assumes solar capital costs remain unchanged through the planning horizon.

[16] NREL. (2023). *Electricity annual Technology Baseline data download*. NREL. https://atb.nrel.gov/electricity/2023/data

Figure 6 – Solar Capital Cost Sensitivities

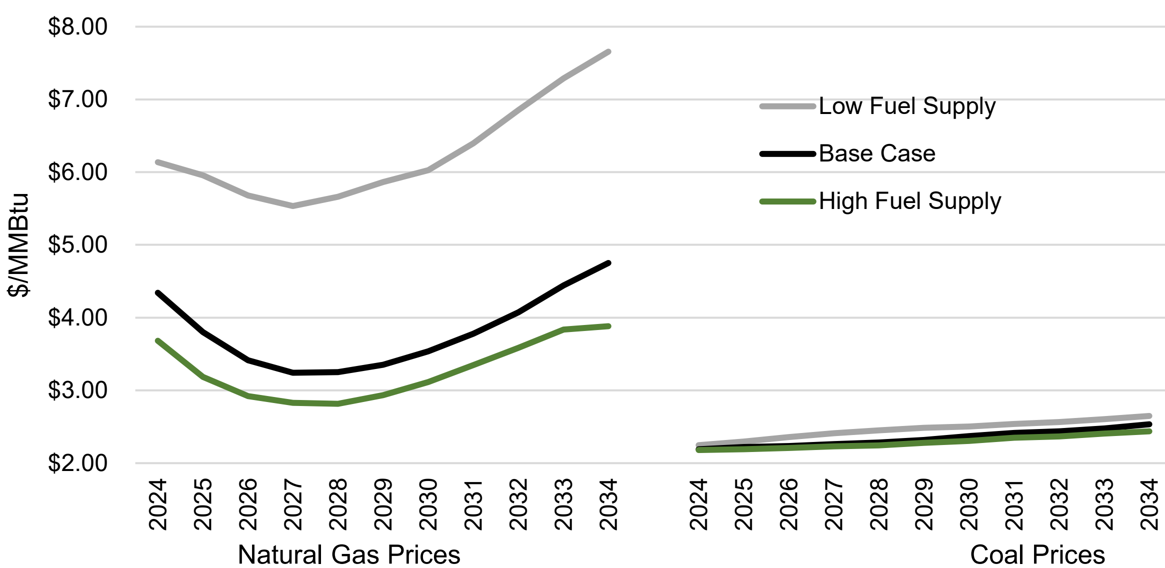


Finally, the CO_2 tax sensitivity assumes a cost of $15 per ton of CO_2 emissions begins in 2029 and escalates by 2% each year afterward.

IV. E. 2. Scenarios

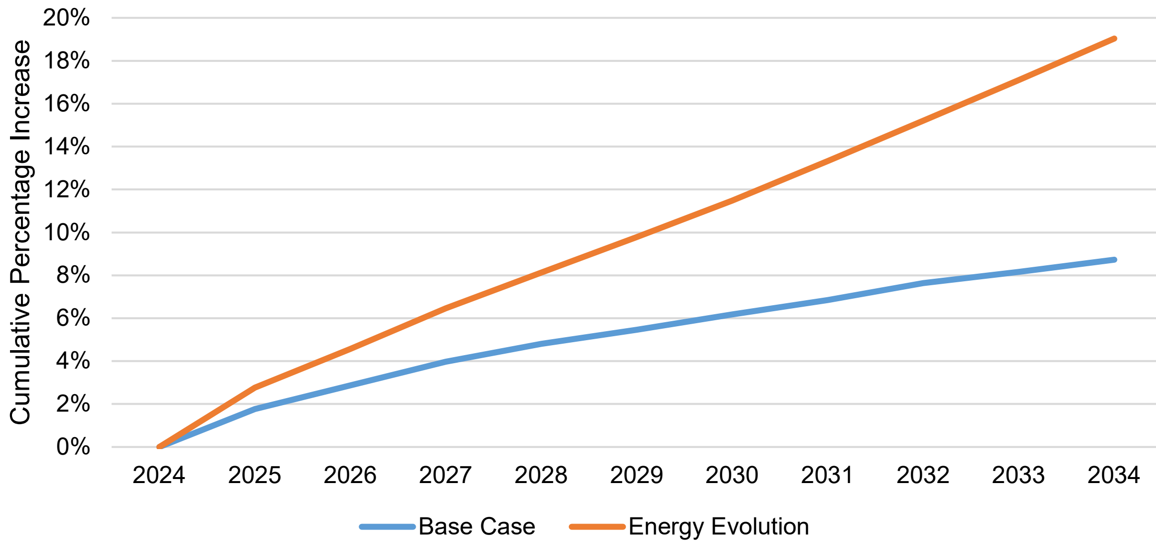
The 2023 AEO provides several scenarios addressing uncertainties in technology improvements, economic performance, commodity prices, legislation, regulation, and energy policies. The Low and High Oil and Gas Resource and Technology cases provide the largest potential variations in commodity prices among scenarios prepared by EIA. These cases also include hypothetical changes to load projections. As a simplification, OG&E labels these cases as Low and High Fuel Supply scenarios. The future commodity prices assumed in these scenarios are provided in Figure 7.

Figure 7 – Scenario Fuel Projections



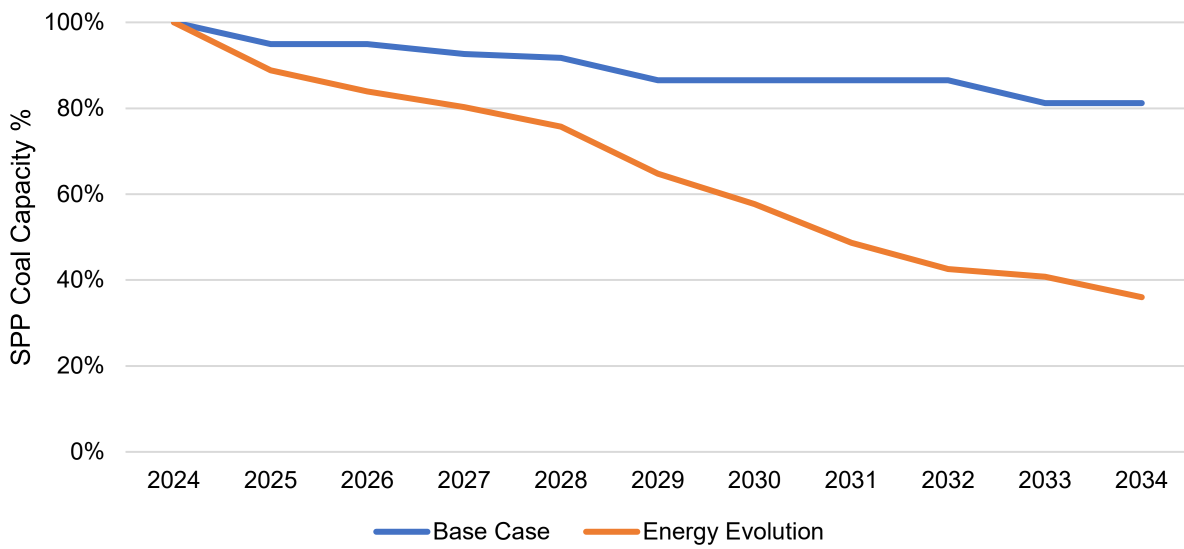
Additionally, OG&E developed an Energy Evolution scenario to analyze the potential impact that could be caused by federal policy leading to increased electrification and a region-wide accelerated coal-fired generation retirement schedule. Increased electrification could involve changes in the residential, commercial, industrial, and transportation sectors resulting in increased load on the power grid. Figure 8 shows the annual SPP load growth percentages for the Energy Evolution case compared to the Base Case.

Figure 8 – Energy Evolution Impact to Load



The Energy Evolution scenario also includes a reduction in SPP coal capacity through accelerated coal unit conversions and retirements. The coal capacity percentage reductions in OG&E's Base Case and the Energy Evolution scenario are provided in Figure 9.

Figure 9 – SPP Coal Capacity Comparison



IV. E. 3. Sensitivity and Scenario Summary

Table 8 provides a summary of the modeling assumptions that were included in the various sensitivities and scenarios.

Table 8 – Sensitivity and Scenario Summary

	Case	Description
Base	Base Case	EIA AEO 2023 Fuel Reference Case, Existing Laws and Regulations
Sensitivities	Low Gas	Base Case Natural Gas Prices x 50%
	High Gas	Base Case Natural Gas Prices x 150%
	CO_2 Tax	$15/ton starting 2029
	Low Solar Capital Cost	NREL low solar cost trajectory
	High Solar Capital Cost	Solar Prices Remain Flat
Scenarios	High Fuel Supply (EIA)	High Oil & Gas Resource and Technology - Low Fuel Cost, Higher Load
	Low Fuel Supply (EIA)	Low Oil & Gas Resource and Technology - High Fuel Cost, Lower Load
	Energy Evolution	Increased electrification, accelerated coal retirements

IV. F. Integrated Marketplace Locational Marginal Prices

Hourly Locational Marginal Prices (LMPs) for both generation and load are established through the SPP Integrated Marketplace (IM). OG&E utilizes Hitachi Energy PROMOD®, an electric market simulation tool, which incorporates generating unit operating characteristics, transmission grid topology and constraints, to simulate future nodal energy prices in the SPP IM. Forecasted LMPs are applied to electricity generated by OG&E units. Market conditions such as availability of diverse generation resources, fuel pricing and emission costs impact market pricing. The resulting average annual OG&E Load LMPs for the Base Case and all sensitivities are shown in Figure 10. Figure 11 shows the average annual OG&E Load LMPs for the Base Case and all scenarios.

Figure 10 – Base Case and Sensitivity Average Annual OG&E Load LMP Comparison

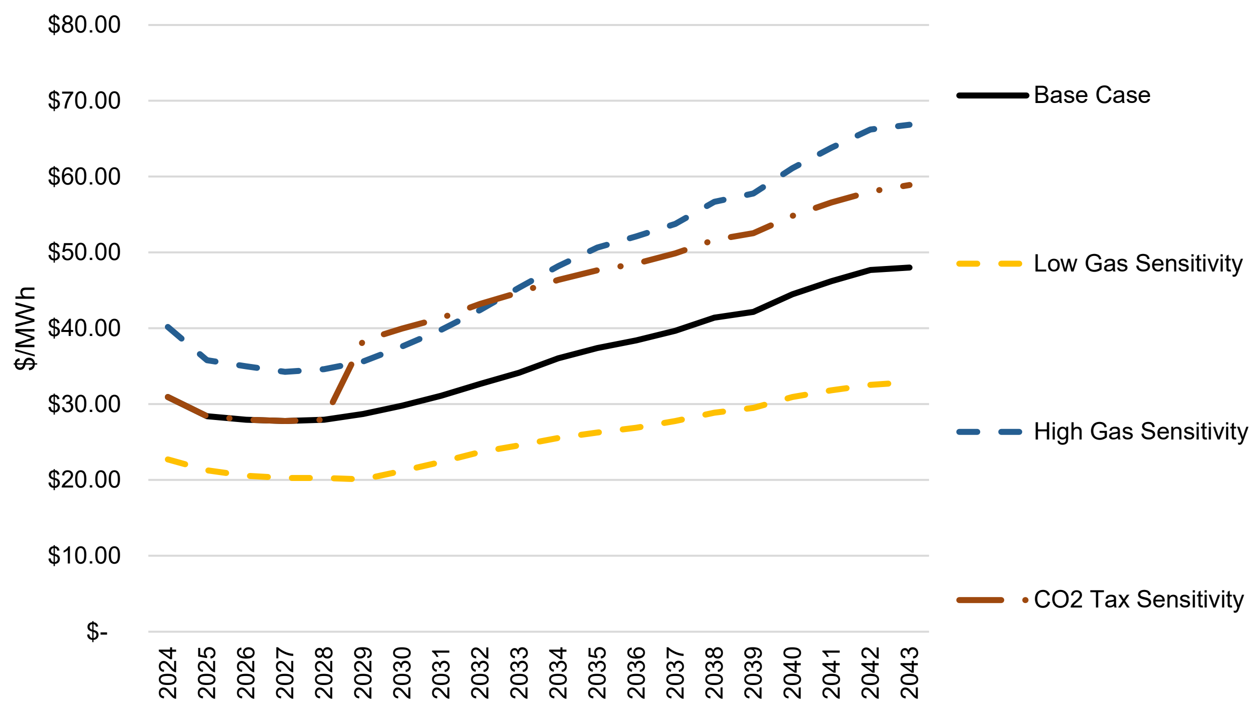
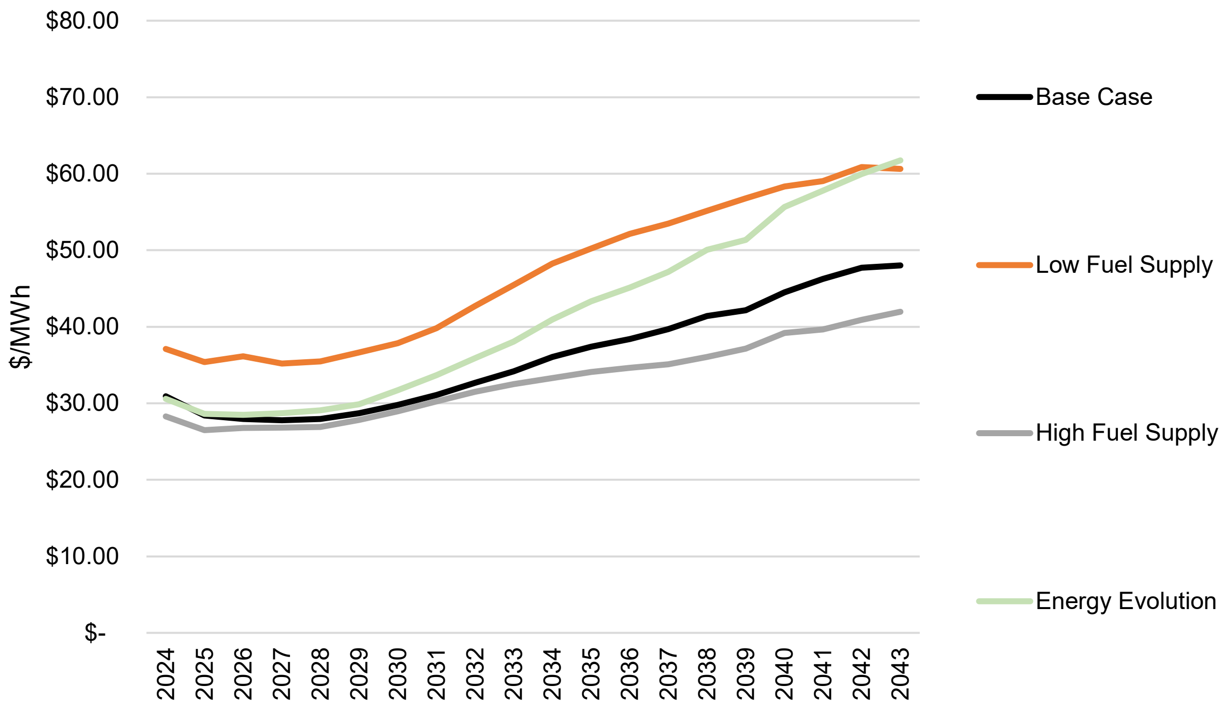


Figure 11 – Base Case and Scenario Average Annual OG&E Load LMP Comparison



IV. G. Alternate Policy Future Cases

As noted above, OG&E has included two alternate Future Cases for analysis in this IRP.

IV. G. 1. CSAPR Compliance Future Case

As noted in Section III. C. 2. a), the Good Neighbor Plan's revisions to the CSAPR program, if implemented in Oklahoma, would require significant reductions in NOx emissions related to OG&E's generation fleet in the immediate future. Litigation is ongoing and future compliance obligations remain uncertain. Compliance may require a range of potential modifications to existing units and other necessary actions. Despite the uncertainty, this IRP evaluates various compliance pathways based on OG&E's understanding of the rule, consistent with a stipulation in OG&E's 2021 Rate Case Final Order (Cause No. PUD 202100164). By 2027, the Good Neighbor FIP requires a 50% reduction from 2021 ozone season NOx emissions levels[17]. After 2027, further revisions to the trading program—including dynamic budgeting, a routine recalibration process for banked allowances, and a backstop daily NOx emissions rate for certain coal units—will likely require additional reductions in emissions levels. OG&E is continuing to evaluate compliance options and may need to take significant measures in the near term to meet compliance obligations under the EPA's Good Neighbor FIP by 2027 depending on the outcome of litigation.

[17] U.S. EPA, "EPA's "Good Neighbor" Plan Cuts Ozone Pollution – Overview Fact Sheet," https://www.epa.gov/system/files/documents/2023-03/Final%20Good%20Neighbor%20Rule%20Fact%20Sheet_0.pdf

As noted in Section III. C. 2. a), full implementation of the EPA's Good Neighbor FIP would require additional compliance actions and significant costs for facilities in OG&E's fleet to comply with lowered NOx emissions allowances. In this CSAPR Compliance Future Case, OG&E has analyzed various potential compliance options including full retirement of all OG&E's coal-fired generators. These scenarios incorporate the same input assumptions for the SPP PRM, the existing generation fleet, fuel costs, new resource costs, new resource availabilities, and load forecast as in the Expected Future Case.

OG&E has some latitude in implementing changes to generation resources, including controls to achieve fleet-wide compliance. Compliance options include some combination of installing controls, converting coal-fired units to natural gas, retiring and replacing certain units, and/or purchasing allowances. Two of the most effective control technologies available to reduce NOx emissions are Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). SCRs and SNCRs represent a significant investment into existing resources and construction times are estimated to vary from three to six years, depending on the generator type.

For OG&E's coal-fired resources, OG&E considered three major compliance options: (1) installing SCRs/SNCRs; (2) converting its coal-fired units to natural gas-fired generators and adding SCRs after conversion, where technically feasible; and (3) retiring and replacing certain units. OG&E also considered any site-specific constraints that limit the controls available to effectively reduce NOx emissions at particular facilities. SNCR is the only technology that can be applied to OG&E's River Valley facility because of the unique combustion technology of that facility.

Certain OG&E resources were not considered for modification based on cost-effectiveness concerns, including units currently equipped with control equipment and those very near retirement. All other gas-fired generators assumed installation of SCRs for compliance with EPA's CSAPR FIP. Table 9 below provides compliance options considered for each unit and the associated incremental estimated costs of each.

Table 9 – CSAPR Compliance Options

Unit Type	Compliance Option	Construction Time (years)	Overnight Capital Cost ($M)	Incremental Fixed O&M Cost ($M)	Incremental Variable O&M Cost ($/MWh)
Gas-Fired Steam	SCR	6	$290	$1.5-$2.1	$1.10-1.30
Combined Cycle	SCR	4	$5-$15	$0.1	$1.00-$3.70
Combustion Turbine	SCR	4	$8-$10	$0.15	$3.50-$4.70
Coal-Fired Steam (Muskogee 6, Sooner 1 & 2)	SCR	6	$360	$2.2	$1.70
Coal-Fired Steam (River Valley)	SNCR	4	$16	$0.2	$0.10
Coal-Fired Steam (Muskogee 6, Sooner 1 & 2)	Conversion + SCR	3 6	$60 $290	varies $1.5-$2.1	varies $1.10-1.30

Costs shown in Table 9 reflect current planning level estimates which will continue to be refined as new information becomes available.

OG&E anticipates allowance purchases will be necessary to remain in compliance during the selected unit modification construction phase(s). Each allowance equates to one ton of NOx. For purposes of this analysis, OG&E assumed allowances would be priced at $25,000 per allowance. OG&E has assumed initial demand for allowances will be high while affected entities implement compliance measures. This demand is expected to drive up allowance prices in the near term.

IV. G. 2. Status Quo Future Case

The Status Quo Future Case assumes policies currently being developed by SPP result in no implemented policy changes. OG&E views this as highly improbable. This Future Case assumes other input assumptions, including existing generation resources, fuel costs, new resource costs and availabilities and the load forecast remain the same as in the Expected Future Case.

IV. G. 3. Summary of Futures, Scenarios, and Sensitivities

This 2024 IRP will consider the forward-looking environmental compliance and Resource Adequacy risks through a number of alternate cases, intended to reflect alternate potential future developments. Below is a recap of the foundational assumptions for each alternative future case.

Expected Future Case

The Expected Future Case assumes SPP Resource Adequacy Policy changes are implemented as planned. This includes the implementation of PBA and ELCC in 2026, as well as an increase of the PRM Requirement to 18% in 2026, which is aligned with the recommendation of SPP's most recent Loss of Load Expectation (LOLE) Study.

CSAPR Compliance Future Case

The CSAPR Compliance Future Case is included to demonstrate potential methods and incremental costs of compliance. It examines the impact expected if OG&E is ultimately required to reduce fleet-wide NOx emissions in a way that is consistent with the EPA CSAPR FIP requirements currently being litigated.

Status Quo Future Case

The Status Quo Future Case assumes the current SPP PRM level of 15%, current SPP resource accreditation policies and current environmental policies remain constant in the future. The case includes neither the SPP Policy changes included in the Expected Future Case nor the environmental compliance requirements included in the CSAPR Compliance Future Case are implemented.

Each of the Future Cases has been evaluated across the full range of Scenarios and Sensitivities, resulting in a very robust set of analysis of potential future conditions. Table 10 below illustrates the Scenario and Sensitivity analysis conducted in each potential Future Case.

Table 10 – Summary of Futures, Scenarios and Sensitivities

	Expected Future Case	CSAPR Future Case	Status Quo Future Case
PRM	**18%**	**18%**	**15%**
PBA	**Yes**	**Yes**	**No**
CSAPR	**No**	**Yes**	**No**
	Scenarios/Sensitivities	**Scenarios/Sensitivities**	**Scenarios/Sensitivities**
Base	Base Case	Base Case	Base Case
Sensitivities	Low Gas	Low Gas	Low Gas
	High Gas	High Gas	High Gas
	CO_2 Tax	CO_2 Tax	CO_2 Tax
	Low Solar Capital Cost	Low Solar Capital Cost	Low Solar Capital Cost
	High Solar Capital Cost	High Solar Capital Cost	High Solar Capital Cost
Scenarios	High Fuel Supply (EIA)	High Fuel Supply (EIA)	High Fuel Supply (EIA)
	Low Fuel Supply (EIA)	Low Fuel Supply (EIA)	Low Fuel Supply (EIA)
	Energy Evolution	Energy Evolution	Energy Evolution

V. Resource Planning Modeling and Analysis

This section explains OG&E's future incremental capacity needs, the modeling and analysis steps utilized to identify the lowest reasonable customer cost plan for satisfying those needs and the risks considered.

V. A. Planning Reserve Margin

The SPP IM does not operate a capacity market, in contrast to certain other regions. OG&E continues to have responsibility for ensuring that it has sufficient planning capacity to serve its peak load requirements plus a PRM. OG&E's minimum PRM is established in Section 4 of the SPP Planning Criteria[18]. However, as noted in Section IV. B of this document, OG&E's Expected Future Case capacity position is premised on an 18% PRM, pursuant to SPP's most recent LOLE study and the resource accreditation impacts of PBA for thermal resources as well as the impacts of ELCC for renewable and energy storage resources. OG&E's projection of its annual capacity needs in the Expected Future Case is shown in Table 11.

Table 11 – Capacity Position (MW unless noted)

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Capacity	Owned Capacity	6,497	6,497	5,740	5,463	5,463	5,463	5,463	5,038	5,015	4,558	4,558
	Planned Additions	0	0	81	493	493	493	493	493	493	493	493
	Purchase Contracts	530	505	674	674	74	74	74	20	20	7	7
	Total Capacity	7,027	7,002	6,495	6,630	6,030	6,030	6,030	5,550	5,528	5,057	5,057
Demand	Demand Forecast	6,632	6,754	7,217	7,264	7,343	7,403	7,497	7,623	7,755	7,861	7,917
	OG&E DSM	559	753	988	1,027	1,049	1,074	1,098	1,119	1,141	1,159	1,160
	Net Demand	6,073	6,001	6,229	6,237	6,295	6,330	6,400	6,504	6,614	6,701	6,757
Margin	Reserve Margin[19]	16%	17%	4%	6%	-4%	-5%	-6%	-15%	-16%	-25%	-25%
Needs	Needed Capacity	-	-	556	431	1,096	1,136	1,215	1,812	1,960	2,529	2,592

V. B. Modeling Methodology

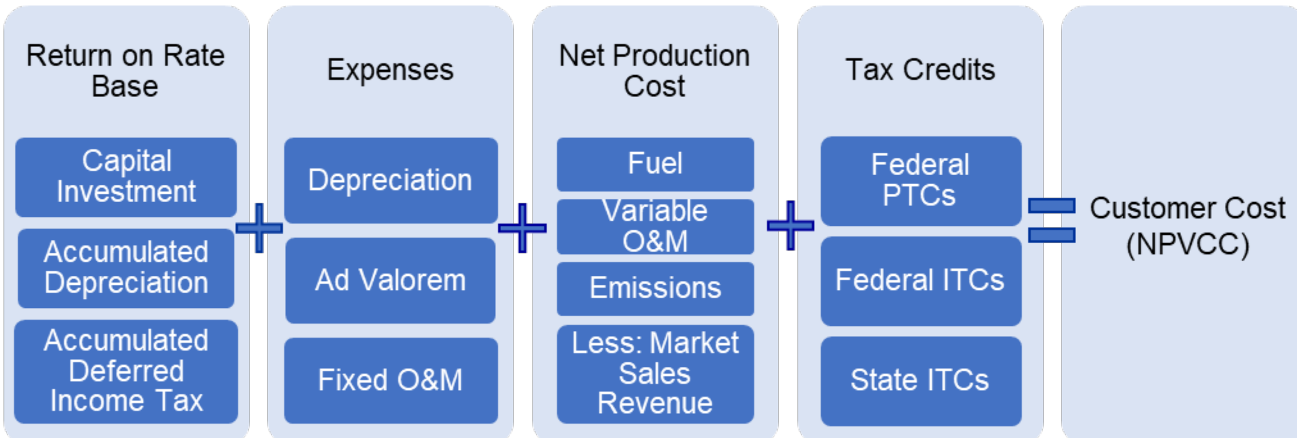
One of the main objectives of OG&E's IRP modeling is to identify portfolios of new generating resources that satisfy the capacity needs at the lowest reasonable Net Present Value of Customer Cost (NPVCC). A revenue requirement model combines all the cost components into the estimated 30-year NPVCC and is illustrated in Figure 12. This analysis approach allows the comparison of resources with a wide range of capital and operating costs. For instance, some renewable generation resources may have a higher

[18] SPP. (2023). *SPP Planning Criteria Revision 4.3*. SPP. 2023. https://www.spp.org/documents/70493/spp%20planning%20criteria%20v4.3.pdf

[19] Reserve Margin % = ((Total Net Capacity) - (Net System Demand)) / Net System Demand

overnight capital cost than conventional generation, however, conventional generation also has ongoing fuel cost over the life of the asset that the renewables do not. This analysis relied on the PROMOD® software to simulate the SPP IM and project hourly nodal LMPs. The EnCompass resource optimization then uses these LMPs to determine ongoing costs and benefits for the generator type. It then selects resources to meet the capacity needs and minimize NPVCC, including the cost components laid out in Figure 12.

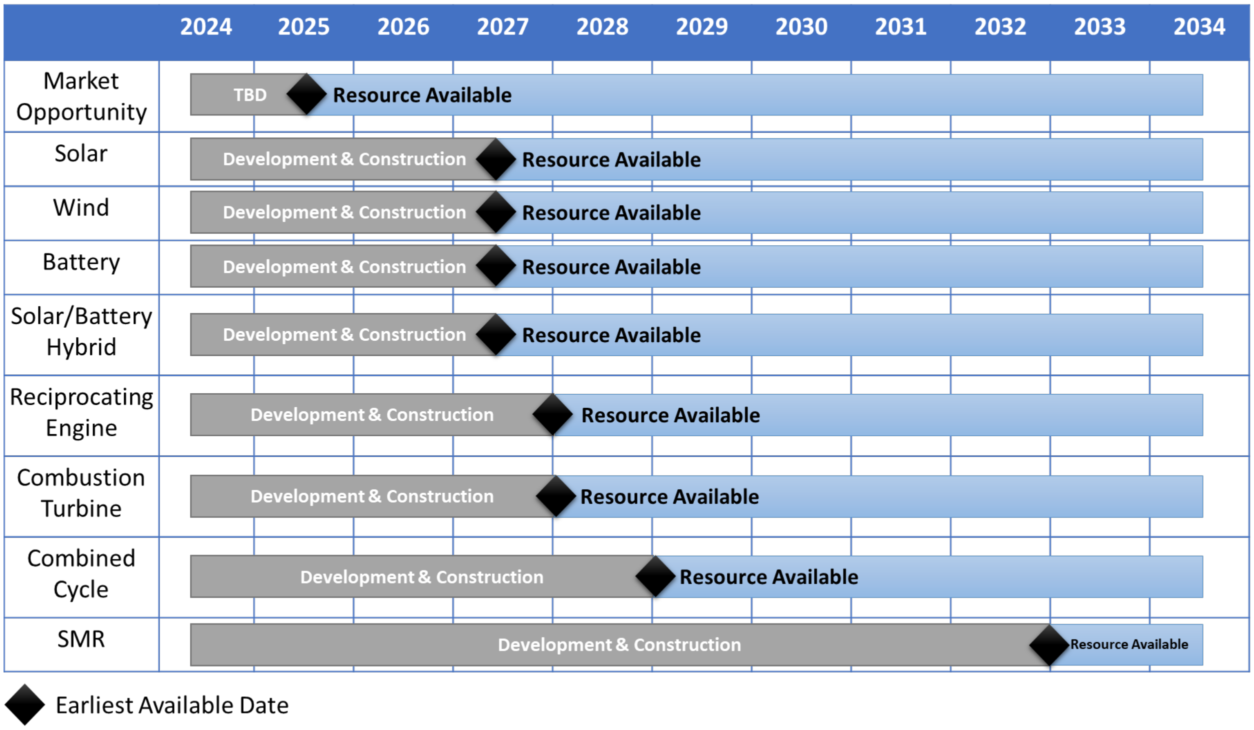
Figure 12 – Customer Cost Components



V. C. Portfolio Development

Potential Portfolios are made up of resources that enable OG&E to meet its forecasted capacity requirements. Assembling portfolios considers the construction time of the resource options to determine the earliest possible in-service date for each resource type. Figure 13 shows the first year that the various resources are available for meeting the PRM requirements based on the expected construction timeframes for each.

Figure 13 – New Resource Option Earliest Availability



V. D. <u>Expected Future Case Analysis</u>

The portfolios analyzed to meet OG&E's Expected capacity needs have NPVCC values ranging from $2.4 billion to $7.2 billion in the Base Case and represent various timing, sizing and combinations of the new resource options shown in Table 7. These portfolios contain a range of technologies and development timelines that address OG&E's capacity needs identified in Table 11. OG&E's 2026 capacity need can likely only be met by a market opportunity, which could take the form of a short-term capacity agreement, long-term capacity agreement, or other structure that satisfies the capacity need. OG&E plans to explore and analyze market opportunities through an RFP process. For analysis purposes, the short-term market opportunity is included in all portfolios shown in Table 12 and consists of 556 MW of capacity at zero cost for illustrative purposes.

Table 12 – Portfolios with Base Case, 30-year NPVCC ($M)

Portfolio	Type	Peak Accredited Capacity (MW)												NPVCC
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total*	NMPL. MW**	
Market Opportunity				X										$0
Solar + CT	Solar				450			90	90	180	270	1,080	1,800	$2,527
	CT					727			485		242	1,454	1,583	
Wind + CT	Wind				450			50	100		500	1,100	5,500	$3,776
	CT					727			485	242		1,454	1,583	
Solar + Wind + CT	Solar				360	180			90		450	1,080	1,800	$3,075
	Wind				100			100	50	150	100	500	2,500	
	CT					485			485			970	1,055	
Solar + CC	Solar				450	630						1,080	1,800	$2,375
	CC						911				911	1,822	1,888	
Wind + CC	Wind				450	650						1,100	5,500	$3,994
	CC							911			911	1,822	1,888	
Solar + Wind + CC	Solar				360	540						900	1,500	$2,697
	Wind				100	100						200	1,000	
	CC						911				911	1,822	1,888	
Solar + RICE	Solar				450	360	90	90	270	90	630	1,980	3,300	$2,975
	RICE					304			304			608	661	
Heavy Solar + CT	Solar				450	180	90		180	180	540	1,620	2,700	$2,581
	CT					485			485			970	1,055	
Solar Only	Solar				450	720		90	630	180	540	2,610	4,350	$2,706
Wind + Battery + Solar	Wind					150	50		100			300	1,500	$3,550
	Battery				100	300			400		300	1,100	1,100	
	Solar				360	180		90	90	180	270	1,170	1,950	
Wind + Battery + CT	Wind				150	150	50	50	400	150	550	1,500	7,500	$4,206
	Battery				300							300	300	
	CT					485			242			727	791	
Solar + CT + SMR	Solar				450			90	90	180		810	1,350	$7,221
	CT					727			485			1,212	1,319	
	SMR										640	640	640	

**Total = Accredited MW*
***NMPL. MW = Nameplate MW*

The NPVCC values in Table 12 demonstrate that a combination of solar generation and natural gas-fired resources are the most cost-effective option for OG&E's needs in the Base Case. The Solar + CT portfolio and the Solar + CC portfolio are the two least cost portfolios identified. Both portfolios contain a combination of solar resources and combustion turbines either in simple cycle or combined cycle configurations. While combined cycle units provide a slightly lower installed cost on a $/kW basis, they have a longer construction time than simple cycle turbines and provide less flexibility in unit sizing. Additionally, new combined cycle resources may have more extensive modification requirements than combustion turbines in the future based on the proposed EPA GHG rule for new generating units described in Section III. C. 2. d). The risk of additional costs for environmental compliance will be fully evaluated as conditions supporting environmental compliance with the final GHG rule become clearer.

While wind is an excellent renewable energy source, only a small percentage of an installed nameplate wind resource can be utilized toward meeting the SPP planning reserve requirements. For this comparison, to achieve the same accredited capacity level as solar, much larger amounts of nameplate wind capacity would be needed.

SMRs represent a potential zero-emitting, dispatchable capacity resource. However, this technology is not fully mature. As shown in Table 7, the expected up-front capital cost for an SMR is currently expected to be significantly higher than all other resources listed, making the portfolio including these resources among the worst performing in NPVCC terms, and is multiple times higher than the Solar + CT and Solar + CC portfolios. OG&E will continue to evaluate this technology as it advances.

V. E. Portfolio Risk Assessment

Each portfolio was also assessed under the various sensitivities and scenarios to determine how each portfolio performed when a particular assumption was adjusted. Comparing the NPVCC of the Base Case to the NPVCC of each sensitivity and scenario shows how each portfolio performs under a range of assumptions. The Solar + CT portfolio has the second lowest customer cost in the Base Case and performs well throughout the Risk Assessment.

As explained in Section IV. E, the sensitivity analysis evaluates the impact of changes in a single input assumption. The sensitivities evaluated for risk are future fuel prices, a potential CO_2 tax and variability in solar project capital costs. Table 13 provides a summary of the 30-year NPVCC for each portfolio in each sensitivity.

Table 13 – Sensitivity, 30-year NPVCC ($M)

Portfolio Name	Base Case	Low Gas	High Gas	CO_2 Tax	Low Solar Cost	High Solar Cost
Solar + CT	$2,527	$2,900	$2,025	$2,201	$2,383	$2,650
Wind + CT	$3,776	$4,620	$2,818	$2,584	$3,776	$3,776
Solar + Wind + CT	$3,075	$3,861	$2,157	$2,240	$2,929	$3,199
Solar + CC	$2,375	$2,601	$1,814	$1,905	$2,338	$2,407
Wind + CC	$3,994	$4,801	$2,913	$2,525	$3,994	$3,994
Solar + Wind + CC	$2,697	$3,036	$2,035	$2,037	$2,665	$2,724
Solar + RICE	$2,975	$3,707	$2,074	$2,431	$2,690	$3,217
Heavy Solar + CT	$2,581	$3,178	$1,847	$2,126	$2,342	$2,784
Solar Only	$2,706	$3,754	$1,517	$1,995	$2,340	$3,015
Wind + Battery + Solar	$3,550	$4,399	$2,584	$2,867	$3,394	$3,681
Wind + Battery + CT	$4,206	$5,372	$2,905	$2,651	$4,206	$4,206
Solar + CT + SMR	$7,221	$7,835	$6,449	$6,705	$7,147	$7,284

The sensitivity risk ranges shown above are graphically illustrated in Figure 14 through Figure 16. The Solar + CT + SMR portfolio data is not shown in the graphs. The bars show each portfolio's deviation in NPVCC from the Base Case in the sensitivities and scenarios. Narrow ranges indicate smaller risks from changes to assumptions. Wide ranges indicate resource portfolios that are highly impacted by assumption changes. Diversified portfolios mitigate a range of risk factors.

Figure 14 – Natural Gas Price Sensitivity Assessment

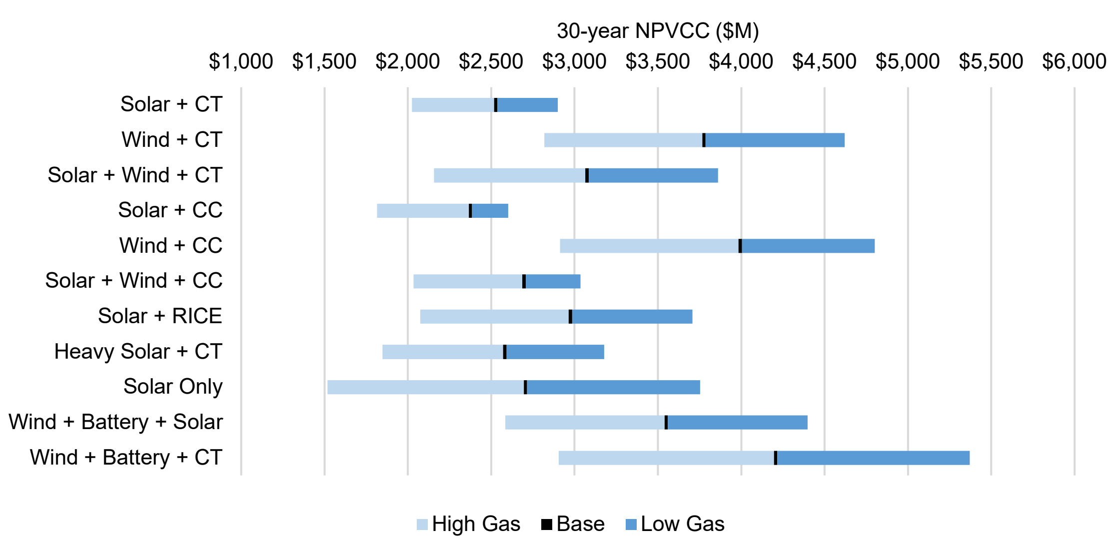


Figure 15 – CO_2 Tax Sensitivity Assessment

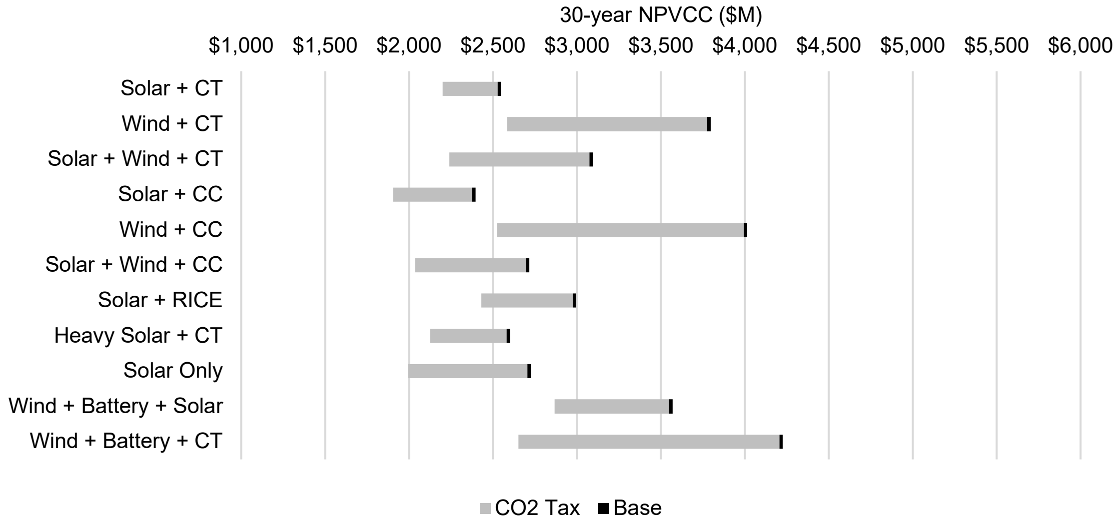
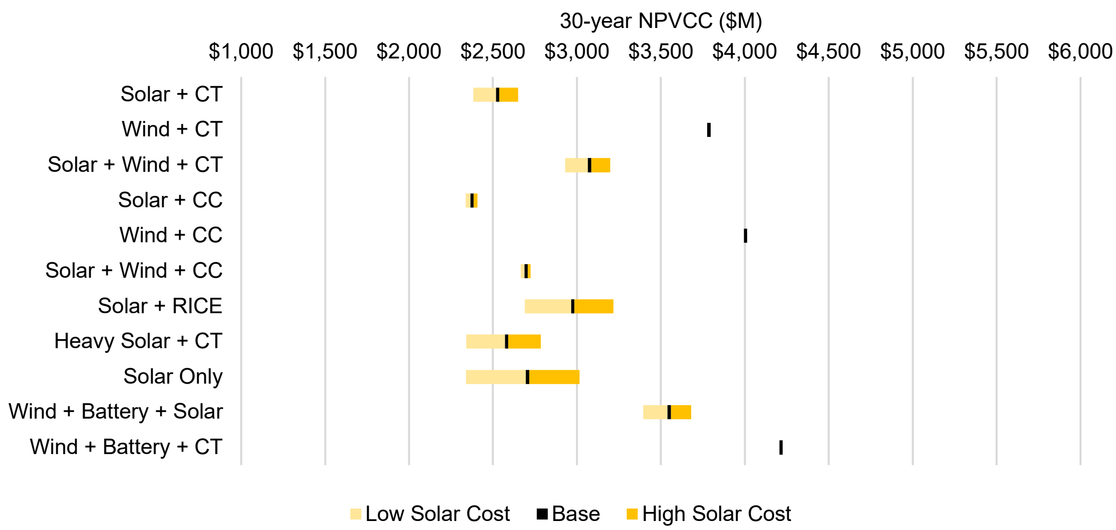


Figure 16 – Solar Capital Cost Sensitivity Assessment



The scenario analysis evaluates the impact of changes to multiple assumptions at the same time. As described in Section IV. E. 2, the three scenarios analyzed are Low Fuel Supply, High Fuel Supply and Energy Evolution. Table 14 provides a summary of the 30-year NPVCC for each portfolio in each scenario.

Table 14 – Scenario, 30-year NPVCC ($M)

Portfolio Name	Base Case	Low Fuel Supply	High Fuel Supply	Energy Evolution
Solar + CT	$2,527	$2,110	$2,650	$2,229
Wind + CT	$3,776	$3,082	$3,776	$2,235
Solar + Wind + CT	$3,075	$2,358	$3,199	$2,114
Solar + CC	$2,375	$1,950	$2,407	$1,592
Wind + CC	$3,994	$3,237	$3,994	$1,891
Solar + Wind + CC	$2,697	$2,206	$2,724	$1,669
Solar + RICE	$2,975	$2,230	$3,217	$2,441
Heavy Solar + CT	$2,581	$1,972	$2,784	$2,172
Solar Only	$2,706	$1,712	$3,015	$2,090
Wind + Battery + Solar	$3,550	$2,757	$3,681	$2,871
Wind + Battery + CT	$4,206	$3,262	$4,206	$2,175
Solar + CT + SMR	$7,221	$6,590	$7,284	$6,714

The risk range of the scenarios shown above are graphically illustrated in Figure 17 and Figure 18.

Figure 17 – Fuel Supply Scenario Assessment

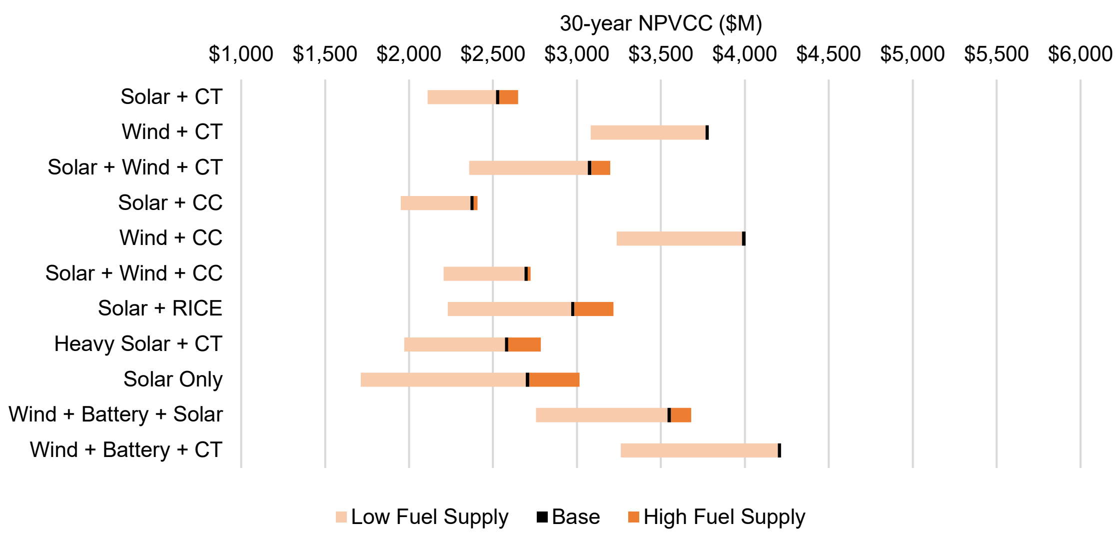
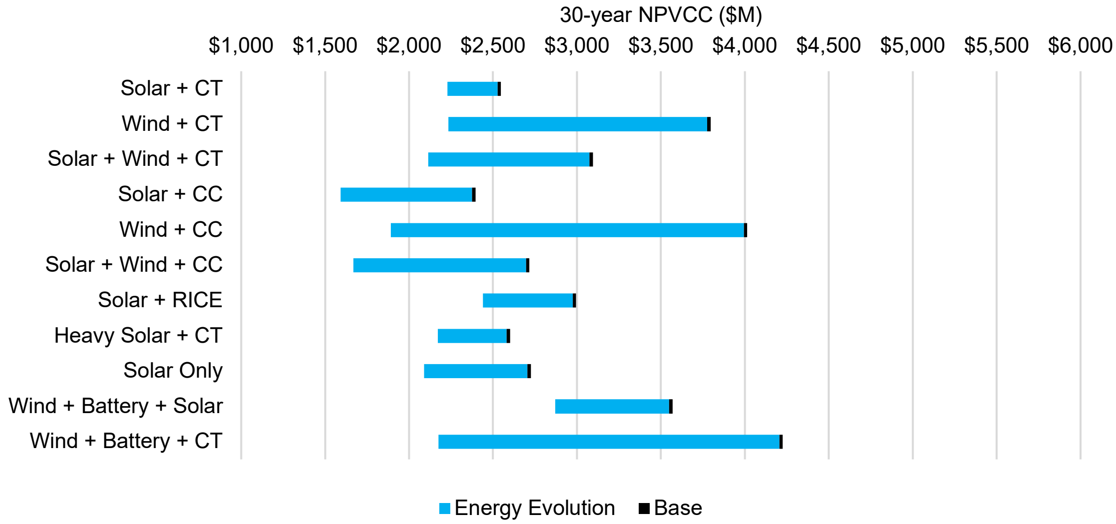


Figure 18 – Energy Evolution Scenario Assessment



The Sensitivity and Scenario analysis shows that OG&E's preferred plan is the Solar + CT portfolio because it has a low reasonable customer cost in the Base Case and mitigates a variety of potential risks while also providing a diversified portfolio of gas and renewable generation.

Table 15 – OG&E Preferred Plan

Portfolio Name	Type	Accredited Capacity (MW)												NMPL. MW**	30-year NPVCC ($M)
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total*		
Solar + CT	Solar				450			90	90	180	270		1,080	1,800	**$2,527**
	CT					727			485		242		1,454	1,583	
	Mkt. Op.***			556									556	556	

**Total = Accredited MW*
***NMPL. MW = Nameplate MW*
****Mkt. Op. = One year Market Opportunity*

The portfolios focus on the incremental decisions for OG&E's generation fleet. In addition to the NPVCC of the incremental portfolios, Figure 19 and Figure 20 show the 30-year net present value of OG&E's load cost, existing generation unit net production costs and fixed operations and maintenance (O&M) expenses under the natural gas and CO_2 Tax sensitivities, and Energy Evolution scenario with base case assumptions.

Figure 19 – Portfolio Cost including Load and Existing Generation Units with Natural Gas Sensitivity

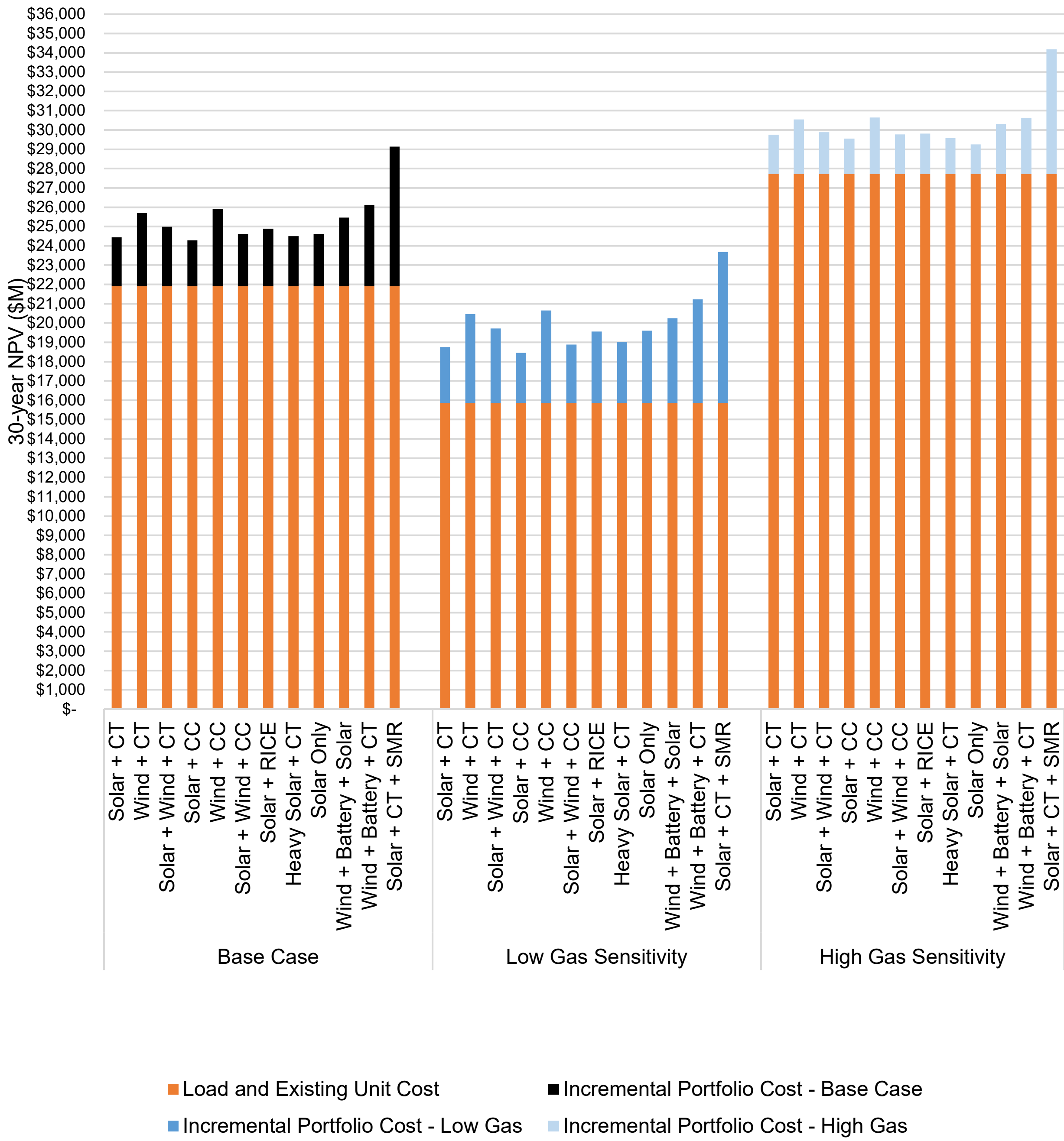
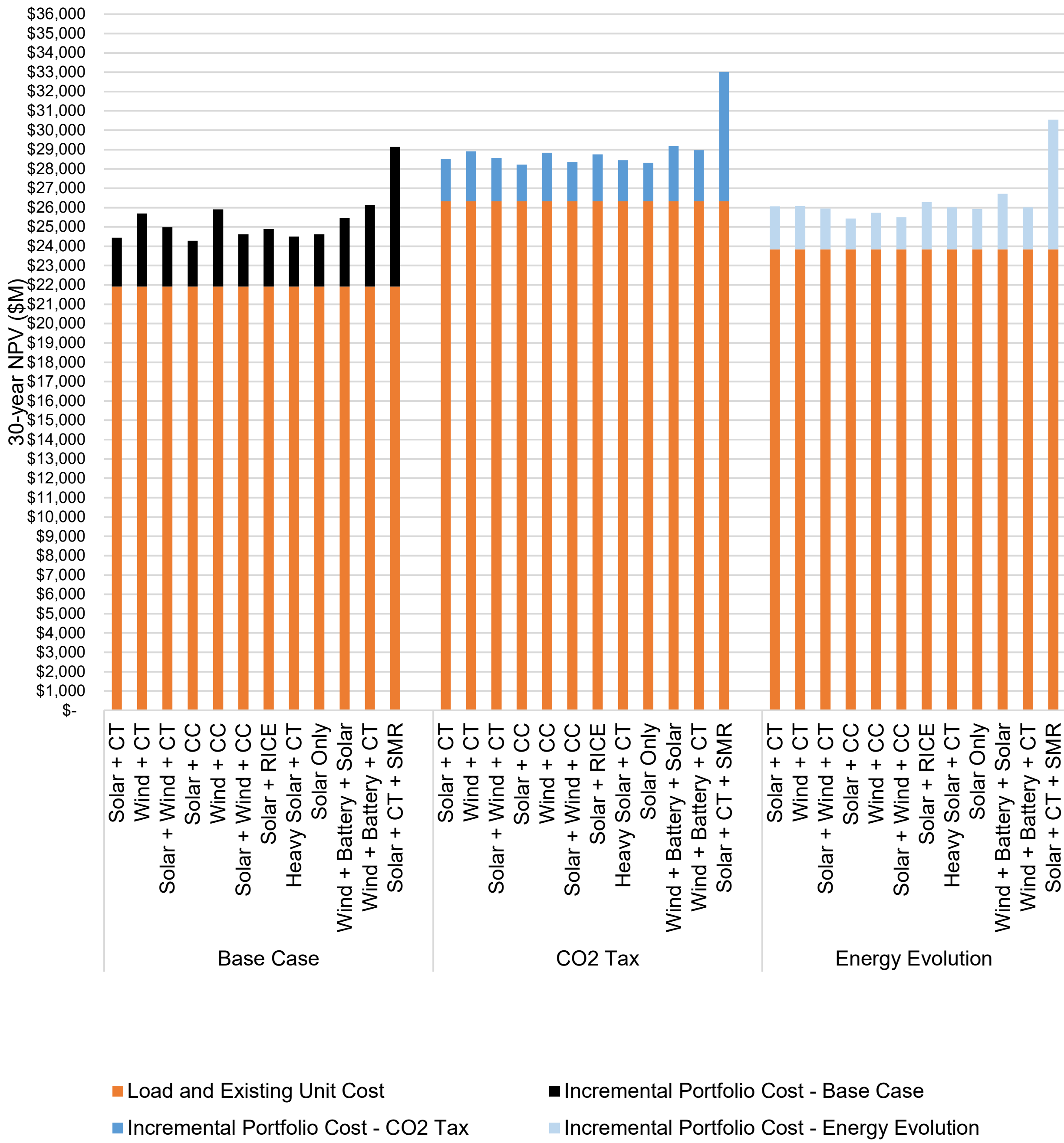


Figure 20 – Portfolio Cost including Load and Existing Generation Units with CO_2 Tax Sensitivity and Energy Evolution Scenario



V. F. CSAPR Compliance Future Case Analysis

With the current litigation surrounding the CSAPR program and Oklahoma's underlying SIP, there is substantial uncertainty concerning the actual timeline and compliance actions needed to meet CSAPR requirements. Despite the uncertainty, this IRP evaluates various compliance plans under the current understanding of the rule to comply with a stipulation in OG&E's 2021 Rate Case Final Order (Cause No. PUD 202100164) requiring OG&E to include analysis of the potential impacts of CSAPR.

The CSAPR Compliance Future Case builds off the capacity needs assumptions in the Expected Future Case and analyzes a variety of potential CSAPR compliance options for OG&E's existing generation resources. All new natural gas-fired resources evaluated in this IRP assume the inclusion of SCRs for NOx emission control. The CSAPR Compliance Future Case incorporates the Preferred Plan identified in Table 15 under the Expected Future Case as a baseline condition to meet the projected future capacity needs. After this assumption was included, the potential CSAPR compliance options were then studied to show the customer cost resulting from compliance, that is incremental to the costs identified in the Expected Future Case preferred plan. OG&E analyzed a range of Good Neighbor FIP compliance portfolios to assess compliance costs. For existing gas fired generators, OG&E assumed installation of SCRs. For OG&E's coal fired resources, OG&E considered three major compliance options: (1) installing SCRs/SNCRs; (2) converting coal-fired units to natural gas-fired generators and adding SCRs after conversion, where technically feasible; and (3) retiring and replacing certain units.

NOx allowances can also be purchased in the market as a potential means for compliance, however, the availability and pricing of allowances in the future is uncertain. The CSAPR compliance portfolios analyzed are shown in Table 16 below.

Table 16 – CSAPR Future Case Portfolios with Base Case, 30-year NPVCC ($M)

Portfolio	Resource		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	NPVCC ($M)
Retire and Replace All Coal	Sooner 1 & 2	Retire/Replace					Retire						$ 2,792
	Muskogee 6	Retire/Replace					Retire						
	River Valley 1 & 2	Retire/Replace					Retire						
	Frontier							SCR					
	McClain							SCR					
	Horseshoe Lake 9 & 10							SCR					
	Mustang 6-12							SCR					
	Seminole 3									SCR			
	Muskogee 4 & 5									SCR			
		Solar Additions (Peak Accredited Capacity MW)					720						
		CT Additions (Peak Accredited Capacity MW)					970						
All SCR	River Valley 1 & 2						SNCR						$ 2,536
	Frontier							SCR					
	McClain							SCR					
	Horseshoe Lake 9 & 10							SCR					
	Mustang 6-12							SCR					
	Seminole 3									SCR			
	Muskogee 4 & 5									SCR			
	Sooner 1 & 2									SCR			
	Muskogee 6									SCR			
Convert and SCR	Sooner 1 & 2						Convert			SCR			$ 2,386
	Muskogee 6						Convert			SCR			
	River Valley 1 & 2						SNCR						
	Frontier							SCR					
	McClain							SCR					
	Horseshoe Lake 9 & 10							SCR					
	Mustang 6-12							SCR					
	Seminole 3									SCR			
	Muskogee 4 & 5									SCR			

The portfolios in the CSAPR Compliance Future Case were analyzed across the same sensitivities and scenarios as the Expected Future Case.

The portfolios analyzed to comply with CSAPR have NPVCC values that range from $2.4 billion to $2.8 billion in the Base Case. The NPVCC values shown below represent only the incremental costs of compliance with CSAPR and do not include the costs to meet OG&E's expected capacity needs. These are customer costs on top of the customer costs identified in the Expected Future Case.

Table 17 – CSAPR Future Case Sensitivity, 30-year NPVCC ($M)

Case Name	Base Case	Low Gas	High Gas	CO_2 Tax	Low Solar Cost	High Solar Cost
Retire and Replace All Coal	$2,792	$2,490	$3,616	$1,877	$2,749	$2,828
All SCR	$2,536	$2,274	$2,599	$2,269	$2,536	$2,536
Convert and SCR	$2,386	$1,922	$3,315	$1,747	$2,386	$2,386

The sensitivity risk ranges shown above are graphically illustrated in Figure 21 and Figure 22.

Figure 21 – CSAPR Future Case Natural Gas Price Sensitivity Assessment

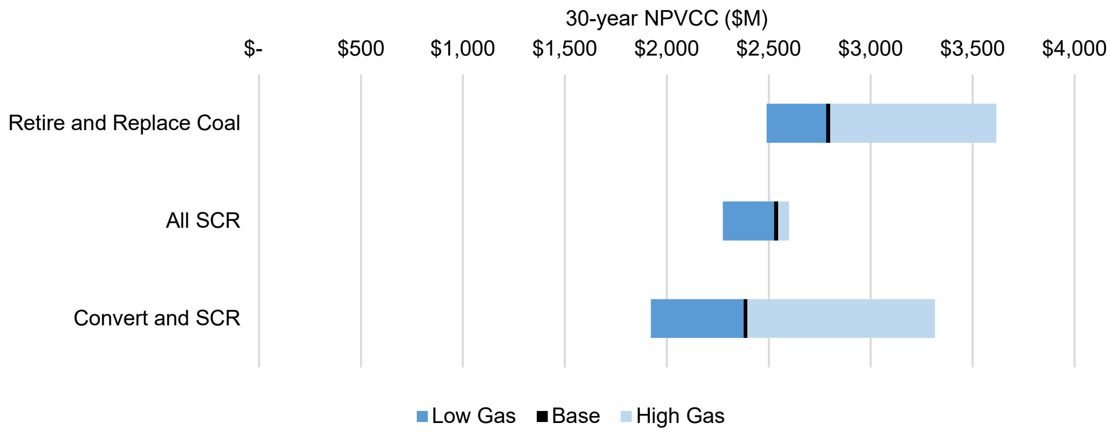


Figure 22 – CSAPR Future Case CO_2 Tax Sensitivity Assessment

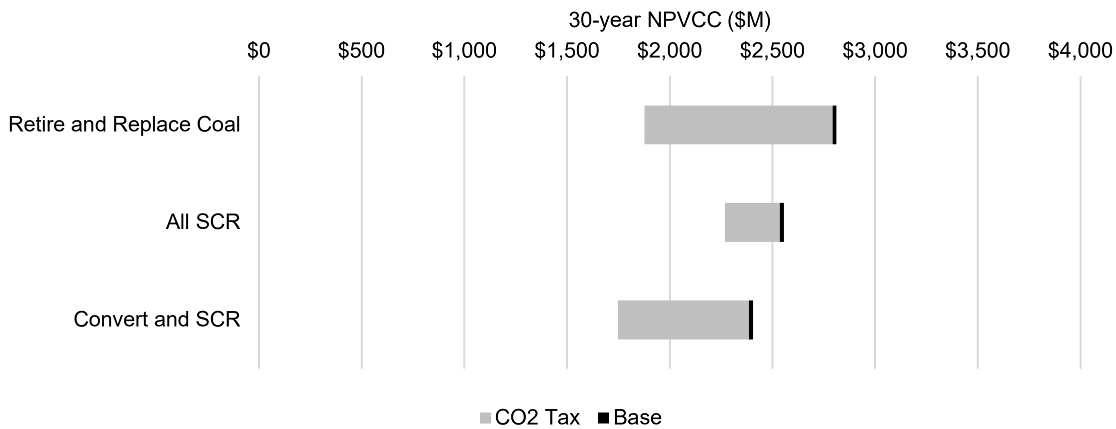


Table 18 – CSAPR Future Case Scenario, 30-year NPVCC ($M)

Portfolio Name	Base	Low Fuel Supply	High Fuel Supply	Energy Evolution
Retire and Replace All Coal	$2,792	$3,546	$2,631	$3,076
All SCR	$2,536	$2,565	$2,509	$2,729
Convert and SCR	$2,386	$3,236	$2,171	$2,826

The risk range of the scenarios shown above are graphically illustrated in Figure 23 and Figure 24.

Figure 23 – CSAPR Future Case Fuel Supply Scenario Assessment

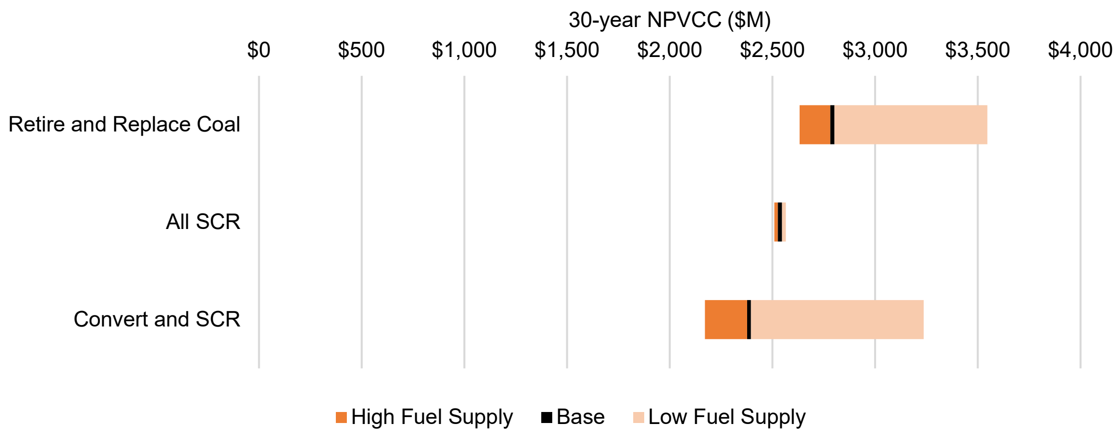
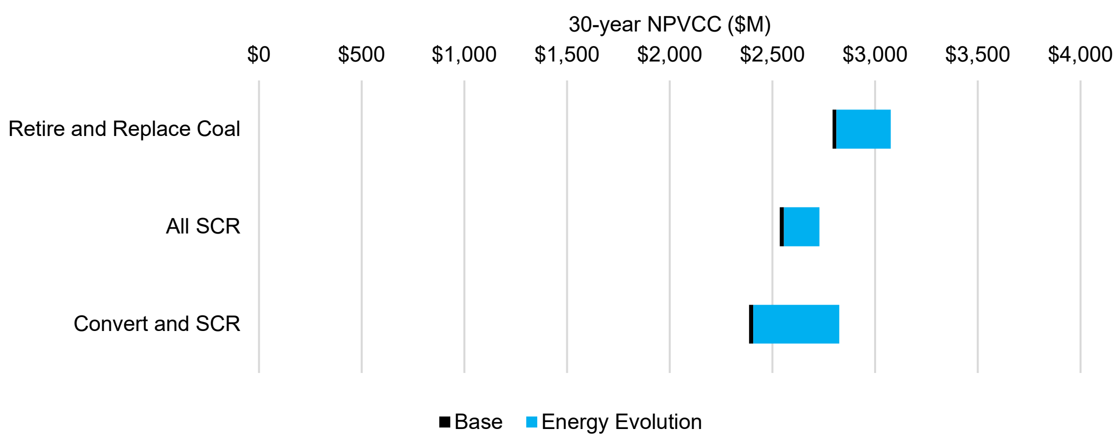


Figure 24 – CSAPR Future Case Energy Evolution Scenario Assessment



Due to the uncertainty relating to the disapproval of the Oklahoma Interstate Transport SIP and implementation of the EPA's Good Neighbor FIP, OG&E cannot determine future compliance costs with certainty. Costs are dependent upon the timing and outcome of the litigation discussed in Section III. C. 2. a), the particular compliance strategies ultimately selected for each unit, the terms and timing of regulatory approvals sought from the OCC, and the time period necessary to complete the projects. The results of current litigation regarding CSAPR will influence OG&E's path forward for compliance. To avoid unnecessary expenditures for customers, OG&E will continue to monitor legal and regulatory developments related to the EPA's Good Neighbor FIP and take needed compliance actions after final decisions are made through the legal process.

V. G. Status Quo Future Case Analysis

Table 19 below illustrates OG&E projected capacity position if there are no incremental SPP Resource Adequacy policy adjustments in the near term. OG&E considers this case unlikely but includes it in this IRP to provide a complete picture of future capacity needs. Please see Section III. A. 1 for a description of the SPP Policy changes currently in development, including several initiatives that have been approved by SPP for future implementation. OG&E has substantial near-term capacity needs regardless of the expected changes to SPP Resource Adequacy policies, which are projected to further increase capacity needs. Expected capacity needs are shown in Section V. A.

Table 19 – Status Quo Future Case Capacity Position (MW unless noted)

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Capacity	Owned Capacity	6,497	6,497	6,433	6,058	6,058	6,058	6,058	5,558	5,539	5,026	5,026
	Planned Additions	0	0	88	536	536	536	536	536	536	536	536
	Purchase Contracts	530	505	655	655	55	55	55	19	19	7	7
	Total Capacity	7,027	7,002	7,176	7,249	6,649	6,649	6,649	6,113	6,094	5,569	5,569
Demand	Demand Forecast	6,632	6,754	7,217	7,264	7,343	7,403	7,497	7,623	7,755	7,861	7,917
	OG&E DSM	559	753	988	1,027	1,049	1,074	1,098	1,119	1,141	1,159	1,160
	Net Demand	6,073	6,001	6,229	6,237	6,295	6,330	6,400	6,504	6,614	6,701	6,757
Margin	Reserve Margin	16%	17%	15%	16%	6%	5%	4%	-6%	-8%	-17%	-18%
Needs	Needed Capacity	-	-	-	-	591	631	712	1,367	1,513	2,138	2,202

The Modeling Methodology and Portfolio Development for the Status Quo Future Case are identical to those used for the Expected Future Case and are described in Sections V. B through V. D. However, the projected capacity needs associated with the Status Quo Future Case are lower than those in the Expected Future Case.

The portfolios analyzed to meet OG&E's Status Quo capacity needs have NPVCC values ranging from $1.7 billion to $6.5 billion in the Base Case and represent various timing, sizing, and combinations of the new unit options. The two lowest customer cost portfolios identified in the Base Case were consistent with the lowest cost portfolios identified in the

Expected Future Case, which were a combination of solar resources and either combined cycle resources or combustion turbine resources.

Table 20 – Status Quo Future Case Portfolios with Base Case, 30-year NPVCC ($M)

Portfolio Name	Accredited Capacity (MW)												NPVCC
	Type	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total*	NMPL. MW**	
Solar + CT	*Solar*					90		90	450	90	360	1,080	1,800	$1,848
	CT					528			264		264	1,056	1,056	
Wind + CT	*Wind*					100	50	50	400	150	350	1,100	5,500	$2,952
	CT					528			264		264	1,056	1,056	
Solar + Wind + CT	*Solar*					270		90	180	90	360	990	1,650	$2,562
	Wind					100			200	50	300	650	3,250	
	CT					264			264			528	528	
Solar + CC	*Solar*					630		90			540	1,260	2,100	$1,733
	CC								944			944	944	
Wind + CC	*Wind*					600	50	100			450	1,200	6,000	$3,078
	CC								944			944	944	
Solar + Wind + CC	*Solar*					270					360	630	1,050	$2,448
	Wind					350	50	50			150	600	3,000	
	CC								944			944	944	
Solar + RICE	*Solar*					270	90	90	270	180	630	1,530	2,550	$2,302
	RICE					330			330			660	660	
Heavy Solar + CT	*Solar*					360		90	450	90	630	1,620	2,700	$1,925
	CT					264			264			528	528	
Solar Only	*Solar*					630		90	720	90	630	2,160	3,600	$2,033
Wind + Battery + Solar	*Wind*					400	50	100	50		50	650	3,250	$3,185
	Battery					100			300		300	700	700	
	Solar					90			270	180	270	810	1,350	
Heavy Wind + CT	*Wind*					350	50	50	400	150	600	1,600	8,000	$3,540
	CT					264			264			528	528	
Solar + CT + SMR	*Solar*					90		90	450	90		720	1,200	$6,479
	CT					528			264			792	792	
	SMR										640	640	640	

**Total = Accredited MW*
***NMPL. MW = Nameplate MW*

Table 21 – Status Quo Future Case Sensitivity, 30-year NPVCC ($M)

Portfolio Name	Base Case	Low Gas	High Gas	CO_2 Tax	Low Solar Cost	High Solar Cost
Solar + CT	$1,848	$2,203	$1,384	$1,555	$1,624	$2,038
Wind + CT	$2,952	$3,742	$2,047	$1,820	$2,952	$2,952
Solar + Wind + CT	$2,562	$3,400	$1,602	$1,653	$2,381	$2,715
Solar + CC	$1,733	$2,091	$1,159	$1,320	$1,540	$1,897
Wind + CC	$3,078	$3,937	$2,030	$1,697	$3,078	$3,078
Solar + Wind + CC	$2,448	$3,067	$1,631	$1,531	$2,337	$2,541
Solar + RICE	$2,302	$2,811	$1,642	$1,903	$2,001	$2,556
Heavy Solar + CT	$1,925	$2,508	$1,225	$1,501	$1,614	$2,188
Solar Only	$2,033	$2,859	$1,086	$1,468	$1,652	$2,355
Wind + Battery + Solar	$3,185	$4,123	$2,159	$2,216	$3,013	$3,330
Heavy Wind + CT	$3,540	$4,753	$2,213	$1,894	$3,540	$3,540
Solar + CT + SMR	$6,479	$7,047	$5,779	$6,016	$6,349	$6,590

The sensitivity risk ranges shown above are graphically illustrated in Figure 25 through Figure 27. The Solar + CT + SMR portfolio data is not shown in the graphs. The bars show each portfolio's deviation in NPVCC from the Base Case in the sensitivities and scenarios. Narrow ranges indicate smaller risks from changes to assumptions. Wide ranges indicate resource portfolios that are highly impacted by assumption changes. Diversified portfolios mitigate a range of risk factors.

Figure 25 – Status Quo Future Case Natural Gas Price Sensitivity Assessment

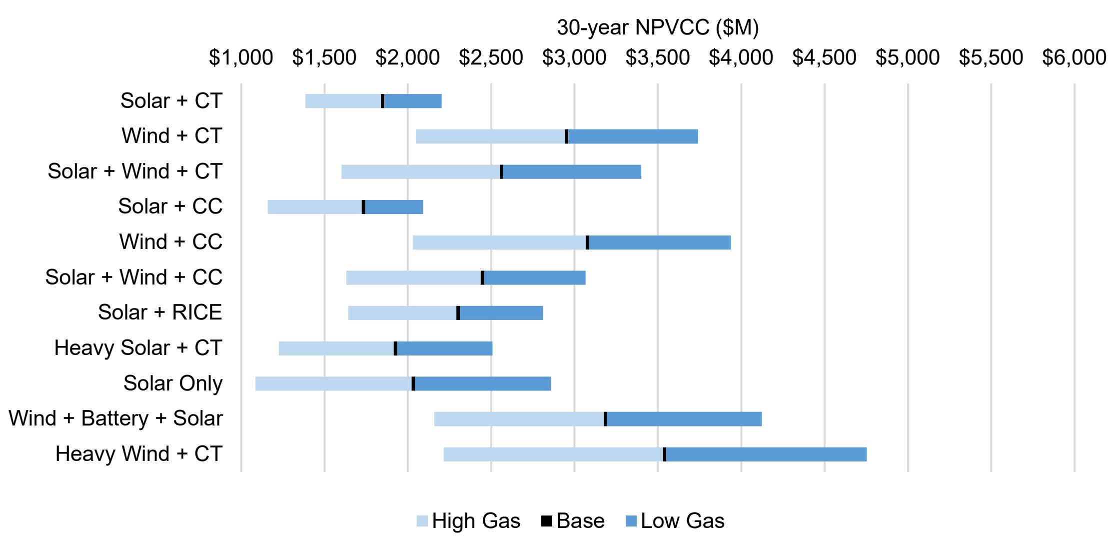


Figure 26 – Status Quo Future Case CO_2 Tax Sensitivity Assessment

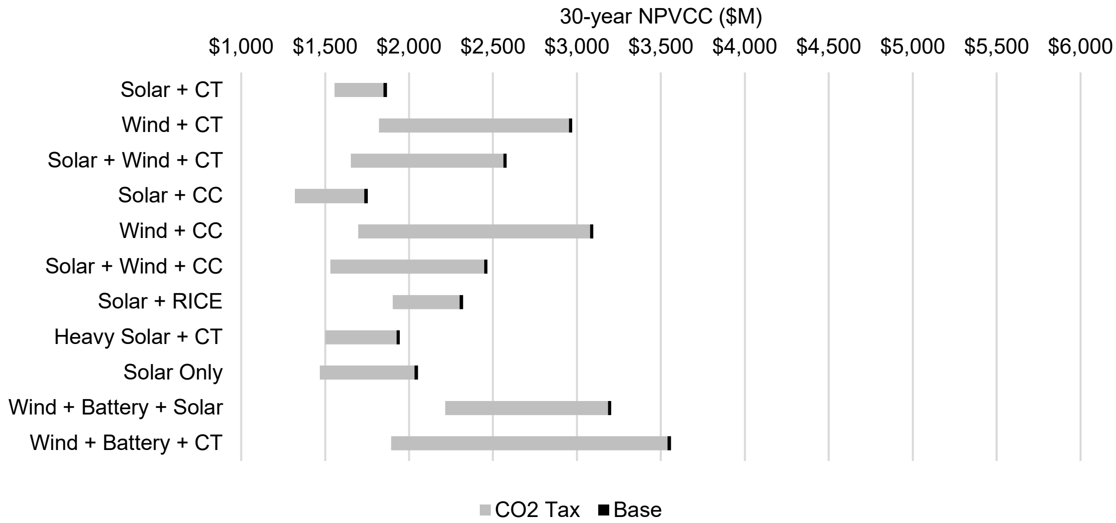


Figure 27 – Status Quo Future Case Solar Capital Cost Sensitivity Assessment

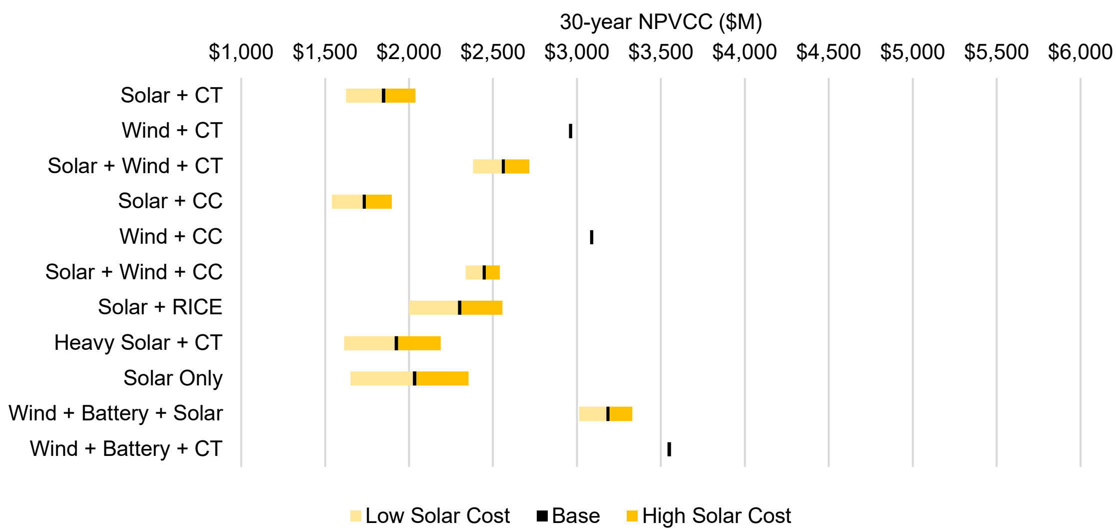


Table 22 – Status Quo Future Case Scenario, 30-year NPVCC ($M)

Portfolio Name	Base Case	Low Fuel Supply	High Fuel Supply	Energy Evolution
Solar + CT	$1,848	$1,474	$2,033	$1,570
Wind + CT	$2,952	$2,308	$3,234	$1,452
Solar + Wind + CT	$2,562	$1,833	$2,895	$1,454
Solar + CC	$1,733	$1,285	$1,889	$1,176
Wind + CC	$3,078	$2,344	$3,328	$1,172
Solar + Wind + CC	$2,448	$1,852	$2,650	$1,206
Solar + RICE	$2,302	$1,770	$2,548	$1,878
Heavy Solar + CT	$1,925	$1,354	$2,199	$1,534
Solar Only	$2,033	$1,252	$2,398	$1,528
Wind + Battery + Solar	$3,185	$2,389	$3,524	$2,094
Heavy Wind + CT	$3,540	$2,590	$3,948	$1,377
Solar + CT + SMR	$6,479	$5,918	$6,758	$6,012

The risk range of the scenarios shown above are graphically illustrated in Figure 28 and Figure 29.

Figure 28 – Status Quo Future Case Fuel Supply Scenario Assessment

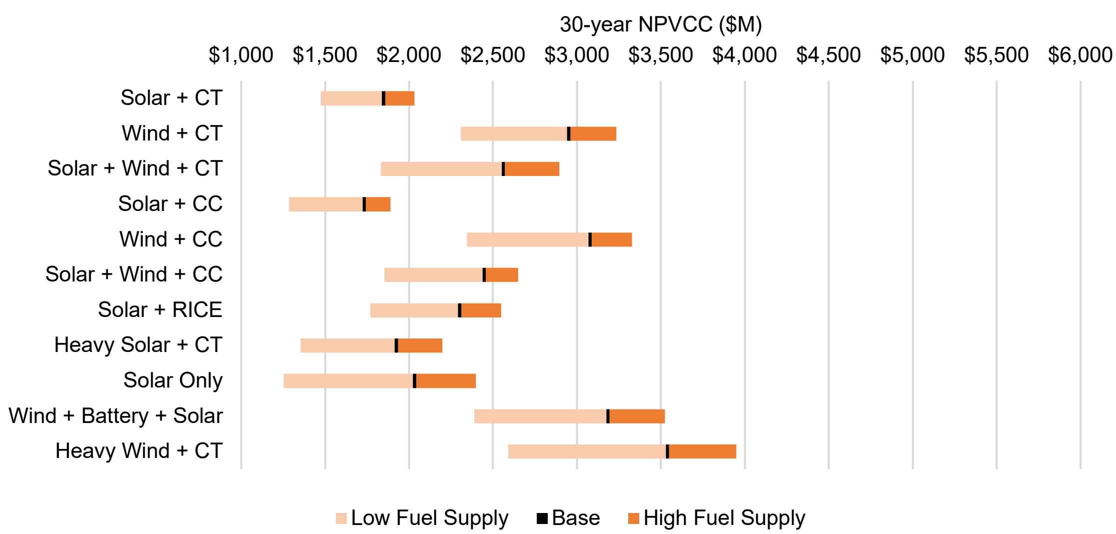
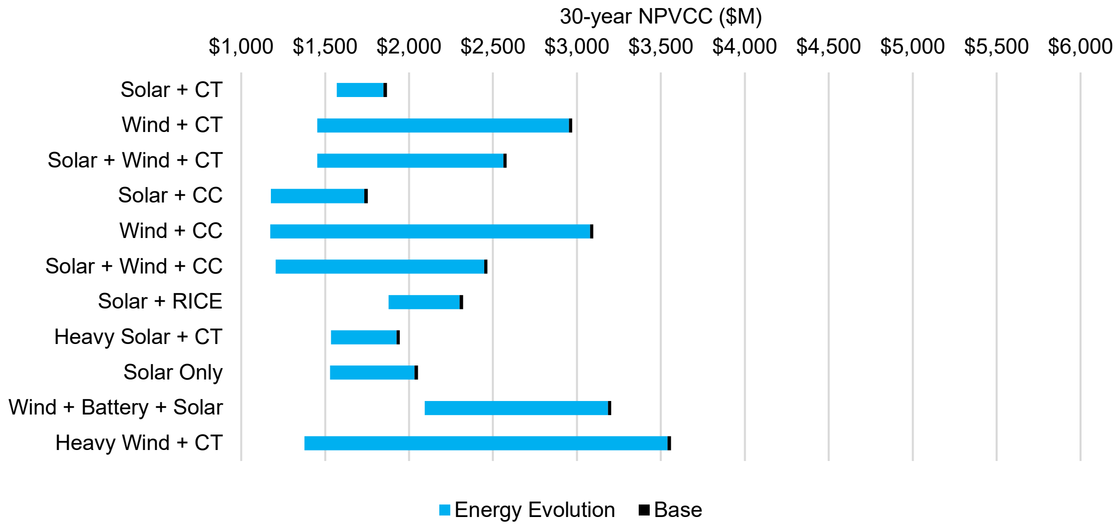


Figure 29 – Status Quo Future Case Energy Evolution Scenario Assessment



The Sensitivity and Scenario analysis shows that OG&E's Preferred Plan under the Status Quo Future Case is the Solar + CT portfolio because it has a low reasonable customer cost in the Base Case compared to other portfolios, and it mitigates a variety of potential risks while also providing a diversified portfolio of renewable and natural gas-fired generation.

Table 23 – OG&E Status Quo Future Case Preferred Plan

Portfolio Name	Type	Accredited Capacity (MW)												NMPL. MW**	30-year NPVCC ($M)
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total*		
Solar + CT	Solar					90		90	450	90	360		1,080	1,800	**$1,848**
	CT					528			264		264		1,056	1,056	

**Total = Accredited MW*
***NMPL. MW = Nameplate MW*

The portfolios focus on the incremental decisions for OG&E's generation fleet. In addition to the NPVCC of the incremental portfolios, Figure 30 and Figure 31 show the 30-year net present value of OG&E's load cost, existing generation unit net production costs and fixed O&M expenses under the natural gas and CO_2 Tax sensitivities, and Energy Evolution scenario with Base Case assumptions.

Figure 30 – Status Quo Future Case Portfolio Cost including Load and Existing Generation Units with Natural Gas Sensitivity

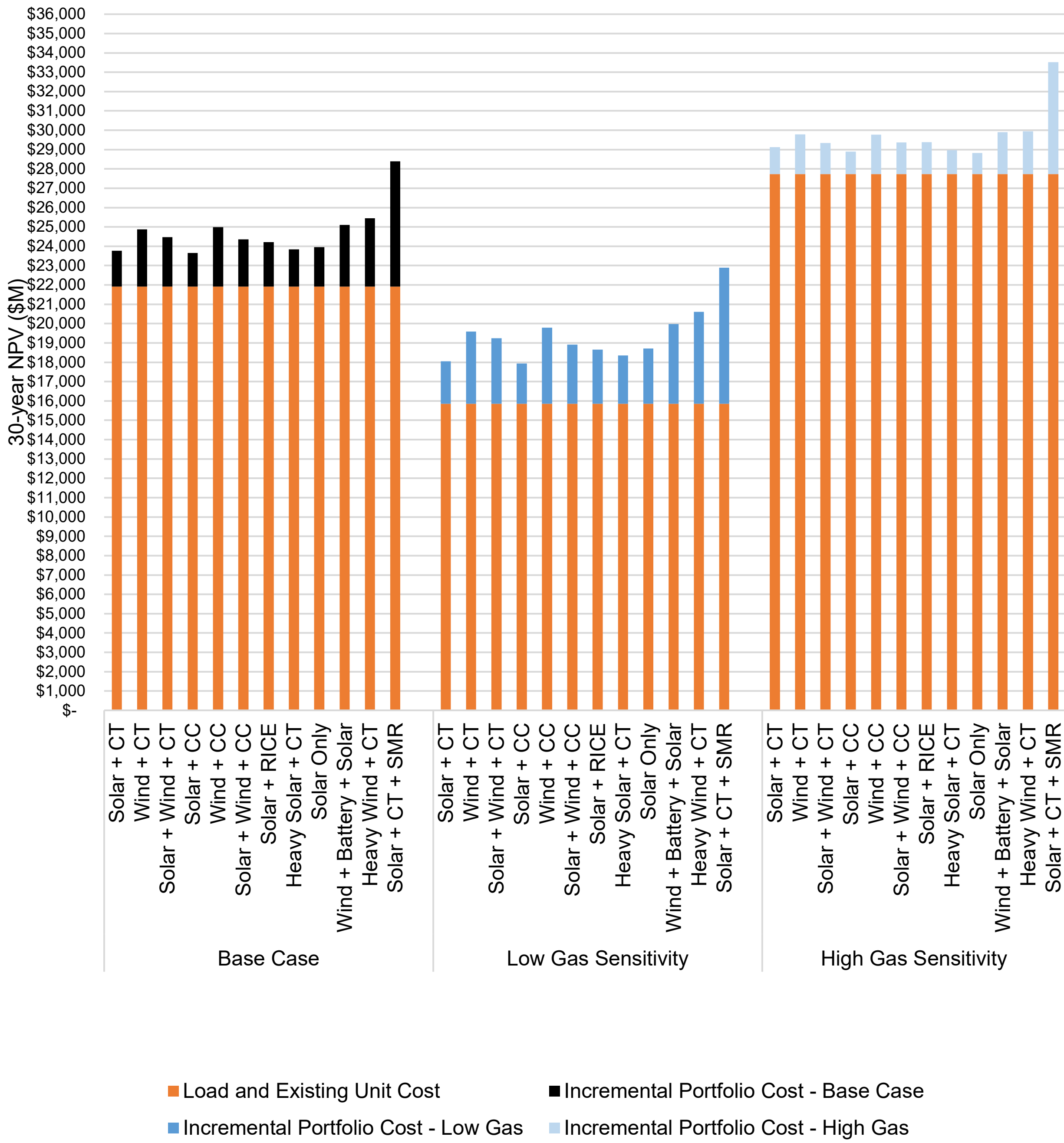
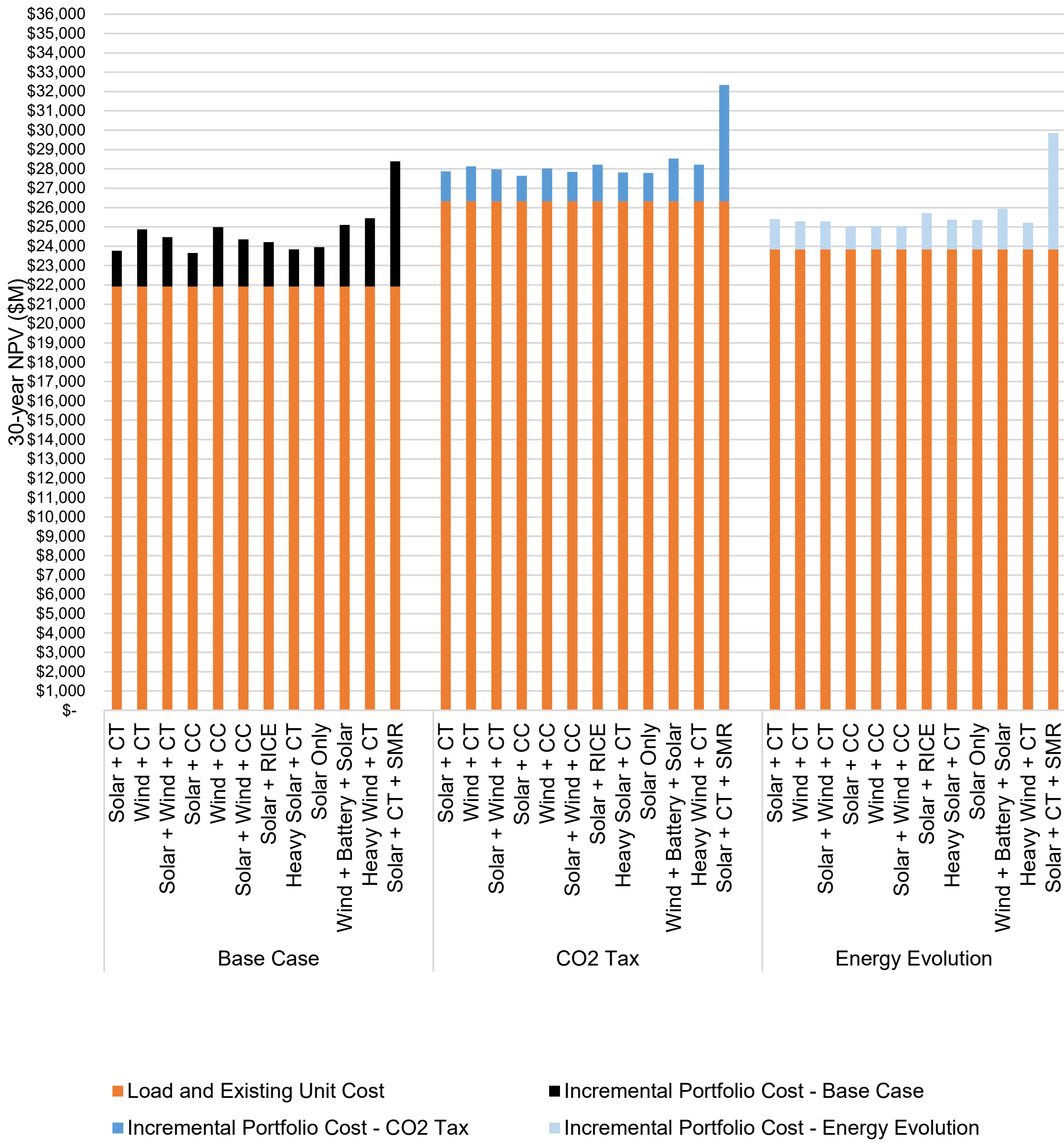


Figure 31 – Status Quo Future Case Portfolio Cost including Load and Existing Generation Units with CO_2 Tax Sensitivity and Energy Evolution Scenario



V. H. Qualitative Considerations

OG&E's preferred Solar + CT plan provides several qualitative benefits.

V. H. 1. Operational Flexibility and Resiliency Benefits

Wind generation capacity in SPP has grown significantly over the past five years to approximately 33 GW[20] as of the end of August 2023 and wind generation growth in SPP is expected to continue in the future. SPP also expects growth in solar generation resources and energy storage resources over the next decade[21]. Combustion turbines complement the intermittency of renewable generation to support reliability during renewable output fluctuations and can respond quickly in the SPP Integrated Marketplace.

SPP recognizes the need for and importance of resources with ramping capability to support reliability. Within the past year, SPP has presented options to address ramping flexibility. "…ramp is critical to serving load under fast-changing conditions; more than adequate capacity is needed; the capacity must be rampable when intermittent resources rapidly reduce[22]."

In an April 8, 2021 article by S&P Global Platts, Lanny Nickell, SPP Executive Vice President and Chief Operating Officer, addressed the need for quick-start resources in SPP.

> In addition to a robust transmission system, Nickell said geographic diversity and a diverse resource portfolio, including 14 GW of quick-start, fast-ramping gas resources, have helped to reliably integrate renewables resources in the region. "And we're not done," he said, pointing to a little over 35 GW of solar and a little less than 35 GW of wind in SPP's generator interconnection queue. "I do expect we're going to continue to see growth in renewables, so we're going to have to make sure that we continue to have the right resources that are available when we need them and that can respond quickly," he said.[23]

V. H. 2. Fuel and Technology Diversity and Reduced Environmental Footprint

The preferred plan adds solar which expands the Company's renewable resources and enhances Fuel and Technology Diversity. In addition, the Solar + CT plan contributes to OG&E's technology diversity by replacing legacy steam gas resources with modern quick-start combustion turbines. Combustion turbines have the flexibility to utilize hydrogen as a fuel. Using hydrogen as a fuel is currently being anticipated by the electric industry for

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[20] SPP. (2024). *Annual State of the Market Report, Summer 2023*. SPP. https://spp.org/documents/70355/spp%20mmu%20qsom%20summer%202023.pdf, page 2.

[21] SPP. (2023). *2023 Integrated transmission planning assessment report*. 2023. SPP. https://www.spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf

[22] SPP. (2024). SPP Resource and Energy Adequacy Leadership Team July 19, 2023 meeting minutes. https://spp.org/documents/69816/real%20draft%20minutes%2007192023.pdf.

[23] "In SPP, preparation, proper valuing of resilience seen as key to energy transition." *S&P Global Platts,* April 8, 2021, www.spglobal.com/platts/en/market-insights/latest-news/electric-power/040821-in-spp-preparation-proper-valuing-of-resilience-seen-as-key-to-energy-transition. Accessed 07/15/2021.

its potential ability to reduce emissions. The proposed EPA GHG rule also includes requirements for new thermal resources to utilize hydrogen as a fuel for emissions reduction. The balance of solar and hydrogen-capable combustion turbines supports OG&E's expectation to reduce CO_2 emissions to 50 percent below 2005 levels by 2030.

VI. OG&E 2024 IRP Conclusion

OG&E has immediate and material capacity needs beginning in 2026 as shown in the Expected Future Case.

MW unless noted	2024	2025	2026	2027	2028
Total Capacity	7,027	7,002	6,495	6,630	6,030
Net Demand	6,073	6,001	6,229	6,237	6,295
Reserve Margin	16%	17%	4%	6%	-4%
Needed Capacity*	0	0	556	431	1,096

**Indicates the capacity needed to meet planning reserve margin requirements.*

The results of the IRP analyses demonstrate that, regardless of future conditions, OG&E expects to have significant and near-term generation capacity needs. The assumptions and analysis shown in the Expected Future Case represents the most likely projection of capacity needs.

In this 2024 IRP, OG&E analyzed a variety of potential resource portfolios to determine the best generation portfolio that satisfies OG&E's "Capacity Obligation" objective of the IRP in the Expected Future Case. The portfolio analysis shows the preferred plan is a combination of solar and combustion turbine resources. In addition to achieving the "Capacity Obligation" IRP objective, the preferred plan also meets the other objectives of the IRP. The preferred plan is one of the lowest reasonable NPVCCs and, therefore, meets the objective for "Expected Cost to Customers." The risk analysis performed by OG&E and presented in this IRP supports a blend of natural gas-fired and solar resources and therefore mitigates "Exposure to Risks" across the range of sensitivities and scenarios analyzed. The balanced approach of solar and natural gas-fired resources fulfills the IRP objective of "Fuel and Technology Diversity," enhances "Reliability and Resiliency Benefits," and improves the "Portfolio Age" of OG&E's generation fleet. The preferred plan also achieves the "Adaptability" objective by retaining the flexibility to adjust the scale of projects and the implementation timetables, depending on changing assumptions in the future.

The solar resources in the preferred plan expand OG&E's renewable generation fleet. Combustion turbines can respond quickly in SPP to enable and support the growth of renewable generation resources into the region. Combined cycle resources are efficient and cost-effective resources, although the risks of future environmental requirements must be considered. The Solar + CT plan allows OG&E to cost-effectively meet capacity needs going forward with newer technology, including hydrogen-capable combustion turbines and zero-emitting resources, consistent with OG&E's environmental stewardship objectives.

The earliest in-service date for newly constructed generation identified in the IRP is 2027, therefore, capacity needs in 2026 must be addressed by a Market Opportunity. OG&E

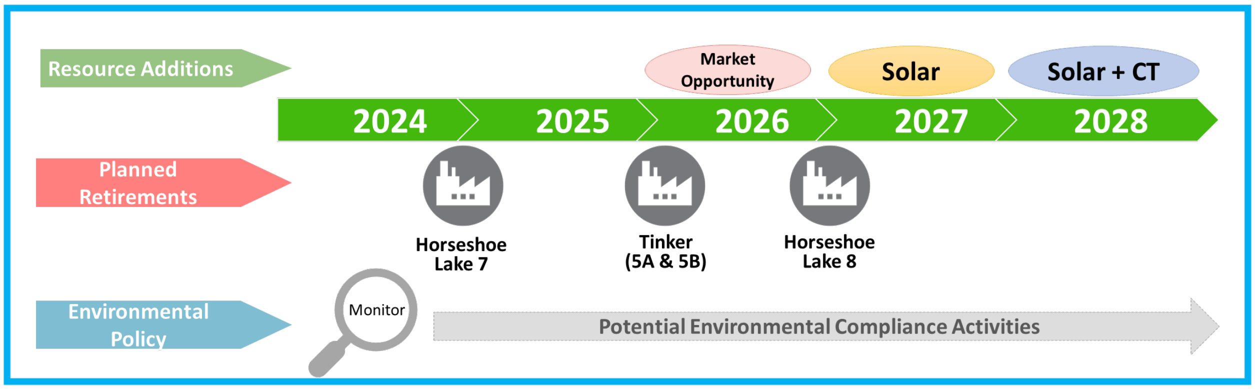
will issue an RFP(s) for Market Opportunities to address near-term capacity needs. Additionally, OG&E will issue RFP(s) for resources to meet the 2027 and later capacity requirements and other IRP objectives. The RFP(s) will recognize and incorporate applicable environmental regulations.

Finally, OG&E is participating in litigation related to EPA's disapproval of the Oklahoma Interstate Transport SIP, which is a statutory prerequisite for EPA's Good Neighbor FIP and CSAPR revisions for Oklahoma. The Oklahoma SIP disapproval is currently under a stay order from the U.S. Tenth Circuit Court, and the EPA has issued an Interim Final Rule preventing implementation of the FIP in Oklahoma while the stay is in effect. To avoid unnecessary expenditures for customers, OG&E will continue to monitor legal and regulatory developments related to the EPA's Good Neighbor FIP and take needed compliance actions after final decisions are made through the legal process.

VII. Action Plan

The Five-Year Action Plan is outlined below.

1) OG&E plans to retire Horseshoe Lake unit 7 in 2024.
2) OG&E plans to retire Tinker units 5A and 5B in 2025.
3) OG&E plans to retire Horseshoe Lake unit 8 in 2027.
4) OG&E will issue multiple RFPs for resources to satisfy the capacity needs identified in this IRP.
5) OG&E will continue to monitor environmental regulation developments and take actions, if deemed necessary.



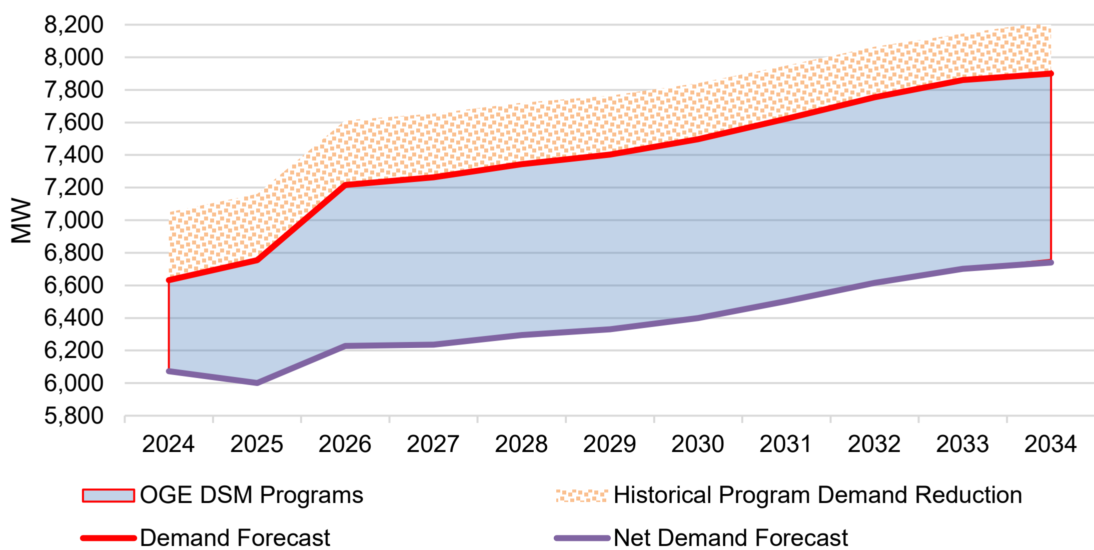
VIII. Schedules

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

VIII. A. Electric Demand and Energy Forecast

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 areas. The peak demand forecast relies on an hourly econometric model. Historical and forecast weather-adjusted retail energy sales are the main driver for the peak demand forecast projections. Historical DSM programs implemented by OG&E since 2007 are incorporated into the load forecast. The peak demand forecast is further reduced by planned future OG&E DSM program implementations to determine the net demand used for planning purposes, as shown in the figure below.

OG&E DSM Impact on Demand Forecast



Energy Sales Forecast (GWh)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Forecast[24]	34,133	35,905	39,768	40,472	41,382	42,307	43,249	44,641	46,087	47,585	47,823
OG&E DSM[25]	185	371	468	565	678	789	889	988	1,094	1,319	1,184
Net Energy	33,947	35,534	39,300	39,908	40,703	41,518	42,360	43,653	44,993	46,266	46,639

[24] Includes SmartHours and Historical Energy Efficiency programs.
[25] Represents estimates for incremental Energy Efficiency programs in Oklahoma and Arkansas, incremental growth of SmartHours, and the Load Reduction Program.

Peak Demand Forecast (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Demand Forecast[26]	6,632	6,754	7,217	7,264	7,343	7,403	7,497	7,623	7,755	7,861	7,917
OG&E DSM[27]	559	753	988	1,027	1,049	1,074	1,098	1,119	1,141	1,159	1,160
Net Demand	6,073	6,001	6,229	6,237	6,295	6,330	6,400	6,504	6,614	6,701	6,757

VIII. B. Existing Generation Resources

This schedule provides a summary of existing resources.

OG&E Existing Thermal Resources

Unit Type	Unit Name	First Year In Service	Summer Capability (MW)
Gas-Fired Steam (3,085 MW)	Horseshoe Lake 7	1963	211
	Horseshoe Lake 8	1969	375
	Seminole 1	1971	500
	Seminole 2	1973	513
	Seminole 3	1975	509
	Muskogee 4	1977	489
	Muskogee 5	1978	488
Combined Cycle (1,111 MW)	Frontier	1989	121
	McClain [28]	2001	373
	Redbud [28]	2004	617
Combustion Turbine (552 MW)	Tinker (Mustang 5A)	1971	33
	Tinker (Mustang 5B)	1971	31
	Horseshoe Lake 9	2000	45
	Horseshoe Lake 10	2000	43
	Mustang 6	2018	57
	Mustang 7	2018	56
	Mustang 8	2018	58
	Mustang 9	2018	57
	Mustang 10	2018	57
	Mustang 11	2018	58
	Mustang 12	2018	57
Coal-Fired Steam (1,878 MW)	Sooner 1	1979	516
	Sooner 2	1980	520
	Muskogee 6	1984	521
	River Valley[29]	1990	321

[26] Includes SmartHours and Historical Energy Efficiency programs.
[27] Represents estimates for incremental Energy Efficiency programs in Oklahoma and Arkansas, incremental growth of SmartHours, and the Load Reduction Program.
[28] Represents OG&E owned interest: 77% of McClain and 51% of Redbud.
[29] River Valley is primarily a coal-fired steam unit but can also utilize natural gas and tire-derived fuel in the combustion process.

OG&E Existing Renewable Resources

Unit Type	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capability (MW)
Wind (61 MW)	Centennial	2006	120	19
	OU Spirit	2009	101	9
	Crossroads	2012	228	33
Solar (22 MW)	Mustang	2015	3	2
	Covington	2018	9	8
	Chickasaw Nation	2020	5	4
	Choctaw Nation	2020	5	4
	Butterfield	2022	5	2
	Branch	2021	5	3

OG&E Existing Power Purchase Contracts

	Unit Name	Contract Start date	Nameplate Capacity (MW)	Summer Capability (MW)
Power Purchase (55 MW)	Keenan	2010	152	22
	Taloga	2011	130	14
	Blackwell	2012	60	12
	Southwestern Power Administration	1979	7	7

OG&E Existing Capacity Purchase Contracts

Agreement Type	Name	Contract Year	Summer Capability (MW)
Capacity Purchase	Bridge Capacity	2024	450
	Bridge Capacity	2025	450
	Bridge Capacity	2026	600
	Bridge Capacity	2027	600

VIII. C. Transmission Capability and Needs

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 552,000 square miles, serves over 19 million customers, and has members in 14 states across all of Kansas and Oklahoma and parts of Arkansas, Colorado, Iowa, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, South Dakota, Texas, and Wyoming. 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.

Each year, SPP produces the SPP Transmission Expansion Plan[30] (STEP) which provides a comprehensive listing a of all transmission projects in the SPP. These projects are derived from several SPP analysis efforts including upgrades required to satisfy requests for Transmission Service or Generator Interconnection, approved projects for the annual ITP assessments, sponsored upgrades from each SPP member if applicable, and any remaining approved projects from previous studies. 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 reports for each SPP study are provided on the SPP website[31]. SPP also provides a comprehensive tracking spreadsheet for all projects[32]. The projects located on the OG&E system are provided in Schedule J.

VIII. D. Needs Assessment

This schedule provides the needs assessment for new generating resources for the next 10 years.

Planning Margin (MW unless noted)

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Capacity	Owned Capacity	6,497	6,497	5,740	5,463	5,463	5,463	5,463	5,038	5,015	4,558	4,558
	Planned Additions	0	0	81	493	493	493	493	493	493	493	493
	Purchase Contracts	530	505	674	674	74	74	74	20	20	7	7
	Total Capacity	7,027	7,002	6,495	6,630	6,030	6,030	6,030	5,550	5,528	5,057	5,057
Demand	Demand Forecast	6,632	6,754	7,217	7,264	7,343	7,403	7,497	7,623	7,755	7,861	7,917
	OG&E DSM	559	753	988	1,027	1,049	1,074	1,098	1,119	1,141	1,159	1,160
	Net Demand	6,073	6,001	6,229	6,237	6,295	6,330	6,400	6,504	6,614	6,701	6,757
Margin	Reserve Margin[33]	16%	17%	4%	6%	-4%	-5%	-6%	-15%	-16%	-25%	-25%
Needs	Needed Capacity	-	-	556	431	1,096	1,136	1,215	1,812	1,960	2,529	2,592

[30] SPP. (2023). *2023 SPP Transmission Expansion Plan Report*. SPP. https://www.spp.org/documents/56611/2023%20spp%20transmission%20expansion%20plan%20report.pdf

[31] SPP. *Integrated Transmission Planning*. ITP reports: https://www.spp.org/engineering/transmission-planning/

[32] SPP. (2023). *2023 SPP Transmission Expansion Plan Report, Appendix 1*. https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.spp.org%2Fdocuments%2F56610%2F2023%2520spp%2520transmission%2520expansion%2520plan%2520project%2520list.xlsx&wdOrigin=BROWSELINK

[33] Reserve Margin % = ((Total Net Capacity) - (Net System Demand)) / Net System Demand

VIII. E. Resource Options

This schedule provides a description of the resource options available to OG&E to address the needs identified in Schedule D.

New Generation Resources (2023$)

Technology	Model	Nameplate Capacity (MW)	Up-front Capital Cost ($/kW)	Summer Capability (MW)	Fixed O&M Cost ($/kW)	Variable O&M Cost ($/MWh)
Wind	Land-Based	250	$1,940	50	$42.40	N/A
Batteries	Lithium Ion	100	$2,130	100	$30.00	N/A
Solar	Photovoltaic Single Axis	150	$2,220	90	$17.40	N/A
Solar/Battery Combo	Single Axis/Lithium Ion	150	$3,230	150	$36.00	N/A
RICE	Reciprocating Engine 3x	55	$1,800	55	$15.40	$4.60
	Reciprocating Engine 6x	110	$1,420	110	$15.10	$4.60
CT Aero	1x LM2500 SCGT	32	$3,200	29	$9.10	$1.70
	12x LM2500 SCGT	389	$2,660	352	$9.20	$1.70
	1x LM6000 SCGT	54	$2,190	50	$5.60	$1.40
	8x LM6000 SCGT	428	$1,870	399	$5.30	$1.40
	1x LMS100 SCGT	102	$2,200	87	$3.10	$1.20
	4x LMS100 SCGT	406	$1,940	347	$3.90	$1.20
CT Frame	1x "E" Class SCGT	86	$2,030	78	$7.50	$7.50
	1x "F" Class SCGT	221	$1,130	211	$3.30	$2.10
	1x "G/H" Class SCGT	280	$930	264	$3.70	$2.20
Combined Cycle (CC)	1x1 J Class	531	$1,180	503	$4.10	$1.50
	1x1 J Class Duct Fired	637	$990	613	$4.10	$2.30
	2x1 G/H Class Duct Fired	1001	$870	944	$2.90	$2.30
	2x1 F Class	729	$1,130	662	$2.70	$1.50
	2x1 F Class Duct Fired	880	$960	828	$2.80	$2.30
	1x1 F Class Duct Fired	441	$1,250	411	$4.90	$2.40
Nuclear	Small Modular Reactor	320	$11,720	320	$234.40	Unknown

VIII. F. Fuel Procurement and Risk Management Plan

On May 15, 2023, OG&E submitted its annual Fuel Supply Portfolio and Risk Management Plan to the OCC as part of Cause No. PUD 200100095. The submitted document can be found at the OCC.

VIII. G. Action Plan

The Five-Year Action Plan is outlined below.

1) OG&E plans to retire Horseshoe Lake unit 7 in 2024.
2) OG&E plans to retire Tinker units 5A and 5B in 2025.

3) OG&E plans to retire Horseshoe Lake unit 8 in 2027.
4) OG&E will issue multiple RFPs for resources to satisfy the capacity needs identified in this IRP.
5) OG&E will continue to monitor environmental regulation developments and take actions, if deemed necessary.

VIII. H. Requests for Proposals

As noted in the Action plan, OG&E will conduct an RFP(s) for resources to satisfy the capacity needs identified in this IRP. The RFP(s) will be issued subsequent to the final IRP, pursuant to the OCC's Electric Utility Rules OAC 165:35-37.

VIII. 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 the source of each assumption and provides a reference for where this information is found in the IRP.

Assumption	Source	Reference
Load Forecast	OG&E	Page 11
Existing Generation Resources	OG&E	Page 12
Resource Changes	OG&E	Page 14
Future Resource Options	Burns & McDonnell, NREL	Page 16
Fuel Price Projections	EIA	Page 19
Risk Assessment	OG&E, EIA, NREL	Page 19
Integrated Market Prices	OG&E, 1898 & Co.	Page 24
Planning Reserve Margin	OG&E	Page 30
Modeling Methodology	OG&E, 1898 & Co.	Page 30
New Resource Earliest Availability	OG&E, Burns & McDonnell	Page 32

For this IRP, OG&E collaborated with 1898 & Co. to utilize two software programs for production cost modeling.

First, PROMOD® - Fundamental Electric Market Simulation software from Hitachi Energy, incorporates generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations to model the SPP IM.

Second, the resource optimization tool EnCompass was utilized for expansion planning and production cost modeling. EnCompass is owned by Anchor Power Solutions, a Yes Energy Company, and is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the power industry. The capacity expansion mode of EnCompass determines the recommended mix of generation resources expected to achieve a least cost dispatch of existing and new generating assets to meet electric load along with regulatory and reliability requirements. The

Production Cost Model then utilizes a detailed economic dispatch mode on an hourly basis for each year of the study period to deliver the optimized result.

VIII. J. Transmission System Adequacy

As described in Schedule C, OG&E is a member of and provides input to SPP, who is ultimately responsible for the planning of the OG&E system. SPP evaluates system adequacy and develops a transmission expansion plan to determine what improvements are necessary to ensure reliable transmission service. The planned projects located on the OG&E system needed to meet the transmission needs are provided in the following table.

Year	Description	Type of Upgrade	Project Type	Current Cost Estimate ($M)	STEP Upgrade Type	Notice to Construct _ID
2024	West Oak 138 kV Breakers	Substation Upgrade	Regional Reliability	$0.92	ITP	210713
2024	Cherry Creek 138 kV Breaker	Substation Upgrade	Regional Reliability	$0.46	ITP	210713
2024	Indian Hill 138 kV Breaker	Substation Upgrade	Regional Reliability	$0.46	ITP	210713
2024	Turner 138 kV Breaker	Substation Upgrade	Regional Reliability	$0.46	ITP	210713
2024	West Oaks - Council - Classen 138 kV Reconductor	Substation Upgrades, Line Upgrade	Regional Reliability	$3.18	DPA-2021-March-1296	210664
2024	Cushing Tap - Shell Cushing Tap - Pipeline	Line Upgrade	Regional Reliability	$5.36	ITP	210589
2024	Rocky Point - OG&E Marietta - WFEC Marietta 138 kV Rebuild	Substation Upgrades, Line Upgrade	Regional Reliability	$15.80	ITP	210656
2024	Norman Hills - Minco - Pleasant Valley - Draper 345 kV	New Substation, Substation Upgrades	Economic	$45.05	ITP	210616
2026	Sooner - Wekiwa 345 kV and Sand Springs - Sheffield 138 kV	Substation Upgrade, New Line	Economic	$4.14	ITP	210540

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.

VIII. K. Resource Plan Assessment

This IRP assessed the need for additional resources to meet reliability, cost and price, environmental, and other criteria established by state and federal laws and regulations. All criteria were met by all portfolios considered in this IRP. These criteria were also met in scenarios and uncertainties which included variations in load growth, fuel prices, emissions prices, environmental regulations, technology improvements, and fuel supply, among others. This plan provides a comprehensive analysis of the proposed options.

VIII. L. Proposed Resource Plan Analysis

This IRP demonstrates that all proposed alternatives meet all planning criteria as outlined in Schedules D and 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.

VIII. M. Physical and Financial Hedging

OG&E's diverse mix of generation assets and its Fuel Cost Adjustment tariff help mitigate customer exposure to price volatility of a single fuel type. Additionally, OG&E's participation in the SPP IM with these generation assets assures OG&E customers the lowest reasonable cost due to the economic commitment and dispatch of the market.

OG&E also has physical fuel storage of both coal and natural gas. In 2022, OG&E expanded its physical hedging of natural gas by expanding its natural gas storage and implementing monthly fixed price gas contracts for a portion of its gas supply. Both of these measures provide a high level of price and volume certainty, further reducing exposure to volatility often seen in the natural gas market.

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 diversified portfolio approach to fuel and purchased power. OG&E has submitted a three-year trial financial hedging plan for natural gas that is currently being reviewed by the Public Utility Division and awaiting approval by the Oklahoma Corporation Commission prior to implementation.

IX. Appendices

Appendix A – Demand Forecast Range and Energy by Class

PEAK DEMAND FORECAST

OG&E's 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 peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility series. A probabilistic range of outcomes is produced to show how often peak demands could reach each level. 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. OG&E is required by SPP to plan for this 50% probability in the PRM calculation.

Peak Demand (MW) Forecasts by Weather Probability before OG&E DSM

Event of Occurrence	Occurrence Probability	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 out of 30 Years	3%	7,185	7,314	7,806	7,855	7,933	7,992	8,086	8,220	8,358	8,460	8,564
1 out of 10 Years	10%	6,931	7,055	7,535	7,582	7,661	7,721	7,816	7,946	8,079	8,186	8,294
1 out of 4 Years	25%	6,760	6,886	7,353	7,403	7,482	7,541	7,633	7,762	7,898	7,999	8,100
1 out of 2 Years	**50%**	6,632	6,754	7,217	7,264	7,343	7,403	7,497	7,623	7,755	7,861	7,968
3 out of 4 Years	75%	6,501	6,622	7,078	7,125	7,205	7,265	7,358	7,483	7,614	7,719	7,825
9 out of 10 Years	90%	6,335	6,458	6,901	6,950	7,030	7,090	7,180	7,304	7,437	7,536	7,636
29 out of 30 Years	97%	6,335	6,458	6,901	6,950	7,030	7,090	7,180	7,304	7,437	7,536	7,636

ENERGY FORECAST

The energy forecast is generated from a regression analysis of historical energy, economic growth patterns and annual weather. OG&E's energy is divided into six market segments (Residential, Commercial, Industrial, Oil Field, Street Lighting and Public Authority). 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.

Energy (GWH) Forecast by Customer Revenue Class before OG&E DSM

GWH	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	9,687	9,732	9,847	9,975	10,121	10,279	10,447	10,634	10,843	11,075	11,130
Commercial	10,584	12,180	15,584	16,003	16,584	17,167	17,755	18,745	19,758	20,796	20,900
Industrial	4,033	3,943	3,910	3,892	3,873	3,855	3,837	3,819	3,802	3,786	3,804
Petroleum	4,484	4,595	4,725	4,859	5,004	5,149	5,294	5,439	5,590	5,742	5,771
Street Lighting	53	52	51	49	48	46	45	43	42	40	40
Public Authority	3,079	3,075	3,073	3,072	3,070	3,069	3,068	3,067	3,065	3,063	3,078
Total Retail Sales	31,921	33,578	37,191	37,849	38,700	39,565	40,446	41,748	43,100	44,501	44,723
Losses	2,212	2,327	2,577	2,623	2,682	2,742	2,803	2,893	2,987	3,084	3,099
Energy Forecast	**34,133**	**35,905**	**39,768**	**40,472**	**41,382**	**42,307**	**43,249**	**44,641**	**46,087**	**47,585**	**47,823**

Appendix B – Portfolio Annual Cost Components

Portfolio Annual Cost Components

Solar + CT					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$61	$0	$0	$0	$61
2026	$161	$0	$0	$0	$161
2027	$208	($94)	$82	($61)	$135
2028	$225	($103)	$124	($69)	$178
2029	$257	($103)	$125	($69)	$209
2030	$310	($124)	$141	($84)	$244
2031	$383	($152)	$187	($101)	$317
2032	$434	($179)	$221	($129)	$348
2033	$431	($236)	$285	($172)	$308
2034	$407	($238)	$286	($173)	$282
2035	$384	($240)	$287	($178)	$252
2036	$361	($233)	$289	($187)	$230
2037	$341	($142)	$290	($191)	$298
2038	$322	($130)	$289	($195)	$286
2039	$305	($131)	$291	($196)	$269
2040	$287	($115)	$292	($198)	$266
2041	$270	($97)	$293	($212)	$254
2042	$253	($59)	$295	($217)	$271
2043	$238	$0	$296	($216)	$317
2044	$223	$0	$288	($223)	$288
2045	$210	$0	$285	($228)	$267
2046	$197	$0	$282	($233)	$245
2047	$184	$0	$279	($238)	$224
2048	$171	$0	$276	($243)	$203
2049	$158	$0	$273	($248)	$183
2050	$146	$0	$269	($253)	$162
2051	$133	$0	$266	($258)	$142
2052	$121	$0	$263	($263)	$121
2053	$109	$0	$260	($268)	$101
30-yr NPV	$2,973	($1,122)	$2,181	($1,505)	$2,527

Wind + CT					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$154	$0	$0	$0	$154
2026	$380	$0	$0	$0	$380
2027	$453	($397)	$283	($165)	$175
2028	$462	($415)	$327	($172)	$202
2029	$510	($420)	$329	($173)	$246
2030	$567	($472)	$364	($202)	$257
2031	$748	($587)	$462	($251)	$373
2032	$965	($555)	$479	($260)	$629
2033	$988	($1,049)	$825	($475)	$289
2034	$931	($1,064)	$831	($485)	$212
2035	$872	($1,090)	$837	($494)	$126
2036	$818	($1,089)	$845	($521)	$52
2037	$769	($679)	$851	($532)	$409
2038	$725	($635)	$856	($537)	$409
2039	$685	($645)	$863	($544)	$359
2040	$644	($613)	$870	($560)	$342
2041	$605	($516)	$877	($595)	$371
2042	$566	($529)	$885	($612)	$310
2043	$530	$0	$892	($611)	$811
2044	$498	$0	$874	($630)	$742
2045	$468	$0	$867	($644)	$691
2046	$438	$0	$861	($659)	$641
2047	$409	$0	$855	($674)	$590
2048	$380	$0	$849	($688)	$540
2049	$351	$0	$843	($703)	$491
2050	$322	$0	$836	($718)	$441
2051	$293	$0	$830	($732)	$391
2052	$264	$0	$824	($747)	$341
2053	$235	$0	$818	($762)	$291
30-yr NPV	$6,486	($4,911)	$6,292	($4,091)	$3,776

Portfolio Annual Cost Components

Solar + Wind + CT					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$81	$0	$0	$0	$81
2026	$226	$0	$0	$0	$226
2027	$300	($163)	$128	($86)	$180
2028	$340	($209)	$190	($114)	$207
2029	$414	($211)	$191	($114)	$280
2030	$520	($307)	$257	($158)	$313
2031	$680	($389)	$338	($198)	$431
2032	$798	($518)	$440	($265)	$455
2033	$793	($713)	$596	($380)	$296
2034	$747	($722)	$599	($389)	$234
2035	$701	($731)	$602	($398)	$174
2036	$659	($726)	$607	($417)	$122
2037	$620	($559)	$610	($426)	$245
2038	$584	($503)	$613	($432)	$262
2039	$551	($509)	$617	($435)	$223
2040	$518	($422)	$621	($449)	$268
2041	$487	($355)	$625	($476)	$281
2042	$456	($205)	$629	($488)	$393
2043	$429	$0	$633	($488)	$574
2044	$404	$0	$615	($502)	$516
2045	$380	$0	$609	($514)	$474
2046	$356	$0	$602	($525)	$433
2047	$333	$0	$595	($537)	$391
2048	$309	$0	$588	($548)	$350
2049	$286	$0	$582	($559)	$308
2050	$263	$0	$575	($571)	$267
2051	$240	$0	$568	($582)	$226
2052	$217	$0	$561	($594)	$184
2053	$193	$0	$555	($605)	$143
30-yr NPV	$5,150	($3,254)	$4,410	($3,230)	$3,075

Solar + CC					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$58	$0	$0	$0	$58
2026	$221	$0	$0	$0	$221
2027	$371	($94)	$82	($61)	$298
2028	$419	($227)	$197	($143)	$246
2029	$412	($238)	$235	($194)	$214
2030	$396	($241)	$236	($202)	$189
2031	$401	($246)	$238	($201)	$191
2032	$415	($233)	$239	($205)	$216
2033	$411	($221)	$282	($245)	$227
2034	$391	($213)	$284	($238)	$224
2035	$371	($218)	$286	($243)	$196
2036	$352	($221)	$287	($259)	$159
2037	$333	($136)	$289	($262)	$223
2038	$316	$0	$291	($265)	$342
2039	$301	$0	$292	($267)	$326
2040	$288	$0	$294	($262)	$320
2041	$274	$0	$295	($284)	$285
2042	$260	$0	$296	($293)	$263
2043	$246	$0	$298	($290)	$254
2044	$233	$0	$295	($298)	$229
2045	$219	$0	$295	($304)	$210
2046	$205	$0	$295	($310)	$190
2047	$191	$0	$295	($316)	$171
2048	$177	$0	$295	($321)	$151
2049	$164	$0	$295	($327)	$132
2050	$151	$0	$295	($333)	$113
2051	$138	$0	$295	($339)	$94
2052	$125	$0	$295	($344)	$75
2053	$112	$0	$294	($350)	$57
30-yr NPV	$3,417	($1,250)	$2,434	($2,226)	$2,375

Portfolio Annual Cost Components

Wind + CC					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$149	$0	$0	$0	$149
2026	$570	$0	$0	$0	$570
2027	$919	($397)	$283	($165)	$640
2028	$985	($994)	$699	($395)	$295
2029	$960	($1,007)	$705	($400)	$259
2030	$922	($1,031)	$748	($477)	$163
2031	$894	($1,060)	$754	($488)	$101
2032	$879	($1,033)	$760	($504)	$103
2033	$848	($990)	$809	($551)	$116
2034	$802	($1,005)	$816	($552)	$60
2035	$757	($1,027)	$823	($560)	($6)
2036	$712	($1,043)	$829	($595)	($96)
2037	$669	($636)	$837	($606)	$264
2038	$631	$0	$844	($609)	$866
2039	$599	$0	$851	($617)	$833
2040	$570	$0	$859	($625)	$803
2041	$540	$0	$866	($668)	$739
2042	$511	$0	$873	($690)	$694
2043	$481	$0	$881	($688)	$674
2044	$452	$0	$872	($707)	$617
2045	$422	$0	$874	($722)	$574
2046	$393	$0	$876	($738)	$531
2047	$363	$0	$878	($753)	$488
2048	$334	$0	$880	($769)	$445
2049	$304	$0	$883	($785)	$402
2050	$275	$0	$885	($800)	$359
2051	$246	$0	$887	($816)	$317
2052	$217	$0	$889	($831)	$275
2053	$189	$0	$891	($847)	$233
30-yr NPV	$7,440	($5,543)	$7,359	($5,262)	$3,994

Solar + Wind + CC					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$79	$0	$0	$0	$79
2026	$294	$0	$0	$0	$294
2027	$481	($163)	$128	($86)	$360
2028	$532	($370)	$291	($191)	$262
2029	$518	($383)	$330	($243)	$222
2030	$495	($388)	$332	($254)	$185
2031	$493	($398)	$334	($255)	$175
2032	$503	($381)	$336	($262)	$197
2033	$493	($363)	$381	($303)	$207
2034	$468	($359)	$384	($298)	$196
2035	$444	($369)	$386	($303)	$158
2036	$419	($374)	$388	($322)	$112
2037	$396	($214)	$391	($327)	$246
2038	$375	$0	$394	($331)	$439
2039	$357	$0	$396	($334)	$420
2040	$341	$0	$400	($331)	$409
2041	$324	$0	$402	($357)	$368
2042	$307	$0	$404	($369)	$343
2043	$290	$0	$407	($366)	$331
2044	$273	$0	$403	($376)	$301
2045	$257	$0	$403	($383)	$277
2046	$240	$0	$404	($391)	$253
2047	$223	$0	$404	($399)	$228
2048	$206	$0	$404	($406)	$204
2049	$190	$0	$405	($414)	$181
2050	$174	$0	$405	($421)	$157
2051	$158	$0	$405	($429)	$134
2052	$142	$0	$406	($437)	$111
2053	$126	$0	$406	($444)	$88
30-yr NPV	$4,195	($2,053)	$3,367	($2,812)	$2,697

Portfolio Annual Cost Components

Solar + RICE					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$59	$0	$0	$0	$59
2026	$196	$0	$0	$0	$196
2027	$305	($94)	$82	($61)	$232
2028	$348	($175)	$174	($112)	$235
2029	$399	($196)	$191	($123)	$271
2030	$461	($218)	$209	($141)	$311
2031	$556	($288)	$289	($186)	$370
2032	$645	($296)	$307	($203)	$453
2033	$645	($422)	$428	($302)	$348
2034	$608	($423)	$429	($311)	$304
2035	$572	($429)	$431	($320)	$253
2036	$538	($419)	$432	($331)	$221
2037	$506	($334)	$434	($339)	$267
2038	$477	($242)	$436	($346)	$325
2039	$450	($224)	$437	($346)	$317
2040	$425	($211)	$439	($358)	$295
2041	$400	($155)	$441	($378)	$307
2042	$375	($138)	$442	($386)	$293
2043	$353	$0	$444	($388)	$409
2044	$332	$0	$429	($398)	$363
2045	$312	$0	$423	($407)	$329
2046	$293	$0	$417	($416)	$294
2047	$273	$0	$411	($424)	$260
2048	$254	$0	$405	($433)	$226
2049	$235	$0	$399	($442)	$192
2050	$216	$0	$392	($450)	$158
2051	$197	$0	$386	($459)	$124
2052	$178	$0	$380	($468)	$90
2053	$159	$0	$374	($477)	$56
30-yr NPV	$4,367	($1,982)	$3,210	($2,619)	$2,975

Heavy Solar + CT					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$59	$0	$0	$0	$59
2026	$174	$0	$0	$0	$174
2027	$254	($94)	$82	($61)	$181
2028	$279	($138)	$143	($90)	$194
2029	$307	($158)	$160	($101)	$207
2030	$366	($160)	$160	($105)	$261
2031	$466	($209)	$223	($137)	$343
2032	$550	($236)	$257	($166)	$404
2033	$550	($348)	$358	($250)	$310
2034	$519	($348)	$359	($255)	$275
2035	$488	($356)	$361	($263)	$229
2036	$459	($347)	$362	($274)	$200
2037	$432	($258)	$364	($280)	$257
2038	$408	($205)	$363	($286)	$281
2039	$385	($187)	$365	($286)	$277
2040	$363	($192)	$366	($294)	$244
2041	$341	($155)	$368	($311)	$243
2042	$320	($119)	$369	($318)	$253
2043	$301	$0	$371	($319)	$353
2044	$283	$0	$358	($328)	$313
2045	$266	$0	$353	($335)	$284
2046	$250	$0	$347	($342)	$255
2047	$233	$0	$342	($350)	$226
2048	$217	$0	$337	($357)	$197
2049	$201	$0	$331	($364)	$169
2050	$185	$0	$326	($371)	$140
2051	$169	$0	$320	($378)	$111
2052	$153	$0	$315	($385)	$82
2053	$137	$0	$309	($393)	$54
30-yr NPV	$3,678	($1,619)	$2,671	($2,148)	$2,581

Portfolio Annual Cost Components

Solar Only					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$56	$0	$0	$0	$56
2026	$223	$0	$0	$0	$223
2027	$365	($94)	$82	($61)	$291
2028	$396	($246)	$214	($155)	$208
2029	$468	($248)	$214	($154)	$280
2030	$581	($270)	$232	($174)	$368
2031	$684	($417)	$350	($270)	$347
2032	$754	($447)	$385	($303)	$387
2033	$740	($545)	$488	($392)	$291
2034	$697	($551)	$489	($406)	$230
2035	$654	($560)	$491	($417)	$168
2036	$615	($543)	$492	($430)	$134
2037	$578	($458)	$493	($441)	$172
2038	$544	($297)	$495	($450)	$291
2039	$513	($299)	$496	($450)	$261
2040	$483	($287)	$498	($467)	$227
2041	$455	($155)	$499	($491)	$308
2042	$428	($119)	$501	($501)	$309
2043	$403	$0	$502	($505)	$401
2044	$380	$0	$483	($518)	$345
2045	$357	$0	$474	($529)	$303
2046	$335	$0	$466	($540)	$261
2047	$312	$0	$458	($552)	$218
2048	$290	$0	$449	($563)	$176
2049	$267	$0	$441	($574)	$134
2050	$245	$0	$433	($585)	$92
2051	$222	$0	$424	($597)	$50
2052	$199	$0	$416	($608)	$8
2053	$177	$0	$408	($619)	($34)
30-yr NPV	$5,065	($2,592)	$3,659	($3,426)	$2,706

Wind + Battery + Solar					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$52	$0	$0	$0	$52
2026	$217	$0	$0	$0	$217
2027	$376	($77)	$77	($52)	$324
2028	$422	($257)	$241	($136)	$271
2029	$493	($305)	$275	($154)	$309
2030	$596	($329)	$293	($175)	$385
2031	$669	($460)	$425	($244)	$390
2032	$720	($493)	$461	($277)	$410
2033	$694	($537)	$551	($334)	$374
2034	$652	($539)	$554	($344)	$323
2035	$612	($549)	$557	($353)	$266
2036	$574	($535)	$560	($367)	$231
2037	$538	($469)	$563	($376)	$256
2038	$505	($277)	$566	($383)	$411
2039	$475	($230)	$570	($385)	$430
2040	$447	($217)	$573	($400)	$402
2041	$419	($97)	$576	($422)	$477
2042	$394	($59)	$580	($432)	$482
2043	$370	$0	$583	($433)	$520
2044	$347	$0	$567	($446)	$467
2045	$324	$0	$561	($456)	$429
2046	$302	$0	$555	($467)	$391
2047	$280	$0	$550	($477)	$353
2048	$257	$0	$544	($487)	$314
2049	$235	$0	$539	($497)	$276
2050	$213	$0	$533	($508)	$238
2051	$190	$0	$527	($518)	$200
2052	$168	$0	$522	($528)	$162
2053	$146	$0	$516	($538)	$124
30-yr NPV	$4,867	($2,613)	$4,283	($2,987)	$3,550

Portfolio Annual Cost Components

Wind + Battery + CT					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$74	$0	$0	$0	$74
2026	$237	$0	$0	$0	$237
2027	$354	($138)	$130	($63)	$283
2028	$408	($283)	$254	($122)	$258
2029	$562	($332)	$288	($141)	$378
2030	$797	($383)	$323	($168)	$569
2031	$1,087	($780)	$607	($334)	$579
2032	$1,326	($919)	$712	($407)	$712
2033	$1,332	($1,453)	$1,096	($647)	$327
2034	$1,252	($1,469)	$1,103	($666)	$220
2035	$1,173	($1,506)	$1,112	($677)	$101
2036	$1,101	($1,483)	$1,121	($712)	$26
2037	$1,034	($1,359)	$1,130	($727)	$78
2038	$973	($1,173)	$1,138	($735)	$203
2039	$916	($1,141)	$1,147	($743)	$178
2040	$860	($1,124)	$1,156	($770)	$122
2041	$806	($722)	$1,166	($815)	$434
2042	$755	($582)	$1,175	($838)	$510
2043	$709	$0	$1,185	($838)	$1,056
2044	$668	$0	$1,154	($863)	$959
2045	$629	$0	$1,143	($883)	$889
2046	$590	$0	$1,132	($903)	$819
2047	$551	$0	$1,121	($923)	$749
2048	$513	$0	$1,109	($943)	$679
2049	$474	$0	$1,098	($963)	$609
2050	$436	$0	$1,087	($984)	$539
2051	$397	$0	$1,076	($1,004)	$469
2052	$359	$0	$1,064	($1,024)	$399
2053	$320	$0	$1,053	($1,044)	$329
30-yr NPV	$8,036	($6,390)	$7,852	($5,292)	$4,206

Solar + CT + SMR					
($M)	Return on Rate Base	Tax Credits	Expenses	Production Cost	Customer Cost
2024	$0	$0	$0	$0	$0
2025	$61	$0	$0	$0	$61
2026	$161	$0	$0	$0	$161
2027	$208	($94)	$82	($61)	$135
2028	$225	($103)	$124	($69)	$178
2029	$257	($103)	$125	($69)	$209
2030	$308	($124)	$141	($84)	$242
2031	$339	($152)	$187	($101)	$273
2032	$331	($179)	$221	($129)	$244
2033	$1,109	($267)	$616	($243)	$1,215
2034	$1,071	($268)	$619	($245)	$1,177
2035	$1,030	($269)	$624	($255)	$1,130
2036	$991	($261)	$630	($266)	$1,094
2037	$955	($169)	$635	($273)	$1,147
2038	$920	($74)	$638	($281)	$1,202
2039	$887	($74)	$643	($283)	$1,173
2040	$855	($57)	$648	($289)	$1,156
2041	$823	($39)	$653	($307)	$1,131
2042	$792	$0	$659	($316)	$1,135
2043	$762	$0	$664	($315)	$1,111
2044	$733	$0	$662	($327)	$1,068
2045	$704	$0	$664	($335)	$1,033
2046	$675	$0	$667	($343)	$998
2047	$646	$0	$669	($351)	$964
2048	$618	$0	$672	($359)	$930
2049	$589	$0	$674	($367)	$896
2050	$561	$0	$676	($375)	$862
2051	$532	$0	$679	($383)	$828
2052	$504	$0	$681	($391)	$794
2053	$478	$0	$684	($399)	$763
30-yr NPV	$6,105	($1,097)	$4,251	($2,037)	$7,221

Appendix C – OG&E 2024 IRP Oklahoma Technical Conference

We Energize Life

2024 Integrated Resource Plan

Oklahoma Technical Conference

February 22, 2024

Meeting Procedures

- As the OG&E team proceeds through this presentation, there will be time after each section for questions

Raise

- To ask a question, please raise your hand from the Teams menu
- Be sure to unmute your microphone after you are recognized by the facilitator to ask your question

Q&A

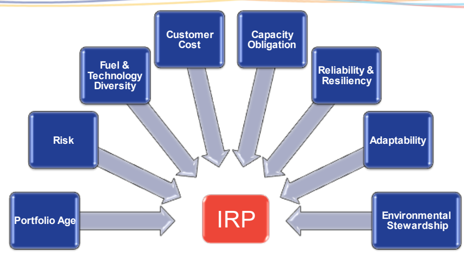
- If time does not allow for all questions, you may use the Q&A feature to submit your question for later follow-up

Presentation Agenda

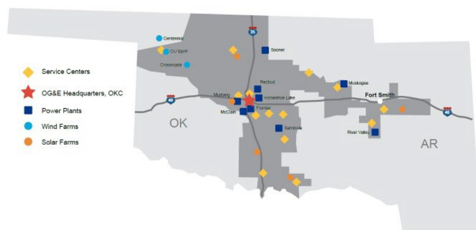
- **Introduction**
  - IRP Objectives and Development Process
  - OG&E Generation
  - SPP Overview and Requirements
  - Risks
  - Future Cases
- **Data Inputs**
  - Generation Resources considered
  - Fuel Price Projections
  - Energy Price Projections
- **Analysis – Expected Future Case**
- **Analysis – CSAPR Future Case**
- **Analysis – Status Quo Future Case**
- **Action Plan**

Introduction

OG&E's Resource Planning Process has multiple objectives

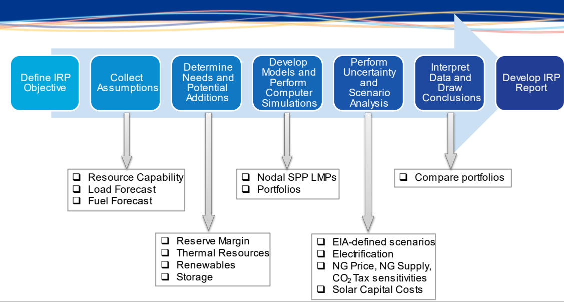


OG&E's Existing Generation Fleet



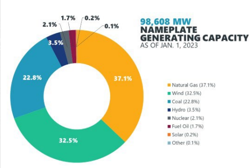
Type	Summer Capacity (MW)
Natural Gas	4,748
Coal	1,878
Wind	61
Renewable PPAs	55
Solar	22
Total	**6,764**

Resource Planning Process

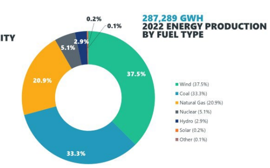


Southwest Power Pool

SPP 2020 Annual State of the Market Report



[SPP 2022 Annual State of the Market Report]



[SPP 2022 Annual State of the Market Report]

Policy and Regulation Risks

Resource Adequacy Policy Risks

Current Risks:
- Expected Change to the Planning Reserve Margin (PRM)
- Planned Change to Resource Accreditation Methodologies
  - Performance Based Accreditation (PBA)
  - Effective Load Carrying Capability (ELCC)

Future Risks:
- Winter Resource Adequacy Requirement
- Change to Demand Response Program Accreditation
- Fuel Assurance Policy
- Ramping Capability Requirement

Environmental Regulation Risks

Current Risks:
- Clean Air Act Good Neighbor Provision and the Cross State Air Pollution Rule (CSAPR)

Future Risks:
- Mercury and Air Toxics Standards (MATS)
- Federal Clean Water Act
- Greenhouse Gas (GHG) Regulations
- National Ambient Air Quality Standards (NAAQS)
- Regional Haze
- Endangered Species Act (ESA) and other federal laws

SPP Resource Adequacy Terminology

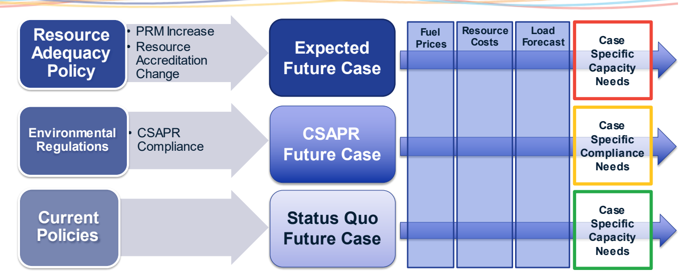
SPP Resource Policy revisions included in OG&E's Expected Future Case:

Planning Reserve Margin (PRM) = The amount of reserve generation a Load Responsible Entity (LRE) must maintain over its forecasted peak demand

Performance Based Accreditation (PBA) = Revision to accreditation methodology for conventional generation resources in SPP

Effective Load Carrying Capability (ELCC) = Revision to accreditation methodology for renewable generation and energy storage resources in SPP

2024 IRP Analysis Approach



Questions

Data Inputs

OG&E Load Forecast with DSM Programs

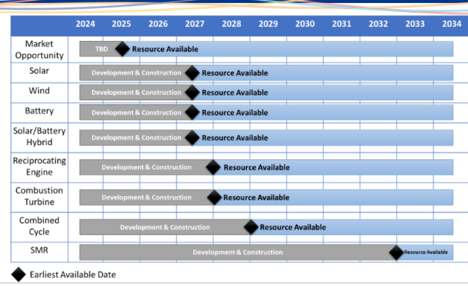
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Gross Peak Demand Forecast	6,632	6,754	7,217	7,264	7,343	7,403	7,497	7,623	7,755	7,861	7,917
OG&E DSM	559	753	988	1,027	1,049	1,074	1,098	1,119	1,141	1,159	1,160
Net Peak Demand Forecast	6,073	6,001	6,229	6,237	6,295	6,330	6,400	6,504	6,614	6,701	6,757

Resource Options Analyzed

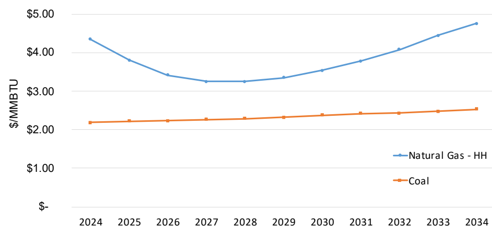
Technology	Model	Nameplate Capacity (MW)	Up-front Capital Cost ($/kW)	Summer Capability (MW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)
Wind	Land-Based	250	$1,940	50	$42.40	N/A
Batteries	Lithium Ion	100	$2,130	100	$30.00	N/A
Solar	Photovoltaic Single Axis	150	$2,220	90	$17.40	N/A
Solar/Battery Combo	Single Axis/Lithium Ion	150	$3,230	150	$36.00	N/A
RICE	Reciprocating Engine 3x	55	$1,800	55	$15.40	$4.60
	Reciprocating Engine 6x	110	$1,420	110	$15.10	$4.60
CT Aero	1x LM2500 SCGT	32	$3,200	29	$9.10	$1.70
	12x LM2500 SCGT	389	$2,660	352	$9.20	$1.70
	1x LM6000 SCGT	54	$2,190	50	$5.60	$1.40
	8x LM6000 SCGT	428	$1,870	399	$5.30	$1.40
	1x LMS100 SCGT	102	$2,200	87	$3.10	$1.20
	4x LMS100 SCGT	406	$1,940	347	$3.90	$1.20
CT Frame	1x "E" Class SCGT	86	$2,030	78	$7.50	$7.50
	1x "F" Class SCGT	221	$1,130	211	$3.30	$2.10
	1x "G/H" Class SCGT	280	$930	264	$3.70	$2.20
Combined Cycle (CC)	1x1 J Class	531	$1,180	503	$4.10	$1.50
	1x1 J Class Duct Fired	637	$990	613	$4.10	$2.30
	2x1 G/H Class Duct Fired	1001	$870	944	$2.90	$2.30
	2x1 F Class	729	$1,130	662	$2.70	$1.50
	2x1 F Class Duct Fired	880	$960	828	$2.80	$2.30
	1x1 F Class Duct Fired	441	$1,250	411	$4.90	$2.40
Nuclear	Small Modular Reactor (SMR)	320	$11,720	320	$234.40	Unknown

Data provided by Burns & McDonnell; $/kW capital costs given in 2023'$

Resource Timing



Base Case Assumptions



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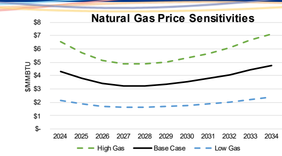
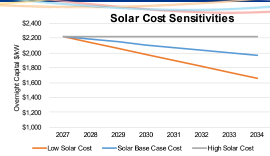
Risk Assessment: Sensitivities





Sensitivities	Natural Gas Price	CO_2	Solar Capital Cost
Base Case	EIA Reference Case	CO_2 Tax is non-existent	NREL low solar trajectory
Low Gas	50% Below Base Case	Base Case	Base Case
High Gas	50% Above Base Case	Base Case	Base Case
CO_2 Tax	Base Case	$15/ton CO_2 tax starting 2029, escalates by 2%	Base Case
Low Solar Capital Cost	Base Case	Base Case	NREL low solar trajectory
High Solar Capital Cost	Base Case	Base Case	Solar Capital Cost remains unchanged

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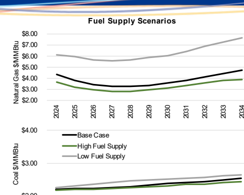
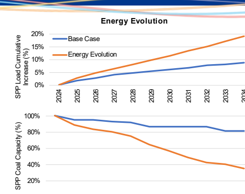
Risk Assessment: Scenarios





Scenarios	Natural Gas Price	Coal Price	Other
Base Case	EIA Reference Case	EIA Reference Case	Current laws and regulations
High Fuel Supply (EIA)	~14% below Ref. Case	~2% below Ref. Case	Base Case
Low Fuel Supply (EIA)	~65% above Ref. Case	~5% above Ref. Case	Base Case
Energy Evolution	Base Case	Base Case	Accelerated SPP Coal Retirements

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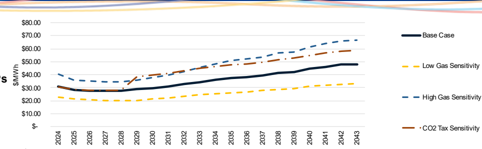
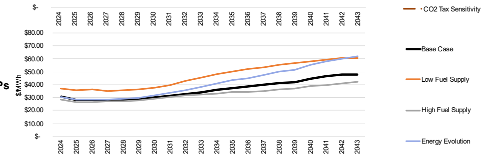
Annual Average Locational Marginal Prices

Sensitivity LMPs



Scenario LMPs



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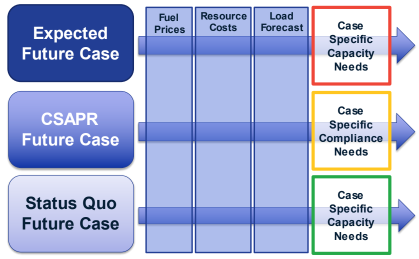
2024 IRP Future Cases



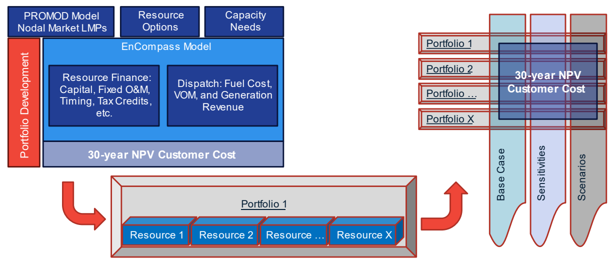
Summary of Futures, Scenarios and Sensitivities

	Expected Future Case	CSAPR Future Case	Status Quo Future Case
PRM Increase	18%	18%	15%
PBA/ELCC	Yes	Yes	No
CSAPR	No	Yes	No
	Scenarios/Sensitivities	Scenarios/Sensitivities	Scenarios/Sensitivities
Base	Base Case	Base Case	Base Case
Sensitivities	Low Gas	Low Gas	Low Gas
	High Gas	High Gas	High Gas
	CO_2 Tax	CO_2 Tax	CO_2 Tax
	Low Solar Capital Cost	Low Solar Capital Cost	Low Solar Capital Cost
	High Solar Capital Cost	High Solar Capital Cost	High Solar Capital Cost
Scenarios	High Fuel Supply (EIA)	High Fuel Supply (EIA)	High Fuel Supply (EIA)
	Low Fuel Supply (EIA)	Low Fuel Supply (EIA)	Low Fuel Supply (EIA)
	Energy Evolution	Energy Evolution	Energy Evolution

Questions

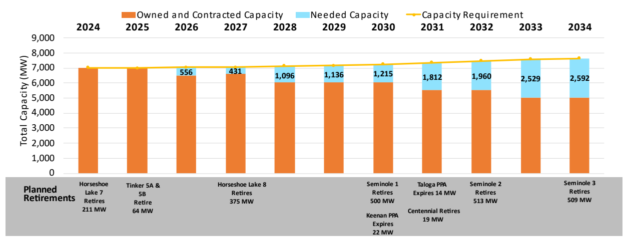
Analysis – Expected Future Case

Analysis Process



Planning Reserve Margin and Capacity Needs –Expected Future

Expected Case includes 18% PRM, Performance Based Accreditation, and Effective Load Carrying Capability in 2026



Expected Future Case Portfolios

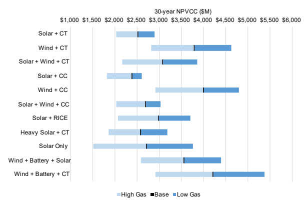
Portfolio	Type	Peak Accredited Capacity (MW) 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total*	NMPL. MW	30-yr NPVCC ($M)
Market Opportunity				X										$0
Preferred Plan: Solar + CT	Solar				450			90	90	180	270	1,080	1,800	$2,527
	CT					727			485		242	1,454	1,583	
Wind + CT	Wind				450			50	100		500	1,100	5,500	$3,776
	CT					727			485	242		1,454	1,583	
Solar + Wind + CT	Solar				360	180			90		450	1,080	1,800	$3,075
	Wind				100			100	50	150	100	500	2,500	
	CT					485			485			970	1,055	
Solar + CC	Solar				450	630						1,080	1,800	$2,375
	CC						911				911	1,822	1,888	
Wind + CC	Wind				450	650						1,100	5,500	$3,994
	CC							911			911	1,822	1,888	
Solar + Wind + CC	Solar				360	540						900	1,500	$2,697
	Wind				100	100						200	1,000	
	CC						911				911	1,822	1,888	
Solar + RICE	Solar				450	360	90	90	270	90	630	1,980	3,300	$2,975
	RICE					304			304			608	661	

Expected Future Case Portfolios

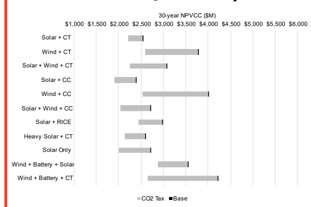
Portfolio	Type	Peak Accredited Capacity (MW) 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total*	NMPL. MW	30-yr NPVCC ($M)
Market Opportunity				X										$0
Preferred Plan: Solar + CT	Solar				450			90	90	180	270	1,080	1,800	$2,527
	CT					727			485		242	1,454	1,583	
Heavy Solar + CT	Solar				450	180	90		180	180	540	1,620	2,700	$2,581
	CT					485			485			970	1,055	
Solar Only	Solar				450	720		90	630	180	540	2,610	4,350	$2,706
Wind + Battery + Solar	Wind					150	50		100			300	1,500	$3,550
	Battery				100	300			400		300	1,100	1,100	
	Solar				360	180		90	90	180	270	1,170	1,950	
Wind + Battery + CT	Wind				150	150	50	50	400	150	550	1,500	7,500	$4,206
	Battery				300							300	300	
	CT					485			242			727	791	
Solar + CT + SMR	Solar				450			90	90	180		810	1,350	$7,221
	CT					727			485			1,212	1,319	
	SMR										640	640	640	

Expected Future Case Risk Assessment

Natural Gas Sensitivity

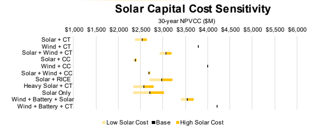


CO_2 Tax Sensitivity

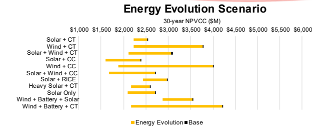


Expected Future Case Risk Assessment (cont.)

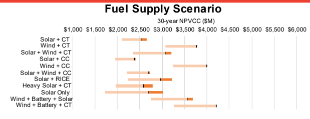
Solar Capital Cost Sensitivity



Energy Evolution Scenario



Fuel Supply Scenario



Preferred Plan

Portfolio Name	Type	Accredited Capacity (MW) 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total	Nameplate Capacity (MW)	30-year NPVCC ($M)
Solar + CT	Solar				450			90	90	180	270		1,080	1,800	**$2,527**
	CT					727			485		242		1,454	1,583	
	Market Opportunity			556									556	556	

Questions

CSAPR Future Case

CSAPR Compliance

- The State of Oklahoma, including OG&E, is currently under a stay granted by the U.S. Tenth Circuit Court
- At least 60% reduction in Nitrogen Oxides (NOx) emission allotments before the end of the decade
- Modifications required for many units in OG&E's thermal generation fleet, including both coal and natural gas

Alternative NOx Reduction Approaches

Coal	Natural Gas
• Retire/Replace • Add SCR • Convert and SCR	• Add SCR

NOx Reduction Options - Gas

Unit Type	Compliance Option	Construction Time (years)	Overnight Capital Cost ($M) per unit	Incremental Fixed O&M Cost ($M) per unit	Incremental Variable O&M Cost ($/MWh)
Gas-Fired Steam	SCR	6	$290	$1.5-$2.1	$1.10-1.30
Combined Cycle	SCR	4	$5-$15	$0.1	$1.00-$3.70
Combustion Turbine	SCR	4	$8-$10	$0.15	$3.50-$4.70

NOx Reduction Options - Coal

Unit Type	Compliance Option	Construction Time (years)	Overnight Capital Cost ($M) per unit	Incremental Fixed O&M Cost ($M) per unit	Incremental Variable O&M Cost ($/MWh)
Coal-Fired Steam (Muskogee 6, Sooner 1 & 2)	SCR	6	$360	$2.2	$1.70
Coal-Fired Steam (River Valley)	SNCR	4	$16	$0.2	$0.10
Coal-Fired Steam (Muskogee 6, Sooner 1 & 2)	Conversion + SCR	6	$60 + $290	varies $1.5-$2.1	varies $1.10-1.30

*Conversion of River Valley is not possible.

Analysis Process - CSAPR Future Case Portfolios

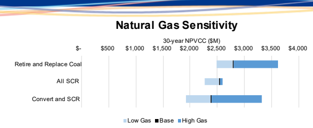
CSAPR NPVCC values are incremental to the Expected Future Case preferred plan

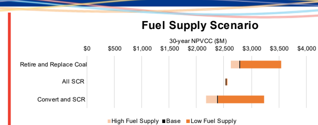
ALTERNATIVE PATHWAYS

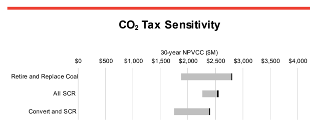
Portfolio Name	Retire Coal	Replace coal capacity	Convert and SCR	Add SCRs	30-Year NPVCC
Retire and Replace all Coal	Sooner 1 & 2, Muskogee 6, River Valley	Mix of Solar and CTs	N/A	Natural Gas Units	**$2,792M**
All SCR	N/A	N/A	N/A	Coal and Natural Gas Units	**$2,536M**
Convert and SCR	N/A	N/A	Sooner 1 & 2 and Muskogee 6	Natural Gas Units and River Valley (SNCR)	**$2,386M**

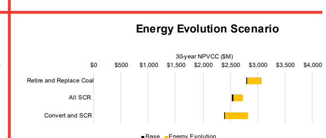
All portfolios include the purchase of allowances for compliance during construction time frames

Risk Assessment – CSAPR Future Case









Solar + CT + SMR portfolio is excluded fromthese charts

CSAPR Future Case Next Steps

To avoid unnecessary expenditures for customers, OG&E will continue to monitor legal and regulatory developments related to the EPA's Good Neighbor FIP and take needed compliance actions after final decisions are made through the legal process.

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Questions

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Analysis – Status Quo Future Case

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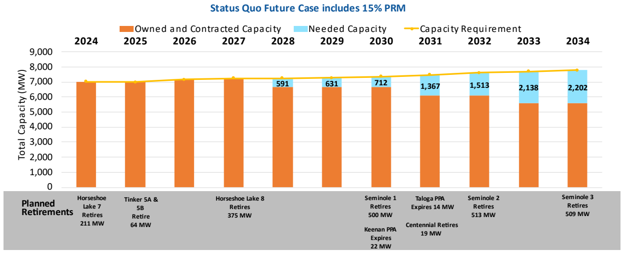
Planning Reserve Margin and Capacity Needs –Status Quo Case



We Energize Life 2024 IRP © 2024 OGE Energy Corp. | 39

Status Quo Future Case Portfolios

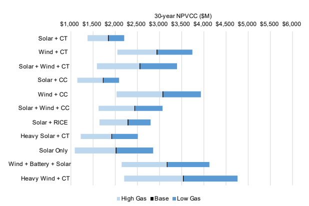
Portfolio	Accredited Capacity (MW) Type	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total*	NMPL. MW	30-yr NPVCC ($M)
Solar + CT	Solar					90		90	450	90	360	1,080	1,800	$1,848
	CT					528			264		264	1,056	1,056	
Wind + CT	Wind					100	50	50	400	150	350	1,100	5,500	$2,952
	CT					528			264		264	1,056	1,056	
Solar + Wind + CT	Solar					270		90	180	90	360	990	1,650	$2,562
	Wind					100			200	50	300	650	3,250	
	CT					264			264			528	528	
Solar + CC	Solar					630		90			540	1,260	2,100	$1,733
	CC								944			944	944	
Wind + CC	Wind					600	50	100			450	1,200	6,000	$3,078
	CC								944			944	944	
Solar + Wind + CC	Solar					270					360	630	1,050	$2,448
	Wind					350	50	50			150	600	3,000	
	CC								944			944	944	

Status Quo Future Case Portfolios

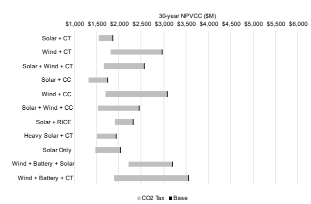
Portfolio	Accredited Capacity (MW) Type	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total*	NMPL. MW	30-yr NPVCC ($M)
Solar + RICE	Solar					270	90	90	270	180	630	1,530	2,550	$2,302
	RICE					330			330			660	660	
Heavy Solar + CT	Solar					360		90	450	90	630	1,620	2,700	$1,925
	CT					264			264			528	528	
Solar Only	Solar					630		90	720	90	630	2,160	3,600	$2,033
Wind + Battery + Solar	Wind					400	50	100	50		50	650	3,250	$3,185
	Battery					100			300		300	700	700	
	Solar					90			270	180	270	810	1,350	
Heavy Wind + CT	Wind					350	50	50	400	150	600	1,600	8,000	$3,540
	CT					264			264			528	528	
Solar + CT + SMR	Solar					90		90	450	90		720	1,200	$6,479
	CT					528			264			792	792	
	SMR										640	640	640	

Status Quo Future Case Risk Assessment

Natural Gas Sensitivity



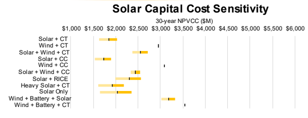
CO_2 Tax Sensitivity



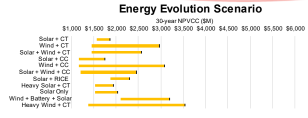
Solar + CT + SMR portfolio is excluded from these charts

Status Quo Future Case Risk Assessment

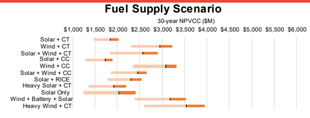
Solar Capital Cost Sensitivity



Energy Evolution Scenario



Fuel Supply Scenario

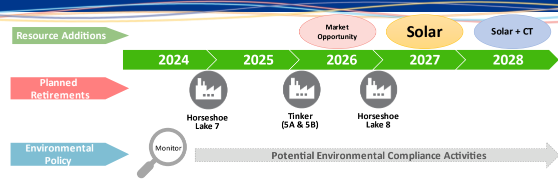


Solar + CT + SMR portfolio is excluded from these charts

Questions

IRP Action Plan

IRP 5-Year Action Plan



1. OG&E plans to retire Horseshoe Lake unit 7 in 2024.
2. OG&E plans to retire Tinker units 5A and 5B in 2025.
3. OG&E plans to retire Horseshoe Lake unit 8 in 2027.
4. OG&E will issue multiple RFP(s) for resources to satisfy the capacity needs identified in the IRP.
5. OG&E will continue to monitor environmental regulation developments and take actions, if necessary.

Questions and Comments

OG&E 2024 IRP – Oklahoma Technical Conference
February 22, 2024
Meeting Minutes

The Oklahoma Technical Conference regarding OG&E's 2024 Integrated Resource Plan (IRP) was held on February 22, 2024, from 10:00 am to 12:00 pm. The meeting was conducted as a webinar and included a presentation provided by members of OG&E's Resource Planning team.

Presenters:

Name	OG&E Role
Kelly Riley	Director, Resource Planning
Aaron Castleberry	Expert Resource Planner
Aadarsh Bhetuwal (Facilitator)	Resource Planner

External Stakeholders:

Name	Organization
Samuel McKinney	1898 & Co.
Sarah Terry-Cobo	City of Oklahoma City, Office of Sustainability
Chip Clark	OG&E Shareholders Association
Ron Stakem	OG&E Shareholders Association
Todd Bohrmann	Oklahoma Attorney General (OAG)
Greg Matejcic	Oklahoma Attorney General
Ashley Youngblood	Oklahoma Attorney General
Brice Betchan	Oklahoma Attorney General
Jana Slatton	Oklahoma Corporation Commission (OCC)
Nicole King	Oklahoma Corporation Commission
Trent Campbell	Oklahoma Corporation Commission
Michael Velez	Oklahoma Corporation Commission
Andrew Scribner	Oklahoma Corporation Commission
David Melvin	Oklahoma Corporation Commission
Thomas Schroedter	Oklahoma Industrial Energy Consumers (OIEC)
Scott Norwood	Oklahoma Industrial Energy Consumers (OIEC)
Montelle Clark	Oklahoma Sustainability Network (OSN)
Madison Miller	Oklahoma Sustainability Network
Kate Huddleston	Sierra Club
Ty Gorman	Sierra Club
Kara-Joy McKee	Sierra Club of Oklahoma
Deborah Thompson	Thompson Tillotson
Kenneth Tillotson	Thompson Tillotson
Becca Bean	

Aadarsh Bhetuwal began the meeting at 10:00 am by explaining the meeting structure and process for asking questions in the virtual format.

Questions and Responses:

- Greg Matejcic (OAG)
    - *Question:* When you are talking about the potential increases in the PRM and PBA, are those the items the company votes on? Do they put together analyses and studies in support of why they have chosen to go one way or the other?
        - *Response:* The company engages in those conversations with SPP and OG&E subject matter experts sit on working groups and committees in SPP. Those policies are voted on by those working group members. Those voting records can be accessed through SPP.
    - *Question:* Are there analyses and studies that are done by the company supporting their opinion on how those votes should go?
        - *Response:* It depends on the policy and the clarity of the implementation timelines. The PRM is based on the SPP-wide LOLE study and is used as the baseline.
- Scott Norwood (OIEC)
    - *Question:* Can you describe why 18% is the right number for the PRM? For the proposed change in accreditation for capacity, are they also reflected explicitly in the modeling or are they supposed to be addressed through the IRP?
        - *Response:* SPP conducts studies for three-year and six-year planning horizons. The results from the LOLE study from SPP showed PRM values ranging from 16-18% in 2026 and 17-21% in 2029. We believe 18% is the middle of the road approximation for where we expect we are going to end up. As mentioned earlier, the members of SPP working groups get to vote. However, there are other stakeholders at the SPP including RSC and SPP Board that votes to set the PRM. That PRM vote is not final presently.
- Montelle Clark (OSN)
    - *Question:* It is my understanding that SPP recommended a PRM of 16.9% but you chose 18%. Do you have any expectation on when SPP may choose a final number for that?
        - *Response:* Those timelines are uncertain right now, but we expect the final numbers sometime this year. As SPP updates the PRM, we will update our needs and update how that impacts the RFPs that follow.
    - *Question:* Would that same answer apply if they introduced a winter PRM as well?
        - *Response:* Yes, that is correct.
    - *Question:* Do you have any implication of the 50% winter PRM? Would you be already meeting that? Or would that be a substantial difference for you?

        - *Response:* A winter PRM at that level would drive some capacity needs for OG&E.
    - *Question:* Do you have any idea of whether it is going to be 150 MW or 300 MW?
        - *Response:* The discussions regarding a winter PRM have been wide ranging and it is changing pretty quickly. We are pausing on any actions until we get firmer answers on the winter PRM.
- Kate Huddleston (Sierra Club)
    - *Question:* How did you arrive to the figures of energy evolution and reduced coal capacity in the SPP?
        - *Response:* There are a number of electrification initiatives that are ongoing across the SPP. We looked at increasing load through time and it was an estimate. Same thing with the coal capacity. There are several coal generation units retiring in the SPP and we accelerated some of that in the modeling.
    - *Question:* How did you decide what to accelerate and how to arrive at those specific figures?
        - *Response:* We increased the load by 1% a year starting in 2025. On the coal retirement, we do not have a firm number right now. To answer your question, we may have to go back to the models and pull some of that out. Can we follow up with you at a later time regarding that?
        - *Follow-up Response:* The load assumption adjustments in the Energy Evolution scenario are derived from the Medium Electrification scenario in the NREL Electrification Futures Study. The Energy Evolution scenario also reflects SPP-located coal unit retirement dates based on publicly available retirement information, as well as the general assumption that 50% of coal capacity could be retired by 2030, and approximately 80% could be retired by 2040. These targets were based on OG&E's understanding of various factors in the marketplace, regulatory, and/or legislative landscape. Coal unit retirement dates were reflected in the Energy Evolution scenario in a way that was diverse with respect to the units' size and age.
    - *Question:* Relatively, I was wondering if there anything similarly related to gas? Perhaps any federal regulation that you had to model regarding gas?
        - *Response:* There is nothing related to federal regulation on gas in that Energy Evolution scenario. I will note that they we did analyze all the scenarios and sensitivities collectively. Energy Evolution is one of the scenarios. There are other scenarios and sensitivities that address volatility in gas prices and availability.
- Montelle Clark (OSN)
    - *Question:* On your peak DSM forecast, it shows large jumps in your DSM peak savings in the first couple of years – almost 200 MW from 2024 to 2025 and more than 200 MW from 2025 to 2026, which is much higher

than historical annual incremental savings. After that, it slows down to a more typical pace. Can you explain the first couple of years? Is that an expansion of your load reduction rider or is it something else?
  - *Response:* Yes, it is an expansion of the load reduction rider, tied to specific projects.

- *Question:* Does that have something to do with bitcoin mining?
  - *Response:* I cannot comment on the industries.
- *Question:* You show the costs of resource options in the table. Does that assume 30% IRA tax credit?
  - *Response:* The costs shown in the table are the upfront capital cost. The analysis includes the application of the IRA production tax credits.
- *Question:* Are you assuming any stacked credits at all that are available in the IRA like the Domestic Content Bonus Credit and Energy Communities?
  - *Response:* To keep our analysis conservative, we assumed Prevailing Wage and Apprenticeship requirements. We did not stack on any adders because the tax credits are so project specific that we did not make assumptions in the analysis about the projects that may be offered. If we go to the market with RFP(s), those project-related credits will be considered.
- *Question:* Large scale centralized solar is running into some challenges with interconnection and siting challenges around the country, particularly in the Midwest. Have you evaluated the costs and benefits of utility scale distributed solar as an option to address these expenses and delays? For example, multiple 20 MW projects connected to the lower voltage distribution grids – something like your Covington facility?
  - *Response:* OG&E is open to all solutions, including the creative ones.
- *Question:* Does that mean you might include those options in your RFP?
  - *Response:* The RFP is under development so I cannot answer definitively today.
- *Question:* Do you plan to include battery energy storage in your RFP?
  - *Response:* Yes.
- *Question:* Beyond the nameplate capacity value, does your model analyze or capture any of the storage value or benefits from components like energy price arbitrage, or congestion management, and renewable energy integration?
  - *Response:* The model is incorporating the energy price arbitrage. It assumes a daily charge and discharge cycle and is consistent with how the last IRP was done as well for those resources.
- *Question:* Is that reflected in your cost listed?
  - *Response:* It is reflected in the analysis.
- *Question:* What about other ancillary services such as fast ramping, voltage control, frequency response? Are you able to capture that with your model or analysis?

    - *Response:* No, they are not captured in this analysis.
  - *Question:* Your model is based on hourly resolutions. Is that right?
    - *Response:* Yes, that is correct.
  - *Question:* How does the model account for potential value of storage to provide intra-hourly benefits like sub hourly dispatch? Is that something you are still looking at?
    - *Response:* There are a lot of people looking at sub hourly modeling and trying to figure out how to make them work. The modeling that we have done for this IRP stops at the hourly level and we do not have any sub-hourly analysis.
  - *Question:* To follow up with my previous question, I assume that is something you can look at in the RFP. Is that right?
    - *Response:* Yes, we will take that into consideration.
  - *Question:* On your CO_2 tax sensitivity, at the 2021 IRP Oklahoma Technical Conference, you had indicated that the CO_2 tax sensitivity was used as a proxy for the various policies and measures that may put constraints in carbon emissions. Is that still how it is being used in this IRP?
    - *Response:* Yes, until we have more clarity on either final or proposed rules that will address carbon emissions.
  - *Question:* Is the CO_2 tax not just limited to the potential of a CO_2 tax per se but it is more of a proxy to the policies?
    - *Response:* Yes.
  - *Question:* In your 2021 IRP, you used a cost of $20/ton starting in 2025. In this 2024 draft IRP, you utilize the cost of $15/ton starting in 2029. Can you explain that change? Do you consider the risk of carbon constraints to be lower now than they were three years ago?
    - *Response:* No. However, in terms of a tax mechanism, there is not a current proposal for a tax on CO_2. So that is one facet. We do have constraints on CO_2 which we allude to with the proxy. Before we started the modeling effort, we did look at other utilities on what they are using for a CO_2 tax. A $15/ton CO_2 tax was relatively standard middle of the road assumption.
  - *Question:* I assumed if you had utilized $20/ton instead of $15/ton, that would have shifted the outcomes in your scenarios a little bit. Is that correct?
    - *Response:* It may have in the CO_2 tax sensitivity, but I do not know the answer to that exactly because we did not analyze a $20/ton CO_2 tax.
- Scott Norwood (OIEC)
  - *Question:* On the IRA related tax credits on renewables and energy storage, can you tell me what you assumed on those in terms of stay period, expiration, phasing out?
    - *Response:* They were not phased out. The ITC was applied to batteries at 30% and is normalized over the life of those assets.

The PTC on wind and solar are in place for the first ten years of operations for each of those resources.

- *Question:* Did you model any scenarios where those tax credits expire, like maybe in five years?
  - *Response:* No.
- *Question:* On your LMPs, I understand you have a separate modeling done. Is that correct?
  - *Response:* The Base Case and each of the scenarios and sensitivities in general are modeled separately to determine the LMPs. The exception to that is the solar capital cost sensitivity which just has a different up-front cost and no change in fuel cost.
- *Question:* Is the modelled LMP linked with the assumptions in terms of fuel and other energy costs, such that they are consistent?
  - *Response:* Yes, absolutely. For example, the Base Case included the Base Case assumptions around natural gas prices, coal prices, and the load forecast. Similarly, for the low gas sensitivity, we take the Base Case and lower the gas price by 50% across the entire modeling time horizon and the resulting LMPs are lower. For the high gas sensitivity, we take the Base Case and increase the gas price by 50% across the entire modeling time horizon and the resulting LMPs are higher because it costs more to run the system.
- *Question:* Are the LMP analysis done on a nodal basis?
  - *Response:* Yes.
- *Question:* We have seen at Seminole that you had high congestion costs. Would that be reflected in this model?
  - *Response:* Yes, the model is nodal and accounts for localized congestion.
- *Question:* What is the assumption in the interconnection cost?
  - *Response:* There is interconnection costs baked into the capital costs of the new resources. Can we follow up with you later regarding that?
  - *Follow-up Response:* Interconnection costs are included in the capital costs of the new resources, including $32 million for transmission lines for greenfield resources and switchyard costs ranging from $5 million to $20 million depending on the size and type of resource.
- *Question:* Did you do any unit disposition analysis or life extension analysis?
  - *Response:* No, we did not do that in this IRP. We assumed the plan that was in the current depreciation study for unit retirements.
- *Question:* I have seen some recent solar projects that are quite a bit lower costs. I guess that would make solar the better option and will be selected again in your analysis. Is that true?
  - *Response:* Yes.
- *Question:* Are the resource options shown in the scenario and sensitivity tables in 2023 dollars?

        - *Response:* Yes.
    - *Question:* Following up to my previous question, that means that the actual cost in 2027 will be even higher than that. Is that correct?
        - *Response:* Yes, accounting for inflation.
    - *Question:* Were there any hydrogen options evaluated in the modeling?
        - *Response:* We did not model hydrogen as a fuel, but we understand that some of the resources that we are modeling have proposed requirements for burning hydrogen in the future. Hydrogen pricing and supply availability is extremely difficult to estimate today.
    - *Question:* Did you let the model optimize the resources selected or were there restrictions plugged in? For example, for the Solar + CT portfolio, it is only choosing Solar and CT in certain years.
    - *Response:* We can address that further in this presentation after we talk about the analysis.
- Kate Huddleston (Sierra Club)
    - *Question:* How are you counting the capacity contribution of batteries to meet SPP's PRM?
        - *Response:* If a battery is a 4-hour resource, the model assumes the resource as 100% for that 4-hour interval of time to meet the resource adequacy requirement.
    - *Question:* Did you explore the interrelationship of solar, wind, and storage and benefits to both of those resources from connecting them and the interplay between renewables and storage?
        - *Response:* We did include some options for hybrid resources (the combination of solar and batteries) and that is certainly something we would be open to in the RFP process.
    - *Question:* Did the capacity contribution change when you paired renewables with storage?
        - *Response:* We assumed that the solar battery hybrid resource would be able to maintain 100% accreditation for their interconnection amount.
    - *Question:* For your sensitivity analysis, is there analysis of PRM not continuing to increase, or is the assumption that PRM will continue to increase at the rate it is currently at, which is quite high?
        - *Response:* In our Expected Future Case, we assumed that in 2026, the PRM goes to 18% and that it remains there for the planning horizon. The Status Quo Future Case maintains the PRM at the current 15% level and it does not increase throughout the planning horizon.
- Montelle Clark (OSN)
    - *Question:* For your Base Case, you have the Heavy Solar + CT portfolio which comes to be about $50M more expensive than the Solar + CT portfolio but it looks like it reduces risk significantly under several sensitivities and is less expensive under two of the three scenarios if I am reading this correctly. It seems like it would also further meet your goal of

providing a diversified fuel portfolio of gas and renewable generation. So, what specifically made you choose the Solar + CT portfolio instead of the Heavy Solar + CT portfolio?

        - *Response:* The Solar + CT portfolio has a lower cost for the customer in the Base Case. If you look at the sensitivity analysis, the Heavy Solar + CT portfolio also has a wider risk range than the Solar + CT portfolio. There is more certainty in the preferred plan.
    - *Question:* Would I also assume that it reduces the risk in the Good Neighbor Plan and Greenhouse Gas regulations?
        - *Response:* Yes, we think it would.
    - *Question:* I am a little confused on the numbers. It says that you need almost 2,600 MW by 2034 but the plan shows 3,090 MW of new accredited capacity. Can you explain the extra almost 500 MW of capacity shown?
        - *Response:* The difference there is the market opportunity that is shown for 2026. The market opportunity assumes the MW is not there long-term.
    - *Question:* Your Preferred Plan shows several CTs. Last time I checked the SPP interconnection queue, there were only a few thermal projects and none of them were in Oklahoma. So would this CTs need to apply for new interconnection approval. Do you anticipate they will only be built in existing OG&E sites to replace retiring assets and utilize the current active interconnection?
        - *Response:* As mentioned earlier, OG&E is open to all solutions so those new CTs could certainly progress through the current generator interconnection queue. There are also some retirement/replacement, surplus or interim type interconnection processes available so we will have to evaluate all of those for individual resources.
    - *Question:* So, you think there will be enough time for a non-existing site to be developed in time for your capacity needs?
        - *Response:* We believe the SPP Generation Interconnection queue is the long pole in the tent right now so that is something we will have to evaluate.
    - *Question:* You talked about hydrogen capable combustion turbines. It is my understanding that there are additional updates required for using hydrogen as a fuel. Do you have an estimate for those, and are those costs reflected in your analysis?
        - *Response:* We do not have an estimate for those and therefore, they are not reflected in the analysis.
    - *Question:* When do you expect to release the RFP?
        - *Response:* We will talk about the RFP at the end of the presentation.
- Scott Norwood (OIEC)
    - *Question:* Is the RFP going to be limited to those resources shown in the Preferred Plan?

        - *Response:* No, the RFP will not be limited to those resources shown in the Preferred Plan.
    - *Question:* Which of the technologies for the CTs and CCs were included in the analysis?
        - *Response:* The resource options table shows the cost of a variety of models. The decisions on the final selection of the model are based on economics and are generally frame units, which are more efficient.
    - *Question:* In the portfolio selection process, for example in the Solar + CT portfolio, did you limit the resources up front to selections of only Solar and CTs?
        - *Response:* OG&E partnered with 1898 & Co. for modelling for this IRP. 1898 & Co. uses EnCompass which is a capacity expansion tool. It is also an optimization tool. So, if we let the model pick the resources, we would get one portfolio as a result, which will be the optimal portfolio. So, to show, in the IRP, the range of technologies, choices, and timing, we did set up the model and allowed it to focus resources based on the portfolios.
    - *Question:* So, there was some upfront forcing of portfolios to just look at two options, for example. Is that correct?
        - *Response:* Maybe guidance would be a more appropriate word, but yes.
    - *Question:* Explain to me again why the combined cycle portfolio is not the preferred option.
        - *Response:* In the Greenhouse Gas rule that has been approved by the EPA, there are requirements for new combined cycle units to burn a very large percentage of hydrogen as a fuel in the future. There is an early requirement for combined cycle and later the percentage of hydrogen required steps up. Combustion Turbines have a similar requirement, but it does not step up over time. Currently, there is no robust and expansive market for hydrogen as a fuel or hydrogen production. So, we see it as a risk. We will certainly allow combined cycle resources to bid into the RFP and we will evaluate those at that time considering the environmental risks.
    - *Question:* In the past our customers have been interested in what the net present value of the study looks like in the near term, first ten years, first fifteen years, and so on so if you had two options that are really close, you could look at near term impact, and evaluate things that are more certain. Did you all develop that, or can you develop that for us?
        - *Response:* Yes, we can. We typically have appended it to the final IRP.
    - *Question:* What are you showing under these plans, your renewable energy percentage of total system mix will be by 2030?
        - *Response:* No, we do not have that value at the moment. We can get back to you if you would like.

    - *Follow-up Response:* Under the Preferred Plan, OG&E estimates its capacity mix would be approximately 19% renewable, 20% coal, and 61% natural gas in 2030.
- Kate Huddleston (Sierra Club)
    - *Question:* With regards to CSAPR and the Good Neighbor Plan, my understanding is that EPA has previously regulated, for example with the [unclear audio] NOx SIP call, and in 2014, and has implemented trading programs for over twenty-five years. It seems like this is being phrased in terms of the Good Neighbor Plan, but even if the Good Neighbor Plan in its current form does not go forward, based on its history, it is reasonable to view increased future regulations of future interstate ozone pollution in some form is likely. How are you accounting for environmental and regulatory risk?
        - *Response:* We will follow up with you on this.
        - *Follow-up Response:* The IRP development process considers risks of specific regulations when they become final. The IRP scenario and sensitivity analyses also assess a range of risks in future developments.
    - *Question:* What are the current retirement dates for Sooner 1, Sooner 2, and Muskogee 6?
        - *Response:* It's in the 2040s. We will follow up with you on this.
        - *Follow-up Response:* Sooner 1 – 2044, Sooner 2 – 2045, Muskogee 6 – 2049.
    - *Question:* I know the SCR risk here is framed in terms of the Good Neighbor Plan, but I am wondering if you are accounting for other kinds of SCR risk, particularly the existing CSAPR rule (even if the Good Neighbor Plan does not go forward and poses NOx emissions limits), section 126 of the CAA allows for the states to petition the EPA about sources of pollution that are affecting other states, and then the Regional Haze program as well. How have you thought of those issues?
        - *Response:* This CSAPR analysis is specifically focused on the current FIP. We did not expand outside of that approach.
    - *Question:* So, the IRP does not account for regulatory risk and the likelihood or possibility of SCR due to other CAA provisions. Is that true?
        - *Response:* This CSAPR analysis applies SCRs on virtually all thermal units except to those that are very close to their retirement. So, we believe that we have fully addressed the risk of SCR requirements on thermal units.
    - *Question:* Has the company thought of the fact that SCRs are not just limited just because of the Good Neighbor Plan? There are a number of CAA provisions that may require of additions of SCRs to this unit.
        - *Response:* Once an SCR is installed like it is in this CSAPR Future Case analysis, it would reduce NOx, regardless of what regulation that NOx reduction falls under.
    - *Question:* I was wondering if the units have FGD installed? Or if they would need them installed?

        - *Response:* We will follow up with you on this.
        - *Follow-up Response:* Sooner 1 and Sooner 2 have FGD (Scrubbers) installed.
    - *Question:* FGD is often needed in Regional Haze context. Has the company studied the costs associated with it?
        - *Response:* If you look at the draft IRP, those risks around Regional Haze, MATS, and GHG are all things that we are keeping an eye on. We did not study them specifically in this IRP, but we are certainly watching the developments on those regulations and will address them when finalized.
    - *Question:* But the costs for compliance with those regulations are not quantified accounted for here. Is that correct?
        - *Response:* That is correct.
    - *Question:* You state that you are installing dry bottom ash handling technology. What plants are they occurring on, and how much that will cost? I know it has a compliance date of 2029 and that seems like a relevant cost including and considering retirement.
        - *Response:* I know they are going in the Sooner units. I do not know the costs.
    - *Question:* Are those costs accounted for in this IRP?
        - *Response:* They were not included in the analysis, but they will be part of the existing resource going forward.
    - *Question:* Are the costs of compliance for each of these regulations accounted for in evaluation regarding unit retirements and when retirement is economically beneficial to customers?
        - *Response:* The bottom ash handling technology is expected to reduce the cost of operations at those resources because it eliminates some amount of equipment maintenance.
    - *Question:* Does it have an upfront cost?
        - *Response:* I am sure that it does, but I do not know what that is.
    - *Question:* Do you know if cooling water retrofit will be needed at any of the units?
        - *Response:* We cannot address this today but will follow-up.
        - *Follow-up Response:* The precise impact of proposed rules remains unknown unless and until the rules are finalized.
    - *Question:* How have you accounted for the 111D with respect to the coal units, especially if the plan is to retire them in 2040s? It would require 88.4% reduction in emissions and would require CCS which is highly expensive?
        - *Response:* We cannot address this today but will follow-up.
        - *Follow-up Response:* The IRP development process considers risks of specific regulations when they become final.
- Madison Miller (OSN)
    - *Question:* My question is related to PM2.5 in the new NAAQS which came out after OG&E published the draft IRP. The next steps are for the EPA to designate areas of attainment, non-attainment which will take a while.

Looking at the data, it looks like Oklahoma County and Kay County where OG&E currently has facilities that can be impacted. My question is whether OG&E has looked at the possibility of implementation and considered accounting for this regulation in the final IRP.

        - *Response:* It is not something we are considering implementing in the final IRP because it is unknown at this time what, if any, potential impacts to OG&E may result, but I appreciate your concern about it.

- Montelle Clark (OSN)
    - *Question:* In the table for compliance and SCR retrofit for the Good Neighbor Plan, I did not see the new Horseshoe Lake units 11 and 12. Would they be additional cost? I also did not see the costs for the Redbud.
        - *Response:* We did not include how the new Horseshoe Lake units 11 and 12 will be impacted in this IRP. Redbud already has SCRs.
    - *Question:* Given the significance of all these potential costs, PRM, and other things going on with SPP, do you anticipate an interim update to the IRP when you have some clearer information on this, or will you go another three years without an IRP? It would be helpful for us given the magnitude of some of these regulations if we could be kept informed.
        - *Response:* OG&E certainly has an interest in keeping the stakeholders informed and up to date. Under the IRP rules, we have a requirement to update with an interim IRP when there is a material change in planning assumptions. We will keep those rules in mind going forward and will have to plan on an interim IRP once certainty develops around some of the various policies.
- Scott Norwood (OIEC)
    - *Question:* On Table 15 of the draft IRP, you are showing that the convert option is the lowest cost option, and you are showing conversion of Sooner 1 & 2 and Muskogee 6 in 2028 if I am correct. Is that what you intend to do?
        - *Response:* We are in a stay in CSAPR, and we will have to see how that litigation plays out. There is still some discussion on the rule. The portfolios we have for CSAPR have sets of assumptions. The results are very close to each other, and we will have to get past the litigation phase and figure out if final implementation aligns with our assumptions and evaluate compliance again.
    - *Question:* Setting aside CSAPR, did you look at converting units in 2028 and compared to how it would look like in the Base Case?
        - *Response:* We looked at unit conversions in the CSAPR Future Case.
- Sarah Terry-Cobo (Office of Sustainability, City of Oklahoma City)
    - *Question:* If I understand it correctly, there are $80M in planned upgrades to the Transmission system from 2024 to 2026 as part of the SPP planning process. Can you confirm that figure?

        - *Response:* The upgrades that are listed in the table in Schedule J are derived from SPP Integrated Transmission Planning process. We have not summed the amount listed in the table.
    - *Comment:* In the draft IRP, there was a discussion on carbon tax sensitivity, but I did not see a figure in the document
        - *Response:* We will double check.
        - *Follow-up Response:* The modeled CO_2 tax was included in the Assumptions section of the document.
    - *Question:* You mentioned the EnCompass tool and the analysis with the dispatch model. I am curious if the software incorporates what SPP has dispatched in the last few years for the day ahead Integrated Marketplace. If so, what were those study years, and if not, I have a follow-up question.
        - *Response:* EnCompass does not have historical data from SPP. We used outputs from the PROMOD nodal model to input to EnCompass for dispatch purposes.
    - *Question:* So, do you use calculations from PROMOD rather than actual SPP data.
        - *Response:* The PROMOD model is from SPP, so it has the units and transmission information which is used to develop future LMPs.
- Montelle Clark (OSN)
    - *Question:* You mentioned your expectation of multiple RFPs. Do you have any sort of timelines for those?
        - *Response:* The timeline is going to be sometime in second quarter this year after the final IRP is submitted to the commissions.
    - *Question:* Recent solar RFPs ran into various hurdles as you know. Are you planning anything different this year to address those hurdles that prevented you from developing solar resources?
        - *Response:* We will certainly ask solar developers to offer into the RFPs. We have more certainty in the solar supply chain now than the last time we issued solar RFPs. The IRA has also firmed up some tax benefits. The market for solar may have settled just a little bit. Hopefully, that will give us a better outcome.
- Scott Norwood (OIEC)
    - *Question:* On Table 1 in the draft IRP, you are showing about 37% growth over the next ten years in energy sales. From Appendix A, it appears like all that growth is in the commercial and petroleum customer classes. Can you explain that?
        - *Response:* We are seeing a lot of economic activity in our region, particularly in Oklahoma and we are seeing larger customers making commitments to the state.
    - *Question:* Did you run any alternative load or energy growth scenario in this IRP forecast?
        - *Response:* No, we did not.
- Kate Huddleston (Sierra Club)

- *Question:* Does this draft IRP accounts for the public health costs of each unit, given the documented effects of those ozone particulate matter pollution. How about the economic costs of public health?
  - *Response:* The point of the IRP analysis is to reflect the increased cost to customers for the supply of electricity. We do not include any estimates of public health impact.

- Thomas Schroedter (OIEC)
  - *Question:* When is the date for the public meeting for this IRP? Will that be at the commission, or would it be a virtual meeting?
    - *Response:* The date is March 27, 2024, as of now. It will be at the commission.
  - *Question:* Could you share your PowerPoint slides from today to the participants?
    - *Response:* We typically add these PowerPoint slides to the appendix of the final IRP.
  - *Question:* It would be helpful to have the PowerPoint slides prior to the public meeting. Would you consider that?
    - *Response:* Yes, we will consider sharing the PowerPoint slides after conversation with our regulatory staff.
- Ashley Youngblood (AG)
  - *Comment:* Yes, it would be helpful to have the PowerPoint slides.