BURNS McDONNELL

Integrated Resource Plan

LUS
LAFAYETTE UTILITIES SYSTEM

Lafayette Utilities System

Project No. 118157

July 2020

BURNS & McDONNELL

July 24, 2020

Mr. Jeff Stewart
Manager, Engineering and Power Supply
Lafayette Utilities System
1314 Walker Road
Lafayette, Louisiana 70506

Re: Integrated Resource Plan

Dear Mr. Stewart:

Burns & McDonnell Engineering Co. ("Burns & McDonnell") was retained by Lafayette Utilities System ("LUS") to provide a power supply planning study, commonly referred to as an Integrated Resource Plant ("IRP"). Burns & McDonnell is pleased to submit our report that details the results of the IRP conducted on the behalf of LUS. Based on the analysis contained herein on of LUS' system and Burns & McDonnell's experience in the electric utility industry, the following conclusions have been developed:

1. LUS should continue to maintain a well-diversified power generation portfolio consisting of both dispatchable and renewable resources. Dispatchable resources, such as natural gas-fired power plants, will be able to provide the required capacity for reliability and resource adequacy while incorporating low cost energy from renewables.
2. LUS should continue procuring short-term capacity resources (as short-term market capacity remains low cost) as well as mid-term and long-term resources such as power purchase agreements and owned resources.
3. Long-term coal-fired operation at Rodemacher Power Station Unit 2 ("RPS2") does not appear to be economical due to significant investment requirements associated with environmental regulations and ongoing operation and maintenance costs, in addition to low market prices. The focus of this specific evaluation was to determine whether to continue coal-fired operations at RPS2, but not to specifically determine its potential replacement. LUS should consider retirement of coal-fired generation by the end of 2027 to avoid investments required to continue coal-fired operation after that time.
4. The decision to retire coal-fired generation requires Joint Owner, individual governing body, environmental, state regulatory, and MISO approvals. LUS should determine, in cooperation with the other co-owners, whether RPS2 should be retired from electric generation altogether when coal-fired operation is retired or converted to natural gas operation.
5. If RPS2 is retired from generation, LUS should consider a self-build simple cycle gas turbine to replace RPS2. LUS has the existing Louis "Doc" Bonin Electric Generating Station that may be suitable for repurposing as simple cycle facility. LUS should consider starting engineering studies for the existing facility to assess the feasibility of repurposing the site.

6. Prior to any long-term power supply decision, LUS should consider other power purchase agreements that may be available when RPS2 retires that may serve as an alternative to a self-build option.
7. LUS should consider the addition of renewable resources, specifically solar resources, to its portfolio through power purchase agreements. LUS should consider issuing a power supply request for proposal to solicit bids for capacity and energy, with an emphasis on solar.
8. LUS should continue to monitor the overall electric utility industry, especially regulations that have potential to impact its power supply portfolio regarding water, coal combustion by-products, air emissions, and fuel supply. Furthermore, LUS should continue to monitor technological improvements for emerging technologies such as energy storage and other renewable resources.
9. As is customary within the electric utility industry, LUS should continue to review and reassess its power supply plan periodically.

It has been a pleasure to work with LUS regarding these matters. Should you have any questions regarding the information presented herein, please feel free to contact Mike Borgstadt at 816-822-3459 or mike.borgstadt@1898andco.com or Kyle Combes at 816-349-6884 or kyle.combes@1898andco.com.

Sincerely,

Mike Borgstadt, PE
Director, Utility Consulting

Kyle Combes

Kyle Combes
Project Manager

MEB/meb

Enclosure: Integrated Resource Plan

Integrated Resource Plan

prepared for

Lafayette Utilities System

Lafayette, Louisiana

Project No. 118157

July 2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
§	section
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AFC	Accelerated Fleet Change
BART	Best Available Retrofit Technology
BAT	Best Available Technology Economically Achievable
BLR	balance of loads and resources
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
BTA	Best Technology Available
Btu	British thermal unit
CCGT	combined cycle gas turbine
CCR	Coal Combustion Residue
CFC	Continued Fleet Change
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
CSAPR	Cross-State Air Pollution Rule
CTs	combustion turbines
CWA	Clean Water Act
DC	District of Columbia
DET	Distributed & Emerging Technologies
DOE	Department of Energy
DSM	demand side management
EE	energy efficiency
ELCC	effective load carrying capability
EGU	Electric Generating Unit
EIA	Energy Information Administration

Abbreviation	Term/Phrase/Name
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
ERCs	emission reduction credits
Forecast	2018 Long-term Load Forecast
FTE	full time equivalent
g	Earth's net acceleration due to gravity
GE	General Electric
GHG	Greenhouse Gas
GT	gas turbine
GW	gigawatt
GWh	gigawatt hour
HHU1	Hargis-Hébert Unit 1
HHU2	Hargis-Hébert Unit 2
hr	hour
ICAP	installed capacity
IDC	interest during construction
IM	impingement mortality
IRP	Integrated Resource Plan
kWh	kilowatt hour
L	liter
Labbe	T.J. Labbé Power Generation Station
lb	pound
LCOC	levelized cost of capacity
LDEQ	Louisiana Department of Environmental Quality
LED	light emitting diode
LEPA	Louisiana Energy and Power Authority
LFC	Limited Fleet Change

Abbreviation	**Term/Phrase/Name**
LMP	locational marginal pricing
LOLE	Loss of Load Expectation
LRZ	Local Resource Zone
LUS	Lafayette Utilities System
m	meter
MATS	Mercury and Air Toxics Standards
mg	milligram
MISO	Midcontinent Independent System Operator
MTEP20	MISO Transmission Expansion Planning for 2020
MM	million
MMBtu	million British thermal units
MSA	Lafayette Metropolitan Statistical Area
MW	megawatt
MWh	megawatt hour
N/A	not applicable
NAAQS	National Ambient Air Quality Standards
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
ng	nanogram
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NPV	net present value
O&M	operation and maintenance
O_2	oxygen
O_3	ozone
OEM	original equipment manufacturer
PCT	programmable communicating thermostat
PE	Professional Engineer

Abbreviation	**Term/Phrase/Name**
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PPA	power purchase agreement
ppb	parts per billion
PRA	Planning Resource Auction
PRM	planning reserve margin
PV	photovoltaic
RACT	Reasonably Available Control Technology
RE	renewable energy
RH	relative humidity
RHR	Regional Haze Rule
Rodemacher	Rodemacher Power Station
RPS2	Rodemacher Power Station Unit 2
SCED	security constrained economic dispatch
SCGT	simple cycle gas turbine
SCR	selective catalytic reduction
sec	second
SO_2	sulfur dioxide
ST	steam turbine
Study	Resource Planning Study
SWPA	Southwestern Power Administration
Tech Assessment	Generation Technology Assessment
TJU1	T.J. Labbé Unit 1
TJU2	T.J. Labbé Unit 2
UCAP	unforced capacity
U.S.	United States
ug	microgram
USD	United States Dollar

Abbreviation	**Term/Phrase/Name**
Woods & Poole	Woods & Poole Economics, Inc.

STATEMENT OF LIMITATIONS

In preparation of this Study, Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") has relied upon information provided by Lafayette Utilities System ("LUS"). While Burns & McDonnell has no reason to believe that the information provided, and upon which Burns & McDonnell has relied, is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness.

Estimates and projections prepared by Burns & McDonnell relating to performance, construction costs and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee the accuracy of its estimates or predictions. Actual rates, costs, performance, schedules, etc., may vary from the data provided.

1.0 EXECUTIVE SUMMARY

1.1 Introduction

Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") was retained by Lafayette Utilities System ("LUS") to provide resource planning assistance for both short-term and long-term power supply needs. LUS requested that Burns & McDonnell perform a resource planning study to assess the options that may be available to LUS for providing reliable, low cost, and environmentally compliant power to its customers. This report summarizes the process, methodology, assumptions, economic evaluation, and conclusions and recommendations of the load forecast and power supply planning assessment ("Study").

1.2 Conclusions & Recommendations

Based on the analysis herein, Burns & McDonnell provides the following overall observations, conclusions, and recommendations.

1. LUS should continue to monitor the overall electric utility industry, especially regulations that have potential to impact their power supply portfolio regarding water, coal combustion by-products, air emissions, and fuel supply. Furthermore, LUS should continue to monitor technological improvements for emerging technologies such as energy storage and other renewable resources.
2. Utilizing a combination of owned resources, power purchase agreements, and short-term capacity contracts to meet reserve margin requirements will allow LUS to continue to benefit from low capacity costs from third-parties while also limiting market exposure to future fluctuations for capacity and energy.
3. Under current environmental regulations, natural gas prices are expected to remain low due to hydraulic fracturing methods. Low natural gas prices, in combination with continued development of renewable resources, will likely maintain the relatively low wholesale energy prices experienced by LUS in the past five years.
4. The cost of capacity continues to remain low within MISO. While that value of capacity has increased slightly as indicated within the most recent MISO Planning Resource Auction, low cost capacity appears available to allow LUS to meet its resource adequacy requirements in the short-term, whether through the MISO auction process or third-party transactions. As LUS has done recently, LUS should continue to consider procuring short-term capacity purchases to meet its resource adequacy requirements.

5. Overall, LUS has maintained its generation fleet at, or exceeding, industry benchmarks based on reliability metrics and overall costs compared to similar units within the industry.
6. Environmental considerations
    a. Under the current environmental regulations, LUS' natural gas-fired units do not appear to require large capital improvements for compliance.
    b. Due to environmental regulations, RPS2 is faced with the need for capital improvements and investment, regardless of its long-term operating configuration.
    c. RPS2 is subject to numerous environmental regulations as it is a coal-fired power plant. The following regulations will impact the unit.
        i. Coal Combustion Residue: Regardless of RPS2's long-term operations (whether utilizing coal, converted to natural gas, or retired), the unit will be required to close the existing on-site ash ponds to comply with CCR. These capital improvements are estimated to be approximately $20 to $25 million (for the entire RPS2 unit).
        ii. Effluent Limit Guidelines: LUS' RPS2 is expected to be impacted by the ELG rule so long as the unit continues to burn coal. The proposed ELG rules do allow for utilities to commit to retiring a unit by December 31, 2028 to avoid any new ELG requirements for bottom ash transport water. If this option is incorporated into a final rule, this option should be considered by LUS and the other co-owners; however, the facility will need to be modified to remain CCR compliant until that date.
        iii. RPS2 will be required to comply with numerous ongoing air regulations, among others, that are currently in place and subject to periodic review or newly proposed.
7. Long-term operation utilizing coal does not appear to be economical for RPS2 and LUS. LUS and the other co-owners should consider retirement of coal-fired operations to avoid ELG investments. LUS and the other co-owners should continue to evaluate RPS2 conversion to natural gas and retirement to determine which capital projects to implement in regard to ELG compliance, CCR regulations, natural gas conversion, and/or decommissioning.
8. In the event LUS and the co-owners decide to retire RPS2 from generation, LUS has several options for meeting its power supply requirements by replacing the capacity from RPS2 (which is approximately 250 MW).
    a. LUS should consider a self-build simple cycle gas turbine to replace RPS2. The power supply path including the simple cycle combustion turbine was one of the lowest cost plans evaluated. LUS has the existing Louis "Doc" Bonin Electric Generating Station that may be suitable for repurposing as simple cycle facility. The site already has access to natural gas

pipelines and electrical infrastructure. LUS should consider starting engineering studies for the existing facility to assess the feasibility of re-purposing the site.

  b. LUS should consider participation in a combined cycle facility, through either co-ownership or power purchase agreements. Even with the retirement of RPS2, LUS does not have a great enough need for capacity to build a large CCGT facility. Therefore, if LUS were to procure a CCGT resource, it would likely be through co-ownership or PPA with a third-party.
  c. LUS should consider other power purchase agreements that may be available when RPS2 retires.

9. The addition of reciprocating engines to LUS' portfolio appears to be higher cost than other power supply resources. Reciprocating engines are typically more economical when procuring smaller amounts of capacity. However, if RPS2 were retired, LUS would have a large capacity deficit which is more economically filled with larger resources with better economies of scale compared to reciprocating engines.
10. LUS should consider the addition of renewable resources, specifically solar resources, to its portfolio through power purchase agreements. The addition of solar resources was part of the lower cost plans evaluated within this Study. By procuring solar resources through power purchase agreements, LUS will be able to capture the benefits of tax incentives through third-party transactions. LUS should consider issuing a power supply request for proposals, specifically for renewable resources, but also other forms of power supply, in order to procure energy and capacity as required.
11. Should LUS re-purpose the Bonin site, LUS may consider pairing a small solar facility within the overall design.
12. LUS should continue to monitor and evaluate battery storage technologies. Battery storage costs might decrease faster than current estimates as they have in the past. The future impact of battery storage on the grid will also become clearer as more utilities start to develop battery storage projects and system operators, specifically MISO, develop policies associated with storage operations.
13. While the benefits of energy efficiency and demand response programs did not exceed their costs as evaluated within this Study, LUS should continue to monitor energy efficiency and demand response programs that may be implemented in the future to reduce the overall cost to customers and provide LUS flexibility in meeting its capacity and energy requirements.

2.0 INTRODUCTION

2.1 Objectives

Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") was retained by Lafayette Utilities System ("LUS") to provide an Integrated Resource Plan ("IRP"), which is a comprehensive study that evaluates a utility's future load requirements and its options for supplying power to satisfy those customers' needs. Power supply planning studies evaluate both short-term and long-term power supply needs, with a specific focus on assisting the utility in making short-term decisions to position the utility for long-term success. LUS requested that Burns & McDonnell perform a power supply planning study to assess the options that may be available to LUS for providing reliable, low cost, and environmentally compliant power to its customers ("Study").

The electric industry is experiencing significant changes due to economic, technological, and political influences, thus it is important for a utility to consider numerous future scenarios when evaluating its long-term power supply. An IRP has many components and assumptions that must be developed in order to complete a robust analysis. The overall objectives of this Study include the following:

- Conduct a load forecast projecting future load requirements regarding capacity and energy.
- Conduct a condition assessment to estimate capital expenditures and fixed O&M costs needed to maintain LUS' currently owned generation operating reliably.
- Conduct an environmental assessment and determine the compliance plan for Rodemacher Power Station Unit 2 ("RPS2") evaluating regulations and economics.
- Conduct a technology assessment to develop screening level costs associated with new generation resources that may be available to LUS to meet future power supply requirements.
- Conduct an evaluation to determine an economic operating path forward for RPS2.
- Evaluate the economic competitiveness of new and existing resources in the Midcontinent Independent System Operator, Inc. ("MISO") market to determine an overall power supply path.

This report summarizes the process, methodology, assumptions, economic evaluation, and conclusions and recommendations of the power supply options study.

2.2 Study Organization

This Study is organized into several sections as follows:

- Section 1.0 Executive Summary: Provides an executive summary and an introduction of the Study.

- Section 2.0 Introduction: Provides a general introduction of the study including objectives and review of the overall electric power industry.
- Section 3.0 Condition Assessment: Provides a detailed assessment on the condition of LUS existing generation to determine overall costs to continue to operate the units reliably.
- Section 4.0 Environmental Assessment: Provides discussion on the environmental regulations that could impact LUS' fleet and provide estimates for compliance costs.
- Section 5.0 Technology Assessment: Provides detailed discussion and costs associated with the development and construction of new power generation resources.
- Section 6.0 RPS2 Evaluation: Provides an analysis to determine whether RPS2 should continue to operate utilizing coal or retire from coal-fired operation.
- Section 7.0 Demand Side Management/Energy Efficiency Evaluation: Provides a summary of the cost-benefit evaluation associated with LUS' opportunities for demand-side management and energy efficiency programs.
- Section 8.0 Economic Evaluation Assumptions: Provides the assumptions and forecasts utilized within the economic evaluation.
- Section 9.0 Economic Evaluation: Aggregates the overall power supply costs for LUS' load and power generation resources under various power supply portfolios.
- Section 10.0 Conclusions & Recommendations: Provides the overall observations, conclusions, and recommendations of the study.

2.3 Overall Electric Power Industry Trends

As previously stated, the electricity industry continues to be impacted by numerous trends including significant economic, technological, and political influences. The following provides a brief discussion of the overall trends that are currently impacting electric utilities and generators.

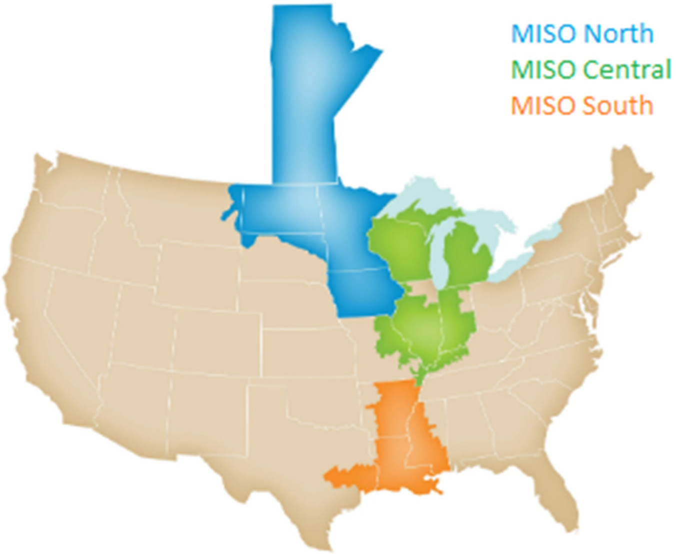
- Environmental regulations: Both federal and state environmental regulating agencies continue to pursue more stringent environmental regulations regarding emissions and waste from power generating facilities, specifically coal-fired power plants.
- Low natural gas prices: Natural gas prices remain low as production from natural gas fracking continues to outpace demand requirements. However, industry forecasts, such as U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO"), appear to increase in the long term.

- Continued renewable development: The use of wind and solar resources continues to increase. Many state and federal regulators continue to pursue increased renewable portfolio and energy requirements. Federal renewable tax credits for wind were recently extended at the end of 2019.
- Relatively low load growth: While much of the U.S. has seen economic growth since the economic recession in the 2008 and 2009 timeframe, the recovery of demand and energy has been much slower. Increased conservation programs have also contributed to lower load growth. This low load growth has led to lower capacity values in the short-term.
- Low wholesale market energy prices: The combination of low natural gas prices, increased renewable development, and relatively low load growth has kept wholesale market energy prices low compared to historical averages.
- Coal-fired retirements: With the combination of all the above factors, the investment in costly environmental compliance solutions at coal-fired power plants has reduced the overall economic benefit of coal-fired generation. Across the United States, coal-fired plants continue to be retired.
- Increased interest in “firm” natural gas pipeline capacity: Several factors including coal-fired retirements, recent extreme winter weather, and increased dependence of natural gas for the electric industry have led to increased interest in firm capacity. If firm natural gas transport contracts are required for power generators, it could increase the cost of delivery significantly.

2.3.1 MISO Market

The power grid, consisting of power generation and transmission lines, is operated by independent system operators across many areas of the country. Within the central part of the country, MISO is the system operator. MISO initiated its integrated marketplace on April 1, 2005. On December 18, 2013, LUS officially joined MISO, along with several other utilities which formed the MISO South region, and was integrated into MISO’s transmission system. MISO is separated into three areas, North, Central, and South. LUS operates in the MISO South region. The MISO market is made up of numerous utilities operating in 15 states and the Canadian province of Manitoba as illustrated in Figure 2-1.

Figure 2-1: MISO Market Area



Source: MISO https://www.misoenergy.org/about/

The MISO market has a wide range of capacity and energy resources including fossil fuel, renewable, and nuclear generation. The capacity and energy mix of resources within MISO for 2019 is presented in Figure 2-2 and Figure 2-3, respectively.

Figure 2-2: MISO Summer Capacity by Fuel Type (MW).

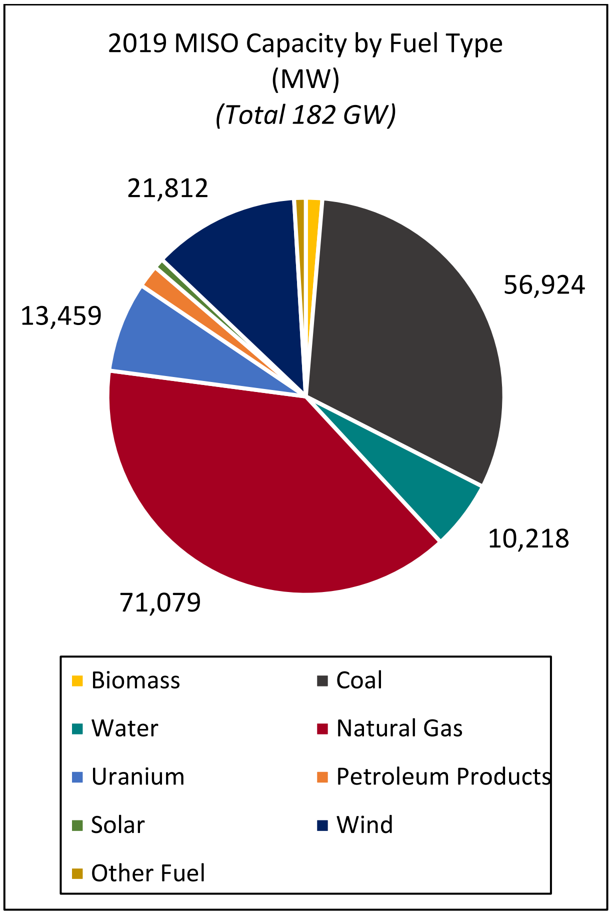
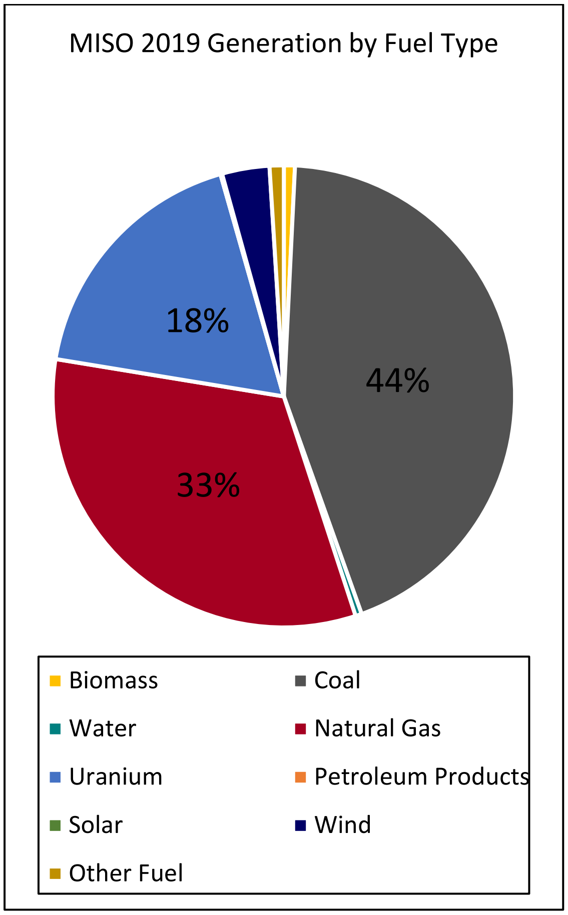


Figure 2-3: MISO 2019 Generation by Fuel Type (%).



MISO South is more heavily based on natural gas resources compared to the other two MISO regions, which rely more heavily on coal-fired resources. MISO North has the most extensive wind generation within the MISO footprint.

Wholesale electricity markets are increasingly more mature and utilities are becoming more comfortable with market operations. It is common for utilities today to acquire all their energy from the market and sell energy from their resources into the market when it is accepted for dispatch, rather than self-scheduling resources. Wholesale energy prices have remained low due to several factors including:

- Economic downturn and relatively slow economic and load growth

- Significant addition of wind resources (MISO had 20.5 GW of wind installed as of June 30, 2019)[1]
- Low price of natural gas

In order to provide sufficient capacity near load centers, MISO is divided into nine Local Resource Zones ("LRZ"), as presented in Figure 2-4.. A utility must obtain enough capacity within its LRZ to meet MISO's requirements. To support the procurement of capacity, MISO holds a Planning Resource Auction ("PRA") assessment to analyze the costs of capacity for each LRZ in MISO. MISO holds a PRA because it "provides MISO members, who choose not to submit their own Fixed Resource Adequacy Plans or Self-Schedule their capacity, a flexible option for the remaining 5 percent our footprint's Resource Adequacy requirements"[2]. Prices are provided for each LRZ. LUS is located in LRZ 9. As presented in Figure 2-5, market prices for capacity have historically been low, although prices are trending upwards. In general MISO has more than enough capacity to meet resource adequacy needs as presented in Figure 2-6, with the UCAP value (green bar) exceeding the forecast peak (black bar).

Figure 2-4: MISO LRZs[3].

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[1] MISO, *Planning Year 2020-2021 Wind & Solar Capacity Credit*, December 2019, https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

[2] MISO, https://www.misoenergy.org/about/media-center/miso-closes-eighth-annual-planning-resource-auction/

[3] MISO, *2020/2021 Planning Resource Auction (PRA) Results*, April 2020, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

Figure 2-5: MISO Historical PRA Prices for LRZ 9[4]

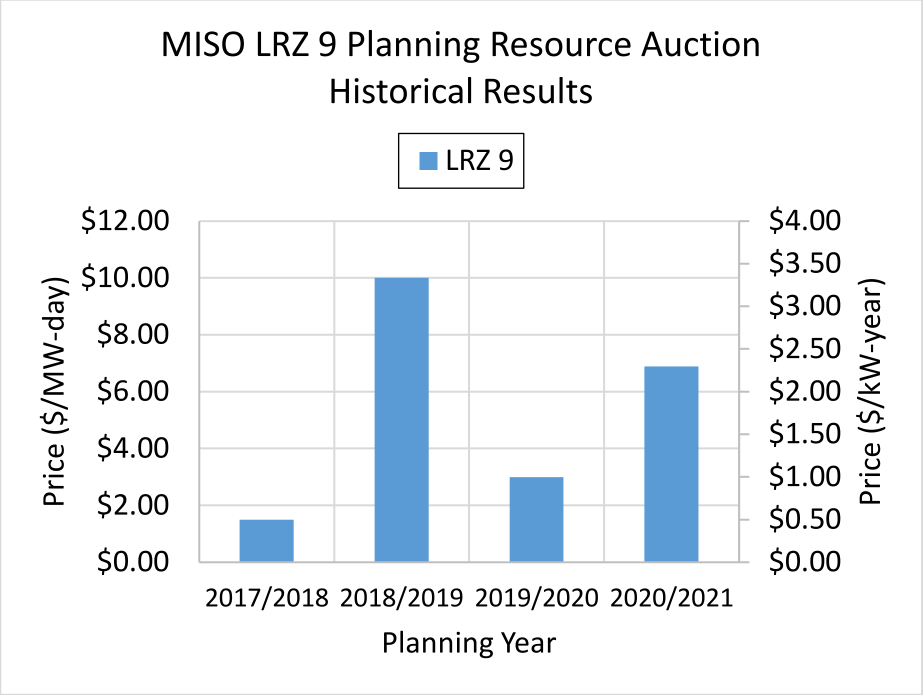
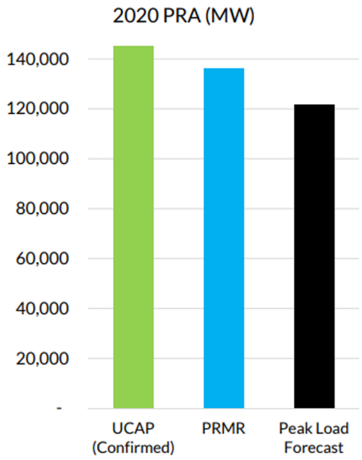


Figure 2-6: MISO Capacity[5]



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[4] MISO, *2020/2021 Planning Resource Auction (PRA) Results*, April 2020, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf
MISO, *2019/2020 Planning Resource Auction (PRA) Results*, April 2019, https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf
MISO, *2018/2019 Planning Resource Auction (PRA) Results*, April 2018, https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf
MISO, *2017/2018 Planning Resource Auction (PRA) Results*, April 2017, https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf

[5] MISO, *2020/2021 Planning Resource Auction (PRA) Results*, April 2020, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

2.4 LUS Power Supply Review

LUS provides energy and capacity to its customers through owned resources and power supply contracts. LUS' total peak demand is forecasted to be approximately 480 megawatts ("MW") in 2020 and growing to 500 MW by 2036. Based on the load forecast conducted within this Study, LUS is forecasted to experience long-term load growth around two tenths of a percent, which is consistent with other utilities' load forecasts in the region[6]. Table 2-1 presents the approximate installed capacity ("ICAP"), and unforced capacity ("UCAP") for LUS' power supply resources.

Table 2-1: LUS Power Supply Resources (Net Capacity)

LUS Power Plants			
Unit	Fuel	Installed Capacity (ICAP, MW)	Unforced Capacity (UCAP, MW)
Hargis-Hebert 1	Natural Gas	47	42
Hargis-Hebert 2	Natural Gas	47	46
TJ Labbe 1	Natural Gas	48	47
TJ Labbe 2	Natural Gas	47	36

LUS Power Purchase Agreements			
Unit	Fuel	Installed Capacity (ICAP, MW)	Unforced Capacity (UCAP, MW)
Lafayette Public Power Authority (LPPA) RPS2	Coal	246	228
Southwest Power Administration	Hydro	23	6
NRG	Capacity only	40	40

As illustrated by the list above, LUS has a diverse power supply portfolio consisting of coal, natural gas, and hydroelectric resources. The Southwest Power Administration contract consists of hydroelectric resources and is expected to operate until 2033.

A balance of loads and resources ("BLR") based on the load forecast and resources that LUS will have available to meet its obligations are presented in Figure 2-7. As presented in Figure 2-7, RPS2 is assumed to be retired at the end of 2027[7]. This assumption derived from the RPS2 Evaluation discussed later in

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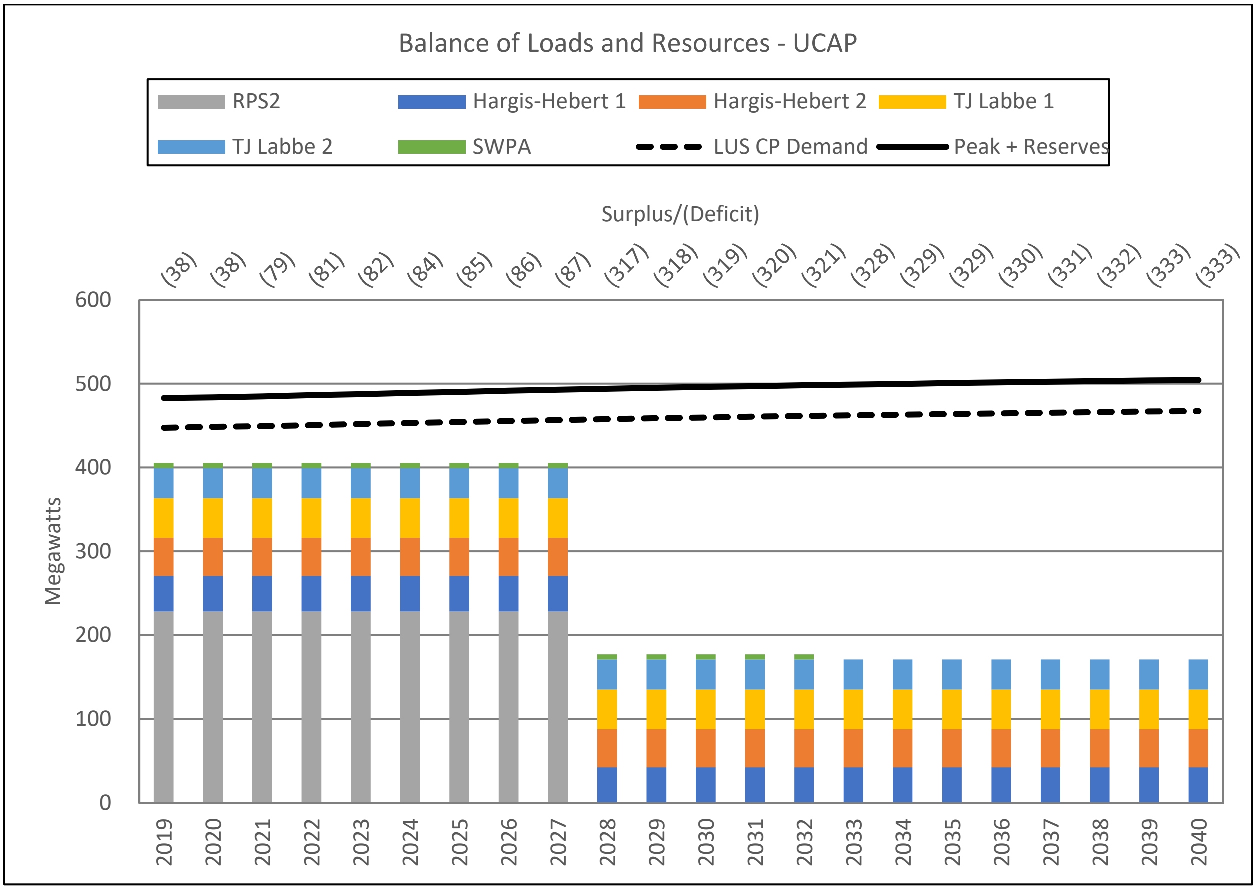
[6] Recent impacts associated with COVID-19 have not been included within the forecast.

[7] RPS2 is co-owned between multiple utilities. No firm retirement date has been set by the co-owners.

this report. Based on existing resources and current load projections, LUS will be capacity deficient both in the short-term and long-term.

Figure 2-7: LUS Balance of Loads and Resources (UCAP)



2.4.1 Energy Efficiency and Demand Side Management

The following section provides an overview of the demand side management and energy efficiency programs that LUS is currently implementing. Please see Section 7.0 for the evaluation of additional programs.

2.4.1.1 Existing Programs

LUS currently implements a net metering program. Net Metering allows customers who produce their own electricity (typically via solar panels) to lower their bills in two ways. First, any electricity they generate lowers their bill by displacing electricity they otherwise would have bought from LUS. Secondly, any electricity they produce in excess of their own demand can be put back into the grid and results in credits on their bill.

In addition to the net metering program, LUS provides numerous energy saving tips and actions that customers can implement in order to save electricity.

- Energy Saving Tips: LUS offers a list of energy saving tips on their website that require minimal effort and/or cost by the homeowner. This page also includes a breakdown of typical home energy use and provides links to additional resources.
- Bright Ideas: LUS highlights a specific energy saving tip in this section. Since cooling costs are a significant portion of a homeowner's bill, this section provides more information and resources.
- Energy Star: LUS provides information on energy efficient products for homes and businesses. Links to more detailed ENERGY STAR information are included.
- Home Audits: LUS provides two resources for conducting home energy audits:
    - In-home energy audits: LUS provides Utilities Conservation Specialist that inspect a customer's home and review the findings with the customer to identify potential problems. From there, the specialist can provide suggestions on how the customer can modify their lifestyle patterns to reduce utility usage.
    - Home Energy Saver is a do-it-yourself energy audit tool. The homeowner enters detailed information on their home energy usage and receives recommendations on possible energy efficiency improvements.
- Kill A Watt Meter: A Kill A Watt Meter is a device that the homeowner can use to determine the efficiency of an appliance. By being able to see a specific appliance's energy consumption, the homeowner can determine whether to replace the appliance, unplug it when not in use, etc.

3.0 CONDITION ASSESSMENT

The following section provides a summary of the Condition Assessment. Appendix A presents the complete analysis of the Condition Assessment.

3.1 Objective & Background

Lafayette Utilities System retained the services of Burns & McDonnell to perform a condition assessment study of the T.J. Labbé Unit 1 and Unit 2 (“TJU1” and “TJU2”) at the T.J. Labbé Power Generation Station (“Labbe”), Hargis-Hébert Unit 1 and Unit 2 (“HHU1” and “HHU2”) at the Hargis-Hebért Generating Station (“Hargis”), and RPS2 at the Rodemacher Power Station (“Rodemacher”) to determine the overall costs to continue to operate the units reliably. LUS used the information to support the Integrated Resource Plan (“IRP”) by using the fixed O&M and capital expenditure results as assumptions in the power supply path modeling.

Labbé and Hargis each consist of two LM6000 PC SPRINT combustion turbines (“CTs”) running in a simple cycle. Each facility has a maximum net capability of approximately 100 MW. Labbe entered commercial operation in 2005 while Hargis entered commercial operation in 2006. Labbe and Hargis are each fully owned and operated by LUS.

RPS2 consists of a coal fired, reheat boiler which generates steam to drive a steam turbine (“ST”) to produce electricity. Coal is prepared for the boiler by six roller wheel coal mills. The maximum net capacity of the unit is approximately 500 MW. RPS2 entered commercial operation in 1982. RPS2 is 50 percent owned by LUS, 20 percent owned by Louisiana Energy and Power Authority (“LEPA”), and 30 percent owned by CLECO who operates the station.

The intent of the Condition Assessment was to assist LUS in identifying the maintenance and capital expenditures associated with operating the unit at a level which meets or exceeds the average reliability of similar units. The analysis conducted was based on historical operations data, maintenance and operating practices of units similar to those owned by LUS, as well as Burns & McDonnell’s professional judgement. For this condition assessment study, Burns & McDonnell reviewed data provided by LUS and CLECO, interviewed plant personnel, and conducted a walk-down of Labbe and Hargis in order to obtain information on the units. Burns & McDonnell also analyzed any necessary updates for the units and any necessary capital replacements to maintain reliability.

3.2 Results

3.2.1 Cost Projections

Burns & McDonnell evaluated the overall costs for operating and maintaining the facilities. The projected costs included baseline historical O&M costs plus specific future projects identified through the condition assessment. Figure 3-1 and Figure 3-2 present the total annual baseline O&M expenses and project expenditures required to operate Labbe and Hargis through 2039, respectively. Figure 3-3 shows the annual baseline O&M costs for RPS2. Baseline O&M expenses are comprised of the typical annual O&M costs excluding major projects (shown in blue), the 5 year horizon project costs (shown in orange), the 10 year horizon costs (shown in green), and the 20 year horizon costs (shown in yellow) The costs are all presented in 2019$ and do not include inflation.

Figure 3-1: T.J. Labbé Total Annual O&M Cost Summary

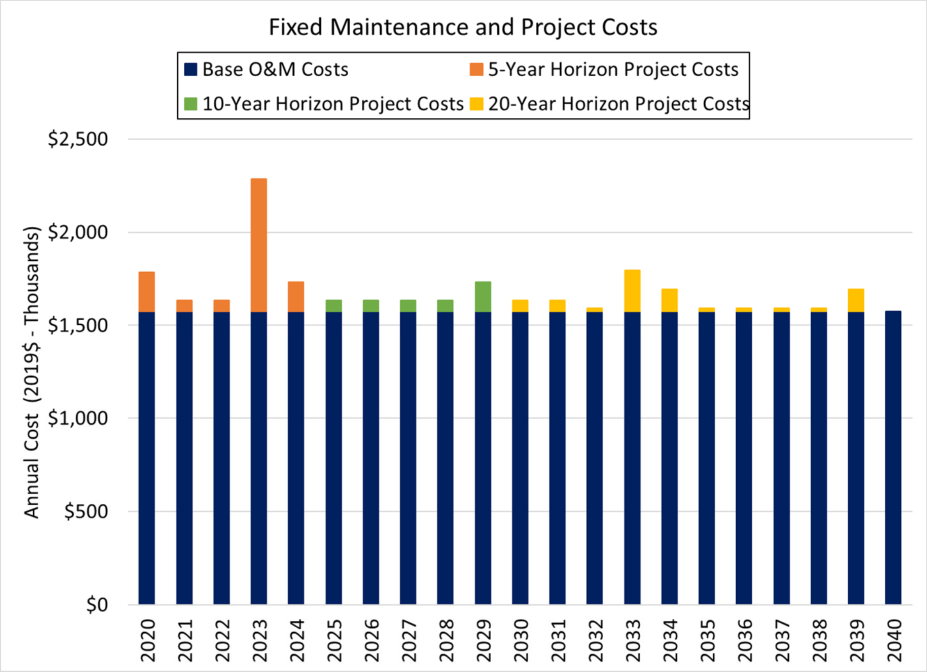


Figure 3-2: Hargis-Hébert Total Annual O&M Cost Summary

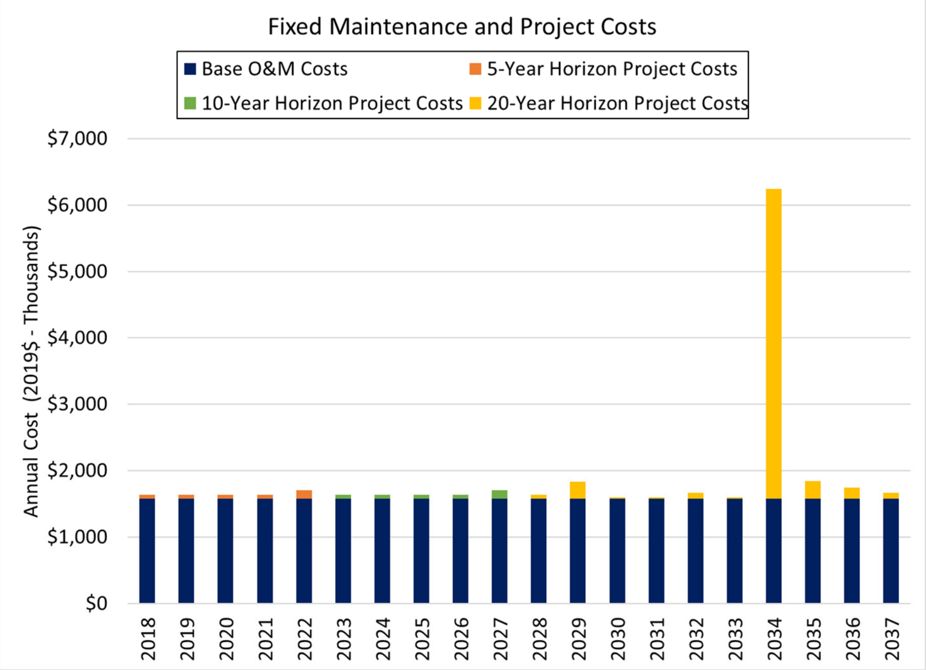
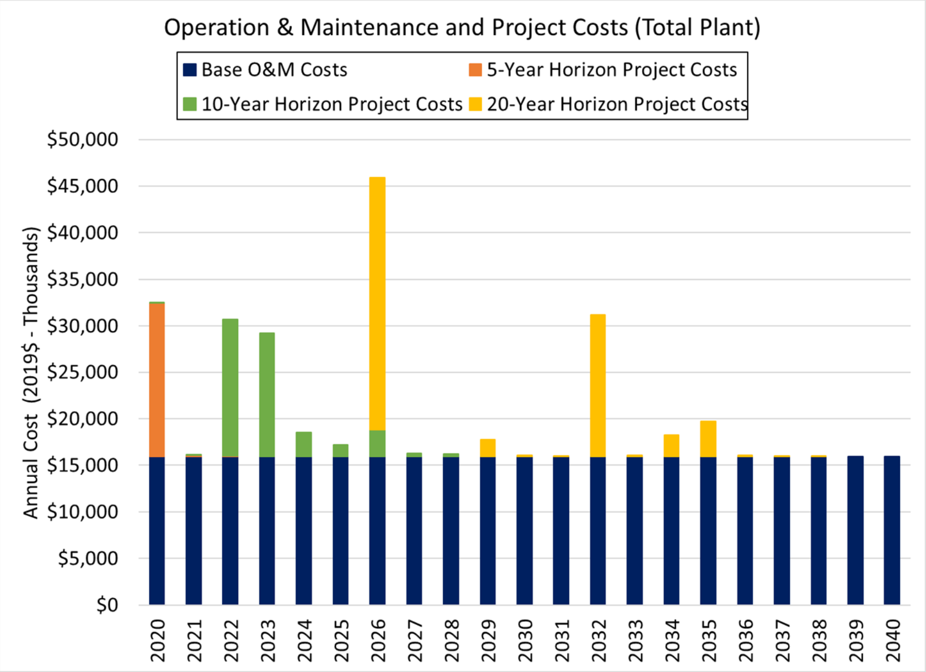


Figure 3-3: RPS2 Total Annual O&M Cost Summary



3.3 Conclusions

The following conclusions and recommendations are based on the observations and analysis from the Condition Assessment.

1. Labbe and Hargis entered commercial operation in 2005 and 2006, respectively. At the end of the study period, the units will be 35 years old. Half of similarly sized units in the region are anticipated to reach an age 44 years before retirement. Considering that the units receive fewer starts and, therefore, fewer thermal stresses than similar units in the region, along with the proactive maintenance operating philosophy on site, it is anticipated that Labbe and Hargis will have substantial service life past the end of the study period.
2. RPS2 entered commercial operation in 1982. The current operating agreement between LUS and CLECO is set to expire in 2032. At the end of the operating agreement, RPS2 will be 47 years old. Half of similarly sized units in the region are anticipated to reach an age 53 years before retirement. It is anticipated that RPS2 will be capable of operating to the end of the operating agreement, notwithstanding environmental and economic considerations.
3. Over the past few years, the units at Labbe and Hargis have operated with an EAF higher (better) than the fleet average and an EFOR generally lower (better) than the fleet average. The operational excellence at Labbe and Hargis should be maintained with continued preventative maintenance and regular inspections of the equipment at the plants.
4. Over the past few years, RPS2 has operated about equal to the industry average for EAF and lower (better) than the industry average for EFOR. The current operations should be maintained with continued preventative maintenance and regular inspections of the equipment at the plants.
5. Although Labbe and Hargis have experienced an increase in NCF over the past five years, they are still below national and regional averages. Based on discussions with operations staff, it may be beneficial to reevaluate dispatch parameters to ensure the operating costs are properly accounted for and not overly conservative. Increasing operation at base load conditions should also improve the average NHRs for Labbe and Hargis. It should be noted however, that with increased operating hours, the major overhaul intervals projected in this study would be accelerated (major overhauls would need to be performed sooner).
6. LUS, LEPA, and CLECO should develop an end-of-life plan in order to adequately allocate capital to RPS2. If the co-owners determine RPS2 is an essential asset until 2032, then larger capital investments will be warranted to maintain reliable operation. If RPS2 is not an essential asset, LUS, LEPA, and CLECO should consider operating the unit with minimal capital investment until decommissioning.

4.0 ENVIRONMENTAL ASSESSMENT

The following section provides a summary of the Environmental Assessment. Appendix B presents the complete analysis of the Environmental Assessment. Some of the conclusions and recommendations of the Environmental Assessment were used in the evaluation to provide estimates for environmental compliance costs.

4.1 Introduction

Lafayette Utilities System retained Burns & McDonnell Engineering Company to evaluate numerous environmental regulations that could impact its existing generation fleet in support of its integrated resource planning efforts. The Environmental Assessment provides a summary of Burns & McDonnell's review of the environmental regulations' impact on LUS' fleet.

The purpose of the Environmental Assessment was to evaluate and summarize the promulgated and proposed environmental regulations that are currently, and may have the potential, to significantly impact the power generation industry in the coming years. Additionally, for regulations that may impact any LUS fossil fuel unit, a screening level compliance cost is included.

The environmental regulations that were explicitly considered included:

- Effluent Limitation Guidelines ("ELG")
- Coal Combustion Residue ("CCR") regulations
- Clean Water Act ("CWA") Section 316(b)
- Air regulations
    - Cross-State Air Pollution Rule ("CSAPR") requirements
    - National Ambient Air Quality Standards ("NAAQS") for sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), ozone, and particulate matter ("PM")
    - National Emissions Standards for Hazardous Air Pollutants ("NESHAPs") for power plants (Mercury and Air Toxics Standards ("MATS"))
    - Regional Haze Rule ("RHR") and Best Available Retrofit Technology ("BART") which was assumed to be equivalent to the CSAPR requirements
    - Greenhouse gas ("GHG") regulations, specifically the Affordable Clean Energy ("ACE") Plan

4.2 Conclusions & Recommendations

Based on the review summarized in the Environmental Assessment, Burns & McDonnell offers the following conclusions:

1. Under the current environmental regulations, LUS' natural gas-fired units do not appear to require large capital improvements to comply with environmental rules.
2. RPS2 is subject to numerous environmental regulations as it is a coal-fired power plant. The following regulations will impact the unit.
    a. Coal Combustion Residue: Regardless of RPS2's long-term operations (whether utilizing coal, converted to natural gas, or retired), the Unit will be required to close the existing on-site ash ponds in order to comply with CCR. These capital improvements are estimated to be approximately $20 to $25 million (for the entire plant).
    b. Effluent Limit Guidelines: LUS' RPS2 is expected to be impacted by the ELG rule so long as the unit continues to burn coal. A dry bottom ash handling conversion is more likely to occur at RPS2 to comply with ELG rules. LUS will be required to meet the ELG requirements between November 1, 2020, and December 31, 2023, at a date to be established in the next NPDES permit received for the site. The proposed ELG rules do allow for utilities to commit to retiring a unit by December 31, 2028 and avoid any new ELG requirements for bottom ash transport water. If this option is incorporated into a final rule, this may be an option for LUS to consider at RPS2; however, the facility will need to be modified to remain CCR compliant until that date. Should RPS2 continue to operate past 2028 utilizing coal, capital improvements will be required to comply with ELG regulations. The total capital cost (spread across all owners) for compact submerged conveyors at RPS2 has been estimated between $15 and $20 million.
    c. RPS2, as a coal-fired power plant, will be required to comply with numerous ongoing air regulations, among others, that are currently in place and subject to periodic review or newly proposed. At this time, there are no additional capital improvements anticipated besides those mentioned above for CCR and ELG. However, a detailed study would need to be conducted to determine whether any large capital improvements are required for compliance with the Affordable Clean Energy ("ACE") rule regarding carbon dioxide emissions. However, the co-owners of RPS2 may decide to wait until LDEQ has completed its evaluation before conducting detailed evaluations of RPS2.

5.0 TECHNOLOGY ASSESSMENT

Burns & McDonnell evaluated various power generation technologies in support of its power supply planning efforts. The Generation Technology Assessment ("Tech Assessment") is screening-level in nature and includes a comparison of technical features, cost, performance, and emissions characteristics of natural gas simple cycle, combined cycle, reciprocating engine, wind, solar and battery storage technologies. Costs and characteristics from this Tech Assessment were used as assumptions in the evaluation.

It is the understanding of Burns & McDonnell that this Tech Assessment will be used for preliminary information in support of the LUS' long-term power supply planning process. Any technologies of interest to LUS should be followed by additional detailed studies to further investigate each technology and its direct application within LUS' long-term plans.

The Tech Assessment is presented in Appendix C. This report summarizes the key conclusions reached during the Tech Assessment.

5.1 Evaluated Technologies

Burns & McDonnell evaluated and considered numerous technologies for the IRP to provide reliable, safe, and economic generation to meet LUS' power supply requirements. These technologies included natural gas-fired, renewable, and storage resources. Each type of resource presents advantages and disadvantages when being considered within a comprehensive power supply portfolio. Burns & McDonnell and LUS identified, evaluated, and preliminarily screened the resources for their ability to complement LUS' existing resources and meet future load requirements for its customers. Burns & McDonnell and LUS considered the following types of resources.

- Natural gas-fired resources including peaking and intermediate resources
- Renewable options including wind and solar
- Storage alternatives including batteries, compressed air energy storage, and pumped hydropower storage

After initial screening based on Burns & McDonnell's experience with planning and project execution, the following resources were selected for further evaluation within the Tech Assessment. These technologies provide representative alternatives for meeting LUS' needs, such as output, operational flexibility, project development feasibility, under a variety of portfolio considerations within the economic evaluations:

- Simple Cycle Gas Turbine (“SCGT”) – 1 x F class 230 MW
- Reciprocating Engine – 5 x 18 MW units (90 MW total)
- Combined Cycle Gas Turbine (“CCGT”) – 1x1 G/H class 420 MW
- Wind Generation – On-shore, land-based 50 MW
- Solar PV – Single axis tracking 50 MW
- Battery Storage – Lithium Ion 25 MW / 100 MWh

5.2 Summary of Technology Assessment

The technology assessment provides information to support LUS’ power supply planning efforts for further evaluation within the economic modeling efforts for the IRP. Information provided in the Tech Assessment is preliminary in nature and is intended to highlight indicative, differential costs associated between each technology. After identifying the preferred combination of resources within the IRP, LUS should pursue additional engineering studies to define specific items such as project scope, design, and equipment, budgets, and implementation timeline for the preferred technologies of interest.

The selected alternatives from this screening effort were further evaluated within the IRP for their ability to complement or replace existing resources within LUS’ power supply portfolio, both from a technical ability and economic evaluation. A brief highlight of the advantages and disadvantages of the technologies is presented in Table 5-1. For the full evaluation report see Appendix C.

Table 5-1: Summary of Technologies

Technology	Advantages	Disadvantages
Gas-Fired Resources		
Aeroderivative	• Flexible operation (ability to quickly turn-on/off in response to market signals) • More efficient than large frame units • Ability for on-system installation	• High fuel gas pressure • Higher capital cost compared to other peaking resources on $/kW basis
F-Class	• Lowest cost peaking resource on a $/kW basis • Flexible compared to CCGT, but slightly less than Aeroderivative and reciprocating engines • Ability for on-system installation	• High fuel gas pressure • Large capacity on a single shaft • Less flexible compared to aeroderivatives and reciprocating engines • Higher heat rate compared to aeroderivative turbines
Reciprocating Engines	• Most flexible gas-fired resource (ability to quickly turn-on/off in response to market signals) • Low fuel gas pressure	• Higher capital cost compared to F-Class or CCGT technology on a $/kW basis

Technology	Advantages	Disadvantages
	• Shaft diversification (9-18MW)[8] • Ability for on-system installation	
CCGT	• Most efficient gas-fired technology • Lower capital cost due to economies of scale on a $/kW basis	• Lacks flexibility compared to other gas-fired technologies • Must be one of potentially several pseudo-owners of a large unit • Most likely located off-system
Renewables		
Locally Owned Wind (Louisiana)	• Reduced transmission congestion	• No Production Tax Credit or Interconnection Tax Credit (need taxable partner) • Uneconomical compared to resources available in nearby regions • Wind farms cannot be easily integrated into residential, commercial, or industrial areas
Regional Wind (MISO)	• Economically justifiable • Production Tax Credit through PPA (subject to Congress) • Large wind farms reduce the overall cost of the technology	• LUS is not the operator of the wind farms • Potential congestion costs
Off-Shore Wind (Louisiana)	• Higher wind resource potential compared to local on-shore wind	• Off-shore wind in the U.S. is still in the infancy of development • Only one off-shore facility is operational in the U.S. with none currently in development in Louisiana[9][10]
Local Solar	• Increase to renewable energy production for utility portfolio • Potential tax credits through PPA (subject to Congress)	• Lack of solar resource availability in Louisiana • Higher cost of energy compared to regional wind
Storage		
Flow Battery	• Scalable technology in development • Higher cycling life compared to conventional batteries • Offsets electric peak loads	• Technology is not entirely mature currently • Required operation of ancillary equipment

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[8] Shaft diversification provides a utility the opportunity for increased reliability since it would have the ability to utilize multiple engines providing the same level of capacity and generation, as opposed to having all of the energy sourced from a single engine.

[9] https://www.awea.org/Awea/media/Resources/Fact%20Sheets/Offshore-Fact-Sheet.pdf

[10] https://www.boem.gov/renewable-energy/state-activities

Technology	Advantages	Disadvantages
Conventional Battery (Lead Acid and Lithium Ion)	• Low capital costs • Responsive to changes in grid demand • Offsets electric peak loads	• Life is dependent on cycling and discharge rates, potentially 5 to 10 years for high cycling utilization • High maintenance cost • Materials used are associated with being high toxicity
High Temperature	• High discharge rates • Life expected to be around 15 years • Offsets electric peak loads	• Energy requirement to maintain liquid electrolytes • Technology is still being developed for utility level applications • Uneconomically compared to other storage technologies
Pumped Hydro	• Large reservoir of storage energy • Offsets electric peak loads	• Geology required for water storage • Environmental impacts to surrounding areas • High capital costs
Compressed Air Energy Storage (CAES)	• Large reservoir of storage energy • Offsets electric peak loads	• Specific geology required for compressed air storage • High capital costs

6.0 RPS2 EVALUATION

The following section provides a summary of the RPS2 Evaluation. Appendix D presents the complete analysis of the RPS2 Evaluation.

6.1 Introduction

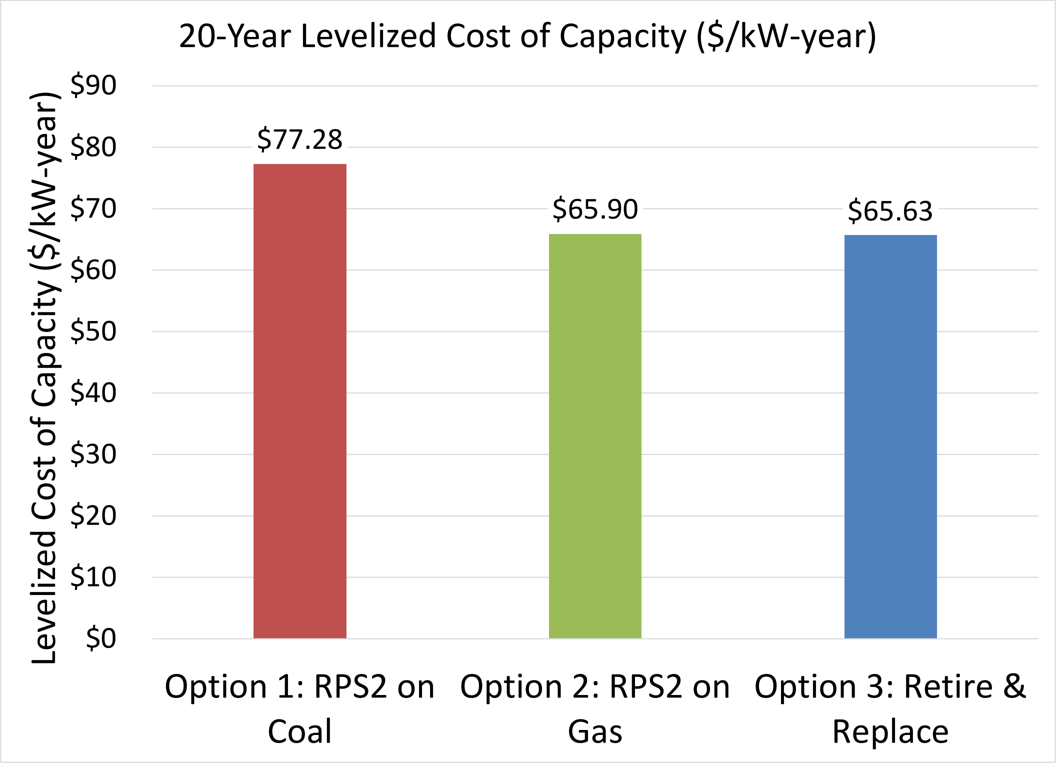
There are several environmental regulations impacting the long-term operation of RPS2, namely the coal combustion residue and effluent limit guideline regulations. Burns & McDonnell conducted an economic evaluation to determine whether RPS2 should continue to operate utilizing coal or retire from coal-fired operation.

6.2 Analysis

The analysis specifically investigated the ongoing fixed costs associated with coal-fired operation at RPS2 versus two alternative options for providing capacity to LUS' power supply portfolio. The two alternative options that were evaluated consisted of natural gas conversion of RPS2 and replacement with a simple cycle combustion turbine. The focus of this evaluation was to determine whether to continue coal-fired operations at RPS2, but not to specifically determine its potential replacement.

The analysis focused on the fixed costs associated with each power supply option. To compare the alternatives, the fixed costs were evaluated on a capacity basis ($/kW-year). The levelized cost of capacity ("LCOC") was used to represent the overall fixed costs associated with operating for each option and was considered over a 20-year timeframe from 2021 to 2040. The results are presented in Figure 6-1.

Figure 6-1: Levelized Cost of Capacity ($/kW-year)



6.3 Conclusion

Long-term operation of RPS2 utilizing coal has a higher levelized cost of capacity than the other two options evaluated. Coal operation is approximately 17 percent more costly than the other two options. Based on a combination of factors including environmental compliance upgrade costs, fixed O&M costs, and the potential exposure to future environmental regulations, LUS should consider retiring RPS2 from coal-fired operation in the 2027 timeframe in order to avoid ELG compliance upgrades, and as other power supply options are lower cost for providing capacity. Based on this RPS2 evaluation and conclusions, RPS2 was assumed to be retired at the end of 2027 for the power supply path analysis.

7.0 DEMAND SIDE MANAGEMENT/ENERGY EFFICIENCY EVALUATION

Demand Side Management (“DSM”) and Energy Efficiency (“EE”) programs incentivize customers to reduce energy usage and load thereby decreasing the amount of energy and capacity need to be procured by LUS. According to the EIA, “demand-side management programs aim to lower electricity demand, which in turn avoids the cost of building new generators and transmission lines, saves customers money, and lowers pollution from electric generators”[11]. This DSM/EE evaluation considered a wide range of programs. Benefits and costs of varying DSM and EE programs were evaluated to determine if they could potentially provide significant benefits to LUS. The following section provides the assumptions, methodology, and results utilized within the DSM/EE evaluation. Appendix E presents the complete analysis of the DSM/EE Evaluation.

7.1 Program Descriptions

The DSM programs considered in this evaluated were:

- Water Heater Load Control Switching – An opt-in load-control program that would allow LUS to cycle a participant’s water heater during peak events.
- Programmable Communicating Thermostats – An opt-in program to facilitate installation of programmable communicating thermostats in participant’s homes. During peak events, heating and cooling could be controlled by LUS.
- Electric Heat Switching – An opt-in load-control program that would allow LUS to cycle a participant’s electric heating during peak events.
- Pool Pumping – An opt-in load-control program that would allow LUS to cycle a participant’s pool pumping during peak events.

The EE programs considered in this evaluated were:

- EE Weatherization – An program which offers energy audits and home improvements to reduce wasted electricity.
- Old Fridge Removal – A program which offers free removal of older, less energy-efficient fridge appliances
- EE Appliances – A program which markets and advocates the use and energy efficient lighting and appliances within customer homes

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[11] EIA, *Demand-side management programs save energy and reduce peak demand* https://www.eia.gov/todayinenergy/detail.php?id=38872

7.2 Methodology

The overall costs and benefits of the programs were considered. Data utilized in this analysis was sourced from EIA in its Residential Energy Consumption Survey from 2015[12]. There are a wide range of benefits and costs that might be considered in a DSM/EE evaluation.

The costs considered in this analysis included:

- Adoption costs
- Incentive costs
- Program marketing
- Third-party program maintenance
- Program director staffing

The benefits considered in this analysis included:

- Peak reduction savings ($/kW) (includes both capacity and transmission costs)
- Energy savings for EE programs only ($/kWh)

The costs and benefit metrics were considered from 2021 to 2030 on a 10-year net present value ("NPV") basis.

7.3 Results

The overall NPV results are outlined in Figure 7-1. Due to the marketing costs, adoption costs, program maintenance costs, and low peak reduction impacts, no DSM programs were found to have savings within the 10-year analysis period. The EE Weatherization program was found to have savings over the 10-year analysis period. The EE programs had less costs overall due to the generally lower adoption costs, program costs, and the additional savings from the Energy Reduction (kWh) instead of only the Peak Reduction (kW) from the DSM programs. Due to the relatively low cost of energy and capacity, many of the programs do not provide sufficient benefits to offset the cost of the programs.

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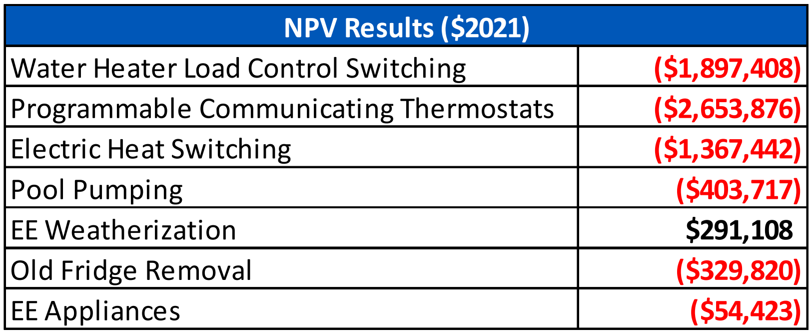
[12] EIA, *Residential Energy Consumption Survey ("RECS")*, https://www.eia.gov/consumption/residential/data/2015/

Figure 7-1: Program Summary NPV Table.



NPV Results ($2021)	
Water Heater Load Control Switching	**($1,897,408)**
Programmable Communicating Thermostats	**($2,653,876)**
Electric Heat Switching	**($1,367,442)**
Pool Pumping	**($403,717)**
EE Weatherization	**$291,108**
Old Fridge Removal	**($329,820)**
EE Appliances	**($54,423)**

8.0 ECONOMIC EVALUATION ASSUMPTIONS

In combination with the assumptions described in previous sections, the following section provides additional assumptions, methodologies, and forecasts utilized within the economic evaluation.

8.1 General Power Supply Assumptions

The analysis began with the development of baseline assumptions and constraints applicable to LUS. The following general assumptions were used:

- The study period covers years 20 years from 2021 through 2040.
- LUS' interest rate for financing was 4 percent, with resources financed over 30 years.
- The general inflation rate was assumed to be 2 percent.
- The discount rate was assumed to be 4 percent.
- Capacity was assumed to be available from the market to meet small capacity deficits at a rate of $30/kW-year starting in 2019 and escalating at the general inflation rate (this compares to recent MISO auction values of $2.51/kW-year).
- Energy market prices were simulated in MISO MTEP20 PROMOD model and integrated into Strategist to develop power supply paths.

These assumptions, and others described herein, served as a basis for the economic analysis.

8.2 Load Forecast

In anticipation of this Study, Burns & McDonnell was tasked with completing a 2018 Long-term Load Forecast ("Forecast"). The Forecast is needed as an input necessary to estimate the overall power supply requirements. Burns & McDonnell created the load and energy forecasts included in this Forecast by developing new economic equations using recent economic forecasts for the Lafayette Metropolitan Statistical Area (MSA) from Woods & Poole Economics, Inc. (Woods & Poole) and historical data through the end of 2017 provided by LUS. The Forecast is class-specific, including residential, commercial, and other customer classes, and covers a period of 20 years from 2017 to 2037. The Long-term Load Forecast is presented in its entirety as presented in Appendix E.

The historical data provided by LUS and corresponding load forecasts (as presented in Appendix E) do not include transmission and distribution losses. To account for transmission and distribution losses at the wholesale power supply level, Burns & McDonnell applied an additional 3.9 percent to the energy and demand requirements. The 3.9 percent adder was based on information received from LUS based on historical losses. In this analysis the forecast was extended from 2037 to 2040 to fit the analysis timeframe by assuming the same annual growth as 2037. A high and low load forecast was also created to test as a sensitivity. Further discussion on the sensitivities is in following sections. The peak demand presented in Figure 8-1 represents LUS total peak demand with high and low forecasts. Figure 8-2 presents the overall wholesale load forecast for LUS that was utilized within this Study with high and low forecasts.

Figure 8-1: LUS Peak Load Forecast

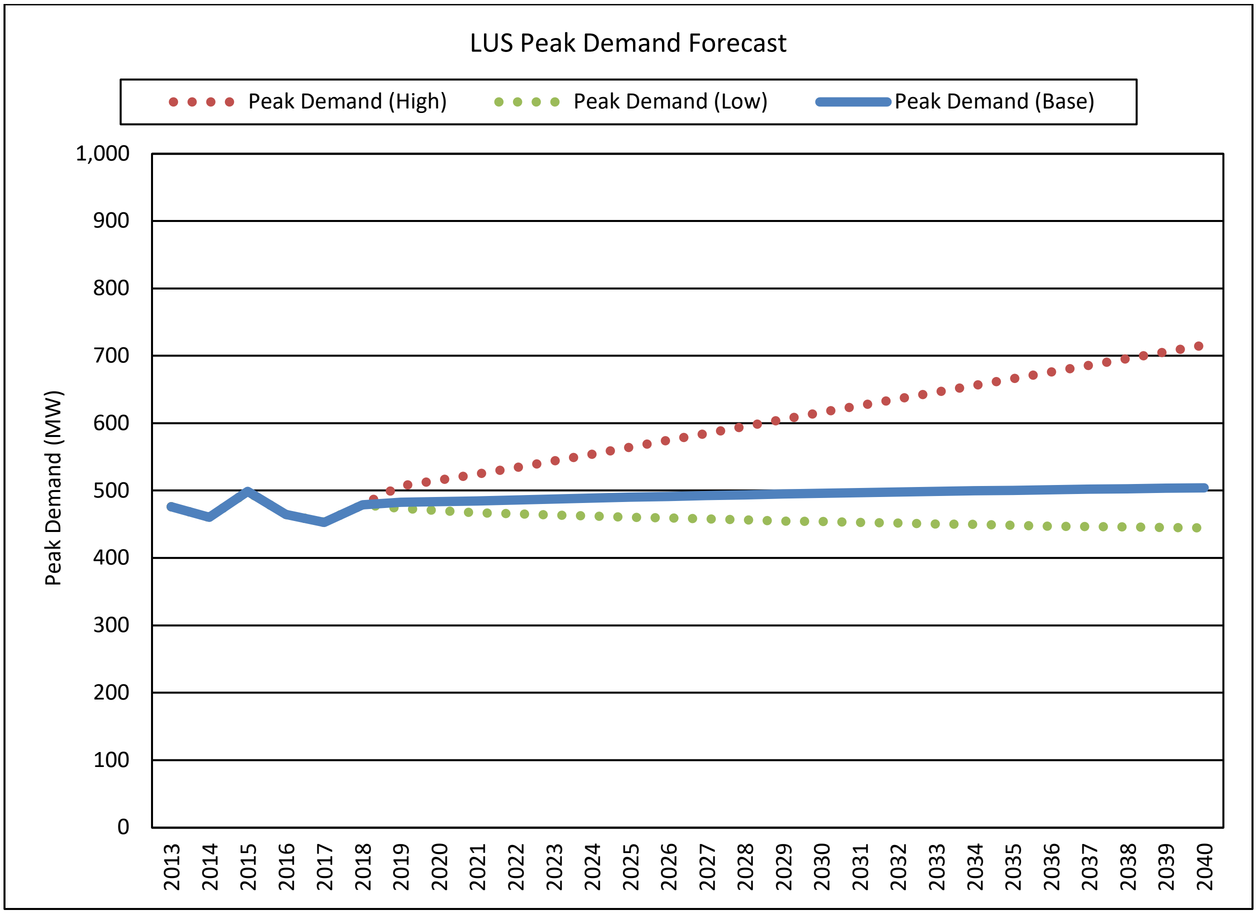
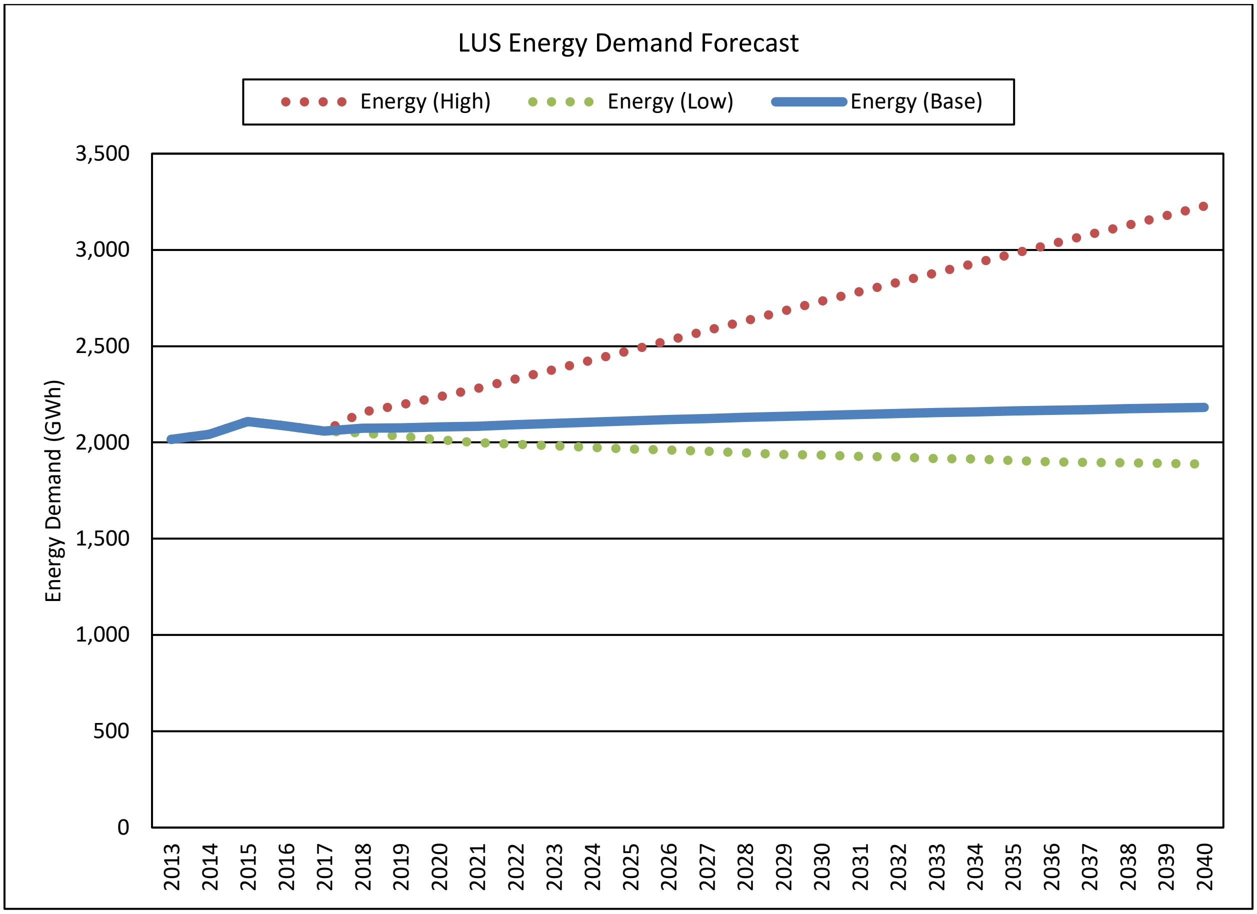


Figure 8-2: LUS Energy Load Forecast



8.3 Balance of Loads and Resources

All utilities are required to have sufficient capacity to meet their demand, based on regulations through the North American Electric Reliability Corporation. As the independent operator of the power system, MISO develops the policies associated with resource adequacy for its members. As a member of MISO, LUS is required to have adequate capacity and reserves to meet its demand requirements. LUS is required to procure sufficient capacity to meet its contribution to the overall MISO co-incident peak. MISO typically experiences its peak demand in July or August. As a member of MISO, LUS must procure as much capacity to meet demand requirements that coincide with MISO's peak. On average LUS has experienced a coincident peak factor of approximately 93 percent over three recent years compared to the MISO peak demand (2016: 95 percent, 2017: 94 percent, 2018: 89 percent). That is, LUS' coincident peak demand (i.e. LUS' demand when MISO experiences its peak) is approximately 93 percent of LUS' annual peak. For example, if LUS' demand is 430 MW when MISO hits its peak, then LUS must procure 430 MW (plus reserves), even if LUS' actual peak demand is 450 MW which occurs at a different time than MISO.

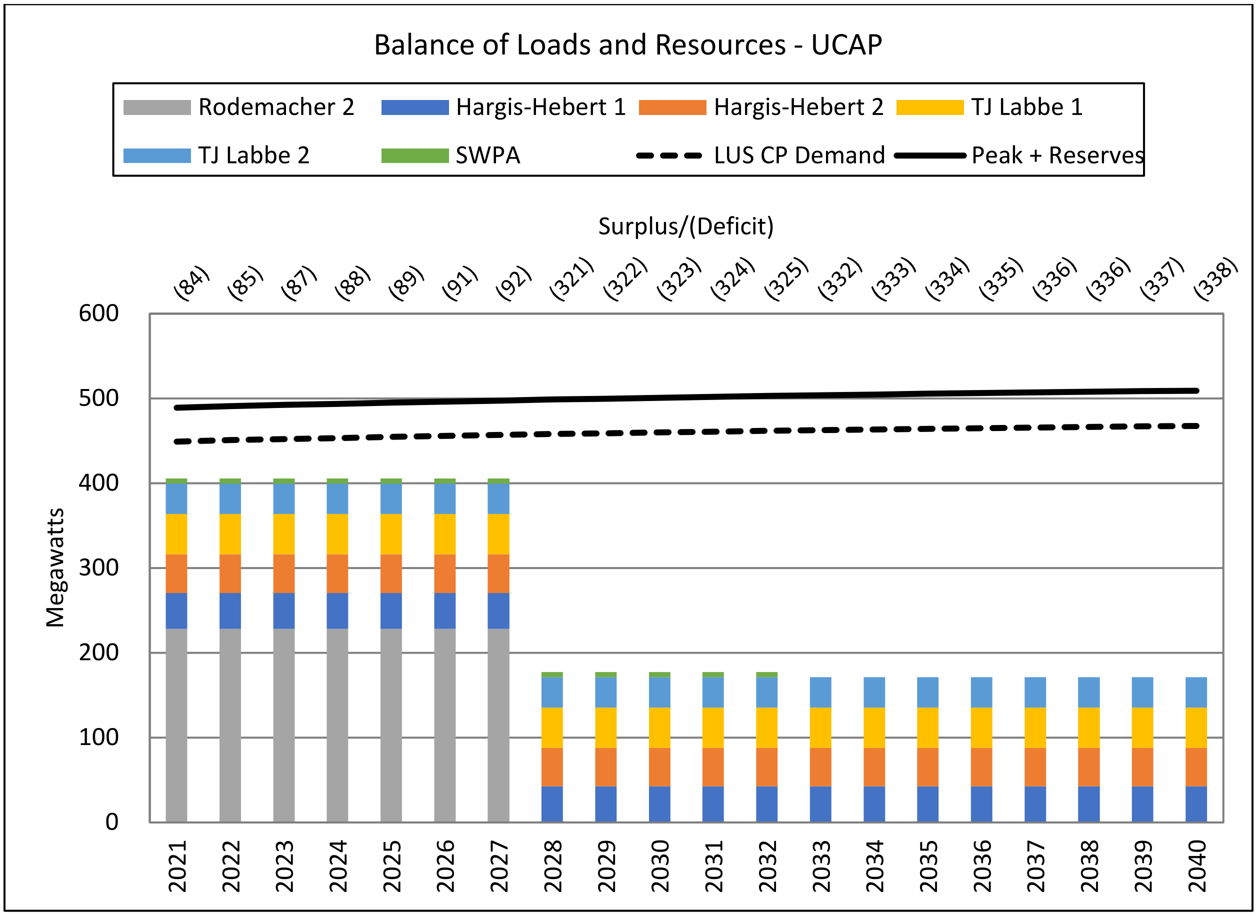
As described in Section 2.4 LUS Power Supply Review, LUS has several resources to meet its capacity reserve margin requirements. Utilities typically utilize two methodologies for evaluating capacity positions, known as the Installed Capacity ("ICAP") and Unforced Capacity ("UCAP") methods.

1. ICAP: The ICAP methodology evaluates the total installed capacity against a utility's peak demand plus a reserve margin (typically about 15 percent). The ICAP methodology has traditionally been the typical process for evaluating capacity requirements by utilities, however independent system operators have been shifting away from the ICAP method.
2. UCAP: The UCAP methodology evaluates the unforced capacity against a utility's peak demand plus a reserve margin. The installed capacity is reduced to an unforced capacity value by reducing the capacity based on the reliability of the unit. However, the reserve margin is typically much lower (approximately seven to eight percent). The UCAP method incentivizes power generators to operate their units more reliably, thus driving the UCAP capacity value closer to the installed capacity value. MISO currently requires utilities to utilize the UCAP method to correspond with the utility's coincident peak of the overall MISO system.

The UCAP methodology was utilized within this assessment. Burns & McDonnell utilized the unforced capacity values for each of LUS' power supply resources to compare the capacity against LUS' July peak demand (which is a typical month when MISO also experiences its peak demand).

The BLR chart for the business-as-usual scenario, which reflects retirement of RPS2 at the end of 2027, is presented in Figure 8-3. LUS must maintain a reserve margin of 7.9 percent, a number which is prescribed by MISO under the UCAP method. The reserve margin is subject to change over time based on MISO's discretion to meet reserve obligations, however for this Study Burns & McDonnell utilizes 7.9 percent throughout the study period. Based on existing resources and current load projections, LUS will be capacity deficit in both the short-term and long-term. Several BLR charts were developed based on the load forecasts, resources, and power supply paths that LUS will have available to meet its obligations. These BLRs are presented in Appendix J.

Figure 8-3: LUS Balance of Loads and Resources (UCAP)



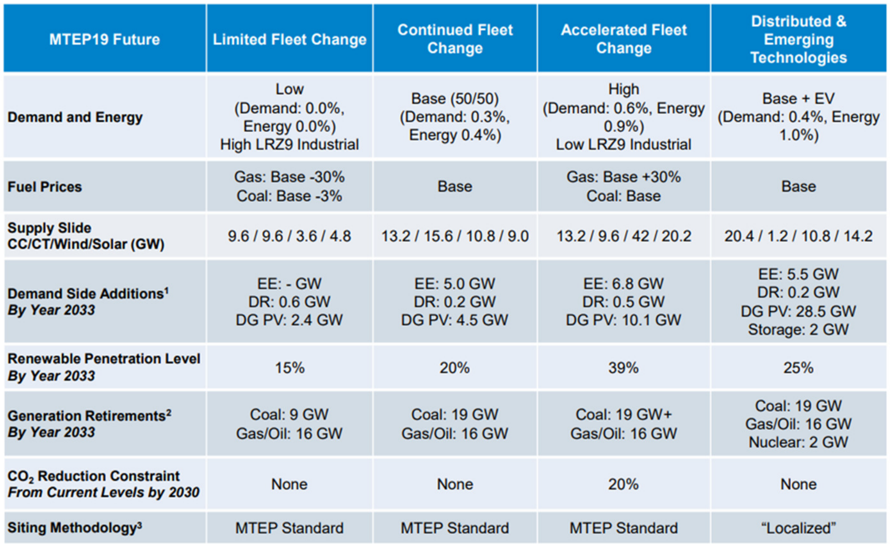
8.4 Fuel & Market Forecasts

To conduct a long-term resource planning assessment for power supply, several forecasts must be developed for evaluation. For this Study, Burns & McDonnell developed key forecasts for fuel costs and market energy costs using reputable publicly available sources. The following sections provide a summary of the forecasts developed and utilized within this Study. Further details of the forecasts are presented in Appendix G.

As a member of MISO, it is important for LUS to leverage key MISO studies and assumptions in this analysis which provides consistency for long-term planning. Therefore, many of MISO's modeling assumptions were used in this analysis. As part of its long-term planning process, MISO develops comprehensive transmission expansion planning studies. Periodically, MISO completes an in-depth evaluation of the power system as part of its MISO Transmission Expansion Planning ("MTEP") process for the year 2020 (known as MTEP20). As part of that evaluation, MISO conducted security constrained economic dispatch ("SCED") analyses around several different futures. The futures evaluated varying levels of environmental constraints, growth opportunities, generation mixes (including both fossil fuel retirements and renewable additions), and fuel costs.

In MISO's MTEP20 model ("MTEP20"), there are four different future scenarios. The scenarios are Continued Fleet Change ("CFC"), Limited Fleet Change ("LFC"), Distributed & Emerging Technologies ("DET"), and Accelerated Fleet Change ("AFC"). Details about the different scenarios are outlined in Figure 8-4.

Figure 8-4: MTEP20 Future Scenarios[13]



MTEP19 Future	Limited Fleet Change	Continued Fleet Change	Accelerated Fleet Change	Distributed & Emerging Technologies
Demand and Energy	Low (Demand: 0.0%, Energy 0.0%) High LRZ9 Industrial	Base (50/50) (Demand: 0.3%, Energy 0.4%)	High (Demand: 0.6%, Energy 0.9%) Low LRZ9 Industrial	Base + EV (Demand: 0.4%, Energy 1.0%)
Fuel Prices	Gas: Base -30% Coal: Base -3%	Base	Gas: Base +30% Coal: Base	Base
Supply Slide CC/CT/Wind/Solar (GW)	9.6 / 9.6 / 3.6 / 4.8	13.2 / 15.6 / 10.8 / 9.0	13.2 / 9.6 / 42 / 20.2	20.4 / 1.2 / 10.8 / 14.2
Demand Side Additions[1] *By Year 2033*	EE: - GW DR: 0.6 GW DG PV: 2.4 GW	EE: 5.0 GW DR: 0.2 GW DG PV: 4.5 GW	EE: 6.8 GW DR: 0.5 GW DG PV: 10.1 GW	EE: 5.5 GW DR: 0.2 GW DG PV: 28.5 GW Storage: 2 GW
Renewable Penetration Level *By Year 2033*	15%	20%	39%	25%
Generation Retirements[2] *By Year 2033*	Coal: 9 GW Gas/Oil: 16 GW	Coal: 19 GW Gas/Oil: 16 GW	Coal: 19 GW+ Gas/Oil: 16 GW	Coal: 19 GW Gas/Oil: 16 GW Nuclear: 2 GW
CO_2 Reduction Constraint *From Current Levels by 2030*	None	None	20%	None
Siting Methodology[3]	MTEP Standard	MTEP Standard	MTEP Standard	"Localized"

These futuress are developed within the PROMOD software modeling program, which is the same program that Burns & McDonnell utilizes for long-term planning studies.

8.4.1 Fuel Cost Forecast

Burns & McDonnell utilized projected natural gas fuel costs developed by MISO within the MTEP20. These different scenarios have varying fuel prices as presented in Figure 8-5. MTEP20 fuel prices were compared to fuel forecasts from the U.S. Department of Energy's Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2019 in addition to the CME Group's NYMEX. Utilizing multiple forecasts that are considerably different provides the ability to assess the resource plan under varying assumptions. A sensitivity analysis was conducted by varying natural gas prices. This provides for a more robust evaluation to determine whether one resource path appears more favorable under a different set of economic forecasts. In order to evaluate a wide-range of fuel forecasts, Burns &

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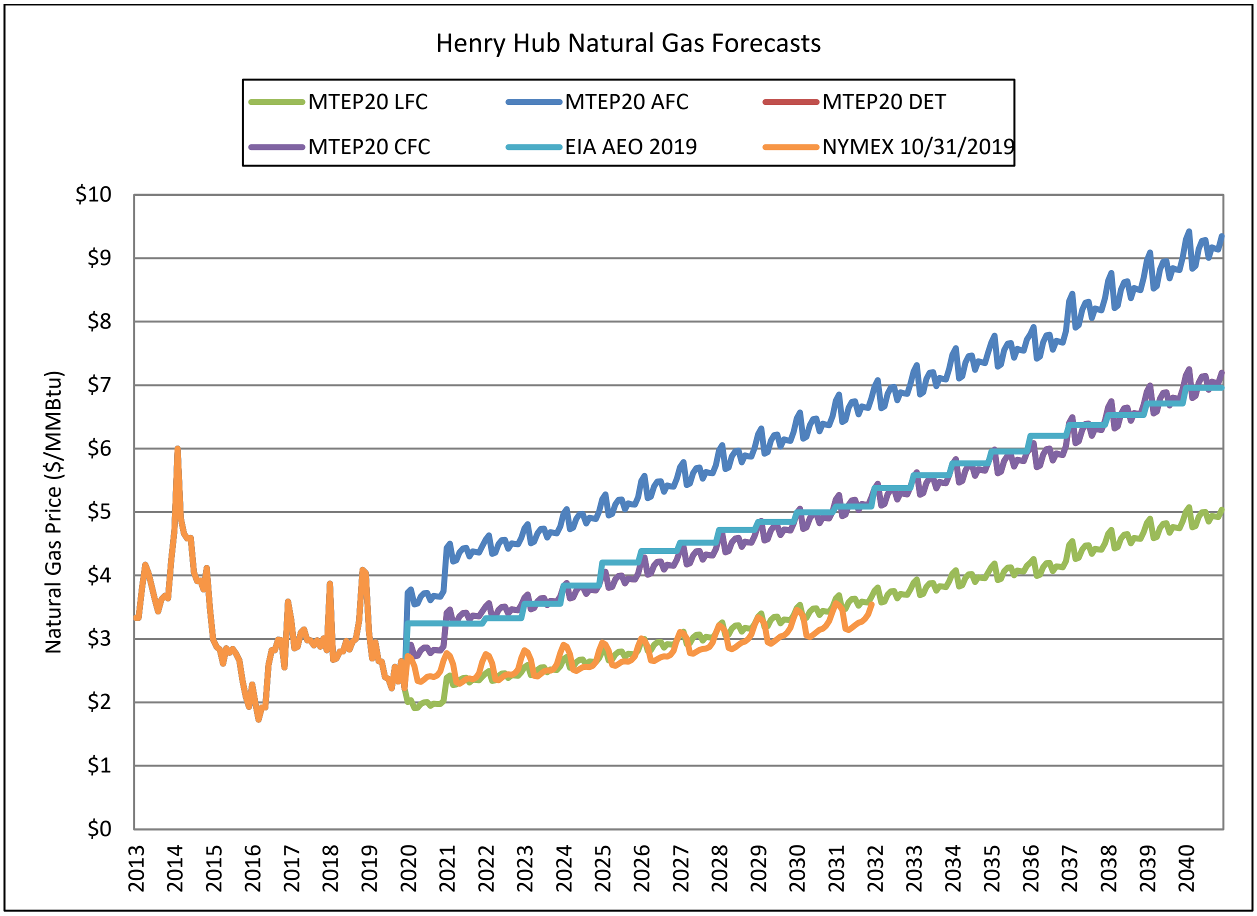
[13] MTEP 20 futures were the same as the future developed by MISO in the previously year. MISO, *MTEP19 Futures Summary*, https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf

McDonnell and LUS selected the fuel forecasts from the MTEP20 CFC, AFC, and LFC scenarios. EIA AEO and NYMEX forecasts were not used since they did not differ significantly from the CFC and LFC MTEP20 forecasts, respectively. Figure 8-5 presents both the MTEP20 forecasts used and the MTEP 20 DET, EIA AEO, and NYMEX forecasts referenced above.

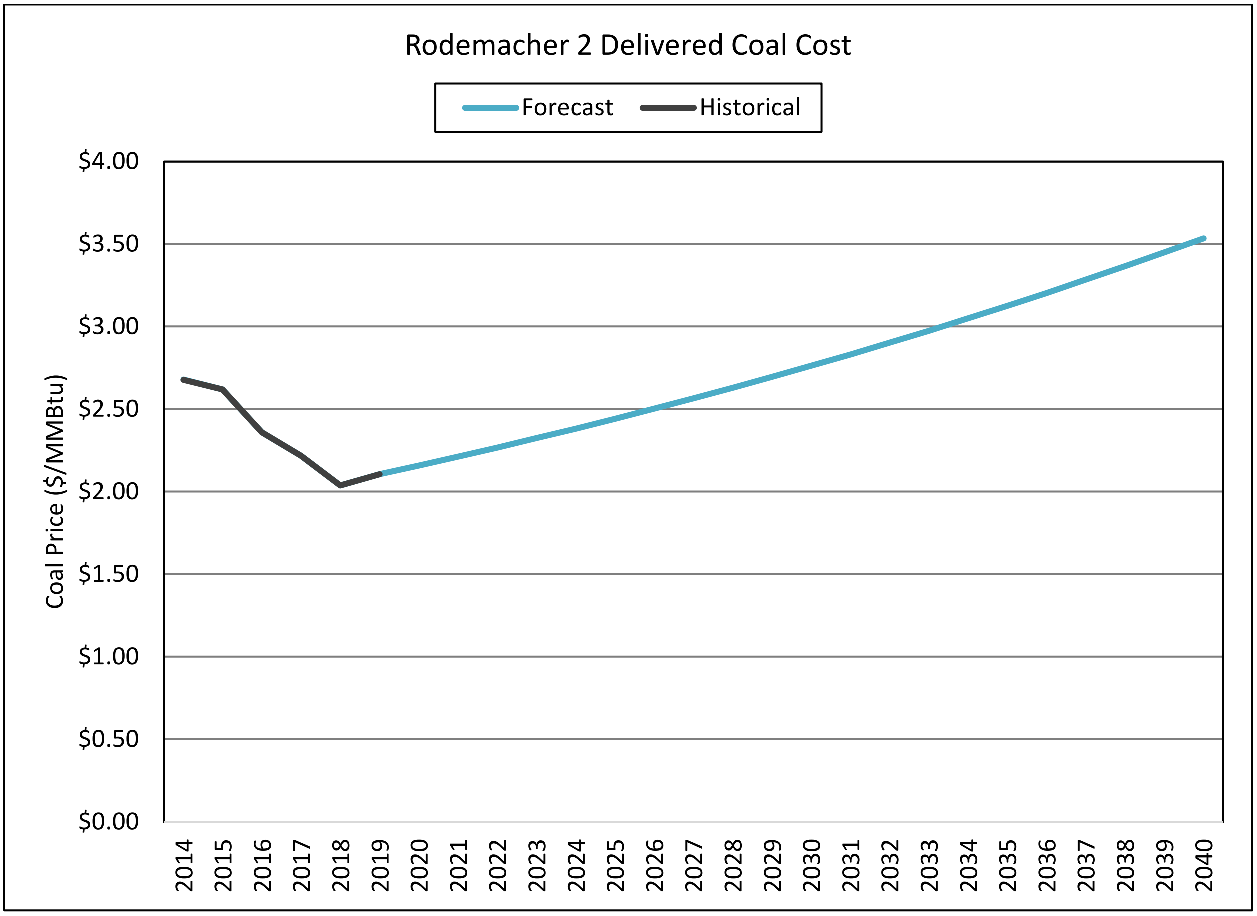
Coal forecasts were also developed for RPS2. The coal forecasts were based on information provided by LUS and the inflation values based on rates developed within the MTEP20 coal forecast. Figure 8-6 presents the coal forecast.

Figure 8-5: Natural Gas Price Forecast



Note: The DET forecast cannot be seen within the figure because it is the same as the CFC forecast.

Figure 8-6: RPS2 Coal Price Forecast

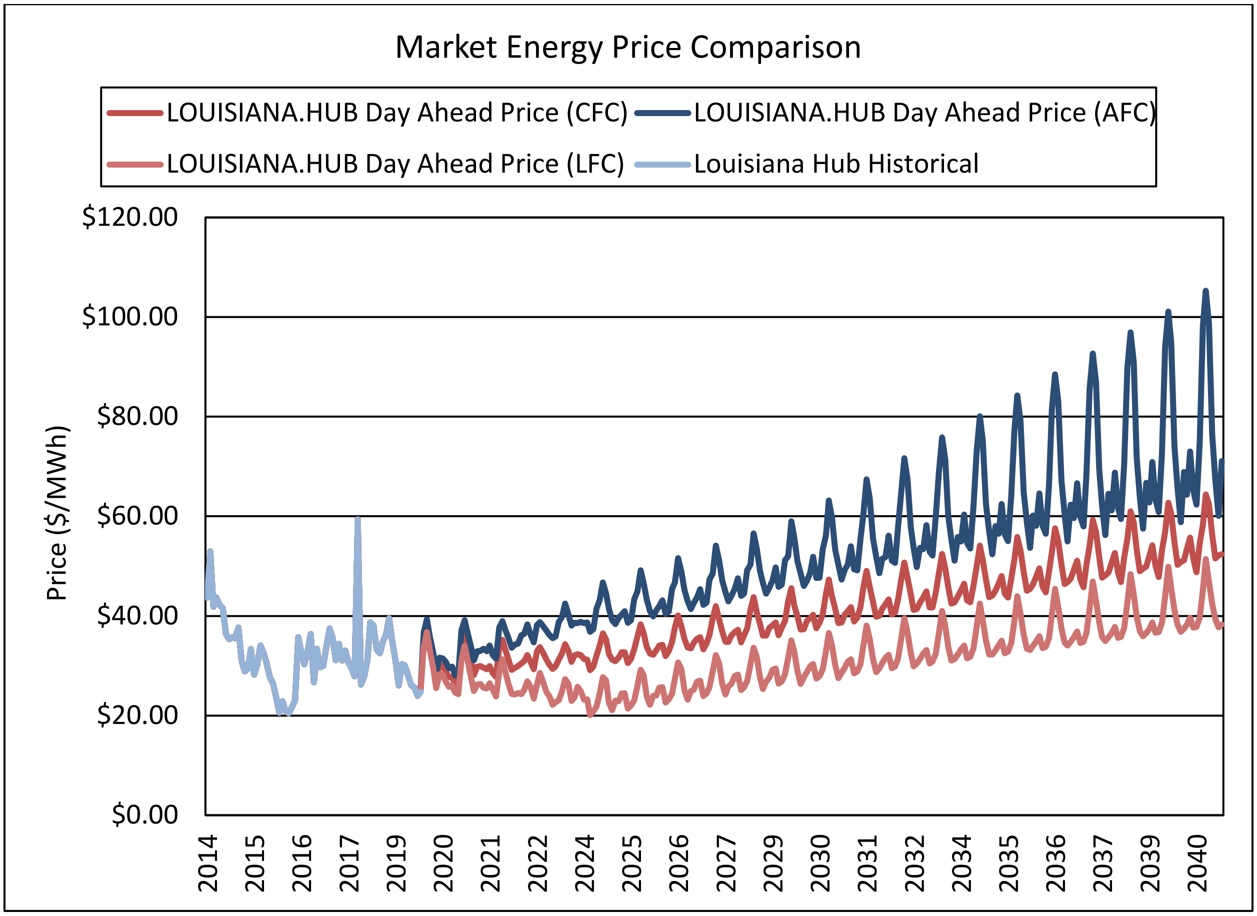


8.4.2 Market Energy Cost Forecast

Burns & McDonnell developed market energy costs utilizing the MISO MTEP model. Locational Marginal Price ("LMP") values represent the wholesale market energy prices at a particular location on the power system, and capture both the price of producing energy from generating plants as well as any transmission constraints which may make it more difficult to supply power to load centers.

LMP values were simulated in the MISO MTEP20 PROMOD model. LMP values were developed for several years consisting of 2024, 2029, and 2034. Figure 8-7 presents the market energy cost forecast utilized within this assessment. As presented in Figure 8-7, there are three lines illustrating the LMP values for the Louisiana Hub for each of the futures listed above. For years in between the 5-year segments, Burns & McDonnell interpolated to develop the full 20-year market energy pricing. Burns & McDonnell utilized the simulated Louisiana Hub prices for futures CFC, AFC and LFC. These market forecasts served as the basis for the economic dispatch for the power supply options under consideration.

Figure 8-7: Market Energy Cost Forecast based on MTEP20



8.5 Effective Load Carrying Capability

Utilities have many options for providing capacity and energy, including fossil-fueled and renewable generation to name a few. However, each generation type has unique characteristics, one of which is capacity accreditation. In order to meet customers' demand requirements, a utility must have sufficient capacity included within its power supply portfolio. Dispatchable resources, those which can be turned on and off, typically receive greater capacity accreditation. Dispatchable resources typically include fossil-fueled units. Non-dispatchable resources, such as renewables that depend on intermittent solar or wind resources, do not receive full capacity accreditation because they are dependent on weather conditions and may not be available during peak demand times. Many system operators have conducted studies to determine the effective load carrying capability ("ELCC") for wind and solar specifically. According to MISO, "the metric used to calculate the planning reserve margin ("PRM") for a system is the 'one day in 10 years' criterion for Loss of Load Expectation ("LOLE"). In other words, the system must have enough generation capacity above the gross peak load to cover load forecast errors, unexpected generation outages, and planned maintenance of generation units. The integration of higher levels of renewable resources into the MISO market has driven the need to quantify the effect of wind resources on the LOLE target. MISO has adopted the ELCC to quantify the capacity value of wind during MISO's peak hours."[14]. ELCC is defined as "the amount of incremental load a resource, in this case wind and solar, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served"[15]. Solar produces more during the day and wind typically produces more during the night. The ELCC for wind and solar was calculated from studies conducted by MISO and was used to apply the appropriate capacity accreditation. MISO released equations in their Renewable Integration Impact Assessment Assumptions[16] that allow analyses to calculate the projected ELCC based on the projected amount of wind and solar additions. The equations are shown below.

$$Wind\ UCAP = 100 * (-0.3 \ln(ICAP) + 0.26) * ICAP, in\ percentage$$
$$Solar\ UCAP = 100 * (-0.07 \ln(ICAP) + 0.42) * ICAP, in\ percentage$$

This analysis used those MISO equations to calculate the ELCC based on the projected solar and wind additions within each MTEP20 future scenario. The calculated ELCC for solar and wind used in this analysis is presented in Figure 8-8 and Figure 8-9, respectively. The ELCC was the basis for the model to choose solar and wind resources to fulfill LUS capacity requirements.

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[14] https://www.iaee.org/en/publications/newsletterdl.aspx?id=792

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

[16] MISO, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

Figure 8-8: Solar ELCC projections used in analysis.

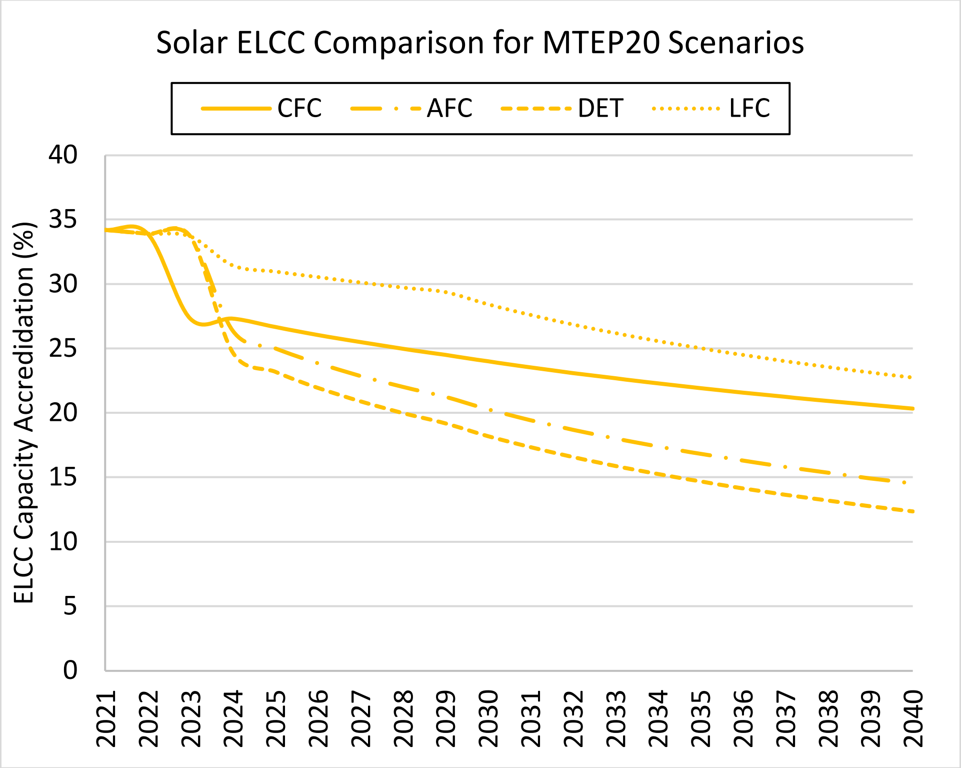
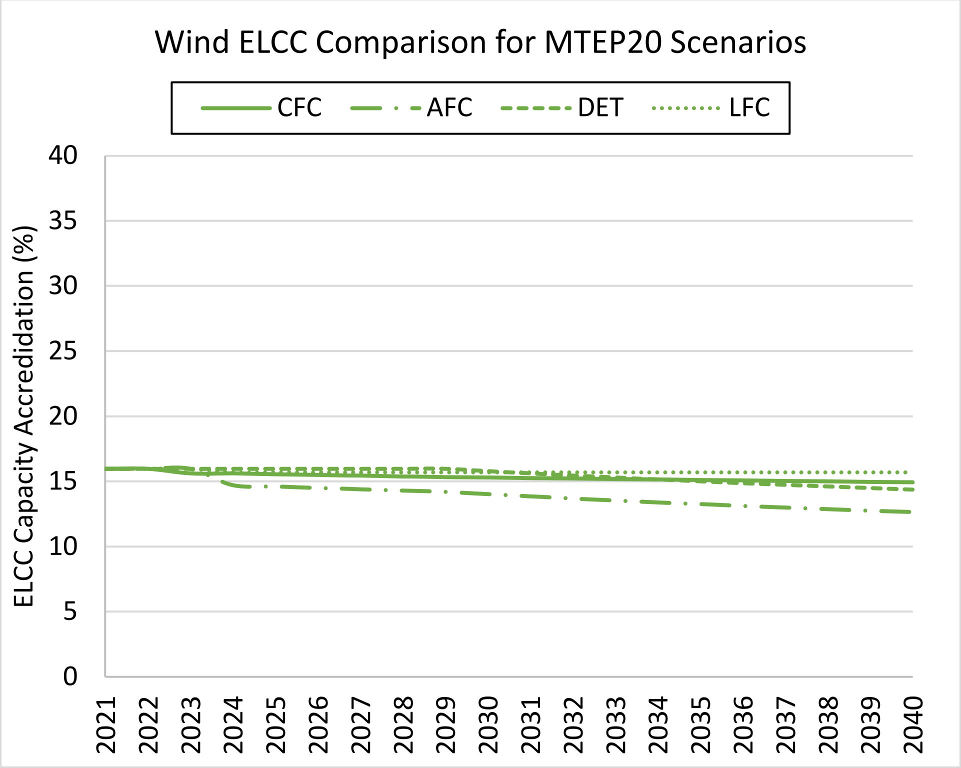


Figure 8-9: Wind ELCC projections used in analysis.



8.6 Scenario Development

Burns & McDonnell and LUS developed several scenarios for evaluation. The scenarios assumed that RPS2 is retired from coal-fired operation at the end of 2027, based on the RPS2 Evaluation conclusion. The retirement of RPS2 leads to a large capacity deficit which LUS will need to fill. While wind and solar resources will provide some capacity, such a large deficit will need to be covered by a dispatchable resource. The following resources were selected for evaluation to replace RPS2:

1. Simple Cycle Gas Turbine
2. Combined Cycle Gas Turbine (50 percent participation)
3. Natural Gas Conversion of RPS2
4. Reciprocating Engines

In addition to the options listed above, the analysis also considered solar PPAs, wind PPAs, and capacity market resources. The following sections discuss the economic evaluation associated with the scenarios.

8.6.1 Methodology

To develop robust power supply paths for LUS' consideration, Burns & McDonnell conducted a portfolio optimization simulation utilizing a modeling software (Strategist). Strategist is a capacity expansion optimization software that can evaluate thousands of potential power supply portfolios. Strategist uses reserve margin logic to evaluate expansion plans, or potential retirements, over a defined period. For this Study, the objective was to minimize utility power supply costs. Strategist evaluates the overall power supply needs (capacity and energy) against the power supply resource alternatives available to meet those needs. Strategist will evaluate the ongoing cost of operation for existing resources and investment in new resources against the overall benefits of capacity and energy while incorporating interactions with the wholesale market.

Using the scenarios described in the previous section as a basis, Strategist was utilized to develop specific power supply paths for evaluation.

The assumptions described herein were utilized within the simulations. Market prices were simulated in MTEP20 for the CFC, AFC, and LFC case and integrated into the Strategist model. The projected cost assumptions for LUS' current fleet were taken from the Condition Assessment, Environmental Assessment, and the RPS2 Evaluation. Cost Assumptions for new generation, including Solar and Wind PPA pricing, was taken from the Technology Assessment. The economic results utilizing the base assumptions are summarized in the following sections.

8.6.2 Sensitivity Analysis

To gauge the robustness of the base assumptions, Burns & McDonnell conducted a sensitivity analysis by varying several key assumptions. Sensitivity analysis included the following variables, many of which have been presented within the assumptions above:

- Natural gas: natural gas prices were fluctuated by utilizing a lower forecast from MTEP20 LFC and using the higher forecast from MTEP20 AFC. This impacted the cost of fuel directly to the natural gas resources and the price of market energy.
- Market Prices: energy market prices were fluctuated by utilizing the lower forecast from MTEP20 LFC and the higher forecast from MTEP20 AFC. The market energy prices are typically correlated with the natural gas prices, therefore the high market prices were used with the high natural gas prices and similarly with the low forecasts.
- LUS Load: the projected load of LUS was fluctuated by utilizing the high and low load forecasts described in the above section.

9.0 ECONOMIC EVALUATION

9.1 Introduction

As previously discussed, Burns & McDonnell and LUS developed several scenarios for evaluation that have both distinct individual attributes and collective considerations. The scenarios consisted of:

1. RPS2 converted to natural gas operation at the end of 2027
2. RPS2 retired at the end of 2027 and adding a 1 x F Class SCGT
3. RPS2 retired at the end of 2027 and adding a 1 x 1 G/H Class CCGT with 50 percent ownership
4. RPS2 retired at the end of 2027 and adding reciprocating engines

The following sections discuss the collective impacts and issues associated with the scenarios.

9.2 Scenario and Power Supply Path Development

Based on the individual evaluations conducted in the previous sections, Burns & McDonnell and LUS developed several scenarios and power supply paths. To effectively develop scenarios and power supply paths, the number of resources under evaluation needed to be reduced. Using Strategist results several power supply paths were selected for evaluation. The following provides a brief description of resources that were considered for further evaluation:

- Based on the screening economic evaluation previously described, two options for RPS2 were considered:
  - Coal-fired operation is retired at the end of 2027 and the units is converted to natural gas operation.
  - Retired from electric generation altogether at the end of 2027.
- Other natural gas-fired options that were considered based on LUS' load requirements were as follows:
  - Self-build power plant consisting of reciprocating engines totaling approximately 180 MW
  - Self-build power plant consisting of a large simple cycle combustion turbine totaling approximately 225 MW
  - Participation in a combined cycle power plant (207 MW portion of a 414 MW CCGT[17])
- Solar and wind power purchase agreements that include both energy and capacity were considered.

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[17] Co-ownership assuming 50 percent of the CCGT option was included to better align the capacity additions with the load requirements.

  - Solar and wind PPAs were considered in 50 MW (ICAP) increments.
  - The analysis could select up to 450 MW (ICAP) of wind and around 350 MW (ICAP) of solar[18]. This limit was imposed to ensure that the power supply paths did not procure excess power supply resources above the required capacity requirements for LUS.
  - The ELCC curve as described in a previous section was considered in this analysis to adjust the projected UCAP of solar and wind.
- Lithium Ion Battery Storage 25 MW 4-hour battery self-build.
- In addition to new resources listed above, the power supply paths also utilized market capacity to satisfy capacity deficits.

Using the above resources and the CFC case as the basis for the evaluation, the power supply paths included the following (and are also presented in Table 9-1):

1. Path No. 1:
   a. RPS2 retired at the end of 2027
   b. Install 227 MW SCGT in 2028
   c. Includes several 50-MW increments of solar via 20-year PPAs (300 MW in total).
   d. Power purchase agreements for capacity only to meet reserve requirements.
2. Path No. 2
   a. RPS2 retired at the end of 2027 and the addition of a CCGT 50% ownership
   b. Participate in a combined cycle power plant (LUS total would be 207 MW) installed in 2028
   c. Includes several 50-MW increments of solar via 20-year PPAs (300 MW in total).
   d. Power purchase agreements for capacity only to meet reserve requirements.
3. Path No. 3
   a. RPS2 retired at the end of 2027 from coal operation and converted to natural gas operation starting 2028
   b. Includes several 50-MW increments of solar via 20-year PPAs (300 MW in total).
   c. Power purchase agreements for capacity only to meet reserve requirements.
4. Path No. 4
   a. RPS2 retired at the end of 2027
   b. Install 180 MW of reciprocating engines (10 x 18 MW engines) in 2028
   c. Includes several 50-MW increments of solar via 20-year PPAs (300 MW in total).

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[18] The amount was adjusted based on the different ELCC characteristics of the sensitivities. For example, AFC scenario has more wind and solar penetration than CFC so the ELCC is lower in the AFC scenario. Since the ELCC is lower, more ICAP is needed to fill the capacity deficit.

d. Power purchase agreements for capacity only to meet reserve requirements.

Each of these scenarios and paths were evaluated under the base case assumptions as well as under the sensitivity evaluation. The BLR charts for each of these power supply paths is presented in Appendix J.

Table 9-1: Power Supply Paths

Year	Path Number			
	1	2	3	4
	Simple Cycle Gas Turbine F Class	Combined Cycle Gas Turbine 1x1G/H Class 50% Ownership	RPS2 Natural Gas Conversion	Reciprocating Engine (10 x 18MW Engines)
	Base case (CFC)	Base case (CFC)	Base case (CFC)	Base case (CFC)
2021	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2022	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2023	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2024	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2025	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2026				
2027	RPS2 Retired	RPS2 Retired	RPS2 Retired from coal	RPS2 Retired
2028	227 MW SCGT	207 MW CCGT	240 MW RPS2 Natural Gas Conversion	180 MW Reciprocating Engine Plant
2029				
2030	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039	50 MW Wind		50 MW Wind	50 MW Wind
2040		50 MW Wind		

9.3 Power Supply Analysis

The objective of the power supply analysis is to determine the overall costs associated with each path. The power supply analysis combined the individual assumptions described within previous sections into a comprehensive evaluation that includes the cost of serving load and the costs-benefits associated with power generation. Burns & McDonnell utilized the dispatch results from the efforts described within previous sections of this Study and aggregated them according to the scenario and power supply paths described above. Using these costs, Burns & McDonnell developed an overall net present value of power supply costs for each path for the 20-year study period from 2021 to 2040. A lower net present value means lower costs in which the customers incur. The power supply costs include:

- Costs for purchasing energy from MISO to serve load.
- Generation revenues and associated costs such as fuel, variable O&M, and fixed O&M for all power supply resource included within LUS' portfolio including existing plants, power purchase agreements, and new resources.
- Costs associated with environmental compliance, and capital investment in new resources.
- Market capacity purchases for power supply paths that incurred a small capacity deficit to meet MISO reserve requirements.

These variables were used to calculate the net present value as shown below.

$$\begin{bmatrix} LUS\ Power \\ Supply\ Cost \end{bmatrix} = \begin{bmatrix} Fuel \\ Costs \end{bmatrix} + \begin{bmatrix} Variable/Fixed \\ Expenses \end{bmatrix} + \begin{bmatrix} New\ Resource \\ Capital\ Costs \end{bmatrix} + \begin{bmatrix} Market/PPA \\ Purchases \end{bmatrix}$$

$$[Net\ Present\ Value] = \begin{bmatrix} LUS\ Power \\ Supply\ Cost \end{bmatrix} - \begin{bmatrix} LUS\ Fleet \\ Generation\ Revenues \end{bmatrix} + \begin{bmatrix} LUS \\ Load\ Payment \end{bmatrix}$$

Table 9-2 presents the net present value for each scenario and power supply path over the 20-year period under the base case assumptions and sensitivity analysis assumptions. Table 9-3 presents a heat map highlighting the power supply paths within each sensitivity case. Table 9-4 compares the net present value between each scenario. The power supply paths with lower net present value for costs are shaded in green and the higher cost paths are shaded in red.

Table 9-2: Net Present Value of Power Supply Costs.

Year	Path Number			
	1	2	3	4
	Simple Cycle Gas Turbine F Class	Combined Cycle Gas Turbine 1x1G/H Class 50% Ownership	RPS2 Natural Gas Conversion	Reciprocating Engine (10 x 18MW Engines)
	Base case (CFC)	Base case (CFC)	Base case (CFC)	Base case (CFC)
2021	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2022	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2023	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2024	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2025	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2026				
2027	RPS2 Retired	RPS2 Retired	RPS2 Retired from coal	RPS2 Retired
2028	227 MW SCGT	207 MW CCGT	240 MW RPS2 Natural Gas Conversion	180 MW Reciprocating Engine Plant
2029				
2030	50 MW Solar	50 MW Solar	50 MW Solar	50 MW Solar
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039	50 MW Wind		50 MW Wind	50 MW Wind
2040		50 MW Wind		
NPV Heat Map ($2020, $000)				
Base case (CFC)	$1,272,942	$1,287,323	$1,277,595	$1,357,784
Base case low demand (CFC Low)	$1,158,551	$1,173,200	$1,163,778	$1,243,255
Base case high demand (CFC High)	$1,630,057	$1,641,481	$1,636,735	$1,715,073
High gas and market prices (AFC)	$1,415,473	$1,401,531	$1,423,541	$1,491,835
Low gas and market prices (LFC)	$1,121,272	$1,142,426	$1,102,673	$1,207,347

Table 9-3: Net Present Value of scenarios.

NPV Heat Map ($2020, $000)				
Scenario	**Simple Cycle Gas Turbine F Class**	**Combined Cycle Gas Turbine 1x1G/H Class 50% Ownership**	**RPS2 Natural Gas Conversion**	**Reciprocating Engine (10 x 18MW Engines)**
Base case (CFC)	$1,272,942	$1,287,323	$1,277,595	$1,357,784
Base case low demand (CFC Low)	$1,158,551	$1,173,200	$1,163,778	$1,243,255
Base case high demand (CFC High)	$1,630,057	$1,641,481	$1,636,735	$1,715,073
High gas and market prices (AFC)	$1,415,473	$1,401,531	$1,423,541	$1,491,835
Low gas and market prices (LFC)	$1,121,272	$1,142,426	$1,102,673	$1,207,347

Table 9-4: Net Present Value Difference Comparison.

Difference From Minimum NPV Heat Map ($2020, $000)				
Scenario	**Simple Cycle Gas Turbine F Class**	**Combined Cycle Gas Turbine 1x1G/H Class 50% Ownership**	**RPS2 Natural Gas Conversion**	**Reciprocating Engine (10 x 18MW Engines)**
Base case (CFC)	$0	$14,381	$4,653	$84,842
Base case low demand (CFC Low)	$0	$14,650	$5,227	$84,705
Base case high demand (CFC High)	$0	$11,424	$6,678	$85,016
High gas and market prices (AFC)	$13,943	$0	$22,011	$90,305
Low gas and market prices (LFC)	$18,599	$39,753	$0	$104,674

In addition to costs, it is important to also to review other measures associated with the power supply paths. Regardless of the path selected, the retirement of RPS2 from coal-fired generation will drastically reduce LUS' dependence on coal-fired generation toward natural gas-fired generation and energy market purchases. Figure 9-1 and Figure 9-2 present the simulated energy supply by fuel type from 2021 through 2040 for both Path No. 1with the SCGT and Path No. 2 with the CCGT, respectively. As illustrated with the graph, LUS' use of coal for energy will be dramatically decreased after RPS2 retires from coal-fired operation. The addition of a simple cycle unit to replace RPS2 would have higher levels of energy market purchases compared to a path with a combined cycle unit, which would likely offset energy market purchases.

Figure 9-1: Energy by Fuel – Path No. 1 Simple Cycle (SCGT)

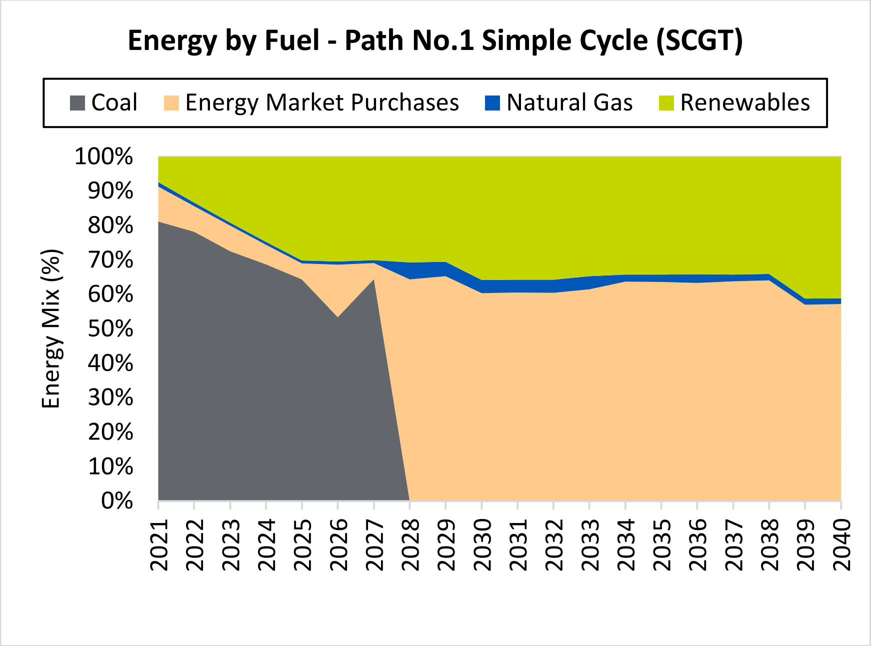


Figure 9-2: Energy by Fuel – Path No. 2 Combined Cycle (CCGT)

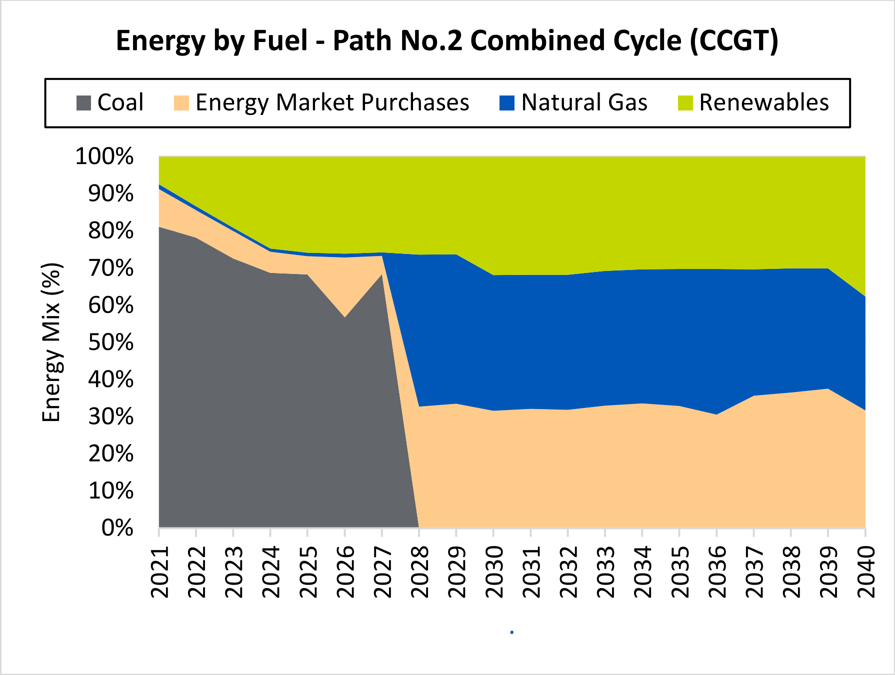


Figure 9-3 and Figure 9-4 present the CO_2 emissions generated from LUS-owned resources for both Path 1 and Path 2, respectively. With the retirement of RPS2, LUS' generation of CO_2 emissions will be dramatically decreased[19].

Figure 9-3: CO_2 Emissions – Path No. 1 Simple Cycle (SCGT)

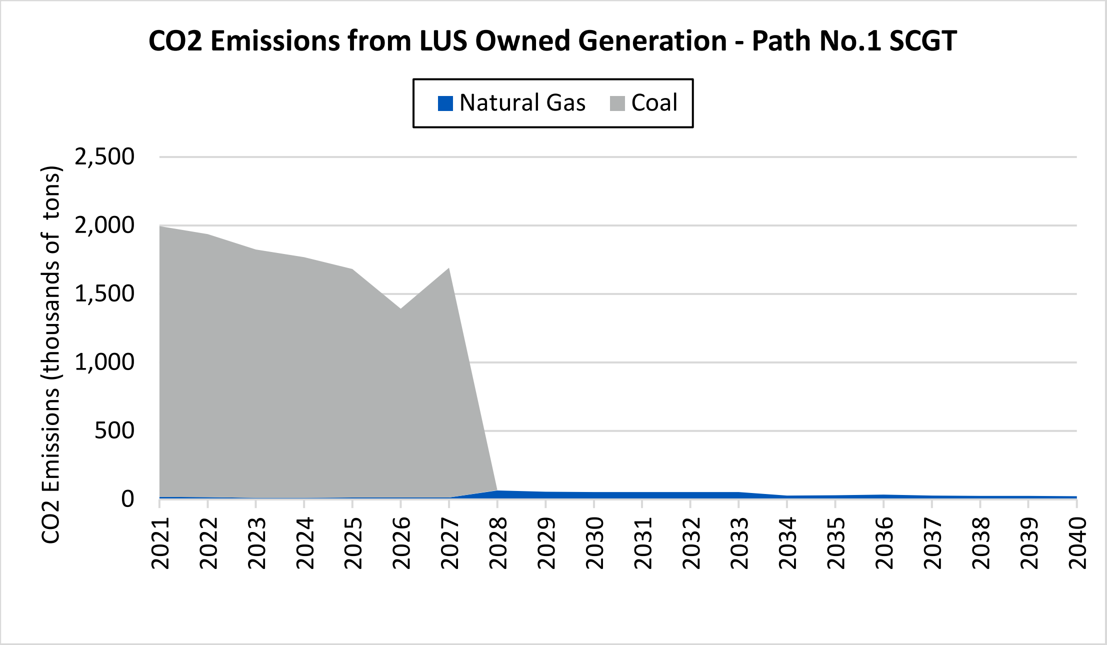
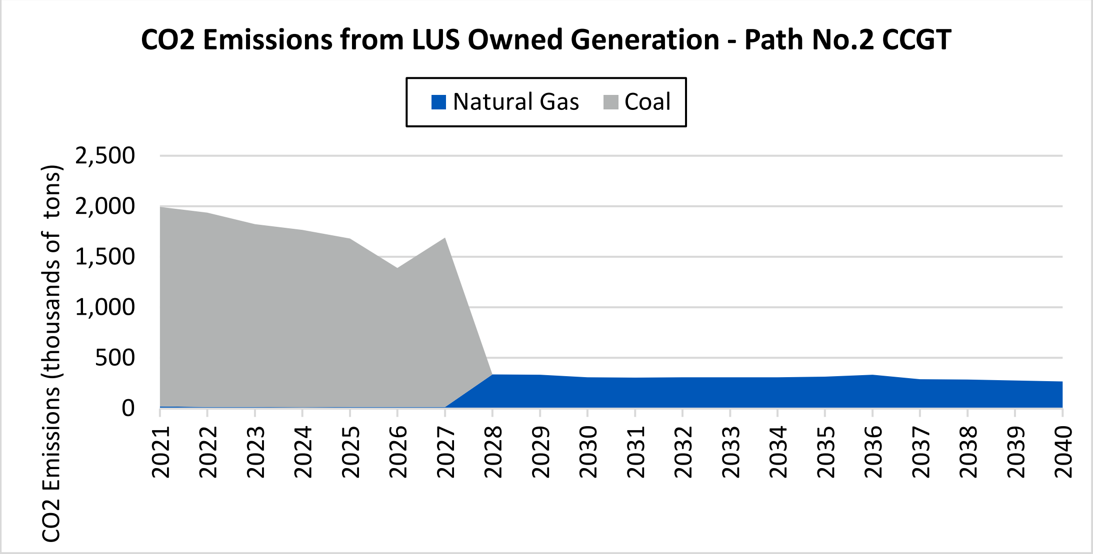


Figure 9-4: CO_2 Emissions – Path No. 2 Combined Cycle (CCGT)



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[19] This does not account for CO_2 emissions attributed to market energy purchases, only from LUS-owned resources.

9.4 Conclusions

Based on the analysis herein, Burns & McDonnell concludes the following from the power supply analysis:

1. The power supply paths were developed to evaluate varying combinations of the RPS2 operations and new generating assets.
2. All options consider the retirement of coal-fired operations at RPS2.
3. The SCGT is the lowest cost option relative to the other studied options for the CFC case (reference) and with high or low LUS load sensitivities.
4. The CCGT is the lowest cost option relative to the other options under the high gas and market prices sensitivity. As gas and market prices increase, the more efficient combined cycle becomes lower cost.
5. The RPS2 conversion to natural gas operation is the lowest cost option relative to the other options under the low gas and market prices sensitivity. Under very low market prices, LUS could rely on energy market purchases from MISO will lower investment in RPS2.
6. Overall, solar PPAs appeared in all the power supply paths early within the evaluation period, indicating that solar PPAs appear to be low cost energy options for LUS' portfolio. In total, 300 MW of solar resources were included.
7. Overall, the SCGT is the lowest cost option when comparing the base case with the different sensitivities.
8. Battery storage was not selected within the models. Within the assumptions used in this analysis battery storage was not an economical option for LUS based on the costs at this time.
9. Regardless of the path selected, the retirement of RPS2 from coal-fired generation will drastically reduce LUS' dependence on coal-fired generation toward natural gas-fired generation and energy market purchases.
10. With the retirement of RPS2, LUS' generation of CO_2 emissions will be dramatically decreased.

10.0 CONCLUSIONS & RECOMMENDATIONS

Based on the analysis herein, Burns & McDonnell provides the following overall observations, conclusions, and recommendations.

1. LUS should continue to monitor the overall electric utility industry, especially regulations that have potential to impact their power supply portfolio regarding water, coal combustion by-products, air emissions, and fuel supply. Furthermore, LUS should continue to monitor technological improvements for emerging technologies such as energy storage and other renewable resources.
2. Utilizing a combination of owned resources, power purchase agreements, and short-term capacity contracts to meet reserve margin requirements will allow LUS to continue to benefit from low capacity costs from third-parties while also limiting market exposure to future fluctuations for capacity and energy.
3. Under current environmental regulations, natural gas prices are expected to remain low due to hydraulic fracturing methods. Low natural gas prices, in combination with continued development of renewable resources, will likely maintain the relatively low wholesale energy prices experienced by LUS in the past five years.
4. The cost of capacity continues to remain low within MISO. While that value of capacity has increased slightly as indicated within the most recent MISO Planning Resource Auction, low cost capacity appears available to allow LUS to meet its resource adequacy requirements in the short-term, whether through the MISO auction process or third-party transactions. As LUS has done recently, LUS should continue to consider procuring short-term capacity purchases to meet its resource adequacy requirements.
5. Overall, LUS has maintained its generation fleet at, or exceeding, industry benchmarks based on reliability metrics and overall costs compared to similar units within the industry.
6. Environmental considerations
    a. Under the current environmental regulations, LUS' natural gas-fired units do not appear to require large capital improvements for compliance.
    b. Due to environmental regulations, RPS2 is faced with the need for capital improvements and investment, regardless of its long-term operating configuration.
    c. RPS2 is subject to numerous environmental regulations as it is a coal-fired power plant. The following regulations will impact the unit.
        i. Coal Combustion Residue: Regardless of RPS2's long-term operations (whether utilizing coal, converted to natural gas, or retired), the unit will be required to close the existing

on-site ash ponds to comply with CCR. These capital improvements are estimated to be approximately $20 to $25 million (for the entire RPS2 unit).

    ii. Effluent Limit Guidelines: LUS' RPS2 is expected to be impacted by the ELG rule so long as the unit continues to burn coal. The proposed ELG rules do allow for utilities to commit to retiring a unit by December 31, 2028 to avoid any new ELG requirements for bottom ash transport water. If this option is incorporated into a final rule, this option should be considered by LUS and the other co-owners; however, the facility will need to be modified to remain CCR compliant until that date.
    iii. RPS2 will be required to comply with numerous ongoing air regulations, among others, that are currently in place and subject to periodic review or newly proposed.

7. Long-term operation utilizing coal does not appear to be economical for RPS2 and LUS. LUS and the other co-owners should consider retirement of coal-fired operations to avoid ELG investments. LUS and the other co-owners should continue to evaluate RPS2 conversion to natural gas and retirement to determine which capital projects to implement in regard to ELG compliance, CCR regulations, natural gas conversion, and/or decommissioning.
8. In the event LUS and the co-owners decide to retire RPS2 from generation, LUS has several options for meeting its power supply requirements by replacing the capacity from RPS2 (which is approximately 250 MW).
    a. LUS should consider a self-build simple cycle gas turbine to replace RPS2. The power supply path including the simple cycle combustion turbine was one of the lowest cost plans evaluated. LUS has the existing Louis "Doc" Bonin Electric Generating Station that may be suitable for repurposing as simple cycle facility. The site already has access to natural gas pipelines and electrical infrastructure. LUS should consider starting engineering studies for the existing facility to assess the feasibility of re-purposing the site.
    b. LUS should consider participation in a combined cycle facility, through either co-ownership or power purchase agreements. Even with the retirement of RPS2, LUS does not have a great enough need for capacity to build a large CCGT facility. Therefore, if LUS were to procure a CCGT resource, it would likely be through co-ownership or PPA with a third-party.
    c. LUS should consider other power purchase agreements that may be available when RPS2 retires.
9. The addition of reciprocating engines to LUS' portfolio appears to be higher cost than other power supply resources. Reciprocating engines are typically more economical when procuring smaller amounts of capacity. However, if RPS2 were retired, LUS would have a large capacity

deficit which is more economically filled with larger resources with better economies of scale compared to reciprocating engines.

10. LUS should consider the addition of renewable resources, specifically solar resources, to its portfolio through power purchase agreements. The addition of solar resources was part of the lower cost plans evaluated within this Study. By procuring solar resources through power purchase agreements, LUS will be able to capture the benefits of tax incentives through third-party transactions. LUS should consider issuing a power supply request for proposals, specifically for renewable resources, but also other forms of power supply, in order to procure energy and capacity as required.
11. Should LUS re-purpose the Bonin site, LUS may consider pairing a small solar facility within the overall design.
12. LUS should continue to monitor and evaluate battery storage technologies. Battery storage costs might decrease faster than current estimates as they have in the past. The future impact of battery storage on the grid will also become clearer as more utilities start to develop battery storage projects and system operators, specifically MISO, develop policies associated with storage operations.
13. While the benefits of energy efficiency and demand response programs did not exceed their costs as evaluated within this Study, LUS should continue to monitor energy efficiency and demand response programs that may be implemented in the future to reduce the overall cost to customers and provide LUS flexibility in meeting its capacity and energy requirements.

APPENDIX A – CONDITION ASSESSMENT

Condition Assessment

Lafayette Utilities System

Condition Assessment
Project No. 118157

1/28/2020

BURNS McDONNELL

April 1, 2020

Jeff Stewart
Manager, Engineering & Power Supply
Lafayette Utilities System
1314 Walker Road
Lafayette, LA 70506

Re: Condition Assessment

Dear Mr. Stewart:

Lafayette Utilities System ("LUS") retained Burns & McDonnell to perform an integrated resource planning study ("IRP"). As part of the IRP, Burns & McDonnell completed a Condition Assessment ("Assessment") of LUS' existing power plants to provide cost estimates in order to continue to operate the units in a reliable manner. The information herein is to be utilized within the IRP process to help LUS set a power supply direction moving forward.

If you have any questions regarding this information, please feel free to contact either Mike Borgstadt at 816-822-3459 or mike.borgstadt@1898andco.com or Kyle Combes at 816-349-6884 or kyle.combes@1898andco.com.

Sincerely,

Mike Borgstadt
Director, Utility Consulting

Kyle Combes

Kyle Combes
Project Manager

MEB/meb

Enclosure
cc: Karen Hoyt
Josh Zeno

9400 Ward Parkway \ Kansas City, MO 64114
O 816-333-9400 \ **F** 816-333-3690 \ burnsmcd.com

Condition Assessment

prepared for

Lafayette Utilities System
Condition Assessment
Lafayette, Louisiana

Project No. 118157

1/28/2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF FIGURES

LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
°F	Degrees Fahrenheit
A	Amperes
AC	Alternating Current
BFP	Boiler Feed Pump
BOP	Balance of Plant
Btu	British Thermal Units
Burns & McDonnell	Burns & McDonnell Engineering Company Inc.
CCR	Coal Combustion Residual
CE	Combustion Engineering
CEMS	Continuous Emissions Monitoring System
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DA	Deaerator
DC	Direct Current
DCS	Distributed Control System
demin	Demineralized
DGA	Dissolved Gas Analysis
EAF	Equivalent Availability Factor
EDG	Emergency Diesel Generator

Abbreviation	**Term/Phrase/Name**
EFOR	Equivalent Forced Outage Rate
EIA	Energy Information Agency
ESP	Electrostatic Precipitator
EWS	Engineering Work Station
FAC	Flow Accelerated Corrosion
FD	Forced Draft
FERC	Federal Energy Regulatory Commission
FOA	Forced Oil Air
FWH	Feedwater Heater
GAC	Granular Activated Carbon
GADS	Generator Availability Data System
GE	General Electric
gpm	Gallons per Minute
GSU	Generator Step Up
Hargis	Hargis-Hebért Generating Station
HCl	Hydrochloric Acid
HEP	High Energy Piping
HHU1	Hargis-Hébert Unit 1
HHU2	Hargis-Hébert Unit 2
HP	High Pressure
hp	Horsepower
HPC	High Pressure Combustion

Abbreviation	**Term/Phrase/Name**
HPT	High Pressure Turbine
Hz	Hertz
ID	Induced Draft
IP	Intermediate Pressure
IRP	Integrated Resource Plan
kV	kilovolts
kVA	Kilovolt Amperes
kW	Kilowatts
Labbe	T.J. Labbé Power Generation Station
lb/hr	Pounds per Hour
LEPA	Louisiana Energy and Power Authority
LP	Low Pressure
L-type	Left Modal Type
LUS	Lafayette Utilities System
MATS	Mercury and Air Toxic Standards
MCC	Motor Control Center
MCR	Maximum Continuous Rating
MISO	Midcontinent Independent System Operator
MV	Medium Voltage
MVA	Megavolt Amps
MW	Megawatts
MWh	Megawatt Hours

Abbreviation	**Term/Phrase/Name**
NAG	Net Actual Generation
NCF	Net Capacity Factor
NDE	Nondestructive Evaluation
NERC	North American Electric Reliability Corporation
Non-seg	Non-segregated Phase
NOx	Nitric Oxide
NSST	Normal Station Service Transformer
O&M	Operation and Maintenance
OA	Oil Air
ODAF	Oil Direct Air Forced
OEM	Original Equipment Manufacturer
OFA	Over Fired Air
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
PA	Primary Air
PCP	Process Control Panel
PCS	Plant Control System
pf	Power Factor
ppm	Parts per Million
psig	Pounds per Square Inch (gauge)
Rodemacher	Rodemacher Power Station
RPM	Rotations per Minute

Abbreviation	**Term/Phrase/Name**
RPS2	Rodemacher Power Station Unit 2
RSST	Reserve Station Service Transformer
R-type	Right Modal Type
scfm	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SERC	Southeaster Reliability Coordination Council
SNCR	Selective Noncatalytic Reduction
SPP	Southern Power Pool
SPRINT	Spray Intercooling
sqft	Square Feet
ST	Steam Turbine
STG	Steam Turbine Generator
Study	Condition Assessment Study
S-type	Symmetric Modal Type
TAS	Turbine Air Systems
TJU1	T.J. Labbé Unit 1
TJU2	T.J. Labbé Unit 2
US	United States
V	Volt
VAR	Variance
VSV	Variable Stator Vane

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In preparation of this report, Burns & McDonnell Engineering Company, Inc. (“Burns & McDonnell”) has relied upon information provided by Lafayette Utilities System (“LUS”) and the owners and operators of the T.J Labbé, Hargis-Hébert, and Rodemacher Generating Stations. While there is no reason to believe that the information provided is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee or warranty its accuracy or completeness.

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1.0 EXECUTIVE SUMMARY

1.1 Objective & Background

Lafayette Utilities System ("LUS") retained the services of Burns & McDonnell Engineering Company Inc. ("Burns & McDonnell") to perform a condition assessment study ("Study") of the T.J. Labbé Unit 1 and Unit 2 ("TJU1" and "TJU2") at the T.J. Labbé Power Generation Station ("Labbe"), Hargis-Hébert Unit 1 and Unit 2 ("HHU1" and "HHU2") at the Hargis-Hebért Generating Station ("Hargis"), and Rodemacher Unit 2 ("RPS2") at the Rodemacher Power Station ("Rodemacher") to determine the overall costs to continue to operate the units reliability. LUS will be using the information to support completing an Integrated Resource Plan ("IRP") as required by the Federal Energy Regulatory Commission ("FERC").

Labbé and Hargis each consist of two LM6000 PC SPRINT combustion turbines ("CTs") running in a simple cycle. Each facility has a maximum net capability of 100 megawatts ("MW"). Labbe entered commercial operation in 2005 while Hargis entered commercial operation in 2006. Labbe and Hargis are each fully owned and operated by LUS.

RPS2 consists of a coal fired, reheat boiler which generates steam to drive a steam turbine ("ST") to produce electricity. Coal is prepared for the boiler by six roller wheel coal mills. The maximum net capacity of the unit is approximately 500 MW. RPS2 entered commercial operation in 1982. RPS2 is 50 percent owned by LUS, 20 percent owned by Louisiana Energy and Power Authority ("LEPA"), and 30 percent owned by CLECO who operates the station.

The intent of this Study is to assist LUS in identifying the maintenance and capital expenditures associated with operating the unit at a level which meets or exceeds the average reliability of similar units. The analysis conducted herein is based on historical operations data, maintenance and operating practices of units similar to those owned by LUS, as well as Burns & McDonnell's professional judgement. For this Study, Burns & McDonnell reviewed data provided by LUS and CLECO, interviewed plant personnel, and conducted a walk-down of Labbe and Hargis in order to obtain information on the units. Burns & McDonnell also analyzed any necessary updates for the units and any necessary capital replacements to maintain reliability.

1.2 Results

1.2.1 Performance & Benchmark

Burns & McDonnell evaluated the units' overall reliability and performance against a fleet average of similar generating stations. The data used to determine the fleet averages of similar generating stations was obtained from the North American Electric Reliability Corporation ("NERC") and from the United States ("US") Energy Information Agency ("EIA")-860 database for the last five years.

Overall, TJU1's and TJU2's reliability performance is better than the fleet average as measured by the equivalent availability factor ("EAF") and by the equivalent forced outage rate ("EFOR"). TJU1's EAF and EFOR are better than the fleet average in all five of the years studied with exception of TJU1's EAF in 2016, which is less than half a percentage point less than the national benchmark. TJU2's EAF and EFOR were both better than the fleet average in three of the past five years.

HHU1's and HHU2's reliability performance is better than the fleet average as measured by the EAF and by the EFOR. HHU1's EAF and EFOR are better than the fleet averages in three of the five years studied. HHU2's EAF and EFOR are better than the fleet average h in all five years studied.

Overall, RPS2's reliability performance is better than the fleet average as measured both by the EAF and by the EFOR. The unit's EAF was better than the fleet average in three of the past five years. RPS2's EFOR was better than the fleet average in four of the past five years.

The overall costs required to operate and maintain simple cycle gas turbine units appear to stay consistent with age as illustrated in Figure 1-1 and Figure 1-2 below. Units experience escalating operation and maintenance ("O&M") cost at age 50 due to retirements and reinvestments in the units to continue to maintain the reliability of the unit. Units operated until failure experience lower O&M, while units needed for reliability reasons will experience an increase in O&M cost in order to repair and replace components. Labbe and Hargis have been above similarly sized simple cycle units in the southeastern US on a generation basis but have been low on a net capacity basis. This is likely due to the unit having reasonable O&M costs for its size but having a low net generation and a low capacity factor.

Figure 1-1: T.J. Labbé and Hargis-Hébert O&M Cost Benchmark ($/MWh)

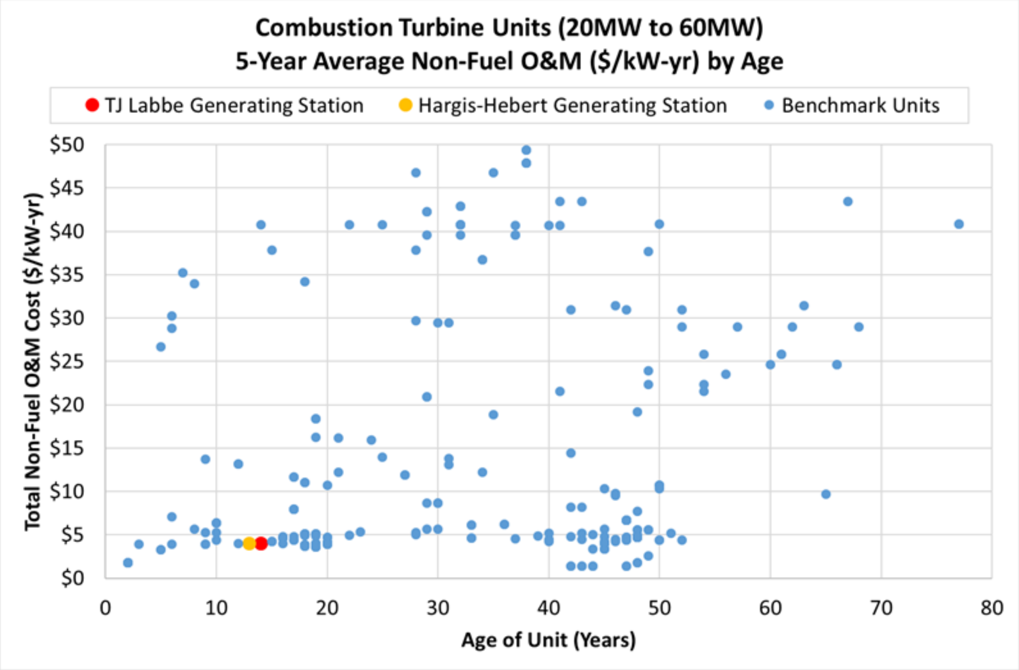
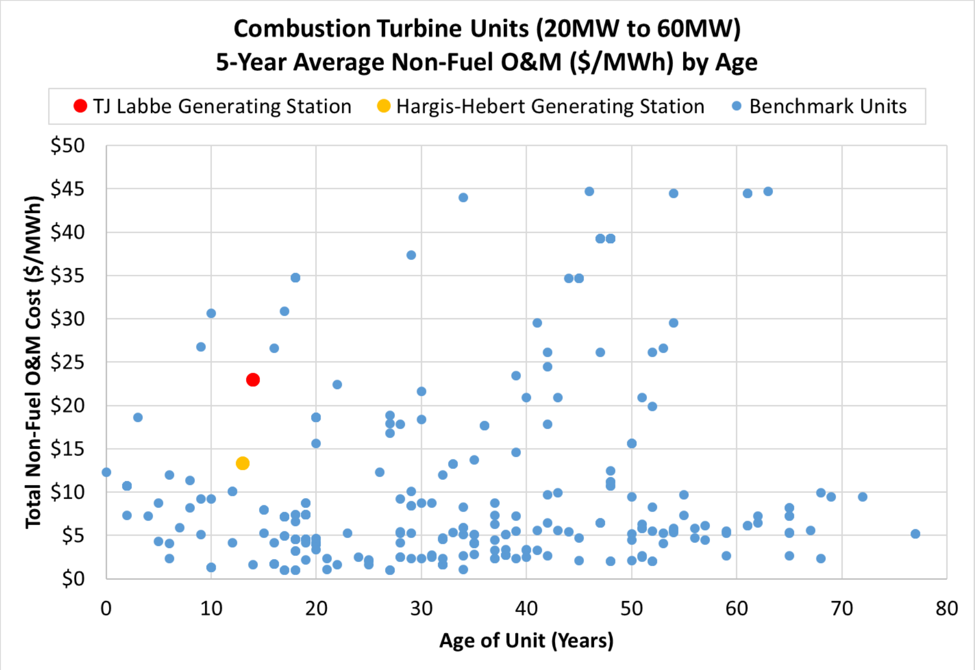


Figure 1-2: T.J. Labbé and Hargis-Hébert O&M Cost Benchmark ($/kW)



The overall costs required to operate and maintain coal units appear to increase with age as illustrated in Figure 1-3 and Figure 1-4 below. RPS2 is spending approximately the same as other units on both a net generation and net capacity basis. From the figures, there is a wide variation in O&M costs for the units approaching end of life. This is most likely attributed to a difference in operating philosophies at site. The differences between the high O&M cost units and the low O&M cost units can likely be attributed to a difference in operating philosophy.

Figure 1-3: RPS2 O&M Cost Benchmark ($/MWh)

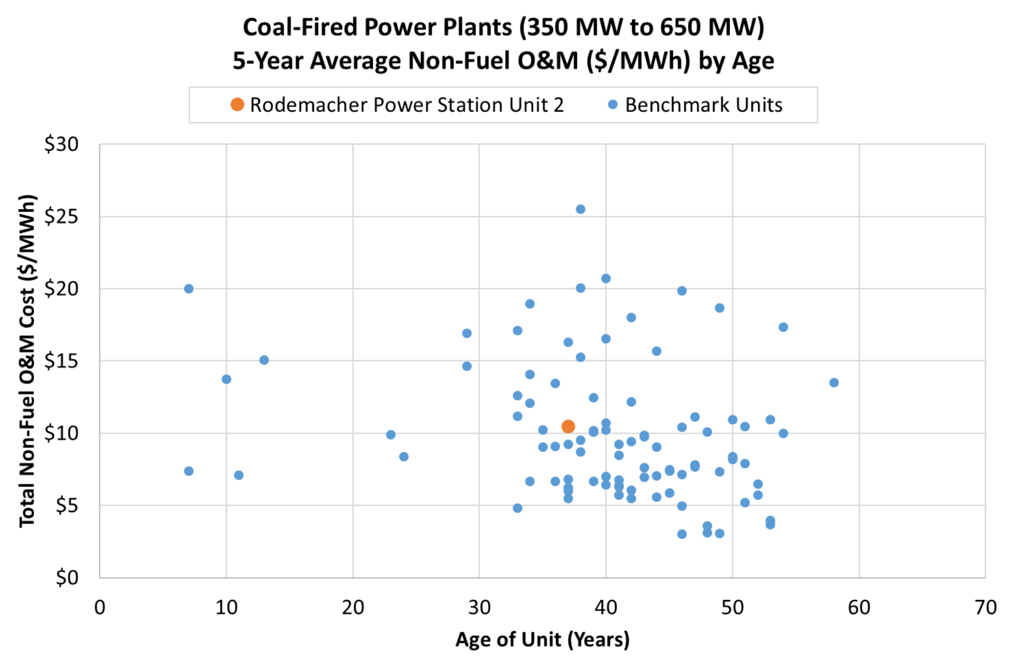
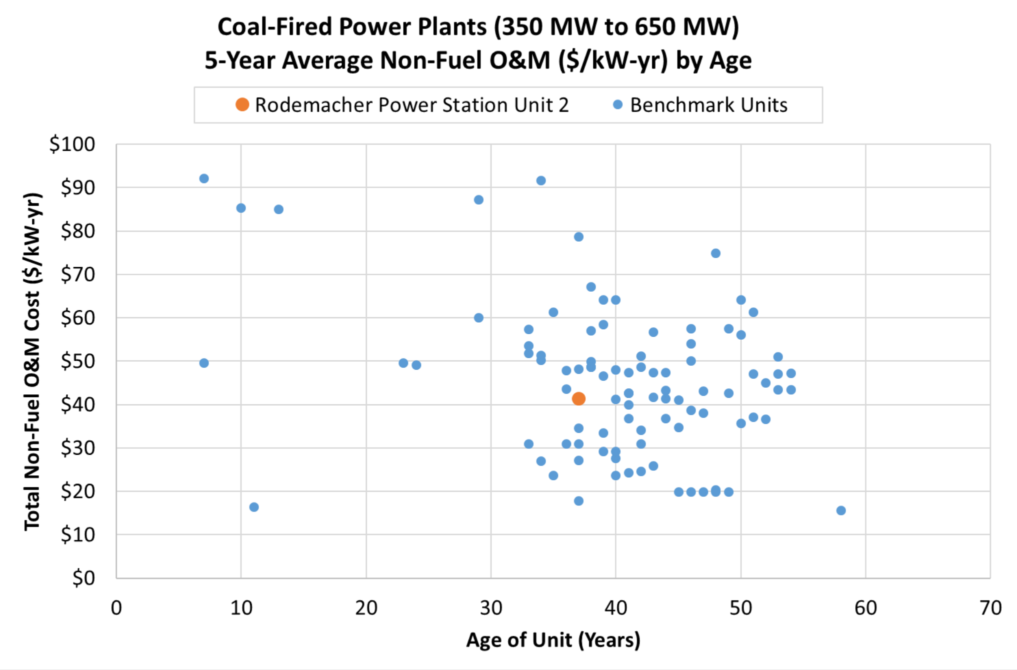


Figure 1-4: RPS2 O&M Cost Benchmark ($/kW)



1.2.2 Cost Projections

Burns & McDonnell evaluated the overall costs for operating and maintaining the facilities. The projected costs included baseline historical O&M costs plus specific future projects identified through the condition assessment. Figure 1-5 and Figure 1-6Figure 1-5 present the total annual baseline O&M expenses and project expenditures required to operate Labbe and Hargis through 2039, respectively. Figure 1-7 shows the annual baseline O&M costs for RPS2. Baseline O&M expenses are comprised of the typical annual O&M costs excluding major projects (shown in blue), the 5 year horizon project costs (shown in orange), the 10 year horizon costs (shown in green), and the 20 year horizon costs (shown in yellow) The costs are all presented in 2019$ and do not include escalation. Appendix A shows a breakdown of individual project costs.

Figure 1-5: T.J. Labbé Total Annual O&M Cost Summary

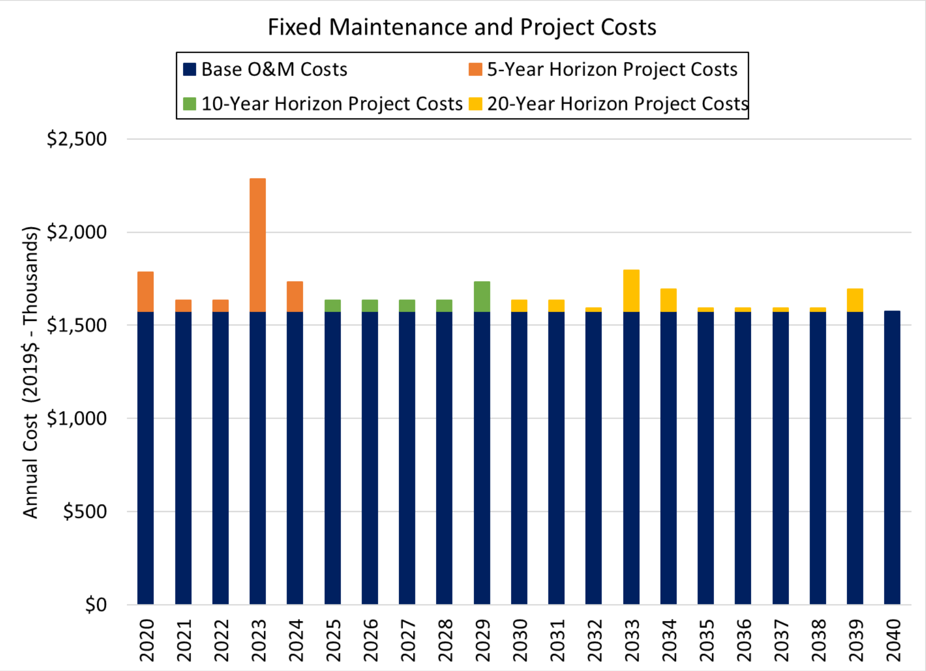


Figure 1-6: Hargis-Hébert Total Annual O&M Cost Summary

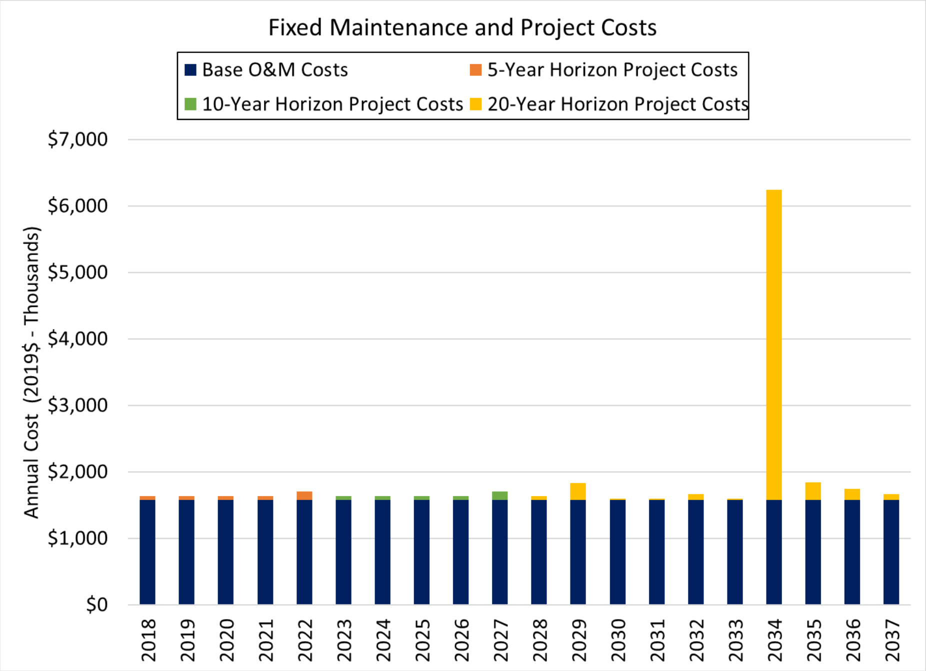
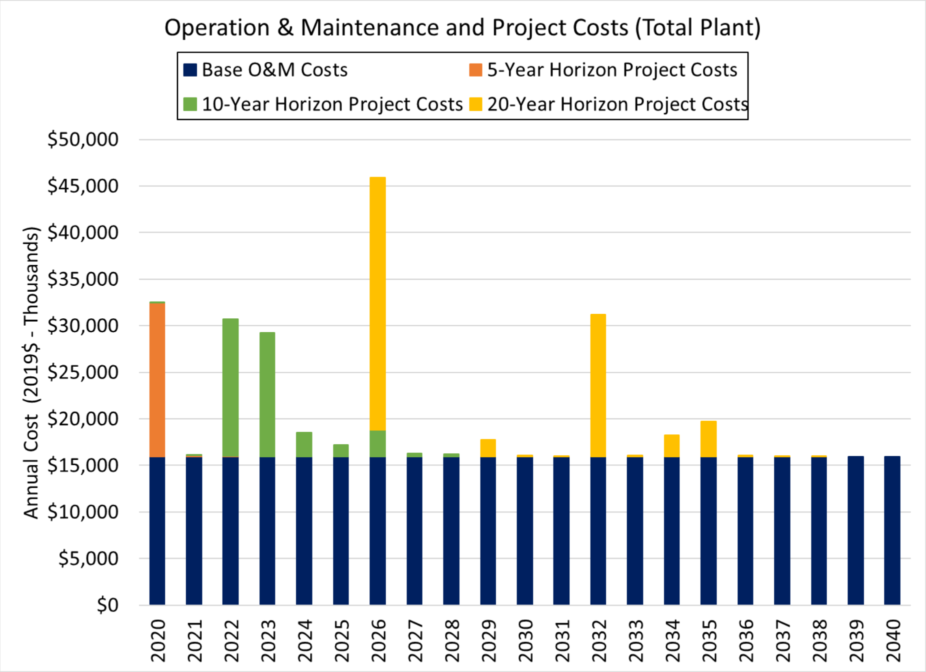


Figure 1-7: RPS2 Total Annual O&M Cost Summary



1.3 Conclusions

The following conclusions and recommendations are based on the observations and analysis from this Study.

1. Labbe and Hargis entered commercial operation in 2005 and 2006, respectively. At the end of the Study period, the units will be 35 years old. Half of similarly sized units in the region are anticipated to reach an age 44 years before retirement. Considering that the units receive fewer starts and, therefore, fewer thermal stresses than similar units in the region, along with the proactive maintenance operating philosophy on site, it is anticipated that Labbe and Hargis will have substantial service life past the end of the Study period.
2. RPS2 entered commercial operation in 1982. The current operating agreement between LUS and CLECO is set to expire in 2032. At the end of the operating agreement, RPS2 will be 47 years old. Half of similarly sized units in the region are anticipated to reach an age 53 years before retirement. It is anticipated that RPS2 will be capable of operating to the end of the operating agreement.
3. Over the past few years, the units at Labbe and Hargis have operated with an EAF higher (better) than the fleet average and an EFOR generally lower (better) than the fleet average. The operational excellence at Labbe and Hargis should be maintained with continued preventative maintenance and regular inspections of the equipment at the plants.
4. Over the past few years, RPS2 has operated about equal to the industry average for EAF and lower (better) than the industry average for EFOR. The current operations should be maintained with continued preventative maintenance and regular inspections of the equipment at the plants.
5. Although Labbe and Hargis have experienced an increase in NCF over the past five years, they are still below national and regional averages. Based on discussions with operations staff, it may be beneficial to reevaluate dispatch parameters to ensure the operating costs are properly accounted for and not overly conservative. Increasing operation at base load conditions should also improve the average NHRs for Labbe and Hargis. It should be noted however, that with increased operating hours, the major overhaul intervals projected in this study would be accelerated (major overhauls would need to be performed sooner).
6. LUS and CLECO should develop an end-of-design life plan in order to adequately allocate capital to RPS2 and other power generating assets within the LUS fleet. If LUS determines RPS2 is an essential asset until 2032, then larger capital investments will be warranted to maintain reliable operation. If RPS2 is not an essential asset, LUS and CLECO should consider operating the unit with minimal capital investment until decommissioning.

2.0 INTRODUCTION

2.1 General Plant Descriptions

LUS is a city owned municipality with generation stations servicing 67,000 customers located in Lafayette, Louisiana. The generating stations include T.J. Labbé Generating Station, Hargis-Hébert Generating Station, and Rodemacher Power Station Unit 2 and service an annual peak demand of 458 MW. Rodemacher Power Station Unit 2 is 50 percent owned by LUS and the operating agreement with CLECO is set to expire in 2032.

2.1.1 T.J. Labbé and Hargis-Hébert

Labbe began commercial operation in 2005. The facility currently has a nameplate gross capacity of 100 MW. Hebert began commercial operation in 2006 and has a nameplate gross capacity of 100 MW. Both facilities are run as peaking sites.

Each facility's major equipment includes two simple cycle CTs. The CTs are both LM6000 PC aeroderivative units that were manufactured by General Electric (“GE”). The units each have a rated net output of 45 MW and 50 MW utilizing GE's Spray Intercooling (“SPRINT”) system. Each unit also includes a TAS chiller system to provide chilled water to coils in the inlet filter house to cool inlet air entering the CT.

2.1.2 Rodemacher Power Station Unit 2

The maximum net capacity for RPS2 is approximately 500 MW. RPS2 entered commercial operation in 1982. RPS2 generates electric power using a coal fired, natural circulation, reheat boiler manufactured by Combustion Engineering (“CE”). The boiler has a maximum continuous rating (“MCR”) of 3,800,000 pounds per hour (“lb/hr”) of steam at the superheater outlet pressure of 2,620 pounds per square inch gauge (“psig”) and temperature of 1,005 degrees Fahrenheit (“°F”). The reheater is designed for an operating temperature of 1,005°F with an MCR of 3,366,000 lb/hr of steam at 562 psig. The superheater outlet temperature is controlled with attemperator spray water and reheater outlet temperature are primarily controlled with gas path damper controls. Attemperator spray can be used for reheat outlet temperature control, but the piping has since been valved out. Coal is prepared for the boiler by three to five of the associated roller wheel coal mills. The coal arrives on site via rail with rotary dump cars.

The boiler has a balanced draft furnace with combustion air being supplied by two 50 percent forced draft fans. The boiler was initially designed to burn various types of coal and natural gas, but primarily burns PRB coal and starts up on natural gas. RPS2 has one motor driven startup boiler feed pump capable of allowing the unit to achieve approximately 330 MW and one 100 percent capacity turbine driven boiler feed pump capable of operating between minimum load and full load. Feedwater and condensate are heated to economizer inlet conditions utilizing four low pressure (“LP”) feed water heaters (“FWHs”), a deaerator (“DA”), and two high pressure (“HP”) feedwater heaters. RPS2 also utilizes a GE steam turbine generator (“STG”), which is a four casing, single reheat, tandem compound, four flow condensing unit. The generators are rated at 496 megavolt amperes (“MVA”). Cooling water for the Units is circulated through a two-shell single pass condenser, which receives water from, and discharges water to, a lake.

2.2 Study Objectives & Overview

LUS retained the services of Burns & McDonnell to perform a study to determine the anticipated maintenance costs and capital expenditures for continuing to operate Labbe, Hargis, and RPS2 reliably until 2039. The intent of this assessment is to assist LUS in creating an IRP. Burns & McDonnell also evaluated potential environmental regulations that could affect the continued operation of the facilities. The environmental assessment is a separate report provided by Burns & McDonnell. The costs associated with complying with environmental regulations has not been included as part of this assessment.

This Study includes an analysis of the current condition of the facilities to assess how the current operational state would impact the forecasted capital expenditure, and O&M budget. The determined condition of the units is based on historical operational data and other equipment inspection and condition assessment reports provided by LUS and CLECO, maintenance and operations practices of similar units, and Burns & McDonnell’s professional opinion. To complete this assessment, Burns & McDonnell engineers reviewed plant documentation, interviewed management, engineering and plant personnel, and conducted a walkdown of Labbe and Hargis to determine the condition of the equipment. Burns & McDonnell did not perform any detailed equipment testing such as nondestructive or destructive testing, turbine or generator inspections, performance testing, etc. for this Study.

2.3 Study Contents

The following report details the current condition of the facilities and their units and presents the capital expenditures and ongoing O&M costs that would be associated with continuing to operate each site reliably through 2039. Since virtually any single component within a power plant can be replaced, the remaining useful life of a plant is typically driven by the economics of replacing the various components as necessary to keep the plant operating economically at industry standards versus shutting it down and either purchasing power or building a replacement facility. Specifically, the critical physical components that will likely determine a facility’s remaining useful life include the following:

1. HEP systems
2. CT rotor
3. ST rotor, valves, and steam chest
4. Generator rotor, stator and rotor windings, stator and rotor insulation, and retaining rings
5. Boiler tubing, steam drum, headers and downcomers
6. Boiler bottom ash handling equipment compliance with Coal Combustion Residual (“CCR”) regulations

The following items, although not as critical as the ones listed above, will also play a role in determining the remaining life of a plant:

1. Boiler ductwork and insulation
2. CT blades, combustor parts, diaphragms, nozzle blocks, casing, and shells
3. ST blades, diaphragms, nozzle blocks, casing, and shells
4. Generator stator-winding bracing, direct current (“DC”) exciter, and voltage regulator
5. Balance of plant (“BOP”) equipment such as the distributed controls system (“DCS”), Condenser, boiler feed pumps (“BFPs”), and BFP motors
6. Structural steel, stack, concrete structures
7. Electrical equipment such as station main generator step-up (“GSU”) transformers and switchgears

2.4 Approach and Assumptions

Burns & McDonnell performed a benchmarking study, a useful life analysis, and cost projections for each of the Labbe, Hargis, and RPS2 units. The benchmarking study included comparing units’ net capacity factors (“NCF”), EAF, EFOR, starting reliabilities, actual starts, operating costs, net actual generation (“NAG”), and net heat rates (“NHR”) to industry averages. Except for NHRs and operating costs, the benchmarking parameters were pulled from NERC Generator Availability Data System (“GADS”). For NHR and operating costs, the US EIA-860 database was used. The data for all the benchmarking parameters was used to generate both national and regional 5-year averages. The GADS unit data provided by LUS was the compared to the benchmarks. Since Labbe and Hargis have identical units, the same benchmarks were used for both sites.

For the useful life analysis, a set of data was pulled from the US EIA-860 database containing unit characteristics, region, retirement date, and commercial operation date. The national and regional data was filtered down to compare similar units to the ones at Labbe, Hargis, and RPS2. The data was used to determine the current proportions of units surviving and their corresponding ages. Burns & McDonnell approximated the probability of unit survivals with the use of Iowa-Type Survivor Curves; a set of standardized curves used to approximate useful life of varying technologies. Iowa Survivor Curves, specifically, are widely used in the utility industry in depreciation studies for establishing the useful life of generating assets and performing statistical analyses of transmission and distribution equipment. The Iowa Curves that most closely fit the data were used. Since Labbe and Hargis have identical units, the same survival curves were used for both sites.

Lastly, for the O&M cost projections, Burns & McDonnell analyzed LUS' financial statement over the last 5 years. Burns & McDonnell then isolated the operating and maintenance costs for each site. It was assumed that employee salaries were evenly split between Labbe and Hargis since RPS2's information was not included. The fixed O&M costs were then added to Burns & McDonnell's major maintenance and capital expenditure estimates (see Appendix A) to create a cost forecast for the two sites. Since financial statements were not provided for RPS2, Burns & McDonnell used the US EIA-860 database to estimate O&M costs. The average was then added to the Burns & McDonnell capital expenditure estimates.

3.0 SITE VISITS

3.1 T.J. Labbé & Hargis-Hébert

A representative from Burns & McDonnell, along with LUS staff, visited Labbe and Hargis on September 10, 2019. The purpose of the site visit was to gather information to conduct this Study, interview the plant management and operations staff, and conduct an on-site review of the plants. Chad Swope, a Project Manager with Burns & McDonnell, performed the site visit for the two facilities.

Through visual observation of the units during the site visits, the units appear to be maintained adequately and operated in a reliable working condition. All buildings seemed to be kept clean with no significant corrosion or structural damage. The plant grounds were clean, organized, and free of clutter and debris.

The plants were operating during the site visit. The moving equipment that was visually assessed appeared to be in order with minimal leakage and free from abnormal noise or vibration.

3.2 RPS2

RPS2 was not visited as part of this Study. Instead, a conference call was held on September 18, 2019 between Burns & McDonnell representatives and representatives from both CLECO and LUS. Chad Swope, Kyle Haas, and Kyle Combs, Project Managers with Burns & McDonnell, performed the phone interview with RPS2 Plant Managers and Operating Managers.

From the conversation, it was made clear that RPS2 is operating reliably and is being adequately maintained.

4.0 T.J. LABBÉ AND HARGIS-HÉBERT

4.1 Combustion Turbines

Each plant consists of two GE LM6000 PC aeroderivative CTs that vent exhaust gas out a stack to the surrounding atmosphere. Each turbine is equipped with a SPRINT system. The SPRINT system injects atomized water into the compressor stages to decrease air temperature and increase mass flow thereby increasing output. The SPRINT systems are rarely used at each site and only operate above 40 MW. The two turbines each drive their own 60 Hertz (“Hz”), 3 phase generators. TJU1, TJU2, HHU1, and HHU2 CTs are rated with a nominal gross nameplate capacity of 50 MW each. The LM6000s are rated at a 50 MW/minute ramp rate and the units can reach baseload levels in less than 10 minutes.

For each unit, in coming air passes by chiller coils in the inlet filter house. By cooling the inlet air, higher density air can be moved through the turbine and output can be increased. The chilled ambient air enters the axial compressor and is compressed to a high-pressure prior to entering the unit combustors. The compressor section consists of a five stage LP section and a 14 stage HP section. Variable inlet guide vanes are used to provide stall free operation and high efficiency throughout the full starting and operating range. The combustion section consists of 30 fuel nozzles arranged in an annular formation and are designed to deliver water injection for nitric oxide (“NOx”) control to 25 parts per million (“ppm”). The turbine section consists of a two-stage high pressure turbine (“HPT”) and a five stage LP turbine. A radial drive shaft connects the HP rotor and drives the auxiliary gear box. The gear box drives the lube and scavenger pumps and the variable inlet guide vanes. The start motor is connected to the auxiliary gear box.

Natural gas is delivered to both Labbe and Hargis at pressures in the range of 675 psig plus or minus 20 psig. As such, the three 50 percent natural gas compressors at Labbe are not needed and have been permanently bypassed and decommissioned in Spring 2017. Hargis does not have compressors but does have dew point heaters. The natural gas at both sites is delivered through a fuel gas strainer, gas flow meter, instrumentation, a primary and secondary shut off valve, a fuel gas manifold, and goes to the fuel nozzles. The pressurized natural gas is mixed with the compressed inlet air and ignited in the combustors. The high-pressure, high-temperature gas from the combustors is directed through the turbine which converts the energy of the motive gas into mechanical energy in the shaft. The exhaust gas then passes through the exhaust diffuser and out the stack. There are no selective catalytic reduction (“SCR”) or carbon monoxide (“CO”) catalysts downstream of the CT exhaust; the NOx water injection in the turbine is the only emissions control. The stacks are also equipped with continuous emissions monitoring systems (“CEMS”).

From a maintenance perspective, the CTs undergo regular inspection outages at specific intervals. LUS has chosen to perform the major maintenance inspections more frequently than recommended by GE due to feedback from other LM6000 owners in the industry. Plant personnel indicated that the CTs undergo a borescope inspection twice a year, once in Spring and once in Fall. It is also documented that units will receive a borescope inspection if there is a trip where the cause is not readily known. Hot section exchanges (“HSE”) are scheduled every 15,000 hours instead of the recommended 25,000 hours. The major overhauls are scheduled every 30,000 hours instead of the recommended 50,000 hours. Variable stator vane (“VSV”) bushings are changed every 10,000 hours instead of the recommended 12,500 hours. High pressure combustion (“HPC”) stage 1 blades are changed every 15,000 hours and the HPC stage 3-5 blades are changed every 1,000 starts. Although the more frequent major maintenance activities result in a higher O&M cost for the facilities, the low number of operating hours per year for each of the units means that each unit has only undergone one (1) HSE to date and no major overhauls have been completed.

Labbe and Hargis are under a long-term service agreement with GE, the original equipment manufacturer (“OEM”), for discounted services for major maintenance. There is no lease engine program in place and the most recently negotiated agreement allows LUS to competitively bid maintenance work to other maintenance service providers.

4.1.1 T.J. Labbé Combustion Turbine Unit 1

In 2019, the TJU1 CT underwent a borescope inspection conducted by GE. At the time of the inspection, TJU1 CT had experienced 851 fired starts and 20,219 fired hours. During the borescope inspection, the inlet/compressor, combustion, turbine, and exhaust sections were evaluated. All sections were considered serviceable and no major concerns were noted.

The TJU1 CT also received a hot section exchange inspection in 2013. At the time of the inspection, the unit had experienced 17,520 fired hours and 548 fired starts. During the inspection, the HPT rotor assembly, and the stage 1 and 2 nozzle assemblies were replaced. The combustor has no visual defects detected. The combustor for TJU1 was previously replaced in 2011 when the unit was at 16,784 fired hours and 477 fired starts.

The unit has not yet received a major overhaul given its limited operating hours. The first major overhaul is planned for 30,000 hours.

4.1.2 T.J. Labbé Combustion Turbine Unit 2

In 2019, TJU2 CT underwent a borescope inspection conducted by GE. At the time of the inspection, TJU2 CT had experienced 13,740 fired hours and 962 fired starts. During the borescope inspection, the inlet/compressor, combustion, turbine, and exhaust sections were evaluated. It was noted that some of fuel nozzles were found to be damaged beyond the serviceable limit and that the nozzles were changed out with new ones.

TJU2 CT also received a hot section exchange inspection in 2015. At the time of the inspection, the unit had experienced 12,475 fired hours and 729 fired starts. During the inspection, the engine was shipped to Houston to receive a hot section replacement. The combustion chamber, the HPT rotor, and the stage 1 and 2 nozzle assemblies were also replaced. A new VBV expansion joint was installed.

The turbine #1 and #3 air oil seals received upgrades in Spring 2017. The unit has not yet received a major overhaul given its limited operating hours. The first major overhaul is planned for 30,000 hours.

4.1.3 Hargis-Hébert Combustion Turbine Unit 1

In 2019, HHU1 CT underwent a borescope inspection conducted by GE. At the time of the inspection, HHU1 CT had experienced 1,122 fired starts and 17,152 fired hours. During the borescope inspection, the inlet/compressor, combustion, turbine, and exhaust sections were evaluated. All sections were considered serviceable and no major concerns were noted.

CT1 also received a hot section exchange inspection in 2013. At the time of the inspection, the unit had experienced 14,917 fired hours and 870 fired starts. During the inspection, the hot section was replaced except for the combustion chamber.

The unit has not yet received a major overhaul given its limited operating hours. The first major overhaul is planned for 30,000 hours.

4.1.4 Hargis-Hébert Combustion Turbine Unit 2

In 2019, HHU2 CT underwent a borescope inspection conducted by GE. However, only the 2018 report was available. At the time of the 2018 inspection, HHU2 CT had experienced 1,029 fired starts and 16,619 fired hours. During the borescope inspection, the inlet/compressor, combustion, turbine, and exhaust sections were evaluated. It was noted that some of fuel nozzles were found to be damaged beyond the serviceable limit and that the nozzles were changed out with new ones.

In 2012, CT2 received a hot section exchange performed by GE. At the time of the inspection, CT2 had experienced 14,680 operating hours and an unreported number of starts. The whole hot section was overhauled for the inspection. Repairs were made to the gaskets and oil pumps, and the unit was returned to good operating condition.

The unit has not yet received a major overhaul given its limited operating hours. The first major overhaul is planned for 30,000 hours.

4.2 Turbine Auxiliaries

The CT auxiliaries include an inlet air filter house, lube oil systems, chiller systems, and water treatment systems.

4.2.1 Inlet Filter Houses

Each of the CTs are designed with inlet air filters which remove airborne particles 5 microns or greater from the ambient air. Removing large particles from the ambient air increases the performance and reliability of the CTs by reducing the likelihood of erosion, compressor fouling, and reduced CT performance. The inlet air systems each includes a left and right-side weather hood, anti-icing recirculation air manifold, pre-filter coalesce, high efficiency filter, chilled water-cooling coils, drift eliminators, and barrier filters. The chiller coils help to decrease the temperature of inlet air and increase the mass flow through the turbines. The desired inlet air condition is 48°F and inlet air can be supplied at 230,000 standard cubic feet per minute (“scfm”).

Plant personnel indicated that the inlet air filters are replaced as needed and are regularly inspected. The prefilters are subject to sagging during periods of high moisture or high relative humidity. There are spare filters kept on site and filters typically last one year.

4.2.2 Lube Oil System

Each CT is equipped with a 150 gallon lube oil reservoir that supplies the gear driven main lube oil pump and VG lube oil pump to provide cool, clean, lubricating oil to the CT bearings, accessory drive gears, shaft splines, hydraulically powered fuel valve actuators and VSV control actuators. The turbine lube oil systems are equipped with water-cooled, shell and tube lube oil coolers; supply and scavenge oil filters (6 microns each); and an oil tank heater. Additionally, there is an air/oil separator, and an air/air heat exchanger equipped on the lube oil system.

Each CTG is equipped with 7.5 horsepower (“hp”) main lube oil pump, a gear driven auxiliary lube oil pump, and a 15 hp jacking pump fed from a 500-gallon oil sump to provide cool, clean lubricating oil to the generator bearings. The lube oil filters are 6 microns. The generator lube oil is cooled in a shell and tube lube oil cooler and the tank heater is 4 kilowatts (“kW”).

Labbe has three 30-gallon lube oil supply tanks, three pre-lube oil pumps rated at 1.5 hp, and three lube oil air cooled heat exchangers for the natural gas compressors. These systems have been decommissioned alongside the natural gas compressors. Hargis does not have natural gas compressors and, therefore, does not have a natural gas compression lube oil system.

Lube oil for each site is reported to be tested every six months by Petroleum Analytical Lab. The cooling water for the lube oil is provided by the onsite cooling towers.

4.2.3 Chiller System

The purpose of the chiller systems is to provide chilled water to the air intake coils in the inlet filter houses to increase power generation of each CT. Each inlet air house has 12 inlet air cooler coil panels for inlet air conditioning. The coils have experienced leakage issues in the past due to coils not being able to be fully drained and freezing during cold ambient conditions. A manifold has been added to the bottom of the coils to provide the ability to fully drain. This resolves the Turbine Air Systems ("TAS") design flaw where chiller coils were subject to freezing. The current plan by LUS is to replace 1 panel per year and to replace Hargis' condenser tubes in the upcoming fall season.

Each site is equipped with two two-cell, induced draft ("ID"), counter flow cooling towers for a total of four chiller trains to support the inlet air cooling system and the lube oil heat exchangers. It is reported that only three chiller trains are typically needed at full load to reach the desired inlet air conditions. The fans for the cooling towers are 30 hp variable speed fans. The cooling towers were designed for roughly 2,000 refrigeration tons. The cooling towers were designed for an evaporative cooling rate of 115 gallons per minute ("gpm") and blowdown rate of 29 gpm. The cooling towers were recently replaced in 2018. The materials of construction were changed to stainless steel, but all other design ratings are reported to be the same. The chillers are always run when the units are online, including at minimum load to provide a consistent inlet air temperature to the CTs and allow for faster response times all the way up to 45 MW. The pumping system utilizes 100 percent potable water and is designed to be drained to provide freeze protection in the winter months. A bladder type expansion tank is provided to the closed loop system in order to account for thermal expansion and contractions.

The cooling water pump system at each site consist of three 50 percent, base mounted, double suction, centrifugal water pumps. The pumps are rated at 4,000 gpm with 75 hp motors and operate at 1,780 rpm.

The auxiliary cooling water system at each site provides cooling water to their respective units' lube oil coolers. The auxiliary cooling water pump system at Labbe is comprised of three 50 percent, Goulds, 190 gpm, 10 hp auxiliary pumps while Hargis has three 50 percent, Goulds, 240 gpm, 15 hp auxiliary pumps. Only one auxiliary pump is required to be in operation for each combustion turbine generator ("CTG") in operation at each location.

4.2.4 Water Treatment System

Water treatment at each site consists of chemical treatment, granular activated carbon ("GAC") pre-filtration, cartridge filtration, reverse osmosis, and mixed bed demineralizer systems. The water treatment system is used to meet the facilities' 143 gpm makeup water requirement for lost system water due to cooling towers, water injection for NOx control and for the SPRINT system.

At each site, the city water supply is delivered under pressure to the inlet of the pre-filtration skid. Prior to entering the filtration system, the feed water supply is dosed with sodium meta bi-sulfite to remove chlorine. The GAC filter contains GAC which removes organic matter and any residual chlorine from the feed water supply prior to its use in the reverse osmosis system. The reverse osmosis system removes most of the dissolved solids from the feed water. Each reverse osmosis train consists of two passes. The second pass outlet is tied to a mixed bed demineralizer which removes the remaining dissolved solids and silica from the feed water. The demineralized ("demin") water is stored in a 180,000-gallon storage tank at each site. Each site contracts with a third party to regenerate the mixed bed and carbon filters. Due to low water pressures, the city has recently added a well near the Hargis site that is untreated. The location of the well causes a higher percentage of untreated water to be supplied to Hargis and the conductivity of the water is too high for the reverse osmosis system. Hargis has recently installed carbon filters and green sand filters to manage to conductivity.

Additionally, Labbe has wastewater discharge restrictions, so there is a wastewater storage tank on site that manages the discharge. Hargis does not have water discharge limitations but has experienced water supply issues.

4.3 Electrical & Controls

4.3.1 Electrical System Overview

Power at both sites is generated by two 72 MVA, 13.8 kilovolts ("kV") turbine generators. Each generator sends electricity to a GSU transformer via cable bus systems. The GSUs at Labbe step the 13.8 kV power up to 230 kV while Hargis' GSUs step the 13.8 kV power up to 69 kV. Each of the turbine generators each also send electrical power to auxiliary transformers that drop the voltage down to 4.16 kV. The 4.16 kV from the auxiliary transformers is sent to the medium voltage ("MV") switchgear where it is relayed to the station service transformers and the chiller system. The station service transformers further step down the voltage from 4.16 kV to 480 kV for station auxiliaries such as fans, pumps, and motors.

4.3.2 Generator

The generators at Labbe are rated at a maximum of 72 MVA, supplying three phase alternating current ("AC") power output at 13.8 kV, a 0.85 power factor ("pf") and constant frequency of 60 Hz. Each generator is a synchronous two-pole, open ventilation, air cooled unit. The generators are over-sized for the rated output and thus allows for variance ("VARs") support to the grid and includes some margin for future turbine efficiency improvements without necessitating a generator replacement. The mineral oil filled generator is also equipped with a rotating brushless excitation system. The generators are in separate pressurized compartments. The generator windings are rated with Class F insulation and a Class B temperature rise design.

The generators at Hargis are identical to the generators at Labbe with the exception that the Hargis generators are equipped with inline clutch systems so that the generators can act as synchronous condensers. The generators have never been used as synchronous condensers but have been fully commissioned to do so.

Generator inspection were completed in 2017 for Labbe and 2018 for Hargis. No major concerns were reported.

4.3.3 Transformers

On each site, there are two main power GSU transformers, two auxiliary transformers, and two station transformers. Each CTG is accompanied by one GSU, an auxiliary transformer and a station transformer. All transformers receive annual dissolved gas analysis ("DGA") and oil screenings. The most recently provided DGA from 2017 shows that all gases are within normal limits. No spare transformers or bushings are kept on site.

4.3.4 Non-Segregated Bus Duct

The Labbe and Hargis CTGs delivering nominally 2,452 amperes ("A") at 49.8 MW, 58.6 MVA, and 0.85 pf are connected via a 13.8 kV non–segregated bus to a 3,000 A, 1,000 MVA, outdoor switchgear containing a 3,000 A, 1,000 MVA vacuum operated circuit breaker.

4.3.5 Medium Voltage Switchgear

Each facility uses a 4.16 kV switchgear. The 4.16 kV switchgears are GE metal-clad outdoor type rated at 3,000 A with a 1,000 MVA short-circuit rating and contain vacuum operated circuit breakers. The 4.16 kV switchgears run the inlet chillers. The 4.16 kV switchgears are double ended. Each end can support the full load of their respective plants.

Each site has two 4.16 kV auxiliary transformers that feed a double ended 5 kV switchgear. Both are sized to carry the entire plant auxiliary load with one transformer out of service. By opening one of the switchgear main feeder breakers and closing the normally open bus–tie breaker, either auxiliary transformer can provide power to both bus sections.

Each section of the double ended 480-volt (“V”) switchgears are monitored for voltage and current by the instrumentation on the switchgear. The 480 V switchgear is divided into two buses, each fed from its respective station service transformer. A tie–breaker is provided to tie the two bus sections together in the event that one station service transformer must be removed from service. One switchgear section is connected to a 750 kilovolt amperes (“kVA”) black start generator, and the other is connected to a 300 kVA standby transformer fed from the 13.8 kV distribution system. The switchgear breakers are electrically interlocked to trip the Standby Transformer 480 V breaker.

It is unknown if thermography testing has been performed on the switchgears or if an arc flash study has been conducted and protection enhancements have been incorporated to reduce arc flash concerns.

4.3.6 480 V Load Centers and Motor Control Centers

The plant electrical equipment enclosure has a power room housing the 4.16 kV and 480 V switchgear, 480 V Motor Control Centers (“MCCs”) for the BOP, and 480 V, and 125 V DC panelboards for plant equipment.

The MCCs are reported to be in good condition with no issues.

4.4 Station Emergency Power Systems

Labbe is provided with battery emergency power in the form of a 125 V DC system. The system consists of a string of 90 nickel-cadmium battery cells. There is also a 24 V DC system consisting of a single string of 19 nickel-cadmium battery cells. No documentation was provided for Hargis, but it is presumed that Hargis has a nearly identical set up to Labbe.

Labbe and Hargis have two plant 125 V DC battery chargers are fed from 480 V distribution panels to provide alternate sources of power in the event of loss of one 480 V distribution panel. Each CTG has three 24 V DC battery chargers (two for the control battery and one for the fire system battery) and one 125 V DC battery charger (for the CTG switchgear battery) fed from the respective CTG MCCs.

It was stated during the site visit that some of the battery banks are in the process of being replaced.

4.5 Emergency Generator

Each site has an emergency diesel generator rated at 750 kVA and allows the facility black start capabilities.

4.6 Fire Protection Systems

Labbe is supplied with a 10-inch fire loop supplied by the LUS city water supply by a 12-inch main. Hargis is also supplied with a 10-inch fire loop but is supplied by the LUS city water supply by an 8-inch main. Both the plant fire loops contain four fire hydrants along with post indicator valves along the loop.

Each of the LM6000s at Labbe and Hargis are provided with a self-contained and automatically actuated carbon dioxide (“CO_2”) fire protection system. The system will actuate upon the detection of fire or combustible gas inside the enclosure. Upon activation, the fire protection system will shut down the unit, close the fire dampers in the turbine and generator compartments, and flood each compartment with CO_2.

From the documentation provided, it is evident that there are no fire sprinkler systems on site at Labbe or Hargis. However, the facilities are provided with automated fire detection in the water treatment building, chiller building, the CEMS enclosures, battery rooms, control room, and electrical rooms. Two manual pull stations are also provided in the control room and one manual pull station is provided in the gas compressor area. Activation of any of the above listed detection systems will activate local strobes and alarms. Upon being notified, the LUS fire district will respond to fires and will commence a manual response.

4.7 Electrical Protection

The units’ electrical protection systems safeguard motors and breakers from the damaging effects of faults. The system works by overcurrent monitoring and low-voltage monitoring that automatically trip breakers. Current transformers convert current flow through each feeder into signals that are inputs to protection relays on the cubicle doors. The bus voltage is monitored by potential transformers and undervoltage protection relay in the auxiliary cubicle. Protection relays trigger alarms in the presence of critical conditions and lockout relays are tripped to ensure protection of the electrical system.

The generators are protected by redundant solid-state, multi-function, protective relays located on the CTG control panels. A 15 kV generator circuit breaker is used to synchronize the generator to the utility grid.

Protection for the auxiliary transformers is provided by Beckwith M–3311 relays located in the 4.16 kV switchgears. Protection for the chiller compressor motors resides in the chiller package. The feeder breakers to the station service transformers and the chiller package are protected with MULTILIN SR750 relays.

Beckwith M–3311 and Schweitzer SEL–387 relays provide differential and overcurrent protection for the 230 kV and 13.8 kV systems. The relays are located on the relay panel. A Beckwith M–3311 relay provides protective relaying for unit auxiliary transformers while a Schweitzer SEL–387 relay provides bus overcurrent protection for 4.16 kV buses. These relays are located on the 4.16 kV switchgear. Redundant Beckwith M–3425A generator protection relays located in the turbine control panel provide electrical protection for the CTG.

Regular protective device replacement and upgrades are expected as part of normal plant maintenance through the Study period to support unit reliability and reduce arc flash incident energy level risks.

4.8 Control Systems

Each of the facilities control systems are identical. The BOP operations are each managed by a plant control system ("PCS"). The purpose of the PCS is to monitor, display, record, and control the process variables throughout the plant. The process control panel ("PCP") is manufactured by GE and is the control node for the GE Mark VIe distributed control system ("DCS") controlling the CTs. The PCP also contains the hardware required to control the overall BOP processes such as the chillers, air compressors, and water treatment systems. The PCP is equipped with redundant processors, communication modules, power supplies, field terminations and other accessories. The PCS is powered by two independent, 120 V AC, uninterruptible power supplies. All the power supplies share a common current load.

The communication from the PLC processors and servers to the CTGs is accomplished by a fully redundant ethernet system while the communication from the PLC processors and servers is accomplished by a fully redundant Modbus over the plant's ethernet system.

The PCS is also equipped with a separate historian. The historian allows system parameters to be monitored, trended, and recorded for tracking purposes.

The PCS interfaces with plant operators through the engineering workstation ("EWS"). The EWS is a computer system that directly displays the control system for visualization. Through the EWS, the plant activities can be configured, monitored, and verified via screens. The EWS allows for the customization of control configurations, definition of hardware configurations, editing of process parameters, setting operating modes, tuning parameters, and monitoring the processes.

4.9 Instrument Air

The compressed air system at each site provides clean, dry compressed air at a range of 110 to 120 psig for the operation of pneumatic control valves and instrumentation. Each instrument air system is driven by two Kobelco, 300 scfm, 125 psig, 100 hp air compressors. Each air receiver tank is manufactured by Manchester and is 2,220 gallons. The compressors are accompanied by a coalescing pre-filter, air dryer, moister analyzer, and particulate type after filters. The air dryers are two 100 percent capacity air dryers that are twin tower desiccant type and bring air to 40°F below the dew point to ensure dry air is provided. The compressed air is distributed through each plant by a 2-inch stainless steel instrument air header system. Branch lines are provided as necessary for instrument air services. It was noted that the air compressors tend to overheat in the summer months. To prevent overheating, the load is split between the two compressors.

5.0 RODEMACHER POWER STATION UNIT 2

5.1 Boiler

5.1.1 Boiler Overview

The RPS2 boiler was manufactured by Foster Wheeler. The boiler is a natural circulation, reheat, balanced draft furnace with opposing wall fired burners designed to burn pulverized coal. RPS2 was designed for an MCR of 3,800,000 lb/hr of steam at a superheater outlet pressure of 2,620 psig and temperature of 1,005°F. The reheater is designed for an operating temperature of 1,005°F with an MCR of 3,366,000 lb/hr of steam at 562 psig. The superheater outlet temperature is controlled with attemperator spray and the reheater outlet temperature are primarily controlled gas path damper controls. Attemperator spray can be used for the reheat section, but the piping has since been valved out. The boiler design includes water walls in the furnace, radiant and convective superheater sections, reheater, and an economizer heating surfaces. The boiler includes four air heaters, two primary and two secondary.

RPS2 has experienced ongoing boiler maintenance, but generally the boiler and its ductwork are reported to be in satisfactory condition. RPS2 has required the replacement of multiple boiler tubes due to blistering. Boiler tubes that have experienced leaks and erosion have been repaired.

5.1.2 Waterwalls

The inner walls of the boiler are made up of vertical boiler waterwalls which are comprised of tubes welded together into panel sections. Heat transfer occurs in the waterwall tubes and the temperature of the fluid flowing through the tube increases from the heat supplied from the combustion of fuel in the furnace. All the tubes facing the furnace receive radiant heat to transition feedwater into saturated steam. The boiler circulating water and the steam generated in the waterwalls are directed to the main steam drum where steam is separated from the saturated liquid and delivered to the superheater.

There have been no major repairs to the waterwalls. The last boiler chemical clean was in 2016. Tube samples are taken annually to determine when chemical cleaning is needed. The site is trying to get rid of copper in the condensate and feedwater system which has caused copper deposition in the HP turbine. Plant personnel did not report any issue with the drum within the boiler. The drum is inspected yearly, and no major issues have been found. Plant personnel indicated that they have replaced chevrons and separators and there has not been any ligament cracking. Burns & McDonnell recommends continuing regular inspections of the drum and boiler tubes and continuing to perform boiler chem cleaning as needed.

5.1.3 Superheaters

The superheater section of the boiler is used to superheat the saturated steam supplied from the main steam drum. The temperature of the fluid increases as it passes through the sections of the superheater. Saturated steam from the main steam drum enters the primary superheater section and through the superheater attemperators to the secondary superheater section. After completion of superheating, the steam leaves the boiler and enters the main steam header to the high pressure (“HP”) ST.

The superheater had experienced blistering in the tubes where they penetrate the boiler wall. These tubes have been replaced over the past few years. Additionally, there were some issues with the outlet header that had some cracking. The outlet header cracking has been repaired via welding.

Burns & McDonnell recommends performing NDE inspections on the high temperature headers every 3 years. Burns & McDonnell additionally recommends replacing the superheater attemperator liner.

5.1.4 Reheater

The reheater section of the boiler increases unit efficiency by capturing additional energy released during the boiler combustion process. Exhaust steam from the HP turbine is reheated to 1,005°F before being directed to the intermediate pressure (“IP”) turbine. Both hot and cold reheat lines have low point drain valves to remove accumulated moisture in the piping.

The plant controls reheater temperatures with dampers and there are reheater attemperators that have been valved out. The reheater had experienced tube failures due to creep. These tubes have been replaced over the past few years. Additionally, there was cracking in the outlet header, but it has been repaired.

5.1.5 Economizer

The economizer section of the boiler is used to improve unit efficiency by preheating the boiler feedwater before entering the main steam drum and waterwall sections of the boiler. The economizer utilizes heat from combustion gases that would otherwise be lost through the stack. The economizer tubes are exposed to hot boiler outlet gases in the convection pass in order to preheat the water. This process increases the rate of heat transfer and limits the amount of thermal stress applied to the main steam drum.

The unit has finned tubes. There have been tube failures in the economizer over the last two to three years. The tubes have been plugged, but no major economizer replacements have been completed.

Burns & McDonnell recommends replacing the economizer tubes in the near future.

5.1.6 Safety Valves

Safety valves are installed on RPS2 which are critical for safe operation. The main function of the safety valves is to prevent over-pressurization within the boiler by automatically relieving excess steam pressure to the atmosphere. The safety valves must have the capacity to discharge all the steam that can be generated without allowing the pressure to rise more than six percent above the highest working pressure of the boiler. The boiler is equipped with a total of 16 safety valves and one power relief valve to protect the pressure parts of the boiler. These valves provide excess pressure protection to the finishing superheater outlet and main steam header, the boiler drum, the reheat inlet piping and reheater, and the reheat outlet piping. All of the steam valves vent to the atmosphere. Each valve is additionally equipped with low point drains to remove condensate.

Burns & McDonnell recommends that safety valves are continually monitored and inspected per Code requirements.

5.1.7 Burners

RPS2 has 24 opposing wall fired burners that are designed to burn pulverized coal. In 2015, the burners were replaced with Low NOx burners and over fired air (“OFA”) was installed. There are also 24 natural gas fired ignitors for startup. The fire generated from the burners is directed into the furnace. Combustion gases and radiant energy from the burners flow upwards through the furnace heating the working fluid in the boiler tubes.

5.1.8 Sootblowing System

The sootblowing system is designed to maintain boiler efficiency by preventing accumulations of ash and slag on surfaces of the furnace walls, superheaters, reheaters, the economizer, and air preheaters.

The plant has a smart sootblowing system that utilizes steam and it is maintained with the plant maintenance cycle. Other than some erosion on the economizer, the soot blowing system has not had any major issues.

5.2 Boiler Auxiliary Systems

5.2.1 Fans

The air and flue gas circuit for the boiler can be separated into two distinct parts. The air circuit is under pressure and handles clean cold and heated air. This part is comprised of two FD fans, and two primary air (“PA”) fans. The flue gas circuit is under suction and handles hot flue gas, cooled flue gas, and fly ash. The flue gas circuit is comprised of an electrostatic precipitator (“ESP”), air heater, two ID fans, a baghouse, and two ID booster fans. The FD fans are manufactured by Westinghouse, driven by a 4,000 hp, 890-rotations per minute ("rpm"), 6,600 V AC motor. The PA system provides the mills with hot air necessary for heating and drying the pulverized fuel. The PA system also acts as the medium to transport the fuel from the mills to the furnace for combustion. The PA fans are centrifugal fans manufactured by American Standard and driven by 4,500 hp, 1,200 rpm motors. The ID fans pull combustion gases over the reheater, superheater, and economizer elements. Gases are then drawn through the ESPs and into the two air preheaters, and into the baghouse while maintaining operational pressure in the furnace. The ID booster fans then draw gas through the baghouse and out the stack. The ID fans are manufactured by Westinghouse and are each driven by a two speed, 10,000/6,000 hp, 720/600 rpm, 6,600 VAC motor. No data was provided on the ID booster fans.

Plant personnel indicated that they have not had any major issues with the PA or FD fans and the fans have received routine maintenance. Plant personnel also indicated that the ID fan rotors were changed out in 2015. ID fan motors were overhauled during the 2015 outage. Burns & McDonnell recommends all fans should be cleaned and inspected every two years and the motors should be tested annually.

5.2.2 Air Heaters

The air preheaters are large, rotating heat exchangers designed to transfer the remaining useful heat in flue gases to the incoming combustion air to increase boiler efficiency. Conversations with plant personnel indicated that the air heater baskets were replaced in 2014. Additionally, all the seals were replaced in 2014. There have been no bearing issues. The drives are electric with an electric backup. There have been minor coupling and gearbox issues over the years, but no major repairs or replacements are reported to be needed.

Burns & McDonnell recommends regular maintenance for the air preheater including the replacement of the cold end baskets every 10 years, replacement of the hot end baskets every 20 years, and replacement of other air heater components every 30 years.

5.2.3 Flues & Ducts

Ductwork transports combustion air to the boiler and transports hot flue gas from the boiler through the back-end equipment and to the stack. The ductwork is inspected during outages to look for areas that need to be patched. There is also a procedure in place to inspect the ductwork for hotspots right before an outage.

5.2.4 Stack

Flue gas from the ID booster fan is directed to the stack. The RPS2 stack is concrete. Plant personnel reported that there have been no major issues with the stack. The stack is equipped with a seal drain to dispose of the liquids that condensate in the stack.

5.3 Steam Turbine

5.3.1 Turbine

The ST was manufactured by GE and is a three-casing, tandem compound, four flow exhaust condensing reheat unit. The turbine is designed for initial steam conditions of 2,400 psig at 1,000°F, and a reheat temperature of 1,000°F.

According to plant personnel, the ST is scheduled for a major inspection every six years. The next major inspection is scheduled for 2020, with the last major inspection in 2014. There were minor repairs done to correct erosion in the last stage blades but nothing major was needed to be done by Turbo Care. No solid particle erosion was reported on the HP and IP sections.

Burns & McDonnell has included cost in Appendix A for HP/IP Row 1 buckets and L-0 Buckets to be replaced at the STG major inspection. These are included on six-year intervals to match Cleco's current maintenance cycle. However, based on Burns & McDonnell's experience, it may be possible to increase the interval between major ST inspections to eight years. BFP inspections and any necessary chemical cleaning of the turbine should also occur at the same time as the ST major inspection.

5.3.2 Turbine Valves

RPS2's ST valves are scheduled to be inspected every three years, with the last inspection in 2017. Personnel indicated that that ST valves have no current issues since all recent repairs have been performed. Burns & McDonnell recommends all turbine valves to be regularly inspected and repaired.

5.4 High Energy Piping Systems

5.4.1 Main Steam Piping

The main steam piping transfers steam from the boiler superheater outlet header to the HP ST. The main steam piping operating temperature is greater than 800°F, and, therefore, the piping is susceptible to creep, which is a high temperature, time dependent phenomenon that can progressively occur at the highest stress locations in the piping system. As such, this piping system carries a high priority for inspections and maintenance.

Burns & McDonnell recommends that the pipe support system continue to be visually inspected annually. The hangers should be inspected to verify operation within the indicated travel range, that the position has not significantly changed since previous inspections, that the pipe is growing or contracting in the right directions between cold and hot positions, that the actual load being carried is close to its design point and has not changed, and that the pipe support hardware is intact and operating as designed. In addition, Burns & McDonnell recommends that the hangers be load tested to determine their actual current loading and that a stress analysis be completed to verify that all loads and stresses are within the allowable limits.

5.4.2 Hot Reheat Piping

The hot reheat piping transfers steam discharged from the reheater outlet header to the IP ST. The hot reheat piping operating temperature is also within the creep range (greater than 800°F), meaning this piping system also carries a high priority for inspections and maintenance.

Burns & McDonnell recommends that the pipe support system be visually inspected annually. The hangers should be inspected to verify operation within the indicated travel range and are not bottomed out, that the position has not significantly changed since previous inspections, that the pipe is growing or contracting in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

5.4.3 Cold Reheat Piping

The cold reheat piping transfers steam discharged by the HP ST to the boiler reheater inlet header connections. The cold reheat piping normal operating temperature is below the creep range (less than 800°F) and creep is not a concern for this system. Therefore, the cold reheat piping system does not require the same level of examination recommended for the main steam and hot reheat system. Burns & McDonnell, however, still recommends inspecting the highest stress weld locations using replication examination to determine the extent of any carbide graphitization that may have occurred from occasional high temperature operations during startup or shutdown.

Burns & McDonnell also recommends that the pipe support system be visually inspected annually. The hangers should be inspected to verify operation within their indicated travel range, that the position has not significantly changed since previous inspections, that the pipe is growing or contracting in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

5.4.4 Extraction Piping

The extraction piping transfers steam from the various ST extraction locations to the FWHs. These piping systems are not typically a major concern for most utilities and are not examined to the same extent as the main and reheat steam systems. However, the extraction steam non-return valves should be tested on a regular basis to confirm proper operation and reduce the risk of turbine water induction.

Burns & McDonnell recommends that the pipe support system be visually inspected annually. The hangers should be inspected to verify operation within their indicated travel range, that the position has not significantly changed since previous inspections, that the pipe is growing or contracting in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

5.4.5 Feedwater Piping

The feedwater piping system transfers water from the DA storage tank to the boiler feedwater pumps, through the high-pressure FWHs, and eventually to the boiler economizer inlet header. Although this system operates at a relatively low temperature, the discharge of the boiler feedwater pumps is the highest-pressure location in RPS2, which make it particularly subject to Flow Accelerated Corrosion ("FAC"). Burns & McDonnell recommends inspecting and monitoring feedwater regularly for FAC.

5.5 Balance of Plant

5.5.1 Condensate System

The condensate system transfers condensed steam from the condenser hotwell through the low-pressure FWHs to the DA.

5.5.1.1 Condenser

The RPS2 condenser is a twin-shell, single-pressure, two-pass, once-through condenser manufactured by Foster-Wheeler Energy Corp. The condenser has 288,100 square feet ("sqft") of heat transfer surface. The tube bundles were upgraded to stainless steel in 2008. The purpose of the condenser is to condense steam from the turbine exhaust for use in the condensate pumps. Plant personnel reported no air in leakage issues. The expansion joints were replaced during the last major outage. Additionally, the waterboxes were recoated in 2008.

The condenser is manually cleaned during each spring outage and is backwashed every other week. Burns & McDonnell recommends regular inspection and maintenance for the condenser to maintain reliable operation.

5.5.1.2 Condenser Vacuum System

The condenser vacuum system establishes a negative pressure, or vacuum, in the condensers during unit start-up by removing all air and non-condensable gases. This is accomplished by means of two main vacuum pumps which are two stage, 100 percent capacity, liquid ring pumps manufactured by Nash. The pumps are powered by 100 hp, 500 rpm GE motors. It is reported that during unit startup, both main condenser vacuum pumps are used for hogging. During turbine operation, only one vacuum pump is required to maintain the condenser vacuum.

5.5.1.3 Feedwater Heaters

The boiler has eight feed water heater sections. Section 1a, 1b, 2, 3, and 4 are LP sections manufactured by Foster-Wheeler Energy Corp. and consist of a shell and U-tube design that heats the condensate prior to entering the feedwater system. The DA is heater 5 which removes non-condensable gasses from the condensate. RPS2 has two HP FWHs (FWH6 and FWH7), both manufactured by Foster-Wheeler Energy Corp. The HP FWHs are both vertical, two pass, shell and tube heat exchangers with integral drain sub-cooler, condensing and desuperheating sections. The feedwater system transfers water from the condensate system through boiler feedwater pumps and HP FWHs to the economizer inlet header. Feedwater is also supplied to the superheater and reheat steam attemperators.

The FWHs increase the temperature of the feedwater before it flows to the economizer using extraction steam from the main turbine. Preheating feedwater improves efficiency of RPS2 and reduces thermal stress within the boiler. Eddy current testing is regularly performed to identify any tube wall thinning.

It is reported that sections 3, 4, 6, and 7 have been replaced with stainless steel while sections 1 and 2 are copper nickel alloy. There are plans to replace sections 1 and 2 in 2021. Burns & McDonnell recommends that the feedwater heaters with copper nickel alloy be budgeted for replacement to reduce copper plating in the system.

5.5.1.4 Deaerator Heater & Storage Tank

The HP FHW drains cascade to the DA and the LP FWH drains cascade to the condenser.

The DA had previously experienced cracking in the upper tray. The trays have since been replaced with stainless steel. No issues have been reported.

5.5.2 Cycle Pumps

5.5.2.1 Condensate Pumps

RPS2 is equipped with three 50 percent condensate pumps. The pumps are vertically mounted, motor driven pumps. The condensate pumps are 3,260 gpm capacity pumps manufactured by Worthington Corporation and turn at 1,785 rpm. The condensate pumps are used to move the condensate from the hotwell through the LP condensate FWHs to the DA. The pumps are driven by 1,250 hp motors manufactured by Louis-Allis.

No issues have been reported by site personnel with respect to the condensate pumps' recent performances. The pumps receive online and offline testing during outages and the data are trended so that baselines can be tracked. PdMA testing is also performed.

The recirculation valves are reported to have minor cavitation issues associated with running the unit at minimal load. The valves are inspected during outages.

5.5.2.2 Boiler Feedwater Pumps

The unit is equipped with two Ingersoll Rand BFPs. The primary pump is a turbine driven, centrifugal pump that can handle full load operation down to minimum continuous load. The turbine driven pump is run most of the time the unit is in operation. The second BFP is a motor driven, 8 stage, centrifugal pump that is run only on startup. The steam for the primary turbine driven pump is supplied from an extraction from the main ST and the main steam supply during low load. No issues have been reported with bearing temperatures, vibration, lube oil systems, or the recirculation valves. There is an interstage takeoff for reheat attemperation spray, although it is reported to be rarely used. The BFPs are designed to provide 3,965,000 lb/hr of feedwater at 486F to the main boiler when it is operating at maximum capacity.

5.5.3 Circulating Water System

The circulating water system is used to condense steam from the ST exhaust and transfer the latent heat of vaporization to the atmosphere. The nearby lake serves as the heat sink. The circulating water pumps take suction from the lake to be sent to the condenser. The circulating water flows through the condenser tubes, extracts heat from the LP turbine exhaust steam, and exits the condenser outlet waterboxes. The hot water is then returned to the lake. The circulating water pumps are three 33 percent capacity, single stage, vertical, mixed flow pumps designed for 82,000 gpm flow and were manufactured by Allis-Chalmers. The pumps are driven by 6,600 VAC, 1,000 hp electric motors.

Three 50 percent LP service water pumps take suction from the nearby lake as well. The LP service water pumps supply cooling water to the turbine lube oil coolers, condenser vacuum pump seal water coolers, generator hydrogen coolers, exciter air coolers, and to the closed cooling water heat exchangers. The LP Service water pumps are vertical wet pit, single stage, double suction pumps with a design capacity of 11,500 gpm each and manufactured by Worthington Corporation. The pumps are driven by 700 hp, 6600 VAC electric motors.

The plant personnel reported issues with mayflies getting into the circulating water pump motors during the summer months but have reported no other issues. These pumps are on a six year rebuild schedule and budget is included to inspect the pumps for scaling Circulating water piping is unlined steel and has begun to experience degradation. Plans are in place to line the circulating water piping with concrete in the future if rust areas continue to grow.

Burns & McDonnell recommends inspecting and repairing the circulating water piping in the near future. Additionally, Burns & McDonnell recommends rebuilding the circulating water pumps every 6 years and that budgeting for replacing the valves near 2026.

5.5.4 Water Treatment, Chemical Feed & Sample Systems

Water is supplied from the nearby lake. The water is pretreated with UFs and then sent through a RO and a demineralizer. There are two 250,000-gallon aluminum tanks that hold the demin water. Hydrazine and phosphate are used in the drum.

5.5.5 Instrument Air

The instrument air and service air are run on separate systems. The station service air supplies the selective noncatalytic reduction (“SNCR”) and mercury and air toxic standards (“MATS”) systems and ties the two systems together. Two 100 percent air compressors provide air to the station service air. The instrument air system is supplied by three 50 percent air compressors. The site has redundant air driers for the control air system.

5.5.6 Fire Protection Systems

The fire protection systems at RPS2 are fed by the HP service water system which takes suction from the LP service water pumps. There are primary fire booster pumps and a backup diesel pump that are intended to provide water to the site sprinklers at the necessary flow and pressure for fire suppression and control. The pumps are on separate power supplies and tested monthly.

The site is also equipped with silo and mill fire procedures that include shutting down equipment and alerting local fire departments. Chemetron inert gas utilizing CO_2 is used to protect the mills and the turbine bearings. The pulverizers utilize CO monitoring systems.

The fire pump is a vertical turbine pump rated at 2,000 gpm and 400 feet head pressure. The pump is diesel driven and the driver is rated at 325 hp. Automatic/manual deluge sprinkler systems are installed around the transformers, oil reservoirs, conveyors, dust collectors and storage. There are automatic dry pipe sprinklers covering the mill bay. Wet pipe automatic sprinklers cover the turbine area and lower boiler.

5.6 Electrical and Controls

5.6.1 Electrical System Overview

RPS2 consists of a GE generator, a GSU transformer, two reserve station service transformers (“RSST”), two normal station service transformers (“NSST”), and 13.8 kilovolt (“kV”), 6900 V, and 480 V switchgear, motor controls centers, and BOP distribution transformers and panels.

5.6.2 Generator

The generator is a 3600 rpm, two pole, hydrogen cooled unit manufactured by GE. The generator is rated at a maximum of 620,000 kVA with a 0.90 pf supplying three phase AC power output at 22,000 V and constant frequency of 60 Hz. The generator is composed of the hydrogen gas cooled stator, which has an output of 16,271 A.

The exciter was manufactured by GE and has an output voltage of 356 V. The most recent inspection was in 2014 and the generator was rewound. No issues were reported by CLECO.

Based upon current maintenance records and anticipated generator maintenance already planned, it is expected that the generator will provide reliable operations for RPS2 through the Study period as normal maintenance is continued.

Burns & McDonnell recommends performing major generator inspections on a 6-year basis and minor generator inspections on a 3-year basis. Burns & McDonnell also recommends budgeting for an exciter replacement near 2026.

5.6.3 Transformers

There are five main power transformers in the facility, which include a GSU transformer, two NSSTs and two RSSTs. Dissolved gas analysis is reported to be done by CLECO group every outage.

5.6.3.1 GSU Transformer

The main GSU transformer is a three-phase unit and steps up the generator output voltage from 22 kV to 230 kV. The GSU transformer is rated at 600 MVA oil direct air forced (“ODAF”). The transformer core and windings are oil immersed in a sealed tank and is equipped with a high-voltage, no load tap changer. The windings are kept cool by circulating the oil they are immersed in which is cooled through finned tube coolers. The GSU low voltage terminals are connected to unpressurized isophase.

The GSU failed from old age and was replaced in 2017 due to insulation failure leading to a short. Otherwise the GSU has operated normally and has undergone normal troubleshooting. CELCO transformer group does NERC testing on transformers every outage and RPS2 conducts electrical testing every three to four years. Burns & McDonnell recommends that RPS2 continue its inspection cycle and current maintenance and testing plan.

5.6.3.2 Reserve Service Station Transformer

RPS2 has two RSSTs. One of the RSSTs, RAT 2B, was replaced in 2009, the other RSST, RAT 2A, is original. RAT 2A is manufactured by Westinghouse Electric in 1980 and is an oil air/forced oil air/forced oil air (“OA/FOA/FOA”) type, oil cooled transformer rated at 14, 18.6, 23.3, and 46.6 MVA. RAT 2B was manufactured in 2009 by ASEA-Brown Boveri. The transformer is Oil Natural Air/Oil Direct Air Forced/Oil Direct Air Forced (“ONAN/ODAF/ODAF”) and is oil cooled. RAT 2B is rated at 25, 33.3, and 41.7 MVA.

Burns & McDonnell recommends that the RSSTs be replaced within the next ten years to ensure reliable operation of the Unit. Burns & McDonnell also recommends that the Plant continue its five-year inspection cycle and current maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

5.6.3.3 Normal Service Station Transformer

RPS2 has two NSSTs. Each NSST is a three-phase, two-winding unit transformer that is used to step down the 6.9 kV output of the generator to 480 V. The power generated is used for the unit load and common load during normal operation. The NSST core and windings are oil immersed in a sealed tank and are equipped with high-voltage, no load tap changers.

The NSSTs have both failed within the last two years and have since been replaced. Burns & McDonnell recommends that the plant continue its inspection cycle and current maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

5.6.4 Isolated Phase Bus

Isophase connect the GSU transformers to the generator terminals and to the NSSTs. The main Isophase bus at the generator terminals is not reported to have any issues. The Isophase was inspected while the station transformers were replaced.

Burns & McDonnell recommends RPS2 perform a regular internal inspection to clean or replace internal insulators as needed and verify bolted connections are secure. The inspection cycle should be determined by plant personnel experience based on the contaminants observed during regular inspections.

5.6.5 Non-Segregated Bus Duct

Non-segregated Phase ("Non-seg") Bus Duct connects the RSSTs and NSSTs to the 13.8 kV Switchgear and the Station Aux Transformers to the 4,160 V switchgear. There are no issues reported with the bus duct.

5.6.6 Medium Voltage Switchgear

RPS2's switchgear previously had a breaker failure due to debris connecting the two phases. The switchgear has faced some aging issues and replacements are being made as needed. The vacuum bottles have also recently been replaced. The switchgear is manufactured by GE and is rated at 6.9 kV AC. It was installed in 1981. An arc flash study has been performed on the switchgear.

Burns & McDonnell recommends that replacement of the 13.8 kV and 6900 V switchgear be evaluated within ten years while considering the long-term availability of spare parts and the latest enhancements to industry arc flash standards. Switchgear replacement and adherence to the planned 5-year maintenance cycle should maintain the switchgear's serviceability through the Study period.

5.6.7 480 V Load Centers and Motor Control Centers

The MCC was installed in 1981 and was manufactured by Westinghouse. The switchgear is a low voltage AC power circuit breaker. The MCCs are comprised of manually operated, air circuit breakers, full voltage non-reversing and reversing starters, and control power transformers.

5.7 Station Emergency Power Systems

The station is provided with an emergency power supply in the form of batter storage. The batteries and chargers were replaced in 2011 and receive quarterly and annual resting as required by NERC. The batteries are model LCR-33 manufactured by C&D. The individual voltage reading of each better is 2.25 V with 60 cells.

5.8 Emergency Generator

The original emergency diesel generator ("EDG") is still installed on site. The EDG is run weekly.

5.9 Electrical Protection

The generator breaker is a 2014 ABB SACE TMAX. From the electrical one-line drawings, it appears that the electrical system is provided with an appropriate amount of breakers and redundancy.

5.10 Control Systems

The plant is managed by an ABB DCS S+. The boiler management system is also tied into the DCS and was last upgraded in 2014 alongside the DCS. The plant indicated that the coal feeder controls are planned to be upgraded in 2020. Additionally, Burns & McDonnell recommends that the PCSs and electrostatic controls are upgraded in 2024.

5.11 Material Handling

The coal handling system for RPS2 is designed for the efficient receiving, storing, and distribution of coal required for plant operation. Since the coal is delivered in 2 in by 2 in chunks, there are no crushers on site, only pulverizers.

5.11.1 Rotary Car Dumper

Coal is received at RPS2 from railcars at the rotary car dumper. Plant personnel indicated that there have been no major issues with the system. Burns & McDonnell recommends that LUS continue its current practices of inspecting and maintaining the rotary car dumper equipment.

5.11.2 Gravimetric Feeders and Pulverizers

RPS2 has six gravimetric feeders that feed coal into the pulverizers and six pulverizers that take in crushed coal, pulverize it, and admit it to the furnace for combustion. Crushed coal is fed to the pulverizers from gravimetric feeders at rate determined by load demand. Feeder speed is regulated by boiler controls to ensure the correct amount of coal is fed under all loading conditions. The pulverizer grinds the coal to dust-like particles that is transported to the burners with the help of the PA fans. The feeders are manufactured by Stock Equipment Company and the pulverizers are manufactured by Foster-Wheeler. LUS is in the process of upgrading the feeder controls and one feeder has already been upgraded. Pulverizers require significant expenditures for maintenance activities but Burns & McDonnell has assumed that pulverizer maintenance activities are part of LUS's baseline O&M budget.

5.12 Bottom Ash Handling

The bottom ash handling system is designed to collect and prepare bottom ash for disposal. Ash that is too heavy to be carried by the flue gas stream is collected in a water-impounded hopper.

The steam generator has a dry bottom and the bottom ash falls into a water filled ash hopper. The ash hopper has a capacity of approximately 24 hours of bottom ash storage when the unit is burning coal with a 10 percent average ash and operating at full load. The ash collected in the hopper is automatically and periodically sluiced out of the hopper by hydraulic Jetpulsion pumps. Water is supplied to the Jetpulsion pumps by two full-size ash sluice water pumps. The bottom ash is hydraulically sluiced out to storage through the ash discharge piping. In addition, the hot ash from the economizer hoppers discharges to a dry holding tank and is hydraulically sluiced to storage by separate Jetpulsion pumps through the same ash discharge piping. Each pulverizer has a pyrites hopper from which pyrites is sluiced to a pyrites transfer and storage tank. From the tank, the pyrites are hydraulically sluiced by a Jetpulsion pump to storage, using the same bottom ash discharge piping.

Burns & McDonnell recommends continuing the current maintenance program for the bottom ash handling system to continue reliable operation of RPS2. Burns & McDonnell recommends replacing the bottom ash system to a dry drag chain conveyor in the near future.

5.12.1 Bottom Ash Hopper

The bottom ash hopper is designed to receive and collect heavy ash produced from combustion in the boiler. The hopper contains cooled water to quench the hot ash and prevent ash solidification in storage. The net capacity for the bottom ash hopper is 4,900 cubic ft.

5.12.2 Surge Tank

The surge tank provides storage volume for the water used by the bottom ash system and its primary function is to collect overflow from the settling tank. The unit utilizes a steel 25,000-gallon sluice surge tank.

5.13 Fly Ash Handling

Fly ash is collected by two ESPs and removed from the precipitator hoppers by the fly ash handling system. The primary handling system removes the fly ash from the precipitator by vacuum using mechanical blowers. The fly ash is transported dry to a fly ash silo with a 72-hour storage capacity. The silo is provided with a rotary unloader where water is mixed with the fly ash for dust suppression during the unloading operation. The moist fly ash is routed from the unloader spout into trucks for disposal. The silo is also provided with a dry unloading spout for handling dry fly ash if desired.

Fly ash captured in the baghouse is handled in a similar way, however, due to contamination from the dry sorbent injection, the fly ash cannot be sold and is therefore landfilled on site.

An alternate fly ash system is provided for use when burning oil and coal in combination. In this system the fly ash and water from the jet pumps are mixed in an air separator. The fly ash and water mixture is sluiced by gravity to the ash storage area through the same piping used for the bottom ash, HP water for the water jets is supplied by the two full-size ash sluice pumps.

5.13.1 Flue Gas Conditioning System

The flue gas condition system consists of an SNCR, ESP, dry sorbent injection, and baghouse. The SNCR utilizes urea injection in the furnace for NOx control. The flue gas then enters the ESP which is designed to remove fly ash from the flue gas. The ESP gives fly ash particles an electric charge which causes the particles to attach to the surrounding collecting surfaces. The ESPs then use rappers that vibrate to release the collected fly ash to surrounding precipitator chambers. The fly ash is later removed from each of the hoppers through air locks and an air blown ash extraction system. Dry sorbent injection with activated carbon is then injected upstream of the baghouse inlet to remove the hydrochloric acid (“HCl”) and mercury. The baghouse is located downstream of the dry sorbent injection to provide additional contact time between the dry sorbent and the flue gas while also removing additional particulates from the flue gas. There are no issues reported with the bag house or stack.

Burns & McDonnell recommends that the duct work and expansion joints be inspected and repaired every 6 years.

5.13.2 Fly Ash System

The fly ash system transfers the fly ash that has been separated from the flue gas in the ESP and the baghouse to the fly ash storage silo for unloading. Fly ash is disposed of through the bottom outlets of ESP and baghouse into collection hoppers. Piping then connects each of the ash hoppers to RPS2’s fly ash silo for storage. Movement through the ash piping is stimulated by vacuum type blowers. The silo is equipped with a continuous operating separator.

6.0 UNIT BENCHMARKING

6.1 T.J. Labbé

Burns & McDonnell compared Labbe to similarly sized CTs to determine how the units are operating. Utilizing historical performance and cost information at Labbe, Burns & McDonnell was able to make observations about the Plant. Also, Burns & McDonnell used operating and retirement data for CT facilities to create useful life curves. Survivor curves can help LUS plan for the anticipated retirement of the units in the future.

6.1.1 Historical Performance

Burns & McDonnell benchmarked the historical performance at Labbe against other similarly sized simple cycle units. Burns & McDonnell's analysis included natural gas, CTs with a rated operating capacity between 20 and 60 MWs. Burns & McDonnell conducted a national and regional benchmark analysis to determine whether trends seen at a national level are applicable to the southeastern region of the US. The regional fleet benchmarking analysis consists of South Eastern Reliability Council ("SERC") and Southern Power Pool ("SPP") for benchmarking while the regional fleet benchmarking analysis consists of units in either the SERC or the Midcontinent Independent System Operator ("MISO") NERC regions for useful life analysis. Data used in the benchmarking analysis was derived from NERC GADS and data for the useful life analysis was derived from the US EIA-860 database for the last five years.

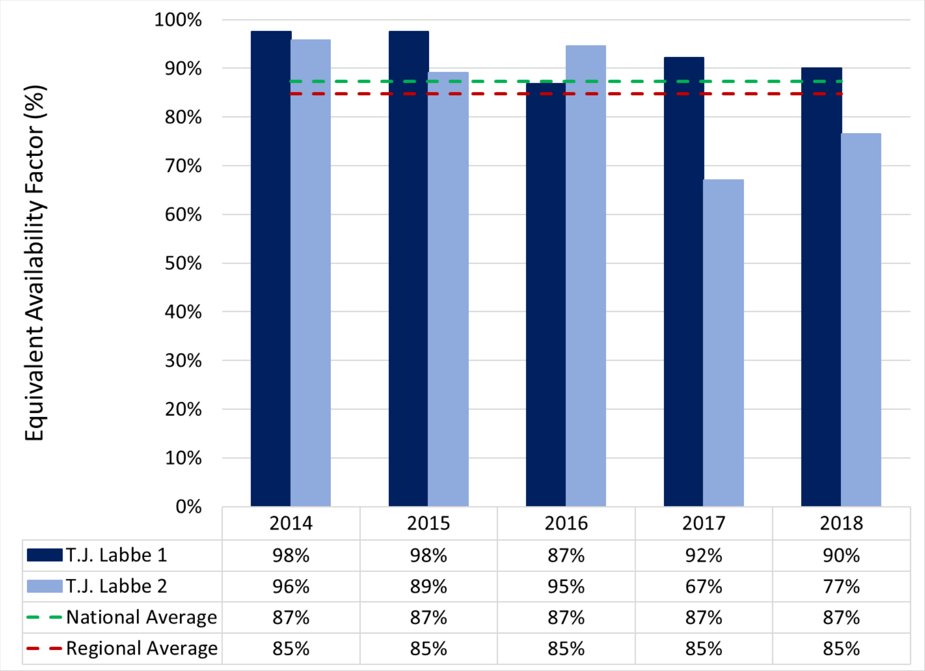
Labbe's historical monthly operating statistics were provided to Burns & McDonnell by LUS. Burns & McDonnell requested LUS provide historical monthly operating statistics for the prior five years. The information provided to Burns & McDonnell included data from January 2014 to June 2019. 2019 did not include a full year of operating data which reduced Burns & McDonnell's ability to make substantial conclusions about 2019. A five-year analysis from 2014 through 2018 was performed.

It should be noted that the data set used for the benchmarking did not differentiate between frame and aeroderivative units. While Burns & McDonnell actively considered the size of the units while performing the analysis, it was not possible to isolate aeroderivative units in the analysis. It is known that aeroderivative units will typically have higher efficiencies than frame units while incurring a greater O&M cost per kW to maintain. Aeroderivative units are typically more flexible and used as peaking units.

6.1.2 Availability and Reliability

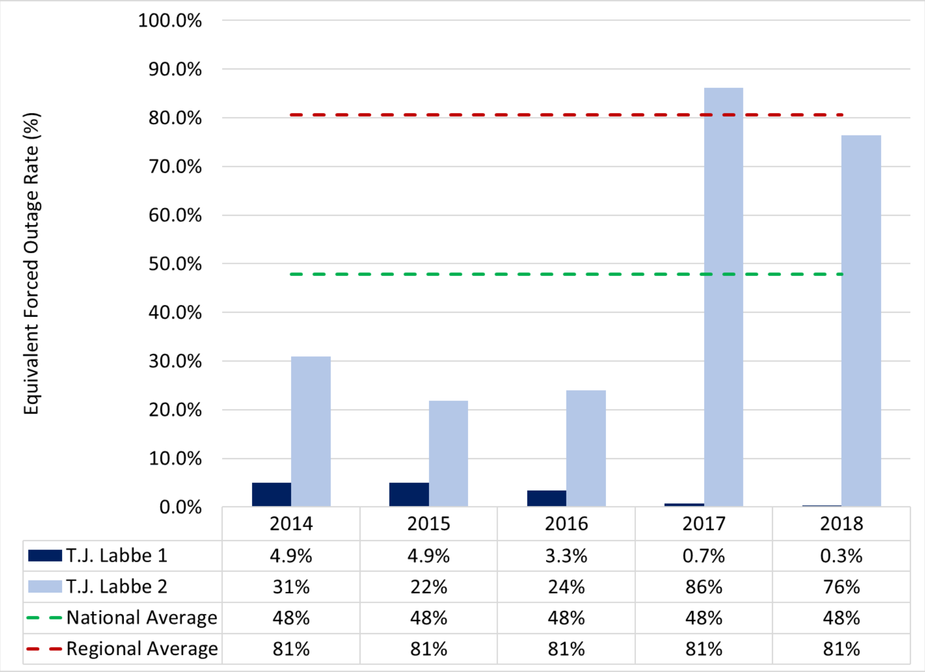
Burns & McDonnell evaluated the Labbe's units' overall availabilities and reliability performances against a fleet average of similar generating units. Figure 6-1 presents the EAF for the units against the fleet benchmark data as provided from the NERC GADS. Similarly, Figure 6-2 presents the EFOR for the units against the fleet benchmark.

Figure 6-1: T.J. Labbé EAF Benchmark



	2014	2015	2016	2017	2018
T.J. Labbe 1	98%	98%	87%	92%	90%
T.J. Labbe 2	96%	89%	95%	67%	77%
National Average	87%	87%	87%	87%	87%
Regional Average	85%	85%	85%	85%	85%

Figure 6-2: T.J. Labbé EFOR Benchmark



	2014	2015	2016	2017	2018
T.J. Labbe 1	4.9%	4.9%	3.3%	0.7%	0.3%
T.J. Labbe 2	31%	22%	24%	86%	76%
National Average	48%	48%	48%	48%	48%
Regional Average	81%	81%	81%	81%	81%

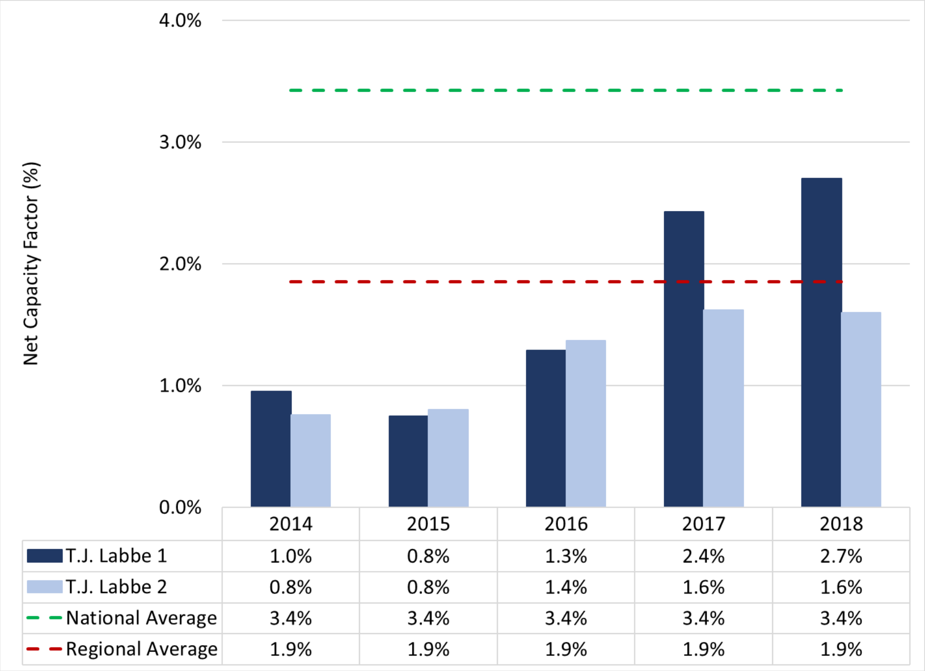
As depicted in Figure 6-1, TJU1 was above (better than) the regional EAF fleet benchmark for all five years of data. TJU1 was also above the national EAF for four of the five years of data. TJU1 was less than half of a percent lower (worse) for the one year that it had a lower EAF than the national average. TJU1's average EAF from January 2014 through December 2018 was approximately 6.4 percent higher (better) than the national fleet benchmark and approximately 9.6 percent higher (better) than the regional fleet benchmark, this is largely due to the investments made to have the unit ready to generate at all times. Due to the Unit's high EAF performance, TJU1 has operated above industry availability standards over the past five years TJU2 was above (better than) the national and regional averages for three years (2014, 2015, 2016). TJU2's average EAF was 3.0 percent lower (worse) than the regional average and was equal to the national average (0.1 percent difference).

Similarly, as illustrated in Figure 6-2, TJU1 had an EFOR that was lower (better) than the EFOR fleet benchmark in all five years. The average EFOR for TJU1 from January 2014 through December 2018 was substantially lower (better) than the national and regional benchmarks. Due to the unit's low EFOR performance, TJU1 has operated substantially better than industry reliability standards over the past five years largely due to the same reasons listed above in that LUS has invested heavily in making the unit available. TJU2, however, has shown EFOR values higher (worse) than the national average for both 2017 and 2018. TJU2 is only greater than the regional average in 2017. The average EFOR for TJU2 from January 2014 through December 2018 was substantially equal to the national averages (0.0 percent difference) and 40.6 percent lower than the regional benchmarks.

6.1.3 Generation

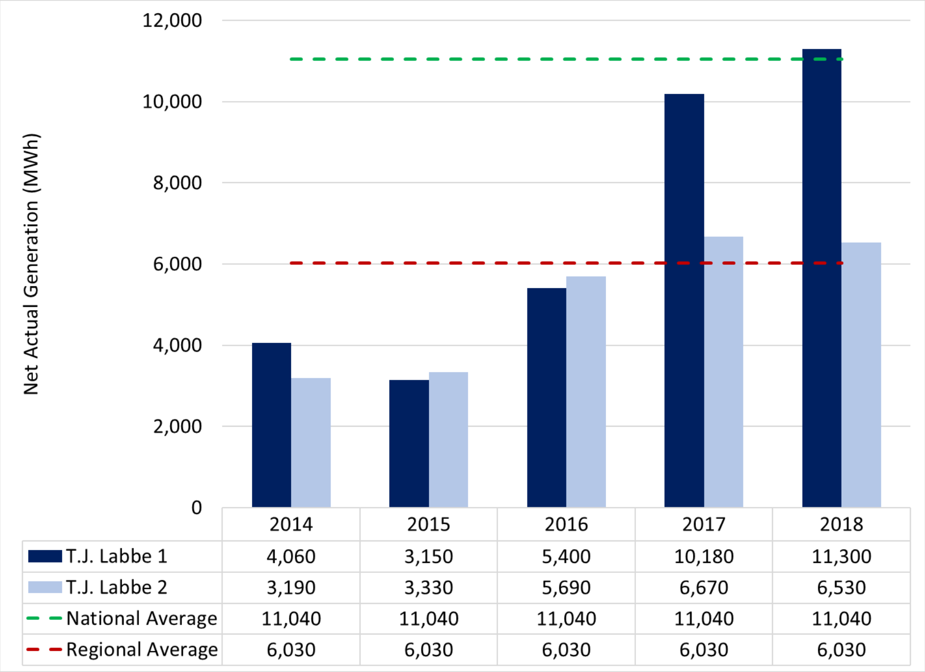
Burns & McDonnell evaluated the units' overall generation performance against a fleet average of similar generating units. Figure 6-3 presents the net capacity factor for the units against the fleet benchmark data as provided from NERC GADS. Similarly, Figure 6-4 presents the NAG for the Units against the fleet benchmark data as provided from NERC GADS.

Figure 6-3: T.J. Labbé Net Capacity Factor Benchmark



	2014	2015	2016	2017	2018
T.J. Labbe 1	1.0%	0.8%	1.3%	2.4%	2.7%
T.J. Labbe 2	0.8%	0.8%	1.4%	1.6%	1.6%
National Average	3.4%	3.4%	3.4%	3.4%	3.4%
Regional Average	1.9%	1.9%	1.9%	1.9%	1.9%

Figure 6-4: T.J. Labbé Net Actual Generation Benchmark

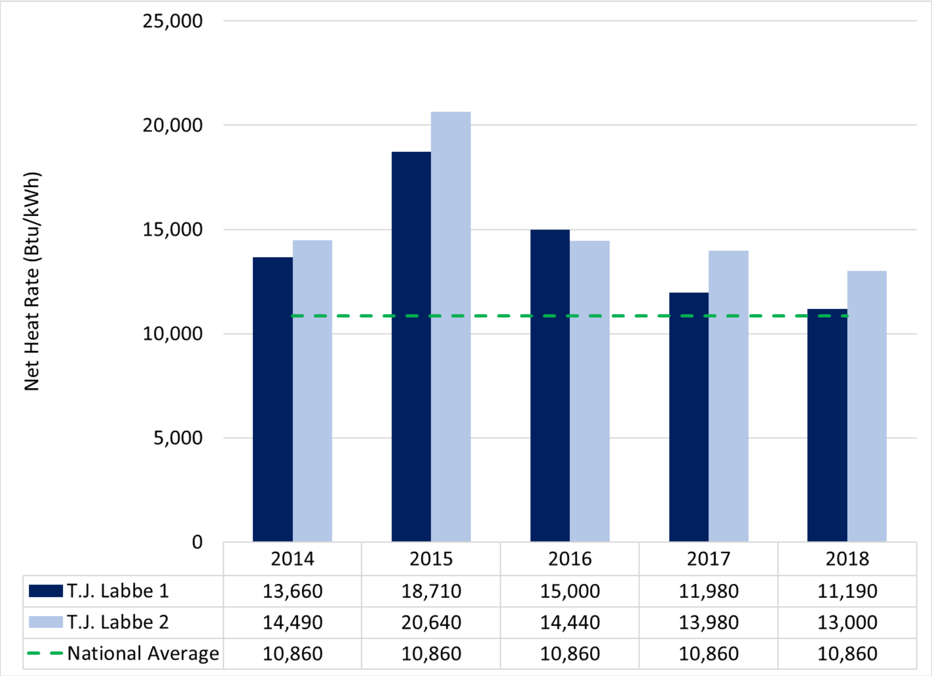


	2014	2015	2016	2017	2018
T.J. Labbe 1	4,060	3,150	5,400	10,180	11,300
T.J. Labbe 2	3,190	3,330	5,690	6,670	6,530
National Average	11,040	11,040	11,040	11,040	11,040
Regional Average	6,030	6,030	6,030	6,030	6,030

As depicted in Figure 6-3 and Figure 6-4, Labbe has experienced a steady increase in generation since 2014. In 2017, Labbe exceeded the regional fleet benchmarks for NAG. The change in NCF and NAG at Labbe is a result of Labbe being dispatched to produce power more frequently. Data provided to Burns & McDonnell from January 2014 through December 2018 indicate that TJU1 has generated an annual average of 6,800 megawatt hours (“MWh”) of energy while operating at a 1.6 percent NCF over the past 5 years. TJU1’s average NCF is 52.5 percent lower (worse) than the national average and 12.3 percent lower (worse) than the regional average. TJU1’s average NAG is 38.3 percent lower (worse) than the national average, but 13.1 percent higher (better) than the regional average. The same data indicate that TJU2 has generated 5,100 MWh of energy while operating at a 1.2 percent NCF. TJU2’s average NCF is 64.1 percent lower (worse) than the national average and 33.6 percent lower (worse) than the regional average. TJU2’s average NAG is 54.0 percent lower (worse) than the national average and 15.7 percent lower (worse) than the regional average.

Burns & McDonnell used information from EIA-860 to benchmark Labbe’s NHR. Figure 6-5 presents the NHR for the units against the national fleet benchmark data. There were not enough units in the EIA-860 regional data to create a reliable regional benchmark.

Figure 6-5: T.J. Labbé Net Heat Rate Benchmark



	2014	2015	2016	2017	2018
■ T.J. Labbe 1	13,660	18,710	15,000	11,980	11,190
□ T.J. Labbe 2	14,490	20,640	14,440	13,980	13,000
- - National Average	10,860	10,860	10,860	10,860	10,860

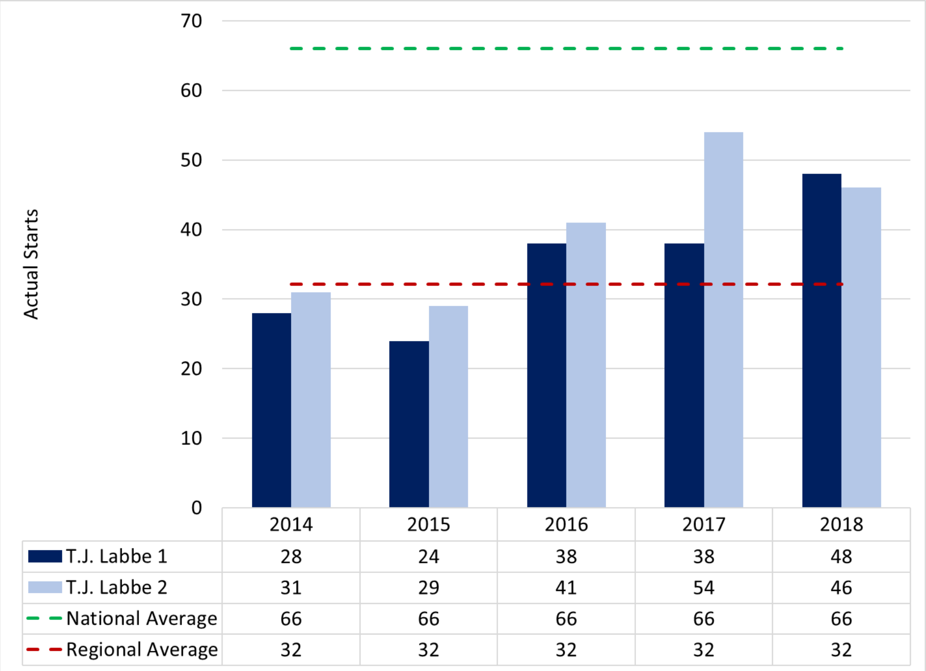
Both units at Labbe have been above (worse than) the national fleet benchmark for NHR for all five years. The reason for the high heat rate performance is because the units are dispatched into the grid at part load and as peaking units. The five-year average NHRs for TJU1 and TJU2 are 14,100 British Thermal Units (“Btu”) per kWh and 15,300 Btu/kWh, respectively. These values are 29.8 percent and 40.9 percent higher (worse) than the national fleet benchmark, respectively.

In August 2005, Labbe received a performance test performed by McHale & Associates, Inc. The results of the test indicated that the units could operate at an average corrected net plant heat rate of 9,772 Btu/kWh with uncertainty. The test reported values are below the national average, thus the units should be able to perform at or near the national benchmark. The reason that the units are not performing at or below the tested and the national benchmarks is likely due to the units being part loaded most of the dispatch hours. There is no reason to suspect that the units have deteriorated given the information provided.

6.1.4 Start Up

Burns & McDonnell evaluated the units' overall start-up performance against a fleet average of similar generating units. Figure 6-6 presents the actual starts for the units against the fleet benchmark data as provided from NERC GADS.

Figure 6-6: T.J. Labbé Actual Starts Benchmark

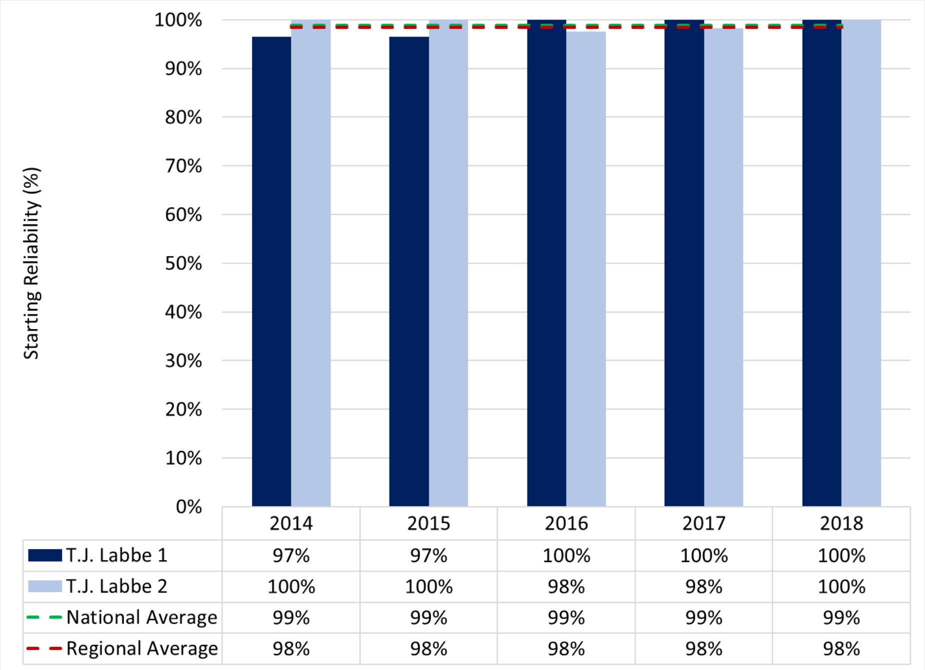


	2014	2015	2016	2017	2018
■ T.J. Labbe 1	28	24	38	38	48
■ T.J. Labbe 2	31	29	41	54	46
– – National Average	66	66	66	66	66
– – Regional Average	32	32	32	32	32

As depicted in Figure 6-6, the units have experienced increasingly more starts within the time period from January 2014 to December 2018. Labbe's units have exceeded the regional fleet benchmark for starts in each of the past three years, while managing to not exceed the national benchmark. Since Labbe has been exposed to increasingly more starts over the past years, attention should be directed to components that are likely to fail due to cycling conditions. Cycling may require replacing components earlier than anticipated which will increase the O&M costs and reduce unit availability.

Figure 6-7 presents the starting reliability for the units against the fleet benchmark data as provided from NERC GADS.

Figure 6-7: T.J. Labbé Starting Reliability Benchmark



	2014	2015	2016	2017	2018
■ T.J. Labbe 1	97%	97%	100%	100%	100%
■ T.J. Labbe 2	100%	100%	98%	98%	100%
- - National Average	99%	99%	99%	99%	99%
- - Regional Average	98%	98%	98%	98%	98%

As depicted in Figure 6-7, the units have each operated above (better) the national and regional fleet benchmarks for starting reliability in three of the past five years. Lower (worse) starting reliability was experienced by TJU1 in 2014 and 2015 while TJU2 saw lower (worse) starting reliability in 2016 and 2017. Burns & McDonnell's review of monthly operating data indicates that there is little concern over the long-term starting reliability of the units. If Labbe continues to be operated as a peaking unit requiring the units to quickly respond to changes in demand, then LUS should be cognizant of the units' conditions. More frequent start up and shutdown operations will result in accelerated unit damages which may require accelerated maintenance activities.

6.1.5 Historical O&M Costs

In addition to replacing key equipment and components through major project upgrades, much of the remaining equipment would require increased maintenance as the units continue to age. Burns & McDonnell evaluated the trend in non-fuel O&M costs associated with similar gas turbine facilities which are required to report O&M costs as part of the FERC Form 1 submission. Burns & McDonnell developed an industry trend by plotting units based on a five-year average of current service life and O&M costs. Each unit included in the benchmark is represented as a single data point that is a five-year average of the O&M costs. Labbe's units are shown in red while Hargis' units are shown in yellow. For simplicity, the analysis was limited to the southeastern US. Figure 6-8 shows O&M costs on a $/MWh basis and Figure 6-9 shows the units on a $/kW basis.

Figure 6-8: Gas Turbine Non-Fuel O&M Costs ($/MWh) by Unit Age

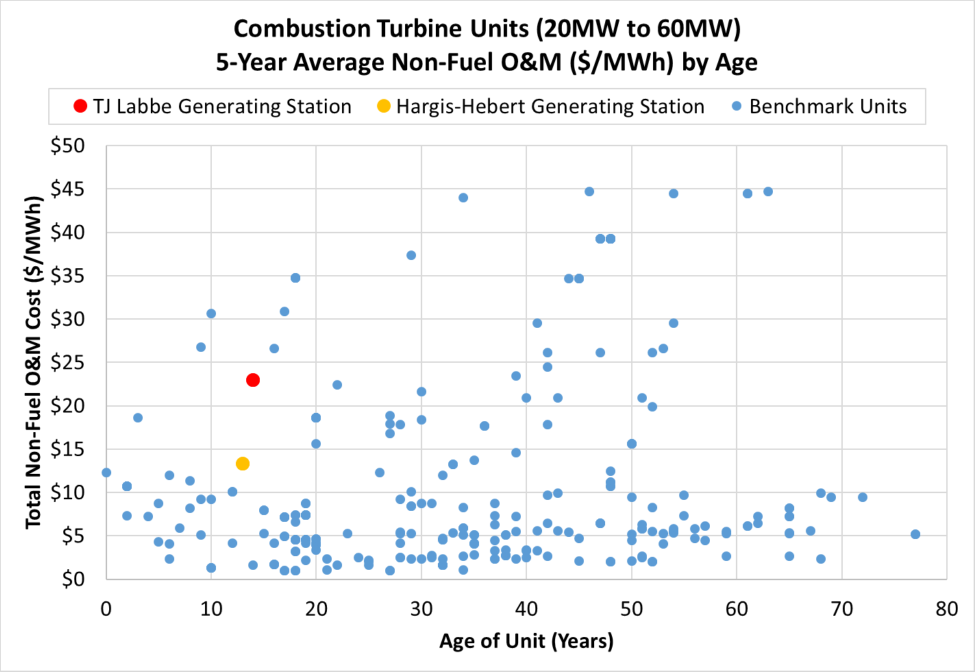
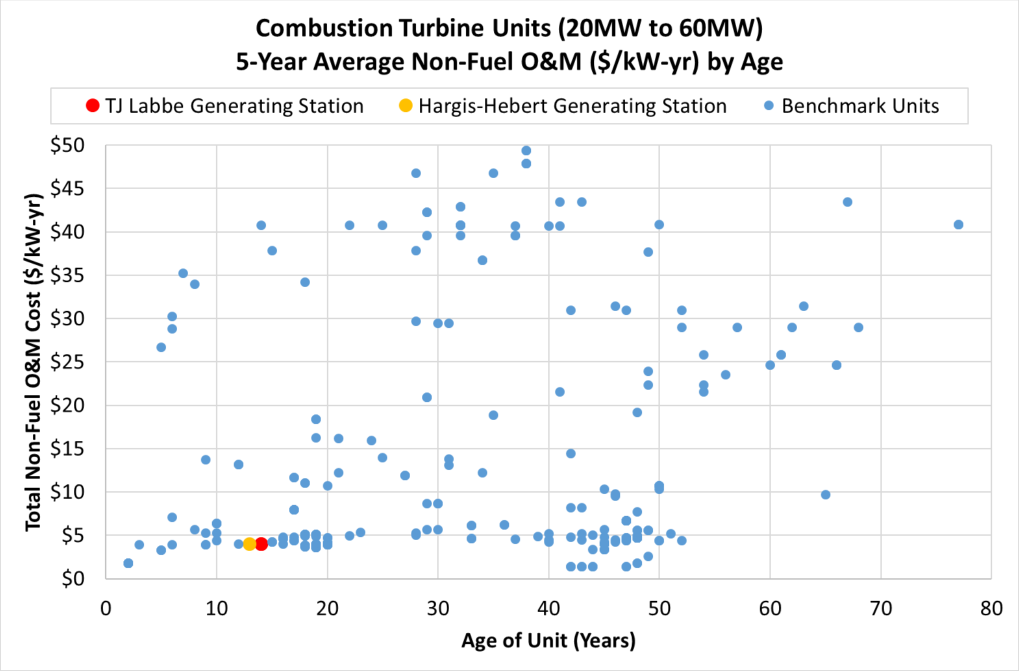


Figure 6-9: Gas Turbine Non-Fuel O&M Costs ($/kW) by Unit Age



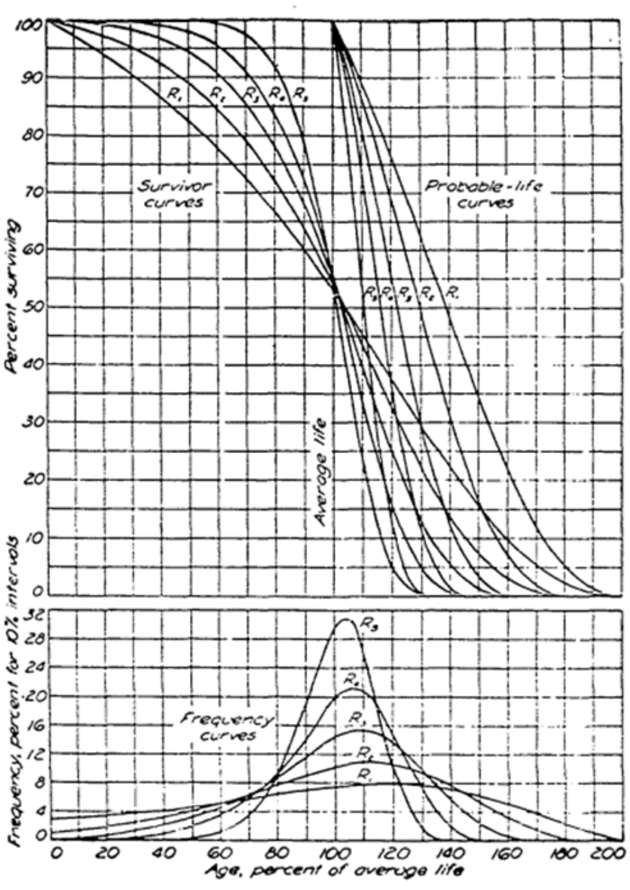
Based on Figure 6-8 and Figure 6-9, the expenditures at Labbe and Hargis have been above similarly sized simple cycle units in the southeastern US on a generation basis, but have been low on a net capacity basis. This is likely due to the unit having reasonable O&M costs for its size but having a low net generation and a low capacity factor. The figure indicates that the benchmark units experience a consistent level of O&M costs through their early and middle life cycle and increase near end of life. The differences between the high O&M cost units and the low O&M cost units can likely be attributed to a difference in operating philosophy. Some owners and operators will elect to increase O&M spending near unit retirement as an attempt to lengthen the unit lifecycle. Similarly, some owners and operators will elect to decrease O&M spending near the end of a unit's operation life as an attempt to decrease costs associated with a unit near retirement.

6.1.6 Useful Life Evaluation

Burns & McDonnell approximated the probability of unit survival with the use of Iowa-Type Survivor Curves; a set of standardized curves used to approximate useful life of varying technologies. Survivor curves are commonly utilized in asset management solutions to estimate the percentage of a population in an asset class that survives over time. Iowa Survivor Curves, specifically, are widely used in the utility industry in depreciation studies for establishing the useful life of generating assets and performing statistical analyses of transmission and distribution equipment.

The curves are fitted to the specific asset types based on the frequency distribution of a dataset. The frequency distribution determines whether a Right-modal type ("R-type"), Left-modal type ("L-type") or Symmetrical-modal type ("S-type") curve is used. Figure 6-10 displays the varying R-type survivor curves and how the survivor curves relate to frequency distributions.

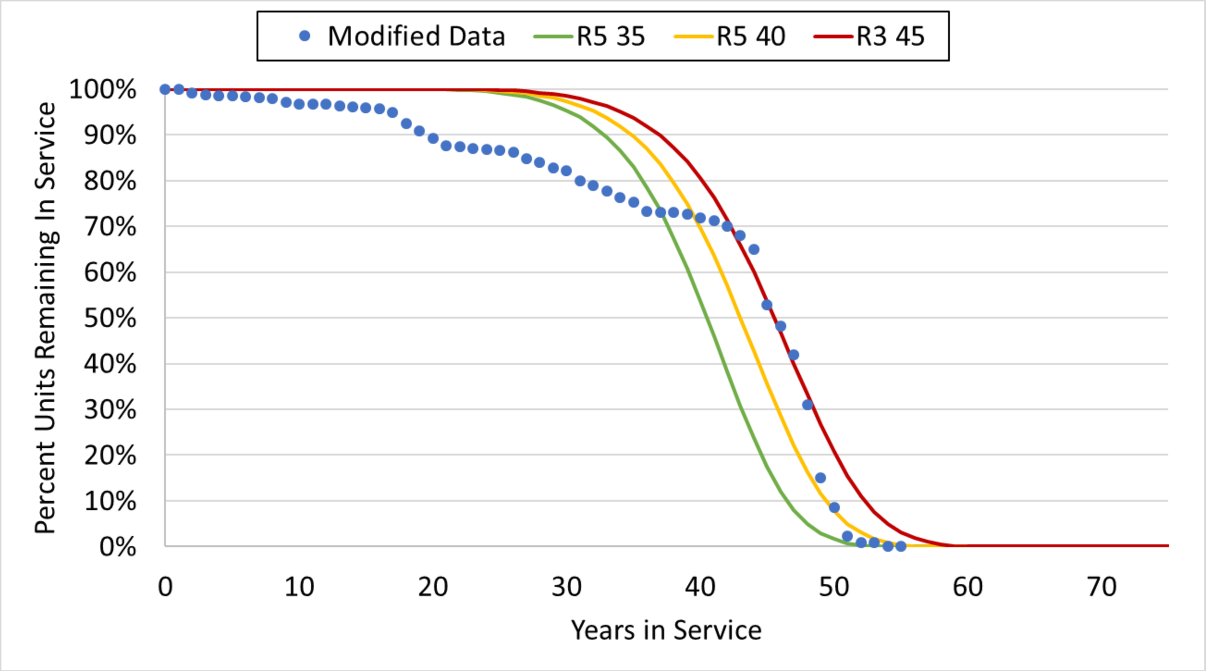
Figure 6-10: R-type Survivor Curve Example



Based on the dataset Burns & McDonnell obtained for total service life, CT units were fitted with R-type survivor curves. Once a frequency distribution is determined, Iowa-Type Survivor Curves require two steps to fit a curve to the dataset. The first step requires assumption of the average service life for simple cycle units. For the second step, Burns & McDonnell fit the dataset as closely as possible with one of the standard Iowa-Type Curves. Burns & McDonnell possesses R0.5, R1, R1.5, R2, R2.5, R3, R4, and R5 Iowa-Type Survivor Curves. R0.5 curves have the least difference between peak and minimum frequency, while R5 curves have the greatest disparity between peak and minimum frequency. Based on the data Burns & McDonnell obtained, R3 Iowa-Type Survivor Curves fit the datasets most effectively for simple cycle units.

Figure 6-11 displays the survivor data for simple cycle units, in blue, and three Iowa-Type Survivor Curves that fit the modified data. The three survivor curves are used to help Burns & McDonnell to determine a range of expected useful lives for simple cycle units based on a national database.

Figure 6-11: National Combustion Turbine Unit Survival Curves



The Iowa Survivor Curves in Figure 6-11 indicate simple cycle units begin retiring around 35 years of service. By 43 years, approximately 50 percent of simple cycle units will have been retired. However, based on data, units begin retiring as early as 10 years. Burns & McDonnell cannot determine from the data obtained the exact reasoning for the retirements but acknowledges many of the retirements may have been a byproduct of changing economic and environmental factors that impact the viability of simple cycle units. Additionally, Burns & McDonnell recognizes that infant mortality may play a role in the difference between the data and I-Curves in early years of service.

Burns & McDonnell attempted to gain more insights by only evaluating units within the southeastern US. Units within the southeast should be exposed to the same economic and political constraints giving more insights than the national database. Figure 6-12 displays the survivor data for simple cycle units for the west, in blue, and three Iowa-Type Survivor Curves that fit the modified data.

Figure 6-12: Regional Combustion Turbine Unit Survival Curves

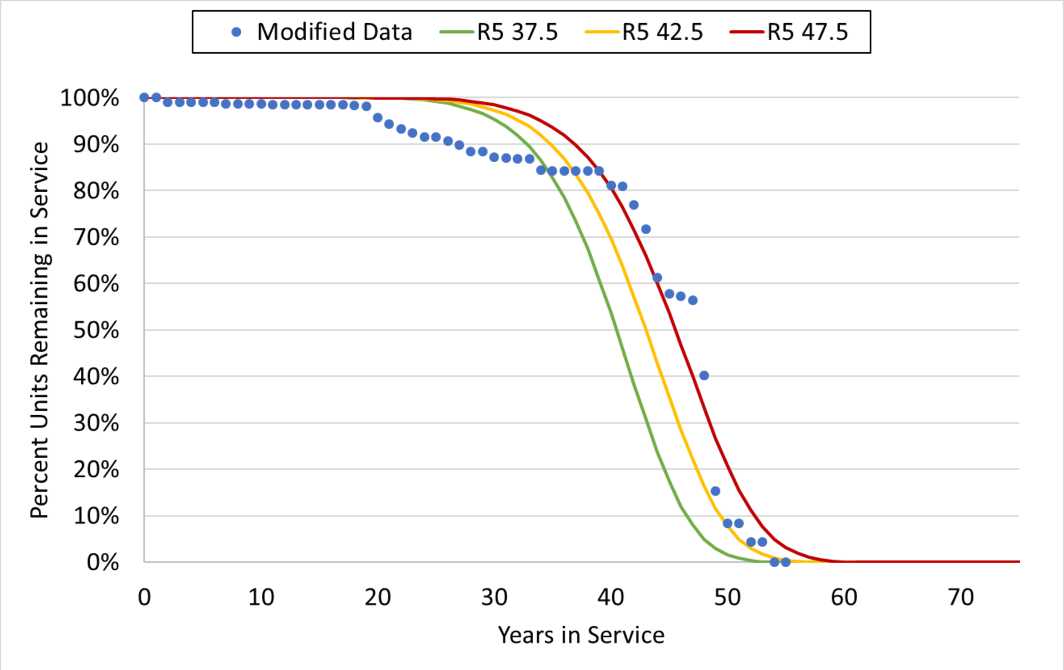


Figure 6-12 indicates simple cycle units begin retiring around 35 years of service. By 43 years, approximately 50 percent of simple cycle units will have been retired. Burns & McDonnell determined the trends experienced nationwide are similar to the trends experienced in the southeastern region

6.2 Hargis-Hébert

Burns & McDonnell compared Hargis to similarly sized simple cycles to determine how the units are operating. Utilizing historical performance and cost information at Hargis, Burns & McDonell was able to make observations about the plant. Also, Burns & McDonnell used operating and retirement data for simple cycle units to create useful life curves. Survivor curves can help LUS plan for the anticipated retirement of the unit in the future.

6.2.1 Historical Performance

Burns & McDonnell benchmarked the historical performance at Hargis against other similarly sized simple cycle units. Burns & McDonnell's analysis included natural gas, CTs with a rated operating capacity between 20 and 60 MWs. Burns & McDonnell conducted a national and regional benchmark analysis to determine whether trends seen at a national level are applicable to the southern region of the US. The regional fleet benchmarking analysis consists of the SERC and the SPP NERC regions. Data used in the benchmarking analysis was derived from either NERC's GADS or the US EIA-860 database for the last five years.

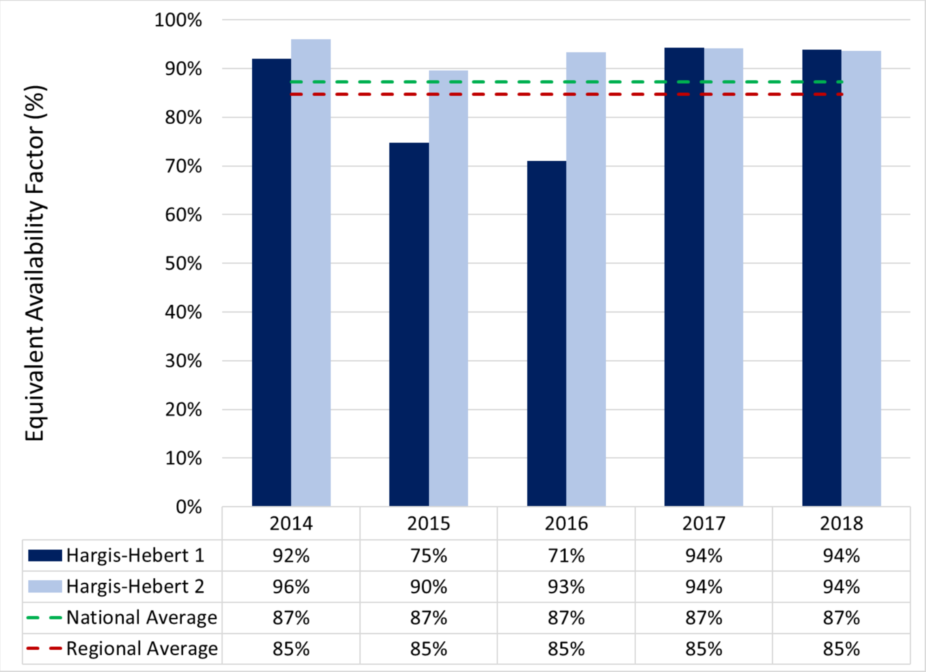
Hargis' historical monthly operating statistics were provided to Burns & McDonnell by LUS. Burns & McDonnell requested LUS provide historical monthly operating statistics for the prior five years. The information provided to Burns & McDonnell included data from January 2014 to June 2019. 2019 did not include a full year of operating data which reduced Burns & McDonnell's ability to make substantial conclusions about 2019. A five-year analysis from 2014 through 2018 was performed.

It should be noted that the data set used for the benchmarking did not differentiate between frame and aeroderivative units. While Burns & McDonnell actively considered the size of the units while performing the analysis, it was not possible to isolate aeroderivative units in the analysis. It is known that aeroderivative units will typically have higher efficiencies than frame units while incurring a greater O&M cost per kW to maintain. Aeroderivative units are typically more flexible and used as peaking units.

6.2.2 Availability and Reliability

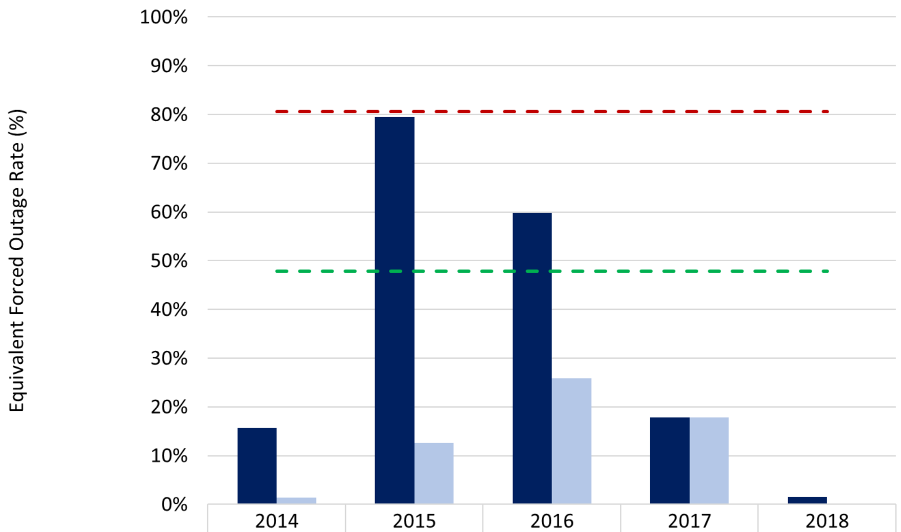
Burns & McDonnell evaluated the unit's overall availability and reliability performance against a fleet average of similar generating units. Figure 6-13 presents the EAF for the units against the fleet benchmark data as provided from the NERC GADS. Similarly, Figure 6-14 presents the EFOR for the units against the fleet benchmark.

Figure 6-13: Hargis-Hébert EAF Benchmark



	2014	2015	2016	2017	2018
■ Hargis-Hebert 1	92%	75%	71%	94%	94%
■ Hargis-Hebert 2	96%	90%	93%	94%	94%
- - National Average	87%	87%	87%	87%	87%
- - Regional Average	85%	85%	85%	85%	85%

Figure 6-14: Hargis-Hébert EFOR Benchmark



	2014	2015	2016	2017	2018
■ Hargis-Hebert 1	16%	79%	60%	18%	2%
■ Hargis-Hebert 2	1%	13%	26%	18%	0%
– – National Average	48%	48%	48%	48%	48%
– – Regional Average	81%	81%	81%	81%	81%

As depicted in Figure 6-13, HHU1 was above (better than) the national and regional EAF fleet benchmarks in three of the past five years. The lowest availability occurred in 2016. Overall, HHU1's average EAF from June 2014 through December 2018 was approximately 2.4 percent lower (worse) than the national fleet benchmark and approximately equal to the regional fleet benchmark. Due to HHU1's lower EAF performance, the unit has operated below industry availability standards over the past five years. HHU2 was above (better than) the national and regional EAF fleet benchmarks for all five past years. HHU1's performance is due to the investments made to make the unit always available. Overall, HHU2's average EAF from June 2014 through December 2018 was approximately 7.0 percent more (better) than the national fleet benchmark and approximately 10.2 percent more (better) than the regional fleet benchmark. Due to the Unit's high EAF performance, the Unit has operated above industry availability standards over the past five years. HHU2's strong ratings are due to its consistent 100 percent EAF.

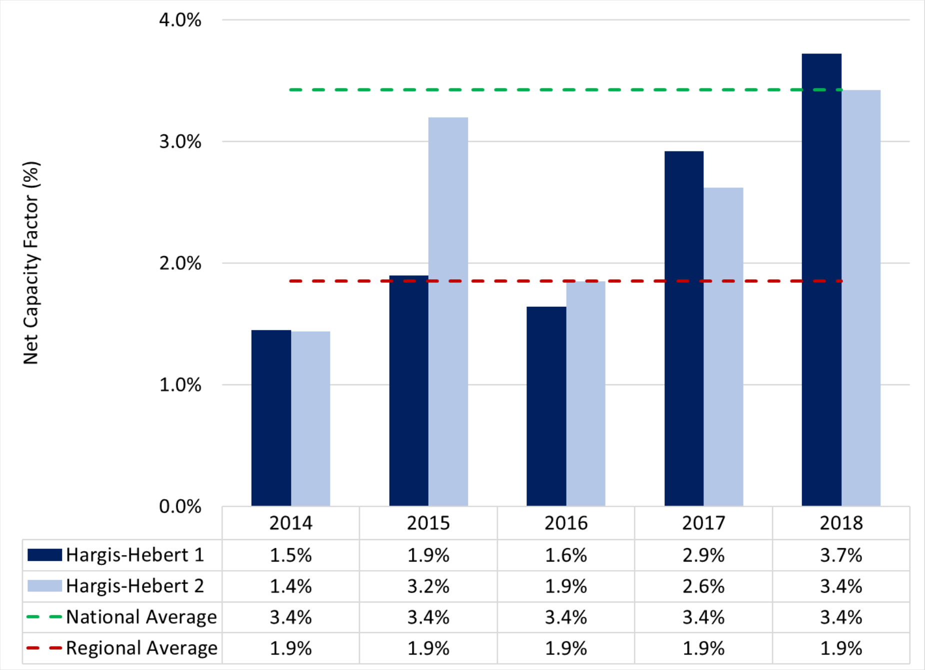
Similarly, as illustrated in Figure 6-14, HHU1's EFOR was lower (better) than the EFOR fleet benchmark in three of the past five years. HHU1's average EFOR from June 2014 through December 2018 was approximately 27.2 percent lower (better) than the national fleet benchmark and approximately 56.7 percent lower (better) than the regional fleet benchmark. The average EFOR from June 2014 through December 2018 considers 2015 and 2016 when HHU1 experienced high EFOR. Due to the Unit's low EFOF performance, the unit has operated at better industry reliability standards over the past five years. HHU2's EFOR was substantially lower (better) than the EFOR fleet benchmark in all five past years.

HHU2’s average EFOR from June 2014 through December 2018 was approximately 76 percent lower (better) than the national fleet benchmark and approximately 85.7 percent lower (better) than the regional fleet benchmark. HHU2’s strong EFOR performance is associated with investments made to make the unit fully available. Due to the unit’s low EFOF performance, the unit has operated substantially above reliability standards over the past five years.

6.2.3 Generation

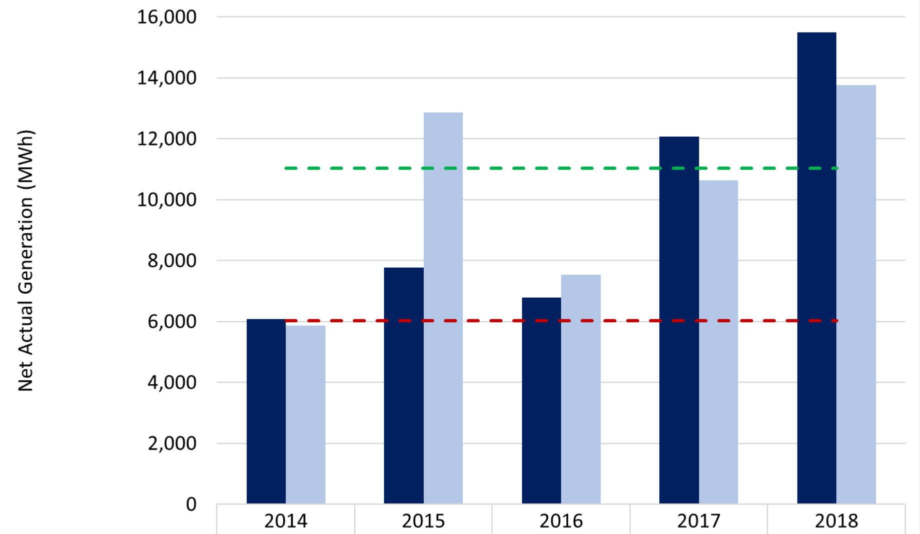
Burns & McDonnell evaluated the units’ overall generation performance against a fleet average of similar generating units. Figure 6-15 presents the NCF for the units against the fleet benchmark data as provided from NERC GADS. Similarly, Figure 6-16 presents the NAG for the units against the fleet benchmark data as provided from NERC GADS.

Figure 6-15: Hargis-Hébert Net Capacity Factor Benchmark



	2014	2015	2016	2017	2018
Hargis-Hebert 1	1.5%	1.9%	1.6%	2.9%	3.7%
Hargis-Hebert 2	1.4%	3.2%	1.9%	2.6%	3.4%
National Average	3.4%	3.4%	3.4%	3.4%	3.4%
Regional Average	1.9%	1.9%	1.9%	1.9%	1.9%

Figure 6-16: Hargis-Hébert Net Actual Generation Benchmark

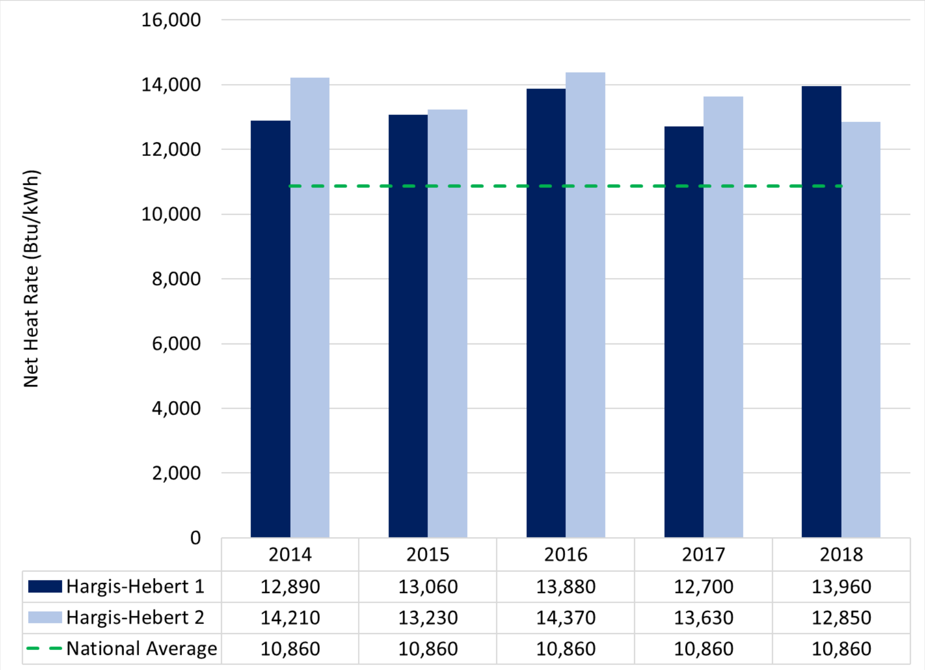


	2014	2015	2016	2017	2018
■ Hargis-Hebert 1	6,070	7,760	6,790	12,060	15,490
■ Hargis-Hebert 2	5,860	12,860	7,530	10,630	13,760
– – National Average	11,040	11,040	11,040	11,040	11,040
– – Regional Average	6,030	6,030	6,030	6,030	6,030

As depicted in Figure 6-15 and Figure 6-16, Hargis has experienced a steady increase in generation since 2014. The increase in NCF and NAG at Hargis is a result of increased power production at the facility. Data provided to Burns & McDonnell indicate from January 2014 through December 2018 that HHU1 has generated an average of 9,600 MWh of energy per year while operating at a 2.3 percent average NCF. HHU1's average NCF is 32 percent below (worse than) the national benchmark and 25.6 percent above (better than) the regional benchmark while the NAG for HHU1 is 12.8 percent below (worse than) the national benchmark and 59.8 percent higher (better) than the regional benchmark. Similarly, HHU2 has generated an average of 10,100 MWh of energy per year while operating at a 2.5 percent average NCF. HHU2's average NCF is 26.8 percent below (worse than) the national benchmark and 35.3 percent above (better than) the regional benchmark while the NAG for HHU2 is 8.3 percent below (worse than) the national benchmark and 68.0 percent higher (better) than the regional benchmark.

Burns & McDonnell used information from EIA-860 to benchmark Hargis' NHR. Figure 6-17 presents the NHR for the unit against the fleet benchmark data. There were not enough units in the EIA-860 regional data to create a reliable regional benchmark.

Figure 6-17: Hargis-Hébert Net Heat Rate Benchmark



	2014	2015	2016	2017	2018
Hargis-Hebert 1	12,890	13,060	13,880	12,700	13,960
Hargis-Hebert 2	14,210	13,230	14,370	13,630	12,850
National Average	10,860	10,860	10,860	10,860	10,860

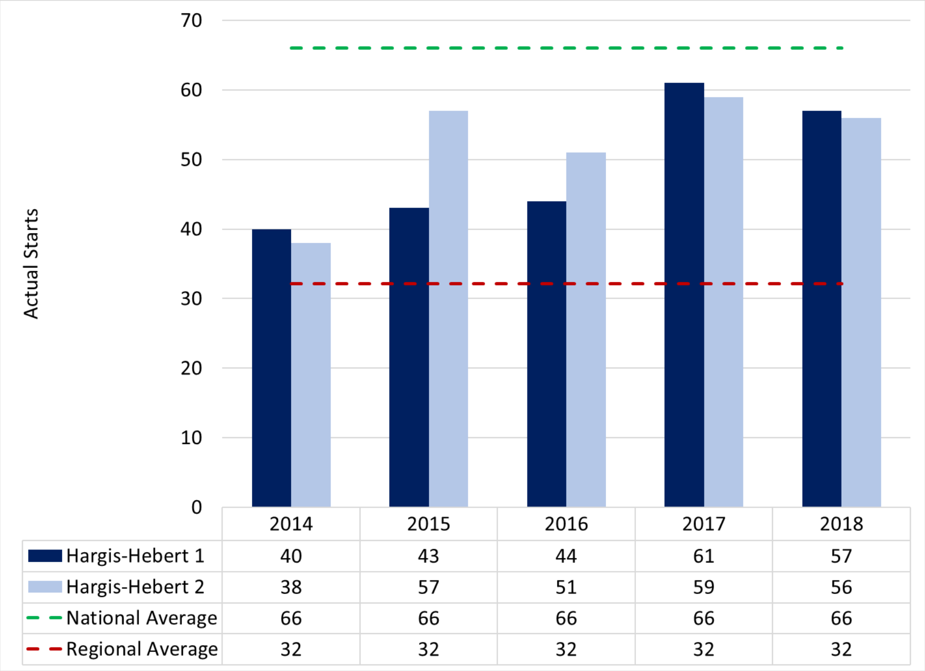
Both units at Hargis have been above (worse than) the national fleet benchmark for NHR for all five years. The reason for the high heat rate performance is because the units are dispatched into the grid at part load and as peaking units. The five-year average NHRs for HHU1 and HHU2 are 13,300 Btu/kWh and 13,650 Btu/kWh, respectively. These values are 22.5 percent and 25.8 percent higher (worse) than the national fleet benchmark, respectively.

McHale & Associates, Inc. visited Hargis in May of 2006. The performance test results indicated that the units could operate at an average corrected net plant heat rate of 9,724 Btu/kWh with uncertainty. The test reported values are below the national average, thus the units should be able to perform at or near the national benchmark. The reason that the units are not performing at or below the tested and the national benchmarks is due to the units being part loaded most of the dispatch hours. There is no reason to suspect that the units have deteriorated given the information provided.

6.2.4 Start Up

Burns & McDonnell evaluated the units' overall start-up performance against a fleet average of similar generating units. Figure 6-18 presents the actual starts for the units against the fleet benchmark data as provided from NERC GADS.

Figure 6-18: Hargis-Hébert Actual Starts Benchmark

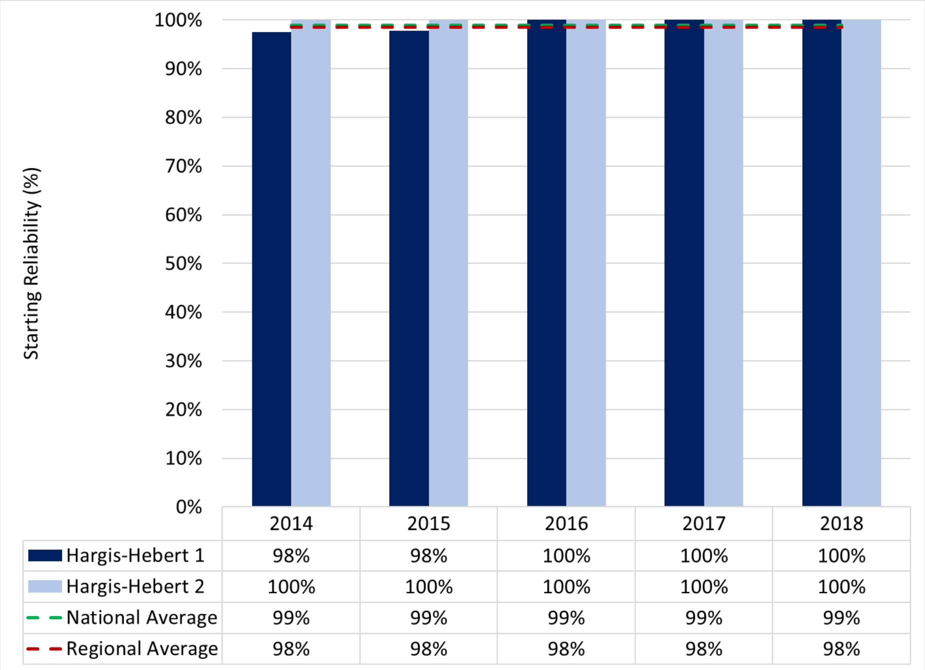


	2014	2015	2016	2017	2018
▬ Hargis-Hebert 1	40	43	44	61	57
▬ Hargis-Hebert 2	38	57	51	59	56
– – National Average	66	66	66	66	66
– – Regional Average	32	32	32	32	32

As depicted in Figure 6-18, Hargis has experienced more starts than other units within the regional fleet benchmark while experiencing fewer starts than the national fleet benchmark. Since Hargis has been exposed to more starts than the industry standard over the past four years, attention should be directed to components that are likely to fail due to cycling conditions. Cycling may require replacing components earlier than anticipated which will increase the O&M costs and reduce unit availability.

Figure 6-19 presents the starting reliability for the Units against the fleet benchmark data as provided from NERC GADS.

Figure 6-19: Hargis-Hébert Starting Reliability Benchmark



	2014	2015	2016	2017	2018
■ Hargis-Hebert 1	98%	98%	100%	100%	100%
■ Hargis-Hebert 2	100%	100%	100%	100%	100%
– – National Average	99%	99%	99%	99%	99%
– – Regional Average	98%	98%	98%	98%	98%

As depicted in Figure 6-19, HHU1 has operated above the national and regional fleet benchmarks for starting reliability in three of the past five years while HHU2 has operated above the national and regional fleet benchmarks for all five years. Burns & McDonnell's review of monthly operating data indicates that there is little concern over the long-term starting reliability of the units. If the units are operated as peaking units requiring the units to quickly respond to changes in demand, then LUS should be cognizant of the units' conditions. More frequent start up and shutdown operations will result in accelerated unit damage which may require accelerated maintenance activities.

6.2.5 Historical O&M Costs

Hargis' O&M costs were evaluated alongside Labbe. Please see Section 6.1.5.

The major conclusion from the section is that both Labbe and Hargis are spending more on a $/MWh basis than other similarly sized units in the region. However, since the units' O&M spending on a per kW basis is in line with the benchmark, the high $/MWh value is likely attributed to the units' low net generation and net capacity factors.

6.2.6 Useful Life Evaluation

Since both Hargis and Labbe are similar sites with similar units, the same Useful Life Evaluation can be used. For an explanation of the analysis, please refer to Section 6.1.6.

The major conclusion from the Section is that the southeast region appears to perform slightly better than the nation when it comes to unit longevity. However, the two models are substantially similar. Units in the southeast begin retiring at age 35 and half the southeastern units are expected to reach the age of 43, both nationwide and regionally.

6.3 Rodemacher Power Station Unit 2

Burns & McDonnell compared RPS2 to similarly sized coal units to determine how the unit is operating. Utilizing historical performance and cost information at RPS2, Burns & McDonell was able to make observations about the plant. Also, Burns & McDonnell used operating and retirement data for coal plants to create useful life curves. Survivor curves can help LUS plan for the anticipated retirement of RPS2 in the future.

6.3.1 Historical Performance

Burns & McDonnell benchmarked the historical performance at RPS2 against other similarly sized coal units. Burns & McDonnell's analysis included fossil fuel fired, STs with a rated operating capacity between 350 and 650 MWs. Burns & McDonnell conducted a national and regional benchmark analysis to determine whether trends seen at a national level are applicable to the southern region of the US The regional fleet benchmarking analysis consists of the SERC and the SPP NERC regions. Data used in the benchmarking analysis was derived from either NERC's GADS or the US EIA-860 database for the last five years.

RPS2's historical monthly operating statistics were provided to Burns & McDonnell by LUS. Burns & McDonnell requested LUS provide historical monthly operating statistics for the prior five years. The information provided included data from January 2013 to December 2018. Only the most recent five years of data was used or the analysis, as such, the 2013 data was omitted from the analysis.

6.3.2 Availability and Reliability

Burns & McDonnell evaluated the RPS2's overall availability and reliability performance against a fleet average of similar generating units. Figure 6-20 presents the EAF for RPS2 against the fleet benchmark data as provided from the NERC GADS. Similarly, Figure 6-21 presents the EFOR for RPS2 against the fleet benchmark.

Figure 6-20: RPS2 EAF Benchmark

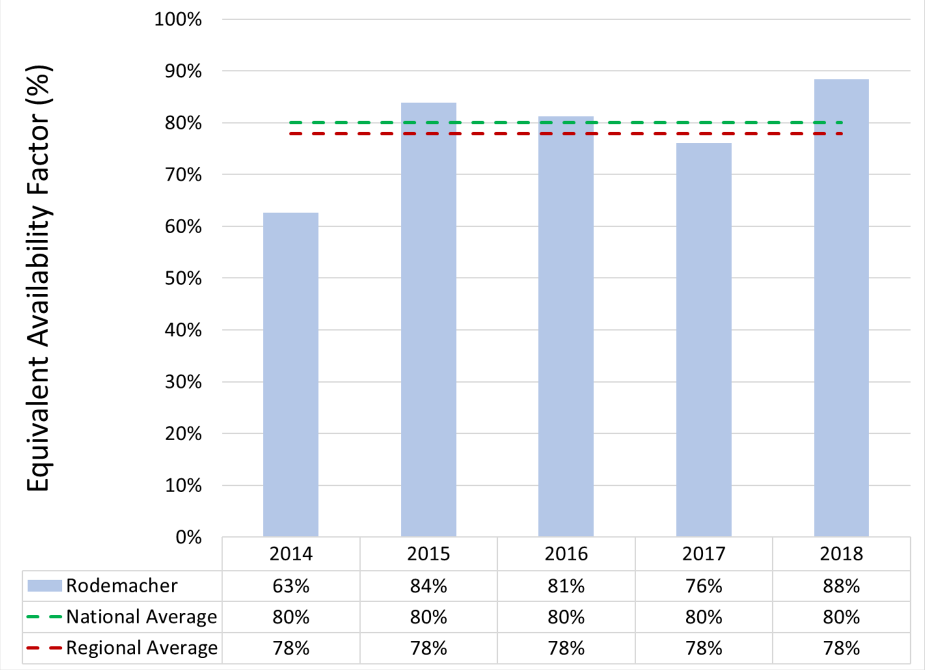
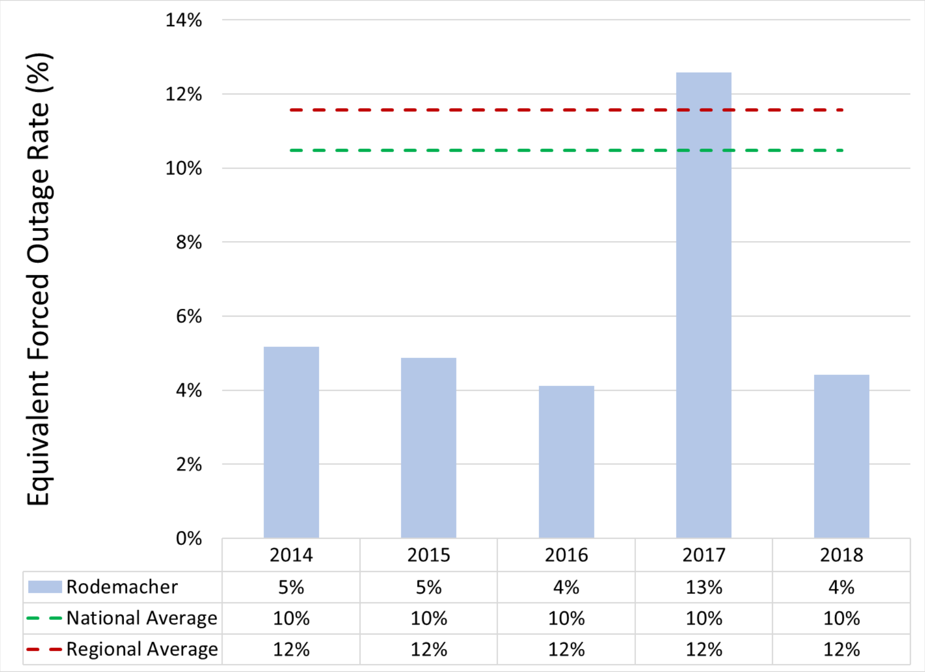


Figure 6-21: RPS2 EFOR Benchmark

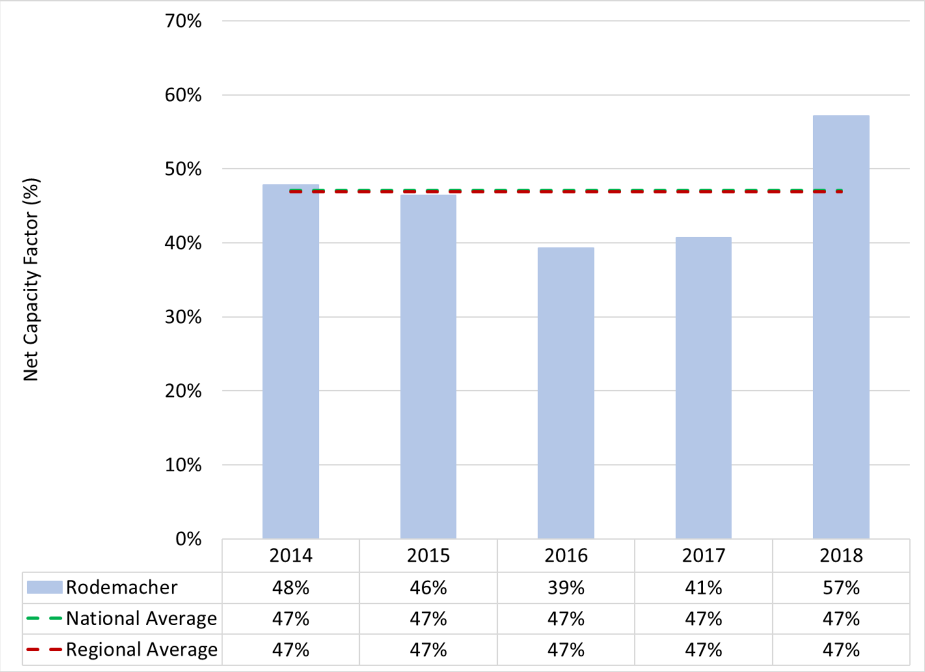


As depicted in Figure 6-20, RPS2 was above (better than) the EAF fleet benchmark in three of the past five years. The lowest availability occurred in 2014. Overall, the unit's average EAF from January 2014 through December 2019 was approximately 1 percent lower (worse) than the fleet benchmarks; however, this is largely due to RPS2 having relatively low performance in 2014. Given RPS2's EAF performance, the unit has operated at industry availability standards over the past five years. Similarly, as illustrated Figure 6-21, the unit's EFOR was lower (better) than the EFOR fleet benchmark in four of the past five years. RPS2's average EFOR from January 2014 through December 2018 was approximately 40 percent less (better) than the national fleet benchmark and approximately 46 percent less (better) than the regional fleet benchmark. The average EFOR from January 2014 through December 2018 was skewed by 2017 when the unit experienced and exceptionally high. Due to the unit's low EFOR performance, the unit has operated above industry reliability standards over the past five years.

6.3.3 Generation

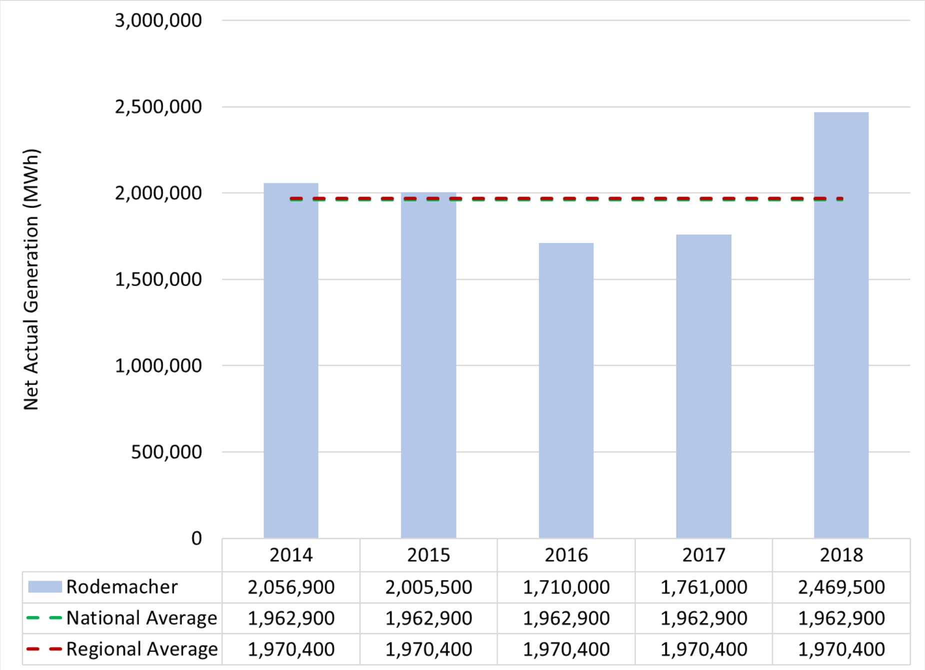
Burns & McDonnell evaluated the RPS2's overall generation performance against a fleet average of similar generating units. Figure 6-22 presents the NCF for the unit against the fleet benchmark data as provided from NERC GADS. Similarly, Figure 6-23 presents the NAG for the unit against the fleet benchmark data as provided from NERC GADS.

Figure 6-22: RPS2 Net Capacity Factor Benchmark



	2014	2015	2016	2017	2018
Rodemacher	48%	46%	39%	41%	57%
National Average	47%	47%	47%	47%	47%
Regional Average	47%	47%	47%	47%	47%

Figure 6-23: RPS2 Net Actual Generation Benchmark

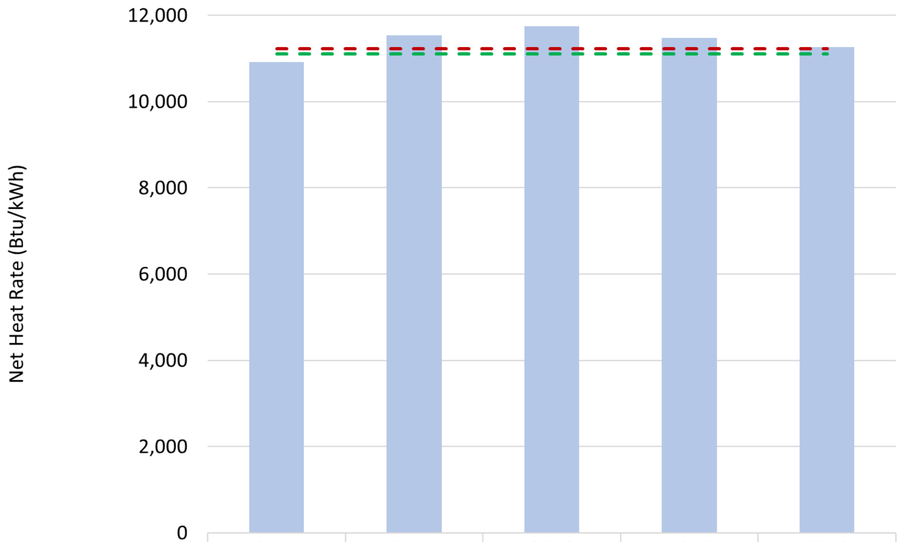


	2014	2015	2016	2017	2018
Rodemacher	2,056,900	2,005,500	1,710,000	1,761,000	2,469,500
National Average	1,962,900	1,962,900	1,962,900	1,962,900	1,962,900
Regional Average	1,970,400	1,970,400	1,970,400	1,970,400	1,970,400

As depicted in Figure 6-22 and Figure 6-23, RPS2 was at or below (equal to or worse than) the national and regional fleet benchmarks for both NCF and NAG fleet benchmarks four out of the five years. This is likely due to the unit being run at baseload and ramped to partial load as it is economically dispatched. Data provided to Burns & McDonnell indicate from January 2014 through December 2019, RPS2 has generated an annual average of 2,000,000 MWh of energy while operating at an average NCF of 46.3 percent.

Since NHR information could not be obtained from NERC GADS, Burns & McDonnell used information from EIA-860 to benchmark RPS2's NHR. Figure 6-24 presents the NHR for the unit against the fleet benchmark data.

Figure 6-24: RPS2 Net Heat Rate Benchmark



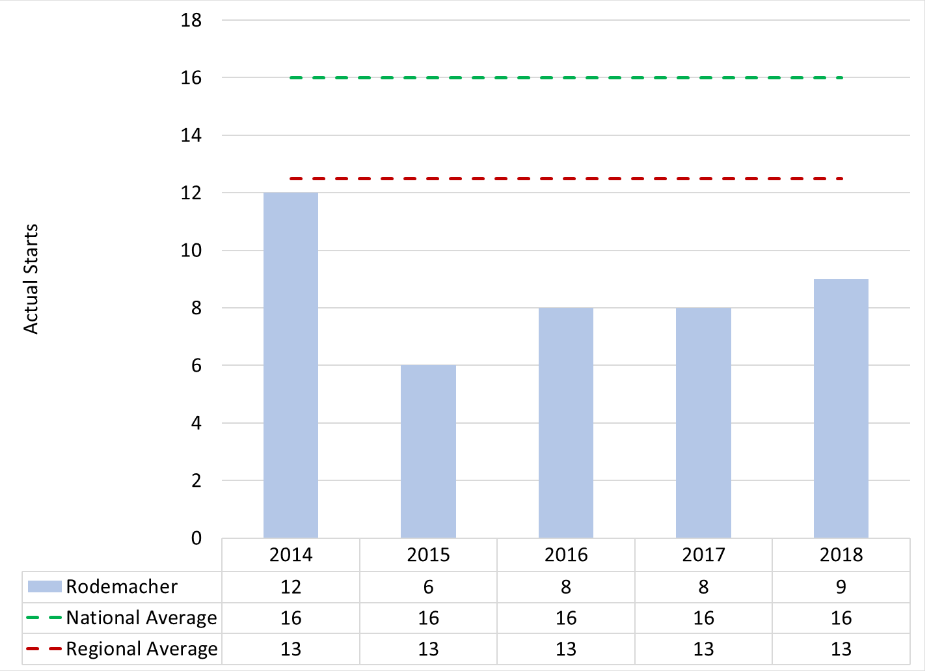
	2014	2015	2016	2017	2018
▬ Rodemacher	10,920	11,540	11,740	11,480	11,260
- - National Average	11,100	11,100	11,100	11,100	11,100
- - Regional Average	11,230	11,230	11,230	11,230	11,230

As shown in Figure 6-24, during the most recent four years, RPS2 operated at a heat rate that was higher (worse) than the fleet benchmark despite relatively constant capacity factors. However, as the capacity factor increased in 2018, the unit heat rate decreased. From 2014 until 2018, RPS2 operated at a five-year average NHR of 11,400 Btu/kWh which was 2.6 percent above the national fleet benchmark and 1.4 percent above the regional fleet benchmark.

6.3.4 Start Up

Burns & McDonnell evaluated the unit's overall start-up performance against a fleet average of similar generating units. Figure 6-25 presents the actual starts for the unit against the fleet benchmark data as provided from NERC GADS.

Figure 6-25: RPS2 Actual Starts Benchmark

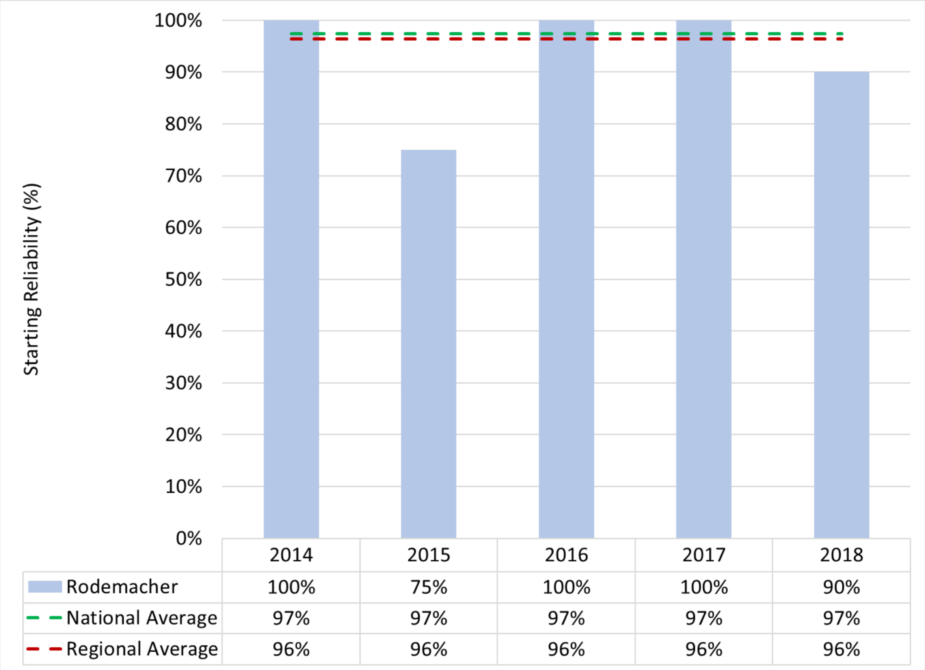


	2014	2015	2016	2017	2018
Rodemacher	12	6	8	8	9
National Average	16	16	16	16	16
Regional Average	13	13	13	13	13

As depicted in Figure 6-25, RPS2 has experienced fewer starts than other units within the fleet benchmark. RPS2's comparatively low number of starts is likely due to the unit being self-dispatched at minimum load. Since RPS2 has been exposed to fewer starts than the industry standard over the past years, it has been exposed to fewer thermal stresses that accompany starting a unit. Should RPS2 increase the frequency of its starts and shutdowns, attention should be directed to components that are likely to fail due to cycling conditions. Cycling will expose RPS2 to accelerated damage mechanisms such thermal fatigue, creep, creep fatigue, and corrosion which will reduce the useful life of components within the unit. Cycling may require replacing components earlier than anticipated which will increase the O&M costs and reduce unit availability.

Figure 6-26 presents the starting reliability for the Unit against the fleet benchmark data as provided from NERC GADS.

Figure 6-26: RPS2 Starting Reliability Benchmark



	2014	2015	2016	2017	2018
Rodemacher	100%	75%	100%	100%	90%
National Average	97%	97%	97%	97%	97%
Regional Average	96%	96%	96%	96%	96%

As depicted in Figure 6-26, RPS2 has operated above the national and regional fleet benchmarks for starting reliability in three of the past five years. Poor starting reliability was experienced at RPS2 in 2015 and 2018. Burns & McDonnell's review of monthly operating data indicates that there is little concern over the long-term starting reliability of the unit. If RPS2 is transitioned to cycle more frequently, then LUS should be cognizant of the unit's condition. More frequent start up and shutdown operations will result in accelerated unit damage which may require accelerated maintenance activities.

6.3.5 Historical O&M Costs

In addition to replacing key equipment and components through major project upgrades, much of the remaining equipment would require increased maintenance as the unit continues to age. Burns & McDonnell evaluated the trend in non-fuel O&M costs associated with similar fossil fuel ST facilities which are required to report O&M costs as part of the FERC Form 1 submission. Burns & McDonnell developed an industry trend by plotting units based on a 5-year average of current service life and O&M spending ($/MWh). Figure 6-27 and Figure 6-28 present the relationship between average non-fuel O&M costs, in blue, as units age and the previous five years of non-fuel O&M costs at RPS2, in orange. Each unit included in the benchmark is represented as a single data point defined by the five-year average non-fuel O&M cost. It should be noted that historical O&M costs were not provided by Calpine, as such, the RPS2's FERC Form 1 information was used for this section of the analysis. For simplicity, the analysis was limited to the southeastern US. Figure 6-27 shows the non-fuel O&M costs on a $/MWh basis and Figure 6-28 shows the non-fuel O&M costs on a $/kW basis.

Figure 6-27: Coal Fired Steam Non-Fuel O&M Cost ($/MWh) by Unit Age

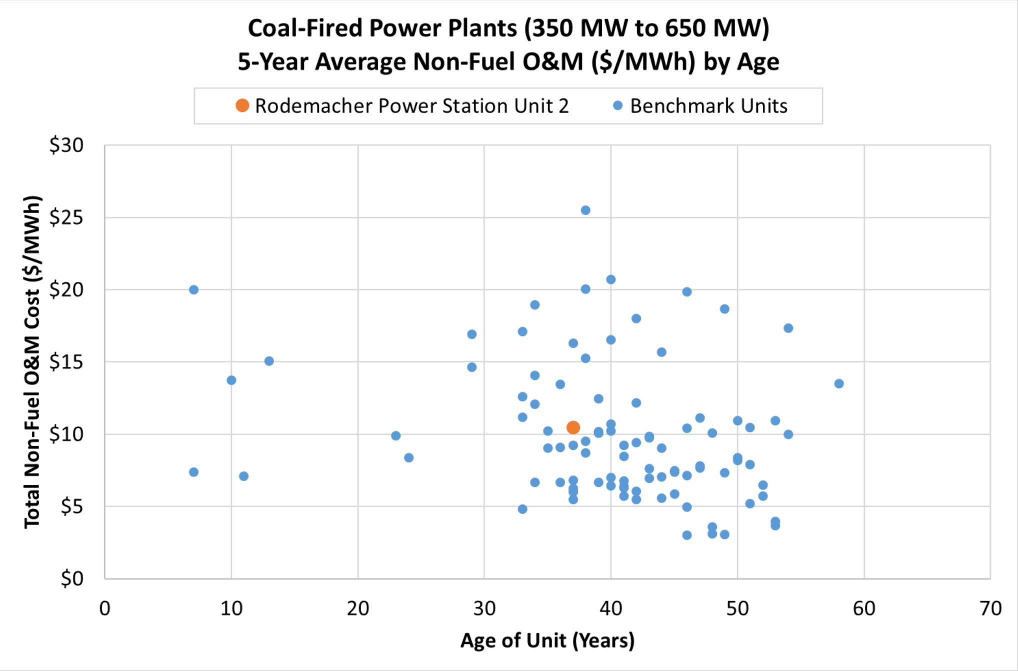
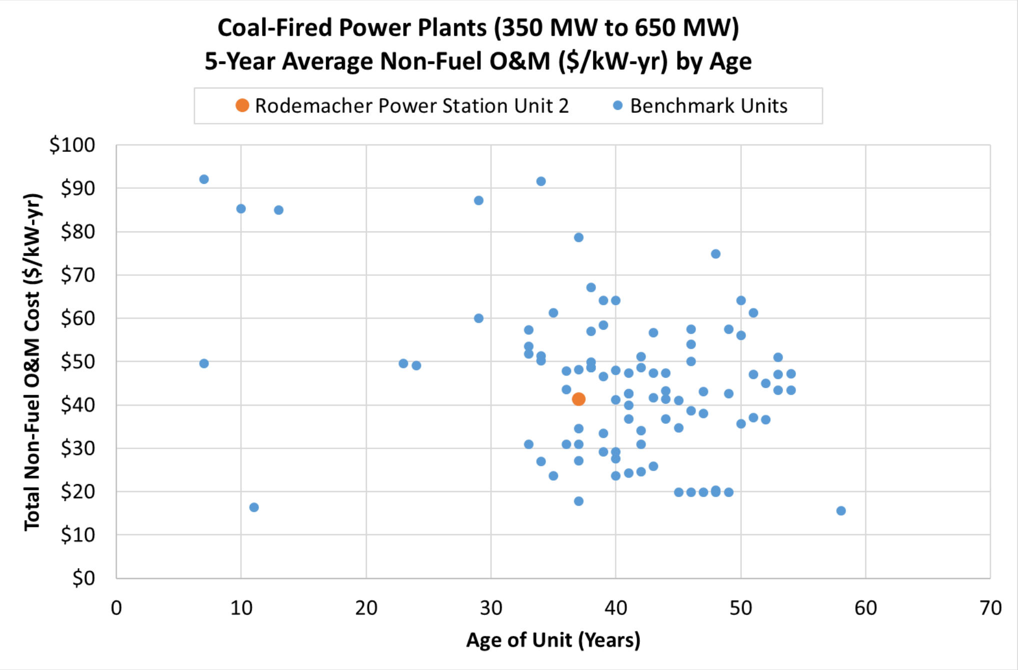


Figure 6-28: Coal-Fired Non-Fuel O&M ($/kW) by Unit Age



From Figure 6-27 and Figure 6-28, it can be seen that RPS2 is spending approximately the same as other units on both a net generation and net capacity basis. From the figures, there is a wide variation in O&M costs for the units approaching end of life. This is most likely attributed to a difference in operating philosophies at site. The differences between the high O&M cost units and the low O&M cost units can likely be attributed to a difference in operating philosophy. Some owners and operators will elect to increase O&M spending near unit retirement as an attempt to lengthen the unit lifecycle. Similarly, some owners and operators will elect to decrease O&M spending near the end of a unit's operation life as an attempt to decrease costs associated with a unit near retirement.

6.3.6 Useful Life Evaluation

Burns & McDonnell approximated the probability of unit survival with the use of Iowa-Type Survivor Curves that are a set of standardized curves used to approximate useful life of varying technologies. Survivor curves are commonly utilized in asset management solutions to estimate the percentage of a population in an asset class that survives over time. Iowa Survivor Curves, specifically, are widely used in the utility industry in depreciation studies for establishing the useful life of generating assets and performing statistical analyses of transmission and distribution equipment.

The curves are fitted to the specific asset types based on the frequency distribution of a dataset. The frequency distribution determines whether a R-type, L-type or S-type curve is used. Figure 6-10 in Section 6.1.6 displays the varying R-type survivor curves and how the survivor curves relate to frequency distributions.

Based on the dataset Burns & McDonnell obtained for total service life, coal units were fitted with R-type survivor curves. Once a frequency distribution is determined, Iowa-Type Survivor Curves require two steps to fit a curve to the dataset. The first step requires assumption of the average service life for coal units. For the second step, Burns & McDonnell fit the dataset as closely as possible with one of the standard Iowa-Type Curves. Burns & McDonnell possesses R0.5, R1, R1.5, R2, R2.5, R3, R4, and R5 Iowa-Type Survivor Curves. R0.5 curves have the least difference between peak and minimum frequency, while R5 curves have the greatest disparity between peak and minimum frequency. Based on the data Burns & McDonnell obtained, R5 Iowa-Type Survivor Curves fit the datasets most effectively for coal units.

Figure 6-29 displays the national survivor data for coal units, in blue, and three Iowa-Type Survivor Curves that fit the modified data. The three survivor curves are used to help Burns & McDonnell to determine a range of expected useful lives for coal units based on a national database.

Figure 6-29: National Coal Unit Survival Curves

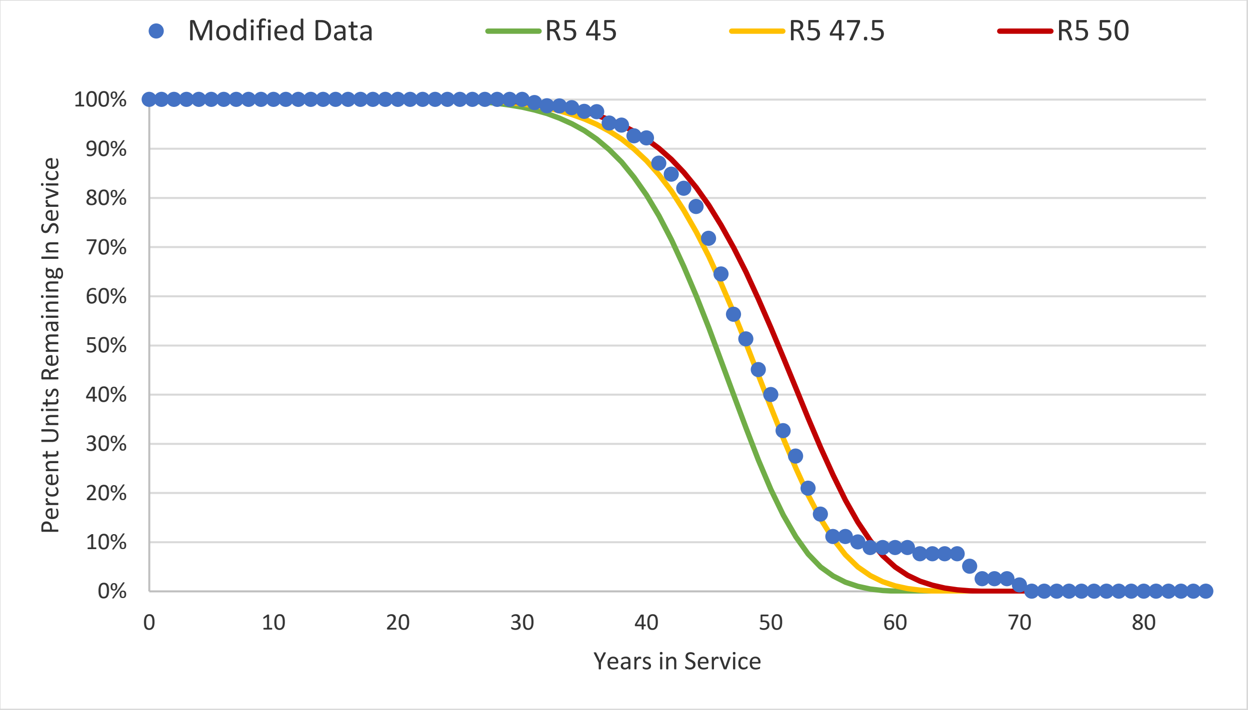


Figure 6-29 indicates coal units begin retiring around 39 years of service. By 48 years, approximately 50 percent of coal units will have been retired. Burns & McDonnell cannot determine from the data obtained the exact reasoning for the retirements but acknowledges many of the retirements may have been a byproduct of changing economic and environmental factors that impact the viability of combined cycle units.

Burns & McDonnell attempted to gain more insights by only evaluating units within the southeastern US. Units within the southeast should be exposed to the same economic and political constraints giving more insights than the national database. Figure 6-30 displays the survivor data for coal units for the southeast, in blue, and three Iowa-Type Survivor Curves that fit the modified data.

Figure 6-30: Regional Coal Unit Survival Curves

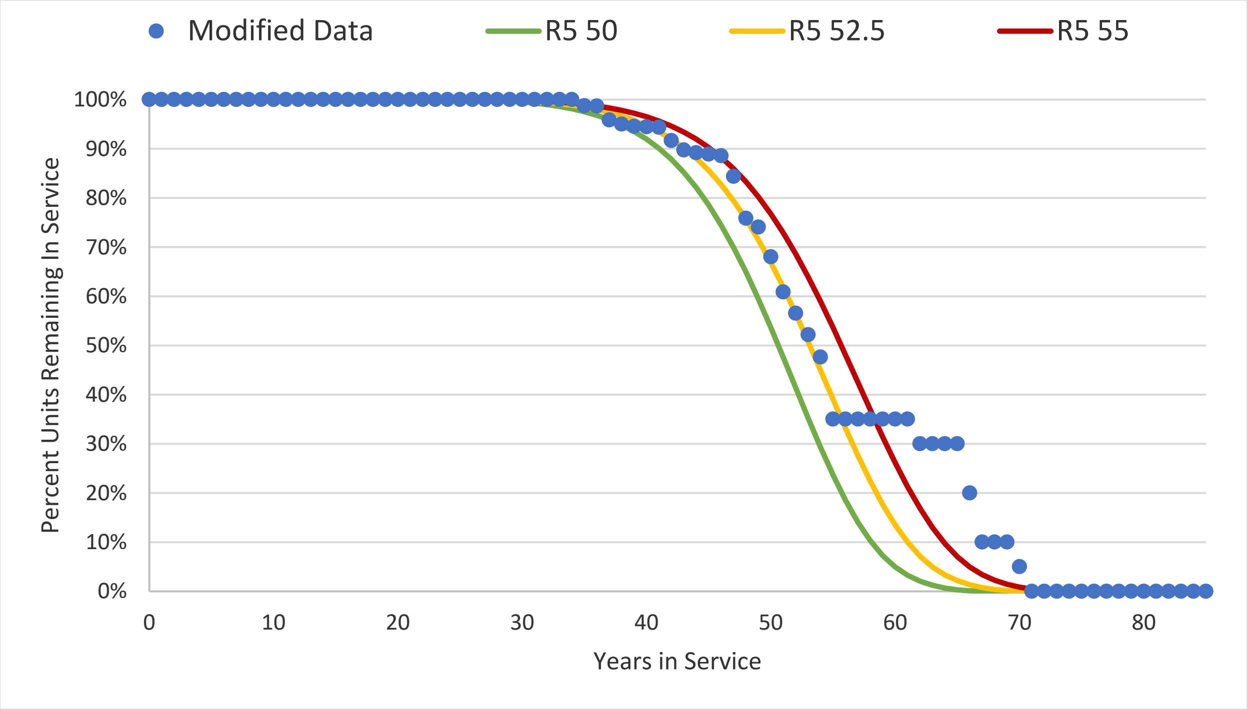


Figure 6-30 indicates coal units begin retiring around 43 years of service. By 53 years, approximately 50 percent of coal cycle units will have been retired. Burns & McDonnell determined the trends experienced regionally display a longer lifetime than the national trends. Burns & McDonnell believes that the regional model is a more likely representation for the unit lifecycle due to the units in the model having similar factors, such as economic and political pressures, as the unit in question.

7.0 COST PROJECTIONS

7.1 T.J. Labbé and Hargis-Hébert

The units are currently scheduled to operate through 2039, which would reflect 35 years of service. Typical simple cycle designs target a minimum 30-year service life, yet the service life of the units can be longer if equipment is properly maintained. As such, it is expected that additional expenditures will be required for reliable operation through the study period. Burns & McDonnell developed a forecast of specific project cost expenditures that would likely be required (see Appendix A). The forecast was developed based on findings from the site visit, plant documentation, and interviews with plant personnel. The forecast was not developed to capture all the maintenance and capital expenditures required for operating the units, but rather is reflective of major equipment projects that will be likely to maintain unit reliability.

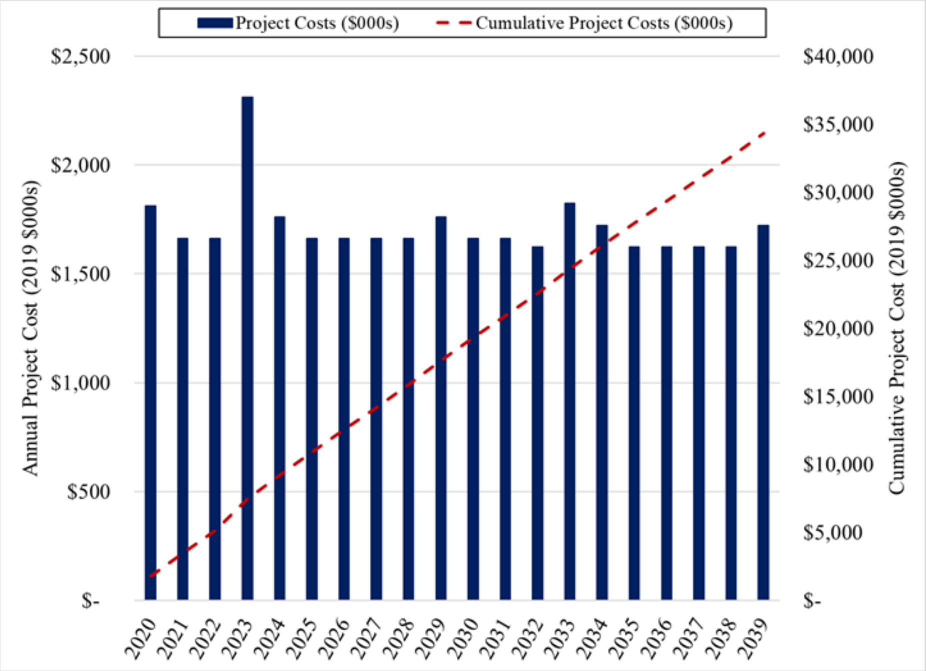
Burns & McDonnell used historical cost information at Labbe and Hargis to determine the baseline O&M costs at the facilities. The financial statements provided to Burns & McDonnell by LUS included a breakdown of fixed and variable costs at the facility over the last five years. Burns & McDonnell was able to determine baseline O&M costs (such as fixed costs and regularly scheduled maintenance) Labor costs were not broken out according to plant, so it was presumed that each facility incurred half the total fixed O&M costs such as personnel salaries and annual leave.

Burns & McDonnell anticipates recurring inspections and maintenance events. Inspection and maintenance items that will need to be performed include semiannual borescope inspections, hot section exchanges (“HSE”), combustor replacements, major overhauls, VSV bushing changes, control system replacements, chiller coil panel replacements. Appendix A, provides a detailed schedule of the forecasted estimated cost and expenditures and maintenance costs required for reliable operation through 2039.

7.1.1 T.J. Labbé

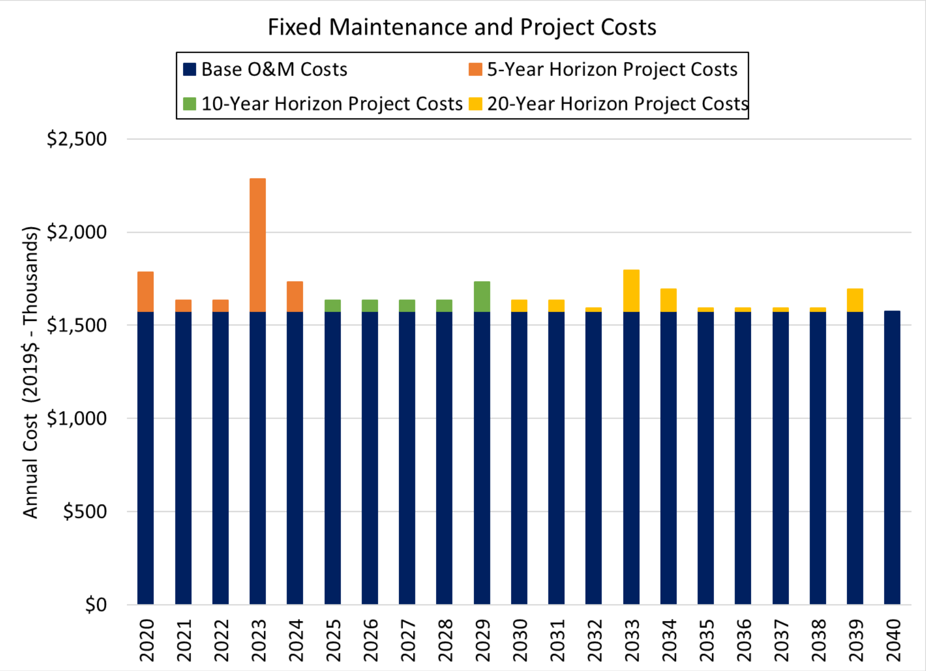
Figure 7-1 presents a summary of the cost projection estimates derived by Burns & McDonnell for Labbe in today’s dollars (2019$), with no inflation included and assuming the units are in service through 2039. For the units with a net capacity of 100 MW, a cost of approximately $35 million will be required to cover project maintenance expenditures through the Study period This is approximately $17.5/kW-yr on average.

Figure 7-1: T.J. Labbé Project Cost Forecast



From Figure 7-1, it can be seen the Labbe is projected to experience consistent O&M costs. This is exemplified through the steady project costs near $1.7 million leading to a near constant slope in the cumulative project cost line. This is largely because, overall, the total capital and maintenance costs will be significantly reliable for operation through 2039. Figure 7-2 presents the total annual projected costs associated with fixed baseline maintenance, specific project maintenance, and operations expenses. The costs are presented in 2019$ and do not include inflation.

Figure 7-2: T.J. Labbé Total Annual O&M Cost Summary

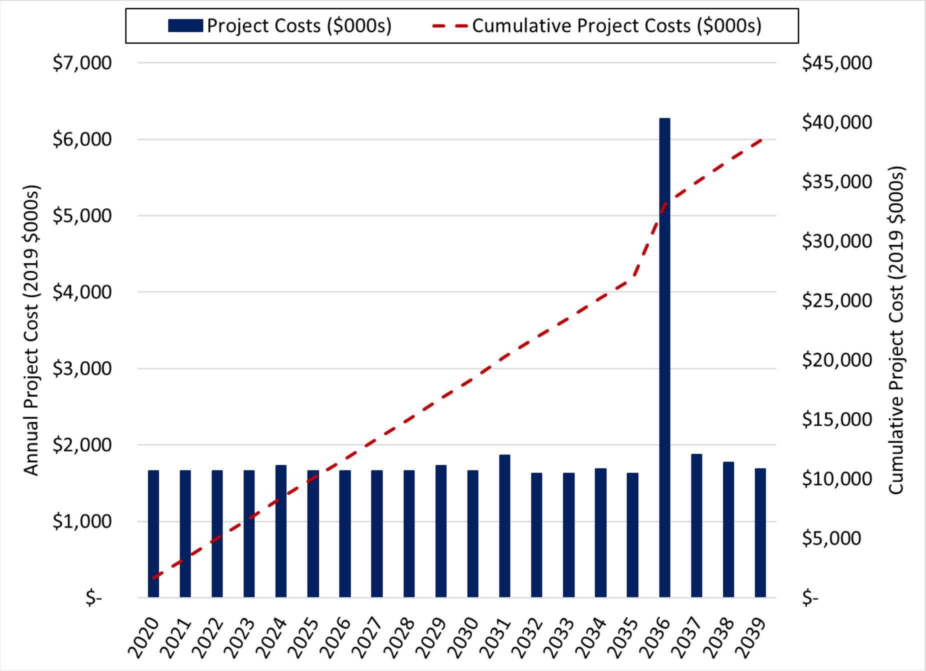


As seen in Figure 7-2, the consistent anticipated operating costs is driven by the few starts and fired hours resulting in few major maintenance projects. The unit is not projected to reach enough starts or operating hours to require major maintenance milestones in the next 20 years.

7.1.2 Hargis-Hébert

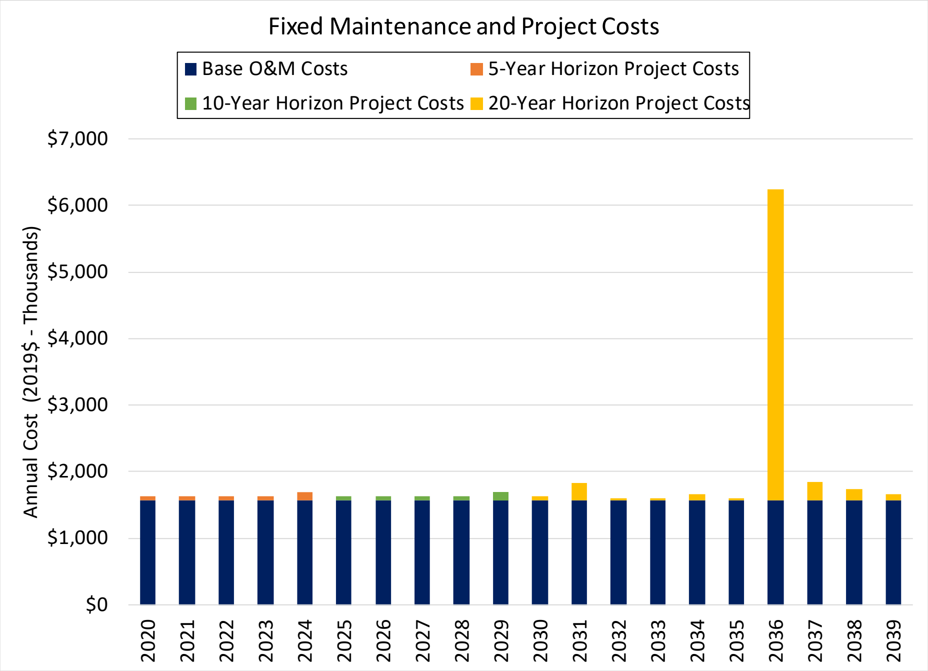
Figure 7-3 presents a summary of the cost projection estimates derived by Burns & McDonnell for Hargis in real/constant dollars (2019$), with no inflation included and assuming the units are in service through 2039. For the units with a net capacity of 100 MW, a cost of approximately $38.5 million will be required to cover project maintenance expenditures through the study period. This is approximately $19.25/kW-yr on average.

Figure 7-3: Hargis-Hébert Project Cost Forecast



From Figure 7-3, it can be seen the Hargis is projected to experience consistent O&M costs until it reaches it major inspection and overhaul in 2036. This is exemplified through the steady project costs near $1.7 million leading to a near constant slope in the cumulative project cost line. This is largely because, overall, the total capital and maintenance costs will be significantly reliable for operation through 2039. Figure 7-4 presents the total annual projected costs associated with fixed baseline maintenance, specific project maintenance, and operations expenses. The costs are presented in 2019$ and do not include inflation.

Figure 7-4: Hargis-Hébert Total Annual O&M Cost Summary



As seen in Figure 7-4, the consistent anticipated operating cost is driven by the relatively low maintenance project and capital expenditure costs as compared to the fixed labor costs. The reason why the project costs are consistently low is due to the few projected hours and starts associated with the units at Hargis. Unit 1 is projected to reach enough operating hours to require a major overhaul toward the end of the study period, but likely will not require any other major maintenance milestones in the next 20 years.

7.2 Rodemacher Power Station Unit 2

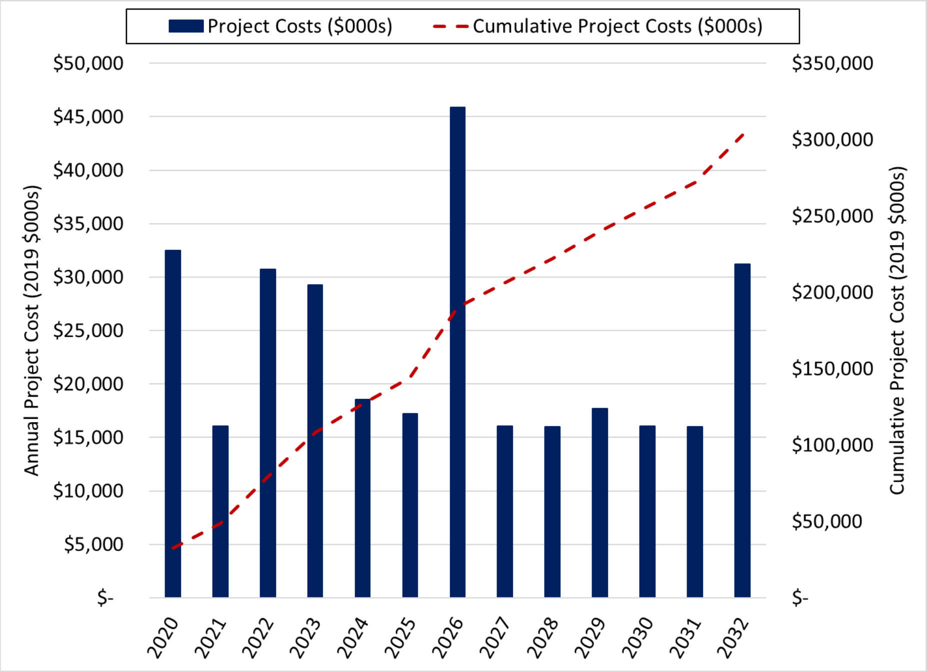
LUS' RPS2 is currently scheduled to operate through 2032 when the current operating agreement expires, which would reflect 47 years of service. Typical coal design assumes a 40 to 50-year service life, yet the service life of a unit can be longer if equipment it is adequately maintained. As such, it is expected that additional expenditures will be required for reliable operation through 2032. Burns & McDonnell developed a forecast of specific project cost expenditures that would likely be required to maintain reliable operation (see Appendix A). The forecast was developed based on findings from plant documentation, and interviews with plant personnel. The forecast was not developed to capture all the maintenance and capital expenditures required for operating RPS2, but rather is reflective of major equipment projects that will be likely to maintain unit reliability.

Burns & McDonnell attempted to use historical cost information at RPS2 to determine the baseline O&M cost at the facility; however, no RPS2 financial statements were provided to Burns & McDonnell. In order to model the O&M costs, Burns & McDonnell pulled the 5-year historical O&M costs that RPS2 reported in the FERC Form 1 submission.

Burns & McDonnell anticipates recurring inspections and maintenance events. Items that will likely need to be inspected include, the air heaters, boiler, circulating water system, coal handling equipment, condensate pumps and condenser, controls system, electrical transformers, feedwater heaters, flue gas conditioning equipment, and the ST. Appendix A, provides a detailed schedule of the forecasted estimated capital cost expenditures and maintenance costs required for reliable operation through three different retirement horizons, 2022, 2027, and 2032.

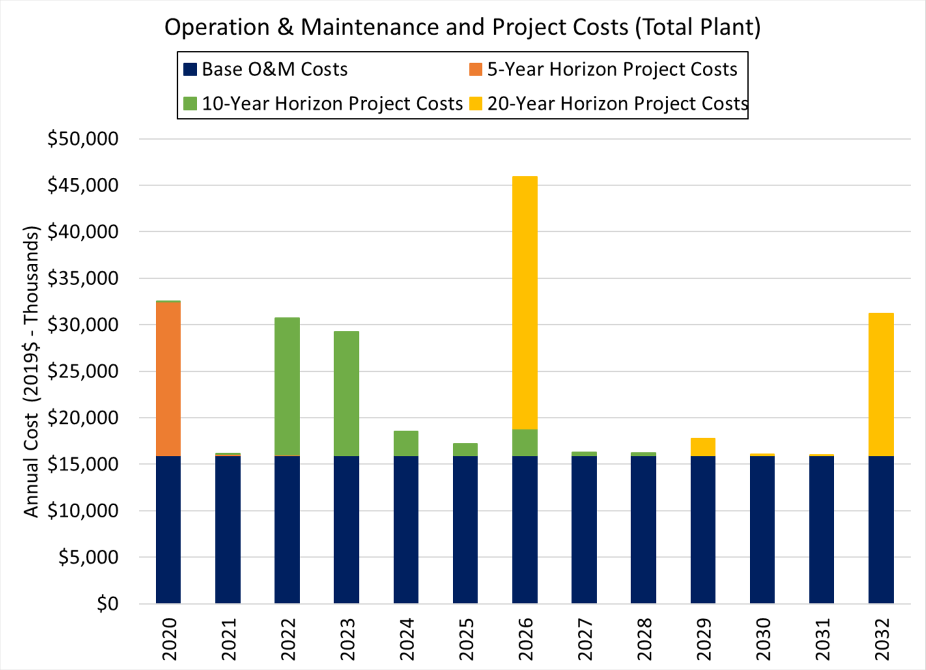
Figure 7-5 presents a summary of the cost projection estimates derived by Burns & McDonnell for RPS2 in today’s dollars (2019$), with no inflation included. Assuming RPS2 will be in service through 2032, major equipment maintenance will be required. For the unit, at a net capacity of 500 MW, a cost of approximately $285 million will be required to cover project maintenance expenditures through 2032. This is approximately $44/kW-yr on average.

Figure 7-5: RPS2 Project Cost Forecast



Overall, the total capital and maintenance costs will be significant for reliable operation through 2032. Figure 7-6 presents the total annual projected costs associated with O&M expenses and capital expenditures. The costs are presented in 2019$ and do not include inflation. Additionally, the costs associated with ash pond closures and Effluent Limitation Guidelines ("ELG") compliance have not been included in this report. The Environmental Assessment included several potential scenarios for costs associated with complying with these recently revised regulations.

Figure 7-6: RPS2 Total Annual O&M Cost Summary



From Figure 7-6, the major maintenance intervals can be identified. At the beginning, investments are made into RPS2 to maintain unit reliability through the target end of life. As the unit approaches end of life, O&M spending is decreased.

7.2.1 RPS2 Gas Conversion

LUS and the other co-owners of RPS2 are considering a switch from coal-fired operation to natural gas-fired operation. Cleco, the operator of RPS2, has conducted many studies regarding RPS2's ability to switch to natural gas-fired operation and the associated costs. Within the cost estimates presented herein, Burns & McDonnell developed an additional cost estimate forecast for the conversion of RPS2 to natural gas-fired operation. Eliminating the coal-fired operation will reduce the overall O&M and project costs, however significant capital cost improvements will be required to implement natural gas firing capabilities. The cost projection presented herein, along with other supplemental information provided by Cleco, will be utilized within the economic evaluations to assess RPS2's economic viability utilizing natural gas for power production.

8.0 CONCLUSIONS & RECOMMENDATIONS

The following conclusions and recommendations are based on the observations and analysis from this Study.

1. Labbe and Hargis entered commercial operation in 2005 and 2006, respectively. At the end of the Study period, the units will be 35 years old. Half of similarly sized units in the region are anticipated to reach an age 44 years before retirement. Considering that the units receive fewer starts and, therefore, fewer thermal stresses than similar units in the region, along with the proactive maintenance operating philosophy on site, it is anticipated that Labbe and Hargis will have substantial service life past the end of the Study period.
2. RPS2 entered commercial operation in 1982. The current operating agreement between LUS and CLECO is set to expire in 2032. At the end of the operating agreement, RPS2 will be 47 years old. Half of similarly sized units in the region are anticipated to reach an age 53 years before retirement. It is anticipated that RPS2 will be capable of operating to the end of the operating agreement.
3. Over the past few years, the units at Labbe and Hargis have operated with an EAF higher (better) than the fleet average and an EFOR generally lower (better) than the fleet average. The operational excellence at Labbe and Hargis should be maintained with continued preventative maintenance and regular inspections of the equipment at the plants.
4. Over the past few years, RPS2 has operated about equal to the industry average for EAF and lower (better) than the industry average for EFOR. The current operations should be maintained with continued preventative maintenance and regular inspections of the equipment at the plants.
5. Although Labbe and Hargis have experienced an increase in NCF over the past five years, they are still below national and regional averages. Based on discussions with operations staff, it may be beneficial to reevaluate dispatch parameters to ensure the operating costs are properly accounted for and not overly conservative. Increasing operation at base load conditions should also improve the average NHRs for Labbe and Hargis. It should be noted however, that with increased operating hours, the major overhaul intervals projected in this study would be accelerated (major overhauls would need to be performed sooner).
6. LUS and CLECO should develop an end-of-design life plan in order to adequately allocate capital to RPS2 and other power generating assets within the LUS fleet. If LUS determines RPS2 is an essential asset until 2032, then larger capital investments will be warranted to maintain reliable operation. If RPS2 is not an essential asset, LUS and CLECO should consider operating the unit with minimal capital investment until decommissioning.

APPENDIX A – LUS COST ESTIMATES

Lafayette Utilities System
Burns & McDonnell Project No. 118157
Condition Assessment

Cost Forecasts
All costs are presented in 2019$, no inflation is included

PROJECT EXPENDITURES (Presented in $000)

						20 YEARS																			
DESCRIPTION	**SYSTEM**	**Last Performed**	**Typical Interval (years)**	**Next Year Expected**	**TOTAL**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
T.J. Labbe Unit 1																									
20 Year Forecast																									
Replace Chiller Coil Panel	BOP	2020	1 yr	2020	$ 240	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20								
Allowances for BOP Replacements	BOP	2019	5 yr	2024	$ 200					$ 50					$ 50					$ 50					$ 50
Replace Controls System	Controls	2016	15 yr	2031	$ 100														$ 100						
Borescope Inspection	Gas Turbine	2019	Semiannual	2020	$ 200	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Hot Section Exchange Inspection	Gas Turbine	17520 hr	1/15000 hr	32520 hr	$ -																				
Combustor Replacment	Gas Turbine	16780 hr	1/15000 hr	31780 hr	$ -																				
Major Overhaul and Inspection	Gas Turbine	Never	1/30000 hr	30000 hr	$ -																				
Variable Stator Vane Bushing Change	Gas Turbine	Never	1/10000 hr	2020	$ -																				
HPC Stage 3-5 Blande Change	Gas Turbine	793 start	1/1000 start	1800 start	$ -																				
HPC Stage 1 Blade Change	Gas Turbine	18864 hr	1/15000 hr	33860 hr	$ -																				
20 Year TOTAL																									
20 YEAR TOTAL Hargis Hebert Unit 1					**$ 670**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 80**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 80**	**$ 30**	**$ 30**	**$ 10**	**$ 110**	**$ 60**	**$ 10**	**$ 10**	**$ 10**	**$ 10**	**$ 60**
T.J. Labbe Unit 2																									
20 Year Forecast																									
Replace Chiller Coil Panel	BOP	2020	1 yr	2020	$ 240	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20								
Allowances for BOP Replacements	BOP	2019	5 yr	2024	$ 200					$ 50					$ 50					$ 50					$ 50
Replace Controls System	Controls	2016	15 yr	2031	$ 100														$ 100						
Borescope Inspection	Gas Turbine	2019	Semiannual	2020	$ 200	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Hot Section Exchange Inspection	Gas Turbine	12475 hr	1/15000 hr	27475 hr	$ -																				
Combustor Replacment	Gas Turbine	0 hr	1/15000 hr	15000 hr	$ 650				$ 650																
Major Overhaul and Inspection	Gas Turbine	Never	1/30000 hr	30000 hr	$ -																				
Variable Stator Vane Bushing Change	Gas Turbine	13349 hr	1/10000 hr	23350 hr	$ 150	$ 150																			
HPC Stage 3-5 Blande Change	Gas Turbine	864 start	1/1000 start	1800 start	$ -																				
HPC Stage 1 Blade Change	Gas Turbine	12658 hr	1/15000 hr	27658 hr	$ -																				
20 Year TOTAL																									
20 YEAR TOTAL Hargis Hebert Unit 2					**$ 1,470**	**$ 180**	**$ 30**	**$ 30**	**$ 680**	**$ 80**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 80**	**$ 30**	**$ 30**	**$ 10**	**$ 110**	**$ 60**	**$ 10**	**$ 10**	**$ 10**	**$ 10**	**$ 60**
T.J. Labbe TOTAL					**$ 2,140**	**$ 210**	**$ 60**	**$ 60**	**$ 710**	**$ 160**	**$ 60**	**$ 60**	**$ 60**	**$ 60**	**$ 160**	**$ 60**	**$ 60**	**$ 20**	**$ 220**	**$ 120**	**$ 20**	**$ 20**	**$ 20**	**$ 20**	**$ 120**
Hargis-Hebert Unit 1																									
20 Year Forecast																									
Replace Chiller Coil Panel	BOP	2020	1 yr	2020	$ 240	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20								
Allowances for BOP Replacements	BOP	2019	5 yr	2024	$ 200					$ 50					$ 50					$ 50					$ 50
Replace Controls System	Controls	2016	15	2031	$ 100												$ 100								
Borescope Inspection	Gas Turbine	2019	Semiannual	2020	$ 200	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Hot Section Exchange Inspection	Gas Turbine	14917 hr	1/15000 hr	29917 hr	$ -																				
Combustor Replacment	Gas Turbine	16948 hr	1/15000 hr	31948 hr	$ -																				
Major Overhaul and Inspection	Gas Turbine	Never	1/30000 hr	30000 hr	$ 4,500																	$ 4,500			
Variable Stator Vane Bushing Change	Gas Turbine	15892 hr	1/10000 hr	25900 hr	$ 150																			$ 150	
HPC Stage 3-5 Blande Change	Gas Turbine	980 start	1/1000 start	1980 start	$ 250																		$ 250		
HPC Stage 1 Blade Change	Gas Turbine	15396 hr	1/15000 hr	30400 hr	$ -																				
20 Year TOTAL																									
20 YEAR TOTAL Hargis-Hebert Unit 1					**$ 5,420**	$ 30	$ 30	$ 30	$ 30	$ 80	$ 30	$ 30	$ 30	$ 30	$ 80	$ 30	$ 130	$ 10	$ 10	$ 60	$ 10	$ 4,510	$ 260	$ 160	$ 60
Hargis-Hebert Unit 2																									
20 Year Forecast																									
Replace Chiller Coil Panel	BOP	2020	1 yr	2020	$ 240	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20								
Allowances for BOP Replacements	BOP	2019	5 yr	2024	$ 60					$ 15					$ 15					$ 15					$ 15
Replace Controls System	Controls	2016	15	2031	$ 100												$ 100								
Borescope Inspection	Gas Turbine	2018	Semiannual	2020	$ 200	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Hot Section Exchange Inspection	Gas Turbine	14680 hr	1/15000 hr	29680 hr	$ -																				
Combustor Replacment	Gas Turbine	14680 hr	1/15000 hr	29680 hr	$ -																				
Major Overhaul and Inspection	Gas Turbine	Never	1/30000 hr	30000 hr	$ -																				
Variable Stator Vane Bushing Change	Gas Turbine	12756 hr	1/10000 hr	22760 hr	$ 150																	$ 150			
HPC Stage 3-5 Blande Change	Gas Turbine	1029 start	1/1000 start	2030 start	$ -																				
HPC Stage 1 Blade Change	Gas Turbine	15967 hr	1/15000 hr	30970 hr	$ -																				
20 Year TOTAL																									
20 YEAR TOTAL Hargis-Hebert Unit 2					**$ 715**	$ 30	$ 30	$ 30	$ 30	$ 45	$ 30	$ 30	$ 30	$ 30	$ 45	$ 30	$ 130	$ 10	$ 10	$ 25	$ 10	$ 160	$ 10	$ 10	$ 25
T.J. Labbe TOTAL					**$ 2,140**	**$ 210**	**$ 60**	**$ 60**	**$ 710**	**$ 160**	**$ 60**	**$ 60**	**$ 60**	**$ 60**	**$ 160**	**$ 60**	**$ 60**	**$ 20**	**$ 220**	**$ 120**	**$ 20**	**$ 20**	**$ 20**	**$ 20**	**$ 120**
Hargis-Hebert TOTAL					**$ 6,135**	**$ 60**	**$ 60**	**$ 60**	**$ 60**	**$ 125**	**$ 60**	**$ 60**	**$ 60**	**$ 60**	**$ 125**	**$ 60**	**$ 260**	**$ 20**	**$ 20**	**$ 85**	**$ 20**	**$ 4,670**	**$ 270**	**$ 170**	**$ 85**
LUS TOTAL					**$ 8,275**	**$ 270**	**$ 120**	**$ 120**	**$ 770**	**$ 285**	**$ 120**	**$ 120**	**$ 120**	**$ 120**	**$ 285**	**$ 120**	**$ 320**	**$ 40**	**$ 240**	**$ 205**	**$ 40**	**$ 4,690**	**$ 290**	**$ 190**	**$ 205**
Base O&M Costs																									
T.J. Labbe TOTAL					**$ 31,483**	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574
Hargis-Hebert TOTAL					**$ 31,483**	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 1,574

Lafayette Utilities System
Rodemacher Power Station Unit 2
Burns & McDonnell Project No. 118157
Condition Assessment

Cost Forecasts
All costs are presented in 2019$, no inflation is included

PROJECT EXPENDITURES (Presented in $000)

							5 YEARS					10 YEARS					20 YEARS									
DESCRIPTION	**SYSTEM**	**Last Year Performed**	**Typical Interval (years)**	**Next Year Expected**	**Estimated Cost ($000)**	**TOTAL**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
5 Year Forecast																										
Perform NDE inspection of the high temp. headers	Boiler	2017	3	2020	$50	$100	$50			$50																
Perform steam drum visual, MT, and UT inspections	Boiler	2017	3	2019	$75	$75		$75																		
Replace SH Attemperator Liner	Boiler	Never	15	2023	$250	$0																				
Inspect and Repair Circulating Water Piping	Circulating Water	Never	Once	2020	$2,500	$2,500	$2,500																			
Rebuild Circ Water Pumps	Circulating Water	2014	6	2020	$100	$100	$100																			
Major Generator Inspection	Electrical	2014	6	2020	$2,000	$2,000	$2,000																			
Med Voltage Switchgear Circuit Breaker Replacement	Electrical	2019	30	2020	$1,250	$1,250	$1,250																			
Inspect and Repair duct work and expansion joints	Flue Gas	Unknown	6	2020	$400	$400	$400																			
Inspect HEP Hangers	HEP	2019	1	2020	$20	$80	$20	$20	$20	$20																
Replace HP/IP Row 1 Buckets	Steam Turbine	2014	6	2020	$1,000	$1,000	$1,000																			
Replace L-0 Buckets	Steam Turbine	2014	6	2020	$3,000	$3,000	$3,000																			
Steam Turbine Major Inspection	Steam Turbine	2014	6	2020	$4,000	$4,000	$4,000																			
TDBFP inspection	Steam Turbine	2014	6	2020	$1,000	$1,000	$1,000																			
Turbine Valve Inspection	Steam Turbine	2017	3	2020	$1,200	$1,200	$1,200																			
5 Year TOTAL																										
5 YEAR TOTAL						**$16,705**	$16,520	$95	$20	$70	$0															
10 Year Forecast																										
Replace air heater cold end baskets	Air preheater	2015	10	2025	$500	$500						$500														
Replace air heater components other than baskets (seals, bearings, bearing supports, etc.)	Air preheater	2015	30	2045	N/A	$0																				
Replace air heater hot end baskets	Air preheater	2015	20	2035	$1,500	$0																				
Boiler Chem Clean	Boiler	2016	As Needed	2026	$800	$0																				
Perform NDE inspection of the high temp. headers	Boiler	2017	3	2020	$50	$150	$50			$50			$50													
Perform steam drum visual, MT, and UT inspections	Boiler	2017	3	2019	$75	$225		$75			$75			$75												
Replace Economizer Tubes	Boiler	Never	Once	2026	$8,000	$300							$100	$100	$100											
Replace SH Attemperator Liner	Boiler	Never	15	2023	$250	$250				$250																
Inspect and Repair Circulating Water Piping	Circulating Water	Never	Once	2020	$2,500	$2,500	$2,500																			
Rebuild Circ Water Pumps	Circulating Water	2014	6	2020	$100	$200	$100						$100													
Coal Feeder Controls Upgrade	Coal Handling	Never	Once	2020	$10	$50	$10	$10	$10	$10	$10															
Repair/Replace Coal Conveyor Belts	Coal Handling	2014	7	2021	$750	$3,000			$750	$750		$750	$750													
Replace Condensate Recirculation Valves	Condensate	Never	Once	2026	$100	$100							$100													
Controls Upgrade	Controls	2014	10	2024	$1,500	$1,500					$1,500															
Major Generator Inspection	Electrical	2014	6	2020	$2,000	$2,000	$2,000						$0													
Med Voltage Switchgear Circuit Breaker Replacement	Electrical	2019	30	2020	$1,250	$1,250	$1,250																			
Minor Generator Inspection	Electrical	2017	3	2023	$500	$500				$500																
Replace steam trubine generator exciter	Electrical	Never	Once	2026	$2,500	$450							$150	$150	$150											
Replace Switchgear	Electrical	Never	Once	2023	$1,000	$1,000				$1,000																
Station Service Transformer Replacement	Electrical	Never	Once	TBD	$2,500	$0																				
Replace Feedwater Heaters 1a & 1b	Feedwater	Never	Once	2026	$5,000	$0							$0													
Replace Feedwater Heaters 2a & 2b	Feedwater	Never	Once	2021	$5,000	$5,000			$5,000																	
Inspect and Repair duct work and expansion joints	Flue Gas	Unknown	6	2020	$400	$800	$400						$400													
Inspect HEP Hangers	HEP	2019	1	2020	$20	$160	$20	$20	$20	$20	$20	$20	$20	$20												
Replace ESP Controls	Precipitator	Never	Once	2024	$1,000	$1,000					$1,000															
Replace HP/IP Row 1 Buckets	Steam Turbine	2014	6	2020	$1,000	$1,000	$1,000						$0													
Replace L-0 Buckets	Steam Turbine	2014	6	2020	$3,000	$3,000	$3,000						$0													
Steam Turbine Major Inspection	Steam Turbine	2014	6	2020	$4,000	$4,000	$4,000						$0													
TDBFP inspection	Steam Turbine	2014	6	2020	$1,000	$1,000	$1,000						$0													
Turbine Chem Cleaning	Steam Turbine	2016	As Needed	2023	$500	$500				$500																
Turbine Valve Inspection	Steam Turbine	2017	3	2020	$1,200	$3,600	$1,200			$1,200			$1,200													
10 Year TOTAL																										
10 YEAR TOTAL						**$34,035**	$16,530	$105	$5,780	$4,280	$2,605	$1,270	$2,870	$345	$250	$0										
20 Year Forecast																										
Replace air heater cold end baskets	Air preheater	2015	10	2025	$500	$1,000						$500										$500				
Replace air heater components other than baskets (seals, bearings, bearing supports, etc.)	Air preheater	2015	30	2045	N/A	$0																				
Replace air heater hot end baskets	Air preheater	2015	20	2035	$1,500	$1,500																$1,500				
Boiler Chem Clean	Boiler	2016	As Needed	2026	$800	$1,600							$800								$800					
Perform NDE inspection of the high temp. headers	Boiler	2017	3	2020	$50	$350	$50			$50			$50			$50			$50			$50			$50	
Perform steam drum visual, MT, and UT inspections	Boiler	2017	3	2019	$75	$450		$75			$75			$75			$75			$75			$75			
Replace Economizer Tubes	Boiler	Never	Once	2026	$8,000	$8,000							$8,000													
Replace SH Attemperator Liner	Boiler	Never	15	2023	$250	$250				$250																
Inspect and Repair Circulating Water Piping	Circulating Water	Never	Once	2020	$2,500	$2,500	$2,500																			
Rebuild Circ Water Pumps	Circulating Water	2014	6	2020	$100	$300	$100						$100						$100							
Coal Feeder Controls Upgrade	Coal Handling	Never	Once	2020	$10	$50	$10	$10	$10	$10	$10															
Repair/Replace Coal Conveyor Belts	Coal Handling	2014	7	2021	$750	$3,000			$750	$750		$750	$750													
Replace Condensate Recirculation Valves	Condensate	Never	Once	2026	$100	$100							$100													
Controls Upgrade	Controls	2014	10	2024	$1,500	$3,000					$1,500										$1,500					
Major Generator Inspection	Electrical	2014	6	2020	$2,000	$6,000	$2,000						$2,000						$2,000							
Med Voltage Switchgear Circuit Breaker Replacement	Electrical	2019	30	2020	$1,250	$1,250	$1,250																			
Minor Generator Inspection	Electrical	2017	3	2023	$500	$1,500				$500						$500						$500				
Replace steam turbine generator exciter	Electrical	Never	Once	2026	$2,500	$2,500							$2,500													
Replace Switchgear	Electrical	Never	Once	2023	$1,000	$1,000				$1,000																
Station Service Transformer Replacement	Electrical	Never	Once	TBD	$2,500	$2,500													$2,500							
Replace Feedwater Heaters 1a & 1b	Feedwater	Never	Once	2026	$5,000	$5,000							$5,000													
Replace Feedwater Heaters 2a & 2b	Feedwater	Never	Once	2021	$5,000	$5,000			$5,000																	
Inspect and Repair duct work and expansion joints	Flue Gas	Unknown	6	2020	$400	$1,200	$400						$400						$400							
Inspect HEP Hangers	HEP	2019	1	2020	$20	$380	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	
Replace ESP Controls	Precipitator	Never	Once	2024	$1,000	$1,000					$1,000															
Replace HP/IP Row 1 Buckets	Steam Turbine	2014	6	2020	$1,000	$3,000	$1,000						$1,000						$1,000							
Replace L-0 Buckets	Steam Turbine	2014	6	2020	$3,000	$9,000	$3,000						$3,000						$3,000							
Steam Turbine Major Inspection	Steam Turbine	2014	6	2020	$4,000	$12,000	$4,000						$4,000						$4,000							
TDBFP inspection	Steam Turbine	2014	6	2020	$1,000	$3,000	$1,000						$1,000						$1,000							
Turbine Chem Cleaning	Steam Turbine	2016	As Needed	2023	$500	$500				$500																
Turbine Valve Inspection	Steam Turbine	2017	3	2020	$1,200	$7,200	$1,200			$1,200			$1,200			$1,200			$1,200			$1,200				
20 Year TOTAL																										
20 YEAR TOTAL						**$84,060**	$16,530	$105	$5,780	$4,280	$2,605	$1,270	$29,920	$95	$20	$1,770	$95	$20	$15,270	$95	$2,320	$3,770	$95	$20	$70	$0
Base O&M Costs																										
RPS2-Coal						**$ 319,128**	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 15,956

Lafayette Utilities System
Rodemacher Power Station Unit 2
Burns & McDonnell Project No. 118157
Condition Assessment

Cost Forecasts
All costs are presented in 2019$, no inflation is included

PROJECT EXPENDITURES (Presented in $000)

							20 YEARS																			
DESCRIPTION	**SYSTEM**	**Last Year Performed**	**Typical Interval (years)**	**Next Year Expected**	**Estimated Cost ($000)**	**TOTAL**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
20 Year Forecast																										
Replace air heater cold end baskets	Air preheater	2015	20	2035	$500	$500						$500														
Replace air heater components other than baskets (seals, bearings, bearing supports, etc.)	Air preheater	2015	30	2045	N/A	$0																				
Replace air heater hot end baskets	Air preheater	2015	20	2035	$1,500	$1,500																$1,500				
Boiler Chem Clean	Boiler	2016	As Needed	2026	$800	$1,600							$800								$800					
Perform NDE inspection of the high temp. headers	Boiler	2017	3	2020	$50	$350	$50			$50			$50			$50			$50			$50			$50	
Perform steam drum visual, MT, and UT inspections	Boiler	2017	3	2019	$75	$450		$75			$75			$75			$75			$75			$75			
Replace Economizer Tubes	Boiler	Never	Once	2026	$8,000	$8,000				$8,000																
Replace SH Attemperator Liner	Boiler	Never	15	2023	$250	$250				$250																
Inspect and Repair Circulating Water Piping	Circulating Water	Never	Once	2020	$2,500	$2,500	$2,500																			
Rebuild Circ Water Pumps	Circulating Water	2014	6	2020	$100	$300	$100						$100						$100							
Replace Condensate Recirculation Valves	Condensate	Never	Once	2026	$100	$100							$100													
Controls Upgrade	Controls	2014	10	2024	$1,500	$1,500															$1,500					
Major Generator Inspection	Electrical	2014	6	2020	$2,000	$6,000	$2,000						$2,000						$2,000							
Med Voltage Switchgear Circuit Breaker Replacement	Electrical	2019	30	2020	$1,250	$1,250	$1,250																			
Minor Generator Inspection	Electrical	2017	3	2023	$500	$1,500				$500						$500						$500				
Replace steam trubine generator exciter	Electrical	Never	Once	2026	$2,500	$2,500							$2,500													
Replace Switchgear	Electrical	Never	Once	2023	$1,000	$1,000				$1,000																
Station Service Transformer Replacement	Electrical	Never	Once	TBD	$2,500	$2,500													$2,500							
Replace Feedwater Heaters 1a & 1b	Feedwater	Never	Once	2026	$5,000	$5,000							$5,000													
Replace Feedwater Heaters 2a & 2b	Feedwater	Never	Once	2021	$5,000	$5,000			$5,000																	
Inspect and Repair duct work and expansion joints	Flue Gas	Unknown	6	2020	$400	$800	$400						$200						$200							
Inspect HEP Hangers	HEP	2019	1	2020	$20	$380	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	
Replace HP/IP Row 1 Buckets	Steam Turbine	2014	6	2020	$1,000	$3,000	$1,000						$1,000						$1,000							
Replace L-0 Buckets	Steam Turbine	2014	6	2020	$3,000	$9,000	$3,000						$3,000						$3,000							
Steam Turbine Major Inspection	Steam Turbine	2014	6	2020	$4,000	$12,000	$4,000						$4,000						$4,000							
TDBFP inspection	Steam Turbine	2014	6	2020	$1,000	$3,000	$1,000						$1,000						$1,000							
Turbine Chem Cleaning	Steam Turbine	2016	As Needed	2023	$500	$500				$500																
Turbine Valve Inspection	Steam Turbine	2017	3	2020	$1,200	$7,200	$1,200			$1,200			$1,200			$1,200			$1,200			$1,200				
20 Year TOTAL																										
20 YEAR TOTAL						**$77,610**	$16,520	$95	$5,020	$11,520	$95	$520	$20,970	$95	$20	$1,770	$95	$20	$15,070	$95	$2,320	$3,270	$95	$20	$70	$0
Base O&M Costs																										
RPS2-Gas (from Cleco study: save $7M per year if converted to gas)						**$ 179,128**	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956	$ 8,956

BURNS & McDONNELL

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
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APPENDIX B – ENVIRONMENTAL ASSESSMENT

Environmental Assessment

Lafayette Utilities System

Environmental Assessment
Project No. 118157

1/29/2020

BURNS McDONNELL

March 31, 2020

Jeff Stewart
Manager, Engineering & Power Supply
Lafayette Utilities System
1314 Walker Road
Lafayette, LA 70506

Re: Environmental Assessment

Dear Mr. Stewart:

Lafayette Utilities System ("LUS") retained Burns & McDonnell to perform an integrated resource planning study ("IRP"). As part of the IRP, Burns & McDonnell completed an Environmental Assessment ("Assessment") to provide information regarding anticipated environmental compliance and costs for LUS' existing power plants. The information herein is to be utilized within the IRP process to help LUS set a power supply direction moving forward.

If you have any questions regarding this information, please feel free to contact either Mike Borgstadt at 816-822-3459 or mike.borgstadt@1898andco.com or Kyle Combes at 816-349-6884 or kyle.combes@1898andco.com.

Sincerely,

Mike Borgstadt
Director, Utility Consulting

Kyle Combes

Kyle Combes
Project Manager

MEB/meb

Enclosure
cc: Karen Hoyt
Josh Zeno

Environmental Assessment

prepared for

Lafayette Utilities System
Environmental Assessment
Lafayette, Louisiana

Project No. 118157

1/29/2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
µg/L	Micrograms per Liter
ACE	Affordable Clean Energy
ACI	Activated Carbon Injection
Assessment	Environmental Assessment
BART	Best Available Retrofit Technology
BAT	Best Available Technology
BPT	Best Practicable Technology
BSER	Best System of Emissions Reduction
BTA	Best Technology Available
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CCR	Coal Combustion Residuals
Clean Air Act	CAA
CPP	Clean Power Plan
CSAPR	Cross State Air Pollution Rule
CWA	Clean Water Act
CWIS	Cooling Water Intake Structures
DSI	Dry Sorbent Injection
EGU	Electric Generating Unit
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
FGD	Fuel Gas Desulfurization
FGMC	Flue Gas Mercury Control

Abbreviation	**Term/Phrase/Name**
GHG	Greenhouse Gas
HAP	Hazardous Air Pollutant
HCl	Hydrochloric Acid
HRI	Heat Rate Improvement
IM	Impingement Mortality
IRP	Integrated Resource Plan
LDEQ	Louisiana Department of Environmental Quality
LUS	Lafayette Utilities System
MATS	Mercury and Air Toxics Standards
mg/L	Milligrams per Liter
MGD	Million Gallons per Day
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
ng/L	Nanograms per Liter
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter Less than 2.5 Microns
POTW	Publicly Owned Treatment Works

Abbreviation	**Term/Phrase/Name**
ppb	Parts per Billion
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
RHR	Regional Haze Rule
SCC	Submerged Chain Conveyer
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TRI	Toxic Release Inventory

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1.0 ENVRONMENTAL ASSESSMENT

1.1 Introduction

Lafayette Utilities System (“LUS”) retained Burns & McDonnell Engineering Company (“Burns & McDonnell”) to evaluate numerous environmental regulations that could impact its existing generation fleet in support of its integrated resource planning efforts (“IRP”). The Environmental Assessment (“Assessment”) provides a summary of Burns & McDonnell’s review of the environmental regulations’ impact on LUS’ fleet.

The purpose of the Assessment was to evaluate and summarize the promulgated and proposed environmental regulations that are currently, and may have the potential, to significantly impact the power generation industry in the coming years. Additionally, for regulations that may impact any LUS fossil fuel unit, a screening level compliance cost is included.

The environmental regulations that were explicitly considered included:

- Effluent Limitation Guidelines (“ELG”)
- Coal Combustion Residue (“CCR”) regulations
- Clean Water Act (“CWA”) Section 316(b)
- Air regulations
  - Cross-State Air Pollution Rule (“CSAPR”) requirements
  - National Ambient Air Quality Standards (“NAAQS”) for sulfur dioxide (“SO_2”), nitrogen oxides (“NO_x”), ozone, and particulate matter (“PM”)
  - National Emissions Standards for Hazardous Air Pollutants (“NESHAPs”) for power plants (Mercury and Air Toxics Standards (“MATS”))
  - Regional Haze Rule (“RHR”) and Best Available Retrofit Technology (“BART”) which was assumed to be equivalent to the CSAPR requirements
  - Greenhouse gas (“GHG”) regulations, specifically the Affordable Clean Energy (“ACE”) Plan

1.2 Conclusions & Recommendations

Based on the review summarized herein, Burns & McDonnell offers the following conclusions:

1. Under the current environmental regulations, LUS’ natural gas-fired units do not appear to require large capital improvements to comply with environmental rules.

2. Rodemacher Power Station Unit 2 ("RPS2") is subject to numerous environmental regulations as it is a coal-fired power plant. The following regulations will impact the unit.
    a. Effluent Limit Guidelines: LUS' RPS2 is expected to be impacted by the ELG rule so long as the unit continues to burn coal. A dry bottom ash handling conversion is more likely to occur at RPS2 to comply with ELG rules. LUS will be required to meet the ELG requirements between November 1, 2020, and December 31, 2023, at a date to be established in the next NPDES permit received for the site. The proposed ELG rules do allow for utilities to commit to retiring a unit by December 31, 2028 and avoid any new ELG requirements for bottom ash transport water. If this option is incorporated into a final rule, this may be an option for LUS to consider at RPS2; however, the facility will need to be modified to remain CCR compliant until that date. Should RPS2 continue to operate past 2028 utilizing coal, capital improvements will be required to comply with ELG regulations. The total capital cost (spread across all owners) for compact submerged conveyors at RPS2 has been estimated between $15 and $20 million.
    b. Coal Combustion Residue: Regardless of RPS2's long-term operations (whether utilizing coal, converted to natural gas, or retired), the Unit will be required to close the existing on-site ash ponds in order to comply with CCR. These capital improvements are estimated to be approximately $20 to $25 million (for the entire plant).
    c. RPS2, as a coal-fired power plant, will be required to comply with numerous ongoing air regulations, among others, that are currently in place and subject to periodic review or newly proposed. At this time, there are no additional capital improvements anticipated besides those mentioned above for CCR and ELG. However, a detailed study would need to be conducted to determine whether any large capital improvements are required for compliance with the Affordable Clean Energy ("ACE") rule regarding carbon dioxide emissions. However, the co-owners of RPS2 may decide to wait until LDEQ has completed its evaluation before conducting detailed evaluations of RPS2.

2.0 EFFLUENT LIMITATION GUIDELINES

The CWA was enacted in 1972 (with several revisions thereafter) and establishes procedures and requirements for discharges of pollutants into the waters of the United States and regulates water quality standards for surface water discharges. The CWA is applicable to all wastewater discharges regardless of industry sector. The revision to the CWA affecting the electric utility industry that occurred in 1982 has since become out of date with the current processes employed by utilities, as well as inadequate regarding its discussion of toxic pollutant discharges of concern.

2.1 Background

The U.S. Environmental Protection Agency ("EPA") is required by the CWA to establish national technology-based effluent limit guidelines ("ELGs") and to periodically review all ELGs to determine whether revisions are warranted. In 2005, the EPA's annual ELG review identified the Steam Electric Power Generating industry for study due to high discharge of toxic and nonconventional pollutants as indicated in the reports by National Pollutant Discharge Elimination System ("NPDES") permit program and the Toxics Release Inventory ("TRI") and the expectation that pollutant discharges from fossil fueled power plants will increase significantly in the next few years as new air pollution controls are installed. A detailed study was conducted, and the results were compiled into a report titled "Steam Electric Power Generating Point Source Category: Final Detailed Study Report" (October 2009). A summary of the findings of the report is as follows:

- The current regulations do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades.
- Steam electric power plants are responsible for a significant amount of the toxic pollutant loadings discharged to surface waters by point sources.
- Coal ash ponds and flue gas desulfurization ("FGD") systems are the source of many of these pollutants.

Upon completion of the study in the fall of 2009, the EPA announced its intent to update the effluent guidelines for the Steam Electric Power Generating Point Source Category. The proposed guidelines were published in the Federal Register on June 7, 2013, the pre-published final regulations were released on September 30, 2015, and the final regulations were published in the Federal Register on November 3, 2015. The final regulation was effective on January 4, 2016; however, a portion of the rule has been stayed and the requirements for FGD wastewater and bottom ash transport water are being reauthored by the EPA. In general, all facilities are required to comply between November 1, 2020, and December 31, 2023. EPA released a proposed rule for these two remaining waste streams in late 2019. The following sections outline the current rule as initially written by EPA.

2.2 Scope/Applicability of the Final Rule

The finalized ELGs establish new or additional effluent limitations for certain plants within the steam electric industry. The requirements would apply to discharges of wastewater associated with the following processes and byproducts:

- FGD Wastewater
- Fly Ash Transport Water
- Bottom Ash Transport Water
- Combustion Residuals Leachate
- Gasification of Fuels such as Coal and Petroleum Coke
- Flue Gas Mercury Control (“FGMC”) Wastewater

EPA has established Best Available Technology Economically Achievable (“BAT”) for existing sources, New Source Performance Standards (“NSPS”), Pretreatment Standards for Existing Sources (“PSES”), and Pretreatment Standards for New Sources (“PSNS”) that apply to discharges of pollutants for the waste streams listed above. These limits will apply to the following facility and discharge types:

- BAT limits established for discharges directly to surface water from existing facilities [except oil-fired and less than 50 megawatts (“MW”)]
- NSPS limits established for discharges directly to surface water from new sources
- PSES limits established for discharges to publicly-owned treatment works (“POTWs”) from existing facilities (except oil-fired and less than 50 MW)
- PSNS limits established for discharges to POTWs from new sources

The discharge requirements would apply to all plants whose generation of electricity is the predominant source of revenue or principal reason for operation, including plants fired by fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (petroleum coke, synthetic gas), or nuclear fuel. As stated above, the rules do not apply to existing small generating units (defined as 50 MW or less), existing oil-fired units (units that are fired solely on oil and that do not burn coal or petroleum coke), or generating units owned and operated by industrial facilities not traditionally regulated by the steam electric ELGs. BAT effluent limits will not be added as part of the rule for these units, and the existing discharge limits based on the best practicable control technology currently available ("BPT") will remain in place.

For the purposes of this Study, Burns & McDonnell will focus only on the impacts resulting from the BAT limits that are being established for existing facilities. The evaluated sites are not believed to currently discharge pollutants to POTWs (other than sanitary wastewater, which is not covered under the ELGs), and the development of any new plants or new sources is beyond the scope of the Study.

2.3 ELG Regulations

The final ELGs establish new definitions for FGD wastewater, FGMC wastewater, gasification wastewater, and combustion residual leachate. The final rule also establishes BAT for six waste streams: fly ash transport water, bottom ash transport water, FGMC wastewater, FGD wastewater, gasification wastewater, and combustion residual leachate.

The final BAT limitation for fly ash transport water, bottom ash transport water, and FGMC wastewater is zero discharge for all pollutants. This limitation is based on dry handling or in the instance of bottom ash transport water, the use of a closed-loop system. A notable exception to this discharge limitation is the allowable use of fly ash or bottom ash transport water as FGD absorber makeup water (untreated). This exception does not apply to FGMC wastewater, so the location of any activated carbon injection, and waste collection, is critical to determine if the wastewater can be used in the scrubber.

The following tables (Table 5-1 through Table 5-4) present the final ELG limits for existing discharges of FGD wastewater, gasification wastewater, and combustion residual leachate, along with the technology basis for each of the limits:

Table 5-1: FGD Wastewater – Chemical Precipitation plus Biological Treatment

Pollutant or pollutant property[a]		BAT Effluent Limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total	(µg/L)	11	8
Mercury, total	(ng/L)	788	356
Selenium, total	(µg/L)	23	12
Nitrate/nitrite as N	(mg/L)	17	4.4

(a) µg/L = micrograms per liter; ng/L = nanograms per liter; mg/L = milligrams per liter

Table 5-2: Gasification Wastewater - Evaporation

Pollutant or pollutant property[a]		BAT Effluent Limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total	(µg/L)	4	---
Mercury, total	(ng/L)	1.8	1.3
Selenium, total	(µg/L)	453	227
Total dissolved solids	(mg/L)	38	22

(a) µg/L = micrograms per liter; ng/L = nanograms per liter; mg/L = milligrams per liter

Table 5-3: Combustion Residual Leachate - Surface Impoundments

Pollutant or pollutant property[a]		BAT Effluent Limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
TSS	(mg/L)	100.0	30.0
Oil and grease	(mg/L)	20.0	15.0

(a) mg/L = milligrams per liter

Table 5-4: FGD Wastewater Voluntary Option – Thermal Evaporation

Pollutant or pollutant property[a]		BAT Effluent Limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total	(µg/L)	4[b]	---[c]
Mercury, total	(ng/L)	39	24
Selenium, total	(µg/L)	5	---
TDS	(mg/L)	50	24

(a) µg/L = micrograms per liter; ng/L = nanograms per liter; mg/L = milligrams per liter
(b) Limitation is set equal to the quantitation limit
(c) Monthly average limitation is not established when the daily maximum limitation is based on the quantitation limit

2.4 Prohibition of Co-Mingling (Anti-Circumvention Provisions)

The only anti-circumvention provision the EPA included in the final ELGs is regarding the existing sources of streams that have a zero-discharge provision. These streams may not be mixed with any other stream that results in an eventual discharge. As noted previously, the only exception to this anti-circumvention provision is the use of fly ash or bottom ash transport water as FGD makeup water.

While the anti-circumvention provisions do not apply to other waste streams, the ELGs make clear that when any two streams are mixed, the resulting discharge limits should be prorated to account for any dilution effect mixing the streams could have. In essence, mixing is allowed but the eventual discharge limit will be reduced to ensure the resulting discharge will contain the same amount of contaminants as if the mixing had not occurred.

2.5 Legacy Wastewater

The final ELGs do not apply to wastewater generated before the compliance date (legacy wastewater). If a new treatment system is added for a particular waste stream to comply with the final rules, such as a tank-based system for FGD wastewater, the effluent from the tank-based treatment system (in compliance with numeric limits outlined in the final rules) could be combined with legacy FGD wastewater and then discharged to surface waters under the prior BPT limits that apply to FGD wastewater. If a utility chooses to combine new FGD wastewater (generated after the compliance date required by the permitting agency) with legacy wastewater prior to treatment in a tank-based system, then the legacy wastewater would have to meet the new discharge limits as well. This same example would apply to all legacy wastewater. Specific state water regulations should also be considered in the ELG evaluation. Some states may have more stringent regulations than the federal ELG rule. On April 12, 2019, the Fifth Circuit (Court of Appeals) ordered EPA to revisit the limits for legacy wastewater. EPA may be revising these limits for in the updated rule expected in late 2019, or more likely may perform a subsequent rulemaking to do so.

2.6 Implementation Schedule

The final rule indicates these limitations do not apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2020, but also no later than December 31, 2023. The rule further describes ‘as soon as possible’ is November 1, 2020 unless the permitting agency determines otherwise taking into account: 1) time to implement the project, 2) impacts of other regulations, 3) commissioning period (FGD only), and 4) or other factors as appropriate.

An exception to the ‘as soon as possible’ limit application is if prior to the next permit the utility informs the permitting agency it intends to comply with the voluntary alternative FGD limitations (based on evaporation). In this instance the more stringent limit will be deferred until December 31, 2023. Additionally, it is possible that different waste streams may have different compliance dates (40 CFR 423.11(t)).

2.7 State and Local Considerations

In addition to the federal ELG rule, some states can have more stringent regulations or regulatory interpretations of the federal ELG rule. Additional discussion with the state agency is recommended to ensure all requirements are known for ELG at RPS2.

2.8 Potential ELG Impacts at RPS2

LUS' RPS2 is expected to be impacted by the ELG rule so long as the unit continues to burn coal. RPS2 (located at the site known as the Brame Energy Center) has bottom ash transport water discharges that will be subject to the ELG rules. EPA recently proposed some changes to the ELG rule (on November 4, 2019), specifically around FGD wastewater and bottom ash transport water. RPS2 is not impacted by the FGD wastewater changes since this unit does not have wet scrubbers. Bottom ash transport water used in high-recycle rate systems can be purged at up to a maximum of 10 percent of the primary active wetted volume bottom ash system volume; however, EPA does not intend for this to include the volume of water in a pond. Since LUS does not currently recycle the water from the RPS2 pond, the compliance cost to convert this to a closed-loop system with zero discharge would be cost prohibitive and a dry bottom ash handling conversion is more likely to occur at RPS2. The compliance date for bottom ash transport water did not change, and LUS will be required to meet the ELG requirements between November 1, 2020, and December 31, 2023, at a date to be established in the next NPDES permit received for the site. Based on the information received, the NPDES permit for RPS2 was valid until October 2019. The new ELG limits will likely be incorporated into the next NPDES permit.

The proposed ELG rules do allow for utilities to commit to retiring a unit by December 31, 2028 and avoid any new ELG requirements for bottom ash transport water. If this option is incorporated into a final rule, this may be an option for LUS to consider at RPS2; however, the facility will need to be modified to remain CCR compliant until that date.

2.8.1 Dry Bottom Ash Conversion

The existing bottom ash system at RPS2 utilizes water-impounded bottom ash hoppers to collect, cool, and temporarily store bottom ash. On an intermittent basis, water pulled from Lake Rodemacher is used to sluice the bottom ash to the bottom ash pond. In a similar fashion, pyrites/mill rejects are collected in mill hoppers and sluiced to the ash ponds through the common line. Bottom ash is sluiced once in every twelve (12) hour shift.

There are several options for plant bottom ash conversion including a dewatering bin recirculation system, remotely located submerged chain conveyer ("SCC"), a compact submerged conveyor located directly beneath the existing boiler hopper, or complete dry bottom ash hopper/conveying system. The choice of each option depends on several plant specific criteria including local space constraints, capital and O&M costs, potential outage durations, water usage, and final storage/disposal of the material. The system evaluated for RPS2 is a compact submerged conveyor system.

As part of this solution, a new conveyor system will replace the boiler hopper ash jet pumps. During operation, bottom ash falls from the boiler into the hopper and is routed through the crushers. The crushed ash is removed by the conveyor, which consists of a chain with metal flight bars that drags ash along the bottom of the conveyor to the inclined “dewatering” section. The dewatering section contains a chain conveyor that pulls bottom ash up an inclined ramp while water gravity drains back into the conveyor. The inclined ramp drops dewatered ash into a three-walled bottom ash bunker. Typically, ash collects in the bunker and is loaded into haul trucks with a front-end loader.

Economizer ash and mill rejects typically require a separate system. Economizer ash may be handled with a series of dry flight conveyors that route the ash from the existing economizer hoppers to the compact submerged conveyors in a dry condition, thus eliminating the use of ash transport water. This ash is comingled with bottom ash in the SGC and deposited in the bunker with the bottom ash. During an economizer wash event, temporary piping should be utilized to tie into the economizer hoppers and bypass the dry flight conveyors. Wash water can be drained to the bottom ash sump and treated within the Unit 2/3 Metal Cleaning Waste Pond (not a CCR surface impoundment and not ash transport water per the EPA’s Effluent Limitations Guidelines and Standards for Steam Electric Power Plants [ELG Rule]). The current bottom ash sluice pumps are replaced with smaller pumps dedicated to the mill rejects system which sluice mill rejects directly to the bottom ash hoppers. Sluice flows from the mill reject system are not considered ash transport water since mill rejects are considered pre-combustion wastes (i.e. not CCR).

Seal trough and hopper makeup to the existing boiler are maintained using the existing service water connections. Discharge from these systems, and overflow from the mill rejects sluice cycles, continue to be removed by the existing bottom ash sump pumps near the hopper. This overflow may also be conveyed to the Unit 2/3 Metal Cleaning Waste Pond, assuming LUS can modify the discharge permit accordingly. The total capital cost (spread across all owners) for compact submerged conveyors at RPS2 has been estimated between $15 and $20 million.

2.9 ELG at Labbe

The ELG rules likely do not apply to Labbe due to the lack of ash transport water, combustion residual leachate, and FGD wastewater generated at the site.

2.10 ELG at Hargis-Hebert

The ELG rules likely do not apply to Hargis-Hebert due to the lack of ash transport water, combustion residual leachate, and FGD wastewater generated at the site.

3.0 COAL COMBUSTION RESIDUE REGULATIONS

In January 2009, the EPA began activity to develop federal rules to regulate CCRs. For the purposes of the regulations, CCRs include fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity. After gathering information from several utilities across the country, the EPA developed the proposed draft federal CCR rules and published them to the Federal Register on June 21, 2010. In response to numerous comments, the EPA revised the rule and issued a pre-publication final version on December 19, 2014. The final rule was published in the Federal Register on April 17, 2015 and was effective on October 19, 2015.

The final rule establishes a federal minimum standard for disposal of CCR material in surface impoundments and landfills. The rule establishes a framework to address risks of groundwater contamination, structural failures of CCR impoundments, locational issues, and fugitive dust emissions. Any of these CCR units posing an unacceptable risk are subject to closure. Unlike other regulations issued by the EPA, enforcement will be completed under a citizen suit approach. The rule does not require permits, does not require states to adopt or implement these requirements, and EPA cannot enforce the requirements. Instead citizens, environmental groups, or states will enforce the requirements of the rule through lawsuits brought against utilities. Ultimately, the states will likely adopt the regulations into their solid waste management plans and issue permits for new disposal facilities or closure of existing facilities; however, the compliance requirements and schedules for the state program are unknown and for the purposes of this study, the discussion will be focused on the federal minimum standards.

EPA recently proposed some changes to the CCR Rule on November 4, 2019 and published these proposed rules in the Federal Register on December 2, 2019. Public comments are due on January 31, 2020. The major changes to the rule are that impoundments that previously met the clay liner criteria or that were classified as unlined in the 2015 rule are now subject to closure beginning on August 31, 2020. Utilities may request alternate deadlines for their sites if they can demonstrate no alternative disposal capacity exists on-site or off-site and if they can justify the requested extension to EPA, based on a plan to either modify or retire the units. These extensions must be approved by EPA, and EPA’s decision will be subject to a public comment period.

3.1 Potential Impacts of CCR Regulations

As discussed in Section 1.1.8, the CCR and ELG rules are inter-related. Burns & McDonnell performed review of a minimum, base and stringent compliance cases. For the resource planning effort, the base case costs and assumptions were used.

3.2 CCR at RPS2

There are two CCR disposal ponds at the Brame Energy Center site, including the RPS2 bottom ash pond and the RPS2 fly ash pond. The bottom ash pond currently receives bottom ash, economizer fly ash, sluice water, and other plant process flows from RPS2. Flow from the pond is discharged by gravity draining from the pond overflow structure to the permitted LPDES Outfall 401. The fly ash pond currently receives ESP fly ash that has been loaded onto trucks from the dry fly ash silo, hauled to the pond, and dumped into the pond. This ash is mixed with storm water which can be discharged by pumping into the bottom ash pond and then gravity draining from the bottom ash pond overflow structure to the permitted LPDES Outfall 401. While this pond does not contain any fly ash transport water and may therefore follow the ELG regulations, it is still considered a CCR impoundment and will be subject to the CCR regulations. Both ponds are considered unlined per the CCR Rule and are subject to closure beginning on August 31, 2020 (in the proposed rule, with the actual date to be confirmed once the rules are finalized).

3.2.1 Potential CCR Compliance Scenario

When the CCR rule forces closure of the impoundments at the Brame Energy Center, it is likely that the facilities will be closed by removal with the CCR placed in the adjacent landfill onsite. This would require permitting the Madison Unit 3 landfill to receive CCR material. Based on initial estimates and forecasted production of CCR up to a closure date beginning in 2023 (to coincide with the ELG compliance date), closure of the RPS2 impoundments is expected to cost \$20 to \$25 million (total plant) excluding any landfill expansion costs that may be required. This extension may not be approved by EPA and LUS may be required to close sooner than this date. This would likely reduce the cost for closure by removal but accelerate the cash flow associated with this project.

3.3 CCR at Labbe

Labbe does not have any CCR impoundments or landfills and is not subject to the CCR rule.

3.4 CCR at Hargis-Hebert

Hargis-Hebert does not have any CCR impoundments or landfills and is not subject to the CCR rule.

4.0 SECTION 316(B) REGULATIONS

Section 316(b) of the Clean Water Act specifies that cooling water intake structures ("CWIS") will be located, designed, constructed, and operated, and incorporate the best technology available ("BTA") to minimize adverse impacts to the aquatic environment. Over the decades since enactment, the adverse impacts have become defined as mortality of fish and shellfish caused by impingement and entrainment. The Final Rule for existing facilities (40 CFR 125 Subpart J) applies to facilities that withdraw more than 2 million gallons per day ("MGD") from waters of the United States, of which 25 percent or more is used for cooling purposes.

The Final Rule requires that existing facilities subject to the rule must comply with one of the following seven impingement mortality ("IM") reduction options:

- IM Option 1: Operate a closed-cycle recirculating system as defined by the Final Rule (at §125.92)
- IM Option 2: Operate a CWIS that has a maximum design through-screen design intake velocity of 0.5 foot per second
- IM Option 3: Operate a CWIS that has a maximum through-screen intake velocity of 0.5 foot per second
- IM Option 4: Operate an offshore velocity cap that is a minimum of 800 feet offshore
- IM Option 5: Operate a modified traveling screen that the Director determines meets the definition of the rule (at §125.92(s)) and that the Director determines is the best technology available for impingement reduction
- IM Option 6: Implement any other combination of technologies, management practices and operational measures that the Director determines is the best technology available for impingement reduction
- IM Option 7: Achieve the specified impingement mortality performance standard of less than 24 percent.

IM Option 1, IM Option 2, and IM Option 4 are considered pre-approved technologies that require no demonstration or only a minimal demonstration that the flow reduction and control measures are functioning as EPA envisioned. IM Option 3, IM Option 5, and IM Option 6 require more detailed information be submitted to the Director before the Director may specify it as the requirement to control IM.

- IM Option 3: EPA considers this option to be a streamlined alternative. The facility must submit information to the Director that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 foot per second.
- IM Option 5: The facility must submit a site-specific impingement technology performance optimization study that must include two years of biological sampling demonstrating that the operation of the modified traveling screens has been optimized to minimize impingement mortality. If the facility does not already have this technology installed and chooses this option, the Director may postpone this study until the modified traveling screens and fish return system are installed.
- IM Option 6: Similar to IM Option 5, the facility must submit a site-specific impingement study including two years of biological data collection demonstrating that the operation of the system of technologies, operational measures and best management practices has been optimized to minimize IM. If this demonstration relies in part on a credit for reductions in the rate of impingement already achieved by measures taken at the facility, an estimate of those reductions and any relevant supporting documentation must be submitted. The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody.
- IM Option 7: Requires that a facility must achieve a 12-month impingement mortality performance of all life stages of fish and shellfish of no more than 24 percent mortality, including latent mortality, for all non-fragile species that are collected or retained in a sieve with maximum opening dimension of 0.56 inches and kept for a holding period of 18 to 96 hours. Biological monitoring must be completed at a minimum frequency of monthly.

The pre-approved BTA for entrainment is an intake rate commensurate with closed-cycle cooling. The actual BTA for entrainment at a given facility, however, is to be determined on a site-specific basis by the agency that issues the facility’s discharge permit. The selection of entrainment BTA is based on a cost/benefit analysis of entrainment compliance technologies, including at a minimum, the options to install fine mesh screens and to convert to closed-cycle cooling.

To justify the selection of impingement and entrainment BTA, all subject facilities must submit seven information reports (40 CFR 122.21(r)(2-8)) that describe the source water body, the current cooling water intake system, the current and future status of the facility, and the chosen impingement compliance method. In addition, facilities that have had an actual average cooling water intake rate greater than 125

MGD over the past three years must also submit studies (§ 122.21(r)(9-13)) that will form the basis of the cost/benefit analysis the permitting agency will use to determine BTA for entrainment. These studies are described in Table 5-5.

Addressing the requirements of the § 316(b) Final Rule could require a substantial commitment of resources.

Table 5-1: Section 316(b) Studies Required Under 40 CFR 122.21(r)

§ 122.21(r) Paragraph	Title	Description
All Facilities		
(2)	Source Water Physical Data	Unchanged from Phase I &II rule. Submit data to characterize facility and evaluate type of water body affected.
(3)	Cooling Water Intake Structures Data	Unchanged from Phase I & II rule. Submit data to characterize cooling water intake and evaluate potential for impingement and entrainment of aquatic organisms.
(4)	Source Water Baseline Biological Characterization	Similar to Phase I rule. Characterize biological community in the vicinity of the cooling water intake structure in terms of species composition, vulnerability to impingement and entrainment, and presence of threatened or endangered species.
(5)	Cooling Water System Data	These data used to determine appropriate standards to be applied to a specific facility. Includes narrative description of the cooling operation system and its relationship to intake structures; proportion of intake flow that is used in the system; a distribution of water re-use.
(6)	Chosen Method(s) of Compliance with Impingement Mortality Standard	New rule provides seven compliance options for meeting requirements. Facility must identify its approach for meeting the mortality requirements. Must identify the method for the entire facility or for each intake structure. EPA has eliminated the requirement for a separate impingement mortality reduction plan. Data collection requirements only apply where the facility must demonstrate performance outcomes as further explained in (r) (6).
(7)	Entrainment Performance Studies	Facilities must submit only previously conducted entrainment related studies. Impingement studies, where relevant, are already part of the permit application at 122.21(r) (6). Applicant must submit a description of biological studies conducted at the facility and summary/conclusions. Studies over 10 years old must include a relevancy explanation. Focuses on previous and current studies rather than requiring new studies.

§ 122.21(r) Paragraph	**Title**	**Description**
(8)	Operational Status	Submit description of operational status of each unit for which a cooling water intake structure provides water for cooling. Includes age of unit, capacity utilization for last five years (including any outages) and any major upgrades in last 15 years, any uprates, relicensing, decommissioning or replacement plans, and current and future production schedules.
	Facilities > 125 MGD	
(9)	Entrainment Characterization Study	Must develop a study that includes a minimum of two years of entrainment data. Would include documentation of data collection period and frequency, identification of organisms found to lowest taxon. Must be representative of the entrainment at each intake and document how the location of the intake in the water body and water column is accounted for. Must include analysis of data to determine total entrainment and entrainment mortality. Will be used in determination of BTA for entrainment for each site
(10)	Comprehensive Technical Feasibility and Cost Evaluation Study	Must submit an engineering study of technical feasibility and incremental costs of candidate entrainment control technologies. Study must include an evaluation of technical feasibility of closed cycle cooling, use of fine mesh screens, reuse of water or alternate sources of cooling water, and any other entrainment reduction technologies identified by the applicant or requested by the director. Must also include a description of all technologies considered. Cost information in both capital costs and in net present value terms with corresponding annual value are required.
(11)	Benefits Valuation Study	Must submit a detailed discussion of the benefits of the candidate entrainment reduction technologies evaluated in (r) (10) and data from (r) (9). Categories of benefits are to be narrative and quantified in physical or biological units and monetized using economic valuation methods, when possible. Peer review of this study is required.
(12)	Non-Water Quality and Other Environmental Impacts Study	Must submit a discussion of changes in non-water quality environmental studies and other factors attributed to technologies or operational measures. Examples include energy consumption, air and noise impacts, potential for plumes, grid reliability, consumptive water use, etc.
(13)	External Peer Review of Study 9-12	Studies required under (r) (10, 11, 12) must be submitted for peer review. Can be submitted as one combined document and panel must be of appropriate background to conduct a combined and complete technical review.

The determination of the § 122.21(r) studies that need to be conducted for each facility was based on the exceedance of the 125-MGD threshold.

Compliance options are evaluated using the following stepwise process:

1. Determine if the facility is already compliant with BTA for impingement and entrainment under IM Options 1, 2, or 3.
2. Determine if the facility has low rates of impingement that could be considered de minimis by the Director.
3. Determine if the facility is eligible for the capacity exemption. The average capacity factor must be less than 8 percent over the past three years.
4. Evaluate the likely efficacy, technical feasibility, and relative costs of the impingement BTA alternatives applicable to open-cycle cooling systems.
5. Evaluate the technical feasibility, capital costs, and other environmental impacts of the BTA alternatives for entrainment of conversion of closed-cycle cooling or using fine-mesh screens.

4.1 316(b) at RPS2

RPS2 will be not be significantly impacted by Section 316(b) rules since the plant water source is from a manmade lake constructed as a cooling system for the plant. This meets the definition of a closed-cycle recirculating system in the final rule and no significant plant modifications should be required

4.2 316(b) at Labbe

This facility uses closed-cycle cooling systems which are identified as BTA for impingement and entrainment. No plant modifications are anticipated.

4.3 316(b) at Hargis-Hebert

This facility uses closed-cycle cooling systems which are identified as BTA for impingement and entrainment. No plant modifications are anticipated.

5.0 AIR REGULATIONS

This section outlines the various defined regulations that could impact air emissions from LUS-owned facilities. The following air regulations were reviewed in detail and their histories are summarized in the following sections of this report:

- CSAPR requirements
- NAAQS for SO2, NOx, ozone, and PM
- NESHAPs for power plants (MATS)
- RHR and BART which was assumed to be equivalent to the CSAPR requirements
- GHG regulations, specifically the ACE Rule

5.1 Pollutant Interstate Transport

On July 6, 2011 the EPA finalized the CSAPR to address air pollution from upwind states that crosses state lines and affects air quality in downwind states. SO_2 and NO_x emissions react in the atmosphere and contribute to the formation of fine particle (soot) pollution. NO_x also contributes to ground-level ozone (smog) formation. The CSAPR is designed to help states achieve compliance with the following NAAQS:

- Particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) NAAQS set in 1997 (annual standard)
- $PM_{2.5}$ NAAQS set in 2006 (24-hour standard)
- Ozone NAAQS set in 1997
- Ozone NAAQS set in 2008

CSAPR does not address the current $PM_{2.5}$ NAAQS finalized in 2012. The EPA may address compliance with these NAAQS in a follow up rule.

EPA's CSAPR approach is based on state-wide SO_2 and NO_x emission budgets. Each state's budget consists of the emissions that the EPA estimates will remain after the state has made the reductions required to reduce its significant contribution to non-attainment and interference with maintenance of the relevant NAAQS in other states in an average year. The EPA established each state's budget by estimating unit-level allocations, then totaling the unit-level allocations for each state. The EPA found that emissions from Louisiana impact ozone concentrations in downwind states, so an ozone-season NO_x budget has been finalized.

Burns & McDonnell has reviewed EPA's Clean Air Markets Data to obtain 2015 ozone season NO_x emissions. EPA's November 10, 2015 CSAPR allocations to LUS units and EPA's proposed NO_x season allowances under the 2008 ozone standards were also reviewed. In Table 5-6 below, the existing emissions were compared to the current and proposed ozone season NO_x allowances to determine if the LUS fleet would be short or long on allowances. Note that unlike the CCR and ELG costs, these are LUS only obligations.

As can be seen in Table 5-6, NO_x credits for each facility cover emissions under the current program through 2030. Therefore, for purposes of this study, no further NO_x controls were considered because the facilities currently have enough NO_x credits.

Table 5-1: CSAPR Ozone Season Allowance Comparison

	NO_x Credits Start			NO_x Emissions (tons per year)			Ending NO_x Credits		
Year	**Labbe**	**Hargis**	**Brame[a]**	**Labbe**	**Hargis**	**Brame[a]**	**Labbe**	**Hargis**	**Brame[a]**
2010	5	4	68,262	-	-	24,643	5	4	43,619
2011	5	4	54,212	1	-	12,749	4	4	41,463
2012	4	4	60,118	-	-	10,750	4	4	49,368
2013	4	4	63,835	-	-	11,321	4	4	52,514
2014	4	4	65,506	-	-	9,028	4	4	56,478
2015	4	4	70,685	-	-	5,692	4	4	64,993
2016	879	867	86,174	5	5	5,702	879	867	80,472
2017	879	867	101,629	5	6	5,176	879	867	96,453
2018	879	867	117,640	7	7	7,042	879	867	110,598
2019	872	860	110,598	7	7	9,028	865	853	101,570
2020	865	853	101,570	7	7	9,028	858	847	92,542
2021	858	847	92,542	7	7	9,028	852	840	83,514
2022	852	840	83,514	7	7	9,028	845	833	74,486
2023	845	833	74,486	7	7	9,028	838	826	65,458
2024	838	826	65,458	7	7	9,028	831	819	56,430
2025	831	819	56,430	7	7	9,028	824	813	47,402
2026	824	813	47,402	7	7	9,028	817	806	38,374
2027	817	806	38,374	7	7	9,028	811	799	29,346
2028	811	799	29,346	7	7	9,028	804	792	20,318
2029	804	792	20,318	7	7	9,028	797	785	11,290
2030	797	785	11,290	7	7	9,028	790	778	2,262
2031	790	778	2,262	7	7	9,028	783	772	(6,766)

Source: EPA Clean Air Markets

(a) Brame Energy Center is also known as Rodemacher Station. Note, LUS owns 50 percent of Rodemacher Unit 2 and does not own any other units at the facility.

5.2 National Ambient Air Quality Standards

The EPA is required to set limits on ambient air concentrations for each criteria pollutant (SO_2, NO_2, carbon monoxide, ozone, lead, and particulate matter) to protect the public's health and welfare. The EPA is required to review these NAAQS and the latest health data periodically and modify the standards if needed. There have been no changes to the NAAQS for NO_2, SO_2, or particulate matter since 2012. The SO_2 standards were retained without revision on March 18, 2019.

EPA has identified Evangeline Parish and St. Bernard Parish as an SO_2 non-attainment areas. Evangeline Parish is approximately 50 miles away from Rodemacher, Labbe, and Hargis-Hebert, St. Bernard Parish is located approximately 200 miles from Rodemacher and 160 miles from Labbe and Hargis-Hebert. Demonstrating compliance is based on three years' worth of monitoring data or air dispersion modeling, so states may require emissions controls several years before the compliance date. For ambient air monitoring, once three years of data have been collected, a state may decide to start taking action to achieve attainment. In response to the SO_2 Data Requirements Rule published on August 21, 2015, Louisiana Department of Environmental Quality ("LDEQ") and the facilities involved have set up five air monitoring sites near sulfur dioxide emitting facilities:

1. Oxbow Calcining LLC Baton Rouge Calcined Coke Plant-East Baton Rouge Parish, monitor AQS #22-033-0015, established 1/1/17 with data collection beginning 1/11/2017
2. Sid Richardson Carbon Company Addis Plant- West Baton Rouge Parish, monitor AQS #22-121-0002, established 1/1/17 with data collection beginning 1/9/17
3. Rain CII Carbon LLC Norco Coke Plant- St. Charles Parish, monitor AQS #22-089-0006, established 1/1/17 with data collection beginning 1/14/2017
4. Rain CII Carbon LLC Gramercy Coke Plant- St. James Parish, monitor AQS # 22-093-0003, established 1/1/17 with data collection beginning 1/16/2017
5. Reynolds Metals Co Lake Charles Carbon Co- Calcasieu Parish, monitor AQS #22-019-0011, established 1/1/17 with data collection beginning 1/1/2017

In 2015, the EPA tightened the NAAQS for ozone from 75 parts per billion ("ppb") to 70 ppb. Ozone formation is impacted by emissions of volatile organic compounds and NO_x. If the plant is deemed to cause or significantly contribute to an ozone non-attainment area, some form of NO_x control (i.e. Reasonably Available Control Technology) could be required for the plant in the 2017 to 2019 timeframe; however, absent of any detailed regional air dispersion modeling results, it is impossible to determine what, if any, additional controls will be required. If EPA proposes a new ozone standard soon, attainment with the new standard is expected to be required between 2021 and 2034, depending on the severity of the non-attainment issue. There are currently no ozone non-attainment areas in Louisiana.

EPA set the current $PM_{2.5}$ standard on September 21, 2006. At that time, the EPA revised the 24-hour standard, but made no changes to the previous annual standard. Pursuant to an order from the DC Circuit Court in December 2012, EPA finalized a new $PM_{2.5}$ annual standard which lowered the previous 15 micrograms per cubic meter to 12 micrograms per cubic meter level. The final rule does not recommend changes to the current 24-hour standard. $PM_{2.5}$ primarily consists of sulfate and nitrate particles which are created from SO_2 and NO_x emissions. Therefore, some form of SO_2 and NO_x control could be required for the plants; however, it is impossible to determine what, if any, additional controls will be required without any detailed air dispersion modeling results. On September 5, 2019, EPA's Office of Air Quality Planning and Standards released a draft reassessment of the particulate matter NAAQS. The Independent

Particulate Matter Review Panel will likely recommend that the primary annual standard for exposure to fine particulates ($PM_{2.5}$) be cut from 12 micrograms per cubic meter of air to somewhere between 8 and 10 micrograms per cubic meter.

Since the LUS facilities are currently located in attainment areas, no NAAQS related reductions are assumed for LUS facilities; however, environmental groups have aggressively challenged Title V renewals on the basis that an agency should not issue a permit renewal unless the facility can demonstrate compliance with all regulations, including the new 1-hour SO_2 and NO_2 NAAQS. To date, the environmental groups have not been successful in their challenges; however, sometime in the future, they may be successful, and facilities would be required to demonstrate compliance by ambient air monitoring or air dispersion modeling.

At this point, there are no clear drivers for additional air quality controls for NAAQS compliance. If the $PM_{2.5}$ NAAQS is lowered, it might have an effect on the LUS facilities depending on whether the areas are in attainment with a lower standard. Therefore, no additional NAAQS compliance costs have been included.

5.2.1 NAAQS at RPS2

The SO_2 non-attainment areas are over 50 and 100 miles away from RPS2 and with the recent SO_2 controls for MATS compliance, RPS2 has reduced its SO_2 footprint in the past few years. It may be possible that RPS2 has some impact on the area, but it has not been identified by LDEQ as a major contributor to the non-attainment area.

The stack for RPS2 is only 250 feet tall, which relatively short compared to other similar sized boilers. It is possible that a future NAAQS modeling study could indicate the need for a higher stack but since there is no current indication that the stack needs to be changed, no compliance costs have been included.

5.2.2 NAAQS at Labbe

There are no specific NAAQS concerns at Labbe.

5.2.3 NAAQS at Hargis-Hebert

There are no specific NAAQS concerns at Hargis-Hebert.

5.3 NESHAP for Power Plants

The NESHAP for Coal-and Oil-Fired electric utility generating units (EGUs), also referred to as MATS was signed by EPA on December 16, 2011.

On December 27, 2018, EPA issued a proposed revised Supplemental Cost Finding for the Mercury and Air Toxics Standards, as well as the Clean Air Act required “risk and technology review.” After taking account of both the cost to coal- and oil-fired power plants of complying with the MATS rule (costs that range from $7.4 to $9.6 billion annually) and the benefits attributable to regulating hazardous air pollutant (“HAP”) emissions from these power plants (quantifiable benefits that range from $4 to $6 million annually), as EPA was directed to do by the United States Supreme Court, the EPA proposed to determine that it is not “appropriate and necessary” to regulate HAP emissions from power plants under Section 112 of the Clean Air Act. The emission standards and other requirements of the MATS rule, first promulgated in 2012, would remain in place, however, since EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under Section 112 of the Act.

5.3.1 MATS at Rodemacher

RPS2 is a coal-fired unit. An activated carbon injection (“ACI”) system for mercury control, a dry sorbent injection (“DSI”) system for HCl control, and fabric filters for residual PM control were installed in 2015, as part of the unit’s compliance with the EPA’s MATS. No further add-on controls are needed for MATS compliance.

5.3.2 MATS at Labbe

MATS does not apply to Labbe since the units do not meet the applicability criteria.

5.3.3 MATS at Hargis-Hebert

MATS does not apply to Hargis-Hebert since the units do not meet the applicability criteria.

5.4 Regional Haze Rule

On July 1, 1999, the EPA issued the Regional Haze Rule (40 CFR Part 51, Subpart P) aimed at protecting visibility in 156 Federal Class I areas. Subsequently, the EPA issued proposed guidelines for determining BART, which provides guidance to the States in determining the air pollution controls needed to reduce visibility-impairing pollutants.

The EPA finalized the RHR and Guidelines for BART Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). In July 2016, the EPA issued draft guidance for the second implementation period of the regional haze regulations.[2] The draft guidance for the second implementation period retains many

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[1] “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations”; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

[2] “Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other

aspects of the BART guidelines. The guidance document requires a “four factor analysis” to be conducted for sources that have the potential to impair visibility in Class I areas. The four statutory factors are:

1. The cost of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of the source

The guidance documents, in general, indicate the goal of the second implementation period is to look at all sources for incremental visibility improvement including all sources that were previously BART eligible.

On September 11, 2018, EPA issued the Regional Haze Reform Roadmap, which directs EPA staff to take certain actions to ensure adequate support for states to enable timely and effective implementation of the regional haze program today and in the future. These actions are anchored in the regional haze program’s core statutory foundation and certain key principles. The second planning period’s revised deadline is July 2021 and the EPA listed tools and guidance products that were released in 2018 and 2019 to support the SIP development process.

5.4.1 RHR at Rodemacher

The LDEQ State Implementation Plan (SIP)[3] for the first planning period was approved by EPA in December 2017. A summary of the SIP dated December 21, 2017 for Rodemacher 2 is as follows:

- Enhanced DSI is SO_2 BART for Rodemacher 2, with a SO_2 emission limit of 0.30 lbs/MMBtu on a 30-day rolling basis. LUS will have to operate the existing DSI system at a higher injection rates to maintain future emissions below 0.30 lbs/MMBtu on a rolling 30-day basis.
- PM BART determination is 545 lbs/hr on a 30-day rolling basis.
- LDEQ’s February 2017 SIP revision relies on CSAPR as an alternative to BART for control of NOx from EGUs.

As mentioned above, the second implementation period deadline is July 2021. Without the SIP for the second implementation period and regulatory uncertainty it is difficult to predict what pollution technologies may be required, if any. Therefore, no additional compliance analysis was performed at this

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Requirements for Regional Haze State Implementation Plans for the Second Implementation Period”, Environmental Protection Agency; Federal Register, Volume 81, No. 131; July 8, 2016.

[3] https://www.federalregister.gov/documents/2017/12/21/2017-27452/approval-and-promulgation-of-implementation-plans-louisiana-regional-haze-state-implementation-plan

point. Burns & McDonnell suggests that LUS continue to follow up on this issue in case there is a change in the regional haze compliance requirements.

5.4.2 RHR at Labbe

Labbe does not have any BART-eligible sources.

5.4.3 RHR at Hargis-Hebert

Hargis-Hebert does not have any BART-eligible sources.

5.5 Greenhouse Gases and ACE

On June 19, 2019, EPA issued the ACE Rule, an effort to provide existing coal-fired EGUs, with “achievable and realistic” standards for reducing GHG emissions. This action not only proposed the ACE but also repealed the Clean Power Plan (“CPP”). ACE receives authority under Clean Air Act (“CAA”) section 111(d) – NSPS.

ACE establishes heat rate improvement (“HRI”), or efficiency improvement, as the best system of emissions reduction (“BSER”) for carbon dioxide from coal-fired EGUs. ACE requires States to present a plan individualized for each coal-fired utility boiler that sets a unit specific emission rate after analyzing which HRI are applicable and appropriate to the boiler. Each State determines if standard of performance is gross or net output-based. ACE mandates the HRI “candidate technologies” that must be evaluated:

1. Neural Network
2. Intelligent Sootblowers
3. Boiler Feed Pumps
4. Air Heater and Duct Leakage Control
5. Variable Frequency Drives
6. Blade Path Upgrade (Steam Turbine)
7. Redesign/Replace Economizer
8. Improved Operating and Maintenance Practices

For each candidate technology, EPA has provided information regarding the degree of emission limitation achievable through application of the BSER as ranges of expected improvement and costs. Once a rate limit is set, it can be meet by almost any methods including co-firing natural gas or other HRIs not specifically listed.

The State must set an emission rate that is quantifiable, permanent, verifiable, and enforceable. The State must document how each standard of performance was determined and detail the evaluation of each of the HRIs for each facility. A state may find an HRI technology is applicable but costs are not reasonable considering source's remaining useful life or that an HRI technology is applicable, but it is not reasonable to replace current HRI technology with a newer version of the same technology. While the rule explicitly acknowledges many HRI could trigger New Source Review ("NSR"), NSR implications are not addressed.

5.5.1 ACE Rule at RPS2

As a coal-fired steam generating unit, RPS2 is subject to the ACE Rule.

Two of the technologies that are expected to offer some of the largest improvements in unit-level heat rate (steam turbine blade path upgrade and economizer redesign/replace) have the most potential to trigger NSR requirements. If an HRI triggers NSR, the resulting requirements for analysis, permitting, and capital investments will greatly increase the cost of implementing those HRI technologies and, in the absence of NSR reforms, states will be more likely to determine that those technologies are not cost-effective when analyzing "other factors" in determining a standard of performance for an individual facility.

Louisiana has not yet held its first stakeholder meeting. Since the LDEQ is responsible for the compliance, there are a large number of possibilities and unknowns associated with the implementation of the ACE Rule such as the emission rate and verification method set by the State, cost to comply with the limits, and what controls will be required (if any). States have 3 years (until July 8, 2022) to evaluate all units and submit a SIP to the EPA. It is unknown at this time what, if any, proposals the State of Louisiana will make for compliance with the ACE Rule. Considering the large number of possibilities and uncertainty surrounding LDEQ decisions, the co-owners of RPS2 believe it is reasonable to wait for LDEQ's completed analysis before analyzing every possible means of compliance.

5.5.2 ACE Rule at Labbe

The ACE Rule does not apply to Labbe since the units do not meet the applicability criteria.

5.5.3 ACE Rule at Hargis-Hebert

The ACE Rule does not apply to Hargis-Hebert since the units do not meet the applicability criteria.

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APPENDIX C – TECHNOLOGY ASSESSMENT

Technology Assessment

LAFAYETTE UTILITIES SYSTEM

Lafayette Utilities System

New Generation Technology Assessment
Project No. 118157

January 2020

BURNS McDONNELL

March 30, 2020

Jeff Stewart
Manager, Engineering & Power Supply
Lafayette Utilities System
1314 Walker Road
Lafayette, LA 70506

Re: New Generation Technology Assessment

Dear Mr. Stewart:

Lafayette Utilities System ("LUS") retained Burns & McDonnell to perform an integrated resource planning study ("IRP"). As part of the IRP, Burns & McDonnell completed a New Generation Technology Assessment ("Assessment") to provide information regarding the capital costs, operation and maintenance costs, and performance estimates, along with other characteristics, for a variety of different technologies for evaluation within the IRP. The information herein is to be utilized within the IRP process to help LUS set a power supply direction moving forward.

If you have any questions regarding this information, please feel free to contact either Mike Borgstadt at 816-822-3459 or mike.borgstadt@1898andco.com or Kyle Combes at 816-349-6884 or kyle.combes@1898andco.com.

Sincerely,

Mike Borgstadt
Director, Utility Consulting

Kyle Combes

Kyle Combes
Project Manager

MEB/meb

Enclosure
cc: Karen Hoyt
Josh Zeno

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Technology Assessment

prepared for

Lafayette Utilities System
New Generation Technology Assessment
Lafayette, Louisiana

Project No. 118157

January 2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
Assessment	New Generation Technology Assessment
AWEA	American Wind Energy Association
BACT	Best Available Control Technology
BOEM	Bureau of Ocean Energy Management
Btu/kWh	British Thermal Units per Kilowatt Hour
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CI	Combustion Inspection
CO	Carbon Monoxide
DLN	Dry Low Nitrogen Oxide
DOE	Department of Energy
EIA	Energy Information Administration
EPC	Engineer, Procure, Construct
°F	Fahrenheit
GADS	Generating Availability Data System
GE	General Electric
GSU	Generator Step-Up Transformer
HAP	Hazardous Air Pollutants
HGP	Hot Gas Path
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IRP	Integrated Resource Plan
lb/MMBtu	Pounds per Million British Thermal Units
LHV	Lower Heating Value
LTSA	Long-term Service Agreement
LUS	Lafayette Utilities System
MECL	Minimum Emissions Complain Load
MI	Major Inspection
MISO	Midcontinent Independent System Operator

Abbreviation	**Term/Phrase/Name**
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NaS	Sodium Sulfur
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxide
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
O&M	Operation and Maintenance
O_2	Oxygen
OEM	Original Equipment Manufacturer
Owner	Lafayette Utilities System
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter 2.5 Microns or Smaller
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
psig	Pounds per Square Inch Gauge
PV	Photovoltaic
RH	Relative Humidity
RICE	Reciprocating Internal Combustion Engine
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
STG	Steam Turbine Generator
U.S.	United States
USD	United States Dollar
VOC	Volatile Organic Compounds

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1.0 INTRODUCTION

Lafayette Utilities System ("LUS" or "Owner") retained Burns & McDonnell Engineering Company ("Burns & McDonnell") to evaluate various power generation technologies in support of its integrated resource planning efforts ("IRP"). The New Generation Technology Assessment ("Assessment") is screening-level in nature and includes a comparison of technical features, cost, performance, and emissions characteristics of the generation technologies listed below.

Within the IRP, LUS is considering numerous power supply alternatives including the retirement of units, the addition of new resources, potential power purchases, or any combination of resources thereof. The Assessment is screening-level in nature and includes a comparison of technical features, cost, performance, and emissions characteristics of power generation and storage technologies that may be available to LUS.

It is the understanding of Burns & McDonnell that this Assessment will be used for preliminary, screening level information in support of the LUS' long-term power supply planning process for identifying those technologies that best meet LUS needs. The technologies selected from this process will be examined in much more detail, including their expected economic and reliability performance in the Midcontinent Independent System Operator ("MISO") market. Any technologies of interest to LUS should be followed by additional detailed studies to further investigate each technology and its direct application within the Owner's long-term plans.

1.1 Evaluated Technologies

Burns & McDonnell evaluated and considered numerous technologies for the IRP to provide reliable, safe, and economic generation to meet LUS' power supply requirements. These technologies included natural gas-fired, renewable, and storage resources. Each type of resource presents advantages and disadvantages when being considered within a comprehensive power supply portfolio. Burns & McDonnell and LUS identified, evaluated, and preliminarily screened the resources for their ability to complement LUS' existing resources and meet future load requirements for its customers. Burns & McDonnell and LUS considered the following types of resources.

- Natural gas-fired resources including peaking and intermediate resources
- Renewable options including wind and solar
- Storage alternatives including batteries, compressed air energy storage, and pumped hydropower storage

After initial screening based on Burns & McDonnell's experience with planning and project execution, the following resources were selected for further evaluation within this Assessment. These technologies provide representative alternatives for meeting LUS' needs, such as output, operational flexibility, project development feasibility, under a variety of portfolio considerations within the economic evaluations:

- Simple Cycle Gas Turbine (SCGT) – 1 x F class 230 MW
- Reciprocating Engine – 5 x 18 MW units (90 MW total)
- Combined Cycle Gas Turbine (CCGT) – 1x1 G/H class 420 MW
- Wind Generation – On-shore, land-based 50 MW
- Solar PV – Single axis tracking 50 MW
- Battery Storage – Lithium Ion 25 MW / 100 MWh

1.2 Assessment Approach

This report summarizes the evaluated results and compiles the assumptions and methodologies used by Burns & McDonnell during the Assessment. Its purpose is to articulate that the delivered information is in alignment with LUS' intent to advance its resource planning initiatives.

The following sections provide a description of the technologies considered within this assessment. Appendix A provides the cost and performance estimates for each technology.

1.3 Conclusions & Recommendations

This technology assessment provides information to support LUS' power supply planning efforts for further evaluation within the economic modeling efforts for the IRP. Information provided in this assessment is preliminary in nature and is intended to highlight indicative, differential costs associated between each technology. After identifying the preferred combination of resources within the IRP, LUS should pursue additional engineering studies to define specific items such as project scope, design, and equipment, budgets, and implementation timeline for the preferred technologies of interest.

The selected alternatives from this screening effort will be further evaluated within the IRP for their ability to complement or replace existing resources within LUS' power supply portfolio, both from a technical ability and economic evaluation. A brief highlight of the advantages and disadvantages of the technologies is presented in Table 1-1.

Table 1-1: Summary of Technologies

Technology	Advantages	Disadvantages
Gas-Fired Resources		
Aeroderivative	• Flexible operation (ability to quickly turn-on/off in response to market signals) • More efficient than large frame units • Ability for on-system installation	• High fuel gas pressure • Higher capital cost compared to other peaking resources on $/kW basis
F-Class	• Lowest cost peaking resource on a $/kW basis • Flexible compared to CCGT, but slightly less than Aeroderivative and reciprocating engines • Ability for on-system installation	• High fuel gas pressure • Large capacity on a single shaft • Less flexible compared to aeroderivatives and reciprocating engines • Higher heat rate compared to aeroderivative turbines
Reciprocating Engines	• Most flexible gas-fired resource (ability to quickly turn-on/off in response to market signals) • Low fuel gas pressure • Shaft diversification (9-18MW)[1] • Ability for on-system installation	• Higher capital cost compared to F-Class or CCGT technology on a $/kW basis
CCGT	• Most efficient gas-fired technology • Lower capital cost due to economies of scale on a $/kW basis	• Lacks flexibility compared to other gas-fired technologies • Must be one of potentially several pseudo-owners of a large unit • Most likely located off-system
Renewables		
Locally Owned Wind (Louisiana)	• Reduced transmission congestion	• No Production Tax Credit or Interconnection Tax Credit (need taxable partner) • Uneconomical compared to resources available in nearby regions • Wind farms cannot be easily integrated into residential, commercial, or industrial areas
Regional Wind (MISO)	• Economically justifiable • Production Tax Credit through PPA (subject to Congress) • Large wind farms reduce the overall cost of the technology	• LUS is not the operator of the wind farms • Potential congestion costs

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[1] Shaft diversification provides a utility the opportunity for increased reliability since it would have the ability to utilize multiple engines providing the same level of capacity and generation, as opposed to having all of the energy sourced from a single engine.

Technology	Advantages	Disadvantages
Off-Shore Wind (Louisiana)	• Higher wind resource potential compared to local on-shore wind	• Off-shore wind in the U.S. is still in the infancy of development • Only one off-shore facility is operational in the U.S. with none currently in development in Louisiana[2][3]
Local Solar	• Increase to renewable energy production for utility portfolio • Potential tax credits through PPA (subject to Congress)	• Lack of solar resource availability in Louisiana • Higher cost of energy compared to regional wind
Storage		
Flow Battery	• Scalable technology in development • Higher cycling life compared to conventional batteries • Offsets electric peak loads	• Technology is not entirely mature currently • Required operation of ancillary equipment
Conventional Battery (Lead Acid and Lithium Ion)	• Low capital costs • Responsive to changes in grid demand • Offsets electric peak loads	• Life is dependent on cycling and discharge rates, potentially 5 to 10 years for high cycling utilization • High maintenance cost • Materials used are associated with being high toxicity
High Temperature	• High discharge rates • Life expected to be around 15 years • Offsets electric peak loads	• Energy requirement to maintain liquid electrolytes • Technology is still being developed for utility level applications • Uneconomically compared to other storage technologies
Pumped Hydro	• Large reservoir of storage energy • Offsets electric peak loads	• Geology required for water storage • Environmental impacts to surrounding areas • High capital costs
Compressed Air Energy Storage (CAES)	• Large reservoir of storage energy • Offsets electric peak loads	• Specific geology required for compressed air storage • High capital costs

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[2] https://www.awea.org/Awea/media/Resources/Fact%20Sheets/Offshore-Fact-Sheet.pdf

[3] https://www.boem.gov/renewable-energy/state-activities

2.0 NATURAL GAS-FIRED TECHNOLOGY OVERVIEW

In general, there are three main natural gas-fired technologies that have been implemented within the industry for power generation including simple cycle gas turbines, reciprocating internal combustion engines, and combined cycle gas turbines. The following section provides an overview and description of the natural gas-fired technologies considered within this Assessment.

2.1 Simple Cycle Gas Turbine Technologies

A simple cycle gas turbine plant utilizes natural gas to produce power in a gas turbine generator. The gas turbine cycle (the Brayton cycle) is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power to produce electricity.

2.1.1 Technology Description

Simple cycle gas turbine generation is a widely used, mature technology, typically used for peaking power due to their fast load ramp rates and relatively low capital costs. However, the units have higher heat rates compared to combined cycle gas turbine technologies.

The output of combustion turbine technologies is dependent on the mass of flow through the turbine. This is impacted by both altitude and ambient temperatures. To achieve higher output at elevated ambient temperatures, evaporative coolers are often used to cool the air entering the gas turbine by evaporating additional water vapor into the air, which increases the mass flow through the turbine and therefore increases the output. Evaporative coolers are not included for the SCGT technology in this assessment due to the humid ambient conditions.

While this is a mature technology category, it is also a highly competitive marketplace. Manufacturers are continuously seeking incremental gains in output and efficiency while reducing emissions and onsite construction time. Both frame and aeroderivative manufacturers are striving to implement faster starts and improved efficiency. Advances in frame unit combustor design allow improved ramp rates, turndown, fuel variation, efficiency, and emissions characteristics. Alternatively, aeroderivative turbines benefit from the research and development efforts of the aviation industry, including advances in metallurgy and other materials.

Low load or part load capability may be an important characteristic depending on the market price signals and the resulting operational profile of the plant. Low load operation allows the SCGTs to remain online and generate a small amount of power while having the ability to quickly ramp to full load without going through the full start sequence.

2.1.2 Aeroderivative Gas Turbines

Aeroderivative gas turbine technology is based on aircraft jet engine design, built with high quality materials that allow for increased turbine cycling. The output of commercially available aeroderivative turbines ranges from less than 20 MW to approximately 100 MW in generation capacity. In simple cycle configurations, these machines typically operate more efficiently than larger frame units and exhibit shorter ramp up and turndown times, making them ideal for peaking and load following applications. Aeroderivative units typically require fuel gas to be supplied at higher pressures (i.e. 675 pounds per square inch gauge ("psig") to 960 psig for many models) than more traditional frame units. This requires the addition of natural gas compressors, which are included in the cost estimates for this technology.

A desirable attribute of aeroderivative turbines is the ability to start and ramp up quickly. Most manufacturers will guarantee 10-minute starts, measured from the time the start sequence is initiated to when the unit is at 100 percent load. Simple cycle starts are generally not affected by cold, warm, or hot temperature conditions of the equipment. Depending on the original equipment manufacturer ("OEM") and packages included with the major equipment, some combustion turbines can have very quick turnaround times from shutdown to start cycles with others requiring longer down periods between cycles. However, all gas turbine start times in this Assessment assume that all start permissives are met, which can include items such as lube oil temperature and fuel pressure. Costs have been included with the operation and maintenance cost estimates in order to operate in this manner.

Aeroderivative turbines are considered mature technology and have been used in power generation applications for decades. These machines are commercially available from several vendors, including General Electric ("GE"), Siemens, and Mitsubishi-owned PW Power Systems (formerly known as Pratt & Whitney).

2.1.3 Frame Gas Turbines

Frame style turbines are more conventionally designed industrial engines that are typically used in intermediate to baseload applications. In simple cycle configurations, these engines typically have higher heat rates (less efficient) when compared to aeroderivative engines. The smaller frame units have simple cycle heat rates around 11,000 British thermal units per kilowatt hour ("Btu/kWh") on a high heating value ("HHV") or higher while the largest units exhibit heat rates approaching 9,000 Btu/kWh (HHV). However, frame units have higher exhaust temperatures (≈1,100°F) compared to aeroderivative units (≈850°F), making them more efficient in combined cycle operation because exhaust energy is further utilized. Frame units typically require fuel gas at lower pressures, around 500 psig, than aeroderivative units.

Traditionally, frame turbines exhibit slower startup times and ramp rates than aeroderivative models, but current market conditions are driving manufacturers to consistently improve these characteristics. Conventional start times are commonly 20 to 30 minutes for frame turbines, but fast start options allow 10 to 15-minute starts.

Frame engines are offered in a large range of sizes by multiple suppliers, including GE, Siemens, Mitsubishi, and Alstom. Commercially available frame units range in size from approximately 50 MW up to 350 MW. Continued development by gas turbine manufacturers has resulted in the separation of gas turbines into several classes, grouped by output and firing temperature. For the purposes of this Assessment, Burns & McDonnell selected the F-class turbine (nominal 200 MW to 240 MW) as the representative equipment for the frame technology. The cost and performance estimates for this Assessment are based on the GE 7F.05 turbine for a simple cycle alternative. LUS' Bonin site has power generation infrastructure on-site, as it has historically supported approximately 300 MW of generation. For this Assessment, Burns & McDonnell developed a cost estimate based on a greenfield location. However, the Bonin site very well could be suitable for a SCGT development and leverage the existing infrastructure that is currently at the site regarding transmission, natural gas, and water. However, further evaluations would need to be conducted before selecting a specific site location.

2.1.4 Environmental Regulations & Emissions Controls

Emissions levels and required nitrogen oxides ("NO_x") and carbon monoxide ("CO") controls vary by technology and site constraints. Historically, natural gas SCGT peaking plants in attainment areas have not required post-combustion emissions control systems because they operate at low capacity factors. However, permitting trends suggest post-combustion controls may be required depending on annual number of gas turbine operating hours, location in a non-attainment area, and current state regulations.

Regulations pertaining to simple cycle combustion turbines are typically straight forward. New Source Performance Standard ("NSPS") (40 CFR Part 60), Subpart KKKK apply to combustion turbines. Per NSPS Subpart KKKK, natural gas-fired units with heat inputs below 850 million Btu per hour ("MMBtu/hr") have a NO_x limit of 25 ppm, but units with heat inputs greater than 850 MMBtu/hr have a NO_x limit of 15 ppm. These limits are generally met by the OEMs with low-NO_x burners, with some exception. In the rare case where a combustion turbine cannot meet the NSPS, a selective catalytic reduction system ("SCR") is required to meet the NO_x emission limits per the NSPS. The NSPS also has limits for fuel oil combustion of 42 ppm and 96 ppm for units with heat inputs of 850 MMBtu/hr and above and those under 850 MMBtu/hr, respectively. Most OEMs can meet these thresholds for fuel oil combustion.

F-class gas turbines use dry-low-NO_x ("DLN") combustors to achieve NO_x emissions of 9 ppm at 15 percent oxygen ("O_2") while operating on natural gas fuel. Since these units emit less than 15 ppm NO_x, no SCR is assumed to be required. Further, traditional guarantees for fuel oil, if used as a back-up fuel, can meet the required limits in Subpart KKKK.

Aeroderivative units utilize water injection to achieve NO_x emissions of 25 ppm at 15 percent O_2 while operating on natural gas fuel. Because the aeroderivative units have heat inputs typically below 850 MMBtu/hr, it meets the appropriate NO_x limit and therefore it is assumed that an SCR is not required.

Within attainment areas, in the event the overall facility has the potential to emit greater than 250 tons per year of any pollutant and over 40 tons per year of NO_x emissions, selective catalytic reduction ("SCR") may be required to meet Prevention of Significant Deterioration Best Available Control Technology requirements or the units may opt to limit the number of operating hours available for the facility.[4] If the site is a greenfield site, it is rare for simple cycle peaking facilities to not be able to limit/adjust hours of operation to remain below the prevention of significant deterioration ("PSD") threshold of 250 tons per year avoiding the need for SCR.

The NSPS for greenhouse gases from electric utilities limits CO_2 emissions to 120 lb/MMBtu CO_2. Most simple cycle combustion turbines can easily meet this limit. Additionally, regulations limit the operation of simple cycle technologies greater than 25 MW per unit to a maximum capacity factor equal to the overall efficiency of the unit. For most combustion turbines, this is approximately a 33-percent annual capacity factor (or approximately 2,900 hours per year per turbine).

The federal requirements for combustion turbines also include National Emission Standards for Hazardous Air Pollutants ("NESHAP") at 40 CFR Part 63, Subpart YYYY. Subpart YYYY is stayed for lean pre-mix combustion turbines and therefore there are no requirements for the frame or aeroderivative combustion turbines that are included in this technology assessment. This regulation limits formaldehyde emissions at major sources of hazardous air pollutants ("HAP"). It is also not expected that a greenfield simple cycle combustion turbine site would be a major source of HAPs.

Most turbine manufacturers will guarantee emissions down to a specified minimum load, commonly 40 to 50 percent load. Below this minimum load, turbine emissions may spike. As such, emissions on a ppm basis may be significantly higher at low loads. For this reason, the turbines will have a defined start-up

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[4] Recent greenhouse gas regulations limit the operation of simple cycle technologies greater than 25 MW per unit to a maximum capacity factor equal to the unit's overall efficiency.

and shutdown period when emissions are allowed to spike, but timeframe for starts and stops may be limited and would need to be quantified in the air permit application.

During the permitting of simple cycle combustion turbines, if emissions exceed 40 tons per year of NO_x and/or 10 tons per year of particulate matter 2.5 microns and smaller (“$PM_{2.5}$”), the state of Louisiana will require air dispersion modeling. Further, air dispersion modeling is recommended even if not required by the state agency to make sure that the stacks will be tall enough to result in modeled concentrations that are below the National Ambient Air Quality Standards (“NAAQS”).

Should facilities be required to install an SCR system, it is assumed that oxidation catalysts would also be included to control CO emissions to 2 ppm at 15 percent O_2 and to control volatile organic compound (“VOC”) emissions while operating on natural gas fuel. On plants without SCR systems, no post-combustion controls for CO are included.

Outside of good combustion practices, it is assumed that emissions control equipment is not required for carbon dioxide (“CO_2”) and particulate matter (“PM”). Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Sulfur dioxide emissions will be minimal and do not present an issue for operating simple cycle combustion turbines utilizing natural gas.

2.1.5 Operation & Maintenance Considerations

Electric utilities typically have several options to consider regarding operation and maintenance (“O&M”) of major equipment components, such as combustion turbines. In the power generation market, the purchase of a combustion turbine typically includes a long-term service agreement (“LTSA”) with the OEM to provide maintenance services and parts to maintain the turbine in accordance with the turbine manufacturer’s recommendations for optimal performance. Typical OEM LTSAs include the following coverage, but can vary dependent on the OEM and class of turbine:

- Covered maintenance of borescopes, combustion inspection (“CI”), hot gas path (“HGP”) inspection, major inspection (“MI”), and generator inspections
- Mandatory spare parts storage either on-site or as a part of a “parts pool”
- Discount on service and parts
- Warranty (short-term and long-term) on classified parts and services (covered parts are covered for the length of the LTSA contract)
- Guarantees on parts delivery, performance, and degradation after major inspections, and technical field advisor support during unplanned outages.

LTSAs are complex agreements that may not always be the preferred choice for O&M service for an Owner to execute with the OEM. Considerations must be made based on capacity factor (inspections points are based on equivalent operating hours), long-term pricing competitiveness, limitations of liability, and risk mitigation with the upkeep and performance of the equipment. Other options that Owner’s may consider for O&M services is to self-perform maintenance, either with existing staff or contracting with a third-party specializing in turbine maintenance. For example, this has been done by numerous utilities for widely installed combustion turbines that have a large pool of qualified O&M providers.

Furthermore, with some technologies, OEMs offer turbine lease agreements during major overhauls of turbines. These lease agreements offer the utilities to operate a facility with a “spare” combustion turbine, while the original turbine 1) is physically removed from facility, 2) undergoes maintenance which is performed in an OEM shop located off-site, and 3) returned to service at the facility. This is typically only available to aeroderivative turbines, which are smaller combustion turbines and able to be removed and replaced more easily than larger frame-type combustion turbines.

The specific O&M plan for a combustion turbine will be driven on the specific OEM selected and the overall economics of the contract when the turbine is being selected for design and construction. For the purposes of this Assessment, Burns & McDonnell assumed an LTSA from the OEM to serve as the ongoing costs associated with maintenance of new turbine installations.

2.2 Reciprocating Internal Combustion Engine Technology

This Assessment includes a reciprocating internal combustion engine plant for comparison among the SCGT options, which are both used primarily for peaking purposes.

2.2.1 Technology Description

The internal combustion, reciprocating engine operates on the four-stroke Otto cycle to convert pressure into rotational energy. Fuel and air are injected into a combustion chamber prior to its compression by the piston assembly of the engine. A spark ignites the compressed fuel and air mixture causing a rapid pressure increase driving the piston downward. The piston is connected to an offset crankshaft, thereby converting the linear motion of the piston into rotational motion that is used to turn a generator for power production. By design, cooling systems are typically closed-loop, minimizing water consumption.

Reciprocating engines are generally more tolerant of altitude and ambient temperature than gas turbines. With site conditions below 6,000 feet and 100°F, altitude and ambient temperature have minimal impact on the electrical output of reciprocating engines, though the efficiency may be slightly affected. Above 100°F, the units will experience a slight reduction in output (approximately one percent per °F).

Reciprocating engines can start up and ramp load more quickly than most gas turbines, but it should be noted that the engine jacket temperature must be kept warm to accommodate start times under 10 minutes.[5] However, it is common to keep water jacket heaters energized during all hours that the engines may be expected to run, which increases the auxiliary load of the facility while it is idle (associated costs have been included within the fixed O&M costs).

Many vendors manufacture reciprocating engines including Wärtsilä, Fairbanks Morse, Caterpillar, Kawasaki, Mitsubishi, and GE's Jenbacher. Reciprocating engines have become popular as a means to follow wind turbine generation with their quick start times and operational flexibility. This flexibility could lead to increased market dispatch and increased revenue opportunities. There are slight differences between manufacturers in engine sizes and other characteristics, but all largely share the common characteristics of quick ramp rates and start-ups when compared to gas turbines.

The reciprocating engines are manufactured in varied sizes for bulk power generation, ranging from 2 MW to 20 MW. Utility scale applications most commonly rely on medium speed engines in the 9 to 10 MW and 18 to 20 MW classes. All of the OEMs indicated above offer a spark ignition engine in the 9 to 10 MW class, but only Wärtsilä and MAN have commercially available 18 to 20 MW class engines in the United States.

The 90 MW plant evaluated in this Assessment is based on Wärtsilä natural gas engines, model 18V50SG. These heavy duty, medium speed, four-stroke combustion engines are easily adaptable to grid-load variations. The evaluated engines are single fuel, gas-only units, although dual fuel engines are available.

2.2.2 Environmental Regulations & Emissions Controls

Reciprocating engines must comply with the NSPS Subpart JJJJ (NSPS for Spark Ignition Reciprocating Internal Combustion Engines). As such, most vendors have stated that they can meet the required NO_x, CO, and VOC emission limits in this regulation for the 8-MW to 20-MW sized engines. It is important to note that SCR and oxidation catalysts are typically included with reciprocating engines, but may not be required if emissions are below the major source threshold for PSD, as OEMs have stated that they will

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[5] If the engine jacket temperature is 1) greater than185°F, the engine can start in 7 minutes, 2) between 120°F and 185°F it will take 1 to 2 hours to get to full load, and 3) less 120°F will require several hours for start-up. Auxiliary loads for jacket heating are approximately 300 to 400 kWh per engine. For this Assessment,

guarantee uncontrolled emissions to meet the NSPS limits. Further analysis would need to be performed for determination of NO_x and CO/VOC controls are warranted. NSPS Subpart TTTT (NSPS for greenhouse gases from power plants) is not applicable to the engines as units that are less than 25 MW are exempt from this regulation.

As is typical for reciprocating engines, especially if they exceed the PSD thresholds, it is assumed that SCR and CO catalysts are required to control NO_x and CO emissions. Operation on natural gas fuel with an SCR yields reduction of NO_x emissions to 5 ppm at 15 percent excess O_2, while a CO catalyst results in anticipated CO emissions of 15 ppm. It is assumed that emissions control equipment is not required for CO_2 and PM. Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel. Sulfur dioxide emissions will be minimal and do not present an issue for operating reciprocating engines utilizing natural gas.

There is also a NESHAP regulation for engines that would be applicable to these large reciprocating engines. Subpart ZZZZ (40 CFR Part 63, Subpart ZZZZ) has requirements for all makes, models, years and fuels for reciprocating engines (spark-ignition as well as compression-ignition).

As with the combustion turbines, it is recommended that even if not required by the state agency, air dispersion modeling should be performed to optimize the stack heights for the engines. Typically, taller stacks are required for $PM_{2.5}$ emissions when a large number of reciprocating engines are installed in a long engine hall building to prevent downwash from the building.

2.2.3 Operation & Maintenance Considerations

Similar to combustion turbines, electric utilities typically have several options to consider regarding O&M of reciprocating engines (see Section 2.1.5). The OEMs have the ability to provide for long-term O&M services and spare parts. While lease programs are not as prevalent due to the design of reciprocating engines, their design does allow for the maintenance of individual engines while the other engines at the facility can remain operational. This allows for only a single engine to be out-of-service and the rest of the plant to be available for dispatch.

The specific O&M plan for a reciprocating engine will be driven on the specific OEM selected and the overall economics of the contract when the engine is being selected for design and construction. For the purposes of this Assessment, Burns & McDonnell assumed an LTSA from the OEM to serve as the ongoing costs associated with maintenance of new reciprocating engine installation.

2.3 Combined Cycle Gas Turbine Technologies

The basic principle of a combined cycle gas turbine ("CCGT") plant is to utilize natural gas to produce mechanical power in a combustion turbine which can be converted to electric power by a coupled generator, while also using the hot exhaust gas from the combustion turbine to produce steam in a heat recovery steam generator ("HRSG"). This steam is then used to drive a steam turbine generator ("STG") to produce electric power.

2.3.1 Technology Description

The use of both combustion and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high energy conversion efficiencies and low emissions. Combined cycle facilities have efficiencies typically in the range of 52 percent to 58 percent on a lower heating value ("LHV") basis. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing. The heat rate will increase during duct fired operation, though this incremental duct fired heat rate is generally less than the resultant heat rate from a similarly sized simple cycle gas turbine ("SCGT") peaking plant.

While combined cycle resources have the lowest, most efficient heat rate of the natural gas-fired resources, combined cycle resources are not quite as flexible in regard to starts and shutdown compared to the simple cycle and reciprocating engines technologies. While the combustion turbine attributes are similar, the steam cycle requires a longer startup and shutdown period to bring the equipment to proper temperatures, such as the HRSG and STG. Combined cycle start durations are affected by temperature conditions of the equipment (i.e. cold, warm, or hot). The start duration is longer for the times when the temperature gradient is greater between the equipment temperature and the operating temperature (~1,000ºF). Additionally, the CCGT technology cannot move as quickly to changes in generation output due to the steam cycle compared to peaking resources. However, the new CCGT are much more flexible than traditional steam units such as coal-fired or natural gas-fired boilers.

As discussed in prior sections, continued development by gas turbine manufacturers has resulted in the separation of gas turbine technology into various classes. For the purposes of this Assessment, Burns & McDonnell evaluated greenfield configurations of with G/H-class turbines. While LUS' Bonin site has power generation infrastructure on-site, it has historically supported approximately 300 MW of generation. It is assumed the Bonin site would be unsuitable for a large CCGT development due the overall size of 500 to 1,000 MW, which will require significantly more infrastructure regarding transmission, natural gas, and water than is currently available. However, further evaluations would need to be conducted before selecting a specific site location.

2.3.2 Environmental Regulations & Emissions Controls

Similar to simple cycle combustion turbines, combined cycle combustion turbines are subject to NSPS, Subpart KKKK. As such they have the same NO_x limits as the simple cycle turbines (see Section 2.1.4). The J-class gas turbines can achieve NO_x emissions at 25 ppm down to minimum emissions compliant load ("MECL"). An SCR will be required for the CCGT options to reduce NO_x emissions to 2 ppm at 15 percent excess O_2, as is required to not only meet the NSPS but will also be considered Best Available Control Technology ("BACT") due to the high capacity factor that is common with combined cycle units. Large combined cycle turbines will often exceed PSD thresholds (due, in most part because of high operating hours) and therefore will need to perform a BACT analysis. BACT will result in SCR and oxidation catalyst for control of NO_x and CO/VOC emissions, respectively. It is also important to note that new combined cycle combustion turbines must meet NSPS Subpart TTTT which has a limit of 1,000 lb CO_2/gross MWh. Most combined cycle combustion turbines can easily meet this limit, even while duct firing, because it is an annual average. It is unlikely that emissions of HAPs will result in the site being considered a major source for HAPs, as such NESHAP Subpart YYYY (for HAP emissions) should not be applicable. With an SCR, the estimated emissions rate for NO_x is 0.01 pounds per MMBtu ("lb/MMBtu"). It is anticipated that a CO catalyst will also be required to reduce CO emissions. This assessment assumes CO emissions will be controlled to 2 ppm CO at 15 percent O_2.

The use of an SCR and CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with NO_x molecules. This requires on-site ammonia storage and provisions for ammonia unloading and transfer. The costs associated with these requirements have been included in this assessment.

For all CCGT options, CO_2 emissions are estimated to be 120 lb/MMBtu.

Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Sulfur dioxide emissions of a CCGT plant are very low compared to coal technologies, and the emission rate of sulfur dioxide for a combined cycle unit is estimated to be less than 0.01 lb/MMBtu.

2.3.3 Operation & Maintenance Considerations

Similar to combustion turbines operating in simple cycle mode, combined cycle technologies utilize the same LTSA structure for long-term O&M with the addition of the STG as well (see Section 2.1.5).

2.4 Dual Fuel Operation

Due to a significant amount of coal-fired power plant retirements, there has been an increased interest in firm fuel supply for natural gas-fired resources. Coal-fired generation can stockpile a significant amount of fuel on-site, from 60 to 90 days in some cases. In the event of coal supply disruptions, the power plants would be able to effectively operate with minimal impact due to having sufficient fuel supply located on-site.

Very few natural gas-fired power plants have implemented on-site natural gas storage due to safety and economic factors. Rather, most natural gas power plants, especially peaking resources, operate on interruptible natural gas delivery service. Since peaking resources typically operate in the summer months when air conditioning load is high, natural gas supply is plentifully with few competing uses.

Conversely during the winter months, natural gas experiences higher demand due to residential and commercial heating in addition to more generation being provided by natural gas power plants year-round. Thus, natural gas power plants are experiencing increased competition securing natural gas supplies and deliveries, especially during extreme cold snaps when demand for both natural gas and electricity are high. Combined cycle units, which will likely operate both during summer and winter months, often will secure firm natural gas supplies and/or deliveries to ensure a minimum level of natural gas is supplied to the site. This requires reserving space within the pipeline, so delivery will not be interrupted during peak usages. This reservation can be a significant cost.

On-site fuel oil has been implemented across the U.S. in areas which have determined the need for robust on-site storage due to a variety of factors relating to reliability such as limited natural gas infrastructure in the area (i.e. the power plant is located at the end of the line) or the area is prone to hurricanes which can curtail natural gas availability.

All the combustion turbine technologies considered within this Assessment can utilize dual fuel operation, which is having the ability to operate using either natural gas or fuel oil (i.e. diesel fuel). Installing on-site fuel oil storage would provide firm fuel supply on-site. However, fuel oil operation comes at an increased cost. First, additional capital costs are required to 1) design the combustion turbines or reciprocating engines for dual fuel capability and 2) install additional infrastructure for unloading, storage, and handling of fuel oil. Secondly, the commodity cost of fuel oil is approximately four to five times that of natural gas.

Combustion turbine technologies can operate solely using natural gas or fuel oil. For reciprocating engines that are dual fuel capable, they require that a stream of fuel oil during all hours of operation (approximately one percent of the total heat input). This requires using some level of fuel oil for all operations.

The decision on fuel supply procurement is largely driven on a case-by-case basis for utilities depending on the resource utilization and surrounding infrastructure. Power plants which are located within a robust natural gas area, may elect to utilize interruptible service, especially if they project minimal hours of operation during the winter months. Large combined cycle units typically procure a minimum level of firm natural gas delivery. For most new power plants, fuel oil storage has typically been driven by the requirements for reliability issues and the need for firm on-site fuel supply.

For the IRP, Burns & McDonnell and LUS intend to evaluate non-dual fuel, natural gas-fired only resources. If the IRP indicates the installation of new natural gas-fired resources, an evaluation of natural gas procurement process and on-site storage would be conducted to determine the cost and benefits associated with firm fuel supplies.

2.5 Natural Gas-Fired Technologies Selected for Evaluation

Based on Burns & McDonnell's experience with planning and project execution, the following natural gas-fired resources were selected for further evaluation within this Assessment as the representative technologies in each class.

- Simple cycle gas turbine ("SCGT") technologies
  - 220-MW F-class frame SCGT (greenfield installation)
- Reciprocating internal combustion engine ("RICE" or "reciprocating engine") technology
  - 5 x 18-MW engine plant (greenfield installation)
- Combined cycle gas turbine ("CCGT") technologies
  - 650-MW 1x1 G/H-class (greenfield installation, partial ownership considered)

3.0 RENEWABLE GENERATION OVERVIEW

The following section provides an overview and description of the renewable technologies considered within this Assessment including wind and solar generation resources.

3.1 Wind Energy General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, and are typically used to pump water or generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW are horizontal-axis. Subsystems for either configuration typically include blades or rotor to convert wind energy to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. The power generated by a turbine is proportional to the cube of the prevailing wind speed, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital. According to the Department of Energy's ("DOE") National Renewable Energy Laboratory ("NREL"), wind areas rated with a minimum average wind speed of 7 meters per second and above are generally considered to have suitable wind resources for wind generation development, but obviously higher wind speeds are desired. Figure 3-1 presents the wind resources across the United States as developed by NREL[6]. As presented in Figure 3-1, the Midwest has excellent wind resources stretching from North Dakota through Texas. A significant area that possess wind capable of justifying wind generation development is within the operation of MISO, which is the integrated energy and transmission system LUS operates within. Though most of MISO's wind development is located in the MISO North area while LUS is located in MISO South.

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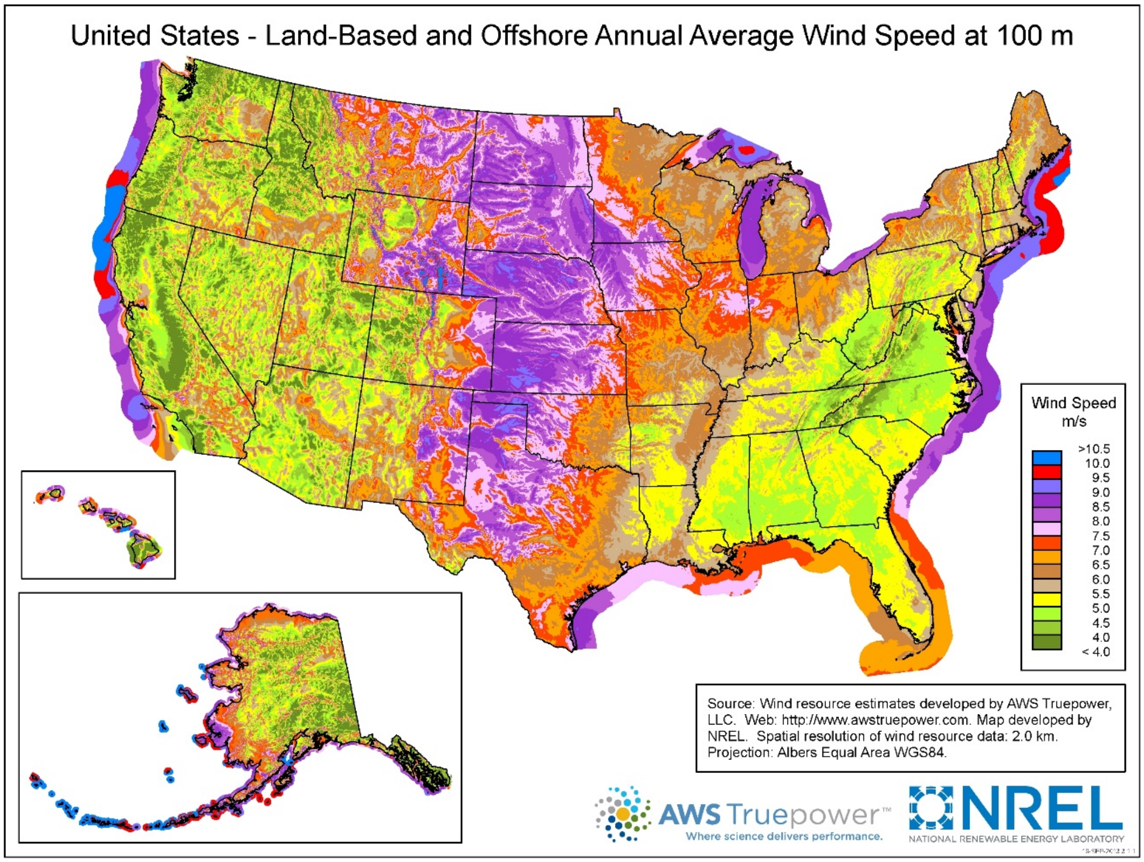
[6] https://www.nrel.gov/gis/wind.html

Figure 3-1: U.S. Wind Resource Map



Source: Wind resource estimates developed by AWS Truepower, LLC. Web: http://www.awstruepower.com. Map developed by NREL. Spatial resolution of wind resource data: 2.0 km. Projection: Albers Equal Area WGS84.

The land-based wind resources surrounding LUS do not have adequate average wind speeds to compete economically with other locations such as Texas, Oklahoma, and Kansas. Off-shore wind resources appear more favorable than local land-based resources in Louisiana, however off-shore wind in the United States is still in the infancy of development. According to the American Wind Energy Association ("AWEA"), there is only one operational off-shore wind project, the Block Island Wind Farm which consists of only 30 MW located three miles off the coast of Rhode Island[7]. Furthermore, according to the Bureau of Ocean Energy Management ("BOEM"), there is no development activity for off-shore wind generation in the state of Louisiana[8]. Land-based wind farms have proven to be much more economical in the United States as illustrated by the large amount of wind generation that has been installed.

The economies of scale greatly reduce the overall energy cost from large wind farms (100 MW or greater for example) compared to smaller wind farms. A 100-MW wind farm will generally span across

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[7] https://www.awea.org/Awea/media/Resources/Fact%20Sheets/Offshore-Fact-Sheet.pdf
[8] https://www.boem.gov/renewable-energy/state-activities

approximately 3,000 to 5,000 acres of land, which is typically located in rural areas. Currently, the industry has not co-located wind farms and residential, commercial, or industrial development due to a number of factors including safety, construction, and permitting. The wind development industry has several guidelines for the minimum distance in which other structures, such as homes, buildings, and roads, can be located within the proximity to wind turbines, for both safety reasons and aesthetics issues such as noise and flicker. Future development within the land inside of a wind farm for residential, commercial, or industrial development would be limited due to the typical setback guidelines. Lastly, tax incentives heavily incentivize a taxable entity to own the wind farm, with non-taxable entities (such as LUS) purchasing energy in the form of a power purchase agreement. Typically, municipal utilities, including LUS, have been able to more economically purchase wind energy from a remote, large wind farm located in regions with better average wind speeds compared to self-owning local wind generation.

LUS currently has contracts for renewable generation. Due to 1) the tax incentives set forth by the Internal Revenue Service which incentivizes taxable entities to develop renewable generation and 2) the location of the more preferred wind resource areas outside of Louisiana, Burns & McDonnell eliminated local wind generation developed within or near LUS' footprint, including off-shore developments, from further consideration in this Assessment. However, land-based wind generation will be considered within the IRP and economic evaluations through participation in power purchase agreements.

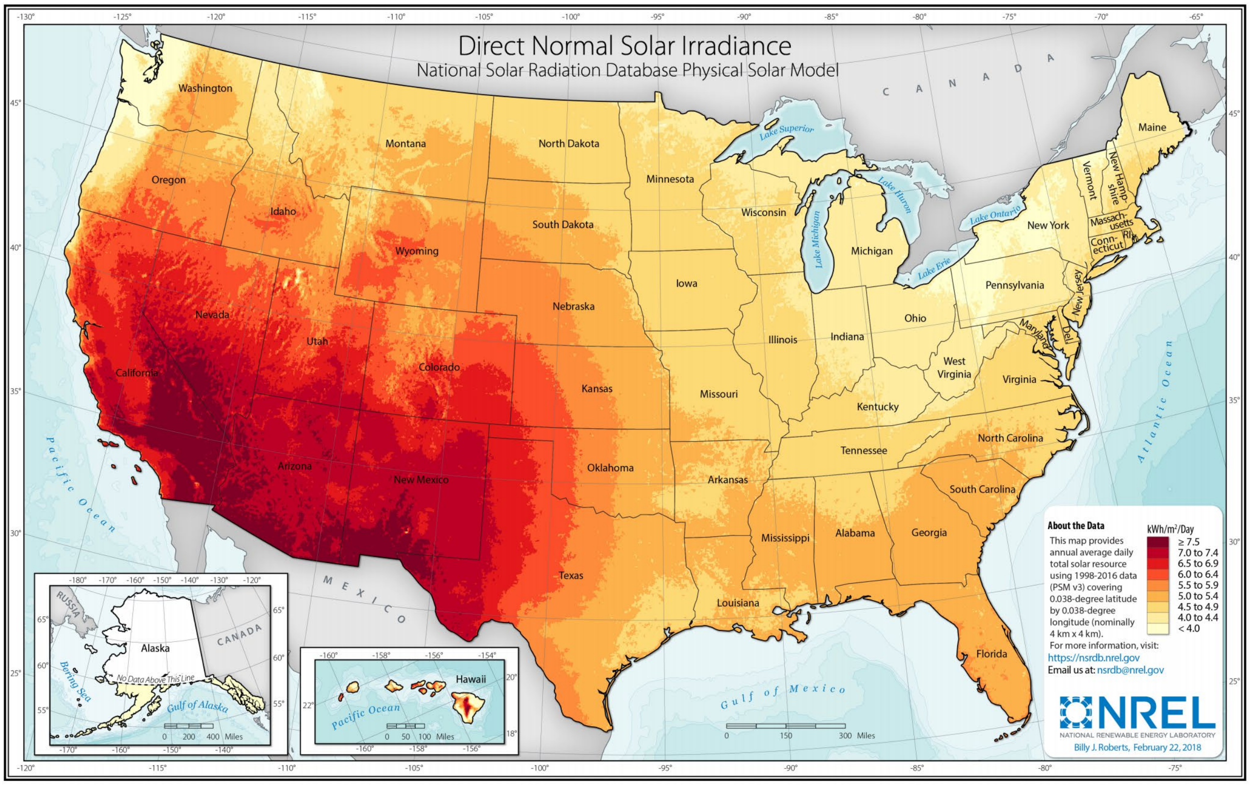
3.2 Solar Generation Technology General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. One form of solar generation technology is solar thermal energy conversion. There are several subsets of solar thermal power systems, but the main types employ reflector systems to concentrate sunlight. These reflector systems focus the concentrated sunlight onto receivers that are often filled with fluid. In the receiver, the fluid temperature raises enough to be used in an energy-producing heat exchange process.

A more common form of solar generation technology is photovoltaic ("PV") electric generation. PV cells consist of a base material (most commonly silicon) which is manufactured into thin slices. The thin slices are layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15 percent of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the solar panels/cells age, the conversion efficiency, that is the amount of energy produced, degrades at a rate of 0.7 percent per year. At the end of a typical 30-year period, the conversion efficiency of the cell will still be approximately 80 percent of its initial efficiency. This technology is similar to the system that the University of Louisiana-Lafayette recently installed. The University of Louisiana-Lafayette system covers approximately six acres of land, located on campus, and has a peak generation output of approximately one megawatt.

Figure 3-3 presents the photovoltaic solar resources across the United States as developed by NREL[9]. As presented in Figure 3-3, the best solar resources are in the Southwest, where weather is less impacted by cloud cover.

Figure 3-2: Photovoltaic Solar Resources



Similar to wind resources, Louisiana does not possess the most abundant solar resources within the U.S., such as the southwestern region in California, Nevada, and Arizona. In general, wind generation is more economical than solar generation in the Midwest. However, solar generation will be considered within the

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[9] https://www.nrel.gov/gis/assets/pdfs/solar_dni_2018_01.pdf

IRP and economic evaluations through participation in a power purchase agreement or jointly-owned facilities.

4.0 ENERGY STORAGE TECHNOLOGY

Energy storage systems are a form of generation that can be used to offset electrical peak loads through potential energy storage created during low (valley) energy usage times. Typical energy storage technologies available today that can provide large levels of capacity storage include pumped hydro and compressed air energy storage, and batteries. Thermal or ice storage systems can also be used on a smaller basis. For this Assessment, Burns & McDonnell evaluated several storage technologies that have been implemented within the utility industry including battery storage, pumped hydropower, and compressed air energy storage ("CAES"). The following provides a description of the storage technologies.

4.1 Battery Storage

The following section provides an overview and description of the battery storage technologies considered within this Assessment. This Assessment includes an option for a 25 MW / 100 MWh, using lithium ion technology. When evaluating battery storage technologies, both capacity (i.e. MW) and energy (i.e. MWh) must be considered. For example, the 25 MW / 100 MWh battery can discharge no more than 25 MW at any instance. However, it is sized to provide 25 MW of output continuously for 4 hours. However, if it was discharged at 12.5 MW continuously, it could provide up to 8 hours of operation.

Appendix A provides the detailed cost and performance estimates for each of the technologies under consideration.

4.1.1 General Description

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing into one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed "flow," "conventional," and "high temperature" battery designs. Each battery type has unique features yielding specific advantages compared to one another.

4.1.1.1 Flow Batteries

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the redox reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Continued research and design is being conducted to develop flow batteries that are scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. However, this is not commercially viable currently. As development continues, many feel that flow batteries will be less capital intensive than some conventional batteries, but require additional installation and operation costs associated with balance of plant equipment.

4.1.1.2 Conventional Batteries

A conventional battery contains a cathodic and anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Battery types are designated by the electrochemicals utilized within the cell, with the most popular conventional battery technologies being lead acid and lithium ion.

4.1.1.2.1 Lead Acid

Lead acid batteries are the most mature and commercially available battery technology, with approximately 35 MW installed worldwide. This design has undergone considerable development since conceptualized in the late 1800s. However, though lead acid batteries require relatively lower capital cost, the technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (meaning higher land and civil work is required for installation) and a short life cycle of between 5 and 10 years.

4.1.1.2.2 Lithium Ion

Lithium ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Lithium ion technology has seen a resurgence of development interest due to its high energy density, low self-discharge, and cycling tolerance, but remains mostly developmental for utility generation applications. Life cycle is dependent on cycling (charging and discharging) and depth of charge (charged load depletion), ranging from 2,000 to 3,000 cycles at high discharge rates, and up to 7,000 cycles at very low discharge rates.

Lithium ion batteries are gaining traction in several markets, including the utility and automotive industries. For example, Tesla’s Powerwall battery storage application utilizes the lithium ion battery technology. Lithium ion battery prices are trending downward, and continued development and investment by manufacturers are expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, lithium ion technologies are anticipated to expand their reach in the utility market sector.

4.1.1.3 High Temperature Batteries

High temperature batteries operate similarly to conventional batteries, but utilize molten salt electrodes. Salt electrodes also carry the added advantage that high temperature operation can yield heat for other applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level, with the most popular and technically mature type being the Sodium Sulfur (“NaS”) battery.

The NaS battery is typically a hermetically sealed cell consisting of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium.

The melting points of sodium and sulfur are approximately 98ºC and 113ºC, respectively. To maintain the electrolytes as liquid and optimize performance, the NaS battery systems are typically operated and stored at around 300ºC, which results in a higher self-discharge rate of 14 percent to 18 percent. These systems are expected to have an operable life of around 15 years and are currently one of the most developed chemical energy storage systems. Japan-based NGK insulators, the largest NaS battery manufacturer, recently installed a 4 MW system in Presidio, Texas, in 2010 following operation of systems totaling more than 160 MW since the project's inception in the 1980s. Commercial development in utility level applications continues to progress, the costs of which have remained relatively stable in recent years compared to other technologies. However, these batteries have not gained significant traction within the industry due to their high cost resulting in poor economics compared to other alternatives.

4.1.1.4 Representative Battery Technology

While each of the battery technologies presented above has both advantages and disadvantages, the lithium ion battery was selected as the representative battery storage technology. Lithium ion systems can respond in seconds and exhibit excellent ramp rates and round-trip cycle efficiencies. Since the technology is still maturing, there is uncertainty regarding projections for cycle life, and these estimates vary greatly depending on the application and depth of discharge.

While all utility scale battery technologies are still developing, lithium ion batteries are the most mature of the battery storage alternatives. Both flow batteries and high temperature batteries are still under development to scale up to utility grade/size currently. If the IRP indicates the installation of an energy storage system, further evaluation of the costs and benefits of the available technologies should be conducted as the technology is developing rapidly.

4.1.2 Battery Emissions Controls

No emission controls are required for a battery storage facility. Much of the battery equipment can be recycled at the end of the useful life of the facility, specifically for lithium ion batteries. However, currently recycling the batteries is more costly than new installations.

4.1.3 Battery Storage Performance

This Assessment includes performance of a 25 MW / 100 MWh battery storage system, based on lithium ion batteries. The systems in this Assessment are assumed to perform one full cycle per day.

Generating Availability Data System ("GADS") performance statistics do not cover battery storage applications, so the availability was estimated based on Burns & McDonnell experience and research.

4.1.4 Battery Storage Cost Estimate

The estimated costs of the lithium ion battery systems are included in Appendix B, based on Burns & McDonnell experience and industry research. The key cost elements of a battery system are the inverter, battery cells, interconnection, and installation. It is assumed that the system will be co-located with an existing asset. It is also assumed that the system will operate at 480V and with a step-up transformer to connect at a distribution voltage.

Battery storage capital costs include current estimates for 2020 battery prices. Rapid development of battery technology should be considered when evaluating price impacts for future installations. Recent pricing indicates that lithium ion battery prices are dropping on average approximately three percent per year for the next several years.

4.1.5 Battery Storage O&M Cost Estimate

O&M estimates for the lithium ion battery system are shown in Appendix B, based on Burns & McDonnell experience and industry research. The battery storage system is assumed to be operated remotely. The fixed O&M costs assume that the end user enters into a full-service contract with the OEMs that covers routine and unplanned maintenance. It includes an allowance for routine maintenance costs and administrative costs such as computers and software licenses. The technical life of a battery project is expected to be 10 to 15 years, while battery cells may need to be replaced every 5 to 10 years. The system is over-designed by 10 percent to account for degradation and limited battery failures, but additional replacement costs for batteries are not included.

4.2 Compressed Air Energy Storage ("CAES") System

The following section provides an overview and description of compressed air energy storage technologies considered within this Assessment.

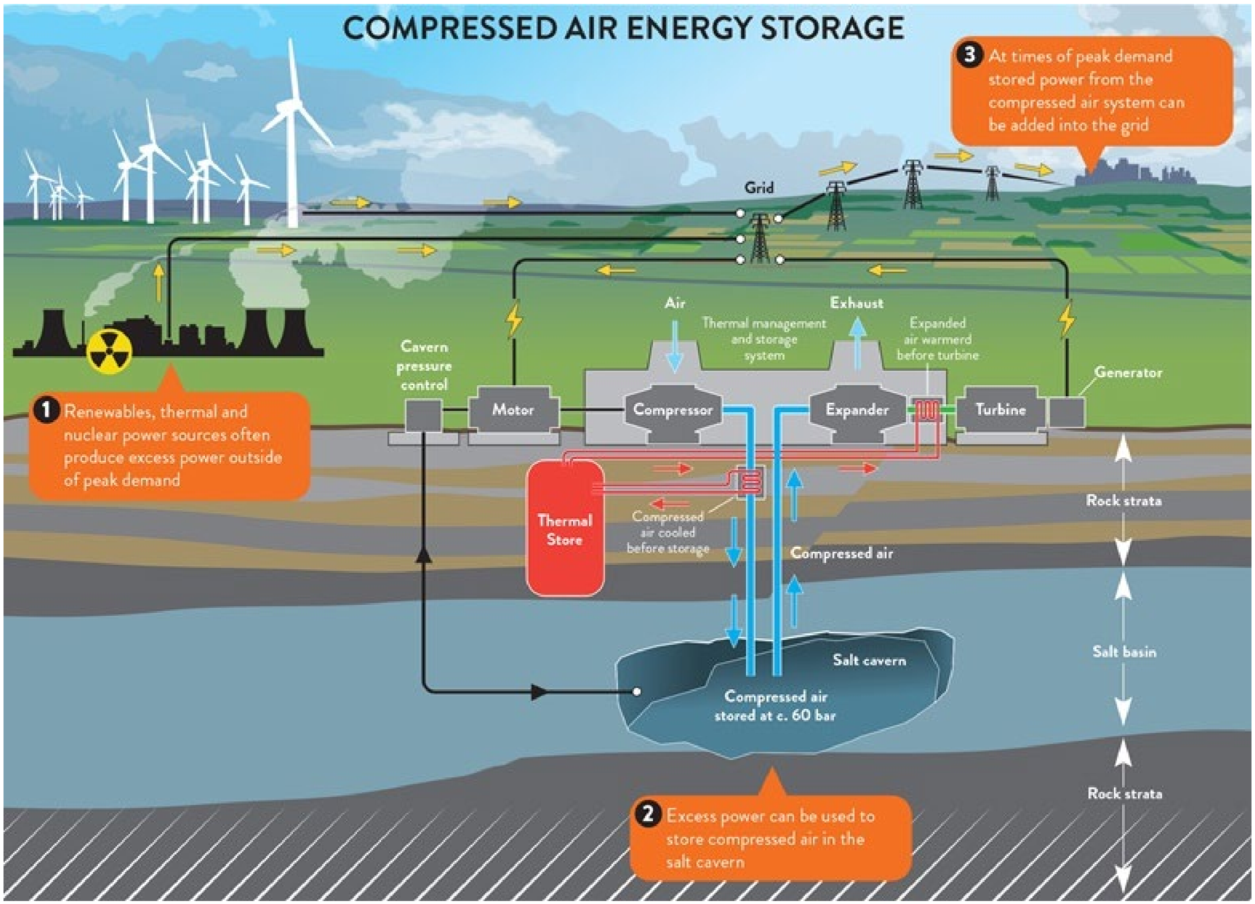
4.2.1 Technology Description

CAES systems are currently being evaluated by the electric industry as a means to provide power during on-peak hours, utilizing off-peak resources (such as wind energy) to compress air which is then stored in a reservoir for use later.

Several arrangements of CAES systems that have been studied, and even though CAES is considered a mature and developed technology, only two facilities have been built in the world. There are two primary reasons why only two systems have been constructed, geologic formations and economics. First, a suitable location must have adequate formations that meet the requirements for CAES applications. This significantly limits the viability of this technology based on location. Secondly, the high cost of the technology has limited its application since the price difference between daily on-peak and off-peak energy must be large enough to provide positive cash flow after paying for the installation and operation of the CAES unit.

Figure 4-1 presents on illustration of a compressed air energy storage system.

Figure 4-1: Illustration of Compressed Air Energy Storage



See footnote for reference[10]

Only two CAES units are operating worldwide which are located in McIntosh, Alabama (110 MW built in 1991), and the other located in Huntorf, Germany (290 MW built in 1978). Both facilities utilize the air in a diabatic process, replacing the compressor stage of a standard combustion turbine which consumes two-thirds (or 67 percent) of the turbine capacity. Essentially, this replacement of the compressor section both reduces natural gas consumption for compression and overall plant emissions requiring a minimum

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[10] Parker, D. (2018, June 6). *Going Underground: Compressed Air Energy Storage*, New Civil Engineer, Retrieved from https://www.newcivilengineer.com/

compressed air pressure of approximately 500 psig. Burns & McDonnell developed the only CAES system in operation in the U.S. The storage cavern for the Alabama facility used a sluiced salt dome that is nearly one-half mile deep and at full charge has a pressure of 1,100 psig.[11]

The compressed air can be stored in several types of reservoirs including underground porous rock formations, depleted natural gas/oil fields, and caverns in salt or rock formations. Underground formations utilize a combination of the depth and shear strength of the overburden material to meet adequate pressure requirements. Compressed air can also be stored in above ground (or "near surface") high pressure pipelines, but previous studies have found these storage options to be up to five (5) times more expensive than underground systems, due to their limited capacity (typically 2 to 4 hours) and additional infrastructure required. There are ongoing studies being performed to develop viable man-made storage options, but these have not yet become economically viable.

Since storage of compressed air is not viable in the geological formations in the Lafayette area due to the geological deficiencies, the high cost of the technology, and the lack of working examples from which to draw upon, CAES has been eliminated from further consideration within this Assessment.

4.3 Pumped Hydropower Storage

Similar to CAES, the hydropower pumped storage system requires suitable geology before the system can be economically applied. Pumped hydropower storage systems require large upper reservoirs to provide potential energy that can be converted into kinetic energy as the water flows through a hydro-electric turbine generator. An equivalent lower reservoir is needed to receive the water for later pumping back to the upper reservoir.

According to the Department of Energy's Energy Information Administration ("EIA") there are 40 pumped storage plants operating in the United States.[12] Figure 4-2 presents a map developed by the EIA that illustrates the locations of the pumped hydroelectric storage facilities across the U.S. Figure 4-3 presents an illustration of a pumped hydropower storage system.

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[11] PowerSouth Energy Cooperative. *Compressed Air Energy Storage*. Retrieved from http://www.powersouth.com/wp-content/uploads/2017/07/CAES-Brochure-FINAL.pdf

[12] *Pumped storage provides grid reliability even with net generation loss*. U.S. Energy Information Administration (2013, July 8). Retrieved from https://www.eia.gov/.

Figure 4-2: Map of Pumped Hydropower Storage Facilities

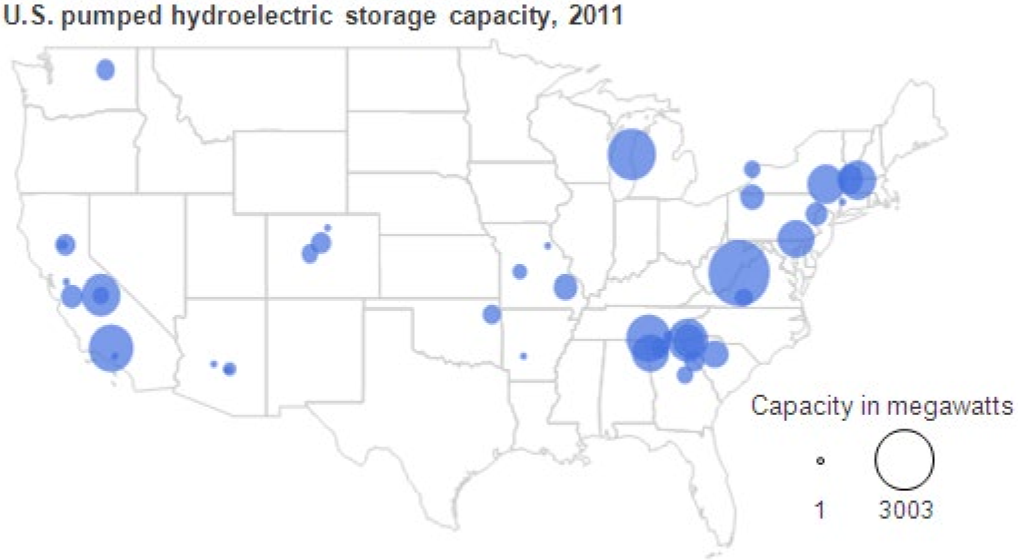
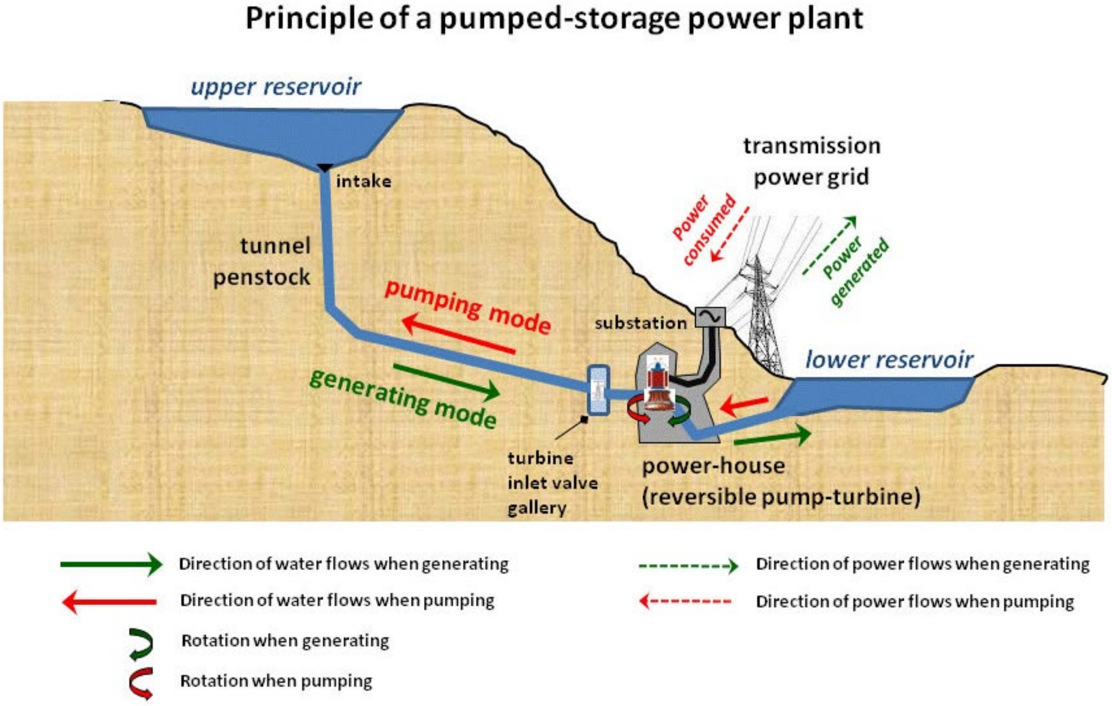


Figure 4-3: Illustration of Pumped Hydropower Storage System



See footnote for reference[13]

Hydropower pumped storage utilizes an upper and lower reservoir to store water used for generation during peak demand times. When the price for energy is low, a pumped storage facility stores energy by

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[13] *What is pumped hydroelectric storage?* Our World of Energy (2018, April 23). Retrieved from https://www.ourworldofenergy.com/

pumping water from a lower reservoir to an upper reservoir. During times of peak demand or high market price, the stored water is released back into the lower reservoir to produce electricity. The DOE defines large hydropower facilities as those with capacity of greater than 30 MW. A large storage reservoir, would require significant amounts of space near a suitable water resource. Similar to CAES, pumped hydropower storage requires significant price differences between daily on-peak and off-peak energy prices in order to provide positive cash flows.

According to the EIA “pumped storage is a long-proven storage technology, however, the facilities are very expensive to build, may have controversial environmental impacts, have extensive permitting procedures, and require sites with specific topologic and/or geologic characteristics. As estimated in a report commissioned by EIA, the overnight cost to construct a pumped hydroelectric plant is about $5,600/kW, higher than the $3,100/kW for a conventional hydroelectric plant. A conventional natural gas combustion turbine, which might be used to supply the peak daytime power added by the pumped storage plant, is $1,000/kW, though hydroelectric operating costs are much lower than those of a combustion turbine.”[14]

Louisiana has no pumped storage facilities. The DOE has reported that the expansion of the United States hydropower fleet has slowed from previous years and retrofitting and additions at existing facilities is one of the few areas where growth is occurring. Since pumped hydropower storage can have massive environmental implications and risks, require large construction funds, and is heavily dependent on optimal geographical features such as large rivers and topography with large elevation differences, it is not considered a viable energy storage technology for LUS and was eliminated from further consideration within this Assessment.

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[14] *Electricity storage: Location, location, location … and cost*. U.S. Energy Information Administration (2012, June 29). Retrieved from https://www.eia.gov/

5.0 STUDY BASIS AND ASSUMPTIONS

5.1 Scope Basis

Scope and economic assumptions used in developing the Assessment are presented below. Key assumptions are listed as footnotes in the Summary Tables in Appendix A, but the following expands on those with greater detail for what is assumed for the various technologies.

5.2 General Assumptions

The assumptions below govern the overall approach of the Assessment:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes. Estimates concentrate on differential values between options and not absolute information.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M estimates are stated in 2019 US dollars ("USD"). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct ("EPC") fixed price contract for project execution.
- All options are based on a generic site with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material.
- Sites are assumed to be flat, with minimal rock and with soils suitable for spread footings.
- Technologies were evaluated for generic locations near Lafayette, LA.
- Ambient conditions are representative of Lafayette average conditions:
  - Elevation: 36 ft.
  - Winter Conditions: 56°F and 71% relative humidity ("RH")
  - Summer Conditions: 82°F and 78% RH
  - Nominal/Average Conditions: 69°F and 74% RH
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- The fuel for the SCGT ,CCGT, and reciprocating engine options is pipeline quality natural gas.
- Natural gas pipeline costs outside the site boundary are excluded. It is assumed that pipeline natural gas is available to the site. Metering and regulation equipment owned and operated by the gas company for billing purposes is excluded from this assessment.

  - Supplemental metering and regulation equipment is included for natural gas technology options. This equipment is not intended for billing purposes, but rather for Owner confirmation and regulation of fuel provided by the gas company.
  - Fuel gas compression is excluded for the options. It is assumed that compression is unnecessary.
- Duct firing is excluded from the base capital costs and performance estimate for the combined cycle option.
- Fuel and power consumed during construction, startup, and/or testing are included in the Owner's costs.
- Piling is included under heavily loaded foundations.
- Water is assumed to be sourced from wells or surface water and available at the site boundary. Pipeline costs and intake structure costs are excluded.
- Waste water is assumed to be delivered to site boundary. Treatment facilities are excluded.
- Electrical scope for the EPC cost is assumed to end at the high side of the generator step up transformer ("GSU"). Switchyard costs are included in the Owner's costs. GSU costs assume 230 kV transmission voltage.
- Demolition or removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- Emissions are estimated at base load operation at annual average conditions.

5.3 EPC Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Performance testing and CEMS/stack emissions testing (where applicable)
- Construction/startup technical service
- Startup and commissioning
- Engineering and construction management
- Freight
- Startup spare parts
- EPC fees & contingency

5.4 Owner Costs

Allowances for the following Owner's costs are included in the pricing estimates:

- Project development
- Owner's operational personnel
- Owner's project management
- Legal fees
- Permitting/licensing
- Construction power, temporary utilities, startup consumables
- Site security
- Operating spare parts
- Switchyard (assumes 230 kV for transmission voltage)
    - Transmission costs are excluded
    - Exceptions: Storage and PV options assume interconnection at distribution voltage.
- Political concessions / area development fees
- Permanent plant equipment and furnishings
- Builder's risk insurance at 0.45 percent of construction cost.
- Owner project contingency at 5 percent of total costs for screening purposes

5.5 Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing fees
- Owner's engineering
- Interest during construction ("IDC")
- Escalation
- Land
- Performance and payment bond
- Sales tax
- Property tax and property insurance
- Transmission interconnect and upgrades
- Water rights
- Off-site infrastructure
- Utility demand costs
- Decommissioning costs
- Salvage values

5.6 Operating and Maintenance Assumptions

Operations and maintenance (“O&M”) estimates are based on the following assumptions:

- O&M costs are based on a greenfield facility with new and clean equipment.
- O&M costs are in 2019 USD.
- O&M estimates exclude emissions credit costs and property insurance.
- Property taxes are included for Wind O&M only.
- Land lease allowance included for the wind option.
- Where applicable, fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Where applicable, variable O&M costs include routine maintenance, makeup water, water treatment, water disposal, ammonia, SCR replacements, and other consumables not including fuel.
- Fuel costs are excluded from O&M estimates.
- Where applicable, major maintenance costs are shown separately from variable O&M costs.
- Gas turbine and reciprocating engine major maintenance assumes third party maintenance based on the recommended maintenance schedule set forth by the original equipment manufacturer (“OEM”).
- Base O&M costs are based on performance estimates at annual average ambient conditions.

5.7 Technology Specific Assumptions

5.7.1 Simple Cycle Gas Turbine

The EPC cost includes all equipment procurement, construction, and indirect costs for a greenfield simple cycle project. Additional cost clarifications and assumptions are shown below:

- It is assumed that natural gas is available at approximately 550 to 600 psig. Fuel compression is excluded for the frame unit.
- The estimate assumes the turbines are installed outdoors with OEM standard enclosures.
- Cost estimates include a building with administrative/control spaces and a warehouse.

Major Maintenance costs for the frame engine option is estimated on a dollar per gas turbine start ($/GT-start) basis. In general, if there are more than 27 operating hours per start, the maintenance will be hours based. If there are less than 27 hours per start, maintenance will be start-based. Note that the $/GT-hr and $/start costs are not meant to be additive or combined in any way. The operational profile determines which value to use to determine annual major maintenance costs. It is assumed that there is no penalty for 10-minute starts, but some OEMs may have penalties depending on specific project conditions. The major maintenance $/MWh cost shown in the summary is calculated using the $/hr major maintenance cost (it is intended as another way to show the same cost, so it is also not intended to be added to $/start or $/hr). If a start-based maintenance scheme is desired, it should be noted that the applicable $/MWh will need to be calculated based on the start-based annual cost expectations. Fixed costs for the SCGT option includes an allowance for seven full time employees (greenfield site).

5.7.2 Reciprocating Engine

The EPC costs include all equipment procurement, construction, and indirect costs for a greenfield reciprocating engine project.

Additional cost clarifications and assumptions are shown below:

- SCR and CO catalysts are included for reciprocating engines. It is assumed that CEMS equipment is not required.
- It is assumed that natural gas is available above 125 psig. Fuel compression is not required.
- The reciprocating engine plant includes an indoor engine hall with associated administrative/ control/ warehouse facilities.
- All five engines are tied to a single, three-winding GSU.
- Fixed O&M costs include eight (8) FTE personnel for this option. Fixed O&M also includes an estimate for standby electricity costs to keep the engines warm and accommodate start times of less than ten minutes. Additional fixed O&M costs include allowances for administrative, communications, and other routine maintenance items.
- Major maintenance costs are shown per engine, regardless of configuration. It is assumed that an LTSA with the OEM or other third party would include parts and labor for major overhauls and catalyst replacements.
- Variable costs account for lube oil, SCR reagent, routine BOP maintenance, and scheduled minor engine maintenance. It is expected that the LTSA would include supervision and parts for these minor intervals (i.e. ~2,000 hour intervals), but that these may not be considered capital maintenance intervals, so they are included in the variable O&M.

5.7.3 Combined Cycle Gas Turbine

The project cost includes all equipment procurement, construction, and indirect costs for combined cycle projects.

Cost estimates were developed using in-house information based on Burns & McDonnell's project experience. Cost estimates assume an EPC project plus typical Owner's costs. The following cost items are assumed:

- Capital costs assume the inclusion of terminal point desuperheaters, full bypass, and associated controls to accommodate the startup times shown in the Summary Tables.
- Estimate assumes natural gas operation with no inlet conditioning and no dual fuel capability.
- The estimate assumes that gas turbines are installed outdoors in OEM standard enclosures.
- The estimate assumes that HRSGs are installed outdoors.
- An administrative/control building and a warehouse are included.
- Generic well water is assumed for all sites. No intake structures or supply piping outside the plant boundary are included.
- O&M estimates are based on plant performance at annual average conditions.
- The CCGT options assumes 22 full time employees.
- SCR systems are included in the O&M evaluation. SCR systems assume 19 percent aqueous ammonia and five-year catalyst life.
- Major maintenance costs are based on $/GT-hr, but are also shown in $/MWh. These numbers reflect the same total annual cost and are not meant to be combined.
- Note that major maintenance costs vary by term coverage and scope, OEM, and operational profile.

5.7.4 Wind

The cost estimate assumes a two-contract approach with the Owner awarding a turbine supply contract and a separate BOP contract. Typical Owner's costs are also presented. Costs are based on a 50 MW plant with 3.6 MW turbines (14 total turbines) and 90-meter hub heights.

- Additional costs for hurricane supports are not included.
- The EPC scope includes a GSU transformer for interconnection at 230 kV.
- Land costs are excluded from the EPC and Owner's cost. It is assumed that land is leased, and those costs are incorporated into the O&M estimate.

Wind O&M costs are modeled as fixed O&M, including all typical operating expenses such as:

- Labor costs
- Turbine O&M
- BOP O&M and other fixed costs (G&A, insurance, environmental costs, etc.)
- Property taxes
- Land lease payments

5.7.5 Solar

The solar cost estimate was developed using in-house information based on Burns & McDonnell project experience. The cost estimate assumes an EPC project approach plus typical Owner's costs.

Solar cost estimates for the single axis tracking systems with 1,500V central inverters are included. Costs are based on the 1.4 DC/AC ratio. The project scope assumes a medium voltage interconnection and the Owner's costs include an allowance for interconnection downstream of the 34.5 kV circuit breaker.

Solar installed costs have steadily declined for years. The main drivers of cost decreases include substantial module price reductions, lower inverter prices, and higher module efficiency. However, also impacting solar prices are United States' tariffs on solar panels and steel imports. The panel tariffs only impact crystalline solar modules, however the availability of CdTe is limited for the next couple years, so it is prudent to assume similar cost increases for thin film panels until the impacts of the tariff are clearer.

The Assessment excludes land costs from capital and Owner costs.

The following assumptions and clarifications apply to PV O&M:

- O&M costs assume that the system is remotely operated and that all O&M activities are performed through a third-party contract. Therefore, all O&M costs are modeled as fixed costs, shown in terms of $/kW$_{AC}$ per year.
- Equipment O&M costs are included to account for inverter maintenance and other routine equipment inspections.
- BOP costs are included to account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- The capital replacement allowance is a sinking fund for inverter replacements, assuming they will be replaced once during the project life. It is a 15-year levelized cost based on the current inverter capital cost.

5.7.6 Battery Storage

The estimated costs of the lithium ion battery system included is based on Burns & McDonnell's experience and vendor correspondence. The key cost elements of a battery system are the inverter, the battery cells, the interconnection, and the installation. The capital costs reflect recent trends for overbuild capacity to account for short term degradation. The battery enclosures include space for future augmentation, but the costs associated with augmentation are covered in the O&M costs. It is assumed that the system will be co-located with an existing asset. It is assumed that the system will operate at 480V and the scopes include a transformer to connect at 34.5 kV.

The battery storage system is assumed to be operated remotely.

The technical life of a battery project is expected to be 15 years but overbuild and augmentation philosophies can vary between projects. Because battery costs are expected to continue falling, many installers/integrators are aiming for lower initial overbuild percentages to reduce initial capital costs, which means guarantees and service contracts will require more future augmentation (i.e. battery replacements or additions) to maintain capacity. Because costs will likely be lower in the future, the project economics should favor this approach.

O&M costs are modeled to represent the fixed and variable portions of performance guarantees and augmentation from recent Burns & McDonnell project experience. Variable O&M costs also include the cost of parasitic load to run HVAC during charging cycles. During discharge, parasitic loads are treated like auxiliary loads in conventional plants and therefore are not included in VOM estimates.

6.0 CONCLUSIONS

This technology assessment provides information to support LUS' power supply planning efforts for further evaluation within the economic modeling efforts within the IRP. Information provided in this assessment is preliminary in nature and is intended to highlight indicative, differential costs associated between each technology. Prior to final selection of technologies, design, and construction of any alternatives, LUS should pursue additional engineering studies to define project scope, budget, and timeline for specific technologies of interest.

These alternatives will be further evaluated within the IRP for their ability to compliment or replace existing resources within LUS' power supply portfolio, both from a technical ability and economic evaluation. A brief highlight of the advantages and disadvantages of the technologies is presented in Table 6-1.

Table 6-1: Summary of Technologies

Technology	Advantages	Disadvantages
Gas-Fired Resources		
Aeroderivative	• Flexible operation (ability to quickly turn-on/off in response to market signals) • More efficient than large frame units • Ability for on-system installation	• High fuel gas pressure • Higher capital cost compared to other peaking resources on $/kW basis
F-Class	• Lowest cost peaking resource on a $/kW basis • Flexible compared to CCGT, but slightly less than Aeroderivative and reciprocating engines • Ability for on-system installation	• High fuel gas pressure • Large capacity on a single shaft • Less flexible compared to aeroderivatives and reciprocating engines • Higher heat rate compared to aeroderivative turbines
Reciprocating Engines	• Most flexible gas-fired resource (ability to quickly turn-on/off in response to market signals) • Low fuel gas pressure • Shaft diversification (9-18MW)[15] • Ability for on-system installation	• Higher capital cost compared to F-Class or CCGT technology on a $/kW basis
CCGT	• Most efficient gas-fired technology • Lower capital cost due to economies of scale on a $/kW basis	• Lacks flexibility compared to other gas-fired technologies • Must be one of potentially several pseudo-owners of a large unit • Most likely located off-system

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[15] Shaft diversification provides a utility the opportunity for increased reliability since it would have the ability to utilize multiple engines providing the same level of capacity and generation, as opposed to having all of the energy sourced from a single engine.

Technology	Advantages	Disadvantages
Renewables		
Locally Owned Wind (Louisiana)	• Reduced transmission congestion	• No Production Tax Credit or Interconnection Tax Credit (need taxable partner) • Uneconomical compared to resources available in nearby regions • Wind farms cannot be easily integrated into residential, commercial, or industrial areas
Regional Wind (MISO)	• Economically justifiable • Production Tax Credit through PPA (subject to Congress) • Large wind farms reduce the overall cost of the technology	• LUS is not the operator of the wind farms • Potential congestion costs
Off-Shore Wind (Louisiana)	• Higher wind resource potential compared to local on-shore wind	• Off-shore wind in the U.S. is still in the infancy of development • Only one off-shore facility is operational in the U.S. with none currently in development in Louisiana[16][17]
Local Solar	• Increased to renewable energy production for utility portfolio • Potential tax credits through PPA (subject to Congress)	• Lack of solar resource availability in Louisiana • Higher cost of energy compared to regional wind
Storage		
Flow Battery	• Scalable technology in development • Higher cycling life compared to conventional batteries • Offsets electric peak loads	• Technology is not entirely mature currently • Required operation of ancillary equipment
Conventional Battery (Lead Acid and Lithium Ion)	• Low capital costs • Responsive to changes in grid demand • Offsets electric peak loads	• Life is dependent on cycling and discharge rates, potentially 5 to 10 years for high cycling utilization • High maintenance cost • Materials used are associated with being high toxicity
High Temperature	• High discharge rates • Life expected to be around 15 years • Offsets electric peak loads	• Energy requirement to maintain liquid electrolytes • Technology is still being developed for utility level applications • Uneconomically compared to other storage technologies
Pumped Hydro	• Large reservoir of storage energy • Offsets electric peak loads	• Geology required for water storage • Environmental impacts to surrounding areas • High capital costs

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[16] https://www.awea.org/Awea/media/Resources/Fact%20Sheets/Offshore-Fact-Sheet.pdf

[17] https://www.boem.gov/renewable-energy/state-activities

Technology	Advantages	Disadvantages
Compressed Air Energy Storage (CAES)	• Large reservoir of storage energy • Offsets electric peak loads	• Specific geology required for compressed air storage • High capital costs

APPENDIX A - SUMMARY TABLES

LAFAYETTE UTILITES SYSTEM 2020 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
FOR ECONOMIC EVALUATIONS ONLY - NOT FOR CONSTRUCTION
January 2020

PROJECT TYPE	**1x F Class SCGT - Natural Gas**	**Reciprocating Engine (18MW Engines)**
Number of Gas Turbines/Engines/Units	1	5
Representative Class Gas Turbine	GE 7F.05	Wartsila 18V50SG
Capacity Factor (%)	10%	10%
Startup Time to Base Load, min (Notes 1, 2)	12 min	5
Startup Time to MECL, min (Note 3)	9 min	4
Estimated Fuel Consumption to Maximum Load, MMBtu	138	50 (total for all engines)
Estimated Fuel Consumption to MECL, MMBtu	56	30 (total for all engines)
Maximum Ramp Rate (Online)	18% per min	50% per min
Forced Outage Factor (%) (Notes 4, 8)	0.7%	1.8%
Equivalent Forced Outage Rate (%) (Notes 4, 8)	5.8%	4.5%
Availability Factor (%) (Notes 4, 8)	93.8%	95.3%
Fuel Design	Natural Gas	Natural Gas
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NO_x Control	DLN Combustors	SCR
CO Control	Good Combustion Practice	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice
ESTIMATED PERFORMANCE (Note 7)		
AVERAGE WINTER AMBIENT		
Base Load Performance @ 55.9°F / 70.9%		
Net Plant Output, kW	230,700	91,600
Net Plant Heat Rate, Btu/kWh (HHV)	9,920	8,290
Heat Input, MMBtu/h (HHV)	2,290	760
Minimum Load Performance @ 55.9°F / 70.9%		
Net Plant Output, kW	115,400	4,600
Net Plant Heat Rate, Btu/kWh (HHV)	12,110	11,040
Heat Input, MMBtu/h (HHV)	1,400	50
ANNUAL AVERAGE AMBIENT		
Base Load Performance @ 68.9°F / 74.0% RH		
Net Plant Output, kW	226,800	91,600
Net Plant Heat Rate, Btu/kWh (HHV)	10,010	8,290
Heat Input, MMBtu/h (HHV)	2,270	760
Minimum Load Performance @ 68.9°F / 74.0% RH		
Net Plant Output, kW	113,400	4,600
Net Plant Heat Rate, Btu/kWh (HHV)	12,210	11,040
Heat Input, MMBtu/h (HHV)	1,380	50
AVERAGE SUMMER AMBIENT		
Base Load Performance @ 81.5°F / 77.8% RH		
Net Plant Output, kW	221,000	91,600
Net Plant Heat Rate, Btu/kWh (HHV)	10,130	8,310
Heat Input, MMBtu/h (HHV)	2,240	760
Minimum Load Performance @ 81.5°F / 77.8% RH		
Net Plant Output, kW	110,500	4,600
Net Plant Heat Rate, Btu/kWh (HHV)	12,420	11,210
Heat Input, MMBtu/h (HHV)	1,370	50

LAFAYETTE UTILITES SYSTEM 2020 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS

FOR ECONOMIC EVALUATIONS ONLY - NOT FOR CONSTRUCTION

January 2020

PROJECT TYPE	**1x F Class SCGT - Natural Gas**	**Reciprocating Engine (18MW Engines)**
ESTIMATED CAPITAL AND O&M COSTS		
Project EPC Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$108**	**$106**
Owner's Costs, 2019 MM$	**$22**	**$18**
Owner's Project Development	$0.3	$0.3
Owner's Operational Personnel Prior to COD	$0.3	$0.3
Owner's Engineer	Excluded	Excluded
Owner's Project Management	$1.0	$1.0
Owner's Legal Costs	$0.5	$0.5
Owner's Start-up Engineering	$0.2	$0.2
Temporary Utilities	$0.5	$0.5
Permitting and Licensing Fees	$0.5	$0.5
Land	Excluded	Excluded
Water Rights	Excluded	Excluded
Switchyard	$4.9	$4.9
Political Concessions & Area Development Fees	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$0.2	$0.3
Site Security	$0.4	$0.4
Operating Spare Parts	$5.5	$2.0
Permanent Plant Equipment and Furnishings	$0.3	$0.3
Builders Risk Insurance (0.45% of Construction Costs)	$0.5	$0.5
Sales Tax	Excluded	Excluded
Owner's Contingency (5% of EPC and Owner's costs)	$6.2	$5.9
Financing Fees	Excluded	Excluded
Interest During Construction	Excluded	Excluded
Total Project Costs, 2019 MM$	**$130**	**$124**
Project Cost Per kW, 2019 $/kW	**$480**	**$1,160**
Total Cost Per kW, 2019 $/kW	**$570**	**$1,350**
BASE PLANT O&M COSTS		
Fixed O&M Cost, 2019$MM-Yr	$2.0	$1.8
Fixed O&M Cost, 2019$/kW-Yr	$8.70	$19.60
Major Maintenance Cost, 2019$/GT-hr (see note 5,6)	$350	$28.00
Major Maintenance Cost, 2019$/MWh	$1.50	$1.50
Major Maintenance Cost, 2019$/GT Start	$9,500	N/A
Variable O&M Cost, 2019$/MWh (Excludes GT major maintenance)	$0.90	$4.60

LAFAYETTE UTILITES SYSTEM 2020 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS

FOR ECONOMIC EVALUATIONS ONLY - NOT FOR CONSTRUCTION

January 2020

PROJECT TYPE	1x F Class SCGT - Natural Gas	Reciprocating Engine (18MW Engines)
ESTIMATED BASE LOAD OPERATING EMISSIONS, ppmvd @15% O2		
NO_X	9	5
CO	7	15
VOC	1.2	26
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (Annual Average Ambient)		
NO_X	0.04	0.002
SO_2	< 0.002	< 0.002
CO	0.02	0.003
CO_2	120	120
PM/PM_{10}	0.003	0.003
VOC	0.001	0.003
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/hr (Annual Average Ambient)		
NO_X	81.4	1.2
SO_2	< 3.5	< 0.002
CO	38.5	2.5
CO_2	272,430	91,120
PM/PM_{10}	7.0	2.0
VOC	2.3	2.5

Notes

Note 1: Simple cycle starts are not affected by downtime.

Note 2: Fast start packages for frame turbines allow for 10 minute starts. Fast start options are NOT reflected in base capital costs. Market trends suggest that O&M impacts from fast starts are negligible.

Note 3: For reciprocating engines, if the engine jacket temperature is >185 F, the engine can start in 5 mins. Between 120 F and 185 F, it will take 1-2 hours to get to full load. For jacket temperatures < 120 F, jacket heaters can be used heat engine to 120 F.

Note 4: Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2006 or later. Reporting period is 2011-2016. Note that a unique gas reciprocating engine category does not exist in GADS. Diesel Engine data is used as a proxy.

Note 5: Major maintenance $/hr holds for frame gas turbines where hours per start is >27. Where hours per start is <27 on frame units, use the $/start value.

Note 6: Reciprocating engine major maintenance is shown per engine.

Note 7: New and clean performance assumed for all options.

Note 8: EFOR data from GADS may not accurately represent the benefits of a reciprocating plant, depending on how events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so the plant would not be completely offline as it may be during an event at 1x gas turbine plant.

LAFAYETTE UTILITES SYSTEM 2020 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
FOR ECONOMIC EVALUATIONS ONLY - NOT FOR CONSTRUCTION
January 2020

PROJECT TYPE	1x1 G/H Class CCGT - Unfired
Number of Gas Turbines	1
Number of Steam Turbines	1
Representative Class Gas Turbine	GE HA.01
Steam Conditions (Main Steam / Reheat)	1,050°F / 1,050°F
Main Steam Pressure	2,400
Steam Cycle Type	Subcritical
Capacity Factor (%)	50%
Startup Time (Cold Start to Unfired Base Load) (Note 3, 4)	180 Minutes
Startup Time (Warm Start to Unfired Base Load) (Note 3, 4)	120 Minutes
Startup Time (Hot Start to Unfired Base Load) (Note 3, 4)	80 Minutes
Startup Time (Cold Start to Stack Emissions Compliance) (See note 6)	60 Minutes
Startup Time (Warm / Hot Start to Stack Emissions Compliance) (See note 6)	30 Minutes
Estimated Fuel Consumed to Stack Emissions Compliance, MMBtu	1,390
Estimated Fuel Consumed to Base Load, MMBtu	4,790
Maximum Ramp Rate (Online)	10% per minute
Forced Outage Factor (%)	2.2%
Equivalent Forced Outage Rate (%)	3.6%
Availability Factor (%)	87.8%
Fuel Design	Natural Gas
Heat Rejection	Wet Cooling Tower
NO_x Control	DLN/SCR
CO Control	Oxidation Catlyst
SO_2 Control	Low Sulfur Fuel
CO_2 Control	N/A
Ash Disposal	N/A
Particulate Control	Good Combustion Practice
ESTIMATED PERFORMANCE (See note 2)	
AVERAGE WINTER AMBIENT	
Base Load Performance @ 55.9°F / 70.9% RH	
Net Plant Output, kW	423,100
Net Plant Heat Rate, Btu/kWh (HHV)	6,310
Heat Input, MMBtu/h (HHV)	2,670
Minimum Load Performance @ 55.9°F / 70.9% RH	
Net Plant Output, kW	232,800
Net Plant Heat Rate, Btu/kWh (HHV)	6,850
Heat Input, MMBtu/h (HHV)	1,590
ANNUAL AVERAGE AMBIENT	
Base Load Performance @ 68.9°F / 74.0% RH	
Net Plant Output, kW	413,000
Net Plant Heat Rate, Btu/kWh (HHV)	6,300
Heat Input, MMBtu/h (HHV)	2,600
Minimum Load Performance @ 68.9°F / 74.0% RH	
Net Plant Output, kW	227,100
Net Plant Heat Rate, Btu/kWh (HHV)	6,860
Heat Input, MMBtu/h (HHV)	1,560
AVERAGE SUMMER AMBIENT	
Base Load Performance @ 81.5°F / 77.8% RH	
Net Plant Output, kW	401,100
Net Plant Heat Rate, Btu/kWh (HHV)	6,330
Heat Input, MMBtu/h (HHV)	2,540
Minimum Load Performance @ 81.5°F / 77.8% RH	
Net Plant Output, kW	220,300
Net Plant Heat Rate, Btu/kWh (HHV)	6,910
Heat Input, MMBtu/h (HHV)	1,520

LAFAYETTE UTILITES SYSTEM 2020 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE

COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS

FOR ECONOMIC EVALUATIONS ONLY - NOT FOR CONSTRUCTION

January 2020

PROJECT TYPE	**1x1 G/H Class CCGT - Unfired**
ESTIMATED CAPITAL AND O&M COSTS (See note 7)	
Project EPC Capital Cost, 2019 MM$ (w/o Owner's Costs)	**$328**
Owner's Costs, 2019 MM$	**$53**
Owner's Project Development	$3.5
Owner's Operational Personnel Prior to COD	$1.7
Owner's Engineer	Excluded
Owner's Project Management	$6.1
Owner's Legal Costs	$1.0
Owner's Start-up Engineering	$0.5
Temporary Utilities	$1.7
Permitting and Licensing Fees	$0.5
Land	Excluded
Water Rights	Excluded
Switchyard	$8.7
Political Concessions & Area Development Fees	$0.5
Startup/Testing (Fuel & Consumables)	$1.0
Site Security	$0.8
Operating Spare Parts	$6.5
Permanent Plant Equipment and Furnishings	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.5
Sales Tax	Excluded
Owner's Contingency (5% of EPC and Owner's costs)	$18.2
Financing Fees	Excluded
Interest During Construction	Excluded
Total Project Cost, 2019 MM$	**$382**
Project Cost Per kW, 2019 $/kW	**$790**
Total Cost Per kW, 2019 $/kW	**$920**
FIXED O&M COSTS	
Fixed O&M Cost, 2019$MM-Yr	$4.9
Fixed O&M Cost, 2019$/kW-Yr (unfired kW)	$12.30
MAJOR MAINTENANCE COSTS (See note 5)	
Major Maintenance Cost, 2019$/MWh	$1.43
Major Maintenance Cost, 2019$/GT Start	$15,500
Major Maintenance Cost, 2019$/GT-hr	$575
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)	
Total Variable O&M Cost, 2019$/MWh	$1.82

LAFAYETTE UTILITES SYSTEM 2020 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
FOR ECONOMIC EVALUATIONS ONLY - NOT FOR CONSTRUCTION
January 2020

PROJECT TYPE	1x1 G/H Class CCGT - Unfired
ESTIMATED BASE LOAD OPERATING EMISSIONS, ppmvd @15% O2	
NO_X	2.0
CO	2.0
VOC	0.4
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (Unfired, Annual Average Ambient)	
NO_X	0.008
SO_2	< 0.002
CO	0.005
CO_2	120
PM/PM_{10}	0.003
VOC	0.001
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/hr (Annual Average Ambient)	
NO_X	20.2
SO_2	< 2.7
CO	12.3
CO_2	312,000
PM/PM_{10}	8.5
VOC	2.5

Notes

Note 1: New and clean performance is assumed. No performance degradation is included.

Note 2: Performance ratings based on elevation of 38 ft above msl.

Note 3: Startup times reflect unrestricted, conventional starts.

Note 4: Cold start is >72 hours after shutdown. Hot start is <8 hours after shutdown.

Note 5: Major maintenance $/hr holds for frame gas turbines where hours per start is >27. Where hours per start is <27 on frame units, use the $/start value.

Note 6: The time to achieve stack emissions compliance is assumed to be driven by the temperature of the CO catalyst in addition to the time for the turbine to achieve MECL.

Note 7: Fixed O&M costs assume 22 full time equivalent (FTE) personnel for 1x1 plants

LAFAYETTE UTILITES SYSTEM 2020 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
FOR ECONOMIC EVALUATIONS ONLY - NOT FOR CONSTRUCTION

January 2020

PROJECT TYPE	**Wind Energy**	**Solar Photovoltaic**	**Battery Storage**
BASE PLANT DESCRIPTION	Onshore	Single Axis Tracking	Lithium Ion
Nominal Output, MW	50	50 MWac	25 MW / 100 MWh
Representative Technology	14 x 3.6 MW Turbines	Ground mount, single axis tracking	Lithium Ion
Capacity Factor (%) (Note 1)	31%	26%	17%
PV Inverter Loading Ratio (DC/AC)	N/A	1.4	N/A
Startup Time (Cold Start) (See note 4)	N/A	N/A	N/A
Equivalent Availability Factor (%)	95%	99%	97%
Fuel Design	N/A	N/A	N/A
Heat Rejection	N/A	N/A	N/A
NO_x Control	N/A	N/A	N/A
CO Control	N/A	N/A	N/A
SO_2 Control	N/A	N/A	N/A
Particulate Control	N/A	N/A	N/A
ESTIMATED PERFORMANCE			
Base Load Performance @ (Annual Average) Net Plant Output, kW	50,000	50,000	25,000
ESTIMATED CAPITAL AND O&M COSTS			
Project EPC Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$56**	**$63**	**$34**
Owner's Costs, 2019 MM$	**$16**	**$7.1**	**$5.2**
Project Development	$5.7	$0.3	$0.3
Owner's Project Management	Included in Proj. Dev. Costs	$0.1	$0.2
Owner's Legal Costs	Included in Proj. Dev. Costs	$0.3	$0.1
Wind Resource Assessment	$0.3	N/A	N/A
Land Control	$0.6	N/A	N/A
Permitting and Licensing Fees	$0.8	$0.5	$0.5
Generation Switchyard	$2.0	$2.0	$2.0
Transmission Interconnection	Excluded	Excluded	Excluded
Transmission Interconnection Application and Upgrades	Excluded	Excluded	Excluded
Land (Note 4)	$0.0	$0.0	$0.0
Operating Spare Parts	Included in O&M	$0.4	Included in O&M
Temporary Facilities and Construction Utilities	$3.0	Included in Project Cost	$0.1
Builders Risk Insurance (0.45% of Project Cost)	Included in Project Costs	$0.3	$0.2
Owner's Contingency (5% of EPC and Owner's costs)	$3.4	$3.3	$1.9
Total Project Costs, 2019 MM$	**$71**	**$70**	**$39**
Project Cost Per kW, 2019 $/kW	**$1,110**	**$1,260**	**$1370/kW / $340/kWh**
Total Cost Per kW, 2019 $/kW	**$1,420**	**$1,400**	**$1580/kW / $390/kWh**
Fixed O&M Cost, 2019$/kWac-Yr (See note 2)	$50.00	$17.20	$9.55
Major Maintenance Cost, 2019$/MWh (See note 3)	Included in FOM	Included in FOM	Included in FOM
Variable O&M Cost, 2019$/MWh (excl. major maint.)	Included in FOM	Included in FOM	$14.93
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)			
NO_X	N/A	N/A	N/A
CO	N/A	N/A	N/A
CO_2	N/A	N/A	N/A
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/hr (HHV)			
NO_X	N/A	N/A	N/A
CO	N/A	N/A	N/A
CO_2	N/A	N/A	N/A

Notes

Note 1: Wind capacity factor based on 90m hub heights and represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor represents siting outside of Lafayette to capture higher wind speeds.

Note 2: Capital and O&M costs for PV are shown as $/kW based on AC output. O&M excludes property taxes and land lease allowances.

Note 3: For wind, it is assumed that 20% of fixed O&M budget is set aside for unscheduled maintenance not covered by service and maintenance agreement. Solar O&M includes capital replacement allowance for inverters.

Note 4: Wind and solar assume land is leased, not purchased. Battery option assumes the installation is located at an existing asset.

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APPENDIX D – RPS2 EVALUATION

January 15, 2020

Mr. Jeff Stewart
Manager, Engineering & Power Supply
Lafayette Utilities System
1314 Walker Road
Lafayette, LA 70506

Re: Evaluation of Rodemacher Power Station Unit 2 Long-Term Coal-Fired Operation

Dear Mr. Stewart:

Lafayette Utilities System ("LUS") requested that Burns & McDonnell Engineering Co. ("Burns & McDonnell") help with the evaluation of long-term coal-fired operation at Rodemacher Power Station Unit 2 ("RPS2"). The following provides a summary of the evaluation.

BACKGROUND

LUS owns 50 percent of RPS2. RPS2 is a large coal-fired power generating station. There are a number of environmental regulations impacting the long-term operation of RPS2, namely the coal combustion residue ("CCR") and effluent limit guideline ("ELG") regulations.

LUS, along with the other co-owners of RPS2, need to inform the U.S. Environmental Protection Agency ("EPA") of its long-term compliance plan for meeting CCR and ELG regulations. Coal-fired power plant operators need to provide notice to the EPA in the May 2020 timeframe.

OBJECTIVE

LUS is currently conducting a long-term integrated resource plan ("IRP") that was initially scheduled to be completed around mid-summer. However, the EPA's regulations expedited the need to determine a path forward for coal-fired power plants to the timeframe mentioned above. The objective of this analysis was to determine whether RPS2 should continue to operate utilizing coal or whether RPS2 should retire from coal-fired operation.

METHODOLOGY & ASSUMPTIONS

As part of the IRP process, LUS and Burns & McDonnell have developed several assumptions and forecasts for the long-term options associated with RPS2.

Methodology

The analysis specifically investigated the ongoing fixed costs associated with coal-fired operation at RPS2 versus two alternative options for providing capacity to LUS' power supply portfolio. The focus of this evaluation was to determine whether to continue coal-fired operations at RPS2, but not to specifically determine its potential replacement. The alternatives served as representative proxies for options to replace coal-fired operations should the evaluation determine that RPS2 be retired from coal-fired generation.

The two alternative options that were evaluated consisted of natural gas conversion of RPS2 and replacement with a simple cycle combustion turbine. The following options were considered:

1. Option 1: RPS2 on Coal – Continued long-term operation of RPS2 on coal
2. Option 2: RPS2 on Gas – Convert RPS2 to operate on natural gas on January 1, 2024.
3. Option 3: Retire and Replace – Retire RPS2 at the end of 2027 and replace with a new, greenfield simple cycle combustion turbine in 2028.

The overall evaluation of power supply options within an IRP consists of analyses of both capacity and energy. However, based on the dispatch of RPS2 and the replacement alternatives, this evaluation focused on the fixed cost of providing reliable capacity to LUS' power supply portfolio. The overall fixed costs of each alternative were compared against the amount of MISO accredited capacity (UCAP) the option provided. Fixed costs consisted of fixed operation and maintenance costs including staffing, project and capital expenditures, and any new debt service requirements.

The evaluation is presented as a 20-year Levelized Cost of Capacity (LCOC) in $/kW-year.

Assumptions

The following assumptions were utilized within this assessment.

1. Costs are presented in nominal dollars which include 2.5 percent inflation. The simple cycle combustion turbine is assumed to be financed with 100 percent debt, for 30 years with an interest rate of 4 percent. The discount rate was assumed to be 4 percent.
2. All three options will incur CCR costs for the ash ponds, regardless of the long-term operations of RPS2
3. Fixed O&M costs for RPS2 were utilized based on information provided by LUS and Cleco.
4. Costs savings have been included for converting RPS2 to natural gas as outlined within the Cleco/S&L presentation for both fixed O&M and staffing.
5. The FGR option (option 2 as outlined within Cleco documentation) for the gas conversion with no derate was selected as the conversion option for evaluation.
6. The replacement SCGT was assumed to be an F-class machine built on a greenfield location and included some off-site linear infrastructure allowances within the capital costs.
7. The evaluation has only included CCR and ELG compliance costs for RPS2. No additional costs associated with the Affordable Clean Energy ("ACE") or any other potential future regulation has been included.
8. Existing debt associated with RPS2 was considered a "sunk cost" and not considered within this evaluation.

The following tables provide additional detail on the capital expenditures and O&M cost savings for natural gas conversion at RPS2.

Table 1: Capital Improvement Options

Capital Improvement Options	Capital Costs ($Millions)	Notes
Fly Ash Pond Closure	$11.5	CCR compliance, required independent of long-term operation of RPS2
Bottom Ash Pond Closure	$13.5	CCR compliance, required independent of long-term operation of RPS2
Bottom Ash Conversion	$18.0	ELG compliance, only required if RPS2 continues coal operation
Natural Gas Conversion	$40.6	Option from Cleco/S&L: FGR (Option 2) from S&L plus natural gas pipeline, no derate incurred
Simple Cycle Combustion Turbine	$158	Greenfield simple cycle option that would have a commercial operation date of 2028

Table 2: Capital Expenditures Forecast for New Environmental Projects ($Millions)

RPS2 Operating Scenario	2021	2022	2023	2024	2025	2026	2027	2028
Option 1: RPS2 on Coal - Continue Coal-Fired Operation	$5.8	$14.8	$9.0	$6.8	$6.8			
Option 2: RPS2 on Gas - Convert to Natural Gas	$5.8	$26.1	$20.3	$6.8	$6.8			
Option 3: Retire RPS2 at the end of 2027	$5.8	$5.8					$6.8	$6.8

Note: Option 3 does not include the cost of the simple cycle turbine in the table above, however those costs are included within the analysis.

Table 3: Cost Savings due to Natural Gas Conversion (from Cleco)

Cost Category	Annual Savings ($Millions)
Fixed O&M	$2.8
Payroll	$4.2

RESULTS

Burns & McDonnell conducted an economic evaluation utilizing the assumptions outlined herein for the three options. The analysis focused on the fixed costs associated with each power supply option. In order to compare the alternatives, the fixed costs were evaluated on a capacity basis ($/kW-year). The levelized cost of capacity ("LCOC") represents the overall fixed costs associated with operating for each option over a 20-year timeframe from 2021 to 2040.

The tables below present the cost of capacity for each option from 2021 to 2040, both annual and levelized costs are presented.

Long-term operation of RPS2 utilizing coal has a higher levelized cost of capacity than the other two options evaluated. Coal operation is approximately 17 percent more costly than the other two options.

Table 4: Annual Cost of Capacity ($/kW-year)

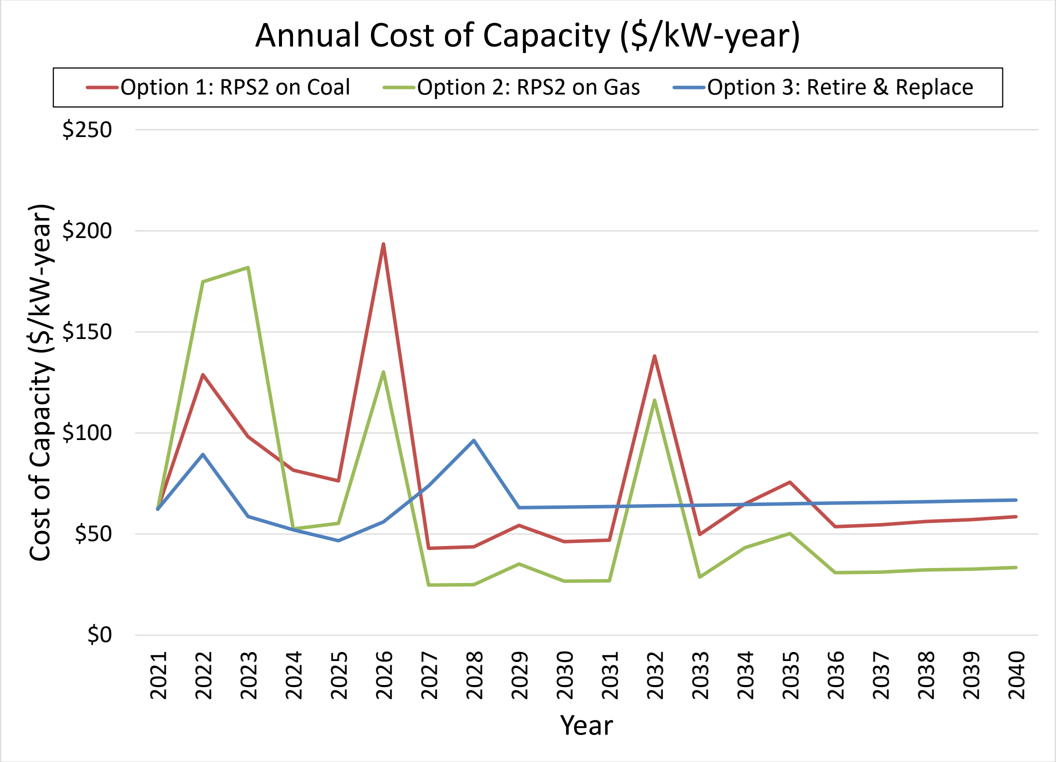
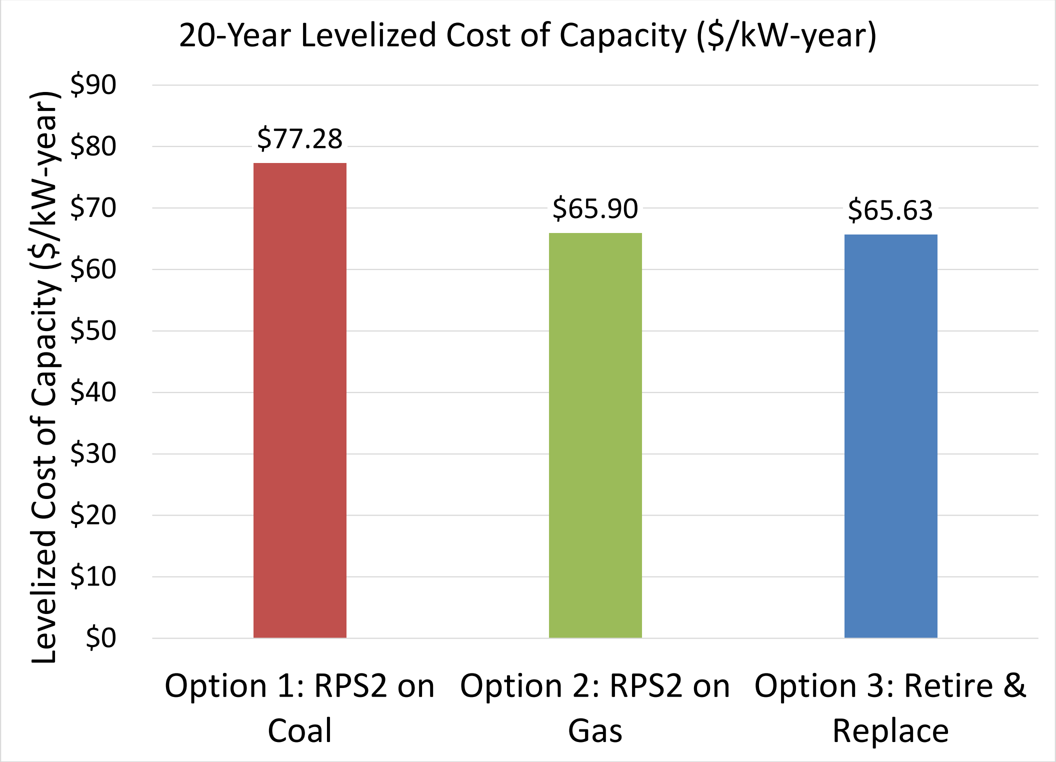


Table 5: Levelized Cost of Capacity ($/kW-year)



CONCLUSIONS & RECOMMENDATIONS

Based on the assumptions and analysis conducted herein, Burns & McDonnell offers the following conclusions and recommendations.

1. This evaluation focused strictly on the long-term coal-fired operation of RPS2.
2. In order to continue to operate on coal, RPS2 will be required to install environmental upgrades associated with ELG. Regardless of operation, the plant will be required to comply with the CCR regulations.
3. Based on a combination of factors including environmental compliance upgrade costs, fixed O&M costs, and the potential exposure to future environmental regulations, LUS should consider retiring RPS2 from coal-fired operation in the 2027 timeframe as other power supply options are lower cost for providing capacity.
4. LUS should discuss the results of this evaluation with the other co-owners to assess the next steps associated with RPS2 environmental compliance and subsequent application process.
5. The compliance plan will be subject to the acceptance of the application by the appropriate environmental regulating bodies (likely both state and federal agencies).
6. LUS should continue to evaluate the power supply options available for replacing the coal-fired capacity and energy associated with RPS2 within the long-term IRP, which will include thermal gas units, renewable resources such as wind and solar, energy storage, and power purchase options for capacity and energy.
7. If LUS decided to retire all electrical generation at RPS2, it would also be subject to the MISO process (Attachment Y).

Should you have any questions or comments regarding this evaluation, conclusions, or recommendations, please contact Mike Borgstadt at 816-822-3459 or mike.borgstadt@1898andco.com, or Kyle Combes at 816-349-6884 or kyle.combes@1898andco.com.

Sincerely,

Mike Borgstadt, PE
Director of Utility Consulting

Kyle Combes

Kyle Combes
Project Manager

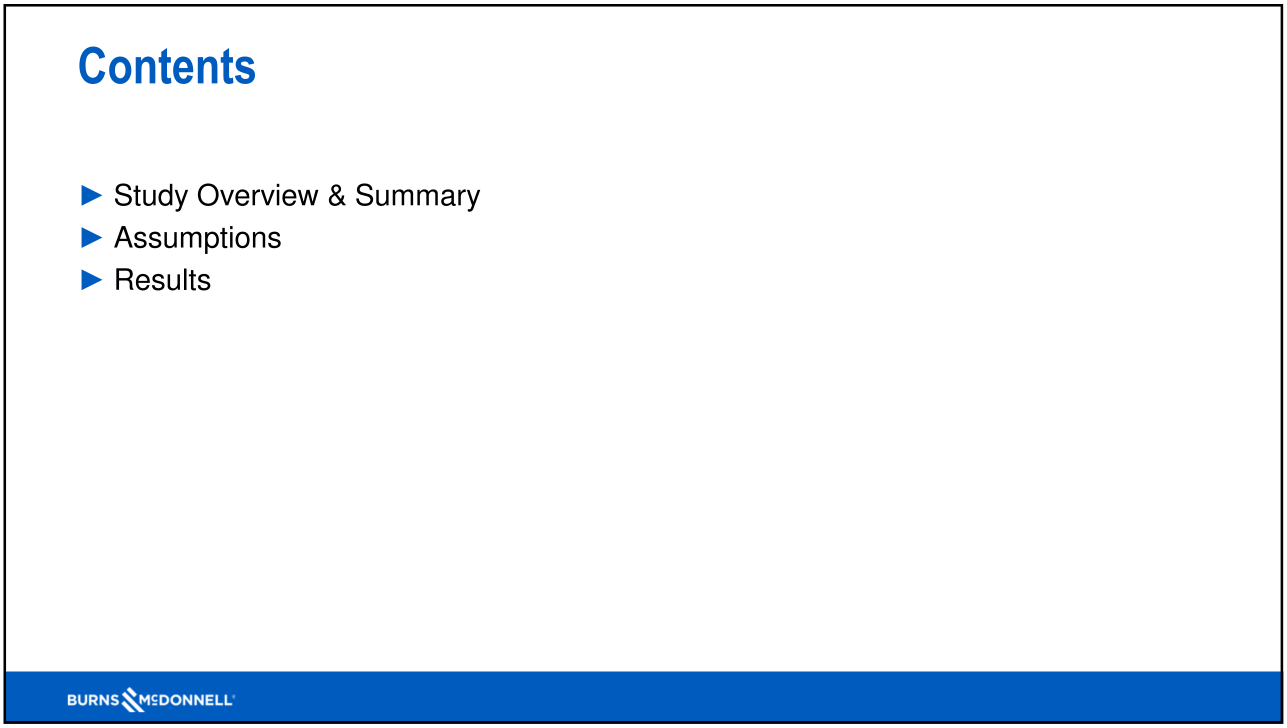
cc: Karen Hoyt, LUS

APPENDIX E – DSM/EE EVALUATION

DSM/EE Evaluation

Lafayette Utilities System

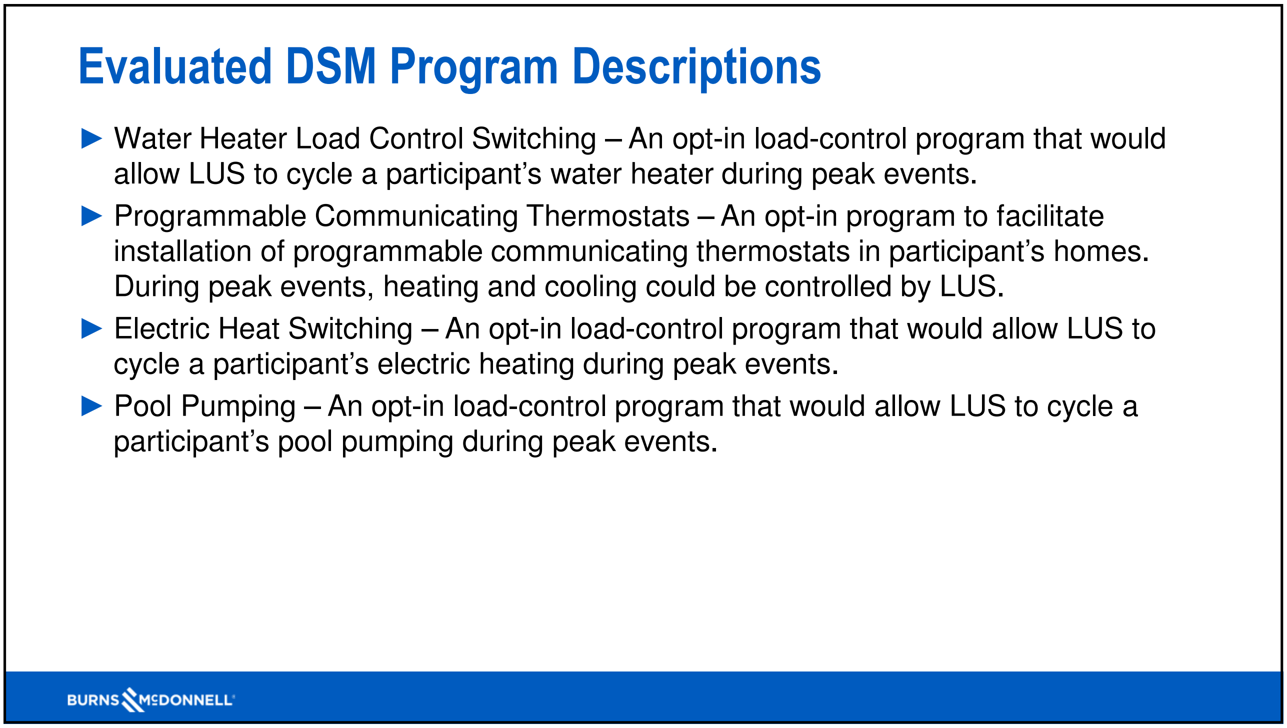
April 6, 2020



Contents

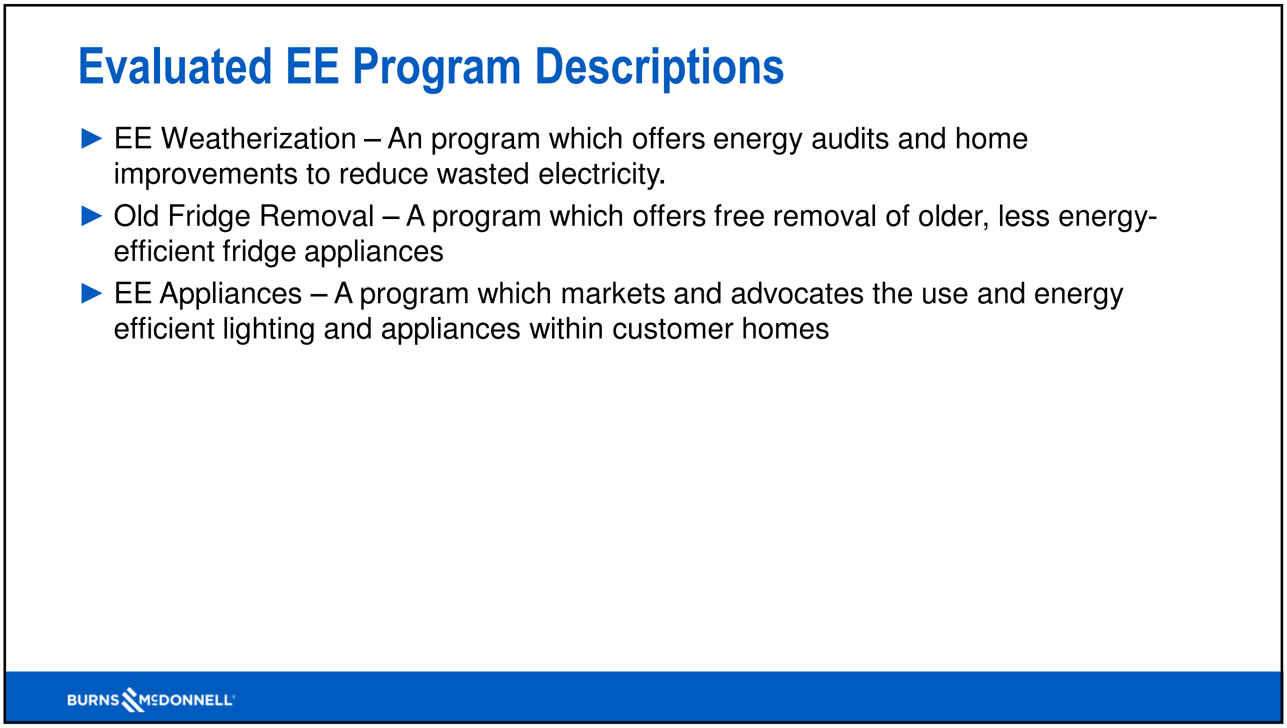
- Study Overview & Summary
- Assumptions
- Results

STUDY OVERVIEW & SUMMARY



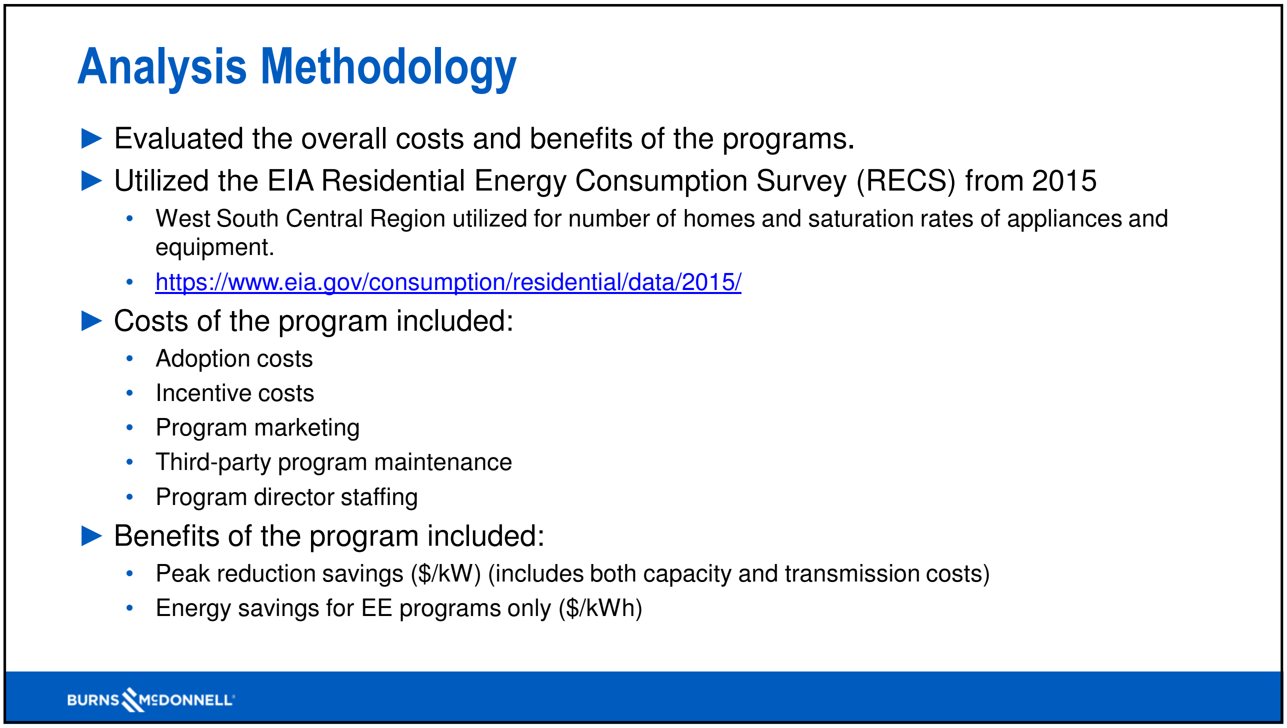
Evaluated DSM Program Descriptions

- Water Heater Load Control Switching – An opt-in load-control program that would allow LUS to cycle a participant’s water heater during peak events.
- Programmable Communicating Thermostats – An opt-in program to facilitate installation of programmable communicating thermostats in participant’s homes. During peak events, heating and cooling could be controlled by LUS.
- Electric Heat Switching – An opt-in load-control program that would allow LUS to cycle a participant’s electric heating during peak events.
- Pool Pumping – An opt-in load-control program that would allow LUS to cycle a participant’s pool pumping during peak events.



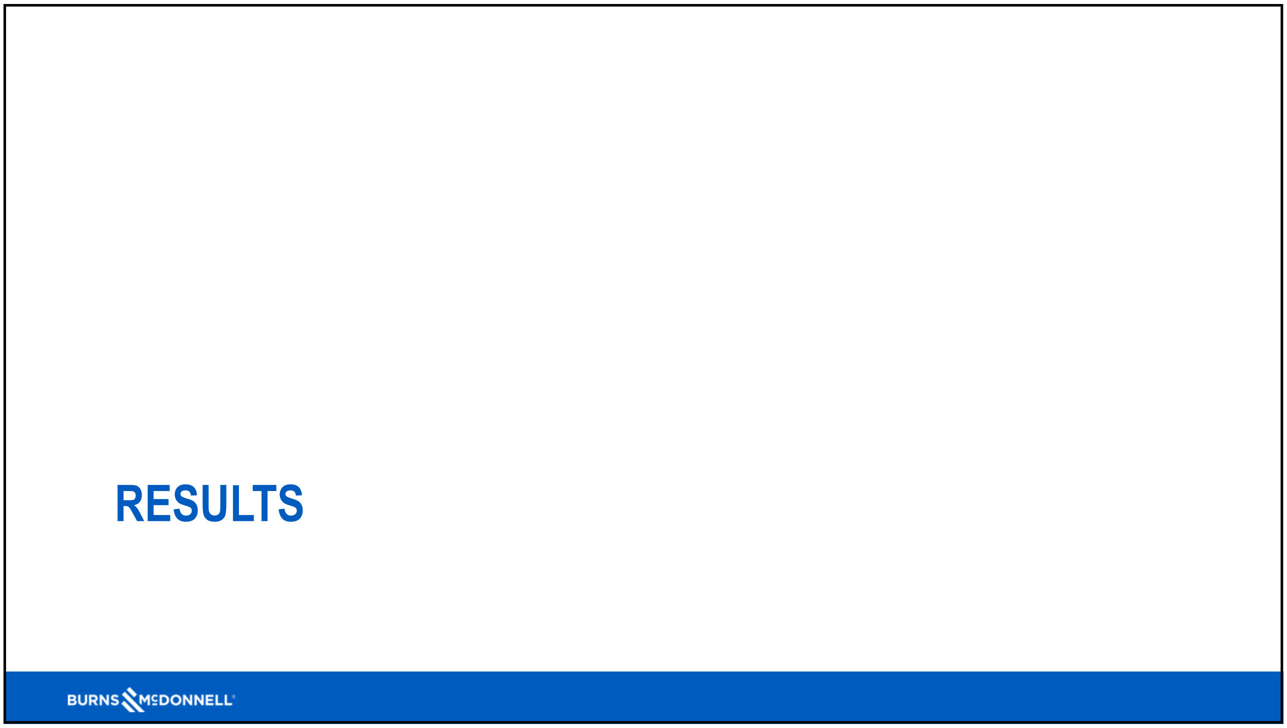
Evaluated EE Program Descriptions

- EE Weatherization – An program which offers energy audits and home improvements to reduce wasted electricity.
- Old Fridge Removal – A program which offers free removal of older, less energy-efficient fridge appliances
- EE Appliances – A program which markets and advocates the use and energy efficient lighting and appliances within customer homes

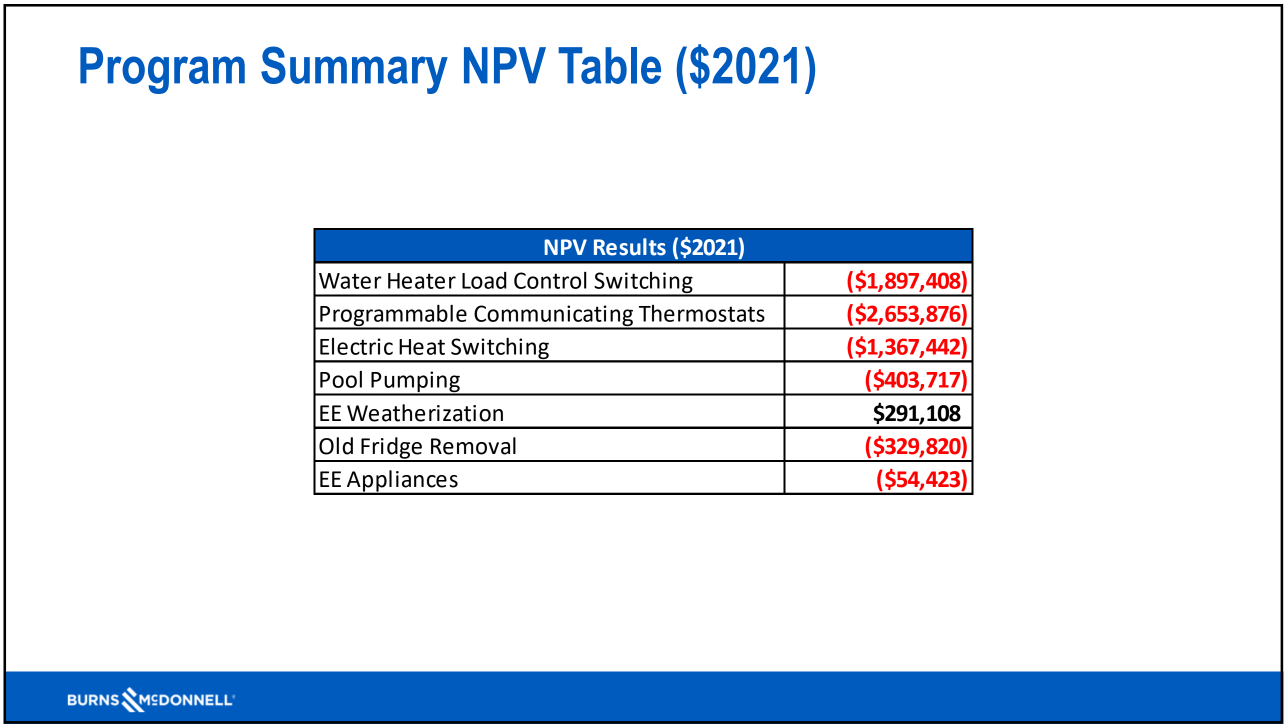


Analysis Methodology

- Evaluated the overall costs and benefits of the programs.
- Utilized the EIA Residential Energy Consumption Survey (RECS) from 2015
  - West South Central Region utilized for number of homes and saturation rates of appliances and equipment.
  - https://www.eia.gov/consumption/residential/data/2015/
- Costs of the program included:
  - Adoption costs
  - Incentive costs
  - Program marketing
  - Third-party program maintenance
  - Program director staffing
- Benefits of the program included:
  - Peak reduction savings ($/kW) (includes both capacity and transmission costs)
  - Energy savings for EE programs only ($/kWh)

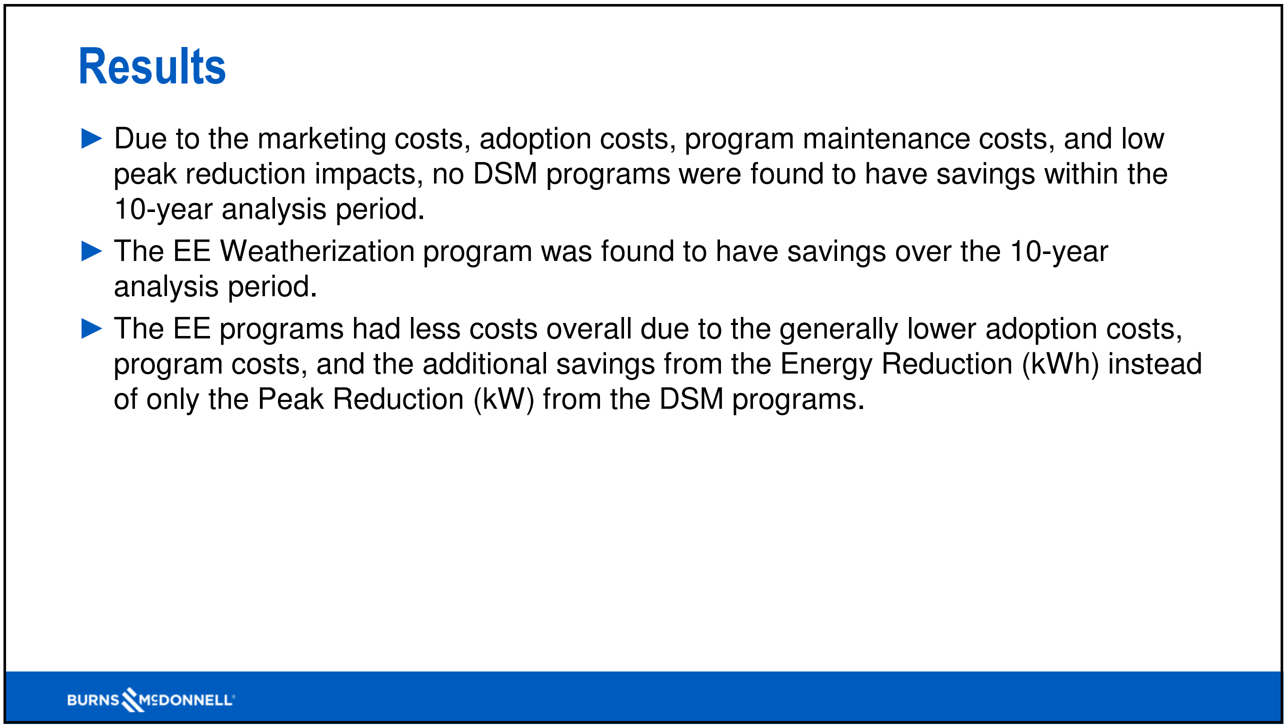


RESULTS



Program Summary NPV Table ($2021)

NPV Results ($2021)	
Water Heater Load Control Switching	($1,897,408)
Programmable Communicating Thermostats	($2,653,876)
Electric Heat Switching	($1,367,442)
Pool Pumping	($403,717)
EE Weatherization	$291,108
Old Fridge Removal	($329,820)
EE Appliances	($54,423)



Results

- Due to the marketing costs, adoption costs, program maintenance costs, and low peak reduction impacts, no DSM programs were found to have savings within the 10-year analysis period.
- The EE Weatherization program was found to have savings over the 10-year analysis period.
- The EE programs had less costs overall due to the generally lower adoption costs, program costs, and the additional savings from the Energy Reduction (kWh) instead of only the Peak Reduction (kW) from the DSM programs.

CREATE AMAZING.

Cost Summary - Capacity Cost - High ($/kW-yr)

Water Heater Load Control Switching

Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-Yr Total
Participation Rate (%)	4%	6%	8%	10%	12%	12%	12%	12%	12%	12%	-
Total Participating Customers	1,298	1,973	2,664	3,369	4,088	4,133	4,177	4,221	4,265	4,307	-
Total Peak Reduction (kW)	159	242	327	413	501	507	512	518	523	528	-
Total Peak Demand Savings ($)	$6,517	$10,105	$13,913	$17,947	$22,216	$22,910	$23,620	$24,346	$25,088	$25,843	$192,506
Total Program Cost ($)	$385,229	$233,348	$263,123	$294,361	$327,224	$183,377	$188,431	$193,628	$198,922	$204,141	$2,471,784
Savings or (Cost)	**($378,712)**	**($223,243)**	**($249,210)**	**($276,414)**	**($305,008)**	**($160,467)**	**($164,811)**	**($169,282)**	**($173,834)**	**($178,298)**	**($2,279,279)**

Programmable Communicating Thermostats

Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-Yr Total
Participation Rate (%)	4%	6%	8%	10%	12%	12%	12%	12%	12%	12%	-
Total Participating Customers	1,864	2,833	3,825	4,837	5,870	5,935	5,998	6,062	6,124	6,184	-
Total Peak Reduction (kW)	174	265	357	452	549	555	561	566	572	578	-
Total Peak Demand Savings ($)	$7,132	$11,058	$15,225	$19,640	$24,311	$25,071	$25,847	$26,641	$27,454	$28,280	$210,659
Total Program Cost ($)	$526,979	$328,278	$368,476	$410,621	$454,943	$247,927	$254,707	$261,682	$268,786	$275,773	$3,398,171
Savings or (Cost)	**($519,847)**	**($317,220)**	**($353,250)**	**($390,981)**	**($430,631)**	**($222,856)**	**($228,860)**	**($235,041)**	**($241,332)**	**($247,493)**	**($3,187,512)**

Electric Heat Switching

Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-Yr Total
Participation Rate (%)	4%	6%	8%	10%	12%	12%	12%	12%	12%	12%	-
Total Participating Customers	915	1,391	1,878	2,375	2,883	2,914	2,946	2,977	3,007	3,037	-
Total Peak Reduction (kW)	29	45	60	76	92	94	95	96	96	97	-
Total Peak Demand Savings ($)	$1,051	$1,629	$2,243	$2,893	$3,581	$3,693	$3,808	$3,925	$4,044	$4,166	$31,033
Total Program Cost ($)	$283,499	$160,074	$179,387	$199,631	$220,917	$119,179	$122,429	$125,773	$129,178	$132,525	$1,672,592
Savings or (Cost)	**($282,449)**	**($158,445)**	**($177,144)**	**($196,737)**	**($217,335)**	**($115,486)**	**($118,622)**	**($121,849)**	**($125,134)**	**($128,359)**	**($1,641,560)**

Pool Pumping

Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-Yr Total
Participation Rate (%)	4%	6%	8%	10%	12%	12%	12%	12%	12%	12%	-
Total Participating Customers	183	278	376	475	577	583	589	595	601	607	-
Total Peak Reduction (kW)	17	25	34	43	52	53	53	54	54	55	-
Total Peak Demand Savings ($)	$676	$1,049	$1,444	$1,863	$2,306	$2,378	$2,451	$2,527	$2,604	$2,682	$19,980
Total Program Cost ($)	$101,140	$38,899	$45,356	$52,153	$59,318	$39,444	$40,577	$41,740	$42,927	$44,111	$505,665
Savings or (Cost)	**($100,463)**	**($37,850)**	**($43,912)**	**($50,290)**	**($57,013)**	**($37,066)**	**($38,126)**	**($39,214)**	**($40,323)**	**($41,428)**	**($485,685)**

EE Weatherization

Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-Yr Total
Participation Rate (%)	4%	6%	8%	10%	12%	12%	12%	12%	12%	12%	-
Total Participating Customers	758	1,152	1,555	1,967	2,387	2,413	2,439	2,465	2,490	2,515	-
Total Peak Reduction (kW)	474	720	972	1,229	1,492	1,508	1,524	1,540	1,556	1,572	-
Total Peak Demand Savings ($)	$29,188	$45,259	$62,314	$80,382	$99,501	$102,610	$105,787	$109,038	$112,362	$115,743	$862,185
Total Program Cost ($)	$414,512	$223,443	$232,583	$241,843	$251,380	$34,680	$35,169	$35,710	$36,235	$36,525	$1,542,079
Savings or (Cost)	**($343,208)**	**($112,879)**	**($80,356)**	**($45,480)**	**($8,310)**	**$215,983**	**$223,256**	**$230,657**	**$238,253**	**$246,222**	**$564,138**

Old Fridge Removal

Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-Yr Total
Participation Rate (%)	4%	6%	8%	10%	12%	12%	12%	12%	12%	12%	-
Total Participating Customers	666	1,012	1,366	1,727	2,096	2,120	2,142	2,165	2,187	2,209	-
Total Peak Reduction (kW)	60	91	123	155	189	191	193	195	197	199	-
Total Peak Demand Savings ($)	$3,692	$5,725	$7,883	$10,168	$12,587	$12,980	$13,382	$13,793	$14,214	$14,641	$109,066
Total Program Cost ($)	$151,607	$88,180	$91,585	$95,036	$98,588	$22,658	$23,039	$23,443	$23,845	$24,170	$642,153
Savings or (Cost)	**($141,787)**	**($72,953)**	**($70,620)**	**($67,992)**	**($65,111)**	**$11,865**	**$12,553**	**$13,243**	**$13,959**	**$14,772**	**($352,071)**

EE Appliances

Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-Yr Total
Participation Rate (%)	4%	6%	8%	10%	12%	12%	12%	12%	12%	12%	-
Total Participating Customers	758	1,152	1,555	1,967	2,387	2,413	2,439	2,465	2,490	2,515	-
Total Peak Reduction (kW)	84	128	172	218	264	267	270	273	276	278	-
Total Peak Demand Savings ($)	$5,170	$8,016	$11,037	$14,237	$17,624	$18,174	$18,737	$19,313	$19,901	$20,500	$152,709
Total Program Cost ($)	$106,652	$38,869	$40,113	$41,376	$42,674	$21,355	$21,761	$22,180	$22,605	$23,013	$380,598
Savings or (Cost)	**($94,908)**	**($20,659)**	**($15,042)**	**($9,035)**	**($2,640)**	**$19,930**	**$20,801**	**$21,690**	**$22,603**	**$23,555**	**($33,705)**

APPENDIX F – LUS LOAD FORECAST

BURNS McDONNELL

December 18, 2018

Ms. Karen Hoyt
Utility Marketing Supervisor
Lafayette Utilities System
1314 Walker Road
Lafayette, Louisiana 70506

Re: 2018 Long-Term Load Forecast

Dear Ms. Hoyt:

Lafayette Utilities System (LUS) retained Burns & McDonnell (BMcD) to provide a Power Supply Planning Assessment (Study). As part of that Study, BMcD was tasked with completing a 2018 Long-term Load Forecast (Forecast). The Forecast is needed as an input necessary to complete the Power Supply Plan. This letter report provides the assumptions, methodology, and results of the Forecast.

Burns & McDonnell created the load and energy forecasts included in this Forecast by developing new economic equations using recent economic forecasts for the Lafayette metropolitan statistical area (MSA) from Woods & Poole Economics, Inc. (Woods & Poole) and historical data provided by LUS. The energy forecasts are class-specific and both the energy and load forecasts cover a period of 20 years from 2017 to 2037.

INTRODUCTION

The Forecast is a 20-year forecast of class-specific energy sales and peak demand for LUS and includes historical data through 2017 with projections through 2037.

As with the previous load and energy forecast, this Forecast was prepared in a bottom-up fashion. Class-specific energy data was acquired from LUS and used for class-specific energy forecasts. These were then aggregated to form a forecast of total energy sales at the system level. A forecast of system peak demand was then developed separately based on the forecast of total energy sales and the resulting forecasted load factor was checked for reasonableness.

The development of the LUS forecast involved direct input from LUS management and staff. All models and forecast development, which included statistical analyses, judgment, and this report were the primary responsibility of Burns & McDonnell.

Historical economic and demographic data and forecasts for the city of Lafayette were obtained from Woods & Poole. Woods & Poole is an independent, widely-used firm that specializes in long-term county economic and demographic projections. Woods & Poole's database for every county in the U.S. contains projections through 2050 for more than 900 variables.

LAFAYETTE UTILITIES SYSTEM

LUS is customer-owned and operated. LUS employs approximately 500 people and is a department of the Lafayette Consolidated Government. LUS was established in 1896 and has approximately 64,000 retail customers, more than 900 miles of primary distribution line, and an annual peak of approximately 460 MW.

Lafayette, Louisiana (City), is a city located along the Vermilion River in southwestern Louisiana. The city of Lafayette is the fourth largest in the state, with a population of 120,623 at the 2010 census. Lafayette is the parish seat of Lafayette Parish, Louisiana. The electric service territory of LUS consists primarily of the area encompassing the city of Lafayette.

Lafayette's climate is described as humid subtropical using the Köppen climate classification. Lafayette's climate is hot and humid during the summer and mild in the winter, which is typical of areas along the Gulf of Mexico. The average high temperature in July and August is 92 degrees Fahrenheit and the average low temperature in July and August is 74 degrees Fahrenheit.

Lafayette is considered the center of Acadiana, the most significant area of Cajun culture in Louisiana and the United States. As such, the city is a destination for tourism attracted to its Cajun culture. Lafayette also serves as the retail hub of the five-parish Acadiana area. According to Woods & Poole, the population of the City of Lafayette is expected to exhibit sustained growth over the forecast period. It is estimated that Lafayette's households will grow from 198,479 in 2017 to over 242,000 by 2037.

OVERVIEW OF MULTIVARIATE FORECASTING

The basic premise of econometric forecasting is that the historical relationship between energy sales and economic and demographic factors will continue into the future. Thus, the underlying hypothesis of this Forecast is that LUS's future energy sales growth, in general, is likely to be determined by the same factors that have influenced its growth in the past.

Regression analysis is one of the most widely applied statistical methods for modeling time series data. It is the statistical technique in which the historical variation in one variable (the dependent variable) is explained statistically by the historical variation in one or more other variables (the independent variables). This is a way in which to model cause and effect. For example, when the population of a utility's service area increases, the number of Residential consumers increases. However, two variables may have a high correlation without being causally related; thus, it is necessary to apply judgment and understand the dependent variable in order to select the appropriate independent variable.

Application of regression analysis yields statistical estimates of the magnitude and direction of the historical relationship between the dependent and each independent (explanatory) variable. A properly specified explanatory model, or regression equation, can be used to predict future values of the dependent variable at given values of the explanatory variables by assuming these relationships will continue.

Multivariate forecasting, as applied in this Forecast, uses regression analysis to relate historical electricity sales and the number of consumers to explanatory economic variables such as population, income, employment levels, and retail sales.

RESIDENTIAL CONSUMERS

The forecast of Residential consumers is based on the percent of households in Lafayette, Louisiana, that are LUS consumers. The historical number and forecast of households in the Lafayette, Louisiana MSA was provided by Woods & Poole. LUS' Residential consumers grew by an average rate of 1.48 percent per year over the last 29 years, with the average rate for the last five years of 0.84 percent.

Growth is expected to decrease slightly, with the forecast for the next five years projected at an annual average of 0.94 percent growth, with a 0.43 percent average annual growth rate over the next 20 years, as presented within Table 1 in the Attachment. In 2017, LUS served 54,559 Residential consumers and is forecasted to serve approximately 59,420 by 2037.

RESIDENTIAL ENERGY SALES

Energy sales to the Residential sector grew by an average rate of 1.99 percent per year over the last 29 years and 0.85 percent per year for the last five years. The forecast of Residential energy sales is based on Residential energy sales lagged one year.

Residential energy sales are expected to grow by an average of 0.24 percent and 0.09 percent per year on average over the next five and twenty years, respectively (as presented within Table 2 in the Attachment). In 2017, LUS had 806,567 MWh in Residential energy sales and is forecasted to have in excess of 821,000 MWh in Residential energy sales in 2037.

COMMERCIAL ENERGY SALES

Energy sales to the Commercial sector grew by an average rate of 2.00 percent per year over the last 29 years, with an average annual rate of only 0.12 percent over the last five years. The forecast of Commercial energy sales is based on Residential Energy and Retail Sales for General Stores as provided by Woods & Poole.

Commercial energy sales are expected to grow by an average rate of 0.43 percent per year over the next five years and 0.40 percent per year over the next twenty years, as presented in Table 3 in the Attachment. In 2017 LUS had 188,658 MWh in Commercial energy sales and is forecasted to have over 204,000 MWh in Commercial energy sales by 2037.

COMMERCIAL (with DEMAND) ENERGY SALES

Energy sales to the Commercial (with demand) sector grew by an average rate of 1.85 percent per year over the last 29 years and 0.50 percent per year over the last five years. The forecast of Commercial (with demand) energy sales is based on Commercial (with demand) energy sales (MWh) lagged one year as provided by LUS.

No new large loads are known for certain to be connecting to the system or leaving the system at this time. Commercial (with demand) energy sales are expected to grow by an average rate of 0.64 percent per year and an average rate of 0.46 percent per year over the next five and twenty years, respectively (as shown in the Attachment in Table 4). In 2017 LUS had 805,520 MWh in Commercial (with demand) energy sales and is forecasted to have over 883,000 MWh in Commercial (with demand) energy sales in 2037.

LIGHTING ENERGY SALES

Lighting energy sales grew by over 160 percent between 1998 and 1999, but have been much more consistent since then. Therefore, the forecast for Lighting energy sales is based on the historical period from 1999 to 2017. Lighting energy sales grew by an average annual rate of 2.01 percent over the last eighteen years and decreased by -0.82 percent over the last five years.

The forecast for Lighting energy sales is based on Total Personal Income per Capita, as provided by Woods & Poole and a dummy variable. Lighting energy sales are expected to decrease by an average annual rate of 10.33 percent over the next five years and 1.95 percent per year over the next twenty years, as presented in Table 5 in the Attachment. This decrease is primarily due to the conversion of LED lights. In 2017 LUS had 22,829 MWh in Lighting energy sales, but is only forecasted to have 15,392 MWh in Lighting energy sales in 2037.

OTHER ENERGY SALES

Other energy sales grew by an average annual rate of 1.41 percent over the last 29 years and 1.39 percent over the last five years. The forecast for other energy sales is based on Actual and Projected Residential Consumers, as provided by LUS and on Other Energy Lagged One Year as shown in Table 6 in the Attachment.

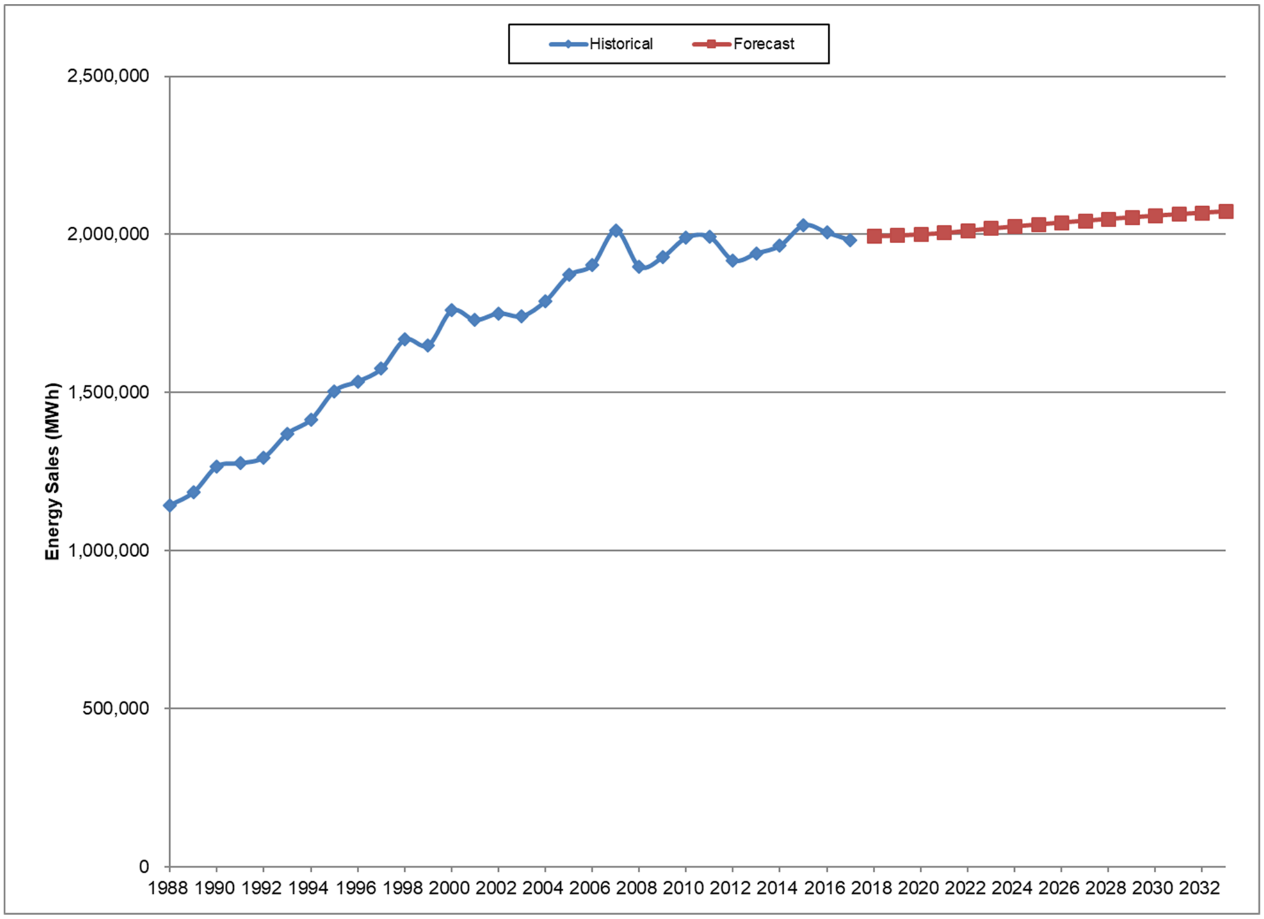
Other energy sales growth rates are expected to be flat over the forecast period, with an average annual predicted growth rate of 0.08 percent per year over the next five years and 0.19 percent per year over the next 20 years, as presented in Table 6 within the Attachment. In 2017 LUS had 158,771 MWh of Other energy sales and is forecasted to have over 164,000 MWh of Other energy sales in 2037.

TOTAL ENERGY SALES

Total energy sales are equal to the sum of all the classes previously discussed. Total energy sales increased by an average rate of 1.91 percent per year over the last 29 years, with an average annual growth rate of 0.66 percent over the last five years. Total energy sales are expected to grow by an average rate of 0.31 percent per year and an average rate of 0.26 percent per year over the next five and twenty years, respectively as presented in Table 7 in the Attachment.

In 2017 LUS had 1,982,344 MWh in Total energy sales and is forecasted to have approximately 2,100,000 MWh in Total energy sales in 2037, as presented in Table 7 in the Attachment. The forecasts presented in the Attachment and Figure 1 below do not include transmission and distribution losses. Transmission and distribution losses are accounted for within the power supply modeling and discussed later in this letter report.

Figure 1: Total Annual Energy Sales (excludes losses)



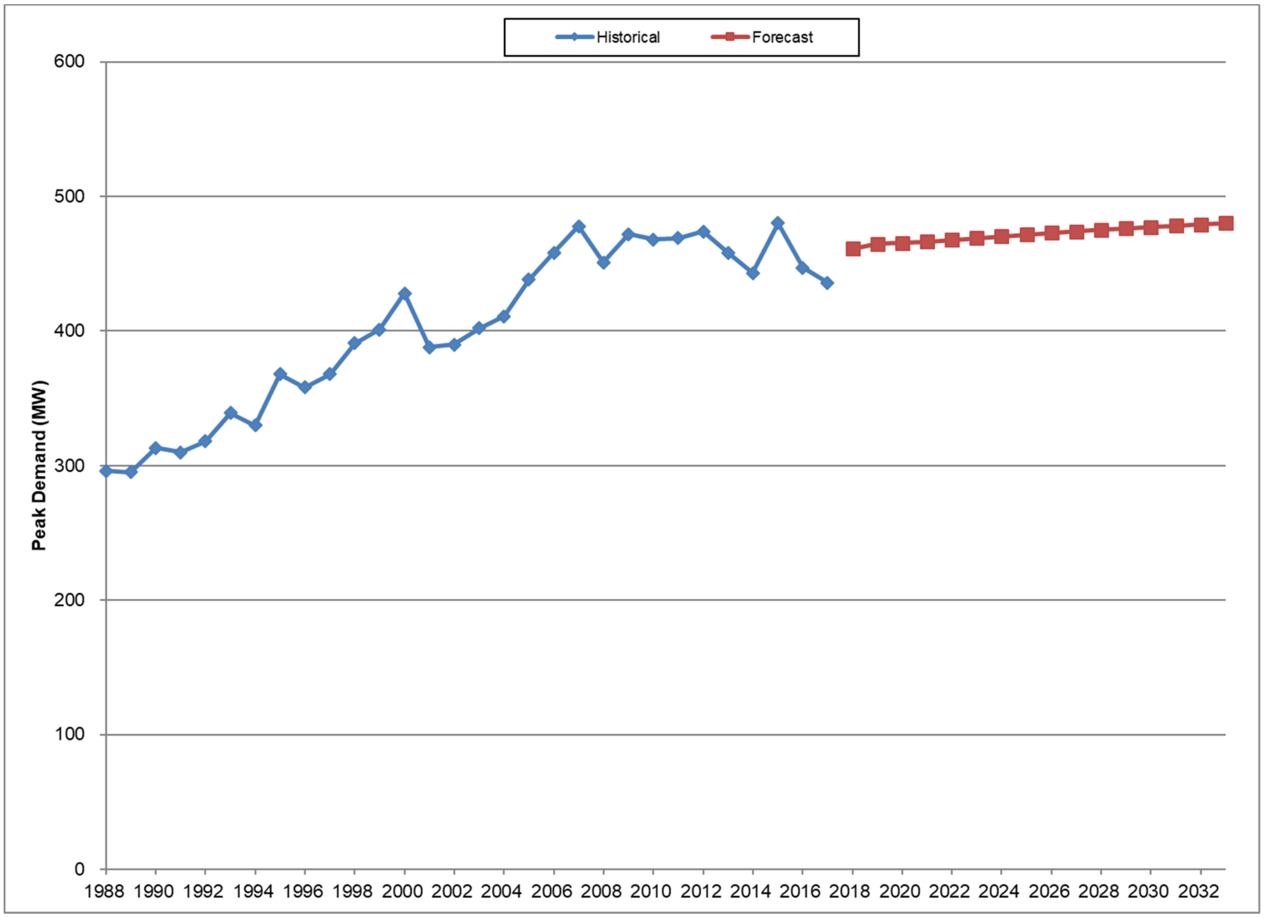
BASE PEAK DEMAND

Base Peak Demand is the maximum peak (MW) on the LUS system each year. Base Peak Demand has increased by an average rate of 1.34 percent per year over the last 29 years, dropping to an average annual decline rate of -1.66 percent per year over the last five years.

The forecast of the Base Peak Demand is based on Total energy sales (MWh). Base Peak Demand is expected to increase by an average rate of 1.41 percent per year over the next five years and by 0.51 percent per year over the next 20 years (as presented in Table 8 within the Attachment). In 2017 LUS' Base Peak Demand was 436 MW and LUS is forecasted to have a

Base Peak Demand of approximately 483 MW in 2037, as presented in Figure 2 below and in Table 8 in the Attachment.

Figure 2: Base Peak Demand Forecast (excludes losses)



PEAK DEMAND AND LOAD FACTOR

LUS' Load Factor has ranged from a minimum of 44.1 percent to a maximum of 51.9 percent over the last 29 years. The average load factor during that time period was 49.3 percent. Based on the forecasted Base Peak Demand in Table 8 and forecasted Total energy sales in Table 7, LUS' load factor is forecasted to drop from 51.90 percent in 2017 to 49.37 percent in 2037. The actual and projected Base Peak Demand, Total energy sales and resulting Load Factors are presented in Table 9 within the Attachment.

MONTHLY ENERGY SALES & MONTHLY PEAK DEMAND

In addition to the Total energy and Base Peak Demand annual forecasts, LUS requested that Burns & McDonnell develop monthly forecasts for Total energy sales and Base Peak Demand. Utilizing historical information, Burns & McDonnell developed forecasts for monthly Total energy sales and Base Peak Demand. The monthly total energy sales shape was developed utilizing an average monthly shape from five years of LUS data. The monthly Base Peak Demand shape was developed utilizing the ten years of LUS historical monthly peak demands.

LUS' monthly Total energy sales and monthly Base Peak Demand forecasts are presented in Table 10 in the Attachment. The monthly Total energy sales and monthly Base Peak Demand forecast shapes are presented below in Table 1.

Table 1: Monthly Shapes for Total Energy and Base Peak Demand

Month	5 Year Energy Average Percent	10 Year Peak Average Percent
1	7.6%	72.2%
2	7.4%	65.3%
3	7.0%	62.8%
4	7.0%	71.5%
5	7.8%	85.0%
6	9.5%	95.3%
7	10.4%	95.3%
8	10.4%	100.0%
9	10.2%	91.5%
10	8.2%	80.9%
11	7.3%	63.5%
12	7.2%	69.2%

TRANSMISSION AND DISTRIBUTION LOSSES

The historical data provided by LUS and corresponding forecasts do not include transmission and distribution losses. To account for transmission and distribution losses at the wholesale power supply level, Burns & McDonnell applied an additional 6.5 percent to the Total energy and Base Peak Demand requirements. The 6.5 percent adder was based on information received from LUS based on historical losses.

HIGH AND LOW ECONOMIC SCENARIOS

In addition to the base forecasts, high growth and low growth scenarios were developed. The high growth scenario forecasts are also class specific and based on a robust Lafayette economy and high economic growth. The low growth scenario forecasts are class specific and based on a flat or declining Lafayette economy with little to no overall economic growth. The high and low economic forecasts are presented in the Attachment.

CONCLUSION

Thank you for allowing Burns & McDonnell the opportunity to assist LUS with its 2018 Long-term Load Forecast. We look forward to working with LUS in the future. If you have questions or comments, please contact Mike Borgstadt at 816-822-3459 or mborgstadt@burnsmcd.com.

Sincerely,

Mike Borgstadt, PE
Project Manager

Attachment

ATTACHMENT -FORECAST TABLES

Table 1

RESIDENTIAL CONSUMERS

Lafayette Utilities System

	Year	Total Households [1]	Percentage of Households Served	Actual and Projected Residential Consumers	Actual and Projected Residential Consumer Growth
	1988	131,906	27.0%	35,603	na
	1989	133,839	27.9%	37,374	4.97%
	1990	135,372	28.5%	38,646	3.40%
	1991	137,692	28.6%	39,421	2.01%
	1992	139,864	28.7%	40,184	1.94%
	1993	141,846	29.2%	41,369	2.95%
	1994	143,158	29.5%	42,215	2.05%
	1995	145,549	29.7%	43,175	2.27%
	1996	148,664	29.4%	43,728	1.28%
	1997	151,494	29.7%	45,002	2.91%
	1998	154,062	29.3%	45,169	0.37%
	1999	155,438	29.3%	45,473	0.67%
	2000	156,266	29.0%	45,305	-0.37%
	2001	160,671	28.2%	45,286	-0.04%
	2002	162,324	28.3%	46,006	1.59%
	2003	164,887	28.4%	46,799	1.72%
	2004	165,736	28.4%	47,048	0.53%
	2005	167,730	28.4%	47,690	1.36%
	2006	171,877	28.3%	48,597	1.90%
	2007	174,170	28.6%	49,775	2.42%
	2008	175,680	29.1%	51,119	2.70%
	2009	176,714	28.6%	50,581	-1.05%
	2010	178,072	28.8%	51,262	1.35%
	2011	181,737	28.6%	51,930	1.30%
	2012	184,658	28.3%	52,335	0.78%
	2013	187,961	28.1%	52,829	0.94%
	2014	189,815	28.1%	53,359	1.00%
	2015	192,491	27.9%	53,686	0.61%
	2016	194,985	27.8%	54,212	0.98%
Historical	2017	198,479	27.5%	54,559	0.64%
Projected	2018	201,708	27.6%	55,571 [3]	1.85%
	2019	204,683	27.4% [2]	56,047	0.86%
	2020	207,500	27.2%	56,472	0.76%
	2021	210,199	27.0%	56,858	0.68%
	2022	212,675	26.9%	57,177	0.56%
	2023	215,017	26.7%	57,455	0.49%
	2024	217,279	26.6%	57,705	0.44%
	2025	219,481	26.4%	57,935	0.40%
	2026	221,636	26.2%	58,147	0.37%
	2027	223,767	26.1%	58,349	0.35%
	2028	225,861	25.9%	58,536	0.32%
	2029	227,889	25.8%	58,702	0.28%
	2030	229,852	25.6%	58,846	0.25%
	2031	231,764	25.4%	58,974	0.22%
	2032	233,608	25.3%	59,081	0.18%
	2033	235,393	25.1%	59,170	0.15%
	2034	237,139	25.0%	59,246	0.13%
	2035	238,839	24.8%	59,307	0.10%
	2036	240,508	24.7%	59,357	0.09%
	2037	242,236	24.5%	59,420	0.10%

Average Annual Compound Growth Rates:

1988	2017	1.42%	0.06%	1.48%
2007	2017	1.32%	-0.39%	0.92%
2012	2017	1.45%	-0.61%	0.84%
2017	2022	1.39%	-0.44%	0.94%
2017	2037	1.00%	-0.57%	0.43%

[1] Data from Woods & Poole

[2] Forecast based on growth from 2012 -2017

[3] Includes new neighborhood Holiday Gardens and the addition of 400 homes

Table 2

RESIDENTIAL ENERGY SALES

Lafayette Utilities System

RES_MWH = 80,113.249 + .90186 (RES_LAG)

Variable	T-statistic	Variable Description
RES_MWH		Residential Energy Sales (MWh)
RES_LAG	18.968	Residential Energy Sales Lagged One Year (MWh)

R-Squared =	92.8%	Standard Error =	30,437
Adjusted R-Squared =	92.5%	F-Statistic =	359.800

	Year	Residential Energy Lagged One Year	Actual and Projected Residential Energy		Actual and Projected Residential Energy Growth	Actual and Projected Residential Consumers	[1]	Actual and Projected Residential Energy/Consumer (kWh)	Actual and Projected Residential Energy/Consumer Growth
	1988	455,282	455,282		na	35,603		12,788	na
	1989	455,282	487,735		7.13%	37,374		13,050	2.05%
	1990	487,735	536,456		9.99%	38,646		13,881	6.37%
	1991	536,456	542,978		1.22%	39,421		13,774	-0.77%
	1992	542,978	545,142		0.40%	40,184		13,566	-1.51%
	1993	545,142	592,114		8.62%	41,369		14,313	5.51%
	1994	592,114	602,814		1.81%	42,215		14,280	-0.23%
	1995	602,814	648,969		7.66%	43,175		15,031	5.26%
	1996	648,969	655,419		0.99%	43,728		14,989	-0.28%
	1997	655,419	672,123		2.55%	45,002		14,935	-0.35%
	1998	672,123	721,282		7.31%	45,169		15,969	6.92%
	1999	721,282	695,855		-3.53%	45,473		15,303	-4.17%
	2000	695,855	740,536		6.42%	45,305		16,346	6.82%
	2001	740,536	711,418		-3.93%	45,286		15,709	-3.89%
	2002	711,418	732,666		2.99%	46,006		15,925	1.37%
	2003	732,666	726,600		-0.83%	46,799		15,526	-2.51%
	2004	726,600	743,091		2.27%	47,048		15,794	1.73%
	2005	743,091	794,261		6.89%	47,690		16,655	5.45%
	2006	794,261	754,912		-4.95%	48,597		15,534	-6.73%
	2007	754,912	823,632		9.10%	49,775		16,547	6.52%
	2008	823,632	774,019		-6.02%	51,119		15,142	-8.49%
	2009	774,019	801,278		3.52%	50,581		15,841	4.62%
	2010	801,278	844,669		5.42%	51,262		16,477	4.01%
	2011	844,669	831,448		-1.57%	51,930		16,011	-2.83%
	2012	831,448	**772,997**		-7.03%	52,335		14,770	-7.75%
	2013	772,997	**791,352**		2.37%	52,829		14,979	1.42%
	2014	791,352	**801,799**		1.32%	53,359		15,027	0.31%
	2015	801,799	**827,250**		3.17%	53,686		15,409	2.55%
	2016	827,250	**827,166**		-0.01%	54,212		15,258	-0.98%
Historical	2017	827,166	**806,567**	[2]	-2.49%	54,559		14,783	-3.11%
Projected	2018	806,567	814,857		0.12%	55,571		14,663	-0.81%
	2019	807,525	814,251		0.11%	56,047		14,528	-0.92%
	2020	808,390	815,036		0.10%	56,472		14,433	-0.66%
	2021	809,170	815,745		0.09%	56,858		14,347	-0.59%
	2022	809,873	816,383		0.08%	57,177		14,278	-0.48%
	2023	810,507	816,960		0.07%	57,455		14,219	-0.41%
	2024	811,079	817,479		0.06%	57,705		14,166	-0.37%
	2025	811,595	817,948		0.06%	57,935		14,118	-0.34%
	2026	812,060	818,370		0.05%	58,147		14,074	-0.31%
	2027	812,480	818,751		0.05%	58,349		14,032	-0.30%
	2028	812,858	819,095		0.04%	58,536		13,993	-0.28%
	2029	813,199	819,405		0.04%	58,702		13,959	-0.24%
	2030	813,507	819,685		0.03%	58,846		13,929	-0.21%
	2031	813,784	819,937		0.03%	58,974		13,903	-0.19%
	2032	814,035	820,164		0.03%	59,081		13,882	-0.15%
	2033	814,260	820,369		0.03%	59,170		13,865	-0.12%
	2034	814,464	820,554		0.02%	59,246		13,850	-0.11%
	2035	814,648	820,721		0.02%	59,307		13,839	-0.08%
	2036	814,813	820,871		0.02%	59,357		13,829	-0.07%
	2037	814,963	821,007		0.02%	59,420		13,817	-0.09%

Average Annual Compound Growth Rates:

1988	2017	2.08%	1.99%	1.48%	0.50%
2007	2017	0.92%	-0.21%	0.92%	-1.12%
2012	2017	-0.10%	0.85%	0.84%	0.02%
2017	2022	-0.42%	0.24%	0.94%	-0.69%
2017	2037	-0.07%	0.09%	0.43%	-0.34%

[1] Data from Table 1

[2] Data from 2012 to 2017 was weather-normalized

Table 3

COMMERCIAL ENERGY SALES

Lafayette Utilities System

COM_MWH = -23,531.92 + 0.21486 (RES_MWH) + 5.56963 (TOT_RET_GEN)

Variable	T-statistic	Variable Description
COM_MWH		Commercial Energy Sales (MWh)
TOT_RET_GEN	7.815	Total Retail Sales for General Stores
RES_MWH	2.805	Residential Energy Sales (MWh)

R-Squared =	96.3%	Standard Error =	6,457.626
Adjusted R-Squared =	96.1%	F-Statistic =	355.295

	Year	Retail Sales General Stores [1]	Actual and Projected Residential Energy [2]	Actual and Projected Commercial Energy		Actual and Projected Commercial Energy Growth
	1988	$3,480	455,282	106,382		na
	1989	$3,609	487,735	106,177		-0.2%
	1990	$3,692	536,456	108,253		2.0%
	1991	$3,704	542,978	111,435		2.9%
	1992	$3,894	545,142	111,616		0.2%
	1993	$4,158	592,114	124,566		11.60%
	1994	$4,498	602,814	129,043		3.59%
	1995	$4,726	648,969	135,998		5.39%
	1996	$5,003	655,419	137,438		1.06%
	1997	$5,245	672,123	145,659		5.98%
	1998	$5,368	721,282	158,210		8.62%
	1999	$5,642	695,855	155,160		-1.93%
	2000	$5,725	740,536	171,768		10.70%
	2001	$5,638	711,418	166,023		-3.34%
	2002	$5,583	732,666	165,880		-0.09%
	2003	$5,843	726,600	159,778		-3.68%
	2004	$6,205	743,091	168,830		5.67%
	2005	$6,545	794,261	177,075		4.88%
	2006	$6,872	754,912	190,740		7.72%
	2007	$7,085	823,632	197,865		3.74%
	2008	$6,905	774,019	187,371		-5.30%
	2009	$6,513	801,278	192,017		2.48%
	2010	$6,836	844,669	200,750		4.55%
	2011	$7,230	831,448	194,819		-2.95%
	2012	$7,538	772,997	187,571		-3.72%
	2013	$7,751	791,352	195,228		4.08%
	2014	$8,001	801,799	199,733		2.31%
	2015	$8,210	827,250	202,060		1.17%
	2016	$8,348	827,166	180,207		-10.81%
Historical	2017	$8,571	806,567	188,658		4.69%
Projected	2018	$8,728	814,857	189,305	[3]	0.34%
	2019	$8,875	814,251	189,955		0.34%
	2020	$9,015	815,036	190,855		0.47%
	2021	$9,169	815,745	191,807		0.50%
	2022	$9,317	816,383	192,719		0.48%
	2023	$9,462	816,960	193,597		0.46%
	2024	$9,604	817,479	194,455		0.44%
	2025	$9,747	817,948	195,300		0.43%
	2026	$9,888	818,370	196,127		0.42%
	2027	$10,026	818,751	196,936		0.41%
	2028	$10,163	819,095	197,728		0.40%
	2029	$10,299	819,405	198,505		0.39%
	2030	$10,434	819,685	199,275		0.39%
	2031	$10,568	819,937	200,032		0.38%
	2032	$10,702	820,164	200,782		0.37%
	2033	$10,835	820,369	201,525		0.37%
	2034	$10,968	820,554	202,261		0.37%
	2035	$11,101	820,721	202,999		0.36%
	2036	$11,234	820,871	203,727		0.36%
	2037	$11,367	821,007	204,458		0.36%

Average Annual Compound Growth Rates:

1988	2017	3.16%	1.99%	2.00%
2007	2017	1.92%	-0.21%	-0.48%
2012	2017	2.60%	0.85%	0.12%
2017	2022	1.68%	0.24%	0.43%
2017	2037	1.42%	0.09%	0.40%

[1] Data from Woods & Poole

[2] Data from Table 2

[3] Forecast based on model-estimated growth

Table 4

COMMERCIAL (with DEMAND) ENERGY SALES

Lafayette Utilities System

COMwD_MWH = 38,356.269 + 0.95920 (COMwD_LAG)

Variable	T-statistic	Variable Description
COMwD_MWH		Commercial (with Demand) Energy Sales (MWh)
COMwD_LAG	31.11	Commercial (with Demand) Energy Sales Lagged One Year (MWh)

R-Squared =	97.2%	Standard Error =	20,542.3
Adjusted R-Squared =	97.1%	F-Statistic =	968.126

	Year	[1]	Commercial (with Demand) Energy Lagged One Year	Actual and Projected Commercial (with Demand) Energy		Projected Commercial (with Demand) Energy Growth
	1988		477,805	473,332		na
	1989		473,332	473,130		-0.04%
	1990		473,130	497,109		5.07%
	1991		497,109	496,326		-0.16%
	1992		496,326	511,180		2.99%
	1993		511,180	526,603		3.02%
	1994		526,603	547,511		3.97%
	1995		547,511	578,822		5.72%
	1996		578,822	602,105		4.02%
	1997		602,105	614,060		1.99%
	1998		614,060	645,451		5.11%
	1999		645,451	647,906		0.38%
	2000		647,906	700,035		8.05%
	2001		700,035	723,825		3.40%
	2002		723,825	737,195		1.85%
	2003		737,195	701,067		-4.90%
	2004		701,067	731,795		4.38%
	2005		731,795	745,948		1.93%
	2006		745,948	796,126		6.73%
	2007		796,126	822,515		3.31%
	2008		822,515	781,121		-5.03%
	2009		781,121	780,166		-0.12%
	2010		780,166	775,136		-0.64%
	2011		775,136	792,875		2.29%
	2012		792,875	785,806		-0.89%
	2013		785,806	781,262		-0.58%
	2014		781,262	793,062		1.51%
	2015		793,062	815,519		2.83%
	2016		815,519	815,087		-0.05%
Historical	2017		815,087	805,520		-1.17%
Projected	2018		805,520	811,159	[1]	0.70%
	2019		811,159	816,568		0.67%
	2020		816,568	821,758		0.64%
	2021		821,758	826,737		0.61%
	2022		826,737	831,514		0.58%
	2023		831,514	836,096		0.55%
	2024		836,096	840,493		0.53%
	2025		840,493	844,710		0.50%
	2026		844,710	848,757		0.48%
	2027		848,757	852,639		0.46%
	2028		852,639	856,363		0.44%
	2029		856,363	859,937		0.42%
	2030		859,937	863,364		0.40%
	2031		863,364	866,653		0.38%
	2032		866,653	869,808		0.36%
	2033		869,808	872,835		0.35%
	2034		872,835	875,739		0.33%
	2035		875,739	878,525		0.32%
	2036		878,525	881,198		0.30%
	2037		881,198	883,762		0.29%

Average Annual Compound Growth Rates:

1988	2017	1.86%	1.85%
2007	2017	0.24%	-0.21%
2012	2017	0.55%	0.50%
2017	2022	0.28%	0.64%
2017	2037	0.39%	0.46%

[1] Forecast based on model-estimated growth

Table 5

LIGHTING ENERGY SALES

Lafayette Utilities System

LIGHT_MWH = -392.868 + 0.58635 (TOT_PI_PC)

Variable	T-statistic
LIGHT_MWH	
TOT_PI_PC	7.44

R-Squared = 76.5%

Adjusted R-Squared = 75.1%

Standard Error = 1,521.41

F-Statistic = 55.32

	Year	Total Personal Income per Capita	[1]	Actual and Projected Lighting Energy		Actual and Projected Lighting Energy Growth
	1999	$26,857		15,952		na
	2000	$27,864		15,335		-3.87%
	2001	$29,700		16,243		5.92%
	2002	$29,449		16,488		1.51%
	2003	$29,600		17,880		8.44%
	2004	$29,760		15,534		-13.12%
	2005	$32,146		18,326		17.97%
	2006	$34,985		20,895		14.02%
	2007	$36,054		21,550		3.13%
	2008	$39,254		21,138		-1.91%
	2009	$36,366		21,552		1.96%
	2010	$37,301		17,747		-17.66%
	2011	$37,305		23,302		31.30%
	2012	$40,036		23,794		2.11%
	2013	$39,343		21,321		-10.39%
	2014	$40,875		22,952		7.65%
	2015	$38,920		22,571		-1.66%
	2016	$35,719		23,641		4.74%
Historical	2017	$37,650		22,829		-3.43%
Projected	2018	$38,306		23,175	[2]	1.51%
	2019	$38,876		19,870	[3]	-14.26%
	2020	$39,404		16,488	[3]	-17.02%
	2021	$39,927		13,055	[3]	-20.82%
	2022	$40,466		13,234		1.37%
	2023	$40,989		13,408		1.31%
	2024	$41,505		13,580		1.28%
	2025	$42,037		13,757		1.30%
	2026	$42,555		13,929		1.25%
	2027	$43,051		14,094		1.18%
	2028	$43,532		14,254		1.13%
	2029	$44,001		14,410		1.09%
	2030	$44,441		14,556		1.02%
	2031	$44,833		14,687		0.90%
	2032	$45,201		14,809		0.83%
	2033	$45,555		14,927		0.79%
	2034	$45,909		15,044		0.79%
	2035	$46,284		15,169		0.83%
	2036	$46,640		15,287		0.78%
	2037	$46,953		15,392		0.68%

Average Annual Compound Growth Rates:

1999	2017	1.89%	2.01%
2007	2017	0.43%	0.58%
2012	2017	-1.22%	-0.82%
2017	2022	1.45%	-10.33%
2017	2037	1.11%	-1.95%

[1] Data from Woods & Poole

[2] Forecast based on model estimated growth and historical data from 1999 - 2017

[3] Forecast includes a lighting reduction of 10,968 MWh spread over 3 years for street light replacement program

Table 6

OTHER ENERGY SALES

Lafayette Utilities System

OTHER_MWH = 18,860.904 + 1.37769 (RES_CON) + 0.39118 (OTHER_LAG)

Variable	T-statistic	Variable Description
OTHER_MWH		Other Energy Sales (MWh)
RES_CON	2.576	Residential Consumers
OTHER_LAG	2.224	Other Energy Sales Lagged One Year (MWh)

R-Squared =	70.2%	Standard Error =	8,840.67
Adjusted R-Squared =	68.0%	F-Statistic =	31.80

	Year	Actual and Projected Residential Consumers	[1] Other Energy Lagged One Year	Actual and Projected Other Energy	Actual and Projected Other Energy Growth
	1988	35,603	99,926	105,868	na
	1989	37,374	105,868	114,547	8.20%
	1990	38,646	114,547	121,433	6.01%
	1991	39,421	121,433	121,812	0.31%
	1992	40,184	121,812	123,559	1.43%
	1993	41,369	123,559	123,491	-0.05%
	1994	42,215	123,491	130,984	6.07%
	1995	43,175	130,984	137,230	4.77%
	1996	43,728	137,230	135,750	-1.08%
	1997	45,002	135,750	138,384	1.94%
	1998	45,169	138,384	136,435	-1.41%
	1999	45,473	136,435	134,778	-1.21%
	2000	45,305	134,778	131,847	-2.18%
	2001	45,286	131,847	112,370	-14.77%
	2002	46,006	112,370	98,557	-12.29%
	2003	46,799	98,557	136,779	38.78%
	2004	47,048	136,779	130,641	-4.49%
	2005	47,690	130,641	136,084	4.17%
	2006	48,597	136,084	141,009	3.62%
	2007	49,775	141,009	147,323	4.48%
	2008	51,119	147,323	134,725	-8.55%
	2009	50,581	134,725	134,016	-0.53%
	2010	51,262	134,016	151,920	13.36%
	2011	51,930	151,920	150,028	-1.25%
	2012	52,335	150,028	148,179	-1.23%
	2013	52,829	148,179	151,587	2.30%
	2014	53,359	151,587	147,905	-2.43%
	2015	53,686	147,905	162,585	9.93%
	2016	54,212	162,585	160,384	-1.35%
Historical	2017	54,559	160,384	158,771	-1.01%
Projected	2018	55,571	158,771	157,217	[2] -0.98%
	2019	56,047	157,217	157,264	0.03%
	2020	56,472	157,264	157,868	0.38%
	2021	56,858	157,868	158,634	0.49%
	2022	57,177	158,634	159,372	0.47%
	2023	57,455	159,372	160,041	0.42%
	2024	57,705	160,041	160,647	0.38%
	2025	57,935	160,647	161,200	0.34%
	2026	58,147	161,200	161,707	0.31%
	2027	58,349	161,707	162,182	0.29%
	2028	58,536	162,182	162,625	0.27%
	2029	58,702	162,625	163,026	0.25%
	2030	58,846	163,026	163,381	0.22%
	2031	58,974	163,381	163,696	0.19%
	2032	59,081	163,696	163,966	0.16%
	2033	59,170	163,966	164,193	0.14%
	2034	59,246	164,193	164,386	0.12%
	2035	59,307	164,386	164,546	0.10%
	2036	59,357	164,546	164,677	0.08%
	2037	59,420	164,677	164,814	0.08%

Average Annual Compound Growth Rates:

1988	2017	1.48%	1.64%	1.41%
2007	2017	0.92%	1.30%	0.75%
2012	2017	0.84%	1.34%	1.39%
2017	2022	0.94%	-0.22%	0.08%
2017	2037	0.43%	0.13%	0.19%

[1] Data from Table 1

[2] Forecast based on model-estimated growth and includes the loss of 2,269 MWh from the University of Louisiana at Lafayette's new solar facility

Table 7

TOTAL ENERGY SALES (MWh)

Lafayette Utilities System

	Year	Residential Energy [1]	Commercial Energy [2]	Commercial (with demand) Energy [3]	Lighting Energy [4]	Other Energy [5]	Actual and Projected TOTAL Energy	Actual and Projected TOTAL Energy Growth
	1988	455,282	106,382	473,332	2,756	105,868	1,143,620	na
	1989	487,735	106,177	473,130	2,809	114,547	1,184,399	3.57%
	1990	536,456	108,253	497,109	3,242	121,433	1,266,493	6.93%
	1991	542,978	111,435	496,326	3,477	121,812	1,276,027	0.75%
	1992	545,142	111,616	511,180	3,598	123,559	1,295,094	1.49%
	1993	592,114	124,566	526,603	3,645	123,491	1,370,419	5.82%
	1994	602,814	129,043	547,511	3,711	130,984	1,414,062	3.18%
	1995	648,969	135,998	578,822	4,030	137,230	1,505,050	6.43%
	1996	655,419	137,438	602,105	4,461	135,750	1,535,174	2.00%
	1997	672,123	145,659	614,060	4,778	138,384	1,575,003	2.59%
	1998	721,282	158,210	645,451	6,110	136,435	1,667,488	5.87%
	1999	695,855	155,160	647,906	15,952	134,778	1,649,651	-1.07%
	2000	740,536	171,768	700,035	15,335	131,847	1,759,520	6.66%
	2001	711,418	166,023	723,825	16,243	112,370	1,729,880	-1.68%
	2002	732,666	165,880	737,195	16,488	98,557	1,750,786	1.21%
	2003	726,600	159,778	701,067	17,880	136,779	1,742,103	-0.50%
	2004	743,091	168,830	731,795	15,534	130,641	1,789,891	2.74%
	2005	794,261	177,075	745,948	18,326	136,084	1,871,694	4.57%
	2006	754,912	190,740	796,126	20,895	141,009	1,903,683	1.71%
	2007	823,632	197,865	822,515	21,550	147,323	2,012,885	5.74%
	2008	774,019	187,371	781,121	21,138	134,725	1,898,374	-5.69%
	2009	801,278	192,017	780,166	21,552	134,016	1,929,029	1.61%
	2010	844,669	200,750	775,136	17,747	151,920	1,990,222	3.17%
	2011	831,448	194,819	792,875	23,302	150,028	1,992,472	0.11%
	2012	772,997	187,571	785,806	23,794	148,179	1,918,347	-3.72%
	2013	791,352	195,228	781,262	21,321	151,587	1,940,750	1.17%
	2014	801,799	199,733	793,062	22,952	147,905	1,965,451	1.27%
	2015	827,250	202,060	815,519	22,571	162,585	2,029,985	3.28%
	2016	827,166	180,207	815,087	23,641	160,384	2,006,484	-1.16%
Historical	2017	806,567	188,658	805,520	22,829	158,771	1,982,345	-1.20%
Projected	2018	814,857	189,305	811,159	23,175	157,217	1,995,712	0.67%
	2019	814,251	189,955	816,568	19,870	157,264	1,997,909	0.11%
	2020	815,036	190,855	821,758	16,488	157,868	2,002,005	0.21%
	2021	815,745	191,807	826,737	13,055	158,634	2,005,978	0.20%
	2022	816,383	192,719	831,514	13,234	159,372	2,013,222	0.36%
	2023	816,960	193,597	836,096	13,408	160,041	2,020,103	0.34%
	2024	817,479	194,455	840,493	13,580	160,647	2,026,654	0.32%
	2025	817,948	195,300	844,710	13,757	161,200	2,032,915	0.31%
	2026	818,370	196,127	848,757	13,929	161,707	2,038,891	0.29%
	2027	818,751	196,936	852,639	14,094	162,182	2,044,603	0.28%
	2028	819,095	197,728	856,363	14,254	162,625	2,050,065	0.27%
	2029	819,405	198,505	859,937	14,410	163,026	2,055,282	0.25%
	2030	819,685	199,275	863,364	14,556	163,381	2,060,261	0.24%
	2031	819,937	200,032	866,653	14,687	163,696	2,065,004	0.23%
	2032	820,164	200,782	869,808	14,809	163,966	2,069,529	0.22%
	2033	820,369	201,525	872,835	14,927	164,193	2,073,849	0.21%
	2034	820,554	202,261	875,739	15,044	164,386	2,077,985	0.20%
	2035	820,721	202,999	878,525	15,169	164,546	2,081,959	0.19%
	2036	820,871	203,727	881,198	15,287	164,677	2,085,761	0.18%
	2037	821,007	204,458	883,762	15,392	164,814	2,089,433	0.18%

Average Annual Compound Growth Rates:

1988	2017	1.99%	2.00%	1.85%	7.56%	1.41%	1.91%
2007	2017	-0.21%	-0.48%	-0.21%	0.58%	0.75%	-0.15%
2012	2017	0.85%	0.12%	0.50%	-0.82%	1.39%	0.66%
2017	2022	0.24%	0.43%	0.64%	-10.33%	0.08%	0.31%
2017	2037	0.09%	0.40%	0.46%	-1.95%	0.19%	0.26%

[1] Data from Table 2

[2] Data from Table 3

[3] Data from Table 4

[4] Data from Table 5

[5] Data from Table 6

Table 8

BASE PEAK DEMAND

Lafayette Utilities System

PEAK = 59.826 + 0.0002026 (TOT_MWH)

Variable	T-statistic	Variable Description
PEAK		Base Peak Demand (MW)
TOT_MWH	21.681	Totial Energy Sales (MWh)

R-Squared = 94.4%
Adjusted R-Squared = 94.2%

Standard Error = 14.613
F-Statistic = 470.064

	Year	Actual and Projected Total Energy	[1] Actual and Projected Peak Demand	Actual and Projected Peak Demand Growth
	1988	1,143,620	296	na
	1989	1,184,399	295	-0.34%
	1990	1,266,493	313	6.10%
	1991	1,276,027	310	-0.96%
	1992	1,295,094	318	2.58%
	1993	1,370,419	339	6.60%
	1994	1,414,062	330	-2.65%
	1995	1,505,050	368	11.52%
	1996	1,535,174	358	-2.72%
	1997	1,575,003	368	2.79%
	1998	1,667,488	391	6.25%
	1999	1,649,651	401	2.56%
	2000	1,759,520	428	6.73%
	2001	1,729,880	388	-9.35%
	2002	1,750,786	390	0.52%
	2003	1,742,103	402	3.08%
	2004	1,789,891	411	2.24%
	2005	1,871,694	438	6.57%
	2006	1,903,683	458	4.57%
	2007	2,012,885	478	4.37%
	2008	1,898,374	451	-5.65%
	2009	1,929,029	472	4.66%
	2010	1,990,222	468	-0.85%
	2011	1,992,472	469	0.21%
	2012	1,918,347	474	1.07%
	2013	1,940,750	458	-3.38%
	2014	1,965,451	443	-3.28%
	2015	2,029,985	480	8.35%
	2016	2,006,484	447	-6.88%
Historical	2017	1,982,345	436	-2.46%
Projected	2018	1,995,712	461	5.73%
	2019	1,997,909	465	0.78%
	2020	2,002,005	465	0.18%
	2021	2,005,978	466	0.17%
	2022	2,013,222	468	0.31%
	2023	2,020,103	469	0.30%
	2024	2,026,654	470	0.28%
	2025	2,032,915	472	0.27%
	2026	2,038,891	473	0.26%
	2027	2,044,603	474	0.24%
	2028	2,050,065	475	0.23%
	2029	2,055,282	476	0.22%
	2030	2,060,261	477	0.21%
	2031	2,065,004	478	0.20%
	2032	2,069,529	479	0.19%
	2033	2,073,849	480	0.18%
	2034	2,077,985	481	0.17%
	2035	2,081,959	482	0.17%
	2036	2,085,761	482	0.16%
	2037	2,089,433	483	0.15%

Average Annual Compound Growth Rates:

1988	2017	1.91%	1.34%
2007	2017	-0.15%	-0.92%
2012	2017	0.66%	-1.66%
2017	2022	0.31%	1.41%
2017	2037	0.26%	0.51%

[1] Data from Table 7

Table 9

PEAK DEMAND and LOAD FACTOR

Lafayette Utilities System

	Year	Actual and Projected Peak Demand (MW)	[1]	Actual and Projected TOTAL Energy (MWh)	[2]	Actual and Projected Load Factor (%)
	1988	296		1,143,620		44.10%
	1989	295		1,184,399		45.83%
	1990	313		1,266,493		46.19%
	1991	310		1,276,027		46.99%
	1992	318		1,295,094		46.49%
	1993	339		1,370,419		46.15%
	1994	330		1,414,062		48.92%
	1995	368		1,505,050		46.69%
	1996	358		1,535,174		48.95%
	1997	368		1,575,003		48.86%
	1998	391		1,667,488		48.68%
	1999	401		1,649,651		46.96%
	2000	428		1,759,520		46.93%
	2001	388		1,729,880		50.90%
	2002	390		1,750,786		51.25%
	2003	402		1,742,103		49.47%
	2004	411		1,789,891		49.71%
	2005	438		1,871,694		48.78%
	2006	458		1,903,683		47.45%
	2007	478		2,012,885		48.07%
	2008	451		1,898,374		48.05%
	2009	472		1,929,029		46.65%
	2010	468		1,990,222		48.55%
	2011	469		1,992,472		48.50%
	2012	474		1,918,347		46.20%
	2013	458		1,940,750		48.37%
	2014	443		1,965,451		50.65%
	2015	480		2,029,985		48.28%
	2016	447		2,006,484		51.24%
Historical	2017	436		1,982,345		51.90%
Projected	2018	461		1,995,712		49.42%
	2019	465		1,997,909		49.09%
	2020	465		2,002,005		49.10%
	2021	466		2,005,978		49.12%
	2022	468		2,013,222		49.14%
	2023	469		2,020,103		49.16%
	2024	470		2,026,654		49.18%
	2025	472		2,032,915		49.20%
	2026	473		2,038,891		49.22%
	2027	474		2,044,603		49.24%
	2028	475		2,050,065		49.25%
	2029	476		2,055,282		49.27%
	2030	477		2,060,261		49.28%
	2031	478		2,065,004		49.30%
	2032	479		2,069,529		49.31%
	2033	480		2,073,849		49.32%
	2034	481		2,077,985		49.34%
	2035	482		2,081,959		49.35%
	2036	482		2,085,761		49.36%
	2037	483		2,089,433		49.37%

Average Annual Compound Growth Rates:

1988	2017	1.34%	1.91%
2007	2017	-0.92%	-0.15%
2012	2017	-1.66%	0.66%
2017	2022	1.41%	0.31%
2017	2037	0.51%	0.26%

[1] Data from Table 8

[2] Data from Table 7

Table 10

MONTHLY ENERGY and PEAK DEMAND

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2018	4	138,931	329
2018	5	156,557	392
2018	6	188,672	439
2018	7	208,546	440
2018	8	207,869	461
2018	9	202,602	422
2018	10	164,292	373
2018	11	144,762	293
2018	12	143,762	319
2019	1	152,039	335
2019	2	148,077	303
2019	3	140,087	292
2019	4	139,084	332
2019	5	156,729	395
2019	6	188,880	443
2019	7	208,776	443
2019	8	208,098	465
2019	9	202,825	425
2019	10	164,473	376
2019	11	144,922	295
2019	12	143,920	322
2020	1	152,351	336
2020	2	148,381	304
2020	3	140,374	292
2020	4	139,369	333
2020	5	157,050	396
2020	6	189,267	443
2020	7	209,204	444
2020	8	208,525	465
2020	9	203,240	426
2020	10	164,810	377
2020	11	145,219	296
2020	12	144,215	322

Table 10

MONTHLY ENERGY and PEAK DEMAND

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2021	1	152,654	337
2021	2	148,675	304
2021	3	140,652	293
2021	4	139,645	333
2021	5	157,362	396
2021	6	189,642	444
2021	7	209,619	445
2021	8	208,939	466
2021	9	203,644	426
2021	10	165,137	377
2021	11	145,507	296
2021	12	144,502	323
2022	1	153,205	338
2022	2	149,212	305
2022	3	141,160	293
2022	4	140,150	334
2022	5	157,930	398
2022	6	190,327	446
2022	7	210,376	446
2022	8	209,693	468
2022	9	204,379	428
2022	10	165,733	378
2022	11	146,032	297
2022	12	145,023	324
2023	1	153,728	339
2023	2	149,722	306
2023	3	141,643	294
2023	4	140,629	335
2023	5	158,470	399
2023	6	190,978	447
2023	7	211,095	447
2023	8	210,410	469
2023	9	205,078	429
2023	10	166,300	380
2023	11	146,531	298
2023	12	145,519	325

Table 10

MONTHLY ENERGY and PEAK DEMAND

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2024	1	154,227	340
2024	2	150,208	307
2024	3	142,102	295
2024	4	141,085	336
2024	5	158,984	400
2024	6	191,597	448
2024	7	211,779	449
2024	8	211,092	470
2024	9	205,743	430
2024	10	166,839	381
2024	11	147,007	299
2024	12	145,991	326
2025	1	154,703	341
2025	2	150,672	308
2025	3	142,541	296
2025	4	141,521	337
2025	5	159,475	401
2025	6	192,189	449
2025	7	212,434	450
2025	8	211,744	472
2025	9	206,378	431
2025	10	167,355	382
2025	11	147,461	300
2025	12	146,442	327
2026	1	155,158	341
2026	2	151,115	309
2026	3	142,960	297
2026	4	141,937	338
2026	5	159,944	402
2026	6	192,754	451
2026	7	213,058	451
2026	8	212,367	473
2026	9	206,985	433
2026	10	167,847	383
2026	11	147,894	300
2026	12	146,873	327

Table 10

MONTHLY ENERGY and PEAK DEMAND

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2027	1	155,593	342
2027	2	151,538	309
2027	3	143,361	297
2027	4	142,334	339
2027	5	160,392	403
2027	6	193,294	452
2027	7	213,655	452
2027	8	212,962	474
2027	9	207,565	434
2027	10	168,317	384
2027	11	148,309	301
2027	12	147,284	328
2028	1	156,009	343
2028	2	151,943	310
2028	3	143,744	298
2028	4	142,715	340
2028	5	160,820	404
2028	6	193,810	453
2028	7	214,226	453
2028	8	213,531	475
2028	9	208,119	435
2028	10	168,766	384
2028	11	148,705	302
2028	12	147,677	329
2029	1	156,406	344
2029	2	152,330	311
2029	3	144,109	299
2029	4	143,078	340
2029	5	161,230	405
2029	6	194,304	454
2029	7	214,771	454
2029	8	214,074	476
2029	9	208,649	436
2029	10	169,196	385
2029	11	149,083	302
2029	12	148,053	330

Table 10

MONTHLY ENERGY and PEAK DEMAND

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2030	1	156,784	345
2030	2	152,699	312
2030	3	144,458	299
2030	4	143,424	341
2030	5	161,620	406
2030	6	194,774	455
2030	7	215,291	455
2030	8	214,593	477
2030	9	209,154	437
2030	10	169,606	386
2030	11	149,444	303
2030	12	148,412	330
2031	1	157,145	345
2031	2	153,050	312
2031	3	144,791	300
2031	4	143,755	342
2031	5	161,992	407
2031	6	195,223	456
2031	7	215,787	456
2031	8	215,087	478
2031	9	209,636	437
2031	10	169,996	387
2031	11	149,789	304
2031	12	148,754	331
2032	1	157,490	346
2032	2	153,385	313
2032	3	145,108	301
2032	4	144,070	342
2032	5	162,347	407
2032	6	195,650	456
2032	7	216,260	457
2032	8	215,558	479
2032	9	210,095	438
2032	10	170,369	388
2032	11	150,117	304
2032	12	149,080	332

Table 10

MONTHLY ENERGY and PEAK DEMAND

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2033	1	157,818	347
2033	2	153,706	313
2033	3	145,411	301
2033	4	144,370	343
2033	5	162,686	408
2033	6	196,059	457
2033	7	216,711	458
2033	8	216,008	480
2033	9	210,534	439
2033	10	170,724	388
2033	11	150,430	305
2033	12	149,391	332
2034	1	158,133	347
2034	2	154,012	314
2034	3	145,701	302
2034	4	144,658	344
2034	5	163,011	409
2034	6	196,450	458
2034	7	217,143	458
2034	8	216,439	481
2034	9	210,954	440
2034	10	171,065	389
2034	11	150,730	305
2034	12	149,689	333
2035	1	158,436	348
2035	2	154,307	314
2035	3	145,980	302
2035	4	144,935	344
2035	5	163,322	409
2035	6	196,826	459
2035	7	217,559	459
2035	8	216,853	482
2035	9	211,357	441
2035	10	171,392	390
2035	11	151,018	306
2035	12	149,975	333

Table 10

MONTHLY ENERGY and PEAK DEMAND

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2036	1	158,725	348
2036	2	154,588	315
2036	3	146,246	303
2036	4	145,200	345
2036	5	163,621	410
2036	6	197,185	460
2036	7	217,956	460
2036	8	217,249	482
2036	9	211,743	441
2036	10	171,705	390
2036	11	151,294	306
2036	12	150,249	334
2037	1	159,004	349
2037	2	154,861	315
2037	3	146,504	303
2037	4	145,455	345
2037	5	163,909	411
2037	6	197,532	460
2037	7	218,340	461
2037	8	217,631	483
2037	9	212,116	442
2037	10	172,007	391
2037	11	151,560	307
2037	12	150,513	334

Table 1

RESIDENTIAL CONSUMERS - HIGH

Lafayette Utilities System

	Year	Total Households [1]	Percentage of Households Served	Actual and Projected Residential Consumers	Actual and Projected Residential Consumer Growth
	1988	131,906	27.0%	35,603	na
	1989	133,839	27.9%	37,374	4.97%
	1990	135,372	28.5%	38,646	3.40%
	1991	137,692	28.6%	39,421	2.01%
	1992	139,864	28.7%	40,184	1.94%
	1993	141,846	29.2%	41,369	2.95%
	1994	143,158	29.5%	42,215	2.05%
	1995	145,549	29.7%	43,175	2.27%
	1996	148,664	29.4%	43,728	1.28%
	1997	151,494	29.7%	45,002	2.91%
	1998	154,062	29.3%	45,169	0.37%
	1999	155,438	29.3%	45,473	0.67%
	2000	156,266	29.0%	45,305	-0.37%
	2001	160,671	28.2%	45,286	-0.04%
	2002	162,324	28.3%	46,006	1.59%
	2003	164,887	28.4%	46,799	1.72%
	2004	165,736	28.4%	47,048	0.53%
	2005	167,730	28.4%	47,690	1.36%
	2006	171,877	28.3%	48,597	1.90%
	2007	174,170	28.6%	49,775	2.42%
	2008	175,680	29.1%	51,119	2.70%
	2009	176,714	28.6%	50,581	-1.05%
	2010	178,072	28.8%	51,262	1.35%
	2011	181,737	28.6%	51,930	1.30%
	2012	184,658	28.3%	52,335	0.78%
	2013	187,961	28.1%	52,829	0.94%
	2014	189,815	28.1%	53,359	1.00%
	2015	192,491	27.9%	53,686	0.61%
	2016	194,985	27.8%	54,212	0.98%
Historical	2017	198,479	27.5%	54,559	0.64%
Projected	2018	201,708	27.5%	55,571 [3]	1.85%
	2019	204,683	27.5% [2]	56,335	1.38%
	2020	207,500	27.5%	57,147	1.44%
	2021	210,199	27.6%	57,926	1.36%
	2022	212,675	27.6%	58,646	1.24%
	2023	215,017	27.6%	59,329	1.16%
	2024	217,279	27.6%	59,991	1.12%
	2025	219,481	27.6%	60,637	1.08%
	2026	221,636	27.6%	61,271	1.05%
	2027	223,767	27.7%	61,899	1.03%
	2028	225,861	27.7%	62,517	1.00%
	2029	227,889	27.7%	63,118	0.96%
	2030	229,852	27.7%	63,702	0.92%
	2031	231,764	27.7%	64,273	0.90%
	2032	233,608	27.7%	64,825	0.86%
	2033	235,393	27.8%	65,361	0.83%
	2034	237,139	27.8%	65,888	0.81%
	2035	238,839	27.8%	66,402	0.78%
	2036	240,508	27.8%	66,908	0.76%
	2037	242,236	27.8%	67,431	0.78%

Average Annual Compound Growth Rates:

1988	2017	1.42%	0.06%	1.48%
2007	2017	1.32%	-0.39%	0.92%
2012	2017	1.45%	-0.61%	0.84%
2017	2022	1.39%	0.06%	1.46%
2017	2037	1.00%	0.06%	1.06%

[1] Data from Woods & Poole

[2] Forecast based on growth from 1988 -2017.

[3] Includes new neighborhood Holiday Gardens and the addition of 400 homes

Table 2

RESIDENTIAL ENERGY SALES - HIGH

Lafayette Utilities System

RES_MWH = 181,832.98 + 36.479 (RES_LAG)

Variable	T-statistic	Variable Description
RES_MWH		Residential Energy Sales (MWh)
RES_LAG	11.101	Residential Energy Sales Lagged One Year (MWh)

R-Squared = 76.4%

Adjusted R-Squared = 75.8%

Standard Error = 88,212

F-Statistic = 123.232

	Year	Total Personal Income [1]	Actual and Projected Residential Energy	Actual and Projected Residential Energy Growth	Actual and Projected Residential Consumers [2]	Actual and Projected Residential Energy/Consumer (kWh)	Actual and Projected Residential Energy/Consumer Growth
	1988	7,583	455,282	na	35,603	12,788	na
	1989	7,825	487,735	7.13%	37,374	13,050	2.05%
	1990	8,159	536,456	9.99%	38,646	13,881	6.37%
	1991	8,303	542,978	1.22%	39,421	13,774	-0.77%
	1992	8,510	545,142	0.40%	40,184	13,566	-1.51%
	1993	8,835	592,114	8.62%	41,369	14,313	5.51%
	1994	9,308	602,814	1.81%	42,215	14,280	-0.23%
	1995	9,647	648,969	7.66%	43,175	15,031	5.26%
	1996	10,191	655,419	0.99%	43,728	14,989	-0.28%
	1997	11,025	672,123	2.55%	45,002	14,935	-0.35%
	1998	11,612	721,282	7.31%	45,169	15,969	6.92%
	1999	11,390	695,855	-3.53%	45,473	15,303	-4.17%
	2000	11,847	740,536	6.42%	45,305	16,346	6.82%
	2001	12,675	711,418	-3.93%	45,286	15,709	-3.89%
	2002	12,673	732,666	2.99%	46,006	15,925	1.37%
	2003	12,814	726,600	-0.83%	46,799	15,526	-2.51%
	2004	12,976	743,091	2.27%	47,048	15,794	1.73%
	2005	14,142	794,261	6.89%	47,690	16,655	5.45%
	2006	15,769	754,912	-4.95%	48,597	15,534	-6.73%
	2007	16,380	823,632	9.10%	49,775	16,547	6.52%
	2008	18,022	774,019	-6.02%	51,119	15,142	-8.49%
	2009	16,874	801,278	3.52%	50,581	15,841	4.62%
	2010	17,443	844,669	5.42%	51,262	16,477	4.01%
	2011	17,559	831,448	-1.57%	51,930	16,011	-2.83%
	2012	18,986	**772,997**	-7.03%	52,335	14,770	-7.75%
	2013	18,870	**791,352**	2.37%	52,829	14,979	1.42%
	2014	19,823	**801,799**	1.32%	53,359	15,027	0.31%
	2015	19,065	**827,250**	3.17%	53,686	15,409	2.55%
	2016	17,557	**827,166**	-0.01%	54,212	15,258	-0.98%
Historical	2017	18,695	**806,567** [3]	-2.49%	54,559	14,783	-3.11%
Projected	2018	19,229	891,318	9.51%	55,571	16,039	8.50%
	2019	19,728	912,718	2.06%	56,335	16,202	1.01%
	2020	20,214	936,951	1.97%	57,147	16,396	1.20%
	2021	20,705	961,678	1.95%	57,926	16,602	1.26%
	2022	21,212	987,268	1.97%	58,646	16,834	1.40%
	2023	21,718	1,013,152	1.93%	59,329	17,077	1.44%
	2024	22,228	1,039,478	1.91%	59,991	17,327	1.47%
	2025	22,753	1,066,724	1.93%	60,637	17,592	1.53%
	2026	23,278	1,094,263	1.89%	61,271	17,859	1.52%
	2027	23,797	1,121,895	1.84%	61,899	18,125	1.48%
	2028	24,314	1,149,764	1.80%	62,517	18,391	1.47%
	2029	24,829	1,177,908	1.76%	63,118	18,662	1.47%
	2030	25,335	1,205,973	1.69%	63,702	18,931	1.44%
	2031	25,814	1,233,330	1.58%	64,273	19,189	1.36%
	2032	26,280	1,260,457	1.51%	64,825	19,444	1.33%
	2033	26,739	1,287,601	1.47%	65,361	19,700	1.32%
	2034	27,198	1,315,092	1.45%	65,888	19,960	1.32%
	2035	27,671	1,343,425	1.47%	66,402	20,232	1.36%
	2036	28,133	1,371,660	1.42%	66,908	20,501	1.33%
	2037	28,570	1,399,151	1.32%	67,431	20,749	1.21%

Average Annual Compound Growth Rates:

1988	2017	3.16%	1.99%	1.48%	0.50%
2007	2017	1.33%	-0.21%	0.92%	-1.12%
2012	2017	-0.31%	0.85%	0.84%	0.02%
2017	2022	2.56%	4.13%	1.46%	2.63%
2017	2037	2.14%	2.79%	1.06%	1.71%

[1] Data from Woods & Poole

[2] Data from Table 1

[3] Data from 2012 to 2017 was weather-normalized

Table 3

COMMERCIAL ENERGY SALES - HIGH

Lafayette Utilities System

$$COM\_MWH = -23{,}531.9223 + 0.21486\ (RES\_MWH) + 5.56963\ (TOT\_RET\_GEN)$$

Variable	T-statistic	Variable Description
COM_MWH		Commercial Energy Sales (MWh)
TOT_RET_GEN	7.815	Total Retail Sales for General Stores
RES_MWH	2.805	Residential Energy Sales (MWh)

R-Squared = 96.3%
Adjusted R-Squared = 96.1%
Standard Error = 6,457.626
F-Statistic = 355.295

	Year	Retail Sales General Stores	[1]	Actual and Projected Residential Energy	[2]	Actual and Projected Commercial Energy		Actual and Projected Commercial Energy Growth
	1988	$3,479.8		455,282		106,382		na
	1989	$3,609.3		487,735		106,177		-0.2%
	1990	$3,691.7		536,456		108,253		2.0%
	1991	$3,703.7		542,978		111,435		2.9%
	1992	$3,894.2		545,142		111,616		0.2%
	1993	$4,158.4		592,114		124,566		11.60%
	1994	$4,498.3		602,814		129,043		3.59%
	1995	$4,726.0		648,969		135,998		5.39%
	1996	$5,003.1		655,419		137,438		1.06%
	1997	$5,245.1		672,123		145,659		5.98%
	1998	$5,368.0		721,282		158,210		8.62%
	1999	$5,641.6		695,855		155,160		-1.93%
	2000	$5,725.0		740,536		171,768		10.70%
	2001	$5,638.1		711,418		166,023		-3.34%
	2002	$5,583.3		732,666		165,880		-0.09%
	2003	$5,842.9		726,600		159,778		-3.68%
	2004	$6,204.6		743,091		168,830		5.67%
	2005	$6,544.7		794,261		177,075		4.88%
	2006	$6,872.4		754,912		190,740		7.72%
	2007	$7,085.0		823,632		197,865		3.74%
	2008	$6,904.7		774,019		187,371		-5.30%
	2009	$6,513.5		801,278		192,017		2.48%
	2010	$6,836.1		844,669		200,750		4.55%
	2011	$7,230.1		831,448		194,819		-2.95%
	2012	$7,537.5		772,997		187,571		-3.72%
	2013	$7,750.5		791,352		195,228		4.08%
	2014	$8,001.0		801,799		199,733		2.31%
	2015	$8,210.4		827,250		202,060		1.17%
	2016	$8,348.2		827,166		180,207		-10.81%
Historical	2017	$8,570.7		806,567		188,658		4.69%
Projected	2018	$8,728.0		891,318		193,375	[3]	2.50%
	2019	$8,874.8		912,718		198,210		2.50%
	2020	$9,015.3		936,951		203,557		2.70%
	2021	$9,168.8		961,678		209,064		2.71%
	2022	$9,317.1		987,268		214,710		2.70%
	2023	$9,461.7		1,013,152		220,395		2.65%
	2024	$9,604.5		1,039,478		226,155		2.61%
	2025	$9,746.9		1,066,724		232,089		2.62%
	2026	$9,887.6		1,094,263		238,072		2.58%
	2027	$10,026.5		1,121,895		244,064		2.52%
	2028	$10,163.4		1,149,764		250,091		2.47%
	2029	$10,299.1		1,177,908		256,164		2.43%
	2030	$10,434.4		1,205,973		262,221		2.36%
	2031	$10,568.4		1,233,330		268,135		2.26%
	2032	$10,702.0		1,260,457		274,003		2.19%
	2033	$10,835.1		1,287,601		279,872		2.14%
	2034	$10,967.8		1,315,092		285,806		2.12%
	2035	$11,101.3		1,343,425		291,905		2.13%
	2036	$11,233.9		1,371,660		297,981		2.08%
	2037	$11,367.4		1,399,151		303,918		1.99%

Average Annual Compound Growth Rates:

1988	2017	3.16%	1.99%	2.00%
2007	2017	1.92%	-0.21%	-0.48%
2012	2017	2.60%	0.85%	0.12%
2017	2022	1.68%	4.13%	2.62%
2017	2037	1.42%	2.79%	2.41%

[1] Data from Woods & Poole
[2] Data from Table 2
[3] Forecast based on model-estimated growth

Table 4

COMMERCIAL (with DEMAND) ENERGY SALES - HIGH

Lafayette Utilities System

COMwD_MWH = 309,907.187 + 27.68557 (COMwD_LAG)

Variable	T-statistic	Variable Description
COMwD_MWH		Commercial (with Demand) Energy Sales (MWh)
COMwD_LAG	14.36	Commercial (with Demand) Energy Sales Lagged One Year (MWh)

R-Squared =	88.0%	Standard Error =	42,373.2
Adjusted R-Squared =	87.6%	F-Statistic =	206.115

	Year	[1]	Total Personal Income	[1]	Actual and Projected Commercial (with Demand) Energy		Projected Commercial (with Demand) Energy Growth
	1988		$7,583		473,332		na
	1989		$7,825		473,130		-0.04%
	1990		$8,159		497,109		5.07%
	1991		$8,303		496,326		-0.16%
	1992		$8,510		511,180		2.99%
	1993		$8,835		526,603		3.02%
	1994		$9,308		547,511		3.97%
	1995		$9,647		578,822		5.72%
	1996		$10,191		602,105		4.02%
	1997		$11,025		614,060		1.99%
	1998		$11,612		645,451		5.11%
	1999		$11,390		647,906		0.38%
	2000		$11,847		700,035		8.05%
	2001		$12,675		723,825		3.40%
	2002		$12,673		737,195		1.85%
	2003		$12,814		701,067		-4.90%
	2004		$12,976		731,795		4.38%
	2005		$14,142		745,948		1.93%
	2006		$15,769		796,126		6.73%
	2007		$16,380		822,515		3.31%
	2008		$18,022		781,121		-5.03%
	2009		$16,874		780,166		-0.12%
	2010		$17,443		775,136		-0.64%
	2011		$17,559		792,875		2.29%
	2012		$18,986		785,806		-0.89%
	2013		$18,870		781,262		-0.58%
	2014		$19,823		793,062		1.51%
	2015		$19,065		815,519		2.83%
	2016		$17,557		815,087		-0.05%
Historical	2017		$18,695		805,520		-1.17%
Projected	2018		$19,229		811,159	[2]	0.70%
	2019		$19,728		824,470		1.64%
	2020		$20,214		837,420		1.57%
	2021		$20,705		850,518		1.56%
	2022		$21,212		864,020		1.59%
	2023		$21,718		877,516		1.56%
	2024		$22,228		891,107		1.55%
	2025		$22,753		905,122		1.57%
	2026		$23,278		919,117		1.55%
	2027		$23,797		932,956		1.51%
	2028		$24,314		946,734		1.48%
	2029		$24,829		960,479		1.45%
	2030		$25,335		973,950		1.40%
	2031		$25,814		986,733		1.31%
	2032		$26,280		999,156		1.26%
	2033		$26,739		1,011,386		1.22%
	2034		$27,198		1,023,640		1.21%
	2035		$27,671		1,036,238		1.23%
	2036		$28,133		1,048,564		1.19%
	2037		$28,570		1,060,209		1.11%

Average Annual Compound Growth Rates:

1988	2017	3.16%	1.85%
2007	2017	1.33%	-0.21%
2012	2017	-0.31%	0.50%
2017	2022	2.56%	1.41%
2017	2037	2.14%	1.38%

[1] Data from Woods & Poole

[2] Forecast based on model-estimated growth

Table 5

LIGHTING ENERGY SALES - HIGH

Lafayette Utilities System

LIGHT_MWH = -392.868 + 0.58635 (TOT_PI_PC)

Variable	T-statistic	Variable Description
LIGHT_MWH		Lighting Energy Sales (MWh)
TOT_PI_PC	7.44	Total Personal Income per Capita

R-Squared = 76.5%

Adjusted R-Squared = 75.1%

Standard Error = 1,521.41

F-Statistic = 55.32

	Year	Total Personal Income per Capita	[1]	Actual and Projected Lighting Energy		Actual and Projected Lighting Energy Growth
	1999	$26,857		15,952		na
	2000	$27,864		15,335		-3.87%
	2001	$29,700		16,243		5.92%
	2002	$29,449		16,488		1.51%
	2003	$29,600		17,880		8.44%
	2004	$29,760		15,534		-13.12%
	2005	$32,146		18,326		17.97%
	2006	$34,985		20,895		14.02%
	2007	$36,054		21,550		3.13%
	2008	$39,254		21,138		-1.91%
	2009	$36,366		21,552		1.96%
	2010	$37,301		17,747		-17.66%
	2011	$37,305		23,302		31.30%
	2012	$40,036		23,794		2.11%
	2013	$39,343		21,321		-10.39%
	2014	$40,875		22,952		7.65%
	2015	$38,920		22,571		-1.66%
	2016	$35,719		23,641		4.74%
Historical	2017	$37,650		22,829		-3.43%
Projected	2018	$38,306		23,234	[2]	1.77%
	2019	$38,973		19,990	[3]	-13.96%
	2020	$39,652		16,688	[3]	-16.52%
	2021	$40,343		13,328	[3]	-20.13%
	2022	$41,046		13,564		1.77%
	2023	$41,761		13,804		1.77%
	2024	$42,489		14,049		1.77%
	2025	$43,229		14,298		1.77%
	2026	$43,983		14,551		1.77%
	2027	$44,749		14,808		1.77%
	2028	$45,529		15,070		1.77%
	2029	$46,322		15,337		1.77%
	2030	$47,129		15,608		1.77%
	2031	$47,950		15,884		1.77%
	2032	$48,786		16,164		1.77%
	2033	$49,636		16,450		1.77%
	2034	$50,501		16,740		1.77%
	2035	$51,380		17,036		1.77%
	2036	$52,276		17,337		1.77%
	2037	$53,187		17,643		1.76%

Average Annual Compound Growth Rates:

1999	2017	1.89%	2.01%
2007	2017	0.43%	0.58%
2012	2017	-1.22%	-0.82%
2017	2022	1.74%	-9.89%
2017	2037	1.74%	-1.28%

[1] Data from Woods & Poole, forecast based on growth from 2017 to 2018

[2] Forecast based on model estimated growth and historical data from 1999 - 2017

[3] Forecast includes a lighting reduction of 10,968 MWh spread over 3 years for street light replacement program

Table 6

OTHER ENERGY SALES - HIGH

Lafayette Utilities System

OTHER_MWH = 18,860.904 + 1.37769 (RES_CON) + 0.39118 (OTHER_LAG)

Variable	T-statistic	Variable Description
OTHER_MWH		Other Energy Sales (MWh)
RES_CON	2.576	Residential Consumers
OTHER_LAG	2.224	Other Energy Sales Lagged One Year (MWh)

R-Squared =	70.2%	Standard Error =	8,840.67
Adjusted R-Squared =	68.0%	F-Statistic =	31.80

	Year	Actual and Projected Residential Consumers	[1]	Other Energy Lagged One Year	Actual and Projected Other Energy		Actual and Projected Other Energy Growth
	1988	35,603		99,926	105,868		na
	1989	37,374		105,868	114,547		8.20%
	1990	38,646		114,547	121,433		6.01%
	1991	39,421		121,433	121,812		0.31%
	1992	40,184		121,812	123,559		1.43%
	1993	41,369		123,559	123,491		-0.05%
	1994	42,215		123,491	130,984		6.07%
	1995	43,175		130,984	137,230		4.77%
	1996	43,728		137,230	135,750		-1.08%
	1997	45,002		135,750	138,384		1.94%
	1998	45,169		138,384	136,435		-1.41%
	1999	45,473		136,435	134,778		-1.21%
	2000	45,305		134,778	131,847		-2.18%
	2001	45,286		131,847	112,370		-14.77%
	2002	46,006		112,370	98,557		-12.29%
	2003	46,799		98,557	136,779		38.78%
	2004	47,048		136,779	130,641		-4.49%
	2005	47,690		130,641	136,084		4.17%
	2006	48,597		136,084	141,009		3.62%
	2007	49,775		141,009	147,323		4.48%
	2008	51,119		147,323	134,725		-8.55%
	2009	50,581		134,725	134,016		-0.53%
	2010	51,262		134,016	151,920		13.36%
	2011	51,930		151,920	150,028		-1.25%
	2012	52,335		150,028	148,179		-1.23%
	2013	52,829		148,179	151,587		2.30%
	2014	53,359		151,587	147,905		-2.43%
	2015	53,686		147,905	162,585		9.93%
	2016	54,212		162,585	160,384		-1.35%
Historical	2017	54,559		160,384	158,771		-1.01%
Projected	2018	55,571		158,771	157,217	[2]	-0.98%
	2019	56,335		157,217	157,661		0.28%
	2020	57,147		157,661	158,950		0.82%
	2021	57,926		158,950	160,525		0.99%
	2022	58,646		160,525	162,129		1.00%
	2023	59,329		162,129	163,695		0.97%
	2024	59,991		163,695	165,216		0.93%
	2025	60,637		165,216	166,698		0.90%
	2026	61,271		166,698	168,148		0.87%
	2027	61,899		168,148	169,578		0.85%
	2028	62,517		169,578	170,987		0.83%
	2029	63,118		170,987	172,363		0.80%
	2030	63,702		172,363	173,703		0.78%
	2031	64,273		173,703	175,011		0.75%
	2032	64,825		175,011	176,280		0.73%
	2033	65,361		176,280	177,514		0.70%
	2034	65,888		177,514	178,719		0.68%
	2035	66,402		178,719	179,896		0.66%
	2036	66,908		179,896	181,052		0.64%
	2037	67,431		181,052	182,222		0.65%

Average Annual Compound Growth Rates:

1988	2017	1.48%	1.64%	1.41%
2007	2017	0.92%	1.30%	0.75%
2012	2017	0.84%	1.34%	1.39%
2017	2022	1.46%	0.02%	0.42%
2017	2037	1.06%	0.61%	0.69%

[1] Data from Table 1

[2] Forecast based on model-estimated growth and includes the loss of 2,269 MWh from the University of Louisiana at Lafayette's new solar facility

Table 7

TOTAL ENERGY SALES (MWh) - HIGH

Lafayette Utilities System

	Year	Residential Energy [1]	Commercial Energy [2]	Commercial (with demand) Energy [3]	Lighting Energy [4]	Other Energy [5]	Actual and Projected TOTAL Energy	Actual and Projected TOTAL Energy Growth
	1988	455,282	106,382	473,332	2,756	105,868	1,143,620	na
	1989	487,735	106,177	473,130	2,809	114,547	1,184,399	3.57%
	1990	536,456	108,253	497,109	3,242	121,433	1,266,493	6.93%
	1991	542,978	111,435	496,326	3,477	121,812	1,276,027	0.75%
	1992	545,142	111,616	511,180	3,598	123,559	1,295,094	1.49%
	1993	592,114	124,566	526,603	3,645	123,491	1,370,419	5.82%
	1994	602,814	129,043	547,511	3,711	130,984	1,414,062	3.18%
	1995	648,969	135,998	578,822	4,030	137,230	1,505,050	6.43%
	1996	655,419	137,438	602,105	4,461	135,750	1,535,174	2.00%
	1997	672,123	145,659	614,060	4,778	138,384	1,575,003	2.59%
	1998	721,282	158,210	645,451	6,110	136,435	1,667,488	5.87%
	1999	695,855	155,160	647,906	15,952	134,778	1,649,651	-1.07%
	2000	740,536	171,768	700,035	15,335	131,847	1,759,520	6.66%
	2001	711,418	166,023	723,825	16,243	112,370	1,729,880	-1.68%
	2002	732,666	165,880	737,195	16,488	98,557	1,750,786	1.21%
	2003	726,600	159,778	701,067	17,880	136,779	1,742,103	-0.50%
	2004	743,091	168,830	731,795	15,534	130,641	1,789,891	2.74%
	2005	794,261	177,075	745,948	18,326	136,084	1,871,694	4.57%
	2006	754,912	190,740	796,126	20,895	141,009	1,903,683	1.71%
	2007	823,632	197,865	822,515	21,550	147,323	2,012,885	5.74%
	2008	774,019	187,371	781,121	21,138	134,725	1,898,374	-5.69%
	2009	801,278	192,017	780,166	21,552	134,016	1,929,029	1.61%
	2010	844,669	200,750	775,136	17,747	151,920	1,990,222	3.17%
	2011	831,448	194,819	792,875	23,302	150,028	1,992,472	0.11%
	2012	772,997	187,571	785,806	23,794	148,179	1,918,347	-3.72%
	2013	791,352	195,228	781,262	21,321	151,587	1,940,750	1.17%
	2014	801,799	199,733	793,062	22,952	147,905	1,965,451	1.27%
	2015	827,250	202,060	815,519	22,571	162,585	2,029,985	3.28%
	2016	827,166	180,207	815,087	23,641	160,384	2,006,484	-1.16%
Historical	2017	806,567	188,658	805,520	22,829	158,771	1,982,345	-1.20%
Projected	2018	891,318	193,375	811,159	23,234	157,217	2,076,302	4.74%
	2019	912,718	198,210	824,470	19,990	157,661	2,113,048	1.77%
	2020	936,951	203,557	837,420	16,688	158,950	2,153,567	1.92%
	2021	961,678	209,064	850,518	13,328	160,525	2,195,113	1.93%
	2022	987,268	214,710	864,020	13,564	162,129	2,241,691	2.12%
	2023	1,013,152	220,395	877,516	13,804	163,695	2,288,561	2.09%
	2024	1,039,478	226,155	891,107	14,049	165,216	2,336,004	2.07%
	2025	1,066,724	232,089	905,122	14,298	166,698	2,384,931	2.09%
	2026	1,094,263	238,072	919,117	14,551	168,148	2,434,151	2.06%
	2027	1,121,895	244,064	932,956	14,808	169,578	2,483,301	2.02%
	2028	1,149,764	250,091	946,734	15,070	170,987	2,532,645	1.99%
	2029	1,177,908	256,164	960,479	15,337	172,363	2,582,252	1.96%
	2030	1,205,973	262,221	973,950	15,608	173,703	2,631,455	1.91%
	2031	1,233,330	268,135	986,733	15,884	175,011	2,679,093	1.81%
	2032	1,260,457	274,003	999,156	16,164	176,280	2,726,062	1.75%
	2033	1,287,601	279,872	1,011,386	16,450	177,514	2,772,823	1.72%
	2034	1,315,092	285,806	1,023,640	16,740	178,719	2,819,997	1.70%
	2035	1,343,425	291,905	1,036,238	17,036	179,896	2,868,499	1.72%
	2036	1,371,660	297,981	1,048,564	17,337	181,052	2,916,593	1.68%
	2037	1,399,151	303,918	1,060,209	17,643	182,222	2,963,143	1.60%

Average Annual Compound Growth Rates:

1988	2017	1.99%	2.00%	1.85%	7.56%	1.41%	1.91%
2007	2017	-0.21%	-0.48%	-0.21%	0.58%	0.75%	-0.15%
2012	2017	0.85%	0.12%	0.50%	-0.82%	1.39%	0.66%
2017	2022	4.13%	2.62%	1.41%	-9.89%	0.42%	2.49%
2017	2037	2.79%	2.41%	1.38%	-1.28%	0.69%	2.03%

[1] Data from Table 2

[2] Data from Table 3

[3] Data from Table 4

[4] Data from Table 5

[5] Data from Table 6

Table 8

BASE PEAK DEMAND - HIGH

Lafayette Utilities System

PEAK = 59.826 + 0.0002026 (TOT_MWH)

Variable	T-statistic	Variable Description
PEAK		Base Peak Demand (MW)
TOT_MWH	21.681	Total Energy Sales (MWh)

R-Squared = 94.4%
Adjusted R-Squared = 94.2%
Standard Error = 14.613
F-Statistic = 470.064

	Year	Actual and Projected Total Energy	[1]	Actual and Projected Peak Demand	Actual and Projected Peak Demand Growth
	1988	1,143,620		296	na
	1989	1,184,399		295	-0.34%
	1990	1,266,493		313	6.10%
	1991	1,276,027		310	-0.96%
	1992	1,295,094		318	2.58%
	1993	1,370,419		339	6.60%
	1994	1,414,062		330	-2.65%
	1995	1,505,050		368	11.52%
	1996	1,535,174		358	-2.72%
	1997	1,575,003		368	2.79%
	1998	1,667,488		391	6.25%
	1999	1,649,651		401	2.56%
	2000	1,759,520		428	6.73%
	2001	1,729,880		388	-9.35%
	2002	1,750,786		390	0.52%
	2003	1,742,103		402	3.08%
	2004	1,789,891		411	2.24%
	2005	1,871,694		438	6.57%
	2006	1,903,683		458	4.57%
	2007	2,012,885		478	4.37%
	2008	1,898,374		451	-5.65%
	2009	1,929,029		472	4.66%
	2010	1,990,222		468	-0.85%
	2011	1,992,472		469	0.21%
	2012	1,918,347		474	1.07%
	2013	1,940,750		458	-3.38%
	2014	1,965,451		443	-3.28%
	2015	2,029,985		480	8.35%
	2016	2,006,484		447	-6.88%
Historical	2017	1,982,345		436	-2.46%
Projected	2018	2,076,302		461	5.73%
	2019	2,113,048		488	5.84%
	2020	2,153,567		496	1.68%
	2021	2,195,113		505	1.70%
	2022	2,241,691		514	1.87%
	2023	2,288,561		523	1.85%
	2024	2,336,004		533	1.84%
	2025	2,384,931		543	1.86%
	2026	2,434,151		553	1.84%
	2027	2,483,301		563	1.80%
	2028	2,532,645		573	1.78%
	2029	2,582,252		583	1.75%
	2030	2,631,455		593	1.71%
	2031	2,679,093		603	1.63%
	2032	2,726,062		612	1.58%
	2033	2,772,823		622	1.55%
	2034	2,819,997		631	1.54%
	2035	2,868,499		641	1.56%
	2036	2,916,593		651	1.52%
	2037	2,963,143		660	1.45%

Average Annual Compound Growth Rates:

1988	2017	1.91%	1.34%
2007	2017	-0.15%	-0.92%
2012	2017	0.66%	-1.66%
2017	2022	2.49%	3.35%
2017	2037	2.03%	2.10%

[1] Data from Table 7

Table 9

PEAK DEMAND and LOAD FACTOR - HIGH

Lafayette Utilities System

	Year	Actual and Projected Peak Demand (MW)	[1]	Actual and Projected TOTAL Energy (MWh)	[2]	Actual and Projected Load Factor (%)
	1988	296		1,143,620		44.10%
	1989	295		1,184,399		45.83%
	1990	313		1,266,493		46.19%
	1991	310		1,276,027		46.99%
	1992	318		1,295,094		46.49%
	1993	339		1,370,419		46.15%
	1994	330		1,414,062		48.92%
	1995	368		1,505,050		46.69%
	1996	358		1,535,174		48.95%
	1997	368		1,575,003		48.86%
	1998	391		1,667,488		48.68%
	1999	401		1,649,651		46.96%
	2000	428		1,759,520		46.93%
	2001	388		1,729,880		50.90%
	2002	390		1,750,786		51.25%
	2003	402		1,742,103		49.47%
	2004	411		1,789,891		49.71%
	2005	438		1,871,694		48.78%
	2006	458		1,903,683		47.45%
	2007	478		2,012,885		48.07%
	2008	451		1,898,374		48.05%
	2009	472		1,929,029		46.65%
	2010	468		1,990,222		48.55%
	2011	469		1,992,472		48.50%
	2012	474		1,918,347		46.20%
	2013	458		1,940,750		48.37%
	2014	443		1,965,451		50.65%
	2015	480		2,029,985		48.28%
	2016	447		2,006,484		51.24%
Historical	2017	436		1,982,345		51.90%
Projected	2018	461		2,076,302		51.41%
	2019	488		2,113,048		49.44%
	2020	496		2,153,567		49.55%
	2021	505		2,195,113		49.66%
	2022	514		2,241,691		49.79%
	2023	523		2,288,561		49.91%
	2024	533		2,336,004		50.02%
	2025	543		2,384,931		50.14%
	2026	553		2,434,151		50.25%
	2027	563		2,483,301		50.36%
	2028	573		2,532,645		50.46%
	2029	583		2,582,252		50.56%
	2030	593		2,631,455		50.66%
	2031	603		2,679,093		50.75%
	2032	612		2,726,062		50.84%
	2033	622		2,772,823		50.92%
	2034	631		2,819,997		51.00%
	2035	641		2,868,499		51.09%
	2036	651		2,916,593		51.17%
	2037	660		2,963,143		51.24%

Average Annual Compound Growth Rates:

1988	2017	1.34%	1.91%
2007	2017	-0.92%	-0.15%
2012	2017	-1.66%	0.66%
2017	2022	3.35%	2.49%
2017	2037	2.10%	2.03%

[1] Data from Table 8

[2] Data from Table 7

Table 10

MONTHLY ENERGY and PEAK DEMAND - HIGH

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2018	4	144,541	329
2018	5	162,879	392
2018	6	196,291	439
2018	7	216,967	440
2018	8	216,263	461
2018	9	210,783	422
2018	10	170,926	373
2018	11	150,608	293
2018	12	149,567	319
2019	1	160,802	352
2019	2	156,611	319
2019	3	148,160	306
2019	4	147,099	349
2019	5	165,761	415
2019	6	199,765	465
2019	7	220,807	465
2019	8	220,091	488
2019	9	214,513	446
2019	10	173,951	395
2019	11	153,273	310
2019	12	152,215	338
2020	1	163,885	358
2020	2	159,614	324
2020	3	151,001	311
2020	4	149,920	355
2020	5	168,940	422
2020	6	203,595	473
2020	7	225,041	473
2020	8	224,311	496
2020	9	218,627	454
2020	10	177,287	401
2020	11	156,213	315
2020	12	155,133	343

Table 10

MONTHLY ENERGY and PEAK DEMAND - HIGH

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2021	1	167,047	364
2021	2	162,693	329
2021	3	153,914	317
2021	4	152,812	361
2021	5	172,199	429
2021	6	207,523	481
2021	7	229,383	481
2021	8	228,639	505
2021	9	222,844	462
2021	10	180,707	408
2021	11	159,226	320
2021	12	158,126	349
2022	1	170,591	371
2022	2	166,145	336
2022	3	157,180	323
2022	4	156,055	367
2022	5	175,853	437
2022	6	211,926	490
2022	7	234,250	490
2022	8	233,490	514
2022	9	227,573	470
2022	10	184,542	416
2022	11	162,605	326
2022	12	161,481	356
2023	1	174,158	378
2023	2	169,619	342
2023	3	160,466	328
2023	4	159,317	374
2023	5	179,530	445
2023	6	216,357	499
2023	7	239,148	499
2023	8	238,372	523
2023	9	232,331	479
2023	10	188,400	424
2023	11	166,005	332
2023	12	164,858	362

Table 10

MONTHLY ENERGY and PEAK DEMAND - HIGH

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2024	1	177,768	385
2024	2	173,136	348
2024	3	163,793	335
2024	4	162,620	381
2024	5	183,251	453
2024	6	220,843	508
2024	7	244,106	508
2024	8	243,314	533
2024	9	237,147	488
2024	10	192,306	431
2024	11	169,446	339
2024	12	168,275	369
2025	1	181,492	392
2025	2	176,762	355
2025	3	167,223	341
2025	4	166,026	388
2025	5	187,090	462
2025	6	225,468	517
2025	7	249,218	518
2025	8	248,410	543
2025	9	242,114	497
2025	10	196,333	439
2025	11	172,995	345
2025	12	171,800	376
2026	1	185,237	399
2026	2	180,410	361
2026	3	170,674	347
2026	4	169,453	395
2026	5	190,951	470
2026	6	230,121	527
2026	7	254,362	527
2026	8	253,536	553
2026	9	247,111	506
2026	10	200,385	447
2026	11	176,565	351
2026	12	175,345	383

Table 10

MONTHLY ENERGY and PEAK DEMAND - HIGH

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2027	1	188,978	406
2027	2	184,053	368
2027	3	174,121	353
2027	4	172,874	402
2027	5	194,806	479
2027	6	234,768	536
2027	7	259,498	537
2027	8	258,656	563
2027	9	252,101	515
2027	10	204,432	455
2027	11	180,130	358
2027	12	178,886	390
2028	1	192,733	414
2028	2	187,710	374
2028	3	177,580	360
2028	4	176,309	409
2028	5	198,677	487
2028	6	239,433	546
2028	7	264,654	546
2028	8	263,795	573
2028	9	257,110	524
2028	10	208,494	464
2028	11	183,710	364
2028	12	182,440	397
2029	1	196,508	421
2029	2	191,386	381
2029	3	181,059	366
2029	4	179,763	417
2029	5	202,569	496
2029	6	244,123	555
2029	7	269,838	556
2029	8	268,962	583
2029	9	262,146	533
2029	10	212,577	472
2029	11	187,308	370
2029	12	186,014	404

Table 10

MONTHLY ENERGY and PEAK DEMAND - HIGH

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2030	1	200,252	428
2030	2	195,033	387
2030	3	184,509	372
2030	4	183,188	424
2030	5	206,429	504
2030	6	248,774	565
2030	7	274,979	565
2030	8	274,087	593
2030	9	267,141	542
2030	10	216,628	480
2030	11	190,877	377
2030	12	189,558	410
2031	1	203,877	435
2031	2	198,564	393
2031	3	187,849	378
2031	4	186,504	431
2031	5	210,166	512
2031	6	253,278	574
2031	7	279,957	575
2031	8	279,049	603
2031	9	271,977	551
2031	10	220,550	488
2031	11	194,332	383
2031	12	192,990	417
2032	1	207,451	442
2032	2	202,045	400
2032	3	191,142	384
2032	4	189,774	437
2032	5	213,850	520
2032	6	257,718	583
2032	7	284,865	584
2032	8	283,941	612
2032	9	276,745	560
2032	10	224,416	495
2032	11	197,739	389
2032	12	196,373	424

Table 10

MONTHLY ENERGY and PEAK DEMAND - HIGH

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2033	1	211,010	449
2033	2	205,511	406
2033	3	194,421	390
2033	4	193,029	444
2033	5	217,518	528
2033	6	262,139	592
2033	7	289,752	593
2033	8	288,812	622
2033	9	281,493	569
2033	10	228,266	503
2033	11	201,131	395
2033	12	199,742	430
2034	1	214,600	456
2034	2	209,007	412
2034	3	197,729	396
2034	4	196,313	451
2034	5	221,219	537
2034	6	266,599	601
2034	7	294,681	602
2034	8	293,725	631
2034	9	286,282	577
2034	10	232,149	511
2034	11	204,553	401
2034	12	203,140	437
2035	1	218,291	463
2035	2	212,602	418
2035	3	201,129	402
2035	4	199,690	458
2035	5	225,024	545
2035	6	271,184	611
2035	7	299,750	611
2035	8	298,777	641
2035	9	291,206	586
2035	10	236,142	519
2035	11	208,071	407
2035	12	206,634	444

Table 10

MONTHLY ENERGY and PEAK DEMAND - HIGH

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2036	1	221,951	470
2036	2	216,167	425
2036	3	204,502	408
2036	4	203,038	465
2036	5	228,797	553
2036	6	275,731	620
2036	7	304,775	620
2036	8	303,787	651
2036	9	296,088	595
2036	10	240,101	526
2036	11	211,560	413
2036	12	210,098	450
2037	1	225,493	477
2037	2	219,617	431
2037	3	207,765	414
2037	4	206,278	472
2037	5	232,448	561
2037	6	280,132	629
2037	7	309,640	629
2037	8	308,635	660
2037	9	300,814	604
2037	10	243,933	534
2037	11	214,936	419
2037	12	213,452	457

Table 1

RESIDENTIAL CONSUMERS - LOW

Lafayette Utilities System

	Year	Total Households	[1]	Percentage of Households Served		Actual and Projected Residential Consumers		Actual and Projected Residential Consumer Growth
	1988	131,906		27.0%		35,603		na
	1989	133,839		27.9%		37,374		4.97%
	1990	135,372		28.5%		38,646		3.40%
	1991	137,692		28.6%		39,421		2.01%
	1992	139,864		28.7%		40,184		1.94%
	1993	141,846		29.2%		41,369		2.95%
	1994	143,158		29.5%		42,215		2.05%
	1995	145,549		29.7%		43,175		2.27%
	1996	148,664		29.4%		43,728		1.28%
	1997	151,494		29.7%		45,002		2.91%
	1998	154,062		29.3%		45,169		0.37%
	1999	155,438		29.3%		45,473		0.67%
	2000	156,266		29.0%		45,305		-0.37%
	2001	160,671		28.2%		45,286		-0.04%
	2002	162,324		28.3%		46,006		1.59%
	2003	164,887		28.4%		46,799		1.72%
	2004	165,736		28.4%		47,048		0.53%
	2005	167,730		28.4%		47,690		1.36%
	2006	171,877		28.3%		48,597		1.90%
	2007	174,170		28.6%		49,775		2.42%
	2008	175,680		29.1%		51,119		2.70%
	2009	176,714		28.6%		50,581		-1.05%
	2010	178,072		28.8%		51,262		1.35%
	2011	181,737		28.6%		51,930		1.30%
	2012	184,658		28.3%		52,335		0.78%
	2013	187,961		28.1%		52,829		0.94%
	2014	189,815		28.1%		53,359		1.00%
	2015	192,491		27.9%		53,686		0.61%
	2016	194,985		27.8%		54,212		0.98%
Historical	2017	198,479		27.5%		54,559		0.64%
Projected	2018	199,887	[2]	27.8%		55,571	[4]	1.85%
	2019	201,305		27.6%	[3]	55,624		0.10%
	2020	202,733		27.5%		55,678		0.10%
	2021	204,172		27.3%		55,731		0.10%
	2022	205,620		27.1%		55,784		0.10%
	2023	207,079		27.0%		55,838		0.10%
	2024	208,548		26.8%		55,891		0.10%
	2025	210,028		26.6%		55,945		0.10%
	2026	211,518		26.5%		55,998		0.10%
	2027	213,018		26.3%		56,052		0.10%
	2028	214,530		26.2%		56,106		0.10%
	2029	216,052		26.0%		56,159		0.10%
	2030	217,584		25.8%		56,213		0.10%
	2031	219,128		25.7%		56,267		0.10%
	2032	220,683		25.5%		56,321		0.10%
	2033	222,248		25.4%		56,375		0.10%
	2034	223,825		25.2%		56,429		0.10%
	2035	225,413		25.1%		56,483		0.10%
	2036	227,012		24.9%		56,537		0.10%
	2037	228,623		24.8%		56,591		0.10%

Average Annual Compound Growth Rates:

1988	2017	1.42%	0.06%	1.48%
2007	2017	1.32%	-0.39%	0.92%
2012	2017	1.45%	-0.61%	0.84%
2017	2022	0.71%	-0.26%	0.45%
2017	2037	0.71%	-0.52%	0.18%

[1] Data from Woods & Poole

[2] Forecast based on half the growth from 1988 to 2017

[3] Forecast based on growth from 2012 -2017.

[4] Includes new neighborhood Holiday Gardens and the addition of 400 homes

Table 2

RESIDENTIAL ENERGY SALES - LOW

Lafayette Utilities System

RES_MWH = 3,194,674.19 + -944,735.952 (RES_LAG)

Variable	T-statistic	Variable Description
RES_MWH		Residential Energy Sales (MWh)
RES_LAG	-13.701	Residential Energy Sales Lagged One Year (MWh)

R-Squared =	87.0%	Standard Error =	40,780
Adjusted R-Squared =	86.6%	F-Statistic =	187.706

	Year	Persons Persons Household [1]	Actual and Projected Residential Energy	Actual and Projected Residential Energy Growth	Actual and Projected Residential Consumers [2]	Actual and Projected Residential Energy/Consumer (kWh)	Actual and Projected Residential Energy/Consumer Growth
	1988	2.86	455,282	na	35,603	12,788	na
	1989	2.82	487,735	7.13%	37,374	13,050	2.05%
	1990	2.78	536,456	9.99%	38,646	13,881	6.37%
	1991	2.77	542,978	1.22%	39,421	13,774	-0.77%
	1992	2.75	545,142	0.40%	40,184	13,566	-1.51%
	1993	2.75	592,114	8.62%	41,369	14,313	5.51%
	1994	2.76	602,814	1.81%	42,215	14,280	-0.23%
	1995	2.74	648,969	7.66%	43,175	15,031	5.26%
	1996	2.71	655,419	0.99%	43,728	14,989	-0.28%
	1997	2.69	672,123	2.55%	45,002	14,935	-0.35%
	1998	2.68	721,282	7.31%	45,169	15,969	6.92%
	1999	2.67	695,855	-3.53%	45,473	15,303	-4.17%
	2000	2.66	740,536	6.42%	45,305	16,346	6.82%
	2001	2.60	711,418	-3.93%	45,286	15,709	-3.89%
	2002	2.60	732,666	2.99%	46,006	15,925	1.37%
	2003	2.57	726,600	-0.83%	46,799	15,526	-2.51%
	2004	2.58	743,091	2.27%	47,048	15,794	1.73%
	2005	2.57	794,261	6.89%	47,690	16,655	5.45%
	2006	2.57	754,912	-4.95%	48,597	15,534	-6.73%
	2007	2.56	823,632	9.10%	49,775	16,547	6.52%
	2008	2.57	774,019	-6.02%	51,119	15,142	-8.49%
	2009	2.58	801,278	3.52%	50,581	15,841	4.62%
	2010	2.58	844,669	5.42%	51,262	16,477	4.01%
	2011	2.54	831,448	-1.57%	51,930	16,011	-2.83%
	2012	2.52	**772,997**	-7.03%	52,335	14,770	-7.75%
	2013	2.51	**791,352**	2.37%	52,829	14,979	1.42%
	2014	2.51	**801,799**	1.32%	53,359	15,027	0.31%
	2015	2.50	**827,250**	3.17%	53,686	15,409	2.55%
	2016	2.48	**827,166**	-0.01%	54,212	15,258	-0.98%
Historical	2017	2.46	**806,567** [3]	-2.49%	54,559	14,783	-3.11%
Projected	2018	2.45	806,856	9.11%	55,571	14,519	-1.79%
	2019	2.44	803,563	1.07%	55,624	14,446	-0.50%
	2020	2.43	800,270	1.06%	55,678	14,373	-0.51%
	2021	2.42	796,976	1.05%	55,731	14,300	-0.51%
	2022	2.42	796,976	0.00%	55,784	14,287	-0.10%
	2023	2.42	796,976	0.00%	55,838	14,273	-0.10%
	2024	2.42	796,976	0.00%	55,891	14,259	-0.10%
	2025	2.42	796,976	0.00%	55,945	14,246	-0.10%
	2026	2.43	800,270	-1.04%	55,998	14,291	0.32%
	2027	2.43	800,270	0.00%	56,052	14,277	-0.10%
	2028	2.43	800,270	0.00%	56,106	14,264	-0.10%
	2029	2.43	800,270	0.00%	56,159	14,250	-0.10%
	2030	2.44	803,563	-1.05%	56,213	14,295	0.32%
	2031	2.44	803,563	0.00%	56,267	14,281	-0.10%
	2032	2.45	806,856	-1.06%	56,321	14,326	0.31%
	2033	2.45	806,856	0.00%	56,375	14,312	-0.10%
	2034	2.46	810,150	-1.07%	56,429	14,357	0.31%
	2035	2.46	810,150	0.00%	56,483	14,343	-0.10%
	2036	2.46	810,150	0.00%	56,537	14,330	-0.10%
	2037	2.47	813,443	-1.09%	56,591	14,374	0.31%

Average Annual Compound Growth Rates:

1988	2017	-0.52%	1.99%	1.48%	0.50%
2007	2017	-0.40%	-0.21%	0.92%	-1.12%
2012	2017	-0.48%	0.85%	0.84%	0.02%
2017	2022	-0.33%	-0.24%	0.45%	-0.68%
2017	2037	0.02%	0.04%	0.18%	-0.14%

[1] Data from Woods & Poole

[2] Data from Table 1

[3] Data from 2012 to 2017 was weather-normalized

Table 3

COMMERCIAL ENERGY SALES - LOW

Lafayette Utilities System

COM_MWH = -23,531.9223 + 0.21486 (RES_MWH) + 5.56963 (TOT_RET_GEN)

Variable	T-statistic	Variable Description
COM_MWH		Commercial Energy Sales (MWh)
TOT_RET_GEN	7.815	Total Retail Sales for General Stores
RES_MWH	2.805	Residential Energy Sales (MWh)

R-Squared =	96.3%	Standard Error =	6,457.626
Adjusted R-Squared =	96.1%	F-Statistic =	355.295

	Year	Retail Sales General Stores	[1]	Actual and Projected Residential Energy	[2]	Actual and Projected Commercial Energy		Actual and Projected Commercial Energy Growth
	1988	$3,480		455,282		106,382		na
	1989	$3,609		487,735		106,177		-0.2%
	1990	$3,692		536,456		108,253		2.0%
	1991	$3,704		542,978		111,435		2.9%
	1992	$3,894		545,142		111,616		0.2%
	1993	$4,158		592,114		124,566		11.60%
	1994	$4,498		602,814		129,043		3.59%
	1995	$4,726		648,969		135,998		5.39%
	1996	$5,003		655,419		137,438		1.06%
	1997	$5,245		672,123		145,659		5.98%
	1998	$5,368		721,282		158,210		8.62%
	1999	$5,642		695,855		155,160		-1.93%
	2000	$5,725		740,536		171,768		10.70%
	2001	$5,638		711,418		166,023		-3.34%
	2002	$5,583		732,666		165,880		-0.09%
	2003	$5,843		726,600		159,778		-3.68%
	2004	$6,205		743,091		168,830		5.67%
	2005	$6,545		794,261		177,075		4.88%
	2006	$6,872		754,912		190,740		7.72%
	2007	$7,085		823,632		197,865		3.74%
	2008	$6,905		774,019		187,371		-5.30%
	2009	$6,513		801,278		192,017		2.48%
	2010	$6,836		844,669		200,750		4.55%
	2011	$7,230		831,448		194,819		-2.95%
	2012	$7,538		772,997		187,571		-3.72%
	2013	$7,751		791,352		195,228		4.08%
	2014	$8,001		801,799		199,733		2.31%
	2015	$8,210		827,250		202,060		1.17%
	2016	$8,348		827,166		180,207		-10.81%
Historical	2017	$8,571		806,567		188,658		4.69%
Projected	2018	$8,728		806,856		188,762	[3]	0.06%
	2019	$8,875		803,563		188,867		0.06%
	2020	$9,015		800,270		188,938		0.04%
	2021	$9,169		796,976		189,078		0.07%
	2022	$9,317		796,976		189,864		0.42%
	2023	$9,462		796,976		190,630		0.40%
	2024	$9,604		796,976		191,386		0.40%
	2025	$9,747		796,976		192,141		0.39%
	2026	$9,888		800,270		193,559		0.74%
	2027	$10,026		800,270		194,295		0.38%
	2028	$10,163		800,270		195,021		0.37%
	2029	$10,299		800,270		195,739		0.37%
	2030	$10,434		803,563		197,129		0.71%
	2031	$10,568		803,563		197,839		0.36%
	2032	$10,702		806,856		199,220		0.70%
	2033	$10,835		806,856		199,925		0.35%
	2034	$10,968		810,150		201,302		0.69%
	2035	$11,101		810,150		202,009		0.35%
	2036	$11,234		810,150		202,711		0.35%
	2037	$11,367		813,443		204,092		0.68%

Average Annual Compound Growth Rates:

1988	2017	3.16%	1.99%	2.00%
2007	2017	1.92%	-0.21%	-0.48%
2012	2017	2.60%	0.85%	0.12%
2017	2022	1.68%	-0.24%	0.13%
2017	2037	1.42%	0.04%	0.39%

[1] Data from Woods & Poole

[2] Data from Table 2

[3] Forecast based on model-estimated growth

Table 4

COMMERCIAL (with DEMAND) ENERGY SALES - LOW

Lafayette Utilities System

COMwD_MWH = 38,356.269 + 0.95920 (COMwD_LAG)

Variable	T-statistic	Variable Description
COMwD_MWH		Commercial (with Demand) Energy Sales (MWh)
COMwD_LAG	31.11	Commercial (with Demand) Energy Sales Lagged One Year (MWh)

R-Squared = 97.2%

Adjusted R-Squared = 97.1%

Standard Error = 20,542.3

F-Statistic = 968.1263982

	Year	Commercial (with Demand) Energy Lagged One Year	Actual and Projected Commercial (with Demand) Energy		Projected Commercial (with Demand) Energy Growth
	1988	477,805	473,332		na
	1989	473,332	473,130		-0.04%
	1990	473,130	497,109		5.07%
	1991	497,109	496,326		-0.16%
	1992	496,326	511,180		2.99%
	1993	511,180	526,603		3.02%
	1994	526,603	547,511		3.97%
	1995	547,511	578,822		5.72%
	1996	578,822	602,105		4.02%
	1997	602,105	614,060		1.99%
	1998	614,060	645,451		5.11%
	1999	645,451	647,906		0.38%
	2000	647,906	700,035		8.05%
	2001	700,035	723,825		3.40%
	2002	723,825	737,195		1.85%
	2003	737,195	701,067		-4.90%
	2004	701,067	731,795		4.38%
	2005	731,795	745,948		1.93%
	2006	745,948	796,126		6.73%
	2007	796,126	822,515		3.31%
	2008	822,515	781,121		-5.03%
	2009	781,121	780,166		-0.12%
	2010	780,166	775,136		-0.64%
	2011	775,136	792,875		2.29%
	2012	792,875	785,806		-0.89%
	2013	785,806	781,262		-0.58%
	2014	781,262	793,062		1.51%
	2015	793,062	815,519		2.83%
	2016	815,519	815,087		-0.05%
Historical	2017	815,087	805,520		-1.17%
Projected	2018	805,520	796,065	[1]	-1.17%
	2019	796,065	786,722		-1.17%
	2020	786,722	777,488		-1.17%
	2021	777,488	768,362		-1.17%
	2022	768,362	759,344		-1.17%
	2023	759,344	750,431		-1.17%
	2024	750,431	741,624		-1.17%
	2025	741,624	732,919		-1.17%
	2026	732,919	724,317		-1.17%
	2027	724,317	715,815		-1.17%
	2028	715,815	707,414		-1.17%
	2029	707,414	699,111		-1.17%
	2030	699,111	690,905		-1.17%
	2031	690,905	682,796		-1.17%
	2032	682,796	674,782		-1.17%
	2033	674,782	666,862		-1.17%
	2034	666,862	659,035		-1.17%
	2035	659,035	651,299		-1.17%
	2036	651,299	643,655		-1.17%
	2037	643,655	636,100		-1.17%

Average Annual Compound Growth Rates:

1988	2017	1.86%	1.85%
2007	2017	0.24%	-0.21%
2012	2017	0.55%	0.50%
2017	2022	-1.17%	-1.17%
2017	2037	-1.17%	-1.17%

[1] Forecast based on historical growth from 2016 to 2017.

Table 5

LIGHTING ENERGY SALES - LOW

Lafayette Utilities System

LIGHT_MWH = -392.868 + 0.58635 (TOT_PI_PC)

Variable	T-statistic	Variable Description
LIGHT_MWH		Lighting Energy Sales (MWh)
TOT_PI_PC	7.44	Total Personal Income per Capita

R-Squared =	76.5%	Standard Error =	1,521.41
Adjusted R-Squared =	75.1%	F-Statistic =	55.32

	Year	Total Personal Income per Capita	[1]	Actual and Projected Lighting Energy		Actual and Projected Lighting Energy Growth
	1999	$26,857		15,952		na
	2000	$27,864		15,335		-3.87%
	2001	$29,700		16,243		5.92%
	2002	$29,449		16,488		1.51%
	2003	$29,600		17,880		8.44%
	2004	$29,760		15,534		-13.12%
	2005	$32,146		18,326		17.97%
	2006	$34,985		20,895		14.02%
	2007	$36,054		21,550		3.13%
	2008	$39,254		21,138		-1.91%
	2009	$36,366		21,552		1.96%
	2010	$37,301		17,747		-17.66%
	2011	$37,305		23,302		31.30%
	2012	$40,036		23,794		2.11%
	2013	$39,343		21,321		-10.39%
	2014	$40,875		22,952		7.65%
	2015	$38,920		22,571		-1.66%
	2016	$35,719		23,641		4.74%
Historical	2017	$37,650		22,829		-3.43%
Projected	2018	$37,813		22,930	[2]	0.44%
	2019	$37,978		19,423	[3]	-15.29%
	2020	$38,142		15,901	[3]	-18.13%
	2021	$38,308		12,363	[3]	-22.25%
	2022	$38,474		12,418		0.44%
	2023	$38,641		12,472		0.44%
	2024	$38,809		12,527		0.44%
	2025	$38,978		12,583		0.44%
	2026	$39,147		12,638		0.44%
	2027	$39,317		12,694		0.44%
	2028	$39,487		12,750		0.44%
	2029	$39,659		12,807		0.44%
	2030	$39,831		12,863		0.44%
	2031	$40,004		12,920		0.44%
	2032	$40,177		12,977		0.44%
	2033	$40,352		13,034		0.44%
	2034	$40,527		13,092		0.44%
	2035	$40,703		13,150		0.44%
	2036	$40,880		13,208		0.44%
	2037	$41,057		13,266		0.44%

Average Annual Compound Growth Rates:

1999	2017	1.89%	2.01%
2007	2017	0.43%	0.58%
2012	2017	-1.22%	-0.82%
2017	2022	0.43%	-11.47%
2017	2037	0.43%	-2.68%

[1] Data from Woods & Poole, forecast based on growth from 2077 to 2017

[2] Forecast based on model estimated growth and historical data from 1999 - 2017

[3] Forecast includes a lighting reduction of 10,968 MWh spread over 3 years for street light replacement program

Table 6

OTHER ENERGY SALES - LOW

Lafayette Utilities System

OTHER_MWH = 18,860.904 + 1.37769 (RES_CON) + 0.39118 (OTHER_LAG)

Variable	T-statistic	Variable Description
OTHER_MWH		Other Energy Sales (MWh)
RES_CON	2.576	Residential Consumers
OTHER_LAG	2.224	Other Energy Sales Lagged One Year (MWh)

R-Squared = 70.2% Standard Error = 8,840.67

Adjusted R-Squared = 68.0% F-Statistic = 31.80

	Year	Actual and Projected Residential Consumers	[1]	Other Energy Lagged One Year	Actual and Projected Other Energy		Actual and Projected Other Energy Growth
	1988	35,603		99,926	105,868		na
	1989	37,374		105,868	114,547		8.20%
	1990	38,646		114,547	121,433		6.01%
	1991	39,421		121,433	121,812		0.31%
	1992	40,184		121,812	123,559		1.43%
	1993	41,369		123,559	123,491		-0.05%
	1994	42,215		123,491	130,984		6.07%
	1995	43,175		130,984	137,230		4.77%
	1996	43,728		137,230	135,750		-1.08%
	1997	45,002		135,750	138,384		1.94%
	1998	45,169		138,384	136,435		-1.41%
	1999	45,473		136,435	134,778		-1.21%
	2000	45,305		134,778	131,847		-2.18%
	2001	45,286		131,847	112,370		-14.77%
	2002	46,006		112,370	98,557		-12.29%
	2003	46,799		98,557	136,779		38.78%
	2004	47,048		136,779	130,641		-4.49%
	2005	47,690		130,641	136,084		4.17%
	2006	48,597		136,084	141,009		3.62%
	2007	49,775		141,009	147,323		4.48%
	2008	51,119		147,323	134,725		-8.55%
	2009	50,581		134,725	134,016		-0.53%
	2010	51,262		134,016	151,920		13.36%
	2011	51,930		151,920	150,028		-1.25%
	2012	52,335		150,028	148,179		-1.23%
	2013	52,829		148,179	151,587		2.30%
	2014	53,359		151,587	147,905		-2.43%
	2015	53,686		147,905	162,585		9.93%
	2016	54,212		162,585	160,384		-1.35%
Historical	2017	54,559		160,384	158,771		-1.01%
Projected	2018	55,571		158,771	157,217	[2]	-0.98%
	2019	55,624		157,217	156,683		-0.34%
	2020	55,678		156,683	156,548		-0.09%
	2021	55,731		156,548	156,569		0.01%
	2022	55,784		156,569	156,650		0.05%
	2023	55,838		156,650	156,755		0.07%
	2024	55,891		156,755	156,870		0.07%
	2025	55,945		156,870	156,988		0.08%
	2026	55,998		156,988	157,108		0.08%
	2027	56,052		157,108	157,229		0.08%
	2028	56,106		157,229	157,350		0.08%
	2029	56,159		157,350	157,471		0.08%
	2030	56,213		157,471	157,592		0.08%
	2031	56,267		157,592	157,713		0.08%
	2032	56,321		157,713	157,835		0.08%
	2033	56,375		157,835	157,957		0.08%
	2034	56,429		157,957	158,078		0.08%
	2035	56,483		158,078	158,200		0.08%
	2036	56,537		158,200	158,322		0.08%
	2037	56,591		158,322	158,444		0.08%

Average Annual Compound Growth Rates:

1988	2017	1.48%	1.64%	1.41%
2007	2017	0.92%	1.30%	0.75%
2012	2017	0.84%	1.34%	1.39%
2017	2022	0.45%	-0.48%	-0.27%
2017	2037	0.18%	-0.06%	-0.01%

[1] Data from Table 1

[2] Forecast based on model-estimated growth and includes the loss of 2,269 MWh from the University of Louisiana at Lafayette's new solar facility

Table 7

TOTAL ENERGY SALES (MWh) - LOW

Lafayette Utilities System

	Year	Residential Energy [1]	Commercial Energy [2]	Commercial (with demand) Energy [3]	Lighting Energy [4]	Other Energy [5]	Actual and Projected TOTAL Energy	Actual and Projected TOTAL Energy Growth
	1988	455,282	106,382	473,332	2,756	105,868	1,143,620	na
	1989	487,735	106,177	473,130	2,809	114,547	1,184,399	3.57%
	1990	536,456	108,253	497,109	3,242	121,433	1,266,493	6.93%
	1991	542,978	111,435	496,326	3,477	121,812	1,276,027	0.75%
	1992	545,142	111,616	511,180	3,598	123,559	1,295,094	1.49%
	1993	592,114	124,566	526,603	3,645	123,491	1,370,419	5.82%
	1994	602,814	129,043	547,511	3,711	130,984	1,414,062	3.18%
	1995	648,969	135,998	578,822	4,030	137,230	1,505,050	6.43%
	1996	655,419	137,438	602,105	4,461	135,750	1,535,174	2.00%
	1997	672,123	145,659	614,060	4,778	138,384	1,575,003	2.59%
	1998	721,282	158,210	645,451	6,110	136,435	1,667,488	5.87%
	1999	695,855	155,160	647,906	15,952	134,778	1,649,651	-1.07%
	2000	740,536	171,768	700,035	15,335	131,847	1,759,520	6.66%
	2001	711,418	166,023	723,825	16,243	112,370	1,729,880	-1.68%
	2002	732,666	165,880	737,195	16,488	98,557	1,750,786	1.21%
	2003	726,600	159,778	701,067	17,880	136,779	1,742,103	-0.50%
	2004	743,091	168,830	731,795	15,534	130,641	1,789,891	2.74%
	2005	794,261	177,075	745,948	18,326	136,084	1,871,694	4.57%
	2006	754,912	190,740	796,126	20,895	141,009	1,903,683	1.71%
	2007	823,632	197,865	822,515	21,550	147,323	2,012,885	5.74%
	2008	774,019	187,371	781,121	21,138	134,725	1,898,374	-5.69%
	2009	801,278	192,017	780,166	21,552	134,016	1,929,029	1.61%
	2010	844,669	200,750	775,136	17,747	151,920	1,990,222	3.17%
	2011	831,448	194,819	792,875	23,302	150,028	1,992,472	0.11%
	2012	772,997	187,571	785,806	23,794	148,179	1,918,347	-3.72%
	2013	791,352	195,228	781,262	21,321	151,587	1,940,750	1.17%
	2014	801,799	199,733	793,062	22,952	147,905	1,965,451	1.27%
	2015	827,250	202,060	815,519	22,571	162,585	2,029,985	3.28%
	2016	827,166	180,207	815,087	23,641	160,384	2,006,484	-1.16%
Historical	2017	806,567	188,658	805,520	22,829	158,771	1,982,345	-1.20%
Projected	2018	806,856	188,762	796,065	22,930	157,217	1,971,830	-0.53%
	2019	803,563	188,867	786,722	19,423	156,683	1,955,258	-0.84%
	2020	800,270	188,938	777,488	15,901	156,548	1,939,145	-0.82%
	2021	796,976	189,078	768,362	12,363	156,569	1,923,348	-0.81%
	2022	796,976	189,864	759,344	12,418	156,650	1,915,252	-0.42%
	2023	796,976	190,630	750,431	12,472	156,755	1,907,266	-0.42%
	2024	796,976	191,386	741,624	12,527	156,870	1,899,384	-0.41%
	2025	796,976	192,141	732,919	12,583	156,988	1,891,607	-0.41%
	2026	800,270	193,559	724,317	12,638	157,108	1,887,892	-0.20%
	2027	800,270	194,295	715,815	12,694	157,229	1,880,303	-0.40%
	2028	800,270	195,021	707,414	12,750	157,350	1,872,804	-0.40%
	2029	800,270	195,739	699,111	12,807	157,471	1,865,397	-0.40%
	2030	803,563	197,129	690,905	12,863	157,592	1,862,052	-0.18%
	2031	803,563	197,839	682,796	12,920	157,713	1,854,831	-0.39%
	2032	806,856	199,220	674,782	12,977	157,835	1,851,670	-0.17%
	2033	806,856	199,925	666,862	13,034	157,957	1,844,634	-0.38%
	2034	810,150	201,302	659,035	13,092	158,078	1,841,656	-0.16%
	2035	810,150	202,009	651,299	13,150	158,200	1,834,807	-0.37%
	2036	810,150	202,711	643,655	13,208	158,322	1,828,045	-0.37%
	2037	813,443	204,092	636,100	13,266	158,444	1,825,345	-0.15%

Average Annual Compound Growth Rates:

1988	2017	1.99%	2.00%	1.85%	7.56%	1.41%	1.91%
2007	2017	-0.21%	-0.48%	-0.21%	0.58%	0.75%	-0.15%
2012	2017	0.85%	0.12%	0.50%	-0.82%	1.39%	0.66%
2017	2022	-0.24%	0.13%	-1.17%	-11.47%	-0.27%	-0.69%
2017	2037	0.04%	0.39%	-1.17%	-2.68%	-0.01%	-0.41%

[1] Data from Table 2

[2] Data from Table 3

[3] Data from Table 4

[4] Data from Table 5

[5] Data from Table 6

Table 8

BASE PEAK DEMAND - LOW

Lafayette Utilities System

PEAK = 59.826 + 0.00020 (TOT_MWH)

Variable	T-statistic	Variable Description
PEAK		Base Peak Demand (MW)
TOT_MWH	21.681	Total Energy Sales (MWh)

R-Squared =	94.4%	Standard Error =	14.613
Adjusted R-Squared =	94.2%	F-Statistic =	470.064

	Year	Actual and Projected Total Energy [1]	Actual and Projected Peak Demand	Actual and Projected Peak Demand Growth
	1988	1,143,620	296	na
	1989	1,184,399	295	-0.34%
	1990	1,266,493	313	6.10%
	1991	1,276,027	310	-0.96%
	1992	1,295,094	318	2.58%
	1993	1,370,419	339	6.60%
	1994	1,414,062	330	-2.65%
	1995	1,505,050	368	11.52%
	1996	1,535,174	358	-2.72%
	1997	1,575,003	368	2.79%
	1998	1,667,488	391	6.25%
	1999	1,649,651	401	2.56%
	2000	1,759,520	428	6.73%
	2001	1,729,880	388	-9.35%
	2002	1,750,786	390	0.52%
	2003	1,742,103	402	3.08%
	2004	1,789,891	411	2.24%
	2005	1,871,694	438	6.57%
	2006	1,903,683	458	4.57%
	2007	2,012,885	478	4.37%
	2008	1,898,374	451	-5.65%
	2009	1,929,029	472	4.66%
	2010	1,990,222	468	-0.85%
	2011	1,992,472	469	0.21%
	2012	1,918,347	474	1.07%
	2013	1,940,750	458	-3.38%
	2014	1,965,451	443	-3.28%
	2015	2,029,985	480	8.35%
	2016	2,006,484	447	-6.88%
Historical	2017	1,982,345	436	-2.46%
Projected	2018	1,971,830	461	5.73%
	2019	1,955,258	456	-1.09%
	2020	1,939,145	453	-0.72%
	2021	1,923,348	449	-0.71%
	2022	1,915,252	448	-0.36%
	2023	1,907,266	446	-0.36%
	2024	1,899,384	445	-0.36%
	2025	1,891,607	443	-0.35%
	2026	1,887,892	442	-0.17%
	2027	1,880,303	441	-0.35%
	2028	1,872,804	439	-0.34%
	2029	1,865,397	438	-0.34%
	2030	1,862,052	437	-0.15%
	2031	1,854,831	436	-0.33%
	2032	1,851,670	435	-0.15%
	2033	1,844,634	434	-0.33%
	2034	1,841,656	433	-0.14%
	2035	1,834,807	432	-0.32%
	2036	1,828,045	430	-0.32%
	2037	1,825,345	430	-0.13%

Average Annual Compound Growth Rates:

1988	2017	1.91%	1.34%
2007	2017	-0.15%	-0.92%
2012	2017	0.66%	-1.66%
2017	2022	-0.69%	0.54%
2017	2037	-0.41%	-0.07%

[1] Data from Table 7

Table 9

PEAK DEMAND and LOAD FACTOR - LOW

Lafayette Utilities System

	Year	Actual and Projected Peak Demand (MW)	[1]	Actual and Projected TOTAL Energy (MWh)	[2]	Actual and Projected Load Factor (%)
	1988	296		1,143,620		44.10%
	1989	295		1,184,399		45.83%
	1990	313		1,266,493		46.19%
	1991	310		1,276,027		46.99%
	1992	318		1,295,094		46.49%
	1993	339		1,370,419		46.15%
	1994	330		1,414,062		48.92%
	1995	368		1,505,050		46.69%
	1996	358		1,535,174		48.95%
	1997	368		1,575,003		48.86%
	1998	391		1,667,488		48.68%
	1999	401		1,649,651		46.96%
	2000	428		1,759,520		46.93%
	2001	388		1,729,880		50.90%
	2002	390		1,750,786		51.25%
	2003	402		1,742,103		49.47%
	2004	411		1,789,891		49.71%
	2005	438		1,871,694		48.78%
	2006	458		1,903,683		47.45%
	2007	478		2,012,885		48.07%
	2008	451		1,898,374		48.05%
	2009	472		1,929,029		46.65%
	2010	468		1,990,222		48.55%
	2011	469		1,992,472		48.50%
	2012	474		1,918,347		46.20%
	2013	458		1,940,750		48.37%
	2014	443		1,965,451		50.65%
	2015	480		2,029,985		48.28%
	2016	447		2,006,484		51.24%
Historical	2017	436		1,982,345		51.90%
Projected	2018	461		1,971,830		48.83%
	2019	456		1,955,258		48.95%
	2020	453		1,939,145		48.90%
	2021	449		1,923,348		48.85%
	2022	448		1,915,252		48.82%
	2023	446		1,907,266		48.79%
	2024	445		1,899,384		48.76%
	2025	443		1,891,607		48.74%
	2026	442		1,887,892		48.72%
	2027	441		1,880,303		48.70%
	2028	439		1,872,804		48.67%
	2029	438		1,865,397		48.65%
	2030	437		1,862,052		48.63%
	2031	436		1,854,831		48.61%
	2032	435		1,851,670		48.60%
	2033	434		1,844,634		48.57%
	2034	433		1,841,656		48.56%
	2035	432		1,834,807		48.53%
	2036	430		1,828,045		48.51%
	2037	430		1,825,345		48.50%

Average Annual Compound Growth Rates:

1988	2017	1.34%	1.91%
2007	2017	-0.92%	-0.15%
2012	2017	-1.66%	0.66%
2017	2022	0.54%	-0.69%
2017	2037	-0.07%	-0.41%

[1] Data from Table 8

[2] Data from Table 7

Table 10

MONTHLY ENERGY and PEAK DEMAND - LOW

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2018	4	137,268	329
2018	5	154,683	392
2018	6	186,414	439
2018	7	206,050	440
2018	8	205,382	461
2018	9	200,177	422
2018	10	162,326	373
2018	11	143,030	293
2018	12	142,042	319
2019	1	148,794	329
2019	2	144,916	298
2019	3	137,096	286
2019	4	136,115	326
2019	5	153,383	388
2019	6	184,847	434
2019	7	204,319	435
2019	8	203,656	456
2019	9	198,495	417
2019	10	160,962	369
2019	11	141,828	290
2019	12	140,848	316
2020	1	147,568	327
2020	2	143,722	296
2020	3	135,966	284
2020	4	134,993	324
2020	5	152,119	385
2020	6	183,324	431
2020	7	202,635	432
2020	8	201,977	453
2020	9	196,859	414
2020	10	159,635	366
2020	11	140,659	288
2020	12	139,687	313
2021	1	146,365	325

Table 10

MONTHLY ENERGY and PEAK DEMAND - LOW

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2021	2	142,551	293
2021	3	134,859	282
2021	4	133,893	321
2021	5	150,880	382
2021	6	181,831	428
2021	7	200,984	429
2021	8	200,332	449
2021	9	195,255	411
2021	10	158,335	364
2021	11	139,513	285
2021	12	138,549	311
2022	1	145,749	323
2022	2	141,951	292
2022	3	134,291	281
2022	4	133,330	320
2022	5	150,245	381
2022	6	181,065	427
2022	7	200,138	427
2022	8	199,489	448
2022	9	194,433	410
2022	10	157,668	362
2022	11	138,926	284
2022	12	137,966	310
2023	1	145,142	322
2023	2	141,359	291
2023	3	133,731	280
2023	4	132,774	319
2023	5	149,618	379
2023	6	180,310	425
2023	7	199,304	425
2023	8	198,657	446
2023	9	193,623	408
2023	10	157,011	361
2023	11	138,347	283
2023	12	137,391	309

Table 10

MONTHLY ENERGY and PEAK DEMAND - LOW

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2024	1	144,542	321
2024	2	140,775	290
2024	3	133,178	279
2024	4	132,225	318
2024	5	149,000	378
2024	6	179,565	424
2024	7	198,480	424
2024	8	197,836	445
2024	9	192,822	407
2024	10	156,362	360
2024	11	137,775	282
2024	12	136,823	308
2025	1	143,950	320
2025	2	140,199	289
2025	3	132,633	278
2025	4	131,684	317
2025	5	148,390	377
2025	6	178,830	422
2025	7	197,667	422
2025	8	197,026	443
2025	9	192,033	405
2025	10	155,722	358
2025	11	137,211	281
2025	12	136,263	307
2026	1	143,667	319
2026	2	139,923	289
2026	3	132,373	278
2026	4	131,425	316
2026	5	148,099	376
2026	6	178,479	421
2026	7	197,279	422
2026	8	196,639	442
2026	9	191,656	405
2026	10	155,416	358
2026	11	136,941	281
2026	12	135,995	306

Table 10

MONTHLY ENERGY and PEAK DEMAND - LOW

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2027	1	143,090	318
2027	2	139,361	288
2027	3	131,840	277
2027	4	130,897	315
2027	5	147,503	375
2027	6	177,761	420
2027	7	196,486	420
2027	8	195,849	441
2027	9	190,885	403
2027	10	154,791	357
2027	11	136,391	280
2027	12	135,449	305
2028	1	142,519	317
2028	2	138,805	287
2028	3	131,315	276
2028	4	130,375	314
2028	5	146,915	373
2028	6	177,052	418
2028	7	195,703	419
2028	8	195,068	439
2028	9	190,124	402
2028	10	154,174	355
2028	11	135,847	279
2028	12	134,908	304
2029	1	141,955	316
2029	2	138,256	286
2029	3	130,795	275
2029	4	129,859	313
2029	5	146,334	372
2029	6	176,352	417
2029	7	194,929	417
2029	8	194,296	438
2029	9	189,372	400
2029	10	153,564	354
2029	11	135,310	278
2029	12	134,375	303

Table 10

MONTHLY ENERGY and PEAK DEMAND - LOW

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2030	1	141,701	316
2030	2	138,008	285
2030	3	130,561	274
2030	4	129,626	312
2030	5	146,072	372
2030	6	176,036	416
2030	7	194,579	417
2030	8	193,948	437
2030	9	189,033	400
2030	10	153,289	354
2030	11	135,067	278
2030	12	134,134	303
2031	1	141,151	314
2031	2	137,473	284
2031	3	130,054	273
2031	4	129,123	311
2031	5	145,505	370
2031	6	175,353	415
2031	7	193,824	415
2031	8	193,196	436
2031	9	188,300	398
2031	10	152,694	352
2031	11	134,543	277
2031	12	133,614	302
2032	1	140,911	314
2032	2	137,239	284
2032	3	129,833	273
2032	4	128,903	311
2032	5	145,257	370
2032	6	175,054	414
2032	7	193,494	415
2032	8	192,866	435
2032	9	187,979	398
2032	10	152,434	352
2032	11	134,314	276
2032	12	133,386	301

Table 10

MONTHLY ENERGY and PEAK DEMAND - LOW

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2033	1	140,375	313
2033	2	136,717	283
2033	3	129,339	272
2033	4	128,414	310
2033	5	144,705	369
2033	6	174,389	413
2033	7	192,759	413
2033	8	192,133	434
2033	9	187,264	397
2033	10	151,855	351
2033	11	133,804	275
2033	12	132,879	300
2034	1	140,149	313
2034	2	136,496	283
2034	3	129,131	272
2034	4	128,206	309
2034	5	144,472	368
2034	6	174,108	412
2034	7	192,448	413
2034	8	191,823	433
2034	9	186,962	396
2034	10	151,610	350
2034	11	133,588	275
2034	12	132,665	300
2035	1	139,628	312
2035	2	135,989	282
2035	3	128,650	271
2035	4	127,729	308
2035	5	143,934	367
2035	6	173,460	411
2035	7	191,732	411
2035	8	191,110	432
2035	9	186,267	395
2035	10	151,046	349
2035	11	133,091	274
2035	12	132,171	299

Table 10

MONTHLY ENERGY and PEAK DEMAND - LOW

Lafayette Utilities System

Year	Month	Retail Energy (MWh)	Peak Demand (KW)
2036	1	139,113	311
2036	2	135,488	281
2036	3	128,176	270
2036	4	127,259	307
2036	5	143,404	366
2036	6	172,821	410
2036	7	191,025	410
2036	8	190,406	430
2036	9	185,580	393
2036	10	150,489	348
2036	11	132,600	273
2036	12	131,684	298
2037	1	138,907	310
2037	2	135,287	280
2037	3	127,987	270
2037	4	127,071	307
2037	5	143,192	365
2037	6	172,566	409
2037	7	190,743	410
2037	8	190,124	430
2037	9	185,306	393
2037	10	150,267	348
2037	11	132,404	273
2037	12	131,490	297

APPENDIX G – ECONOMIC EVALUATION ASSUMPTIONS

LUS Power Supply Options Study

Financial and Economic Assumptions

Financial and Economic Assumptions	
General Escalation	2.0%
Interest Rate	4.0%
Utility Discount Rate	4.0%
Debt Financing Percentage	100%
Financing Term (years)	30

LUS Power Supply Options Study

Load Forecast

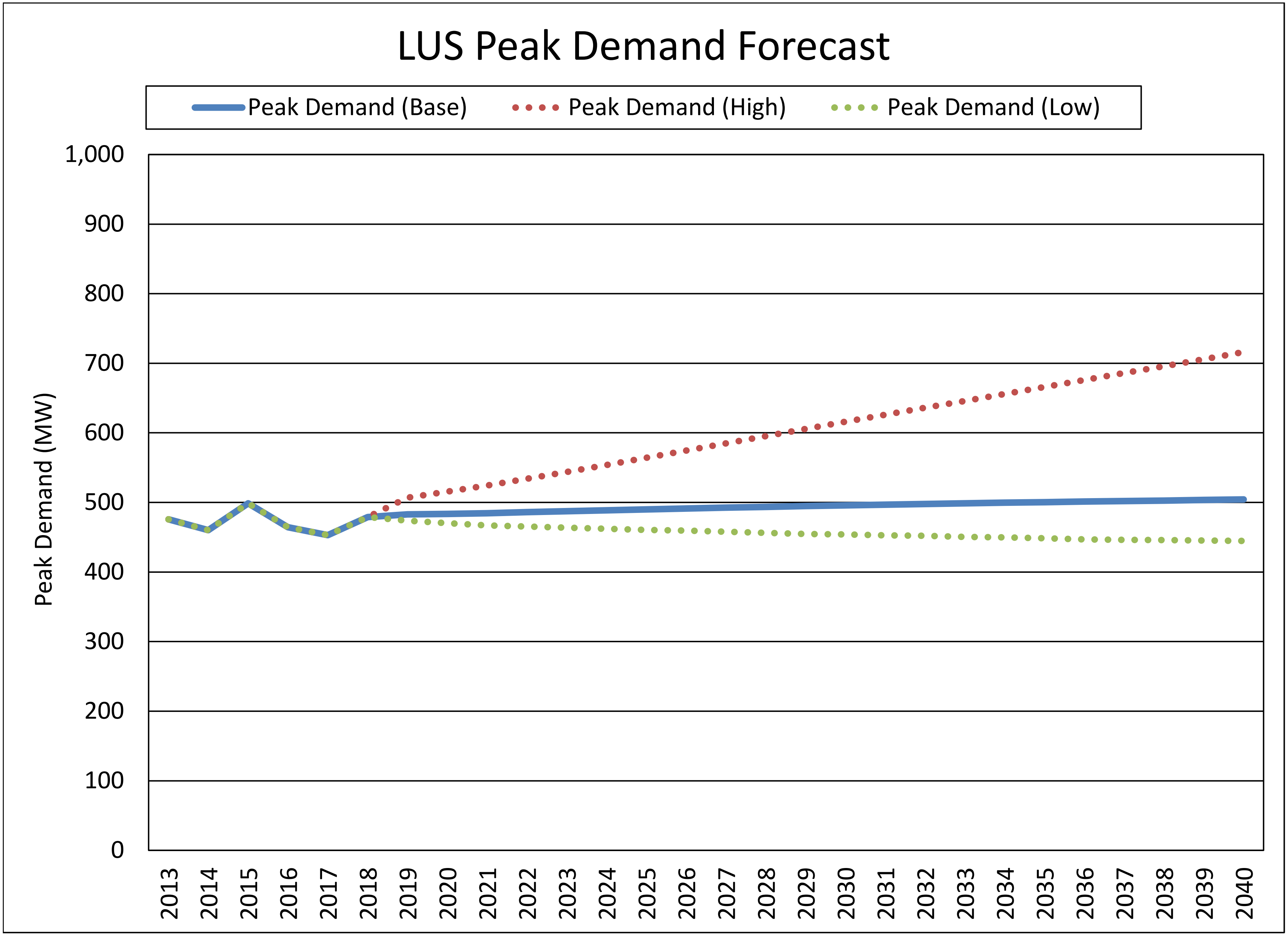
Load Forecast (MW)

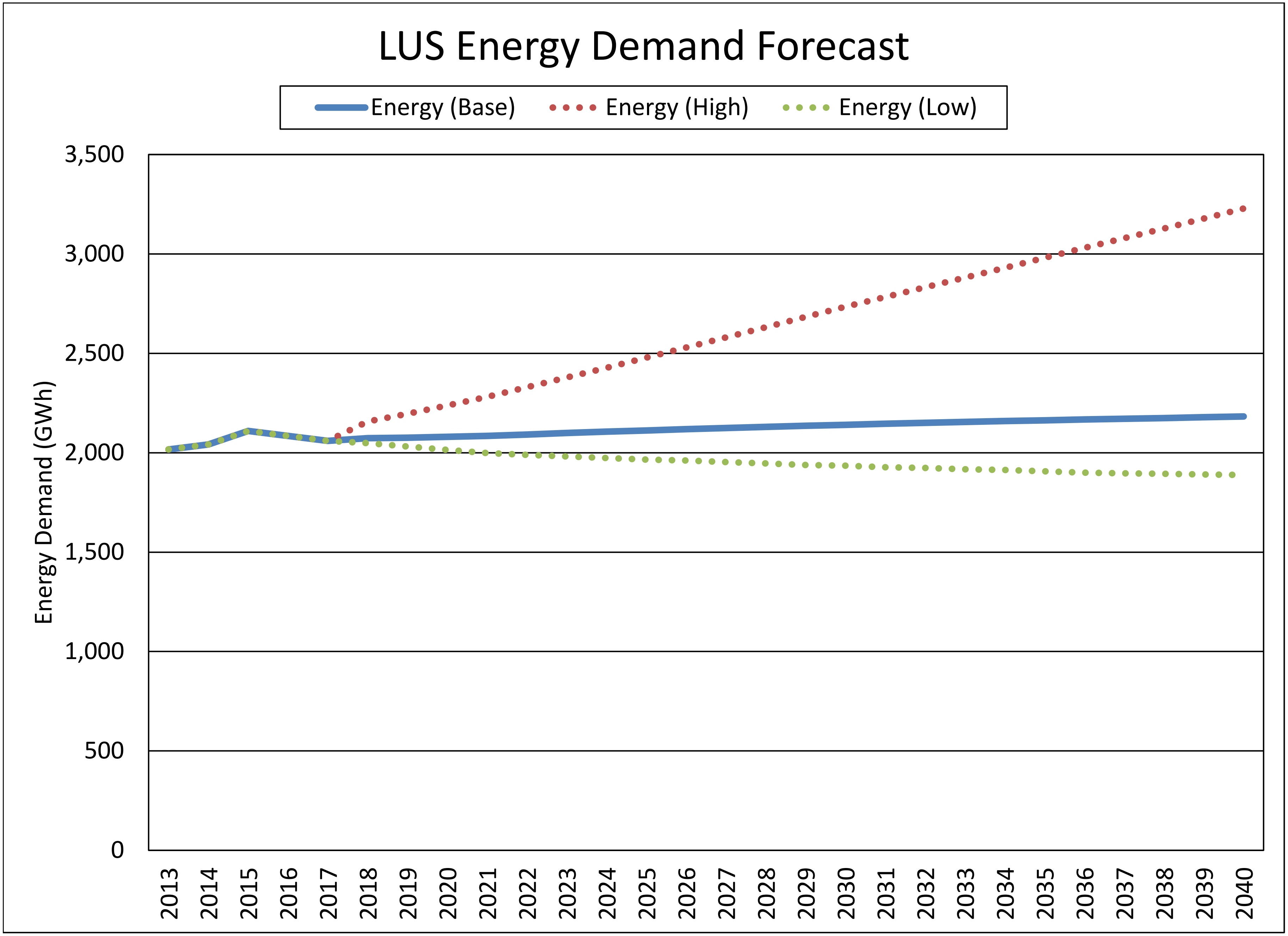
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Peak Demand	458	443	480	447	436	461	465	465	466	468	469	470	472	473	474	475	476	477	478	479	480	481	482	482	483	484	485	485
Losses (3.9%)	18	17	19	17	17	18	18	18	18	18	18	18	18	18	18	19	19	19	19	19	19	19	19	19	19	19	19	19
Peak Load Including Losses	476	460	499	464	453	479	483	484	484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
Annual Growth		-3.3%	8.4%	-6.9%	-2.5%	5.7%	0.8%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Peak Demand (High Demand Sensitivity)	458	443	480	447	436	461	488	496	505	514	523	533	543	553	563	573	583	593	603	612	622	631	641	651	660	670	679	689
Losses (3.9%) (High Demand Sensitivity)	18	17	19	17	17	18	19	19	20	20	20	21	21	22	22	22	23	23	24	24	24	25	25	25	26	26	26	27
Peak Load Including Losses (High Demand Sensitivity)	476	460	499	464	453	479	507	515	524	534	544	554	564	575	585	595	606	616	626	636	646	656	666	676	686	696	706	716
Annual Growth (High Demand Sensitivity)		-3.3%	8.4%	-6.9%	-2.5%	5.7%	5.8%	1.7%	1.7%	1.9%	1.8%	1.8%	1.9%	1.8%	1.8%	1.8%	1.8%	1.7%	1.6%	1.6%	1.5%	1.5%	1.6%	1.5%	1.4%	1.4%	1.4%	1.4%
Peak Demand (Low Demand Sensitivity)	458	443	480	447	436	461	456	453	449	448	446	445	443	442	441	439	438	437	436	435	434	433	432	430	430	429	429	428
Losses (3.9%) (Low Demand Sensitivity)	18	17	19	17	17	18	18	18	18	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Peak Load Including Losses (Low Demand Sensitivity)	476	460	499	464	453	479	474	470	467	465	464	462	460	460	458	456	455	454	453	452	450	450	448	447	446	446	445	445
Annual Growth (Low Demand Sensitivity)		-3.3%	8.4%	-6.9%	-2.5%	5.7%	-1.1%	-0.7%	-0.7%	-0.4%	-0.4%	-0.4%	-0.4%	-0.2%	-0.3%	-0.3%	-0.3%	-0.2%	-0.3%	-0.1%	-0.3%	-0.1%	-0.3%	-0.3%	-0.1%	-0.1%	-0.1%	-0.1%

Energy Forecast (GWh)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Energy	1,941	1,965	2,030	2,006	1,982	1,996	1,998	2,002	2,006	2,013	2,020	2,027	2,033	2,039	2,045	2,050	2,055	2,060	2,065	2,070	2,074	2,078	2,082	2,086	2,089	2,093	2,097	2,100
Losses (3.9%)	76	77	79	78	77	78	78	78	78	79	79	79	79	80	80	80	80	80	81	81	81	81	81	81	81	82	82	82
Energy Including Losses	2,016	2,042	2,109	2,085	2,060	2,074	2,076	2,080	2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
Load Factor	48.4%	50.6%	48.3%	51.2%	51.9%	49.4%	49.1%	49.1%	49.1%	49.1%	49.2%	49.2%	49.2%	49.2%	49.2%	49.3%	49.3%	49.3%	49.3%	49.3%	49.3%	49.3%	49.3%	49.4%	49.4%	49.4%	49.4%	49.4%
Annual Growth		1.3%	3.3%	-1.2%	-1.2%	0.7%	0.1%	0.2%	0.2%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Energy (High Demand Sensitivity)	1,941	1,965	2,030	2,006	1,982	2,076	2,113	2,154	2,195	2,242	2,289	2,336	2,385	2,434	2,483	2,533	2,582	2,631	2,679	2,726	2,773	2,820	2,868	2,917	2,963	3,010	3,058	3,107
Losses (3.9%) (High Demand Sensitivity)	76	77	79	78	77	81	82	84	86	87	89	91	93	95	97	99	101	103	104	106	108	110	112	114	116	117	119	121
Energy Including Losses (High Demand Sensitivity)	2,016	2,042	2,109	2,085	2,060	2,157	2,195	2,238	2,281	2,329	2,378	2,427	2,478	2,529	2,580	2,631	2,683	2,734	2,784	2,832	2,881	2,930	2,980	3,030	3,079	3,128	3,178	3,228
Load Factor (High Demand Sensitivity)	48.4%	50.6%	48.3%	51.2%	51.9%	51.4%	49.4%	49.6%	49.7%	49.8%	49.9%	50.0%	50.1%	50.2%	50.4%	50.5%	50.6%	50.7%	50.8%	50.8%	50.9%	51.0%	51.1%	51.2%	51.2%	51.3%	51.4%	51.5%
Annual Growth (High Demand Sensitivity)		1.3%	3.3%	-1.2%	-1.2%	4.7%	1.8%	1.9%	1.9%	2.1%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%	1.9%	1.8%	1.8%	1.7%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.6%
Energy (Low Demand Sensitivity)	1,941	1,965	2,030	2,006	1,982	1,972	1,955	1,939	1,923	1,915	1,907	1,899	1,892	1,888	1,880	1,873	1,865	1,862	1,855	1,852	1,845	1,842	1,835	1,828	1,825	1,823	1,820	1,817
Losses (3.9%) (Low Demand Sensitivity)	76	77	79	78	77	77	76	76	75	75	74	74	74	74	73	73	73	73	72	72	72	72	72	71	71	71	71	71
Energy Including Losses (Low Demand Sensitivity)	2,016	2,042	2,109	2,085	2,060	2,049	2,032	2,015	1,998	1,990	1,982	1,973	1,965	1,962	1,954	1,946	1,938	1,935	1,927	1,924	1,917	1,913	1,906	1,899	1,897	1,894	1,891	1,888
Load Factor (Low Demand Sensitivity)	48.4%	50.6%	48.3%	51.2%	51.9%	48.8%	49.0%	48.9%	48.8%	48.8%	48.8%	48.8%	48.7%	48.7%	48.7%	48.7%	48.6%	48.6%	48.6%	48.6%	48.6%	48.6%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%
Annual Growth (Low Demand Sensitivity)		1.3%	3.3%	-1.2%	-1.2%	-0.5%	-0.8%	-0.8%	-0.8%	-0.4%	-0.4%	-0.4%	-0.4%	-0.2%	-0.4%	-0.4%	-0.4%	-0.2%	-0.4%	-0.2%	-0.4%	-0.2%	-0.4%	-0.4%	-0.1%	-0.1%	-0.1%	-0.1%

Annual Load Profile	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10 Year Peak Average Percent	0.722	0.653	0.628	0.715	0.850	0.953	0.953	1.000	0.915	0.809	0.635	0.692
5 Year Energy Average Percent	0.076	0.074	0.070	0.070	0.078	0.095	0.104	0.104	0.102	0.082	0.073	0.072


LUS Peak Demand Forecast
Peak Demand (Base)
Peak Demand (High)
Peak Demand (Low)
Peak Demand (MW)
1,000
900
800
700
600
500
400
300
200
100
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040


LUS Energy Demand Forecast
Energy (Base)
Energy (High)
Energy (Low)
Energy Demand (GWh)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040

Year	MISO Peak Hour	LUS Load at MISO Peak	LUS Peak Hour	LUS Peak Load	Coincidence Factor
2013	07/17/13 17:00	334	08/08/13 16:00	458	73%
2014	07/22/14 16:00	395	08/25/13 16:00	443	89%
2015	07/29/15 16:00	464	08/10/13 17:00	480	97%
2016	07/20/16 15:00	426	07/21/13 15:00	447	95%
2017	07/20/17 16:00	408	07/26/13 16:00	436	94%
2018	06/29/18 16:00	407	07/23/13 17:00	456	89%

Minimum	89%	2016-2018
Average	93%	2016-2018
Maximum	95%	2016-2018

LUS Power Supply Options Study

Generation Resource Assumptions

Generation Resource Summary

Resource	ICAP	UCAP	Maximum Capacity	Minimum Capacity	Minimum Capacity	Firm Capacity	Development Status	Commission Date	Retirement Date	Cost Year Basis	Total Variable O&M	Variable O&M Escalation	Fixed O&M	Fixed O&M Escalation	Heat Rate at Max Cap	Ownership	Capital Cost	Fuel Type	Maint Required	Forced Outage Rate	Minimum Downtime	Minimum Runtime	Must Run	Primary Fuel Startup	Startup Energy Req	Startup Cost Adder (intermediate)	Startup Cost Adder Esc	Ramp Up Rate	Ramp Down Rate	Heat Rate at Min Cap
	MW	MW	MW	MW	%	%					$/MWh	%	$/kW-year	%	MMBtu/MWh	%	2019$		Hours	%	Hours	Hours		%	MMBtu	$	%	MW/Hour	MW/Hour	MMBtu/MWh
1x F Class SCGT	226.8	210.0	226.8	113.4	50.0%	92.6%	planned	1/1/2020	12/31/2099		$2.40		$8.70		10.01	100%		Gas	168	5.8	1	1	No	100	57	$9,500		40.8	40.8	12.21
Reciprocating Engine (5x 18 MW Engines)	91.6	87.0	91.6	4.6	5.0%	95.0%	planned	1/1/2020	12/31/2099		$6.10		$19.60		8.29	100%		Gas	168	4.5	1	1	No	100	0	$0		45.8	45.8	11.04
1x1 G/H Class CCGT Unfired	413.0	381.0	413.0	227.1	55.0%	92.3%	planned	1/1/2020	12/31/2099		$3.26		$12.30		6.30	100%		Gas	336	3.6	8	6	No	100	1,377	$15,500		41.3	41.3	6.86
50 MW Wind PPA	50.0		50.0	0.0	0.0%	ELCC Curve	planned	1/1/2020	12/31/2099		$0.00		$50.00			100%				0.0			No							
50 MW Solar PPA	50.0		50.0	0.0	0.0%	ELCC Curve	planned	1/1/2020	12/31/2099		$0.00		$17.20			100%				0.0			No							
25 MW 100 MWh Battery	25.0		25.0	0.0	0.0%	95.0%	planned	1/1/2020	12/31/2099		$14.93		$9.55			100%				0.0			No							
Hargis-Hebert 1	47.3	42.4	46.7	11.7	25%	91%	existing	6/9/2006	N/A	2019	$13.71	2.00%	$16.64	2.00%	9.95	100%		Gas	70.4	3.6	4	3	No	100	35	$250				14.85
Hargis-Hebert 2	46.5	45.6	45.9	11.5	25%	99%	existing	6/9/2006	N/A	2019	$13.71	2.00%	$16.93	2.00%	9.95	100%		Gas	84.95	3.6	4	3	No	100	35	$250				14.85
TJ Labbe 1	47.8	47.4	47.9	12.0	25%	99%	existing	7/29/2005	N/A	2019	$13.71	2.00%	$16.47	2.00%	9.95	100%		Gas	77.38	3.6	4	3	No	100	35	$250				14.85
TJ Labbe 2	47.0	35.9	47.5	11.9	25%	76%	existing	7/29/2005	N/A	2019	$13.71	2.00%	$16.75	2.00%	9.95	100%		Gas	61.1	3.6	4	3	No	100	35	$250				14.85
Rodemacher 2	246.0	228.2	245.4	98.2	40%	93%	existing	8/1/1982		2019	$0.84	2.00%	$32.43	2.00%	11.10	50%		Coal		8.1	24	24	Yes		5,334	$8,317		69	68	13.20

Variable O&M Forecast ($/MWh)

Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1x F Class SCGT	$2.40	$2.45	$2.50	$2.55	$2.60	$2.65	$2.70	$2.76	$2.81	$2.87	$2.93	$2.98	$3.04	$3.10	$3.17	$3.23	$3.29	$3.36	$3.43	$3.50	$3.57	$3.64
Reciprocating Engine (5x 18 MW Engines)	$6.10	$6.22	$6.35	$6.47	$6.60	$6.73	$6.87	$7.01	$7.15	$7.29	$7.44	$7.58	$7.74	$7.89	$8.05	$8.21	$8.37	$8.54	$8.71	$8.89	$9.06	$9.25
1x1 G/H Class CCGT Unfired	$3.26	$3.32	$3.39	$3.46	$3.52	$3.59	$3.67	$3.74	$3.81	$3.89	$3.97	$4.05	$4.13	$4.21	$4.30	$4.38	$4.47	$4.56	$4.65	$4.74	$4.84	$4.94
50 MW Wind PPA	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
50 MW Solar PPA	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
25 MW 100 MWh Battery	$14.93	$15.23	$15.53	$15.84	$16.16	$16.48	$16.81	$17.15	$17.49	$17.84	$18.20	$18.56	$18.93	$19.31	$19.70	$20.09	$20.49	$20.90	$21.32	$21.75	$22.18	$22.63
Hargis-Hebert 1	$13.71	$13.98	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
Hargis-Hebert 2	$13.71	$13.98	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
TJ Labbe 1	$13.71	$13.98	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
TJ Labbe 2	$13.71	$13.98	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
Rodemacher 2	$0.84	$0.86	$0.87	$0.89	$0.91	$0.93	$0.95	$0.96	$0.98	$1.00	$1.02	$1.04	$1.07	$1.09	$1.11	$1.13	$1.15	$1.18	$1.20	$1.22	$1.25	$1.27

Fixed O&M Forecast ($/kW-year)

Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1x F Class SCGT	$8.70	$8.87	$9.05	$9.23	$9.42	$9.61	$9.80	$9.99	$10.19	$10.40	$10.61	$10.82	$11.03	$11.25	$11.48	$11.71	$11.94	$12.18	$12.43	$12.67	$12.93	$13.19
Reciprocating Engine (5x 18 MW Engines)	$19.60	$19.99	$20.39	$20.80	$21.22	$21.64	$22.07	$22.51	$22.96	$23.42	$23.89	$24.37	$24.86	$25.35	$25.86	$26.38	$26.91	$27.44	$27.99	$28.55	$29.12	$29.71
1x1 G/H Class CCGT Unfired	$12.30	$12.55	$12.80	$13.05	$13.31	$13.58	$13.85	$14.13	$14.41	$14.70	$14.99	$15.29	$15.60	$15.91	$16.23	$16.55	$16.89	$17.22	$17.57	$17.92	$18.28	$18.64
50 MW Wind PPA	$50.00	$51.00	$52.02	$53.06	$54.12	$55.20	$56.31	$57.43	$58.58	$59.75	$60.95	$62.17	$63.41	$64.68	$65.97	$67.29	$68.64	$70.01	$71.41	$72.84	$74.30	$75.78
50 MW Solar PPA	$17.20	$17.54	$17.89	$18.25	$18.62	$18.99	$19.37	$19.76	$20.15	$20.56	$20.97	$21.39	$21.81	$22.25	$22.70	$23.15	$23.61	$24.08	$24.57	$25.06	$25.56	$26.07
25 MW 100 MWh Battery	$9.55	$9.74	$9.93	$10.13	$10.33	$10.54	$10.75	$10.96	$11.18	$11.41	$11.64	$11.87	$12.11	$12.35	$12.59	$12.85	$13.10	$13.37	$13.63	$13.91	$14.18	$14.47
Hargis-Hebert 1	$16.64	$16.97	$17.31	$17.66	$18.01	$18.37	$18.74	$19.11	$19.50	$19.89	$20.28	$20.69	$21.10	$21.53	$21.96	$22.40	$22.84	$23.30	$23.77	$24.24	$24.73	$25.22
Hargis-Hebert 2	$16.93	$17.26	$17.61	$17.96	$18.32	$18.69	$19.06	$19.44	$19.83	$20.23	$20.63	$21.05	$21.47	$21.90	$22.33	$22.78	$23.24	$23.70	$24.18	$24.66	$25.15	$25.65
TJ Labbe 1	$16.47	$16.80	$17.13	$17.47	$17.82	$18.18	$18.54	$18.91	$19.29	$19.68	$20.07	$20.47	$20.88	$21.30	$21.73	$22.16	$22.60	$23.06	$23.52	$23.99	$24.47	$24.96
TJ Labbe 2	$16.75	$17.08	$17.42	$17.77	$18.13	$18.49	$18.86	$19.24	$19.62	$20.01	$20.41	$20.82	$21.24	$21.66	$22.10	$22.54	$22.99	$23.45	$23.92	$24.40	$24.88	$25.38
Rodemacher 2	$32.43	$33.08	$33.74	$34.42	$35.11	$35.81	$36.52	$37.25	$38.00	$38.76	$39.53	$40.32	$41.13	$41.95	$42.79	$43.65	$44.52	$45.41	$46.32	$47.25	$48.19	$49.16

Strategist Input (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RPS2 conversion to NG in 2028	245.4	245.4	245.4	245.4	245.4	245.4	245.4	235.5	235.5	235.5	235.5	235.5	235.5	235.5	235.5	235.5	235.5	235.5	235.5	235.5

Contract Purchases Summary

Seller	Capacity (MW)	Annual Energy	Energy Charge ($/MWh)	Capacity Charge ($/kW-year)	Expiration
SWPA	23.2	27,840	$15.30	54	5/31/2033

SWPA	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Energy Charge ($/MWh)	$15.30	$15.61	$15.92	$16.24	$16.56	$16.89	$17.23	$17.57	$17.93	$18.28	$18.65	$19.02	$19.40	$19.79	$20.19	$20.59	$21.00	$21.42	$21.85	$22.29	$22.73	$23.19
Capacity Charge ($/kW-year)	$54.00	$55.08	$56.18	$57.31	$58.45	$59.62	$60.81	$62.03	$63.27	$64.53	$65.83	$67.14	$68.49	$69.85	$71.25	$72.68	$74.13	$75.61	$77.13	$78.67	$80.24	$81.85

SWPA Contract Details

Monthly Capacity Charge ($/kW)	Peaking energy charge ($/kWh)	Supplemental Energy Charge ($/kWh)	Purchased Power Adder ($/kWh)	Transformation Service Cap Charge ($/kW)	Freq Regulation & Response ($/kW)	Monthly Spinning Reserve ($/kW)	Monthly Supplemental Reserve
$4.50	$0.0094	$0.0094	$0.0059	$0.4600	$0.0700	$0.0146	$0.0146

Levelized Fixed Cost ($000/year)

ITC

Year	CCGT	SCGT	BATT	S50	W50	WART
2019	$24,615	$8,319	$2,279	$2,837	$4,120	$7,975
2020	$24,927	$8,546	$2,156	$2,840	$4,128	$8,193
2021	$25,241	$8,612	$2,091	$2,842	$4,135	$8,256
2022	$25,557	$8,719	$2,022	$2,840	$4,140	$8,359
2023	$25,673	$8,718	$1,950	$2,837	$4,144	$8,358
2024	$25,984	$8,810	$1,873	$2,994	$4,146	$8,446
2025	$26,401	$8,936	$1,794	$3,149	$4,147	$8,567
2026	$26,821	$9,064	$1,770	$3,625	$4,146	$8,689
2027	$27,242	$9,193	$1,745	$3,614	$4,144	$8,813
2028	$27,686	$9,336	$1,718	$3,601	$4,139	$8,950
2029	$28,079	$9,462	$1,689	$3,586	$4,133	$9,071
2030	$28,548	$9,617	$1,659	$3,569	$4,125	$9,219
2031	$29,031	$9,777	$1,671	$3,600	$4,173	$9,373
2032	$29,490	$9,927	$1,682	$3,631	$4,220	$9,517
2033	$29,983	$10,090	$1,694	$3,661	$4,267	$9,673
2034	$30,497	$10,258	$1,705	$3,692	$4,314	$9,834
2035	$30,993	$10,423	$1,717	$3,722	$4,361	$9,992
2036	$31,503	$10,591	$1,728	$3,752	$4,408	$10,153
2037	$32,031	$10,767	$1,738	$3,781	$4,455	$10,322
2038	$32,602	$10,960	$1,749	$3,811	$4,501	$10,507
2039	$33,165	$11,151	$1,759	$3,840	$4,548	$10,690
2040	$33,742	$11,346	$1,769	$3,868	$4,594	$10,877

Interest Rate	4.00%
Financing Term (years)	30
General Escalation	2.00%

Annual MWh
113,004
135,780

			Capital Cost Adders				
Gen Name	Total Capital Cost (2019 $000)*	Project Capital Costs (2019 $000)	Transmission Costs (2019 $000)	Pipeline Costs (2019 $000)	Water (2019 $000)	Interest During Construction (2019 $000)	Interest During Construction (%)
CCGT	$425,649	$381,556	$5,000	$10,000	$5,000	$24,093	6%
SCGT	$143,855	$129,665	$5,000	$5,000	$0	$4,190	3%
BATT	$39,401	$39,401					
S50	$70,094	$70,094					
W50	$71,243	$71,243					
WART	$137,909	$123,892	$5,000	$5,000	$0	$4,017	3%

2019 NREL ATB *https://atb.nrel.gov/electricity/data.html*

Overnight Capital Cost ($/kW)	CCGT	SCGT	BATT	S50	W50	WART
2019	1.00	1.00	1.00	1.00	1.00	1.00
2020	0.99	1.01	0.93	0.98	0.98	1.01
2021	0.99	1.00	0.88	0.96	0.96	1.00
2022	0.98	0.99	0.84	0.94	0.95	0.99
2023	0.96	0.97	0.79	0.92	0.93	0.97
2024	0.96	0.96	0.74	0.90	0.91	0.96
2025	0.95	0.95	0.70	0.88	0.89	0.95
2026	0.95	0.95	0.68	0.86	0.88	0.95
2027	0.94	0.94	0.65	0.85	0.86	0.94
2028	0.94	0.94	0.63	0.83	0.84	0.94
2029	0.94	0.93	0.61	0.81	0.82	0.93
2030	0.93	0.93	0.59	0.79	0.81	0.93
2031	0.93	0.93	0.58	0.78	0.80	0.93
2032	0.93	0.92	0.57	0.77	0.79	0.92
2033	0.92	0.92	0.56	0.76	0.78	0.92
2034	0.92	0.92	0.56	0.75	0.78	0.92
2035	0.92	0.91	0.55	0.74	0.77	0.91
2036	0.91	0.91	0.54	0.73	0.76	0.91
2037	0.91	0.91	0.53	0.73	0.76	0.91
2038	0.91	0.90	0.53	0.72	0.75	0.90
2039	0.91	0.90	0.52	0.71	0.74	0.90
2040	0.90	0.90	0.51	0.70	0.74	0.90

Fixed O&M ($000)

Year	CCGT	SCGT	BATT	S50	W50	WART
2019	$5,080	$1,973	$239	$860	$2,500	$1,795
2020	$5,181	$2,013	$243	$877	$2,550	$1,831
2021	$5,285	$2,053	$248	$895	$2,601	$1,868
2022	$5,391	$2,094	$253	$913	$2,653	$1,905
2023	$5,499	$2,136	$258	$931	$2,706	$1,943
2024	$5,609	$2,179	$263	$950	$2,760	$1,982
2025	$5,721	$2,222	$269	$968	$2,815	$2,022
2026	$5,835	$2,267	$274	$988	$2,872	$2,062
2027	$5,952	$2,312	$280	$1,008	$2,929	$2,104
2028	$6,071	$2,358	$285	$1,028	$2,988	$2,146
2029	$6,192	$2,405	$291	$1,048	$3,047	$2,189
2030	$6,316	$2,453	$297	$1,069	$3,108	$2,232
2031	$6,443	$2,502	$303	$1,091	$3,171	$2,277
2032	$6,571	$2,552	$309	$1,113	$3,234	$2,322
2033	$6,703	$2,604	$315	$1,135	$3,299	$2,369
2034	$6,837	$2,656	$321	$1,157	$3,365	$2,416
2035	$6,974	$2,709	$328	$1,181	$3,432	$2,465
2036	$7,113	$2,763	$334	$1,204	$3,501	$2,514
2037	$7,255	$2,818	$341	$1,228	$3,571	$2,564
2038	$7,400	$2,875	$348	$1,253	$3,642	$2,616
2039	$7,548	$2,932	$355	$1,278	$3,715	$2,668
2040	$7,699	$2,991	$362	$1,303	$3,789	$2,721

Solar ITC Schedule

Year	S50
2019	30%
2020	30%
2021	30%
2022	30%
2023	30%
2024	26%
2025	22%
2026	10%
2027	10%
2028	10%
2029	10%
2030	10%
2031	10%
2032	10%
2033	10%
2034	10%
2035	10%
2036	10%
2037	10%
2038	10%
2039	10%
2040	10%

Cost of Energy ($/MWh)

Year	S50	W50
2019	$32.72	$48.76
2020	$32.89	$49.18
2021	$33.07	$49.61
2022	$33.21	$50.03
2023	$33.34	$50.45
2024	$34.90	$50.86
2025	$36.44	$51.28
2026	$40.82	$51.69
2027	$40.90	$52.09
2028	$40.96	$52.49
2029	$41.01	$52.89
2030	$41.05	$53.28
2031	$41.51	$54.08
2032	$41.98	$54.90
2033	$42.44	$55.72
2034	$42.91	$56.55
2035	$43.38	$57.40
2036	$43.86	$58.25
2037	$44.33	$59.11
2038	$44.81	$59.98
2039	$45.29	$60.85
2040	$45.77	$61.74

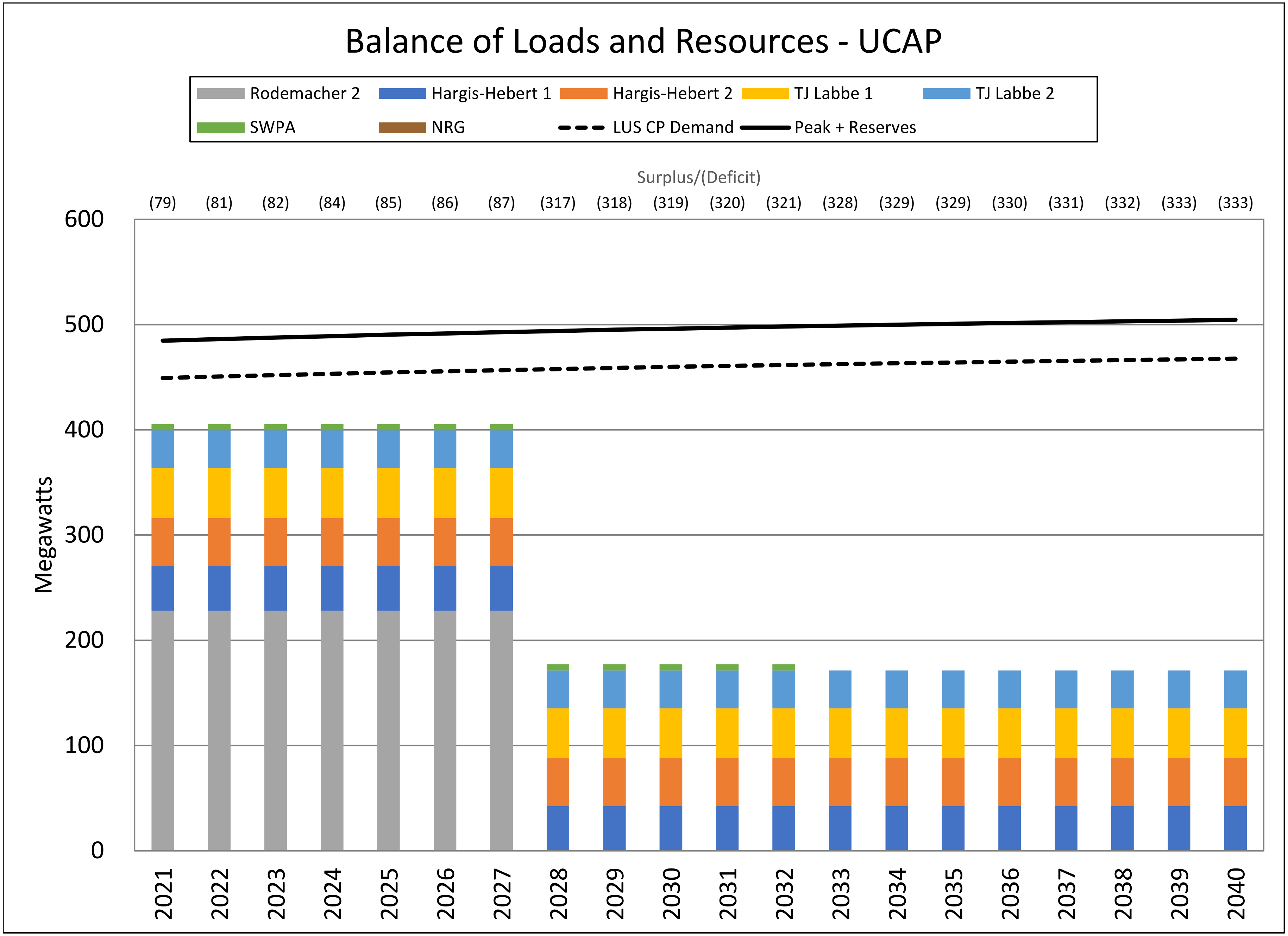
LUS Power Supply Options Study

Balance of Loads and Resources

Source: *https://cdn.misoenergy.org/2019%20LOLE%20Study%20Report285051.pdf*

Balance of Loads and Resources (MW)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Hargis-Hebert 1	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4	42.4
Hargis-Hebert 2	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6	45.6
Rodemacher 2	228.2	228.2	228.2	228.2	228.2	228.2	228.2	228.2	228.2													
TJ Labbe 1	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4	47.4
TJ Labbe 2	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
SWPA	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0								
NRG	40.0	40.0																				
LUS Total UCAP	445.5	445.5	405.5	405.5	405.5	405.5	405.5	405.5	405.5	177.3	177.3	177.3	177.3	177.3	171.3	171.3	171.3	171.3	171.3	171.3	171.3	171.3
LUS CP Demand	447.7	448.5	449.3	450.7	452.0	453.3	454.5	455.7	456.8	457.9	458.9	459.9	460.8	461.7	462.5	463.3	464.1	464.8	465.5	466.3	467.0	467.7
Reserves (7.9%)	35.4	35.4	35.5	35.6	35.7	35.8	35.9	36.0	36.1	36.2	36.3	36.3	36.4	36.5	36.5	36.6	36.7	36.7	36.8	36.8	36.9	36.9
Peak + Reserves	483.0	483.9	484.7	486.3	487.7	489.1	490.4	491.7	492.9	494.0	495.1	496.2	497.2	498.1	499.0	499.9	500.8	501.6	502.3	503.1	503.9	504.7
Surplus/(Deficit)	(38)	(38)	(79)	(81)	(82)	(84)	(85)	(86)	(87)	(317)	(318)	(319)	(320)	(321)	(328)	(329)	(329)	(330)	(331)	(332)	(333)	(333)


Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
NRG
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(79) (81) (82) (84) (85) (86) (87) (317) (318) (319) (320) (321) (328) (329) (329) (330) (331) (332) (333) (333)
Megawatts
600
500
400
300
200
100
0
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040

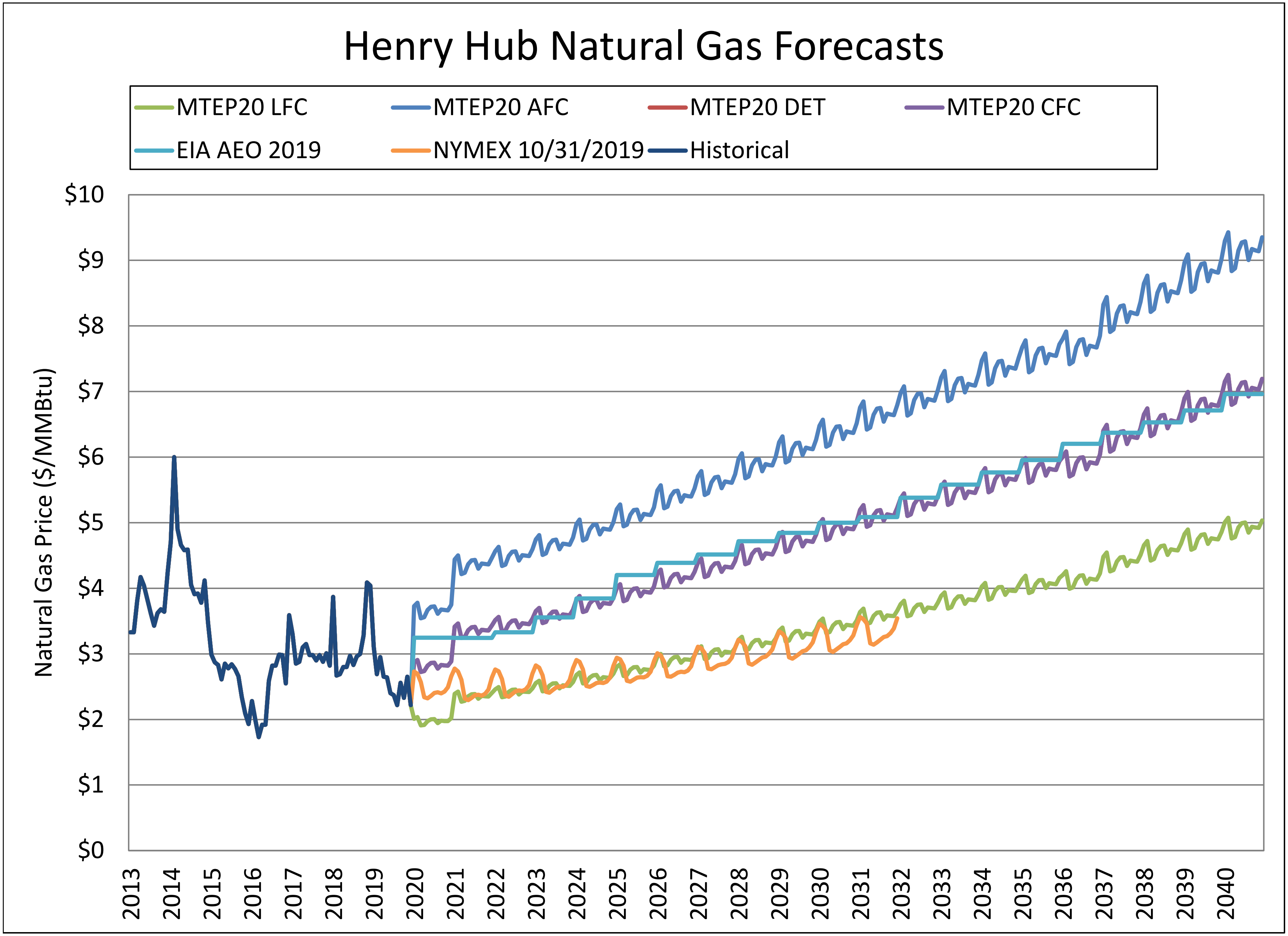
Natural Gas Supply, Disposition, and Prices
Mon Jan 27 2020 10:35:29 GMT-0600 (Central Standard Time)
Source: U.S. Energy Information Administration

Natural Gas Spot Price at Henry Hub	**full name**	**units**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
(nominal dollars per million Btu)	Natural Gas: Henry Hub Spot Price: Reference case	nom $/MMBtu	$3.25	$3.24	$3.33	$3.56	$3.84	$4.20	$4.39	$4.52	$4.72	$4.84	$5.00	$5.09	$5.38	$5.58	$5.77	$5.95	$6.20	$6.37	$6.53	$6.71	$6.96

https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1997	$3.45	$2.15	$1.89	$2.03	$2.25	$2.20	$2.19	$2.49	$2.88	$3.07	$3.01	$2.35	1997
1998	$2.09	$2.23	$2.24	$2.43	$2.14	$2.17	$2.17	$1.85	$2.02	$1.91	$2.12	$1.72	1998
1999	$1.85	$1.77	$1.79	$2.15	$2.26	$2.30	$2.31	$2.80	$2.55	$2.73	$2.37	$2.36	1999
2000	$2.42	$2.66	$2.79	$3.04	$3.59	$4.29	$3.99	$4.43	$5.06	$5.02	$5.52	$8.90	2000
2001	$8.17	$5.61	$5.23	$5.19	$4.19	$3.72	$3.11	$2.97	$2.19	$2.46	$2.34	$2.30	2001
2002	$2.32	$2.32	$3.03	$3.43	$3.50	$3.26	$2.99	$3.09	$3.55	$4.13	$4.04	$4.74	2002
2003	$5.43	$7.71	$5.93	$5.26	$5.81	$5.82	$5.03	$4.99	$4.62	$4.63	$4.47	$6.13	2003
2004	$6.14	$5.37	$5.39	$5.71	$6.33	$6.27	$5.93	$5.41	$5.15	$6.35	$6.17	$6.58	2004
2005	$6.15	$6.14	$6.96	$7.16	$6.47	$7.18	$7.63	$9.53	$11.75	$13.42	$10.30	$13.05	2005
2006	$8.69	$7.54	$6.89	$7.16	$6.25	$6.21	$6.17	$7.14	$4.90	$5.85	$7.41	$6.73	2006
2007	$6.55	$8.00	$7.11	$7.60	$7.64	$7.35	$6.22	$6.22	$6.08	$6.74	$7.10	$7.11	2007
2008	$7.99	$8.54	$9.41	$10.18	$11.27	$12.69	$11.09	$8.26	$7.67	$6.74	$6.68	$5.82	2008
2009	$5.24	$4.52	$3.96	$3.50	$3.83	$3.80	$3.38	$3.14	$2.99	$4.01	$3.66	$5.35	2009
2010	$5.83	$5.32	$4.29	$4.03	$4.14	$4.80	$4.63	$4.32	$3.89	$3.43	$3.71	$4.25	2010
2011	$4.49	$4.09	$3.97	$4.24	$4.31	$4.54	$4.42	$4.06	$3.90	$3.57	$3.24	$3.17	2011
2012	$2.67	$2.51	$2.17	$1.95	$2.43	$2.46	$2.95	$2.84	$2.85	$3.32	$3.54	$3.34	2012
2013	$3.33	$3.33	$3.81	$4.17	$4.04	$3.83	$3.62	$3.43	$3.62	$3.68	$3.64	$4.24	2013
2014	$4.71	$6.00	$4.90	$4.66	$4.58	$4.59	$4.05	$3.91	$3.92	$3.78	$4.12	$3.48	2014
2015	$2.99	$2.87	$2.83	$2.61	$2.85	$2.78	$2.84	$2.77	$2.66	$2.34	$2.09	$1.93	2015
2016	$2.28	$1.99	$1.73	$1.92	$1.92	$2.59	$2.82	$2.82	$2.99	$2.98	$2.55	$3.59	2016
2017	$3.30	$2.85	$2.88	$3.10	$3.15	$2.98	$2.98	$2.90	$2.98	$2.88	$3.01	$2.82	2017
2018	$3.87	$2.67	$2.69	$2.80	$2.80	$2.97	$2.83	$2.96	$3.00	$3.28	$4.09	$4.04	2018
2019	$3.11	$2.69	$2.95	$2.65	$2.64	$2.40	$2.37	$2.22	$2.56	$2.33	$2.65	$2.22	2019


Henry Hub Natural Gas Forecasts
MTEP20 LFC
MTEP20 AFC
MTEP20 DET
MTEP20 CFC
EIA AEO 2019
NYMEX 10/31/2019
Historical
Natural Gas Price ($/MMBtu)
$10
$9
$8
$7
$6
$5
$4
$3
$2
$1
$0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
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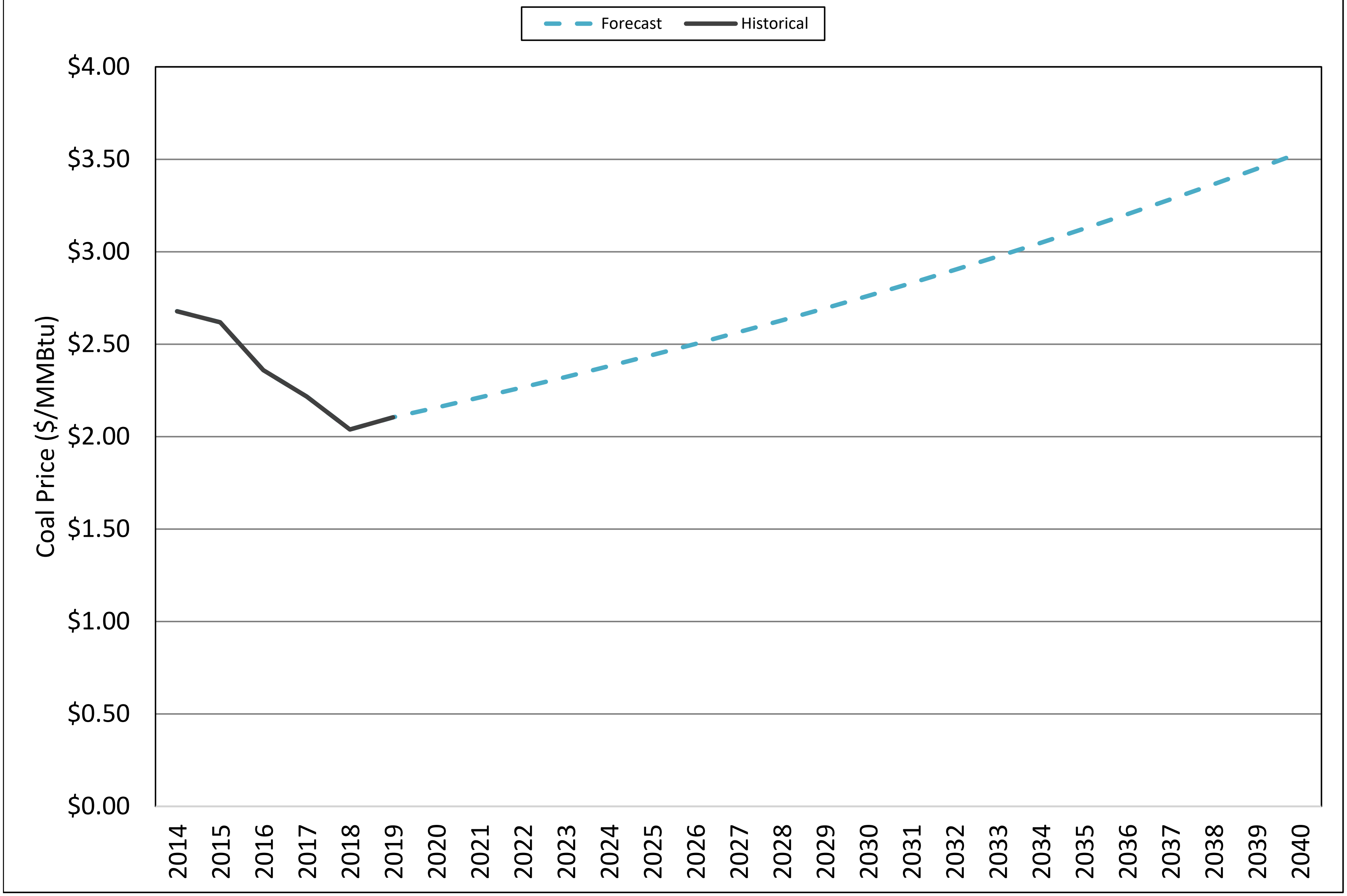
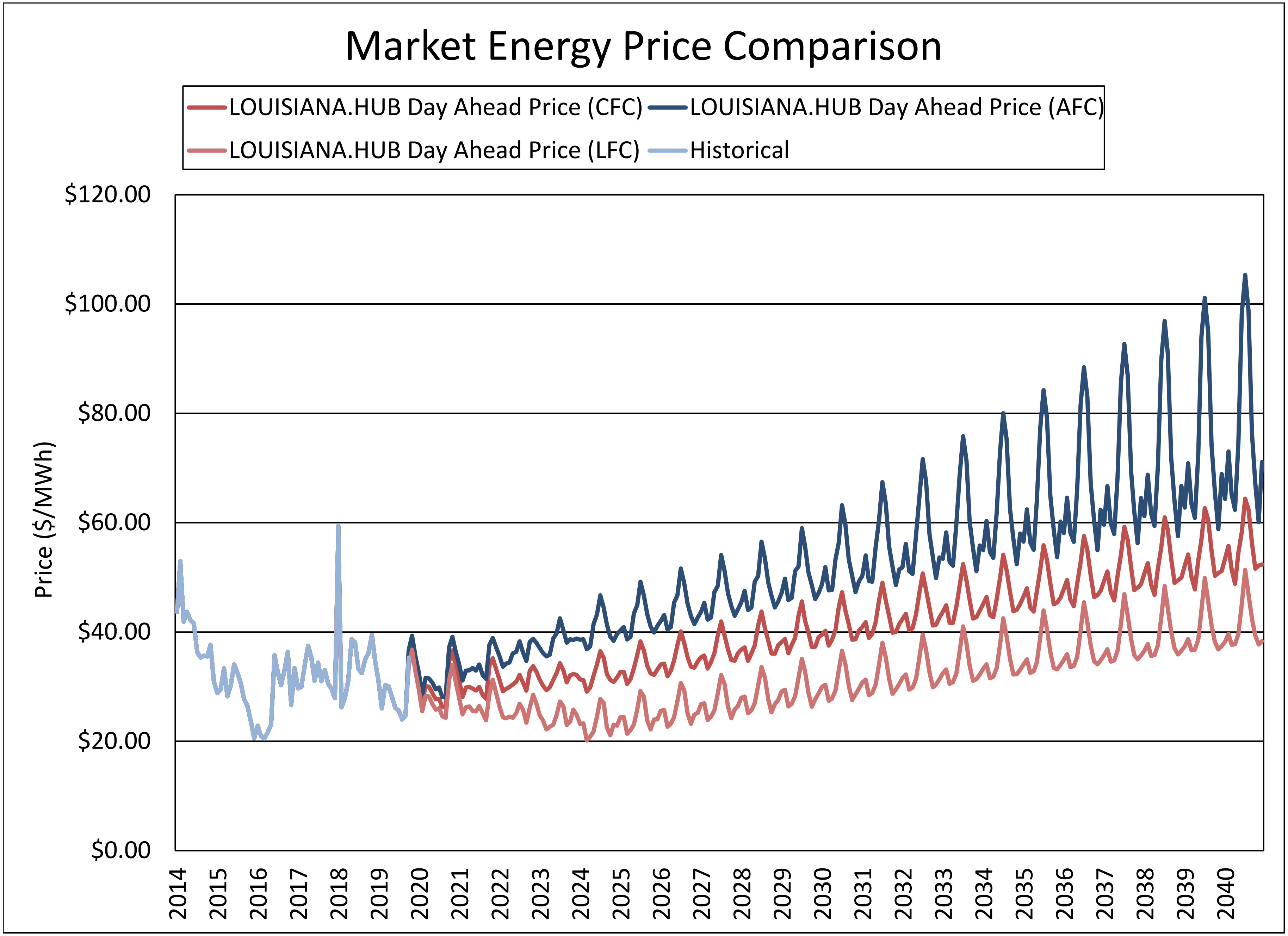
Rodemacher 2 Delivered Coal Cost




Market Energy Price Comparison
LOUISIANA.HUB Day Ahead Price (CFC)
LOUISIANA.HUB Day Ahead Price (AFC)
LOUISIANA.HUB Day Ahead Price (LFC)
Historical
Price ($/MWh)
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
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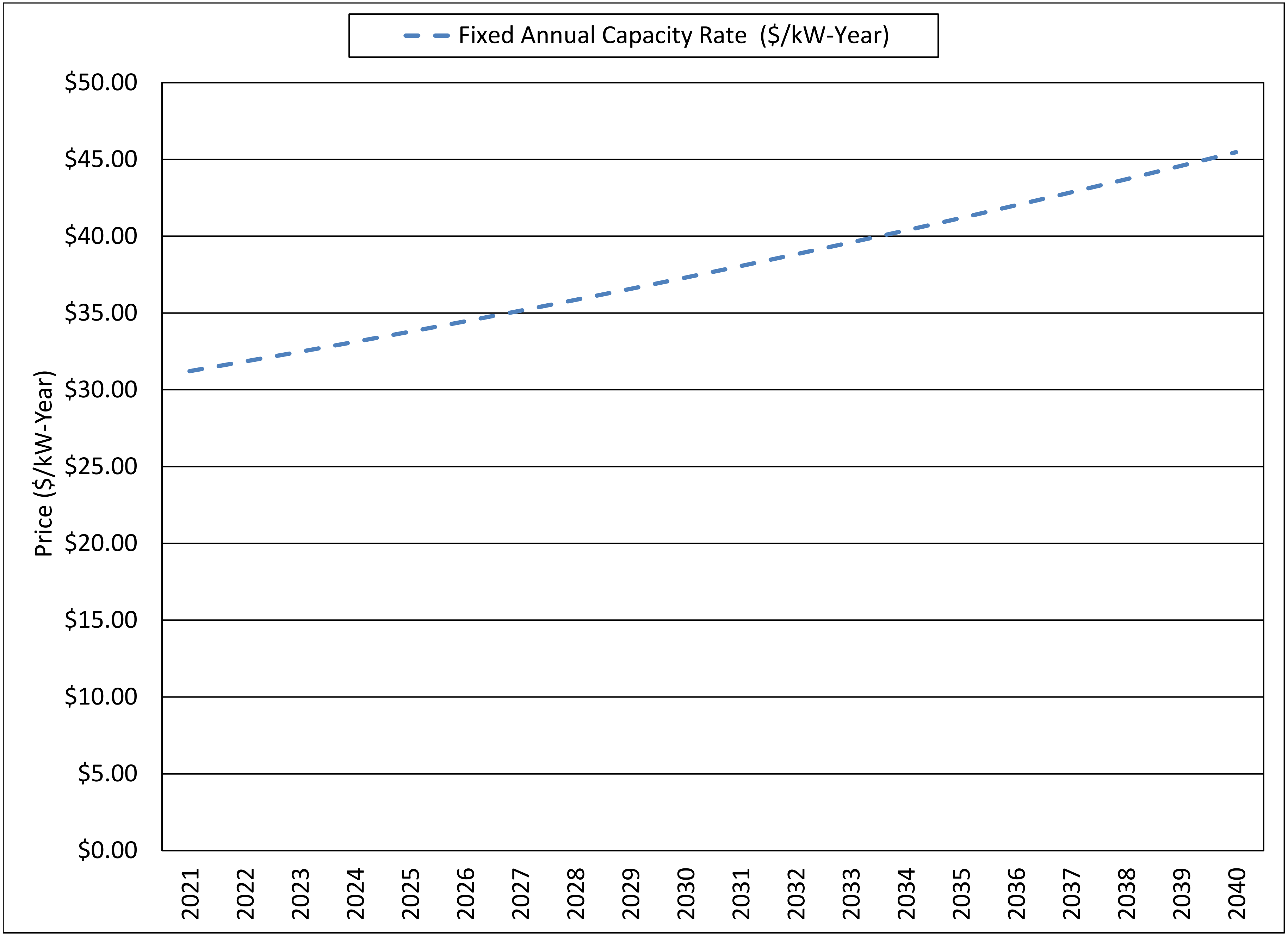
Fixed Annual Capacity Rate ($/kW-Year)
Price ($/kW-Year)
$50.00
$45.00
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
2021
2022
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2040

Planning Year 2018-2019 Pooled EFORd Class	Pooled EFORd (%)	Data Source	PROMOD Category
Combined Cycle	5.37	MISO	CC
Combustion Turbine (0-20 MW)	23.18	MISO	CT Gas, CT Oil, CT Other
Combustion Turbine (20-50 MW)	15.76	MISO	CT Gas, CT Oil, CT Other
Combustion Turbine (50+ MW)	5.18	MISO	CT Gas, CT Oil, CT Other
Diesel Engines	10.26	MISO	IC Oil
Fluidized Bed Combustion	9.28	MISO*	
HYDRO (0-30MW)	9.28	MISO*	Conventional Hydro
HYDRO (30+ MW)	9.28	MISO*	Conventional Hydro
Nuclear	9.28	MISO*	Nuclear
Pumped Storage	9.28	MISO*	Pumped Storage Hydro
Steam - Coal (0-100 MW)	4.60	MISO	ST Coal
Steam - Coal (100-200 MW)	9.28	MISO*	ST Coal
Steam - Coal (200-400 MW)	9.82	MISO	ST Coal
Steam - Coal (400-600 MW)	9.28	MISO*	ST Coal
Steam - Coal (600-800 MW)	8.22	MISO	ST Coal
Steam - Coal (800-1000 MW)	9.28	MISO*	ST Coal
Steam - Gas	11.56	MISO	ST Gas
Steam - Oil	9.28	MISO*	ST Other
Steam - Waste Heat	9.28	MISO*	ST Renewable
Steam - Wood	9.28	MISO*	ST Renewable
Wind			Wind
Solar			Solar PV
Demand Response			Interruptible Loads
Diesel Engines	10.26	MISO	IC Gas
Steam - Waste Heat	9.28	MISO*	Geothermal
Diesel Engines	10.26	MISO	IC Renewable

*MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data

ELCC Calculation

Source: *MISO MTEP20 PROMOD Model*

Equation 1 Approximate ELCC functions for wind and solar

$$\text{Wind } UCAP = (-0.3\ln(ICAP) + 0.26) * ICAP$$

$$\text{Solar } UCAP = (-0.07\ln(ICAP) + 0.42) * ICAP$$

CFC

MISO Installed Nameplate Capacity (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar PV	1,163	3,050	3,175	8,135	8,135	8,942	9,748	10,555	11,362	12,168	13,069	13,970	14,870	15,771	16,671	17,572	18,473	19,373	20,274	21,174	22,075
Wind	27,003	28,211	28,211	31,851	31,851	32,467	33,082	33,698	34,313	34,928	35,385	35,842	36,298	36,755	37,211	37,668	38,125	38,581	39,038	39,494	39,951
Solar PV - ELCC (%)	40.94%	34.19%	33.91%	27.33%	27.33%	26.67%	26.06%	25.50%	24.99%	24.51%	24.01%	23.54%	23.10%	22.69%	22.30%	21.94%	21.59%	21.25%	20.93%	20.63%	20.34%
Wind - ELCC (%)	16.11%	15.98%	15.98%	15.62%	15.62%	15.56%	15.50%	15.45%	15.39%	15.34%	15.30%	15.26%	15.22%	15.19%	15.15%	15.11%	15.08%	15.04%	15.01%	14.97%	14.94%

AFC

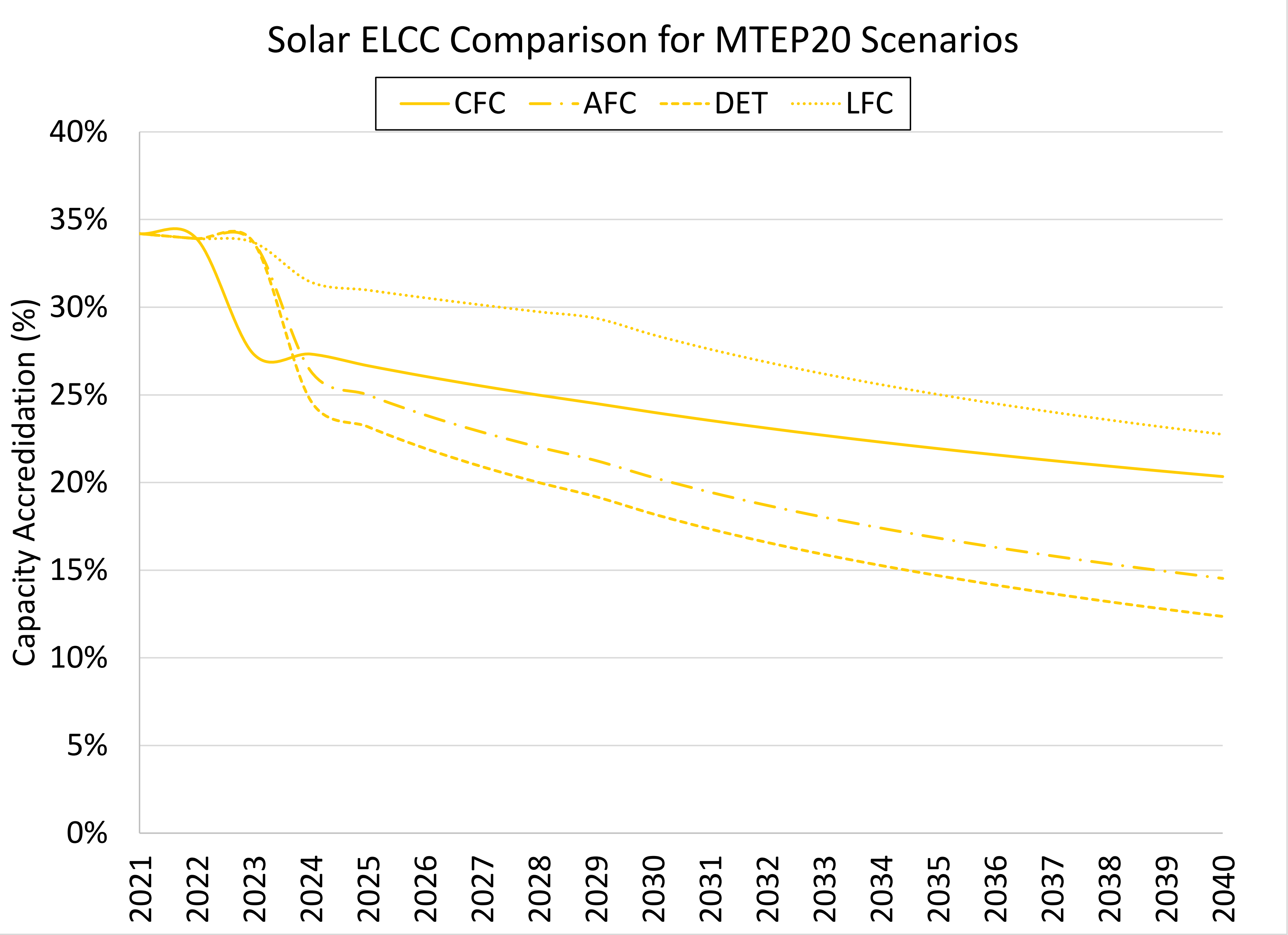
MISO Installed Nameplate Capacity (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar PV	1,163	3,050	3,175	3,275	9,332	11,338	13,345	15,351	17,358	19,364	22,206	25,047	27,889	30,730	33,572	36,414	39,255	42,097	44,938	47,780	50,622
Wind	27,003	28,211	28,211	28,211	42,919	44,519	46,119	47,719	49,319	50,919	54,078	57,237	60,395	63,554	66,712	69,871	73,030	76,188	79,347	82,505	85,664
Solar PV - ELCC (%)	40.94%	34.19%	33.91%	33.70%	26.37%	25.00%	23.86%	22.88%	22.02%	21.26%	20.30%	19.45%	18.70%	18.02%	17.40%	16.84%	16.31%	15.82%	15.36%	14.93%	14.53%
Wind - ELCC (%)	16.11%	15.98%	15.98%	15.98%	14.72%	14.61%	14.51%	14.40%	14.31%	14.21%	14.03%	13.86%	13.70%	13.54%	13.40%	13.26%	13.13%	13.00%	12.88%	12.76%	12.65%

DET

MISO Installed Nameplate Capacity (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar PV	1,163	3,050	3,175	3,275	11,870	14,694	17,518	20,342	23,167	25,991	29,902	33,813	37,724	41,635	45,546	49,457	53,368	57,280	61,191	65,102	69,013
Wind	27,003	28,211	28,211	28,211	28,211	28,211	28,211	28,211	28,211	28,211	30,012	31,813	33,613	35,414	37,214	39,015	40,816	42,616	44,417	46,217	48,018
Solar PV - ELCC (%)	40.94%	34.19%	33.91%	33.70%	24.68%	23.19%	21.96%	20.91%	20.00%	19.20%	18.21%	17.35%	16.59%	15.90%	15.27%	14.69%	14.16%	13.66%	13.20%	12.77%	12.36%
Wind - ELCC (%)	16.11%	15.98%	15.98%	15.98%	15.98%	15.98%	15.98%	15.98%	15.98%	15.98%	15.80%	15.62%	15.46%	15.30%	15.15%	15.01%	14.87%	14.74%	14.62%	14.50%	14.39%

LFC

MISO Installed Nameplate Capacity (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar PV	1,163	3,050	3,175	3,275	4,520	4,831	5,142	5,452	5,763	6,074	6,945	7,816	8,687	9,558	10,429	11,300	12,171	13,042	13,912	14,783	15,654
Wind	27,003	28,211	28,211	28,211	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921	30,921
Solar PV - ELCC (%)	40.94%	34.19%	33.91%	33.70%	31.44%	30.98%	30.54%	30.13%	29.74%	29.37%	28.43%	27.61%	26.87%	26.20%	25.59%	25.03%	24.51%	24.02%	23.57%	23.15%	22.74%
Wind - ELCC (%)	16.11%	15.98%	15.98%	15.98%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%


Solar ELCC Comparison for MTEP20 Scenarios
CFC
AFC
DET
LFC
Capacity Accredidation (%)
40%
35%
30%
25%
20%
15%
10%
5%
0%
2021
2022
2023
2024
2025
2026
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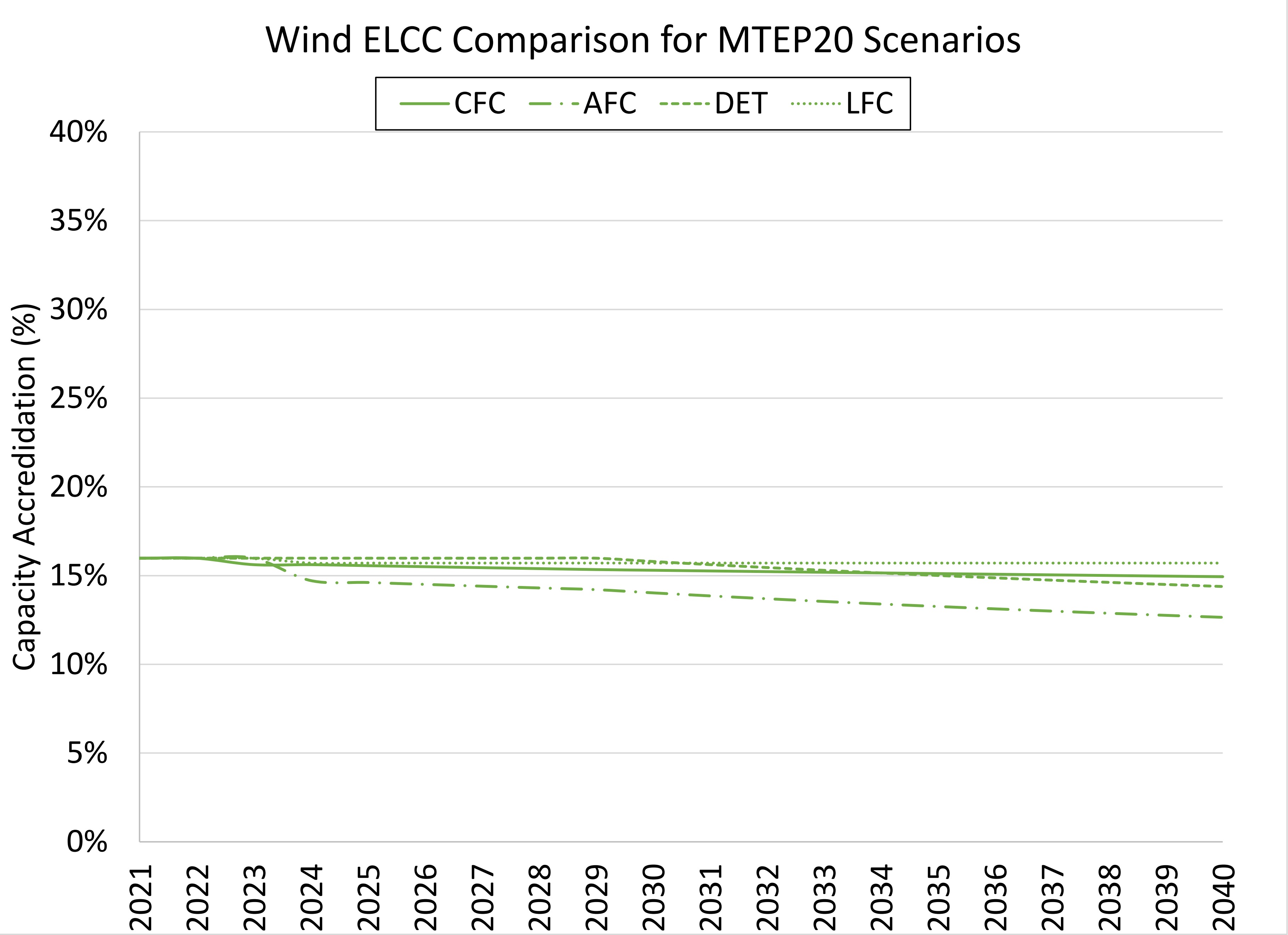
2040


Wind ELCC Comparison for MTEP20 Scenarios
CFC
AFC
DET
LFC
Capacity Accredidation (%)
40%
35%
30%
25%
20%
15%
10%
5%
0%
2021
2022
2023
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APPENDIX H – ECONOMIC RESULTS: BASE CASE

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		210	154	156	121	102	330	101	1,379	1,400	1,316	1,322	1,323	1,348	1,400	1,400	1,396	1,408	1,418	1,272	1,276
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		6,417	4,802	4,869	3,821	3,321	11,374	3,634	51,626	54,910	53,286	55,409	57,267	60,531	66,496	68,492	70,268	73,052	75,677	70,193	72,409
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT:2028:699	0	0	0	0	0	0	0	210	210	210	210	210	210	210	210	210	210	210	210	210
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Wind PPA :2039:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	9
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	37	24	11	13	15	39	41	30	32	32	43	46	47	49	50	51	47	48
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	228	228	228	228	228	228	228	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT:2028:699	0	0	0	0	0	0	0	95	80	76	75	76	77	40	42	49	39	37	36	33
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Hargis-Hebert 1	21	17	14	12	13	13	14	2	4	4	4	1	4	2	2	3	2	2	2	2
GENERATION	GWH	Hargis-Hebert 2	3	2	2	4	3	3	3	4	2	2	2	4	2	1	1	1	1	1	1	1
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	1,692	1,637	1,532	1,474	1,398	1,158	1,407	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 1	2	2	1	1	2	2	2	2	1	1	1	2	1	1	1	1	1	1	1	0
GENERATION	GWH	TJ Labbe 2	2	2	1	1	2	2	2	1	0	0	0	1	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA :2039:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	164	164
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0

CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	1xF SCGT:2028:699								5.16%	4.36%	4.11%	4.06%	4.11%	4.16%	2.16%	2.30%	2.66%	2.09%	2.01%	1.94%	1.79%
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	Hargis-Hebert 1	5.74%	4.51%	3.73%	3.14%	3.53%	3.62%	3.73%	0.67%	1.19%	1.08%	1.05%	0.38%	1.13%	0.58%	0.61%	0.69%	0.57%	0.56%	0.49%	0.46%
CAPACITY FACTOR	%	Hargis-Hebert 2	0.75%	0.58%	0.48%	0.90%	0.67%	0.77%	0.68%	0.98%	0.58%	0.52%	0.52%	0.89%	0.55%	0.28%	0.29%	0.33%	0.28%	0.27%	0.25%	0.22%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	84.63%	81.88%	76.64%	73.74%	69.91%	57.94%	70.37%													
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	TJ Labbe 1	0.45%	0.38%	0.28%	0.35%	0.38%	0.51%	0.40%	0.50%	0.27%	0.24%	0.24%	0.46%	0.26%	0.13%	0.14%	0.15%	0.13%	0.13%	0.13%	0.11%
CAPACITY FACTOR	%	TJ Labbe 2	0.59%	0.49%	0.36%	0.43%	0.50%	0.67%	0.53%	0.29%	0.13%	0.12%	0.12%	0.27%	0.13%	0.06%	0.07%	0.08%	0.06%	0.07%	0.06%	0.05%

O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$2,630	$2,640	$2,679	$2,730	$2,787	$2,846	$2,784	$2,848	$2,927	$2,950	$3,004	$3,059	$3,110
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	Hargis-Hebert 1	$1,123	$1,079	$1,058	$1,046	$1,089	$1,116	$1,145	$981	$1,034	$1,047	$1,066	$1,043	$1,115	$1,099	$1,123	$1,151	$1,166	$1,188	$1,207	$1,228
O AND M COST	$000	Hargis-Hebert 2	$862	$869	$880	$923	$928	$953	$966	$1,005	$998	$1,014	$1,034	$1,081	$1,078	$1,080	$1,103	$1,127	$1,146	$1,168	$1,190	$1,212
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$1,390	$1,510	$1,125	$1,230	$1,252	$1,691	$1,852	$1,950	$2,051	$2,151	$2,217	$2,095	$2,167
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$15,761	$21,813	$14,704	$13,125	$11,846	$13,636	$18,032	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	TJ Labbe 1	$846	$858	$869	$891	$911	$938	$949	$975	$978	$996	$1,016	$1,052	$1,058	$1,069	$1,091	$1,114	$1,135	$1,158	$1,180	$1,202
O AND M COST	$000	TJ Labbe 2	$845	$858	$869	$889	$911	$937	$949	$955	$966	$985	$1,005	$1,033	$1,046	$1,063	$1,084	$1,107	$1,128	$1,151	$1,173	$1,196

FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$2,358	$2,405	$2,453	$2,502	$2,552	$2,604	$2,656	$2,709	$2,763	$2,818	$2,875	$2,932	$2,991
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$1,390	$1,510	$1,125	$1,230	$1,252	$1,691	$1,852	$1,950	$2,051	$2,151	$2,217	$2,095	$2,167
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$14,137	$20,209	$13,157	$11,607	$10,365	$12,374	$16,471	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193

LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,548	$4,548
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT:2028:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2.87	$2.93	$2.98	$3.04	$3.10	$3.17	$3.23	$3.29	$3.36	$3.43	$3.50	$3.57	$3.64
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$272	$235	$226	$227	$235	$242	$128	$140	$164	$132	$129	$127	$120
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$304	$244	$206	$177	$202	$212	$222	$41	$74	$68	$68	$25	$76	$40	$43	$49	$42	$42	$37	$35
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$43	$34	$28	$54	$41	$48	$44	$64	$39	$35	$36	$63	$40	$20	$22	$25	$22	$22	$20	$19
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$1,624	$1,604	$1,547	$1,518	$1,481	$1,262	$1,561	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$27	$23	$17	$22	$24	$33	$27	$34	$19	$17	$18	$34	$19	$10	$11	$12	$10	$11	$11	$9
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$26	$23	$17	$20	$24	$33	$27	$15	$7	$6	$6	$15	$7	$4	$4	$5	$4	$4	$4	$4
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$4,764	$4,172	$4,125	$4,213	$4,409	$4,599	$2,529	$2,762	$3,267	$2,693	$2,673	$2,669	$2,592
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Hargis-Hebert 1	$885	$702	$588	$517	$606	$655	$694	$123	$225	$211	$214	$80	$246	$134	$145	$165	$145	$148	$135	$130
TOTAL FUEL COST	$000	Hargis-Hebert 2	$122	$93	$81	$161	$124	$146	$136	$190	$118	$110	$113	$202	$129	$69	$75	$86	$76	$77	$73	$69
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$42,629	$42,487	$41,053	$40,782	$39,721	$33,615	$41,944	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	TJ Labbe 1	$68	$58	$44	$58	$66	$92	$75	$103	$58	$54	$56	$109	$64	$34	$37	$42	$37	$39	$40	$35
TOTAL FUEL COST	$000	TJ Labbe 2	$67	$57	$44	$54	$65	$92	$75	$45	$22	$20	$21	$49	$24	$13	$14	$16	$14	$15	$15	$13

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT:2028:699								$53.06	$54.96	$57.50	$59.50	$61.39	$63.23	$66.93	$68.48	$70.18	$73.37	$75.75	$78.53	$82.38
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$55.77	$56.48	$57.29	$59.51	$61.70	$64.48	$66.19	$65.74	$67.52	$69.83	$72.16	$74.92	$76.61	$80.37	$82.31	$83.64	$88.04	$90.96	$93.94	$96.99
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$54.95	$54.97	$57.71	$60.01	$61.88	$63.33	$66.23	$65.06	$67.65	$70.02	$72.31	$74.32	$76.79	$80.61	$82.53	$83.95	$88.25	$91.05	$93.58	$97.08
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$26.16	$26.94	$27.81	$28.69	$29.48	$30.11	$30.93													
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$50.37	$51.42	$53.16	$55.63	$56.88	$59.24	$61.18	$65.52	$68.35	$70.76	$73.14	$74.72	$77.60	$81.42	$83.40	$84.79	$89.27	$91.97	$94.90	$98.17
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$50.34	$51.44	$53.20	$54.89	$56.88	$59.25	$61.16	$66.10	$69.32	$71.66	$74.17	$75.35	$78.55	$82.41	$84.56	$85.77	$90.62	$93.35	$96.84	$99.69

TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2030:395	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Wind PPA :2039:394	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,714	$3,788
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$17,768	$15,878	$14,298	$16,452	$20,700	$14,553	$7,753	$7,493	$7,725	$7,878	$8,449	$8,745	$8,981	$9,222	$9,466	$9,678	$9,706	$9,930
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$24,644	$24,772	$24,902	$25,037	$25,172	$25,310	$25,453	$25,598	$25,744	$34,157	$34,383
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,024	$1,927	$1,815	$1,791	$1,774	$1,589	$1,881	$426	$373	$353	$355	$372	$385	$202	$219	$256	$209	$208	$199	$187
TOTAL FUEL COSTS	$000		$43,770	$43,397	$41,811	$41,572	$40,582	$34,601	$42,925	$5,224	$4,595	$4,521	$4,617	$4,849	$5,061	$2,778	$3,032	$3,575	$2,965	$2,953	$2,931	$2,839
TOTAL NET MARKET TRANSACTIONS	$000		$6,417	$4,802	$4,869	$3,821	$3,321	$11,374	$3,634	$51,626	$54,910	$53,286	$55,409	$57,267	$60,531	$66,496	$68,492	$70,268	$73,052	$75,677	$70,193	$72,409
TOTAL COSTS	$000		$75,219	$82,564	$77,573	$78,371	$79,476	$83,615	$88,836	$100,963	$96,867	$99,632	$102,214	$104,603	$108,799	$112,729	$115,371	$118,110	$120,626	$123,594	$126,521	$129,084

Rate
4%

NPV @ 4% ($000): $1,272,942 **2020$**
(2021-2040)

2020 $

NPV

TOTAL FIXED COSTS	$174,349.11
TOTAL DEBT SERVICE COSTS	$68,119.33
TOTAL VARIABLE (EXCL. FUEL) COSTS	$12,775.05
TOTAL FUEL COSTS	$267,563.47
TOTAL NET MARKET TRANSACTIONS	$488,720.04

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		210	154	156	121	102	330	101	659	676	648	660	657	682	695	681	635	742	761	785	666
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		6,417	4,802	4,869	3,821	3,321	11,374	3,634	23,188	24,783	24,506	25,851	26,499	28,783	30,981	31,288	30,025	36,171	38,143	40,516	35,262
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT:2028:699	0	0	0	0	0	0	0	191	191	191	191	191	191	191	191	191	191	191	191	191
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Wind PPA :2040:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	37	24	11	13	15	58	61	50	52	52	62	65	67	68	70	70	74	67
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	228	228	228	228	228	228	228	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36

GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1x1 CCGT:2028:699	0	0	0	0	0	0	0	773	761	703	697	702	702	701	716	760	664	654	635	607
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Hargis-Hebert 1	21	17	14	12	13	13	14	14	32	30	30	21	31	30	31	30	28	28	27	18
GENERATION	GWH	Hargis-Hebert 2	3	2	2	4	3	3	3	24	13	12	12	18	13	12	13	17	11	11	11	15
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	1,692	1,637	1,532	1,474	1,398	1,158	1,407	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 1	2	2	1	1	2	2	2	10	4	4	4	7	4	4	4	6	4	4	3	4
GENERATION	GWH	TJ Labbe 2	2	2	1	1	2	2	2	3	1	1	1	2	1	1	1	2	1	1	1	2

ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA :2040:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	164

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1x1 CCGT:2028:699								46.31%	45.63%	42.14%	41.74%	42.05%	42.08%	41.99%	42.88%	45.53%	39.79%	39.21%	38.06%	36.37%
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	Hargis-Hebert 1	5.74%	4.51%	3.73%	3.14%	3.53%	3.62%	3.73%	3.89%	8.74%	8.15%	8.07%	5.58%	8.23%	8.13%	8.46%	8.13%	7.64%	7.50%	7.24%	4.93%
CAPACITY FACTOR	%	Hargis-Hebert 2	0.75%	0.58%	0.48%	0.90%	0.67%	0.77%	0.68%	5.95%	3.38%	3.11%	3.07%	4.56%	3.15%	3.11%	3.23%	4.22%	2.87%	2.81%	2.67%	3.66%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	84.63%	81.88%	76.64%	73.74%	69.91%	57.94%	70.37%													
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	TJ Labbe 1	0.45%	0.38%	0.28%	0.35%	0.38%	0.51%	0.40%	2.34%	1.08%	1.00%	0.97%	1.69%	1.02%	0.99%	1.03%	1.48%	0.89%	0.87%	0.82%	1.05%
CAPACITY FACTOR	%	TJ Labbe 2	0.59%	0.49%	0.36%	0.43%	0.50%	0.67%	0.53%	0.92%	0.32%	0.31%	0.30%	0.64%	0.32%	0.30%	0.31%	0.51%	0.26%	0.26%	0.25%	0.64%
O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$6,043	$6,119	$6,006	$6,098	$6,242	$6,369	$6,490	$6,686	$7,021	$6,716	$6,804	$6,847	$6,845
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	Hargis-Hebert 1	$1,123	$1,079	$1,058	$1,046	$1,089	$1,116	$1,145	$1,177	$1,502	$1,495	$1,519	$1,386	$1,592	$1,617	$1,672	$1,682	$1,679	$1,703	$1,717	$1,573
O AND M COST	$000	Hargis-Hebert 2	$862	$869	$880	$923	$928	$953	$966	$1,330	$1,185	$1,191	$1,211	$1,342	$1,266	$1,289	$1,323	$1,425	$1,349	$1,371	$1,387	$1,497
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$2,086	$2,221	$1,850	$1,969	$2,007	$2,460	$2,637	$2,750	$2,867	$2,984	$3,066	$3,300	$3,051
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$15,761	$21,813	$14,704	$13,125	$11,846	$13,636	$18,032	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	TJ Labbe 1	$846	$858	$869	$891	$911	$938	$949	$1,100	$1,035	$1,050	$1,069	$1,143	$1,115	$1,135	$1,161	$1,220	$1,197	$1,219	$1,239	$1,283
O AND M COST	$000	TJ Labbe 2	$845	$858	$869	$889	$911	$937	$949	$988	$976	$995	$1,014	$1,054	$1,056	$1,076	$1,099	$1,133	$1,140	$1,163	$1,185	$1,235
FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$3,035	$3,096	$3,158	$3,221	$3,286	$3,351	$3,418	$3,487	$3,557	$3,628	$3,700	$3,774	$3,850
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$2,086	$2,221	$1,850	$1,969	$2,007	$2,460	$2,637	$2,750	$2,867	$2,984	$3,066	$3,300	$3,051
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$14,137	$20,209	$13,157	$11,607	$10,365	$12,374	$16,471	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,594
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT:2028:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3.89	$3.97	$4.05	$4.13	$4.21	$4.30	$4.38	$4.47	$4.56	$4.65	$4.74	$4.84	$4.94
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$3,007	$3,022	$2,847	$2,877	$2,956	$3,017	$3,071	$3,199	$3,464	$3,088	$3,104	$3,073	$2,995
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$304	$244	$206	$177	$202	$212	$222	$236	$543	$516	$521	$368	$553	$557	$591	$580	$555	$556	$548	$380
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$43	$34	$28	$54	$41	$48	$44	$389	$225	$212	$213	$323	$228	$229	$243	$323	$225	$224	$218	$304
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$1,624	$1,604	$1,547	$1,518	$1,481	$1,262	$1,561	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$27	$23	$17	$22	$24	$33	$27	$159	$75	$71	$70	$125	$76	$76	$81	$118	$73	$72	$69	$90
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$26	$23	$17	$20	$24	$33	$27	$47	$17	$16	$16	$36	$18	$17	$18	$31	$16	$17	$16	$42
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$24,013	$24,613	$23,615	$24,334	$25,327	$26,203	$27,447	$28,706	$30,901	$28,856	$29,509	$29,689	$29,403
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Hargis-Hebert 1	$885	$702	$588	$517	$606	$655	$694	$719	$1,672	$1,621	$1,668	$1,201	$1,819	$1,886	$2,012	$1,973	$1,962	$1,998	$1,997	$1,413
TOTAL FUEL COST	$000	Hargis-Hebert 2	$122	$93	$81	$161	$124	$146	$136	$1,177	$705	$675	$693	$1,052	$760	$788	$838	$1,104	$808	$820	$808	$1,135
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$42,629	$42,487	$41,053	$40,782	$39,721	$33,615	$41,944	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	TJ Labbe 1	$68	$58	$44	$58	$66	$92	$75	$490	$241	$231	$234	$413	$261	$267	$286	$411	$267	$271	$263	$345
TOTAL FUEL COST	$000	TJ Labbe 2	$67	$57	$44	$54	$65	$92	$75	$148	$55	$55	$55	$121	$62	$62	$67	$109	$61	$63	$61	$162
TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
TOTAL VARIABLE COST	$/MWH	1x1 CCGT:2028:699								$34.96	$36.29	$37.62	$39.06	$40.30	$41.61	$43.55	$44.58	$45.23	$48.10	$49.84	$51.58	$53.38
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$55.77	$56.48	$57.29	$59.51	$61.70	$64.48	$66.19	$66.21	$68.21	$70.61	$73.04	$75.65	$77.57	$80.87	$82.87	$84.52	$88.77	$91.69	$94.65	$97.94
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$54.95	$54.97	$57.71	$60.01	$61.88	$63.33	$66.23	$65.91	$68.94	$71.37	$73.89	$75.42	$78.44	$81.82	$83.79	$84.76	$89.93	$92.95	$96.02	$98.38
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$26.16	$26.94	$27.81	$28.69	$29.48	$30.11	$30.93													
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$50.37	$51.42	$53.16	$55.63	$56.88	$59.24	$61.18	$66.74	$70.28	$72.67	$75.24	$76.39	$79.85	$83.41	$85.39	$86.04	$91.68	$94.73	$97.77	$100.16
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$50.34	$51.44	$53.20	$54.89	$56.88	$59.25	$61.16	$67.66	$71.50	$73.77	$76.27	$77.23	$80.96	$84.78	$86.79	$87.23	$93.09	$96.09	$99.06	$101.53

TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2030:395	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Wind PPA :2040:394	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,788
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$17,768	$15,878	$14,298	$16,452	$20,700	$15,927	$9,155	$8,922	$9,183	$9,365	$9,966	$10,293	$10,559	$10,832	$11,108	$11,353	$11,752	$11,672
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$24,644	$24,772	$24,902	$25,037	$25,172	$25,310	$25,453	$25,598	$25,744	$25,895	$34,429
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,024	$1,927	$1,815	$1,791	$1,774	$1,589	$1,881	$3,840	$3,882	$3,663	$3,697	$3,808	$3,893	$3,951	$4,132	$4,516	$3,957	$3,974	$3,923	$3,812
TOTAL FUEL COSTS	$000		$43,770	$43,397	$41,811	$41,572	$40,582	$34,601	$42,925	$26,547	$27,285	$26,197	$26,983	$28,113	$29,104	$30,449	$31,908	$34,498	$31,954	$32,661	$32,817	$32,458
TOTAL NET MARKET TRANSACTIONS	$000		$6,417	$4,802	$4,869	$3,821	$3,321	$11,374	$3,634	$23,188	$24,783	$24,506	$25,851	$26,499	$28,783	$30,981	$31,288	$30,025	$36,171	$38,143	$40,516	$35,262
TOTAL COSTS	$000		$75,219	$82,564	$77,573	$78,371	$79,476	$83,615	$88,836	$103,143	$98,849	$101,775	$104,330	$106,530	$110,626	$114,689	$117,041	$119,167	$122,631	$125,716	$128,747	$131,476

Rate
4%

NPV @ 4% ($000):	$1,287,323	2020$
	(2021-2040)	

2020 $

NPV

TOTAL FIXED COSTS	$185,702.89
TOTAL DEBT SERVICE COSTS	$101,004.27
TOTAL VARIABLE (EXCL. FUEL) COSTS	$39,156.86
TOTAL FUEL COSTS	$455,484.64
TOTAL NET MARKET TRANSACTIONS	$248,309.25

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		210	154	337	306	250	426	195	1,393	1,411	1,328	1,334	1,339	1,360	1,410	1,412	1,411	1,418	1,427	1,282	1,288
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		6,417	4,802	9,302	8,507	7,158	13,921	6,162	52,265	55,428	53,896	56,055	58,157	61,138	67,140	69,300	71,181	73,767	76,344	70,941	73,277
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Wind PPA :2039:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	9
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	37	24	11	13	15	30	32	21	23	23	34	37	38	40	41	42	38	39
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION:2021:700	228	228	228	228	228	228	228	219	219	219	219	219	219	219	219	219	219	219	219	219
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Hargis-Hebert 1	21	17	13	12	13	13	15	1	3	3	3	1	4	1	2	2	1	1	1	1
GENERATION	GWH	Hargis-Hebert 2	3	2	2	4	3	3	3	2	1	1	1	2	1	0	0	1	0	0	0	0
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION:2021:700	1,692	1,637	1,340	1,251	1,199	1,023	1,263	86	73	68	66	64	68	32	32	37	30	30	28	24
GENERATION	GWH	TJ Labbe 1	2	2	1	1	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 2	2	2	1	1	1	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA :2039:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	164	164
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0
CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	Hargis-Hebert 1	5.74%	4.51%	3.56%	3.12%	3.62%	3.62%	3.98%	0.36%	0.86%	0.73%	0.73%	0.23%	1.01%	0.33%	0.45%	0.55%	0.38%	0.30%	0.28%	0.24%
CAPACITY FACTOR	%	Hargis-Hebert 2	0.75%	0.58%	0.53%	0.99%	0.73%	0.76%	0.72%	0.58%	0.18%	0.16%	0.16%	0.53%	0.32%	0.08%	0.10%	0.13%	0.10%	0.07%	0.07%	0.05%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION:2021:700	84.63%	81.88%	67.02%	62.58%	59.96%	51.15%	63.20%	4.46%	3.83%	3.53%	3.46%	3.36%	3.52%	1.65%	1.66%	1.92%	1.57%	1.56%	1.44%	1.24%
CAPACITY FACTOR	%	TJ Labbe 1	0.45%	0.38%	0.22%	0.32%	0.36%	0.45%	0.37%	0.19%	0.03%	0.02%	0.02%	0.06%	0.07%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.01%
CAPACITY FACTOR	%	TJ Labbe 2	0.59%	0.49%	0.26%	0.38%	0.47%	0.59%	0.48%	0.07%	0.01%	0.00%	0.00%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%
O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	Hargis-Hebert 1	$1,123	$1,079	$1,048	$1,044	$1,094	$1,116	$1,160	$962	$1,013	$1,025	$1,045	$1,034	$1,106	$1,082	$1,112	$1,141	$1,152	$1,169	$1,191	$1,211
O AND M COST	$000	Hargis-Hebert 2	$862	$869	$883	$929	$932	$952	$969	$979	$971	$989	$1,010	$1,055	$1,062	$1,065	$1,088	$1,112	$1,132	$1,153	$1,176	$1,197
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$1,065	$1,179	$788	$886	$902	$1,333	$1,487	$1,578	$1,671	$1,764	$1,821	$1,692	$1,756
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$15,761	$21,813	$21,260	$12,895	$11,636	$27,989	$32,373	$35,332	$7,329	$5,427	$5,441	$24,635	$5,760	$8,764	$10,218	$6,071	$6,079	$6,272	$6,291	$6,412
O AND M COST	$000	TJ Labbe 1	$846	$858	$866	$889	$909	$934	$947	$954	$961	$980	$1,000	$1,023	$1,044	$1,061	$1,082	$1,103	$1,126	$1,148	$1,171	$1,194
O AND M COST	$000	TJ Labbe 2	$845	$858	$864	$887	$909	$934	$947	$944	$960	$979	$998	$1,019	$1,039	$1,060	$1,081	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$1,065	$1,179	$788	$886	$902	$1,333	$1,487	$1,578	$1,671	$1,764	$1,821	$1,692	$1,756
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$14,137	$20,209	$19,907	$11,607	$10,365	$26,874	$30,971	$35,234	$7,243	$5,346	$5,359	$24,554	$5,673	$8,722	$10,175	$6,020	$6,036	$6,228	$6,250	$6,375
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,548	$4,548
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION:2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$1.14	$1.17	$1.20	$1.23	$1.26	$1.29	$1.32	$1.36	$1.39	$1.43	$1.46	$1.50	$1.54
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$304	$244	$196	$175	$208	$212	$237	$22	$54	$46	$47	$15	$68	$23	$31	$39	$28	$22	$21	$18
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$43	$34	$31	$60	$45	$48	$46	$38	$12	$11	$11	$37	$23	$6	$8	$10	$8	$6	$6	$4
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$1,624	$1,604	$1,353	$1,288	$1,271	$1,115	$1,402	$98	$86	$81	$82	$81	$87	$42	$43	$51	$43	$44	$41	$37
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$27	$23	$14	$20	$23	$30	$25	$13	$2	$1	$2	$5	$5	$1	$1	$1	$2	$2	$2	$1
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$26	$23	$12	$18	$23	$29	$24	$4	$0	$0	$0	$1	$1	$0	$0	$0	$0	$1	$1	$0
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Hargis-Hebert 1	$885	$702	$571	$514	$628	$658	$750	$70	$170	$148	$154	$50	$223	$81	$109	$136	$101	$82	$82	$72
TOTAL FUEL COST	$000	Hargis-Hebert 2	$122	$93	$89	$181	$138	$147	$148	$118	$39	$35	$39	$126	$78	$22	$27	$35	$28	$23	$23	$18
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$42,629	$42,487	$35,728	$34,369	$33,821	$29,482	$37,431	$4,577	$4,067	$3,933	$4,005	$4,010	$4,343	$2,125	$2,206	$2,605	$2,245	$2,299	$2,199	$1,976
TOTAL FUEL COST	$000	TJ Labbe 1	$68	$58	$36	$54	$61	$82	$69	$39	$6	$5	$6	$18	$19	$5	$5	$5	$6	$6	$6	$4
TOTAL FUEL COST	$000	TJ Labbe 2	$67	$57	$32	$48	$61	$81	$69	$11	$1	$1	$0	$2	$3	$1	$0	$0	$1	$2	$2	$1
TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$55.77	$56.48	$57.97	$59.57	$62.13	$64.79	$66.85	$69.06	$69.77	$71.83	$74.10	$75.55	$77.60	$83.68	$84.91	$85.57	$90.75	$94.67	$98.05	$102.13
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$54.95	$54.97	$56.97	$61.03	$62.43	$64.06	$67.28	$66.83	$71.24	$74.01	$76.28	$77.82	$79.14	$84.42	$87.01	$88.95	$92.40	$95.52	$98.19	$102.53
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION:2021:700	$26.16	$26.94	$27.68	$28.51	$29.28	$29.92	$30.74	$54.60	$56.55	$59.29	$61.64	$63.44	$65.53	$68.64	$70.77	$72.05	$76.09	$78.22	$81.16	$84.66
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$50.37	$51.42	$54.19	$56.31	$56.94	$59.29	$61.24	$66.33	$72.52	$75.82	$79.01	$84.38	$81.44	$85.64	$90.55	$94.11	$95.34	$94.79	$97.79	$101.90
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$50.34	$51.44	$53.47	$54.99	$56.94	$59.29	$61.21	$66.80	$68.67	$77.63	$80.88	$77.29	$81.35	$78.57	$101.98	$103.33	$98.92	$91.57	$92.94	$95.05

TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2030:395	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Wind PPA :2039:394	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,714	$3,788
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$24,518	$15,878	$14,298	$30,952	$35,200	$40,062	$12,260	$10,048	$10,237	$29,528	$11,160	$14,446	$16,075	$12,099	$12,296	$12,636	$12,620	$12,903
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$24,644	$24,772	$24,902	$25,037	$25,172	$25,310	$25,453	$25,598	$25,744	$34,157	$34,383
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,024	$1,927	$1,607	$1,562	$1,569	$1,433	$1,735	$174	$154	$140	$142	$139	$184	$72	$83	$102	$80	$74	$71	$61
TOTAL FUEL COSTS	$000		$43,770	$43,397	$36,455	$35,167	$34,709	$30,450	$38,467	$4,816	$4,284	$4,123	$4,204	$4,206	$4,666	$2,234	$2,348	$2,781	$2,381	$2,412	$2,312	$2,070
TOTAL NET MARKET TRANSACTIONS	$000		$6,417	$4,802	$9,302	$8,507	$7,158	$13,921	$6,162	$52,265	$55,428	$53,896	$56,055	$58,157	$61,138	$67,140	$69,300	$71,181	$73,767	$76,344	$70,941	$73,277
TOTAL COSTS	$000		$75,219	$82,564	$83,193	$76,422	$77,235	$96,354	$101,262	$117,115	$92,027	$92,851	$95,411	$116,933	$102,187	$109,065	$113,117	$111,616	$114,122	$117,209	$120,101	$122,694

Rate
4%

NPV @ 4% ($000): $1,277,595 | **2020$**

(2021-2040)

2020 $

NPV

TOTAL FIXED COSTS	$254,364.15
TOTAL DEBT SERVICE COSTS	$0.00
TOTAL VARIABLE (EXCL. FUEL) COSTS	$10,704.18
TOTAL FUEL COSTS	$242,802.02
TOTAL NET MARKET TRANSACTIONS	$508,309.51

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		210	154	156	121	102	330	101	1,352	1,357	1,277	1,281	1,277	1,304	1,324	1,319	1,309	1,337	1,354	1,214	1,221
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		6,417	4,802	4,869	3,821	3,321	11,374	3,634	50,332	52,756	51,268	53,202	54,712	57,949	61,941	63,533	64,775	68,399	71,331	66,085	68,354
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	15	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	15	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	15	15	15	14	13	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	13	13	13	13	12	12	12	12	12	11	11
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Wind PPA :2039:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	9
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	5x 18MW Recips :2028:698	0	0	0	0	0	0	0	87	87	87	87	87	87	87	87	87	87	87	87	87
FIRM CAPACITY	MW	5x 18MW Recips :2028:699	0	0	0	0	0	0	0	87	87	87	87	87	87	87	87	87	87	87	87	87
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	37	24	11	13	15	75	77	66	68	68	79	82	83	85	86	87	83	84
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	228	228	228	228	228	228	228	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips :2028:698	0	0	0	0	0	0	0	70	73	69	71	74	74	75	79	84	71	65	61	57
GENERATION	GWH	5x 18MW Recips :2028:699	0	0	0	0	0	0	0	49	47	42	42	45	44	38	41	48	36	34	31	30
GENERATION	GWH	Hargis-Hebert 1	21	17	14	12	13	13	14	4	8	7	7	3	8	5	5	6	5	4	4	4
GENERATION	GWH	Hargis-Hebert 2	3	2	2	4	3	3	3	6	3	2	2	6	3	1	1	2	1	1	1	1
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	1,692	1,637	1,532	1,474	1,398	1,158	1,407	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 1	2	2	1	1	2	2	2	2	1	1	1	2	1	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 2	2	2	1	1	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2030:395	0	0	0	0	0	0	0	0	0	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA :2039:394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	164	164
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0
CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	5x 18MW Recips :2028:698								9.17%	9.60%	9.11%	9.30%	9.77%	9.66%	9.90%	10.31%	11.03%	9.27%	8.51%	7.95%	7.43%
CAPACITY FACTOR	%	5x 18MW Recips :2028:699								6.47%	6.14%	5.55%	5.51%	5.85%	5.79%	4.95%	5.43%	6.30%	4.69%	4.41%	4.09%	3.91%
CAPACITY FACTOR	%	Hargis-Hebert 1	5.74%	4.51%	3.73%	3.14%	3.53%	3.62%	3.73%	1.09%	2.18%	1.95%	1.94%	0.72%	2.14%	1.28%	1.43%	1.69%	1.27%	1.19%	1.10%	1.03%
CAPACITY FACTOR	%	Hargis-Hebert 2	0.75%	0.58%	0.48%	0.90%	0.67%	0.77%	0.68%	1.42%	0.67%	0.59%	0.59%	1.43%	0.67%	0.35%	0.37%	0.48%	0.36%	0.35%	0.32%	0.30%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	84.63%	81.88%	76.64%	73.74%	69.91%	57.94%	70.37%													
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	TJ Labbe 1	0.45%	0.38%	0.28%	0.35%	0.38%	0.51%	0.40%	0.45%	0.18%	0.14%	0.14%	0.42%	0.18%	0.07%	0.08%	0.09%	0.08%	0.09%	0.08%	0.07%
CAPACITY FACTOR	%	TJ Labbe 2	0.59%	0.49%	0.36%	0.43%	0.50%	0.67%	0.53%	0.14%	0.04%	0.03%	0.03%	0.11%	0.05%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$2,655	$2,732	$2,759	$2,825	$2,910	$2,962	$3,036	$3,123	$3,232	$3,180	$3,192	$3,217	$3,245
O AND M COST	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$2,505	$2,536	$2,553	$2,602	$2,675	$2,724	$2,726	$2,811	$2,924	$2,875	$2,914	$2,951	$2,997
O AND M COST	$000	Hargis-Hebert 1	$1,123	$1,079	$1,058	$1,046	$1,089	$1,116	$1,145	$1,007	$1,095	$1,102	$1,124	$1,066	$1,182	$1,147	$1,180	$1,223	$1,217	$1,235	$1,253	$1,272
O AND M COST	$000	Hargis-Hebert 2	$862	$869	$880	$923	$928	$953	$966	$1,034	$1,004	$1,019	$1,039	$1,119	$1,087	$1,085	$1,109	$1,139	$1,152	$1,174	$1,195	$1,218
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$2,677	$2,823	$2,464	$2,596	$2,646	$3,113	$3,302	$3,429	$3,559	$3,690	$3,786	$3,696	$3,800
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$15,761	$21,813	$14,704	$13,125	$11,846	$13,636	$18,032	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	TJ Labbe 1	$846	$858	$869	$891	$911	$938	$949	$971	$972	$989	$1,009	$1,049	$1,052	$1,065	$1,087	$1,109	$1,131	$1,154	$1,176	$1,199
O AND M COST	$000	TJ Labbe 2	$845	$858	$869	$889	$911	$937	$949	$948	$962	$980	$1,000	$1,024	$1,041	$1,060	$1,081	$1,103	$1,125	$1,148	$1,171	$1,194
FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$2,146	$2,189	$2,232	$2,277	$2,322	$2,369	$2,416	$2,465	$2,514	$2,564	$2,616	$2,668	$2,721
FIXED O AND M COST	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$2,146	$2,189	$2,232	$2,277	$2,322	$2,369	$2,416	$2,465	$2,514	$2,564	$2,616	$2,668	$2,721
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$1,203	$795	$387	$461	$540	$2,677	$2,823	$2,464	$2,596	$2,646	$3,113	$3,302	$3,429	$3,559	$3,690	$3,786	$3,696	$3,800
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$14,137	$20,209	$13,157	$11,607	$10,365	$12,374	$16,471	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231	$18,231
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,548	$4,548
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips :2028:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.29	$7.44	$7.58	$7.74	$7.89	$8.05	$8.21	$8.37	$8.54	$8.71	$8.89	$9.06	$9.25
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips :2028:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.29	$7.44	$7.58	$7.74	$7.89	$8.05	$8.21	$8.37	$8.54	$8.71	$8.89	$9.06	$9.25
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$509	$544	$527	$548	$588	$593	$620	$658	$718	$616	$576	$549	$524
VARIABLE O AND M COSTS	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$360	$348	$321	$325	$352	$355	$310	$347	$410	$311	$299	$283	$275
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$304	$244	$206	$177	$202	$212	$222	$66	$135	$124	$126	$48	$144	$88	$100	$121	$93	$89	$83	$79
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$43	$34	$28	$54	$41	$48	$44	$93	$45	$40	$41	$101	$49	$26	$28	$37	$28	$28	$26	$25
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$1,624	$1,604	$1,547	$1,518	$1,481	$1,262	$1,561	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$27	$23	$17	$22	$24	$33	$27	$31	$12	$10	$10	$31	$13	$6	$6	$7	$7	$7	$7	$6
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$26	$23	$17	$20	$24	$33	$27	$7	$2	$2	$2	$6	$3	$1	$1	$1	$1	$1	$1	$1
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$2,735	$2,976	$2,936	$3,111	$3,380	$3,457	$3,735	$3,985	$4,333	$3,876	$3,685	$3,564	$3,448
TOTAL FUEL COST	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$1,941	$1,915	$1,801	$1,855	$2,039	$2,085	$1,891	$2,123	$2,497	$1,980	$1,930	$1,854	$1,833
TOTAL FUEL COST	$000	Hargis-Hebert 1	$885	$702	$588	$517	$606	$655	$694	$205	$421	$393	$406	$157	$476	$306	$349	$421	$335	$325	$312	$301
TOTAL FUEL COST	$000	Hargis-Hebert 2	$122	$93	$81	$161	$124	$146	$136	$284	$142	$129	$134	$332	$164	$91	$100	$131	$104	$104	$97	$97
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$42,629	$42,487	$41,053	$40,782	$39,721	$33,615	$41,944	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Appendix H
Economic Results Base Case

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	TJ Labbe 1	$68	$58	$44	$58	$66	$92	$75	$95	$40	$33	$35	$105	$46	$21	$23	$27	$25	$27	$25	$23
TOTAL FUEL COST	$000	TJ Labbe 2	$67	$57	$44	$54	$65	$92	$75	$23	$7	$6	$6	$21	$10	$3	$4	$4	$4	$5	$4	$4

TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips :2028:698								$46.43	$48.11	$49.86	$51.61	$53.27	$54.98	$57.70	$59.09	$60.07	$63.54	$65.71	$67.88	$70.09
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips :2028:699								$46.62	$48.38	$50.15	$51.93	$53.60	$55.27	$58.30	$59.64	$60.51	$64.14	$66.32	$68.52	$70.78
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$55.77	$56.48	$57.29	$59.51	$61.70	$64.48	$66.19	$67.19	$68.79	$71.19	$73.57	$76.19	$77.97	$82.54	$84.59	$86.07	$90.30	$93.34	$96.42	$99.41
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$54.95	$54.97	$57.71	$60.01	$61.88	$63.33	$66.23	$66.39	$69.54	$72.24	$74.63	$75.87	$79.03	$83.73	$85.81	$87.50	$91.37	$94.29	$97.43	$101.14
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$26.16	$26.94	$27.81	$28.69	$29.48	$30.11	$30.93													
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$50.37	$51.42	$53.16	$55.63	$56.88	$59.24	$61.18	$67.16	$71.01	$73.89	$76.21	$77.59	$80.46	$85.97	$87.85	$89.68	$93.82	$96.79	$99.87	$103.16
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$50.34	$51.44	$53.20	$54.89	$56.88	$59.25	$61.16	$68.32	$72.61	$75.22	$77.58	$79.28	$81.61	$85.85	$88.80	$91.10	$93.32	$98.37	$102.08	$104.76

TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2030:395	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Wind PPA :2039:394	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,714	$3,788
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$17,768	$15,878	$14,298	$16,452	$20,700	$17,774	$11,038	$10,843	$11,143	$11,364	$12,005	$12,372	$12,680	$12,996	$13,315	$13,603	$13,710	$14,014
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$24,644	$24,772	$24,902	$25,037	$25,172	$25,310	$25,453	$25,598	$25,744	$34,157	$34,383
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,024	$1,927	$1,815	$1,791	$1,774	$1,589	$1,881	$1,066	$1,086	$1,023	$1,052	$1,126	$1,157	$1,050	$1,140	$1,294	$1,056	$1,000	$949	$911
TOTAL FUEL COSTS	$000		$43,770	$43,397	$41,811	$41,572	$40,582	$34,601	$42,925	$5,282	$5,501	$5,298	$5,548	$6,034	$6,239	$6,047	$6,584	$7,412	$6,324	$6,075	$5,857	$5,705
TOTAL NET MARKET TRANSACTIONS	$000		$6,417	$4,802	$4,869	$3,821	$3,321	$11,374	$3,634	$50,332	$52,756	$51,268	$53,202	$54,712	$57,949	$61,941	$63,533	$64,775	$68,399	$71,331	$66,085	$68,354
TOTAL COSTS	$000		$75,219	$82,564	$77,573	$78,371	$79,476	$83,615	$88,836	$112,152	$108,182	$110,977	$113,616	$116,038	$120,286	$124,482	$127,147	$129,830	$132,591	$135,653	$138,657	$141,268

Rate
4%

NPV @ 4% ($000): $1,357,784 | **2020$**

(2021-2040)

2020 $

NPV

TOTAL FIXED COSTS	$200,598.56
TOTAL DEBT SERVICE COSTS	$130,605.83
TOTAL VARIABLE (EXCL. FUEL) COSTS	$18,424.84
TOTAL FUEL COSTS	$282,108.67
TOTAL NET MARKET TRANSACTIONS	$464,630.95

APPENDIX I – ECONOMIC RESULTS: LOW GAS AND MARKET PRICES

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		310	294	356	457	376	518	309	1,337	1,398	1,404	1,409	1,407	1,433	1,462	1,462	1,459	1,471	1,479	1,483	1,487
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		7,181	6,329	7,455	9,473	7,880	11,894	6,831	36,260	40,437	42,081	43,755	45,053	47,619	50,351	51,918	53,330	55,356	57,272	59,116	60,939
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT:2028:699	0	0	0	0	0	0	0	210	210	210	210	210	210	210	210	210	210	210	210	210
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	27	15	0	1	2	26	28	31	34	35	46	49	51	53	54	55	59	61
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	228	228	228	228	228	228	228	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT:2028:699	0	0	0	0	0	0	0	134	82	84	83	87	87	70	73	80	70	69	68	66
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Hargis-Hebert 1	28	16	8	5	5	5	8	6	4	4	4	2	5	4	4	4	4	4	4	2
GENERATION	GWH	Hargis-Hebert 2	4	4	3	4	3	3	4	4	2	2	2	4	2	2	2	3	2	2	2	3
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	1,586	1,499	1,348	1,186	1,167	1,001	1,229	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 1	1	1	1	2	2	2	2	2	1	1	1	2	1	1	1	2	1	1	1	2
GENERATION	GWH	TJ Labbe 2	0	1	1	2	2	2	2	1	0	0	0	1	0	1	0	1	0	0	0	1
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126

Data Item	**Units**	**Description**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0
CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	1xF SCGT:2028:699								7.31%	4.48%	4.55%	4.53%	4.72%	4.76%	3.81%	3.99%	4.35%	3.79%	3.73%	3.68%	3.60%
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	Hargis-Hebert 1	7.62%	4.18%	2.05%	1.43%	1.28%	1.45%	2.13%	1.50%	1.14%	1.16%	1.15%	0.41%	1.32%	1.21%	1.14%	1.05%	1.16%	1.21%	1.17%	0.65%
CAPACITY FACTOR	%	Hargis-Hebert 2	1.11%	0.98%	0.66%	0.99%	0.73%	0.76%	0.90%	0.88%	0.55%	0.55%	0.55%	1.03%	0.62%	0.60%	0.57%	0.71%	0.57%	0.59%	0.58%	0.76%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	79.34%	74.97%	67.44%	59.33%	58.37%	50.08%	61.50%													
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	TJ Labbe 1	0.19%	0.32%	0.32%	0.57%	0.58%	0.60%	0.58%	0.40%	0.26%	0.26%	0.26%	0.53%	0.29%	0.30%	0.29%	0.36%	0.28%	0.29%	0.29%	0.40%
CAPACITY FACTOR	%	TJ Labbe 2	0.16%	0.33%	0.34%	0.56%	0.70%	0.73%	0.65%	0.17%	0.13%	0.13%	0.13%	0.31%	0.14%	0.17%	0.16%	0.21%	0.15%	0.15%	0.16%	0.24%
O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$2,744	$2,646	$2,703	$2,756	$2,822	$2,881	$2,882	$2,950	$3,032	$3,057	$3,114	$3,173	$3,231
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	Hargis-Hebert 1	$1,222	$1,061	$965	$949	$960	$989	$1,049	$1,032	$1,030	$1,052	$1,072	$1,045	$1,127	$1,142	$1,160	$1,177	$1,208	$1,236	$1,258	$1,243
O AND M COST	$000	Hargis-Hebert 2	$882	$892	$891	$929	$931	$952	$980	$998	$996	$1,016	$1,037	$1,091	$1,083	$1,104	$1,124	$1,156	$1,169	$1,194	$1,217	$1,256
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$922	$1,023	$1,163	$1,298	$1,349	$1,805	$1,983	$2,096	$2,212	$2,328	$2,410	$2,634	$2,779
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$15,660	$21,678	$14,519	$12,829	$11,602	$13,465	$17,836	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	TJ Labbe 1	$830	$854	$872	$905	$924	$943	$961	$968	$977	$997	$1,017	$1,057	$1,060	$1,082	$1,103	$1,131	$1,147	$1,170	$1,194	$1,227
O AND M COST	$000	TJ Labbe 2	$826	$850	$868	$896	$920	$940	$955	$950	$966	$985	$1,005	$1,035	$1,047	$1,069	$1,090	$1,114	$1,133	$1,156	$1,180	$1,209
FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$2,358	$2,405	$2,453	$2,502	$2,552	$2,604	$2,656	$2,709	$2,763	$2,818	$2,875	$2,932	$2,991
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$922	$1,023	$1,163	$1,298	$1,349	$1,805	$1,983	$2,096	$2,212	$2,328	$2,410	$2,634	$2,779
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$14,137	$20,209	$13,157	$11,607	$10,365	$12,374	$16,471	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT:2028:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2.87	$2.93	$2.98	$3.04	$3.10	$3.17	$3.23	$3.29	$3.36	$3.43	$3.50	$3.57	$3.64
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$386	$241	$250	$254	$270	$277	$227	$242	$269	$239	$240	$241	$241
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$404	$226	$113	$80	$73	$85	$127	$91	$71	$73	$74	$27	$89	$83	$80	$75	$84	$89	$88	$50
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$63	$57	$39	$60	$45	$48	$58	$58	$37	$37	$38	$73	$45	$44	$43	$54	$44	$47	$47	$63
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$1,523	$1,469	$1,362	$1,222	$1,237	$1,091	$1,365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$11	$19	$20	$36	$37	$39	$39	$27	$18	$18	$19	$39	$21	$23	$23	$29	$23	$24	$24	$34
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$7	$15	$16	$27	$34	$36	$33	$9	$7	$7	$7	$17	$8	$10	$9	$12	$9	$9	$10	$16
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$4,995	$3,154	$3,337	$3,457	$3,693	$3,844	$3,168	$3,404	$3,781	$3,470	$3,539	$3,610	$3,663
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Hargis-Hebert 1	$834	$457	$241	$163	$151	$186	$276	$196	$156	$165	$170	$64	$209	$198	$192	$180	$210	$226	$227	$130
TOTAL FUEL COST	$000	Hargis-Hebert 2	$133	$115	$82	$128	$90	$100	$124	$124	$81	$85	$88	$170	$106	$106	$104	$130	$111	$120	$122	$165
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$40,360	$39,451	$36,912	$34,125	$34,258	$29,802	$37,534	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
TOTAL FUEL COST	$000	TJ Labbe 1	$22	$37	$39	$73	$73	$80	$81	$59	$40	$41	$44	$91	$51	$56	$55	$70	$57	$61	$63	$90
TOTAL FUEL COST	$000	TJ Labbe 2	$13	$28	$30	$52	$67	$73	$68	$20	$15	$16	$17	$41	$20	$24	$23	$31	$23	$25	$26	$42
TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT:2028:699								$40.01	$41.22	$42.88	$44.51	$45.60	$47.10	$48.39	$49.73	$50.66	$53.23	$55.07	$56.97	$59.04
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$43.75	$43.98	$46.48	$45.94	$47.29	$50.24	$51.05	$51.55	$53.53	$55.38	$57.27	$59.45	$60.76	$62.56	$64.11	$65.21	$68.38	$70.48	$72.64	$74.87
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$44.31	$44.03	$45.76	$47.39	$46.54	$48.64	$50.40	$51.73	$53.69	$55.55	$57.40	$58.99	$60.97	$62.70	$64.17	$65.36	$68.51	$70.70	$72.80	$75.24
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$26.41	$27.30	$28.39	$29.80	$30.42	$30.86	$31.64													
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$42.63	$42.46	$43.96	$45.85	$45.95	$47.75	$49.45	$52.41	$54.19	$56.05	$57.94	$59.26	$61.50	$63.13	$64.70	$65.78	$69.02	$71.26	$73.35	$75.64
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$41.46	$41.59	$43.02	$44.88	$45.72	$47.51	$49.00	$53.18	$54.75	$56.65	$58.63	$59.69	$62.11	$63.65	$65.47	$66.44	$69.68	$71.87	$73.99	$76.10
TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$17,428	$15,578	$13,911	$16,022	$20,237	$14,085	$7,266	$7,531	$7,793	$7,974	$8,563	$8,876	$9,126	$9,383	$9,642	$9,871	$10,244	$10,541
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336	$9,336
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$20,006	$20,113	$20,221	$20,333	$20,446	$20,562	$20,681	$20,801	$20,923	$21,049	$21,175
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,007	$1,786	$1,550	$1,425	$1,426	$1,299	$1,621	$570	$373	$385	$392	$426	$440	$387	$396	$439	$399	$410	$411	$404
TOTAL FUEL COSTS	$000		$41,362	$40,087	$37,303	$34,542	$34,640	$30,241	$38,083	$5,394	$3,446	$3,643	$3,776	$4,058	$4,230	$3,552	$3,778	$4,191	$3,871	$3,970	$4,048	$4,091
TOTAL NET MARKET TRANSACTIONS	$000		$7,181	$6,329	$7,455	$9,473	$7,880	$11,894	$6,831	$36,260	$40,437	$42,081	$43,755	$45,053	$47,619	$50,351	$51,918	$53,330	$55,356	$57,272	$59,116	$60,939
TOTAL COSTS	$000		$73,557	$80,640	$75,046	$76,327	$77,358	$79,056	$86,469	$85,444	$80,759	$82,983	$85,166	$87,069	$90,521	$92,948	$95,116	$97,360	$99,406	$101,782	$104,204	$106,486

Rate
4%

NPV @ 4% ($000): $1,121,272 **2020$**
(2021-2040)

2020 $

NPV

TOTAL FIXED COSTS	$173,300.96
TOTAL DEBT SERVICE COSTS	$68,119.33
TOTAL VARIABLE (EXCL. FUEL) COSTS	$12,303.29
TOTAL FUEL COSTS	$241,643.53
TOTAL NET MARKET TRANSACTIONS	$399,983.47

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		310	294	356	457	376	518	309	674	703	708	723	723	747	790	775	733	820	842	860	878
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		7,181	6,329	7,455	9,473	7,880	11,894	6,831	15,967	18,601	19,444	20,608	21,198	22,905	25,645	25,914	25,230	29,115	30,729	32,337	33,949
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT:2028:699	0	0	0	0	0	0	0	191	191	191	191	191	191	191	191	191	191	191	191	191
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	27	15	0	1	2	45	47	51	54	54	65	69	70	72	74	75	79	81
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	228	228	228	228	228	228	228	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1x1 CCGT:2028:699	0	0	0	0	0	0	0	758	739	741	732	733	735	705	723	763	684	671	656	641
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Hargis-Hebert 1	28	16	8	5	5	5	8	25	30	30	29	13	30	29	30	27	28	28	27	17
GENERATION	GWH	Hargis-Hebert 2	4	4	3	4	3	3	4	18	12	12	12	22	12	12	12	16	11	11	11	16
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	1,586	1,499	1,348	1,186	1,167	1,001	1,229	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 1	1	1	1	2	2	2	2	7	4	4	4	9	4	4	4	6	4	4	4	6
GENERATION	GWH	TJ Labbe 2	0	1	1	2	2	2	2	2	1	1	1	3	1	1	1	1	1	1	1	2
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126

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Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0
CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1x1 CCGT:2028:699								45.42%	44.30%	44.38%	43.84%	43.90%	44.05%	42.23%	43.31%	45.71%	40.99%	40.20%	39.30%	38.43%
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	Hargis-Hebert 1	7.62%	4.18%	2.05%	1.43%	1.28%	1.45%	2.13%	6.69%	8.03%	8.10%	7.92%	3.44%	8.16%	7.81%	8.02%	7.40%	7.54%	7.42%	7.29%	4.59%
CAPACITY FACTOR	%	Hargis-Hebert 2	1.11%	0.98%	0.66%	0.99%	0.73%	0.76%	0.90%	4.47%	3.00%	3.02%	2.93%	5.54%	3.04%	2.96%	3.03%	4.12%	2.81%	2.79%	2.75%	4.01%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	79.34%	74.97%	67.44%	59.33%	58.37%	50.08%	61.50%													
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	TJ Labbe 1	0.19%	0.32%	0.32%	0.57%	0.58%	0.60%	0.58%	1.60%	0.91%	0.91%	0.88%	2.13%	0.94%	0.95%	0.96%	1.43%	0.90%	0.92%	0.93%	1.54%
CAPACITY FACTOR	%	TJ Labbe 2	0.16%	0.33%	0.34%	0.56%	0.70%	0.73%	0.65%	0.56%	0.26%	0.25%	0.25%	0.81%	0.28%	0.30%	0.29%	0.47%	0.29%	0.32%	0.35%	0.65%
O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$5,985	$6,031	$6,156	$6,242	$6,372	$6,510	$6,507	$6,717	$7,035	$6,809	$6,882	$6,948	$7,015
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	Hargis-Hebert 1	$1,222	$1,061	$965	$949	$960	$989	$1,049	$1,348	$1,458	$1,491	$1,510	$1,245	$1,587	$1,595	$1,641	$1,630	$1,673	$1,697	$1,721	$1,547
O AND M COST	$000	Hargis-Hebert 2	$882	$892	$891	$929	$931	$952	$980	$1,233	$1,160	$1,184	$1,202	$1,411	$1,258	$1,277	$1,308	$1,418	$1,344	$1,369	$1,393	$1,525
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$1,618	$1,734	$1,887	$2,037	$2,103	$2,574	$2,768	$2,896	$3,028	$3,160	$3,259	$3,500	$3,662
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$15,660	$21,678	$14,519	$12,829	$11,602	$13,465	$17,836	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	TJ Labbe 1	$830	$854	$872	$905	$924	$943	$961	$1,050	$1,023	$1,043	$1,062	$1,175	$1,109	$1,132	$1,155	$1,216	$1,197	$1,223	$1,248	$1,326
O AND M COST	$000	TJ Labbe 2	$826	$850	$868	$896	$920	$940	$955	$969	$973	$992	$1,012	$1,063	$1,054	$1,077	$1,098	$1,131	$1,142	$1,167	$1,192	$1,236
FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$3,035	$3,096	$3,158	$3,221	$3,286	$3,351	$3,418	$3,487	$3,557	$3,628	$3,700	$3,774	$3,850
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$1,618	$1,734	$1,887	$2,037	$2,103	$2,574	$2,768	$2,896	$3,028	$3,160	$3,259	$3,500	$3,662
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$14,137	$20,209	$13,157	$11,607	$10,365	$12,374	$16,471	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT:2028:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3.89	$3.97	$4.05	$4.13	$4.21	$4.30	$4.38	$4.47	$4.56	$4.65	$4.74	$4.84	$4.94
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$2,950	$2,934	$2,998	$3,021	$3,086	$3,158	$3,088	$3,230	$3,478	$3,181	$3,182	$3,173	$3,166
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$404	$226	$113	$80	$73	$85	$127	$407	$498	$513	$512	$226	$548	$535	$560	$527	$549	$551	$552	$354
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$63	$57	$39	$60	$45	$48	$58	$292	$200	$206	$204	$393	$219	$218	$227	$316	$220	$222	$224	$332
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$1,523	$1,469	$1,362	$1,222	$1,237	$1,091	$1,365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$11	$19	$20	$36	$37	$39	$39	$109	$63	$65	$64	$157	$71	$73	$75	$114	$73	$76	$79	$133
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$7	$15	$16	$27	$34	$36	$33	$29	$14	$14	$13	$45	$16	$17	$17	$29	$18	$20	$22	$43
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1x1 CCGT:2028:699	$0	$0	$0	$0	$0	$0	$0	$16,972	$17,350	$18,050	$18,584	$19,246	$19,933	$19,836	$20,819	$22,273	$21,279	$21,625	$21,884	$22,139
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Hargis-Hebert 1	$834	$457	$241	$163	$151	$186	$276	$889	$1,111	$1,164	$1,186	$534	$1,306	$1,294	$1,361	$1,272	$1,383	$1,410	$1,433	$932
TOTAL FUEL COST	$000	Hargis-Hebert 2	$133	$115	$82	$128	$90	$100	$124	$641	$454	$475	$480	$927	$531	$536	$561	$772	$563	$577	$589	$883
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$40,360	$39,451	$36,912	$34,125	$34,258	$29,802	$37,534	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	TJ Labbe 1	$22	$37	$39	$73	$73	$80	$81	$244	$148	$153	$154	$377	$176	$182	$189	$286	$191	$201	$211	$359
TOTAL FUEL COST	$000	TJ Labbe 2	$13	$28	$30	$52	$67	$73	$68	$66	$32	$33	$33	$111	$40	$44	$44	$73	$48	$54	$60	$117
TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				
TOTAL VARIABLE COST	$/MWH	1x1 CCGT:2028:699								$26.28	$27.44	$28.42	$29.53	$30.48	$31.41	$32.53	$33.28	$33.76	$35.76	$36.98	$38.20	$39.45
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$43.75	$43.98	$46.48	$45.94	$47.29	$50.24	$51.05	$52.16	$53.96	$55.75	$57.72	$59.57	$61.20	$63.03	$64.53	$65.50	$68.95	$71.11	$73.29	$75.44
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$44.31	$44.03	$45.76	$47.39	$46.54	$48.64	$50.40	$52.30	$54.60	$56.43	$58.40	$59.60	$61.85	$63.74	$65.25	$66.14	$69.67	$71.82	$73.96	$75.96

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$26.41	$27.30	$28.39	$29.80	$30.42	$30.86	$31.64													
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$42.63	$42.46	$43.96	$45.85	$45.95	$47.75	$49.45	$53.03	$55.56	$57.45	$59.44	$60.37	$62.88	$64.71	$66.34	$67.31	$70.69	$72.78	$74.84	$76.84
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$41.46	$41.59	$43.02	$44.88	$45.72	$47.51	$49.00	$53.74	$56.42	$58.35	$60.40	$61.16	$63.85	$65.58	$67.33	$68.31	$71.38	$73.24	$75.18	$77.43

TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$17,428	$15,578	$13,911	$16,022	$20,237	$15,459	$8,668	$8,960	$9,251	$9,461	$10,080	$10,423	$10,705	$10,993	$11,285	$11,546	$11,953	$12,284
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843	$13,843
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$20,006	$20,113	$20,221	$20,333	$20,446	$20,562	$20,681	$20,801	$20,923	$21,049	$21,175
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,007	$1,786	$1,550	$1,425	$1,426	$1,299	$1,621	$3,787	$3,710	$3,795	$3,814	$3,907	$4,013	$3,932	$4,110	$4,464	$4,041	$4,051	$4,050	$4,028
TOTAL FUEL COSTS	$000		$41,362	$40,087	$37,303	$34,542	$34,640	$30,241	$38,083	$18,811	$19,095	$19,876	$20,438	$21,194	$21,985	$21,891	$22,974	$24,676	$23,465	$23,867	$24,176	$24,429
TOTAL NET MARKET TRANSACTIONS	$000		$7,181	$6,329	$7,455	$9,473	$7,880	$11,894	$6,831	$15,967	$18,601	$19,444	$20,608	$21,198	$22,905	$25,645	$25,914	$25,230	$29,115	$30,729	$32,337	$33,949
TOTAL COSTS	$000		$73,557	$80,640	$75,046	$76,327	$77,358	$79,056	$86,469	$87,665	$83,818	$85,925	$88,066	$89,825	$93,159	$96,181	$98,107	$99,887	$102,550	$104,959	$107,408	$109,707

Rate
4%

NPV @ 4% ($000): $1,142,426 **2020$**

(2021-2040)

2020 $

NPV

TOTAL FIXED COSTS	$184,500.27
TOTAL DEBT SERVICE COSTS	$101,004.27
TOTAL VARIABLE (EXCL. FUEL) COSTS	$38,118.51
TOTAL FUEL COSTS	$371,313.62
TOTAL NET MARKET TRANSACTIONS	$221,567.77

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		310	294	1,115	1,238	1,122	1,117	1,038	1,345	1,402	1,408	1,415	1,413	1,438	1,464	1,465	1,461	1,473	1,483	1,485	1,493
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		7,181	6,329	24,610	26,755	25,034	26,281	24,881	36,505	40,506	42,222	43,943	45,312	47,786	50,373	51,933	53,320	55,392	57,405	59,077	61,177
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	27	15	0	1	2	17	19	22	25	26	37	40	42	44	45	46	50	52
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION:2021:700	228	228	228	228	228	228	228	219	219	219	219	219	219	219	219	219	219	219	219	219
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Hargis-Hebert 1	28	16	6	3	3	4	6	2	2	3	3	1	3	4	4	4	4	4	4	2
GENERATION	GWH	Hargis-Hebert 2	4	4	1	2	1	1	2	0	0	0	1	2	0	1	1	2	1	1	1	2
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION:2021:700	1,586	1,499	571	332	340	345	432	135	85	83	82	86	88	71	73	80	69	67	68	63
GENERATION	GWH	TJ Labbe 1	1	1	1	0	1	1	1	0	0	0	0	0	0	0	0	1	0	0	0	1
GENERATION	GWH	TJ Labbe 2	0	1	1	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0
CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	Hargis-Hebert 1	7.62%	4.18%	1.56%	0.88%	0.90%	1.04%	1.53%	0.48%	0.62%	0.75%	0.77%	0.28%	0.75%	1.00%	1.05%	0.97%	1.14%	1.11%	1.15%	0.49%
CAPACITY FACTOR	%	Hargis-Hebert 2	1.11%	0.98%	0.20%	0.42%	0.25%	0.31%	0.39%	0.07%	0.06%	0.12%	0.13%	0.41%	0.11%	0.29%	0.30%	0.48%	0.33%	0.29%	0.37%	0.57%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION:2021:700	79.34%	74.97%	28.58%	16.60%	16.99%	17.27%	21.63%	7.06%	4.41%	4.35%	4.28%	4.47%	4.58%	3.69%	3.82%	4.16%	3.60%	3.50%	3.54%	3.27%
CAPACITY FACTOR	%	TJ Labbe 1	0.19%	0.32%	0.16%	0.11%	0.18%	0.22%	0.20%	0.05%	0.00%	0.01%	0.01%	0.08%	0.03%	0.09%	0.08%	0.14%	0.08%	0.08%	0.11%	0.20%
CAPACITY FACTOR	%	TJ Labbe 2	0.16%	0.33%	0.20%	0.09%	0.24%	0.28%	0.25%	0.06%	0.00%	0.00%	0.00%	0.05%	0.02%	0.03%	0.02%	0.04%	0.03%	0.03%	0.03%	0.07%
O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	Hargis-Hebert 1	$1,222	$1,061	$938	$918	$938	$965	$1,014	$970	$998	$1,026	$1,048	$1,036	$1,089	$1,128	$1,154	$1,171	$1,207	$1,229	$1,257	$1,231
O AND M COST	$000	Hargis-Hebert 2	$882	$892	$864	$894	$902	$923	$947	$945	$963	$987	$1,007	$1,047	$1,047	$1,081	$1,103	$1,139	$1,150	$1,170	$1,200	$1,240
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$598	$693	$825	$954	$998	$1,447	$1,618	$1,723	$1,832	$1,940	$2,015	$2,231	$2,367
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$15,660	$21,678	$20,484	$11,949	$10,725	$27,250	$31,451	$35,388	$7,342	$5,446	$5,460	$24,662	$5,786	$8,815	$10,275	$6,131	$6,135	$6,326	$6,352	$6,472
O AND M COST	$000	TJ Labbe 1	$830	$854	$862	$876	$898	$918	$936	$944	$960	$979	$999	$1,024	$1,041	$1,066	$1,086	$1,114	$1,131	$1,153	$1,178	$1,210
O AND M COST	$000	TJ Labbe 2	$826	$850	$861	$873	$898	$918	$935	$944	$960	$979	$998	$1,021	$1,040	$1,061	$1,082	$1,104	$1,126	$1,148	$1,172	$1,197
FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$598	$693	$825	$954	$998	$1,447	$1,618	$1,723	$1,832	$1,940	$2,015	$2,231	$2,367
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$14,137	$20,209	$19,907	$11,607	$10,365	$26,874	$30,971	$35,234	$7,243	$5,346	$5,359	$24,554	$5,673	$8,722	$10,175	$6,020	$6,036	$6,228	$6,250	$6,375
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION:2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$1.14	$1.17	$1.20	$1.23	$1.26	$1.29	$1.32	$1.36	$1.39	$1.43	$1.46	$1.50	$1.54
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$404	$226	$86	$49	$52	$61	$91	$29	$38	$48	$50	$18	$50	$69	$74	$69	$83	$82	$87	$38
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$63	$57	$12	$25	$16	$19	$25	$5	$4	$8	$9	$29	$8	$21	$22	$37	$26	$23	$30	$47
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$1,523	$1,469	$577	$342	$360	$376	$480	$154	$99	$100	$101	$108	$113	$93	$100	$111	$99	$98	$102	$97
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$11	$19	$10	$7	$12	$14	$13	$3	$0	$1	$1	$6	$2	$7	$6	$11	$7	$7	$9	$17
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$7	$15	$9	$4	$11	$14	$13	$3	$0	$0	$0	$3	$1	$2	$1	$2	$2	$2	$2	$4
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Hargis-Hebert 1	$834	$457	$198	$110	$114	$142	$208	$71	$94	$114	$121	$45	$132	$170	$182	$168	$211	$214	$228	$102
TOTAL FUEL COST	$000	Hargis-Hebert 2	$133	$115	$23	$60	$34	$43	$57	$11	$10	$21	$23	$74	$21	$53	$57	$91	$68	$61	$80	$127
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION:2021:700	$40,360	$39,451	$15,060	$8,984	$9,526	$9,927	$12,757	$5,273	$3,429	$3,520	$3,604	$3,872	$4,102	$3,414	$3,632	$4,028	$3,681	$3,707	$3,894	$3,723
TOTAL FUEL COST	$000	TJ Labbe 1	$22	$37	$18	$14	$23	$29	$28	$7	$0	$2	$2	$16	$5	$16	$15	$29	$18	$18	$24	$47
TOTAL FUEL COST	$000	TJ Labbe 2	$13	$28	$18	$8	$22	$28	$26	$6	$0	$0	$0	$6	$3	$4	$3	$6	$4	$4	$6	$13
TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$43.75	$43.98	$48.95	$48.79	$49.52	$52.24	$52.56	$56.27	$57.51	$57.92	$59.84	$61.00	$65.61	$64.01	$65.50	$65.95	$69.39	$71.97	$73.58	$76.51
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$44.31	$44.03	$44.16	$50.69	$48.70	$50.57	$52.79	$54.54	$62.07	$60.27	$62.19	$63.06	$65.37	$64.29	$66.34	$66.59	$70.51	$72.92	$74.57	$76.49
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION:2021:700	$26.41	$27.30	$27.37	$28.11	$29.12	$29.85	$30.61	$40.07	$41.70	$43.40	$45.12	$46.45	$47.96	$49.55	$50.87	$51.82	$54.80	$56.73	$58.83	$60.79
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$42.63	$42.46	$42.49	$47.16	$45.73	$47.65	$49.55	$50.80	$55.35	$61.41	$62.30	$62.51	$61.60	$64.32	$67.19	$67.91	$70.42	$72.22	$74.99	$77.75
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$41.46	$41.59	$42.52	$43.77	$45.58	$47.52	$48.93	$50.47	$52.38	$61.53	$62.90	$58.30	$59.76	$64.81	$67.98	$68.85	$71.01	$73.53	$75.49	$78.85
TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$24,178	$15,578	$13,911	$30,522	$34,737	$39,594	$11,773	$10,086	$10,306	$29,624	$11,274	$14,577	$16,220	$12,260	$12,473	$12,829	$13,159	$13,514
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$20,006	$20,113	$20,221	$20,333	$20,446	$20,562	$20,681	$20,801	$20,923	$21,049	$21,175
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,007	$1,786	$694	$427	$450	$485	$622	$194	$141	$157	$160	$164	$175	$192	$203	$231	$216	$212	$230	$203
TOTAL FUEL COSTS	$000		$41,362	$40,087	$15,317	$9,176	$9,719	$10,168	$13,075	$5,368	$3,533	$3,658	$3,750	$4,012	$4,263	$3,657	$3,890	$4,322	$3,982	$4,004	$4,232	$4,010
TOTAL NET MARKET TRANSACTIONS	$000		$7,181	$6,329	$24,610	$26,755	$25,034	$26,281	$24,881	$36,505	$40,506	$42,222	$43,943	$45,312	$47,786	$50,373	$51,933	$53,320	$55,392	$57,405	$59,077	$61,177
TOTAL COSTS	$000		$73,557	$80,640	$76,110	$67,245	$68,617	$87,054	$93,012	$101,460	$75,854	$76,129	$78,272	$99,334	$83,832	$89,245	$92,807	$90,814	$92,863	$95,372	$97,748	$100,080

Rate
4%

NPV @ 4% ($000):	$1,102,673	2020$
	(2021-2040)	

2020 $

NPV

TOTAL FIXED COSTS	$253,316.00
TOTAL DEBT SERVICE COSTS	$0.00
TOTAL VARIABLE (EXCL. FUEL) COSTS	$6,935.30
TOTAL FUEL COSTS	$149,107.32
TOTAL NET MARKET TRANSACTIONS	$467,392.77

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Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY REQUIREMENTS	GWH		2,084	2,092	2,099	2,106	2,112	2,118	2,124	2,130	2,135	2,141	2,146	2,150	2,155	2,159	2,163	2,167	2,171	2,175	2,179	2,182
PEAK DEMAND	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
COINCIDENT PEAK DEMAND (92.7% Coincidence Factor)	MW		449	451	451	453	454	455	457	458	459	460	461	462	463	464	464	464	465	466	467	467
REQUIRED RESERVES (7.9% Reserve Margin)	MW		35	36	36	36	36	36	36	36	36	36	36	36	37	37	37	37	37	37	37	37
TOTAL CAPACITY RESPONSIBILITY	MW		484	486	487	489	490	491	493	494	495	496	497	498	499	500	500	501	502	503	504	504
TOTAL FIRM RESOURCES	MW		485	487	488	490	491	492	494	495	496	497	498	499	500	501	501	502	503	504	505	505
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		310	294	356	457	376	518	309	1,311	1,378	1,382	1,386	1,378	1,403	1,444	1,441	1,430	1,451	1,459	1,464	1,467
ECONOMY INTERCHANGE SALES ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECONOMY INTERCHANGE PURCHASE COST	$000		7,181	6,329	7,455	9,473	7,880	11,894	6,831	35,332	39,702	41,267	42,865	43,904	46,389	49,589	50,946	52,018	54,400	56,289	58,131	59,860
ECONOMY INTERCHANGE SALES COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY ENERGY	GWH		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMERGENCY COST	$000		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	50 MW Solar PPA :2021:400	19	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2022:399	0	19	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2023:398	0	0	18	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2024:397	0	0	0	17	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Solar PPA :2025:396	0	0	0	0	17	17	17	16	16	16	15	15	15	14	14	14	13	13	13	12
FIRM CAPACITY	MW	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	5x 18MW Recips :2028:698	0	0	0	0	0	0	0	87	87	87	87	87	87	87	87	87	87	87	87	87
FIRM CAPACITY	MW	5x 18MW Recips :2028:699	0	0	0	0	0	0	0	87	87	87	87	87	87	87	87	87	87	87	87	87
FIRM CAPACITY	MW	Hargis-Hebert 1	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
FIRM CAPACITY	MW	Hargis-Hebert 2	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
FIRM CAPACITY	MW	MARKET CAPACITY	60	43	27	15	0	1	2	62	64	67	70	71	82	85	87	89	90	91	95	97
FIRM CAPACITY	MW	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	228	228	228	228	228	228	228	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	SWPA Contract	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0
FIRM CAPACITY	MW	TJ Labbe 1	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
FIRM CAPACITY	MW	TJ Labbe 2	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
GENERATION	GWH	1x1 CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	1xF SCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	5x 18MW Recips :2028:698	0	0	0	0	0	0	0	100	64	66	66	71	72	51	55	65	52	51	50	49
GENERATION	GWH	5x 18MW Recips :2028:699	0	0	0	0	0	0	0	61	39	40	40	44	44	34	36	40	35	34	34	34
GENERATION	GWH	Hargis-Hebert 1	28	16	8	5	5	5	8	7	6	6	6	2	7	7	7	6	7	7	7	4
GENERATION	GWH	Hargis-Hebert 2	4	4	3	4	3	3	4	3	2	2	2	5	2	3	3	4	3	3	3	4
GENERATION	GWH	MARKET CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	Rodemacher 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2022 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	1,586	1,499	1,348	1,186	1,167	1,001	1,229	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - END OF 2028 RETIREMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	RODEMACHER 2 - NG CONVERSION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION	GWH	TJ Labbe 1	1	1	1	2	2	2	2	0	0	0	0	2	1	1	1	1	1	1	1	2
GENERATION	GWH	TJ Labbe 2	0	1	1	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2021:400	126	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2022:399	0	126	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126

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Economic Results Low Fuel and Market Prices

Data Item	Units	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2023:398	0	0	126	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2024:397	0	0	0	126	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Solar PPA :2025:396	0	0	0	0	125	126	126	126	126	125	125	126	126	126	126	126	126	126	126	126
ENERGY TAKEN OR SOLD	GWH	50 MW Wind PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY TAKEN OR SOLD	GWH	SWPA Contract	28	28	28	28	28	28	28	28	28	28	28	28	7	0	0	0	0	0	0	0
CAPACITY FACTOR	%	1x1 CCGT																				
CAPACITY FACTOR	%	1xF SCGT																				
CAPACITY FACTOR	%	5x 18MW Recips																				
CAPACITY FACTOR	%	5x 18MW Recips :2028:698								13.12%	8.34%	8.61%	8.60%	9.35%	9.45%	6.70%	7.25%	8.48%	6.84%	6.69%	6.57%	6.44%
CAPACITY FACTOR	%	5x 18MW Recips :2028:699								8.04%	5.07%	5.20%	5.29%	5.75%	5.74%	4.44%	4.78%	5.30%	4.53%	4.52%	4.40%	4.43%
CAPACITY FACTOR	%	Hargis-Hebert 1	7.62%	4.18%	2.05%	1.43%	1.28%	1.45%	2.13%	2.00%	1.66%	1.61%	1.63%	0.51%	1.91%	1.87%	1.92%	1.70%	1.89%	1.89%	1.87%	1.11%
CAPACITY FACTOR	%	Hargis-Hebert 2	1.11%	0.98%	0.66%	0.99%	0.73%	0.76%	0.90%	0.65%	0.43%	0.42%	0.43%	1.33%	0.55%	0.74%	0.71%	0.98%	0.68%	0.70%	0.71%	1.11%
CAPACITY FACTOR	%	MARKET CAPACITY	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Rodemacher 2																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2022 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	79.34%	74.97%	67.44%	59.33%	58.37%	50.08%	61.50%													
CAPACITY FACTOR	%	RODEMACHER 2 - END OF 2028 RETIREMENT																				
CAPACITY FACTOR	%	RODEMACHER 2 - NG CONVERSION																				
CAPACITY FACTOR	%	TJ Labbe 1	0.19%	0.32%	0.32%	0.57%	0.58%	0.60%	0.58%	0.12%	0.09%	0.09%	0.09%	0.37%	0.13%	0.28%	0.24%	0.35%	0.22%	0.25%	0.27%	0.44%
CAPACITY FACTOR	%	TJ Labbe 2	0.16%	0.33%	0.34%	0.56%	0.70%	0.73%	0.65%	0.01%	0.02%	0.02%	0.02%	0.10%	0.02%	0.10%	0.08%	0.12%	0.08%	0.10%	0.11%	0.21%
O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$2,874	$2,661	$2,730	$2,784	$2,885	$2,949	$2,835	$2,928	$3,066	$3,019	$3,069	$3,121	$3,175
O AND M COST	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$2,593	$2,476	$2,533	$2,589	$2,668	$2,721	$2,694	$2,770	$2,859	$2,865	$2,922	$2,972	$3,033
O AND M COST	$000	Hargis-Hebert 1	$1,222	$1,061	$965	$949	$960	$989	$1,049	$1,063	$1,063	$1,080	$1,103	$1,052	$1,167	$1,188	$1,214	$1,223	$1,261	$1,287	$1,311	$1,279
O AND M COST	$000	Hargis-Hebert 2	$882	$892	$891	$929	$931	$952	$980	$983	$988	$1,007	$1,028	$1,112	$1,079	$1,114	$1,134	$1,177	$1,178	$1,202	$1,227	$1,285
O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$2,209	$2,337	$2,502	$2,664	$2,742	$3,227	$3,433	$3,574	$3,720	$3,866	$3,979	$4,235	$4,411
O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$15,660	$21,678	$14,519	$12,829	$11,602	$13,465	$17,836	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O AND M COST	$000	TJ Labbe 1	$830	$854	$872	$905	$924	$943	$961	$949	$966	$985	$1,004	$1,046	$1,048	$1,080	$1,099	$1,130	$1,142	$1,168	$1,192	$1,231
O AND M COST	$000	TJ Labbe 2	$826	$850	$868	$896	$920	$940	$955	$941	$960	$979	$999	$1,024	$1,040	$1,065	$1,085	$1,110	$1,129	$1,153	$1,177	$1,207
FIXED O AND M COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$2,146	$2,189	$2,232	$2,277	$2,322	$2,369	$2,416	$2,465	$2,514	$2,564	$2,615	$2,668	$2,721
FIXED O AND M COST	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$2,146	$2,189	$2,232	$2,277	$2,322	$2,369	$2,416	$2,465	$2,514	$2,564	$2,616	$2,668	$2,721
FIXED O AND M COST	$000	Hargis-Hebert 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	Hargis-Hebert 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	MARKET CAPACITY	$1,858	$1,382	$863	$495	$0	$31	$77	$2,209	$2,337	$2,502	$2,664	$2,742	$3,227	$3,433	$3,574	$3,720	$3,866	$3,979	$4,235	$4,411
FIXED O AND M COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$14,137	$20,209	$13,157	$11,607	$10,365	$12,374	$16,471	$7,043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O AND M COST	$000	TJ Labbe 1	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
FIXED O AND M COST	$000	TJ Labbe 2	$819	$835	$852	$869	$886	$904	$922	$941	$959	$979	$998	$1,018	$1,039	$1,059	$1,080	$1,102	$1,124	$1,147	$1,170	$1,193
LEVELIZED FIXED COST	$000	1x1 CCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	1xF SCGT:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	25 MW Battery:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	**Units**	**Description**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
LEVELIZED FIXED COST	$000	50 MW Solar PPA:LUS	$2,842	$5,682	$8,519	$11,513	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662	$14,662
LEVELIZED FIXED COST	$000	50 MW Wind PPA:LUS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	5x 18MW Recips:LUS	$0	$0	$0	$0	$0	$0	$0	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900
LEVELIZED FIXED COST	$000	RPS2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LEVELIZED FIXED COST	$000	RPS2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$/MWH	1x1 CCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	1xF SCGT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips :2028:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.29	$7.44	$7.58	$7.74	$7.89	$8.05	$8.21	$8.37	$8.54	$8.71	$8.89	$9.06	$9.25
VARIABLE O AND M COSTS	$/MWH	5x 18MW Recips :2028:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.29	$7.44	$7.58	$7.74	$7.89	$8.05	$8.21	$8.37	$8.54	$8.71	$8.89	$9.06	$9.25
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	Hargis-Hebert 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	MARKET CAPACITY	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Rodemacher 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$0.96	$0.98	$1.01	$1.03	$1.06	$1.09	$1.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	RODEMACHER 2 - NG CONVERSION	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 1	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$/MWH	TJ Labbe 2	$14.26	$14.55	$14.84	$15.14	$15.44	$15.75	$16.06	$16.38	$16.71	$17.05	$17.39	$17.74	$18.09	$18.45	$18.82	$19.20	$19.58	$19.97	$20.37	$20.78
VARIABLE O AND M COSTS	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$729	$472	$498	$507	$562	$580	$419	$463	$552	$454	$453	$454	$454
VARIABLE O AND M COSTS	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$447	$287	$301	$312	$346	$352	$278	$305	$345	$301	$306	$304	$312
VARIABLE O AND M COSTS	$000	Hargis-Hebert 1	$404	$226	$113	$80	$73	$85	$127	$122	$103	$102	$105	$33	$128	$128	$134	$121	$137	$140	$141	$86
VARIABLE O AND M COSTS	$000	Hargis-Hebert 2	$63	$57	$39	$60	$45	$48	$58	$43	$29	$29	$30	$94	$40	$54	$53	$75	$53	$56	$58	$92
VARIABLE O AND M COSTS	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$1,523	$1,469	$1,362	$1,222	$1,237	$1,091	$1,365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE O AND M COSTS	$000	TJ Labbe 1	$11	$19	$20	$36	$37	$39	$39	$8	$6	$6	$6	$27	$10	$21	$19	$28	$18	$21	$22	$38
VARIABLE O AND M COSTS	$000	TJ Labbe 2	$7	$15	$16	$27	$34	$36	$33	$1	$1	$1	$1	$6	$1	$6	$5	$7	$5	$6	$7	$14
TOTAL FUEL COST	$000	1x1 CCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	1xF SCGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	5x 18MW Recips :2028:698	$0	$0	$0	$0	$0	$0	$0	$2,823	$1,873	$2,011	$2,091	$2,352	$2,461	$1,807	$2,004	$2,376	$2,044	$2,072	$2,104	$2,132
TOTAL FUEL COST	$000	5x 18MW Recips :2028:699	$0	$0	$0	$0	$0	$0	$0	$1,743	$1,146	$1,224	$1,295	$1,459	$1,506	$1,206	$1,329	$1,499	$1,359	$1,407	$1,419	$1,475
TOTAL FUEL COST	$000	Hargis-Hebert 1	$834	$457	$241	$163	$151	$186	$276	$273	$235	$236	$249	$80	$310	$311	$328	$294	$347	$360	$369	$227
TOTAL FUEL COST	$000	Hargis-Hebert 2	$133	$115	$82	$128	$90	$100	$124	$98	$67	$68	$72	$226	$98	$132	$131	$184	$136	$144	$151	$246
TOTAL FUEL COST	$000	MARKET CAPACITY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	Rodemacher 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2022 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$40,360	$39,451	$36,912	$34,125	$34,258	$29,802	$37,534	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - END OF 2028 RETIREMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	RODEMACHER 2 - NG CONVERSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$000	TJ Labbe 1	$22	$37	$39	$73	$73	$80	$81	$19	$15	$15	$16	$67	$24	$52	$47	$69	$47	$55	$59	$103

Appendix I
Economic Results Low Fuel and Market Prices

Data Item	**Units**	**Description**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
TOTAL FUEL COST	$000	TJ Labbe 2	$13	$28	$30	$52	$67	$73	$68	$2	$2	$2	$2	$14	$3	$15	$12	$19	$12	$17	$19	$37

TOTAL VARIABLE COST	$/MWH	1x1 CCGT																				
TOTAL VARIABLE COST	$/MWH	1xF SCGT																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips																				
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips :2028:698								$35.53	$36.91	$38.23	$39.62	$40.91	$42.19	$43.61	$44.63	$45.32	$47.90	$49.50	$51.10	$52.68
TOTAL VARIABLE COST	$/MWH	5x 18MW Recips :2028:699								$35.71	$37.12	$38.46	$39.85	$41.17	$42.45	$43.84	$44.87	$45.63	$48.11	$49.73	$51.35	$52.94
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 1	$43.75	$43.98	$46.48	$45.94	$47.29	$50.24	$51.05	$53.00	$54.72	$56.67	$58.57	$60.36	$61.91	$63.20	$64.86	$65.82	$69.08	$71.34	$73.47	$75.70
TOTAL VARIABLE COST	$/MWH	Hargis-Hebert 2	$44.31	$44.03	$45.76	$47.39	$46.54	$48.64	$50.40	$53.74	$55.61	$57.54	$59.51	$60.30	$62.59	$63.41	$65.28	$66.37	$69.59	$71.66	$73.76	$76.23
TOTAL VARIABLE COST	$/MWH	MARKET CAPACITY																				
TOTAL VARIABLE COST	$/MWH	Rodemacher 2																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2022 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2027 RETIREMENT :2021:700	$26.41	$27.30	$28.39	$29.80	$30.42	$30.86	$31.64													
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - END OF 2028 RETIREMENT																				
TOTAL VARIABLE COST	$/MWH	RODEMACHER 2 - NG CONVERSION																				
TOTAL VARIABLE COST	$/MWH	TJ Labbe 1	$42.63	$42.46	$43.96	$45.85	$45.95	$47.75	$49.45	$55.34	$56.79	$58.86	$60.90	$61.16	$64.02	$64.11	$66.28	$67.27	$70.35	$72.03	$74.15	$76.82
TOTAL VARIABLE COST	$/MWH	TJ Labbe 2	$41.46	$41.59	$43.02	$44.88	$45.72	$47.51	$49.00	$57.03	$57.93	$59.94	$62.11	$61.93	$65.79	$65.04	$67.59	$68.44	$71.05	$72.47	$74.51	$77.36

TOTAL COST OR REVENUE	$000	50 MW Solar PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2021:400	$894	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2022:399	$0	$912	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2023:398	$0	$0	$930	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2024:397	$0	$0	$0	$949	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Solar PPA :2025:396	$0	$0	$0	$0	$968	$987	$1,007	$1,027	$1,048	$1,069	$1,090	$1,112	$1,134	$1,157	$1,180	$1,204	$1,228	$1,252	$1,277	$1,303
TOTAL COST OR REVENUE	$000	50 MW Wind PPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL COST OR REVENUE	$000	SWPA Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SUMMARY OF COSTS

TOTAL FIXED COSTS	$000		$19,271	$24,932	$17,428	$15,578	$13,911	$16,022	$20,237	$17,306	$10,551	$10,881	$11,211	$11,460	$12,118	$12,503	$12,826	$13,156	$13,491	$13,797	$14,249	$14,625
TOTAL EXISTING DEBT SERVICE COSTS	$000	Information Not Included in Analysis																				
TOTAL NEW DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900	$17,900
TOTAL PPA COSTS	$000		$3,736	$7,507	$11,310	$15,309	$19,502	$19,599	$19,697	$19,798	$19,901	$20,006	$20,113	$20,221	$20,333	$20,446	$20,562	$20,681	$20,801	$20,923	$21,049	$21,175
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$2,007	$1,786	$1,550	$1,425	$1,426	$1,299	$1,621	$1,349	$899	$935	$962	$1,069	$1,111	$907	$978	$1,128	$968	$982	$987	$996
TOTAL FUEL COSTS	$000		$41,362	$40,087	$37,303	$34,542	$34,640	$30,241	$38,083	$4,957	$3,337	$3,555	$3,725	$4,198	$4,403	$3,524	$3,851	$4,442	$3,945	$4,054	$4,121	$4,220
TOTAL NET MARKET TRANSACTIONS	$000		$7,181	$6,329	$7,455	$9,473	$7,880	$11,894	$6,831	$35,332	$39,702	$41,267	$42,865	$43,904	$46,389	$49,589	$50,946	$52,018	$54,400	$56,289	$58,131	$59,860
TOTAL COSTS	$000		$73,557	$80,640	$75,046	$76,327	$77,358	$79,056	$86,469	$96,642	$92,290	$94,545	$96,776	$98,752	$102,255	$104,869	$107,063	$109,325	$111,506	$113,945	$116,436	$118,776

Rate
4%

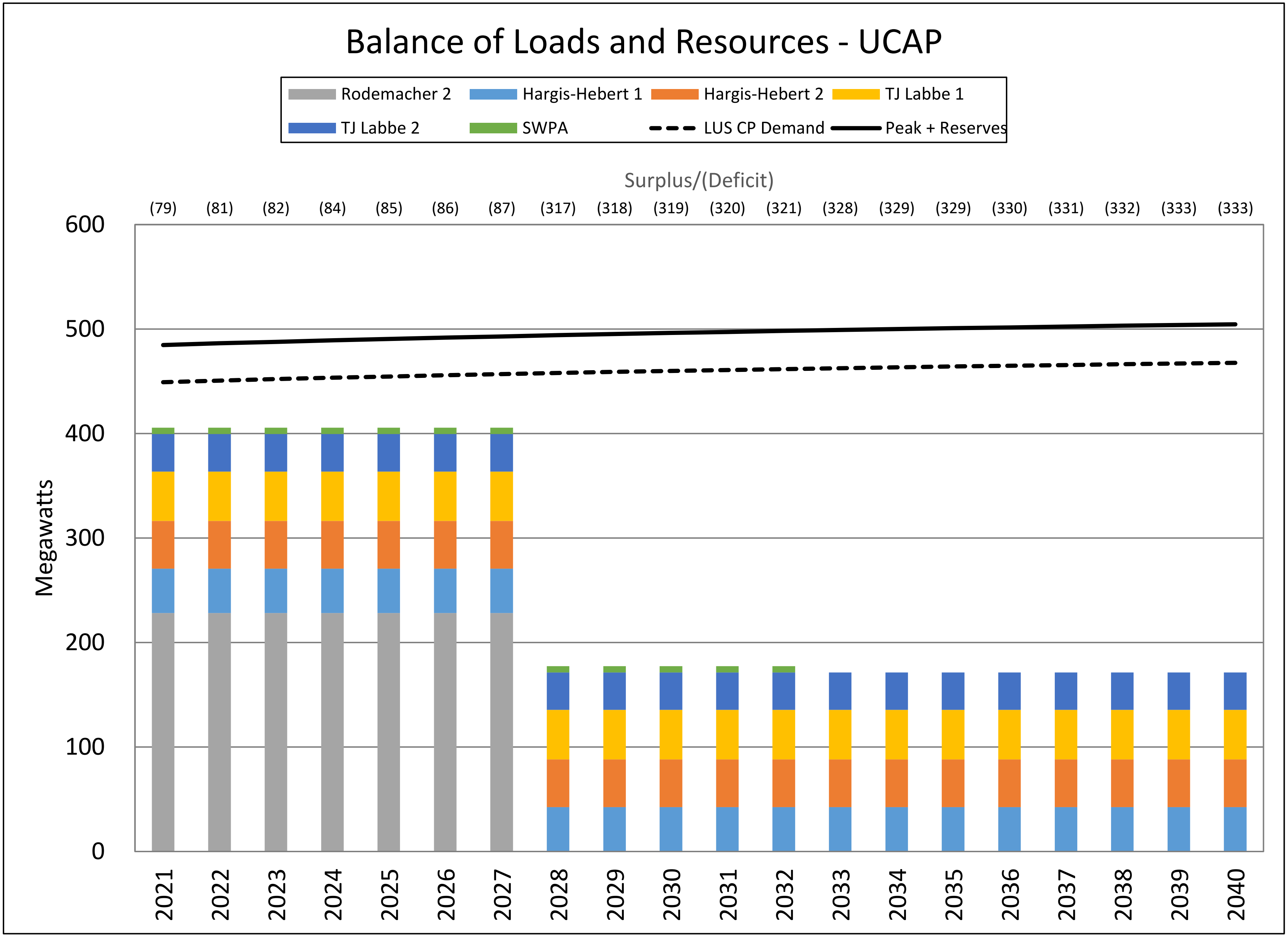
NPV @ 4% ($000): $1,207,347	**2020$**
(2021-2040)	

2020 $

NPV

TOTAL FIXED COSTS	$199,550.41
TOTAL DEBT SERVICE COSTS	$130,605.83
TOTAL VARIABLE (EXCL. FUEL) COSTS	$16,721.04
TOTAL FUEL COSTS	$241,676.98
TOTAL NET MARKET TRANSACTIONS	$392,871.22

APPENDIX J – BLR CHARTS


Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(79) (81) (82) (84) (85) (86) (87) (317) (318) (319) (320) (321) (328) (329) (329) (330) (331) (332) (333) (333)
Megawatts
600
500
400
300
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100
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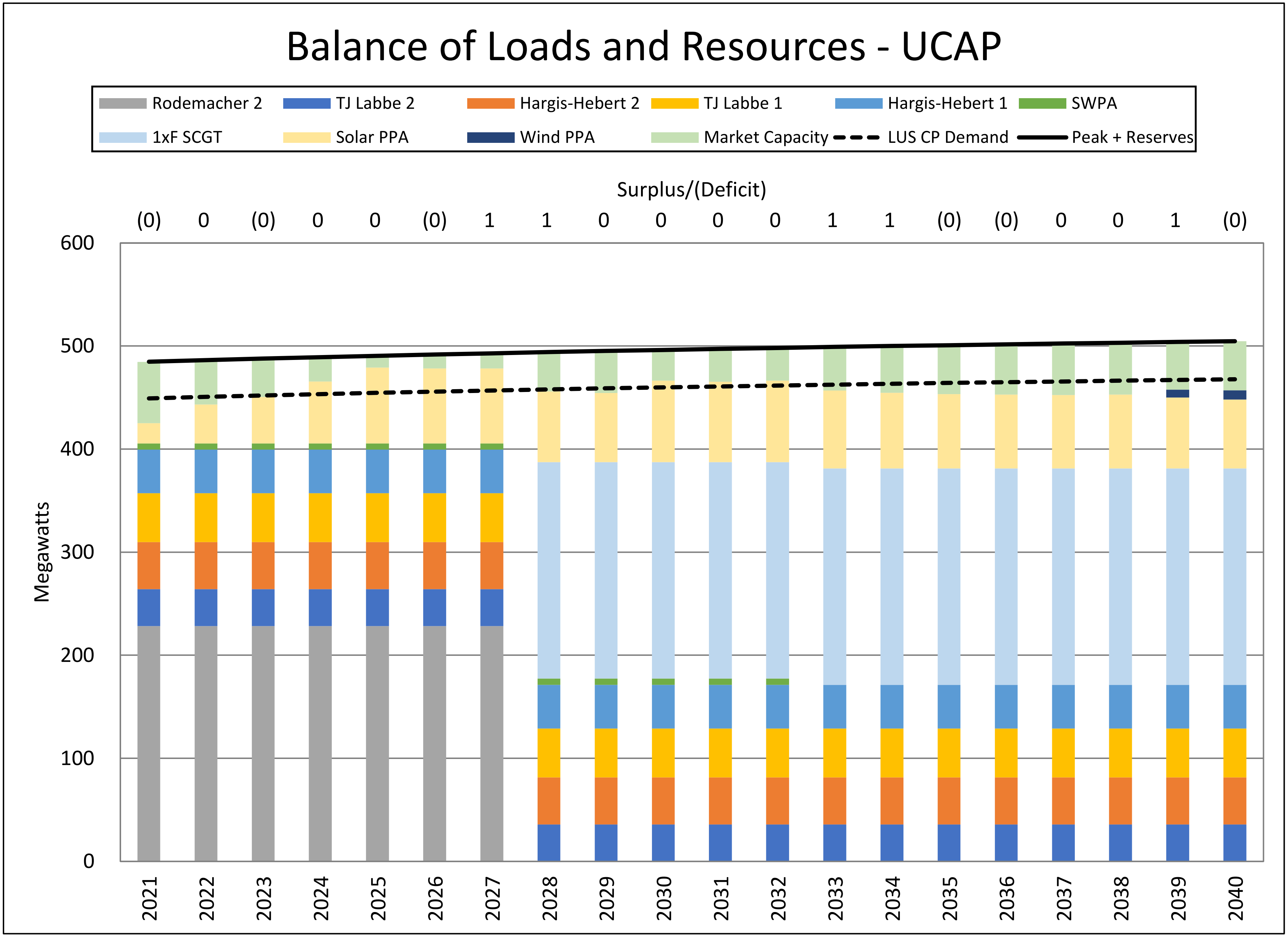
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Rodemacher 2
TJ Labbe 2
Hargis-Hebert 2
TJ Labbe 1
Hargis-Hebert 1
SWPA
1xF SCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 (0) 0 0 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
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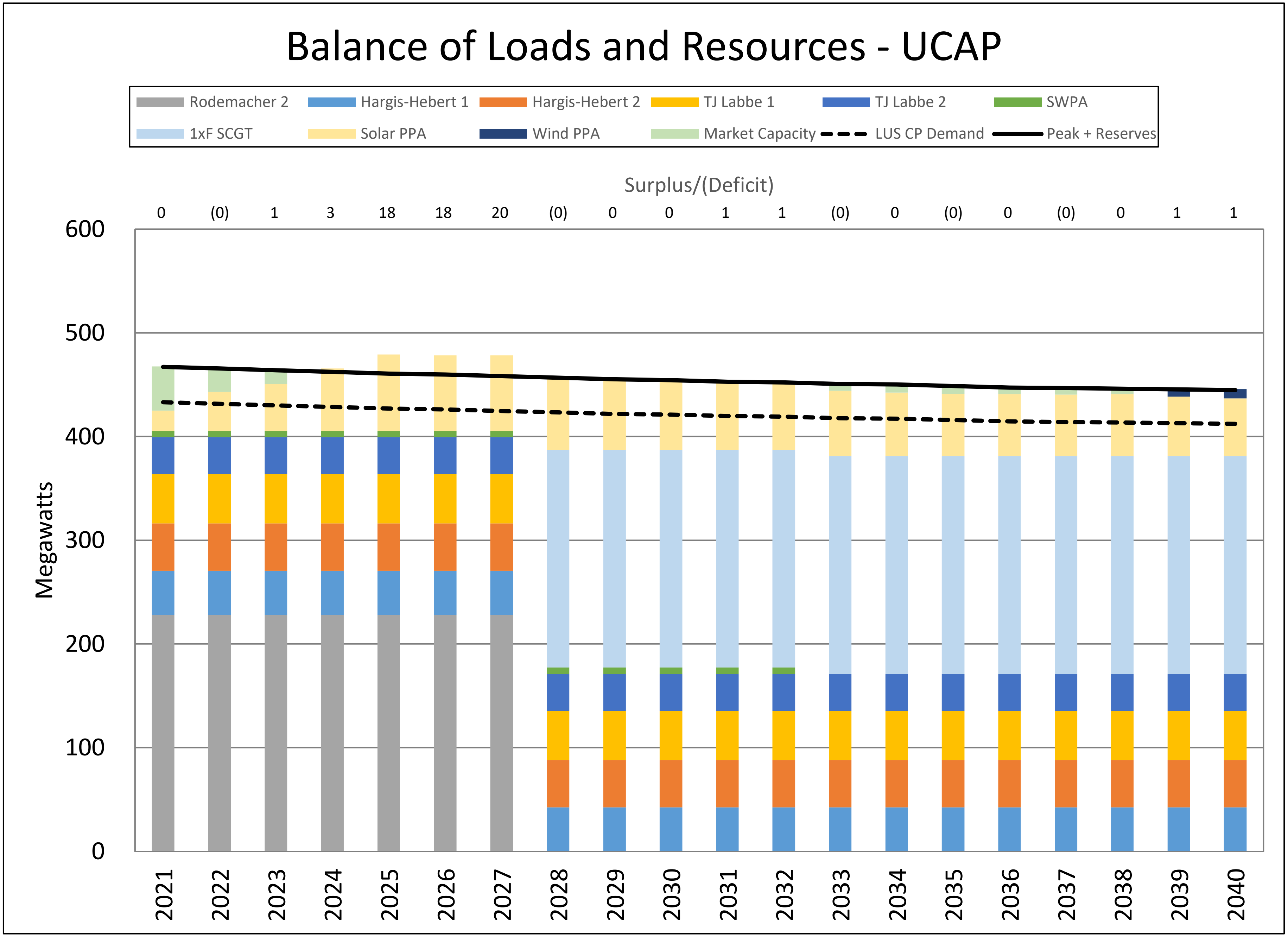
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Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1xF SCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
0
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Megawatts
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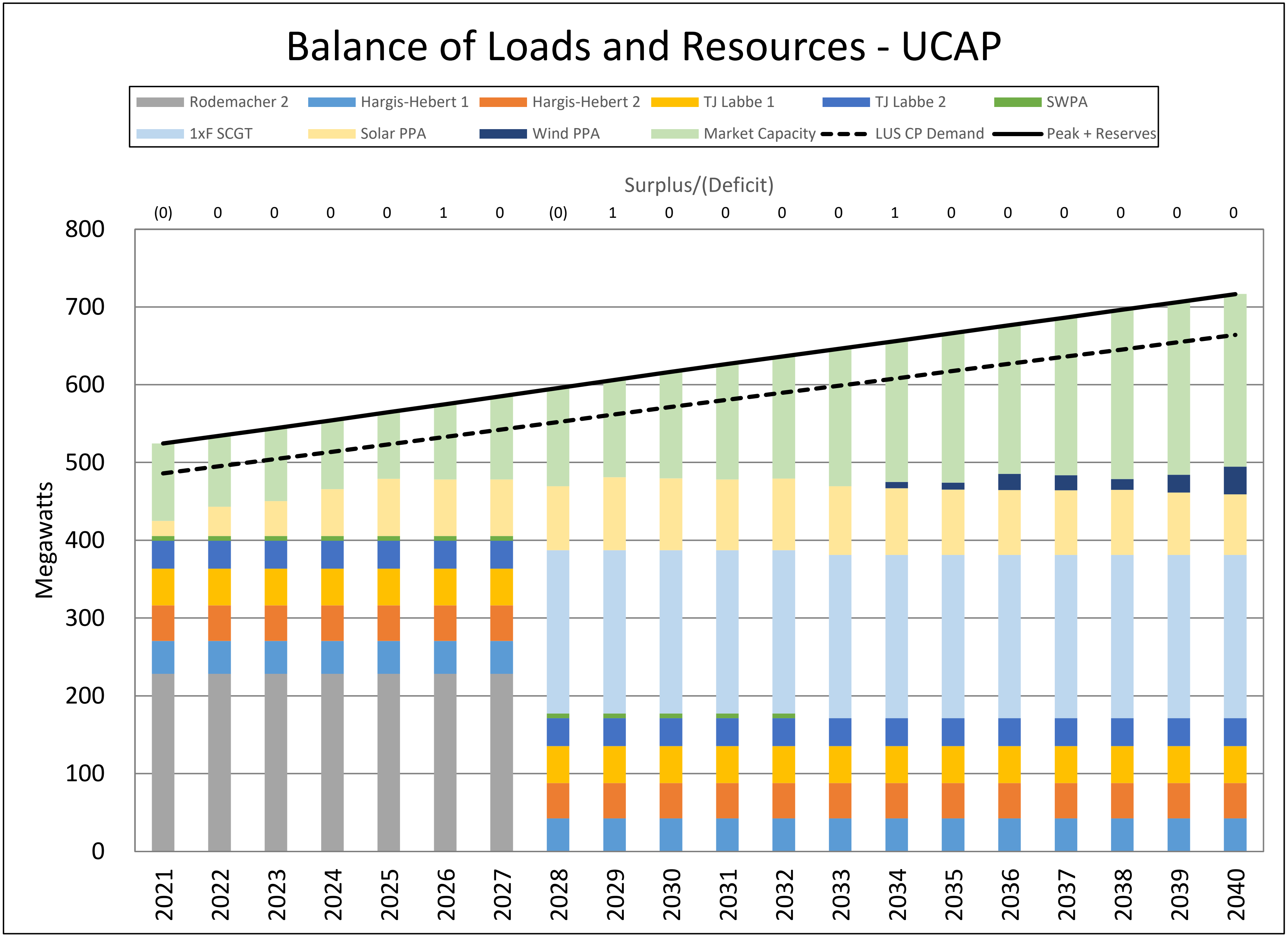
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Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1xF SCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 0 0 0 1 0 (0) 1 0 0 0 0 1 0 0 0 0 0 0
Megawatts
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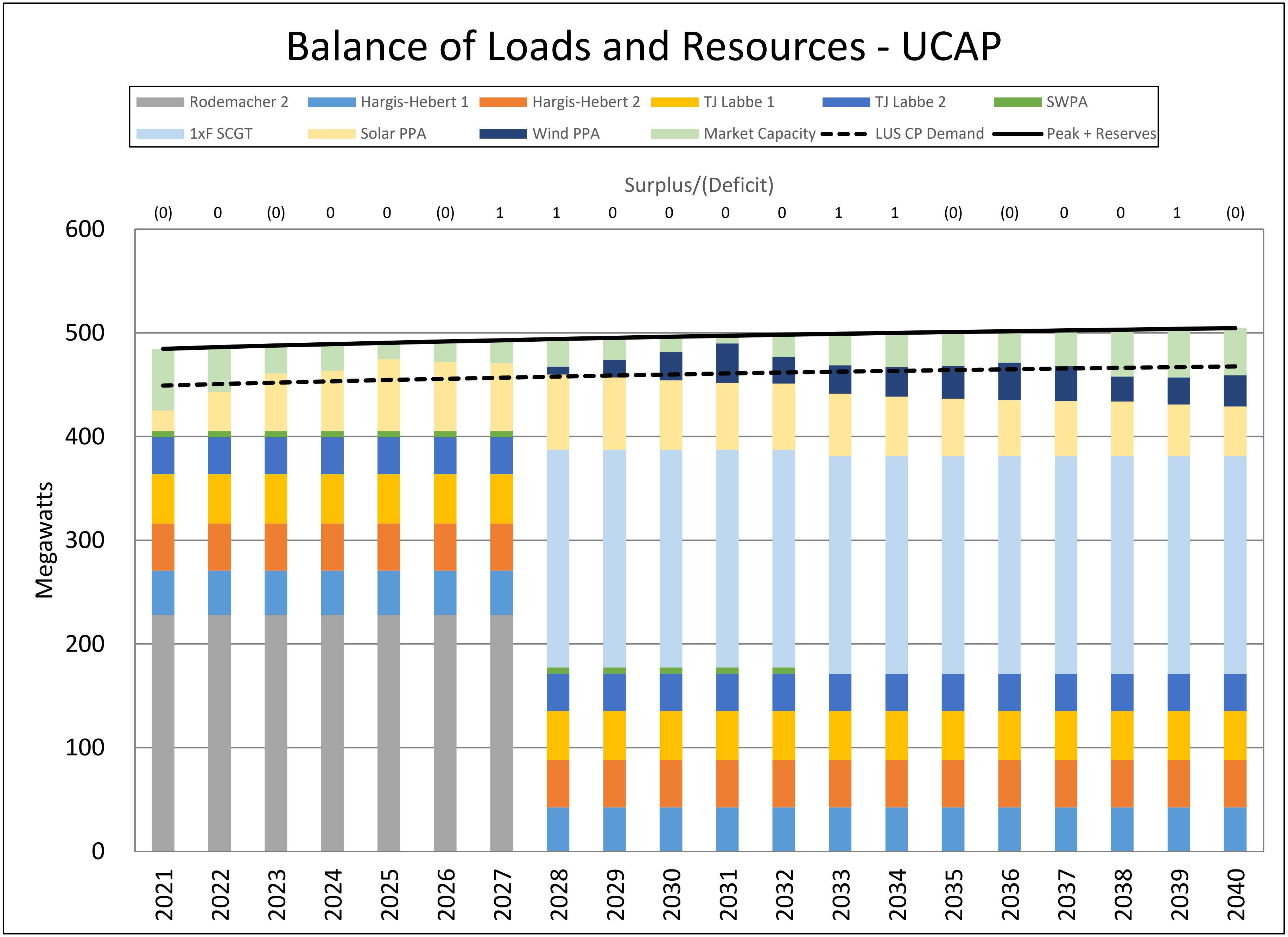
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Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1xF SCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 (0) 0 0 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
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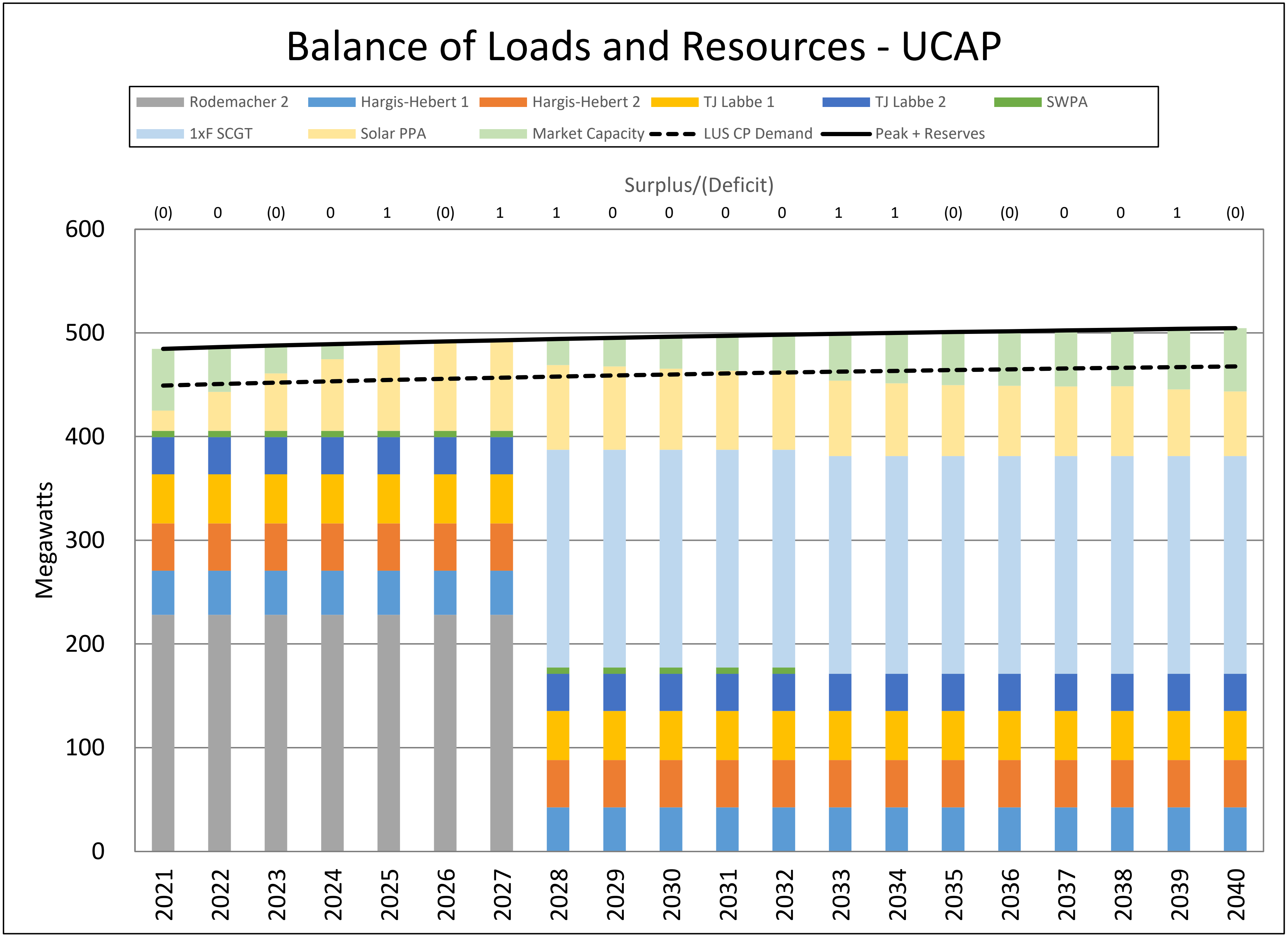
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1xF SCGT
Solar PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
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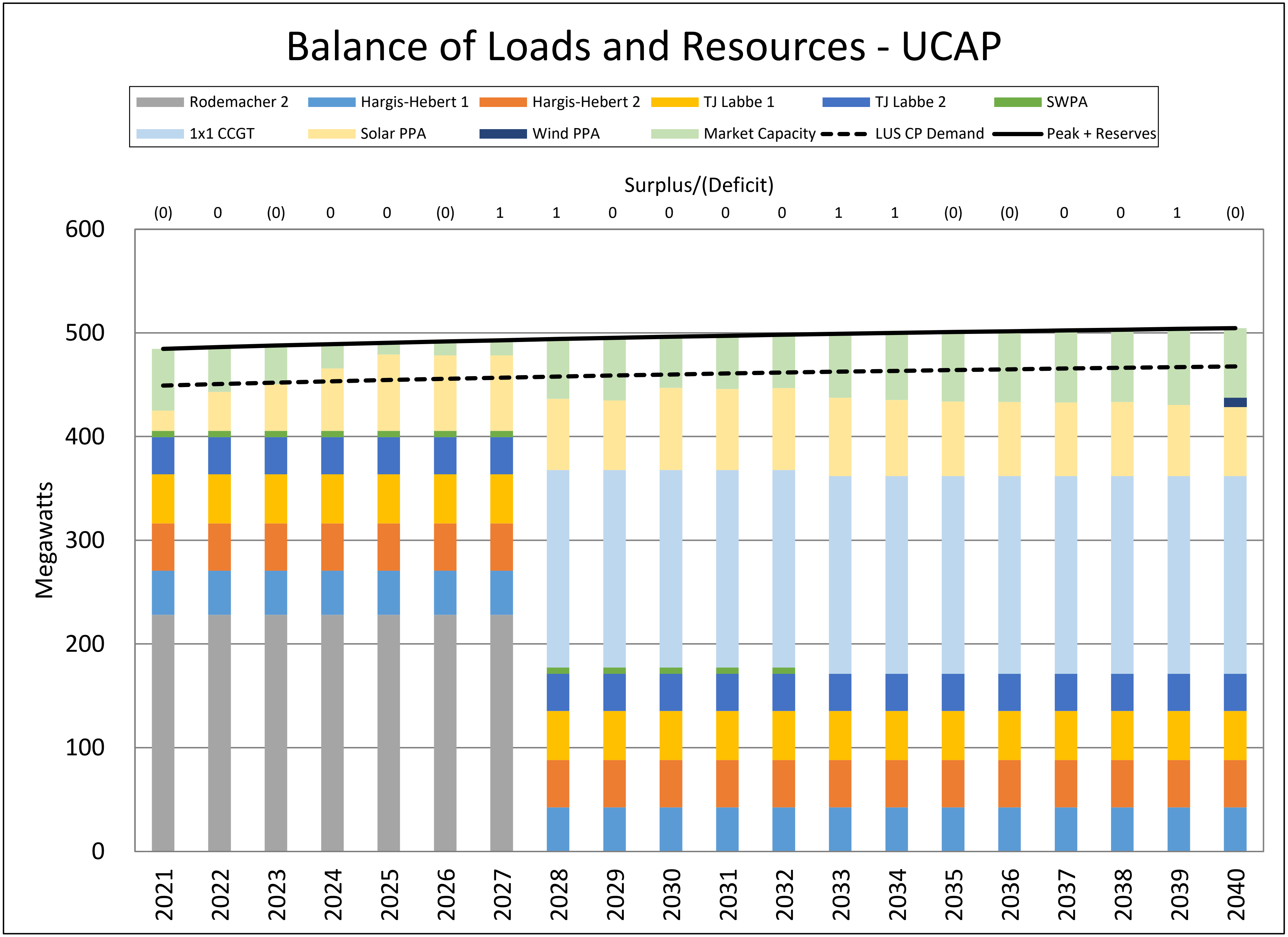
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1x1 CCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 (0) 0 0 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
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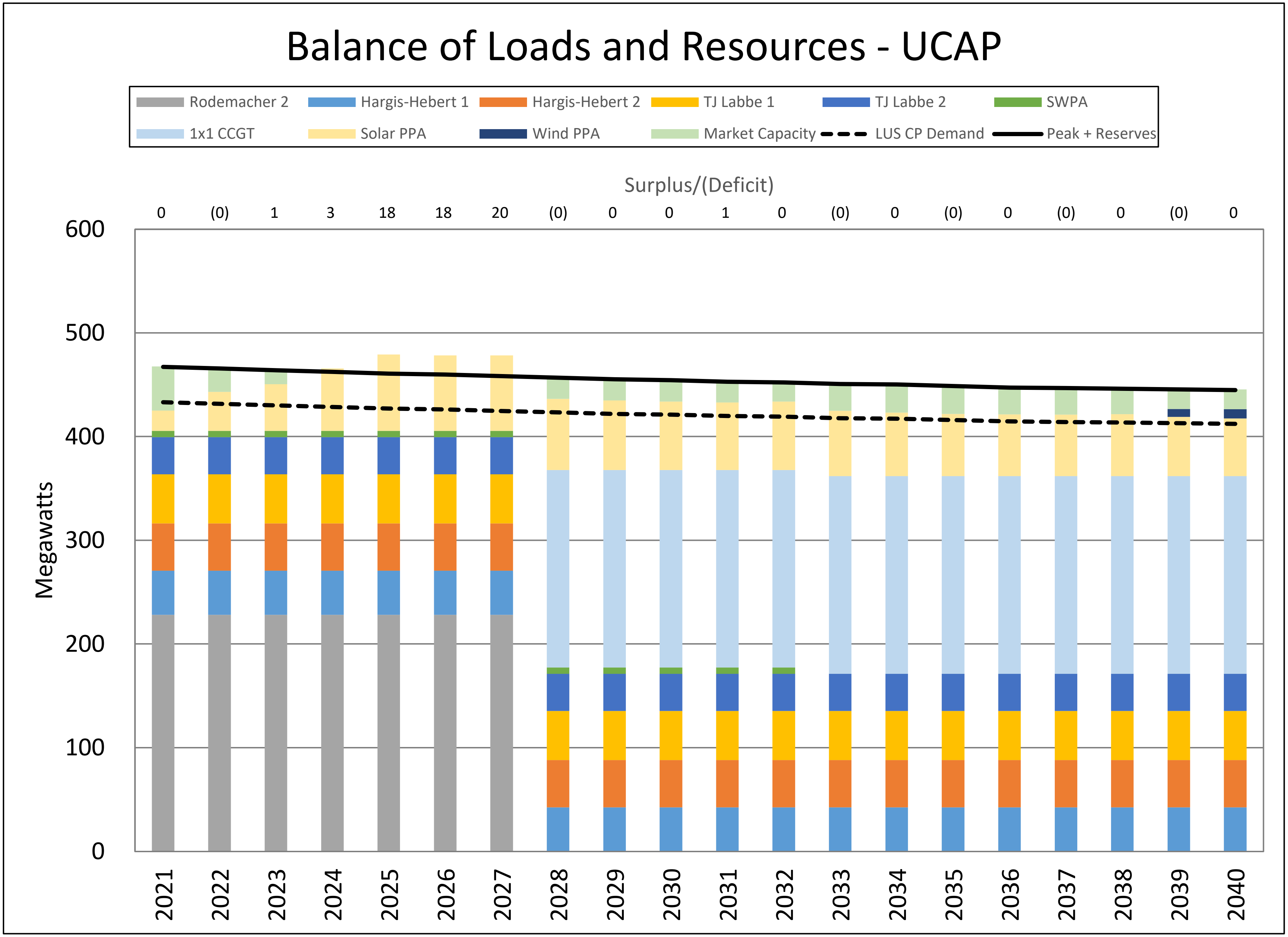
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1x1 CCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
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Megawatts
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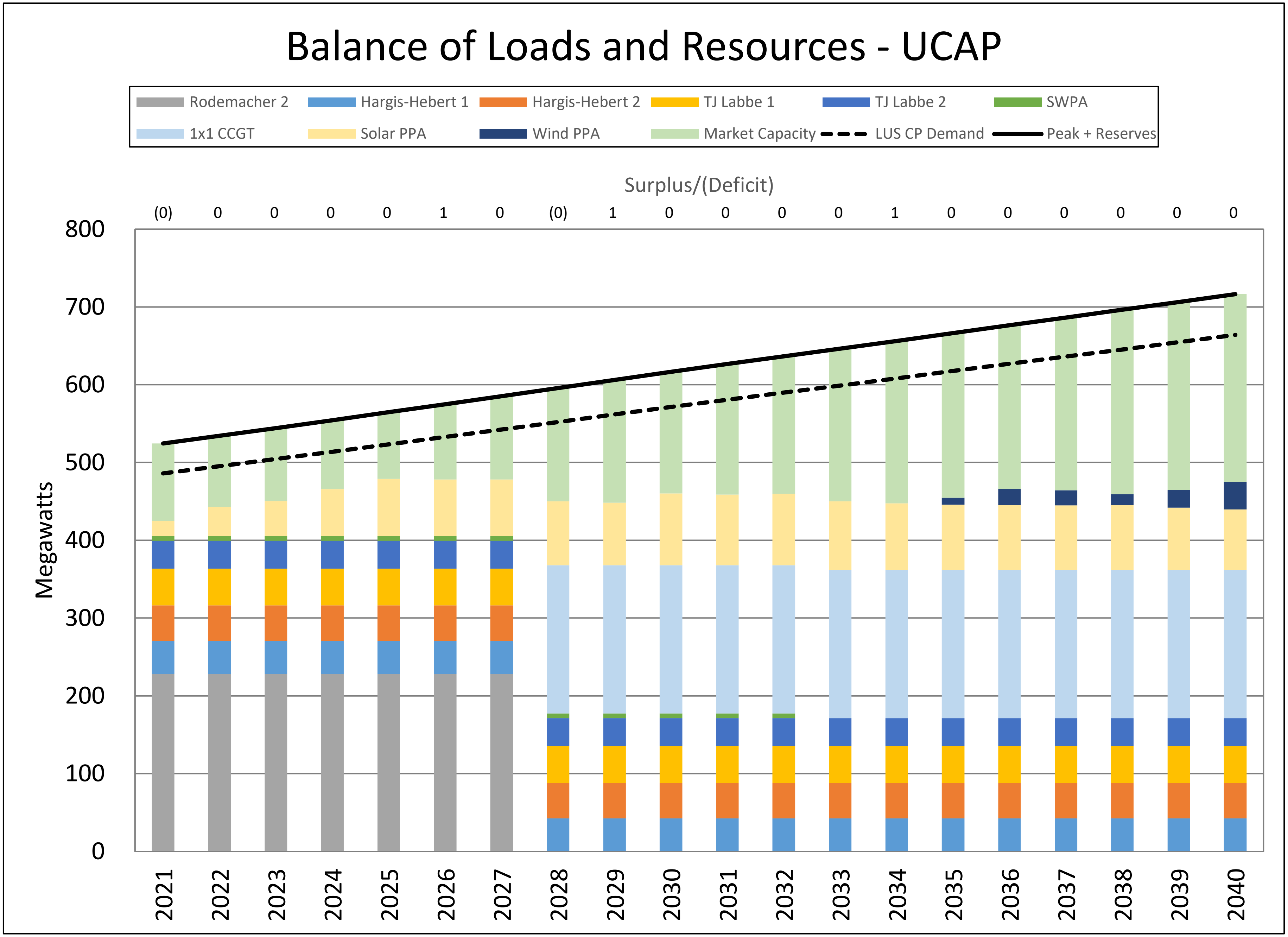
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1x1 CCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
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Megawatts
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700
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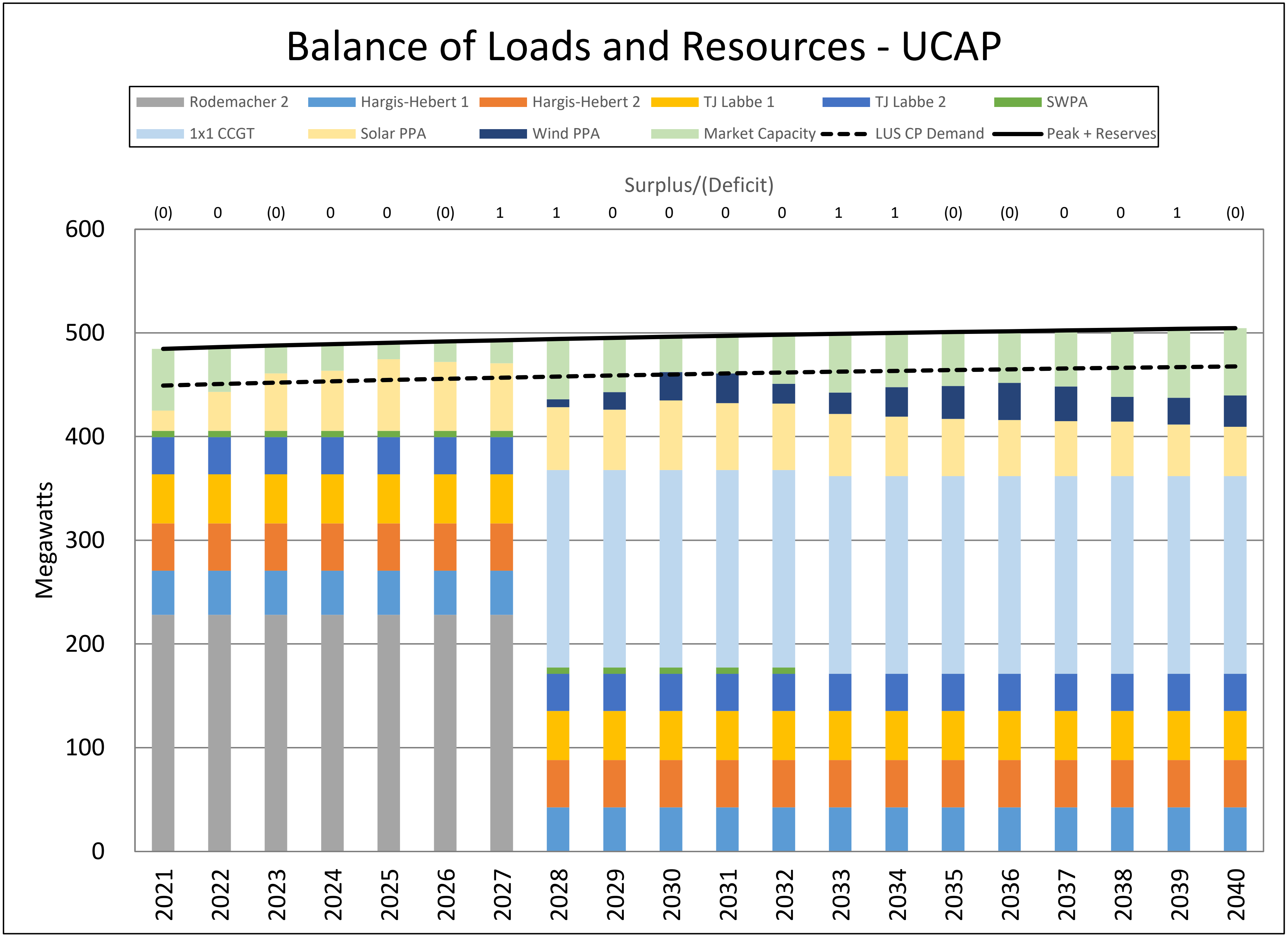
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1x1 CCGT
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0)
0
(0)
0
0
(0)
1
1
0
0
0
0
1
1
(0)
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(0)
Megawatts
600
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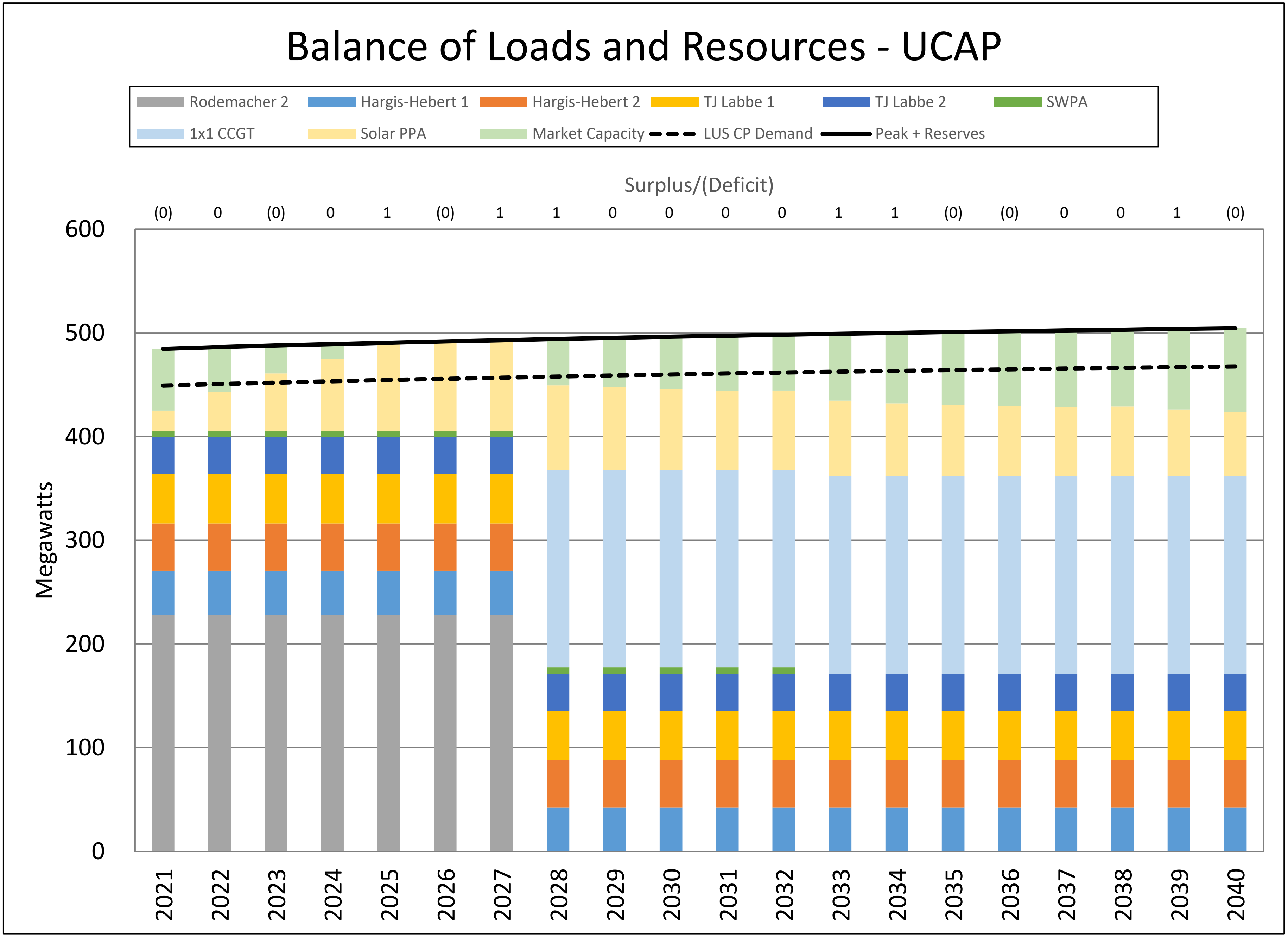
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
1x1 CCGT
Solar PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 (0) 0 1 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
600
500
400
300
200
100
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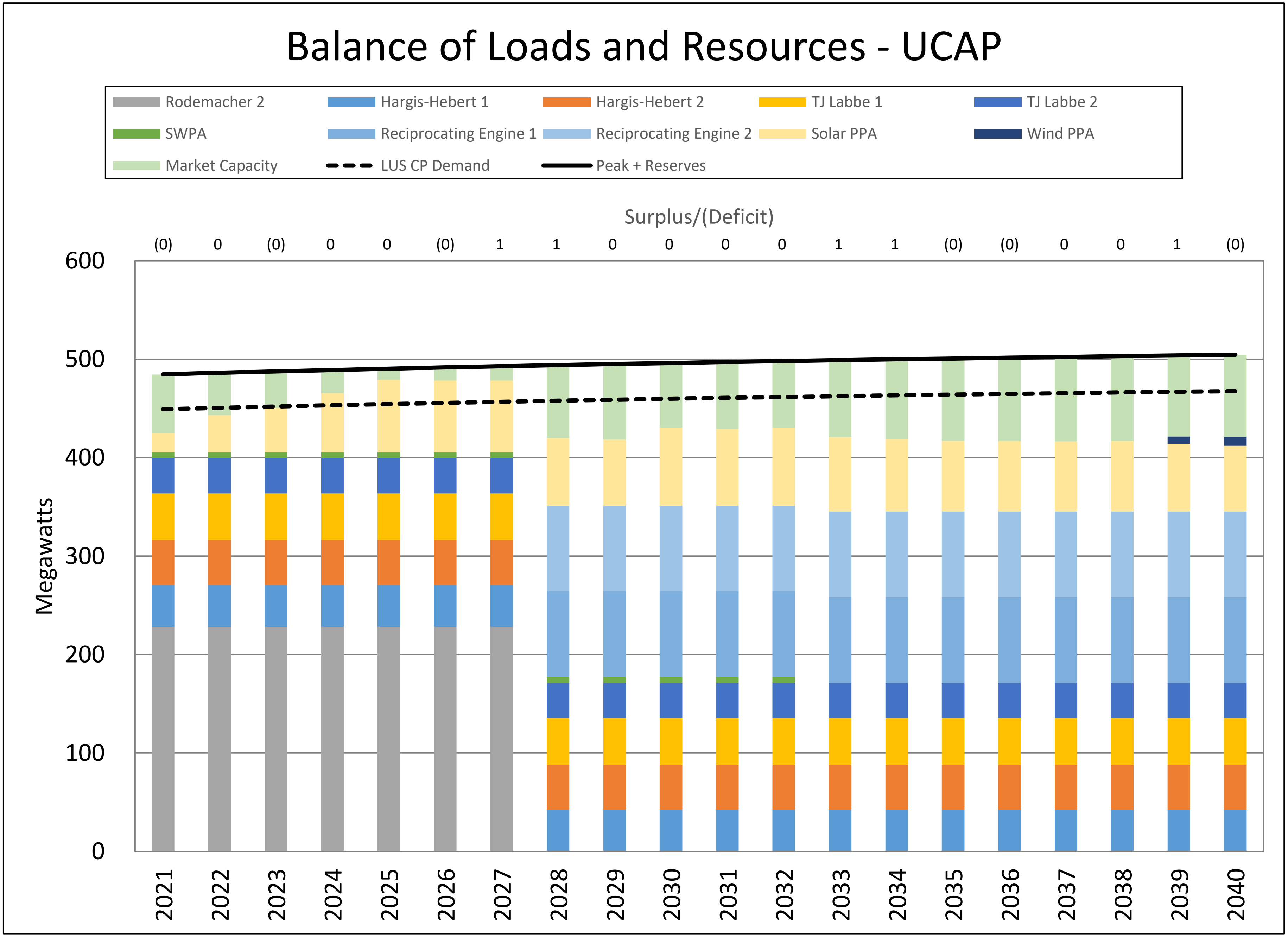
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Reciprocating Engine 1
Reciprocating Engine 2
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 (0) 0 0 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
600
500
400
300
200
100
0
2021
2022
2023
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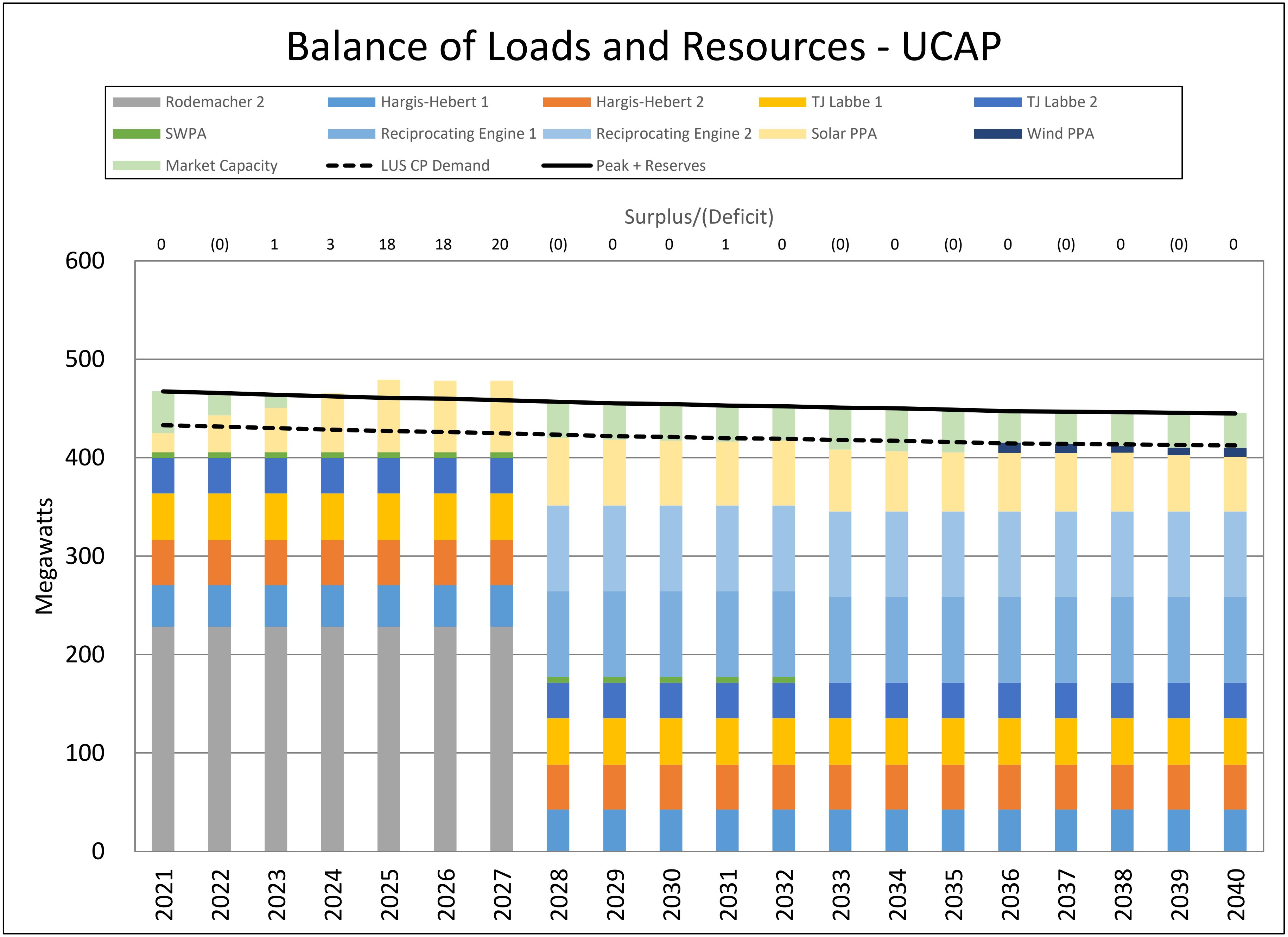
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Reciprocating Engine 1
Reciprocating Engine 2
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
0
(0)
1
3
18
18
20
(0)
0
0
1
0
(0)
0
(0)
0
(0)
0
(0)
0
Megawatts
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100
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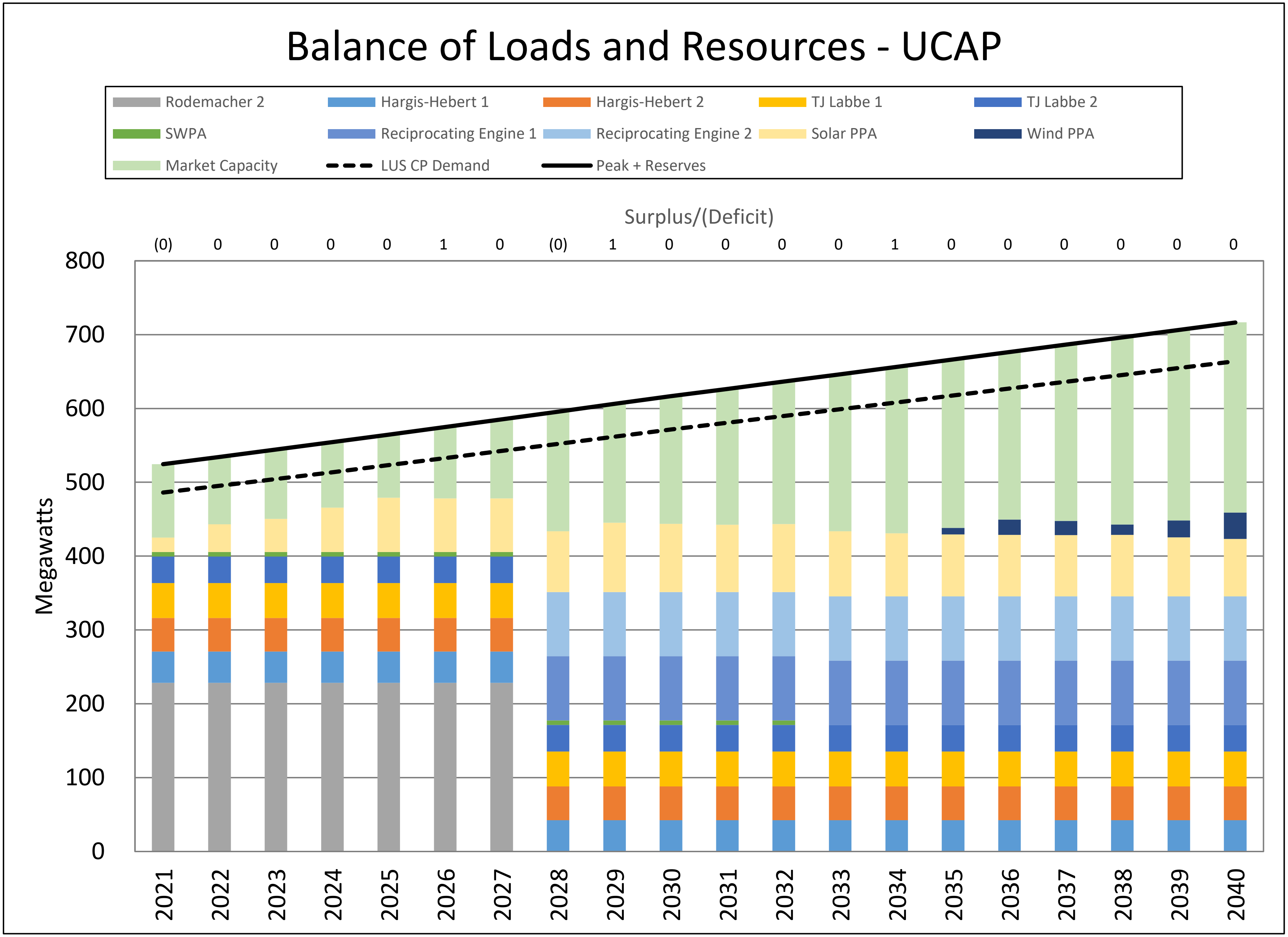
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Reciprocating Engine 1
Reciprocating Engine 2
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 0 0 0 1 0 (0) 1 0 0 0 0 1 0 0 0 0 0 0
Megawatts
800
700
600
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0
2021
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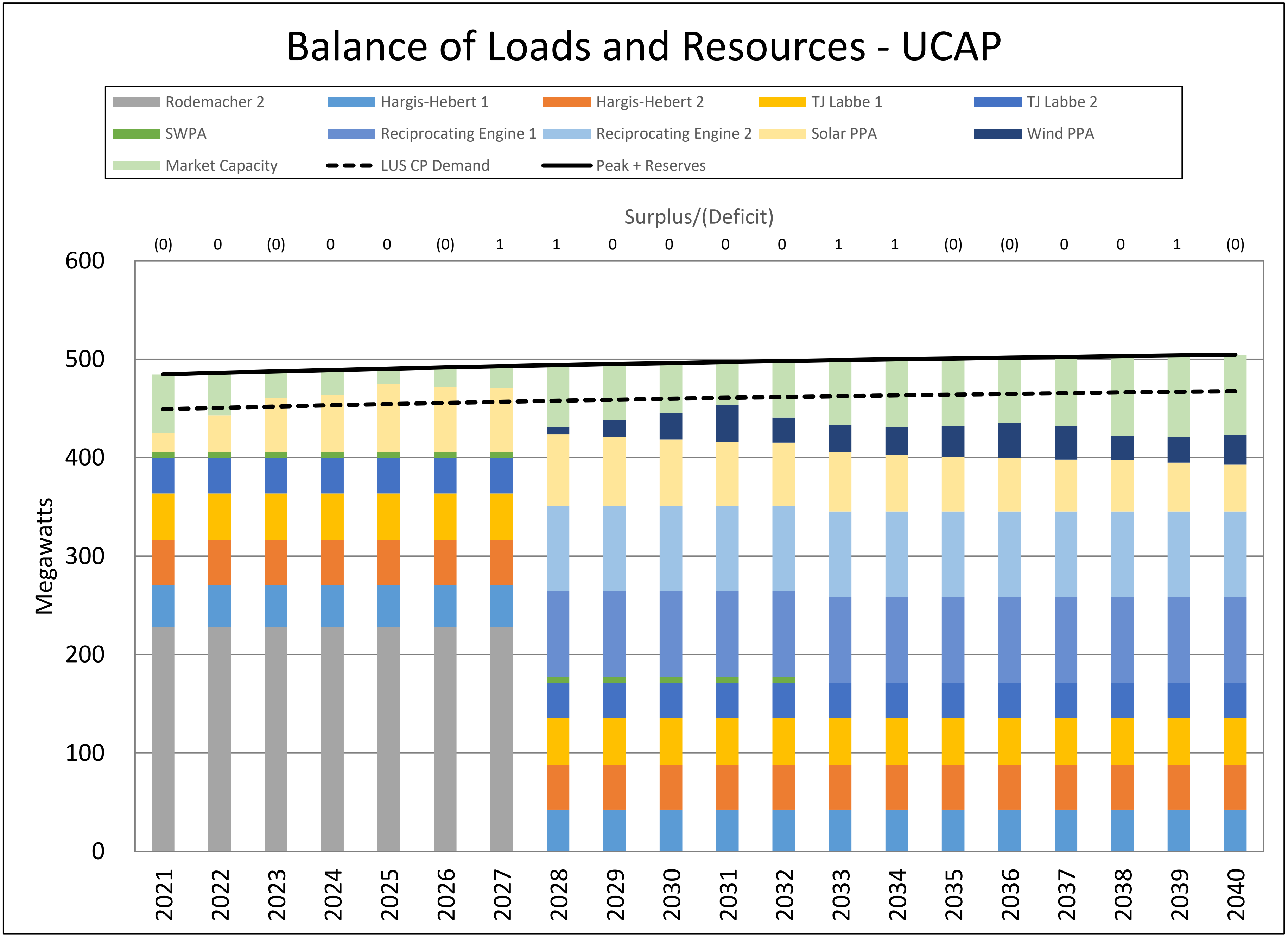
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Reciprocating Engine 1
Reciprocating Engine 2
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 (0) 0 0 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
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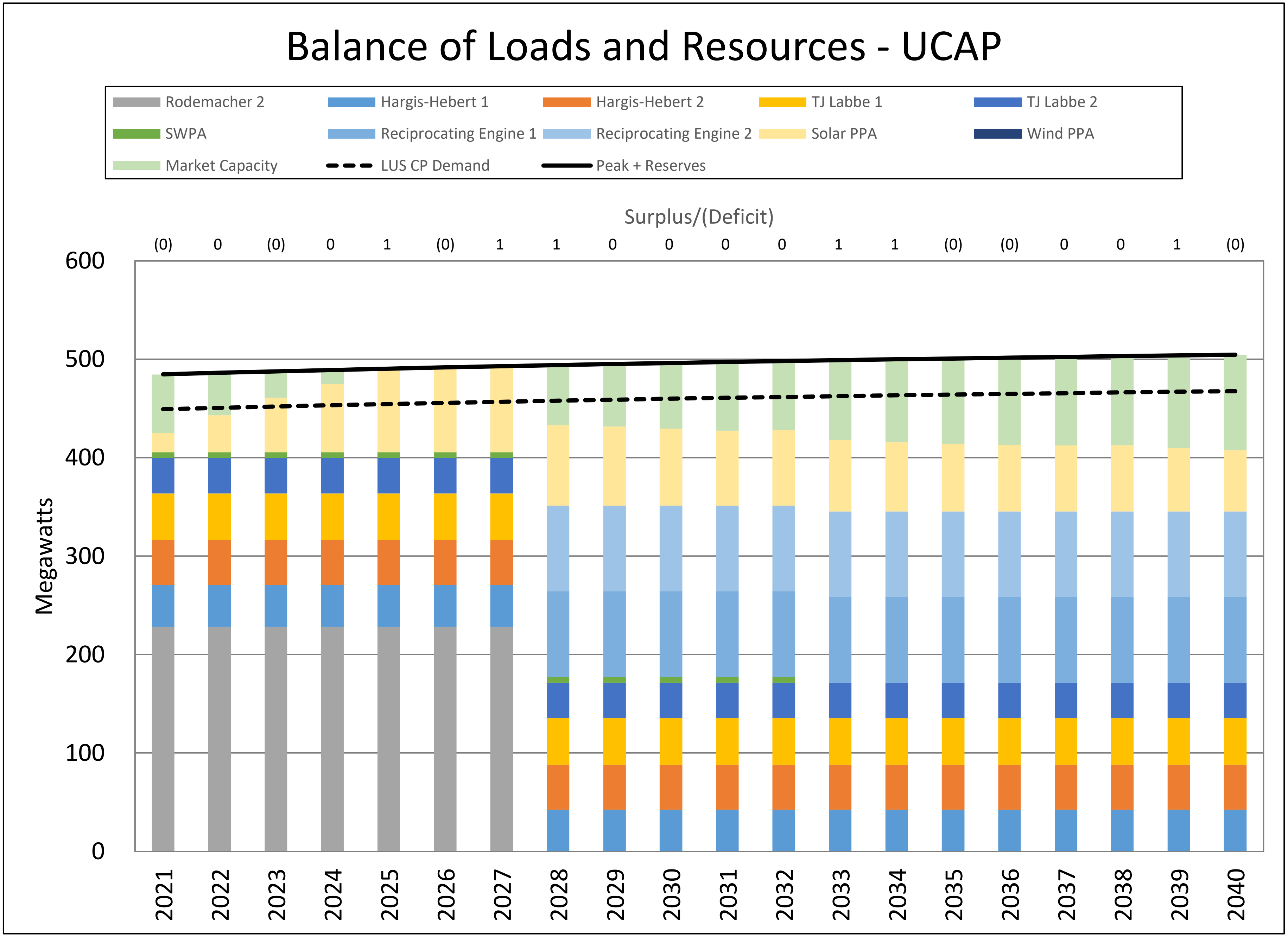
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Reciprocating Engine 1
Reciprocating Engine 2
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
(0) 0 (0) 0 1 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
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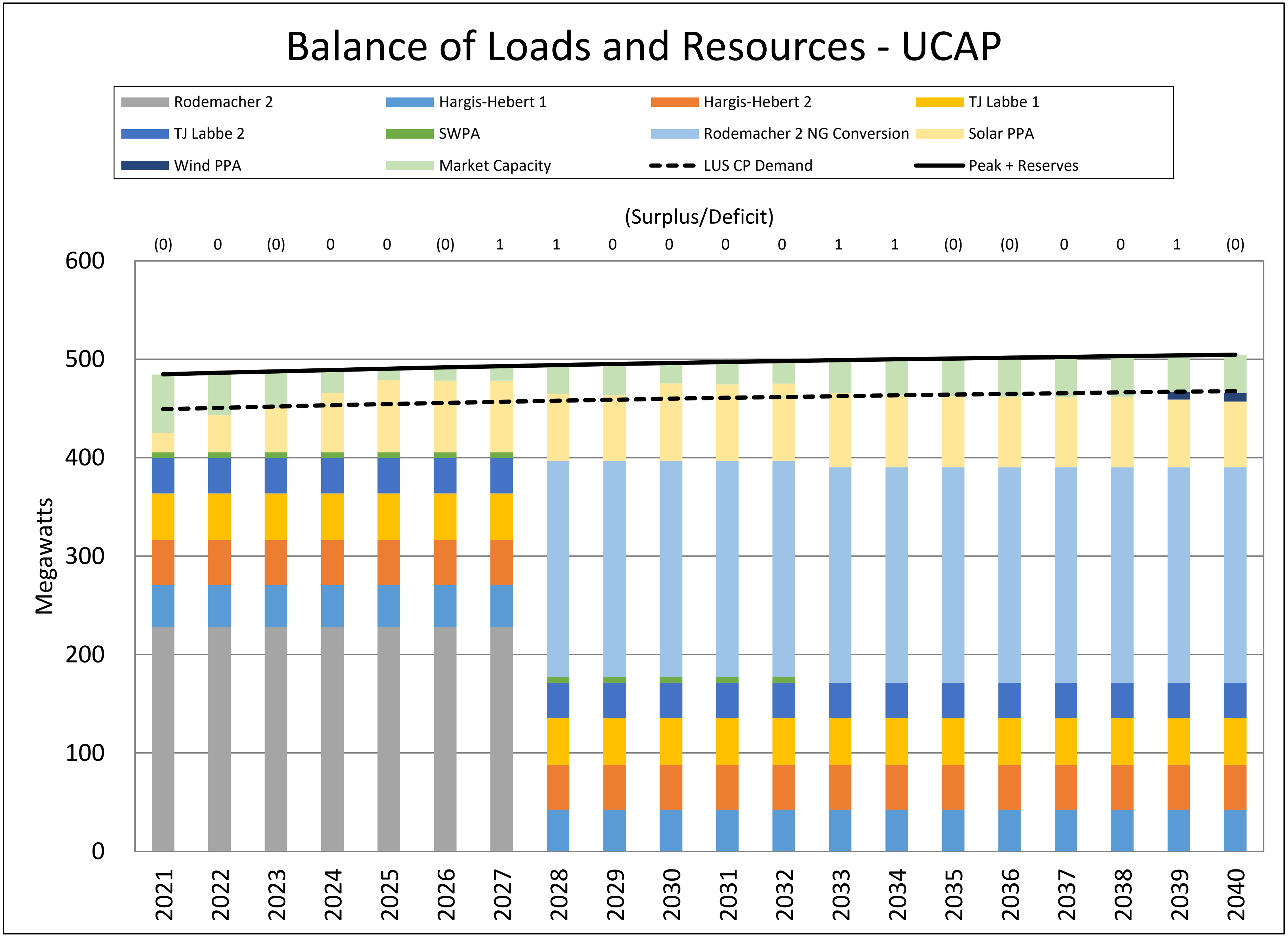
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Rodemacher 2 NG Conversion
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
(Surplus/Deficit)
(0) 0 (0) 0 0 (0) 1 1 0 0 0 0 1 1 (0) (0) 0 0 1 (0)
Megawatts
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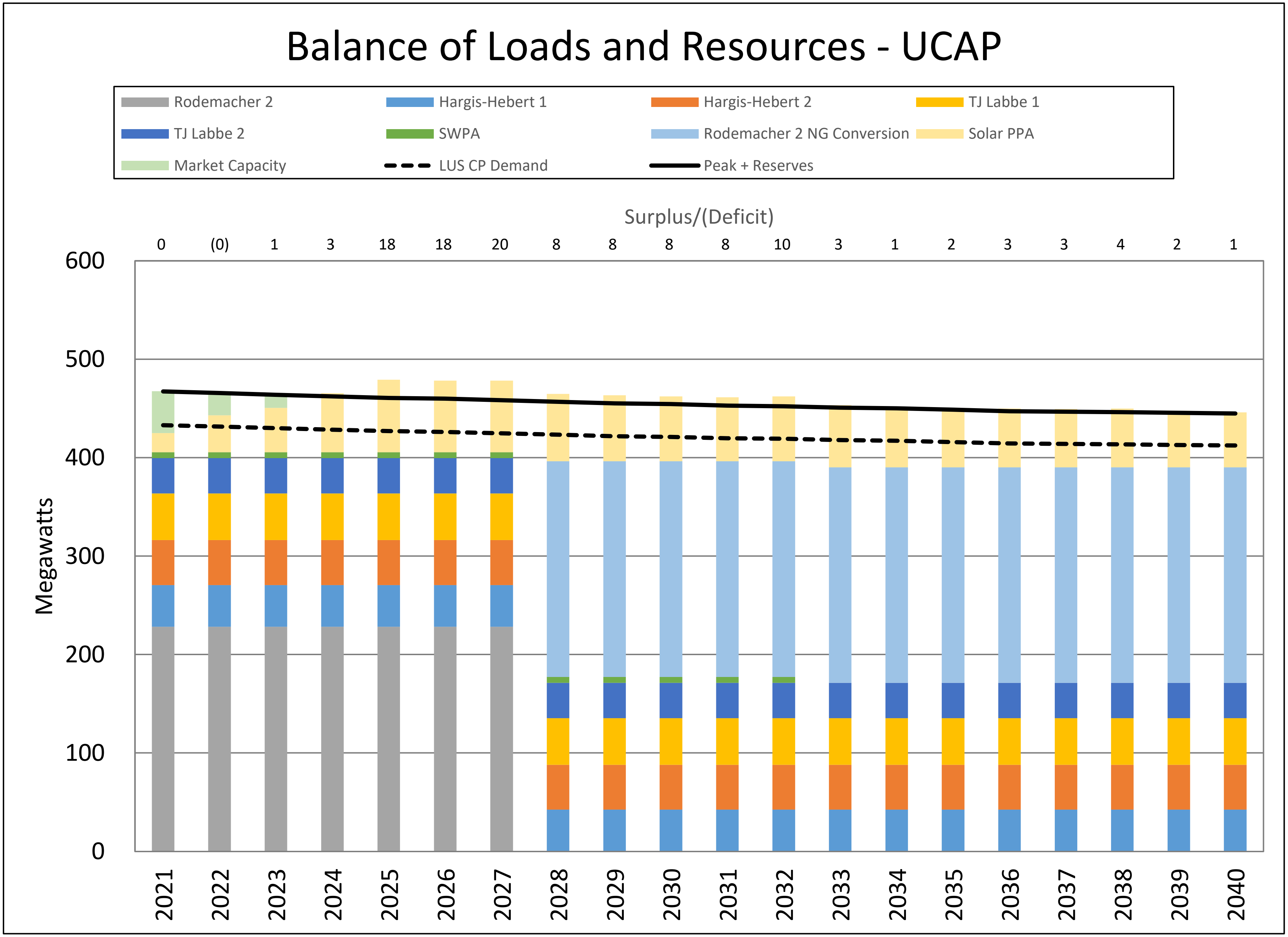
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Rodemacher 2 NG Conversion
Solar PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
0
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Megawatts
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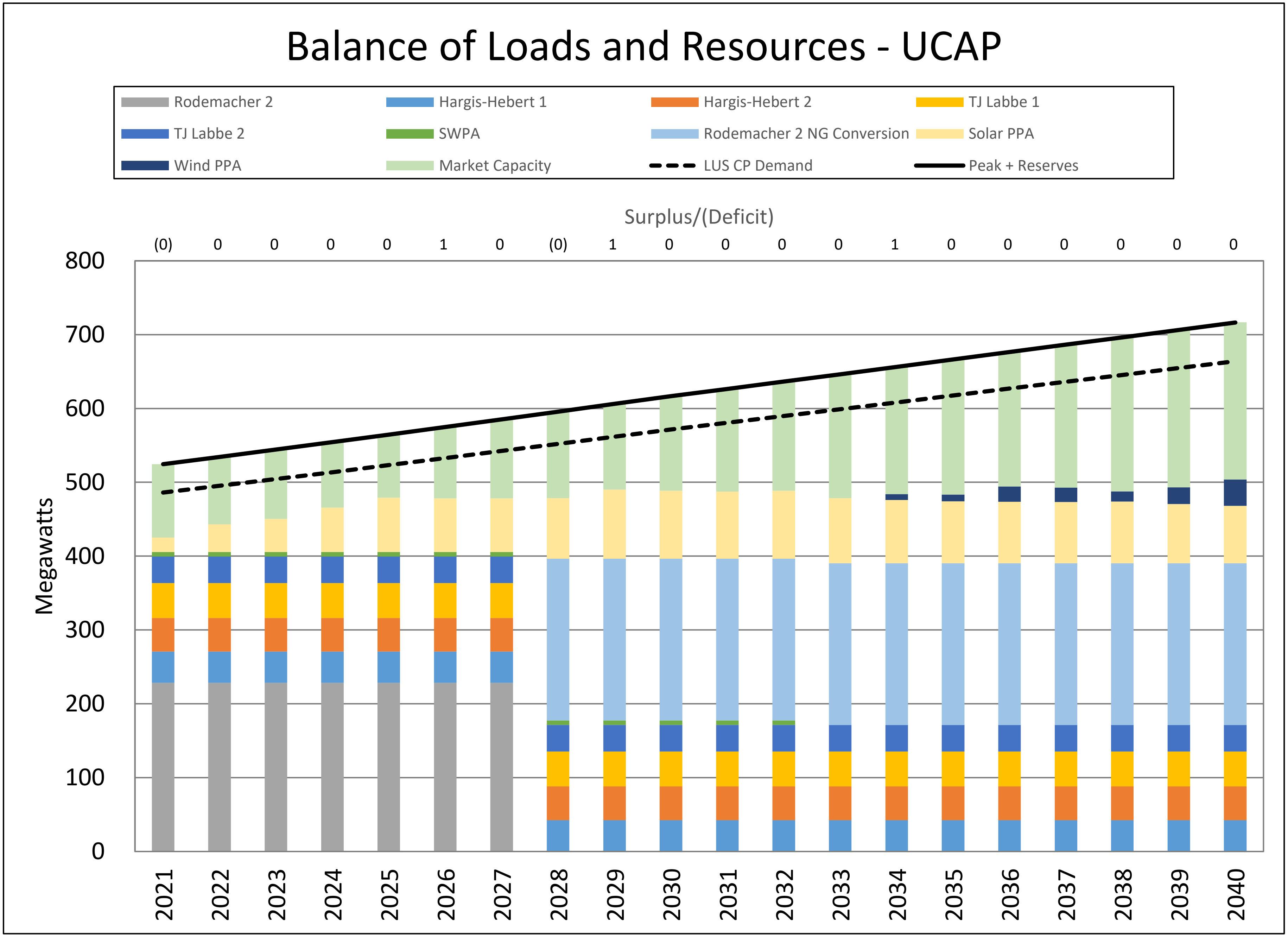
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Rodemacher 2 NG Conversion
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
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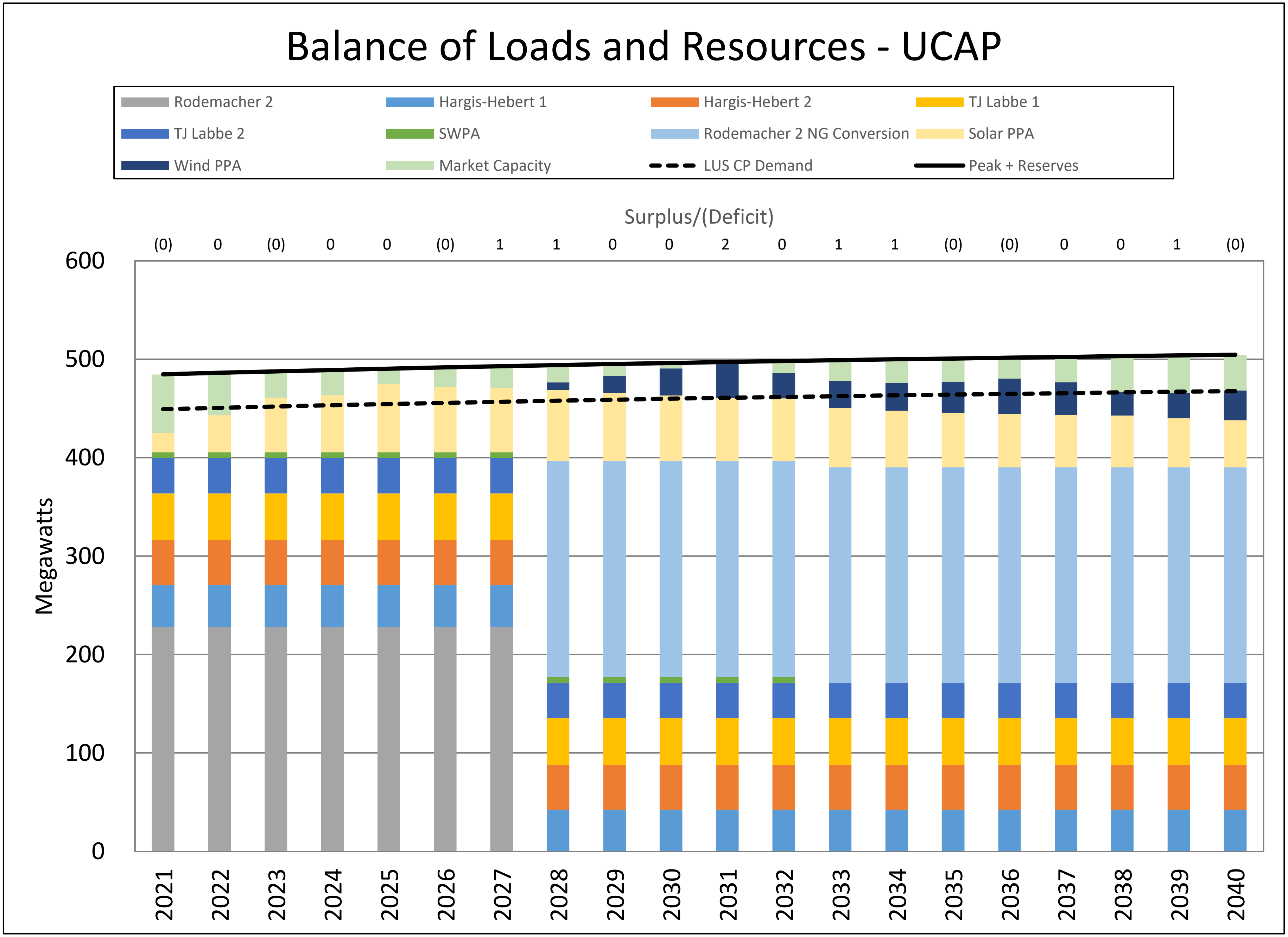
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Rodemacher 2 NG Conversion
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
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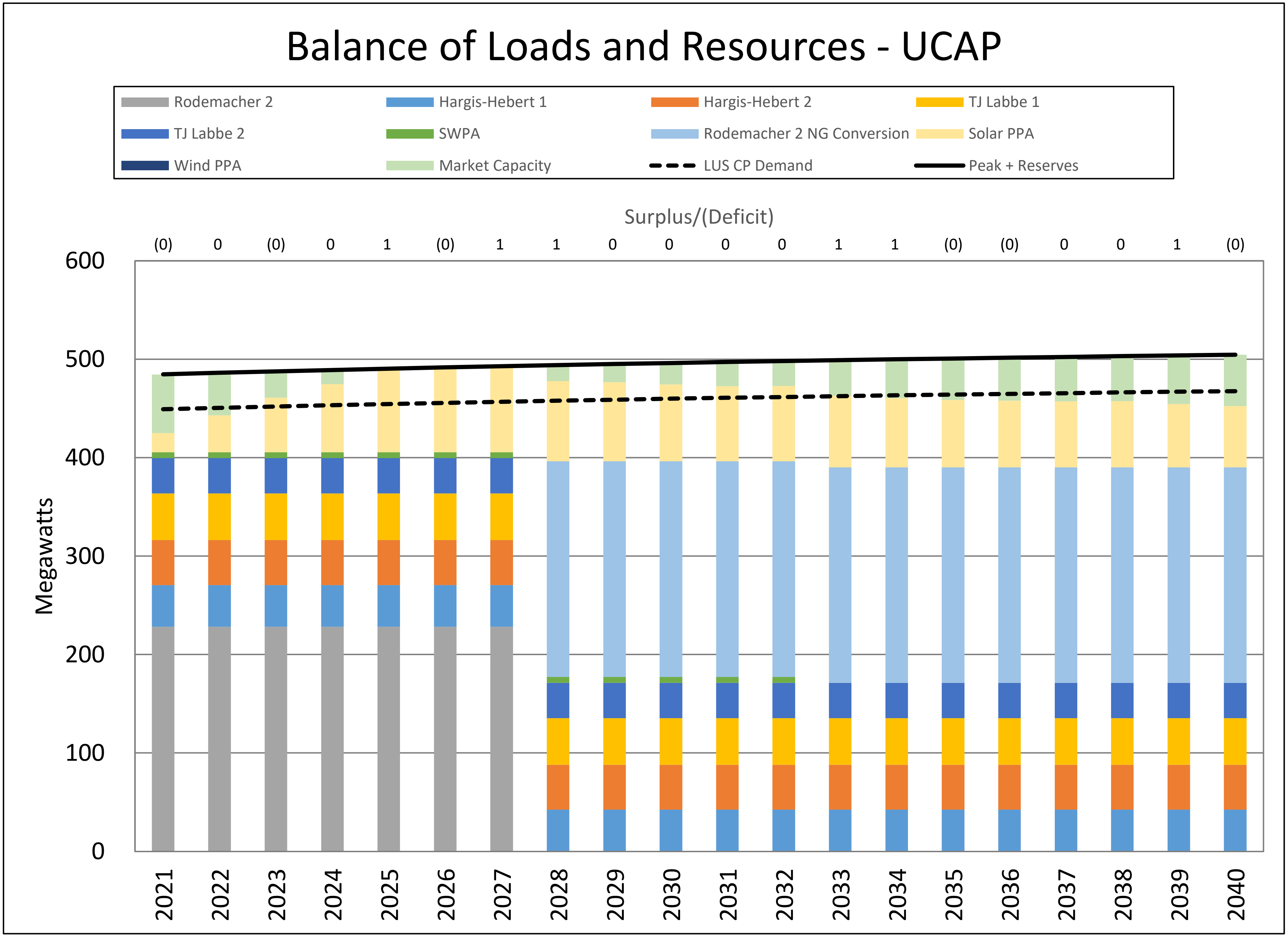
Balance of Loads and Resources - UCAP
Rodemacher 2
Hargis-Hebert 1
Hargis-Hebert 2
TJ Labbe 1
TJ Labbe 2
SWPA
Rodemacher 2 NG Conversion
Solar PPA
Wind PPA
Market Capacity
LUS CP Demand
Peak + Reserves
Surplus/(Deficit)
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