INTEGRATED RESOURCE PLAN

OKLAHOMA GAS & ELECTRIC

PREPARED 2021

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. This IRP is submitted according to the triennial schedule established by the OCC and APSC.

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.

Over the next five years, load growth and unit retirements result in the need for new generation capacity to meet OG&E's planning reserve requirements. These capacity needs are shown in the table below:

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

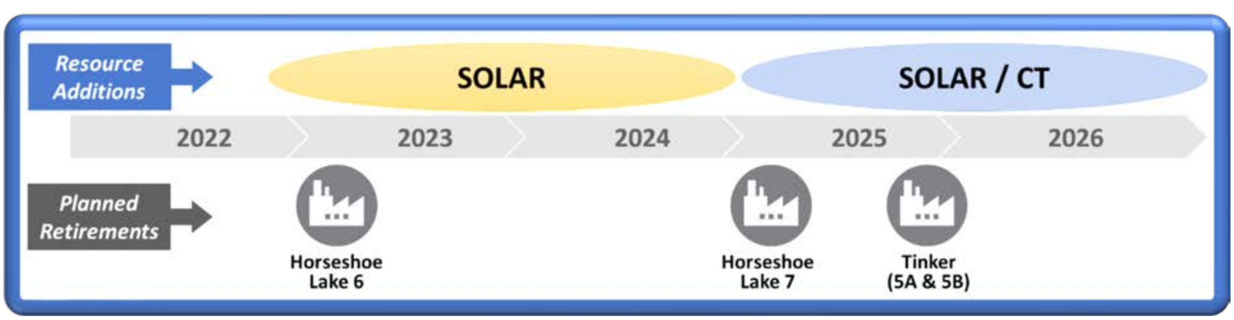
	2022	2023	2024	2025	2026
Total Capacity	6,749	6,581	6,581	6,370	6,306
Net Demand	6,025	6,004	6,039	6,059	6,088
Reserve Margin	12%	10%	9%	5%	4%
Needed Capacity*	0	145	183	417	514

Indicates the capacity needed to restore the reserve margin to 12%.

OG&E evaluated more than one million portfolios that meet the capacity needs utilizing a combination of potential future resources of various technology types, sizes and availability. The IRP analysis shows the lowest reasonable cost plan is a balanced portfolio of solar resources and combustion turbines. This plan helps maintain system resiliency, advances fuel and technology diversity of the generation fleet, improves operational flexibility 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 future expectations for cleaner energy. Additionally, the combustion turbines are capable of using hydrogen as a fuel in the future, providing further emission reduction potential.

OG&E will issue a Request(s) for Proposals (RFP) for resources to meet the capacity requirements and other IRP objectives of the company for future generation designed to increase efficiency, advance cleaner generation and maintain affordability.

OG&E Action Plan



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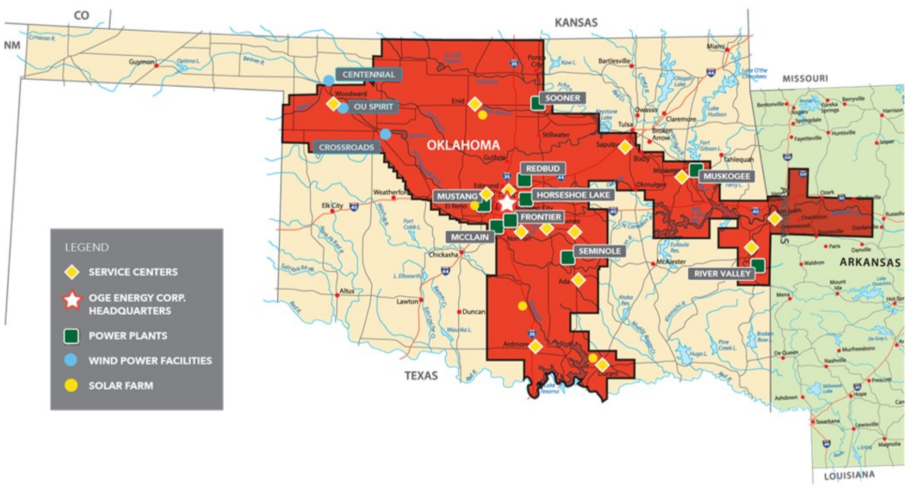
List of Acronyms

Acronym	Phrase Represented	Reference
APSC	Arkansas Public Service Commission	Agency
CO_2	Carbon Dioxide	Chemical
CC	Combined Cycle electricity generating unit	Technology
CT	Combustion Turbine electricity generating unit	Technology
DSM	Demand Side Management	Industry
EIA	Energy Information Administration	Agency
FERC	Federal Energy Regulatory Commission	Agency
IM	Integrated Marketplace	SPP
HH	Henry Hub	Industry
ITP	Integrated Transmission Plan	SPP
IVVC	Integrated Volt Var Control	OG&E
IRP	Integrated Resource Plan	Industry
LMP	Locational Marginal Price	SPP
LRR	Load Reduction Rider	OG&E
NERC	North American Electric Reliability	Agency
NPVCC	Net Present Value of Customer Cost	OG&E
NTC	Notice to Construct	SPP
NREL	National Renewable Energy Laboratory	Agency
O&M	Operations & Maintenance	General
OCC	Oklahoma Corporation Commission	Agency
OG&E	Oklahoma Gas & Electric	Agency
PCI	Power Costs Inc.	Agency
PPA	Power Purchase Agreement	Industry
RFP	Request for Proposal	General
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 871,000 customers in 267 towns and cities in a 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 OCC Electric Utility Rules and APSC Resource Planning Guidelines for Electric Utilities. Sections II - V present the IRP objectives and process, assumptions, resource planning modeling and analysis, and five-year action plan. Section VI 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

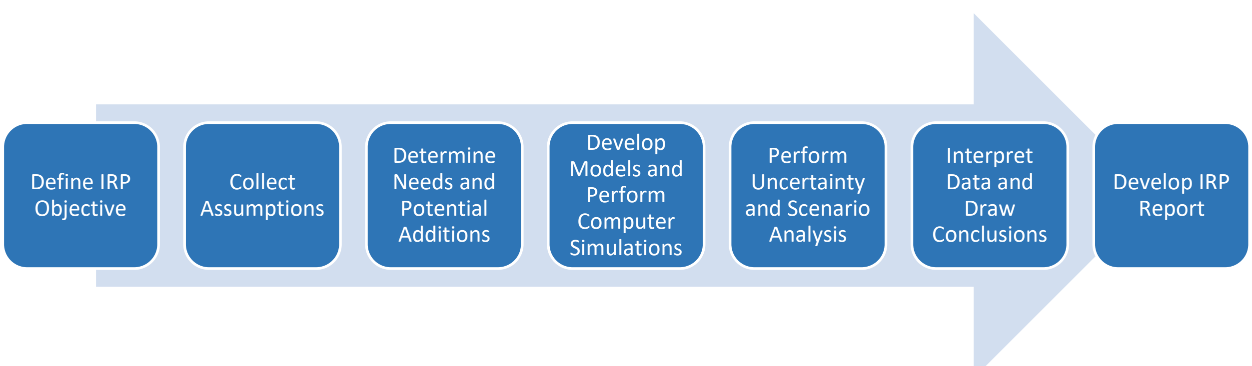
II. IRP Objectives and Process

OG&E strives to develop a resource plan that will allow it to most reasonably and affordably meet its capacity obligations over the planning horizon with due consideration of 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) planning reserve margin requirements
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 & Technology Diversity: maintain a reasonable balance among technologies and fuel sources including natural gas, renewable, coal, energy storage and demand-side resources
5. Operational Flexibility: maintain or increase the ability of OG&E's portfolio to respond at SPP's direction to localized reliability issues
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. Resiliency Benefits: maintain generation capability to minimize disruptions
9. 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. Assumptions

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

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 most recent load forecast also considers anticipated short-term and long-term economic impacts related to the COVID-19 pandemic. 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)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Energy Forecast[1]	29,897	30,053	30,225	30,395	30,620	30,858	31,113	31,389	31,695	31,978
OG&E DSM[2]	615	803	991	1,179	1,353	1,499	1,622	1,725	1,812	1,986
Net Energy	29,283	29,250	29,234	29,215	29,267	29,359	29,491	29,664	29,883	29,992

Table 2 – Peak Demand Forecast (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Demand Forecast[1]	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
OG&E DSM[2]	278	309	340	372	403	432	456	477	494	505
Net Demand	6,025	6,004	6,039	6,059	6,088	6,111	6,133	6,149	6,136	6,154

The baseline Energy and Demand Forecasts include the impacts of historical Energy Efficiency, the SmartHours Program and the Integrated Volt Var Control Program (IVVC). 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

[1] Includes SmartHours, Historical Demand Program Rider programs and Integrated Volt Var Control.
[2] Represents estimates for incremental energy efficiency programs in Oklahoma and Arkansas, the Load Reduction Program, and existing and future OG&E distributed energy resources.

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 more than 100 MW. IVVC manages OG&E's distribution system reactive power flow and voltage level while also reducing demand by nearly 100 MW.

OG&E DSM, shown in the energy and peak demand forecast tables as forecasted incremental program growth, demonstrates OG&E's 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. OG&E's distributed solar resources are also accounted for in the OG&E DSM.

B. Generation Resources

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

1. Existing Resources

OG&E's existing portfolio of electric generating facilities consists of owned thermal generation, owned renewable resources and four PPAs, as presented in the following three tables.

Table 3 – OG&E Existing Thermal Resources

Unit Type	Unit Name	First Year In Service	Summer Capacity (MW)
Coal Fired Steam (1,854 MW)	Muskogee 6	1984	503
	Sooner 1	1979	516
	Sooner 2	1980	515
	River Valley 1	1990	160
	River Valley 2	1990	160
Gas Fired Steam (3,130 MW)	Muskogee 4	1977	423
	Muskogee 5	1978	442
	Horseshoe Lake 6	1958	168
	Horseshoe Lake 7	1963	211
	Horseshoe Lake 8	1969	403
	Seminole 1	1971	485
	Seminole 2	1973	500
	Seminole 3	1975	498
Combined Cycle (1,113 MW)	McClain [3]	2001	378
	Redbud [3]	2002	615
	Frontier	1989	120
Combustion Turbine (553 MW)	Horseshoe Lake 9	2000	45
	Horseshoe Lake 10	2000	43
	Tinker (Mustang 5A)	1971	33
	Tinker (Mustang 5B)	1971	31
	Mustang 6	2018	57
	Mustang 7	2018	57
	Mustang 8	2018	58
	Mustang 9	2018	58
	Mustang 10	2018	57
	Mustang 11	2018	57
	Mustang 12	2018	57

Table 4 – OG&E Existing Renewable Resources

Unit Type	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capacity (MW)
Wind (52 MW)	Centennial	2006	120	15
	OU Spirit	2009	101	9
	Crossroads	2012	228	28
Solar (18 MW)[4]	Mustang	2015	3	2
	Covington	2018	9	8
	Chickasaw Nation	2020	5	4
	Choctaw Nation	2020	5	4

[3] Represents OG&E owned interest: 77% of McClain and 51% of Redbud.
[4] Solar is connected to distribution and is embedded in the Net Demand Forecast. OG&E expects 10 MW of additional nameplate distributed solar resources will be in service by the end of 2021.

Table 5 – Existing Power Purchase Agreements

	Unit Name	Contract Start date	Nameplate Capacity (MW)	Summer Capacity (MW)
Power Purchase (47 MW)	Keenan	2010	152	21
	Taloga	2011	130	10
	Blackwell	2012	60	9
	Southwestern Power Administration	1979	7	7

2. Resource Changes in the Ten-Year Planning Horizon

Six of OG&E's owned generation resources will retire over the next 10 years. In addition, two wind PPAs will expire at the end of the 10 years.

<u>Horseshoe Lake</u>

Horseshoe Lake units 6, 7 and 8 are natural gas-fired steam generating units located at the Horseshoe Lake power plant in Harrah, Okla. These are the oldest units in OG&E's generation fleet and among the oldest units of their type and size operating in the SPP. Horseshoe Lake units 6, 7 and 8 have provided value to OG&E's customers, as well as consumers across the Southwest Power Pool, for many years. The advent of the SPP Integrated Marketplace (IM) in 2014 and changes to the resource mix in SPP have led to the Horseshoe Lake units operating in a more seasonal manner and outside their original design parameters.

OG&E's recent Depreciation Studies have shown the three steam turbine units at Horseshoe Lake have probable retirement dates within the next decade. The Company has determined that these three older Horseshoe Lake steam turbine units should be retired. The risk of significant failure with these units is material and increasing every year. Multiple components of Horseshoe Lake units 6, 7 and 8 have been in service since the units came online in the 1950s and 1960s. Replacement parts for these units are not readily supported by the manufacturers and, instead, must frequently be re-engineered and manufactured at significant expense and production lead time. Additionally, units of this age are more susceptible to catastrophic component failure. Some of these components include but are not limited to high-speed rotating equipment, high voltage equipment and high-pressure components. Failure of any of these components could lead to additional collateral equipment damage and OG&E employee exposure to hazardous conditions.

Horseshoe Lake units 6, 7 and 8 share a number of common systems at the plant, such as the demineralized water unit and gas main. These systems have been in service since the 1950s and pose the same maintenance and end-of-life risks as the generating units themselves. The lake and river intake structure were put in place almost 100 years ago to support Horseshoe Lake units 1-5, which retired in 1981. Both the lake and river intake structure need significant modifications/upgrades to continue to function as the cooling water source to units 6 and 7. While OG&E has outlined dates to retire each unit, a change of conditions, such as failure of a co-dependent system, could advance planned dates.

> Horseshoe Lake Unit 6 is a 168 MW natural gas-fired steam turbine unit originally commissioned in 1958. Unit 6 is 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 2019 EIA-860[5] shows that similarly sized natural gas-fired steam generators have reached retirement after an average of 54 years of operation. OG&E will retire Horseshoe Lake unit 6 as planned in 2023, after 65 years.
>
> 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, last operated in 2015, has since been retired. OG&E has worked to keep the remaining 211 MW steam unit operating without the legacy gas turbine. Previous depreciation studies have shown Horseshoe Lake unit 7's probable retirement date as early as 2019. The 2019 EIA-860 shows that similarly sized natural gas-fired steam generators have reached retirement after an average of 54 years of operation. OG&E plans to retire Horseshoe Lake unit 7 in 2025, after 62 years.
>
> Horseshoe Lake Unit 8 is a 403 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 2019 EIA-860 shows that similarly sized natural gas-fired steam generators have reached retirement after an average of 46 years of operation. OG&E plans to retire Horseshoe Lake unit 8 in 2027, after 58 years.

Tinker

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 onsite resiliency at Tinker. Previous depreciation studies have shown a probable retirement date as early as 2018. The 2019 EIA-860 shows that natural gas-fired simple cycle combustion turbines have reached retirement after an average of 37 years of operation. The two units located at Tinker are planned to be retired in 2025 after 54 years.

Seminole

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

[5] EIA. (2020). 2019 EIA-860 3_1_Generator_Y2019.xlsx. U.S. Energy Information Administration. https://www.eia.gov/electricity/data/eia860/archive/xls/eia8602019.zip

mid-1970's. Previous depreciation studies showed these three units' probable retirement dates in 2030. OG&E currently anticipates retiring Seminole Unit 1 at the end of 2030 after 59 years of service. Seminole Unit 2 retirement would then be extended to the end of 2032 at 59 years of service. Retirement for Seminole Unit 3 would then be extended to the end of 2034, also at 59 years of service. OG&E will update the depreciation study to reflect these dates. The three Seminole units represent almost 1,500 MWs of OG&E's current generating capacity.

Wind Purchase Power Agreements

OG&E entered into PPAs for generation from the Keenan and Taloga Wind facilities starting in 2010 and 2011, respectively. Each agreement provides generation for 20 years and will end within the next ten years.

3. Future Resource Options

OG&E contracted with Burns & McDonnell to provide cost and performance estimates for combined cycle (CC), simple cycle technologies like combustion turbines (CT) and reciprocating engines (RICE), solar and battery storage. The cost estimates for Wind are from the National Renewable Energy Laboratory (NREL)[6]. The potential additional resource options are shown in Table 6.

[6] NREL. (2020). *Electricity annual Technology Baseline data download*. NREL. https://atb-archive.nrel.gov/electricity/2020/data.php

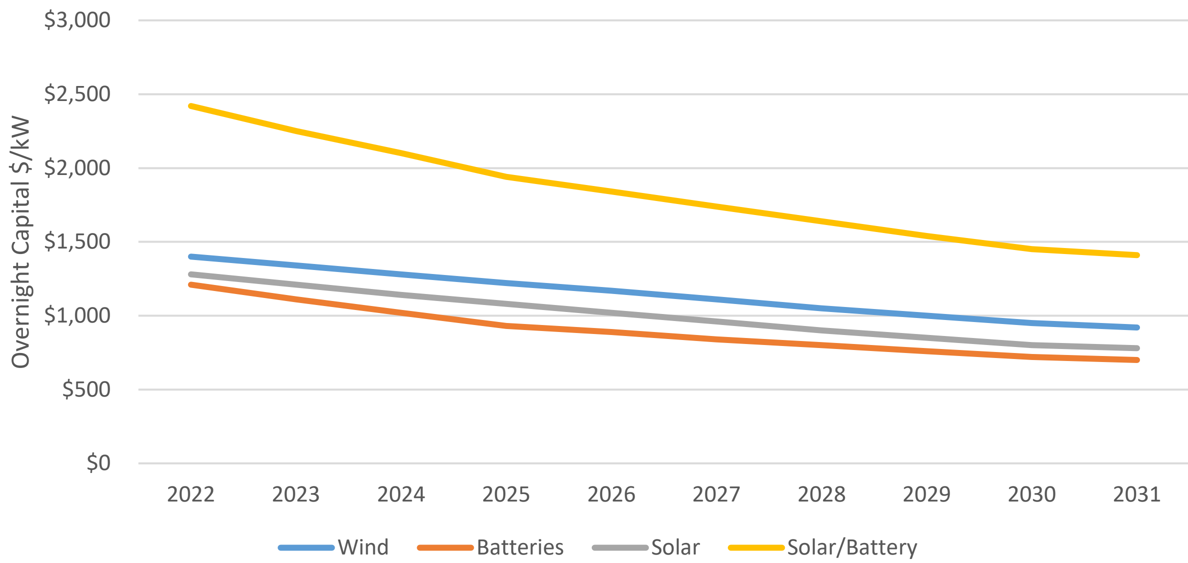
Table 6 – Resource Options in 2021$

Technology	Model	Nameplate Capacity (MW)	Nameplate Overnight Capital Cost ($/kW)	Summer Peak Capacity	Fixed O&M Cost ($/kW)	Variable O&M Cost ($/MWh)
Wind	Land-Based	250	$1,470	50	$46.00	N/A
Batteries	Lithium Ion	100	$1,310	100	$21.00	N/A
Solar	Photovoltaic Single Axis	100	$1,350	60	$16.90	N/A
Solar/Battery Hybrid	Single Axis/Lithium Ion	100	$2,590	100	$37.90	N/A
RICE	Reciprocating Engine 1x	19	$2,430	19	$38.80	$4.50
	Reciprocating Engine 6x	111	$1,320	111	$14.50	$4.50
Combustion Turbine (CT)	AGT 1x	62	$1,690	58	$4.50	$0.90
	AGT 7x	432	$1,100	404	$5.60	$0.90
	LMS100 1x	111	$1,090	101	$2.60	$5.70
	LMS100 4x	444	$860	405	$3.20	$5.70
	E Class 1x	85	$1,120	77	$6.50	$7.20
	E Class 5x	427	$840	386	$6.80	$7.20
	F Class	221	$690	212	$3.20	$1.80
	G/H Class	278	$660	264	$3.50	$2.20
Combined Cycle (CC)	1x1 J Class	531	$930	503	$3.50	$1.50
	1x1 J Class Fired	637	$780	613	$3.50	$2.20
	2x1 G/H Class Fired	1,001	$700	944	$2.50	$2.30
	2x1 F Class	729	$850	662	$2.40	$1.50
	2x1 F Class Fired	880	$750	828	$2.40	$2.30
	1x1 F Class Fired	441	$960	411	$4.30	$2.40

Capital costs for renewable resources have been declining over the last several years and are expected to continue to decline over the next decade, albeit at a slower pace than in the previous decade. OG&E utilized NREL[7] price projections to develop an estimated price reduction curve for wind, solar and battery resources in the IRP, as reflected in Figure 3.

[7]NREL. (2020). *Electricity annual Technology Baseline data download*. NREL. https://atb-archive.nrel.gov/electricity/2020/data.php

Figure 3 – Renewables Nameplate Overnight Cost Projections in 2021$ ($/kW$_{AC}$)



A number of high-potential innovations in electricity generation and storage are currently under development and testing. The Company will continue to assess developments in emerging technologies for future planning consideration as they become viable options.

4. Resource Location Considerations

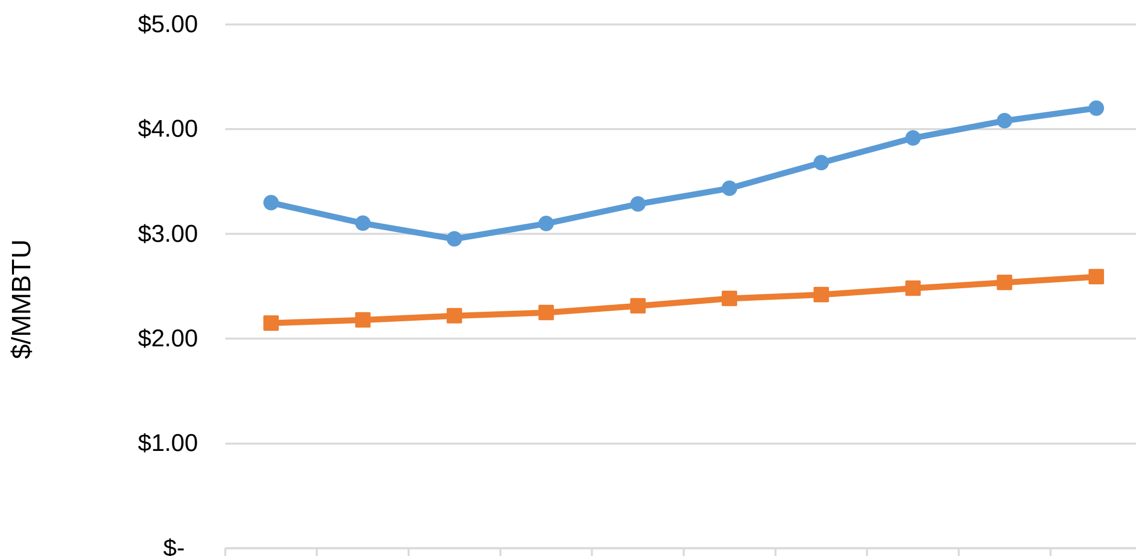
The SPP's long-term Integrated Transmission Plan (ITP)[8] anticipates continued growth in renewable energy resources throughout the SPP system. Additionally, the ITP model assumes retiring thermal generators are primarily replaced by combustion turbines at existing generation sites to meet resource adequacy requirements. Existing generation facilities can provide opportunities for re-development of new generation by providing benefits such as land, water rights, emission permits and are already strategically connected to the existing electric transmission infrastructure. The Horseshoe Lake, Tinker and Seminole sites have the potential to provide these re-development opportunities. Additionally, their locations near OG&E's largest load center offer opportunities to maintain the locational reliability these sites have provided to OG&E's system for many years. OG&E will consider these factors as each site experiences retirements in the future.

[8] SPP. (2020). *2020 Integrated Transmission Planning Assessment Report*. SPP. https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf

C. Fuel Price Projections

OG&E utilizes fuel price projections provided in the EIA 2021 Annual Energy Outlook (AEO)[9]. EIA's models consider macroeconomic conditions, world oil prices, technological developments, and energy policies to provide price projections for the U.S. The AEO "Reference Case" reflects current laws, regulations and market conditions, including projected impacts due to COVID-19. The AEO Reference Case is part of 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 2021 AEO.

Figure 4 – EIA 2021 Annual Energy Outlook Fuel Projections (Nominal $)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Natural Gas - HH	$3.30	$3.10	$2.95	$3.10	$3.29	$3.44	$3.68	$3.91	$4.08	$4.20
Coal	$2.15	$2.18	$2.22	$2.25	$2.31	$2.38	$2.42	$2.48	$2.54	$2.59

D. Risk Assessment

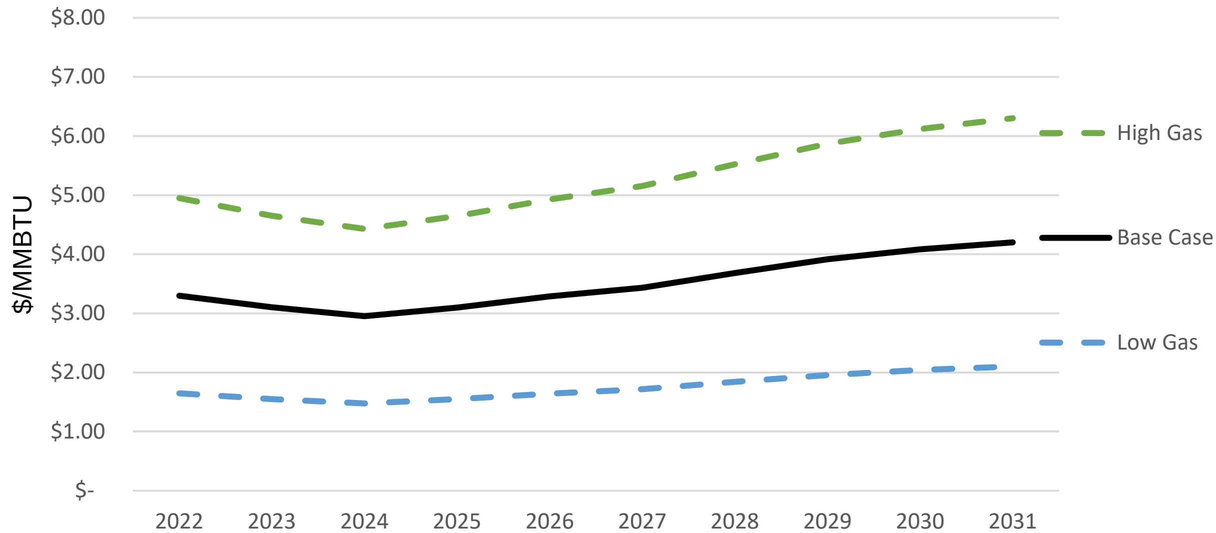
In addition to conducting the resource planning analysis under Base Case conditions, assumptions are varied to develop a range of hypothetical future conditions. Sensitivities involve adjusting a single assumption and measuring the impact of that specific variable on potential resource plans. Scenarios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

1. Sensitivities

The variables considered in the sensitivity analysis are natural gas prices, solar capital costs, load 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.

[9] EIA. (2021, February 3). U.S. Energy Information Administration. *Annual Energy Outlook 2021.* https://www.eia.gov/outlooks/aeo/

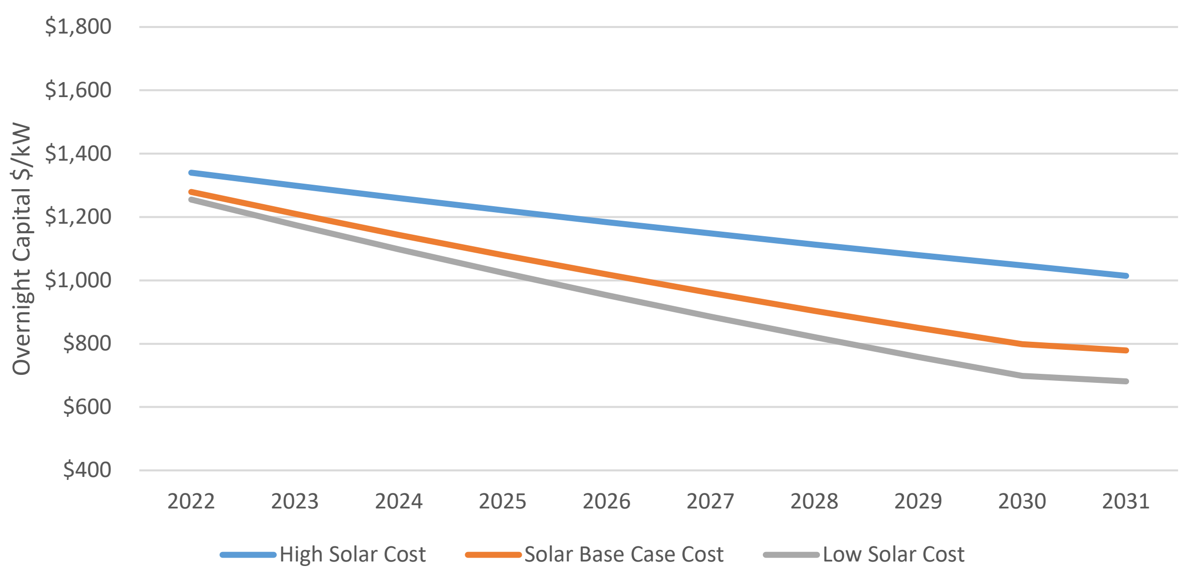
Figure 5 – Natural Gas Sensitivities



NREL provides three 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 6 and the projected capital cost trajectories also provided by NREL[10].

Figure 6 – Solar Capital Cost Sensitivities



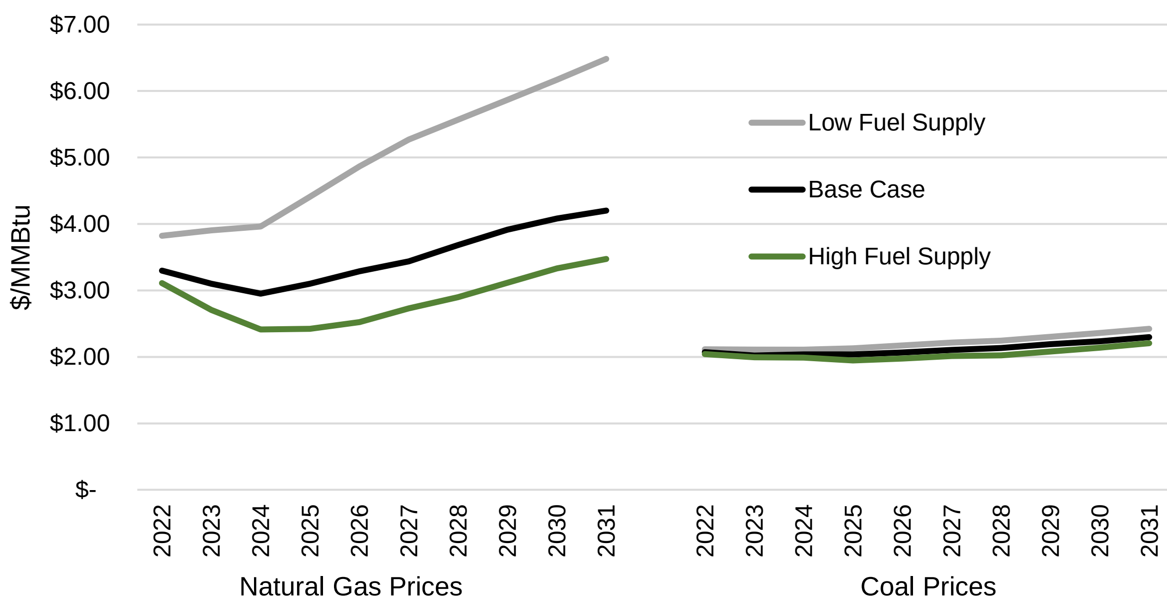
[10] NREL. (2020). *Electricity annual Technology Baseline data download*. NREL. https://atb-archive.nrel.gov/electricity/2020/data.php

The Low Load Sensitivity evaluates the impact of a 10% reduction in energy forecasts for the SPP across the analysis time horizon. Finally, the CO_2 tax sensitivity added a cost of $20 per ton of CO_2 emissions starting in 2025 and escalating by 2% each year afterward.

2. Scenarios

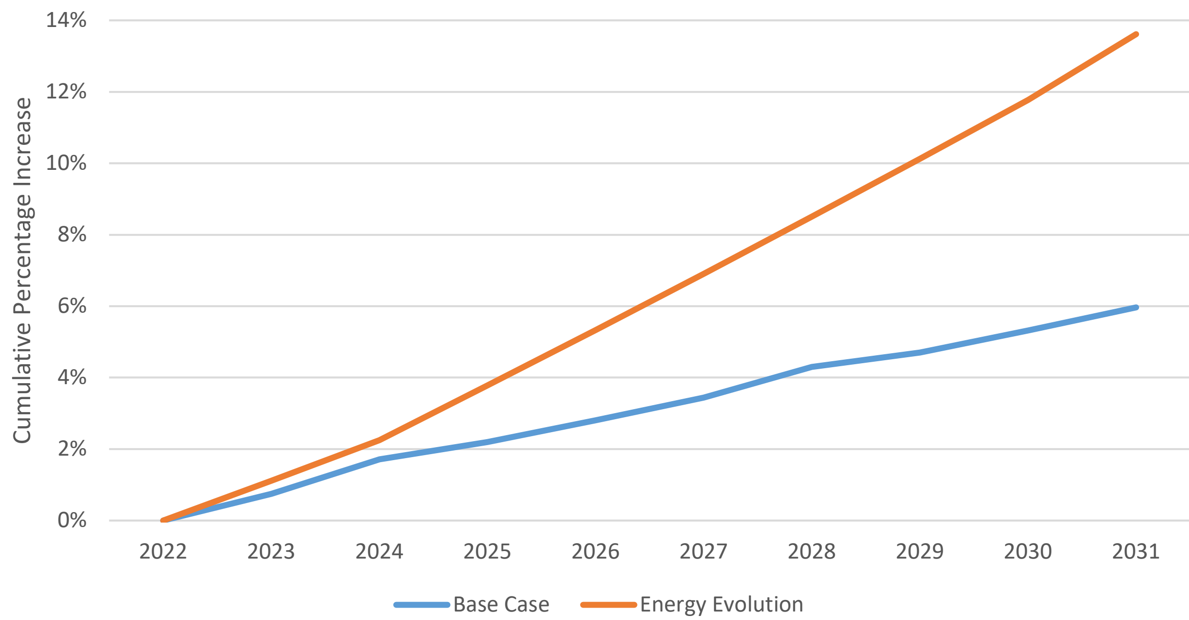
The 2021 Annual Energy Outlook provides several scenarios addressing uncertainties in technology improvements, economic performance, commodity prices, legislation, regulation or energy policies. The Low and High Oil and Gas Resource and Technology cases provide the largest potential variations in commodity 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



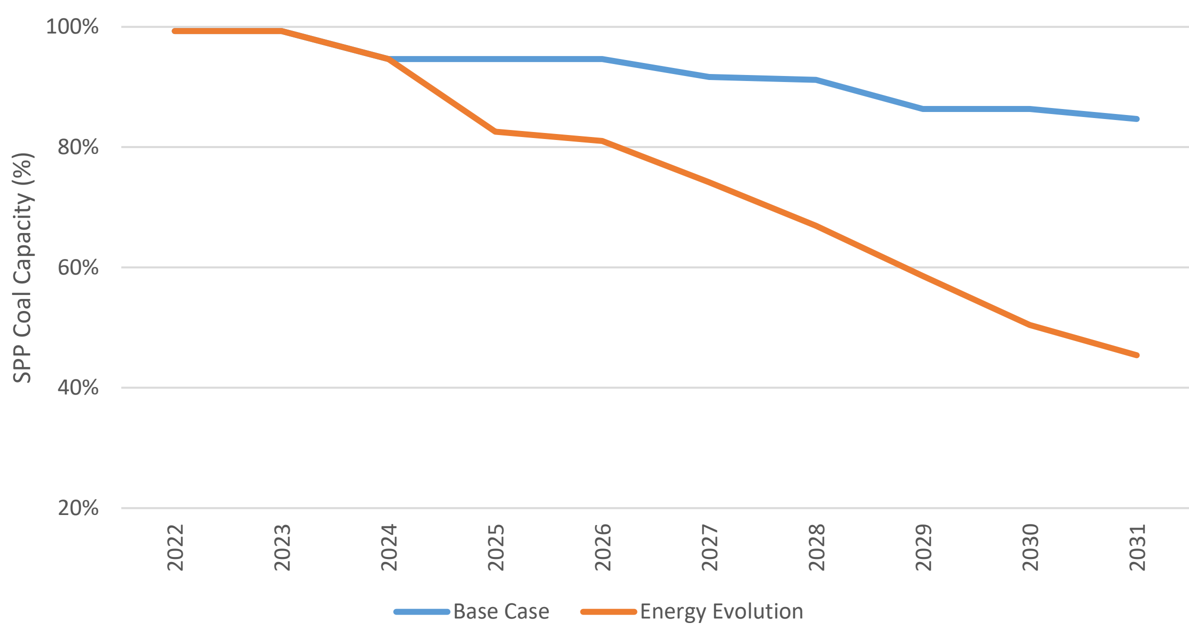
Additionally, OG&E developed an Energy Evolution scenario to analyze the potential impact that could be caused by federal policy leading to increased electrification and a region-wide accelerated coal-fired generation retirement schedule. Increased electrification could involve changes in the residential, 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 percent reduction for the Base Case and the Energy Evolution scenario are provided in Figure 9.

Figure 9 – SPP Coal Capacity Comparison



3. *Sensitivity and Scenario Summary*

Table 7 provides a summary of the assumptions that were changed in the various sensitivities and scenarios.

Table 7 – Sensitivity and Scenario Summary

	Case	Description
Base	Base Case	EIA AEO 2021 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	$20/ton starting 2025
	Low Solar Capital Cost	NREL low solar cost trajectory and $0 transmission cost
	High Solar Capital Cost	NREL high solar cost trajectory
	Low Load	10% SPP load reduction
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

E. <u>Integrated Marketplace Locational Marginal Prices</u>

Hourly Locational Marginal Prices (LMPs) for both generation and load are established through the IM. OG&E utilizes Hitachi ABB Power Grids 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 provided 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

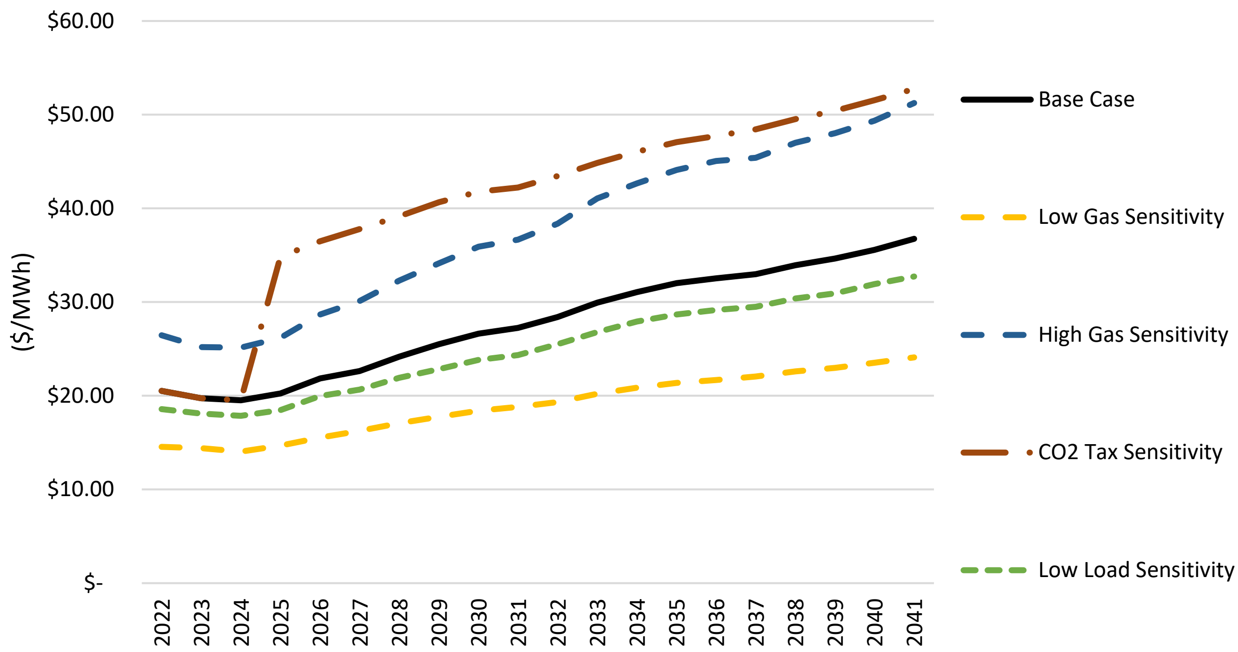
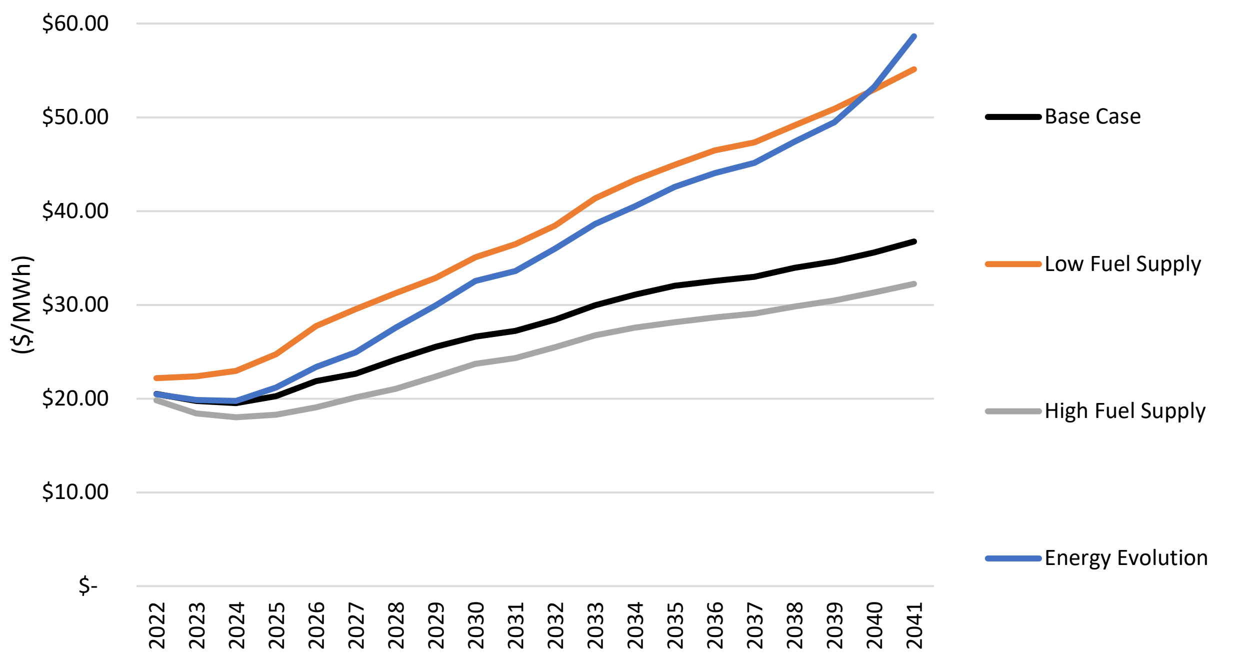


Figure 11 – Base Case and Scenario Average Annual OG&E Load LMP Comparison



IV. 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.

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 and a planning reserve margin. OG&E's minimum 12% planning reserve margin is established in Section 4 of the SPP Planning Criteria [11]. OG&E's projection of the annual planning reserve margin is shown in Table 8.

Table 8 – Planning Reserve Margin (MW unless noted)

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capacity	Owned Capacity	6,702	6,534	6,534	6,323	6,259	5,856	5,856	5,856	5,856	5,371
	Purchase Contracts	47	47	47	47	47	47	47	47	47	16
	Total Capacity	6,749	6,581	6,581	6,370	6,306	5,903	5,903	5,903	5,903	5,386
Demand	Demand Forecast	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
	OG&E DSM	278	309	340	372	403	432	456	477	494	505
	Net Demand	6,025	6,004	6,039	6,059	6,088	6,111	6,133	6,149	6,136	6,154
Margin	Reserve Margin[12]	12%	10%	9%	5%	4%	-3%	-4%	-4%	-4%	-13%
Needs	Needed Capacity	0	145	183	417	514	942	967	985	970	1,507

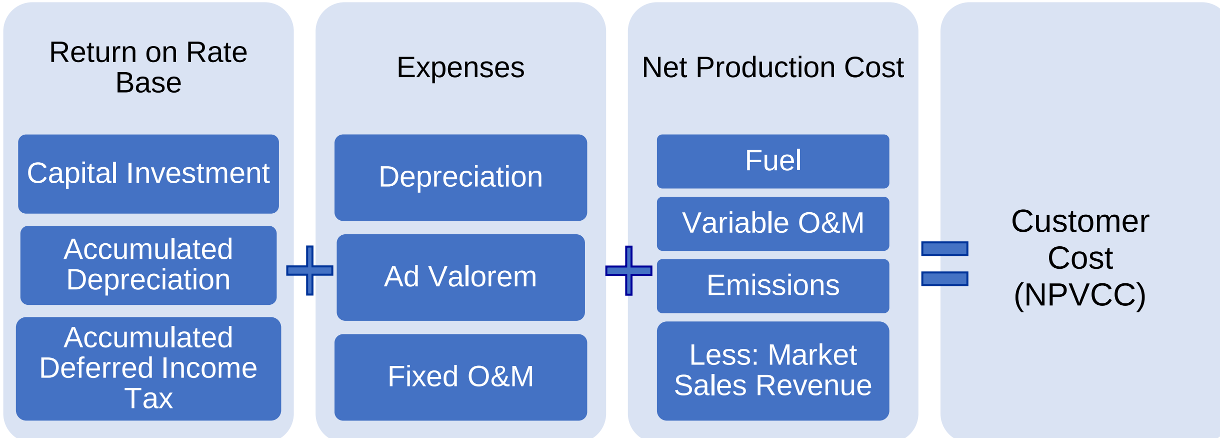
B. Modeling Methodology

OG&E relies on the PROMOD® software to simulate the SPP IM and project hourly nodal LMPs. The PCI GenTrader® software then uses these LMPs to determine production costs and market revenues for the generators. A revenue requirement model combines all the cost components into the estimated 30-year net present value of customer costs (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 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.

[11] SPP. (2021). *SPP Planning Criteria Revision 2.4*. SPP. 2021. https://www.spp.org/documents/58638/spp%20planning%20criteria%20v2.4.pdf

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

Figure 12 – Customer Cost Components



C. Portfolio Development

Potential Portfolios are made up of resources that enable OG&E to meet its 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 Planning Reserve Margin requirement based on the expected construction timeframes for each.

Figure 13 – New Resource Option Earliest Availability

More than one million portfolios were analyzed to meet OG&E's capacity needs over the next 10 years. These portfolios have NPVCC values ranging from $1.2 billion to $3.6 billion in the Base Case and represent various timing, sizing and combinations of the new unit options shown in Table 6. The 100 least cost portfolios consistently contain combinations of solar and combustion turbines. Therefore, a plan that is a balanced approach of solar and combustion turbines is preferred. In Table 9, OG&E first analyzed the technologies available by 2023, which includes solar, battery, hybrid and wind resources. As shown in the table, the only difference between these four portfolios is the technology type in 2023.

Table 9 – Portfolios with Base Case NPVCC in Million $

Portfolio Name	Type	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total*	NMPL. MW**	NPVCC
		Accredited Capacity (MW)												
Solar/CT	**Solar**		**200**		**60**			**60**			**240**	560	933	**$1,182**
	CT				**212**	**212**	**264**				**264**	952	998	
Battery then Solar/CT	*Battery*		200									200	200	$1,256
	Solar				60			60			240	360	600	
	CT				212	212	264				264	952	998	
Solar/ Battery Hybrid then Solar/CT	*Hybrid*		200									200	200	$1,391
	Solar				60			60			240	360	600	
	CT				212	212	264				264	952	998	
Wind then Solar/CT	*Wind*		200									200	1,000	$1,415
	Solar				60			60			240	360	600	
	CT				212	212	264				264	952	998	

**Total = Accredited MW*

***NMPL. MW = Nameplate MW*

As shown in Table 9, solar in 2023 expands the Company's renewable resources and enhances Fuel & Technology Diversity while also being the lowest cost option when compared to batteries, solar/battery hybrids and wind. Stand-alone batteries had higher net present value customer costs than solar over their lifetime in this analysis due to higher maintenance costs, and energy costs associated with charging the batteries. Combining batteries with solar could result in added tax benefits but this hybrid resource approach did not perform as well as stand-alone solar due to assumed operating costs to maintain both the solar resource and the batteries. Finally, 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, which results in a higher total NPVCC.

Figure 14 – Portfolios Comparing 2023 Resource – Base Case NPVCC in Million $

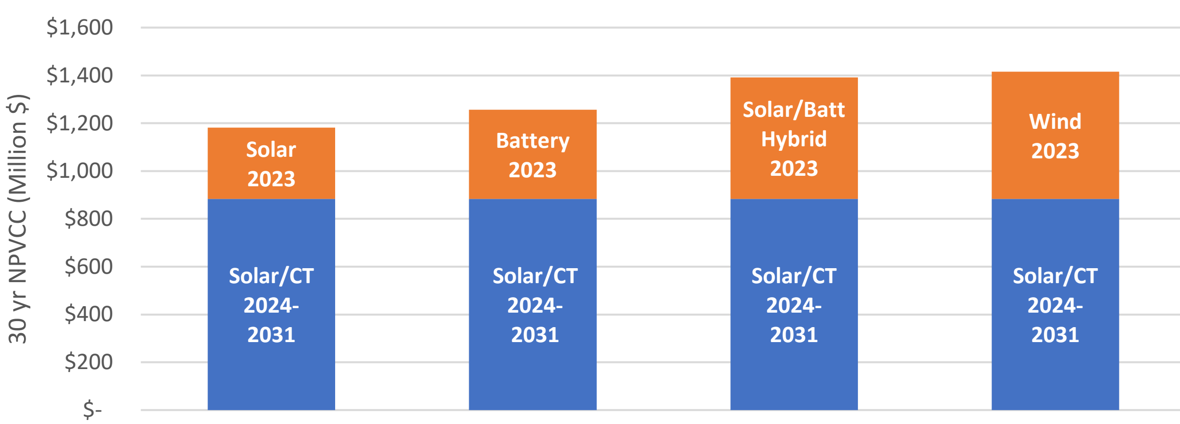


Figure 14 illustrates graphically that, when holding the rest of the portfolio constant, the Solar resource in 2023 results in the lowest net present value of customer costs for the portfolio.

After determining that solar is the lowest reasonable cost resource option in 2023, OG&E then assessed the resource options for its needs in 2025 and beyond. Table 10 below compares various portfolios containing technology options for those post-2023 resource needs.

Table 10 – Representative Portfolios

Portfolio Name	Type	Accredited Capacity (MW)											NMPL. MW**	NPVCC
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total*		
Solar/CT	**Solar**		**200**		**60**			**60**			**240**	560	933	**$1,182**
	CT				**212**	**212**	**264**				**264**	952	998	
Solar then CT Only	*Solar*		200									200	333	$1,191
	CT				264	101	424				528	1,317	1,387	
Solar then CT/CC	*Solar*		200									200	333	$1,334
	CT				264							264	278	
	CC					503			613			1,116	1,168	
Solar Only	Solar		200		240	120	420		60		480	1,520	2,533	$1,398
Solar then RICE and Solar/CT	*Solar*		200				180		60		240	680	1,133	$1,449
	RICE				222	111						333	333	
	CT						264				264	528	556	

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

Table 10 demonstrates that a combination of solar generation and combustion turbines are the most cost-effective option for OG&E's post-2023 needs under the Base Case.

D. 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 lowest customer cost in the Base Case and performs well throughout the Risk Assessment.

As explained in Section III, the sensitivity analysis evaluates the impact of changes in a single input assumption. The sensitivities evaluated for risk are future fuel prices, SPP load, a potential CO_2 tax and solar project capital costs. Table 11 provides a summary of the 30-year NPVCC for each portfolio in each sensitivity.

Table 11 – Sensitivity 30-year NPVCC in Million $

Portfolio Name	Base Case	Low Gas	High Gas	Low Load	CO_2 Tax	Low Solar Cost	High Solar Cost
Solar/CT	$1,182	$1,395	$886	$1,269	$901	$826	$1,302
Battery then Solar/CT	$1,256	$1,378	$1,060	$1,316	$1,103	$967	$1,347
Solar/Battery Hybrid then Solar/CT	$1,391	$1,547	$1,165	$1,463	$1,182	$1,095	$1,500
Wind then Solar/CT	$1,415	$1,906	$828	$1,602	$651	$1,043	$1,506
Solar then CT Only	$1,191	$1,263	$1,054	$1,247	$1,067	$1,041	$1,220
Solar then CT/CC	$1,334	$1,289	$1,164	$1,464	$950	$1,184	$1,363
Solar Only	$1,398	$2,042	$623	$1,584	$618	$437	$1,760
Solar then RICE	$1,449	$1,713	$1,089	$1,557	$1,096	$1,019	$1,605

The sensitivity risk ranges shown above are graphically illustrated in Figure 15 through Figure 18. 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 15 – Natural Gas Price Sensitivity Assessment, NPVCC in Million $

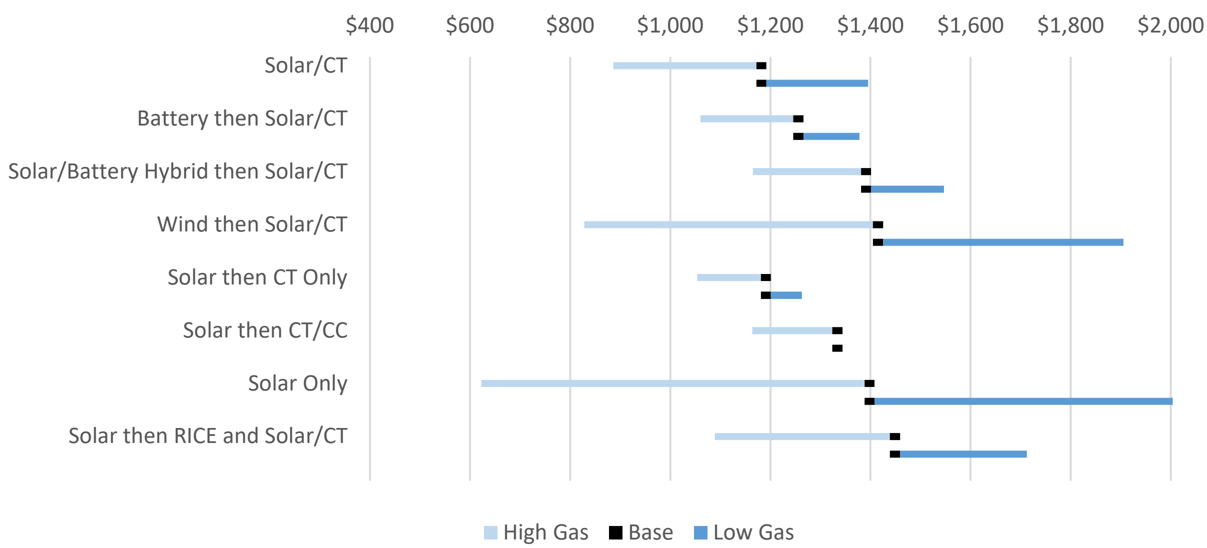


Figure 16 – Low Load Sensitivity Assessment, NPVCC in Million $

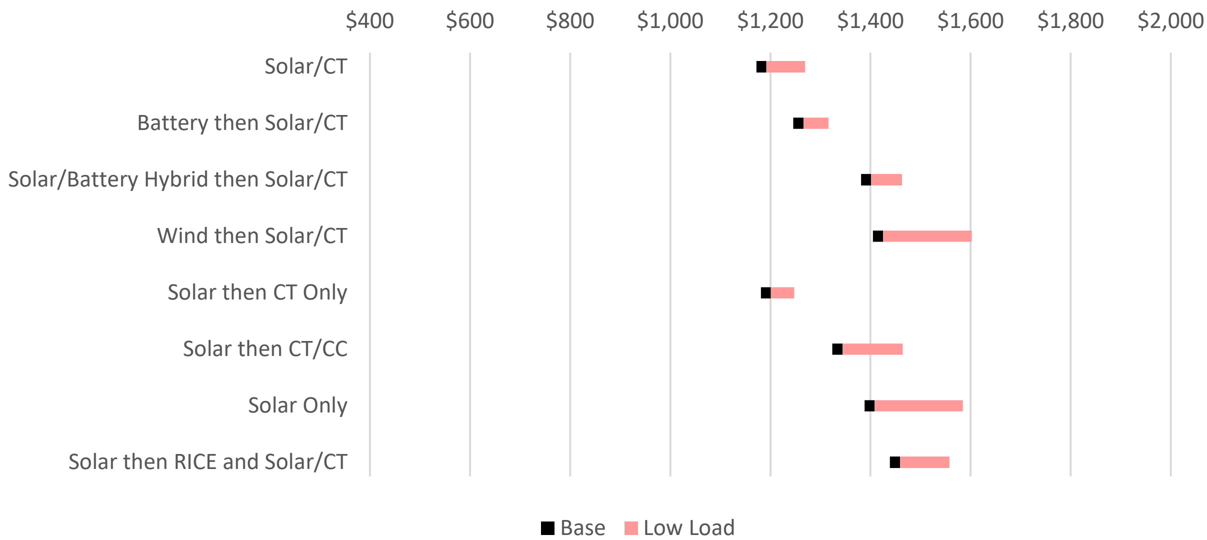


Figure 17 – CO_2 Tax Sensitivity Assessment, NPVCC in Million $

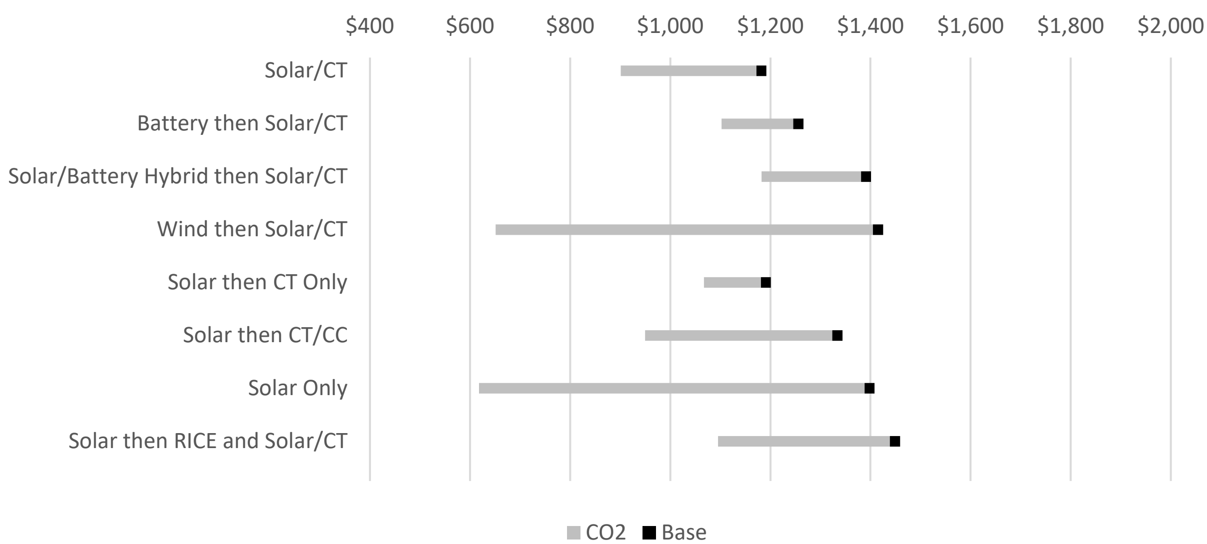
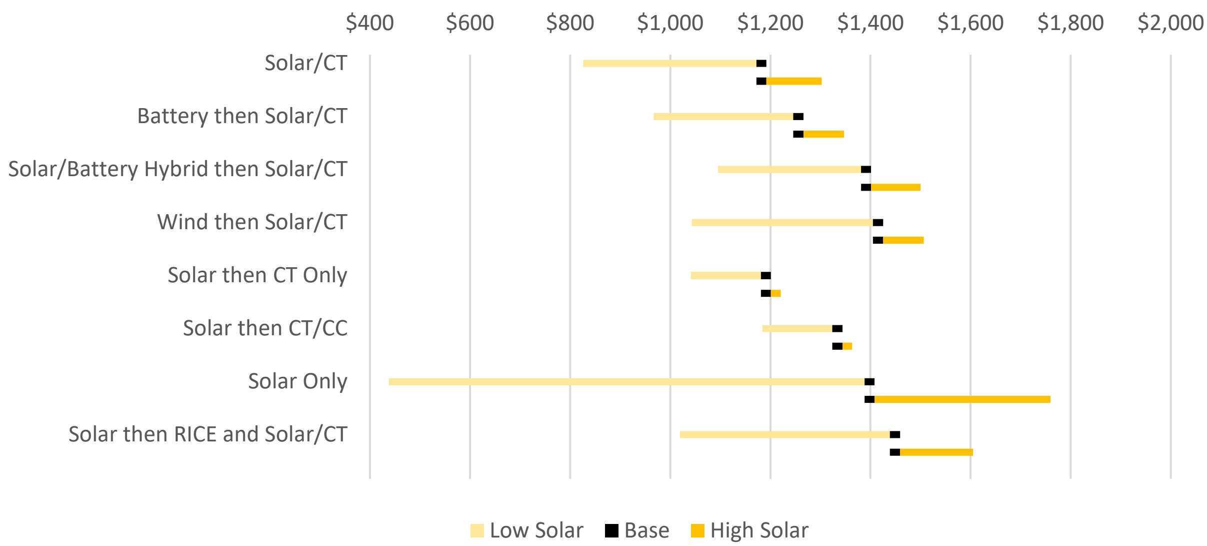


Figure 18 – Solar Capital Cost Sensitivity Assessment, NPVCC in Million $



The scenario analysis evaluates the impact of changes to multiple assumptions at the same time. As described in Section III, the three scenarios analyzed are Low Fuel Supply, High Fuel Supply and Energy Evolution. Table 12 provides a summary of the 30-year NPVCC for each portfolio in each scenario.

Table 12 – Scenario 30-year NPVCC in Million $

Portfolio Name	Base	Low Fuel Supply	High Fuel Supply	Energy Evolution
Solar/CT	$1,182	$857	$1,269	$745
Battery then Solar/CT	$1,256	$1,036	$1,310	$924
Solar/Battery Hybrid then Solar/CT	$1,391	$1,138	$1,457	$1,016
Wind then Solar/CT	$1,415	$782	$1,596	$717
Solar then CT Only	$1,191	$1,053	$1,227	$881
Solar then CT/CC	$1,334	$1,170	$1,340	$665
Solar Only	$1,398	$522	$1,641	$586
Solar then RICE	$1,449	$1,050	$1,555	$933

The risk range of the scenarios shown above are graphically illustrated in Figure 19 and Figure 20.

Figure 19 – Fuel Supply Scenario Assessment, NPVCC in Million $

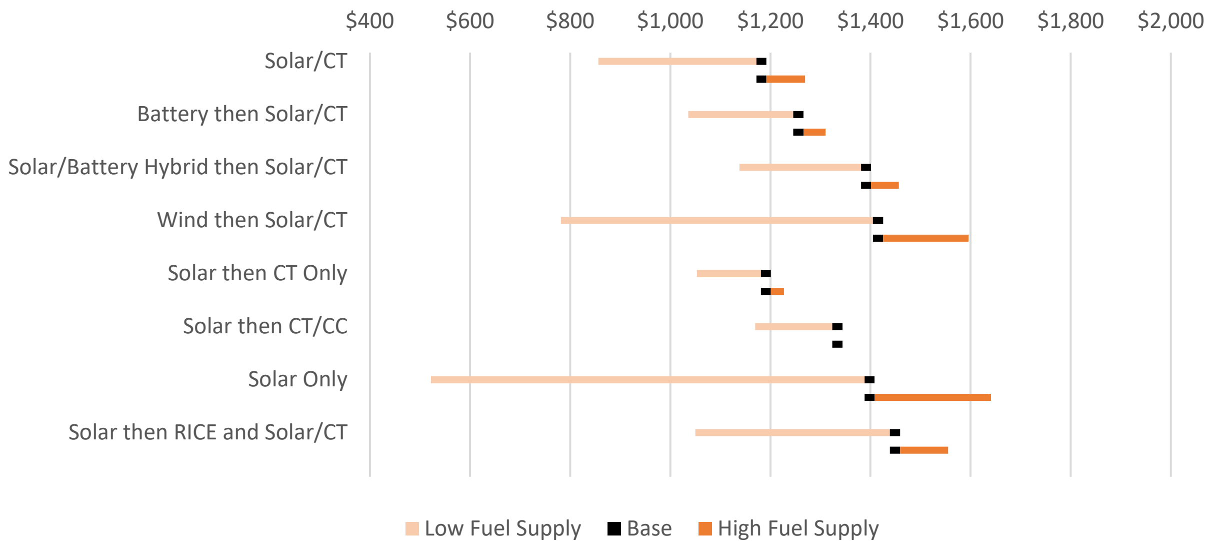
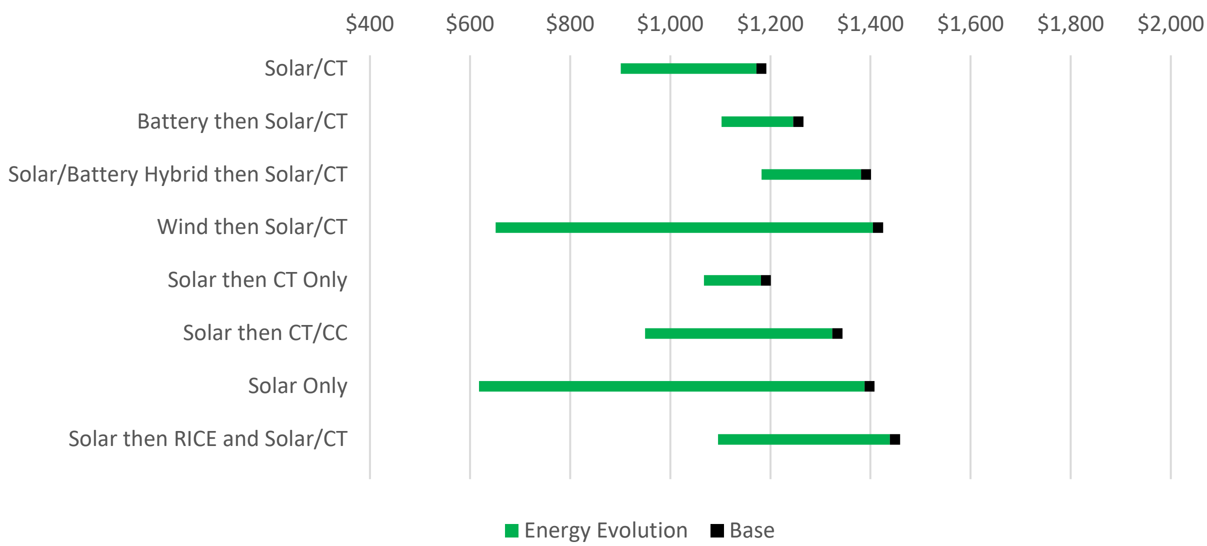


Figure 20 – Energy Evolution Scenario Assessment, NPVCC in Million $



The Sensitivity and Scenario analysis shows that OG&E's preferred plan is the Solar/CT portfolio because it has the lowest customer cost in the Base Case and it mitigates a variety of potential risks.

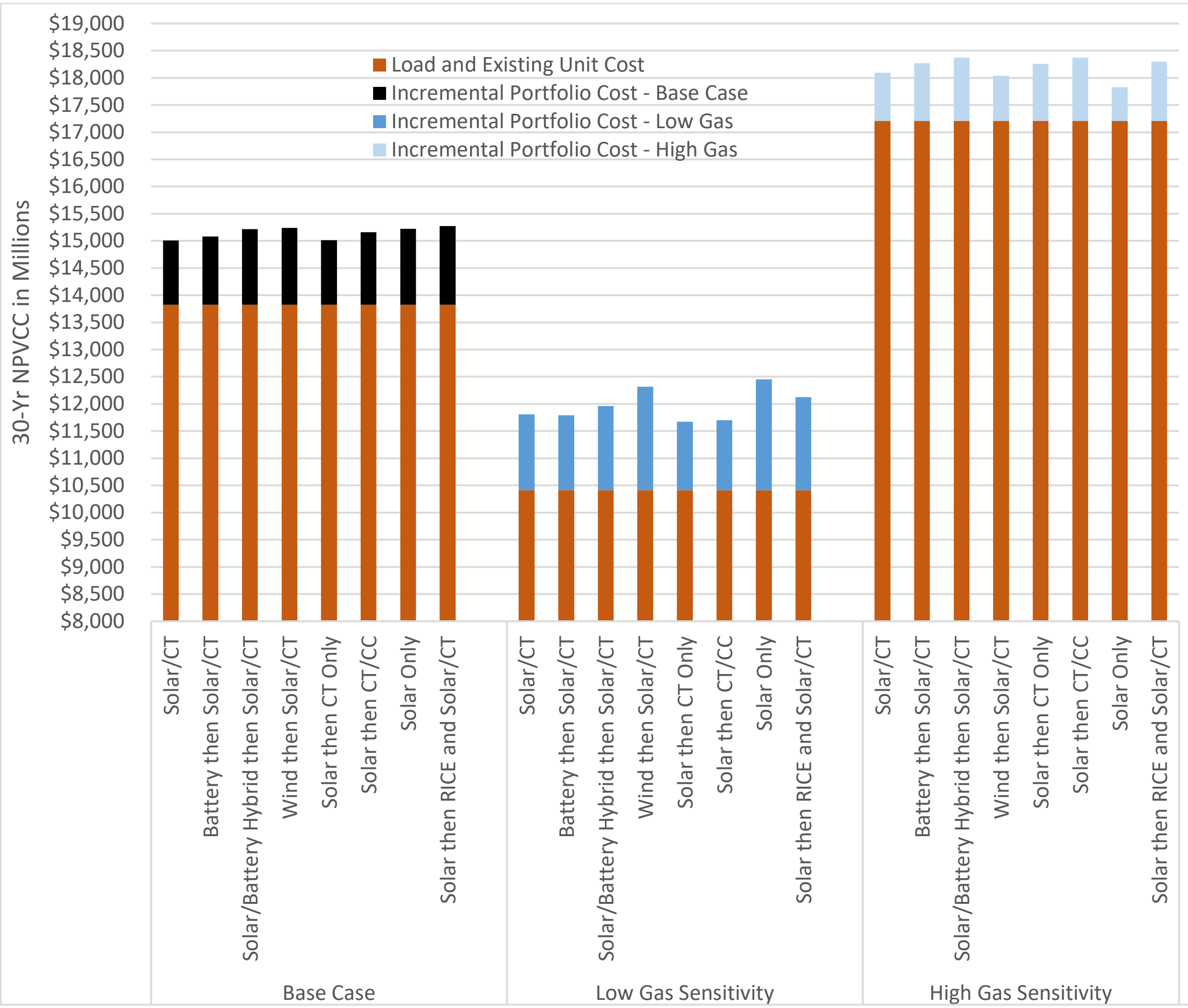
Table 13 – OG&E Preferred Plan

Portfolio Name	Type	Accredited Capacity (MW)											NMPL. MW**	NPVCC
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total*		
Solar/CT	Solar		200		60			60			240	560	933	$1,182
	CT				212	212	264				264	952	998	

*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 21 shows the 30-year NPVCC of OG&E's load cost, existing generation unit net production costs and fixed O&M expenses under the natural gas sensitivities and base case assumptions.

Figure 21 – Portfolio Cost including Load and Existing Generation Units



E. Qualitative Considerations

In addition to being the lowest customer cost plan, OG&E's preferred Solar/CT plan also provides several qualitative benefits.

1. Operational Flexibility and Resiliency Benefits

Wind generation capacity in SPP has doubled over the past five years to approximately 27 GW[13] and the growth of wind generation capacity in SPP is expected to continue in the future. SPP also expects growth in Solar generation resources over the next decade[14]. Combustion turbines complement the intermittency of renewable generation to support reliability during renewable output fluctuations and can respond quickly in the SPP Integrated Marketplace.

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.[15]

Additional notes from SPP's website address the need for quick-start resources.

> Fast-start resources are essential to the reliable provision of energy. These resources typically have short startup times, low minimum run time requirements, and faster than average ramp rates. These characteristics provide the needed flexibility for managing the operational challenges SPP faces.[16]

2. Fuel & Technology Diversity and Reduced Environmental Footprint

OG&E's customers express a growing interest for renewable energy and a reduced environmental footprint. The Company is committed to serving their evolving needs. The preferred plan adds solar which expands the Company's renewable resources and

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[13] SPP. (2021). *State of the market report, Fall 2020*. SPP. https://www.spp.org/documents/63908/spp%20mmu%20%20quarterly%20state%20of%20the%20market%20fall%202020.pdf, page 8

[14] SPP. (2020). *2020 Integrated transmission planning assessment report*. 2020. SPP. https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf

[15] “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.

[16] “SIR17 HITT R3B Fast-Start Resource. *SPP*, March 18, 2020, www.spp.org/documents/61833/sir17_hittr3bfaststartresource_sppbod_ferc.pdf, Accessed 7/15/2021.

enhances Fuel & 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 its potential ability to reduce emissions. The balance of solar and hydrogen-capable combustion turbines is consistent with OG&E's expectation to reduce CO_2 emissions to 50 percent below 2005 levels by 2030 and lowering OG&E's carbon intensity.

F. Conclusion

OG&E will have capacity needs beginning in 2023. In this 2021 IRP, the Company analyzed a wide variety of potential resource portfolios to determine the best generation portfolio that satisfies OG&E's future Capacity Obligations. The portfolio analysis shows the lowest Expected Cost to Customers in the Base Case is a combination of solar and combustion turbine resources. The risk analysis demonstrates this blend of resources mitigates Exposure to Risks across the range of sensitivities and scenarios analyzed. The balanced approach of solar and combustion turbines fulfills the objective of Fuel & Technology Diversity and improves Operational Flexibility, Resiliency and the Portfolio Age of OG&E's generation fleet while also being Adaptable to changing assumptions in the future.

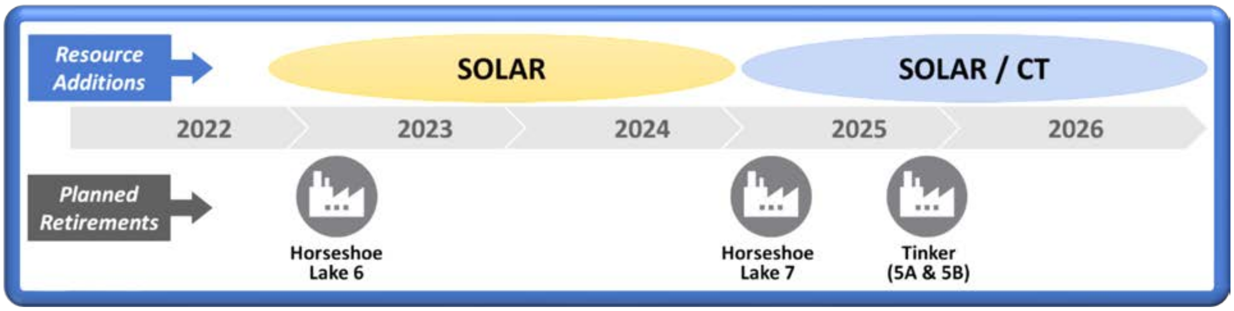
The solar resources in the preferred plan expands OG&E's renewable generation fleet. Combustion turbines can respond quickly in the SPP to enable and support the growth of renewable generation resources into the region. This plan allows the Company to cost-effectively meet capacity needs going forward with newer technology including hydrogen-capable combustion turbines and zero-emitting resources, consistent with OG&E's Environmental Stewardship objective and lowering OG&E's carbon intensity.

OG&E will issue an RFP(s) for resources identified in the Solar/CT plan to meet the capacity requirements and other IRP objectives of the company for future generation designed to increase efficiency, advance cleaner generation and maintain affordability.

V. Action Plan

The Five-Year Action Plan outlined below identifies the steps OG&E will take to address its capacity needs from 2022-2026.

1) OG&E will retire Horseshoe Lake unit 6 in 2023.
2) OG&E plans to retire Horseshoe Lake unit 7 and Tinker units 5A and 5B in 2025.
3) OG&E will issue an RFP(s) for the resources identified in the preferred plan as shown below.



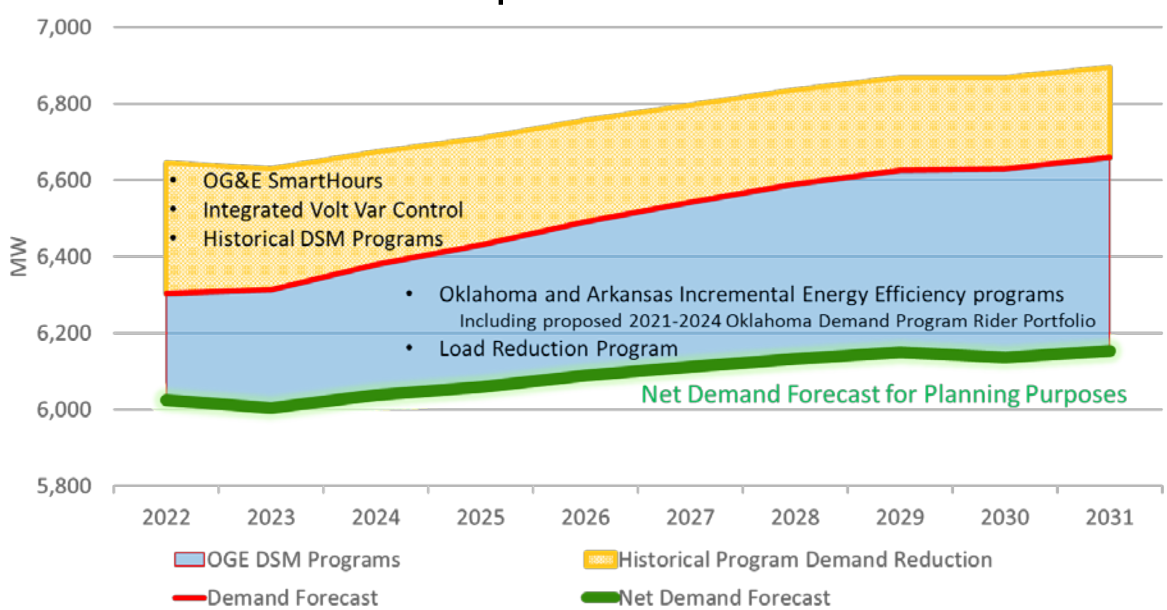
VI. Schedules

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).

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 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. 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)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Energy Forecast[17]	29,897	30,053	30,225	30,395	30,620	30,858	31,113	31,389	31,695	31,978
OG&E DSM[18]	615	803	991	1,179	1,353	1,499	1,622	1,725	1,812	1,986
Net Energy	29,283	29,250	29,234	29,215	29,267	29,359	29,491	29,664	29,883	29,992

[17] Includes SmartHours, Historical Demand Program Rider programs and Integrated Volt Var Control.
[18] Represents estimates for incremental energy efficiency programs in Oklahoma and Arkansas, the Load Reduction Program, and existing and future OG&E distributed energy resources.

Peak Demand Forecast (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Demand Forecast[17]	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
OG&E DSM[18]	278	309	340	372	403	432	456	477	494	505
Net Demand	6,025	6,004	6,039	6,059	6,088	6,111	6,133	6,149	6,136	6,154

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 Capacity (MW)
Coal Fired Steam (1,854 MW)	Muskogee 6	1984	503
	Sooner 1	1979	516
	Sooner 2	1980	515
	River Valley 1	1990	160
	River Valley 2	1990	160
Gas Fired Steam (3,130 MW)	Muskogee 4	1977	423
	Muskogee 5	1978	442
	Horseshoe Lake 6	1958	168
	Horseshoe Lake 7	1963	211
	Horseshoe Lake 8	1969	403
	Seminole 1	1971	485
	Seminole 2	1973	500
	Seminole 3	1975	498
Combined Cycle (1,113 MW)	McClain [19]	2001	378
	Redbud [19]	2002	615
	Frontier	1989	120
Combustion Turbine (553 MW)	Horseshoe Lake 9	2000	45
	Horseshoe Lake 10	2000	43
	Tinker (Mustang 5A)	1971	33
	Tinker (Mustang 5B)	1971	31
	Mustang 6	2018	57
	Mustang 7	2018	57
	Mustang 8	2018	58
	Mustang 9	2018	58
	Mustang 10	2018	57
	Mustang 11	2018	57
	Mustang 12	2018	57

[19] Represents OG&E owned interest: 77% of McClain and 51% of Redbud.

OG&E Existing Renewable Resources

Unit Type	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capacity (MW)
Wind (52 MW)	Centennial	2006	120	15
	OU Spirit	2009	101	9
	Crossroads	2012	228	28
Solar (18 MW)[20]	Mustang	2015	3	2
	Covington	2018	9	8
	Chickasaw Nation	2020	5	4
	Choctaw Nation	2020	5	4

OG&E Existing Power Purchase Contracts

	Unit Name	Contract Start date	Nameplate Capacity (MW)	Summer Capacity (MW)
Power Purchase (47 MW)	Keenan	2010	152	21
	Taloga	2011	130	10
	Blackwell	2012	60	9
	Southwestern Power Administration	1979	7	7

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 18 million customers and has members in 14 states across all of Kansas and Oklahoma and parts of Arkansas, 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[21] (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 (TS) or Generator Interconnection (GI), approved projects for the annual Integrated Transmission Planning (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

[20] Solar is connected to distribution and is embedded in the Net Demand Forecast. OG&E expects 10 MW of additional nameplate distributed solar resources will be in service by the end of 2021.
[21] SPP. (2021). *2021 SPP Transmission Expansion Plan Report*. SPP. https://www.spp.org/documents/56611/2021%20step%20report.pdf

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[22] and SPP provides a comprehensive tracking spreadsheet for all projects[23]. The projects located on the OG&E system are provided in Schedule J.

D. Needs Assessment

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

Planning Margin (MW unless noted)

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capacity	Owned Capacity	6,702	6,534	6,534	6,323	6,259	5,856	5,856	5,856	5,856	5,371
	Purchase Contracts	47	47	47	47	47	47	47	47	47	16
	Total Capacity	6,749	6,581	6,581	6,370	6,306	5,903	5,903	5,903	5,903	5,386
Demand	Demand Forecast	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
	OG&E DSM	278	309	340	372	403	432	456	477	494	505
	Net Demand	6,025	6,004	6,039	6,059	6,088	6,111	6,133	6,149	6,136	6,154
Margin	Reserve Margin[24]	12%	10%	9%	5%	4%	-3%	-4%	-4%	-4%	-13%
Needs	Needed Capacity	0	145	183	417	514	942	967	985	970	1,507

E. Resource Options

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

[22] SPP. *Integrated Transmission Planning*. ITP reports: https://www.spp.org/engineering/transmission-planning/
[23] SPP. (2021). *2021 SPP Transmission Expansion Plan Report, Appendix 1*. https://www.spp.org/Documents/56610/2021%20STEP%20Report%20Appendix%201.xlsx
[24] Reserve Margin % = ((Total Net Capacity) - (Net System Demand)) / Net System Demand

New Generation Resources (2021 Dollars)

Technology	Model	Nameplate Capacity (MW)	Nameplate Overnight Capital Cost ($/kW)	Summer Peak Capacity	Fixed O&M Cost ($/kW)	Variable O&M Cost ($/MWh)
Wind	Land-Based	250	$1,470	50	$46.00	N/A
Batteries	Lithium Ion	100	$1,310	100	$21.00	N/A
Solar	Photovoltaic Single Axis	100	$1,350	60	$16.90	N/A
Solar/Battery Hybrid	Single Axis/Lithium Ion	100	$2,590	100	$37.90	N/A
RICE	Reciprocating Engine 1x	19	$2,430	19	$38.80	$4.50
	Reciprocating Engine 6x	111	$1,320	111	$14.50	$4.50
Combustion Turbine (CT)	AGT 1x	62	$1,690	58	$4.50	$0.90
	AGT 7x	432	$1,100	404	$5.60	$0.90
	LMS100 1x	111	$1,090	101	$2.60	$5.70
	LMS100 4x	444	$860	405	$3.20	$5.70
	E Class 1x	85	$1,120	77	$6.50	$7.20
	E Class 5x	427	$840	386	$6.80	$7.20
	F Class	221	$690	212	$3.20	$1.80
	G/H Class	278	$660	264	$3.50	$2.20
Combined Cycle (CC)	1x1 J Class	531	$930	503	$3.50	$1.50
	1x1 J Class Fired	637	$780	613	$3.50	$2.20
	2x1 G/H Class Fired	1,001	$700	944	$2.50	$2.30
	2x1 F Class	729	$850	662	$2.40	$1.50
	2x1 F Class Fired	880	$750	828	$2.40	$2.30
	1x1 F Class Fired	441	$960	411	$4.30	$2.40

F. Fuel Procurement and Risk Management Plan

On May 14, 2021, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC.

G. Action Plan

The Five-Year Action Plan outlined below identifies the steps OG&E will take to address its capacity needs from 2022-2026.

1) OG&E will retire Horseshoe Lake unit 6 in 2023.
2) OG&E will retire Horseshoe Lake unit 7 and Tinker units 5A and 5B in 2025.
3) OG&E will issue an RFP(s) for the resources identified in the preferred plan.

H. Requests for Proposals

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

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 3
Existing Generation Resources	OG&E	Page 4
Resource Changes	OG&E	Page 6
Future Resource Options	Burns & McDonnell, NREL, EIA	Page 8
Fuel Price Projections	EIA	Page 11
Risk Assessment	OG&E, EIA, NREL	Page 11
Integrated Market Prices	OG&E	Page 15
Planning Reserve Margin	OG&E	Page 17
Modeling Methodology	OG&E	Page 17
New Resource Earliest Availability	Burns & McDonnell	Page 18

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

1. PROMOD® - Fundamental Electric Market Simulation software from Hitachi ABB Power Grids that incorporates generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations. PROMOD® is used to model the SPP Integrated Marketplace.
2. GenTrader® - Power Costs, Inc. software designed to model complex portfolios of power and fuel resources, including generators, contracts, options, and ancillary services in great detail. Some of the functionalities include: multiple and concurrent fuel and emission limits, multi-stage combined-cycle modeling, ancillary services like regulations and spinning reserve as well as energy limited contracts. GenTrader® is used to simulate OG&E's net production costs within the SPP IM.

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 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	NTC ID
2021	Gracemont 345 kV Substation Upgrade for GEN-2015-093 Interconnection	Substation Upgrade	Generator Interconnection	$2.13	GI	N/A
2021	Tap Cleveland - Sooner 345 kV Substation GEN-2015-066 Interconnection	Substation Upgrade	Generator Interconnection	$10.31	GI	N/A
2021	Henessey 138 kV Ckt 1 Terminal Upgrades	Substation Upgrade	Generator Interconnection	$0.14	GI	210556
2021	Westmoore 138 kV Breakers	Substation Upgrade	Regional Reliability	$0.27	ITP	210540
2021	Santa Fe 138 kV Breakers	Substation Upgrade	Regional Reliability	$0.41	ITP	210540
2021	Cleo Corner - Cleo Junction 69kV Ckt 1 Terminal Upgrades	Substation Upgrade	Regional Reliability	$0.02	ITP	210540
2021	Forest Hill 69 kV Terminal Upgrade	Substation Upgrade	Regional Reliability	$0.03	TS	210554
2022	Border - Woodward Tap 345 kV Substation	New Substation	Economic	$11.50	ITP	210587
2022	Chisholm - Woodward Border 345 kV Ckt 1 (OGE)	New Line	Economic	$1.26	ITP	210587
2023	Gracemont 138 kV Ckt 2 Terminal Equipment	Substation Upgrade	Economic	$0.41	ITP	210589
2023	Cushing - Shell Pipeline Area Cushing Tap 69 kV Ckt 1 Rebuild	Line Rebuild	Regional Reliability	$5.36	ITP	210589
2025	Minco - Pleasant Valley - Draper 345 kV Substation equipment upgrades	Substation Upgrade	Economic	$38.59	ITP	210587

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.

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 law and regulation. 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.

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.

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. Generation fleet diversity promotes economic dispatch of generation for the benefit of OG&E's customers and this economic dispatch capability helps ensure OG&E's customers will incur the lowest reasonable costs. OG&E also has physical fuel storage of both coal and natural gas.

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. Currently, the Company is evaluating whether any changes to its fuel procurement strategies are necessary.

On May 14, 2021, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC.

VII. 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 reserve margin calculation.

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

Event of Occurrence	Occurrence Probability	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 out of 30 Years	3%	6,706	6,717	6,849	6,901	6,963	6,937	6,993	7,028	7,061	7,103
1 out of 10 Years	10%	6,588	6,584	6,768	6,820	6,881	6,789	6,894	6,932	6,983	7,049
1 out of 4 Years	25%	6,490	6,501	6,569	6,621	6,682	6,726	6,777	6,812	6,816	6,846
1 out of 2 Years	**50%**	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
3 out of 4 Years	75%	6,142	6,125	6,213	6,265	6,324	6,308	6,439	6,441	6,460	6,512
9 out of 10 Years	90%	5,957	5,952	6,119	6,171	6,230	6,172	6,250	6,291	6,343	6,402
29 out of 30 Years	97%	5,839	5,849	6,031	6,083	6,143	6,089	6,163	6,208	6,254	6,311

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 Forecast by Customer Revenue Class before OG&E DSM

GWH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential	9,465	9,466	9,479	9,486	9,521	9,569	9,629	9,696	9,767	9,854
Commercial	6,894	6,890	6,902	6,932	6,994	7,060	7,132	7,209	7,291	7,356
Industrial	4,256	4,288	4,286	4,252	4,202	4,133	4,044	3,951	3,857	3,892
Petroleum	4,248	4,359	4,487	4,628	4,775	4,937	5,115	5,308	5,518	5,568
Street Lighting	51	48	44	41	40	40	39	39	38	38
Public Authority	3,045	3,055	3,068	3,085	3,103	3,120	3,137	3,153	3,169	3,198
Total Retail Sales	27,960	28,105	28,266	28,425	28,635	28,859	29,096	29,355	29,641	29,906
Losses	1,938	1,948	1,959	1,970	1,984	2,000	2,016	2,034	2,054	2,072
Energy Forecast	29,897	30,053	30,225	30,395	30,620	30,858	31,113	31,389	31,695	31,978

Appendix B – Arkansas Request – Sooner and Muskogee 6 Retirement Dates

In general, electric utilities expect all types of generation assets to be in service over the long-term, typically with service lives ranging from 25 to 65 years. Many factors are considered when determining appropriate retirement dates, such as asset condition, expected lifecycle costs, fuel supply and potential risks. The current projected retirement dates for the Sooner and Muskogee coal units are based on OG&E's depreciation studies and are shown in the table below:

Unit Name	First Year In Service	Projected Retirement Year
Muskogee 6	1984	2049
Sooner 1	1979	2044
Sooner 2	1980	2045

At this time, OG&E has not changed its retirement schedule for its coal-fired units at the Muskogee and Sooner generating stations. OG&E will continue to monitor changing assumptions and environmental regulations and include any revised analysis in future IRPs.

Appendix C – Portfolio Annual Cost Components

Portfolio Annual Cost Components

	Solar/CT			
($Millions)	Return on Rate Base	Expenses	Production Cost	Customer Cost
2021	18	-	-	18
2022	49	-	-	49
2023	52	26	(21)	57
2024	74	26	(21)	78
2025	80	40	(28)	92
2026	87	47	(30)	104
2027	89	56	(32)	113
2028	91	63	(41)	113
2029	110	64	(44)	130
2030	146	64	(45)	165
2031	132	101	(80)	154
2032	125	102	(83)	144
2033	118	103	(87)	134
2034	112	103	(89)	126
2035	106	103	(92)	118
2036	106	104	(93)	117
2037	101	105	(94)	111
2038	95	105	(97)	103
2039	89	106	(98)	97
2040	83	106	(102)	88
2041	78	107	(105)	80
2042	74	108	(107)	75
2043	69	108	(109)	68
2044	65	109	(111)	62
2045	60	110	(114)	56
2046	56	110	(116)	50
2047	52	111	(118)	45
2048	48	112	(121)	39
2049	44	112	(123)	33
2050	40	113	(125)	27
2051	35	114	(128)	22
30 Yr NPV	1,063	844	(725)	1,182

	Battery then Solar/CT			
($Millions)	Return on Rate Base	Expenses	Production Cost	Customer Cost
2021	10	-	-	10
2022	29	-	-	29
2023	39	17	(3)	53
2024	61	17	(3)	75
2025	69	31	(9)	91
2026	77	38	(10)	104
2027	80	47	(12)	115
2028	80	54	(19)	115
2029	100	55	(21)	134
2030	137	55	(21)	171
2031	124	92	(55)	161
2032	118	93	(57)	154
2033	112	93	(60)	145
2034	107	94	(61)	139
2035	101	94	(63)	132
2036	102	95	(64)	132
2037	96	95	(65)	127
2038	91	96	(67)	120
2039	86	97	(68)	115
2040	80	97	(70)	107
2041	76	98	(73)	101
2042	72	98	(73)	97
2043	68	99	(75)	92
2044	64	100	(77)	87
2045	60	100	(78)	82
2046	56	101	(80)	77
2047	52	102	(81)	73
2048	49	102	(83)	68
2049	45	103	(84)	64
2050	41	104	(86)	59
2051	38	105	(88)	55
30 Yr NPV	954	744	(442)	1,256

Portfolio Annual Cost Components

($Millions)	Solar/Battery Hybrid then Solar/CT			
	Return on Rate Base	Expenses	Production Cost	Customer Cost
2021	20	-	-	20
2022	50	-	-	50
2023	52	29	(10)	71
2024	72	30	(9)	93
2025	79	44	(16)	107
2026	86	51	(18)	119
2027	88	60	(19)	129
2028	90	68	(28)	130
2029	109	68	(29)	148
2030	145	68	(30)	183
2031	130	106	(65)	172
2032	123	106	(67)	163
2033	116	107	(70)	153
2034	111	108	(72)	146
2035	104	108	(75)	138
2036	105	109	(76)	138
2037	99	109	(76)	132
2038	93	110	(79)	124
2039	87	111	(80)	118
2040	81	111	(83)	110
2041	76	112	(86)	103
2042	72	113	(87)	98
2043	67	114	(89)	92
2044	63	114	(90)	87
2045	58	115	(92)	81
2046	54	116	(94)	75
2047	50	117	(96)	70
2048	45	118	(98)	65
2049	41	118	(100)	60
2050	37	119	(102)	54
2051	33	120	(104)	49
30 Yr NPV	1,048	895	(551)	1,391

($Millions)	Wind then Solar/CT			
	Return on Rate Base	Expenses	Production Cost	Customer Cost
2021	61	-	-	61
2022	137	-	-	137
2023	46	107	(73)	79
2024	62	108	(77)	92
2025	64	123	(87)	100
2026	67	131	(95)	103
2027	66	140	(99)	107
2028	74	149	(113)	109
2029	89	150	(118)	121
2030	120	151	(124)	147
2031	102	190	(161)	130
2032	90	191	(168)	113
2033	165	193	(176)	181
2034	157	194	(178)	173
2035	149	196	(186)	158
2036	147	197	(193)	152
2037	139	199	(194)	143
2038	131	201	(195)	137
2039	123	203	(203)	122
2040	115	204	(192)	127
2041	108	206	(217)	97
2042	101	208	(215)	94
2043	95	210	(220)	84
2044	88	212	(224)	75
2045	81	214	(229)	66
2046	75	215	(234)	57
2047	69	218	(238)	48
2048	62	220	(243)	39
2049	56	222	(248)	30
2050	50	224	(252)	21
2051	43	226	(257)	13
30 Yr NPV	1,212	1,845	(1,642)	1,415

Portfolio Annual Cost Components

($Millions)	Solar then CT Only			
	Return on Rate Base	Expenses	Production Cost	Customer Cost
2021	18	-	-	18
2022	50	-	-	50
2023	49	26	(21)	53
2024	63	26	(21)	68
2025	77	34	(22)	89
2026	85	40	(24)	101
2027	78	54	(25)	107
2028	84	54	(26)	112
2029	97	55	(28)	123
2030	109	55	(29)	135
2031	100	74	(31)	143
2032	97	74	(32)	139
2033	91	75	(33)	132
2034	87	75	(34)	127
2035	82	75	(36)	122
2036	82	75	(36)	121
2037	77	76	(37)	116
2038	73	76	(37)	111
2039	68	77	(38)	107
2040	63	77	(40)	101
2041	59	77	(41)	95
2042	55	78	(41)	91
2043	51	78	(42)	87
2044	48	79	(43)	83
2045	44	79	(44)	79
2046	40	79	(45)	75
2047	37	80	(46)	71
2048	34	80	(47)	67
2049	31	81	(48)	64
2050	28	81	(49)	60
2051	25	82	(50)	56
30 Yr NPV	884	654	(347)	1,191

($Millions)	Solar then CC/CT			
	Return on Rate Base	Expenses	Production Cost	Customer Cost
2021	18	-	-	18
2022	51	-	-	51
2023	56	26	(21)	61
2024	85	26	(21)	89
2025	96	34	(22)	108
2026	95	53	(32)	117
2027	118	54	(32)	140
2028	134	54	(35)	153
2029	122	79	(46)	155
2030	118	79	(47)	150
2031	117	81	(45)	153
2032	110	80	(48)	142
2033	104	81	(51)	134
2034	106	80	(53)	134
2035	101	82	(52)	131
2036	97	82	(54)	124
2037	92	84	(53)	123
2038	88	82	(57)	113
2039	84	83	(57)	109
2040	79	83	(60)	102
2041	75	85	(61)	99
2042	71	85	(62)	94
2043	67	85	(63)	89
2044	62	86	(65)	84
2045	58	87	(66)	79
2046	54	87	(68)	74
2047	51	88	(69)	69
2048	47	88	(70)	65
2049	44	89	(72)	61
2050	41	90	(73)	57
2051	38	90	(74)	53
30 Yr NPV	1,093	729	(488)	1,334

Portfolio Annual Cost Components

($Millions)	Solar Only: Return on Rate Base	Solar Only: Expenses	Solar Only: Production Cost	Solar Only: Customer Cost	($Millions)	Solar then RICE and Solar/CT: Return on Rate Base	Solar then RICE and Solar/CT: Expenses	Solar then RICE and Solar/CT: Production Cost	Solar then RICE and Solar/CT: Customer Cost
2021	18	-	-	18	2021	18	-	-	18
2022	47	-	-	47	2022	51	-	-	51
2023	57	26	(21)	61	2023	55	26	(21)	59
2024	97	26	(21)	102	2024	73	26	(21)	77
2025	133	56	(47)	141	2025	95	41	(22)	113
2026	181	70	(64)	187	2026	121	49	(24)	146
2027	166	121	(115)	172	2027	114	79	(47)	146
2028	168	122	(122)	168	2028	124	80	(49)	154
2029	189	129	(137)	181	2029	140	87	(60)	166
2030	245	130	(142)	233	2030	174	87	(63)	199
2031	222	186	(210)	198	2031	159	125	(97)	186
2032	215	187	(219)	183	2032	153	126	(101)	178
2033	200	188	(229)	160	2033	144	126	(105)	165
2034	191	189	(235)	146	2034	138	127	(108)	156
2035	180	191	(243)	128	2035	130	128	(112)	146
2036	178	192	(246)	124	2036	129	129	(114)	144
2037	169	193	(248)	114	2037	122	129	(115)	136
2038	160	194	(256)	99	2038	115	130	(118)	127
2039	152	195	(261)	86	2039	108	131	(120)	119
2040	144	196	(268)	72	2040	102	132	(124)	109
2041	136	198	(277)	56	2041	96	132	(128)	99
2042	128	199	(281)	46	2042	90	133	(130)	94
2043	121	200	(287)	34	2043	85	134	(133)	86
2044	114	202	(294)	22	2044	80	135	(136)	79
2045	106	203	(300)	10	2045	74	136	(139)	72
2046	99	204	(306)	(3)	2046	69	137	(141)	65
2047	92	206	(312)	(15)	2047	64	138	(144)	58
2048	84	207	(318)	(27)	2048	59	139	(147)	51
2049	77	209	(324)	(39)	2049	54	140	(150)	44
2050	70	210	(330)	(50)	2050	49	141	(153)	38
2051	62	212	(336)	(62)	2051	45	142	(156)	31
30 Yr NPV	1,751	1,524	(1,876)	1,398	30 Yr NPV	1,283	1,037	(870)	1,449

Appendix D – OG&E 2021 IRP Oklahoma Technical Conference

We Energize Life

2021 Integrated Resource Plan

Oklahoma Technical Conference
August 19, 2021

Presentation Agenda

- **Introduction**
  - IRP Objectives and Development Process
  - SPP Overview and Requirements
  - OG&E Generation and Load
  - Reserve Margin Calculation and Capacity Needs
- **Data Inputs**
  - Generation Resources considered
  - Fuel Price Projections
  - Energy Price Projections
- **Analysis**
  - Net Present Value of Customer Cost
  - Portfolio Analysis
  - Risk Analysis
  - Conclusions
- **IRP Action Plan**

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2021 IRP

Introduction

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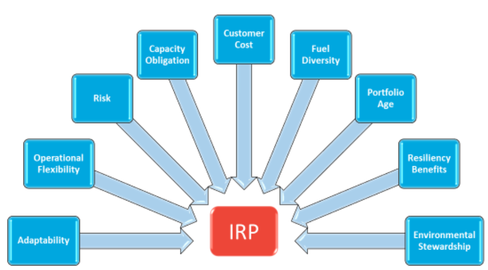
2021 IRP

OG&E's Resource Planning Process has multiple objectives



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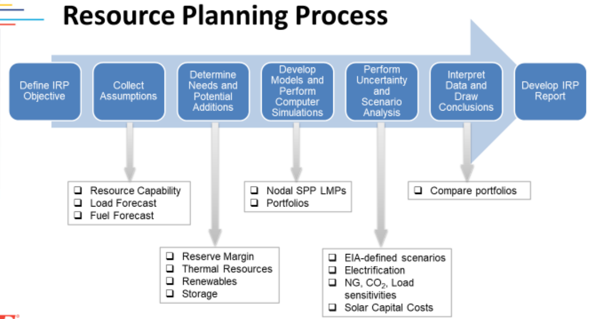
2021 IRP

Resource Planning Process



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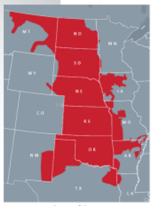
2021 IRP

Southwest Power Pool



SPP 2020 Annual State of the Market Report
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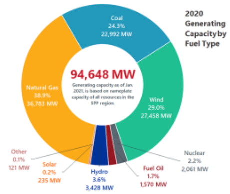

SPP 2020 Annual State of the Market Report
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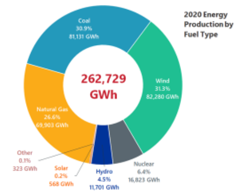

SPP 2020 Annual State of the Market Report
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- **14 States**
- **552,000 Square Miles**
- **95,000 MW Nameplate Generating Capacity**
- **27,000 MW Nameplate Wind Capacity**
- **818 Generation Plants**
- **70,000 miles of transmission**
- **Peak Load: 50,662 MW**

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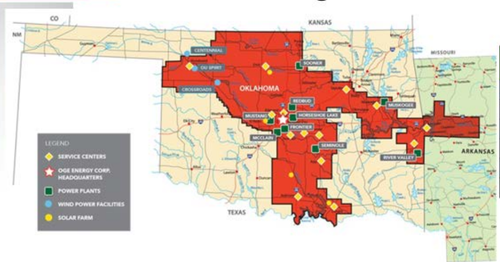
2021 IRP

OG&E's Existing Generation Fleet



Type	2021 Summer Capacity (MW)
Natural Gas	4,796
Coal	1,854
Owned Wind	52
Renewable PPAs	47
Total	6,749
Solar	*18*

- *Total Nameplate Wind Capacity (Owned and PPA) = 791 MW*
- *Solar Resources included as Load Reduction*

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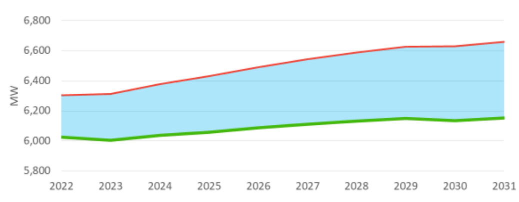
2021 IRP

OG&E Load Forecast with DSM Programs



DSM programs 2007 - 2020 → ~450 MW Embedded Annual Demand Reduction

DSM programs 2007 - 2020 → ~900 GWh Embedded Annual Energy Reduction

- *The SmartHours Program, Historical Demand Program Rider programs, IVVC and the distributed Solar facilities are already included in the Demand forecast.*
- *OG&E DSM represents estimates for incremental energy efficiency programs in Oklahoma and Arkansas, incremental IVVC and the Load Reduction Program.*
- *OG&E DSM incorporates the proposed 2021-2024 Oklahoma Demand Program Rider Portfolio.*

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2021 IRP

Planning Reserve Margin and Capacity Needs

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capacity	Owned Capacity	6,702	6,534	6,534	6,323	6,259	5,856	5,856	5,856	5,856	5,371
	Purchase Contracts	47	47	47	47	47	47	47	47	47	16
	Total Capacity	6,749	6,581	6,581	6,370	6,306	5,903	5,903	5,903	5,903	5,386
Demand	Demand Forecast	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
	OG&E DSM	278	309	340	372	403	432	456	477	494	505
	Net Demand	6,025	6,004	6,039	6,059	6,088	6,111	6,133	6,149	6,136	6,154
Margin	Reserve Margin*	12%	10%	9%	5%	4%	-3%	-4%	-4%	-4%	-13%
Needs	Needed Capacity	0	145	183	417	514	942	967	985	970	1,507

Planned Retirements

Horseshoe Lake 6 Retires 168 MW

Horseshoe Lake 7 Retires 211 MW

Tinker Retires 64 MW

Horseshoe Lake 8 Retires 403 MW

Seminole 1 Retires 485 MW

Keenan & Taloga PPAs Expire 31 MW

*Reserve Margin % = ((Total Net Capacity) - (Net System Demand)) / Net System Demand

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2021 IRP

Data Inputs

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2021 IRP

Resource Options Analyzed

Technology	Model	Nameplate Capacity (MW)	Nameplate Overnight Capital Cost ($/kW)	Summer Peak Capacity
Wind	Land-Based	250	$1,470	50
Batteries	Lithium Ion	100	$1,310	100
Solar	Photovoltaic Single Axis	100	$1,350	60
Solar/Battery Hybrid	Single Axis/Lithium Ion	100	$2,590	100
Reciprocating Engine (RICE)	Reciprocating Engine 1x	19	$2,430	19
	Reciprocating Engine 6x	111	$1,320	111
Combustion Turbine (CT)	AGT 1x	62	$1,690	58
	AGT 7x	432	$1,100	404
	LMS100 1x	111	$1,090	101
	LMS100 4x	444	$860	405
	E Class 1x	85	$1,120	77
	E Class 5x	427	$840	386
	F Class	221	$690	212
	G/H Class	278	$660	264
Combined Cycle (CC)	1x1 J Class	531	$930	503
	1x1 J Class Fired	637	$780	613
	2x1 G/H Class Fired	1,001	$700	944
	2x1 F Class	729	$850	662
	2x1 F Class Fired	880	$750	828
	1x1 F Class Fired	441	$960	411

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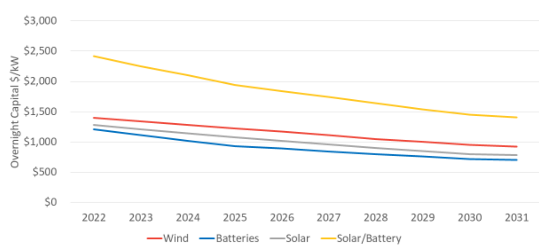
Data provided by Burns & McDonell and NREL ATB; $/kW capital costs given in 2021 $

Renewable Nameplate Overnight Cost Projections in 2021$ ($/$kW_{AC}$)



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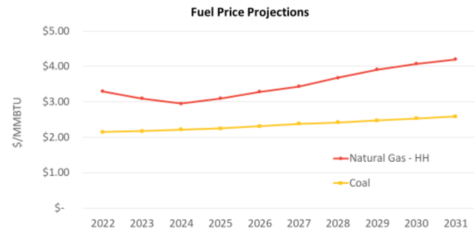
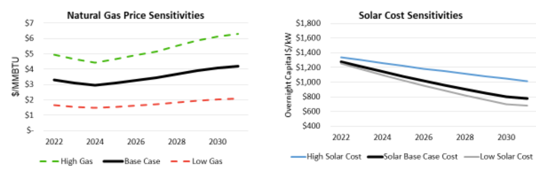
Price curves based on data from Burns & McDonnell and NREL ATB

Base Case Assumptions

Natural Gas Price	Coal Price	Load	Other
EIA Reference Case	EIA Reference Case	2020 Load Forecast	Current laws and regulations

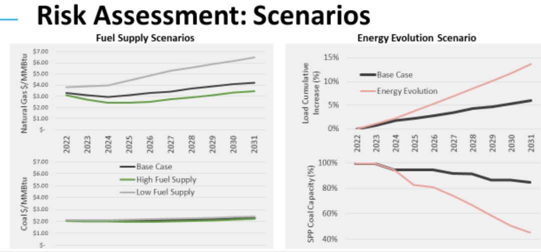


Risk Assessment: Sensitivities



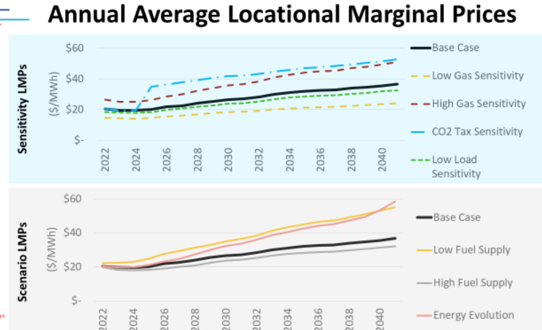
Sensitivities	Natural Gas Price	Coal Price	Load	Other
Base Case	EIA Reference Case	EIA Reference Case	2020 Load Forecast	Current laws and regulations
Low Gas	50% Below Base Case	Base Case	Base Case	Base Case
High Gas	50% Above Base Case	Base Case	Base Case	Base Case
CO_2	Base Case	Base Case	Base Case	$20/ton CO2 tax starting 2025
Low Solar Capital Cost	Base Case	Base Case	Base Case	NREL low solar trajectory
High Solar Capital Cost	Base Case	Base Case	Base Case	NREL high solar trajectory
Low Load	Base Case	Base Case	10% SPP Load Reduction	Base Case

Risk Assessment: Scenarios



Scenarios	Natural Gas Price	Coal Price	Load	Other
Base Case	EIA Reference Case	EIA Reference Case	2020 Load Forecast	Current laws and regulations
High Fuel Supply (EIA)	~20% below Base Case	~5% below Base Case	Up to 3% above Base Case	Base Case
Low Fuel Supply (EIA)	~50% above Base Case	~5% above Base Case	Up to 3% below Base Case	Base Case
Energy Evolution	Base Case	Base Case	Increased Electrification	Accelerated Coal Retirements

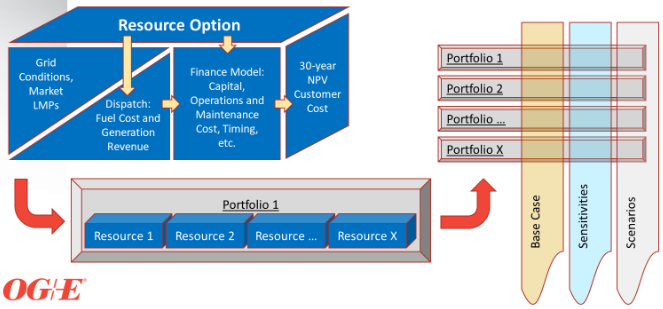
Annual Average Locational Marginal Prices



Analysis

2021 IRP

Analysis Process



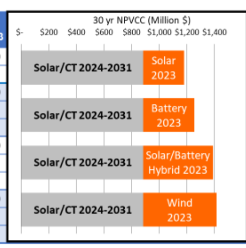
2021 IRP

Resource Timing

2021 IRP

Portfolios: 2023 Option

Portfolio Name	Type	2022	2023	Total*	NMPL. MW**	NPVCC
Solar/CT	**Solar**		**200**	560	933	**$1,182**
	CT			952	998	
Battery then Solar/CT	*Battery*		200	200	200	$1,256
	Solar			360	600	
	CT			952	998	
Solar/ Battery Hybrid then Solar/CT	*Hybrid*		200	200	200	$1,391
	Solar			360	600	
	CT			952	998	
Wind then Solar/CT	*Wind*		200	200	1,000	$1,415
	Solar			360	600	
	CT			952	998	



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

2021 IRP

Representative Portfolios

Portfolio Name	Type	Accredited Capacity (MW) 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total*	NMPL. MW**	NPVCC
Solar/CT	Solar		200		60			60			240	560	933	$1,182
	CT				212	212	264				264	952	998	
Solar then CT Only	Solar		200									200	333	$1,191
	CT				264	101	424				528	1,317	1,387	
Solar then CT/CC	Solar		200									200	333	$1,334
	CT				264							264	278	
	CC					503			613			1,116	1,168	
Solar Only	Solar		200		240	120	420		60		480	1,520	2,533	$1,398
Solar then RICE and Solar/CT	Solar		200				180		60		240	680	1,133	$1,449
	RICE				222	111						333	333	
	CT						264				264	528	556	

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

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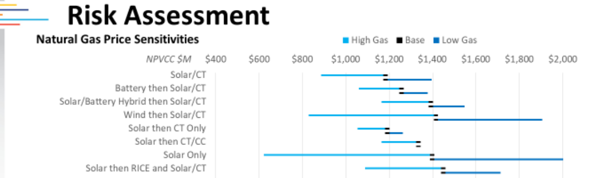
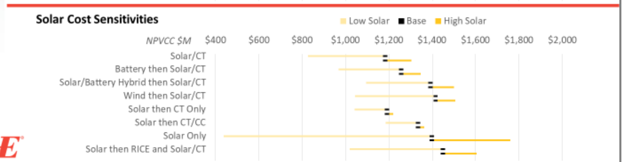
Risk Assessment





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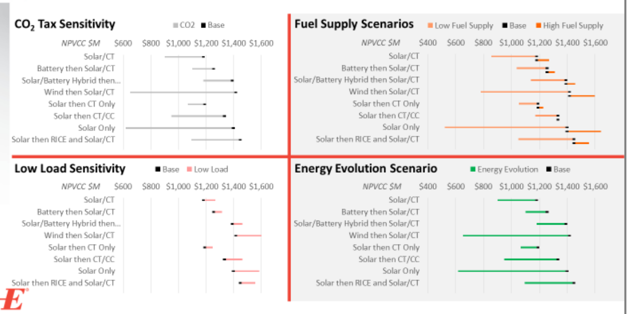
Risk Assessment continued



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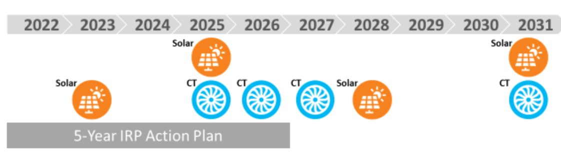
Preferred IRP Plan



Lowest Reasonable Cost plan while meeting the **Capacity Obligation** across a range of **Risks**

Adaptable Plan provides **Fuel & Technology Diversity** and a reduced **Environmental Footprint** while improving **Portfolio Age**

Operational Flexibility and **Resiliency Benefits**

"Fast-start resources are essential to the reliable provision of energy. These resources typically have short startup times, low minimum run time requirements, and faster than average ramp rates. These characteristics provide the needed flexibility for managing the operational challenges SPP faces." – SIR17 HITT R3B Fast-Start Resource. *SPP*, March 18, 2020

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Action Plan

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IRP 5-Year Action Plan

1) OG&E will retire Horseshoe Lake unit 6 in 2023.
2) OG&E plans to retire Horseshoe Lake unit 7 and Tinker units 5A and 5B in 2025.
3) OG&E will issue an RFP(s) for the resources identified in the preferred plan.

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Questions and Comments

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OG&E 2021 IRP – Oklahoma Technical Conference
August 19, 2021
Meeting Minutes

The Oklahoma IRP Technical Conference regarding OG&E's 2021 Integrated Resource Plan (IRP) was held on August 19, 2021 from 10:30 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 and Regulatory teams.

Presenters:

Name	OG&E Role
Kelly Riley	Manager, Resource Planning
Zac Hager	Specialist Resource Planner
Aaron Castleberry	Senior Resource Planner
Emily Shuart (Facilitator)	Director, Regulatory Affairs and Compliance

External Stakeholders:

Name	Organization
Dana Murphy	Oklahoma Corporation Commission (OCC)
Geoffrey Rush	Oklahoma Corporation Commission
Lauren Willingham	Oklahoma Corporation Commission
Nicole King	Oklahoma Corporation Commission
EJ Thomas	Oklahoma Corporation Commission
Richard McKay	Oklahoma Corporation Commission
Isaac Stroup	Oklahoma Corporation Commission
Marydoris Casey	Oklahoma Corporation Commission
Andrew Scribner	Oklahoma Corporation Commission
Chase Snodgrass	Oklahoma Attorney General (AG)
Todd Bohrmann	Oklahoma Attorney General
Montelle Clark	Oklahoma Sustainability Network (OSN)
Tom Schroedter	Oklahoma Industrial Energy Consumers (OIEC)
Scott Norwood	Oklahoma Industrial Energy Consumers
Ryan Baker	City of Oklahoma City (OKC)
Michelle Merchant	Indian Nations Council of Governments (INCOG)
Adriane Jaynes	Indian Nations Council of Governments
Deborah Thompson	OK Energy Firm, PLLC
Danny Musher	Key Capture Energy
Matt Miller	Sierra Club
Jordan Iglesias	Sierra Club
Lauren Hogrewe	Sierra Club
Chip Clark	OG&E Shareholders Association
Ron Stakem	Cheek Falcone, PLLC

Emily Shuart began the meeting at 10:30 am by explaining the meeting structure and process for asking questions in the virtual format.

- Scott Norwood (OIEC)
  - *Question*: Explain the difference between the DSM projections shown in the graph and the load reductions for specific programs noted in the report. The report shows 100 MW on voltage control, 100 MW from SmartHours and 30-40 MW incrementally per year from Energy Efficiency (EE), which seems to be different than what is shown on the graph.
    - *Response*:
      - Several DSM program numbers from the report are already included in the gross load forecast but OG&E wanted to make sure stakeholders were aware of existing programs that benefit customers on an ongoing basis.
      - In addition to what we already have in place (EE/IVVC/SmartHours) we will also have more EE programs. We wanted to incorporate those new programs from a gross load perspective so that they are included when calculating future capacity needs.
      - The Load Reduction Rider program is included in the DSM program shaded area.
  - *Question*: Why is there not more demand reduction built into this forecast?
      - *Response*: The level of demand reduction programs is set in a separate process before the Commission.
  - *Comment*: The 30-40 MW per year incremental from EE plus other programs mentioned in the report made it seem like the numbers in the report do not equate to total demand reduction programs shown in the graph. Parties agreed to defer question.
  - *Question*: Demand reductions related to Smart meters, residential TOU, etc. does not seem to be listed here. Are the benefits of these programs baked into OG&E's load forecast? Do you have anything specific related to Smart Meter related programs?
    - *Response*:
      - Existing programs are modeled in the forecast. The shaded demand reduction area here is intended to reflect incremental savings. SmartHours has been in place for long enough that it is baked into our gross load forecast.
      - We not only have Smart Hours, but we also have a Variable Peak Price (VPP) program and a residential Time-of-Use (TOU) program. Customers have the ability to monitor their daily usage through smart meters and better understand their usage.

- Montelle Clark (OSN)
  - *Question*: Are the projected DSM numbers based on estimated achievable savings under the $2.50 EE cap?
    - *Response*: Yes

- *Comment*: I would like to see what was achievable if DSM was modeled without a cap. A 2017 EPRI study showed Oklahoma was on track to only get 25% of possible DSM savings.
- *Question*: It would be useful to stakeholders to treat DSM just like a resource comparable to the supply side. DSM cost estimates can be seen in other markets around 3¢ per kWh. Has OG&E considered modeling DSM in this way?
  - *Response*: OG&E has not looked at that for this IRP.
- *Question*: I am having trouble reconciling OG&E's stated desire to get rid of EE programs with other statements saying EE programs benefit customers. What is OG&E's ongoing position on DSM resources, and would you be willing to go past the $2.50 cap?
  - *Response*: OG&E is currently very supportive of the DSM programs and recently filed requesting three more years on the programs. In recent years, the stakeholders involved in EE dockets have supported a sustainable approach, which helps OG&E support the continued use of the programs.

- Scott Norwood (OIEC)
  - *Question*: I understand you are retiring older Horseshoe Lake units. I did not see a whole lot on what is triggering those retirements. What was the thinking on the timing of those retirements?
    - *Response*: For all those units, the retirements have already been pushed out more than a decade. All are operating past their originally expected lives. They are getting more difficult to run and it is increasingly difficult to find replacement parts for them.

- Montelle Clarke (OSN)
  - *Question*: Are the Fixed O&M costs are annual?
    - *Response*: Yes.
  - *Comment*: OG&E stated standalone batteries have higher costs due to higher O&M. The O&M numbers shown here are higher than those seen in other reports.
  - *Question*: What was the assumption on battery discharge duration?
    - *Response*: 4 hours
  - *Question*: Were the unique qualities (load leveling, arbitrage) of batteries recognized or monetized in the analysis? For example, do batteries have benefits over CTs (black start, frequency, etc.)?
    - *Response*: IRP assumes battery would charge and discharge daily based on arbitrage dispatch and that economic arbitrage is included in the analysis. OG&E is interested in all the different functional aspects batteries would have for the utility and the power grid. SPP is also discussing characteristics and services supplied by batteries. OG&E and the industry is very interested in the functional benefits of batteries. OG&E, other utilities and SPP will

continue to monitor additional benefits to the overall system provided by batteries.

- *Comment*: The Resource Option table shows higher battery cost and much higher battery O&M costs than what has appeared in other reports. Your report disqualifies batteries primarily due to the high O&M costs. I question the numbers and whether OG&E is capturing the rapidly falling costs of batteries.
    - *Response*: OG&E is not disqualifying batteries in the analysis.
    - *Follow-Up Response*: OG&E reviewed the fixed O&M costs for batteries, which include both regular maintenance and cell augmentation to maintain the battery at the rated capacity throughout the lifetime. Including the augmentation is consistent with NREL assumptions for battery resources and the fixed O&M values OG&E used in the IRP Draft are in line with the NREL values for battery fixed O&M. For the overnight capacity costs for batteries OG&E developed continued price reduction curves for the resources. The declining prices are utilized in the IRP for the cost as the resource is added. The 2021 IRP Draft utilized a cost of $1,110/kW for the overnight capital cost for batteries going into service in 2023, which is in line with comments from stakeholder during the Technical Conference.
- *Question*: If you are going to do an RFP, can you give the Commission/Stakeholders some assurance that batteries have not been overlooked by including them in the RFP to get latest prices?
    - *Response*: OG&E is still developing the RFP.
- *Comment*: Please review battery prices (ex. Tesla) available to Oklahoma today.
    - *Follow-Up Response*: OG&E's expected continued decline of battery prices is consistent with the pricing referenced during the Technical Conference.

- Scott Norwood (OIEC)
    - *Question*: Wind accredited wind capacity seems low, is that what you are actually getting in SPP?
        - *Response*: We are expecting 20% capacity accreditation for new wind resources. Our existing, older wind farms accredited at a level lower than 20% of nameplate, based on historical performance.
    - *Question*: What have you assumed here for tax credits on renewables?
        - *Response*: Tax credits are accounted for in the NPVCC but not included in the capital costs on page 11.
    - *Question*: Regarding River Valley/Frontier acquisition projects, OG&E got advantageous prices on existing capacity. Did you model any PPA/purchase for existing capacity?
        - *Response*: No, OG&E did not model those options.
    - *Question*: Would OG&E open the RFP for short-term capacity and existing generation resources?

        - *Response*: OG&E does not have the details at this time as the RFP is not complete.

- Deborah Thompson (AARP)
    - *Question*: How does your model address nameplate vs accreditation?
        - *Response*: The model takes into account how much would be required to meet accreditation need and the resource would be dispatched accordingly.
    - *Comment*: This is where DSM could be modeled, and you can decide if DSM would be selected over other resources.

- Danny Musher (Key Capture Energy)
    - *Comment*: OG&E's battery costs do not match what is in the market now. Glad to hear hourly resolution was used in the IRP analysis; however, there are additional benefits, as mentioned, before in sub hourly resolution. Key Capture Energy does have a fleet of batteries in Texas so they have internal expertise in optimizing batteries and would be happy to have their experts look at assumptions in OG&E modeling to ensure we are taking proper things into account. OG&E's analysis should take into account the full range of benefits batteries could provide.

- Montelle Clarke (OSN)
    - *Comment*: One challenge with DSM is figuring out the cost per saved kW. The Lawrence Berkeley National Laboratory (LBNL) recently released a report showing DSM peak demand savings at costs between $100-200 per kW.

- Scott Norwood (OIEC)
    - *Question*: In the modeling is OG&E picking up the basis differential from Henry Hub for natural gas prices?
        - *Response*: The modeling includes the basis differential from Henry Hub.

- Matt Miller (Sierra Club)
    - *Question*: Does the modeling assume the coal units will be dispatched in self commit vs market commit and what capacity factors are being projected for coal in the future?
        - *Response*: Economic dispatch is being modeled for coal. Projected coal capacity factors are not available during the meeting, but OG&E will follow up after the meeting and see if we can provide the information.

- Scott Norwood (OIEC)
    - *Question*: Although coal units are scheduled for mid-2040s retirements, would it be possible at some point in the future to include an appendix that includes retirement dates on existing units that impact near-term capacity

requirements and possibly looking at early retirement on coal if dispatching is reduced or eliminated in the future?
        - *Response*: OG&E will consider the request.
        - *Follow-Up Response*: Generation unit retirement dates can be found in the Depreciation Study.

- Matt Miller (Sierra Club)
    - *Question*: On coal retirement dates, I saw years for Sooner and Muskogee 6, nothing for River Valley. Do you have retirement dates for River Valley?
        - *Response*: River Valley is scheduled for retirement in 2048.
    - *Question*: Are the currently scheduled retirement dates serious estimates of retirements or are they manufacturer retirement estimates?
        - *Response*: All generating assets are long term assets. Those assets help serve our customers and provide fuel diversity. The world is changing, and we will continue to review our fleet to ensure we have the right assets in place at the right time.

- Montelle Clarke (OSN)
    - *Question*: On CO_2 sensitivity, can you explain whether OG&E is considering a CO_2 tax as literally the only potential CO_2 limitation or it is a proxy for any potential CO_2 constraint that might be implemented?
        - *Response*: The idea of the sensitivity is to change assumptions and see how it impacts results. There are a lot of different ways to model things, but OG&E decided to utilize the CO_2 tax to see how things in a "different world" might drive impacts/changes and use that as a proxy for any future potential CO_2 constraint.
    - *Comment*: It would be helpful to include a table of annual CO_2 emissions of where you are now and where you think you will be in the next ten years.

- Scott Norwood (OIEC)
    - *Question*: Were commodity prices included in the SPP price modeling?
        - *Response*: Yes.

- Montelle Clarke (OSN)
    - *Comment*: Energy Evolution scenario is valuable for the analysis.
    - *Question*: Is managed charging of electric vehicles (EVs) included in your modeling in the Energy Evolution scenario?
        - *Response*: The energy evolution case was developed many months ago and looked at some of the federal energy policies that are being discussed but does not go into specific topics like managed charging.
    - *Question*: Was the Energy Evolution combined with the CO_2 scenario?
        - *Response*: No.

- Scott Norwood (OIEC)
  - *Question*: Do you plan to include near term revenue requirements as a proxy for rate impacts on customers over the next few years in the report, as you have in the past?
    - *Response*: OG&E expects those details to be included in the final IRP.

- Dana Murphy (OCC Commissioner – current Chairman)
  - *Comment:* This presentation has been easy to understand and follow and I appreciate that.
  - *Question*: Coming out of SPP Cost Allocation Working Group was a report on batteries as a resource and utilizing them as a transmission resource and treat them as a wired solution. Is there any thought about batteries being utilized as both resource adequacy and transmission solution?
    - *Response*: SPP is trying to figure out whether a battery being used as a transmission resource could still be available for resource adequacy. No decision has been made yet.
  - *Question*: With the recommendations that came out of SPP winter event report, in looking at resource adequacy particularly on the gas side, how is that taken into account in the IRP? Developments in flight at SPP right now may have more of an impact than anyone realizes right now.
    - *Response*: Issues like these illustrate why OG&E appreciates being able to participate in groups like SPP Supply Adequacy Working Group (SAWG). OG&E is a voting member of SAWG and has been actively involved in discussions of resource adequacy issues and proposals. There is still a lot of work to be done at SPP to develop recommendations related to resource adequacy.
    - *Follow-up*: Commissioner Murphy encourages OG&E to stay in contact with Jason Chaplin (OCC/PUD SPP representative) regarding SPP issues, especially related to resource adequacy. These issues are tied in with IRP matters.

- Danny Musher (Key Capture Energy)
  - *Question*: It is becoming best practice in the market to let all technologies respond to RFP so current market data is reflected and considered. Key Capture Energy would like to have ability to bid and compete. Would OG&E consider opening up the RFP to batteries?
    - *Response*: RFP is next area of focus and a lot of details still need to be worked out.

- Montelle Clarke (OSN)
  - *Comment*: Echo Danny's comments on opening RFP to batteries.
  - *Question*: Chosen portfolio mitigates some risks, but some other portfolios mitigate more risks like CO_2. How do you build in flexibility to modify decisions in the future if major events change?

    - *Response*: OG&E plans to move forward with a plan that gives us the most flexibility so we can best keep up with a changing world.
  - *Comment*: OSN would like to see a pie chart in the report showing the percentage of OG&E renewable energy mix and where that might go in the future with this plan.