2015 Update of the RPU Infrastructure Study

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Rochester Public Utilities

Project No. 82902

June 2015

June 24, 2015

Mr. Wally Schlink
Director of Power Resources & Customer Relations
Rochester Public Utilities
4000 East River Road
Rochester, MN 55906

Re: 2015 Update to the Rochester Public Utilities Infrastructure Plan

Dear Mr. Schlink:

Rochester Public Utilities (RPU) retained Burns & McDonnell Engineering Co. (BMcD) to conduct an update to the RPU Infrastructure Plan that was started in 2005. The objective was to analyze the power supply needs of RPU from 2016 through 2035 in order to identify short-term, intermediate-term, and long-term infrastructure requirements for providing reliable, low cost electric power and thermal energy to its customers.

The following provides the overall highlights of the infrastructure plan update:

1. Positions RPU for long-term power supply with the expiration of the SMMPA Power Sales Contract (PSC) in 2030
2. Reduces direct dependence from coal resources within the RPU portfolio by 2030 and significantly reduces carbon emissions
3. Meets renewable standards and objectives: 25 percent by 2025 renewable standard, 1.5 percent solar standard, 1.5 percent conservation standard
4. Has the flexibility to accommodate potential sharp increases or decreases in load and energy requirements due to Mayo Clinic, Destination Medical Center development, or customer solar
5. Positions RPU for short-term and long-term compliance with environmental regulations
6. Retires an inefficient resource and modernizes the RPU generation fleet with high efficiency and low emission units
7. Expands partnership opportunities with the Mayo Clinic and other combined heat and power prospects

BMcD is pleased to submit our report to RPU detailing the results of the assessment. It has been a pleasure to assist RPU with this evaluation. If you have any questions regarding the information presented herein, please feel free to contact me at 816-822-3459 or mborgstadt@burnsmcd.com.

Sincerely,

Mike Borgstadt, PE
Manager, Business Consulting

MEB/meb

2015 Update of the RPU Infrastructure Plan

2015 Update of the RPU Infrastructure Study

prepared for

Rochester Public Utilities

Rochester, Minnesota

Project No. 82902

June 2015

prepared by

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

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
BLR	balance of loads and resources
BMcD	Burns & McDonnell Engineering Co.
Btu	British thermal units
CCGT	combined cycle gas turbine
CHP	combined heat and power
CO_2	carbon dioxide
CONE	cost of new entry
CPP	Clean Power Plan
CROD	Contract Rate of Delivery via the SMMPA PSC
DMC	Destination Medical Center
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GOR	gross operating revenues
GW	gigawatt
hr	hour
IDC	interest during construction
kpph	kilopound per hour
kWh	kilowatt hour
klbs	kilopound
Lake Zumbro	Lake Zumbro Hydroelectric Plant
lbs	pounds
LDC	local distribution company
LMP	locational marginal pricing
LNG	liquefied natural gas
LRZ	load resource zone

Abbreviation	Term/Phrase/Name
Mayo	Mayo Clinic
MERC	Minnesota Energy Resources, Co.
MISO	MISO Energy (formerly Midwest Independent System Operator)
MMBtu	million British thermal units
MTEP	MISO Transmission Expansion Planning
MW	megawatt
MWh	megawatt hour
NERC	North American Reliability Corporation
NNG	Northern Natural Gas Company
NPV	net present value
O&M	operation and maintenance
OEM	original equipment manufacturer
OWEF	Olmsted Waste-to-Energy Facility
Plant	Cascade Creek Combustion Turbine Plant
PSC	Power Sales Contract with SMMPA
RPU	Rochester Public Utilities
SLP	Silver Lake Plant
SMMPA	Southern Minnesota Municipal Power Agency
Study	2015 Infrastructure Study
UCAP	unforced capacity
U.S.	United States

STATEMENT OF LIMITATIONS

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

Estimates and projections prepared by BMcD relating to performance and costs are based on BMcD's experience, qualifications, and judgment as a professional consultant. Since BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, contractors' procedures and methods, unavoidable delays, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections, BMcD does not guarantee the accuracy of its estimates or predictions.

1.0 EXECUTIVE SUMMARY

This report section presents a summary of the 2015 Infrastructure Update Study (Study). The Study was completed by Burns & McDonnell Engineering Company (BMcD) for Rochester Public Utilities (RPU). The objectives, methodology, and results of the Study are summarized in the following sections.

1.1 Study Objectives

BMcD was retained by RPU to perform this Study building upon the previous infrastructure studies RPU has conducted in the past. This report provides information on the generation resource planning and other analyses undertaken to make updated decisions and recommendations on RPU's short-term and long-term strategy.

There continues to be significant impacts to utilities within the power industry due to economic conditions, costs of fuel, and regulatory issues. These impacts require electric utilities to continuously monitor their infrastructure and power supply requirements to provide reliable, low cost power to their customers. The objective of this Study was to analyze the power supply needs of RPU from 2016 through 2035 in order to identify short-term, intermediate-term, and long-term infrastructure requirements.

Due to the ever-changing power industry, RPU has monitored its power supply needs regularly by commissioning infrastructure studies starting in 2005 with updates conducted in 2009 and 2012. These previous studies included several supply and demand side activities which RPU could pursue. RPU has continued to aggressively pursue demand side measures that allow customers to reduce their energy consumption. The reductions have targeted an amount of 1.5 percent of the expected retail energy sales for the year. The programs include numerous appliance efficiency upgrades, lighting change out, and direct load control programs.

In addition to continued conservation measures, RPU has a need to address several issues associated with its electric supply portfolio and resources including the following:

- Consider the addition of a new, efficient resources that can limit RPU's exposure to market prices
- Ability to accommodate potential sharp increases in load and energy requirements due to the Destination Medical Center (DMC) and Mayo Clinic (Mayo)
- Position RPU for short-term and long-term compliance with environmental regulations (namely potential carbon dioxide (CO_2) regulations)
- Short-term issues associated with an aging Cascade Creek Unit 1 and potential difficulties obtaining bi-lateral market capacity contracts

- Intermediate-term considerations with the expiration of the steam contract with Mayo in 2025
- Long-term power supply concerns with the expiration of the Southern Minnesota Municipal Power Agency Power Sales Contract in 2030

1.2 Review of Power Supply Conditions

1.2.1 Overall Electricity Industry Trends

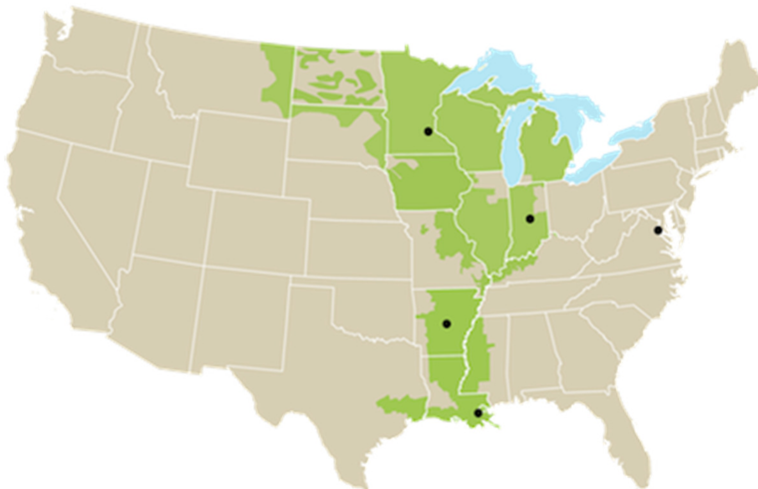
The electricity industry continues to be impacted by numerous trends. The following provides a brief discussion of the overall trends that are currently impacting electric utilities and generators.

- Environmental regulations: Both federal and state environmental regulating agencies continue to pursue more stringent environmental regulations regarding emissions from power generating facilities, specifically coal-fired power plants.
- Low natural gas prices: Natural gas prices remain low as production continues to outpace demand requirements, however industry forecasts appear to be fairly robust with price increases around five percent per year.
- Continued renewable development: Many state and federal regulators continue to pursue increased renewable portfolio and energy requirements.
- 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 has also led to lower load growth.
- 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 of the above factors, the investment in costly environmental compliance solutions at coal-fired power plants has reduced the overall economic benefit for many coal-fired plants and therefore coal-fired power plants are retiring.
- Increased interest in “firm” capacity: A number of factors have led to the increased interest in firm capacity including coal-fired retirements, recent extreme winter weather, and increased dependence of natural gas for the electric industry. If firm natural gas deliveries are required for power generators, it could increase the cost of production significantly.

1.2.2 MISO Energy Market

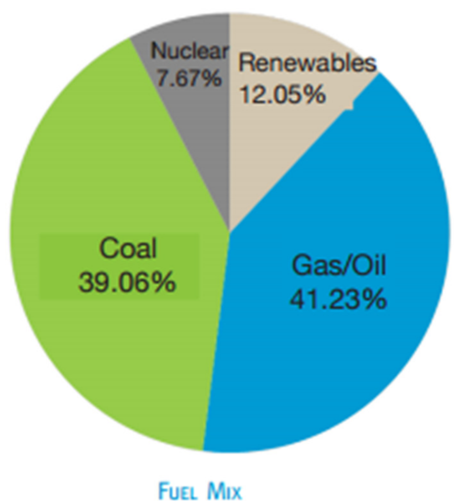
MISO initiated its energy market in 2005, at about the time of the issuance of the initial Infrastructure Plan. At the end of 2013, MISO added several utilities within the south, central portion of the U.S. The MISO market is made up of numerous utilities operating in the 15 states as presented in Figure 1-1.

Figure 1-1: MISO Energy Market Area



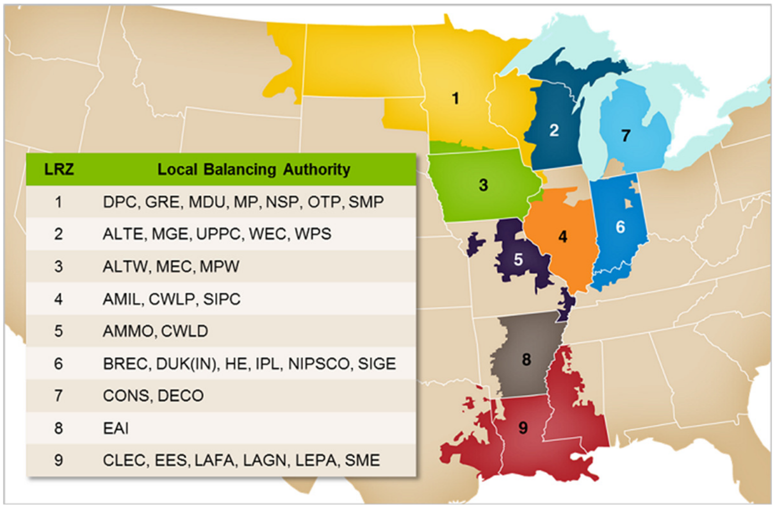
The addition of the southern area of the MISO market brought significantly more natural gas-fired generation resources into MISO. The mix of resources within MISO is shown in Figure 1-2.

Figure 1-2: MISO Energy Resource Mix (2014)



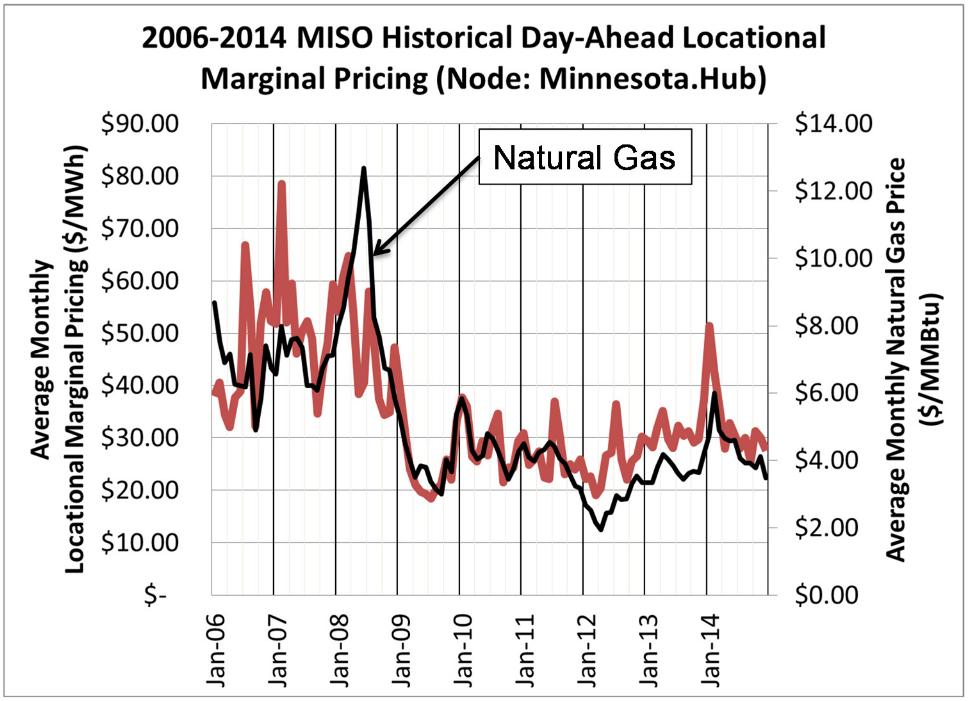
As part of the overall resource adequacy, MISO divided the overall MISO region into sub-regions called local resource zones (LRZ). Figure 1-3 presents an illustration of the LRZs within MISO. As illustrated within the graphic, RPU is located within LRZ 1. Though not required, most utilities procure capacity within their own LRZ to ensure they meet their capacity requirements. Capacity procured outside of a utility's LRZ may present a risk that the entire capacity is not credited toward their requirements should transmission limitations exist.

Figure 1-3: MISO Local Resource Zones



Utilities have become more accustomed to the market operations. It is common for utilities today to acquire all of their energy from the market and sell energy from their resources into the market when it is accepted for dispatch. In essence, all of the electrical energy RPU distributes above its contract with Southern Minnesota Municipal Power Agency (SMMPA) is acquired from the MISO market. The cost for this energy has been affected significantly from the initial operation of the market. The past few years have seen prices decline significantly from the peak year of 2007. Figure 1-4 provides annual averages of hourly locational marginal pricing (LMP) for day-ahead energy at the Minnesota Hub for several years.

Figure 1-4: MISO Energy Historical LMP Price



The decline in pricing is due to several factors including:

- Economic downturn and relatively slow economic and load growth
- Significant addition of wind resources (approximately 2 gigawatt (GW) in 2008 and now approximately 13 GW in 2014)
- Low pricing of natural gas

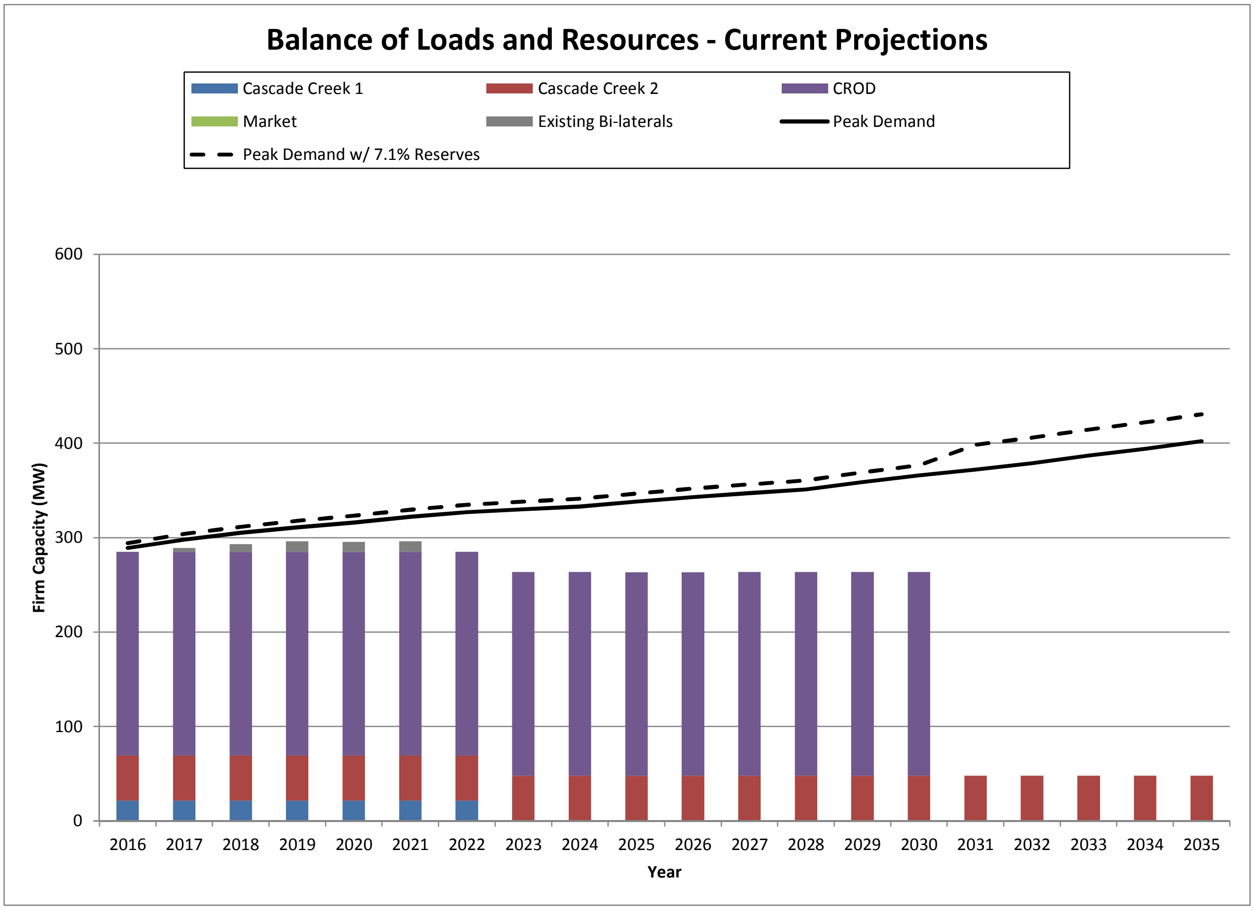
1.2.3 RPU Load and Resources

RPU's load forecast continues to be significantly below the initial forecast used in the 2005 Infrastructure Plan. The forecast used in this update is based on recent SMMPA projections, which was performed by a third-party company, Leidos, in compliance with MISO's standards. The adjusted forecast can be attributed to many factors including increased conservation programs and end-user efficiency. Therefore, it is inherently assumed in the forecast that the aggressive conservation reviewed in the initial Infrastructure Plan is capturing sufficient demand and energy to result in the SMMPA revised forecast.

In order for RPU to meet its load requirements, RPU has several power supply resources currently being utilized within its power supply portfolio including both local generation resources under RPU operating control and power supply contracts with other power generating entities.

A balance of loads and resources (BLR) based on the load forecast and resources that RPU will have available to meet its obligations are presented in Figure 1-5. Based on existing resources and current load projections, RPU will be capacity deficit both in the short-term and long-term, especially after the expiration of the SMMPA Power Sales Contract (PSC) Contract Rate of Delivery (CROD).

Figure 1-5: RPU Balance of Loads and Resources



In addition to the power supply contracts, RPU has a steam contract with the Mayo Clinic. Historically, RPU has provided Mayo with up to 50,000 pounds per hour (pph) of steam from one of the steam units at the Silver Lake Plant (SLP). As it was originally envisioned, the operation of the SLP on coal would allow the extraction of this steam for Mayo at a benefit for both parties. After the last Infrastructure Plan conducted in 2012 illustrated increased environmental regulation costs and dwindling economic benefits, RPU decided to retire SLP from coal-fired operation and electric generation altogether by the end of 2015. RPU has since elected to operate the existing SLP boilers utilizing natural gas fuel only. RPU will continue to provide approximately 50,000 pph of steam to Mayo through 2025.

1.3 Resource Analysis & Strategy

1.3.1 New Resources

The capacity and energy needs of RPU are projected to potentially increase substantially over the study period. There are two approaches to satisfy the capacity and energy obligations. These could be satisfied either from resources owned by RPU or contracted for through the market. Current EPA regulations have removed a new coal-fired power plant from consideration as a new resource. Therefore, gas-fired and renewable resources are the only realistic resource options that RPU could construct. The following resources were considered within this assessment:

- Reciprocating engine plant
- Simple cycle gas turbine aeroderivative technology
- Simple cycle gas turbine frame technology
- Combined cycle gas turbine (CCGT) frame technology
- Combined heat and power (CHP) facility
- Wind generation
- Solar generation

When RPU-owned resources were not available or economical, a bi-lateral contract for market capacity from an accredited resource was used to maintain reserve margins throughout the study period. Market capacity resources are modeled as temporary supply resources, expiring at the end of each year.

1.3.2 Power Supply Analysis

Utilizing the assumptions herein, BMcD developed future power supply plans utilizing the software program Strategist. Strategist evaluates thousands of combinations of power supply options for RPU to meet its load requirements. After Strategist developed several power supply paths, BMcD then evaluated the paths within the hourly dispatch commitment software of Promod. Table 1-1 presents the results of the dispatch analysis.

As presented in Table 1-1, Strategist developed four unique power supply paths for RPU. Appendix C presents the detailed results for each of the four paths. The following provides general observations for the power supply paths:

1. SMMPA PSC expires at the end of 2030.
2. A combined cycle gas turbine facility is added in 2031.
3. Solar and wind generation is added to meet state requirements.

4. Each case relies on purchases of capacity from the market, though the timing and magnitude vary depending on when each new resource is added.
5. Each case retires Cascade Creek Unit 1 and adds a reciprocating engine facility and CHP facility, though the timing of the installations is varied across the cases.
6. All four cases are very close in cost as illustrated with the net present value (NPV) for each case within 1.2 percent.

Table 1-1: Power Supply Paths and Costs

Path No.	1	2	3	4
Plan Year	**Retire CC1 2023, Install Peaker 2023**	**Retire CC1 2018, Install Peaker 2019**	**Retire CC1 2018, Install Peaker 2018**	**Retire CC1 2018, Install Peaker 2018, Install CHP 2026**
2016	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2017				
2018		Retire CC1	Retire CC1 Peaker (50MW)	Retire CC1 Peaker (50MW)
2019		Peaker (50MW)		
2020				
2021	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2022				
2023	Retire CC1 Peaker (50MW)			
2024				
2025				
2026				CHP (30MW)
2027				
2028	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2029	CHP (30MW)	CHP (30MW)	CHP (30MW)	
2030				
2031	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)
2032				
2033	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2034				
2035	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
NPV Cost ($000) *% Difference*	$1,498,056 *0.00%*	$1,506,011 *0.53%*	$1,507,624 *0.64%*	$1,515,469 *1.16%*

1.4 Summary

Based on the analysis presented herein, BMcD provides the following conclusions and recommendations:

1. Environmental groups and agencies continue to aggressively target coal-fired plants in regards to emissions.
   a. This will lead to additional coal-fired plant retirements.
   b. Increased retirements are anticipated to reduce market capacity availability and increase MISO energy prices.
2. With the retirement of SLP from electric generation, RPU lost its "middle of the road" hedge against MISO energy prices.
3. Due to its advanced age, continued operation of Cascade Creek Unit 1 may present additional risks
   a. Facing increased maintenance costs, inefficiency, lack of original equipment manufacturer (OEM) support, and questionable availability of spare parts
   b. Difficult to participate in MISO energy market
4. The infrastructure plans includes:
   a. Voluntary compliance with State of Minnesota renewable mandates
   b. Compliance with proposed CO_2 regulations
   c. Allows RPU to begin the transition away from joint action agency (SMMPA PSC)
   d. It may provide partnering opportunities after SMMPA PSC with other utilities
5. The infrastructure plan provides insight to several windows:
   a. Short-term: The addition of peaking resource and retirement of Cascade Creek 1 will allow RPU to maintain an appropriate amount of risk to market capacity pricing while also allowing RPU to control the retirement of Cascade Creek 1.
   b. Intermediate-term: The addition of a CHP facility appears favorable for RPU within its power supply portfolio and Mayo.
   c. Long-term: The likely replacement of SMMPA PSC is a combination of a CCGT unit and renewable generation.
6. Based on the current economic and market environment, there are several considerations for earlier development of peaking resource:
   a. Interest rates are currently low
   b. The current currency exchange rate (Euro to Dollar) is favorable for reciprocating engines which are primarily priced with the Euro.
   c. Controls capacity risk exposure (controls retirement of Cascade Creek 1)
   d. The capacity market within MISO has shown decreased availability of capacity and increased cost.
   e. Provides a replacement energy-hedge with the retirement of SLP and Cascade Creek 1

   f. Protects against exposure of Cost of New Entry (CONE) pricing, which is approximately $90,000 per megawatt (MW) per year with no benefit of energy revenue or asset investment.

7. RPU should continue to update the analysis of its future resource plans as major changes in the industry occur or as assumptions change from those used herein.

1.5 Infrastructure Plan Highlights

The following provides the overall highlights of the infrastructure plan update:

1. Positions RPU for long-term power supply with the expiration of the SMMPA Power Sales Contract (PSC) in 2030
2. Eliminates coal from the RPU portfolio by 2030 and significantly reduces carbon emissions
3. Meets renewable standards and objectives: 25 percent by 2025 renewable standard, 1.5 percent solar standard, 1.5 percent conservation standard
4. Has the flexibility to accommodate potential sharp increases or decreases in load and energy requirements due to DMC and customer solar
5. Positions RPU for short-term and long-term compliance with environmental regulations
6. Retires inefficient resource and modernizes the RPU generation fleet with high efficiency and low emission units
7. Expands partnership opportunities with the Mayo Clinic and other combined heat and power prospects

2.0 INTRODUCTION

Burns & McDonnell Engineering Company (BMcD) was retained by Rochester Public Utilities (RPU) to perform an Infrastructure Study (Study) building upon the previous infrastructure studies RPU has conducted in the past. This report provides information on the generation resource planning and other analyses undertaken to make updated decisions and recommendations on RPU's short-term and long-term strategy.

2.1 Rochester Public Utilities Overview

Rochester Public Utilities provides electric and water utilities to approximately 100,000 residents of Rochester, Minnesota. RPU has approximately 50,000 electric customers with a peak summer load of approximately 300 megawatt (MW). Additionally, RPU serves the Mayo Clinic (Mayo) providing both a portion of its electric and steam requirements.

2.2 Study Objectives

There continues to be significant impacts to utilities within the power industry due to the economic conditions, costs of fuel, and regulatory issues. These impacts require electric utilities to continuously monitor their infrastructure and power supply requirements to provide reliable, low cost power to their customers. The objective of this Study was to analyze the power supply needs of RPU from 2016 through 2035 in order to identify short-term, intermediate-term, and long-term infrastructure requirements.

2.3 Study Background

Due to the ever-changing power industry, RPU has monitored its power supply needs regularly by commissioning infrastructure studies starting in 2005 with updates conducted in 2009 and 2012. These previous studies included several supply and demand side activities which RPU could pursue. RPU has continued to aggressively pursue demand side measures that allow customers to reduce their energy consumption. These reductions have targeted an amount of 1.5 percent of the expected retail energy sales for the year. The programs include numerous appliance efficiency upgrades, lighting change out and direct load control programs. This Study provides a discussion of the progress that RPU has made in the area of demand side management and energy efficiency.

2.4 Study Methodology

The analysis of power supply options and issues required the projection of RPU's demand and energy over the study period. The forecast for the energy and demand was provided by RPU. The forecast was used as the basis for determining when additional resources would be needed to maintain the capacity reserve margins required by the MISO Energy (MISO, formerly known as Midwest Independent System Operator) and North American Electric Reliability Corporation (NERC).

The analysis of power supply options was performed using the Strategist resource expansion program and Promod hourly unit commitment dispatch model. The Strategist program analyzes the capacity and energy needs of a utility and adds resources from options provided to the software program. Strategist performs thousands of combinations evaluating the different resource portfolios. The Promod software program then takes power supply paths developed in Strategist and simulates hourly dispatch each year over the course of the study period. Various assumptions were developed for such things as capital costs, fixed operations and maintenance costs, fuel supply costs, and variable operating costs of potential new resources. In addition, BMcD developed assumptions for market costs at a representative RPU MISO node. The time frame for the updated resource analysis was from 2016 through 2035.

2.5 Study Organization

This study is organized into several sections as follows:

- Section 1.0: Executive Summary – Provides an executive summary of the Study
- Section 2.0: Introduction – Provides an introduction to the Study
- Section 3.0: Review of Power Supply Conditions – Details of the status of RPU power supply resources, system, and key forecast.
- Section 4.0: Resource Analysis & Strategy – Details the economic analysis evaluating the resource plans including the methodology and results.
- Section 5.0: Summary – Provides a summary of the assumptions and conclusions reached within this Study.

3.0 REVIEW OF POWER SUPPLY CONDITIONS

This section provides information regarding RPU's general power supply assumptions, local generating resources, power supply contracts, and key forecasts utilized within this Study.

3.1 General Power Supply Assumptions

The analysis began with the development of the baseline assumptions and constraints as applicable for RPU. The following general assumptions are applicable to the analysis:

- The study period covers the years 2016 through 2035.
- The hourly load used in this Study was based on information from 2013.
- The interest rate for RPU for financing terms was 5 percent, with resources financed over 30 years.
- The general escalation rate was assumed to be 2.5 percent.
- The discount rate was assumed to be 5 percent.

3.2 Overall Electricity Industry Trends

The electricity industry continues to be impacted by numerous trends. 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 from power generating facilities, specifically coal-fired power plants. One of the most recent regulations proposed by the U.S. Environmental Protection Agency (EPA) was the Clean Power Plan (CPP) specifically targeting a reduction in carbon dioxide (CO_2) emissions from existing coal-fired power plants through several avenues including performance improvements, fuel switching, and increased renewables and energy conservation.
- Low natural gas prices: Natural gas prices remain low as production continues to outpace demand requirements. Increased production is attributable to enhancements in fracking methods and technology. However, environmentalists and regulators continue to evaluate and debate the overall impacts on the environment due to fracking, and increased regulations, and thus increased costs, may be imposed. Furthermore, there is increased interest in developing liquefied natural gas (LNG) export facilities to allow for the U.S. and Canada to export natural gas to world markets with 21 proposed LNG export terminals in various stages of development across the U.S. and Canada (according to information from the Federal Energy Regulatory Commission (FERC)).

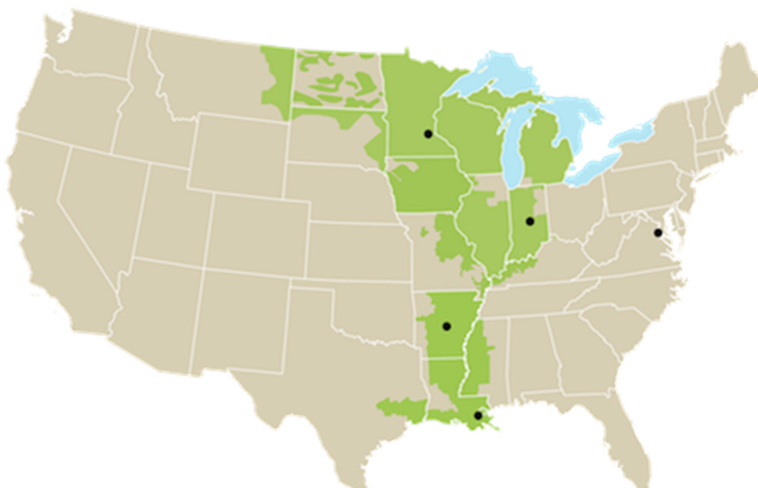
- Continued renewable development: In addition to the proposed CPP, many States continue to pursue increased renewable portfolio and energy requirements. Currently the federal government has tax incentives in place that incentivize renewable development through investment or production tax credits. While these tax credits are set to expire at the end of 2016, it remains to be seen if they will be extended as Congress has previously done.
- 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. Most of the U.S. has experienced relatively low load growth recently, with a few exceptions revolving around the oil/gas boom. Increased conservation programs have led to slower load growth as well. RPU has experienced relatively average growth compared to the U.S. overall which has been around one percent.
- 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. Wholesale market energy prices typically do not reflect fixed cost investments into resources, thus only reflect the variable and fuel cost components of energy production. With low natural gas prices, renewable generation being “dumped” to the market, and slower demand growth, market energy prices remain low.
- Coal-fired retirements: With the combination of all of the above factors, the investment in costly environmental compliance solutions at coal-fired power plants has reduced the overall economic benefit for many coal-fired plants. With the uncertainty in CO_2 regulations and dwindling economics, many coal-fired power plants have elected to cease coal-fired operation. Estimates of approximately 70 gigawatt (GW) of coal-fired capacity may be retired by 2020, representing approximately 25 percent of the entire U.S. coal-fired fleet.
- Increased interest in “firm” capacity: A number of factors have led to the increased interest in firm capacity including coal-fired retirements, recent extreme winter weather, and increased dependence of natural gas for the electric industry. As the regulations and economics drive the electric industry to increase its dependence on natural gas, the ability to provide firm capacity, especially during winter months, is a concern. Historically, natural gas-fired power plants were dispatched during the summer to meet increased demand due to air conditioning needs, when there is little competition for natural gas supply and deliveries. However, with the increased coal-fired power plant retirements, more natural gas-fired generation is going to be required during winter months when increased natural gas demand is prevalent due to residential and commercial heating needs. As such, many of the independent system operators are evaluating the overall reliability of the bulk electric system, especially during winter months, with increased reliance on

natural gas-fired power plants. If firm natural gas deliveries are required for power generators, it could increase the cost of production significantly.

3.3 MISO Energy Market

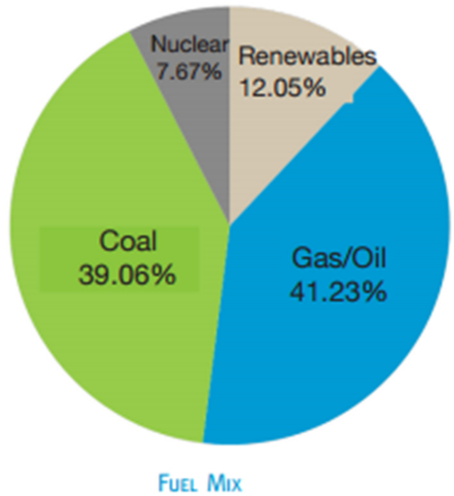
MISO initiated its energy market in 2005, at about the time of the issuance of the initial Infrastructure Plan. At the end of 2013, MISO added several utilities in the south-central portion of the U.S. The MISO market is made up of numerous utilities operating in the 15 states as presented in Figure 3-1.

Figure 3-1: MISO Energy Market Area



The MISO market has a peak load of approximately 127,000 MW. It has resources of approximately 180,000 MW with which to meet this load demand. In addition to these dispatchable resources, MISO has over 13,000 MW of wind generation in its market. The addition of the southern area of the MISO market brought significantly more natural gas-fired generation resources into MISO. The mix of resources within MISO is shown in Figure 3-2.

Figure 3-2: MISO Energy Resource Mix (2014)

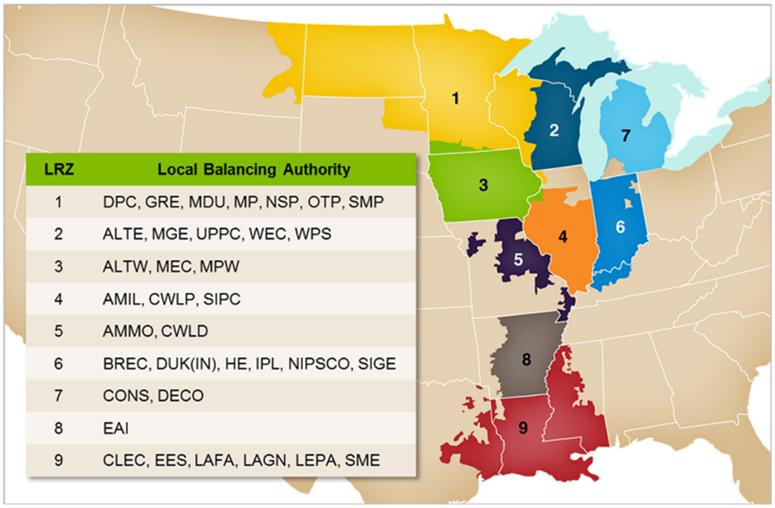


This market allows utilities to operate as they traditionally have and dispatch units they control to satisfy their load or to sell energy from their generation resources into the market and to purchase energy to meet their load requirements from the market. These purchase and sale transactions are performed on a daily basis. Over time, utilities have transitioned to selling generation into the market and procuring energy from the market.

Load serving utilities have two basic obligations in the MISO market. The first is to meet the capacity requirements for peak load demand plus reserve margin. The second is to be able to satisfy the energy requirements of its customers.

The market has matured and evolved in its business practices and standards for utilities. As a participant in the MISO market, RPU is subject to the business practices established by MISO and the MISO tariffs. One of these requirements is to maintain capacity reserves above its peak load obligations. MISO recently revised its capacity obligation requirements to be a function of a resource's overall reliability. Also, MISO recently launched a capacity auction process, however much of the capacity traded between utilities within MISO is still conducted via bi-lateral contracts. As part of the overall resource adequacy, MISO divided the overall MISO region into sub-regions called local resource zones (LRZ). Figure 3-3 presents an illustration of the LRZs within MISO. As illustrated within the graphic, RPU is located within LRZ 1. Though not required, most utilities procure capacity within their own LRZ to ensure they meet their capacity requirements. Capacity procured outside of a utility's LRZ may present a risk that the entire capacity is not credited toward their requirements should transmission limitations exist. In the event a utility does not procure sufficient capacity to meet its requirements, that utility may be exposed to short-term capacity penalty through MISO represented by the cost of new entry (CONE) pricing, which was approximately $90,000/MW-year recently that provides no benefit of energy revenue or asset investment.

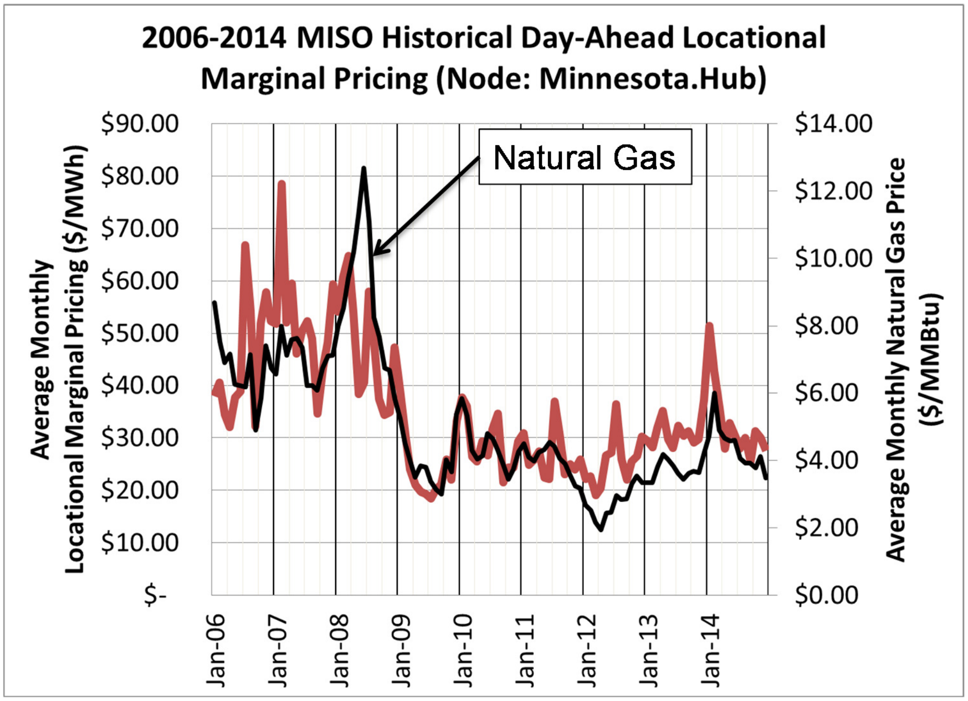
Figure 3-3: MISO Local Resource Zones



LRZ	Local Balancing Authority
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

Utilities have become more accustomed to the market operations. It is common for utilities today to acquire all of their energy from the market and sell energy from their resources into the market when it is accepted for dispatch. In essence, all of the electrical energy RPU distributes above its contract with SMMPA is acquired from the MISO market. The cost for this energy has been affected significantly from the initial operation of the market. The past few years have seen prices decline significantly from the peak year of 2007. Figure 3-4 provides annual averages of hourly locational marginal pricing for day ahead energy at the Minnesota Hub for nine years.

Figure 3-4: MISO Energy Historical LMP Price



The decline in pricing is due to several factors including:

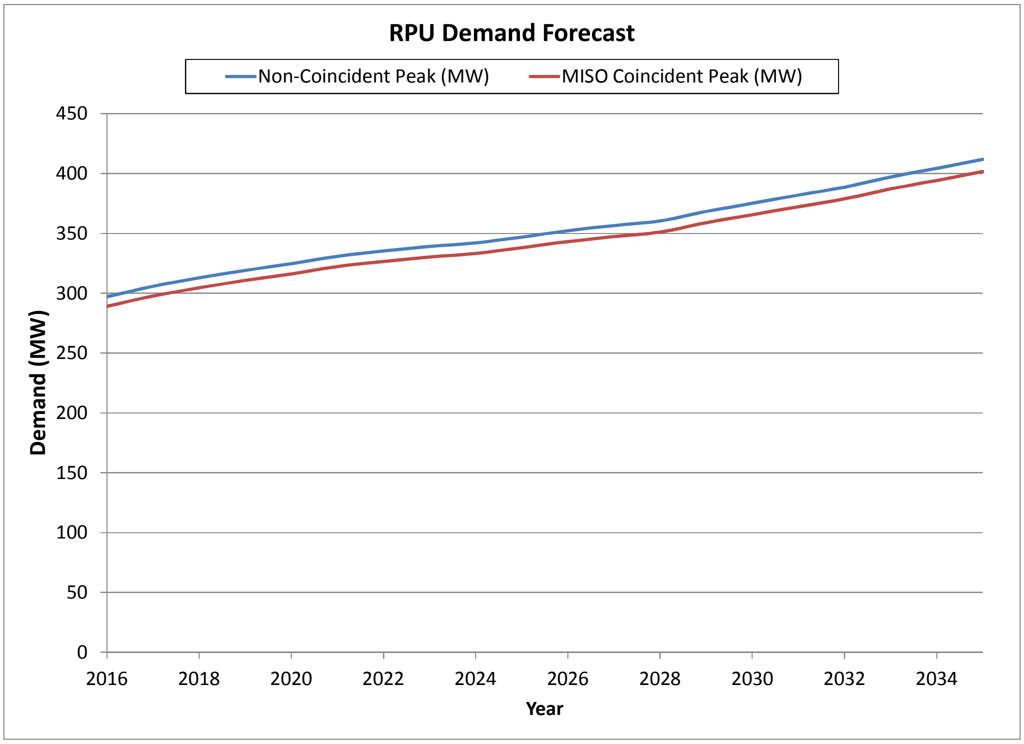
- Economic downturn and relatively slow economic and load growth
- Significant addition of wind resources (approximately 2 GW in 2008 and now approximately 13 GW in 2014)
- Low pricing of natural gas

Many utilities are able to take advantage of this pricing condition and acquire energy from the market much more economically than they could from operating their own generating assets. This has led many utilities to adopt a strategy of either contracting or installing low capital cost assets to meet the capacity obligations for load and reserves. They then buy energy from the market at a more economical average cost than is possible if they were to run the resources themselves. When possible, energy is sold from the resource into the market and this revenue is used to reduce the average power cost of the utility. Due to the attractive pricing in the MISO market, many small to medium sized utilities, such as RPU, are able to purchase energy at pricing well below their ability to generate it from their resources.

3.4 Load Forecast

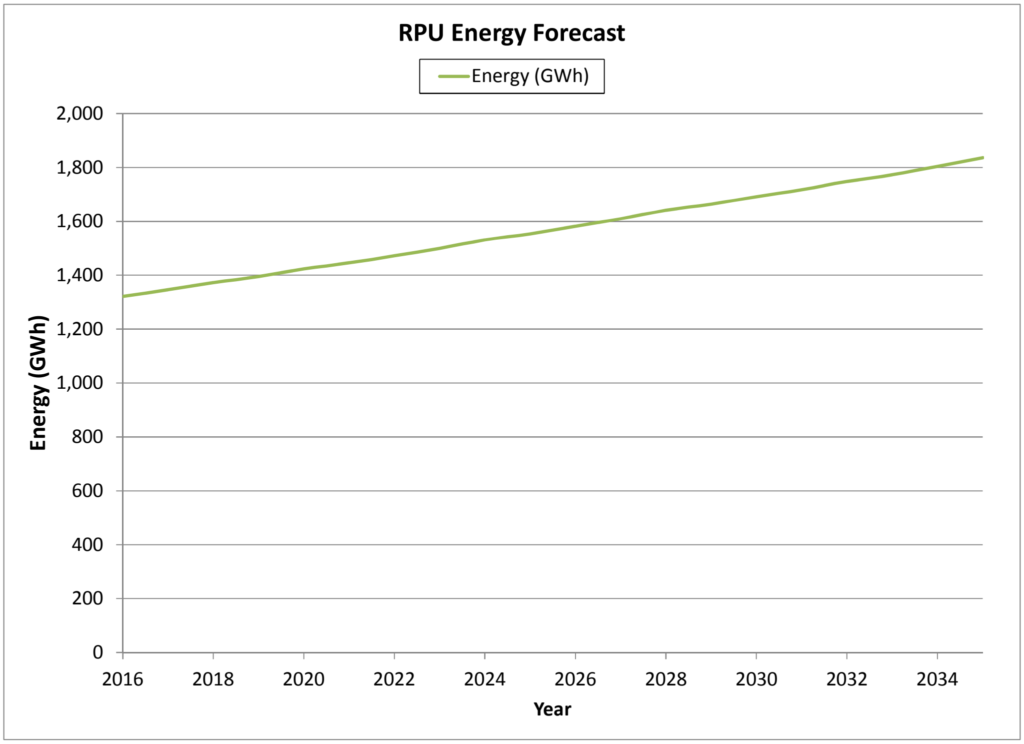
MISO requires that all members conduct an annual load forecast that has a well-defined methodology. RPU's annual forecast is developed by a third-party company, Leidos, through SMMPA. The load forecast was based on a recent SMMPA projection for RPU demand and energy requirements to 2030. The forecasts for demand and energy are summarized on an annual basis over the study period in Figure 3-5 and Figure 3-6, respectively.

Figure 3-5: RPU Demand Forecast



Note: The demand forecast for RPU was developed within SMMPA's planning process.

Figure 3-6: RPU Energy Forecast



Note: The energy forecast for RPU was developed within SMMPA's planning process.

RPU's load forecast continues to be significantly below the initial forecast used in the 2005 Infrastructure Plan. The forecast used in this update is based on recent SMMPA projections. The adjusted forecast can be attributed to many factors including increased conservation programs and end-user efficiency. Therefore, it is inherently assumed in the forecast that the aggressive conservation reviewed in the initial Infrastructure Plan is capturing sufficient demand and energy to result in the SMMPA revised forecast. Table 3-1 provides the estimated savings and cost of capturing the conserved energy and demand reductions.

Table 3-1: RPU Historical Energy Conservation and Spending

		Energy Conservation			Spending on Conservation Programs		
Year	Statute Requirement	Requirement (kWh)	Actual (kWh)	Percent to Goal	Required Spending	Actual Spending	Percent to Goal
2002	1.5% of GOR spending	169,000	7,562,201	4475%	$1,181,305	$1,115,327	94%
2003	1.5% of GOR spending	6,332,853	7,859,697	124%	$1,222,921	$1,327,321	109%
2004	1.5% of GOR spending	8,424,789	9,827,569	117%	$1,208,957	$1,167,760	97%
2005	1.5% of GOR spending	8,424,689	7,743,700	92%	$1,222,924	$1,213,517	99%
2006	1.5% of GOR spending	9,855,000	10,417,072	106%	$1,363,203	$1,377,074	101%
2007	1.5% of GOR spending	11,325,000	15,819,295	140%	$1,363,203	$1,995,606	146%
2008	1.5% of GOR spending	12,704,000	13,665,636	108%	$1,535,535	$1,698,407	111%
2009	0.75% Savings/1.5% Spending	16,274,333	16,994,220	104%	$1,744,800	$2,303,375	132%
2010	1.5% Savings / 1.5% Spending	19,100,443	19,126,719	100%	$1,814,398	$3,088,665	170%
2011	1.5% Savings / 1.5% Spending	19,100,443	20,420,120	107%	$1,896,508	$2,908,226	153%
2012	1.5% Savings / 1.5% Spending	18,785,066	23,248,077	124%	$1,926,061	$3,249,817	169%
2013	1.5% Savings / 1.5% Spending	18,563,927	29,842,896	161%	$1,893,582	$2,491,109	132%
2014	1.5% Savings / 1.5% Spending	18,610,704	22,102,056	119%	$1,932,964	$2,424,762	125%

Note: GOR is an abbreviation for gross operating revenues

3.5 Power Supply Resources

RPU has several power supply resources currently being utilized within its power supply portfolio including both local generation resources under RPU operating control and power supply contracts with other power generating entities. The following paragraphs provide information regarding these resources. Additional information regarding these resources is provided in Appendix A.

3.5.1 RPU Local Power Generating Resources

3.5.1.1 Cascade Creek Combustion Turbines

RPU owns and operates the Cascade Creek Combustion Turbines (Plant) located in Rochester that utilizes both fuel oil and natural gas to generate electricity. Specific details on the performance and costs of the units are presented in Appendix A.

Unit 1 is a nominal 27 MW combustion turbine that was commercial installed in 1975 and utilizes both natural gas and fuel oil. By today's standards Unit 1 is inefficient with a heat rate over 15,000 British thermal unit (Btu) per kilowatt-hour (kWh). Due to its advanced age, Unit 1 is going to require significant capital expenditures in the coming years in order to keep it operational. Furthermore, since the turbine is 40 years of age, the availability of spare parts is questionable moving forward.

Unit 2 consists of a natural gas-fired combustion turbine with a nominal output of approximately 48 MW. Unit 2 was installed in 2002.

Both combustion turbines are dispatched into the MISO market as peaking resources.

The city of Rochester, and the Plant, is served locally by the local distribution company (LDC) Minnesota Energy Resources, Co (MERC). MERC receives gas from the area interstate pipeline network at a high pressure. The pressure is reduced and distributed through a network of pipes within Rochester to retail consumers. Currently, RPU receives natural gas from MERC/Constellation/Northern Natural Gas (NNG) through an interruptible supply tariff. Historically during cold weather conditions, the gas suppliers have limited natural gas deliveries to RPU.

3.5.1.2 Lake Zumbro Hydroelectric

Lake Zumbro Hydroelectric Plant (Lake Zumbro) was built in 1920. Lake Zumbro has consistently provided RPU with a renewable supply of energy. The facility consists of a powerhouse and a 440-foot spillway built across the Zumbro River. The General Electric generators are driven at 225 revolutions per minute by 1,800-horsepower, Francis-type hydraulic turbines. This equates to approximately 1,300 kilowatts per wheel, which rates the station at an output of 2.6 MW.

3.5.1.3 Other Local Resources

In addition to the Plant and Lake Zumbro, RPU receives capacity and energy from several other resources including:

- Olmsted Waste-to-Energy Facility (OWEF): Energy resource only up to 5 MW
- IBM: Peak shaving resource approximately 3.6 MW

3.5.2 Southern Minnesota Municipal Power Agency Contract

In addition to the local power generation facilities described above, RPU has a PSC with SMMPA through CROD. The PSC with SMMPA is set to expire on December 31, 2030. The accounting of this energy is provided through the MISO settlement process and the contract with SMMPA. This contract requires RPU to purchase all of the retail energy it distributes at or below a rate of 216 MW per hour from SMMPA.

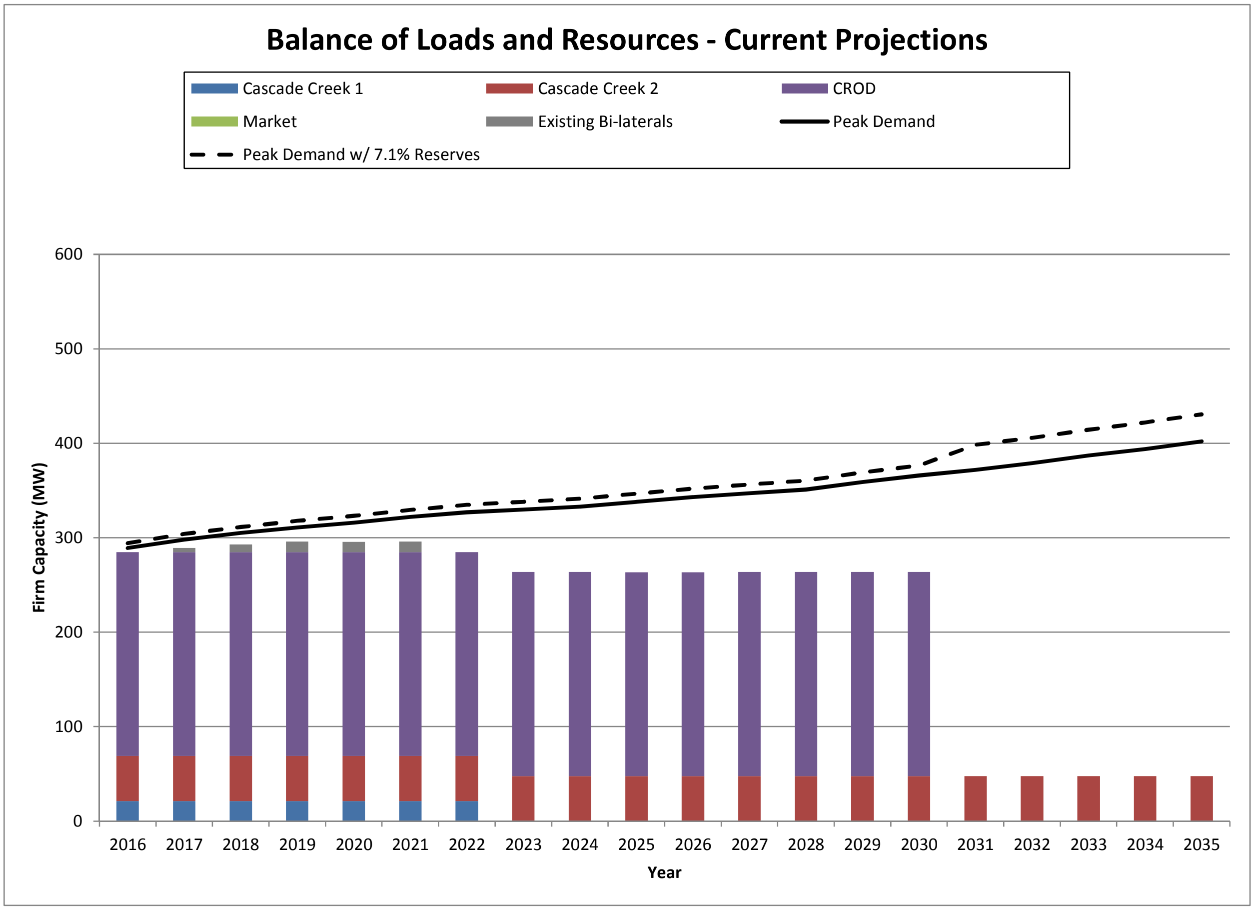
Specific details of the costs of the PSC discussed here are presented in Appendix A.

3.6 Balance of Loads and Resources

As described above, RPU has a number of resources to meet its capacity reserve margin requirements and renewable energy objectives. RPU meets a significant amount of its power supply obligations through its contract with SMMPA, which currently runs through 2030.

A balance of loads and resources (BLR) based on the load forecast and resources that RPU will have available to meet its obligations are presented in Figure 3-7. The reserve margin is based on RPU maintaining a margin of 7.1 percent for its load above CROD and under MISO's Module E Unforced Capacity (UCAP) resource adequacy method. As presented in Figure 3-7, Cascade Creek 1 is assumed to be retired from operation no later than the end of 2022 due to its age. Based on existing resources and current load projections, RPU will be capacity deficit both in the short-term and long-term, especially after the expiration of the SMMPA PSC CROD.

Figure 3-7: RPU Balance of Loads and Resources

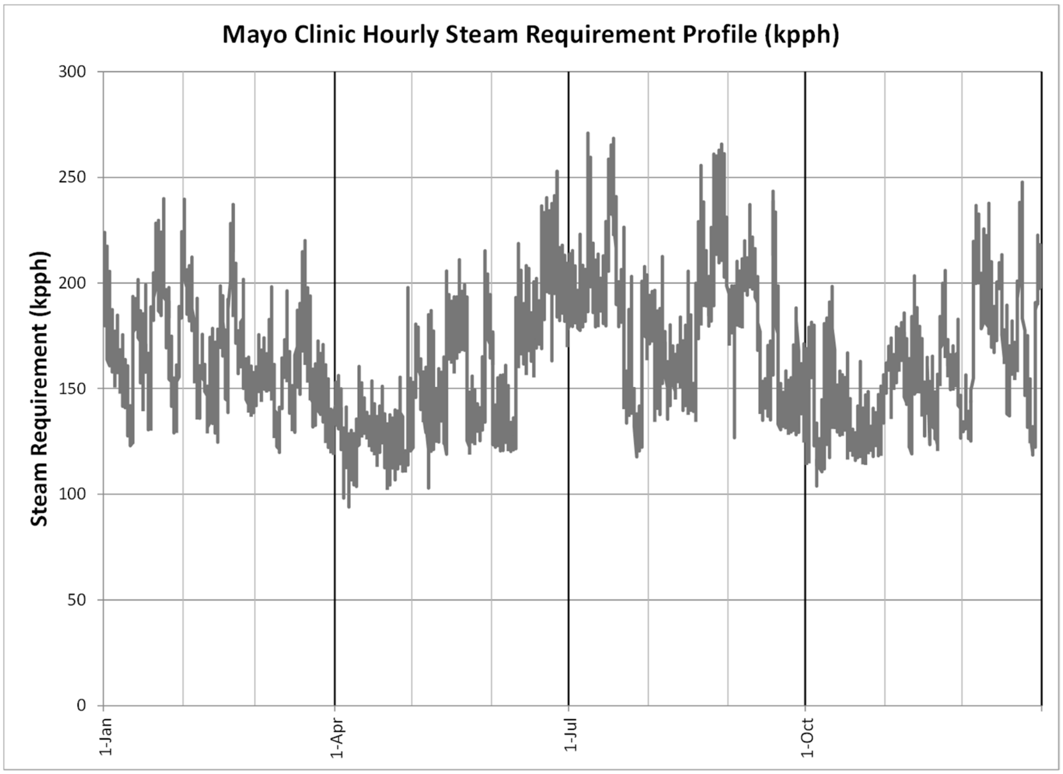


3.7 Mayo Clinic Steam

In addition to the power supply contracts, RPU has a steam contract with the Mayo Clinic. Historically, RPU has provided Mayo with up to 50,000 pph of steam from one of the steam units at the Silver Lake Plant (SLP). As it was originally envisioned, the operation of the SLP on coal would allow the extraction of this steam for Mayo at a benefit for both parties. After the last Infrastructure Plan conducted in 2012 illustrated increased environmental regulation costs and dwindling economic benefits, RPU decided to retire the Silver Lake Plant (SLP) from coal-fired operation and electric generation altogether by the end of 2015. RPU has since elected to operate the existing SLP boilers utilizing natural gas fuel only. RPU will continue to provide approximately 50,000 pph of steam to Mayo through 2025.

Overall, Mayo's internal steam and heat requirements are significantly higher than 50,000 pph and Mayo currently generates much of its heating requirements with internal power and steam producing equipment. Figure 3-8 presents a representative overall hourly steam requirement profile for the Mayo clinic.

Figure 3-8: Mayo Clinic Hourly Steam Requirement Profile



As presented in Figure 3-8, Mayo's steam requirements fluctuate from approximately 100 kilopounds per hour (kpph) to over 250 kpph. Both RPU and Mayo have indicated willingness to potentially partner with a combined heat and power (CHP) facility that would provide mutual benefits to both parties.

3.8 Forecasts

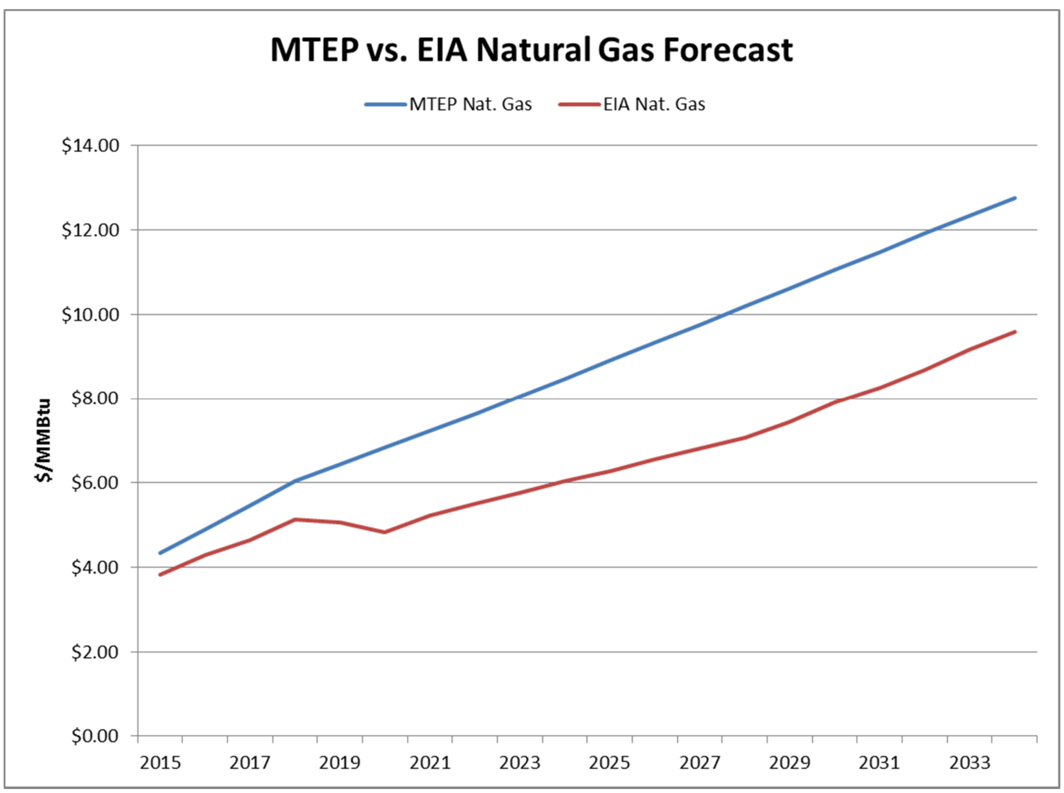
In order to conduct a long-term resource planning assessment for power supply, several forecasts have to be developed for evaluation. For this Study, BMcD developed key forecasts for fuel costs and market energy costs using reputable publicly available sources. The following paragraphs provide a summary of the forecasts developed and utilized within this Study. Further details of the forecasts are presented in Appendix A.

3.8.1 Fuel Cost Forecast

As part of its planning process to ensure electric grid reliability, MISO conducts numerous comprehensive studies of anticipating load, generation, and transmission projects. Part of this planning process requires MISO to project the cost of fuel and market energy. Within this Study, BMcD utilized the fuel forecast developed by MISO within MISO's transmission expansion planning (MTEP). MISO evaluates numerous futures considering varying levels of environmental regulation, renewable requirements, and economic growth. Using this data, BMcD developed a fuel forecast to utilize within this Study.

To compare the MTEP fuel forecast, BMcD also utilized projected information regarding natural gas fuel cost developed by the Department of Energy's (DOE) Energy Information Administration (EIA). Utilizing multiple forecasts that are considerably different provides the ability to assess the resource plan under varying assumptions. This provides for a more robust evaluation to determine whether one resource path appears more favorable under a different set of economic forecasts. Figure 3-9 presents both the MTEP and EIA natural gas forecasts. The MTEP forecast served as a basis for this Study.

Figure 3-9: Natural Gas Cost Forecast



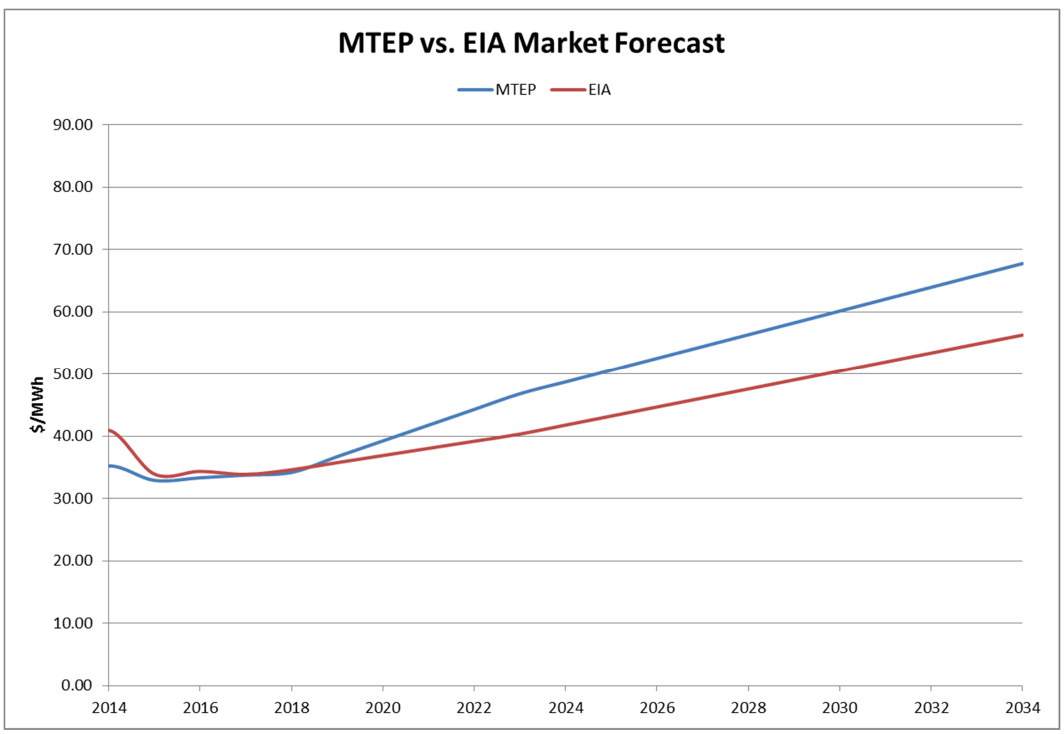
As presented in Figure 3-9, in the near term (from 2015 to 2019) both the MTEP and EIA natural gas forecasts are nearly the same. However, in the long-term (beyond 2020) the MISO MTEP fuel forecast is higher by approximately 15 to 20 percent.

3.8.2 Market Energy Cost Forecast

Similar to the discussion above regarding the natural gas cost forecast, BMcD utilized the market energy forecast developed by MISO within MISO's transmission expansion planning. Specifically, BMcD utilized the MTEP forecasted locational marginal pricing (LMP) for RPU. MISO evaluates numerous futures considering varying levels of environmental regulation and economic growth. Using the MTEP futures and data, BMcD developed a market energy forecast to utilize within this Study.

In addition to using the MISO data, BMcD also utilized the fuel cost forecast information developed by the EIA and made adjustments to the market energy cost forecast to account for a lower projected cost of natural gas. Figure 3-10 presents the market energy cost forecast utilizing both the MISO MTEP values and the EIA values.

Figure 3-10: Market Energy Cost Forecast



As illustrated in Figure 3-10, the market energy cost forecast for MTEP and EIA follows the same trend as the natural gas cost forecast, with both forecasts being fairly similar in the near-term. However, long-term the MTEP forecast is considerably higher by 15 to 20 percent. For this Study, BMcD utilized the MTEP forecast for market energy prices as the base assumption.

3.8.3 Market Capacity Cost Forecast

Capacity in the MISO market is required for utilities to meet their reserve margin obligations. The MISO market does include a specific market for capacity. However, utilities are not forced to participate within the capacity market auction and much of the capacity is traded on a bi-lateral basis between parties. Utilities can contract from a variety of parties to meet their capacity obligations, but are encouraged to contract capacity within their LRZ in order to avoid the risk of transmission limitations and not receiving the full credit for the capacity. In the current MISO capacity construct, this capacity must be sourced from a specific generating resource capable of supplying the capacity stated in the contract. The capacity that is credited to the generating resource is also based on the individual generating resource's performance in regards to availability and reliability. Resources that operate more reliability will receive a larger percentage of its generating capability. Conversely, resources that experience significant outages are de-rated and only receive portion of their maximum output. Under this rule, generators are strongly encouraged to operate reliably in order to receive the largest portion of their capacity.

The price of capacity within MISO has been historically low and significantly below the cost of a newly constructed resource. However, with the retirement of additional coal-fired generation, market capacity has started increasing in cost and the availability of such capacity has decreased as illustrated through RPU's recent capacity contracts.

For this Study, BMcD assumed that RPU is still willing to consider purchasing bi-lateral market capacity to fulfill its resource adequacy requirements as a participant in MISO.

3.9 New Generation Resources

The capacity and energy needs of RPU are projected to potentially increase substantially over the study period. There are two approaches to satisfy the capacity and energy obligations: either from resources owned by RPU or contracted for through the market. Current EPA regulations have removed a new coal fired power plant from consideration as a new resource. Therefore, gas-fired and renewable resources are the only realistic resource options that RPU could construct. The following resources were considered within this assessment:

- Reciprocating engine plant
- Simple cycle gas turbine (SCGT) aeroderivative technology
- Simple cycle gas turbine frame technology

- Combined cycle gas turbine (CCGT) frame technology
- Combined heat and power facility
- Wind generation
- Solar generation

When owned resources were not available or economical, a contract for market capacity from an accredited resource was used to maintain reserve margins throughout the study period. Market capacity resources are modeled as temporary supply resources, expiring at the end of each year.

Table 3-2 presents a summary of the cost and performance estimates for the new resources considered within this Study for meeting RPU's future capacity and energy requirements. Further operating and cost estimate assumptions for the new resources can be found in Appendix B.

Table 3-2: New Resource Cost and Performance Summary

PROJECT TYPE	Reciprocating Engine	Aeroderivative SCGT	"F-Class" SCGT	"F-Class" CCGT	Combined Heat and Power Facility	50 MW Wind	Solar
BASE PLANT DESCRIPTION							
Number of Gas Turbines, Engines or Boilers	6	1	1	1	1	22	N/A
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	N/A	N/A
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
PERFORMANCE							
Summer Peak Performance							
Total Net Fired Plant Output, kW	54,600	44,900	213,800	412,300	32,200	50,000	500
Total Net Fired Plant Heat Rate, Btu/kWh (HHV)	8,490	9,690	9,890	7,110	4,150	N/A	N/A
Total Net Fired Plant Heat Input, MMBtu/h (HHV)	460	440	2,110	2,930	134	N/A	N/A
Assumed Firm Capacity Credit for MISO, kW	52,000	43,000	203,000	392,000	31,000	7,000	8% of Output
CAPITAL COSTS							
Total Plant Capital Costs							
Project Cost, 2015M$ (w/o Owner's Costs)	$51	$58	$100	$314	$54	$90	$1.2
Owner's Costs 2015M$ (without Escalation and IDC)	$15	$18	$32	$60	$17	Incl. in Project Costs	Incl. in Project Costs
Total Capital Cost, 2015M$	$65	$77	$132	$374	$71	$90	$1.2
Total Capital Cost 2015$/kW Avg Annual Fired Output	$1,199	$1,712	$615	$912	$2,214	$1,804	$2,440
NON-FUEL OPERATION & MAINTENANCE COSTS							
Fixed O&M Cost, 2015$/kW-Yr	$10.97	$23.78	$7.18	$12.81	$18.60	$18.45	$11.89
Engine Major Maintenance, 2015$/Start/GT (Note 2 & 3)	N/A	N/A	$15,375	$15,375	N/A	N/A	N/A
Engine Major Maintenance, 2015$/GT-h (Note 2 & 3)	$24	$195	$410	$410	$138	N/A	N/A
Engine Major Maintenance, 2015$/MWh (Note 2 & 3)	$2.59	$4.34	$1.92	$1.29	$4.30	N/A	N/A
Variable O&M, 2015$/MWh (excl. major maintenance)	$4.51	$6.66	$0.92	$1.33	$6.66	Incl. In Fixed	Incl. In Fixed
Total Non-Fuel Variable O&M, 2015$/MWh	$7.10	$11.00	$2.84	$2.63	$10.96	N/A	N/A

Note: Further details of cost and performance estimates including the underlying assumptions are presented in Appendix B.

4.0 RESOURCE ANALYSIS & STRATEGY

RPU has a need to address several issues associated with its electric supply portfolio and resources including the following:

- Consider the addition of a new, efficient resource to limit exposure to high MISO market energy and capacity prices
- Ability to accommodate potential sharp increases in load and energy requirements due to the Destination Medical Center (DMC) and Mayo
- Position RPU for short-term and long-term compliance with environmental regulations (namely potential CO_2 regulations)
- Short-term issues associated with an aging Cascade Creek Unit 1 and potential capacity deficits
- Intermediate-term considerations with the expiration of the steam contract with Mayo in 2025
- Long-term power supply concerns with the expiration of the SMMPA PSC CROD in 2030

In order to assess options that might be beneficial to pursue with regards to these issues, BMcD developed scenarios of various resource options that RPU could follow. This part of the report provides a summary of that analysis.

Various resource planning assumptions and considerations were developed and analyzed using Ventyx's Strategist and Promod software programs to study the various futures considered viable for RPU. The Strategist model is a resource portfolio optimization model that allows an analysis of several different resources with a variety of characteristics to meet the load requirements and any other defined constraints over a finite period of time. The model develops potentially thousands of resource combinations based on the scenario-defined constraints, ranking these combinations by net present value (NPV) over the study period. This allows the selection of the lowest evaluated cost combination of resources, including optimal size and implementation schedules for new resources, based on the performance and construction costs provided. Scenarios were developed to analyze the various approaches which RPU could use to meet its obligations.

Using the results of the Strategist model, BMcD then selected several power supply futures to evaluate within Promod, an hourly dispatch commitment program that can simulate the dispatch of RPU's resources against both RPU's load and MISO market energy prices. Promod provides a granular evaluation of the anticipated operation of RPU's power supply for each hour of the year over the 20-year study period.

4.1 Power Supply Plan Model Development

In order for Strategist to optimize RPU's power supply portfolio, several assumptions were included within the model. The following provides a summary of the major assumptions included within the model:

1. The load forecast for both demand and energy was utilized for RPU based on SMMPA's planning efforts.
2. The MTEP developed forecasts for natural gas costs and market energy prices were utilized as the basis for this Study.
3. Due to its age, condition, and the potential of limited availability of spare parts, Cascade Creek Unit 1 was assumed to be retired in the event a new generator was built by RPU.
4. Renewable requirements (Appendix A provides additional information regarding the schedule of renewable generation)
    a. While CROD is in effect, most of RPU's renewable requirements will be satisfied under the SMMPA PSC.
    b. For renewable requirements over CROD, it has been assumed that RPU will contract for additional solar capacity and energy.
    c. After CROD is terminated, it has been assumed that RPU will meet the State of Minnesota's overall goal of 25 percent renewable energy with wind resource contracts and also comply with the State of Minnesota's solar requirements.
    d. Per MISO, solar and wind resources were given an 8 percent and 14 percent of nameplate capacity credit, respectively, for resource adequacy requirements.
5. For the purposes of planning, a limit of 52 MW was placed on the amount of capacity that RPU would acquire from the market through bi-later contracts before a unit would be constructed by RPU. This limit was selected as it is equal to the overall firm output of the reciprocating engine resource.
6. For the CHP option, it is assumed that fuel costs are passed through to Mayo at a typical consumption rate of a natural gas-fired boiler. Remaining fuel that is attributable to power generation was accounted for within RPU's power supply costs as well as all capital and operational costs.

4.2 Power Supply Analysis

Utilizing the assumptions described herein, BMcD developed future power supply plans utilizing the software program Strategist. After Strategist developed several power supply paths, BMcD then evaluated the paths within the hourly dispatch commitment software of Promod. Table 4-1 presents the results of the dispatch analysis.

As presented in Table 4-1, Strategist developed four unique power supply paths for RPU. Appendix C presents the detailed economic results and BLR charts for each of the four paths. Figure 4-1, Figure 4-2, Figure 4-3, and Figure 4-4 present an illustration of the total annual power supply costs, fixed costs, variable costs, and net market interactions, respectively, for each power supply path.

The following provides general observations for the power supply paths:

1. CROD expires at the end of 2030.
2. A combined cycle gas turbine facility is added in 2031.
3. Solar generation is added in 2016 at 500 kW, 2021 at 3 MW, 2028 at 3 MW, 2031 at 11.5 MW, 2033 at 0.5 MW, and 2035 at 0.5 MW.
4. Wind generation is added in 2031 at 150 MW total.
5. Each path relies on purchases of capacity from the market, though the timing and magnitude vary depending on when each new resource is added.
6. Each path retires Cascade Creek Unit 1 and adds a reciprocating engine facility and CHP facility, though the timing of the installations is varied across the cases.
7. All four paths are very close in costs illustrated with the NPV for each case within 1.2 percent.
    a. All four have fairly consistent growth rates of total power supply costs and similar costs in generation
    b. Depending on cost allocations, there is a substantial shift in fixed costs, variable costs, and net market interactions after the expiration of the SMMPA PSC CROD in 2031. Based on the cost allocation assumed herein, for all four paths starting in 2031 the fixed costs increase substantially, variable costs decrease substantially, and MISO market energy purchases increase substantially [note: most of the renewable costs have been assumed to be fixed cost components within this evaluation].

Table 4-1: Power Supply Paths and Costs

Path No.	1	2	3	4
Plan Year	**Retire CC1 2023, Install Peaker 2023**	**Retire CC1 2018, Install Peaker 2019**	**Retire CC1 2018, Install Peaker 2018**	**Retire CC1 2018, Install Peaker 2018, Install CHP 2026**
2016	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2017				
2018		Retire CC1	Retire CC1 Peaker (50MW)	Retire CC1 Peaker (50MW)
2019		Peaker (50MW)		
2020				
2021	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2022				
2023	Retire CC1 Peaker (50MW)			
2024				
2025				
2026				CHP (30MW)
2027				
2028	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2029	CHP (30MW)	CHP (30MW)	CHP (30MW)	
2030				
2031	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)
2032				
2033	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2034				
2035	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
NPV Cost ($000) *% Difference*	$1,498,056 *0.00%*	$1,506,011 *0.53%*	$1,507,624 *0.64%*	$1,515,469 *1.16%*

Figure 4-1: Total Annual Wholesale Power Supply Costs

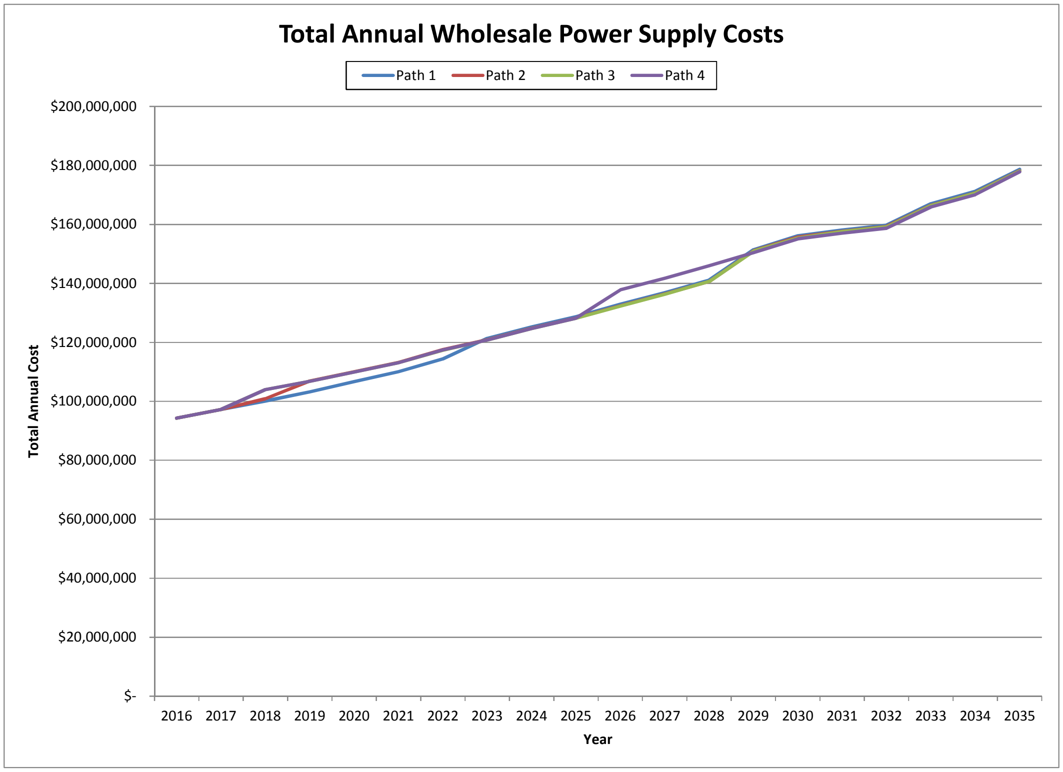


Figure 4-2: Total Fixed Costs (Fixed O&M, Debt Service & Demand Charges)

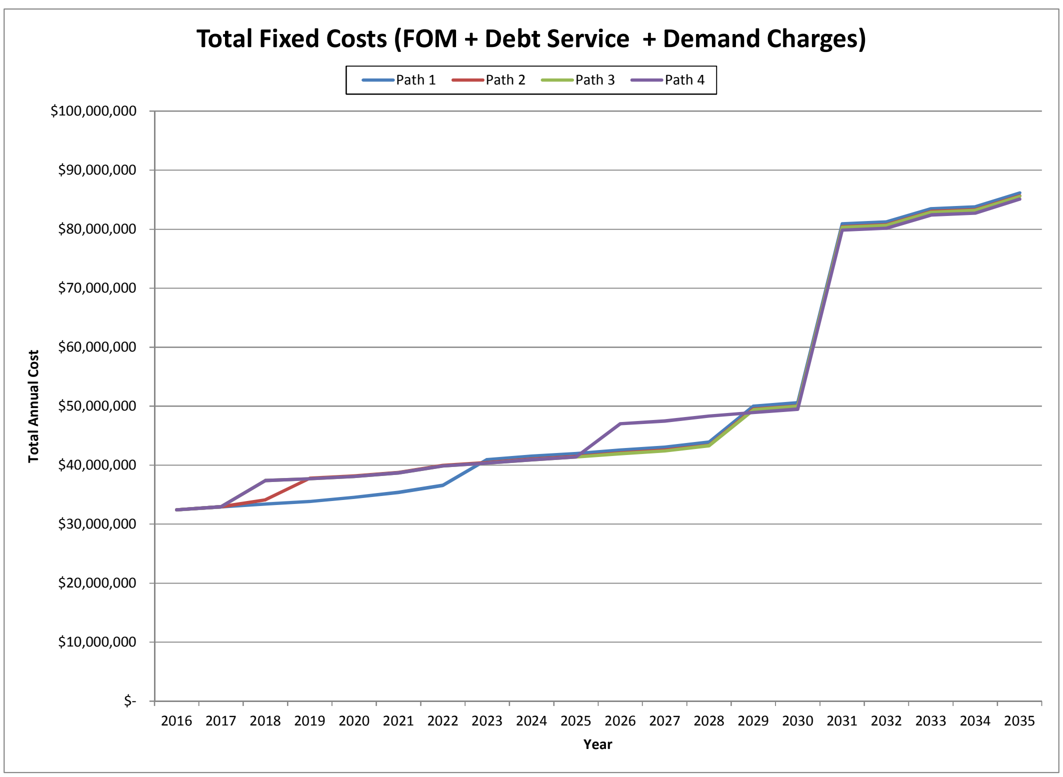


Figure 4-3: Total Variable Costs (Variable O&M & Fuel)

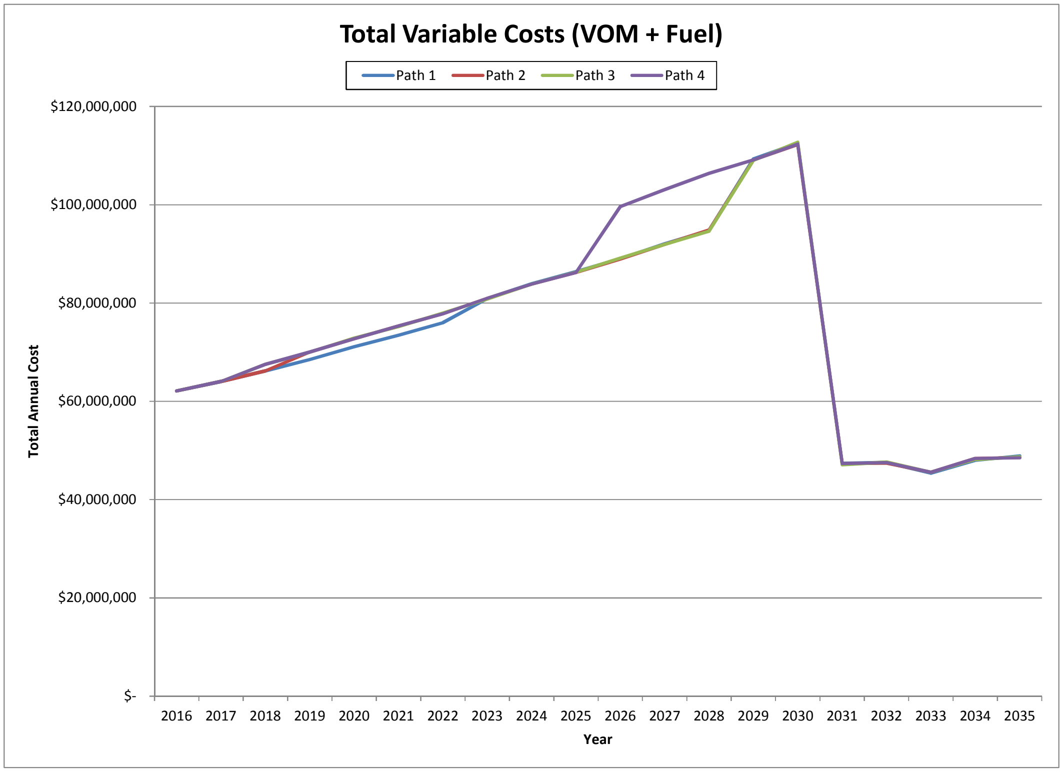
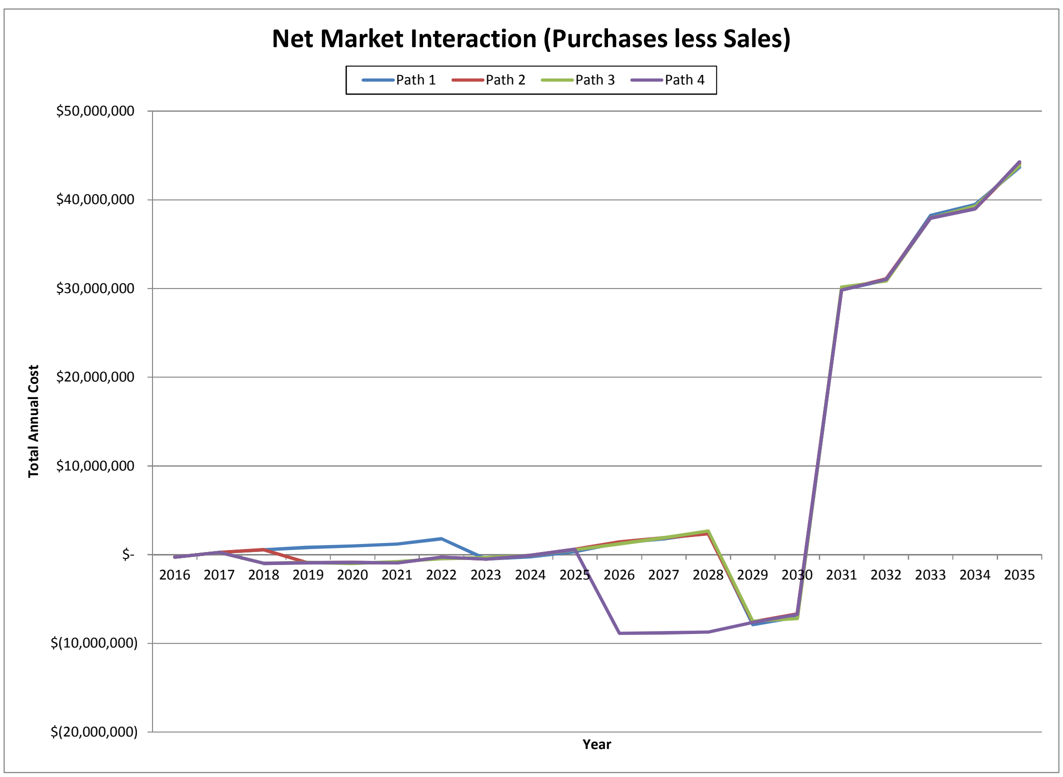


Figure 4-4: Net Market Interactions (Purchases less Sales)



4.3 Sensitivity Considerations

With any power supply plan, evaluating alternative assumptions is important to determine how the power supply path may be impacted should key assumptions vary from those in the base case. In this case, major changes within assumptions for RPU will not greatly impact the infrastructure plan moving forward. Below provides a discussion of the potential impacts that may occur due to changes within key assumptions of forecasts.

- Fluctuations in natural gas and energy prices
  - Due to EPA regulations, the only future is natural gas and renewables within RPU's power supply portfolio (though some MISO market energy will be provided by existing coal resources outside of RPU).
  - For self-build dispatchable resources, RPU will be tied to natural gas fuel regardless of the path.
  - Will not have a large impact on the path forward for RPU meeting its capacity and energy requirements. However, the magnitude of the overall power supply costs will be affected by fluctuations in natural gas and energy prices.
- Increased renewable requirement over 25 percent
  - The main driver for new resources is capacity; wind and solar generation do not provide significant capacity.
  - Increased renewables requirements will likely require "over" procuring of resources.
- Pace of load growth
  - Low load growth (or increased conservation) will avoid energy cost from CROD or MISO market, but the path forward will be relatively unchanged and will likely lead to procuring less market capacity/energy.
  - High load growth (or new load) may accelerate the need for additional capacity resources, though the specific path and resources will remain relatively unchanged, but the timing of the resources may need to be moved forward.
- CO_2 costs
  - Overall MISO market prices will be affected as MISO market energy is dependent on both coal-fired and natural gas-fired resources.
  - RPU's new resources will be compliant, efficient, and competitive within the MISO market.

5.0 SUMMARY

5.1 Summary of Key Assumptions and Conclusions

Based on the analysis presented herein, BMcD provides the following summary of assumptions and conclusions:

1. Environmental groups and agencies continue to aggressively target coal-fired plants in regards to emissions.
    a. This will lead to additional coal-fired plant retirements.
    b. Increased retirements are anticipated to reduce market capacity availability and increase MISO energy prices.
2. With the retirement of SLP from electric generation, RPU lost its "middle of the road" hedge against MISO energy prices.
3. Due to its advanced age, continued operation of Cascade Creek Unit 1 may present additional risks
    a. Facing increased maintenance costs, inefficiency, lack of OEM support, and questionable availability of spare parts
    b. Difficult to participate in MISO energy market
4. The infrastructure plans includes:
    a. Voluntary compliance with State of Minnesota renewable mandates
    b. Compliance with proposed CO_2 regulations
    c. Allows RPU to begin the transition away from joint action agency (SMMPA PSC)
    d. It may provide partnering opportunities after SMMPA PSC with other utilities
5. The infrastructure plan provides insight to several windows:
    a. Short-term: The addition of peaking resource and retirement of Cascade Creek 1 will allow RPU to maintain an appropriate amount of risk to market capacity pricing while also allowing RPU to control the retirement of Cascade Creek 1.
    b. Intermediate-term: The addition of a CHP facility appears favorable for RPU within its power supply portfolio and Mayo.
    c. Long-term: The likely replacement of SMMPA PSC is a combination of CCGT unit and renewable generation.
6. Based on the current economic and market environment, there are several considerations for earlier development of peaking resources:
    a. Interest rates are currently low

   b. The current currency exchange rate (Euro to Dollar) is favorable for reciprocating engines which are primarily priced with the Euro.
   c. Controls capacity risk exposure (controls retirement of Cascade Creek 1)
   d. The capacity market within MISO has shown decreased availability of capacity and increased cost.
   e. Provides a replacement energy-hedge with the retirement of SLP and Cascade Creek 1
   f. Protects against exposure of Cost of New Entry (CONE) pricing, which is approximately $90,000/MW-year with no benefit of energy revenue or asset investment.
7. RPU should continue to update the analysis of its future resource plans as major changes in the industry occur or as assumptions change from those used herein.

5.2 Infrastructure Plan Highlights

The following provides the overall highlights of the infrastructure plan update:

1. Positions RPU for long-term power supply with the expiration of the SMMPA Power Sales Contract (PSC) in 2030
2. Eliminates coal from the RPU portfolio by 2030 and significantly reduces carbon emissions
3. Meets renewable standards and objectives: 25 percent by 2025 renewable standard, 1.5 percent solar standard, 1.5 percent conservation standard
4. Has the flexibility to accommodate potential sharp increases or decreases in load and energy requirements due to DMC and customer solar
5. Positions RPU for short-term and long-term compliance with environmental regulations
6. Retires inefficient resource and modernizes the RPU generation fleet with high efficiency and low emission units
7. Expands partnership opportunities with the Mayo Clinic and other combined heat and power prospects

APPENDIX A – POWER SUPPLY STUDY ASSUMPTIONS

FINANCIAL ASSUMPTIONS

- Inflation/escalation rate: 2.5 percent
- Interest rate: 5.0 percent
- Financing Period: 30 years
- Discount rate for NPV calculations: 5.0 percent
- Actual 2013 hourly load shape used for system profile. This hourly load shape is then adjusted for each year to meet the peak demand and total annual energy.

GENERATION RESOURCES

Cascade Creek 1

- Gas fired combustion turbine
- Commercial operation on 6/1/1975
- 27 MW summer capacity
- 21.2 MW UCAP
- 15,112 Btu/kWh heat rate
- Fixed O&M $7.86/kW-year, 2015$, escalated at inflation
- Variable O&M $1.59/MWh, 2015$, escalated at inflation
- 21.3% forced outage rate

Cascade Creek 2

- Gas fired combustion turbine
- Commercial operation on 4/1/2002
- 49.9 MW summer capacity
- 47.4 MW UCAP
- 10,917 Btu/kWh heat rate
- Fixed O&M $4.43/kW-year, 2015$, escalated at inflation
- Variable O&M $1.59/MWh, 2015$, escalated at inflation
- 4.34% forced outage rate

IBM

- Two diesel fired combustion engines
- Commercial operation on 10/1/2005
- 3.6 MW summer capacity
- 9,589 Btu/kWh heat rate
- No variable or fixed O&M costs modeled

Lake Zumbro

- Hydroelectric plant
- Commercial operation on 11/1/1984
- 2 MW summer capacity
- Fixed O&M $19.70/kW-year, 2015$, escalated at inflation

Olmsted Waste-to-Energy Facility

- Solid waste fired steam turbine
- Commercial operation on 4/1/1987
- 2 MW summer capacity
- Variable O&M $1.06/MWh, 2015$, no escalation

SMMPA PSC CROD

- 216 MW capacity
- Contract expires after 12/31/2030

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Demand ($/kW-mo)	Trans. ($/kW-mo)
2016	$55.21	$41.27	$10.66	$2.66
2017	$56.32	$42.09	$10.66	$2.66
2018	$57.44	$42.94	$10.66	$2.66
2019	$58.59	$43.80	$10.66	$2.66
2020	$59.76	$44.67	$10.66	$2.66
2021	$60.96	$45.56	$10.66	$2.66
2022	$62.18	$46.48	$10.66	$2.66
2023	$63.42	$47.41	$10.66	$2.66
2024	$64.69	$48.35	$10.66	$2.66
2025	$65.98	$49.32	$10.66	$2.66
2026	$67.30	$50.31	$10.66	$2.66
2027	$68.65	$51.31	$10.66	$2.66
2028	$70.02	$52.34	$10.66	$2.66
2029	$71.42	$53.39	$10.66	$2.66
2030	$72.85	$54.45	$10.66	$2.66

FORECASTS

RPU Demand and Energy Forecast

Year	Non-Coincident Peak (MW)	MISO Coincident Peak (MW)	Energy (GWh)
2016	297.0	289.1	1,321.3
2017	305.8	297.7	1,346.4
2018	312.8	304.5	1,372.4
2019	319.1	310.7	1,395.8
2020	324.6	316.1	1,423.3
2021	330.9	322.2	1,445.9
2022	335.3	326.6	1,472.2
2023	339.1	330.3	1,500.1
2024	342.1	333.2	1,531.4
2025	347.0	338.0	1,553.5
2026	352.2	343.2	1,582.0
2027	356.5	347.4	1,609.7
2028	360.3	351.1	1,640.9
2029	368.4	359.0	1,664.2
2030	375.1	365.6	1,691.3
2031	382.0	372.3	1,717.2
2032	388.6	378.8	1,748.0
2033	397.1	387.1	1,772.9
2034	404.3	394.2	1,804.3
2035	411.9	401.6	1,836.4

Natural Gas

Year	EIA Henry Hub ($/MMBtu, nominal)	MTEP Henry Hub ($/MMBtu, nominal)
2016	$4.41	$4.91
2017	$4.76	$5.47
2018	$5.27	$6.03
2019	$5.19	$6.43
2020	$4.96	$6.83
2021	$5.37	$7.24
2022	$5.64	$7.64
2023	$5.90	$8.04
2024	$6.20	$8.47
2025	$6.45	$8.90
2026	$6.72	$9.33
2027	$7.00	$9.76
2028	$7.26	$10.19
2029	$7.63	$10.62
2030	$8.12	$11.05
2031	$8.47	$11.48
2032	$8.91	$11.91
2033	$9.41	$12.34
2034	$9.83	$12.77
2035	$10.31	$13.20

MISO Market Energy

	MTEP Average Annual Market Prices	
Year	Off-Peak ($/MWh, nominal)	On-Peak ($/MWh, nominal)
2016	$23.70	$42.07
2017	$24.14	$43.48
2018	$24.57	$44.88
2019	$26.07	$48.31
2020	$27.57	$51.73
2021	$29.08	$55.16
2022	$30.58	$58.58
2023	$32.08	$62.01
2024	$33.02	$64.43
2025	$33.95	$66.86
2026	$34.89	$69.28
2027	$35.82	$71.71
2028	$36.76	$74.13
2029	$37.69	$76.56
2030	$38.63	$78.98
2031	$39.56	$81.41
2032	$40.50	$83.83
2033	$41.43	$86.26
2034	$42.37	$88.69
2035	$43.31	$91.11

RENEWABLE ENERGY INSTALLATION SCHEDULE

				Solar Generation Summary						Wind Generation Summary			
Year	Annual Energy Forecast (GWh)	CROD Energy (GWh)	Energy Above CROD (GWh)	Solar Requirement - Percent of Annual Energy (%)	Solar Energy Requirement (GWh)	Solar Generation Capacity Factor	Implied Solar Capacity Requirement (MW)	Solar Generation Install Schedule (MW)	Total Solar Generation Installed (MW)	Renewable Requirement - Percent of Annual Energy (%)	Renewable Energy Requirement (GWh)	Wind Capacity Factor	Implied Wind Capacity Requirement (MW)
2016	1,321	1,260	61					0.5	0.5				
2017	1,346	1,260	86						0.5				
2018	1,372	1,260	112						0.5				
2019	1,396	1,260	135						0.5				
2020	1,423	1,260	163						0.5				
2021	1,446	1,260	186	1.5%	3	18%	1.8	3	3.5				
2022	1,472	1,260	212	1.5%	3	18%	2.0		3.5				
2023	1,500	1,260	240	1.5%	4	18%	2.3		3.5				
2024	1,531	1,260	271	1.5%	4	18%	2.6		3.5				
2025	1,553	1,260	293	1.5%	4	18%	2.8		3.5				
2026	1,582	1,260	322	1.5%	5	18%	3.1		3.5				
2027	1,610	1,260	349	1.5%	5	18%	3.3		3.5				
2028	1,641	1,260	381	1.5%	6	18%	3.6	3	6.5				
2029	1,664	1,260	404	1.5%	6	18%	3.8		6.5				
2030	1,691	1,260	431	1.5%	6	18%	4.1		6.5				
2031	1,717	-	1,717	1.5%	26	18%	16.3	11.5	18	25.0%	429	33%	148.5
2032	1,748	-	1,748	1.5%	26	18%	16.6		18	25.0%	437	33%	151.2
2033	1,773	-	1,773	1.5%	27	18%	16.9		18	25.0%	443	33%	153.3
2034	1,804	-	1,804	1.5%	27	18%	17.2		18	25.0%	451	33%	156.0
2035	1,836	-	1,836	1.5%	28	18%	17.5		18	25.0%	459	33%	158.8

APPENDIX B – NEW RESOURCE TECHNOLOGY ASSESSMENT

Rochester Public Utilities
2015 Update of the RPU Infrastructure Plan
Generation Technoogy Assessment
BMcD Project No. 82902

PROJECT TYPE	Reciprocating Engine	Aeroderivative SCGT	"F-Class" SCGT	"F-Class" CCGT	Combined Heat and Power Facility	50 MW Wind	Solar
BASE PLANT DESCRIPTION							
Number of Gas Turbines, Engines or Boilers	6	1	1	1	1	22	N/A
Number of HRSGs	N/A	N/A	N/A	1	1	N/A	N/A
Number of Steam Turbines	N/A	N/A	N/A	1	N/A	N/A	N/A
Expected Service Life (years) (Note 1)	30	30	30	30	30	30	30
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	N/A	N/A
Heat Rejection	Fin-Fan Heat Ex.	Fin-Fan Heat Ex.	Fin-Fan Heat Ex.	Wet Cooling Tower	Fin-Fan Heat Ex.	N/A	N/A
NO_x Control	SCR	Water Injection	DLN	DLN/SCR	Water Injection/SCR	N/A	N/A
SO_2 Control	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	N/A	N/A
CO Control	CO Catalyst	Good Combustion Practice	Good Combustion Practice	CO Catalyst	CO Catalyst	N/A	N/A
CO_2 Control	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
PERFORMANCE							
Summer Peak Base Load Performance (82°F, 56% RH)							
Net Plant Output, kW	54,600	44,900	213,800	317,000	32,200	50,000	500
Net Plant Heat Rate, Btu/kWh (HHV)	8,490	9,690	9,890	6,710	4,150	N/A	N/A
Heat Input, MMBtu/h (HHV)	460	440	2,110	2,130	134	N/A	N/A
Summer Peak Average Fired Performance							
Incremental Duct Firing Net Output, kW	N/A	N/A	N/A	95,300	N/A	N/A	N/A
Incremental Duct Firing Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A	8,390	N/A	N/A	N/A
Incremental Duct Firing Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A	800	N/A	N/A	N/A
Total Net Fired Plant Output, kW	N/A	N/A	N/A	412,300	N/A	N/A	N/A
Total Net Fired Plant Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A	7,110	N/A	N/A	N/A
Total Net Fired Plant Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A	2,930	N/A	N/A	N/A
Assumed Firm Capacity Credit for MISO Resource Adequacy, kW	52,000	43,000	203,000	392,000	31,000	7,000	8% of Output
CAPITAL COSTS							
Base Plant Capital Costs							
Project Cost, 2015M$ (w/o Owner's Costs)	$51	$58	$100	$282	$54	$90	$1.2
Owner's Costs 2015M$ (without Escalation and IDC)	$15	$18	$32	$58	$17	Incl. in Project Costs	Incl. in Project Costs
Total Capital Cost, 2015M$	$65	$77	$132	$340	$71	$90	$1.2
Total Capital Cost 2015$/kW Avg Annual Unfired Output	$1,199	$1,712	$615	$1,076	$2,214	$1,804	$2,440
Incremental Duct-Firing Capital Costs							
Project Cost, 2015M$ (w/o Owner's Costs)	N/A	N/A	N/A	$32	N/A	N/A	N/A
Owner's Costs 2015M$ (without Escalation and IDC)	N/A	N/A	N/A	$2	N/A	N/A	N/A
Total Capital Cost, 2015M$	N/A	N/A	N/A	$34	N/A	N/A	N/A
Total Capital Cost 2015$/kW Avg Annual Incremental Fired Output	N/A	N/A	N/A	$359	N/A	N/A	N/A
Total Plant Capital Costs (Base + Duct-Firing)							
Project Cost, 2015M$ (w/o Owner's Costs)	N/A	N/A	N/A	$314	N/A	N/A	N/A
Owner's Costs 2015M$ (without Escalation and IDC)	N/A	N/A	N/A	$60	N/A	N/A	N/A
Total Capital Cost, 2015M$	N/A	N/A	N/A	$374	N/A	N/A	N/A
Total Capital Cost 2015$/kW Avg Annual Fired Output	N/A	N/A	N/A	$912	N/A	N/A	N/A
NON-FUEL OPERATION & MAINTENANCE COSTS							
Fixed O&M Cost, 2015$/kW-Yr	$10.97	$23.78	$7.18	$12.81	$18.60	$18.45	$11.89
Engine Major Maintenance, 2015$/Start/GT (Note 2 & 3)	N/A	N/A	$15,375	$15,375	N/A	N/A	N/A
Engine Major Maintenance, 2015$/GT-h (Note 2 & 3)	$24	$195	$410	$410	$138	N/A	N/A
Engine Major Maintenance, 2015$/MWh (Note 2 & 3)	$2.59	$4.34	$1.92	$1.29	$4.30	N/A	N/A
Variable O&M, 2015$/MWh (excl. major maintenance)	$4.51	$6.66	$0.92	$1.33	$6.66	Incl. In Fixed	Incl. In Fixed
Total Non-Fuel Variable O&M, 2015$/MWh	$7.10	$11.00	$2.84	$2.63	$10.96	N/A	N/A
ESTIMATED EMISSIONS, ppm							
NO_X	5.0	25.0	9.0	2.0	2.5	N/A	N/A
SO_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CO	15.0	33.0	9.0	2.0	3.3	N/A	N/A
CO_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ESTIMATED EMISSIONS, lb/MMBtu (HHV)							
NO_X	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SO_2	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	N/A	N/A
CO	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CO_2	120	120	120	120	120	N/A	N/A

NOTES

Note 1: Service life is estimated as the expected economic life. Plants may operate longer or shorter in duration, but at the end of the presented durations it may not be economically feasible to maintain the asset depending on how it has been operated and the energy market at that time.
Note 2: For GE frame units, major maintenance cost is calculated based on either individual counts of starts or operating hours. If operating hours is more than or equal to 27 hours/equivalent starts, levelized major maintenance cost in $/hr should be used to determine major maintenance cost. If operating hours/start is less than 27 hours/equivalent starts, $/start should be used to determine major maintenance cost. Both levelized major maintenance cost in $/hr and $/start represent cost for gas turbine maintenance only, including accrual for major overhaul, and does not include fuel and other variable consumptions.
Note 3: GE aero units major maintenance is based on operating hours only.

GENERAL ASSUMPTIONS

The following assumptions govern this analysis:

General
- All estimates in this table are "screening level" and are not to be guaranteed.
- Natural gas fuel is pipeline quality (.75 grains / 100 SCF sulfur)
- All emission limits are subject to the BACT process.

Capital Cost Estimates
- A multiple contract (MCC) contracting method is assumed for this project.
- All capital cost estimates exclude escalation and are reflective of 2015$.
- Plant capital cost ($/kW) is based on the net output at summer conditions (82°F, 56% RH).
- The plant site is a greenfield site that is clear of trees and wetlands and is reasonably level. There are no existing structures or underground utilities.
- Sufficient laydown area is available.
- Piling is included under heavily loaded foundations.
- All options include a full enclosure, generation building, warehouse, control room, and other typical buildings.
- The LM6000 option includes natural gas compressors. All other options assume gas is available at proper pressure at the site boundary.

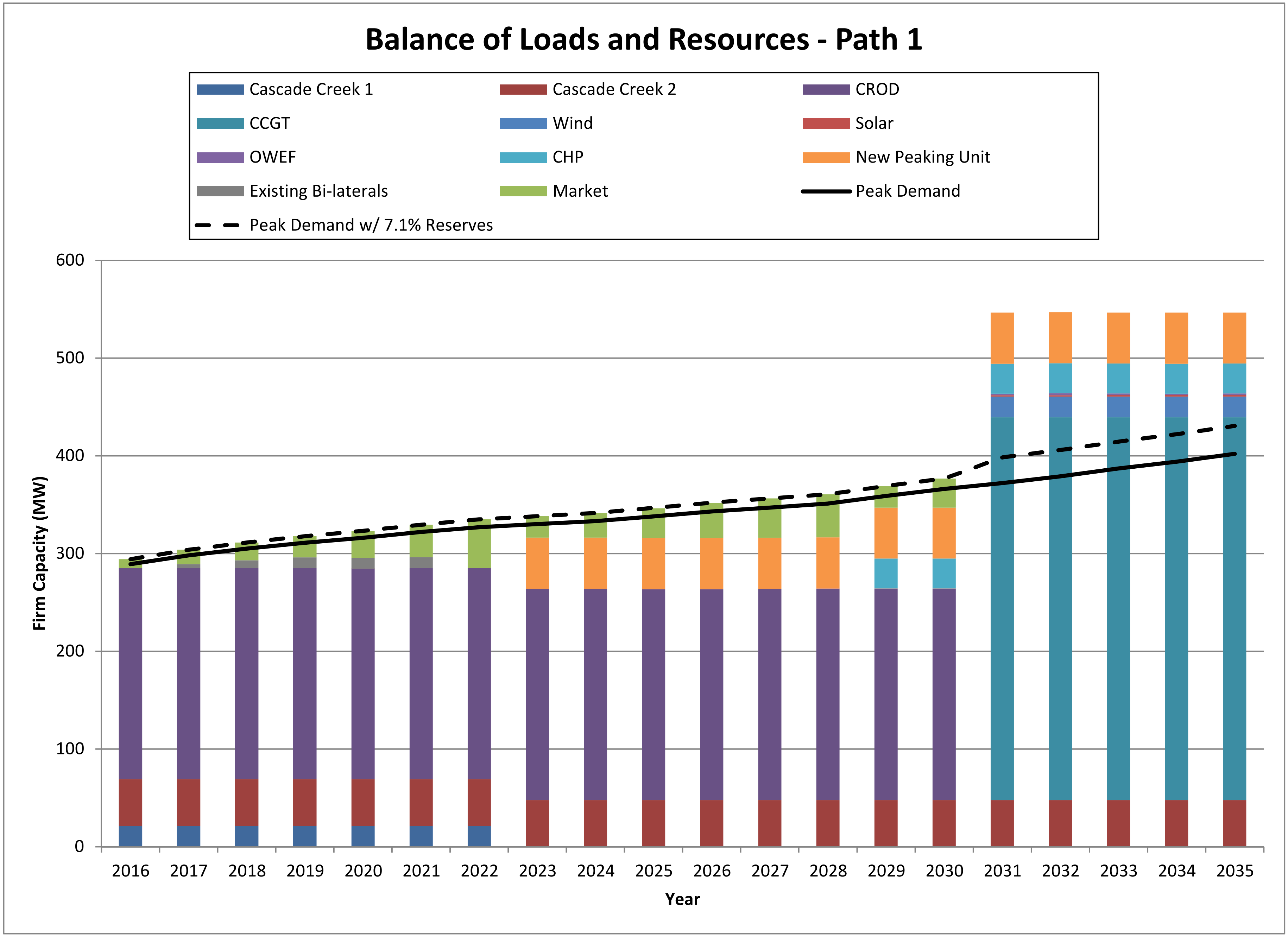
Owner's Cost
- Owner's costs include project development, operations personnel prior to COD, startup management, construction power, legal costs, permitting and licensing fees, site security, operating spare parts, permanent plant furnishings and equipment,water and natural gas infrastructure/supply, sales tax and duties, and 5% owners contingency.
- Owner's costs do not include emissions reduction credits, land, water rights, financing fees, escalation or AFUDC.

Tie-Ins
- On site wells and pipe are included in the owner's costs for raw water supply.
- An on-site switchyard is included in the Owner's costs for all options. Transmission interconnect and lines from the site have been excluded.
- A 5-mile natural gas pipeline is included in the owner's costs.

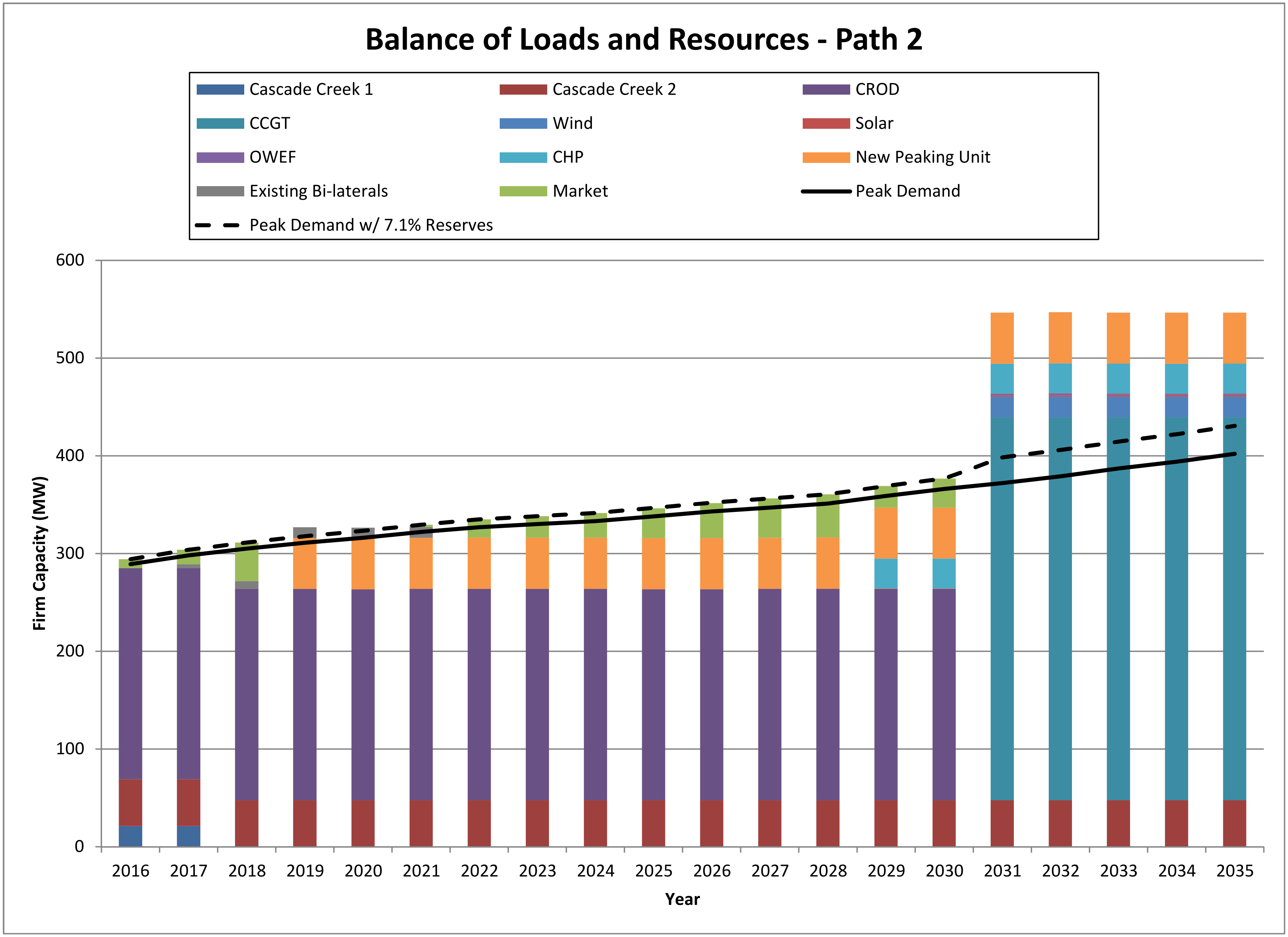
Performance Estimates
- Output and heat rate estimates are at new & clean conditions.
- Performance estimates provided are based on summer conditions (82°F, 56% RH).
- Evaporative cooling is included for the gas turbine options and operates above ambient conditions of 59°F.
- Combined cycle option is fully fired to a duct burner temperature of 1,600F.

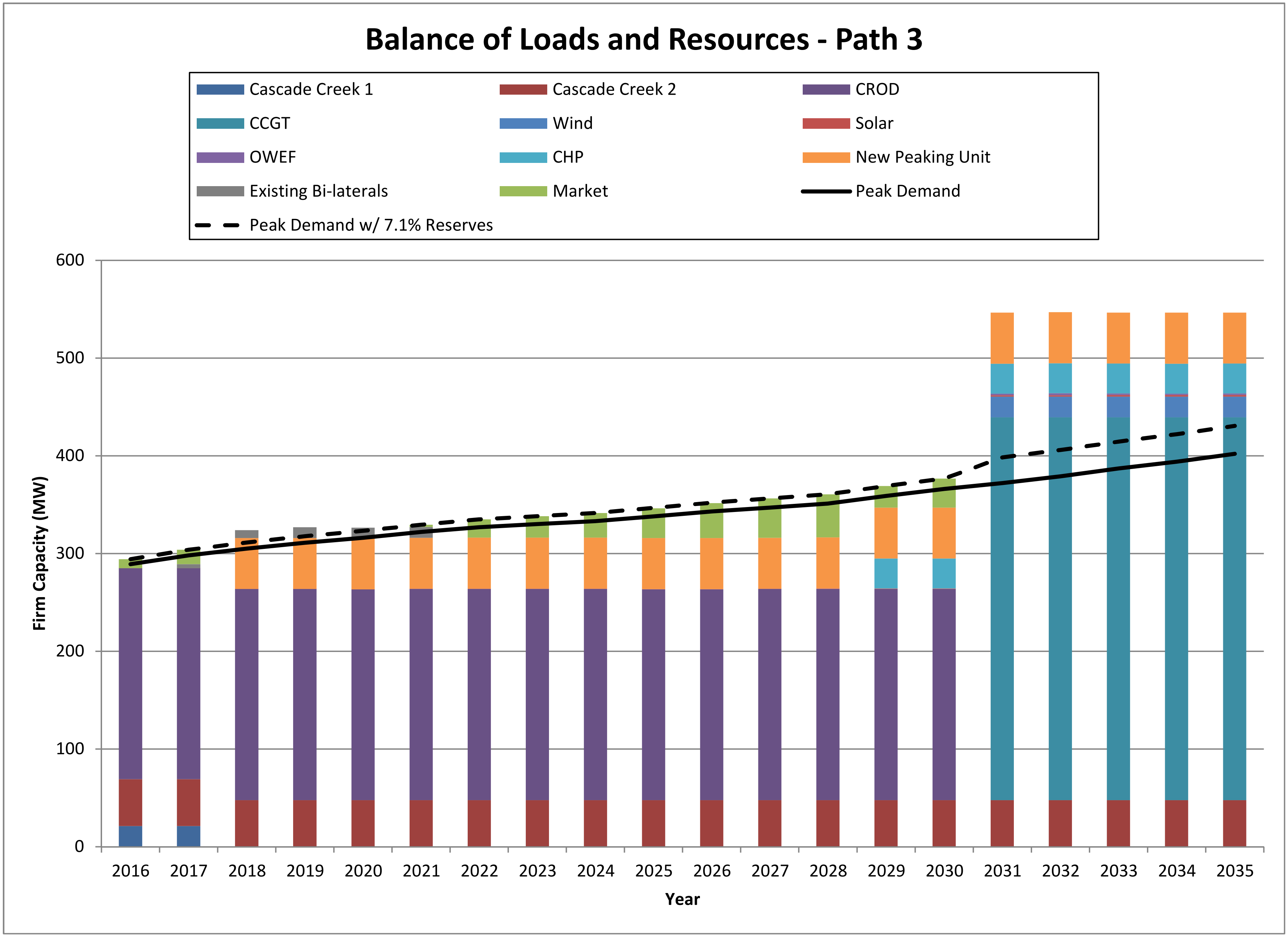
O&M Estimates are based on the following assumptions:
- Fuel costs are not included in the O&M analysis.
- Demineralized and raw water production and treatment costs are included in the variable O&M analysis. Water treatment equipment is included in the capital cost.
- Simple cycle options assume demin trailers (where applicable), while the combined cycle option assumes an on site demineralized water system.
- O&M Costs do not include emissions allowances.
- Fixed O&M includes staffing costs, major maintenance service director fee, standby power, and other office and administration cost.
- Variable O&M includes raw water, consumables, and other O&M such as BOP equipment maintenance and startup cost.

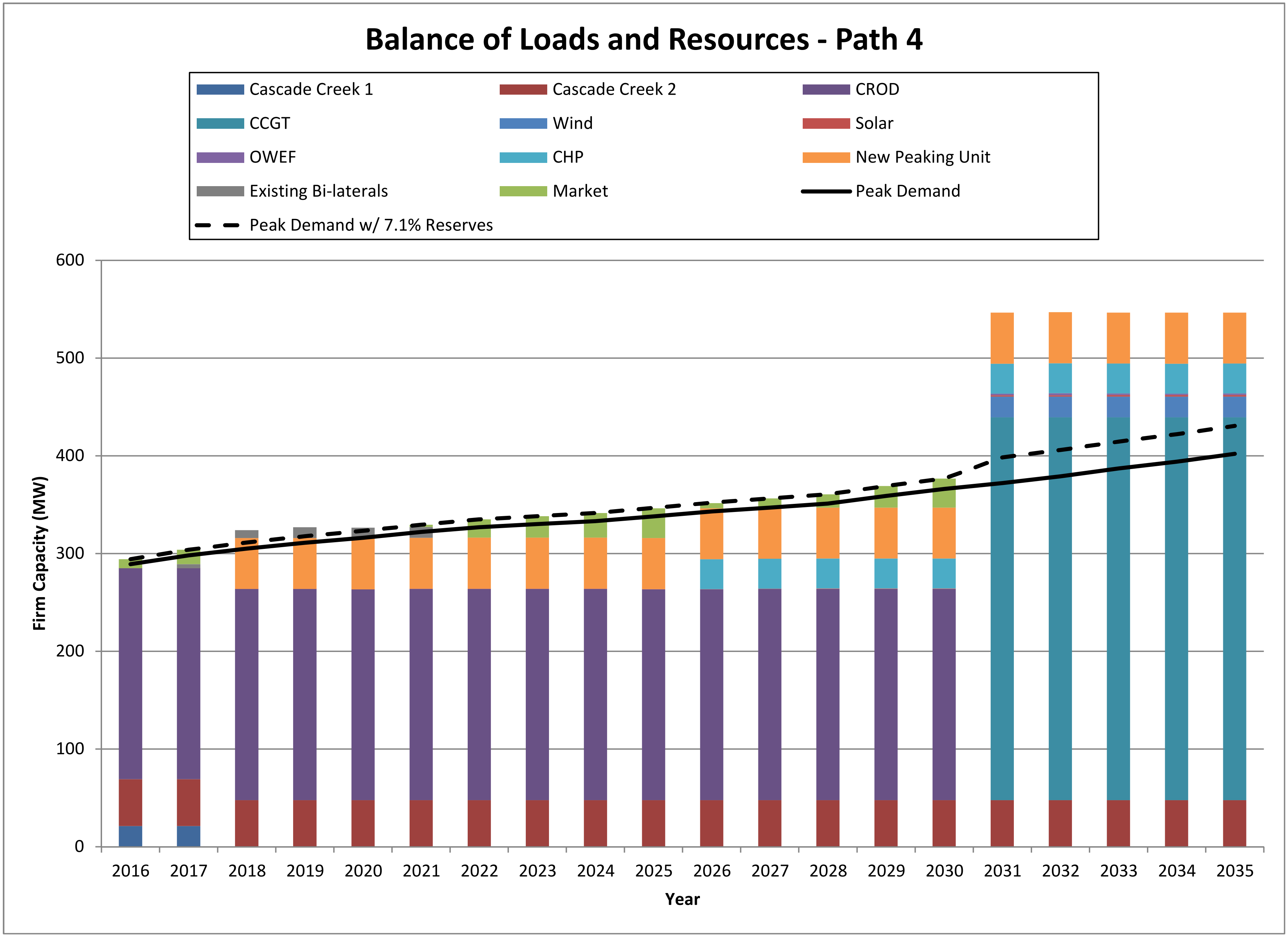
APPENDIX C – DISPATCH MODEL RESULTS



Balance of Loads and Resources - Path 1
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year


Balance of Loads and Resources - Path 2
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year


Balance of Loads and Resources - Path 3
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year



Balance of Loads and Resources - Path 4
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Summary of Results

Promod Modeling Results				
Path No.	**1**	**2**	**3**	**4**
Plan Year	**Retire CC1 2023, Install Recip 2023**	**Retire CC1 2018, Install Recip 2019**	**Retire CC1 2018, Install Recip 2018**	**Retire CC1 2018, Install Recip 2018, Install CHP 2026**
2016	SOLR(1) DEF(9)	SOLR(1) DEF(9)	SOLR(1) DEF(9)	SOLR(1) DEF(9)
2017	DEF(19)	DEF(19)	DEF(19)	DEF(19)
2018	DEF(26)	RCC1(1) DEF(48)	RCC1(1) RENG(1)	RCC1(1) RENG(1)
2019	DEF(33)	RENG(1) DEF(2)	DEF(2)	DEF(2)
2020	DEF(38)	DEF(7)	DEF(7)	DEF(7)
2021	SOLR(6) DEF(44)	SOLR(6) DEF(13)	SOLR(6) DEF(13)	SOLR(6) DEF(13)
2022	DEF(50)	DEF(19)	DEF(19)	DEF(19)
2023	RENG(1) RCC1(1) DEF(22)	DEF(22)	DEF(22)	DEF(22)
2024	DEF(25)	DEF(25)	DEF(25)	DEF(25)
2025	DEF(31)	DEF(31)	DEF(31)	DEF(31)
2026	DEF(36)	DEF(36)	DEF(36)	CHP(1) DEF(5)
2027	DEF(40)	DEF(40)	DEF(40)	DEF(40)
2028	SOLR(6) DEF(44)	SOLR(6) DEF(44)	SOLR(6) DEF(44)	SOLR(6) DEF(14)
2029	CHP(1) DEF(22)	CHP(1) DEF(22)	CHP(1) DEF(22)	DEF(22)
2030	DEF(30)	DEF(30)	DEF(30)	DEF(30)
2031	WIND(3) CCGT(1) SOLR(23)	WIND(3) CCGT(1) SOLR(23)	WIND(3) CCGT(1) SOLR(23)	WIND(3) CCGT(1) SOLR(23)
2032				
2033	SOLR(1)	SOLR(1)	SOLR(1)	SOLR(1)
2034				
2035	SOLR(1)	SOLR(1)	SOLR(1)	SOLR(1)
NPV UTILITY COST (@ 5.0%) PLANNING PERIOD ($000) *% DIFFERENCE*	With CROD $1,498,056 *0.00%*	With CROD $1,506,011 *0.53%*	With CROD $1,507,624 *0.64%*	With CROD $1,515,469 *1.16%*

Notes

The number in parenthesis represents the number of units added in that particular year.
SOLR: Solar generation resource
DEF: Market capacity with a unit output of 1 MW
RCC1: Retirement of Cascade Creek Unit 1
RENG: New peaking unit (reciprocating engine facility is representative technology)
CHP: Combined heat and power facility
WIND: Wind generation resource
CCGT: Combined cycle gas turbine facility

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Path 1: Retire CC1 2023, peaking resource added in 2023, CHP added in 2029

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,298	1,346,402	1,372,397	1,395,798	1,423,297	1,445,898	1,472,201	1,500,100	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	23,583	25,663	26,331	31,408	33,981	41,200	51,301	52,454	55,631	62,315
Market Energy Purchases Cost ($)	$ 1,059,558	$ 1,260,757	$ 1,392,044	$ 1,749,565	$ 2,029,511	$ 2,533,735	$ 3,126,625	$ 3,490,470	$ 3,883,499	$ 4,415,727
Average Market Energy Purchase Cost ($/MWh)	$ 44.93	$ 49.13	$ 52.87	$ 55.70	$ 59.72	$ 61.50	$ 60.95	$ 66.54	$ 69.81	$ 70.86
Market Energy Sales (MWh)	24,528	19,529	17,110	17,459	17,950	22,519	21,988	47,135	46,737	44,730
Market Energy Sales Revenue ($)	$ 1,318,762	$ 998,988	$ 844,014	$ 938,775	$ 1,051,991	$ 1,329,404	$ 1,317,305	$ 3,998,235	$ 4,124,908	$ 4,069,759
Average Market Energy Sales Revenue ($/MWh)	$ 53.76	$ 51.15	$ 49.33	$ 53.77	$ 58.61	$ 59.03	$ 59.91	$ 84.82	$ 88.26	$ 90.99
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 39.72	$ 41.02	$ 42.28	$ 45.36	$ 48.58	$ 51.75	$ 55.00	$ 58.18	$ 60.29	$ 62.50
LMP Off-Peak Average ($/MWh)	$ 24.37	$ 24.82	$ 25.30	$ 26.99	$ 28.53	$ 30.12	$ 31.61	$ 33.18	$ 34.33	$ 35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	18	22	27	33	50	22	25	31
Market Capacity Cost ($/kW-mo)	$ 4.00	$ 4.08	$ 4.16	$ 4.24	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78
Total Market Capacity Cost ($)	$ 439,429	$ 724,403	$ 913,522	$ 1,106,367	$ 1,406,845	$ 1,763,156	$ 2,680,285	$ 1,207,732	$ 1,413,017	$ 1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	27	27	27	27	27	27	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	-	-	-	-	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	1	1	1	-	2	-	-	-
CC2	37	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	-	-	-	-	117	123	114
Unit Generation (MWh)										
CC1	432	270	122	122	122	-	270	-	-	-
CC2	11,277	6,462	4,192	4,541	5,015	4,840	4,017	5,439	4,915	4,516
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	-	-	-	-	23,991	24,101	22,509
CROD OFF	760,826	773,361	786,601	798,348	812,728	823,817	836,952	850,659	866,233	876,518
CROD On	542,200	550,225	558,639	566,042	575,009	581,837	589,826	598,046	607,213	613,160
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,696	5,718	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,236	15,818	16,167	16,654	16,345	15,791	40,935	40,534	38,529
CROD Subtotal (MWh)	1,303,026	1,323,586	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,293	1,293	1,296	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	**1,327,555**	**1,343,115**	**1,362,350**	**1,381,849**	**1,405,688**	**1,428,173**	**1,448,766**	**1,495,840**	**1,520,184**	**1,534,407**
Capacity Factor										
CC1	0.2%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%		
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG								5.0%	5.0%	4.7%
Fuel Cost ($)										
CC1	$ 36,985	$ 25,763	$ 12,785	$ 13,637	$ 14,598	$ -	$ 35,988	$ -	$ -	$ -
CC2	$ 709,869	$ 453,167	$ 320,464	$ 370,121	$ 435,928	$ 444,773	$ 390,827	$ 556,795	$ 527,296	$ 511,760
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,924,846	$ 2,042,340	$ 2,003,099
Total Fuel Costs ($)	**$ 746,853**	**$ 478,930**	**$ 333,249**	**$ 383,758**	**$ 450,526**	**$ 444,773**	**$ 426,815**	**$ 2,481,642**	**$ 2,569,637**	**$ 2,514,860**
Variable O&M ($)										
CC1	$ 714	$ 448	$ 207	$ 211	$ 217	$ -	$ 508	$ -	$ -	$ -
CC2	$ 18,540	$ 10,727	$ 7,126	$ 7,901	$ 8,977	$ 8,858	$ 7,552	$ 10,497	$ 9,683	$ 9,122
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 207,636	$ 213,801	$ 204,669
CROD OFF	$ 31,398,662	$ 32,554,308	$ 33,773,894	$ 34,963,812	$ 36,305,470	$ 37,536,838	$ 38,898,029	$ 40,325,764	$ 41,885,356	$ 43,230,295
CROD On	$ 29,936,295	$ 30,986,936	$ 32,089,981	$ 33,165,541	$ 34,364,802	$ 35,468,276	$ 36,674,429	$ 37,929,244	$ 39,280,854	$ 40,458,821
Total Variable O&M Costs ($)	**$ 61,354,212**	**$ 63,552,419**	**$ 65,871,208**	**$ 68,137,466**	**$ 70,679,466**	**$ 73,013,972**	**$ 75,580,518**	**$ 78,473,141**	**$ 81,389,694**	**$ 83,902,907**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	$ 87.27	$ 97.08	$ 106.93	$ 113.98	$ 121.93		$ 135.17			
CC2	$ 64.59	$ 71.79	$ 78.15	$ 83.25	$ 88.72	$ 93.72	$ 99.17	$ 104.30	$ 109.25	$ 115.34
CCGT										
CHP										
RENG								$ 88.89	$ 93.61	$ 98.08
CROD OFF	$ 41.27	$ 42.09	$ 42.94	$ 43.80	$ 44.67	$ 45.56	$ 46.48	$ 47.41	$ 48.35	$ 49.32
CROD On	$ 55.21	$ 56.32	$ 57.44	$ 58.59	$ 59.76	$ 60.96	$ 62.18	$ 63.42	$ 64.69	$ 65.98
Fixed O&M ($)										
CC1	$ 314,199	$ 317,520	$ 325,620	$ 333,720	$ 342,090	$ 350,460	$ 359,370	$ -	$ -	$ -
CC2	$ 226,610	$ 229,041	$ 234,530	$ 240,518	$ 246,506	$ 252,993	$ 258,981	$ 265,468	$ 272,454	$ 278,941
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 729,777	$ 748,021	$ 766,722
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 31,325,795	$ 31,520,589	$ 31,792,666	$ 32,034,918	$ 32,399,314	$ 32,563,196	$ 32,837,514	$ 33,092,167	$ 33,446,494	$ 33,536,299
LZ	$ 52,338	$ 53,219	$ 54,296	$ 55,373	$ 56,658	$ 57,632	$ 58,762	$ 59,944	$ 61,320	$ 62,387
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 5,946	$ 6,060	$ 6,208	$ 6,366	$ 6,996	$ 46,778	$ 47,987	$ 49,206	$ 50,694	$ 51,696
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs ($)	**$ 31,924,888**	**$ 32,126,430**	**$ 32,413,321**	**$ 32,670,895**	**$ 33,051,564**	**$ 33,271,059**	**$ 33,562,614**	**$ 34,196,562**	**$ 34,578,983**	**$ 34,696,044**
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,199,381	$ 5,199,381	$ 5,199,381
SOLAR (PPA)	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 343,604	$ 343,604	$ 343,604
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Payment	**$ 79,363**	**$ 79,363**	**$ 79,363**	**$ 79,363**	**$ 79,363**	**$ 343,604**	**$ 343,604**	**$ 5,542,985**	**$ 5,542,985**	**$ 5,542,985**
Total Variable ($, VOM + Fuel)	$ 62,101,065	$ 64,031,349	$ 66,204,457	$ 68,521,224	$ 71,129,992	$ 73,458,745	$ 76,007,333	$ 80,954,783	$ 83,959,330	$ 86,417,767
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 32,443,679	$ 32,930,196	$ 33,406,206	$ 33,856,625	$ 34,537,772	$ 35,377,819	$ 36,586,502	$ 40,947,279	$ 41,534,985	$ 41,988,670
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (259,203)	$ 261,769	$ 548,030	$ 810,791	$ 977,520	$ 1,204,331	$ 1,809,320	$ (507,765)	$ (241,409)	$ 345,968
Total Power Supply Cost ($)	$ 94,285,541	$ 97,223,314	$ 100,158,694	$ 103,188,640	$ 106,645,285	$ 110,040,895	$ 114,403,155	$ 121,394,297	$ 125,252,906	$ 128,752,405
Total Power Supply Cost ($/MWh)	$ 71.36	$ 72.21	$ 72.98	$ 73.93	$ 74.93	$ 76.11	$ 77.71	$ 80.92	$ 81.79	$ 82.88

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,697	1,640,901	1,664,201	1,691,300	1,717,197	1,748,004	1,772,901	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,795	78,594	85,667	97,949	111,114	1,717,197	1,744,025	1,772,901	1,804,300	1,836,400
Market Energy Purchases Cost ($)	$ 5,133,172	$ 5,814,662	$ 6,471,221	$ 7,563,607	$ 8,759,055	$ 110,242,103	$ 115,122,250	$ 120,082,732	$ 125,464,083	$ 131,180,376
Average Market Energy Purchase Cost ($/MWh)	$ 72.51	$ 73.98	$ 75.54	$ 77.22	$ 78.83	$ 64.20	$ 66.01	$ 67.73	$ 69.54	$ 71.43
Market Energy Sales (MWh)	41,251	41,461	42,548	218,180	216,654	1,024,075	1,011,405	978,518	988,294	985,864
Market Energy Sales Revenue ($)	$ 3,787,303	$ 4,028,592	$ 3,989,341	$ 15,445,589	$ 15,778,212	$ 80,376,603	$ 84,155,375	$ 81,832,418	$ 85,979,915	$ 87,538,207
Average Market Energy Sales Revenue ($/MWh)	$ 91.81	$ 97.17	$ 93.76	$ 70.79	$ 72.83	$ 78.49	$ 83.21	$ 83.63	$ 87.00	$ 88.79
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 64.78	$ 67.01	$ 69.34	$ 71.55	$ 73.62	$ 75.85	$ 78.16	$ 80.49	$ 82.73	$ 84.93
LMP Off-Peak Average ($/MWh)	$ 36.28	$ 37.29	$ 38.14	$ 39.17	$ 40.37	$ 41.30	$ 42.30	$ 43.15	$ 44.14	$ 45.15
Market Capacity										
Market Capacity Purchase (MW)	36	40	44	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	$ 4.88	$ 4.97	$ 5.07	$ 5.17	$ 5.28	$ 5.38	$ 5.49	$ 5.60	$ 5.71	$ 5.83
Total Market Capacity Cost ($)	$ 2,097,753	$ 2,395,555	$ 2,686,915	$ 1,373,243	$ 1,876,435	$ -	$ -	$ -	$ -	-
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	317	317	317	317	317
CHP	-	-	-	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	18	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	116	112
CHP	-	-	-	13	19	14	15	16	9	17
RENG	108	104	90	98	94	95	87	83	77	84
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,343	3,643	2,720	2,894	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,797	329,163	295,258	306,480	296,177
CHP	-	-	-	176,311	175,538	175,941	174,894	173,349	173,284	173,751
RENG	20,203	20,093	17,184	17,294	16,470	16,141	14,494	13,176	11,529	14,274
CROD OFF	890,213	902,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,908	627,860	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,504	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,382	18,382
SOLAR (PPA)	5,722	5,742	10,649	10,600	10,620	29,357	29,445	34,308	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,705	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	35,051	35,241	31,421	208,003	206,457	547,552	533,088	496,156	505,866	498,625
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,226	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	483,264	483,281	488,092
Total Unit Generation (MWh)	**1,552,372**	**1,572,240**	**1,594,774**	**1,783,858**	**1,797,740**	**1,024,993**	**1,012,242**	**979,419**	**989,147**	**986,718**
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT						12.3%	11.9%	10.6%	11.0%	10.7%
CHP				62.5%	62.2%	62.4%	62.0%	61.5%	61.4%	61.6%
RENG	4.2%	4.2%	3.6%	3.6%	3.4%	3.4%	3.0%	2.7%	2.4%	3.0%
Fuel Cost ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
CC2	$ 396,132	$ 449,529	$ 349,257	$ 389,410	$ 412,275	$ 459,997	$ 454,797	$ 446,258	$ 493,961	$ 485,666
CCGT	$ -	$ -	$ -	$ -	$ -	$ 30,814,364	$ 30,824,475	$ 28,528,309	$ 30,771,023	$ 30,816,946
CHP	$ -	$ -	$ -	$ 9,137,309	$ 9,459,817	$ 9,848,592	$ 10,150,009	$ 10,421,775	$ 10,790,053	$ 11,172,540
RENG	$ 1,886,327	$ 1,966,327	$ 1,751,071	$ 1,837,897	$ 1,824,093	$ 1,858,811	$ 1,732,760	$ 1,632,721	$ 1,484,180	$ 1,887,279
Total Fuel Costs ($)	**$ 2,282,459**	**$ 2,415,855**	**$ 2,100,328**	**$ 11,364,616**	**$ 11,696,185**	**$ 42,981,764**	**$ 43,162,041**	**$ 41,029,064**	**$ 43,539,217**	**$ 44,362,431**
Variable O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
CC2	$ 6,921	$ 7,759	$ 5,929	$ 6,454	$ 6,742	$ 7,446	$ 7,245	$ 7,087	$ 7,764	$ 7,561
CCGT	$ -	$ -	$ -	$ -	$ -	$ 1,327,523	$ 1,314,259	$ 1,208,355	$ 1,285,638	$ 1,273,479
CHP	$ -	$ -	$ -	$ 2,729,701	$ 2,785,680	$ 2,861,869	$ 2,915,968	$ 2,962,453	$ 3,035,387	$ 3,119,654
RENG	$ 188,295	$ 191,954	$ 168,261	$ 173,570	$ 169,437	$ 170,200	$ 156,653	$ 145,972	$ 130,919	$ 166,142
CROD OFF	$ 44,783,891	$ 46,331,575	$ 47,995,210	$ 49,400,630	$ 50,952,483	$ -	$ -	$ -	$ -	-
CROD On	$ 41,789,480	$ 43,102,515	$ 44,480,296	$ 45,670,286	$ 46,951,916	$ -	$ -	$ -	$ -	-
Total Variable O&M Costs ($)	**$ 86,768,588**	**$ 89,633,804**	**$ 92,649,696**	**$ 97,980,640**	**$ 100,866,258**	**$ 4,367,037**	**$ 4,394,126**	**$ 4,323,867**	**$ 4,459,708**	**$ 4,566,836**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	$ 120.56	$ 125.54	$ 130.60	$ 136.78	$ 142.32	$ 147.52	$ 153.05	$ 158.00	$ 163.49	$ 168.96
CCGT						$ 94.31	$ 97.64	$ 100.71	$ 104.60	$ 108.35
CHP				$ 67.31	$ 69.76	$ 72.24	$ 74.71	$ 77.21	$ 79.78	$ 82.26
RENG	$ 102.69	$ 107.41	$ 111.69	$ 116.31	$ 121.04	$ 125.71	$ 130.36	$ 134.99	$ 140.09	$ 143.86
CROD OFF	$ 50.31	$ 51.31	$ 52.34	$ 53.39	$ 54.45					
CROD On	$ 67.30	$ 68.65	$ 70.02	$ 71.42	$ 72.85					
Fixed O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
CC2	$ 285,927	$ 293,412	$ 300,398	$ 307,883	$ 315,867	$ 323,851	$ 331,835	$ 339,819	$ 348,302	$ 357,284
CCGT	$ -	$ -	$ -	$ -	$ -	$ 6,028,236	$ 6,178,942	$ 6,333,415	$ 6,491,751	$ 6,654,044
CHP	$ -	$ -	$ -	$ 846,258	$ 867,415	$ 889,100	$ 911,328	$ 934,111	$ 957,464	$ 981,400
RENG	$ 785,890	$ 805,537	$ 825,676	$ 846,318	$ 867,476	$ 889,162	$ 911,392	$ 934,176	$ 957,531	$ 981,469
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
CROD On	$ 33,718,273	$ 33,881,554	$ 34,086,336	$ 34,060,265	$ 34,078,584	$ -	$ -	$ -	$ -	-
LZ	$ 63,622	$ 64,909	$ 66,351	$ 67,509	$ 68,849	$ 70,241	$ 71,856	$ 73,078	$ 74,549	$ 76,020
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
SOLAR (PPA)	$ 52,939	$ 54,911	$ 103,945	$ 105,907	$ 109,678	$ 308,203	$ 318,166	$ 378,035	$ 387,382	$ 453,820
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 3,856,985	$ 3,974,434	$ 4,052,583	$ 4,152,736	$ 4,256,038
Total Fixed O&M Costs ($)	**$ 34,906,651**	**$ 35,100,322**	**$ 35,382,706**	**$ 36,234,139**	**$ 36,307,869**	**$ 12,365,779**	**$ 12,697,952**	**$ 13,045,217**	**$ 13,369,714**	**$ 13,760,075**
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506
CHP	$ -	$ -	$ -	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864
RENG	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381
SOLAR (PPA)	$ 343,604	$ 343,604	$ 636,870	$ 636,870	$ 636,870	$ 1,812,410	$ 1,812,410	$ 3,707,998	$ 3,707,998	$ 5,660,881
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919
Total Payment	**$ 5,542,985**	**$ 5,542,985**	**$ 5,836,251**	**$ 12,384,116**	**$ 12,384,116**	**$ 68,542,080**	**$ 68,542,080**	**$ 70,437,668**	**$ 70,437,668**	**$ 72,390,551**
Total Variable ($, VOM + Fuel)	$ 89,051,047	$ 92,049,659	$ 94,750,024	$ 109,345,257	$ 112,562,443	$ 47,348,801	$ 47,556,167	$ 45,352,931	$ 47,998,925	$ 48,929,267
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 42,547,389	$ 43,038,862	$ 43,905,872	$ 49,991,498	$ 50,568,419	$ 80,907,859	$ 81,240,032	$ 83,482,885	$ 83,807,383	$ 86,150,626
Net Market Purchases (Sales) ($, Purchases less Sales)	$ 1,345,869	$ 1,786,070	$ 2,481,880	$ (7,881,983)	$ (7,019,157)	$ 29,865,501	$ 30,966,875	$ 38,250,315	$ 39,484,168	$ 43,642,170
Total Power Supply Cost ($)	$ 132,944,305	$ 136,874,591	$ 141,137,777	$ 151,454,772	$ 156,111,705	$ 158,122,160	$ 159,763,073	$ 167,086,131	$ 171,290,475	$ 178,722,062
Total Power Supply Cost ($/MWh)	$ 84.04	$ 85.03	$ 86.01	$ 91.01	$ 92.30	$ 92.08	$ 91.40	$ 94.24	$ 94.93	$ 97.32

Net Present Cost ($) $ 1,498,055,997

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Path 2: Retire CC1 2018, peaking resource added in 2019, CHP added in 2029

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,298	1,346,402	1,372,397	1,395,798	1,423,297	1,445,898	1,472,201	1,500,100	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	23,583	25,663	26,331	31,408	33,981	41,200	51,301	52,454	55,631	62,315
Market Energy Purchases Cost ($)	$ 1,059,558	$ 1,260,757	$ 1,392,044	$ 1,749,565	$ 2,029,511	$ 2,533,735	$ 3,126,625	$ 3,490,470	$ 3,883,499	$ 4,415,727
Average Market Energy Purchase Cost ($/MWh)	$ 44.93	$ 49.13	$ 52.87	$ 55.70	$ 59.72	$ 61.50	$ 60.95	$ 66.54	$ 69.81	$ 70.86
Market Energy Sales (MWh)	24,528	19,529	16,989	38,584	39,185	45,906	43,678	47,135	45,530	42,644
Market Energy Sales Revenue ($)	$ 1,318,762	$ 998,988	$ 830,954	$ 2,661,834	$ 2,904,651	$ 3,476,647	$ 3,403,575	$ 3,997,494	$ 3,967,697	$ 3,810,366
Average Market Energy Sales Revenue ($/MWh)	$ 53.76	$ 51.15	$ 48.91	$ 68.99	$ 74.13	$ 75.73	$ 77.92	$ 84.81	$ 87.15	$ 89.35
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 39.72	$ 41.02	$ 42.28	$ 45.36	$ 48.58	$ 51.75	$ 55.00	$ 58.18	$ 60.29	$ 62.50
LMP Off-Peak Average ($/MWh)	$ 24.37	$ 24.82	$ 25.30	$ 26.99	$ 28.53	$ 30.12	$ 31.61	$ 33.18	$ 34.33	$ 35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	40	-	-	2	19	22	25	31
Market Capacity Cost ($/kW-mo)	$ 4.00	$ 4.08	$ 4.16	$ 4.24	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78
Total Market Capacity Cost ($)	$ 439,429	$ 724,403	$ 1,974,680	$ -	$ -	$ 125,265	$ 1,009,638	$ 1,207,732	$ 1,413,017	$ 1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	-	-	-	-	-	-	-	-
CC2	37	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	107	107	116	109	116	122	111
Unit Generation (MWh)										
CC1	432	270	-	-	-	-	-	-	-	-
CC2	11,277	6,462	4,192	4,541	5,015	4,840	4,017	5,439	4,915	4,516
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	21,246	21,356	23,387	21,960	23,991	22,893	20,423
CROD OFF	760,826	773,361	786,601	798,348	812,728	823,817	836,952	850,659	866,233	876,518
CROD On	542,200	550,225	558,639	566,042	575,009	581,837	589,826	598,046	607,213	613,160
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,696	5,718	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,236	15,696	37,292	37,888	39,732	37,481	40,935	39,326	36,443
CROD Subtotal (MWh)	1,303,026	1,323,586	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,293	1,293	1,296	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	**1,327,555**	**1,343,115**	**1,362,229**	**1,402,974**	**1,426,922**	**1,451,560**	**1,470,456**	**1,495,840**	**1,518,976**	**1,532,321**
Capacity Factor										
CC1	0.2%	0.1%								
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG				4.4%	4.4%	4.9%	4.6%	5.0%	4.8%	4.2%
Fuel Cost ($)										
CC1	$ 36,985	$ 25,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 709,869	$ 453,167	$ 320,464	$ 370,121	$ 435,928	$ 444,773	$ 390,827	$ 556,795	$ 527,296	$ 511,760
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 1,366,031	$ 1,467,260	$ 1,692,672	$ 1,666,841	$ 1,925,774	$ 1,938,761	$ 1,820,208
Total Fuel Costs ($)	**$ 746,853**	**$ 478,930**	**$ 320,464**	**$ 1,736,152**	**$ 1,903,188**	**$ 2,137,445**	**$ 2,057,669**	**$ 2,482,569**	**$ 2,466,057**	**$ 2,331,968**
Variable O&M ($)										
CC1	$ 714	$ 448	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 18,540	$ 10,727	$ 7,126	$ 7,901	$ 8,977	$ 8,858	$ 7,552	$ 10,497	$ 9,683	$ 9,122
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 166,585	$ 171,632	$ 192,656	$ 185,420	$ 207,636	$ 203,086	$ 185,700
CROD OFF	$ 31,398,662	$ 32,554,308	$ 33,773,894	$ 34,963,812	$ 36,305,470	$ 37,536,838	$ 38,898,029	$ 40,325,764	$ 41,885,356	$ 43,230,295
CROD On	$ 29,936,295	$ 30,986,936	$ 32,089,981	$ 33,165,541	$ 34,364,802	$ 35,468,276	$ 36,674,429	$ 37,929,244	$ 39,280,854	$ 40,458,821
Total Variable O&M Costs ($)	**$ 61,354,212**	**$ 63,552,419**	**$ 65,871,001**	**$ 68,303,839**	**$ 70,850,881**	**$ 73,206,628**	**$ 75,765,430**	**$ 78,473,141**	**$ 81,378,979**	**$ 83,883,938**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	$ 87.27	$ 97.08								
CC2	$ 64.59	$ 71.79	$ 78.15	$ 83.25	$ 88.72	$ 93.72	$ 99.17	$ 104.30	$ 109.25	$ 115.34
CCGT										
CHP										
RENG				$ 72.14	$ 76.74	$ 80.61	$ 84.35	$ 88.92	$ 93.56	$ 98.22
CROD OFF	$ 41.27	$ 42.09	$ 42.94	$ 43.80	$ 44.67	$ 45.56	$ 46.48	$ 47.41	$ 48.35	$ 49.32
CROD On	$ 55.21	$ 56.32	$ 57.44	$ 58.59	$ 59.76	$ 60.96	$ 62.18	$ 63.42	$ 64.69	$ 65.98
Fixed O&M ($)										
CC1	$ 314,199	$ 317,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 226,610	$ 229,041	$ 234,530	$ 240,518	$ 246,506	$ 252,993	$ 258,981	$ 265,468	$ 272,454	$ 278,941
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 661,142	$ 677,671	$ 694,612	$ 711,978	$ 729,777	$ 748,021	$ 766,722
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 31,325,795	$ 31,520,589	$ 31,792,666	$ 32,034,918	$ 32,399,314	$ 32,563,196	$ 32,837,514	$ 33,092,167	$ 33,446,494	$ 33,536,299
LZ	$ 52,338	$ 53,219	$ 54,296	$ 55,373	$ 56,658	$ 57,632	$ 58,762	$ 59,944	$ 61,320	$ 62,387
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 5,946	$ 6,060	$ 6,208	$ 6,366	$ 6,996	$ 46,778	$ 47,987	$ 49,206	$ 50,694	$ 51,696
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs ($)	**$ 31,924,888**	**$ 32,126,430**	**$ 32,087,701**	**$ 32,998,317**	**$ 33,387,145**	**$ 33,615,212**	**$ 33,915,221**	**$ 34,196,562**	**$ 34,578,983**	**$ 34,696,044**
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383
SOLAR (PPA)	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 343,604	$ 343,604	$ 343,604
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Payment	**$ 79,363**	**$ 79,363**	**$ 79,363**	**$ 4,789,745**	**$ 4,789,745**	**$ 5,053,986**	**$ 5,053,986**	**$ 5,053,986**	**$ 5,053,986**	**$ 5,053,986**
Total Variable ($, VOM + Fuel)	$ 62,101,065	$ 64,031,349	$ 66,191,465	$ 70,039,991	$ 72,754,069	$ 75,344,073	$ 77,823,099	$ 80,955,710	$ 83,845,037	$ 86,215,906
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 32,443,679	$ 32,930,196	$ 34,141,744	$ 37,788,063	$ 38,176,890	$ 38,794,463	$ 39,978,845	$ 40,458,281	$ 41,045,986	$ 41,499,672
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (259,203)	$ 261,769	$ 561,091	$ (912,268)	$ (875,140)	$ (942,912)	$ (276,950)	$ (507,024)	$ (84,198)	$ 605,361
Total Power Supply Cost ($)	$ 94,285,541	$ 97,223,314	$ 100,894,300	$ 106,915,785	$ 110,055,819	$ 113,195,624	$ 117,524,994	$ 120,906,967	$ 124,806,825	$ 128,320,939
Total Power Supply Cost ($/MWh)	$ 71.36	$ 72.21	$ 73.52	$ 76.60	$ 77.32	$ 78.29	$ 79.83	$ 80.60	$ 81.50	$ 82.60
Net Present Cost ($) $ 1,506,011,381										

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,697	1,640,901	1,664,201	1,691,300	1,717,197	1,748,004	1,772,901	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,795	78,594	85,667	97,949	111,114	1,717,197	1,744,025	1,772,901	1,804,300	1,836,400
Market Energy Purchases Cost ($)	$ 5,133,172	$ 5,814,662	$ 6,471,221	$ 7,563,607	$ 8,759,055	$ 110,242,103	$ 115,122,250	$ 120,082,732	$ 125,464,083	$ 131,180,376
Average Market Energy Purchase Cost ($/MWh)	$ 72.51	$ 73.98	$ 75.54	$ 77.22	$ 78.83	$ 64.20	$ 66.01	$ 67.73	$ 69.54	$ 71.43
Market Energy Sales (MWh)	40,208	40,638	43,646	216,258	214,348	1,024,020	1,010,636	979,945	991,093	983,339
Market Energy Sales Revenue ($)	$ 3,693,044	$ 3,918,083	$ 4,120,250	$ 15,145,889	$ 15,447,455	$ 80,377,778	$ 84,004,926	$ 82,101,413	$ 86,442,887	$ 87,112,430
Average Market Energy Sales Revenue ($/MWh)	$ 91.85	$ 96.42	$ 94.40	$ 70.04	$ 72.07	$ 78.49	$ 83.12	$ 83.78	$ 87.22	$ 88.59
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 64.78	$ 67.01	$ 69.34	$ 71.55	$ 73.62	$ 75.85	$ 78.16	$ 80.49	$ 82.73	$ 84.93
LMP Off-Peak Average ($/MWh)	$ 36.28	$ 37.29	$ 38.14	$ 39.17	$ 40.37	$ 41.30	$ 42.30	$ 43.15	$ 44.14	$ 45.15
Market Capacity										
Market Capacity Purchase (MW)	36	40	44	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	$ 4.88	$ 4.97	$ 5.07	$ 5.17	$ 5.28	$ 5.38	$ 5.49	$ 5.60	$ 5.71	$ 5.83
Total Market Capacity Cost ($)	$ 2,097,753	$ 2,395,555	$ 2,686,915	$ 1,373,243	$ 1,876,435	$ -	$ -	$ -	$ -	$ -
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	317	317	317	317	317
CHP	-	-	-	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	18	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	116	112
CHP	-	-	-	13	19	14	15	16	9	17
RENG	104	100	100	95	88	92	89	82	84	76
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,343	3,643	2,720	2,894	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,797	329,163	295,258	306,480	296,177
CHP	-	-	-	176,311	175,538	175,941	174,894	173,349	173,284	173,751
RENG	19,160	19,270	18,282	15,372	14,164	16,086	13,725	14,603	14,329	11,749
CROD OFF	890,213	902,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,908	627,860	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,504	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,382	18,382
SOLAR (PPA)	5,722	5,742	10,649	10,600	10,620	29,357	29,445	34,308	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,705	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	34,008	34,417	32,519	206,082	204,151	547,497	532,319	497,583	508,666	496,100
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,226	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	483,264	483,281	488,092
Total Unit Generation (MWh)	**1,551,329**	**1,571,417**	**1,595,872**	**1,781,937**	**1,795,435**	**1,024,938**	**1,011,473**	**980,847**	**991,947**	**984,192**
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT						12.3%	11.9%	10.6%	11.0%	10.7%
CHP				62.5%	62.2%	62.4%	62.0%	61.5%	61.4%	61.6%
RENG	4.0%	4.0%	3.8%	3.2%	2.9%	3.3%	2.9%	3.0%	3.0%	2.4%
Fuel Cost ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 396,132	$ 449,529	$ 349,257	$ 389,410	$ 412,275	$ 459,997	$ 454,797	$ 446,258	$ 493,961	$ 485,666
CCGT	$ -	$ -	$ -	$ -	$ -	$ 30,814,364	$ 30,824,475	$ 28,528,309	$ 30,771,023	$ 30,816,946
CHP	$ -	$ -	$ -	$ 9,137,309	$ 9,459,817	$ 9,848,592	$ 10,150,009	$ 10,421,775	$ 10,790,053	$ 11,172,540
RENG	$ 1,794,636	$ 1,877,056	$ 1,865,685	$ 1,639,590	$ 1,576,736	$ 1,853,740	$ 1,643,517	$ 1,805,871	$ 1,833,200	$ 1,555,443
Total Fuel Costs ($)	**$ 2,190,768**	**$ 2,326,584**	**$ 2,214,943**	**$ 11,166,309**	**$ 11,448,829**	**$ 42,976,692**	**$ 43,072,798**	**$ 41,202,213**	**$ 43,888,237**	**$ 44,030,595**
Variable O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 6,921	$ 7,759	$ 5,929	$ 6,454	$ 6,742	$ 7,446	$ 7,245	$ 7,087	$ 7,764	$ 7,561
CCGT	$ -	$ -	$ -	$ -	$ -	$ 1,327,523	$ 1,314,259	$ 1,208,355	$ 1,285,638	$ 1,273,479
CHP	$ -	$ -	$ -	$ 2,729,701	$ 2,785,680	$ 2,861,869	$ 2,915,968	$ 2,962,453	$ 3,035,387	$ 3,119,654
RENG	$ 178,574	$ 184,087	$ 179,013	$ 154,284	$ 145,716	$ 169,621	$ 148,346	$ 161,786	$ 162,713	$ 136,748
CROD OFF	$ 44,783,891	$ 46,331,575	$ 47,995,210	$ 49,400,630	$ 50,952,483	$ -	$ -	$ -	$ -	$ -
CROD On	$ 41,789,480	$ 43,102,515	$ 44,480,296	$ 45,670,286	$ 46,951,916	$ -	$ -	$ -	$ -	$ -
Total Variable O&M Costs ($)	**$ 86,758,866**	**$ 89,625,937**	**$ 92,660,448**	**$ 97,961,355**	**$ 100,842,537**	**$ 4,366,458**	**$ 4,385,818**	**$ 4,339,681**	**$ 4,491,503**	**$ 4,537,442**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	$ 120.56	$ 125.54	$ 130.60	$ 136.78	$ 142.32	$ 147.52	$ 153.05	$ 158.00	$ 163.49	$ 168.96
CCGT						$ 94.31	$ 97.64	$ 100.71	$ 104.60	$ 108.35
CHP				$ 67.31	$ 69.76	$ 72.24	$ 74.71	$ 77.21	$ 79.78	$ 82.26
RENG	$ 102.99	$ 106.96	$ 111.84	$ 116.70	$ 121.61	$ 125.79	$ 130.55	$ 134.74	$ 139.29	$ 144.03
CROD OFF	$ 50.31	$ 51.31	$ 52.34	$ 53.39	$ 54.45					
CROD On	$ 67.30	$ 68.65	$ 70.02	$ 71.42	$ 72.85					
Fixed O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 285,927	$ 293,412	$ 300,398	$ 307,883	$ 315,867	$ 323,851	$ 331,835	$ 339,819	$ 348,302	$ 357,284
CCGT	$ -	$ -	$ -	$ -	$ -	$ 6,028,236	$ 6,178,942	$ 6,333,415	$ 6,491,751	$ 6,654,044
CHP	$ -	$ -	$ -	$ 846,258	$ 867,415	$ 889,100	$ 911,328	$ 934,111	$ 957,464	$ 981,400
RENG	$ 785,890	$ 805,537	$ 825,676	$ 846,318	$ 867,476	$ 889,162	$ 911,392	$ 934,176	$ 957,531	$ 981,469
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 33,718,273	$ 33,881,554	$ 34,086,336	$ 34,060,265	$ 34,078,584	$ -	$ -	$ -	$ -	$ -
LZ	$ 63,622	$ 64,909	$ 66,351	$ 67,509	$ 68,849	$ 70,241	$ 71,856	$ 73,078	$ 74,549	$ 76,020
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 52,939	$ 54,911	$ 103,945	$ 105,907	$ 109,678	$ 308,203	$ 318,166	$ 378,035	$ 387,382	$ 453,820
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 3,856,985	$ 3,974,434	$ 4,052,583	$ 4,152,736	$ 4,256,038
Total Fixed O&M Costs ($)	**$ 34,906,651**	**$ 35,100,322**	**$ 35,382,706**	**$ 36,234,139**	**$ 36,307,869**	**$ 12,365,779**	**$ 12,697,952**	**$ 13,045,217**	**$ 13,369,714**	**$ 13,760,075**
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506
CHP	$ -	$ -	$ -	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864
RENG	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383
SOLAR (PPA)	$ 343,604	$ 343,604	$ 636,870	$ 636,870	$ 636,870	$ 1,812,410	$ 1,812,410	$ 3,707,998	$ 3,707,998	$ 5,660,881
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919
Total Payment	**$ 5,053,986**	**$ 5,053,986**	**$ 5,347,253**	**$ 11,895,117**	**$ 11,895,117**	**$ 68,053,081**	**$ 68,053,081**	**$ 69,948,670**	**$ 69,948,670**	**$ 71,901,552**
Total Variable ($, VOM + Fuel)	$ 88,949,634	$ 91,952,521	$ 94,875,390	$ 109,127,664	$ 112,291,365	$ 47,343,151	$ 47,458,616	$ 45,541,894	$ 48,379,740	$ 48,568,036
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 42,058,390	$ 42,549,864	$ 43,416,874	$ 49,502,499	$ 50,079,420	$ 80,418,860	$ 80,751,033	$ 82,993,887	$ 83,318,384	$ 85,661,628
Net Market Purchases (Sales) ($, Purchases less Sales)	$ 1,440,128	$ 1,896,579	$ 2,350,971	$ (7,582,283)	$ (6,688,400)	$ 29,864,326	$ 31,117,324	$ 37,981,320	$ 39,021,197	$ 44,067,947
Total Power Supply Cost ($)	$ 132,448,153	$ 136,398,964	$ 140,643,235	$ 151,047,881	$ 155,682,386	$ 157,626,337	$ 159,326,973	$ 166,517,101	$ 170,719,321	$ 178,297,610
Total Power Supply Cost ($/MWh)	$ 83.72	$ 84.74	$ 85.71	$ 90.76	$ 92.05	$ 91.79	$ 91.15	$ 93.92	$ 94.62	$ 97.09

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Path 3: Retire CC1 2018, peaking resource added in 2018, CHP added in 2029

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,298	1,346,402	1,372,397	1,395,798	1,423,297	1,445,898	1,472,201	1,500,100	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	23,583	25,663	26,331	31,408	33,981	41,200	51,301	52,454	55,631	62,315
Market Energy Purchases Cost ($)	1,059,558	1,260,757	1,392,044	1,749,565	2,029,511	2,533,735	3,126,625	3,490,470	3,883,499	4,415,727
Average Market Energy Purchase Cost ($/MWh)	44.93	49.13	52.87	55.70	59.72	61.50	60.95	66.54	69.81	70.86
Market Energy Sales (MWh)	24,528	19,529	36,917	37,925	40,557	44,424	45,105	45,324	45,475	42,863
Market Energy Sales Revenue ($)	1,318,762	998,988	2,364,633	2,616,373	3,009,140	3,326,705	3,563,538	3,811,413	3,960,818	3,858,756
Average Market Energy Sales Revenue ($/MWh)	53.76	51.15	64.05	68.99	74.19	74.89	79.00	84.09	87.10	90.02
Market Pricing										
LMP On-Peak Average ($/MWh)	39.72	41.02	42.28	45.36	48.58	51.75	55.00	58.18	60.29	62.50
LMP Off-Peak Average ($/MWh)	24.37	24.82	25.30	26.99	28.53	30.12	31.61	33.18	34.33	35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	-	-	-	2	19	22	25	31
Market Capacity Cost ($/kW-mo)	4.00	4.08	4.16	4.24	4.33	4.42	4.50	4.59	4.69	4.78
Total Market Capacity Cost ($)	439,429	724,403	-	-	-	125,265	1,009,638	1,207,732	1,413,017	1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	-	-	-	-	-	-	-	-
CC2	37	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	106	104	113	114	115	115	123	109
Unit Generation (MWh)										
CC1	432	270	-	-	-	-	-	-	-	-
CC2	11,277	6,462	4,192	4,541	5,015	4,840	4,017	5,439	4,915	4,516
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	19,929	20,588	22,729	21,905	23,387	22,180	22,838	20,642
CROD OFF	760,826	773,361	786,601	798,348	812,728	823,817	836,952	850,659	866,233	876,518
CROD On	542,200	550,225	558,639	566,042	575,009	581,837	589,826	598,046	607,213	613,160
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,696	5,718	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,236	35,625	36,633	39,261	38,250	38,909	39,123	39,271	36,663
CROD Subtotal (MWh)	1,303,026	1,323,586	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,293	1,293	1,296	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	**1,327,555**	**1,343,115**	**1,382,157**	**1,402,315**	**1,428,295**	**1,450,078**	**1,471,884**	**1,494,029**	**1,518,921**	**1,532,540**
Capacity Factor										
CC1	0.2%	0.1%								
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG			4.1%	4.3%	4.7%	4.6%	4.9%	4.6%	4.7%	4.3%
Fuel Cost ($)										
CC1	36,985	25,763	-	-	-	-	-	-	-	-
CC2	709,869	453,167	320,464	370,121	435,928	444,773	390,827	556,795	527,296	511,760
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	1,203,956	1,327,704	1,555,830	1,584,949	1,783,538	1,781,644	1,934,120	1,841,331
Total Fuel Costs ($)	**746,853**	**478,930**	**1,524,419**	**1,697,825**	**1,991,758**	**2,029,722**	**2,174,365**	**2,338,439**	**2,461,417**	**2,353,091**
Variable O&M ($)										
CC1	714	448	-	-	-	-	-	-	-	-
CC2	18,540	10,727	7,126	7,901	8,977	8,858	7,552	10,497	9,683	9,122
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	152,443	161,420	182,662	180,445	197,472	191,956	202,599	187,696
CROD OFF	31,398,662	32,554,308	33,773,894	34,963,812	36,305,470	37,536,838	38,898,029	40,325,764	41,885,356	43,230,295
CROD On	29,936,295	30,986,936	32,089,981	33,165,541	34,364,802	35,468,276	36,674,429	37,929,244	39,280,854	40,458,821
Total Variable O&M Costs ($)	**61,354,212**	**63,552,419**	**66,023,444**	**68,298,674**	**70,861,911**	**73,194,417**	**75,777,483**	**78,457,462**	**81,378,492**	**83,885,935**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	87.27	97.08								
CC2	64.59	71.79	78.15	83.25	88.72	93.72	99.17	104.30	109.25	115.34
CCGT										
CHP										
RENG			68.06	72.33	76.49	80.59	84.70	88.98	93.56	98.29
CROD OFF	41.27	42.09	42.94	43.80	44.67	45.56	46.48	47.41	48.35	49.32
CROD On	55.21	56.32	57.44	58.59	59.76	60.96	62.18	63.42	64.69	65.98
Fixed O&M ($)										
CC1	314,199	317,520	-	-	-	-	-	-	-	-
CC2	226,610	229,041	234,530	240,518	246,506	252,993	258,981	265,468	272,454	278,941
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	645,017	661,142	677,671	694,612	711,978	729,777	748,021	766,722
CROD OFF	-	-	-	-	-	-	-	-	-	-
CROD On	31,325,795	31,520,589	31,792,666	32,034,918	32,399,314	32,563,196	32,837,514	33,092,167	33,446,494	33,536,299
LZ	52,338	53,219	54,296	55,373	56,658	57,632	58,762	59,944	61,320	62,387
OWEF (PPA)	-	-	-	-	-	-	-	-	-	-
SOLAR (PPA)	5,946	6,060	6,208	6,366	6,996	46,778	47,987	49,206	50,694	51,696
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M Costs ($)	**31,924,888**	**32,126,430**	**32,732,718**	**32,998,317**	**33,387,145**	**33,615,212**	**33,915,221**	**34,196,562**	**34,578,983**	**34,696,044**
Debt Service & Demand Charge										
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495
SOLAR (PPA)	79,363	79,363	79,363	79,363	79,363	343,604	343,604	343,604	343,604	343,604
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Total Payment	**79,363**	**79,363**	**4,674,858**	**4,674,858**	**4,674,858**	**4,939,099**	**4,939,099**	**4,939,099**	**4,939,099**	**4,939,099**
Total Variable ($, VOM + Fuel)	62,101,065	64,031,349	67,547,864	69,996,499	72,853,670	75,224,139	77,951,848	80,795,901	83,839,909	86,239,026
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	32,443,679	32,930,196	37,407,576	37,673,175	38,062,003	38,679,576	39,863,958	40,343,393	40,931,099	41,384,784
Net Market Purchases (Sales) ($, Purchases less Sales)	(259,203)	261,769	(972,589)	(866,808)	(979,628)	(792,970)	(436,913)	(320,943)	(77,319)	556,971
Total Power Supply Cost ($)	94,285,541	97,223,314	103,982,850	106,802,866	109,936,044	113,110,745	117,378,893	120,818,351	124,693,689	128,180,780
Total Power Supply Cost ($/MWh)	71.36	72.21	75.77	76.52	77.24	78.23	79.73	80.54	81.42	82.51

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,697	1,640,901	1,664,201	1,691,300	1,717,197	1,748,004	1,772,901	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,795	78,594	85,667	97,949	111,114	1,717,197	1,744,025	1,772,901	1,804,300	1,836,400
Market Energy Purchases Cost ($)	5,133,172	5,814,662	6,471,221	7,563,607	8,759,055	110,242,103	115,122,250	120,082,732	125,464,083	131,180,376
Average Market Energy Purchase Cost ($/MWh)	72.51	73.98	75.54	77.22	78.83	64.20	66.01	67.73	69.54	71.43
Market Energy Sales (MWh)	42,240	40,583	41,340	215,545	217,971	1,022,154	1,012,118	980,055	989,391	984,437
Market Energy Sales Revenue ($)	3,918,256	3,904,611	3,785,530	15,055,118	15,970,450	80,065,211	84,263,759	82,106,215	86,180,320	87,297,042
Average Market Energy Sales Revenue ($/MWh)	92.76	96.21	91.57	69.85	73.27	78.33	83.25	83.78	87.10	88.68
Market Pricing										
LMP On-Peak Average ($/MWh)	64.78	67.01	69.34	71.55	73.62	75.85	78.16	80.49	82.73	84.93
LMP Off-Peak Average ($/MWh)	36.28	37.29	38.14	39.17	40.37	41.30	42.30	43.15	44.14	45.15
Market Capacity										
Market Capacity Purchase (MW)	36	40	44	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	4.88	4.97	5.07	5.17	5.28	5.38	5.49	5.60	5.71	5.83
Total Market Capacity Cost ($)	2,097,753	2,395,555	2,686,915	1,373,243	1,876,435	-	-	-	-	-
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	317	317	317	317	317	317
CHP	-	-	-	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	18	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	116	112
CHP	-	-	-	13	19	14	15	16	9	17
RENG	111	101	97	94	95	92	87	86	76	82
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,343	3,643	2,720	2,894	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,797	329,163	295,258	306,480	296,177
CHP	-	-	-	176,311	175,538	175,941	174,894	173,349	173,284	173,751
RENG	21,191	19,215	15,976	14,658	17,788	14,219	15,207	14,713	12,627	12,847
CROD OFF	890,213	902,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,908	627,860	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,504	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,382	18,382
SOLAR (PPA)	5,722	5,742	10,649	10,600	10,620	29,357	29,445	34,308	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,705	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	36,039	34,362	30,213	205,368	207,774	545,630	533,801	497,693	506,964	497,198
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,226	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	483,264	483,281	488,092
Total Unit Generation (MWh)	**1,553,361**	**1,571,362**	**1,593,566**	**1,781,223**	**1,799,058**	**1,023,071**	**1,012,956**	**980,957**	**990,245**	**985,290**
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT					0.0%	12.3%	11.9%	10.6%	11.0%	10.7%
CHP				62.5%	62.2%	62.4%	62.0%	61.5%	61.4%	61.6%
RENG	4.4%	4.0%	3.3%	3.0%	3.7%	3.0%	3.2%	3.1%	2.6%	2.7%
Fuel Cost ($)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	396,132	449,529	349,257	389,410	412,275	459,997	454,797	446,258	493,961	485,666
CCGT	-	-	-	-	-	30,814,364	30,824,475	28,528,309	30,771,023	30,816,946
CHP	-	-	-	9,137,309	9,459,817	9,848,592	10,150,009	10,421,775	10,790,053	11,172,540
RENG	1,977,821	1,877,404	1,634,911	1,567,301	1,968,479	1,640,910	1,816,544	1,819,451	1,618,167	1,702,931
Total Fuel Costs ($)	**2,373,953**	**2,326,933**	**1,984,169**	**11,094,020**	**11,840,571**	**42,763,863**	**43,245,825**	**41,215,793**	**43,673,204**	**44,178,083**
Variable O&M ($)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	6,921	7,759	5,929	6,454	6,742	7,446	7,245	7,087	7,764	7,561
CCGT	-	-	-	-	-	1,327,523	1,314,259	1,208,355	1,285,638	1,273,479
CHP	-	-	-	2,729,701	2,785,680	2,861,869	2,915,968	2,962,453	3,035,387	3,119,654
RENG	197,506	183,562	156,435	147,121	182,992	149,938	164,367	163,002	143,387	149,528
CROD OFF	44,783,891	46,331,575	47,995,210	49,400,630	50,952,483	-	-	-	-	-
CROD On	41,789,480	43,102,515	44,480,296	45,670,286	46,951,916	-	-	-	-	-
Total Variable O&M Costs ($)	**86,777,798**	**89,625,412**	**92,637,870**	**97,954,192**	**100,879,813**	**4,346,776**	**4,401,840**	**4,340,898**	**4,472,177**	**4,550,222**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	120.56	125.54	130.60	136.78	142.32	147.52	153.05	158.00	163.49	168.96
CCGT						94.31	97.64	100.71	104.60	108.35
CHP				67.31	69.76	72.24	74.71	77.21	79.78	82.26
RENG	102.65	107.26	112.13	116.96	120.95	125.95	130.26	134.74	139.51	144.20
CROD OFF	50.31	51.31	52.34	53.39	54.45					
CROD On	67.30	68.65	70.02	71.42	72.85					
Fixed O&M ($)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	285,927	293,412	300,398	307,883	315,867	323,851	331,835	339,819	348,302	357,284
CCGT	-	-	-	-	-	6,028,236	6,178,942	6,333,415	6,491,751	6,654,044
CHP	-	-	-	846,258	867,415	889,100	911,328	934,111	957,464	981,400
RENG	785,890	805,537	825,676	846,318	867,476	889,162	911,392	934,176	957,531	981,469
CROD OFF	-	-	-	-	-	-	-	-	-	-
CROD On	33,718,273	33,881,554	34,086,336	34,060,265	34,078,584	-	-	-	-	-
LZ	63,622	64,909	66,351	67,509	68,849	70,241	71,856	73,078	74,549	76,020
OWEF (PPA)	-	-	-	-	-	-	-	-	-	-
SOLAR (PPA)	52,939	54,911	103,945	105,907	109,678	308,203	318,166	378,035	387,382	453,820
WIND (PPA)	-	-	-	-	-	3,856,985	3,974,434	4,052,583	4,152,736	4,256,038
Total Fixed O&M Costs ($)	**34,906,651**	**35,100,322**	**35,382,706**	**36,234,139**	**36,307,869**	**12,365,779**	**12,697,952**	**13,045,217**	**13,369,714**	**13,760,075**
Debt Service & Demand Charge										
CCGT	-	-	-	-	-	32,862,506	32,862,506	32,862,506	32,862,506	32,862,506
CHP	-	-	-	6,547,864	6,547,864	6,547,864	6,547,864	6,547,864	6,547,864	6,547,864
RENG	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495	4,595,495
SOLAR (PPA)	343,604	343,604	636,870	636,870	636,870	1,812,410	1,812,410	3,707,998	3,707,998	5,660,881
WIND (PPA)	-	-	-	-	-	22,119,919	22,119,919	22,119,919	22,119,919	22,119,919
Total Payment	**4,939,099**	**4,939,099**	**5,232,366**	**11,780,230**	**11,780,230**	**67,938,194**	**67,938,194**	**69,833,782**	**69,833,782**	**71,786,665**
Total Variable ($, VOM + Fuel)	89,151,751	91,952,346	94,622,038	109,048,212	112,720,384	47,110,638	47,647,665	45,556,691	48,145,380	48,728,305
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	41,943,503	42,434,976	43,301,986	49,387,612	49,964,533	80,303,973	80,636,146	82,879,000	83,203,497	85,546,740
Net Market Purchases (Sales) ($, Purchases less Sales)	1,214,916	1,910,051	2,685,691	(7,491,511)	(7,211,395)	30,176,892	30,858,491	37,976,517	39,283,763	43,883,335
Total Power Supply Cost ($)	132,310,171	136,297,373	140,609,716	150,944,313	155,473,523	157,591,503	159,142,302	166,412,207	170,632,640	178,158,380
Total Power Supply Cost ($/MWh)	83.63	84.67	85.69	90.70	91.93	91.77	91.04	93.86	94.57	97.02

Net Present Cost ($) $ 1,507,624,305

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Path 4: Retire CC1 2018, peaking resource added in 2018, CHP added in 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,298	1,346,402	1,372,397	1,395,798	1,423,297	1,445,898	1,472,201	1,500,100	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	23,583	25,663	26,331	31,408	33,981	41,200	51,301	52,454	55,631	62,315
Market Energy Purchases Cost ($)	$ 1,059,558	$ 1,260,757	$ 1,392,044	$ 1,749,565	$ 2,029,511	$ 2,533,735	$ 3,126,625	$ 3,490,470	$ 3,883,499	$ 4,415,727
Average Market Energy Purchase Cost ($/MWh)	$ 44.93	$ 49.13	$ 52.87	$ 55.70	$ 59.72	$ 61.50	$ 60.95	$ 66.54	$ 69.81	$ 70.86
Market Energy Sales (MWh)	24,528	19,529	36,917	38,584	39,185	45,906	43,678	47,135	45,530	42,644
Market Energy Sales Revenue ($)	$ 1,318,762	$ 998,988	$ 2,364,633	$ 2,661,834	$ 2,904,651	$ 3,476,647	$ 3,403,575	$ 3,997,494	$ 3,967,697	$ 3,810,366
Average Market Energy Sales Revenue ($/MWh)	$ 53.76	$ 51.15	$ 64.05	$ 68.99	$ 74.13	$ 75.73	$ 77.92	$ 84.81	$ 87.15	$ 89.35
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 39.72	$ 41.02	$ 42.28	$ 45.36	$ 48.58	$ 51.75	$ 55.00	$ 58.18	$ 60.29	$ 62.50
LMP Off-Peak Average ($/MWh)	$ 24.37	$ 24.82	$ 25.30	$ 26.99	$ 28.53	$ 30.12	$ 31.61	$ 33.18	$ 34.33	$ 35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	-	-	-	2	19	22	25	31
Market Capacity Cost ($/kW-mo)	$ 4.00	$ 4.08	$ 4.16	$ 4.24	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78
Total Market Capacity Cost ($)	$ 439,429	$ 724,403	$ -	$ -	$ -	$ 125,265	$ 1,009,638	$ 1,207,732	$ 1,413,017	$ 1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	-	-	-	-	-	-	-	-
CC2	37	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	107	107	116	109	116	122	111
Unit Generation (MWh)										
CC1	432	270	-	-	-	-	-	-	-	-
CC2	11,277	6,462	4,192	4,541	5,015	4,840	4,017	5,439	4,915	4,516
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	19,929	21,246	21,356	23,387	21,960	23,991	22,893	20,423
CROD OFF	760,826	773,361	786,601	798,348	812,728	823,817	836,952	850,659	866,233	876,518
CROD On	542,200	550,225	558,639	566,042	575,009	581,837	589,826	598,046	607,213	613,160
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,696	5,718	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,236	35,625	37,292	37,888	39,732	37,481	40,935	39,326	36,443
CROD Subtotal (MWh)	1,303,026	1,323,586	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,293	1,293	1,296	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	**1,327,555**	**1,343,115**	**1,382,157**	**1,402,974**	**1,426,922**	**1,451,560**	**1,470,456**	**1,495,840**	**1,518,976**	**1,532,321**
Capacity Factor										
CC1	0.2%	0.1%								
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG			4.1%	4.4%	4.4%	4.9%	4.6%	5.0%	4.8%	4.2%
Fuel Cost ($)										
CC1	$ 36,985	$ 25,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 709,869	$ 453,167	$ 320,464	$ 370,121	$ 435,928	$ 444,773	$ 390,827	$ 556,795	$ 527,296	$ 511,760
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 1,203,956	$ 1,366,031	$ 1,467,260	$ 1,692,672	$ 1,666,841	$ 1,925,774	$ 1,938,761	$ 1,820,208
Total Fuel Costs ($)	**$ 746,853**	**$ 478,930**	**$ 1,524,419**	**$ 1,736,152**	**$ 1,903,188**	**$ 2,137,445**	**$ 2,057,669**	**$ 2,482,569**	**$ 2,466,057**	**$ 2,331,968**
Variable O&M ($)										
CC1	$ 714	$ 448	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 18,540	$ 10,727	$ 7,126	$ 7,901	$ 8,977	$ 8,858	$ 7,552	$ 10,497	$ 9,683	$ 9,122
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 152,443	$ 166,585	$ 171,632	$ 192,656	$ 185,420	$ 207,636	$ 203,086	$ 185,700
CROD OFF	$ 31,398,662	$ 32,554,308	$ 33,773,894	$ 34,963,812	$ 36,305,470	$ 37,536,838	$ 38,898,029	$ 40,325,764	$ 41,885,356	$ 43,230,295
CROD On	$ 29,936,295	$ 30,986,936	$ 32,089,981	$ 33,165,541	$ 34,364,802	$ 35,468,276	$ 36,674,429	$ 37,929,244	$ 39,280,854	$ 40,458,821
Total Variable O&M Costs ($)	**$ 61,354,212**	**$ 63,552,419**	**$ 66,023,444**	**$ 68,303,839**	**$ 70,850,881**	**$ 73,206,628**	**$ 75,765,430**	**$ 78,473,141**	**$ 81,378,979**	**$ 83,883,938**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	$ 87.27	$ 97.08								
CC2	$ 64.59	$ 71.79	$ 78.15	$ 83.25	$ 88.72	$ 93.72	$ 99.17	$ 104.30	$ 109.25	$ 115.34
CCGT										
CHP										
RENG			$ 68.06	$ 72.14	$ 76.74	$ 80.61	$ 84.35	$ 88.92	$ 93.56	$ 98.22
CROD OFF	$ 41.27	$ 42.09	$ 42.94	$ 43.80	$ 44.67	$ 45.56	$ 46.48	$ 47.41	$ 48.35	$ 49.32
CROD On	$ 55.21	$ 56.32	$ 57.44	$ 58.59	$ 59.76	$ 60.96	$ 62.18	$ 63.42	$ 64.69	$ 65.98
Fixed O&M ($)										
CC1	$ 314,199	$ 317,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 226,610	$ 229,041	$ 234,530	$ 240,518	$ 246,506	$ 252,993	$ 258,981	$ 265,468	$ 272,454	$ 278,941
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 645,017	$ 661,142	$ 677,671	$ 694,612	$ 711,978	$ 729,777	$ 748,021	$ 766,722
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 31,325,795	$ 31,520,589	$ 31,792,666	$ 32,034,918	$ 32,399,314	$ 32,563,196	$ 32,837,514	$ 33,092,167	$ 33,446,494	$ 33,536,299
LZ	$ 52,338	$ 53,219	$ 54,296	$ 55,373	$ 56,658	$ 57,632	$ 58,762	$ 59,944	$ 61,320	$ 62,387
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 5,946	$ 6,060	$ 6,208	$ 6,366	$ 6,996	$ 46,778	$ 47,987	$ 49,206	$ 50,694	$ 51,696
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs ($)	**$ 31,924,888**	**$ 32,126,430**	**$ 32,732,718**	**$ 32,998,317**	**$ 33,387,145**	**$ 33,615,212**	**$ 33,915,221**	**$ 34,196,562**	**$ 34,578,983**	**$ 34,696,044**
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495
SOLAR (PPA)	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 343,604	$ 343,604	$ 343,604
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Payment	**$ 79,363**	**$ 79,363**	**$ 4,674,858**	**$ 4,674,858**	**$ 4,674,858**	**$ 4,939,099**	**$ 4,939,099**	**$ 4,939,099**	**$ 4,939,099**	**$ 4,939,099**
Total Variable ($, VOM + Fuel)	$ 62,101,065	$ 64,031,349	$ 67,547,864	$ 70,039,991	$ 72,754,069	$ 75,344,073	$ 77,823,099	$ 80,955,710	$ 83,845,037	$ 86,215,906
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 32,443,679	$ 32,930,196	$ 37,407,576	$ 37,673,175	$ 38,062,003	$ 38,679,576	$ 39,863,958	$ 40,343,393	$ 40,931,099	$ 41,384,784
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (259,203)	$ 261,769	$ (972,589)	$ (912,268)	$ (875,140)	$ (942,912)	$ (276,950)	$ (507,024)	$ (84,198)	$ 605,361
Total Power Supply Cost ($)	$ 94,285,541	$ 97,223,314	$ 103,982,850	$ 106,800,898	$ 109,940,932	$ 113,080,737	$ 117,410,107	$ 120,792,080	$ 124,691,938	$ 128,206,051
Total Power Supply Cost ($/MWh)	$ 71.36	$ 72.21	$ 75.77	$ 76.52	$ 77.24	$ 78.21	$ 79.75	$ 80.52	$ 81.42	$ 82.53

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,697	1,640,901	1,664,201	1,691,300	1,717,197	1,748,004	1,772,901	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,795	78,594	85,667	97,949	111,114	1,717,197	1,744,025	1,772,901	1,804,300	1,836,400
Market Energy Purchases Cost ($)	$ 5,133,172	$ 5,814,662	$ 6,471,221	$ 7,563,607	$ 8,759,055	$ 110,242,103	$ 115,122,250	$ 120,082,732	$ 125,464,083	$ 131,180,376
Average Market Energy Purchase Cost ($/MWh)	$ 72.51	$ 73.98	$ 75.54	$ 77.22	$ 78.83	$ 64.20	$ 66.01	$ 67.73	$ 69.54	$ 71.43
Market Energy Sales (MWh)	218,065	217,931	220,681	216,548	215,056	1,024,069	1,011,216	980,638	991,270	982,437
Market Energy Sales Revenue ($)	$ 13,999,241	$ 14,630,160	$ 15,178,205	$ 15,204,051	$ 15,484,642	$ 80,389,154	$ 84,081,654	$ 82,143,325	$ 86,479,560	$ 86,878,293
Average Market Energy Sales Revenue ($/MWh)	$ 64.20	$ 67.13	$ 68.78	$ 70.21	$ 72.00	$ 78.50	$ 83.15	$ 83.77	$ 87.24	$ 88.43
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 64.78	$ 67.01	$ 69.34	$ 71.55	$ 73.62	$ 75.85	$ 78.16	$ 80.49	$ 82.73	$ 84.93
LMP Off-Peak Average ($/MWh)	$ 36.28	$ 37.29	$ 38.14	$ 39.17	$ 40.37	$ 41.30	$ 42.30	$ 43.15	$ 44.14	$ 45.15
Market Capacity										
Market Capacity Purchase (MW)	5	10	14	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	$ 4.88	$ 4.97	$ 5.07	$ 5.17	$ 5.28	$ 5.38	$ 5.49	$ 5.60	$ 5.71	$ 5.83
Total Market Capacity Cost ($)	$ 307,880	$ 569,884	$ 824,732	$ 1,373,243	$ 1,876,435	$ -	$ -	$ -	$ -	-
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	317	317	317	317	317	317
CHP	32	32	32	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	18	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	116	112
CHP	13	19	14	15	16	10	17	19	15	14
RENG	104	100	100	95	88	92	89	82	84	76
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,343	3,643	2,720	2,894	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,797	329,163	295,258	306,480	296,177
CHP	178,774	178,098	177,937	176,617	176,263	175,989	175,538	174,057	173,204	172,914
RENG	19,160	19,270	18,282	15,372	14,164	16,086	13,725	14,603	14,329	11,749
CROD OFF	890,213	902,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,908	627,860	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,504	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,382	18,382
SOLAR (PPA)	5,722	5,742	10,648	10,600	10,620	29,357	29,445	34,308	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,705	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	212,782	212,515	210,456	206,388	204,875	547,545	532,963	498,292	508,586	495,263
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,226	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	483,264	483,281	488,092
Total Unit Generation (MWh)	**1,730,104**	**1,749,515**	**1,773,809**	**1,782,243**	**1,796,159**	**1,024,986**	**1,012,117**	**981,555**	**991,866**	**983,355**
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT					0.0%	12.3%	11.9%	10.6%	11.0%	10.7%
CHP	63.4%	63.1%	63.1%	62.6%	62.5%	62.4%	62.2%	61.7%	61.4%	61.3%
RENG	4.0%	4.0%	3.8%	3.2%	2.9%	3.3%	2.9%	3.0%	3.0%	2.4%
Fuel Cost ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 396,132	$ 449,529	$ 349,257	$ 389,410	$ 412,275	$ 459,997	$ 454,797	$ 446,258	$ 493,961	$ 485,666
CCGT	$ -	$ -	$ -	$ -	$ -	$ 30,814,364	$ 30,824,475	$ 28,528,309	$ 30,771,023	$ 30,816,946
CHP	$ 8,143,875	$ 8,483,159	$ 8,848,042	$ 9,141,207	$ 9,498,316	$ 9,848,550	$ 10,186,951	$ 10,454,806	$ 10,793,291	$ 11,126,425
RENG	$ 1,794,636	$ 1,877,056	$ 1,865,685	$ 1,639,590	$ 1,576,736	$ 1,853,740	$ 1,643,517	$ 1,805,871	$ 1,833,200	$ 1,555,443
Total Fuel Costs ($)	**$ 10,334,643**	**$ 10,809,743**	**$ 11,062,984**	**$ 11,170,207**	**$ 11,487,327**	**$ 42,976,651**	**$ 43,109,740**	**$ 41,235,245**	**$ 43,891,475**	**$ 43,984,480**
Variable O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 6,921	$ 7,759	$ 5,929	$ 6,454	$ 6,742	$ 7,446	$ 7,245	$ 7,087	$ 7,764	$ 7,561
CCGT	$ -	$ -	$ -	$ -	$ -	$ 1,327,523	$ 1,314,259	$ 1,208,355	$ 1,285,638	$ 1,273,479
CHP	$ 2,570,213	$ 2,624,504	$ 2,687,685	$ 2,734,437	$ 2,797,177	$ 2,862,655	$ 2,926,705	$ 2,974,560	$ 3,033,977	$ 3,104,623
RENG	$ 178,574	$ 184,087	$ 179,013	$ 154,284	$ 145,716	$ 169,621	$ 148,346	$ 161,786	$ 162,713	$ 136,748
CROD OFF	$ 44,783,891	$ 46,331,575	$ 47,995,210	$ 49,400,630	$ 50,952,483	$ -	$ -	$ -	$ -	$ -
CROD On	$ 41,789,480	$ 43,102,515	$ 44,480,296	$ 45,670,286	$ 46,951,916	$ -	$ -	$ -	$ -	$ -
Total Variable O&M Costs ($)	**$ 89,329,079**	**$ 92,250,441**	**$ 95,348,132**	**$ 97,966,091**	**$ 100,854,034**	**$ 4,367,244**	**$ 4,396,556**	**$ 4,351,788**	**$ 4,490,093**	**$ 4,522,410**
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	$ 120.56	$ 125.54	$ 130.60	$ 136.78	$ 142.32	$ 147.52	$ 153.05	$ 158.00	$ 163.49	$ 168.96
CCGT						$ 94.31	$ 97.64	$ 100.71	$ 104.60	$ 108.35
CHP	$ 59.93	$ 62.37	$ 64.83	$ 67.24	$ 69.76	$ 72.23	$ 74.71	$ 77.15	$ 79.83	$ 82.30
RENG	$ 102.99	$ 106.96	$ 111.84	$ 116.70	$ 121.61	$ 125.79	$ 130.55	$ 134.74	$ 139.29	$ 144.03
CROD OFF	$ 50.31	$ 51.31	$ 52.34	$ 53.39	$ 54.45					
CROD On	$ 67.30	$ 68.65	$ 70.02	$ 71.42	$ 72.85					
Fixed O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 285,927	$ 293,412	$ 300,398	$ 307,883	$ 315,867	$ 323,851	$ 331,835	$ 339,819	$ 348,302	$ 357,284
CCGT	$ -	$ -	$ -	$ -	$ -	$ 6,028,236	$ 6,178,942	$ 6,333,415	$ 6,491,751	$ 6,654,044
CHP	$ 785,835	$ 805,481	$ 825,618	$ 846,258	$ 867,415	$ 889,100	$ 911,328	$ 934,111	$ 957,464	$ 981,400
RENG	$ 785,890	$ 805,537	$ 825,676	$ 846,318	$ 867,476	$ 889,162	$ 911,392	$ 934,176	$ 957,531	$ 981,469
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 33,718,273	$ 33,881,554	$ 34,086,336	$ 34,060,265	$ 34,078,584	$ -	$ -	$ -	$ -	$ -
LZ	$ 63,622	$ 64,909	$ 66,351	$ 67,509	$ 68,849	$ 70,241	$ 71,856	$ 73,078	$ 74,549	$ 76,020
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 52,939	$ 54,911	$ 103,945	$ 105,907	$ 109,678	$ 308,203	$ 318,166	$ 378,035	$ 387,382	$ 453,820
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 3,856,985	$ 3,974,434	$ 4,052,583	$ 4,152,736	$ 4,256,038
Total Fixed O&M Costs ($)	**$ 35,692,486**	**$ 35,905,803**	**$ 36,208,324**	**$ 36,234,139**	**$ 36,307,869**	**$ 12,365,779**	**$ 12,697,952**	**$ 13,045,217**	**$ 13,369,714**	**$ 13,760,075**
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506
CHP	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343
RENG	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495
SOLAR (PPA)	$ 343,604	$ 343,604	$ 636,870	$ 636,870	$ 636,870	$ 1,812,410	$ 1,812,410	$ 3,707,998	$ 3,707,998	$ 5,660,881
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919
Total Payment	**$ 11,019,442**	**$ 11,019,442**	**$ 11,312,708**	**$ 11,312,708**	**$ 11,312,708**	**$ 67,470,673**	**$ 67,470,673**	**$ 69,366,261**	**$ 69,366,261**	**$ 71,319,143**
Total Variable ($, VOM + Fuel)	$ 99,663,722	$ 103,060,184	$ 106,411,117	$ 109,136,298	$ 112,341,361	$ 47,343,895	$ 47,506,296	$ 45,587,032	$ 48,381,568	$ 48,506,890
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 47,019,807	$ 47,495,129	$ 48,345,764	$ 48,920,091	$ 49,497,012	$ 79,836,452	$ 80,168,625	$ 82,411,478	$ 82,735,975	$ 85,079,219
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (8,866,069)	$ (8,815,498)	$ (8,706,984)	$ (7,640,445)	$ (6,725,587)	$ 29,852,949	$ 31,040,596	$ 37,939,408	$ 38,984,523	$ 44,302,083
Total Power Supply Cost ($)	$ 137,817,461	$ 141,739,815	$ 146,049,897	$ 150,415,944	$ 155,112,786	$ 157,033,295	$ 158,715,516	$ 165,937,918	$ 170,102,067	$ 177,888,192
Total Power Supply Cost ($/MWh)	$ 87.12	$ 88.05	$ 89.01	$ 90.38	$ 91.71	$ 91.45	$ 90.80	$ 93.60	$ 94.28	$ 96.87

Net Present Cost ($) $ 1,515,469,156

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9400 Ward Parkway
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