2019

Gainesville Regional Utilities Integrated Resource Plan

Prepared by

THE EnergyAuthority

for

GRU

More than Energy

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INTRODUCTION AND OBJECTIVES

Given the ubiquity of electricity to modern society, long-term supply planning impacts everyone. How customers consume and ultimately pay for this critical commodity in the future will be driven by the decisions we make today. Power supply decisions have economic lives measured in decades, and long-term planning is fraught with uncertainty, making it a complicated undertaking. Technology development, electricity and commodity pricing, economic factors, and cultural and social forces all present elements of risk to the long-term planning model.

This Integrated Resource Plan (IRP), developed by The Energy Authority, Inc. (TEA) for Gainesville Regional Utilities (GRU), presents the results of a detailed analysis of alternatives GRU may select to meet the electrical energy and demand requirements of its retail electric consumers for the 20-year period from 2019 through 2039. This analysis includes an assessment of existing resources and alternative options for new and replacement resources. This executive summary provides a look at plan objectives, methodology, existing resources, findings, and an overview of plan recommendations. The complete document package includes a more detailed description.

Table 1: GRU Overview

Location	Gainesville, FL		
Peak Demand	408 MW (2018)		
Total Energy	2,079 GWh (2018)		
Current Generation Resources			
Unit	Fuel	Net Summer Capacity (MW)	Installation Date
JR Kelly CC	NG	108	2001
Deerhaven 2	Coal	228	1981
Deerhaven 1	NG/Oil	75	1972
Deerhaven GT1	NG/Oil	17.5	1976
Deerhaven GT2	NG/Oil	17.5	1976
Deerhaven GT3	NG/Oil	71	1996
Deerhaven Renewable	Biomass	102.5	2013
South Energy Center 1	NG	3.5	2009
South Energy Center 2	NG	7.4	2017

The purpose of this study is to develop a robust resource plan that:

- Identifies the long-term, strategic needs of the utility.
- Utilizes least-cost planning principles and estimates the magnitude of future power supply costs and decisions.
- Allows flexibility to respond to market changes.
- Helps GRU manage risk through a diverse mix of resources.
- Performs well over a range of economic, environmental, and regulatory scenarios.

STUDY METHODOLOGY

The long-term generation expansion production cost model used for this IRP simulates production cost and market price interaction. The optimization criterion is to minimize the incremental Net Present Value of Revenue Requirements (NPVRR). For the purposes of this plan, the NPVRR is the net cost that would need to be recovered for all resources in the utility's portfolio, adjusted for the time value of money. Previous capital investments for existing resources are sunk costs are not included in the NPVRR calculation; however, this IRP does consider future fixed and variable operations and maintenance (O&M) costs for existing resources and all costs for new or bettered resources incurred during the study period. A number of sensitivities and scenarios have been evaluated for this IRP. Results of each simulation have been aggregated in the form of relative NPVRR and Levelized Cost of Energy (LCOE), along with the specific resource retirements and additions resulting from each optimization. The LCOE is an industry-standard metric for comparing scenarios with differing loads, calculated as total plan cost divided by energy usage. Tools used in this study include ABB’s PROMOD IV, Velocity Suite, Capacity Expansion, and Portfolio Optimizer.

KEY CONSIDERATIONS AND RISK FACTORS

This study is based on a set of inputs and assumptions that, in TEA’s best judgment, will provide GRU with recommendations based on the most reasonable information available at the time of this study. As time passes, some of the assumptions may not transpire as expected, while other unexpected risk factors may become a reality.

Each of the plans, recommendations, actions, and potential futures discussed in this report has the potential to impact or be impacted by regulatory, financial, market, and other types of risk. Because GRU’s goal is to provide its customers with reliable and affordable energy, it considers factors such as risk tolerance and reliability thresholds when making electric resource decisions.

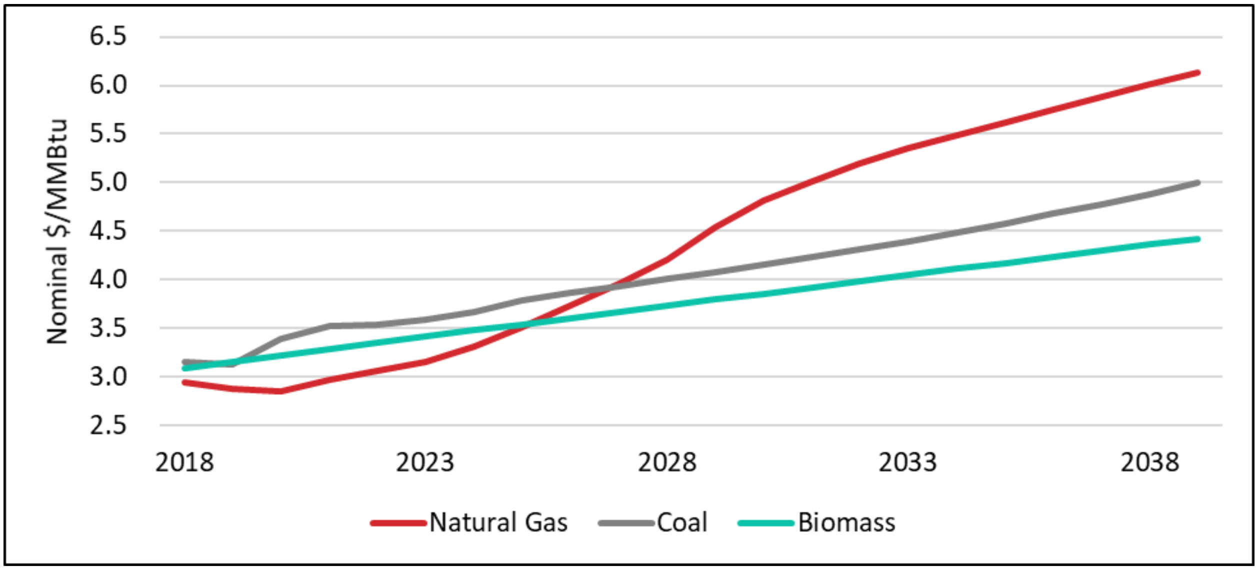
For example, it is GRU’s responsibility to balance market risk and the financial risk of incurring additional debt. Significant factors which could impact the conclusions and recommendations include the following:

- Advancement and cost reductions of emerging technologies
- Changes to federal, state, and local tax incentives
- Renewable resource penetration in and around GRU’s service territory
- Changes in environmental regulations and other public policy
- Market-wide and GRU-specific fuel diversity
- Rate of electric vehicle (EV) adoption in GRU’s service territory

ASSUMPTIONS

- Discount Rate: 3.0%
- Tax Exempt Bond Rate: 3.9%
- Peak Demand and Energy Usage Forecast: 0.4% annual increase
- Import/Export Limit: 120 megawatts (MW)

Figure 1: Reference Case Delivered Fuel Price Forecast



- GRU Minimum Planning Reserve Margin: 15%
- Data specific to GRU's existing load and resources provided by GRU
- Fuel price forecast as shown in Figure 1

Table 2 provides a list of the potential supply-side resource options included in the study. This list was developed through a screening process, which eliminated sizes and technologies that would not be reasonable for GRU. For example, a 1,200 MW combined cycle (CC) or a large nuclear facility would not be reasonable for GRU's system.

Table 2: New Supply-Side Resource Options

Resource Type	Size (MW)	Peak Hour Capacity Planning Factor[1]	Capital Cost (2018$/kW)	Fixed O&M (2018$/kW-Year)	Variable O&M (2018$/MWh)
Siemens SGT-800 2x1 CC	132	100%	$1,102	$11.33	$3.61
Siemens SGT-800 3x1 CC	198	100%	$1,037	$11.33	$3.61
Siemens SGT-800 GT	47	100%	$917	$18.02	$3.61
RICE – Large Size	18	100%	$1,150	$20.00	$7.00
RICE – Mid Size	9	100%	$1,150	$20.00	$7.00
Biomass	103	100%	$3,642	$114.39	$5.70
Solar PPA	20	35%	$0	$0.00	$32.00
Battery Storage	5	100%	$1,357	$36.31	$7.26

[1] Peak Hour Capacity Planning Factor represents the portion of a resource that can be expected to operate during the peak hour used for capacity requirements.

FINDINGS

REFERENCE CASE

The reference case is the scenario to which all other scenarios are compared. Therefore, only base assumptions are included. The plan resulting from this scenario is not necessarily the most advantageous for GRU or its customers from a risk or least-cost perspective.

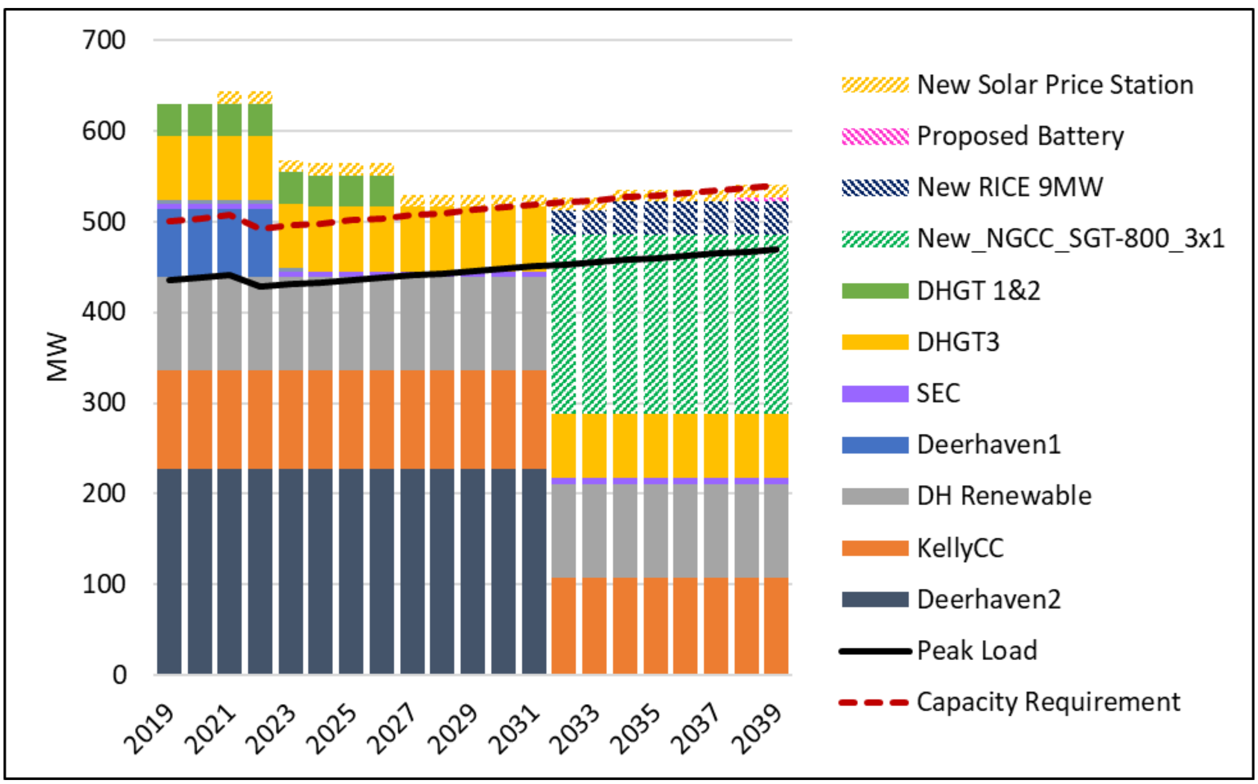
In the reference case plan, an 80 MW solar Power Purchase Agreement (PPA) provides lower cost energy for GRU beginning in 2021. After Deerhaven 2 retires in 2031, a 198 MW natural gas (NG) fired 3x1 CC unit is installed in 2032. Additionally, the plan includes three 9 MW reciprocating internal combustion engine (RICE) units in 2032 and another 9 MW RICE unit in 2034. In 2038, near the end of the term of the study, 5 MW of storage is installed.

The NPVRR of the reference plan is $1,961 million and the LCOE is $44.69 per megawatt-hour (MWh).

SENSITIVITIES AND SCENARIOS

TEA included a sensitivity analysis to assess the performance of the reference case and alternative scenario plans in high and low gas price environments. In addition, TEA utilized ABB's Portfolio Optimizer (PO), a detailed chronological production cost model, to more thoroughly evaluate the impact of unit operating constraints for several key scenarios.

Figure 2: Reference Case Load and Capacity Balance



Scenarios evaluated in the study are grouped into the following categories:

- System scenarios (Scenarios 1-4) examine the effects of changes that GRU requested to its reference electric system.
- Load scenarios (Scenarios 5-7) indicate how the optimum generation plan changes under various peak demand and energy forecasts.
- Area Control Error (ACE) scenarios (Scenarios 8-11) address the recommendations of the ACE study performed by Burns and McDonnell and completed in January 2019.
- Renewable scenarios (Scenarios 12-14) evaluate resource plans with prescribed additions to help GRU achieve the city's renewable energy and greenhouse gas goals.

Figure 3 compares the generation additions, capital investment requirements, and NPVRR for the reference case and two of the 14 scenarios. The NPVRR includes costs of solar as PPAs, not self-built solar. For completeness, the figure shows GRU's direct financing requirements using PPAs for solar and with the assumption that GRU self-finances all solar.

Figure 3: Details of Select Solutions

		Reference Case	ACE REQS-Unlimited Solar- Force 40 MW Solar 2021	Renewable - No Market & No RICE Contribution
New Unit Capacities (MW)	NGCC	198		
	Solar PPA	80	480	780
	Battery	5		195
	RICE	36	216	119.4
	Biomass			103
Total Capital Costs with Solar PPA (2018 $M)		$254	$339	$895
Total Capital Costs with Solar Self-Build (2018 $M)		$362	$987	$1,948
NPVRR (2018 $M)		$1,956	$1,951	$2,547

CONSIDERATION

- GRU's resource plan must provide flexibility to meet the city's resolution to use 100% renewable generation and become a net zero greenhouse gas community by 2045.
- Large amounts of solar, a viable renewable resource for GRU, will require significant land area as well as transmission and distribution upgrades.
- The amount of solar resources necessary to achieve a high renewable energy goal will likely result in some over-building of solar capacity to produce sufficient renewable energy quantities and manage intermittency through solar curtailments and/or usage of storage resources.
- Solar additions require complementary rapid response power resources to adequately respond to sudden and wide swings in power output inherent with intermittent solar power.

- As the cost and technology of solar and battery storage continue to improve, solar plus battery storage options are likely to enhance system performance compared to a system that is heavily dependent on solar alone. The storage component is designed to smooth out some of the variability associated with solar PV energy production.

CONCLUSIONS

- Upgrading GRU's Kelly combined cycle unit by replacing the steam turbine generator delays a significantly larger capital outlay that would be necessary for a replacement resource, maintains distribution system voltage support, and improves flexibility regarding other potential unit replacements.
- Deerhaven 2, GRU's coal-fired generator, and Deerhaven Renewable, its biomass-fired generator, provide fuel diversity and cost savings in a high gas price scenario.
- RICE units are currently more economical than small gas turbines or batteries for rapid response.
- Early additions of up to 80 MW of solar, coupled with up to 40 MW of RICE to facilitate power supply reliability, have an insignificant effect on GRU's NPVRR.
- Based on current cost estimates, a resource plan to shift towards 100% renewable energy will increase GRU NPVRR costs compared to the reference plan by up to approximately $600 million through 2039 and will require additional and significant rate increases compared to the Reference Case. This cost difference is driven in part by capital investment and third-party investment for PPAs.

RECOMMENDATIONS

- Add up to 74.5 MW of a solar resource to lower GRU's average energy cost and advance towards city's goal to utilize 100% generation and become a net zero greenhouse gas community by 2045.
- Add approximately 10 MW of RICE generation per 20 MW of solar.
- Refurbish the Kelly CC to take advantage of the current low-cost NG environment and delay a significant capital expenditure necessary for unit replacement.
- Retain Deerhaven 2 and Deerhaven Renewable at least until the next IRP update.
- Continue to monitor biomass status as a renewable energy source.
- Consider coordination with other FRCC utilities to jointly balance electric systems at a reasonable cost in a high renewable environment.
- Continue to include consistent IRP updates as part of an effective planning process.

DISCLAIMER

This document was prepared by TEA, solely for the benefit of GRU. TEA hereby disclaims (i) all warranties, express or implied, including implied warranties of merchantability or fitness for a particular purpose, and (ii) any liability with respect to the use of any information, recommendations, or methods disclosed in this document. Any unauthorized commercial use of this document by third parties is prohibited. The recommendations resulting from this study are based on the economics of each decision according to the inputs available to TEA. The recommendations are subject to change as the underlying facts and assumptions change. GRU's final action plan may reasonably differ from the TEA's recommendations due to various local, organizational, or other considerations not factored into these recommendations.

Section 1: Introduction

INTEGRATED RESOURCE PLANNING

An Integrated Resource Plan (IRP) is the result of a comprehensive planning study, which provides a recommended mix of supply- and demand-side resources a utility may use to meet its customers' future electricity needs. An IRP should include:

- A demand forecast over a 20-year time horizon.
- An assessment of supply-side generation resources.
- An economic appraisal of renewable and non-renewable resources.
- An assessment of feasible conservation and efficiency resources.
- A least-cost plan for meeting the utility's requirements.
- An action plan.

This IRP should guide Gainesville Regional Utilities (GRU) in making decisions about the capacity resources it will use to meet future load and reserve obligations. Having a long-range resource plan enables GRU to provide affordable, reliable electricity to the people it serves well into the future and may better equip it to meet many of the challenges facing the electric utility industry.

The IRP process is an effort to anticipate and prepare for key challenges which GRU may face within the next 20 years. The process includes determining the potential timing and magnitude of future changes in capacity requirements and identifying a favorable mix of energy and capacity resources to meet future requirements.

Identification of GRU's best path forward considers the evolution of energy resource technologies as well as the risk surrounding potential plan components. To reduce the risks associated with relying too much on a specific fuel or resource type, it is important that GRU maintains a diverse mix of energy resource options, such as natural gas (NG) fired thermal generation, energy efficiency programs, and renewable resources.

Each component of the path forward will take time to implement. GRU must allow adequate time to properly study, engineer, site, and conduct environmental reviews to modify existing resources or build additional generation and transmission infrastructure. Given the long lead times required to plan, permit, and build new resources, the IRP demand forecasts typically involve 10- to 20-year outlooks. This study uses a 20-year time horizon.

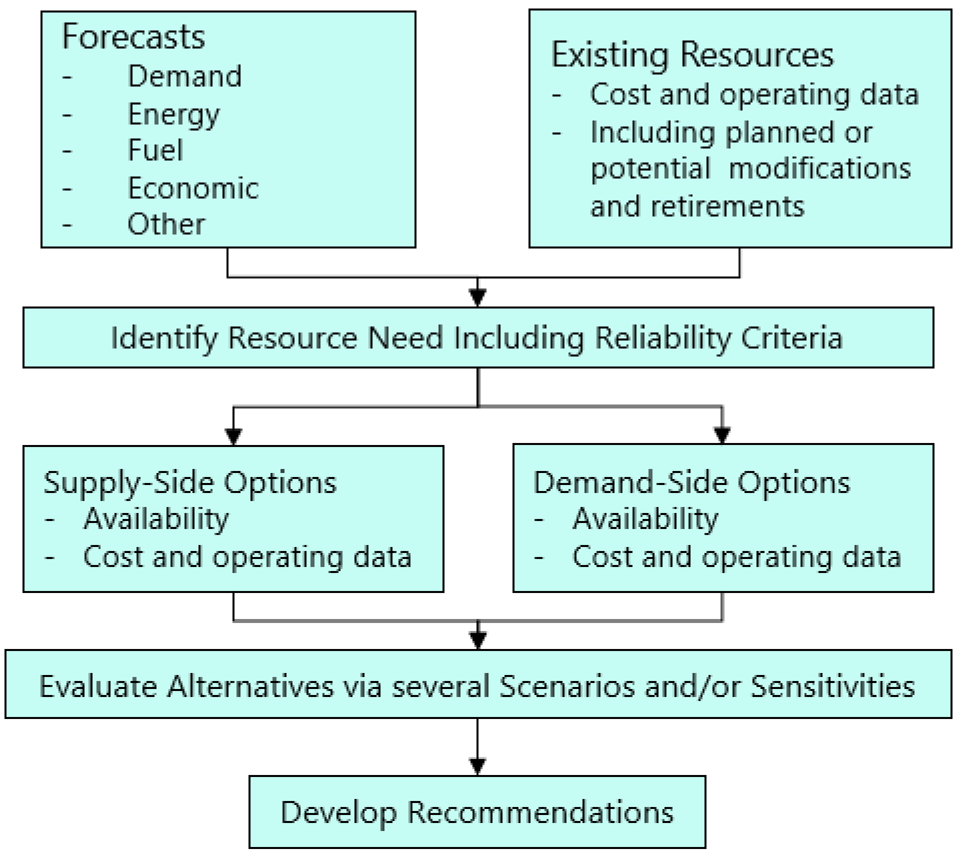
IRP DEVELOPMENT

A typical IRP process is diagrammed in Figure 4. The process begins with an evaluation of existing resources and a load forecast, which are used to determine if new or replacement resources are required to meet system reliability requirements. Next, the IRP process evaluates which supply- and demand-side alternatives best meet plan objectives under a variety of possible scenarios. This stage also considers risk limitations on the basis of physical, policy, regulatory, financial, and non-financial risks. The Energy Authority, Inc. (TEA) evaluates potential resources based on physical feasibility and cost. The process ends with the presentation of TEA's recommendations and this report. As part of the IRP process, GRU may develop an action plan that identifies the steps that should be taken over the next three to five years to implement the IRP recommendations.

METHODOLOGY

This study uses a long-term generation expansion production cost model to aid in identifying the most cost effective generation replacement and expansion plan. The Capacity Expansion[2] (CE) electricity production cost model was used to simulate GRU's production cost and electric market interaction.

Figure 4: Typical IRP Process Diagram



The optimization criterion is to minimize the incremental Net Present Value of the Revenue Requirements (NPVRR) while honoring system and regulatory constraints. For the purposes of this study, the NPVRR is a portion of the net cost that would need to be recovered for all resources in the utility's portfolio, adjusted for the time value of money. Previous capital investments for existing resources are sunk costs and are not included in the NPVRR calculation; however, this IRP does consider future fixed and variable operations and maintenance (O&M) costs for existing resources. While many of these fixed O&M costs are not avoidable in the short-run, they can be avoided entirely if the existing resources can be retired and replaced with

[2] Capacity Expansion is licensed from ABB Group and part of the e7 platform.

new, more cost-effective options. The NPVRR also includes the capital costs for new or bettered resources and any variable and fixed costs associated with new resources. All variable and ongoing fixed costs incurred more than 10 years after the study period are omitted from the NPVRR calculation.

While NPVRR is a generally accepted method to compare the economics of various alternatives, it does present some limitations which require consideration:

- Different investments (various size, type and timing) which have the same present value may have significantly different project lives and different salvage values (costs).
- Investments with the same net present values may have different cash flows within the study period.
- Assumptions of future cash flows, interest rates, and investment costs cannot be known with certainty.
- Although the portfolio selection does account for costs and benefits continuing more than 10 years beyond the study period, the NPVRR calculation included herein does not.

A number of sensitivities and scenarios have been evaluated for this IRP. Results of each simulation have been aggregated in the form of relative incremental NPVRR, Levelized Cost of Energy (LCOE), and a list of the specific resource additions resulting from each optimization. The LCOE is an industry-standard metric for comparing scenarios with differing loads, calculated as total plan cost divided by energy usage. It is further discussed in Appendix B. The model provides the mathematically optimal, least-cost selection of future resources based on a set of input assumptions, a list of alternative resource types and sizes, and certain constraints such as import limits and the minimum required reserve margin. CE facilitates multi-area economic dispatch and unit commitment zones. Other tools used in this study include ABB's PROMOD IV, Velocity Suite, and Portfolio Optimizer (PO).

GRU OVERVIEW

GRU is a multi-service utility owned by the City of Gainesville (the City). It is the fifth largest municipal electric utility in Florida. Its combined services make it the most comprehensive utility service provider in the state. It serves approximately 93,000 retail and wholesale customers in Gainesville and surrounding areas, offering electric, natural gas, water, wastewater, and telecommunications services.

GRU's electric system is a vertically integrated utility which owns and operates electric generation, transmission and distribution, and customer management systems. It operates as a Balancing Authority (BA) and is subject to all reliability and associated regulatory requirements of the North American Electric Reliability Corporation, Inc. (NERC) and the Florida Reliability Coordinating Council, Inc. (FRCC).

EXISTING RESOURCES

GRU currently has 630.4 MW of generation resources, resulting in a 55% reserve margin in 2018. Figure 5 presents a list of GRU's current generation resources.

Figure 5: Existing Generation

		Unit No.	Primary Fuel	Alternative Fuel	Net Summer Capability (MW)
Owned Generation	**JR Kelly Station**				
		Steam Unit 8	Waste Heat	-	36.0
		Combustion Turbine 4	Natural Gas	Distillate Fuel Oil	72.0
	Deerhaven Generating Station				
		Steam Unit 2	Bituminous Coal	-	228.0
		Steam Unit 1	Natural Gas	Residual Fuel Oil	75.0
		Combustion Turbine 3	Natural Gas	Distillate Fuel Oil	71.0
		Combustion Turbine 2	Natural Gas	Distillate Fuel Oil	17.5
		Combustion Turbine 1	Natural Gas	Distillate Fuel Oil	17.5
	South Energy Center				
		Combustion Turbine 1	Natural Gas	-	3.5
		Internal Combustion Engine 2	Natural Gas	-	7.4
	Deerhaven Renewable				
		Steam Unit 1	Biomass	-	102.5
				Owned Total	630.4
PPA		Base Landfill	Landfill Gas	-	3.8
				Grand Total	634.2

DEMAND

Electrical net firm peak demand in 2018 was 408 megawatts[3] (MW), and Net Energy for Load (NEL) was 2,079 gigawatt-hours (GWh). Peak demand and NEL declined following the economic recession in 2007/2008, but stabilized by 2014. Since then, NEL has increased at an average rate of 2.6% per year while peak demand was essentially the same in 2018 as in 2014. Demand and energy are projected to increase a modest 0.4% per year throughout the study period (2019-2039) for this Integrated Resource Plan (IRP). Additional information is available in Section 2.

RESERVE MARGINS AND THE NEED FOR GENERATING CAPACITY

Generating capacity is the maximum electric output an electric generator can produce under specific conditions. Since customer demand for electrical energy varies by season and time of day, only a portion of generating capacity resources may need to be operating at any particular time, with the remaining capacity resources shut-down or on stand-by for the periods when electrical demand is high and/or other generation resources are unable to operate due to equipment malfunctions. When considering its ability to serve demand, an electric utility should also consider the amount of electricity actually produced by the generator, or its energy production.

Requirements for capacity and energy are determined by regulatory requirements and the market in which a utility operates. GRU, as a BA, Generation Owner (GO), Transmission Owner (TO), Transmission Operator (TOP), and Load Serving Entity (LSE), is bound by the reliability standards and requirements of NERC and FRCC.

On October 30, 2018, the FRCC Board of Directors voted to dissolve its Regional Entity (RE). FRCC ended its RE operations effective July 1, 2019 and was integrated with the SERC Reliability Corporation. Therefore, SERC became the new RE and compliance Enforcement Authority for all NERC-registered entities within the FRCC region. SERC uses a 15% planning reserve margin (PRM) criterion, consistent with the PRM GRU used before October 2018. FRCC continues to operate as a Reliability Coordinator and Planning Authority for peninsular Florida.

FUEL SUPPLY

In long-term planning, utilities should consider the costs of construction and energy production over the life of the resource. Different types of generating resources rely on different fuels and technologies resulting in a wide range of overall costs throughout the resources' useful lives.

Over-reliance on a single fuel or resource type presents both price and business risks; therefore, an effective resource planning process should consider fuel and resource diversity.

Beginning in calendar year 2012, as the cost of NG became increasingly competitive with coal, NG began surpassing coal as GRU's primary fuel for electric generation. Previously, Deerhaven 2, a coal-fired generator, provided the majority of GRU's energy requirements. In December 2013, GRU increased its commitment to fuel diversity with the use of wood waste when a local

[3] Schedule 3.1. GRU. 2019. *GRU 2019 Ten-Year Site Plan.* April 1. Accessed September 10, 2019. http://www.gru.com/Portals/0/4.25.19%20GRU%202019%20TYSP.pdf.

biomass facility became operational and began displacing significant amounts of coal and NG-based electric production.

Natural Gas

GRU purchases NG for power generation and for distribution as a Local Distribution Company (LDC). It is a captive shipper on the Florida Gas Transmission (FGT) system; however, GRU's FGT's transportation rates are reasonable compared to alternative pipelines serving Florida at this time. NG supplies, which can be economically delivered to the various receipt points on FGT, are primarily sourced from producers in the Gulf of Mexico region and the southeastern United States.

GRU receives NG under FGT Firm Transportation (FT) contracts and other shorter term arrangements such as delivered gas purchases, Interruptible Transportation (IT), short-term FT capacity releases, and FT purchased from other shippers with unused capacity.

Coal

GRU delivers its coal to the Deerhaven site with a self-owned unit train and supplements its reserves with spot purchases when needed. GRU is a captive shipper on the CSX railroad network and currently receives Central Appalachian (CAPP) bituminous coal.

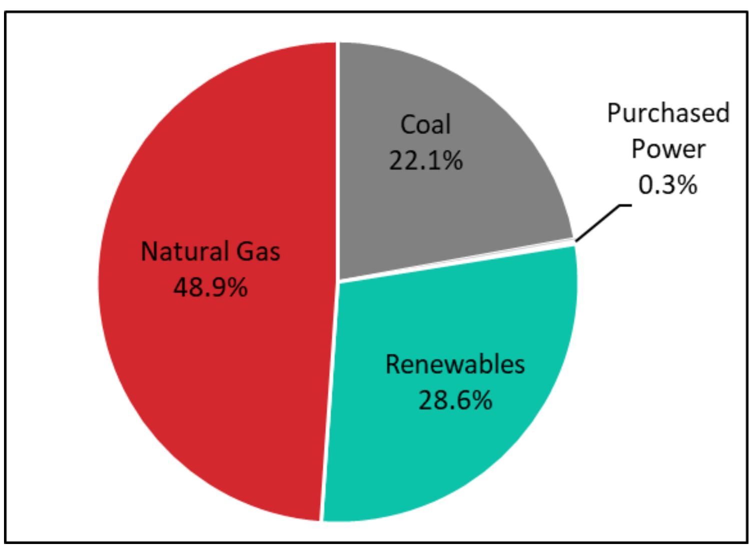
Biomass

In November 2017, GRU purchased the local biomass facility Deerhaven Renewable (DHR) Generation Station, with a total capacity of 102.5 MW. The facility consists of one steam turbine (ST), associated cooling facilities, and biomass unloading and storage facilities. Prior to GRU's purchase of the plant, GRU purchased capacity and energy from the facility in a Power Purchase Agreement (PPA). GRU has contracted with BioResource Management for biomass supply delivered to DHR.

Fuel Mix

Figure 6 shows GRU's fuel mix as a percentage of its 2,079 GWh of net generation and purchases for calendar year 2018. The NEL excludes GRU's solar feed-in-tariff (FIT) contributions.

Figure 6: Fuel Mix



In 2018, GRU-owned gas-fired generation met nearly 50% of GRU's energy requirements. Approximately 60% of the NG was burned in the Kelly combined cycle (CC) unit while about one-third of it was burned in Deerhaven 1. The remaining 7% of the gas was burned in simple cycle gas turbines (GT) at Deerhaven Generating Station and at South Energy Center.

Renewable resources made the next most significant contribution by producing nearly 29% of GRU's energy requirements. The Deerhaven

Renewable Plant, GRU's biomass-fueled facility, provided 96% of renewable energy. The remainder was provided with landfill gas and acquired by GRU through a PPA with G2 Energy Marion, LLC.

Deerhaven 2, a coal-fired unit, supplied approximately 22% of GRU's energy requirements. Coal was GRU's primary fuel source as recently as 2015 but has been surpassed by GRU's NG-fired generation. GRU supplied its remaining energy requirement of less than 1% through short-term power purchases from the market.

MARKET ENVIRONMENT

Electric utilities in the United States have been undergoing profound changes in the way they provide electrical energy to consumers over the last five decades. Fuel choice preferences have shifted from oil, coal and nuclear in the 1960s and 1970s to NG and renewables in recent years. Federal policies in the 1970s banned the use of NG for boiler fuel and mandated generating units that were under construction to burn coal. These 1970s policies have shifted in recent years to policies which greatly encourage renewable energy sources and discourage the use of coal.

Technological changes have dramatically impacted fuel choices. These include evolution of highly efficient advanced technology GT generators and CC units along with unprecedented advances in the methods used to extract NG and oil from shale rock, leading to a surplus of fuel supplies and relatively low NG prices. These fundamental market shifts have caused NG to be the fuel of choice for nearly all new thermal generation in the last five years.

The physical infrastructure required to produce and transmit electricity is capital intensive and long-lived. Utilities have made large investments in power generation and transmission systems based on expected useful lives exceeding 30 years.

GRU owns and operates electric generation and transmission and distribution systems which are used to provide electrical service to its retail electric customers. This IRP addresses long-term plans for its generation resources. Potential changes or improvements to GRU's transmission and distribution system are beyond the scope of this IRP.

POTENTIAL IMPACT OF LAWS AND REGULATIONS

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

GRU has been proactive in sponsoring a number of Energy Efficiency (EE) and Demand-Side Management (DSM) programs since the 1980s. GRU's historical energy efficiency programs included rebates to customers and other financial incentives to promote customer's installation of more efficient air conditioning, customer-owned solar systems, use of natural gas appliances in new construction and a number of other energy efficiency programs. As of the end of 2018, GRU estimates these EE and DSM programs have reduced energy sales to its retail customers by 220 GWh and lowered peak demand by 43 MW.

In addition to these local incentives, the federal government has established a number of incentives and mandates to achieve improvements in end-use EE. Programs such as appliance efficiency standards, interconnection standards, low-income assistance, and loan and grant programs have helped decrease electrical demand and retail energy sales. Much of these impacts are believed to be implicitly recognized in load forecasts. However, rapid changes in these laws and regulations could shift GRU's electrical demand higher or lower than the current forecast.

According to Section 2.4 of GRU's 2019 Ten-Year Site Plan (TYSP) filed with the Florida Public Service Commission (FPSC), "During 2014 budget deliberations, GRU management and the Gainesville Commission agreed to eliminate the majority of programs offering financial incentives in an effort to cut costs and keep prices down for customers." TEA used this decision as a guide for whether DSM programs should be considered in this IRP. As a result, no additional DSM programs have been considered. If the City Commission choses to modify its position with respect to GRU-sponsored and -funded DSM programs, additional programs could be considered in future IRP updates.

While EE may be mutually beneficial for both the end-use consumer and GRU, it is important to recognize the larger long-term implications for electric rates. Utilities tend to have high fixed costs that are recovered largely via variable rates. If EE-influenced demand declines more quickly than fixed costs, utilities will have to change their rate levels and structure to include either a higher fixed rate or higher variable rates. However, the combination of rate changes and decreases in energy usage may lead to a decline in the consumer's total bill.

Any effort to consider additional DSM programs should consider how such programs would impact GRU's customers. At the time of this report, FPSC is considering energy conservation and DSM plans for the larger Florida electric utilities pursuant to the Florida Energy Efficiency and Conservation Act (FEECA). These utilities joined together to retain Nextant, Inc. to prepare Market Potential Studies for a variety of DSM programs. Such studies are complex, time-consuming, and expensive. GRU should consider reviewing this work to determine its applicability to GRU's situation.

In particular, with increasing penetration of solar PV, some DSM programs such as direct load control may be useful for helping to manage rapid ramp rates caused by highly variable output of the solar PV systems during adverse weather conditions and cloud cover.

RENEWABLE RESOURCE GOALS

Many states and/or local governments have established Renewable Portfolio Standards (RPS) which establish goals for or mandate the local electric LSEs to use renewable energy resources such as solar, wind, and biomass for a specified percentage of its annual energy requirements.

GRU has historically facilitated renewable energy programs by offering rebates to customers for installing solar energy equipment, a solar FIT program, purchasing energy from a land-fill gas facility, and installing a large biomass fueled electric generator.

While Florida doesn't have a quantified RPS, the Gainesville City Commission passed a resolution in October 2018 establishing a goal of providing 100% of the city's energy from renewable resources and reaching net zero community-wide greenhouse gas emissions by 2045. The Commission prefers to reach this goal as soon as feasible. The intention of the city-wide energy policy is to include a balanced approach between fiscal responsibility and emissions reduction.

Renewable power is becoming a significant part of overall FRCC generation resources. FRCC estimates that there are approximately 600 MW of utility-scale solar PV in the FRCC region in 2018. An additional 4,010 MW are planned through 2028. With these additions, renewables are expected to produce over 11% of FRCC's total NEL, and solar energy is projected by provide 27,346 GWh of energy in the FRCC region by 2028[4].

FUEL DIVERSITY

Risk Management principals suggest that having dependence on a single source of supply for any commodity is a significant risk factor. This is particularly true for fuel supply for a utility's power generation facilities and even more so for fuels or resources that have other constraints, such as the intermittency of renewables and the prioritization of NG service to residential, commercial, and industrial customers over electric generation.

On July 14, 2008, the Gainesville City Commission held a public hearing on three Standards of the federal Energy Policy Act of 2005. The Commission approved all three standards, including the Standard for Fuel Diversity. The standard states:

> *"[The Gainesville City Commission determined that] Standard 12 … has been implemented through GRU's minimized dependence on one fuel source, and that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies, and that fuel diversity will be an important standard in planning for future generation needs."*[5]

GRU achieved this standard through utilization of coal, NG, and renewable resources such as landfill gas, biomass, and solar. GRU is expected to and plans to maintain fuel diversity throughout the study period. However, in order to achieve a 100% renewable energy goal, it will be necessary to substantially eliminate dependence on fossil fuels. This will lessen GRU's ability to achieve fuel diversity in the future.

CARBON DIOXIDE EMISSIONS MITIGATION

The discussion and debate on the potential impact of greenhouse gas (GHG) emissions on climate change has moved the United States Congress, Environmental Protection Agency (EPA), and state and local governments to consider laws or regulations to reduce anthropogenic carbon dioxide (CO_2) emissions. Though no nation-wide program currently exists, there is a possibility that some form of GHG emissions mitigation program will develop in the future. On June 19, 2019, the EPA finalized the Affordable Clean Energy (ACE) rule[6], which guides the development of state plans to reduce CO_2 emissions from existing coal-fired generating units by setting performance standards for those units. Meanwhile, some states have implemented their own programs to mitigate GHG emissions, including California and several northeastern states participating in the Regional Greenhouse Gas Initiative (RGGI).

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[4] Florida Reliability Coordinating Council, Inc. 2019. "2019 Regional Load & Resource Plan." Tampa, Florida. http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2019/FRCC_RLRP.pdf

[5] GRU Final Recommendations on Standards 11, 12, and 13 of the Energy Policy Act of 2005

[6] Legal challenges of the ACE rule have been filed in the U.S. Court of Appeals by a coalition of 22 states and by other organizations.

This study is focused on finding the best path forward for GRU to meet its reliability and capacity needs from a least-cost and risk management perspective, and does not consider potential environmental or climate impacts of new or existing resources or advocate any alternative on the basis of potential impacts. It merely attempts to help prepare a utility for how the social, political, and regulatory environment will affect the cost and availability of resources in the future. Given the controversial and evolving nature of this topic, utilities should take care to account for this policy and regulatory risk when planning for their future.

This study addresses GHG mitigation by assessing high renewable penetration, consistent with the 2018 City Commission resolution establishing renewable energy goals for Gainesville.

ELECTRIC VEHICLES

The rate of electric vehicle (EV) adoption may have a significant impact on GRU's demand for energy, as well as the need for additional supply-side resources and distribution-level upgrades. National, state, and local regulations could hinder or advance adoption of EVs. GRU should stay abreast of community interest and the actions of various governing bodies to inform the need to further study EVs and their impact on GRU's future. For this IRP, no significant penetration of EV charging has been included in the load forecast.

FEDERAL, STATE, AND LOCAL TAX CREDITS AND INCENTIVES

Though the federal government offers some loan and grant programs for those interested in investing in renewables, the most significant incentives to encourage development of renewable resources are the federal production tax credit (PTC) applicable to wind generation and investment tax credit (ITC) applicable to solar generation.

Federal tax credits have served as one of the primary financial incentives for renewable energy (RE) deployment in the United States over the past two decades. The PTC was first enacted as part of the Energy Policy Act of 1992 and has historically played a significant role in supporting wind energy. The ITC of 30% for solar projects was initially established in the Energy Policy Act of 2005. Since their initial inceptions, federal renewable tax credits have been extended, modified, and nearly expired numerous times. Historically, changes in federal tax policies have been highly correlated with year-to-year variations in annual RE installations, particularly for wind, where the U.S. wind industry has experienced multiple boom-and-bust cycles that coincided with PTC expirations and renewals.[7]

Prior to the passage of the Consolidated Appropriations Act of 2016 in December 2015, the PTC had expired and the ITC was set to decline at the end of 2016. The Consolidated Appropriations Act of 2016 extended these ITC and PTC deadlines by five years from their prior scheduled expiration dates, but included ramp downs in tax credit value during the latter years of the five-

[7] Ryan Wiser et al., *2017 Wind Technologies Market Report*, U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, August 2018, http://eta-publications.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf

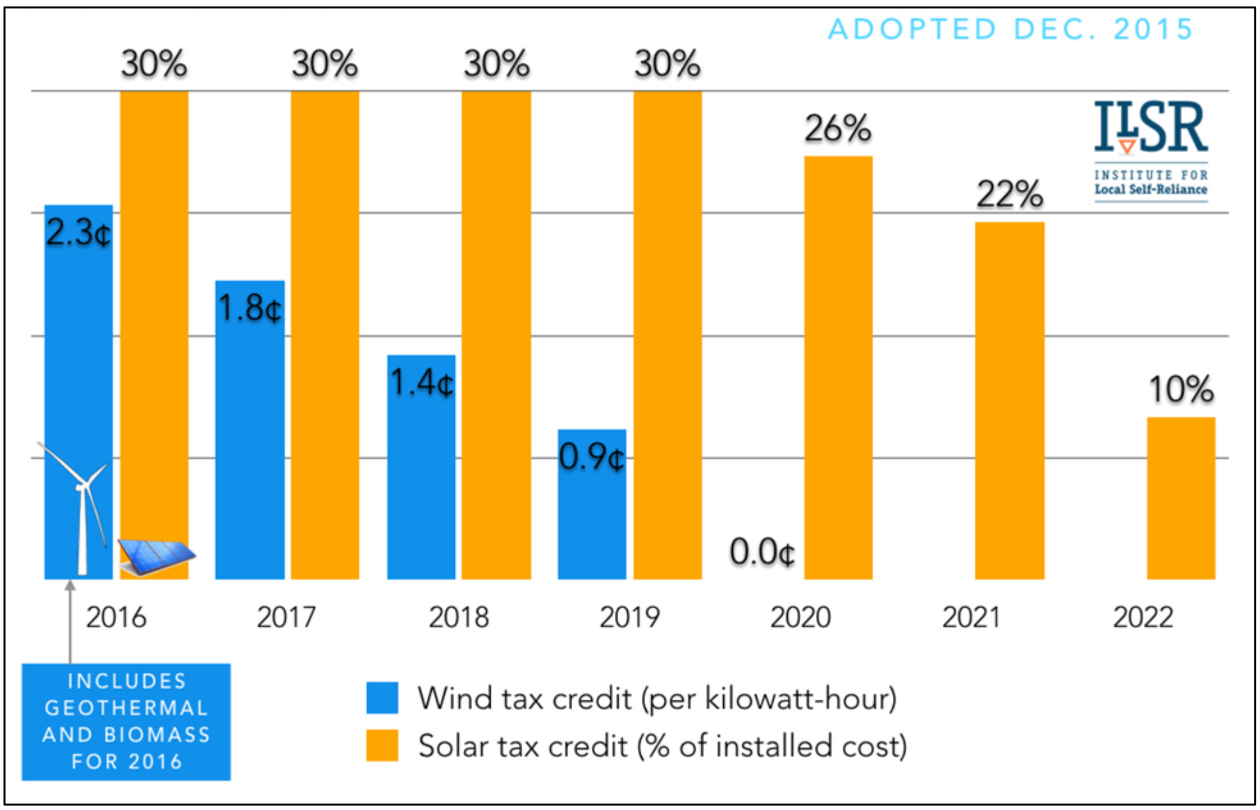
year period. Notably, the act kept the commenced-construction provision for the wind PTC and extended the provision to the ITC for utility-scale and commercial solar.

Table 3, from the Institute for Local Self-Reliance, summarizes the wind and solar tax credit schedule before and after the act was passed.[8] In the new policy, the dates for all categories except Residential Host-Owned Solar ITC change from being based on "placed-in-service" dates to "commenced-construction" dates.

Due to the nature of the credit, non-taxable entities such as GRU are unable to directly capture the economic value associated with the federal PTC and ITC. As such, most assets eligible for tax credits are attained through PPAs whereby the producer, who is a taxable entity, retains the incentives and then offers a more competitive rate to the non-taxable entity.

TEA does not closely monitor changes and updates to state and local incentives, laws, or regulations. Therefore, we rely heavily on each client to inform us of any current or anticipated items that would impact our studies. At this time, we are not aware of any state or local incentives that would affect this study.

Table 3: Federal Renewable Energy Tax Credit Phase Out



[8] Farrell, John. 2016. "Congress Gets Renewable Tax Credit Extension Right." *Institute for Local Self-Reliance*. January 5. Accessed October 9, 2019. https://ilsr.org/congress-gets-renewable-tax-credit-extension-right/.

Section 2: Existing Power Supply Resources

EXISTING RESOURCES

GRU's existing supply-side generation resources[11] are listed in detail in Table 4. This table provides important characteristics for each unit, including type of unit (prime mover), fuel source, capacity, thermal efficiency (heat rate), commercial on-line date, and any planned retirement date. A few notes on GRU's existing generation fleet should provide appropriate insight into this IRP.

Deerhaven (DH) Fossil-Steam (FS) Unit 2, a coal-fired facility with some NG-burning capability, has been the primary base-load "workhorse" in GRU's fleet since it became operational in 1981. It is a large unit compared to GRU's load profile; it provided approximately 80% of GRU's overall energy production between 2000 and 2010. However, as NG prices declined in more recent years due to abundant shale supplies, coal-based generation became less competitive and GRU shifted generation to lower cost NG-fired facilities.

The most efficient generating unit in GRU's fleet is the 118 MW John R. Kelly (JRK or Kelly) CC. The JRK CC uses a G.E. Frame 7EA combustion turbine (CT) which began commercial operation in 2001 and the JRK Unit 8 simple cycle steam unit which began commercial operation in 1965.

Table 4: Existing Supply Resources

Generating Unit	Prime Mover	Fuel	Max Summer Capacity (MW)	Min Capacity (MW)	Online Year	Modeled Retirement Date	Heat Rate at Max (Btu/kWh)
DH FS2	ST	Coal	228	51	1981	2031	10,960
DH FS1	ST	NG/Oil6	75	22	1972	2022	11,588
JRK	CC	NG	108	85	2001		8,101
DHR	AFB, ST	Biomass	102.5	30	2013		11,310
DH GT1	CT	NG/Oil2	17.5	2.9	1976	2026	15,393
DH GT2	CT	NG/Oil2	17.5	2.9	1976	2026	15,393
DH GT3	CT	NG/Oil2	71	49	1996		12,260
SEC1	CT	NG	3.5	0	2009		8,000[9]
SEC2	RICE	NG	7.4	0	2018		8,000[10]
G2 Energy	Purchase	Landfill	3.8		2009	2023	

[9] SEC1 heat rate is specified in the cogeneration contract with UF Shands.
[10] Ibid.
[11] Excludes 18.6 MW of customer-owned solar PV generation under the FIT

This facility is expected to continue in service until after 2039, although many components are currently over 50 years old. At the time of this report, GRU plans to make considerable capital investments into JRK CC in the next couple of years to maintain its operational capabilities.

The SEC, a combined heat and power plant (CHP), began providing services to the UF Health Shands Cancer Hospital in February 2009. It consists of a 3.5 MW NG-fired CT and a 7.4 MW NG-fired reciprocating internal combustion engine. Both the SEC Unit 1 and SEC Unit 2 have the same modeling parameters in the CE model. The energy from the units at SEC is procured at a contractual heat rate of 8,000 British thermal units per kilowatt-hour (Btu/kWh).

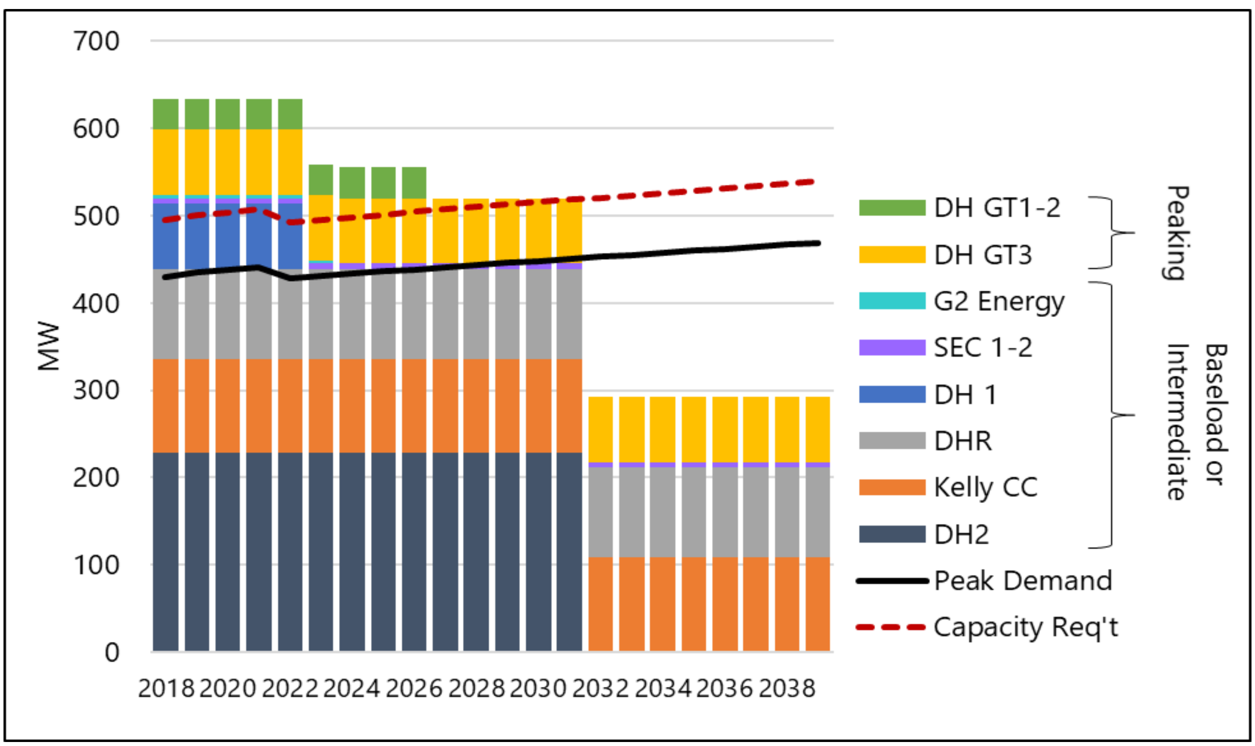
Deerhaven Renewable Plant (DHR) is located on the Deerhaven site and was purchased by GRU in November 2017. The fuel for this pant is locally harvested wood waste, also known as biomass. This plant consists of an atmospheric fluidized-bed boiler (AFB) and a steam turbine.

20-YEAR DEMAND AND RESOURCE BALANCE

GRU's planning requirement for generating capacity is to maintain at least a 15% PRM above forecasted peak demand. Figure 7 shows the peak demand forecast from the previous section as a solid black line and the peak demand plus 15% reserves is shown as a dashed red line.

Capacity for GRU's existing units is depicted on Figure 7 as multi-colored stacked bars. The impact of the planned retirement of DH1 after 2022, the DH GTs 1 and 2 after 2026, and DH2 after 2031 are visible as decreases in the height of the stacks. Note that in 2032, after retirements of DH1, DH GT 1&2, and DH2 GRU will no longer meet its PRM. In order to meet its load-serving obligation, GRU will be required to add replacement generation by 2032 based on the current generation portfolio and retirement schedule.

Figure 7: Demand and Resource Balance



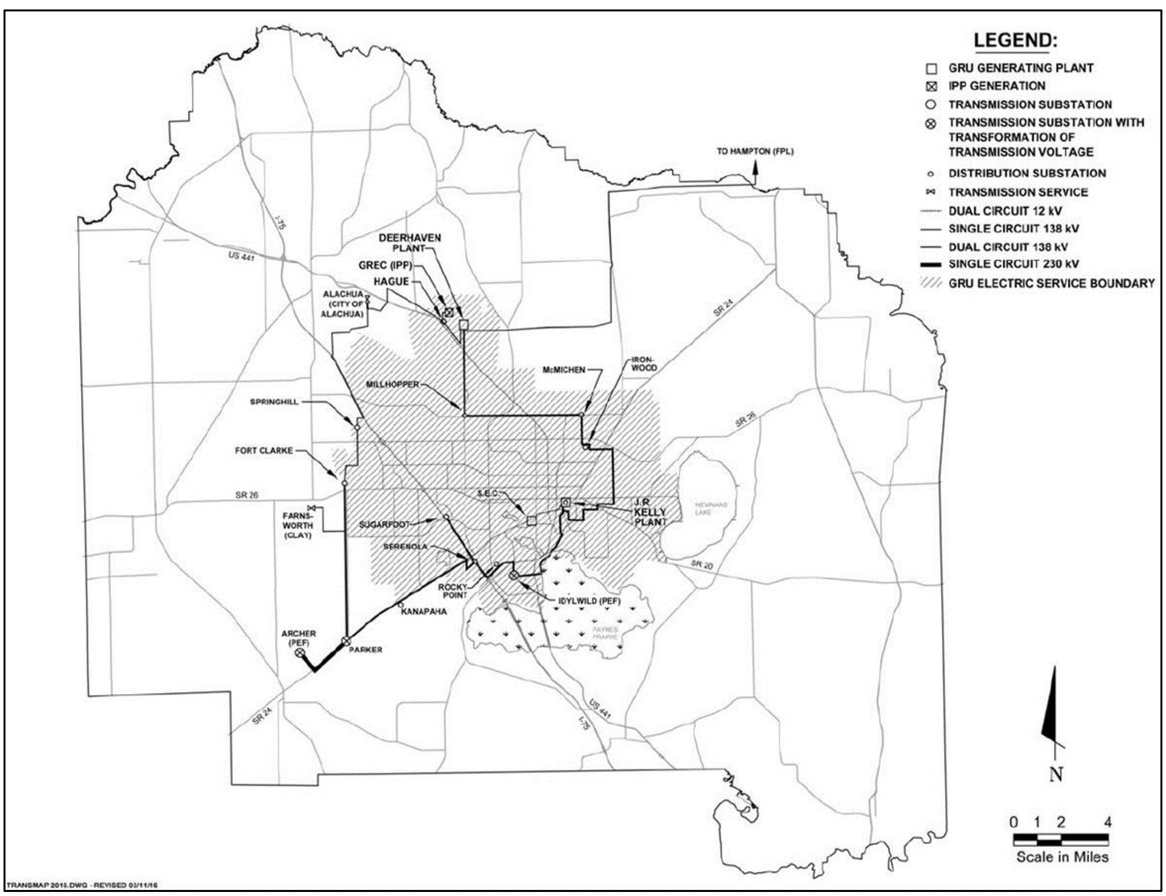
TRANSMISSION AND DISTRIBUTION SYSTEM

GRU's electrical transmission system consists of a 138 kV loop around the greater Gainesville urban area which interconnects three transmission switchyards and serves six loop-fed and four radial distribution substations. The transmission system has three physical interconnections with Duke Energy Florida (DEF) and one physical interconnection with Florida Power & Light (FPL). The system interconnects with DEF's Archer substation via a 230 kV transmission line to GRU's Parker Road Substation and with DEF's Idyllwild substation via two 138kV transmission lines. The system also interconnects with FPL's Hampton substation via a 138 kV transmission line to the Deerhaven generating station. Figure 8 shows a high-level map of GRU's bulk power system.

The system is planned, operated, and maintained to be in compliance with all Federal Energy Regulatory Committee (FERC), NERC, and FRCC requirements to assure the integrity and reliability of Florida's Bulk Electric System. Economic power imports are generally limited to 120 MW. However, GRU is evaluating options to increase this import capability to allow it to take more advantage of low-cost purchases from the wholesale energy market.

GRU provides transmission service to the Seminole Electric Cooperative for serving Seminole's Farnsworth substation located on the western side of GRU's transmission system. Seminole has reserved 20 MW of long-term firm transmission service for this purpose.

Figure 8: GRU System Map



Section 3: Supply and Demand Requirements Analysis

OVERVIEW OF CUSTOMERS

Gainesville is the home of the University of Florida, the oldest university in the state. With over 55,000 students, it is one of the largest universities in the nation. The economic base of Gainesville consists primarily of light industrial, commercial, healthcare, and educational activities.

GRU served an average of approximately 86,500 residential and 11,000 non-residential electric customers in 2018. GRU experienced strong growth in the number of customers served during the 1999 to 2008 period with an average increase of approximately 1,800, or 2.1%, per year. The number of customers then remained relatively constant through 2012 before increasing steadily at an average of nearly 850 additional customers per year through 2018. GRU expects its number of customers to grow by an average of 835 per year through 2028.

GRU provides wholesale electric service to the City of Alachua of about 125 GWh per year.

HISTORICAL DEMAND

Electric utilities across the United States, to varying degrees, have shifted away from an environment where energy sales increased several percent per year (1970s – early 2000s) due to increases in both number of customers and electric usage per customer.

In recent years, most notably after the 2008 economic recession, annual growth in number of customers has slowed but continued an upward trajectory. However, energy use per customer either has leveled out or has been decreasing, resulting in a flattening or declining total electric energy utilization. Reasons for this shift in consumption patterns include implementation of energy efficiency measures by consumers, increasing penetration of energy efficient appliances, a shifting from an economy driven by industrial production to a service-based economy, and an increase in demand-side technologies that reduce metered load and increase consumers' independence from the traditional utility model. These technologies are discussed further in Overview of Available Resources and Technologies in Section 5.

GRU has experienced changes in consumption patterns similar to most other utilities. Between 1999 and 2007, GRU's average annual growth rate of total NEL was around 2.1% per year (not weather adjusted). Beginning in 2008, GRU's NEL began to decline, reaching a low of 1853 GWh in 2013. Since then, GRU's energy demand has steadily increased at an average annual rate of 2.3% and once again reached its 2008 total of 2,079 GWh in 2018.

In 2022, GRU load may be reduced if the City of Alachua decides to obtain all or a portion of its electric requirements that are currently served by GRU from another source. Loss of half of the City of Alachua load would result in approximately a 2.9% decrease in GRU's 2022 peak demand.

CITY OF ALACHUA FULL-REQUIREMENTS CONTRACT

GRU currently serves the City of Alachua with all-requirements, load-following power, which peaks at approximately 30 MW. The contract for wholesale electric service began in January 1988, and it includes energy, demand, and ancillary services. GRU made an agreement in 2016 to extend its service to the City of Alachua until March 2022. Energy sales to Alachua are currently around 125 GWh per year, equaling approximately 98% of Alachua's energy requirements. The remaining energy comes from its share of the St. Lucie nuclear units.

For this IRP, GRU anticipates that this contract is not fully renewed and that GRU will retain only half of the previous City of Alachua load. Therefore, in order to appropriately project GRU's need for generating capacity and associated reserve margins, only a portion of the City of Alachua's requirements are included in this IRP.

SOLAR FEED-IN-TARIFF

In March 2009, GRU began to offer a European-style solar FIT. With this program, private solar developers installed PV generating equipment for GRU's customers and GRU pays the customers an energy charge for all electrical energy produced by these resources for the duration of the 20-year contracts. Though this program has been suspended for new customers, approximately 18.6 MW (19.3 GWh/year) had been contracted by the end of 2013. The commitment to existing customers will continue through 2033.

For this IRP, the energy production from the FIT has been netted against future hourly loads.

DEMAND AND ENERGY FORECAST

Producing accurate demand forecasts allows GRU to ensure sufficient resources are available to meet customer demand. GRU updates its demand and energy forecast each year for inclusion in its TYSP which is filed with the FPSC each April. The forecast presented in the 2018 TYSP was used as the basis for the load forecast in this IRP. Details of the methodology can be found in the 2018 TYSP on the FPSC website.

For facility planning purposes in the 2018 TYSP forecast, GRU projects growth in total number of customers will average 835, or 0.7%, per year between 2018 and 2028. Energy use per customer is expected to stabilize, with total NEL increasing at an average annual rate of 0.7% per year during this same period.

The forecast in the TYSP covered the period 2016-2027. This forecast was extrapolated to 2039 using the average annual growth rates projected for 2019-2027. The NEL history and forecast used for this study is shown in Figure 10.

TEA adjusted the load forecast used in the 2018 TYSP for the potential loss of half of the current City of Alachua load beginning in March 2022. GRU provided TEA with the City of Alachua load forecast, the methodology of which can also be found in GRU's 2018 TYSP. TEA reduced the forecast by half and assumed a coincident peak between GRU and the City of Alachua. The new hourly forecast was shaped using GRU's 2016 actual load as a basis.

GRU forecasts summer and winter seasonal demands by taking an average ratio of the last 25 years of NEL for August and January, respectively, divided by the associated seasonal peak demands for those same months. These two ratios are applied to forecasts for each future August and January to produce a forecast of seasonal peak demands. Therefore, peak demand forecasts track NEL projections. These peak demands were adjusted beginning in 2022 for the potential loss of one half of the City of Alachua load after their contract expires. This forecast assumes a coincident peak for GRU and the City of Alachua. GRU's history and forecast of monthly peak demand are shown in Figure 9.

Figure 9: History and Forecast of Monthly Peak Demand

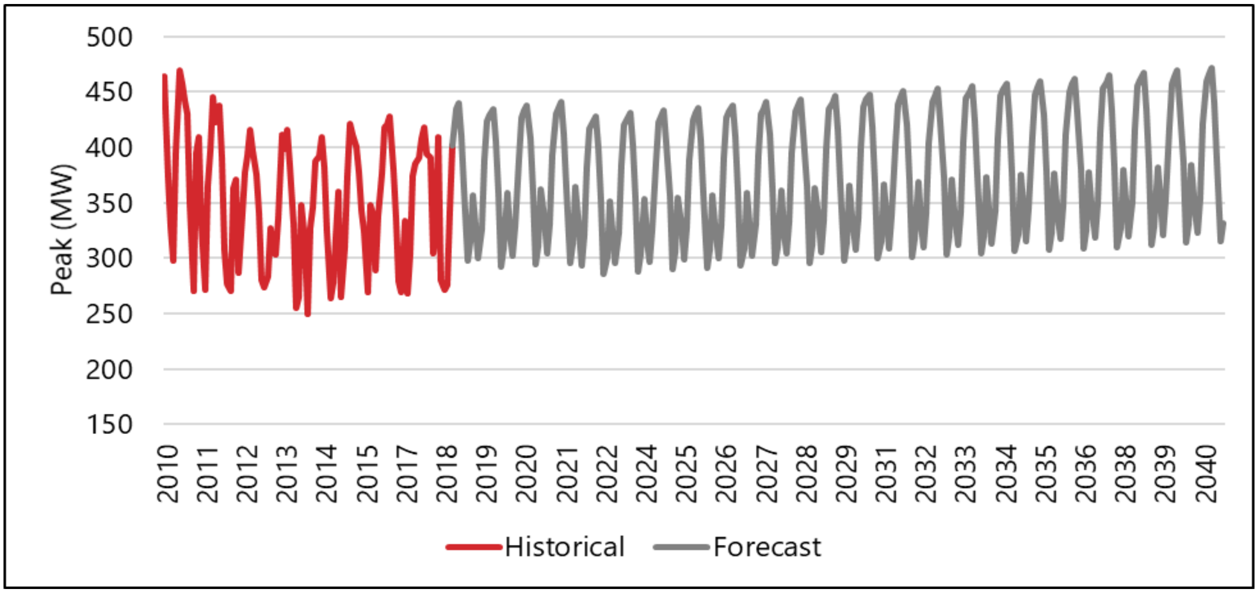
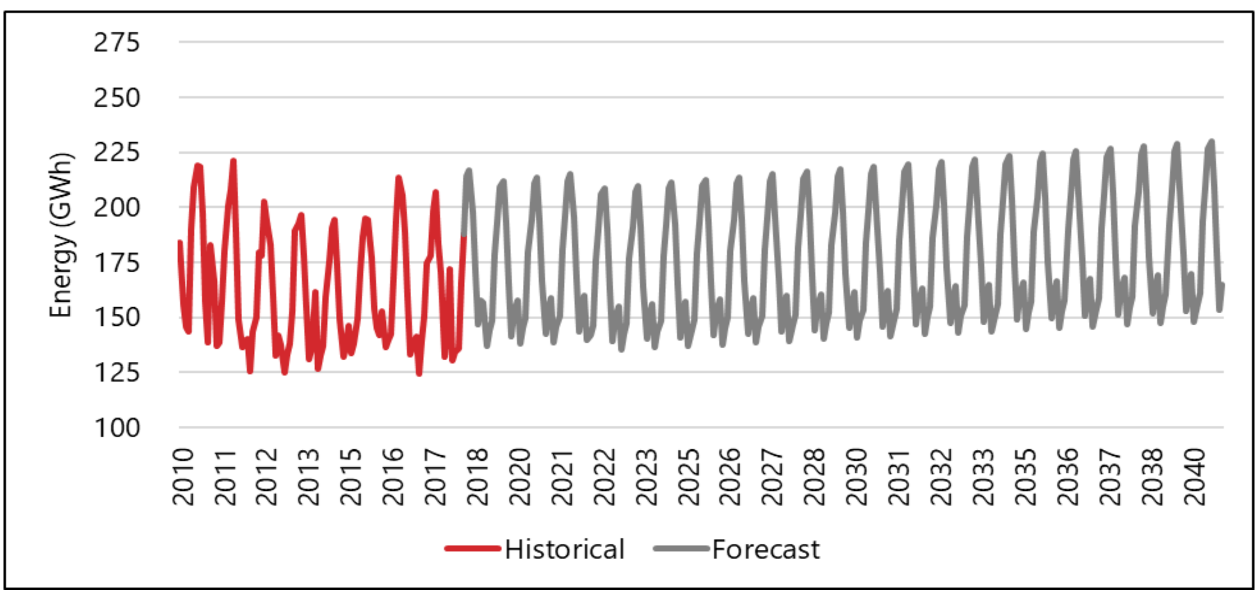


Figure 10: History and Forecast of Monthly Net Energy for Load



Section 4: Fuel Price Projections

OVERVIEW

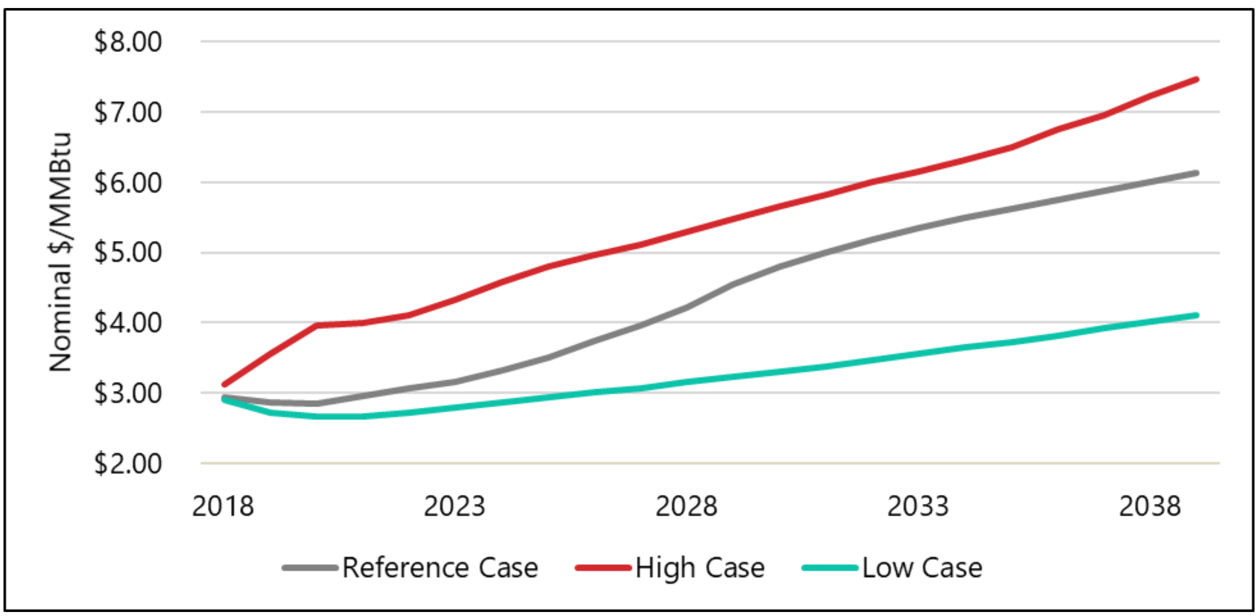
Price forecasts for natural gas (NG), coal, and biomass are key drivers in evaluating GRU's future resource options. NG is GRU's primary fuel for electric generation, and this IRP includes additional gas-fired generating resources as potential options to serve future electric demand. Coal is consumed in Deerhaven 2 and continues to be a major fuel source for GRU.

NATURAL GAS

TEA developed its reference case Henry Hub NG price forecast based on a blend of recent long-term price forecasts from S&P Global Platts (S&P) and Wood Mackenzie (WoodMac). On September 15, 2016, S&P acquired PIRA, a leading international consulting firm in global energy market analysis and intelligence. WoodMac, a subsidiary of Verisk Analytics, is a global research and consultancy group that provides comprehensive data, written analyses, and consultancy advice. Both S&P, through its acquisition of PIRA, and WoodMac develop forecast data through a detailed analysis of fuel supply and demand fundamentals.

Given the uncertainty of future NG prices and the need to consider fuel price risk, TEA also developed alternate NG pricing sensitivities. A high gas price sensitivity is based on the U.S. Energy Information Administration's (EIA) "High Economy" Henry Hub price forecast from its 2018 Annual Energy Outlook. The EIA is a U.S. government agency responsible for collecting, analyzing, and disseminating energy information. The low gas price sensitivity is based on the New York Mercantile Exchange (NYMEX) settle prices from May 15, 2018 extended beyond 2030 using a consistent growth trend.

Figure 11: Henry Hub Natural Gas Price Forecast



COAL

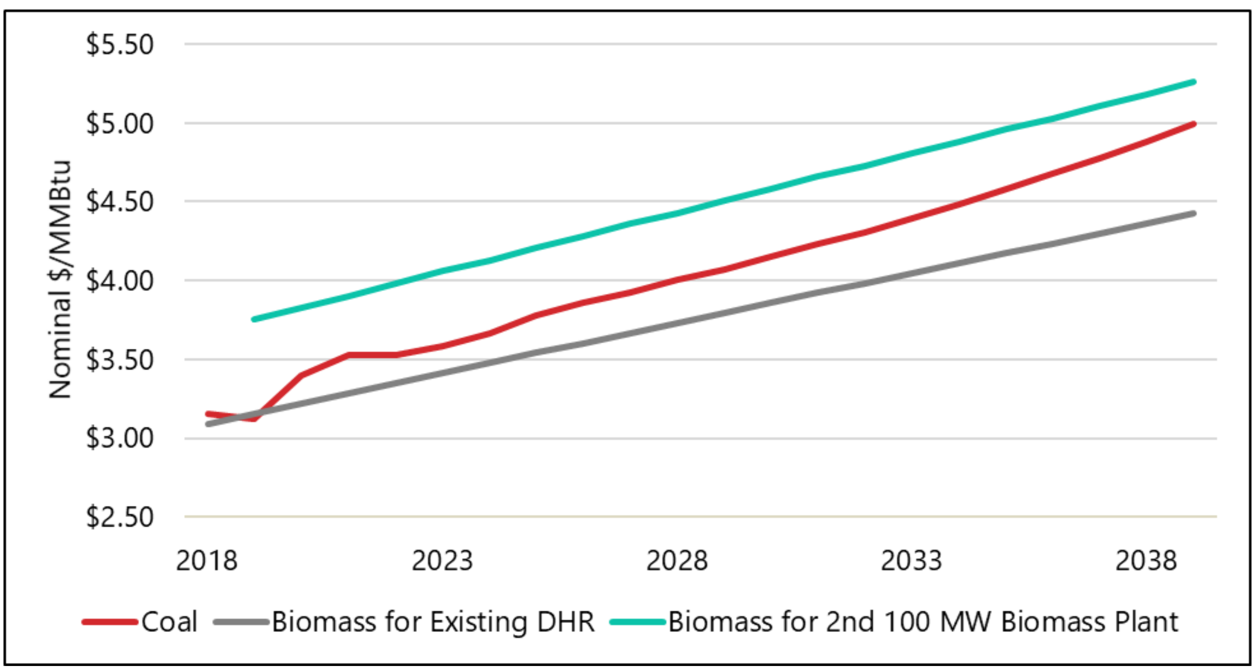
GRU provided a long-term price forecast for delivered coal pricing for use in this study. This forecast is based on the assumption that GRU will continue to burn CAPP coal through calendar year 2020 and a blend of Illinois Basin (IB) and CAPP coal beginning in 2021. The CAPP and IB coal commodity price forecasts are based on S&P and EIA forecasts.

GRU's current transportation contract with CSX expires in 2019. For planning purposes, GRU has assumed that, after a significant increase in transportation costs in 2020, transportation costs from the IB and CAPP basins will increase at 3% annually. With commodity costs expected to decline in real terms, the overall delivered cost of coal is expected to increase at approximately 2% per year between 2020 and 2039, essentially matching the rate of inflation.

BIOMASS

The DHR biomass-fueled generation facility is fueled by a plentiful, local supply of clean wood waste including pulpwood and chip-n-saw timber generated by forestry management and urban wood waste. The wood fuel is delivered by contractor-owned trucks from sources typically within 50 to 75 miles of DHR. GRU provided the delivered biomass price forecast shown in Figure 12 based on the expectation that local supply will continue to be available at competitive prices throughout the study period. GRU's biomass price forecast was derived from expected changes in the cost of diesel fuel, which is used in the transportation of the supply to the Deerhaven plant, and the consumer price index. If GRU builds another biomass plant, it may need to source the additional fuel supply from more distant locations, thus increasing transportation costs. This additional cost is included in the fuel cost for a second biomass plant in Figure 12.

Figure 12: Delivered Coal and Biomass Price Forecasts



Section 5: Future Resource Options

RESOURCE OPTIONS INCLUDED IN IRP

Future resource requirements can be satisfied through the purchase or construction of capacity, the reduction in demand and energy consumption by end-users, or a combination of the two. Available resource options could include:

- Supply-side alternatives
  - Construction or purchase of a new or existing central station thermal resource such as NG-fueled combined cycled (CC), combustion turbine (CT) or reciprocating internal combustion engine (RICE) generators that are wholly or jointly owned by GRU
  - Addition of a wholesale Power Purchase Agreement (PPA) that provides capacity and/or energy
  - Construction of or participation in a new or existing utility-scale renewable facility, such as photovoltaic (PV) solar or energy storage
- Demand-side alternatives
  - Peak reduction programs such as demand response
  - Rooftop or community solar, possibly coupled with customer based battery storage
  - Other types of Distributed Generation (DG) or Combined Heat and Power (CHP, cogeneration)
  - Demand shifting programs such as time-of-use rates, residential demand rates and direct load control
  - Energy efficiency programs such as high efficiency hot water heaters, refrigerators, and Heating, Ventilation, and Air Conditioning systems

The following sections provide descriptions of each type of resource which may be used to meet GRU's future capacity and energy resource options.

OVERVIEW OF AVAILABLE RESOURCES AND TECHNOLOGIES

The topics discussed in this section are not inclusive of all developments in the utility and energy sphere, but a brief screening of some well discussed subjects. For evidence of the current pace of change within the industry, look at IRPs from just a few years previous. Solar was not expected to gain as much market share as it has, coal was still expected to remain as the dominant generating resource, and there was little discussion of batteries or electric vehicles. It would not be surprising if within a few years, some of the issues and technologies addressed in this chapter faded away while new ones appear and play an unexpectedly large role in our electric future.

STEAM UNITS

Simple thermodynamic cycle (Simple Cycle or SC) steam turbine-generators (STG or ST), also known simply as steam turbines, have been the stalwart of electric generating units for many decades. Until the last two decades, SC steam units have been the primary choice for base load operation due to their reliability and fuel flexibility (coal, oil, NG and nuclear). SC-STG's typically have relatively long start-up times (8-24 hours) and are usually restricted in the number of starts and minimum run-time to reduce thermal fatigue and wear on large expensive components.

Over the last two decades, SC-STGs have become less competitive than other alternatives such as CC units due to higher thermal efficiencies realized by CCs and relatively low NG prices.

SIMPLE CYCLE GAS TURBINES

Simple cycle gas (combustion) turbines (GT or CT) began to penetrate the electric generation fleet in the 1960s. Early vintage GTs were relatively inexpensive to build on a $/kilowatt (kW) basis, but were inefficient and generally limited to smaller size units. Because of their inefficiency, they were limited to serving load only during peak load and emergency operating conditions (i.e. less than 1,000 hours per year).

Unlike SC-STGs, fuel choices for CTs are generally limited to light oil and NG, and start time is generally 30 minutes or less, thus providing significant operating flexibility.

Over the last three decades, technological advances have resulted in substantial improvements in CTs, resulting in larger and significantly more efficient electric generation when compared with earlier vintage CTs. Today, there are a variety of sizes, types (aero-derivative vs. industrial or "frame" types), and manufacturers to choose from for CTs.

SIMPLE CYCLE GAS TURBINE WITH INTERCOOLER

Addition of an intercooler to a simple cycle GT can improve overall cycle power and efficiency ratings. As air is compressed, it heats up. If some of this heat is removed via an intercooler, it is possible to achieve a higher compression ratio which results in an increased thermal efficiency. General Electric's LMS100 is an example of a utility scale GT in which intercooler technology is applied. This design retains much of the operational flexibility offered by a simple cycle GT while improving heat rates to a level similar to that achieved with a RICE unit (see below).

COMBINED CYCLE

CC units combine the best features of SC-STGs and SC-GTs and are now a common choice for new fossil-fueled generation. The very hot exhaust gas from the CTs is recovered with a heat recovery steam generator (HRSG) to produce steam which powers a conventional STG. Thermal efficiencies are approaching or exceeding 60%, as compared to the 40% efficiency of SC-STGs.

RECIPROCATING INTERNAL COMBUSTION ENGINE

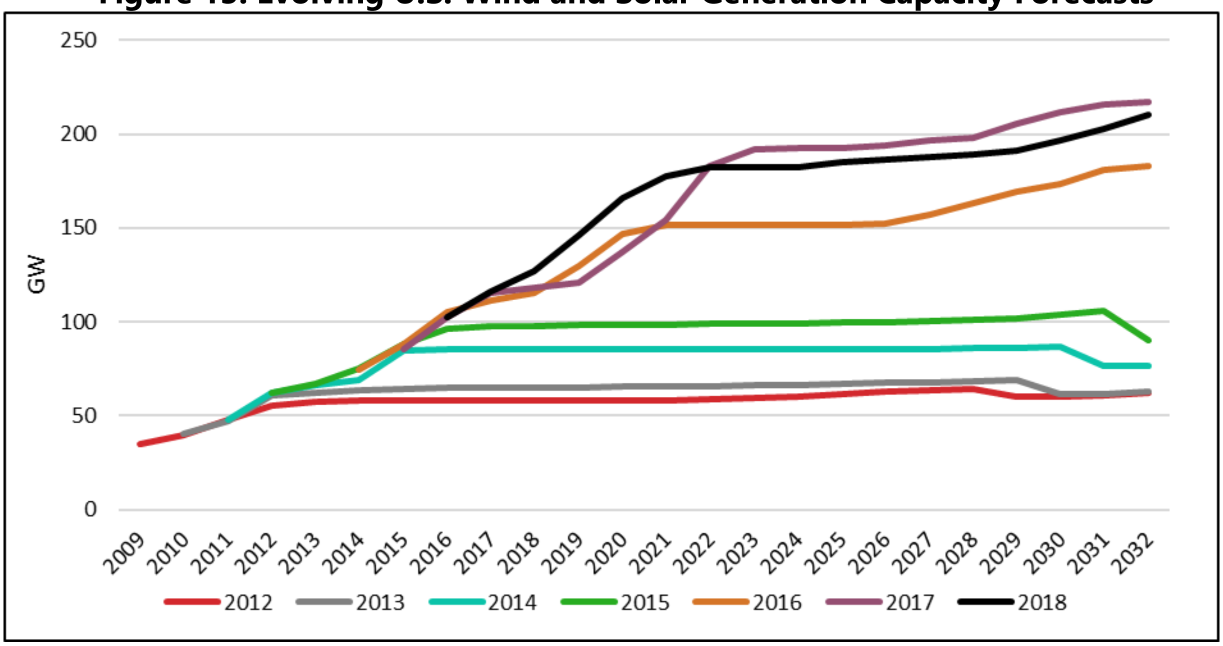
RICE are becoming an increasingly popular choice for utilities. They generally have higher thermal efficiencies than SC-CTs, and efficiency does not vary significantly over the operating range of a single unit. They also offer modularity (ability to add additional units to existing units in small blocks) and quicker start-up and ramp times, are capable of more frequent starts and stops, and help lower operating and maintenance costs while providing dual-fuel capability. This type of flexibility is becoming more valuable given the intermittent nature of wind and solar generation. As wind and solar generation rapidly ramps up or down, this type of rapid response unit is able to quickly respond and balance the intermittent nature of wind and solar generation. However, maximum individual unit capacity is generally limited to 20 MW. The largest RICE engine is Wärtsilä's RT-flex96C, which produces 80 MW but is not in common use.

WIND AND SOLAR GENERATION

Wind, solar, and NG accounted for nearly all generation capacity additions in the US in 2018, with wind and solar making up a majority of those additions. The share of renewable energy (RE) is projected to increase 50% to about 25% of total generation by 2036.[12] However, the actual rate of RE adoption has historically been higher than forecasted, while the costs of RE tend to be lower than forecasted. As shown in Figure 13, there is a consistent trend where each new generation capacity forecast projects a faster growth rate than the previous one.[13]

For example, domestic PV solar energy has grown an annualized rate of 51% since the turn of the century. PV solar capacity (rooftop and utility scale) grew from 30 MW in 2000 to over 50,000 MW at the end of 2017.[14] Part of this growth can be attributed to cost decreases as a result of improvements in manufacturing processes and technologies which boost cell efficiency.

Figure 13: Evolving U.S. Wind and Solar Generation Capacity Forecasts



[12] "Annual Energy Outlook 2019 Table: Electricity Supply, Disposition, Prices, and Emissions," U.S. Energy Information Administration, accessed May 15, 2019.
[13] Ibid.
[14] "Statistical Review of World Energy – all data, 1965 – 2017," BP, accessed October 16, 2018, www.bp.com/statisticalreview.

In fact, solar technology is advancing at a pace such that some of the information in this section will be outdated by the time the report is published. As a result of these improvements, utility scale solar energy, inclusive of subsidies, is now cost competitive with other supply-side resources in many geographic locations. Another factor in the rapid growth of solar is the modularity and flexibility of PV solar. Though economies of scale and budgetary concerns of utilities should play a factor in this decision, a PV solar system can be built to any size from a utility-scale plant with output comparable to a coal plant to a single rooftop array on a house.

Though it was not economically viable just a few years ago, wind generation is currently the resource type with the lowest market price in certain regions of the US on a $/megawatt-hour (MWh) basis. The decrease in costs results from numerous factors such as economies of scale and increases in turbine efficiency. Large-scale wind energy generation is economically best suited for the central plains states and select off-shore areas. According to the U.S. Department of Energy's National Renewable Energy Lab (NREL), on-shore average wind levels in Florida are below 6 meters/second, which is generally considered insufficient to achieve economic feasibility. Therefore, wind energy was not included as a potential resource option for detailed analysis in this IRP.

Due to its environmental benefits, electric generation using renewable energy resources is generally considered good public policy. As a result, state and federal lawmakers and regulatory authorities have placed considerable emphasis on increasing the amount of electricity produced by renewable energy resources through RPS, tax breaks, and other incentives.

However, since solar generally cannot be dispatched as needed, these resources cannot necessarily be depended on to serve load at any particular time. For example, the production profile of solar energy tracks closely to the daily and seasonal orientation of the sun; in other words, solar panels only generate energy when the sun is shining on the panels. To maintain a reliable power supply, there has to be enough dispatchable generation on standby to replace the solar generation when the sun sets or when clouds approach. Much of the backup generation is fueled by NG, and has fast-start and fast ramping capabilities to quickly make up the difference in available energy. Therein lies the paradox of renewable energy: each kilowatt of renewable generation must be backed up with a dispatchable resource, which is almost universally fueled with NG. In the coming years, managing this imbalance may become easier as energy storage becomes more viable.

Examples of such variability of solar output can be found in the hourly data GRU provided for a group of seven of its FIT customers. Figure 14 through Figure 17 compare the aggregated solar samples (in teal) with GRU's total system load (in red).

Figure 14 shows GRU's winter daily peak load ranging from a high of around 350 MW on January 7th and 8th to lows of around 200 MW. Maximum solar PV output was about 55% of design capacity on January 7th, dropping to 25% on January 8th.

Figure 15 shows spring daily peak loads ranging from 200-275 MW, with solar PV output ranging as high as 75% to a low of around 25%. Peak solar output tends to fall between the morning and evening winter system peak loads and to precede spring peak loads.

Figure 16 and Figure 17 show system load and hourly solar PV profiles for summer and fall, respectively. Solar output is generally more consistent from day-to-day, achieving around 60-

Figure 14: GRU Winter Solar Profile

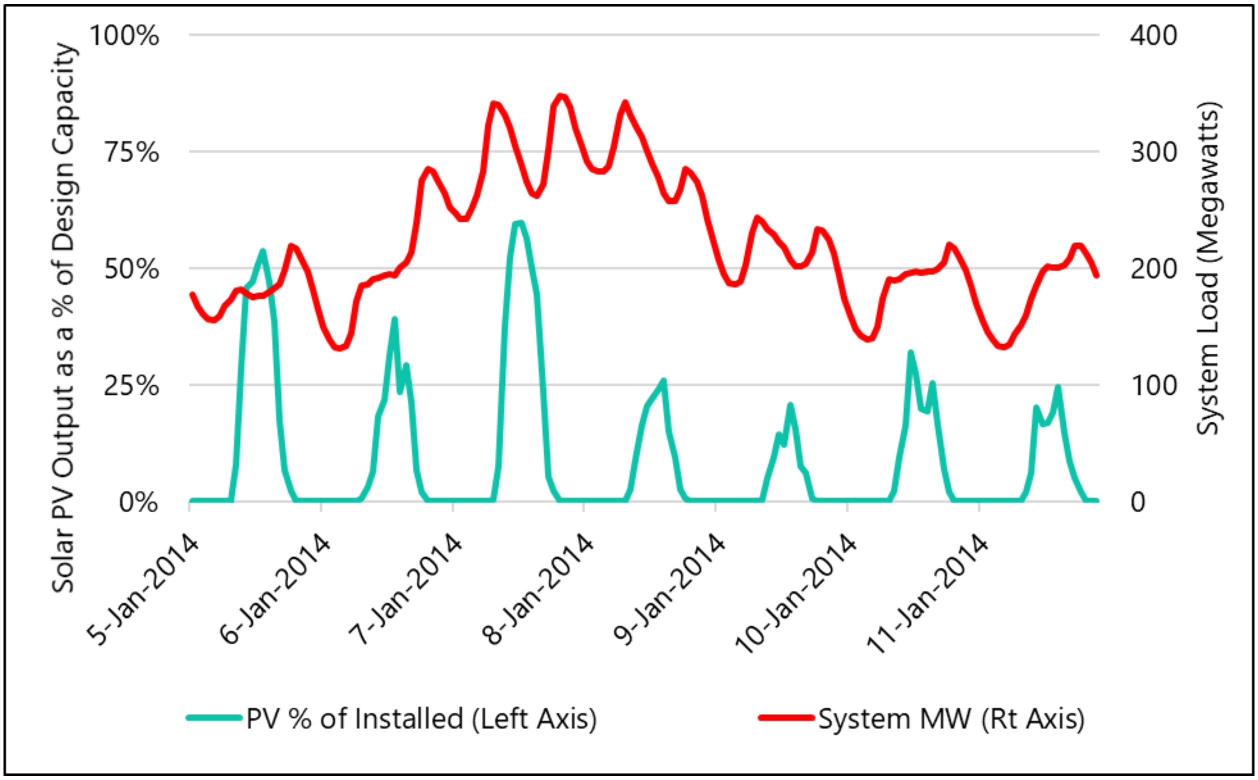


Figure 15: GRU Spring Solar Profile

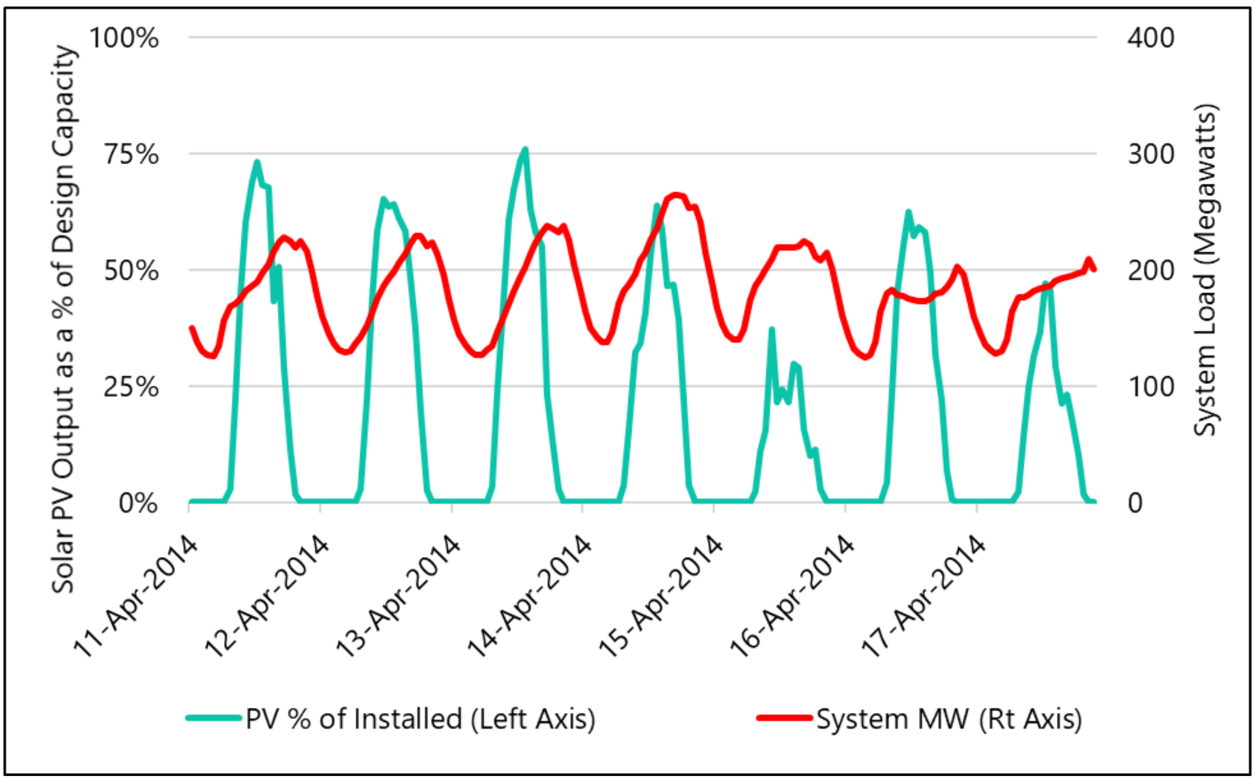


Figure 16: GRU Summer Solar Profile

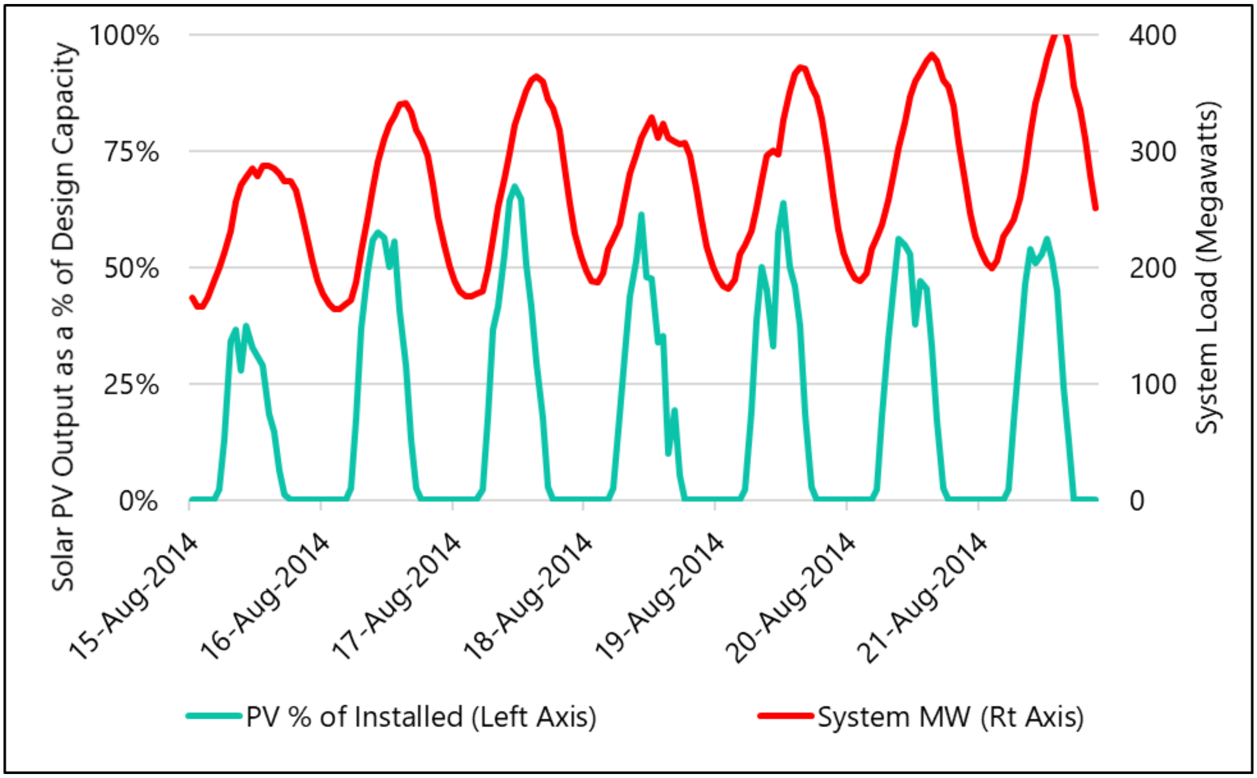
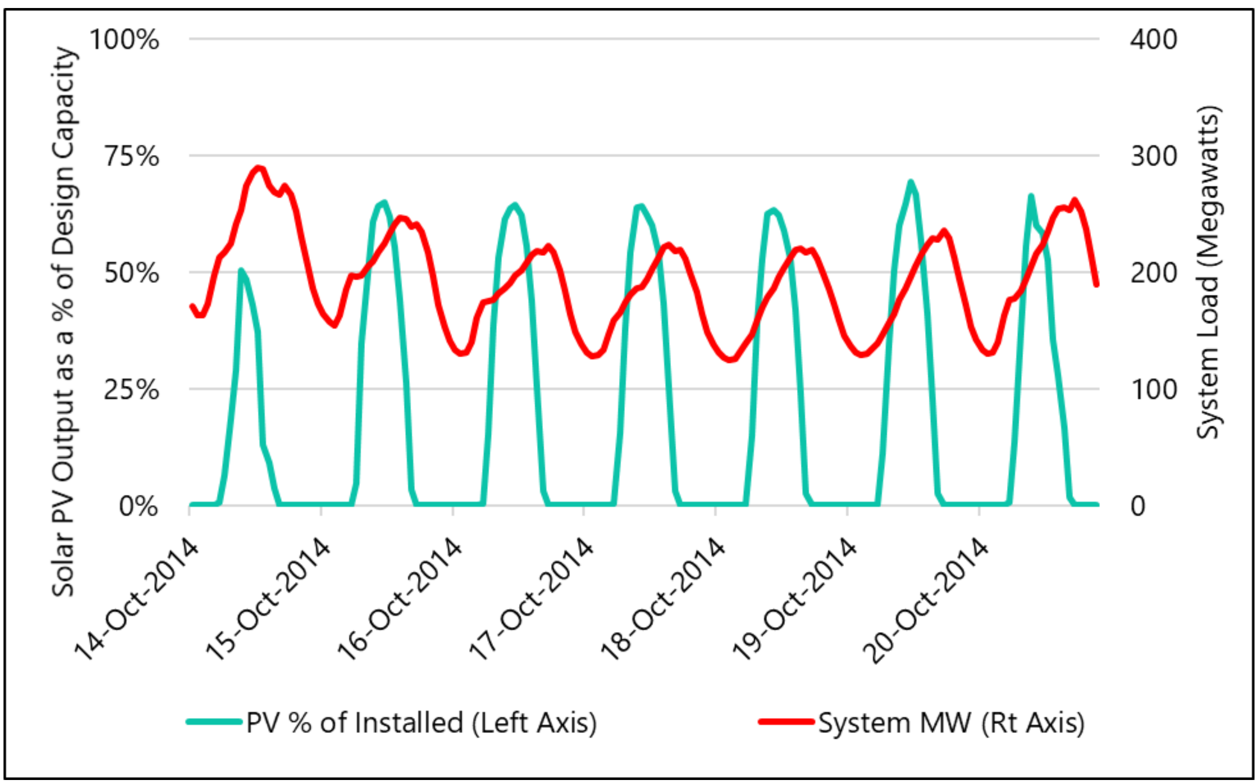


Figure 17: GRU Fall Solar Profile



70% of design capacity on most days, however peak solar PV output precedes system peak by several hours and goes away completely in the early evening.

Due to its intermittency, solar PV contributes 35% of its total capacity towards GRU's capacity requirements for the purposes of this IRP.

ENERGY STORAGE

Along with increasing market penetration of variable resources such as wind and solar, managing the power grid around the variability of these renewable resources has become more challenging. Distributed and grid-scale energy storage resources have gained significant interest by the industry. Energy storage devices are distinguishable from other forms of generation in that they do not directly convert primary energy (such as wind and solar) into electricity. Instead, they store electricity produced from such resources when supply exceeds demand and discharge during periods when demand increases and/or the primary energy is not available. Thus, they can level out the variable production from wind and solar generation.

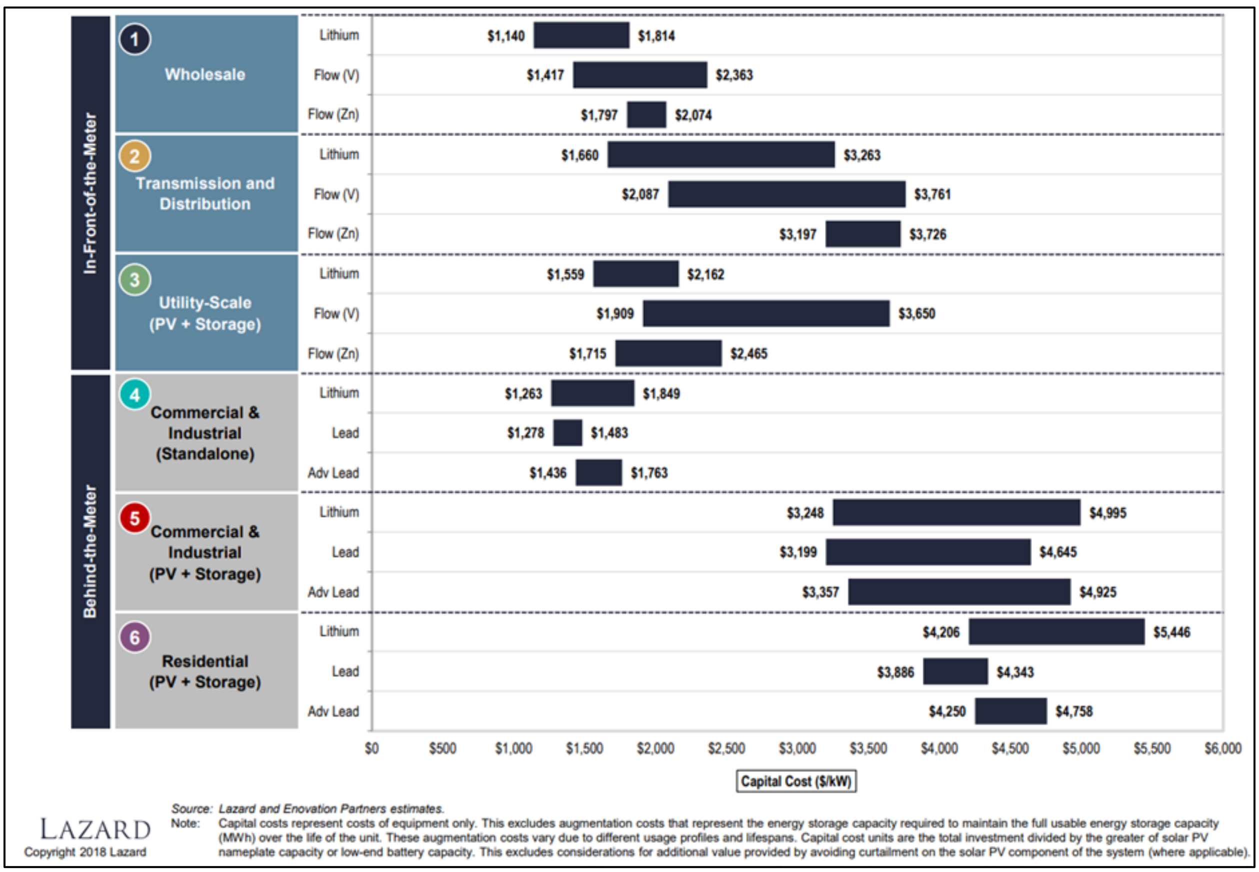
Advancing energy storage technology to the point where it can be used as a backup to renewable energy could eventually solve the current paradoxical imbalance between when renewable generation is available and when it is needed. The storage system would be charged using surplus renewable energy, or during periods of low demand, and released when it is needed. Current energy storage research is diversified among many different technologies which explore storing potential energy in flywheels, compressed air, and hydroelectric pumped storage. The technology poised to dominate new construction in the market, at least in the near term, is battery storage.

Battery storage systems are not a one-size-fits-all solution because the system design varies significantly depending on its desired function. Some possible functions are renewable integration, peaker replacement, frequency regulation, or transmission congestion reduction. Building a battery storage system to absorb excess renewable generation for later use requires more infrastructure than a battery system used for short-term frequency response. Imagine an island grid powered only by solar and batteries. The battery bank will require a capacity that can store enough energy when the sun is shining to meet its nighttime demands. If that island grid also had backup generators on standby as a part of its generation mix, they could increase production when cloud cover unexpectedly hides the sun. The battery storage system then would be relied on for a much shorter burst of energy to maintain grid stability until the generators take over. The costs for the first option should be greater, perhaps even significantly, than the second option. Battery technology, however, is evolving at a rapid pace.

According to a March 2019 Bloomberg New Energy Finance Report, the cost of lithium-ion batteries fell 35% in the first half of 2018.[15] Since 2012, that same cost had dropped 76%. This trend of cost declines is similar to the one recently experienced by wind and solar. Whether and how long this trend will keep its pace is unknown. However, it is relatively certain that technology will continue to advance and costs will keep declining.

Even with these cost declines, battery storage today remains relatively costly. Figure 18 presents capital costs of various types and sizes of battery storage systems as recently estimated by Lazard[16]. Utility-scale lithium batteries cost between $1,550/kW and $2,162/kW. Furthermore, energy storage systems are more costly than the batteries alone due to additional costs including bidirectional inverters that allow the two-way flow of batteries, software, and other integration costs to ensure seamless operation. For perspective, a 20 MW, 80 MWh battery storage system would cost between $31 - $43 million. Such batteries currently have life expectancies in the 15-year range based on daily cycling. Other considerations include ongoing O&M costs and component replacement needed to maintain design capability. There are some

Figure 18: Unsubsidized Capital Cost of Storage



[15] Mai, HJ. 2019. Electricity costs from battery storage down 76% since 2012: BNEF. March 26. Accessed September 10, 2019. https://www.utilitydive.com/news/electricity-costs-from-battery-storage-down-76-since-2012-bnef/551337/.
[16] Lazard, *Lazard's Levelized Cost of Storage Analysis – Version 4.0* (Lazard, 2018), https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

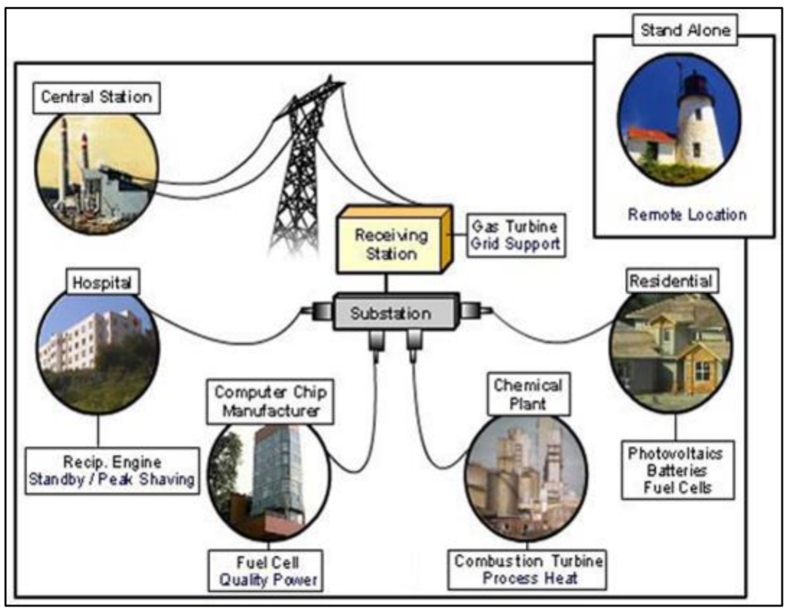
energy losses when charging and discharging, with an overall round-trip efficiency of around 85-90%.

However, there are specific use-cases and ancillary service benefits which could make battery storage the best or most viable option. Also, the immaturity of the technology means it will only improve, and costs should decline. Despite these potential future benefits, there are few data points available to extrapolate out a forecast of when energy storage will become viable beyond niche applications. If the reports are correct, costs will probably need to decline by nearly an order of magnitude to compete in the wholesale energy markets.

DISTRIBUTED ENERGY RESOURCES

Instead of traditional, one-way delivery of electricity from large, central station power plants located far from demand, via high voltage transmission lines, to lower voltage distribution lines, and, finally, to the home or business, technologies are now available that allow customers to generate their own electricity, respond to price changes, reduce (or increase) demand when useful to the system, or store electricity for use at a later time. Many of these technologies are currently affordable to many customers, and that cost effectiveness should spread to more customers and more technologies in the near future as research progresses. Understanding how Distributed Energy Resources (DER) impact the grid itself, including reliability, is an important factor. Understanding where, when, and how DER can benefit the grid is of equal value.

Figure 19: DER Example Diagram



DER is typically defined as small grid-connected power sources that can be aggregated to meet electric demand. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DER are being adopted increasingly often due to favorable policies from both state and federal governments, improvements in technology, reduction in costs, and identifiable customer benefits, both at the individual level and for the grid.

Once DER adoption passes certain levels, DER can begin to cause significant challenges for traditional rate making, utility models, and the delivery of electricity which can result in a cost shift among classes of customers. In defining DER, it is important for electric utilities to identify potential economic and grid issues and benefits from DER. Then, after empirically establishing at what adoption level DER may affect the grid, utilities should explore and implement rates and compensation methodologies designed to lead to greater benefits for the public, customers, developers, and utilities alike. Importantly, having a plan in advance of that determination should facilitate the ability of a jurisdiction to be proactive in planning for and responding to increased levels of DER in concert with the increase.

DEMAND-SIDE RESOURCES

Demand-Side Resources (DR) are a category of DER which are installed or implemented on the site of customers, usually electrically connected "behind-the-meter" (BTM). Examples include roof-top solar PV systems, back-up or emergency generators such as those installed at hospitals and cogeneration units installed at larger industrial facilities. Such generation resources are distinguished from supply-side resources because they are located behind the retail meter and are normally owned or leased by the customer rather than the utility. DR are sometimes referred to collectively with energy efficiency programs as Demand-Side Management (DSM).

There is a growing trend in the industry for retail customers to implement various DR systems. This trend is expected to continue and expand, resulting in decreases in energy consumption and peak demand. GRU's demand forecast implicitly incorporates existing DER operated by GRU's retail customers by extrapolating from historical measured aggregate energy and demand. Specifically, GRU's demand forecast has been adjusted downward to account for its FIT customers.

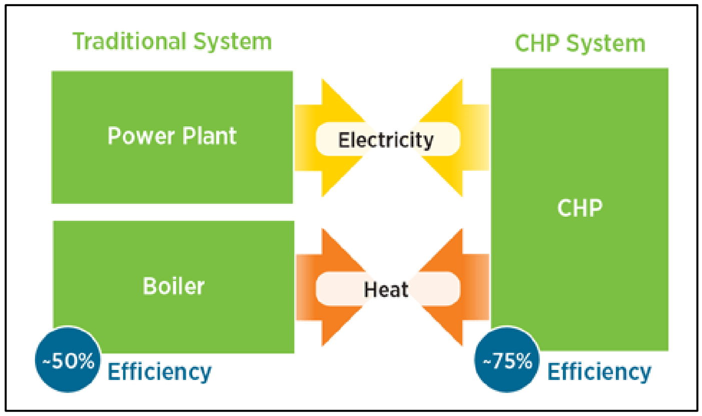
The most common DR is rooftop solar, which customers can monetize in two primary ways. The first approach is to offset consumption. Energy generated onsite at the time of consumption can directly offset electricity usage. Consumption is metered as zero when production equals consumption at any given time. The offsetting electricity in this case has a value equivalent to the retail rate. The second method is by utilizing net metering policies. Net metering nets the total amount of energy generated against the amount of energy consumed over a predetermined period of time, which is usually one month to one year. Only the "net" energy consumption is billed. Nearly every state, including Florida, mandates that at least certain utilities allow net metering.

However, it should be emphasized that even though BTM-DR reduces the net energy sold to the customer, such customers usually remain connected to the utility grid to back up the customer's DR system and to meet customer peak loads, which usually exceed the capacity of the DR system.

COMBINED HEAT AND POWER

CHP such as that found in GRU's South Energy Center, is:

Figure 20: CHP Diagram



- The concurrent production of electricity or mechanical power and useful thermal energy (heating and/or cooling) from a single source of energy.
- A type of distributed generation, which, unlike central station generation, is located at or near the point of consumption.
- A suite of technologies that can use a variety of fuels to generate electricity or power at the point of use, allowing the heat that would normally be lost in the power generation process to be recovered to provide needed heating and/or cooling.

CHP technology can be deployed quickly, cost-effectively, and with few geographic limitations. CHP can use a variety of fuels, both fossil- and renewable-based. It has been employed for many years, mostly in industrial, large commercial, and institutional applications. CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat to some of the most vital industries, largest employers, urban centers, and campuses in the United States. It is reasonable to expect CHP applications to operate at 65-75% efficiency, a large improvement over the national average of approximately 50% for these services when separately provided.

ENERGY EFFICIENCY

Another branch of demand-side management is EE. Since the Great Recession, both population and GDP per capita have increased nationwide, with no discernable impact on loads. Instead, electricity consumption has remained relatively flat. This trend can be explained by the implementation of conservation and efficiency measures, such as converting halogen bulbs to LED and electric resistance coil furnaces to heat pumps.

The impact of energy efficiency cannot be overstated. The estimated energy savings from LED lighting alone in the US in 2016 was 469 trillion British thermal units (BTUs), or roughly 67 terawatt-hours (TWh) of the total national consumptions of 3,500 TWh.[17] By 2035, LEDs are forecasted to reduce consumption by 5.1 quadrillion BTUs by 2035 in the US, translating to a savings of over 700 TWh per year.[18]

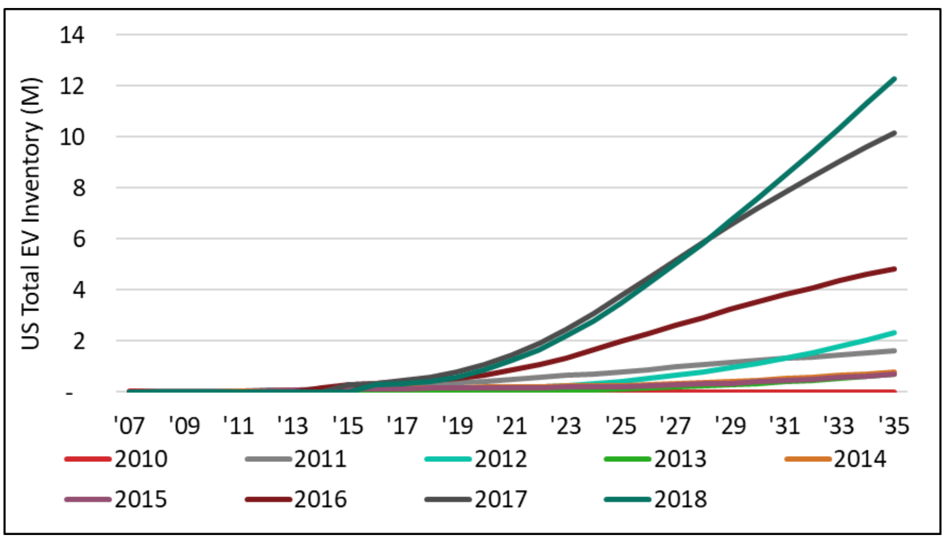
[17] Navigant Consulting Inc, *Adoption of Light-Emitting Diodes in Common Lighting Applications* (US Department of Energy Office of Energy Efficiency & Renewable Energy, 2017).
[18] *Solid-State Lighting 2017 Suggested Research Topics Supplement* (U.S. Department of Energy Office of Energy Efficiency & Renewable Energy, 2017).

Lighting is only a piece of the puzzle. Efficiency is increasing across all household appliances. Electric furnaces that utilize resistance heating, still commonly found in homes across the country, have a coefficient of performance (COP) of 1. For each unit of energy input, a single unit of heat is output. Heat pump systems, on the other hand, have COPs ranging between 2 and 4, meaning that they are between 2 and 4 times more efficient than electric furnaces. Rather than produce hot or cool air, heat pumps separate hot and cold air, injecting heat into the conditioned area and ejecting the cold exhaust into the atmosphere. Heat pump technology continues to improve as well, with newer heat pumps able to separate the air more efficiently and at lower temperatures. This technology is also applicable for water heaters, where the fluid being temperature conditioned is water, rather than air.

Heating/cooling (47%), water heating (14%), and lighting (12%) cumulatively make up roughly 73% of home energy consumption, excluding transportation. Technology that can reduce lighting loads by greater than 80% and conditioning loads by 50-75% is commercially available and viable today. Significant energy efficiency increases of the appliances that make up the bulk of home energy consumptions are impacting overall consumption patterns. Efficiency gains should continue to grow as more of the less efficient appliances are replaced with newer technology.

ELECTRIC VEHICLES

Figure 21: EV Inventory Forecast through Time (2010-2035)



Two major consumer concerns preventing the wide adoption of EVs were the risk of running out of charge mid-transit due to short ranges and the limited number of options available. Both of these limitations are decreasing as the technology develops. Therefore, the electric vehicle adoption forecast has become similar to renewable energy forecasts as later forecasts continue to project higher rates of adoption. In 2010, the EIA forecasted the cumulative 2030 EV inventory at 3,500 vehicles.[19] The

[19] "Annual Energy Outlook 2010 Fleet Vehicle Stock," U.S. Energy Information Administration, accessed May, 30 2018.

Figure 22: EV and ICE Fuel Cost

Input	Input Value
State	Florida
Avg Electricity Price by State ($/kWh)	$0.10
Avg Gas Future Price ($/gal)	$2.00
ICE Efficiency (mi/gal)	30.0
EV Efficiency (mi/kWh)	3.0
Output	**Output Value**
ICE Fuel Cost ($/mi)	$0.07
EV Fuel Cost ($/mi)	$0.03
For compact cars, fuel for an ICE is 1.97 times the cost of fuel for an EV.	

2018 forecast revised that figure upwards to over 7.5 million vehicles (Figure 21).[20] If this trend continues, the point at which EVs outnumber internal combustion engines (ICE) will come sooner than expected.

Another major driver affecting adoption is price parity between ICEs and EVs. According to the assumptions and calculations shown in Figure 22, the fuel cost for an EV is already a fraction of the fuel cost for an internal combustion engine of comparative size.[21] Additionally, Ernst & Young forecast that EVs will reach complete cost and performance parity with ICEs in 2025.[22]

If it occurs, the widespread adoption of electric vehicles has the potential to meaningfully increase electricity consumption. The National Renewable Energy Laboratory (NREL) predicts that the electrification of the transportation sector will result in total terawatt hour consumptions increasing by a compound annual growth rate of 1-2%.[23] If equipped with bidirectional chargers that can both draw energy from and inject energy to the grid, EVs could also affect grid stability as more non-dispatchable renewable resources come online. A well-executed EV integration would treat EVs as exactly what they are: a rolling battery that can be used to draw electricity from the grid when it is available and supply it when demand is higher. Improperly managed, EVs could have the opposite effect. With the correct incentives, EVs can simultaneously increase demand when loads and wholesale prices are lower, decrease them when higher, and increase overall retail sales.

[20] "Annual Energy Outlook 2018 Fleet Vehicle Stock," U.S. Energy Information Administration, accessed May, 30 2018.

[21] Assumptions based on $2.00 wholesale gasoline which exclude state and federal gas taxes, a state-specific electricity price as published by the EIA, and an average EV consumption of 3 miles per kWh, consistent with observed evidence for compact vehicles.

[22] Benoir Laclau, *When Energy Customers Go Off-Grid, Will Utilities Be Left in the Dark?*, (EY, 2018), https://www.ey.com/en_gl/digital/energycountdownclock.

[23] Trieu Mai et al, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States,* (Golden, CO: National Renewable Energy Laboratory, 2018), https://www.nrel.gov/docs/fy18osti/71500.pdf.

COST AND OPERATIONAL CHARACTERISTICS OF SUPPLY-SIDE RESOURCES

Table 5: New Resource Options

	Resource Type	Size (MW)	Fuel	Capital Cost ($/kW)	Fixed O&M ($/kW-Year)	Price or Variable O&M ($MWh)	Full Load Heat Rate (BTU/kWh)	Book Life (Years)
CC	Siemens SGT-800 1x1	66	NG	$1,317	$11.33	$3.61	7,154	30
	Siemens SGT-800 2x1	132	NG	$1,102	$11.33	$3.61	7,059	30
	Siemens SGT-800 3x1	198	NG	$1,037	$11.33	$3.61	7,050	30
CT	GE 7F (Mid-Size Frame)	198	NG	$570	$18.02	$3.61	9,812	30
	GE 7E (Small Frame)	75	NG	$824	$18.02	$3.61	11,337	30
	LMS 100 DLE	98	NG	$999	$7.01	$11.03	8,631	30
	LM6000 DLE	44	NG	$1,091	$7.01	$11.03	9,192	30
	Siemens SGT-800	47	NG	$917	$18.02	$3.61	10,200	30
RICE	Mid-Size	9.2	NG	$1,150	$20.00	$7.00	8,457	30
	Large Size	18.4	NG	$1,150	$20.00	$7.00	8,307	30
Storage	Storage (4-hr Duration)	5		$1,500	$36.31	$7.26		15
	Solar + Energy Storage (4-hr Duration)	20		$1,500	$36.31	$7.26		15
PPA	Solar PV	20	PV			$32		20

There are a variety of types and sizes of new generation which could be used to meet GRU's future requirements for new generating capacity and energy production. Generally, larger central station generation using advanced technologies will be less expensive per kilowatt and more efficient than smaller resources, though an individual utility's need for new resources is often a small fraction of the capacity of these large stations. The choices of new resources considered for this IRP have been limited to those which are size-compatible with GRU's requirements over the next 20 years. Additionally, technologies such as nuclear and coal are not likely to be reasonable choices due to capital requirements, environmental limitations, and public policy constraints. Therefore, those resources were excluded from consideration in the detailed economic analysis.

Table 5 includes all supply-side resource options included in this IRP. All costs are expressed in 2018 dollars. Specifications are based on a combination of indicative vendor information and industry research from organizations such as Gas Turbine World[24, 25] and EIA[26].

[24] *2018 GTW Handbook*, January 2018, 33.
[25] *2016-17 GTW Handbook*, December 2016, 32.
[26] "Annual Energy Outlook 2018", U.S. Energy Information Administration, https://www.eia.gov/outlooks/aeo/data/browser/#.

OPERATION AND MAINTENANCE COSTS

Fixed and Variable Operation and Maintenance costs (FOM and VOM, respectively) are shown in 2018 dollars. An annual escalation rate of 2.1% per year is applied for O&M costs for both existing and new thermal resources.

CAPITAL COST

Capital costs are expressed in $/kW of installed capacity. Except for solar PV and energy storage, these costs are escalated by a 2.1% per year inflation rate up to the year of installation. Because solar PV and energy storage costs are expected to continue to decline as technology improves and mass production evolves, their nominal costs decline at the inflation rate within the model.

TIME VALUE OF MONEY

The following values have been used for this IRP:

- General Inflation Rate: 2.1%/year
- Present Value Discount Rate: 3.0%/year
- Tax Exempt Bond Interest Rate: 3.9%/year

LEVELIZED ANNUAL CAPITAL COSTS

To best represent the cash accounting methods typically used by municipal utilities for determining revenue requirements, this study uses the levelized cost approach for amortization of capital costs. Unlike other accounting methods typical of an investor-owned utility, this approach does not apply the cost of capital to a depreciating book value. The result is a levelized annual cost which does not change until debt issued to finance a major addition amount is repaid.

TEA has assumed that GRU will issue Tax-Exempt Revenue Bonds to finance new builds and betterments at 3.9% annual interest. A 30-year economic life has been used for the financing period of resource additions.

Annual levelized financing requirements do not include an allowance for Debt Service Coverage Ratio (DSCR). While it may be necessary to maintain a DSCR of 150% or greater to maintain adequate bond ratings, these excess revenues can be used to make other capital improvements to GRU's system or to retire debt early.

An example of the levelized annual capital costs for a 200 MW CC is shown below. This example assumes fixed charges based on an estimate of the annualized ownership cost to a taxable corporation investing in a generating station.

Financing Requirement: 200 MW x $2,000/kW = $400,000,000

Capital Financing Charge = 6.1% per year (3.9% interest, 30 years, after IDC and financing cost).

Annual Levelized Debt Service = $400,000,000 x 6.1% / Year = $24,400,000 per year

QUALIFICATION

The assumed values for cost and performance shown in Table 5 are best estimates and are considered to be indicative cost, and not necessarily values which can actually be purchased within the wholesale market. A number of factors will impact actual cost once a particular project is identified and procurement proceeds. The assumed values are for the purpose of identifying the most economical options for power supply which are reasonably available to GRU. More certainty in actual costs of such resources will become apparent as GRU solicits proposals or offers during a Request for Proposal (RFP) process.

Section 6: Reference Case Assumptions and Assessment

DESCRIPTION OF THE REFERENCE CASE

The reference case is used as a baseline on which to build all other scenarios and sensitivities involved in the study. For the reference case assumptions, GRU provided:

- Operating information and fixed, variable, and capital costs for existing fleet
  - Kelly CC capital costs include a total of $26.2 million throughout 2020-2022 for refurbishment costs of replacing the ST generator
- Retirement/expiration schedule:
  - DH1: 2022
  - DH GT1: 2026
  - DH GT2: 2026
  - DH2: 2031
  - G2 Energy: 2023
- System import and export limits of 120 MW each
- Expected load forecasts through 2039, including wholesale electric service to the City of Alachua as described in City of Alachua Full-Requirements Contract
- Expected solid fuel (coal and biomass) price forecasts as discussed in Section 4
- New solar installation limit of 80 MW per GRU direction

Additional assumptions include:

- Natural gas forecast as discussed in Section 4
- Market price streams resulting from ABB's PROMOD F17 model
- Inflation rate of 2.1% and a discount rate of 3.0%
- FRCC reserve capacity requirement of 15%
- Resource option costs and operating information discussed in Section 5
- No carbon pricing
- No forced generation additions and no additional retirements allowed

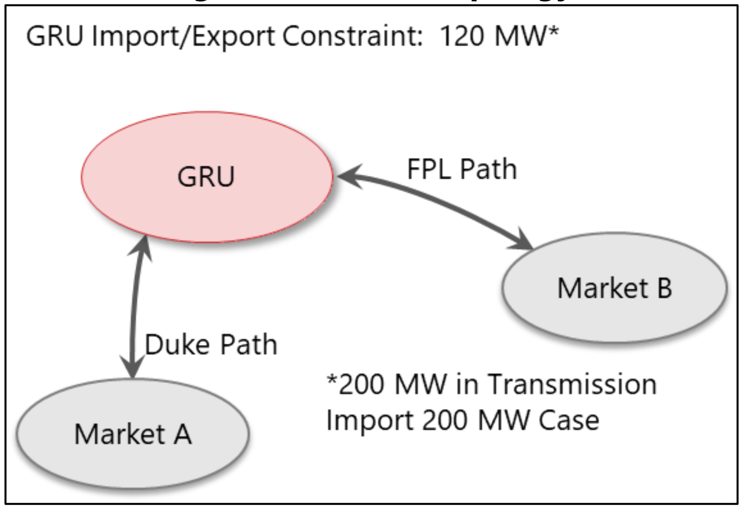
MODEL TOPOLOGY

TEA used ABB's PROMOD of the Southeast Region F17 to create a zonal simulation of the Southeast markets. The Southeast F17 PROMOD model considers demand and energy forecasts, fuel price forecasts, and new and retiring generation.

TEA also reviewed the 2018 TYSPs submitted to the FRCC to ensure that the generation units included in the Southeast F17 PROMOD model were consistent with what the Florida utilities projected. Based on this review, TEA added over 3 gigawatts (GW) of solar PV and approximately 3.5 GW of CC capacity to the model for installation by 2028.

Then, the price streams generated in the PROMOD model and the assumptions above were combined in ABB's CE to simulate GRU's operations. The model examined the economics of future build and retirement options against constraints such as capacity requirements and import and export limits. The basic model topology is explained in Figure 23.

Figure 23: Model Topology



REFERENCE CASE RESULTS

Based on the assumptions above, CE calculated the least-cost portfolio shown in Figure 24. This figure presents GRU's capacity requirement as a red dashed line, existing generation capacity as solid-colored bars, and optimized generation additions as cross-hatched bars.

As soon as available, in 2021, the plan adds a PPA for 80 MW of solar, the maximum amount the model allows due to reliability concerns. The solar is added, not because of capacity requirements, but because it provides more economical energy than existing generation. After DH2 retires in 2031, a 198 MW NG-fired 3x1 CC unit is installed in 2032 and another 9 MW RICE unit in 2034. Near the end of the term of the study, in 2038, 5 MW of storage is installed.

Figure 24: Reference Case Demand and Resource Balance

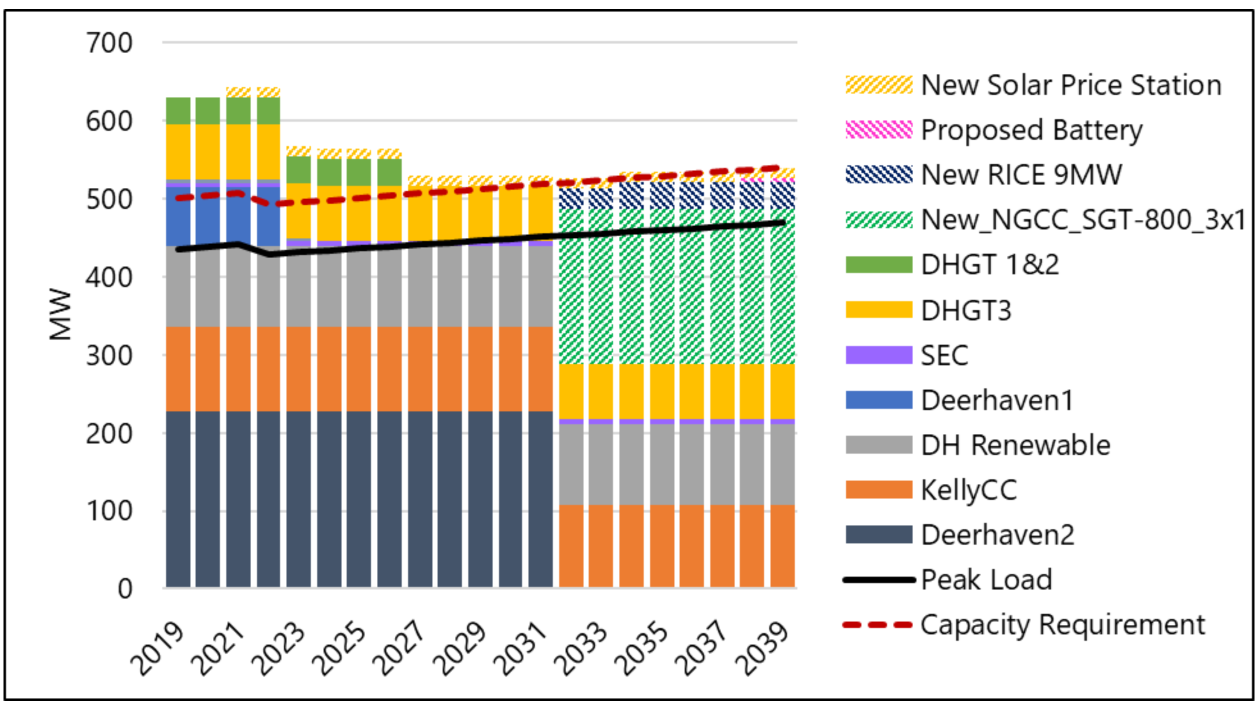


Figure 25 shows the amount of annual energy generation, expressed in average megawatts (aMW) for each generation resource. The aMW quantity is calculated by dividing the annual energy production of the resource by the number of hours per year. The 3x1 CC is more thermally efficient than the Kelly CC. Therefore, the new CC displaces much of the Kelly CC's energy production after it becomes operational in 2032. It also displaces most of the import energy. DHR becomes more economical than the Kelly CC in 2031 and stays that way through the remainder of the study due to the relative growth in the price of biomass and natural gas.

Figure 25: Reference Case Energy Production by Resource

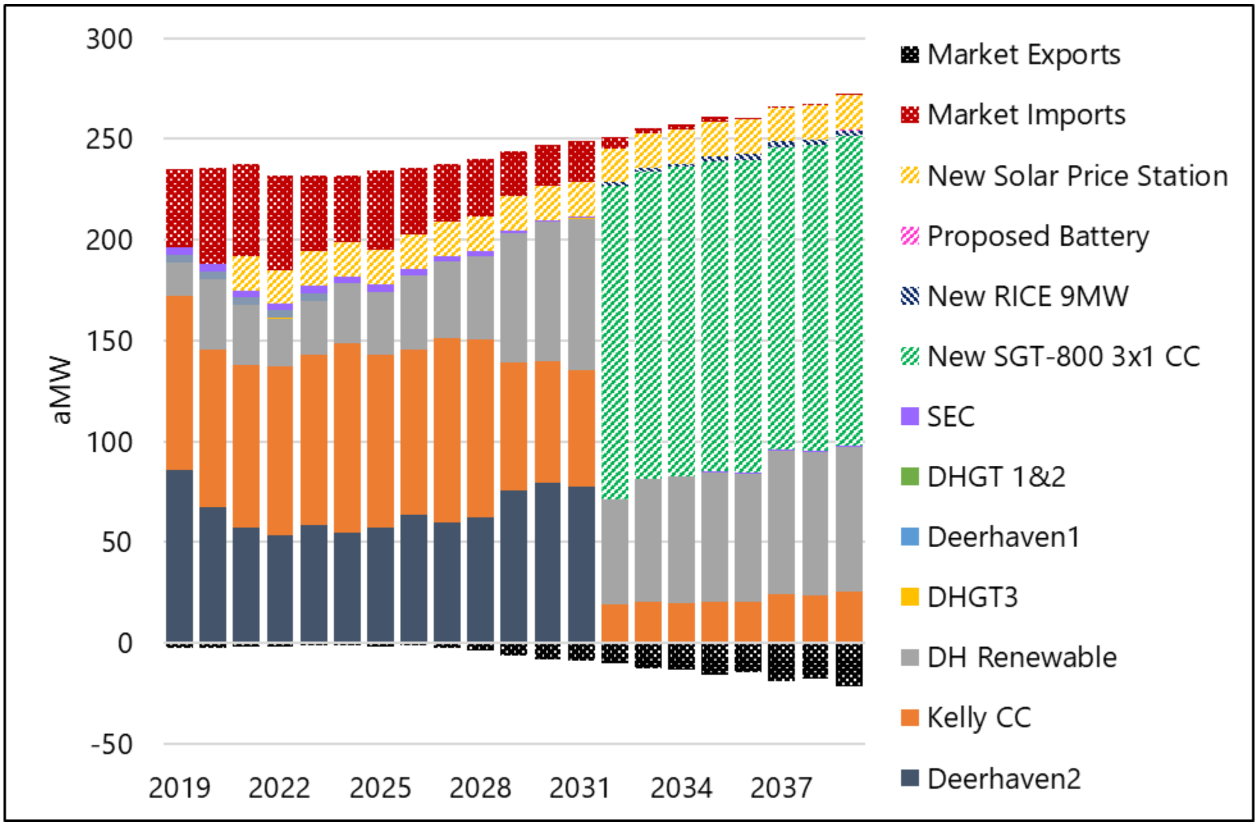


Figure 26 shows the year-by-year revenue requirements for the reference case. Note that this is only a portion of GRU's total revenue requirements. These reported costs do not include costs that are consistent between scenarios, such as transmission, distribution, customer or administrative costs, principal and interest payments on existing debt, payments to customers on the FIT, capital improvements, or transfers to the City's General Fund. However, they do include the fixed maintenance, outage, and capital costs for existing generation which would be eliminated if the unit were retired. For comparison, GRU's total FY 2019 O&M expense budget for the electric system is around $175 million, whereas only around $105 million per year of power supply expenses are included in the model.

Note that the fuel and purchased power cost (red) remains largely flat for the first three years and then grows for the remainder of the study, replacing spot market purchases of energy with self-generation. When the new CC is installed in 2032, its generation replaces virtually all of the spot market purchases. In 2020 and 2021, the fixed cost of existing generation peaks due to the $26.2 million investment in refurbishing the Kelly CC. In 2032, the fixed cost of existing generation decreases due to the retirement of DH2. However, this reduction is partially offset by the fixed cost of the new CC and RICE units.

In order to easily compare the results of the scenarios and sensitivity analyses, annual nominal cash flows shown in Figure 26 are converted into a single NPVRR. Using an NPVRR formula, in effect, normalizes the analysis with respect to the time value of money.

Figure 26: Reference Case Nominal Annual Revenue Requirements

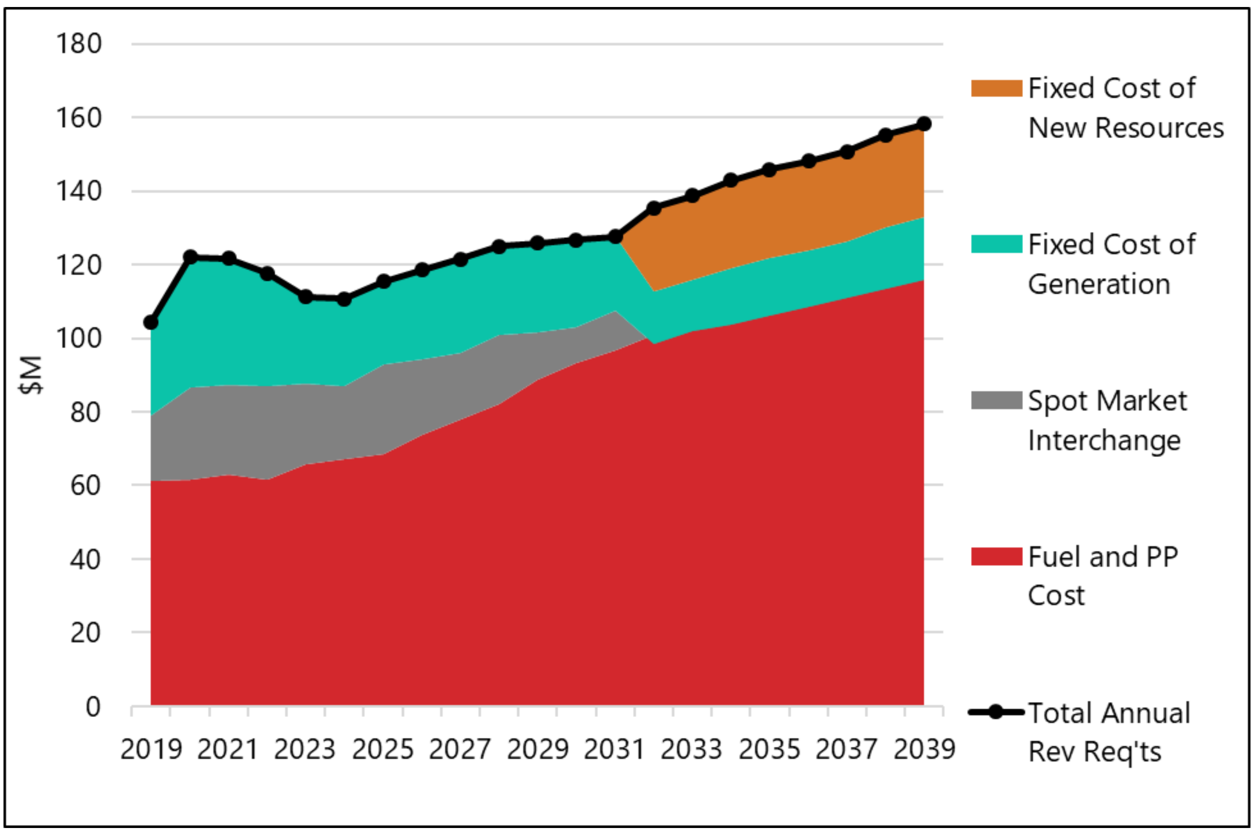
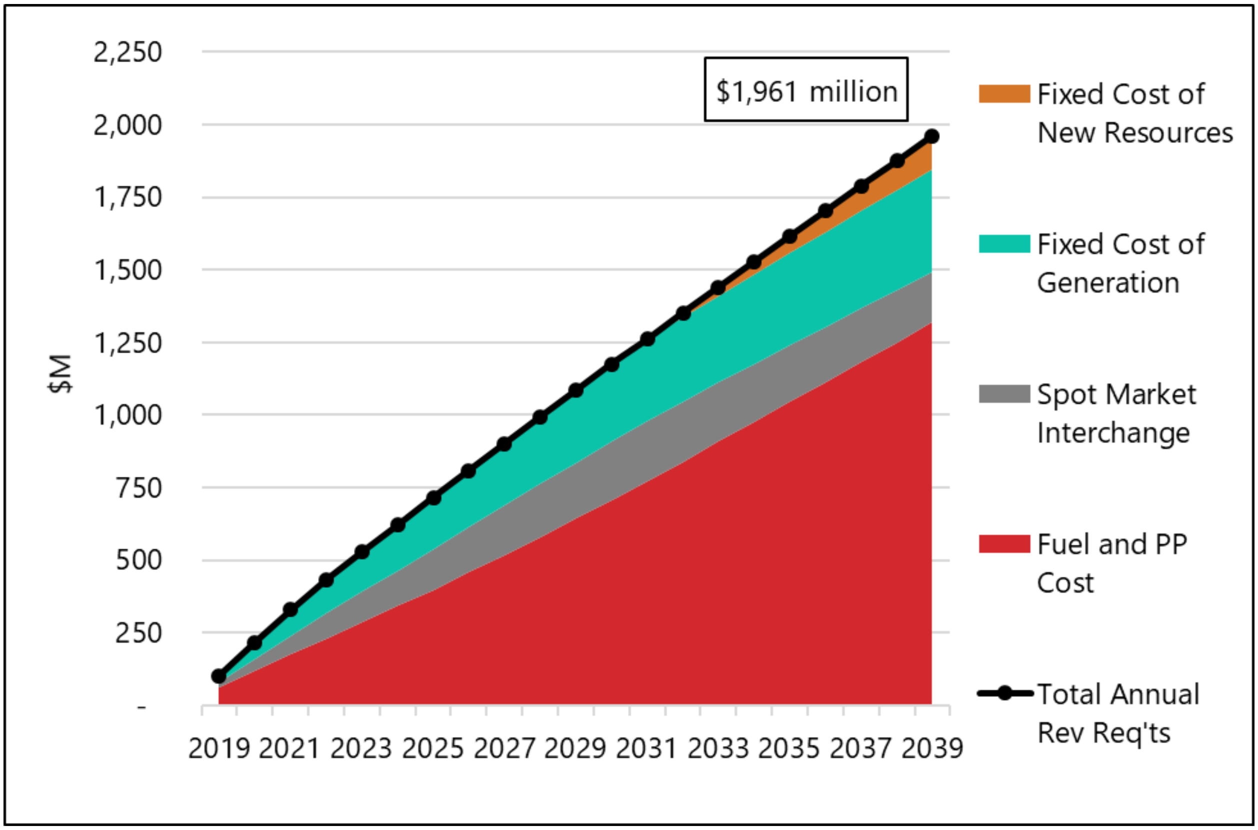


Figure 27 shows how the cumulative NPVRR for the rest of the reference case builds through time by expense type. The cumulative NPVRR in 2039 is $1.961 billion. This equates to a levelized cost of $44.69/MWh for the term. These values are compared to other scenarios and sensitivities later in this report.

Figure 27: Reference Case Cumulative Net Present Value



Section 7: Comparison of Scenario and Sensitivity Results

DESCRIPTION OF THE SCENARIOS

As mentioned previously, the reference case is used as the standard optimized generation expansion/replacement plan to which other scenarios and sensitivities are compared. The additional simulations, detailed in Table 6 and Table 7, are grouped into the following categories:

1. Sensitivity and Expanded Analyses
    a. Gas Price Sensitivities
2. System Scenarios: These scenarios are based on GRU-elected changes to its reference case electric system.
    a. Ease Transmission Constraint: Evaluates the advantages of increasing the 120 MW transmission import limit to 200 MW
    b. K8 Retirement: Considers what would be the optimal system generation plan if the Kelly 8 ST (K8) were retired instead of making the planned capital improvements.
    c. Allow Retirements: Allows the model to optimize the existing retirement schedule as well as generation expansion and replacements.
    d. Allow Retirements Except DHR: Allows the model to optimize the existing retirement schedule with the exception of DHR's retirement
3. Load Scenarios: These scenarios evaluate impacts of changes in load to the optimal plan.
    a. Low Load: Indicates changes to optimum generation plan in a low-load scenario
    b. High Load: Indicates changes to optimum generation plan in a high-load scenario
    c. Winter Peaking: Indicates changes to optimum generation plan in a scenario where GRU's system becomes winter peaking
4. ACE Scenarios: These scenarios adhere to the rapid response capacity restraint resulting from the Area Control Error (ACE) study discussed in in the relevant subsection below.
    a. Solar Limited to 80 MW: Limits total installed solar capacity to 80 MW
    b. Unlimited Solar – Force 40 MW of Solar 2021: Examines effect of forcing 40 MW solar installation in 2021 and removing 80 MW solar installation cap.
    c. Unlimited Solar – Allow Retirements Except DHR: Removes 80 MW reference case constraint for solar and includes constraints related to ACE study from the similar Allow Retirements Except DHR Scenario discussed above
    d. Unlimited Solar: Removes 80 MW solar installation limit from the reference case and includes additional constraints related to ACE study
5. Renewable Scenarios: These scenarios evaluate resource plans with prescribed additions to help GRU achieve the city's renewable energy and GHG goals established October 2018. Since such additions would not be selected under the cost minimization optimization logic of CE, these scenarios force installation of a biomass unit, add RICE

units as thermal backup, and limit choices for potential installations to solar, battery storage, and biomass resources. These imposed constraints address the negative ACE impacts caused by the intermittency of solar energy through combinations of battery storage, rapid response thermal generation, and power from a renewable-based market.

a. No Market and No RICE Contribution: Prevents overreliance on the power market or the RICE units
b. Renewable Market and No RICE Contribution: Allows purchases from the renewable-based power market but excludes the use of RICE units
c. No Market with RICE Contribution: Allows the use of RICE units but prevents any wholesale power market contributions.

Table 6: Scenario and Sensitivity Development

Sensitivities →

Scenarios ↓

Scenarios		Reference Gas Price (based on PIRA and Wood Mackenzie)	High Gas (EIA High Economy)	Low Gas (NYMEX)	Portfolio Optimizer Study with Reference Gas Price
Reference		Resource Plan A	Resource Plan A	Resource Plan A	Resource Plan A
System Scenarios	Change transmission import limit from 120 MW to 200 MW	Resource Plan B	Resource Plan B	Resource Plan B	Resource Plan B
System Scenarios	Force Retirement of Kelly 8 in 2022	Resource Plan C	Resource Plan C	Resource Plan C	Resource Plan C
System Scenarios	Allow Early Retirements of Any Existing Unit	Resource Plan D	Resource Plan D	Resource Plan D	Resource Plan D
System Scenarios	Allow Early Retirements of Any Existing Unit Except DHR	Resource Plan E	Resource Plan E	Resource Plan E	Resource Plan E
Load Scenarios	Low Load – Removing all of Alachua load	Resource Plan F	Resource Plan F	Resource Plan F	
Load Scenarios	High Load – 30 MW of additional load, shape provided	Resource Plan G	Resource Plan G	Resource Plan G	
Load Scenarios	Winter Peaking Load	Resource Plan H	Resource Plan H	Resource Plan H	
ACE Scenarios	ACE REQS Limited 80 MW Solar	Resource Plan I	Resource Plan I	Resource Plan I	Resource Plan I
ACE Scenarios	ACE REQS Unlimited Solar - Force 40 MW Solar 2021	Resource Plan J	Resource Plan J	Resource Plan J	Resource Plan J
ACE Scenarios	ACE Unlimited Solar - Allow Retirements Except DHR	Resource Plan K	Resource Plan K	Resource Plan K	Resource Plan K
ACE Scenarios	ACE REQs - Unlimited Solar	Resource Plan L	Resource Plan L	Resource Plan L	Resource Plan L
Renewable Scenarios	Renewable - No Market & No RICE Contribution	Resource Plan M			Resource Plan M
Renewable Scenarios	Renewable - Renewable Market & No RICE	Resource Plan N			Resource Plan N
Renewable Scenarios	Renewable - No Market with RICE Contribution	Resource Plan O			Resource Plan O

Table 7: List of Scenarios

		Study Scenario	Retirement Schedule	Import Limit	Kelly 8 Capital Costs Included?	Load Forecast	Solar PV Limitations	Other Forced Changes
		Reference	Base	120 MW	Yes	Base	80 MW Total	
System Scenarios	1.	Ease Transmission Constraint	Base	200 MW	Yes	Base	80 MW Total	
System Scenarios	2.	Retire K8	Base + 2022 K8 retirement	120 MW	No	Base	80 MW Total	
System Scenarios	3.	Allow Early Retirements of Any Existing Unit	Optimized retirements of any unit	120 MW	Yes	Base	80 MW Total	
System Scenarios	4.	Allow Early Retirements of Any Existing Unit Except DHR	Optimized retirements of any unit but DHR	120 MW	Yes	Base	80 MW Total	
Load Scenarios	5.	Low Load	Base	120 MW	Yes	Remove all of City of Alachua Load	80 MW Total	
Load Scenarios	6.	High Load	Base	120 MW	Yes	30 MW of additional load	80 MW Total	
Load Scenarios	7.	Winter Peaking Load	Base	120 MW	Yes	Winter peaks equal summer peaks	80 MW Total	
ACE Scenarios	8.	ACE REQS Limited 80 MW Solar	Base	120 MW	Yes	Base	80 MW Total, 9 MW Thermal Quick-Start Generation per 20 MW of Solar Installed	
ACE Scenarios	9.	ACE REQS Unlimited Solar - Force 40 MW Solar 2021	Base	120 MW	Yes	Base	No MW Limit, Forced 40 MW Solar in 2021, 9 MW Thermal Quick-Start Generation per 20 MW of Solar Installed	
ACE Scenarios	10.	ACE Unlimited Solar - Allow Retirements Except DHR	Optimized retirements of any unit but DHR	120 MW	Yes	Base	No MW Limit, 9 MW Thermal Quick-Start Generation per 20 MW of Solar Installed	
ACE Scenarios	11.	ACE REQs - Unlimited Solar	Base	120 MW	Yes	Base	No MW Limit, 9 MW Thermal Quick-Start Generation per 20 MW of Solar Installed	
Renewable Scenarios	12.	Renewable - No Market & No RICE Contribution	Base	0 MW	Yes	Base	No MW Limit, 5 MW Battery Capacity per 20 MW of Solar Installed	120 MW of RICE Installed - No Capacity or Energy Counted, New 103 MW Biomass Unit Installed.
Renewable Scenarios	13.	Renewable - Renewable Market & No RICE Contribution	Base	50 MW Renewable Market	Yes	Base	No MW Limit, 5 MW Battery Capacity per 20 MW of Solar Installed	120 MW of RICE Installed - No Capacity or Energy Counted, New 103 MW Biomass Unit Installed.
Renewable Scenarios	14.	Renewable - No Market with RICE Contribution	Base	0 MW	Yes	Base	No MW Limit, 5 MW Battery Capacity per 20 MW of Solar Installed	120 MW of RICE Installed - Capacity and Energy Counted, New 103 MW Biomass Unit Installed.

SENSITIVITY ANALYSIS RESULTS

GAS PRICE SENSITIVITY ANALYSIS

TEA conducted sensitivity analysis in which the performance of the reference case and the alternative scenario plans were evaluated in high and low gas price environments. These alternative gas prices are shown in Section 4. The associated market price streams for each of the sensitivities were developed using ABB's PROMOD F17 model. The model was allowed to optimize in the various scenarios only under the reference natural gas prices. For the low and high gas price sensitivities, the generation plan resulting from the reference case gas price for each scenario was maintained. This method allowed an assessment of the robustness of the solution by comparing the resultant NPVRRs for varying gas price uncertainties.

The values for each sensitivity are compared to each other in Section 7.

PORTFOLIO OPTIMIZER EXPANDED ANALYSIS

GRU currently uses DH1 to help with the regulation of its system. Due to concern about how the system will be regulated after the unit's scheduled 2022 retirement, TEA conducted expanded analysis using PO, ABB's detailed production cost model, to evaluate the effect of chronological constraints. CE, the long-term generation expansion model used to optimize resource plans, cannot apply chronological unit commitment constraints to evaluate these regulation concerns. The additional constraint of having to hold spinning reserves for one half of the generation from all new solar PPAs is included in the PO analysis. This constraint helps address the regulation needs when the system includes intermittent resources.

For the PO simulations, TEA used the resource plans identified by CE in the scenarios based on reference case load and natural gas prices. These sensitivities evaluate the effects of unit chronological constraints. The effect of generated unit outages and the value of rapid response resources in a high renewable environment become more apparent in the PO results.

The values for each sensitivity are compared to each other in Section 7.

REFERENCE CASE – LOW GAS PRICE SENSITIVITY RESULTS

For the low natural gas price sensitivity, the system relies more heavily on the natural gas units and less on the solid fuel units. Market imports also increase since wholesale power prices, which are highly correlated to natural gas prices, are also lower in this sensitivity than in the reference case. Figure 28 shows the amount of annual energy generation, expressed in aMW for each generation resource.

For this sensitivity study, Figure 29 shows the cumulative NPVRR in 2039 is $1.796 billion. The LCOE for the term is $40.95/MWh.

Figure 28: Reference Case – Low Gas Price Energy Production

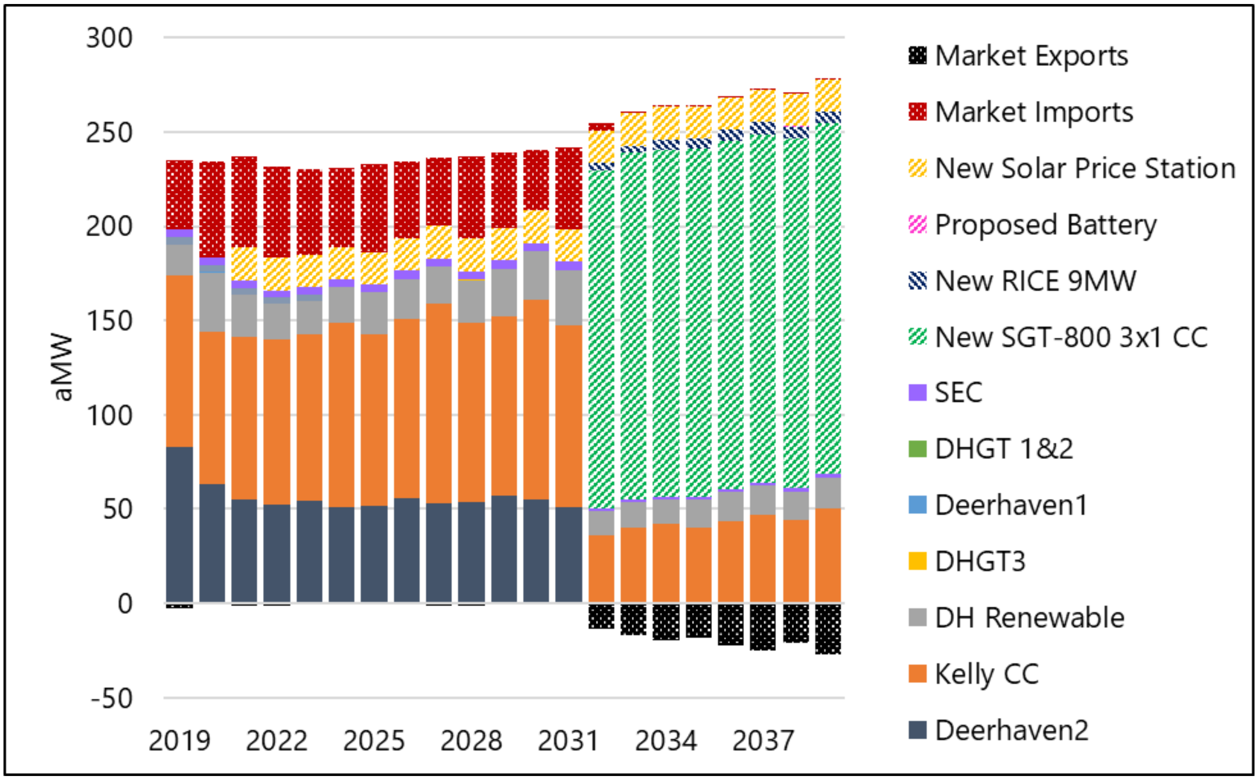
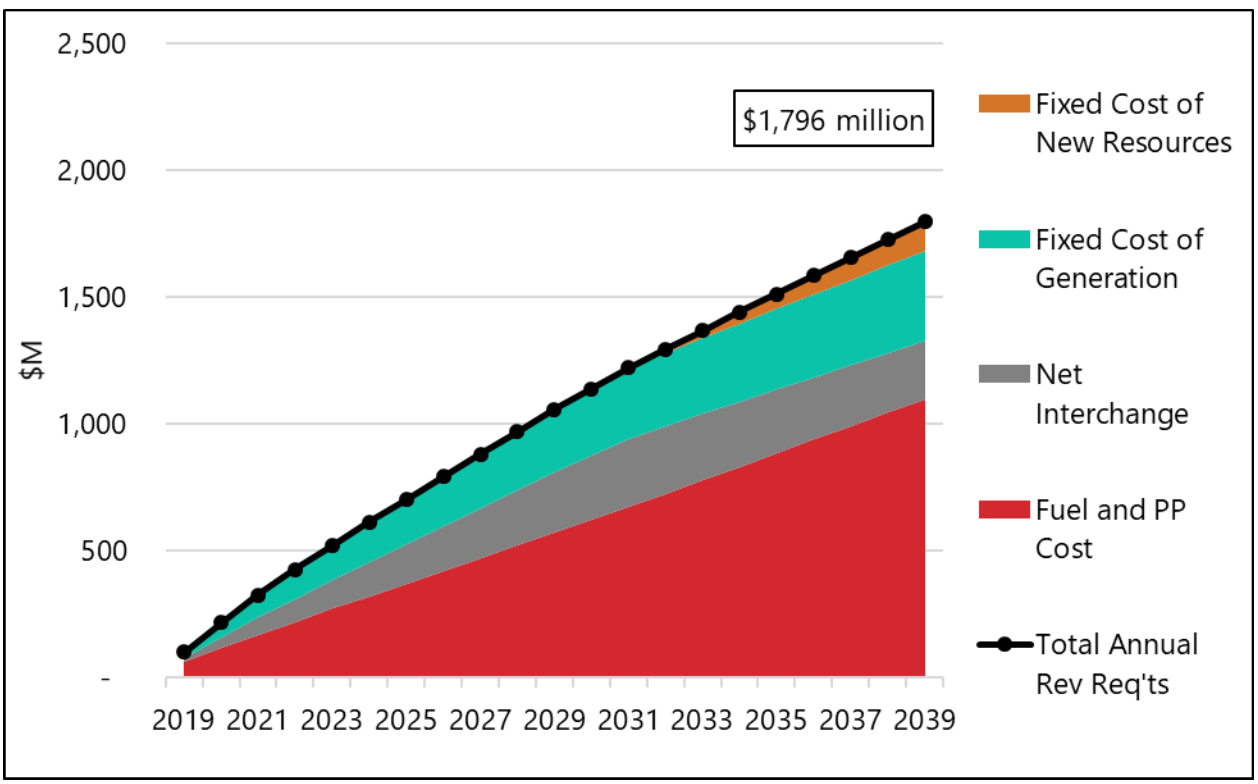


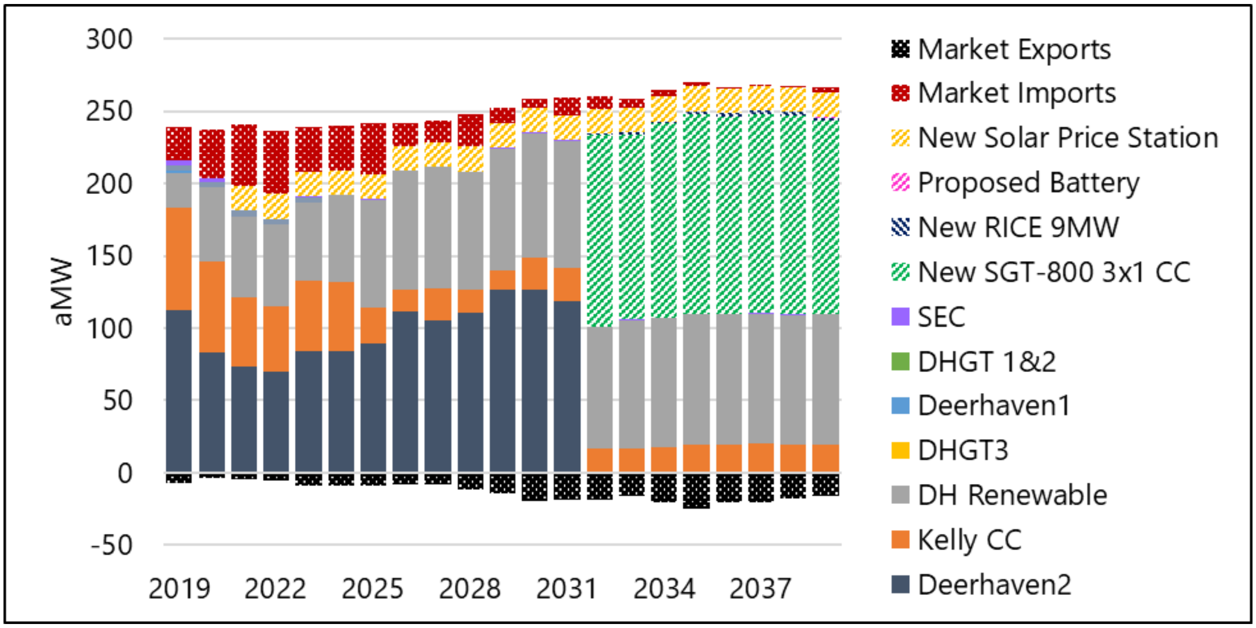
Figure 29: Reference Case – Low Gas Price Cumulative Net Present Value



REFERENCE CASE – HIGH GAS PRICE SENSITIVITY RESULTS

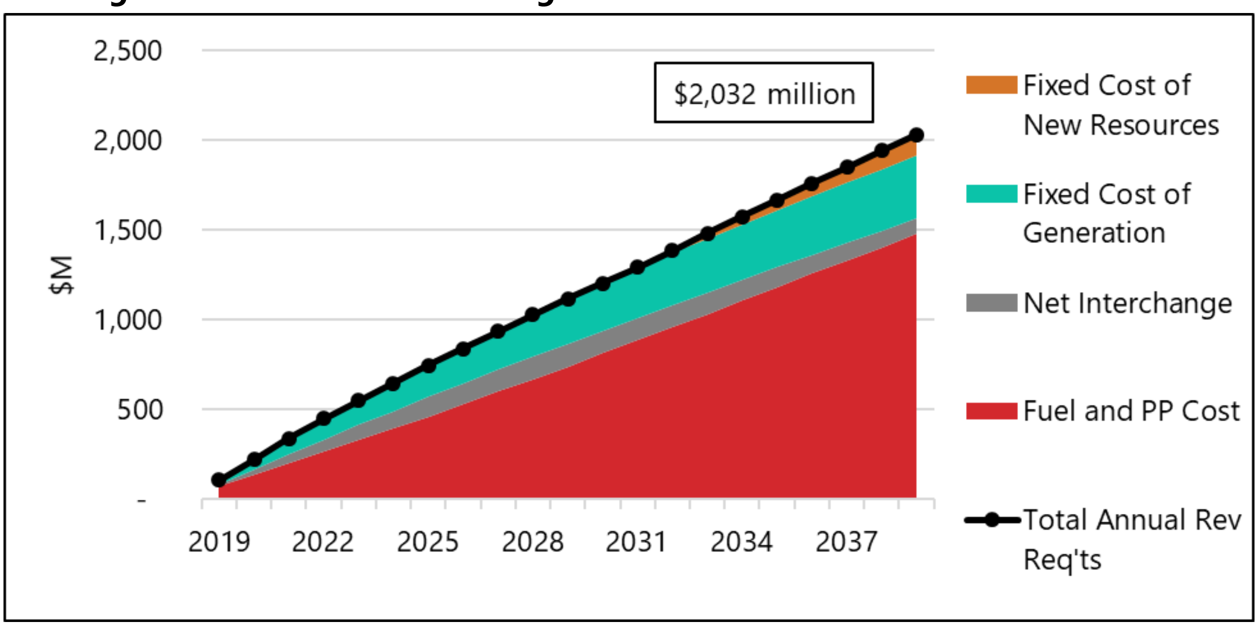
For the high natural gas price sensitivity, the value of fuel diversity is seen with the solid fuel units in comparison to the gas units. The solid fuel units, DH2 and DHR, are serving more of the system load in comparison to the reference gas price case and the low gas price case. Market exports also increase from the reference gas case because the system's production cost is lower than the market energy prices. Figure 30 shows the amount of annual energy generation, expressed in aMW for each generation resource.

Figure 30: Reference Case – High Gas Price Energy Production by Resource



For this sensitivity study, Figure 31 shows the cumulative NPVRR in 2039 is $2.032 billion. The LCOE for the term is $46.33/MWh.

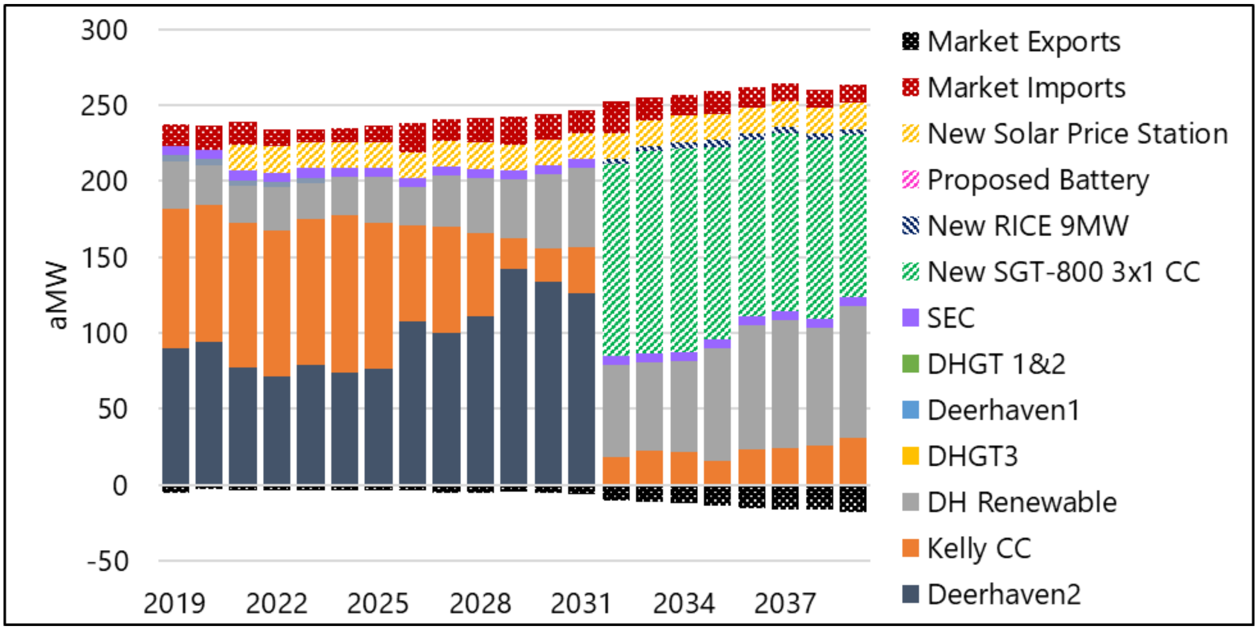
Figure 31: Reference Case – High Gas Price Cumulative Net Present Value



REFERENCE CASE – PORTFOLIO OPTIMIZER SENSITIVITY RESULTS

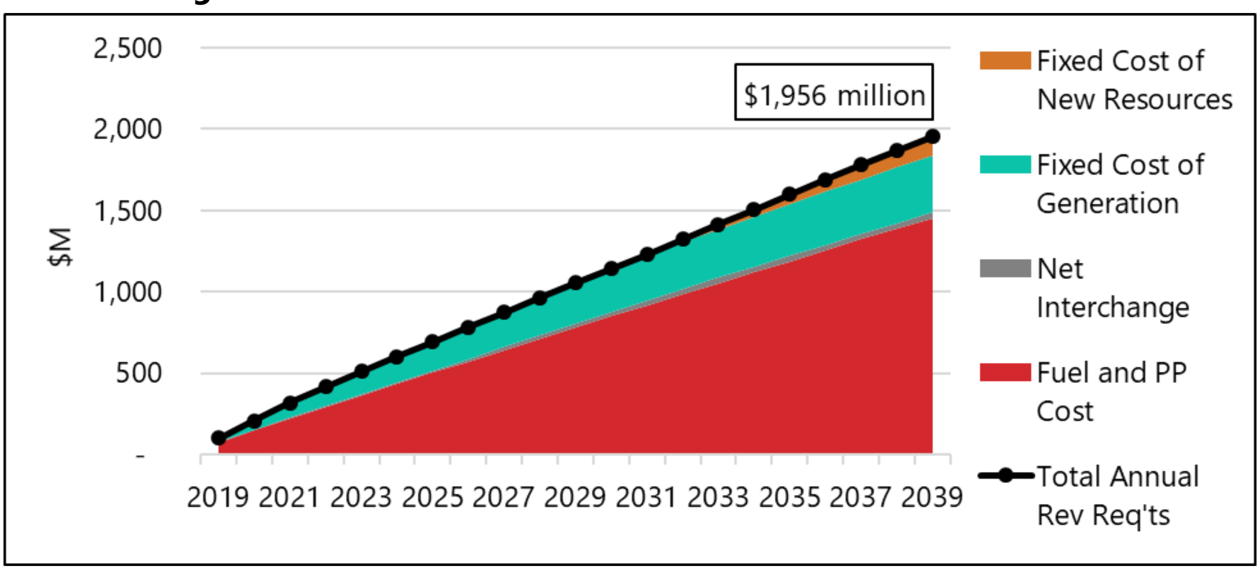
For the PO sensitivity, there are fewer market imports early in the study compared to the reference case, because GRU's generating system must ramp up to hold the spinning reserves required by the solar generation. After the installation of the CC unit, the system is better able to handle reserves due to the faster ramping rates of the new unit compared to DH2, and the system is able to take advantage of the lower cost of import energy. The RICE units have slightly more output, as expected in a case that takes chronological constraints of ramp rates and unit outages into consideration. Figure 32 shows the amount of annual energy generation, expressed in aMW for each generation resource.

Figure 32: Reference Case – PO Energy Production by Resource



For this sensitivity study, Figure 33 shows the cumulative NPVRR in 2039 is $1.956 billion. The LCOE for the term is $44.58/MWh.

Figure 33: Reference Case – PO Cumulative Net Present Value



SCENARIO RESULTS – SYSTEM SCENARIOS (SCENARIOS 1-4)

See the final section for comparative results of all system scenarios and associated sensitivities.

SCENARIO 1 – EASE TRANSMISSION CONSTRAINT SCENARIO

GRU staff has been evaluating various transmission system improvement alternatives to increase its normal import limit above 120 MW. Such an increase will require improvements to DEF and/or FPL's network surrounding GRU. To date, these efforts have resulted in cost estimates which GRU cannot accept. GRU is now working with DEF and FPL to identify less costly options which would increase GRU's imports to around 200 or 250 MW.

For this scenario, TEA assumes that the import limit increases from the current 120 MW to 200 MW in 2019 while retaining all other system constraints included in the reference case. GRU does not currently have a cost estimate for this proposal, so no capital costs for the improvement have been included.

The resultant resource plan from the transmission scenario is only slightly different from the reference case plan. As in the reference case, the plan includes a PPA for 80 MW of solar in 2021 and, after Deerhaven 2 retires in 2031, a 198 MW NG 3x1 combined cycle unit in 2032. Additionally, the plan adds an 18.4 MW RICE unit and a 9 MW RICE unit in 2032, compared to three 9 MW units in the reference case. Another 9 MW RICE unit is included in 2034. The 5 MW of battery storage is added in 2037, one year earlier than in the reference case.

NPVRR and LCOE by Sensitivity

For the reference gas price sensitivity of this scenario, the cumulative NPVRR in 2039 is $1.962 billion, approximately $2 M or 0.1% greater than the than the corresponding sensitivity of the reference case. The LCOE for the term is $44.73/MWh.

For the low gas price sensitivity, the cumulative NPVRR in 2039 is $1.796 billion, approximately equal to that of the reference case. The LCOE for the term is $40.94/MWh.

For the high gas price sensitivity, the cumulative NPVRR in 2039 is $2.033 billion, approximately $1 M higher, nearly unchanged from the reference case. The LCOE for the term is $46.34/MWh.

For the PO sensitivity, cumulative NPVRR in 2039 is $1.955 billion, approximately $1 M less than the reference case. The LCOE for the term is $44.56/MWh.

Observations

Increasing the transmission import capability from 120 MW to 200 MW to improve the ability to purchase non-firm energy does not appear to be a cost effective option. It had a negligible impact on GRU's future revenue requirements, and the evaluation excludes the additional capital costs necessary to increase the import limit. Note that imports were considered to be non-firm energy and, as such, did not count towards capacity requirements.

SCENARIO 2 – K8 RETIREMENT SCENARIO

K8 operates only in combined cycle with JRK CT4. It was built in 1965 and is currently over 50 years old. The reference case includes capital costs for refurbishment of K8 totaling $8.9 M in 2020, $10.3 M in 2021, and $7 M in 2022. The K8 retirement scenario retires K8 in 2022, avoiding the refurbishment costs, and retains the JRK CT, a sub-component of the JR Kelly CC unit and a look-alike generator to DH GT3.

The resultant resource plan adds a PPA for 80 MW of solar in 2021, consistent with the reference case plan. It retires the JR K8 unit in 2022 and immediately replaces it with a 132 MW 2x1 combined cycle unit. After Deerhaven 2 retires in 2031, a second 132 MW 2x1 combined cycle is added in 2032. A 9 MW RICE unit is included at the end of the study in 2039.

NPVRR and LCOE by Sensitivity

For the reference gas price sensitivity for this scenario, the cumulative NPVRR in 2039 is $1.916 billion, approximately $44 M or 2.3% less than the reference case scenario with the reference case gas sensitivity. The LCOE for the term is $43.69/MWh.

For the low gas sensitivity, the cumulative NPVRR in 2039 is $1.758 billion, approximately $38 M or 2.1% less than the reference case. The LCOE for the term is $40.08/MWh.

For the high gas sensitivity, the cumulative NPVRR in 2039 is $2.023 billion, approximately $9 M or 0.5% less than the reference case. The LCOE for the term is $46.13/MWh.

For the PO sensitivity, this scenario's cumulative NPVRR in 2039 is $1.954 billion, approximately $2 M less, essentially unchanged from the reference case. The LCOE for the term is $44.55/MWh.

Observations

The costs of this scenario and the reference case are nearly the same in the PO sensitivity which indicates there is little, if any, advantage to retiring the K8 unit. When K8 retires, the plan replaces it with a 2x1 combined cycle. Although there would be a heat rate improvement with the addition of a new, highly efficient combined cycle resource, this retirement would require a large capital expenditure much earlier than in the reference case and could present a significant financing challenge for GRU. Note that maintaining generation at the Kelly station provides voltage support for the JRK distribution substation.

SCENARIO 3 – ALLOW RETIREMENTS SCENARIO

In Scenario 3, the model was allowed to retire all of GRU's existing thermal generation units earlier (but not later) than the currently specified retirement dates.

This relaxed optimization retires DH2 and the DH GT1-2 in 2021. As in the other scenarios, it adds 80 MW of solar PPAs in 2021. In 2022, the plan still retires Deerhaven 1 but also retires Deerhaven Renewable. The plan simultaneously includes a 198 MW 3x1 combined cycle unit. In 2023, it adds a smaller 132 MW 2x1 combined cycle unit. A 9 MW RICE unit is added in 2035 and 5 MW of battery storage is added in 2039. Note, the Kelly CC is maintained throughout the study and refurbishment capital costs are included. This resource plan includes approximately $130 million in NPVRR due to the system's additional gas transport needs.

NPVRR and LCOE by Sensitivity

For the reference gas price sensitivity, the Allow Retirements scenario's cumulative NPVRR in 2039 is $1.991 billion, approximately $31 million or 1.6% more than the reference case. The LCOE for the term is $45.39/MWh.

For the low gas price sensitivity, the Allow Retirements scenario's cumulative NPVRR in 2039 is $1.745 billion, approximately $51 million or 2.9% less than the reference case. The LCOE for the term is $39.78/MWh.

For the high gas price sensitivity, the Allow Retirements scenario's cumulative NPVRR in 2039 is $2.196 billion, approximately $164 million or 8.1% more than the reference case. The LCOE for the term is $50.06/MWh.

For the PO sensitivity, the Allow Retirements scenario's cumulative NPVRR in 2039 is $2.009 billion, approximately $53 million or 2.7% more than the reference case. The LCOE for the term is $45.79/MWh.

Observations

The Allow Retirements case loses its advantage over the reference case due to the additional costs of gas transport required, as well as the early outlay of capital costs for new unit installations. Only in the low gas price sensitivity is the NPVRR value comparable to the Reference case.

SCENARIO 4 – ALLOW RETIREMENTS EXCEPT DHR SCENARIO

In 2017, GRU purchased the DHR biomass plant from the owners with whom GRU held a 30-year PPA. In light of this recent capital investment and DHR's significant amount of renewable energy production, retirement of DHR in the near term is not considered a reasonable option. Therefore, in Scenario 4, the model is allowed to retire any of GRU's existing thermal generation units earlier than their planned retirement dates except for DHR.

This relaxed optimization retires DH2 and the DH GT1 in 2021. It also includes 80 MW of solar PPAs in 2021. In 2022, consistent with the reference case, the plan retires DH 1 and adds a 198 MW 3x1 combined cycle unit. In 2026, it retires DH GT1-2. It adds one 9 MW RICE unit in both 2027 and 2028. In 2031, two more 9 MW RICE units are added for a total of four 9 MW RICE units for the system. A 5 MW battery is added in 2038. Note, the JR Kelly CC is maintained throughout the study and refurbishment capital costs were included. An additional $50 million in NPVRR costs are included in the analysis to account for the gas transportation required to support the resultant resource plan.

NPVRR and LCOE by Sensitivity

For the reference gas price sensitivity, the Allow Retirements Except DHR scenario's cumulative NPVRR in 2039 is $1.922 billion, approximately $39 million or 2.0% less than the reference case. The LCOE for the term is $43.81/MWh.

For the low gas price sensitivity, the Allow Retirements Except DHR scenario's cumulative NPVRR in 2039 is $1.698 billion, approximately $98 million or 5.5% less than the reference case. The LCOE for the term is $38.71/MWh.

For the high gas price sensitivity, the Allow Retirements Except DHR scenario's cumulative NPVRR in 2039 is $2.086 billion, approximately $54 million or 2.6% more than the reference case. The LCOE for the term is $47.55/MWh.

For the PO sensitivity, the Allow Retirements Except DHR scenario's cumulative NPVRR in 2039 is $1.945 billion, approximately $11 million or 0.6% less than the reference case. The LCOE for the term is $44.34/MWh.

Observations

The Allow Retirements Except DHR scenario is more economical than the reference case for all sensitivity studies except the high gas case; however, this resource plan carries significant fuel risk as it is highly reliant upon natural gas. With DHR as the only solid fuel-fired generator available, the plan's limited fuel diversity makes it less economical in the high gas price sensitivity. The PO sensitivity indicates that net present value of revenue requirements of this scenario is not materially different from that of the reference case. The difference is only 0.6% compared to the 2.0% estimated with the CE model. It is expected that similar reductions would occur for the other gas price sensitivities when the increased modeling detail in PO is applied. Increased dependence on natural gas and an early outlay of capital overshadows the potential minor reduction in revenue requirements provided by early unit retirements.

SYSTEM SCENARIOS COMPARATIVE RESULTS

The following pages contain several figures comparing the system scenarios' resource plans.

Figure 34 compares the system scenarios' NPVRR results for the PO sensitivity. The associated table breaks out the NPVRR into its various cost components, including Fuel and Purchased Power Costs, Spot Market Interchange, Fixed Costs of Existing Generation included in the study, Fixed Costs of New Resources, and the Additional Natural Gas Transport Capacity.

Figure 35 shows the resultant resource plans for each system scenario, including all new builds and unit retirements. It identifies NPVRR in 2018 dollars, as well as an LCOE for all sensitivity studies performed. The plans that are most economical across the sensitivities are highlighted in green. Note the NPVRR includes $130 million of added gas transportation costs to the Allow Retirements scenario and $50 million of added gas transportation costs to the Allow Retirements Except DHR scenario.

Figure 36 compares the system scenarios' capital requirements for each resource plan. Note that all plans that retain the Kelly CC unit include the capital cost projection for the K8 refurbishment. The projections for the K8 retirement scenario do not include these costs. Note that all the retirement scenarios require large capital expenditures early in the term of the study.

Figure 34: System Scenarios PO Sensitivity NPVRR

PO - Reference Gas	Reference Case	Import Transmission 200 MW	K8 Retirement 2022	Allow Retirements	Allow Retirements Except DHR
Fuel and PP Cost Net Renewable Energy	1,455	1,454	1,449	1,354	1,362
Spot Mkt Interchange	32	32	8	10	29
Fixed Cost of Existing Gen.	353	353	286	169	269
Fixed Cost of New Resources	115	116	211	346	235
Add'l NG Transport Capacity	-	-	-	130	50
Total Annual Rev Req'ts ($M)	1,956	1,955	1,954	2,009	1,945

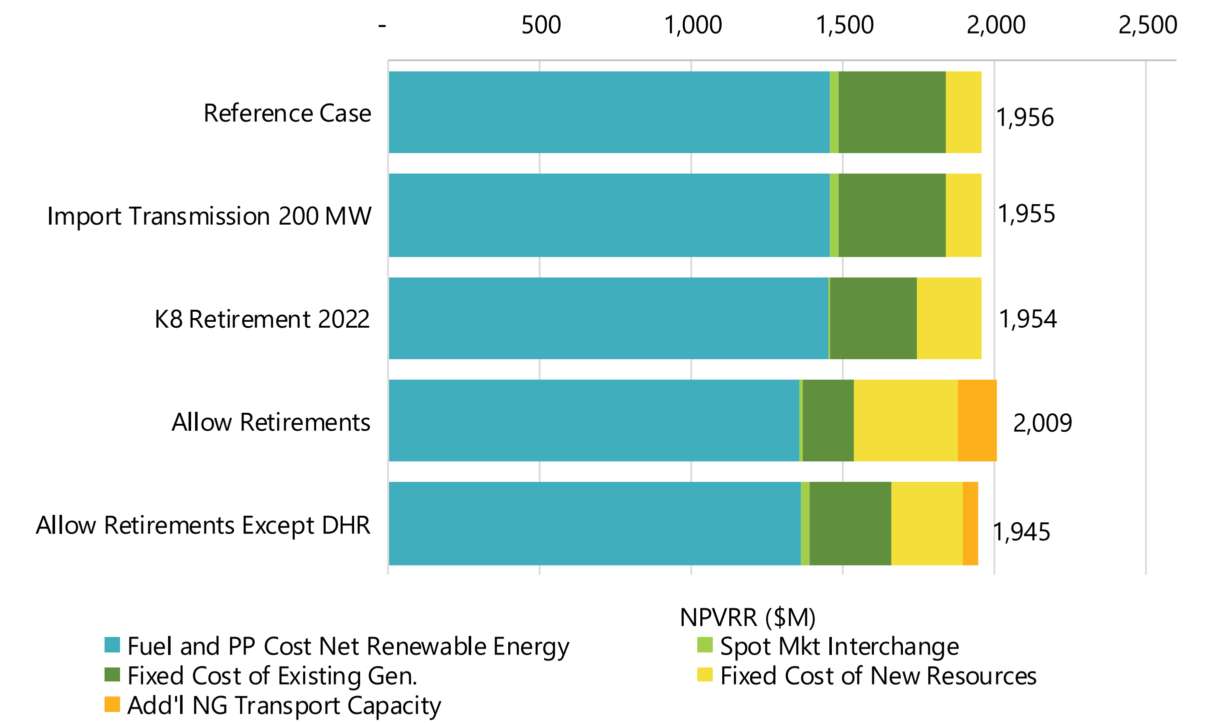
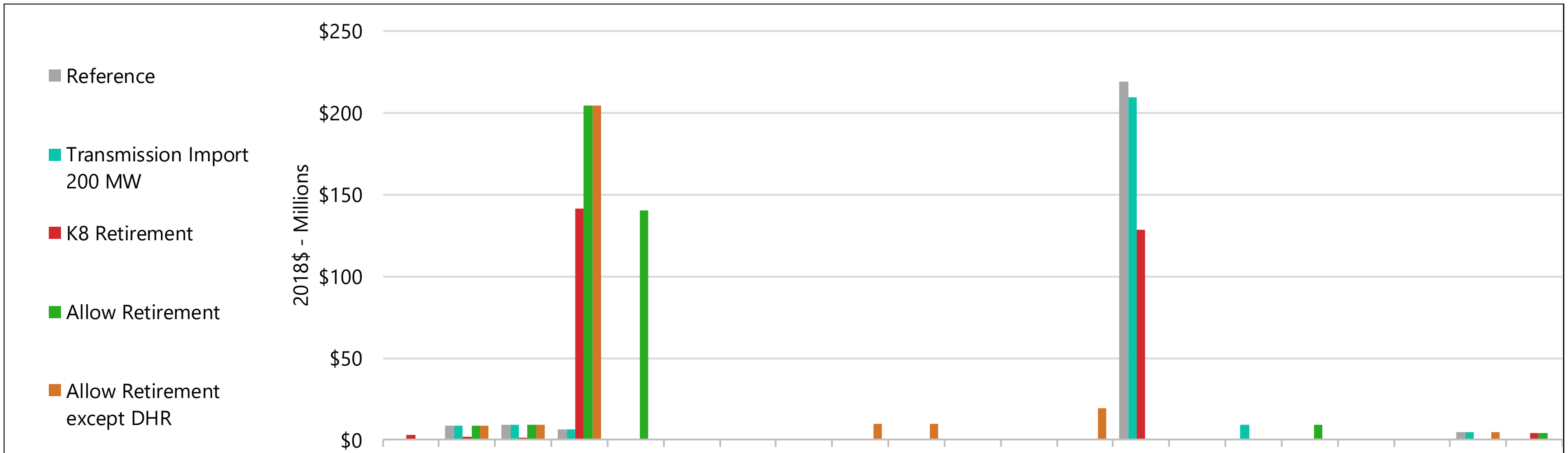


Figure 35: System Scenario Results

		Reference Case			Import Transmission 200 MW			K8 Retirement 2022			Allow Retirements*			Allow Retirements Except DHR*		
Builds		Year	New Unit	Additional Capacity (MW)	Year	New Unit	Additional Capacity (MW)	Year	New Unit	Additional Capacity (MW)	Year	New Unit	Additional Capacity (MW)	Year	New Unit	Additional Capacity (MW)
		2021	4 - Solar	28	2021	4 - Solar	28	2021	4 - Solar	28	2021	4 - Solar	28	2021	4 - Solar	28
		2032	1 - NGCC 3x1	198	2032	1 - NGCC 3x1	198	2022	1 - NGCC 2x1	132	2022	1 - NGCC 3x1	198	2022	1 - NGCC 3x1	198
		2032	3 - 9MW RICE	27	2032	1 - 18MW RICE	18.4	2032	1 - NGCC 2x1	132	2023	1 - NGCC 2x1	132	2027	1 - 9 MW RICE	9
		2034	1 - 9MW RICE	9	2032	1 - 9 MW RICE	9	2039	1 - 9 MW RICE	9	2035	1 - 9 MW RICE	9	2028	1 - 9 MW RICE	9
		2038	1 - Battery	5	2034	1 - 9 MW RICE	9				2039	1 - Battery	5	2031	1 - 18MW RICE	18.4
					2037	1 - Battery	5							2038	1 - Battery	5
Retirements		Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)
		2022	DH1	75	2022	DH1	75	2022	DH1	75	2021	DH2	228	2021	DH2	228
		2023	G2 Energy	3.8	2023	G2 Energy	3.8	2022	K ST 8	31.33	2021	DH GT 1-2	38.8	2021	DH GT 1	19.4
		2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8	2023	G2 Energy	3.8	2022	DH1	75	2022	DH1	75
		2031	DH2	228	2031	DH2	228	2026	DH GT 1-2	38.76	2022	DHR	103	2023	G2 Energy	3.8
								2031	DH2	228	2023	G2 Energy	3.8	2026	DH GT 2	19.4
Net Capacity Change (MW)		Term		-78.6	Term		-78.2	Term		-75.9	Term		-76.6	Term		-78.2
Capacity Expansion Cost Results																
NPVRR ($M - $/MWh)	Reference NG		$1,961	$ 44.69		$1,962	$ 44.73		$1,916	$ 43.69		$1,991	$ 45.39		$1,922	$ 43.81
	Low NG		$1,796	$ 40.95		$1,796	$ 40.94		$1,758	$ 40.08		$1,745	$ 39.78		$1,698	$ 38.71
	High NG		$2,032	$ 46.33		$2,033	$ 46.34		$2,023	$ 46.13		$2,196	$ 50.06		$2,086	$ 47.55
Portfolio Optimizer Cost Results																
NPVRR ($M - $/MWh)	Reference NG		$1,956	$ 44.58		$1,955	$ 44.56		$1,954	$ 44.55		$2,009	$ 45.79		$1,945	$ 44.34

Note: The additional capacity above shows only the capacity of the units which can contribute to reserve margin requirements. Solar PPA capacity for reserve margin criteria is 35% of its nameplate capacity. Each solar unit above has a 20 MW of nameplate capacity contributing only 7 MW towards reserve margin.

Figure 36: System Scenarios Capital Requirements



	Total	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Reference	**$253.8**	$0.4	$8.4	$9.4	$6.3	$1.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$219.3	$0.3	$0.3	$0.3	$0.3	$0.3	$4.5	$0.3
Transmission Import 200 MW	**$253.2**	$0.4	$8.4	$9.4	$6.3	$1.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$209.8	$0.3	$9.3	$0.3	$0.3	$0.3	$4.5	$0.3
K8 Retirement	**$280.9**	$3.0	$1.9	$1.2	$141.5	$0.4	$0.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$128.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.0
Allow Retirement	**$381.0**	$0.4	$8.4	$9.4	$204.5	$140.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$9.2	$0.3	$0.3	$0.3	$4.3
Allow Retirement except DHR	**$270.9**	$0.4	$8.4	$9.4	$204.5	$1.0	$0.3	$0.3	$0.3	$9.9	$9.8	$0.3	$0.3	$19.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$4.5	$0.3

SCENARIO RESULTS – LOAD SCENARIOS (SCENARIOS 5-7)

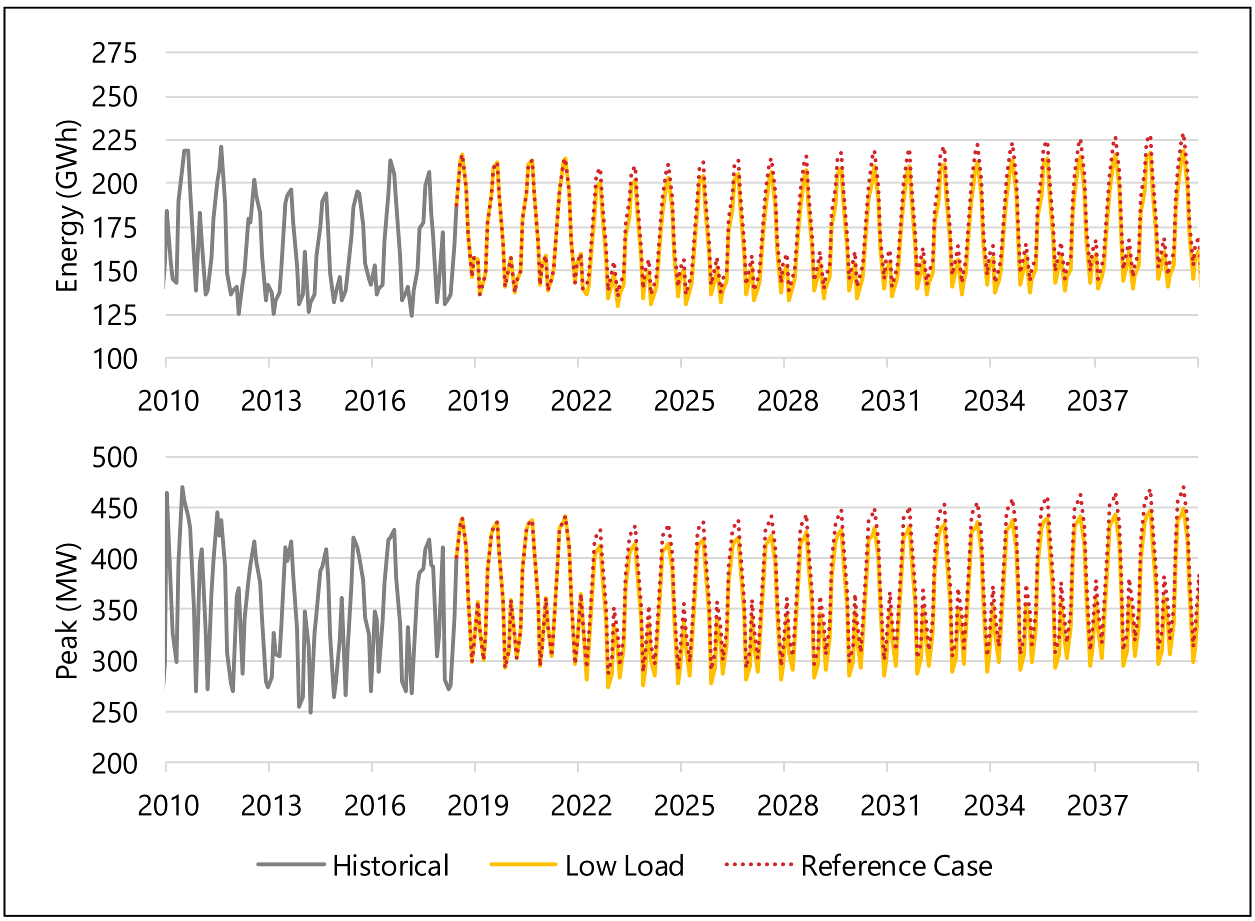
See the final section for comparative results of all load scenarios and associated sensitivities. No PO sensitivities were performed on the load scenarios since little additional information could be gained from the analysis. Note that, because of the load forecast changes in this group of scenarios, it is more appropriate to compare LCOE than total cost.

SCENARIO 5 – LOW LOAD SCENARIO

This scenario assumes that GRU will carry none of the City of Alachua load after the current contract expires in March 2022. Figure 37 shows the change in load forecast compared to the reference case. In 2023, the peak in the low load scenario is about 17 MW lower than the reference case. The change in energy between the two load forecasts for 2023 is about 80 GWh.

The resultant resource plan from the low load scenario is only slightly different from the reference case. As in the reference case, the plan includes PPA for 80 MW of solar in 2021 and a 198 MW natural gas 3x1 CC unit in 2032 after DH2's retirement. Because of the lower load, the system requires fewer RICE generators and no battery storage. The plan adds a 9 MW RICE unit in 2033 and a second 9 MW RICE unit in 2036.

Figure 37: Low Load Forecast vs Reference Case Load Forecast



Sensitivity Results

Note that while the NPVRRs for Scenario 5 sensitivities are less than the reference case, there would also be less revenue because of the lower load. It is much more appropriate to compare the LCOE between the scenarios.

This scenario's cumulative NPVRR in 2039 for the reference gas sensitivity is $1.886 billion. The low load scenario's LCOE for the term is $44.62/MWh, which is 0.2% less than the reference case LCOE of $44.69/MWh.

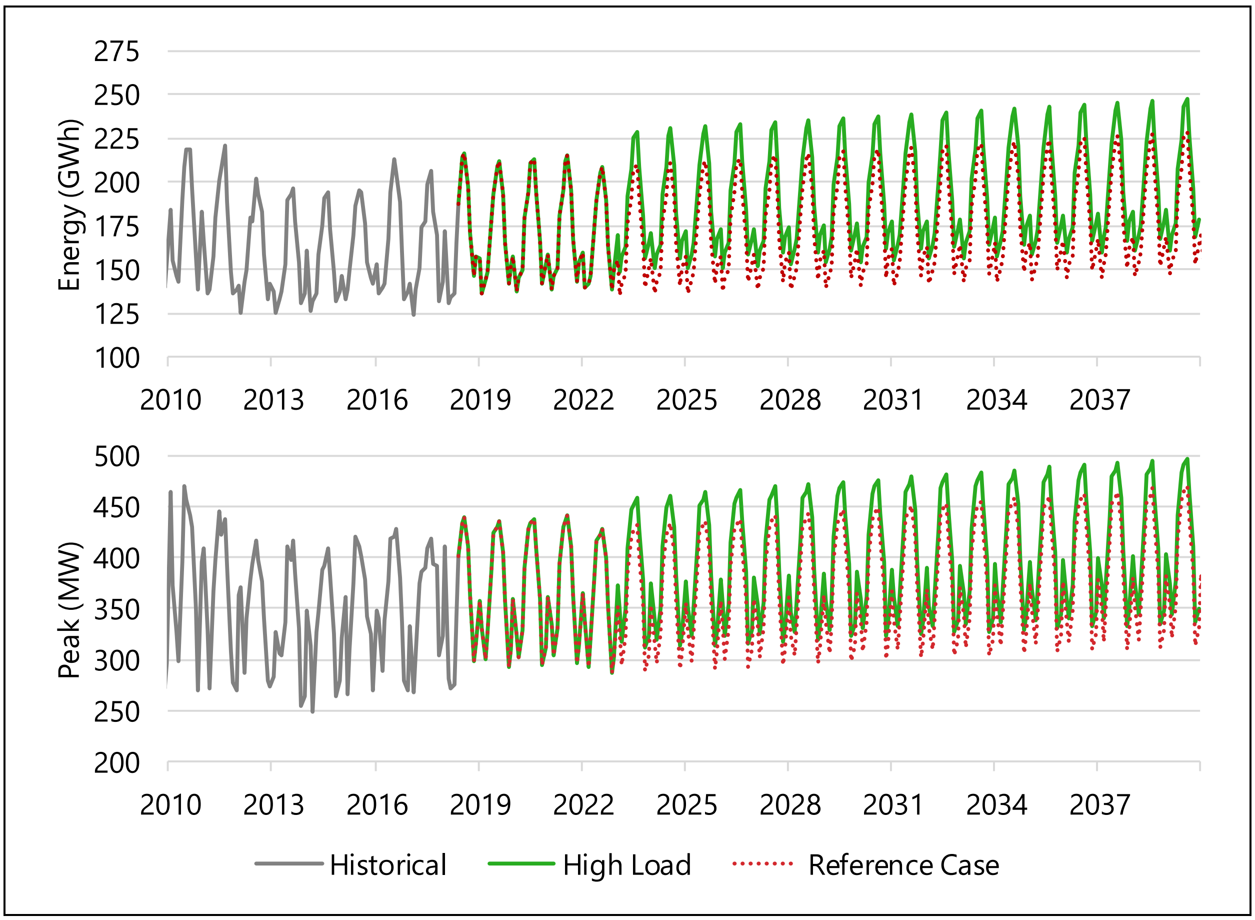
This scenario's cumulative NPVRR in 2039 for the low gas sensitivity is $1.725 billion and the LCOE for the term is $44.62, which is 0.3% less than the reference case.

This scenario's cumulative NPVRR in 2039 for the high gas sensitivity is $1.958 billion and the LCOE for the term is $46.31/MWh, which is almost equal to the reference case.

SCENARIO 6 – HIGH LOAD SCENARIO

The high load scenario included an additional 30 MW of load in the load forecast. GRU provided a shape for this additional load. Figure 38 shows the change in load forecast compared to the reference case. The peak load for this scenario is about 28 MW higher than the reference case in 2023. The change in energy between the two load forecasts in 2023 is about 195 GWh.

Figure 38: High Load Forecast vs. Reference Case Load Forecast



The resource plan resulting from this scenario requires capital investment earlier than the reference case. In 2021, the plan includes PPAs for 80 MW of solar. In 2027, it adds a 132 MW 2x1 CC unit. After Deerhaven 2 retires in 2031, the plan installs a second 132 MW 2x1 CC unit in 2032. The plan includes a 9 MW RICE unit in 2037 to accommodate load growth.

NPVRR and LCOE by Sensitivity

For the reference gas price sensitivity, this scenario's cumulative NPVRR in 2039 is $2.095 billion. The LCOE is $44.40/MWh, which is 0.7% less than the $44.69/MWh LCOE of the reference case.

For the low gas price sensitivity, the cumulative NPVRR in 2039 is $1.886 billion. The LCOE for the term is $39.96/MWh, which is 2.5% less than the reference case.

For the high gas price sensitivity, he cumulative NPVRR in 2039 is $2.192 billion. Its LCOE for the term is $46.46/MWh, which is 0.3% more than the reference case.

Observations

Note that more load does not necessarily equate to a higher cost per MWh. It may allow the system to run more efficiently resulting in a lower cost. Of all the gas price sensitivities, the high load scenario was only the least economical of the load scenarios in the high gas sensitivity. This indicates that having more load may be advantageous to GRU's system.

SCENARIO 7 – WINTER-PEAKING LOAD SCENARIO

In recent history, GRU has experienced higher winter demand because of severe weather events. Therefore, a winter peaking load scenario was included in the analysis. For the winter peaking scenario, the winter peak demand forecast was increased to match that of the summer. The forecasted energy for the winter peaking month was adjusted based upon load history. Figure 39 on page 72 shows the change in load forecast from the reference case. The change in energy between the two load forecasts for 2023 is about 21 GWh.

The resource plan resulting from the winter peaking load scenario is only slightly different from the reference case. As in the reference case, the plan adds PPAs for the 80 MW of solar in 2021 and a 198 MW CC in 2032, after the DH2's 2031 retirement. Also in 2032, the plan includes an 18 MW RICE unit, and it installs a second one in 2033.

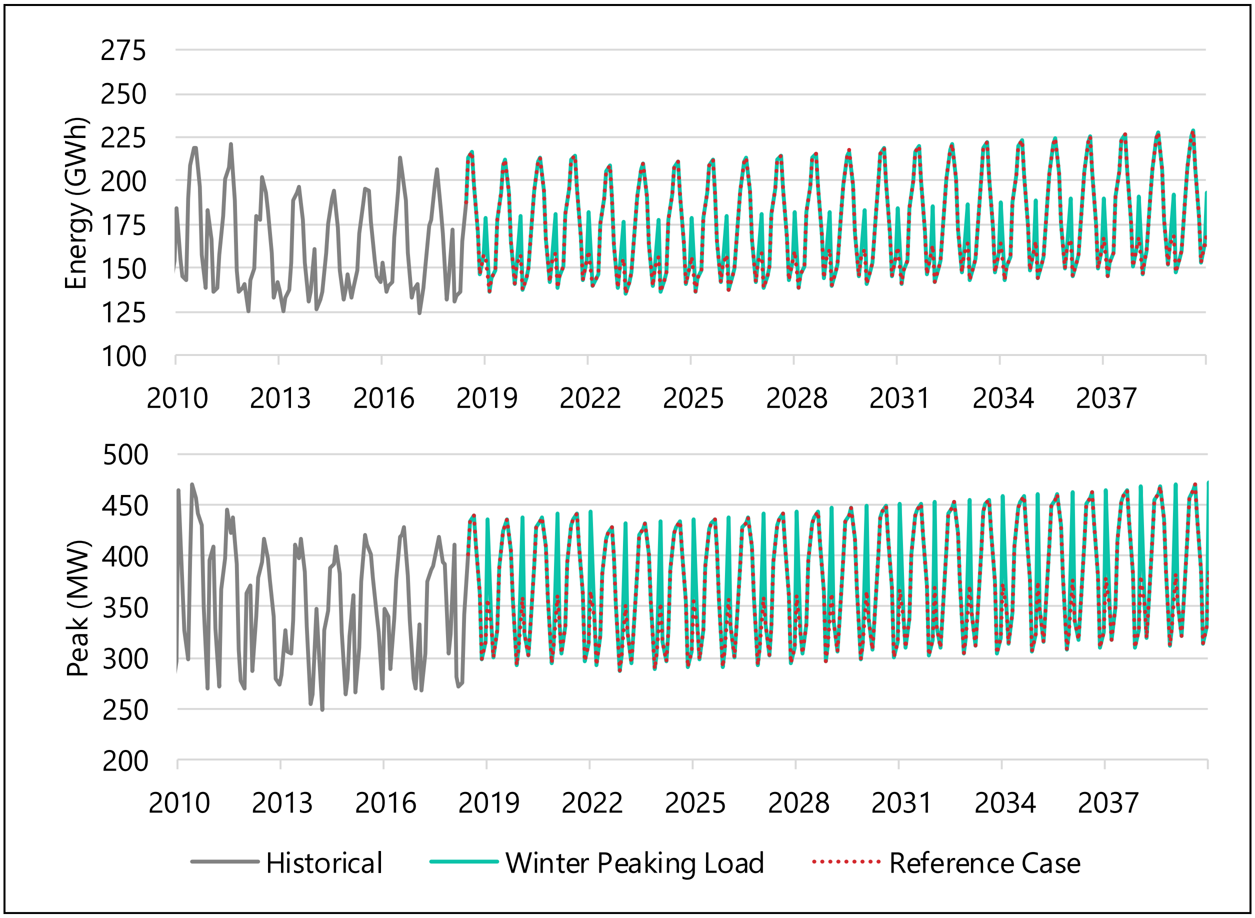
NPVRR and LCOE by Sensitivity

The scenario's cumulative NPVRR in 2039 for the reference gas price sensitivity is $1.978 billion. The LCOE for the term is $44.78/MWh, which is 0.2% higher than the reference case LCOE of $44.69/MWh.

This scenario's cumulative NPVRR in 2039 for the low gas price sensitivity is $1.815 billion. The LCOE for the term is $41.10/MWh, which is 0.4% higher than the reference case.

This scenario's cumulative NPVRR in 2039 for the high gas price sensitivity is $2.050 billion. The LCOE for the term is $46.42, which is 0.2% higher than the reference case.

Figure 39: Winter-Peaking Load Forecast vs. Reference Case Load Forecast



LOAD SCENARIOS COMPARATIVE RESULTS

Figure 40 shows the resource plans resulting from each load scenario, including all new builds and unit retirements. It identifies NPVRR in 2018 dollars and the levelized cost for all sensitivity studies performed. The plans that are most economical across the sensitivities are highlighted in green. According to these results, additional load is likely to improve the economics of GRU's system.

Figure 40: Load Scenario Results

	Reference Case			Low Load			High Load			Winter Peaking Load		
Builds	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)
	2021	4 - Solar	28	2021	4 - Solar	28	2021	4 - Solar	28	2021	4 - Solar	16
	2032	1 - NGCC 3x1	198	2032	1 - NGCC 3x1	198	2027	1 NGCC 2x1	132	2032	1 - NGCC 3x1	198
	2032	3 - 9MW RICE	27	2033	1 - 9 MW RICE	9	2032	1 NGCC 2x1	132	2032	2 - 9 MW RICE	18
	2034	1 - 9MW RICE	9	2036	1 - 9 MW RICE	9	2037	1 - 9 MW RICE	9	2033	2 - 9 MW RICE	18
	2038	1 - Battery	5									
Retirements	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)
	2022	DH1	75	2022	DH1	75	2022	DH1	75	2022	DH1	75
	2023	G2 Energy	3.8	2023	G2 Energy	3.8	2023	G2 Energy	3.8	2023	G2 Energy	3.8
	2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8
	2031	DH2	228	2031	DH2	228	2031	DH2	228	2031	DH2	228
Net Capacity Change	Term		-78.6	Term		-101.6	Term		-44.6	Term		-95.6
Capacity Expansion Cost Results												
NPVRR ($M - $/MWh) Reference NG		$1,961	$ 44.69		$1,886	$ 44.62		$2,095	$ 44.40		$1,978	$ 44.78
NPVRR ($M - $/MWh) Low NG		$1,796	$ 40.95		$1,725	$ 40.81		$1,886	$ 39.96		$1,815	$ 41.10
NPVRR ($M - $/MWh) High NG		$2,032	$ 46.33		$1,958	$ 46.31		$2,192	$ 46.46		$2,050	$ 46.42
Portfolio Optimizer Cost Results												
NPVRR ($M - $/MWh) Reference NG		$1,956	$ 44.58									

Note: The additional capacity above shows only the capacity of the units which can contribute to reserve margin requirements. Solar PPA capacity for reserve margin criteria is 35% of its nameplate capacity. Each solar unit above has a 20 MW of nameplate capacity contributing only 7 MW towards reserve margin.

SCENARIO RESULTS – AREA CONTROL ERROR MITIGATION SCENARIOS (SCENARIOS 8-11)

Because of the intermittency of solar energy, GRU has concerns about the ability to maintain system reliability given large contributions of solar energy. Burns and McDonnel provided GRU with an Area Control Error (ACE) study to help quantify GRU's rapid response resource needs with additional solar resources. This study was completed January 2019 and evaluated GRU's ability to comply with the NERC Standard BAL-001-2 with up to 74.5 MW of utility-scale solar PV capacity added. It evaluated short- and long-term ACE requirements using 40 MW and 74.5 MW of solar additions and identified a need for up to 60 MW additional rapid response resources under several generation and transmission fault scenarios. Near-term deficiency was reduced up to 24 MW by limiting solar to 40 MW.

However, there are several mitigating factors concerning this study. First, deficiencies were overstated by over 25 MW with 2022 load and generation portfolios as the study did not consider reduction of station service load for faulted generators or the reduction in load due to the potential loss of all or a portion of the City of Alachua load. Also, the emergency power purchases (EPP) were limited to pre-fault output of the faulted generator, which may be inconsistent with the Schedule A contract language. TEA is of the opinion that it would be more reasonable to limit EPP to no less than the rated capacity of the faulted unit. Taking these mitigating factors into consideration, the relevant scenarios of this IRP require roughly 20 MW of rapid response capacity per 40 MW of additional solar capacity.

In each of these scenarios, the results of the ACE study were addressed by requiring a 9 MW RICE unit to be added for each 20 MW of solar capacity added. The CE model chose thermal generation over battery storage due to the economics of each resource. Although the capital costs per kW of gas turbines are less than that of RICE units, RICE units outperform gas turbines in an hourly model because of their flexibility and modularity. Therefore, TEA determined that using RICE units to provide rapid response backup to address solar energy intermittency is a more economical alternative for GRU than gas turbine units.

The model assumes solar farms will be located outside of GRU's existing transmission loop and that solar installations over 80 MW will require transmission and distribution upgrades with capital costs of about $5 million per 20 MW of solar.

See the final section for comparative results of all ACE scenarios and associated sensitivities.

SCENARIO 8 – SOLAR LIMITED TO 80 MW SCENARIO

Compared to the rest of the ACE scenarios which allow unlimited solar, Scenario 8 limited solar installations to 80 MW. This limit is aligned with the parameters used in the ACE study.

The resource plan resulting from ACE REQs Limited 80 MW Solar only differed from the reference case in the timing of resource additions. The plan includes three solar PPAs totaling 60 MW and three 9 MW RICE units in 2031, which is later than similar installations in the reference case. After Deerhaven 2 retires in 2031, a 198 MW 3x1 CC is installed in 2032. In 2033, an additional 20 MW solar PPA and a fourth 9 MW RICE unit are added. This scenario requires no additional investment natural gas transportation.

NPVRR and LCOE by Sensitivity

This scenario's cumulative NPVRR in 2039 for the reference gas price sensitivity is $1.992 billion, which is $32 million or 1.6% more than the reference case. The LCOE for the term is $45.42/MWh.

This scenario's cumulative NPVRR in 2039 for the low gas price sensitivity is $1.838 billion, which is $42 million or 2.3% more than the reference case. The LCOE for the term is $41.91/MWh.

This scenario's cumulative NPVRR in 2039 for the high gas price sensitivity is $2.055 billion, which is $23 million or 1.1% more than the reference case. The LCOE for the term is $46.84/MWh.

This scenario's cumulative NPVRR in 2039 for the PO sensitivity is $1.965 billion, which is $3 million or 0.5% more than the reference case. The LCOE for the term is $44.79/MWh.

Observations

The economics of the ACE requirement to force the installation of 9 MW of RICE for each 20 MW solar PPA delays the additions of solar until 2031 or later. Because of this, the effects to the NPVRR compared to the reference case are minimal.

SCENARIO 9 – UNLIMITED SOLAR – FORCE 40 MW SOLAR 2021 SCENARIO

This ACE scenario was performed with a forward look to the City's renewable and greenhouse gas goals. In developing Scenario 9, TEA assumed that the ACE requirement of adding 9 MW of RICE capacity per 20 MW of solar would not change for solar capacities above 80 MW. As with other scenarios in this group, note that this assumption would need to be verified by additional ACE studies and detailed production cost analysis. Given GRU's desire to install solar in the near term, two 20 MW solar PPAs are forced in 2021 and require 18 MW of RICE in 2022, after Deerhaven 1 retires.

The resource plan resulting from this scenario adds another 140 MW of solar in 2031 with 63 MW of associated RICE capacity. Throughout the course of the study, CE adds the following solar/RICE combinations:

- 2032: 200 MW of solar and 90 MW of RICE
- 2033: 20 MW of solar and 9 MW of RICE
- 2037: 40 MW of solar and 18 MW of RICE
- 2038: 20 MW of solar and 9 MW of RICE
- 2039: 20 MW of solar and 9 MW of RICE

At the end of the term, total installed capacity includes 480 MW in solar PPAs and 216 MW in RICE units. With approximately 6-8 acres per MW of solar capacity, Scenario 9 would require 3,000-4,000 acres of land. In this case, the natural gas transportation requirement is approximately $4.4 million NPVRR less than that of the reference case.

NPVRR and LCOE by Sensitivity

The cumulative NPVRR in 2039 for the reference gas sensitivity is $1.981 billion, which is $20 million or 1.0% more than the reference case. The LCOE for the term is $45.16/MWh. The revenue requirement includes $33.83 million NPVRR in transmission and distribution upgrades required to deliver the solar energy.

The cumulative NPVRR in 2039 for the low gas price sensitivity is $1.872 billion, which is $76 million or 4.2% more than the reference case. The LCOE for the term is $42.67/MWh.

The cumulative NPVRR in 2019 for the high gas price sensitivity is $2.042 billion, which is $10 million or 0.5% more than the reference case. The LCOE for the term is $46.56/MWh.

The cumulative NPVRR in 2039 for the PO sensitivity is $1.985 billion, which is $29 million or 1.5% more than the reference case. The LCOE for the term is $45.25/MWh.

Observations

Forcing a limited amount of solar additions early does not have a significant effect on the NPVRR. The minimal cost difference between the reference case sensitivities run using CE and PO shows the value of the flexibility of the RICE units. The 480 MW of solar called for in this scenario require around 3,000-4,000 acres of land. Based on US Census data, this represents nearly 10% of the City's land area. Scenario 9's resource plan allows the system to serve approximately 75% of the NEL with renewable generation. This percentage does not include the current solar FIT contracts, because that energy is included within the load forecast. With market purchases serving over 15% of NEL, this scenario significantly relies on the market.

SCENARIO 10 – UNLIMITED SOLAR – ALLOW RETIREMENTS EXCEPT DHR SCENARIO

Scenario 10 does not limit the amount of solar purchased, and it allows for early retirement of all existing units except for DHR. TEA assumed that the ACE requirement of adding 9 MW of RICE capacity per 20 MW of solar would not change with solar capacities above 80 MW. As with other scenarios in this group, note that this assumption would need to be verified by additional ACE studies and detailed production cost analysis.

The resulting plan retires DH1 in 2021, one year earlier than the reference case. DH2 retires in early 2021, and the JRK CC retires in 2028. In 2038, the model adds 5 MW of battery storage. At this time, this model also adds 80 MW of solar PPAs, along with 36 MW of RICE capacity. Throughout the course of the study, CE adds the following solar/RICE combinations:

- 2021: 80 MW of solar and 36 MW of RICE
- 2022: 200 MW of solar and 90 MW of RICE
- 2027: 120 MW of solar and 54 MW of RICE
- 2029: 140 MW of solar and 63 MW of RICE
- 2034: 20 MW of solar and 9 MW of RICE

The total installed solar and RICE capacity in 2039 is 580 MW and 261 MW, respectively. The land requirement for this amount of solar capacity would be approximately 3,000 to 5,000 acres. The estimated cost for the additional gas transportation for this scenario is $11 million NPVRR.

NPVRR and LCOE by Sensitivity

The cumulative NPVRR in 2039 for the reference gas sensitivity is $2.051 billion, which is $90 million or 4.6% more than the reference case. The LCOE for the term is $46.76/MWh. This includes $82.56 million NPVRR in transmission distribution upgrades required to deliver the solar energy.

The cumulative NPVRR in 2039 for the low gas sensitivity is $1.931 billion, which is $134 million or 7.5% more than the reference case. The LCOE for the term is $44.01/MWh.

The cumulative NPVRR in 2039 for the high gas sensitivity is $2.140 billion, which is $108 million or 5.3% more than the reference case. The LCOE for the term is $48.78/MWh.

Observations

The cost of transmission and distribution system upgrades due to solar installations is significant at $82.5 million NPVRR. The land requirements for the 580 MW of solar in this scenario is 3,000 to 5,000 acres, close to 10% of the city's land area. This scenario's resource plan allows the system to serve approximately 80% of the NEL with renewable generation. This percentage does not include the current solar FIT contracts, because that energy is included within the load forecast. With market purchases serving approximately 23% of NEL, this scenario significantly relies on the market.

SCENARIO 11 – UNLIMITED SOLAR SCENARIO

Scenario 11 maintains the prescribed retirement schedule of GRU's existing units, but allows for unlimited solar capacity. TEA assumed that the ACE requirement of adding 9 MW of RICE capacity per 20 MW of solar would not change with solar capacities above 80 MW. As with other scenarios in this group, note that this assumption would need to be verified by additional ACE studies and detailed production cost analysis.

The resulting resource plan for this study does not add any capacity until 2031. Throughout the course of the study, CE adds the following solar/RICE combinations:

- 2031: 200 MW of solar and 90 MW of RICE
- 2032: 200 MW of solar and 90 MW of RICE
- 2036: 40 MW of solar and 18 MW of RICE
- 2038: 20 MW of solar and 9 MW of RICE
- 2039: 40 MW of solar and 18 MW of RICE

The total installed solar and RICE capacity in 2039 is 500 MW and 225 MW, respectively. The land requirement for this amount of solar capacity would be approximately 3,000 to 4,000 acres. The estimated cost for the additional gas transportation for this scenario is approximately $2.7 million NPVRR less than the reference case.

NPVRR and LCOE by Sensitivity

The cumulative NPVRR in 2039 for the reference case gas sensitivity is $1.991 billion, which is $30 million or 1.5% more than the reference case. The LCOE for the term is $45.38/MWh. This cost includes $35 million NPVRR in transmission and distribution upgrades required to deliver the solar energy.

The cumulative NPVRR in 2039 for the low gas price sensitivity is $1.900 billion, which is $104 million or 5.8% more than the reference case. The LCOE for the term is $43.31/MWh.

The cumulative NPVRR in 2039 for the high gas price sensitivity is $2.045 billion, which is $12 million or 0.6% more than the reference case. The LCOE for the term is $46.61/MWh.

The cumulative NPVRR in 2039 for the PO sensitivity is $1.985 billion, which is $29 million or 1.5% more than the reference case. The LCOE for the term is $45.24/MWh.

Observations

The land requirement for the 500 MW of solar in this scenario is 3,000-4,000 acres, close to 10% of the City's land area. This scenario's resource plan allows the system to serve approximately 75% of the NEL with renewable generation. This percentage does not include the current solar FIT contracts, because that energy is included within the load forecast. With market purchases serving approximately 15% of NEL, this scenario significantly relies on the market.

ACE SCENARIOS COMPARATIVE RESULTS

Figure 41 shows the resource plans resulting from each ACE scenario, including all new builds and unit retirements. It identifies NPVRR in 2018 dollars, as well as the levelized cost for all sensitivity studies performed. The most economical plans across the sensitivities are highlighted in green. Note the NPVRR includes the following gas transportation costs.

- -$4.4 million for the Unlimited Solar – Force 40 MW scenario
- $11 million for the Unlimited Solar – Allow Retirements Except DHR scenario
- -$2.7 million for the Unlimited Solar scenario

The NPVRR also includes the following incremental transmission and distribution upgrade costs required for delivery of solar energy.

- $33.80 million for the Unlimited Solar – Force 40 MW scenario
- $82.56 million for the Unlimited Solar – Allow Retirements Except DHR scenario
- $35.02 million for the Unlimited Solar scenario

Figure 41: ACE Scenario Results

		Reference Case			ACE REQS-Limited 80 MW Solar			ACE REQS-Unlimited Solar-Force 40 MW Solar 2021			ACE REQS-Unlimited Solar-Allow Retirements except DHR			ACE REQS-Unlimited Solar		
Builds		Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)
		2021	4 - Solar	28	2031	3 - Solar	21	2021	2 - Solar	14	2021	4 - Solar	28	2031	10 - Solar	70
		2032	1 - NGCC 3x1	198	2031	3 - 9 MW RICE	27	2022	1 - 18MW RICE	18.4	2021	4 - 9 MW RICE	36	2031	10- 9 MW RICE	90
		2032	3 - 9MW RICE	27	2032	1 - NGCC 3x1	198	2031	7 - Solar	49	2022	10 - Solar	70	2032	10 - Solar	70
		2034	1 - 9MW RICE	9	2033	1 - Solar	7	2031	7 - 9 MW RICE	63	2022	10- 9 MW RICE	90	2032	10- 9 MW RICE	90
		2038	1 - Battery	5	2033	1 - 9 MW RICE	9	2032	10 - Solar	70	2024	1 - Solar	7	2036	2 - Solar	14
Retirements		Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)
		2022	DH1	75	2022	DH1	75	2022	DH1	75	2021	DH1	75	2022	DH1	75
		2023	G2 Energy	3.8	2023	G2 Energy	3.8	2023	G2 Energy	3.8	2021	DH2	228	2023	G2 Energy	3.8
		2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8	2023	G2 Energy	3.8	2026	DH GT 1-2	38.8
		2031	DH2	228	2031	DH2	228	2031	DH2	228	2026	DH GT 1-2	38.8	2031	DH2	228
Net Capacity Change		Term		-78.6	Term		-78.6	Term		38.8	Term		15.4	Term		54.4
Capacity Expansion Cost Results																
NPVRR ($M - $/MWh)	Reference NG		$1,961	$ 44.69		$1,992	$ 45.42		$1,947	$ 44.39		$1,968	$ 44.87		$1,956	$ 44.58
	Low NG		$1,796	$ 40.95		$1,838	$ 41.91		$1,838	$ 41.90		$1,848	$ 42.13		$1,865	$ 42.51
	High NG		$2,032	$ 46.33		$2,055	$ 46.84		$2,009	$ 45.79		$2,057	$ 46.90		$2,010	$ 45.81
Portfolio Optimizer Cost Results																
NPVRR ($M - $/MWh)	Reference NG		$1,956	$ 44.58		$1,953	$ 44.51		$1,951	$ 44.48		$1,955	$ 44.56		$1,950	$ 44.44

Note: The additional capacity above shows only the capacity of the units which can contribute to reserve margin requirements. Solar PPA capacity for reserve margin criteria is 35% of its nameplate capacity. Each solar unit above has a 20 MW of nameplate capacity contributing only 7 MW towards reserve margin.

Figure 42 compares the ACE scenarios' NPVRR results for the PO sensitivity. The associated table breaks out the NPVRR into its various cost components.

See Figure 43 for the percentage of NEL served by renewable generation for the PO sensitivities. As expected, the scenarios that allow unlimited solar additions have the highest percentages of renewables, exceeding 70% by the end of the study period. The retirement case has the largest renewable contribution, approximately 80% by 2039.

The ACE scenarios that allow unlimited solar have a much higher reliance on the market. See Figure 44 for the comparison with the reference case for the PO sensitivity.

Figure 45 compares the ACE scenarios' capital requirements for each resource plan. Note that all cases include capital cost projections for the Kelly refurbishment. Note that the scenario that allows retirements requires large capital expenditures early in the term of the study.

Figure 42: ACE Scenarios PO Sensitivity NPVRR

PO - Reference Gas	Reference Case	Limited 80 MW Solar	Unlimited Solar-Force 40 MW Solar 2021	Unlimited Solar-Allow Retirements except DHR	Unlimited Solar
Fuel and PP Cost	1,455	1,313	1,261	1,100	1,254
Spot Mkt Interchange	32	209	209	350	231
Fixed Cost of Existing Gen.	353	353	353	228	353
Fixed Cost of New Resources	115	118	128	279	120
Add'l NG Transport Capacity	-	-	(4)	11	(3)
Fixed Cost of T&D Upgrades for Solar	-	-	34	83	35
Total Annual Rev Req'ts ($M)	1,956	1,992	1,981	2,051	1,991

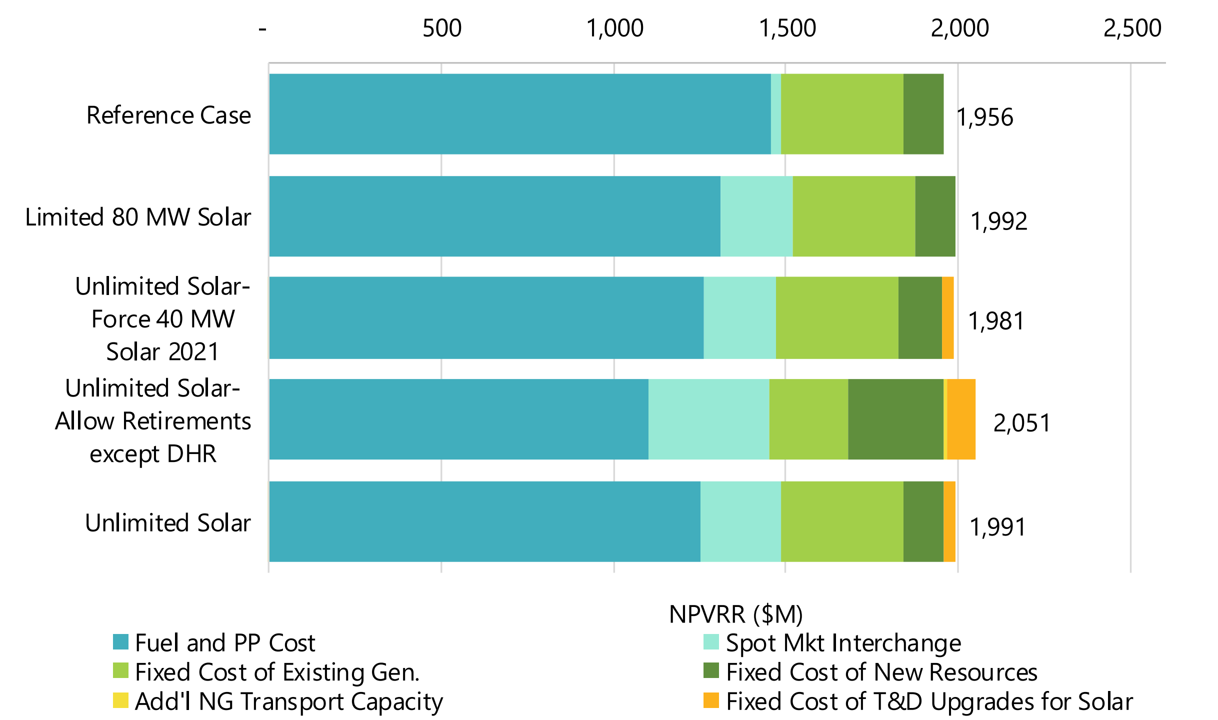


Figure 43: ACE Scenarios Renewable Generation

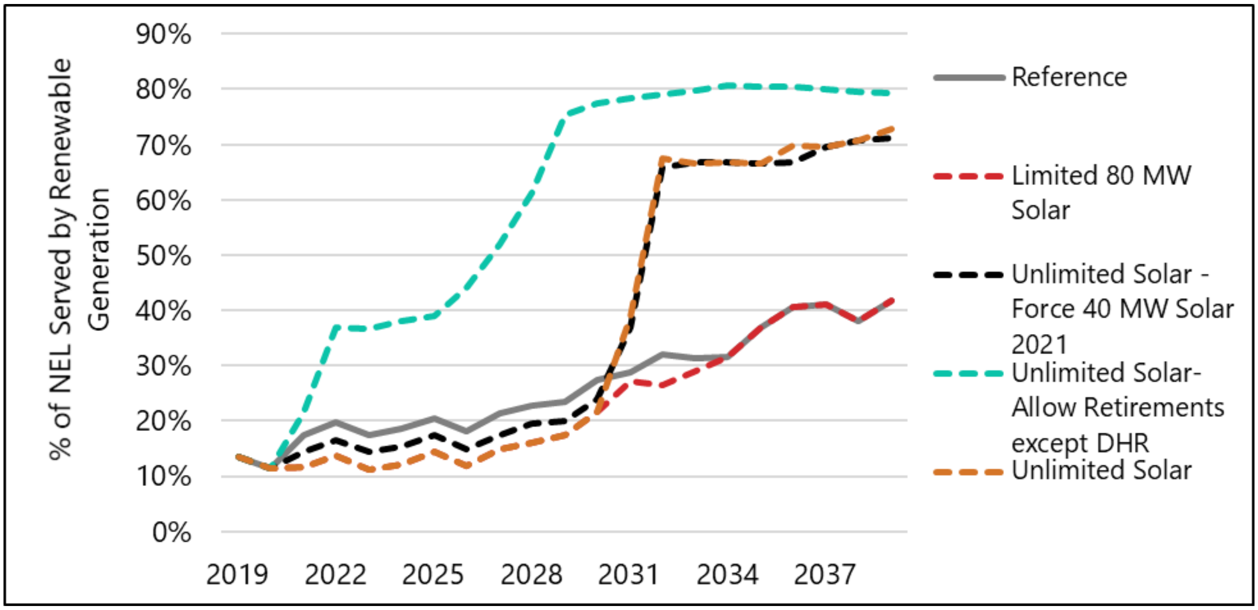


Figure 44: ACE Scenarios Market Purchases

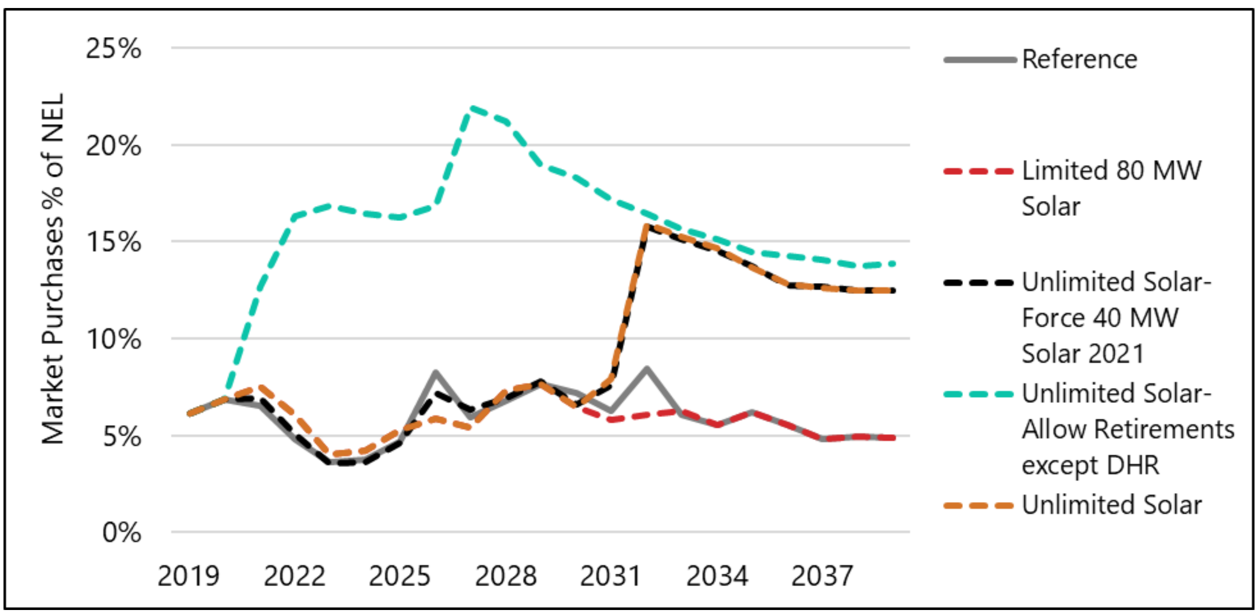
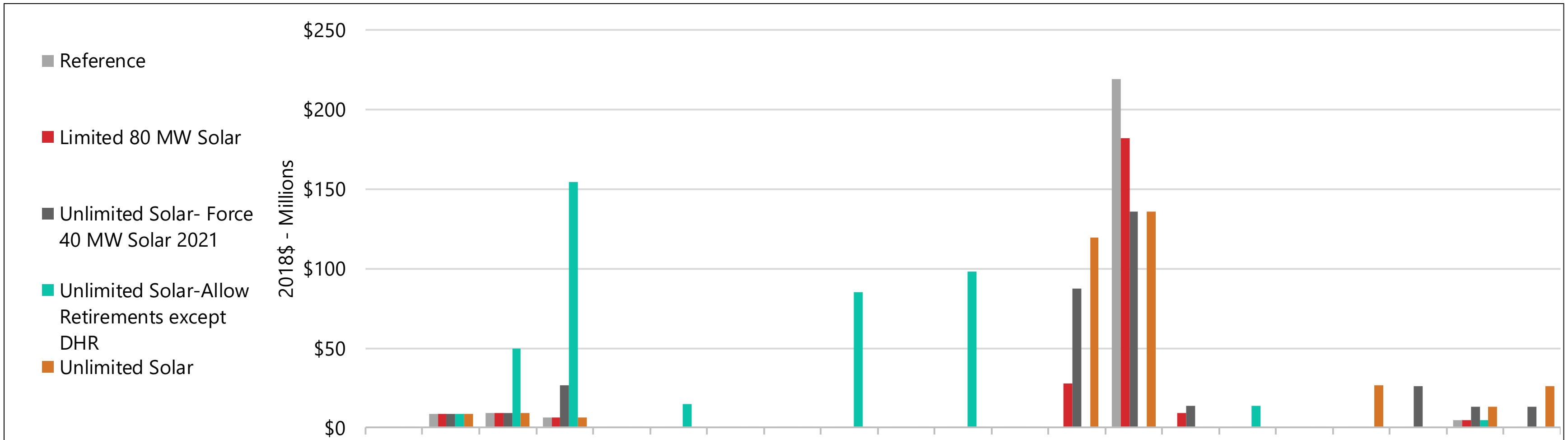


Figure 45: ACE Scenarios Capital Requirements



	Total	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Reference	**$253.8**	$0.4	$8.4	$9.4	$6.3	$1.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$219.3	$0.3	$0.3	$0.3	$0.3	$0.3	$4.5	$0.3
Limited 80 MW Solar	**$253.1**	$0.4	$8.4	$9.4	$6.3	$1.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$28.0	$181.9	$9.4	$0.3	$0.3	$0.3	$0.3	$4.5	$0.3
Unlimited Solar- Force 40 MW Solar 2021	**$338.8**	$0.4	$8.4	$9.4	$26.7	$1.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$87.3	$136.1	$13.8	$0.3	$0.3	$0.3	$26.3	$13.2	$13.1
Unlimited Solar-Allow Retirements except DHR	**$433.8**	$0.4	$8.4	$49.7	$154.5	$1.0	$14.9	$0.3	$0.3	$85.4	$0.3	$97.9	$0.3	$0.3	$0.3	$0.3	$13.7	$0.3	$0.3	$0.3	$4.5	$0.3
Unlimited Solar	**$350.1**	$0.4	$8.4	$9.4	$6.3	$1.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$119.4	$136.1	$0.3	$0.3	$0.3	$26.5	$0.3	$13.2	$25.8

SCENARIO RESULTS – RENEWABLE SCENARIOS (SCENARIOS 12-14)

GRU prescribed three renewable resource scenarios to achieve the City's renewable energy and greenhouse gas goals. Each plan includes solar and biomass plus RICE as backup thermal generation. In all the renewable scenarios, the model forces a new 103 MW biomass plant in 2032 after Deerhaven 2 retires. After Deerhaven 1 retires, the model also forces installation of a total of 119.4 MW of RICE units: 73.6 MW in 2023, 18.4 MW in 2024, 18.4 MW in 2025, and 9 MW in 2026. All other new generation in the model is limited to solar PPAs with battery storage.

The plans address the negative ACE impacts caused by the intermittency of solar energy through combinations of battery storage, rapid response thermal generation, and renewable-based market power. In each of these scenarios, the model constrained the installations by requiring 5 MW, or 20 MWh, of battery to be installed with every 20 MW of solar PPAs. Note this rapid response capacity requirement is less than the requirement assumed in the ACE scenarios because the model forces in additional thermal generation outside of this requirement.

Given a second biomass unit in GRU's generation portfolio, GRU may need to source the additional fuel supply from more distant locations, thus increasing transportation costs. These scenarios assume the cost of the additional biomass fuel will exceed the cost of current supplies by nearly 20%.

The results also include the costs of transmission and distribution upgrades required by introducing large amounts of solar to the system. The model assumes solar farm locations will be outside of GRU's existing transmission loop and that transmission and distribution upgrades will be necessary for solar installations over 80 MW. The capital costs of these upgrades are assumed to be $5 million per 20 MW of solar.

All new solar installations are modeled as the PPAs described in Table 5. No curtailment of the solar energy production is allowed. In the real-world, an ability to curtail production may be allowed contractually; however, the owners of the solar plant would need to recoup any curtailment losses by increasing the energy price or the capacity charge or through take-or-pay contract provisions. Therefore, the price was not changed for the solar PPAs in these studies.

For the purposes of this study, the batteries modeled alongside new solar builds have expected lives of 15 years. Because of the ACE requirement of installing batteries with solar capacity, the term of the solar contract was adjusted to 15 years to match the battery life. In these renewable studies, as the batteries and solar PPAs expire, they are immediately replaced in kind. Therefore, the total amount of solar and battery storage remaining at the end of the study is less than the sum of the solar and battery storage installed over the term of the resource plan.

See the final section for comparative results of all renewable scenarios and associated sensitivities.

SCENARIO 12 – NO MARKET AND NO RICE CONTRIBUTION SCENARIO

One differentiating condition of Scenario 12 is that the system has no access to a market. In other words, the GRU system is considered an island. Although the costs of the RICE units are included, the units are not allowed to generate energy and their capacity is not counted toward

GRU's capacity requirements. In a high renewable environment, reserve margin is not a sufficient criterion for reliability. These units are included in the study to help maintain reliability and meet ACE requirements with large amounts of intermittent solar energy. Disallowing unit operation allows GRU to meet the City's renewable goal in the model while also accounting for the costs of the reliability provided by the RICE units.

In addition to the biomass and RICE units of which the model forces installation, this scenario also includes:

- 2021: 80 MW of solar and 20 MW of battery storage
- 2022: 80 MW of solar and 20 MW of battery storage
- 2024: 20 MW of solar and 5 MW of battery storage
- 2025: 40 MW of solar and 10 MW of battery storage
- 2027: 60 MW of solar and 15 MW of battery storage
- 2028: 80 MW of solar and 20 MW of battery storage
- 2031: 40 MW of solar and 10 MW of battery storage
- 2032: 20 MW of solar and 5 MW of battery storage
- 2033: 60 MW of solar and 15 MW of battery storage
- 2034: 80 MW of solar and 20 MW of battery storage
- 2035: 80 MW of solar and 20 MW of battery storage
- 2036: 80 MW of solar and 20 MW of battery storage
- 2037: 80 MW of solar and 20 MW of battery storage
- 2038: 80 MW of solar and 20 MW of battery storage
- 2039: 80 MW of solar and 20 MW of battery storage

All installations before 2024 will expire by the end of the study term. This results in a total of 780 MW of solar PPAs and 195 MW of battery storage installed.

NPVRR and LCOE by Sensitivity

The total NPVRR of this scenario for the reference gas price sensitivity is $2.225 billion, which is $265 million or 14% more than the reference case. The LCOE for the term is $50.73/MWh. This cost includes $72.1 million NPVRR in transmission and distribution upgrades required to deliver the solar energy.

The high gas and low gas price sensitivities were not evaluated for this scenario as the natural gas prices have a small effect in a high renewable environment with no market access.

The total NPVRR of this scenario for the PO sensitivity is $2.547 billion, which is $592 million or 30% more than the reference case. The LCOE for the term is $58.07/MWh.

Observations

In this scenario, the PO sensitivity indicates that GRU renewable energy will reach 100% of NEL by 2034 and 111% by 2039. This percentage does not include the current solar FIT contracts. Note that the generation includes dump energy that is not included in NEL. Dump energy is surplus electric energy that exceeds existing load requirements or sales abilities. Also, the system still requires some fossil fuel generation, which is provided by the JRK CC.

Although there is some unserved energy in the PO sensitivity study, it is less than 1% on a yearly basis. Unserved energy is the amount of customer demand (measured in MWh) that cannot be supplied within the system due to a deficiency of generation or interconnector capacity. In other words, it is forced load shedding. This study does not allow any market imports, and any unserved energy may be mitigated if market purchases are allowed.

Also in the PO sensitivity study, the system has a significant amount of dump energy due to excess solar energy produced during certain daylight hours. This unused energy grows to nearly 21% of NEL by the end of the study period. This volume can be reduced by curtailing the solar energy coming in to the system. However, as discussed above, the total cost of solar is unlikely to change significantly. Other methods to decrease dump energy are to add more battery storage and to sell the excess energy to a counterparty in the wholesale energy market. Sales opportunities are likely to be limited due to the abundance of solar energy in a high renewable environment.

The land requirement for the 780 MW of solar in this scenario is 5,000 to 6,000 acres, close to 15% of the City's land area.

SCENARIO 13 – RENEWABLE MARKET AND NO RICE CONTRIBUTION SCENARIO

Unlike Scenario 12, this scenario allows GRU to have access to a renewable-based purchase market with 50 MW of import capability. The price of energy from this market is held constant at $50/MWh in nominal dollars throughout the study. The assumed price reduction in real dollars is due to the expectation of continued technology improvements in the renewables industry.

As in Scenario 12, the costs of the RICE units are included, the RICE units are not allowed to generate energy, and their capacity is not counted toward GRU's capacity requirements. In a high renewable environment, reserve margin is not a sufficient criterion for reliability. These units are included to help maintain reliability and meet ACE requirements in an environment with large amounts of intermittent solar energy. Disallowing unit operation allows GRU to meet the City's renewable goal in the model while also accounting for the costs of the reliability provided by the RICE units.

The unit installations of this scenario exactly match those of Scenario 12. See the previous section for a detailed list. By 2039, the system will have a total of 780 MW of solar PPAs and 195 MW of battery storage installed.

NPVRR and LCOE by Sensitivity

The total NPVRR of this scenario for the reference gas case is the same as for Scenario 12. GRU's system never uses the market access it is allowed in the CE model. The total NPVRR for Scenario 13 is $2.225 billion, which is $265 million or 14% more than the reference case. The LCOE for the term is $50.73/MWh. This cost includes $72.11 million NPVRR in transmission and distribution upgrades required to deliver the solar energy.

The high and low gas price sensitivities were not evaluated for this scenario as natural gas prices have a small effect in a high renewable environment with access to only a renewable market.

In the PO sensitivity study, costs are higher than in the CE reference case, but the NPVRR is significantly lower than the same sensitivity study from Scenario 12. The resultant NPVRR of

Scenario 13 for PO is $2.461 billion, which is $505 million or almost 26% more than the reference case for CE. The LCOE for the term is $56.09/MWh.

Observations

This decrease in costs in Scenario 13 in the PO sensitivity compared to Scenario 12's PO sensitivity shows the value of having access to the market.

In this scenario, the PO sensitivity indicates GRU's renewable generation will reach 100% of NEL by 2034 and 116% by 2039. Note that the generation includes dump energy not included in NEL. Also, the system still requires fossil fuel generation, which is provided by the JRK CC.

There is some unserved energy in the PO sensitivity case, although it is less than 1% annually. Due to the ability to access the market, it is also less than the unserved energy in Scenario 12. The unserved energy can be mitigated by an import capability greater than 50 MW.

The PO sensitivity case shows a significant amount of dump energy due to excess solar energy produced during daylight hours. This unused energy grows to 19% of NEL by the end of the study period. Although it is unlikely to significantly change the overall cost of solar energy production, GRU can reduce the volume of dump energy by curtailing solar energy production, adding more battery storage, or selling the excess energy to a counterparty in the wholesale energy market. Sales opportunities are likely to be limited due to the abundance of solar energy in a high renewable environment.

The land requirement for the solar PPAs is 5,000 -6,000 acres, nearly 15% of the City's land area.

SCENARIO 14 – NO MARKET WITH RICE CONTRIBUTION SCENARIO

Scenario 14 allows the RICE units to contribute energy and capacity to the system. However, as in Scenario 12, the system has no access to a market and is considered an island.

This scenario sees fewer additions of solar and battery storage compared with the previous scenarios. In addition to the biomass and RICE units of which the model forces installation, this scenario also includes:

- 2021: 80 MW of solar and 20 MW of battery storage
- 2022: 80 MW of solar and 20 MW of battery storage
- 2031: 60 MW of solar and 15 MW of battery storage
- 2033: 80 MW of solar and 20 MW of battery storage
- 2034: 80 MW of solar and 20 MW of battery storage
- 2035: 80 MW of solar and 20 MW of battery storage
- 2036: 80 MW of solar and 20 MW of battery storage
- 2037: 80 MW of solar and 20 MW of battery storage
- 2038: 80 MW of solar and 20 MW of battery storage
- 2039: 80 MW of solar and 20 MW of battery storage

All installations before 2024 will expire by the end of the study term. In 2039, the system has 700 MW of solar PPAs and 175 MW of battery storage installed.

NPVRR and LCOE by Sensitivity

The total NPVRR for the reference case gas sensitivity of Scenario 14 is $2.192 billion, which is $232 million or 12% more than the reference case. The LCOE for the term is $49.97/MWh. This cost includes $50.95 million NPVRR in transmission and distribution upgrades required to deliver the solar energy.

The high and low gas price sensitivities were not evaluated for this scenario as the natural gas prices have a small effect in a high renewable environment with no market access.

In the PO sensitivity study, costs are higher than in the CE reference case. The resultant NPVRR of Scenario 14's PO sensitivity is $2.399 billion, which is $443 million or 23% more than the reference case. The LCOE for the term is $54.68/MWh.

In this scenario, the PO sensitivity indicates GRU's renewable generation will not reach 100% of NEL until 2039. Note that the generation includes dump energy that is not included in NEL. Also, the system still requires some fossil fuel generation, which is provided by the JRK CC and the RICE units.

The PO sensitivity includes some unserved energy, although it is less than 1% annually. As in Scenario 12, this scenario did not allow any market imports and the unserved energy may be mitigated if the system is allowed to make market purchases.

The PO sensitivity case shows a significant amount of dump energy due to the production of excess solar energy during daylight hours. This unused energy grows to 14% of NEL by the end of the study period, less than the other two renewable scenarios. Note that this scenario also installs less solar capacity. Although it is unlikely to significantly change the overall cost of solar energy production, GRU can reduce the volume of dump energy by curtailing solar energy production, adding more battery storage, or selling the excess energy to a counterparty in the wholesale energy market. Sales opportunities are likely to be limited due to the abundance of solar energy in a high renewable environment.

The land requirement for 700 MW of is 4,000-6,000 acres, which is about 13% of the City's land area.

RENEWABLE SCENARIOS COMPARATIVE RESULTS

Figure 46 shows the generation additions in each renewable scenario by 2039. Note the life of the battery storage is 15 years and the terms of the solar PPA in these scenarios has been adjusted to match. As battery storage and solar PPAs expire, they are replaced in kind.

Figure 46: Renewable Scenarios Generation Additions

		No Market & No RICE Contribution	Renewable Mkt & No RICE Contribution	No Market with RICE Contribution
Installed MW	Solar PPA	780	780	700
	Battery	195	195	175
	Biomass	103	103	103
	RICE	119.4	119.4	119.4

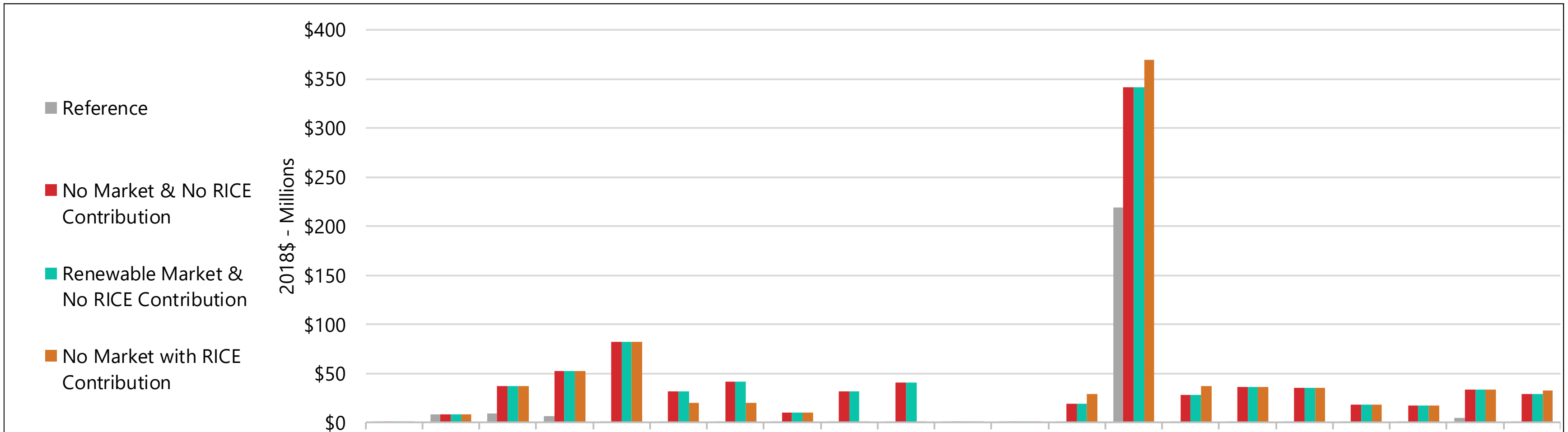
Figure 47 shows the resource plans resulting from each renewable scenario, including all new builds and unit retirements. It identifies NPVRR in 2018 dollars, as well as the levelized cost for all sensitivity studies performed. The most economical plans across the sensitivities are highlighted in green. Note the NPVRR includes incremental transmission and distribution upgrade costs equal to $72 million for scenarios not allowing RICE contribution and $51 million for the scenario allowing RICE contribution.

Figure 47: Renewable Scenario Results

		Reference Case			No Market & No RICE Contribution			Renewable Market & No RICE Contribution			No Market with RICE Contribution		
Builds		Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)	Year	New Unit	Add'l Capacity (MW)
		2021	4 - Solar	28	2021	4 - Solar/Battery	48	2021	4 - Solar/Battery	48	2021	4 - Solar/Battery	48
		2032	1 - NGCC 3x1	198	2022	4 - Solar/Battery	48	2022	4 - Solar/Battery	48	2022	4 - Solar/Battery	48
		2032	3 - 9MW RICE	27	2023	4 - 18MW RICE	73.6	2023	4 - 18MW RICE	73.6	2023	4 - 18MW RICE	73.6
		2034	1 - 9MW RICE	9	2024	1 - Solar/Battery	12	2024	1 - Solar/Battery	12	2024	1 - 18MW RICE	18.4
		2038	1 - Battery	5	2024	1 - 18MW RICE	18.4	2024	1 - 18MW RICE	18.4	2025	1 - 18MW RICE	18.4
					2025	2 - Solar/Battery	24	2025	2 - Solar/Battery	24	2026	1 - 9MW RICE	9
					2025	1 - 18MW RICE	18.4	2025	1 - 18MW RICE	18.4	2031	3 - Solar/Battery	36
					2026	1 - 9MW RICE	9	2026	1 - 9MW RICE	9	2032	4 - Solar/Battery	48
					2027	3 - Solar/Battery	36	2027	3 - Solar/Battery	36	2032	1 - Biomass	103
					2028	4 - Solar/Battery	48	2028	4 - Solar/Battery	48	2033	4 - Solar/Battery	48
					2031	2 - Solar/Battery	24	2031	2 - Solar/Battery	24	2034	4 - Solar/Battery	48
					2032	1 - Solar/Battery	12	2032	1 - Solar/Battery	12	2035	4 - Solar/Battery	48
					2032	1 - Biomass	103	2032	1 - Biomass	103	2036	4 - Solar/Battery	48
					2033	3 - Solar/Battery	36	2033	3 - Solar/Battery	36	2037	4 - Solar/Battery	48
					2034	4 - Solar/Battery	48	2034	4 - Solar/Battery	48	2038	4 - Solar/Battery	48
					2035	4 - Solar/Battery	48	2035	4 - Solar/Battery	48	2039	4 - Solar/Battery	48
					2036	4 - Solar/Battery	48	2036	4 - Solar/Battery	48			
					2037	4 - Solar/Battery	48	2037	4 - Solar/Battery	48			
					2038	4 - Solar/Battery	48	2038	4 - Solar/Battery	48			
					2039	4 - Solar/Battery	48	2039	4 - Solar/Battery	48			
Retirements		Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)	Year	Unit	Retired Capacity (MW)
		2022	DH1	75	2022	DH1	75	2022	DH1	75	2022	DH1	75
		2023	G2 Energy	3.8	2023	G2 Energy	3.8	2023	G2 Energy	3.8	2023	G2 Energy	3.8
		2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8	2026	DH GT 1-2	38.8
		2031	DH2	228	2031	DH2	228	2031	DH2	228	2031	DH2	228
Net Capacity Change (MW)		Term		-78.6	Term		236.8	Term		236.8	Term		296.8
Capacity Expansion Cost Results													
NPVRR ($M - $/MWh)	Reference NG		$1,961	$ 44.69		$2,225	$ 50.73		$2,225	$ 50.73		$2,192	$ 49.97
	Low NG		$1,796	$ 40.95									
	High NG		$2,032	$ 46.33									
Portfolio Optimizer Cost Results													
NPVRR ($M - $/MWh)	Reference NG		$1,956	$ 44.58		$2,547	$ 58.07		$2,461	$ 56.09		$2,399	$ 54.68

Note: The additional capacity above shows only the capacity of the units which can contribute to reserve margin requirements. Solar PPA capacity for reserve margin criteria is 35% of its nameplate capacity. Each solar unit above has a 20 MW of nameplate capacity contributing only 7 MW towards reserve margin.

Figure 48: Renewable Scenarios Capital Requirements



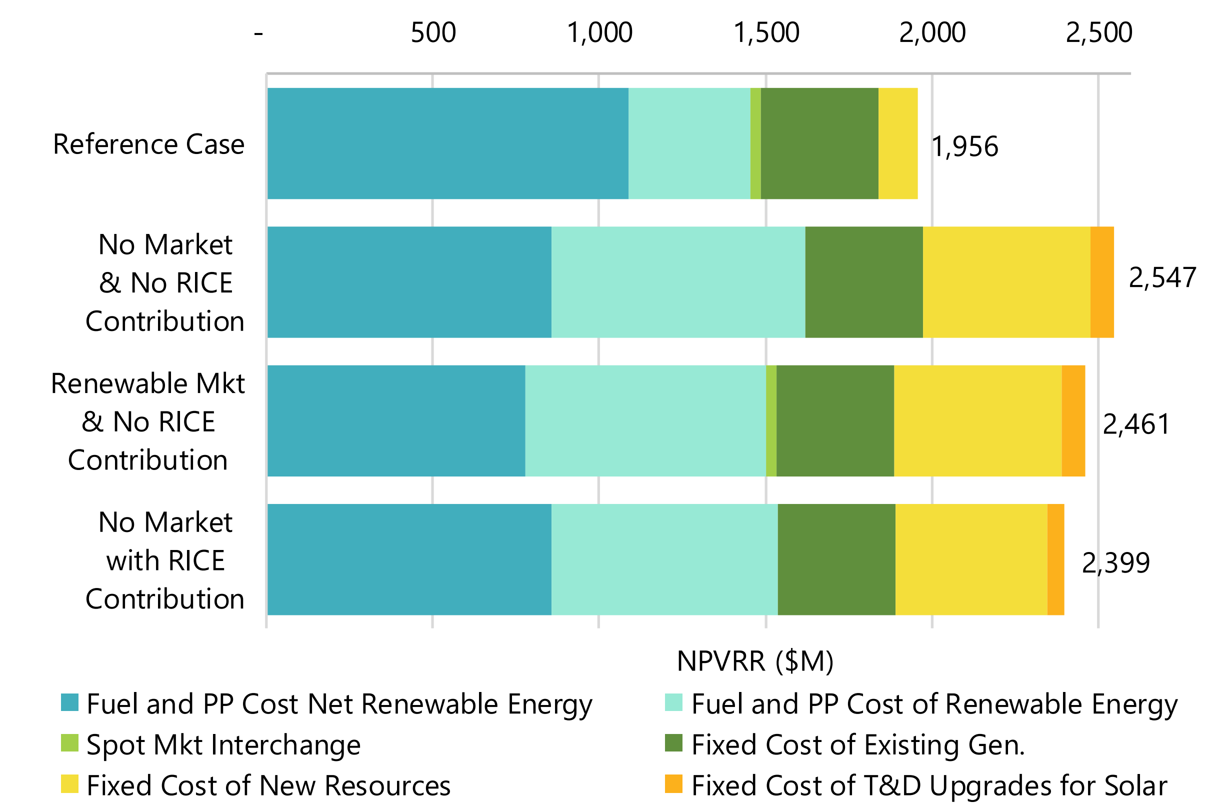
	Total	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Reference	**$253.8**	$0.4	$8.4	$9.4	$6.3	$1.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$219.3	$0.3	$0.3	$0.3	$0.3	$0.3	$4.5	$0.3
Renewable - No Market & No RICE Contribution	**$895.1**	$0.4	$8.4	$36.8	$52.2	$82.0	$31.4	$41.8	$10.0	$31.4	$41.0	$0.3	$0.3	$19.5	$341.5	$27.9	$36.4	$35.7	$17.9	$17.4	$33.7	$28.9
Renewable - Renewable Market & No RICE Contribution	**$895.1**	$0.4	$8.4	$36.8	$52.2	$82.0	$31.4	$41.8	$10.0	$31.4	$41.0	$0.3	$0.3	$19.5	$341.5	$27.9	$36.4	$35.7	$17.9	$17.4	$33.7	$28.9
Renewable - No Market with RICE Contribution	**$841.7**	$0.4	$8.4	$36.8	$52.2	$82.0	$20.4	$20.2	$10.0	$0.3	$0.3	$0.3	$0.3	$29.0	$369.6	$37.1	$36.4	$35.7	$17.9	$17.4	$33.7	$33.1

Figure 48 compares the renewable scenarios' capital requirements for each resource plan. Note that all cases include capital cost projections for the Kelly refurbishment. All of the scenarios require more capital investments earlier in the term of the study than the reference case.

Figure 49 compares the renewable scenarios' NPVRR results for the PO sensitivity. The associated table breaks out the NPVRR into its various cost components.

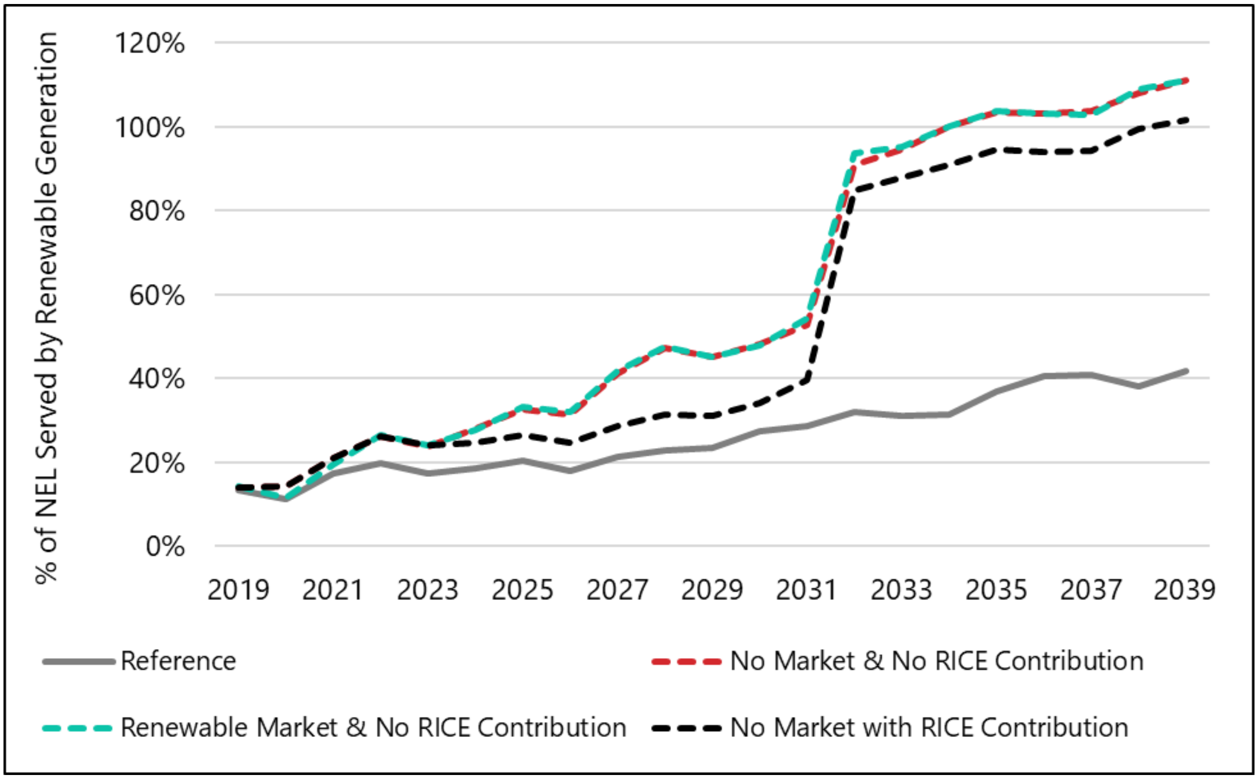
Figure 49: Renewable Scenarios PO Sensitivity NPVRR

PO - Reference Gas	Reference Case	No Market & No RICE Contribution	Renewable Mkt & No RICE Contribution	No Market with RICE Contribution
Fuel and PP Cost Net Renewable Energy	1,089	858	779	859
Fuel and PP Cost of Renewable Energy	366	763	724	678
Spot Mkt Interchange	32	-	31	-
Fixed Cost of Existing Gen.	353	353	353	353
Fixed Cost of New Resources	115	501	501	458
Fixed Cost of T&D Upgrades for Solar	-	72	72	51
Total Annual Rev Req'ts ($M)	1,956	2,547	2,461	2,399



See Figure 50 for the percentage of NEL served by renewable generation for the PO sensitivities. The renewable percentages in the renewable scenarios exceed 100% because there is significant dump energy in these PO sensitivity studies.

Figure 50: Renewable Scenarios Renewable Generation



Section 8: Conclusions and Recommendations

CONCLUSIONS

THE KELLY COMBINED CYCLE INVESTMENT DECISION

The retirement or replacement of the ST generator requires a timely decision. An ST replacement delays a large capital outlay for alternative replacement generation and improves future flexibility regarding unit retirements and replacement generation. The upgrade would also maintain the existing voltage support for the JRK distribution substation.

SOLID FUEL GENERATION

The fuel diversity offered by DHR and DH2 improves economics in a high gas price scenario. Additionally, the potential savings from retiring DH2 early are marginal. Such a retirement would require a $140-$200 million capital expense in 2022 and adding approximately 10,000 MMBtu/day in NG transportation.

Biomass is a carbon-neutral renewable energy resource pursuant to Section 451 of the US Congress's Consolidated Appropriations Act.[27]

ACE STUDY REQUIREMENTS WITH ADDITION OF SOLAR CAPACITY

Early solar additions of up to 80 MW have little effect on GRU's NPVRR even with rapid response generation requirements. For solar backup, RICE is currently more economical than small gas turbines or storage. GRU's system would require approximately 9 MW of RICE for every 20 MW of solar to maintain reliability. Solar additions above 74.5 MW may require a larger proportion of rapid response generation.

100% RENEWABLE ENERGY REQUIREMENT

Meeting this requirement results in a cost increase of $433-$591 million in NPVRR through 2039 and would require significant rate increases. This future includes an additional thermal biomass unit that contributes to system reliability and fuel and RICE engines that provide rapid response backup due to ACE requirements for addressing the intermittency of solar energy. This scenario results in a significant increase in dump energy that may be mitigated by solar curtailment, adding battery storage, or selling the excess energy in the wholesale market. However, sales opportunities are likely to be limited due to the abundance of solar energy in a high renewable environment. Although the model projects less than 1% of energy demand will be unserved, this number may potentially be higher in actual operation. The plans in this study include thermal generation throughout the study period, in the form of the Kelly CC and RICE units.

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[27] Environmental Protection Agency. 2018. "EPA's Treatment of Biogenic Carbon Dioxide (CO_2) Emissions from Stationary Sources that Use Forest." April 23. Accessed September 10, 2019. https://www.epa.gov/sites/production/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf.

RESOURCE PLAN CONSIDERATIONS

The following must be considered before progressing with a resource plan:

- The resource plan must have the flexibility to meet the City's resolution to use 100% renewable generation and become a net zero greenhouse gas community by 2045.
- Any early replacement of existing thermal generation with large solar installations would require a corresponding addition of thermal rapid response (i.e. RICE) units or batteries to avoid ACE deficiencies.
- Delaying large installations of solar allows battery storage technologies time to develop and mature so that the use of batteries may become a viable alternative to thermal rapid response generation.
- An early installation of 40-80 MW of solar with 20-40 MW of rapid response thermal generation will have a minimal impact on economics.
- Large amounts of solar will require transmission and distribution system upgrades of approximately $5 million per 20 MW of solar in 2018 dollars.
- Large amounts of solar will require significant land. One MW requires about 6 to 8 acres.

RECOMMENDATIONS

The recommendations resulting from this study are based on the economics of each decision according to the inputs determined by TEA. These inputs were selected according to TEA's best judgment based on industry experience, private and government research, vendor information, and GRU records.

- Add solar resources to lower average energy cost and advance towards City's goal of 100% renewable system.
- Limit additional solar capacity to 74.5 MW until additional ACE and detailed production cost analysis is performed.
- Add 10 MW of RICE per 20 MW of solar as rapid response back up due to intermittency of solar energy. Battery storage may become a more cost-effective alternative as the economics and technology improve.
- Refurbish JR Kelly CC to take advantage of the current low-cost NG environment and delay a significant capital expenditure for unit replacement.
- Retain DH2 and DHR at least until the next IRP update.
- Continue to monitor biomass status as a renewable energy resource.
- Consider coordinating with other utilities by jointly balancing systems to help maintain system reliability at a reasonable cost in a high renewable environment.
- Continue to include regular IRP updates as part of an effective planning process.

KEY RISK FACTORS

The most significant risk factors which could impact the recommendations include the following:

- The **rate of EV adoption and falling cost of DERs** could drive energy growth while increasing costs at the distribution level. These could also have significant impact on load growth, load shape, rates, distribution level upgrades, and future supply needs. Conversely, the falling cost of DERs could speed load destruction for key commercial and industrial accounts, potentially decreasing important revenue streams from GRU's largest accounts.

- **Federal, state, and local tax incentives** could greatly alter pricing of wind and solar. PPA pricing is highly dependent on national incentives, and the political makeup of the executive and legislative branch of the federal government strongly influences the future of those incentives.
- The **rate of technological change** should drive smaller investments with shorter return cycles. The rate at which all technology improves, regardless of industry, is increasing rapidly. The further out into the future a study examines, the harder it is to predict what will happen. To lessen the risk of a plan, it is important to consider smaller, more frequent investments over the more traditional approach of investments with 30-50 year lifespans.
- **Changes to public policy** on issues such as renewable targets, emissions mitigation targets, hydraulic fracturing, adoption of new technologies, and energy market structure can affect the cost and feasibility of utility resource decisions.
- A **large amount of intermittent renewable resources** (i.e. solar) can affect GRU's capability of meeting its ACE requirements. There needs to be sufficient balance between renewable generation and rapid response capability. The latest ACE study considered up to 74.5 MW of solar energy on GRU's system. Solar installations greater than that will require additional study.
- The **categorization of biomass as a carbon-neutral resource** is important given GRU's current goals and generation portfolio. Biomass is currently considered a renewable resource according to the EPA. The June 2019 Affordable Clean Energy (ACE) notice excludes the use of biomass fuel to reduce carbon emissions on existing units. The EPA definition of carbon neutral fuels needs to be monitored.
- **Dependency on a small number of large generating units** relative to load increases risk. For example, an extended outage of DH2 or DHR may result in inadequate reliability.

DISCLAIMER

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Appendices

APPENDIX A: LIST OF ACRONYMS

ACE	Affordable Clean Energy
ACE	Area Control Error
AFB	Atmospheric Fluidized-Bed Boiler
aMW	average megawatt
BA	Balancing Authority
BTM	Behind-the-Meter
Btu	British thermal units
CAPP	Central Appalachian
CC	Combined Cycle Gas Turbine
CHP	combined heat and power
CO2	carbon dioxide
COP	Coefficient of Performance
CT or GT	Simple Cycle Gas-Fired Combustion Turbine
DEF	Duke Energy Florida
DER	distributed energy resources
DG	distributed generation
DH	Deerhaven
DHR	Deerhaven Renewable
DSCR	Debt Service Coverage Ratio
DSM	Demand-Side Management
DR	Demand-Side Resources
EE	Energy Efficiency
EIA	United States Energy Information Agency
EPA	U.S. Environmental Protection Agency
EPP	Emergency Power Purchases
EV	Electric Vehicle
FEECA	Florida Energy Efficiency and Conservation Act
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission
FIT	Feed-In-Tariff
FOM	Fixed O&M
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council, Inc.

FS	Fossil-Steam
FT	Firm Transmission
GHG	Greenhouse Gases
GO	Generation Owner
GRU	Gainesville Regional Utilities
GW	Gigawatt (power)
GWh	Gigawatt-hour (energy)
HRSG	Heat Recovery Steam Generator
IB	Illinois Basin
ICE	internal combustion engine
IRP	Integrated Resource Plan
IT	Interruptible Transmission
ITC	Federal Investment Tax Credit
JRK	John R. Kelly
K8	Kelly 8 Steam Turbine Generator
kW	Kilowatt (power)
kWh	Kilowatt-hour (energy)
LCOE	Levelized Cost of Energy
LDC	Local Distribution Company for natural gas
LSE	Load Serving Entity
MMBtu	Million British Thermal Units
MW	Megawatt (power)
MWh	Megawatt-hour (energy)
NEL	Net Energy for Load
NERC	North American Electric Reliability Corporation, Inc.
NG	Natural Gas
NPVRR	Net Present Value of Revenue Requirements
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance Expense
PO	Portfolio Optimizer
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PTC	Federal Production Tax Credit
PV	Photovoltaics
RE	Regional Entity
RE	Renewable Energy
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative

RICE	Reciprocated Internal Combustion Engine
RPS	Renewable Portfolio Standards
S&P	S&P Global Platts
SC or Simple Cycle	Simple thermodynamic cycle generating unit
SEC	South Energy Center
ST or STG	Steam Turbine Generators
TEA	The Energy Authority
The City	The City of Gainesville, Fl
TO	Transmission Owner
TOP	Transmission Operator
TWh	terawatt-hours
TYSP	Ten-Year Site Plan
VOM	Variable O&M
WoodMac	Wood Mackenzie

APPENDIX B: LEVELIZED COST OF ENERGY

The levelized cost of energy (LCOE) is an industry-standard measure of cost over the life of a resource expressed in terms of cost per MWh. LCOE typically divides the total lifetime cost of the resource by the total lifetime output, as shown below.

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{\mathrm{I}_t + \mathrm{M}_t + \mathrm{F}_t}{(1+\mathrm{r})^t}}{\sum_{t=1}^{n} \frac{\mathrm{E}_t}{(1+\mathrm{r})^t}}$$

I_t = Capital investment and financing expenditures in year t

M_t = O&M expenditures in year t

F_t = Fuel expenditures in year t

E_t = Electric output in year t

r = Discount rate

n = Life of system

Because this study uses four different demand and energy forecasts between all the scenarios, LCOE is used here in conjunction with NPVRR to help illustrate the comparative costs of each plan. For the purposes of this IRP, the calculation was slightly altered to the total plan cost (the NPVRR) divided by the total energy usage.

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{\mathrm{I}_t + \mathrm{M}_t + \mathrm{F}_t + \mathrm{P}_t}{(1+\mathrm{r})^t}}{\sum_{t=1}^{n} \frac{\mathrm{L}_t}{(1+\mathrm{r})^t}}$$

I_t = Capital investment expenditures in year t, including and financing expenditures on new resources

M_t = O&M expenditures in year t

F_t = Fuel expenditures in year t

P_t = Net market purchase costs in year t

L_t = Energy usage for load in year t

r = Discount rate

n = Length of study period