MEAN

MUNICIPAL ENERGY AGENCY
OF NEBRASKA

2017 Integrated Resource Plan

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LIST OF ABBREVIATIONS

APPA	American Public Power Association
ARR	Auction Revenue Rights
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BTMG	Behind the Meter Generation
BTU	British Thermal Unit
CAES	Compressed Air Energy Storage
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
CES	Creative Energy Systems
CF	Capacity Factor
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CP	Coincident Peak
CPP	Clean Power Plan
CRSP	Colorado River Storage Project
CSAPR	Cross-State Air Pollution Rule
DG	Distributed Generation
DLC	Direct Load Control
DMEA	Delta-Montrose Electric Association
DOE	Department of Energy
DSM	Demand-Side Management
EGS	Enhanced Geothermal Systems
EIA	Energy Information Administration
EIS	Energy Imbalance Service
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ERPA	Electrical Resources Pooling Agreement

FCRC	Fixed Cost Recovery Charge
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
FY	Fiscal Year
GGS	Gerald Gentleman Station
GHG	Greenhouse Gasses
HDD	Heating Degree Days
HVAC	Heating, Ventilating, and Air Conditioning
IGCC	Integrated Gasification Combined Cycle
IM	Integrated Marketplace
IMU	Indianola Municipal Utilities
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-Hour
LAP	Loveland Area Projects
LED	Light Emitting Diode
LES	Lincoln Electric System
LF	Load Factor
LFG	Landfill Gas
LMP	Locational Marginal Price
LTCR	Long-Term Congestion Rights
MATS	Mercury and Air Toxics Standards
MBA	Member Based Association
MCF	Thousand Cubic Feet
MEAN	Municipal Energy Agency of Nebraska
MEC	MidAmerican Energy Company
MISO	Midcontinent Independent System Operator
MSW	Municipal Solid Waste
MUP	Multi-Unit Participation Agreement
MW	Megawatt
MWh	Megawatt-Hour
NAAQS	National Ambient Air Quality Standards

NCP	Non-Coincident Peak
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
NITSA	Network Integration Transmission Service Agreement
NMPP	Nebraska Municipal Power Pool
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrous Oxide
NPD	Non-Powered Dam
NPPD	Nebraska Public Power District
NREL	National Renewable Energy Laboratory
NSD	New Stream-Reach Development
PC	Pulverized Coal
PCT	Participant Cost Test
PHES	Pumped Hydropower Energy Storage
PM	Particulate Matter
PPA	Purchased Power Agreement
PPGA	Public Power Generation Agency
PRM	Planning Reserve Margin
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PTP	Point-To-Point Transmission
RCRA	Resource Conservation and Recovery Act
RDF	Refuse-Derived Fuel
RECS	Residential Energy Consumption Survey
RICE	Reciprocating Internal Combustion Engine
RMR	Rocky Mountain Region
RPS	Renewable Portfolio Standard
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SLCA	Salt Lake City Area
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool

TCR	Transmission Congestion Rights
TDF	Tire-Derived Fuel
TES	Thermal Energy Storage
TO	Transmission Owner
TRC	Total Resource Cost
TRP	Total Requirements Participant
UCT	Utility Cost Test
UGP	Upper Great Plains
WAPA	Western Area Power Administration
WEC	Whelan Energy Center
WECC	Western Electricity Coordinating Council
WSEC	Walter Scott Energy Center
WU	Waverly Utilities

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I. Executive Summary

A. IRP Requirements

Integrated resource planning was mandated by the Energy Policy Act of 1992 (*"EPAct"*).

EPAct requires all Western Area Power Administration customers to submit Integrated Resource Plans (*"IRPs"*) to WAPA every five years. The requirement is included in WAPA's power sales contracts with long-term firm customers.

WAPA has identified the following criteria for customer IRPs:

- Identify and compare all practicable energy efficiency and energy supply resource options.
- Include action plan with timing set by customer.
- Describe efforts to minimize adverse environmental effects of new resource acquisitions.
- Provide ample opportunity for full public participation.
- Conduct load forecasting.
- Include brief description of measurement strategies for options identified in IRP to determine whether objectives are being met.

IRPs and alternative reports will be evaluated by WAPA on the basis of:

- Meeting all criteria in 10 CFR 905
- Reasonableness of the plan with regard to: customer size, type, resource needs, geographic area and competitive situation
- Resource choice selection (EPAct 1992 section 114)

B. Introduction

1. Purpose

The purpose of this Integrated Resource Plan is to develop long-range implementation plans to serve MEAN's Total Requirements Participants' power supply requirements consistent with prudent utility planning practices utilizing the lowest cost, environmentally responsible energy supply.

This plan is also designed to fulfill the requirements of the Western Area Power Administration according to the Energy Policy Act of 1992, as described in section II.A.

2. Scope

This resource plan encompasses a time period of 15 years on the basis of MEAN's fiscal year. MEAN's fiscal year begins April 1st and ends March 31st. This IRP is inclusive of the planning period of FY 2017-18 to FY 2032-33.

The IRP conducts resource planning for MEAN's entire service footprint as a whole, as well as within the individual Regional Transmission Organizations ("*RTO*") regions in which MEAN's designated resources are assigned. MEAN operates in the Southwest Power Pool ("*SPP*") RTO, Midcontinent Independent System Operator ("*MISO*") RTO, and in the West region. Resources must be designated to meet the load and required reserve margin of

each region separately. However, there are several metrics that MEAN prefers to evaluate on an accumulated basis for the entire service area.

This IRP will consider all reasonable options for supply side resources and demand side management. Supply side and demand side options will be given equal consideration for incorporation into the future resource portfolio.

3. Methodology

The IRP analysis will begin with a qualitative evaluation of all resource options. Using selected criteria and criteria weighting, the complete list of options will be narrowed to a smaller list of qualified options that receive a high ranking in accordance with the criteria.

The qualified options will be subject to an economic analysis that applies resource availability and cost to MEAN's hourly loads and projected market pricing. The sum of the hourly costs and revenues over the study period will be summed to arrive at a total revenue requirement for each option for comparison purposes. The economic analysis will be repeated under various sensitivity scenarios to calculate the impact of potential changes to key inputs.

The combined results of the base case revenue requirement and the variability due to sensitivity cases will ultimately lead to the determination of a preferred portfolio for future resource acquisition planning.

4. About MEAN

The Municipal Energy Agency of Nebraska ("MEAN") is a body corporate and politic under the laws of the State of Nebraska. MEAN was created on June 22, 1981 under the Municipal Cooperative Financing Act, Sections 18-2401 through 18-2485, Reissue Revised Statutes of Nebraska (the "Act"). MEAN was created for the purpose of planning, acquiring, financing and operating facilities to generate and transmit electric power and energy.

MEAN's power supply system consists of ownership and contractual rights and interests in various electric generating and transmission resources and supplies (the *"Power Supply System"*). MEAN uses the Power Supply System to provide wholesale power supply, transmission and ancillary services to its participating municipal utilities (*"Participants"*). MEAN's services include power supply, dispatching, energy load forecasting, wheeling arrangements, load research, limited political action, demand-side management, load factor improvement, training, community development, and energy cost analysis.

MEAN's 69 Participants currently include 41 municipalities and one public power district in Nebraska, 14 municipalities and one joint action agency in Colorado, two Wyoming municipalities and 10 Iowa municipalities. Each of the Participants owns and operates an electrical utility system that provides electric service to consumers. 61 of the Participants (the *"Total Requirements Participants"*) receive "total-requirements" electric supply services from MEAN, exclusive only of their allocations of firm power and energy from the Western Area Power Administration of the U.S. Department of Energy (*"WAPA"*), except for certain generating facilities of Waverly Utilities (*"WU"*) and Aspen, Colorado.

Participants may take additional steps to become members of MEAN (*"Members"*) under the Act by making application with the Nebraska Power Review Board. Each Member

appoints and is represented by a director on the MEAN Board of Directors. MEAN currently has 54 Members. MEAN's participant communities are shown on the map in *Figure I-1*.

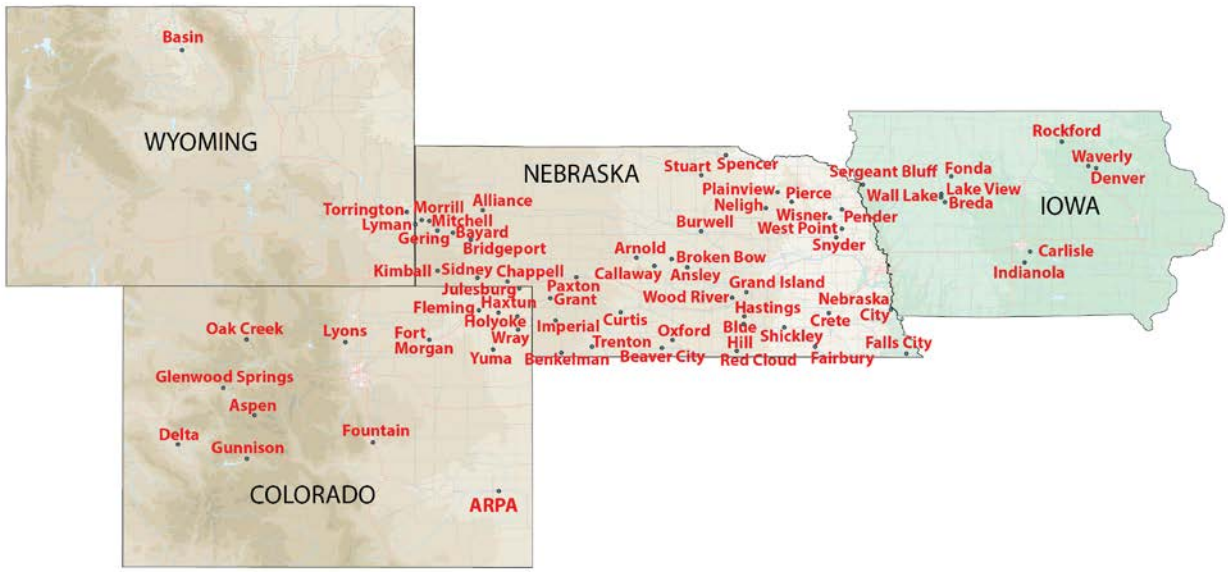


Figure I-1

5. Regional Markets

MEAN's regional footprint stretches from Central Iowa across Nebraska and into Colorado and Wyoming. Due to this footprint, MEAN is required to operate in two regional transmission organizations, MISO and SPP. Both MISO and SPP operate day-ahead and real-time energy markets. Market participants must pay for costs to serve load and receive revenue for their electrical generation. MEAN also operates in the western United States through the Western Electricity Coordinating Council (*"WECC"*).

C. Uncertainties/Limitations

There are many parameters that impact the inputs to the IRP analysis. Many of these parameters have been calculated or assigned with certain assumptions. Should these assumptions be incorrect or prove to change over time, the outcome of the analysis could potentially change as well. This section explores some of the uncertainties and limitations underlying these variable inputs to the analysis.

1. Environmental Legislation

Electric utilities are subject to continuing environmental regulation. Various environmental permits and approvals from state and federal agencies are necessary in order to operate the Power Supply System. To date, MEAN reports that all environmental permits and approvals necessary for the operation of the Power Supply System have been obtained. However, federal, state, and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that the Power Supply System and the utility facilities owned or operated by the Participants will remain subject to the regulations currently in effect or indefinitely maintain current compliance status. An inability to comply with environmental standards could result in reduced operating levels

or the complete shutdown of individual electric generating units not in compliance. MEAN constantly monitors environmental regulations and the relevance of these regulations on MEAN's Power Supply System assets.

The IRP analysis is conducted under the status quo environmental regulations, including the stay of the Clean Power Plan. However, sensitivity analysis explores the impact of a future carbon tax.

2. Load Forecast

MEAN employs a robust statistical method for forecasting load. A number of input variables are used to formulate a forward-looking equation to calculate the monthly peak demand and monthly energy usage for each participant community for the entirety of the study period. The individual participant load forecasts are combined to result in a total load forecast for each region. However, the statistical analysis is dependent upon several variables, such as weather data, population, and income. Changes in any of these factors will impart changes in the load forecast.

In addition to the variables identified as inputs to the load forecast calculation, there are other external factors that act on the system load:

Throughout the MEAN footprint, demand side management (*"DSM"*) measures are being adopted by utilities and end-use customers in participant communities. DSM measures act to reduce either the peak demand for electricity or the total electricity consumption.

Distributed Generation (*"DG"*) is customer and/or community ownership of generating assets to serve end use load. Each installation of DG removes energy consumption from the MEAN system and thereby decreases the resource need, either on a capacity or energy basis depending on the timing of DG energy supply.

Recent years have seen an emphasis on energy efficiency and energy conservation on all levels: residential, commercial, and industrial. The widespread use of these practices has led to a decrease in the growth rate of electric loads, and is a trend which is likely to continue, but at a pace that is difficult to predict.

3. Energy Markets

Since the establishment of the SPP and MISO Integrated Markets, several changes have been introduced that have changed the way resources are designated to load, the way resources are dispatched into the marketplace, and energy prices and cost recovery for generation resources. Given the fast pace of developments in the markets, it is likely that changes will continue in the future.

In recent years, transmission providers in the west have been contemplating joining together to form a Mountain West RTO and possibly integrate into the SPP IM. This will undoubtedly impose changes on load and resource interaction in the west. The effects of these structural changes would be seen not only in the western region, but in SPP as well. The current analysis does not assume a market in the west.

The existing markets and potential creation of future markets present significant opportunity for uncertainty.

4. Fuel Pricing

Fuel pricing is an obvious source of uncertainty.

Recent natural gas pricing has been low compared to historical pricing and has seen less volatility in the last two to three years. However, within the past 20 years there have been several periods of elevated pricing and extreme volatility. As a global resource, natural gas is also subject to the influence of global supply and demand. This relationship carries with it the risk of price fluctuations in response to market occurrences elsewhere. Fuel pricing projections assume low pricing and low volatility into the future. However, this contains inherent uncertainty.

Coal prices are similarly subject to external influence and resulting volatility. Although Appalachian coal prices experienced a peak about ten years ago, more recently prices have stabilized and remained relatively low. Coal in most regions has seen flat or declining pricing over the past five years. However, fuel prices respond to a number of factors and can be difficult to predict.

Sensitivity cases are included in the economic analysis to capture the effects of changes in fuel pricing.

D. System Load Forecast

1. Methodology

MEAN employed multiple regression analysis to forecast the non-coincident peaks for each of its Total Requirement Participants for FY 2017-2018 (annual forecast) through FY 2032-33 (15-year forecast). The model took into consideration three main factors as independent variables: economic factors such as population growth and income growth; temperature factors such as average daily temperature, heating degree days (*"HDD"*) and cooling degree days (*"CDD"*); and calendar factors such as weekdays and month.

The coincident peak forecast is calculated as MEAN's non-coincident peak multiplied by the coincidence factor. The coincidence factor was forecasted based upon regression analysis of the difference between the mean temperature and the max temperature at the time of historical peaks.

2. MISO

MEAN's load forecast for peak demand and energy consumption in MISO for the 15-year study period is shown in the graphs in *Figures I-2* and *I-3*:



Figure I-2

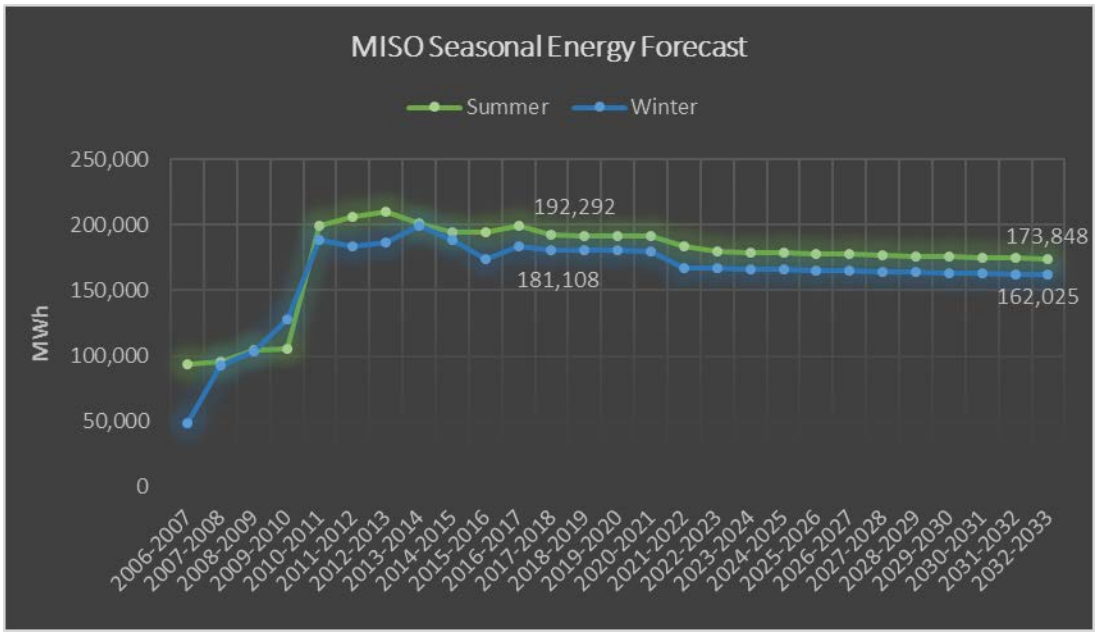


Figure I-3

3. SPP

MEAN's load forecast for peak demand and energy consumption in SPP for the 15-year study period is shown in the graphs in *Figures I-4* and *I-5*:

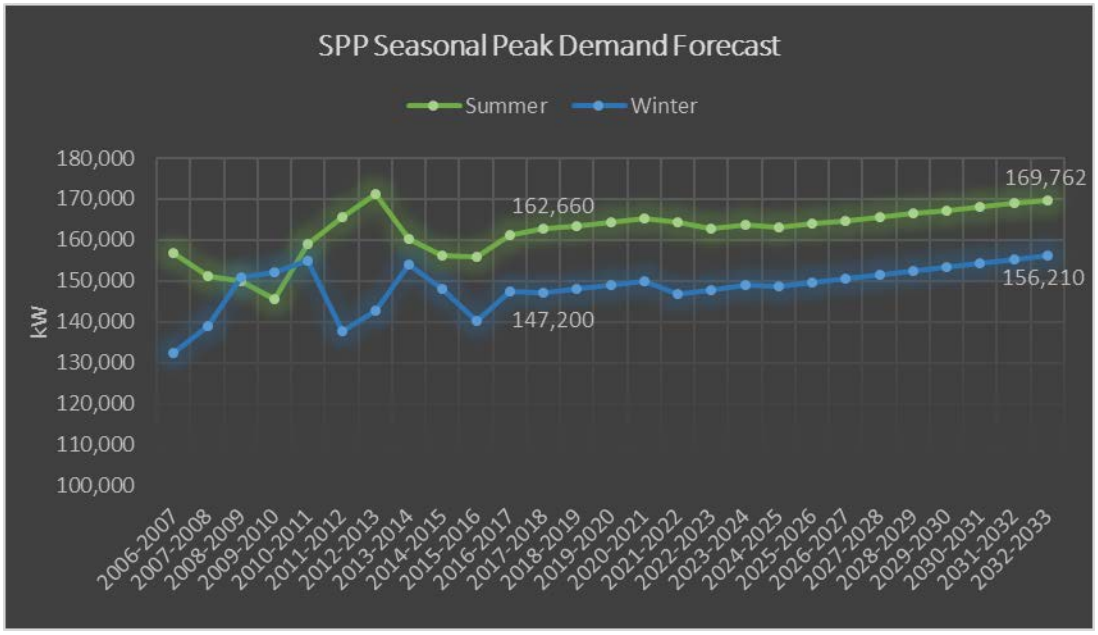


Figure I-4

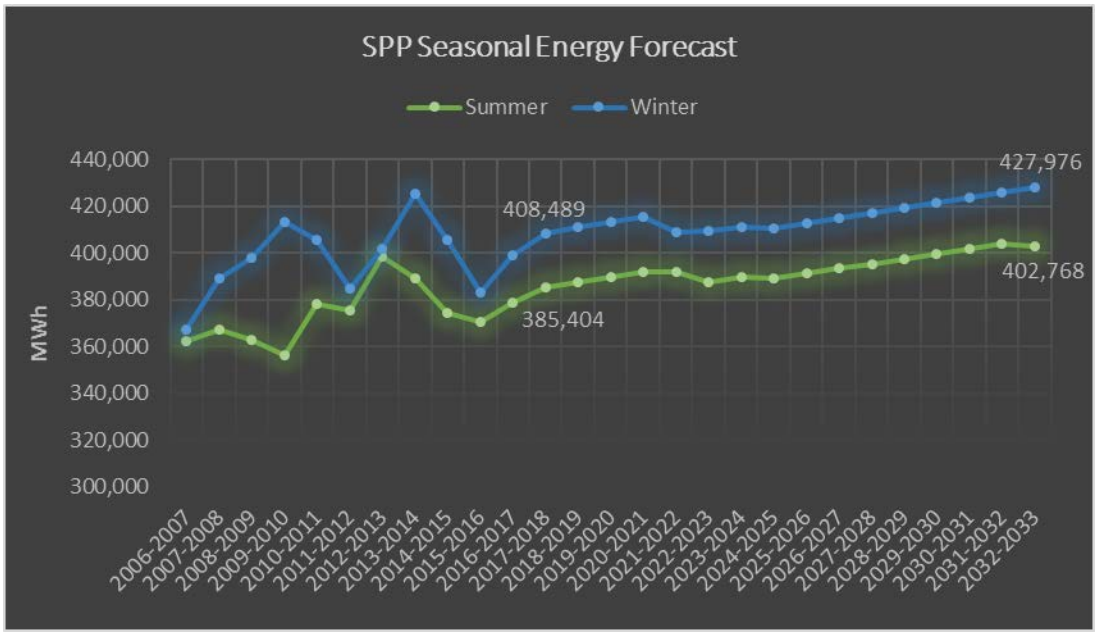


Figure I-5

4. West

MEAN's load forecast for peak demand and energy consumption in the west region for the 15-year study period is shown in the graphs in *Figures I-6* and *I-7*:

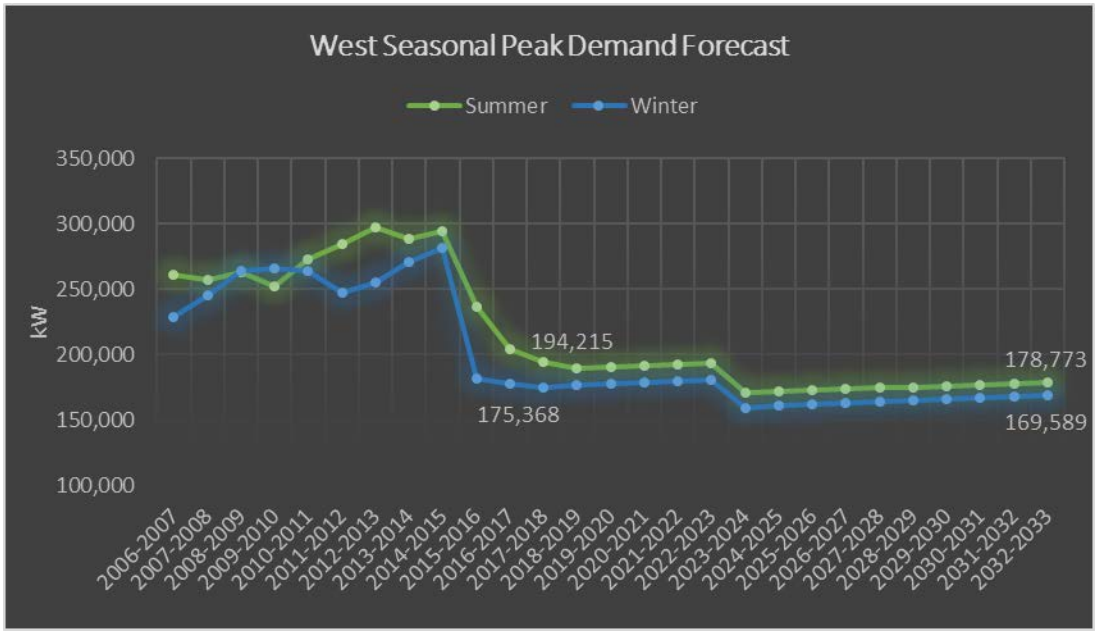


Figure I-6

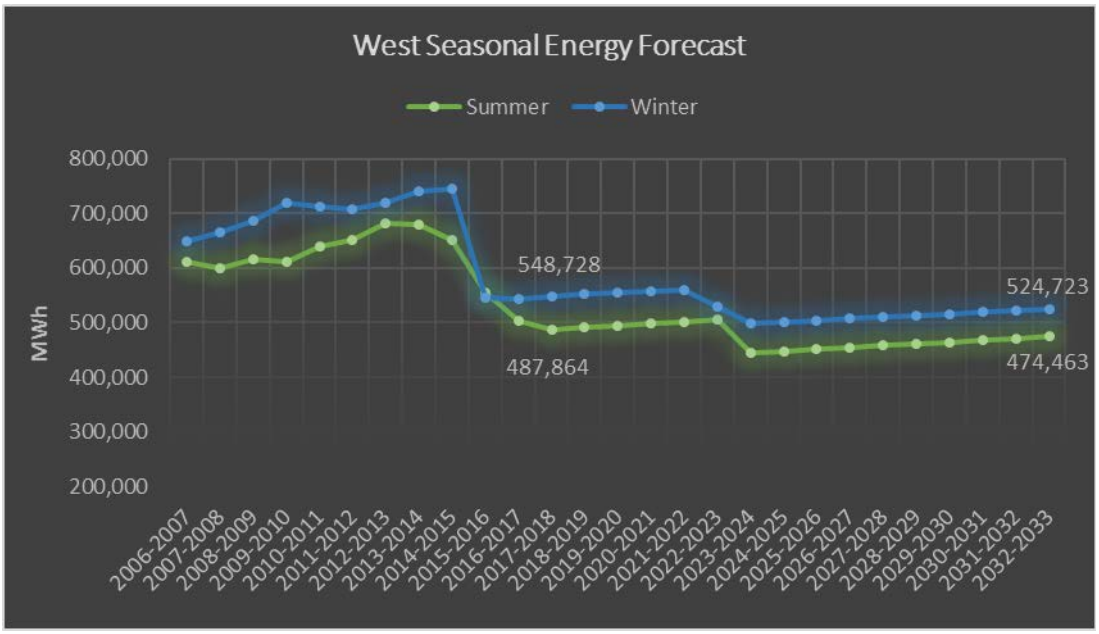


Figure I-7

5. MEAN System

MEAN's load forecast for peak demand and energy consumption for the entire system for the 15-year study period is shown in the graphs in *Figures I-8* and *I-9*:

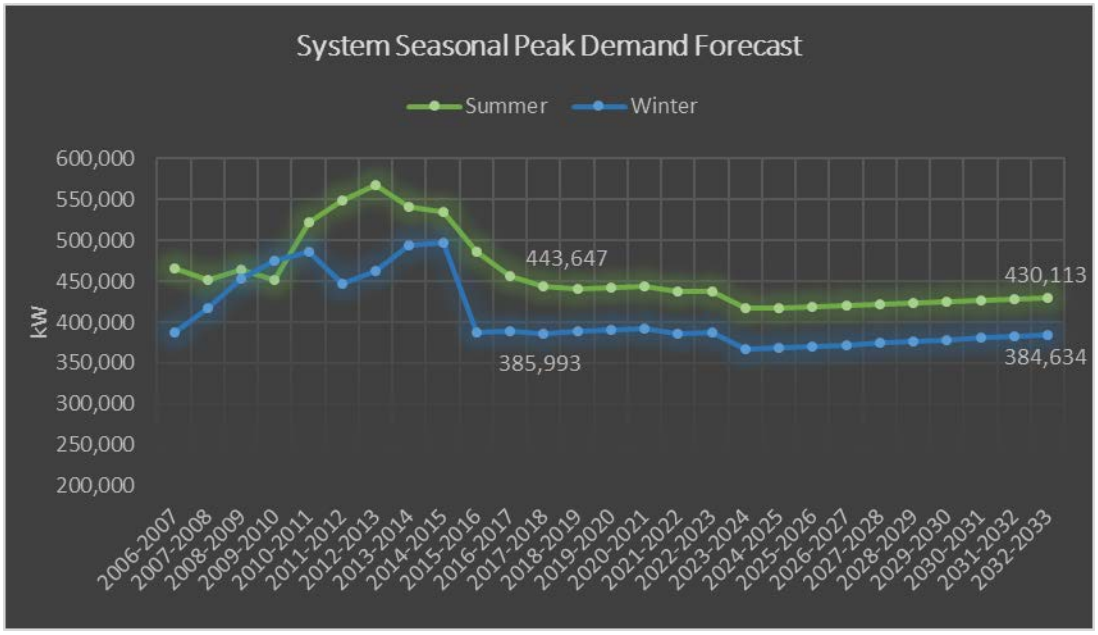


Figure I-8

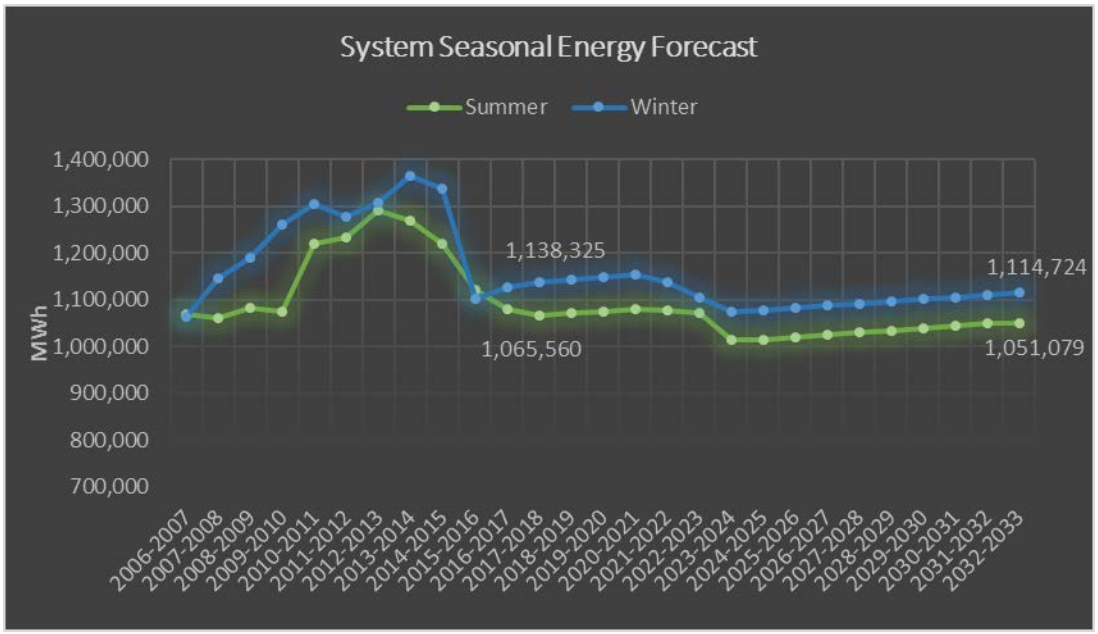


Figure I-9

6. Reserve Margin and Transmission Losses

MEAN must maintain capacity to serve not only the forecasted load in each region, but the total resource obligation which adds to the peak demand a reserve margin and transmission losses.

The SPP and MISO market constructs require each load serving entity to maintain a designated percentage of reserve capacity in addition to the entity's forecasted peak load. In SPP, the established required Capacity Margin is 12%. For the 2017/18 planning year, the MISO Planning Reserve Margin (*"PRM"*) is 15.8%. As the MISO definition of the PRM is specific to the operation of the upcoming year, the PRM changes annually.

For loads and resources in the west, there is no prescribed reserve margin. MEAN incorporates a 12% reserve margin in addition to forecasted load when determining the load and resource balance in the west.

MEAN's total obligation for service must also include the losses that occur throughout the transmission system. The rate of loss depends on the transmission system, and is typically reported to MEAN on an annual basis. However, MEAN does not have to provide for transmission loss on WAPA allocations. Therefore, this amount is deducted from the calculations. In total, MEAN serves network load on six transmission systems.

E. System Resources

1. Summary

The Power Supply System consists of owned, leased and purchased power supply resources as well as transmission system arrangements used to transmit resources to the Total Requirements Participants. MEAN receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnected System (the *"Western Interconnection"*).

The table in *Figure I-10* summarizes MEAN's long-term power supply resources as of the date of this report:

Resource	MEAN Nameplate Capacity	Primary Energy Source	Market Region[1]	% of Capacity
Total Requirements Committed Facilities (Participant Owned Generation)	136 MW	Oil/Gas	MISO (77 MW), SPP (47 MW), WEST (12 MW)	22.9%
WAPA[2]	124.5 MW	Hydroelectric	MISO (7.5 MW), SPP (30 MW), WEST (87 MW)	21.0%
Whelan Energy Center Unit 2[3]	82 MW	Coal	SPP	13.8%
Walter Scott Energy Center Unit 4	59 MW	Coal	MISO	10.0%
NPPD Multi-Unit Participation	50 MW	Coal/Nuclear	SPP	8.4%
Laramie River Station Unit 1	9 MW	Coal	SPP	1.5%
Laramie River Station Unit 2 & Unit 3	19 MW	Coal	WECC	3.2%
Wygen Unit I	20 MW	Coal	WECC	3.4%
Neil Simpson Unit 2	10 MW	Coal	WECC	1.7%
Wygen Unit III	10 MW	Coal	WECC	1.7%
Wind Project at Kimball[4]	10.5 MW	Wind	WECC	1.8%
Wessington Springs Wind Project	10 MW	Wind	SPP	1.7%
NPPD Elkhorn Ridge Wind Plant	8 MW	Wind	SPP	1.3%
NPPD Laredo Ridge Wind Project	8 MW	Wind	SPP	1.3%
Louisa Generating Station	8 MW	Coal	MISO	1.3%
DMEA Shavano Falls/Drop 4 & Drop 6	7.6 MW	Hydroelectric	WECC	1.3%
NPPD Ainsworth Wind Energy Facility	7 MW	Wind	SPP	1.2%
Whelan Energy Center Unit 1	5.3 MW	Coal	SPP	0.9%
Waste Management Landfill Gas Facility	4.8 MW	Landfill Gas	MISO	0.8%
NPPD Crofton Bluffs Wind Project	4.2 MW	Wind	SPP	0.7%
TOTAL	592.9 MW			

(1) Resources located in MISO and SPP are dispatched by MISO and SPP.

(2) Comprised of approximately 109.5 MW of participant allocations, 6.7 MW of MEAN allocation, and 8.0 MW of Kansas Tribal allocation.

(3) Comprised of MEAN's Entitlement Share under its Participation Agreement with PPGA (80 MW) and purchase from Hastings Utilities (currently 2 MW). Under a power sales agreement dated June 9, 2008, between Hastings Utilities and MEAN, Hastings Utilities has agreed to sell capacity and associated energy from its Entitlement Share under its Participation Agreement with PPGA at cost through April 2018.

(4) Existing 10.5 MW Kimball Wind Farm owned by MEAN is being replaced by a PPA for energy output of a 30 MW wind farm at the same location. Commercial operating date is projected to be in Q1 2018.

Figure I-10

2. Resource Mix by Fuel Type

When presenting resource mix metrics, resource capacity is listed according to unit nameplate. This is notable in relation to intermittent resources, namely existing wind contracts. "Participant Oil/Gas" represents Participant Owned Generation.

On the basis of capacity, MEAN's resource mix for the entire system is shown below in *Figure I-11* for the current 2017 portfolio as well as a projection of the resource portfolio in 2030 in *Figure I-12*. From 2017 to 2030, the proportions remain relatively the same. The WAPA Displacement agreement ends, and a new resource must take the place of that capacity as well as the decrease in coal resources. The required future resource will represent approximately 13% of the total MEAN resource mix.

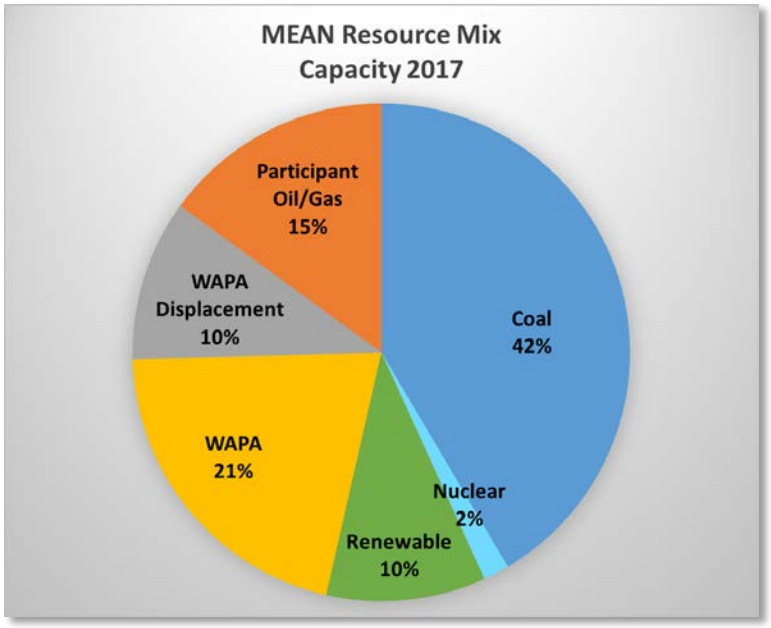


Figure I-11

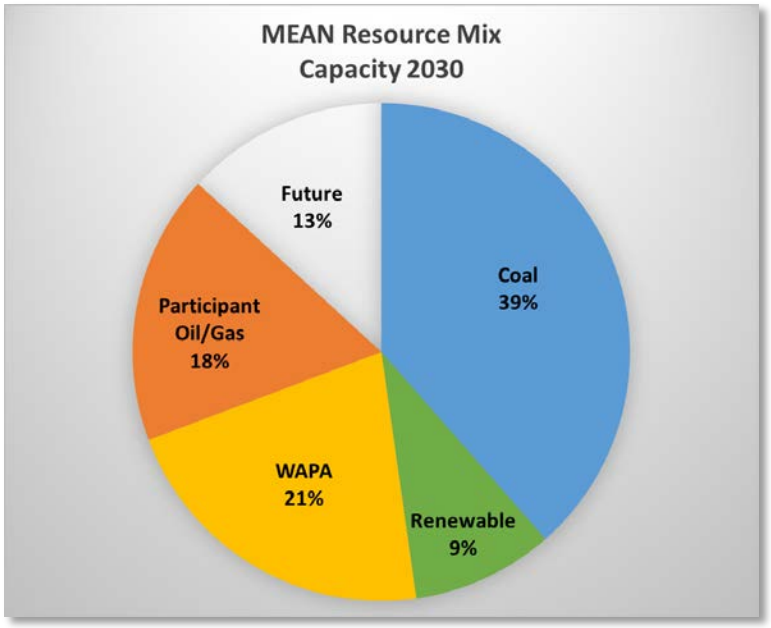


Figure I-12

Figures I-13 and *I-14* show MEAN's present and future resource mix in terms of energy generation. A large portion of MEAN's energy is generated by coal resources, in 2017 and in 2030. The contract for nuclear power expires as does the WAPA Displacement agreement and a small portion of the coal energy, leaving 8% of future energy to be generated by a new resource.

The future energy mix is a projection based on not only the availability of resources, but the operation based on historical capacity factors and contract energy requirements. Changes in market dynamics and the introduction of an integrated market in the west could substantially alter the actual energy production.

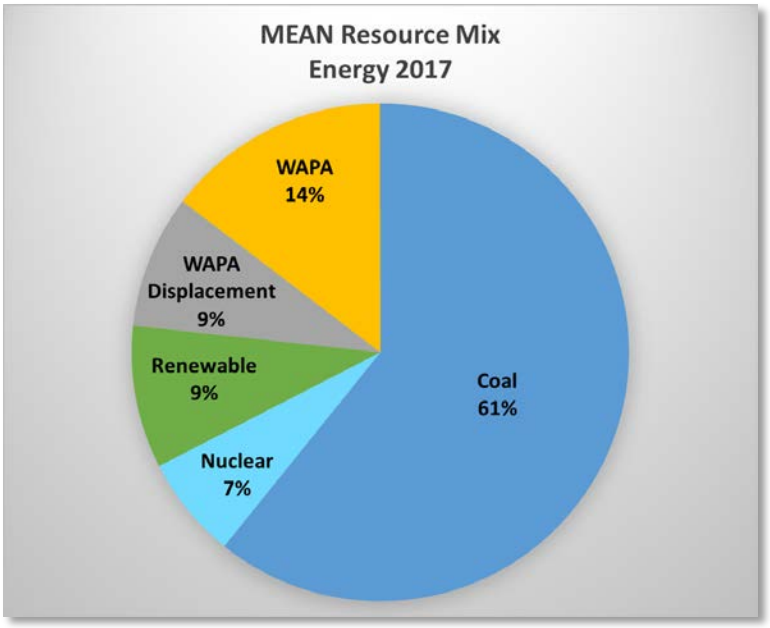


Figure I-13

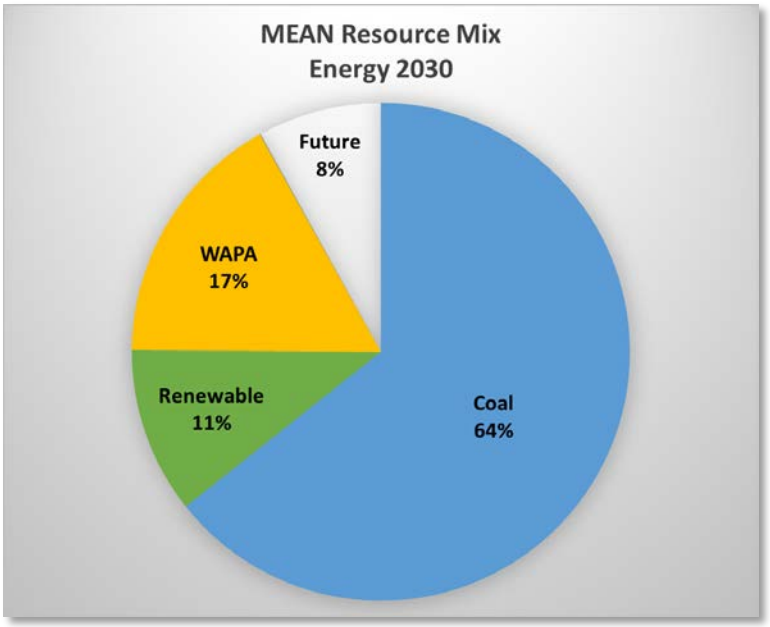


Figure I-14

3. Market Purchases/Exposure

During discussions at the MEAN Power Supply Committee meeting in January 2017, the committee members expressed an interest in investigating a resource portfolio strategy that intentionally leaves a portion of the energy supply to be sourced from the market. In the integrated market construct, MEAN ultimately purchases all energy for load from the market, but the actual operating or contract pricing of MEAN's assets acts as a hedge against fluctuations in market conditions. The committee asked about supplying a percentage of energy needs with market purchases for which MEAN does not maintain a hedge with owned or contracted energy. To gather more input on this possibility, the question was presented as part of the online participant survey in April 2017. The results shown below in *Figures I-15* and *I-16* indicate that a majority of respondents approve of this strategy, with an average recommended market exposure of 21.3% of MEAN's energy portfolio.

This approach carries a certain amount of risk. Current market prices are low, and therefore market energy purchases are favorable. However, in the case that market prices increase, MEAN would see a negative financial impact.

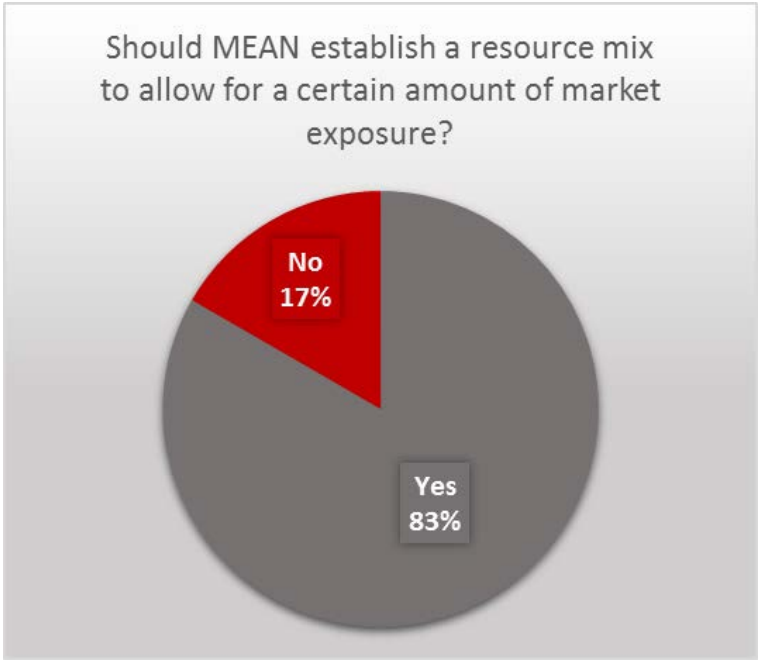


Figure I-15

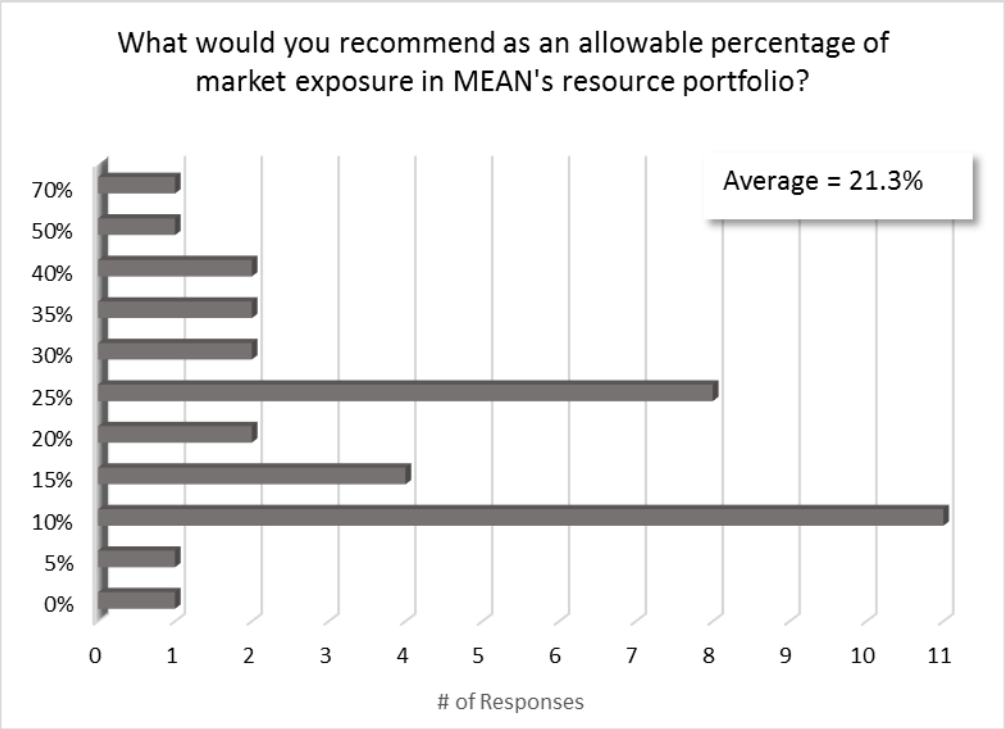


Figure I-16

F. Distributed Generation

1. Renewable Distributed Generation Policy

MEAN adopted a Renewable Distributed Generation Policy (the *"DG Policy"*) in 2016 that, in limited amounts and in certain circumstances, allows the Participants that have committed to purchase all of their electricity requirements from MEAN to (a) permit their retail customers to utilize output from renewable generation resources to supply all or a portion their own loads, (b) purchase output from renewable generation resources owned by their retail customers, and (c) subject to a cap set forth in the DG Policy, own and operate renewable generation resources, including community solar projects, to offset a portion of their total requirements purchases from MEAN. The DG Policy includes provisions to mitigate any adverse economic impacts of renewable generation resources purchased or undertaken by an individual Participant on MEAN and its other Participants.

The existing policy limits Participants to installation of a distributed renewable generating resource capable of generating 2% of the Participant's average annual energy needs. The type of resource determines the capacity factor, and therefore the allowable capacity of the installed resource.

A 2016 MEAN Participant survey found that throughout the entire MEAN footprint, there is a total installed grandfathered DG capacity of 2,875 kW. Of this total, 71 kW are located in SPP, 739 kW are located in MISO, and 2,065 kW are located in the west.

G. Existing Demand Side Management

1. MEAN Programs

MEAN has conducted several Demand Side Management (*"DSM"*) programs in the past, with varying degrees of adoption and impact.

Lighting Upgrade Program: The most recent DSM program currently administered by MEAN is the LED Lighting Upgrade Program. The ENERGYsmart commercial LED lighting program includes cash incentives paid directly to commercial customers to help cover the cost of lighting upgrades and replacements. 2016-17 was the first program year. The total annual energy savings achieved by the program is projected to be 1,131 MWh. The peak demand savings is projected to be 209 kW. Detailed results are shown in *Figure I-17* below:

Equipment Info (Conversion)	Sum of Quantity	KW Savings	Hours ran (annual)	Coincidence	Annual KWh Savings	KW Savings
High Bay - 10-70 watts	431	17.24	4160	95%	71718	16.4
High Bay - 141-203 watts	181	18.1	4160	95%	75296	17.2
High Bay - 71-140 watts	32	2.08	4160	95%	8653	2.0
LED Exit	8	0.16	8672	99%	1388	0.2
LED Refrigerator	14	0.56	8672	99%	4857	0.6
Customized Application Fixtures (Linear)	326	9.128	5200	95%	47466	8.7
Linear Replace/Retrofit - 17-24 watts LED	5,472	98.496	5200	95%	512179	93.6
Linear Replace/Retrofit - 25-48 watts LED	1,114	22.28	5200	95%	115856	21.2
Linear Replace/Retrofit - 49-72 watts LED	76	2.66	5200	95%	13832	2.5
Linear Replace/Retrofit - 73-96 watts LED	193	9.65	5200	95%	50180	9.2
Replace Incand.	883	44.15	5200	85%	229580	37.5
Grand Total	**8,730**	**225**			**1,131,004**	**209**

Figure I-17

The total cost of the LED Lighting Program per kW of savings is $373. This compares very favorably to even the most economical supply side option for additional resources, making DSM the lowest cost alternative to meet MEAN's future resource needs in terms of capacity. The NMPP Services Committee has approved the continuance of the LED Lighting Upgrade program through FY17-18.

Other current MEAN DSM Programs include:

- Infrared Energy Audits
- ENERGYsmart Vending Miser Bulk Purchasing Program
- Member Exclusive Education Sessions
- Essent Newsletter Subscription

2. Community Programs

The 2016 Participant DSM survey revealed a total of 26 communities with 42 DSM programs in place. The non-coincident sum of the demand and energy savings from these DSM programs is 15.15 MW and 6,988 MWh. Of this total, a large portion of the available demand savings is in the form of interruptible load supplied to irrigation wells. The projected annual savings of the community DSM programs are summarized in *Figure I-18* below.

Region	# of Communities	# of Programs	Demand Savings (kW)	Energy Savings (kWh)
MISO	7	15	1,167	307,533
SPP	10	13	13,226	5,846,040
West	9	14	762	834,931

Figure I-18

H. Renewable Energy Resources

1. MEAN Renewable Goals

MEAN has not previously defined a requirement or goal for the amount of renewable energy in our portfolio. To determine whether renewable goals should be a consideration of MEAN's long-term planning strategy, this question was asked in the April 2017 online survey. Of the respondents, 81% agreed that MEAN should establish a renewable energy goal. Of those answering in support of such a goal, the average recommended target percentage was 26%. The most common answer was 20%. Survey results are illustrated in *Figures I-19* and *I-20*.

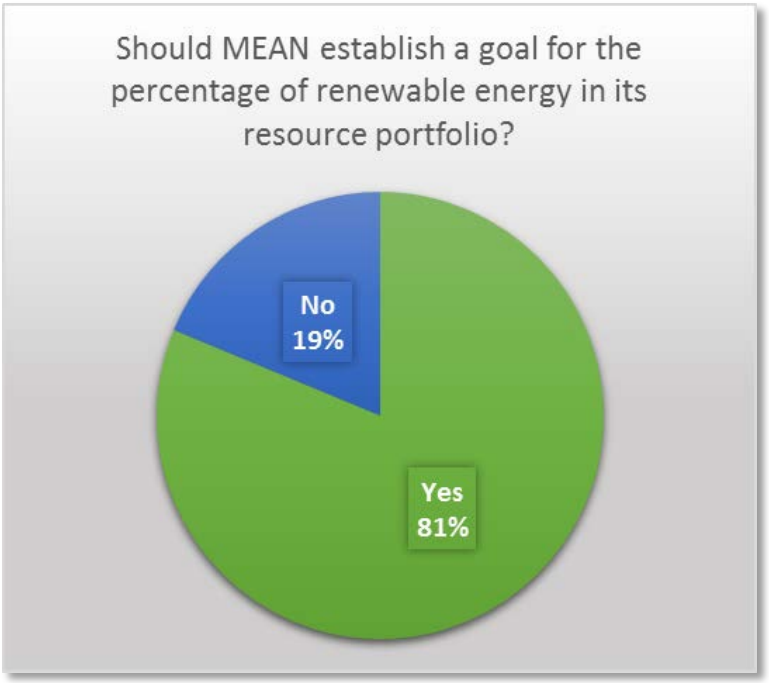


Figure I-19

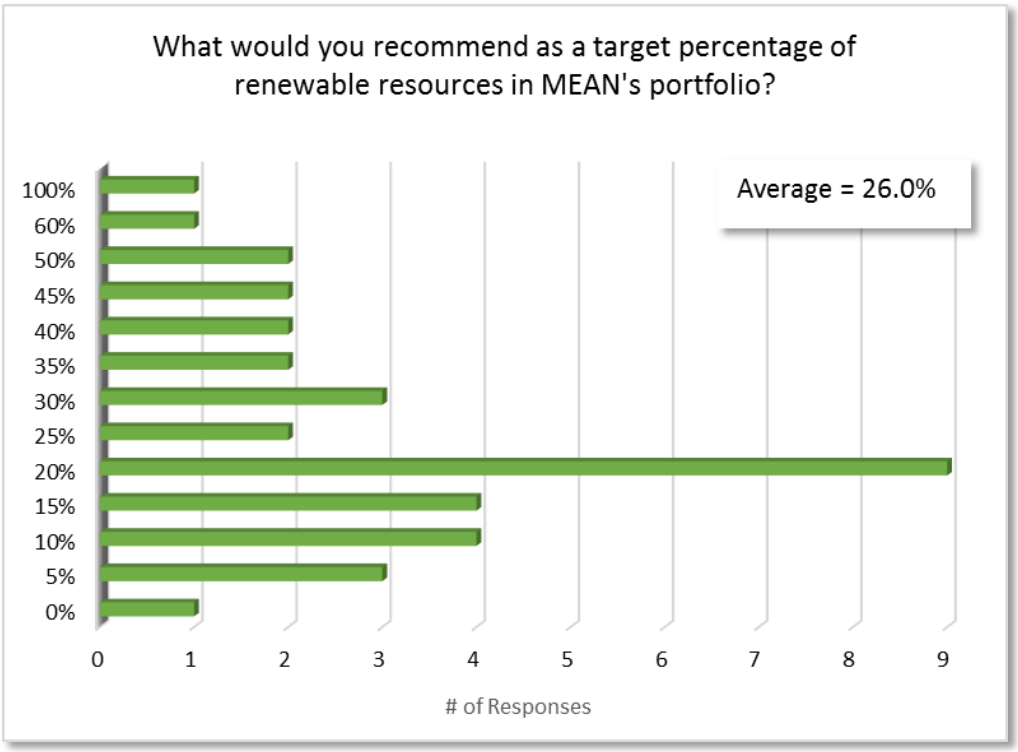


Figure I-20

2. Renewable Resource Mix

A review of Section VI.D. shows the current and future resource mix, specifically the percentage of renewable energy in each region's mix and MEAN's overall mix. In some contexts, existing hydropower administered by WAPA is not considered renewable energy due to the size of the resources and their environmental impact. However, small hydro units with less than 30 MW capacity are categorized as renewable. In MEAN's consideration of an internal renewable goal, WAPA allocations may or may not be included. However, in the case of a legislated RPS, the target would have to be met exclusive of WAPA allocations.

Figure I-21 summarizes the regional and total percentages of renewable resources (on a nameplate basis), both including and excluding WAPA:

Region	2017 Renewable Capacity (including WAPA)	2017 Renewable Capacity (excluding WAPA)	2030 Renewable Capacity (including WAPA)	2030 Renewable Capacity (excluding WAPA)
West	73%	14%	60%	17%
SPP	25%	16%	12%	2%
MISO	11%	4%	8%	4%
MEAN	**42%**	**10%**	**30%**	**6%**

Figure I-21

I. Load and Resource Balance

For the calculation of load and resource balance, resources will be quantified according to accredited capacity, or the maximum capacity that is expected to be available during the system peak load. The peak demand as shown in the load and resource balance in the total service obligation, which includes not only the forecasted peak load, but also the required reserve margin and the expected transmission losses. Resource capability in terms of capacity and energy is classified by fuel type. Behind-the-Meter-Generation ("BTMG") designates Participant Owned Generation.

1. MEAN System

The graph in *Figure I-22* shows the balance of peak demand and resource capacity for MEAN's entire footprint. Available capacity is sufficient to serve load until 2024. At that point, MEAN has a slowly growing capacity need into the future.

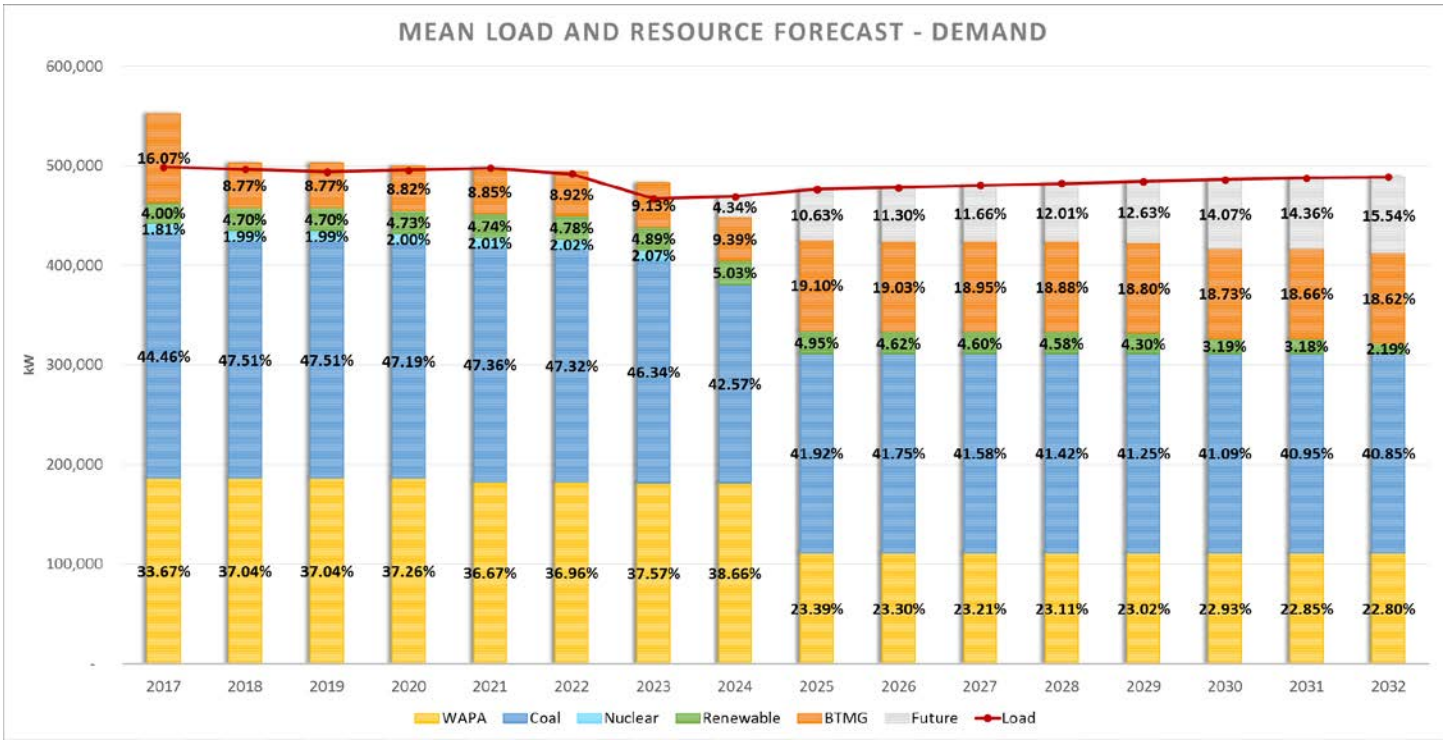


Figure I-22

2. West Region

The graph in *Figure I-23* shows the peak demand and resource capacity balance for the west region. The west region is long on capacity until 2025. At that point, the region has a deficit of 21.9% of the load obligation. This continues to grow through the remainder of the study period.

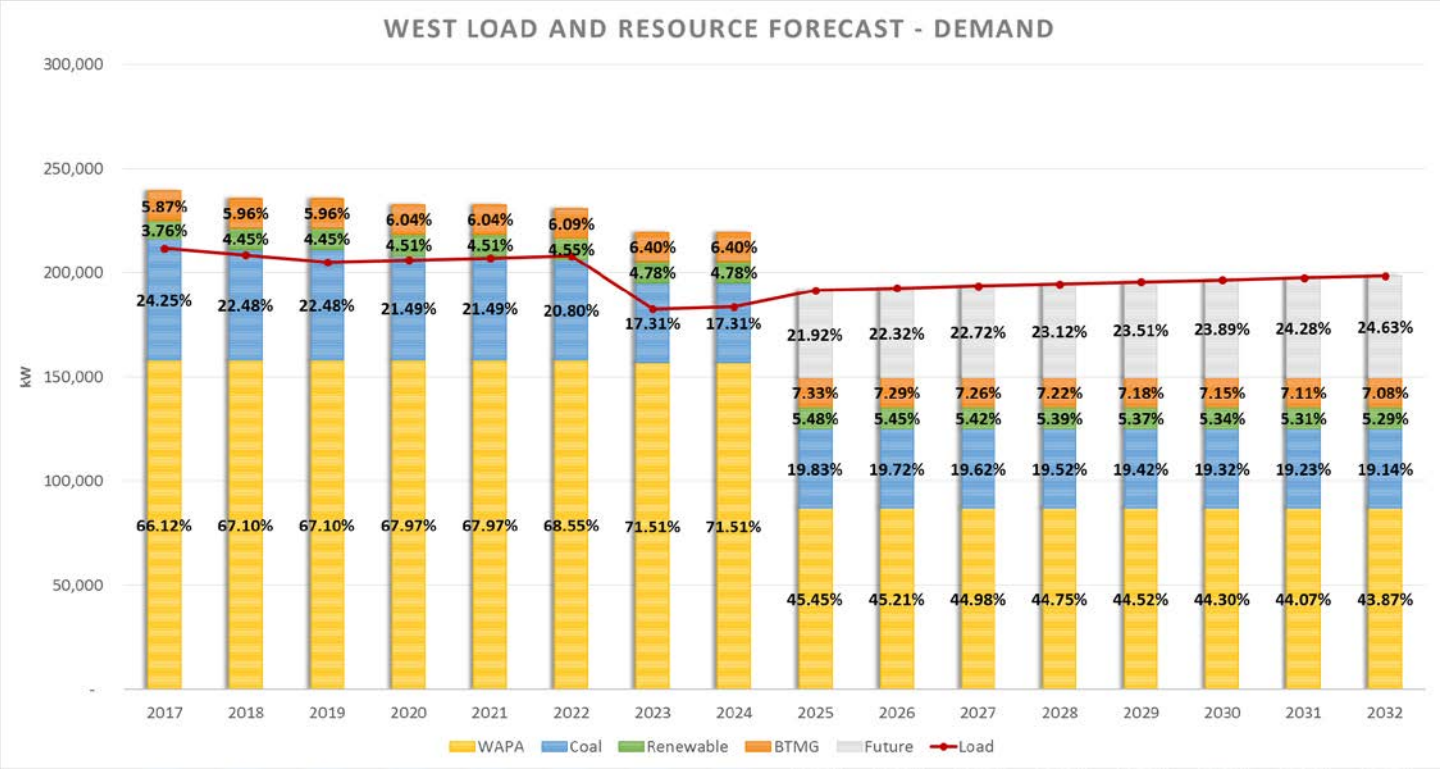


Figure I-23

3. SPP Region

Figure I-24 illustrates the peak demand and resource capacity balance for SPP. In 2017, capacity remains adequate to cover the service obligation. However, with the termination of the Generation Agent Arrangement contracting certain excess participant owned generation in 2018, SPP capacity is no longer sufficient to meet the load. The termination of the NPPD Multi-Unit Participation Agreement in 2023 is evident in the further reduction of resource levels after that year. In 2025, the WAPA Displacement Agreement ends, allowing the capacity dedicated to that contract to be again applied to MEAN's load. However, this does not recover enough capacity to remove the deficiency through the rest of the study period.

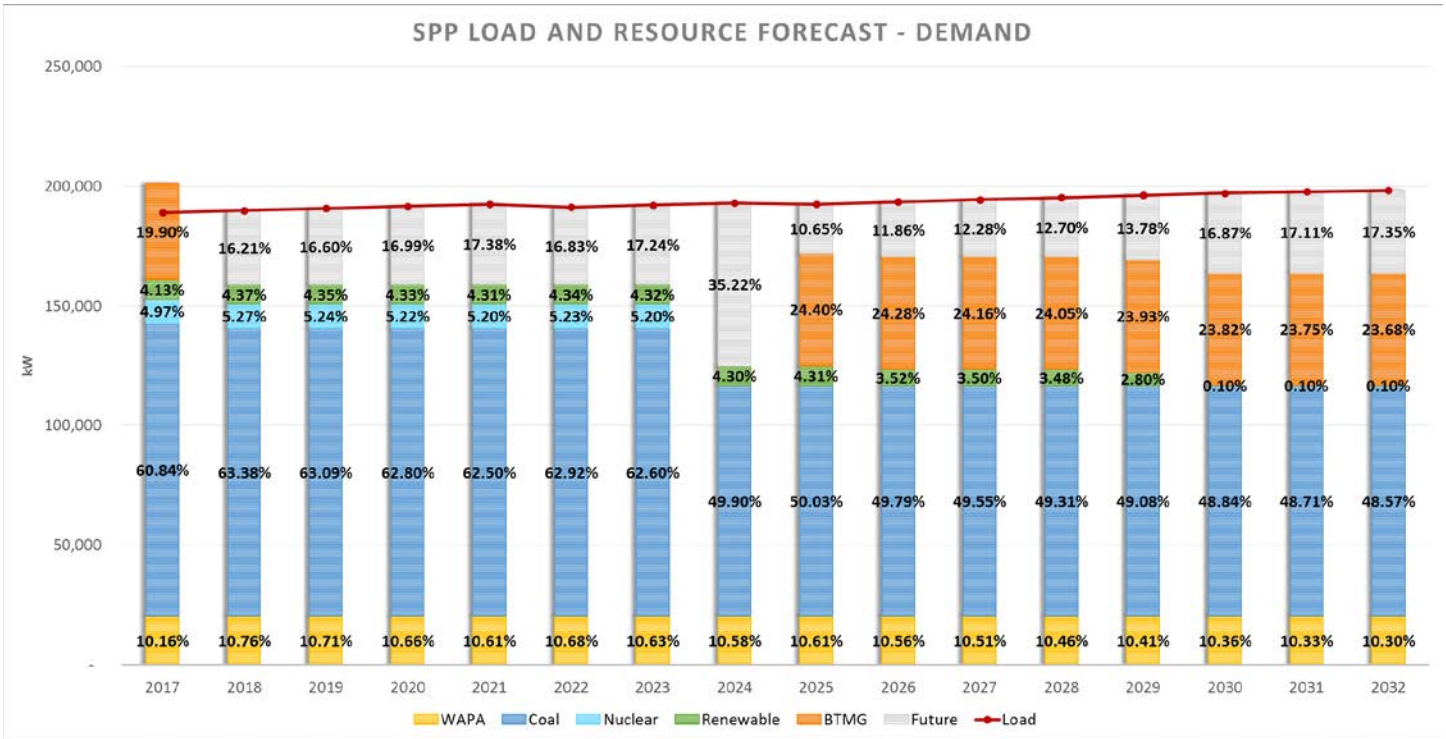


Figure I-24

4. MISO Region

Throughout the study period, MEAN has sufficient capacity in MISO. There are few changes in resources or load during the next 15 years. Resource levels are constant, with the exception of the end of the IMU and WU Generation Agent Arrangement. There is no resource deficiency in terms of capacity in MISO. This balance is shown in *Figure I-25*.

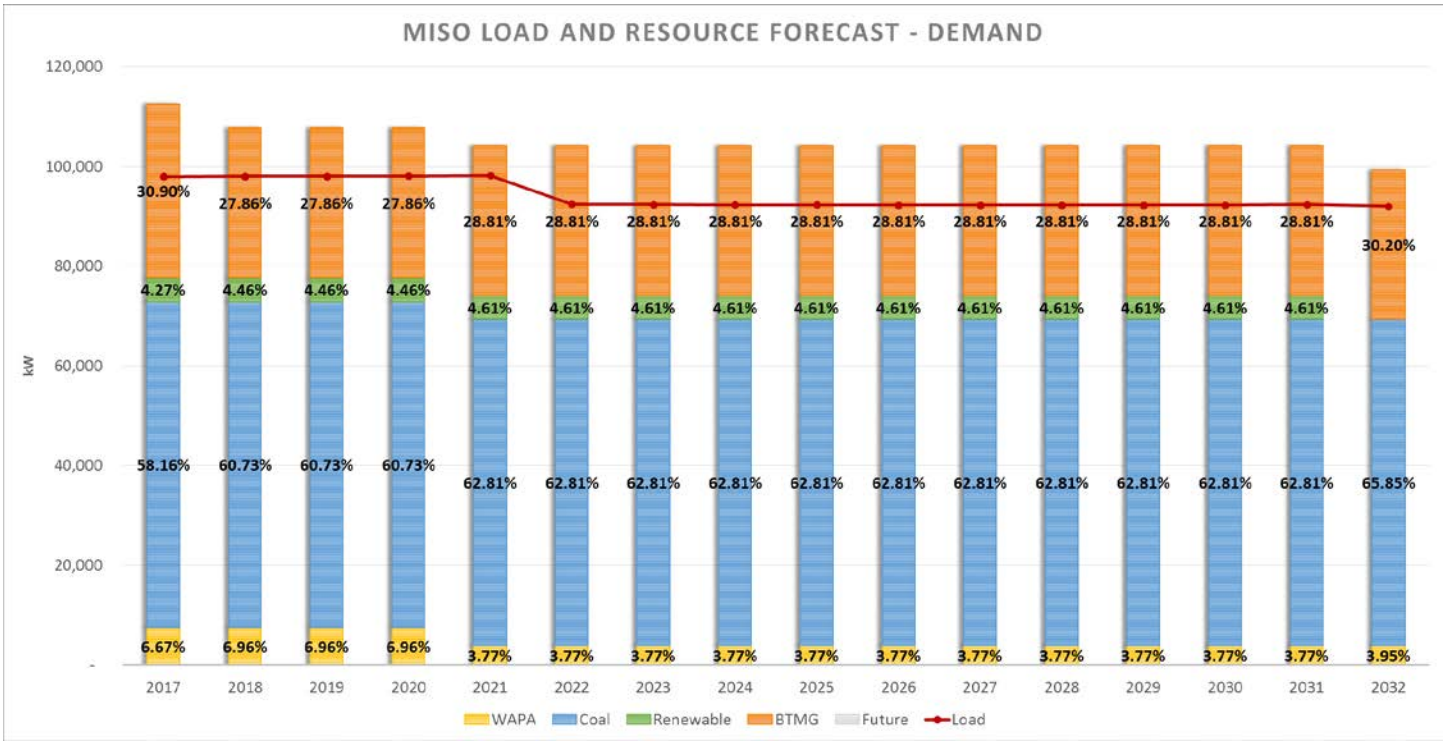


Figure I-25

5. Projected Resource Needs

A compilation of capacity and energy needs throughout MEAN's footprint is illustrated in *Figure I-26*:

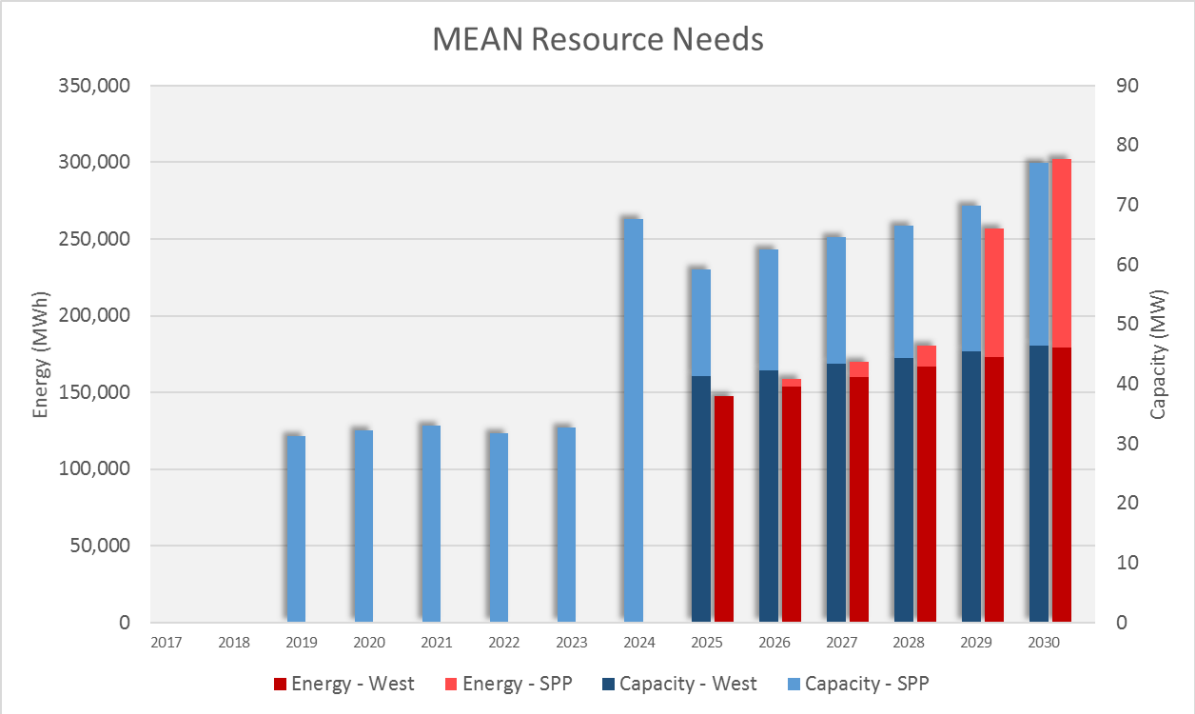


Figure I-26

J. Transmission

MEAN is a transmission-dependent utility and receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnection. Transmission costs include network integration transmission service and point-to-point transmission service. Transmission costs also include the impact of auction revenue rights and transmission congestion rights in SPP and auction revenue rights and financial transmission rights in MISO. These financial instruments were primarily designed to allow firm transmission customers the opportunity to offset price differences due to transmission congestion costs between resources and loads.

K. Phase I Supply Side Resource Evaluation

1. Phase I Supply Side Evaluation Objectives

Phase I is a preliminary evaluation undertaken to investigate a comprehensive list of supply side options and focus this list down to fewer qualified options that prove to be feasible potential additions to the MEAN portfolio. The Phase I evaluation is in large part qualitative and based on simplified metrics. A more in-depth economic analysis is reserved for the qualified options in Phase II.

2. Supply Side Options

To follow in *Figure I-27* is the complete list of the supply side options included in the Phase I evaluation for MEAN's future resource needs.

Supply-Side Resource Options
New Coal Plant*
New Coal IGCC Plant*
Natural Gas Combustion Turbine
Natural Gas Combined Cycle*
Co-Fire (new or retrofit)
Nuclear
Geothermal
Biomass (100%)
Landfill Gas/ MSW
Hydropower
Wind
Utility/Community Solar
Battery Storage
Compressed Air Storage
Pumped Hydropower
*with and without CCS

Figure I-27

3. Criteria

The goal of Phase I was to narrow the complete list of supply side options to a list of qualified options that represent the most feasible supply side resources for MEAN. To select the qualified options, appropriate criteria had to be determined. To this end, MEAN conducted an online survey wherein the participants were asked to rank a list of criteria in terms of importance in resource selection.

The results of the survey indicated that the participants' most important criteria in resource selection is cost. With a score of 4.77 out of 5, Cost was the most highly rated criteria. This was followed by Local Benefit with a score of 4.02 and Flexibility/Dispatchability with a score of 3.92. The lowest priorities were PPA vs. Ownership and Renewable Fuel. The complete results are shown in the graph in *Figure I-28*.

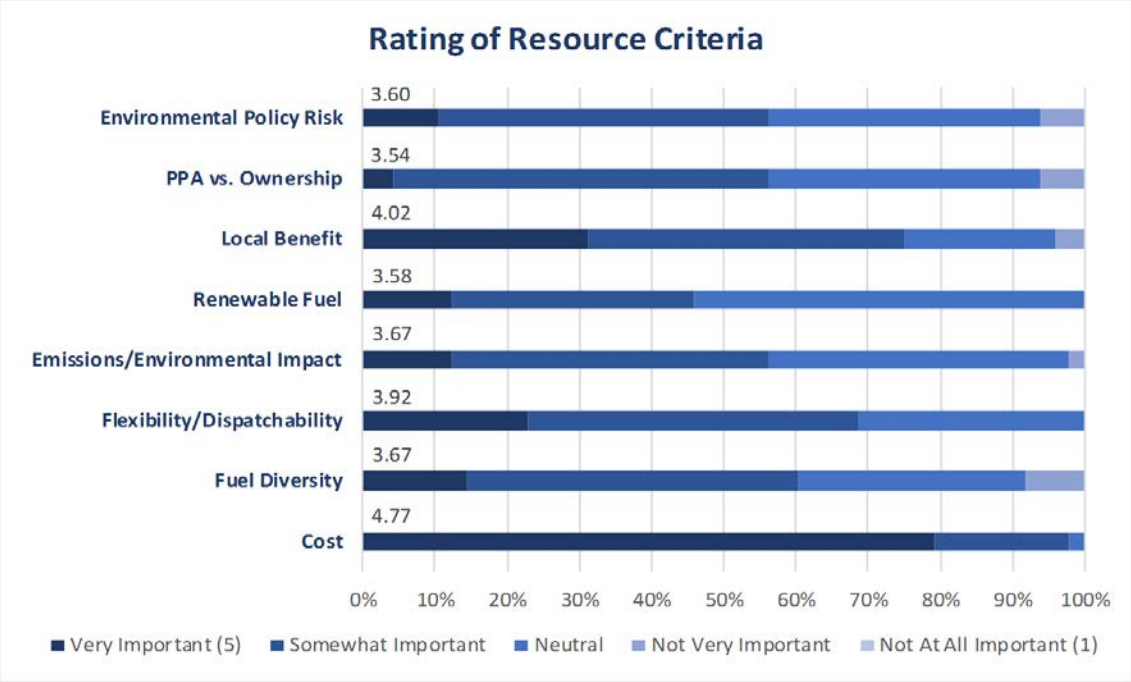


Figure I-28

The chart in *Figure I-29* shows the total combined weighted score for each of the supply side options. The individual components of the score are color coded by criteria as described above. Input data for this evaluation is located in Appendix B.

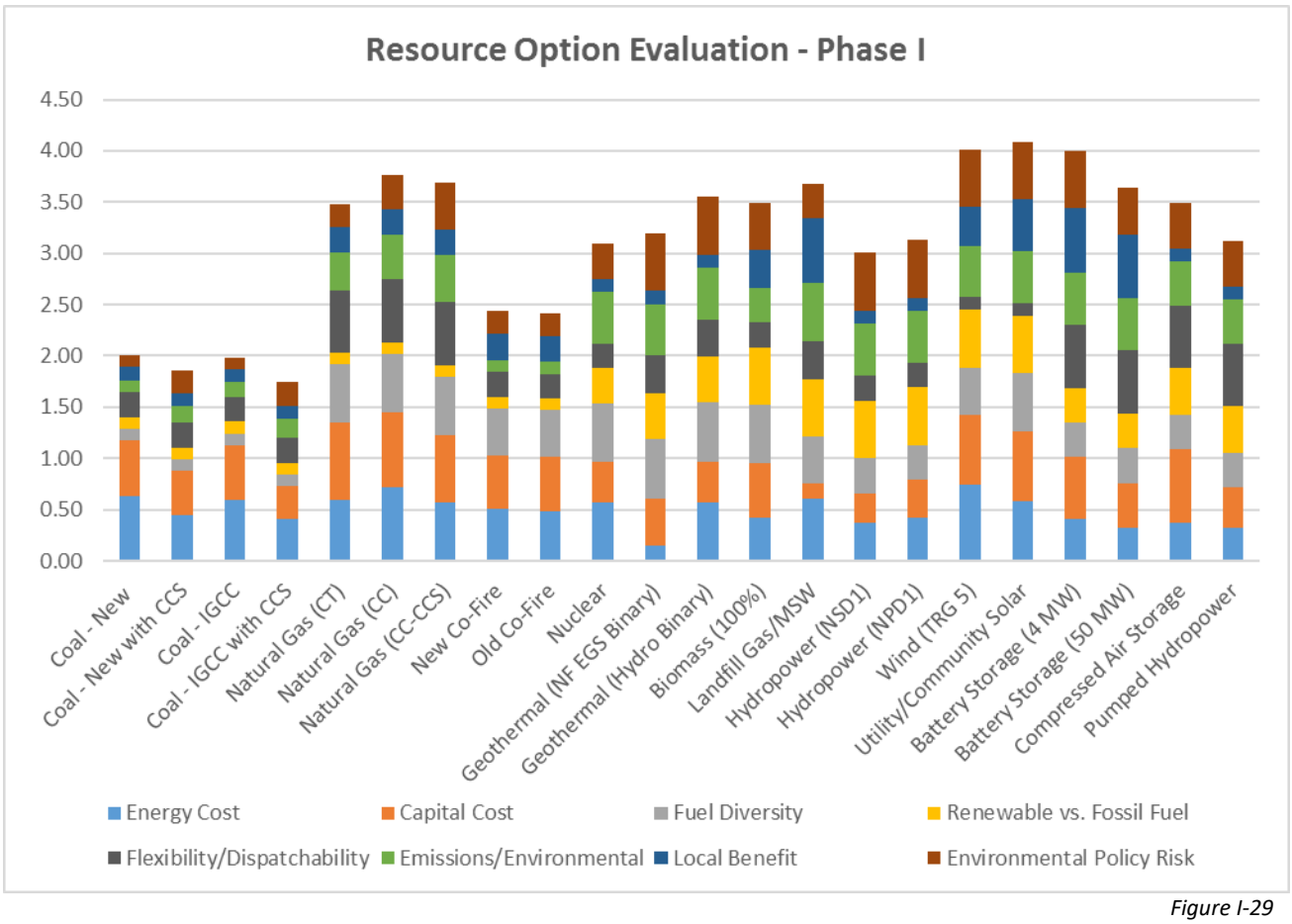


Figure I-29

4. Qualified Options

The Phase I evaluation resulted in final combined weighted scores for each of the supply side options defined at the beginning of the process. Because the criteria were weighted according to the participants' survey, the scores reflect the options most likely to achieve the priorities of the participants. The top scoring options were:

- Utility/Community Solar
- Wind
- Battery Storage
- Natural Gas Combined Cycle
- Landfill Gas/Municipal Solid Waste

In discussions at the MEAN Power Supply Committee Workshop held in April 2017, participants suggested additions to the qualified options determined by the Phase I evaluation.

Participant Owned Generation: Participants were supportive of the option of allowing participant communities to install new behind-the-meter generation to their fleets and add these units to MEAN's portfolio through the same contract by which MEAN leases existing generation.

Extension of Existing PPAs: Contracts considered for extension were the NPPD Multi-Unit Participation Agreement (GGS 1 and 2 and Cooper Nuclear Station), the Black Hills PPA (Wygen III and Neil Simpson 2), and the NPPD Wind PPAs. The Black Hills PPA was discounted for the lack of flexibility and dispatchability. The NPPD wind contracts were excluded as the assets are expected to be at or near the end of their useful service life when the contracts expire.

Extension of Generation Agent Arrangements: In January 2005, the MEAN Board placed a moratorium on participant owned generation, disallowing the lease of any generating unit additions. At a later date, MEAN entered into the Generation Agent Arrangements with Indianola and Waverly for lease of additional participant owned generation. This agreement includes a total of approximately 47 MW. The contract term extends through the MISO Planning year 2017-18. Of the total contracted generation, 40 MW is currently exported from MISO to SPP.

Creative Energy Solutions: MEAN has entered into discussions with Creative Energy Solutions to purchase the energy generated at CES's planned pyrolysis plant in Colorado. The pyrolysis facility would utilize municipal solid waste and waste tires to produce a synthetic gas, which would then be used to generate electricity via combustion turbines. This plant would be a 22 MW baseload renewable resource expected to come online sometime in 2019.

Battery Storage: Internal MEAN discussions and participant conversations at the April 2017 workshop and the May 2017 Board and Committee Meetings revealed an aversion to the serious consideration of battery storage as a resource option. Therefore, battery storage was not included in the Phase II analysis.

L. Demand Side Option Evaluation

Demand side management (*"DSM"*) programs can be utilized to reduce peak demand and thereby eliminate or delay the need for future capacity additions. Alternately, DSM measures can be designed to lower energy consumption to decrease the energy generation required by existing and future resources. Since MEAN's load and resource balance shows a future deficit in terms of both capacity and energy, both types of DSM are viable solutions.

In an attempt to minimize the required supply side resources to meet MEAN's total obligation, a demand side resource evaluation was performed to determine the value of proposed DSM programs.

1. Market Feasibility

The first step in the analysis was to determine the market feasibility of the potential programs. In April 2017 MEAN conducted an online survey to ask each community's MEAN representative to rate the potential implementation in their community of each of the prospective DSM programs. The results of the survey are shown in *Figure I-30*.

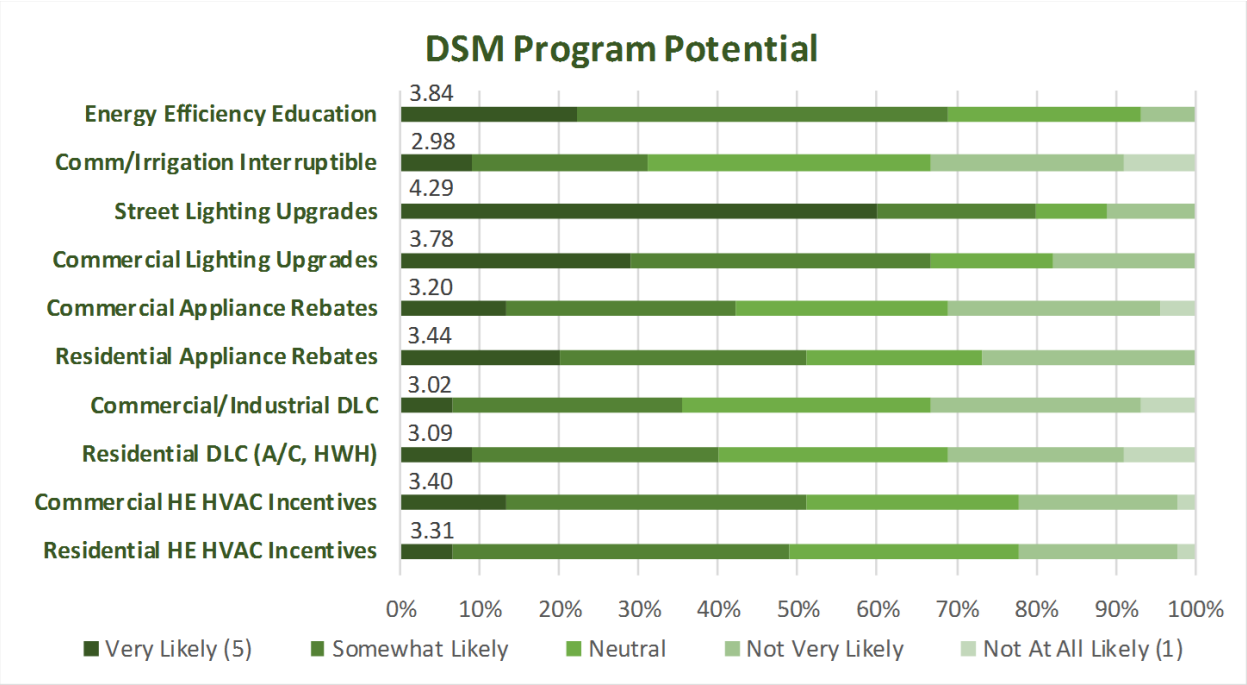


Figure I-30

2. Qualified Options

Based on the results of the Participant survey, the qualified options were broadly categorized as Residential and Commercial Appliance Rebates, and Residential and Commercial High Efficiency HVAC Incentives. In order to perform a more accurate analysis, these categories were studied and more specific programs defined for the next step in the analysis. The following DSM programs were advanced to the final analysis:

Residential and Commercial Appliance Rebate Programs:

- Refrigerator Rebate
- Freezer Rebate
- Water Heater Conversion (Gas to Electric) Rebate

Residential and Commercial High Efficiency HVAC Incentives:

- Air Source Heat Pump Conversion Incentive
- Room Air Conditioner Upgrade Incentive
- Central Air Conditioner Upgrade Incentive

3. Economic Feasibility

The costs and benefits of the proposed DSM programs were compared using three different calculation methods, all of which are commonly used by utilities for this purpose. These three tests consider the costs and benefits of the DSM programs from different perspectives. A calculated ratio greater than 1 indicates benefits that exceed costs.

- The Utility Cost Test (*"UCT"*), also called the Program Administrator Cost Test. This test measures cost-effectiveness from the viewpoint of MEAN. If MEAN's avoided supply costs exceed the costs incurred by MEAN in administering the program and paying the incentives or rebates to the end-use customer, the program is a net benefit to MEAN.

- Participant Cost Test (*"PCT"*). This test measures benefits and costs to the end-use customers participating in DSM programs. The test compares net bill savings, considering electric bills and gas bills, against incremental costs of the efficient HVAC equipment or appliance, which are calculated to include the incentive or rebate received from the utility. If the savings exceed the incremental costs, the program provides a positive financial impact to end-use customers.

- Total Resource Cost Test (*"TRC"*). This test examines each program from the viewpoint of the entire MEAN system. The TRC test compares the program benefits of avoided supply costs against the administration costs to the utility and the customer costs of upgrading equipment. When a program's TRC score is favorable, this indicates a decrease in total resource costs, benefitting MEAN and the customer.

The table in *Figure I-31* summarizes the benefits and costs included in the calculations of the ratios.

TEST	BENEFITS	COSTS
Utility Cost Test	Utility Avoided Costs	• Program Administration Costs • Incentives/Rebates Paid
Participant Cost Test	Net Bill Savings	• Incremental Cost of Investment (Net of Incentive/Rebate)
Total Resource Cost Test	Utility Avoided Costs	• Program Administration Costs • Incremental Cost of Investment

Figure I-31

4. Results

The costs and benefits as described above were applied to the potential market participants for each of the proposed DSM programs. The costs were escalated and summed for a ten-year period. Finally, a Net Present Value was calculated for the annual costs and benefits and this value used to determine the final benefit/cost ratio. The results of the three Benefit/Cost tests are shown in *Figure I-32*.

DSM PROGRAM	UTILITY COST TEST (Benefit/Cost)	PARTICIPANT COST TEST (Benefit/Cost)	TOTAL RESOURCE COST TEST (Benefit/Cost)
Air Source Heat Pump Incentive	-0.36	-0.11	-0.36
Room Air Conditioner Rebate	0.01	0.19	0.01
Central Air Conditioner Incentive	0.03	0.14	0.04
Refrigerator Rebate	0.04	0.54	0.05
Freezer Rebate	0.08	1.53	0.10
Water Heater Conversion Incentive	-0.64	-4.03	-1.49

Figure I-32

As stated initially, only a ratio greater than 1 would indicate that a program is likely to result in benefits that outweigh its costs and therefore provide a net positive impact to MEAN or the end-use customer, depending on the test.

The results show two programs that resulted in a negative benefit/cost ratio. In these cases, the benefit was a negative value, meaning there was no net benefit, discounting these options. In total, only one program had a favorable result, and in only one of the tests. Therefore, none of the potential programs would prove beneficial to MEAN and the end-use customer to a point that would compensate for the required costs.

M. Phase II Analysis and Results

The qualified options from the Phase I supply side evaluation are combined with MEAN's existing contracted resources to create a number of future resource portfolios for study in the Phase II economic analysis. Depending on the capacity and energy potential of each resource, it is studied as either an independent addition or in combination with another resource to provide the capacity and energy required to meet the regional load. The date on which a resource is modeled to begin generation is aligned with the timing of the regional resource deficit.

1. Studied Portfolios

SPP

- Portfolio 1: Natural Gas Combined Cycle
- Portfolio 1D: Identified Natural Gas Combined Cycle
- Portfolio 2: Landfill Gas
- Portfolio 3: Municipal Solid Waste

- Portfolio 4: Wind + Generation Agent Arrangement
- Portfolio 5: Solar + Generation Agent Arrangement
- Portfolio 6: Extend Multi-Unit Participation Agreement + Generation Agent Arrangement
- Portfolio 7: Generation Agent Arrangement
- Portfolio 8: Wind + New Participant Owned Generation
- Portfolio 9: Solar + New Participant Owned Generation
- Portfolio 10: Extend Multi-Unit Participation Agreement + New Participant Owned Generation

West Region

- Portfolio 1: Natural Gas Combined Cycle
- Portfolio 2: Landfill Gas
- Portfolio 3: Municipal Solid Waste
- Portfolio 4: Wind + Natural Gas Combined Cycle
- Portfolio 5: Solar + Natural Gas Combined Cycle
- Portfolio 6: CES + Natural Gas Combined Cycle
- Portfolio 7: Wind + New Participant Owned Generation
- Portfolio 8: Solar + New Participant Owned Generation
- Portfolio 9: CES + New Participant Owned Generation

2. Economic System Model

The Economic System Model used for the portfolio analysis is depicted in the *Figure I-33* graphic:

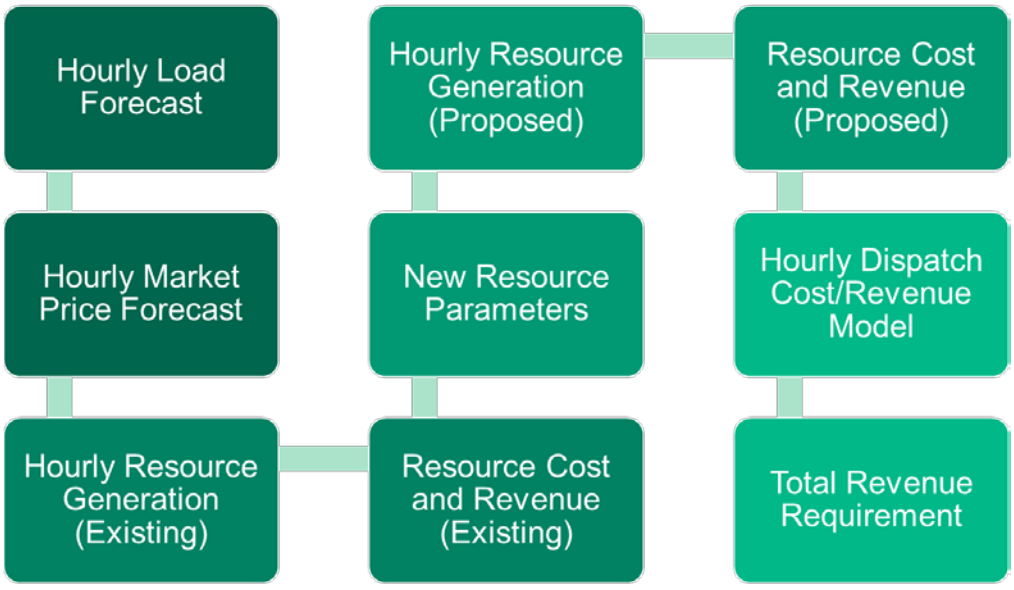


Figure I-33

3. Sensitivity Scenario Analysis

The model was expanded to include the effects of a number of different scenarios. As external conditions change, generation costs and market costs change. This alters the economics of each portfolio in a different way. Two very significant factors that affect generation are natural gas prices and the potential of a carbon tax.

The sensitivity analysis included three levels of natural gas pricing: low (lower than current projections), base (equal to current projections), and high (higher than current projections). Each of these price levels was combined with three possible carbon tax futures: no tax, a medium tax rate, and a high tax rate. Each of these scenarios introduced variations in fuel costs and carbon costs into the variable energy cost of each resource, ultimately affecting the final revenue requirement of each portfolio.

The table in *Figure I-34* displays the scenarios under which the model was simulated. Each portfolio was entered into the model for each sensitivity.

Sensitivity Analysis Scenarios

		Natural Gas Price		
		Low	Base	High
CO_2 Tax	No	1	4	7
	Med	2	5	8
	High	3	6	9

Figure I-34

For the model results, Scenario 5, which included the base natural gas pricing and a medium carbon tax, was considered the base case. Other scenarios indicate a variation from the base case conditions.

4. SPP Model Results

Figure I-35 shows the results of the SPP model for all eleven portfolios listed in Section I.M.1. and all nine scenarios shown in *Figure I-34*. The dark blue bar represents the base case total revenue requirement for each portfolio. The light blue vertical line shows the range between the maximum revenue requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the "scenario variance".

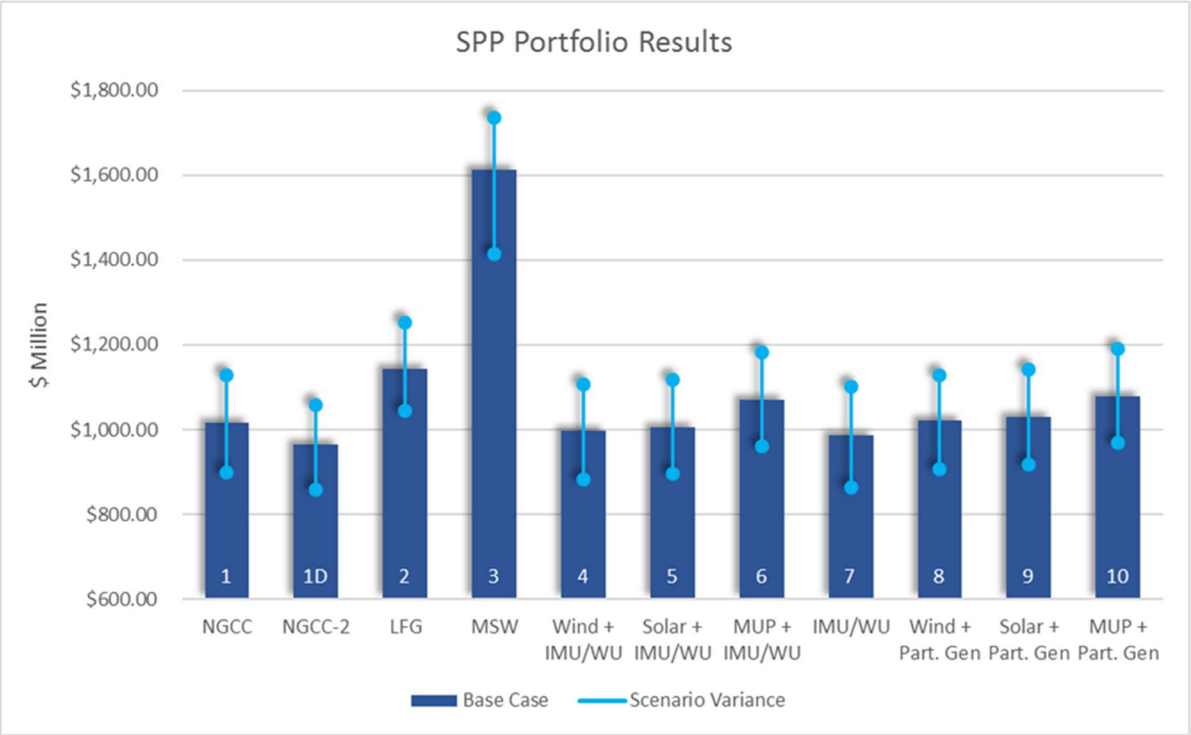


Figure I-35

The positive variance, or the differential between the maximum scenario revenue requirement and the base case revenue requirement, quantifies the risk inherent in each portfolio relative to possible changes in fuel pricing and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the SPP Portfolios. To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in *Figure I-36* to follow.

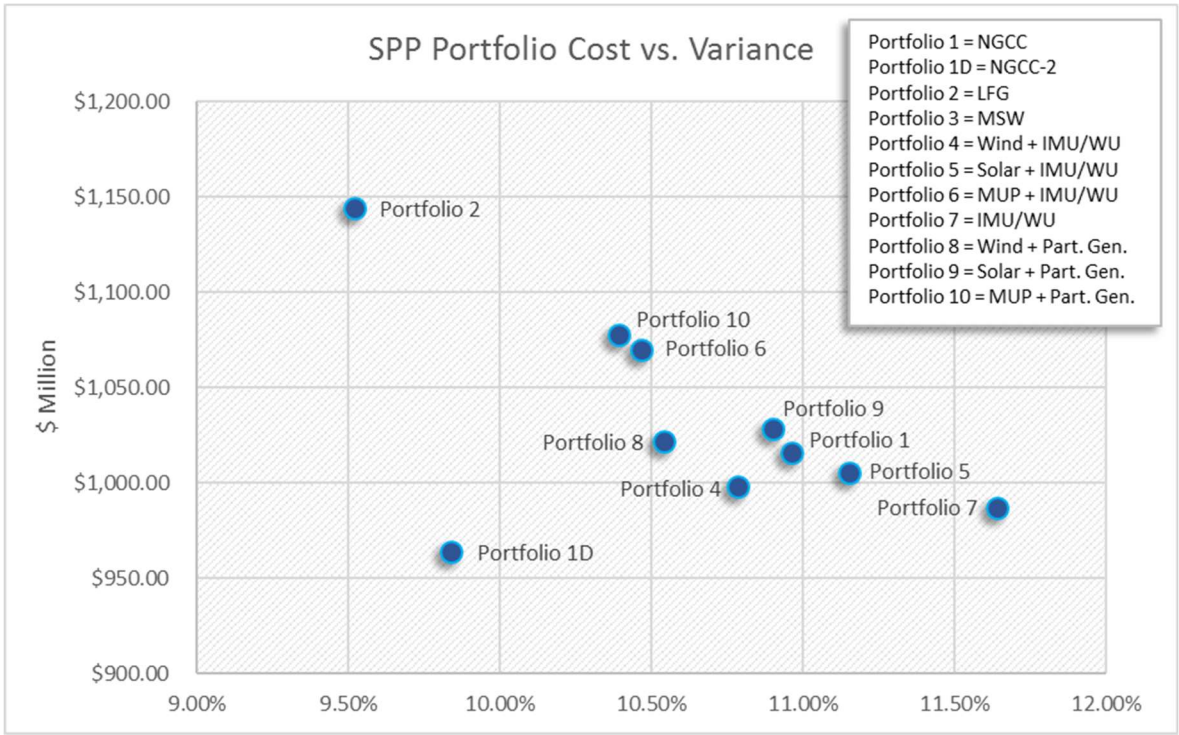


Figure I-36

The values and graphical results show that Portfolio 1D, the identified natural gas plant, has the lowest revenue requirement. While Portfolio 2, the landfill gas plant, has the lowest variance, its base case cost is the highest of all options, and the variance of Portfolio 1D is only slightly higher.

5. West Region Model Results

Figure I-37 shows the results of the west model for all nine portfolios and all nine scenarios. The dark green bar represents the base case total revenue requirement for each portfolio. The light green vertical line shows the range between the maximum revenue requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the "scenario variance".

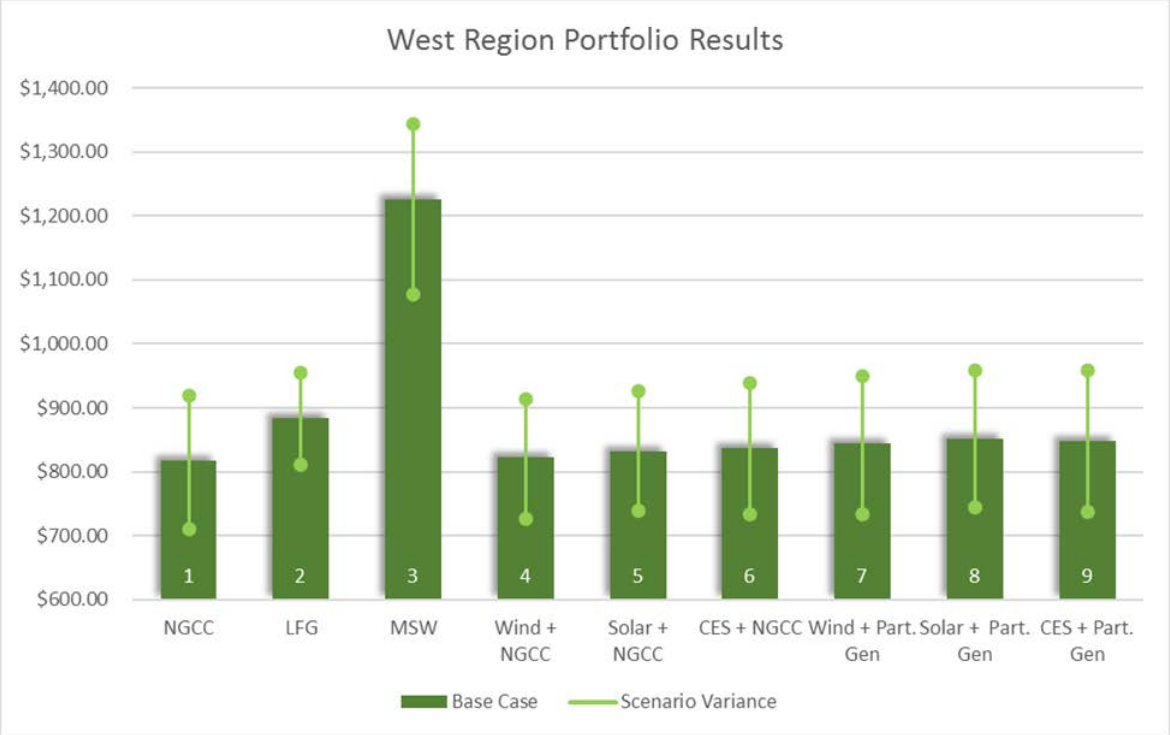


Figure I-37

The positive variance, or the differential between the maximum scenario revenue requirement and the base case revenue requirement, quantifies the risk inherent in each portfolio relative to possible changes in fuel pricing and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the west Portfolios. To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in *Figure I-38* to follow.

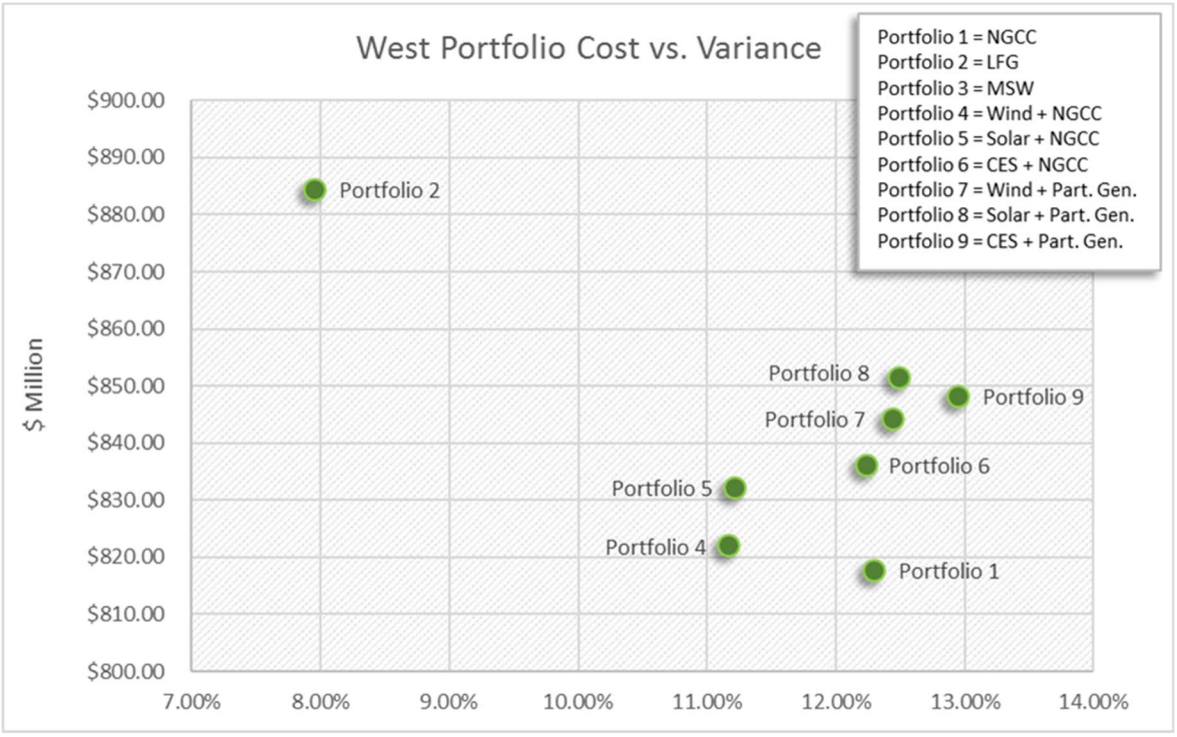


Figure I-38

The values and graphical results show that Portfolio 1, the natural gas plant, has the lowest revenue requirement, but not significantly lower than Portfolio 4, the wind resource and natural gas plant. While Portfolio 2, the landfill gas plant, has the lowest variance, its base case cost is the highest of all options.

N. Environmental Impact

1. Existing Environmental Considerations

MEAN is subject to environmental and other regulations, in varying degrees, at federal, state and local levels. As part of a long-term strategy, MEAN has invested in environmental regulation compliant base load generating resources expected to provide highly reliable base load generation for the Participants' present and future energy requirements.

In addition to these state-of-the-art coal facilities and WAPA allocations, MEAN has acquired renewable resources and nuclear capacity. MEAN has considered, as part of this IRP and recent planning efforts, the addition of new renewable resources as capacity and energy needs arise in future years.

2. Supply Side Resource Options Environmental Impact

In the Phase I evaluation of supply side options, environmental impact was considered for all options as part of the scoring process. Two categories reflected the consideration of a resource's current and future effects on the environment. Scoring categories included Emissions/Environmental Impact, which calculated and compared the emissions levels for carbon, SO2, NOx, and mercury, and Environmental Policy Risk, which estimated the degree to which a resource could be affected by the imposition of future environmental regulations.

3. Carbon Cost Scenario Impact

The inclusion of the carbon tax sensitivity scenarios provides a method by which the impact of carbon emissions can be quantified for each portfolio as a whole. For each level of natural gas pricing, the results for the scenarios with no carbon tax can be compared against the results for the scenarios with a high carbon tax to show the consequence of high carbon emissions. The average variance resulting from only the carbon tax (holding the natural gas pricing constant) is shown in *Figures I-39* and *I-40*.

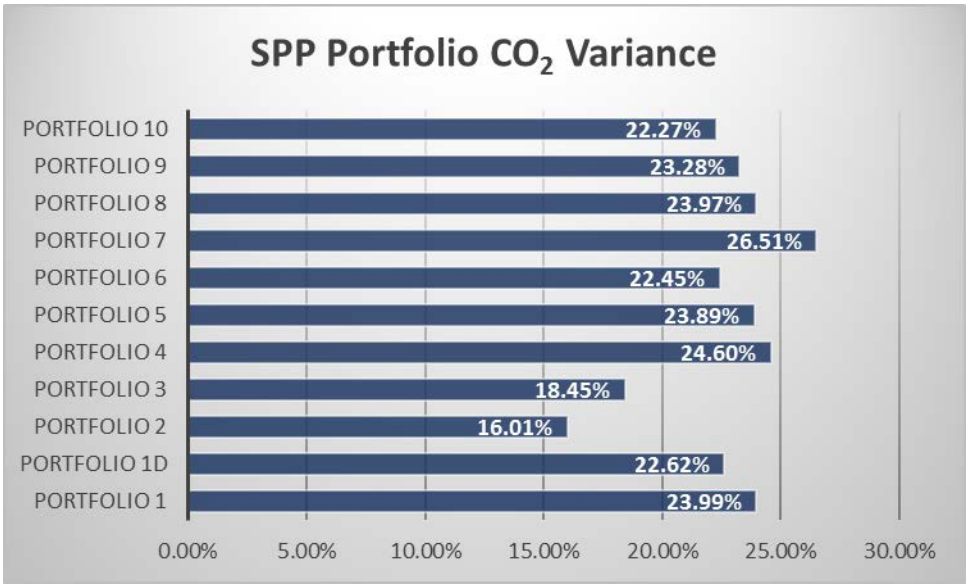


Figure I-39

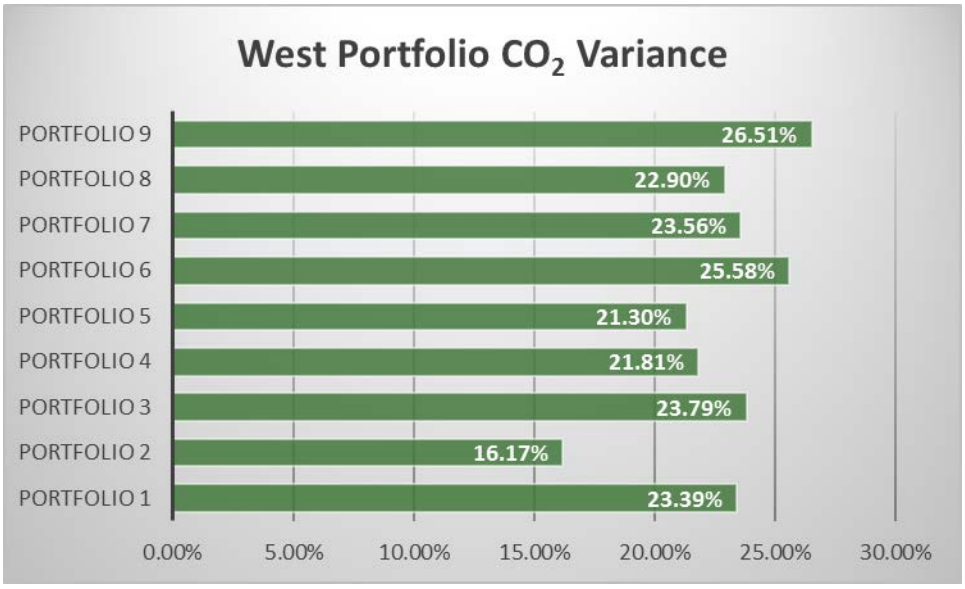


Figure I-40

These results show an expected relation. Portfolios that include more fossil fueled capacity or more market energy purchases see a higher cost impact from a carbon tax. In this way, higher emitting resources are "penalized" in the model with a higher degree of variance. The effects of carbon emissions were included in the variance factor used in the analysis of the final portfolio results.

O. Conclusions and Recommended Action Plan

Based on the data and analysis in this IRP report, MEAN has developed conclusions relative to proposed demand side solutions and supply side solutions.

1. Demand Side Management – Conclusions

New DSM Programs: Through the use of three different calculation methods, the costs and benefits of the proposed new DSM programs were compared, and none of the potential programs proved beneficial to MEAN and the end-use customer to a point that would compensate for the required costs.

MEAN DSM programs to be continued include: Lighting Upgrade Program, Infrared Energy Audits, ENERGYsmart Vending Miser Bulk Purchasing Program, Member Exclusive Education Sessions, and the energy efficiency education content of Essent Newsletter subscriptions.

Participant DSM Programs: The 42 existing community DSM programs are expected to be maintained in future years. MEAN conducts an annual DSM survey to track these programs and the impact on MEAN's demand and load.

2. Supply Side Resources – Conclusions

Based on the April 2017 Participant survey, the preferred resource portfolio option should consider low cost as a primary condition. In the course of multiple participant meetings and workshop sessions, MEAN received feedback from participants that signified an inclination toward resource solutions that provide a local benefit or allow for local participation. Internal feedback from MEAN staff communicated an appeal for resources that allow for operational flexibility.

Both the Phase I evaluation and the Phase II economic modeling incorporated these preferences into the options included and the method of analysis, and the final results reflect these criteria.

SPP:

- The proposed portfolio in SPP that best achieved the primary goal of low cost was Portfolio 1D, the addition of capacity and energy from an identified natural gas combined cycle plant located in the SPP footprint. This option also provides for operational flexibility, but not local benefit.

- The second lowest cost option in SPP was Portfolio 7, the extension of the Generation Agent Arrangement with IMU and WU for lease of their participant owned generation. This option is low cost and provides local benefit. Since these units are typically not run for energy needs, this option relies on market purchases for energy.

- The next best options in terms of cost were Portfolios 4 and 5, the combination of the Generation Agent Arrangement for capacity and the addition of a wind or solar resource for energy needs. These options achieve the low-cost goal and can be configured for local benefit, but do not allow operational flexibility.

West:

- The proposed portfolio in the west that best achieved the primary goal of low cost was Portfolio 1, the addition of capacity and energy from a natural gas combined cycle plant. This option also provides for operational flexibility, but not local benefit.

- The next best options in terms of cost were Portfolios 4 and 5, the combination of the natural gas combined cycle plant for capacity and energy and the addition of a wind or solar resource for additional energy needs. These options achieve the low-cost goal, the wind and solar resources can be configured for local benefit, and the natural gas combined cycle plant allows for operational flexibility.

- In response to participant interest in resources with local benefit, MEAN will further investigate more economical ways to include the CES project (to be located in a participant community) and additional participant owned generation into other portfolios.

3. Short-Term Recommended Action Plan

MEAN will continue to administer all current DSM programs: LED Lighting Upgrades, Infrared Energy Audits, ENERGYsmart Vending Miser Bulk Purchasing Program, Member Exclusive Education Sessions, and the *Essent* Newsletter subscriptions. MEAN will revisit the proposed new programs upon any significant change in the analysis inputs to reevaluate the benefit to cost ratio. Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities.

In SPP, MEAN will pursue one of the low-cost portfolio options to prevent the impending capacity shortage. This would involve the initiation of negotiations with the owners of the natural gas combined cycle plant as previously described toward a partial ownership or PPA arrangement, discussions with IMU and WU regarding extension of the Generation Agent Arrangement, or even investigation into additional existing participant owned generation not under a lease contract with MEAN that would be available in the near term.

In the west, there is no short term need for supply side resources. MEAN will gather data on potential future resources and maintain a readiness for procurement of new capacity and energy when the projected shortage approaches.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change should trigger a revised resource plan to determine required modifications and future actions.

Throughout MEAN's footprint, continual efforts should be made to acquire additional load. All three served regions have an energy surplus, representing an opportunity for additional energy sales without an immediate expense of additional capacity purchase.

4. Long -Term Recommended Action Plan

MEAN will regularly evaluate the impact and implementation of existing DSM programs. Based on the results of the evaluation, MEAN will continue to administer successful programs. MEAN will revisit the proposed new programs on a regular basis to recalculate the analysis inputs and reevaluate the benefit to cost ratio. Programs that receive a favorable ratio should be planned for a trial roll-out in interested communities to verify projected savings prior to widespread execution. Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities.

In SPP, depending on the actions taken to relieve the short-term capacity deficit, MEAN will secure a low-cost, long-term solution for additional capacity and an energy resource for future years. If not already secured during the short-term action plan, this could involve negotiations with the owners of the previously described natural gas combined cycle plant toward a partial ownership or PPA arrangement, discussions with IMU and WU regarding extension of the Generation Agent Arrangement, or investigation into additional new or existing participant owned generation. For energy requirements, the natural gas combined cycle plant would offer an energy solution, or a wind or solar resource would provide low cost energy and increase MEAN's renewable portfolio.

In the west, MEAN will search out the lowest cost resources for capacity and energy as determined in the analysis. MEAN will explore opportunities to contract with a natural gas combined cycle plant in the region for capacity and energy purchase or a partial ownership arrangement. Concurrently, MEAN will solicit its participants for opportunities to lease new or existing participant owned generation. If terms and costs of this option are favorable in comparison to the natural gas plant, MEAN would require a separate energy source. According to the analysis results, MEAN should explore available wind and/or solar resources, giving preference to community-based installations.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change should trigger a revised resource plan to determine required modifications and future actions.

Throughout MEAN's footprint, continual efforts should be made to acquire additional load. Depending on the load profile in comparison to the rest of MEAN's system load and resource additions made in the short term, there may be opportunity to supply energy without additional capacity investment.

5. Tracking/Measurement Strategy

MEAN will employ the following Measurement Strategies to gauge the progress and impacts of the Recommended Action Plans described above.

METRIC	MEASUREMENT STRATEGY	MEASUREMENT BASELINE
Load vs. Forecast	MEAN will annually compare the actual peak demand and energy consumption against the forecast values. Data will be tracked by participant, region, and system. MEAN also conducts an annual load survey to aid in this measurement.	• Annual Load Forecast • 15-Year Load Forecast • Hourly/Monthly Participant Load Data
Load vs. Capability	On a semi-annual basis, MEAN is required to calculate and present to the Board the upcoming peak season Load and Capability balance for planning purposes. MEAN typically presents a long-term outlook. In this way, changes in the timing of deficits can be foreseen to prepare via resource planning.	• Annual Load Forecast • 15-Year Load Forecast • Resource Contracts • Hourly Resource Generation Data • Current Season Load and Capability Report
DSM Savings/Impact	MEAN conducts an annual DSM survey to all participants to gather data on the programs offered and the expected demand and energy savings. Responses will be compared year-to-year to verify savings. This is valuable in the contemplation of future programs. MEAN also tracks data on its administered Lighting Upgrade Program for estimated power savings.	• Previous Year Hourly Participant Load Data – Peak and Energy Usage • DSM Survey Responses • Energy Star® Energy Efficiency Calculation Tools
Existing Resource Performance	MEAN tracks the operation, performance, and cost of its contracted resources. This is measured against expected and contracted values and can be used to gauge the cost-effectiveness of future resources.	• Resource Contracts • Previous Year Hourly Resource Generation Data • Resource Invoices
New Resource Parameters	MEAN regularly tracks research on the costs and parameters of new resources. Understanding the performance of established and emerging technologies and the total generating cost in relation to market conditions will prepare MEAN for future resource acquisition.	• Resource Data Used for IRP (EIA, NREL, DOE) • Market Pricing
Environmental Regulation	MEAN continually monitors environmental regulations, paying particular attention to future legislation affecting the power supply industry. When changes are proposed or adopted, MEAN projects the impacts on existing or potential future resources. Currently, MEAN is alert for changes in the status of the Clean Power Plan and power resource tax credits.	• Status Quo Regulations • MEAN's current compliance status

Figure I-41

II. IRP Requirements and Checklist

A. WAPA Requirements

Integrated resource planning was mandated by the Energy Policy Act of 1992 (*"EPAct"*).

EPAct requires all Western Area Power Administration customers to submit Integrated Resource Plans (*"IRPs"*) to WAPA every five years. The requirement is included in WAPA's power sales contracts with long-term firm customers. The current Resource Planning Approval Criteria (10 CFR Part 905) went into effect May 1, 2000, after WAPA reviewed the original regulations and completed a public process.

WAPA has identified the following criteria for customer IRPs:

- Identify and compare all practicable energy efficiency and energy supply resource options.
- Include action plan with timing set by customer.
- Describe efforts to minimize adverse environmental effects of new resource acquisitions.
- Provide ample opportunity for full public participation.
- Conduct load forecasting.
- Include brief description of measurement strategies for options identified in IRP to determine whether objectives are being met.

IRPs and alternative reports will be evaluated by WAPA on the basis of:

- Meeting all criteria in 10 CFR 905
- Reasonableness of the plan with regard to: Customer size, type, resource needs, geographic area and competitive situation
- Resource choice selection (EPAct 1992 section 114)

B. WAPA Utility/Customer Overview

The following customer profile data listed in *Figure II-1* is submitted to the U.S. Energy Information Administration (EIA) as part of the form EIA-861, summarizing MEAN's service obligations during the most recent annual reporting period.

Reporting Period	
Reporting Period Start Date (mm/dd/yyyy)	01/01/2016
Reporting Period End Date (mm/dd/yyyy)	12/31/2016
Energy Sales & Usage	
Energy sales to Ultimate End Customers (MWh)	0
Energy sales for Resale (MWh)	2,270,592
Energy Furnished Without Charge (MWh)	0
Energy Consumed by Respondent Without Charge (MWh)	0
Total Energy Losses (MWh entered as positive number)	135,980
Total Energy Usage (sum of previous 5 lines in MWh)	2,406,572

Peak Demand (Reporting Period)	
Highest Hourly Summer (Jun. – Sept.) Peak Demand (MW)	433.0
Highest Hourly Winter (Dec. – Mar.) Peak Demand (MW)	362.8
Date of Highest Hourly Peak Demand (mm/dd/yyyy)	07/21/2016
Hour of Highest Hourly Peak Demand (hh AM/PM)	06 PM
Peak Demand (Historical)	
All-Time Highest Hourly System Peak Demand (MW)	536.1
Date of All-Time Hourly System Peak Demand (mm/dd/yyyy)	07/23/2012
Hour of All-Time Hourly Peak System Demand (hh AM/PM)	04 PM
Number of Customers/Meters (Year End of Reporting Period)	
Number of Residential Customers	85,504
Number of Commercial Customers	11,665
Number of Industrial Customers	543
Other (Specify):	

Figure II-1

Historical Energy Use: The peak system demand and total annual energy use for the preceding ten (10) reporting years is listed below in *Figure II-2*. Values listed are by calendar year.

Reporting Year	Peak Demand (MW)	Total Energy (MWh)
2007	426.9	2,159,720
2008	431.1	2,294,150
2009	436.2	2,298,260
2010	476.7	2,500,840
2011	521.9	2,532,440
2012	536.1	2,557,670
2013	518.5	2,593,620
2014	502.8	2,525,660
2015	467.9	2,352,270
2016	434.0	2,270,592

Figure II-2

C. Checklist

The checklist of questions in *Figure II-3* is provided by WAPA as a means for customers to determine the completion of their IRP document and satisfaction of WAPA standards for IRP reporting. MEAN has indicated the section of the report wherein the question is addressed.

1. Does the IRP evaluate the full range of alternatives for new energy resources (905.11(a))?	
• New generating capacity?	Section XII.C.
• Power purchases?	Section XII.C
• Energy conservation and efficiency?	Section XIII.C.

• Cogeneration and district heating/cooling applications?	Section XII.C.
• Renewable energy resources?	Section XII.C.
2. Does the IRP provide adequate and reliable service to the customer's electric consumers (905.11(a))?	Section X.
3. Does the IRP take into account the necessary features for system operation (905.11(a))?	
• Diversity?	Section XII.D.
• Reliability?	Section XII.D.
• Dispatchability?	Section XII.D.
• Other risk factors?	Section XIV.F.-G.
4. Does the IRP take into account the ability to verify energy savings achieved through energy efficiency (905.11(a))?	Section VIII.A.-B. Section XIII.E. Section XVI.D.
5. Does the IRP take into account the projected durability of such savings measured over time (905.11(a))?	Section XIII.E. Section XIV.G. Appendix C
6. Does the IRP treat demand and supply resources on a consistent and integrated basis (905.11(a))?	Section XIII.E. Section XIV.B. Section XIV.G. Section XVI.D.
7. Does the IRP consider electrical energy resource needs? (905.11(b)).	Section X.
8. Does the IRP identify and compare resource options? The customer must conduct an assessment and comparison of available existing and future supply and demand-side resource options based on its size, type, resource needs, geographic location and competitive situation. The options should relate to the customer's unique resource situation as determined by profile data (service area, geographical characteristics, customer mix, historical loads, projected growth, existing system data, rates and financial information) (905.11(b)(1)).	
• Supply-side options include, but are not limited to, purchased power contracts, and conventional and renewable generation options (905.11(b)(1)(i)).	Section XII. Section XIV.
• Demand-side options alter the customer's use pattern to provide for an improved combination of energy services to the customer and ultimate consumer (905.11(b)(1)(ii)).	Section XIII. Section XIV.
• Considerations that may be used to develop potential options include cost, market potential, consumer preferences, environmental impacts, demand or energy impacts, implementation issues, revenue impacts, and commercial availability (905.11(b)(1)(iii)).	Section XII. Section XIV.
9. Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options (905.11(b)(1)(iv))?	Section XIV. Section XII.
10. Does the IRP include an action plan describing specific actions the customer will take to implement the IRP (905.11(b)(2))?	Section XVI.C.
11. Does the IRP list the time period that the action plan covers (905.11(b)(2)(i))?	Section XVI.C.
12. Does the IRP include an action plan summary consisting of (905.11(b)(2)(ii)(a-c):	
• Actions the customer expects to take in accomplishing the goals identified in the IRP?	Section XVI.C.-D.
• Milestones to evaluate accomplishment of those actions during implementation?	Section XVI.D.

• Estimated energy and capacity benefits for each action planned?	Section XIV. Section XV.
13. Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts (905.11(b)(3))?	Section XV.
14. Does the IRP include a qualitative analysis of environmental effects in a summary format (905.11(b)(3))?	Section XV. Section XII.D. Section XII.F.
15. Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP (905.11(b)(4))?	Section II.D. Appendix A
16. Does the IRP include a brief description of public involvement activities (905.11(b)(4))?	
• How the customer gathered information from the public?	Section I.D. Section XII.G.2.
• How public concerns were identified?	Section I.D. Section XII.G.2.
• How information was shared with the public?	Section I.D. Appendix A
• How public comments were responded to?	Section I.D. Section XII.G.2.
17. Does the IRP document that each MBA member approved the IRP, confirming that all requirements have been met (905.11(b)(4)(i))? [Effective July 21, 2008, IRPs submitted by member-based associations no longer need unanimous approval of the MBA's members.]	Section XVI.B. Appendix D
18. Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body (905.11(b)(4)(i))?	Section XVI.B. Appendix D
19. Does the IRP contain a statement that the customer conducted load forecasting, including specific data (905.11(b)(5))?	Section V.
20. Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met (905.11(b)(6))?	Section XVI.D.
21. Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation (905.11(b)(6))?	Section XVI.D.
22. Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA (905.12(b)(2))?	Section III.E.-F.

Figure II-3

D. Public Participation

The following actions were taken by MEAN to ensure the provision of ample opportunity for public participation throughout the IRP process.

1. Board and Committee Meetings – January 2017

MEAN Quarterly Board and Committee Meetings were held on January 18-19, 2017 in North Platte, NE. This is a public meeting subject to the State of Nebraska Public Meetings Act and the requirements contained therein. On January 18, the Power Supply Committee met to hear presentations and vote on issues under the purview of the committee. The IRP falls under the jurisdiction of this committee. All members of the

Power Supply Committee (see description of this committee in Section III.E.) are invited to attend, and a quorum must be present to conduct the meeting. On January 19, the MEAN Board of Directors met to hear presentations and vote on recommendations from the committees that met the previous day. All members of the Board are invited, and a quorum must be present to conduct the meeting and vote on proposed resolutions. The IRP requirements and process were presented at each of these meetings. The presentation material and attendance list are included in Appendix A.

2. Online Survey – April 2017

In April, in anticipation of the Power Supply Committee Workshop scheduled later in the month, an online survey was sent to all MEAN participants to gather input for the IRP Phase I evaluation. Questions were asked regarding MEAN's resource mix, renewable energy, market purchases, resource procurement criteria, and demand side management. The survey questions and responses are included in Appendix A.

3. Power Supply Committee Workshop – April 2017

On April 19, a Power Supply Committee Workshop was held in Kearney, NE. Workshops are intended as an opportunity for committee members to receive information and engage in informal discussion regarding specific topics relevant to the responsibilities of the committee to allow more efficient decisions in the future. The workshop discussion included the results of the online survey, MEAN's load and resource balance, MEAN's resource mix, fuel pricing, demand side management, and supply side options for future resource needs. The presentation materials and workshop attendance sheet are included in Appendix A. Workshops are not governed by the Public Meetings Act, and as such no formal action can take place. A quorum is not required for a workshop.

4. Board and Committee Meeting – May 2017

On May 17-18, 2017, MEAN conducted its quarterly Board and Committee Meetings in Kearney, NE. On the 17th, the Power Supply Committee convened. One of the topics presented was the progress of the IRP. MEAN staff reviewed the material and discussions of the workshop held in April for the benefit of those not in attendance and to prompt any follow-up questions or observations from those who attended. The next day on the 18th, the MEAN Board of Directors, Executive Committee, and Management Committee met. Again, a presentation was given to share the contents of the April workshop and open up the same points of discussion to allow input from Board members. The presentations at the May meetings included resource mix, load and resource balance, Phase I evaluation details and results, and expected upcoming requirements for Board and committee member participation. The materials presented at the May meetings are included in Appendix A.

5. Power Supply Committee Workshop – August 2, 2017

On August 2, 2017 MEAN held a workshop for the Power Supply Committee and the Ad Hoc Committee at its offices in Lincoln, Nebraska. As with other participant workshops, this was intended to be a forum during which participant representatives can seek details and ask questions in an informal setting in preparation for the August Board and Committee meetings. The first half of the day-long event was scheduled to review the IRP. Previously determined conclusions and assumptions were reviewed in introduction. The results of the Phase II economic analysis were presented, along with a detailed discussion of the supply side portfolios included in the analysis and an explanation of the

economic model utilized for this purpose. Attendees inquired about the specific payment structures that would be used to compensate additional participant owned generation, which led to discussions about the timeline required for this type of project and local governmental regulations for this process. Participants overall expressed an interest in this option to alleviate capacity shortages. Comments were also offered on the value of distributed renewable generation, with participants interested in locating renewable resources in their communities. The presentation and attendance list from the workshop are included in Appendix A.

6. Distribution of Draft Report – August 9, 2017

An up-to-date draft version of the IRP document in pdf format was distributed to all MEAN participants via email on August 9, 2017. At this time, an email address dedicated to receipt of comments and questions related to the IRP was established and communicated to participants for direction of responses to the draft. Participants were invited to make the draft report and email address available to their community members in either hard copy or electronic format and to advertise the availability of the document. It was communicated that public comment would be accepted through September 8, 2017.

7. Board and Committee Meeting – August 16-17, 2017

The MEAN quarterly Board and Committee meetings for the third quarter of 2017 were held in Kearney, Nebraska on August 16th and 17th. As per MEAN's typical schedule, the Committee meetings were conducted the first day to review detailed information and allow the committees to prepare their recommendations to be presented the following day at the Board meeting. The IRP material presented at both the committee and board meetings closely followed the contents of the IRP workshop held in early August. The committee meeting was intended to present the material to those not in attendance at the workshop and allow follow-up discussion for those who wished to revisit topics and details covered at the workshop. Members of the Power Supply Committee reviewed the top priorities of the committee in relation to resource selection and discussed the analysis results in pursuit of the established priorities. As a result of the committee meeting deliberations, the Power Supply Committee ultimately voted to recommend to the Board the adoption of the IRP with the inclusion of a specific recommended action for each of MEAN's service regions experiencing resource needs in the future.

The following day at the MEAN Board meeting, the same material was presented to give all board members the background and detail behind the analysis as well as the final analysis results. The presentation included an advertised public hearing time period to allow for public review and comment. No members of the public were in attendance, and MEAN received no public comment, outside of MEAN representatives, during this meeting. Following the presentation and public hearing, the Power Supply Committee made its recommendation to the Board, and the Board voted in favor of the resolution to adopt the IRP with the inclusion of the Committee's recommended action plan.

8. Board Approval of IRP

The resolution unanimously passed by the Board, which included the governing body's acceptance of the 2017 Integrated Resource Plan and recommended action plan, is found in Appendix A.

9. Public Comment

Aside from discussions with MEAN committee and Board representatives, no public comment was received in person at the several meetings held to discuss the IRP or via the email address specifically assigned for receipt of such comment. As explained throughout this report, comment and direction received from the MEAN participants was incorporated into each step of the IRP process and is reflected in the conclusions and recommended plans for MEAN's future resource planning.

10. Distribution and Submittal of Final IRP Report

All comments received from internal and external stakeholders were collected for evaluation throughout the IRP process. MEAN was purposeful in presenting the procedures and results of each step of the IRP to the board and committee members to solicit input and gather feedback. This narrative points to instances where MEAN participants guided the process in terms of priorities and options and finally the determination of the recommended action plan. This final report incorporates all conclusions from participant discussions and reflects the directives of the participants. The final report was completed in October 2017, at which time it was submitted to WAPA, posted to the NMPP Energy website, and distributed to all participants.

E. MEAN Strategic Plan

1. Overview

The Mission Statement of MEAN is *"To collaborate with municipal utilities to provide economical and dependable power supply and utility related services that support local control and community needs and are consistent with environmental and regulatory stewardship."*

Throughout 2016, MEAN completed a company-wide Strategic Plan. The planning process involved MEAN staff as well as the members of the Executive Committee. In defining the strategic initiatives of the organization, goals were prioritized and assigned action plans for implementation. Timelines and staff assignments were established for each goal. "Resource Management," one of the five Strategic Goals, identifies a Tier One Goal to "Develop a Comprehensive Integrated Resource Plan."

2. Resource Planning

The Strategic Plan calls for the IRP to be utilized as a strategic and operational working document. The individual tasks outlined to achieve this goal include the following:

- Evaluate existing owned resource obligations
- Energy efficiency and demand side management (*"DSM"*)
- Investigate new generation opportunities and maintain existing generation in participant communities in line with Distributed Generation concepts

III. Introduction

A. Purpose

The purpose of this Integrated Resource Plan is to develop long-range implementation plans to serve MEAN's Total Requirements Participants' power supply requirements consistent with prudent utility planning practices utilizing the lowest cost, environmentally responsible energy supply.

The Strategic Plan put in place by MEAN's leadership has called for a comprehensive Integrated Resource Plan to guide future resource acquisition and portfolio planning. The plan is to be a living document that is consulted prior to resource decisions and revisited when circumstances change.

This plan is also designed to fulfill the requirements of the Western Area Power Administration according to the Energy Policy Act of 1992, as described in section II.A.

B. Scope

This resource plan encompasses a time period of 15 years on the basis of MEAN's fiscal year. MEAN's fiscal year begins April 1st and ends March 31st. This IRP is inclusive of the planning period of FY 2017-18 to FY 2032-33.

The IRP conducts resource planning for MEAN's entire service footprint as a whole, as well as within the individual RTO regions in which MEAN's designated resources are assigned. MEAN operates in the SPP RTO, MISO RTO, and in the West region. Resources must be designated to meet the load and required reserve margin of each region separately. However, there are several metrics that MEAN prefers to evaluate on an accumulated basis for the entire service area.

It should be noted that Lake View, Iowa submits an Integrated Resource Plan specific to their community and separate from MEAN's IRP. However, as MEAN is responsible for supplying Lake View's total power requirements, the needs of this community are included in MEAN's total obligations as part of this analysis.

C. Approach/Methodology

This IRP will consider all reasonable options for supply side resources and demand side management. Supply side and demand side options will be given equal consideration for incorporation into the future resource portfolio.

The IRP analysis will begin with a qualitative evaluation of all resource options. Using selected criteria and criteria weighting, the complete list of options will be narrowed to a smaller list of qualified options that receive a high ranking in accordance with the criteria.

The qualified options will be subject to an economic analysis that applies resource availability and cost to MEAN's hourly loads and projected market pricing. The sum of the hourly costs and revenues over the study period will be summed to arrive at a revenue requirement for each option for comparison purposes.

Lastly, the economic analysis will be repeated under various sensitivity scenarios to calculate the impact of potential changes to key inputs.

The combined results of the base case revenue requirement and the variability due to sensitivity cases will ultimately lead to the determination of a preferred portfolio for future resource acquisition planning.

This methodology is displayed graphically in *Figure III-1*.

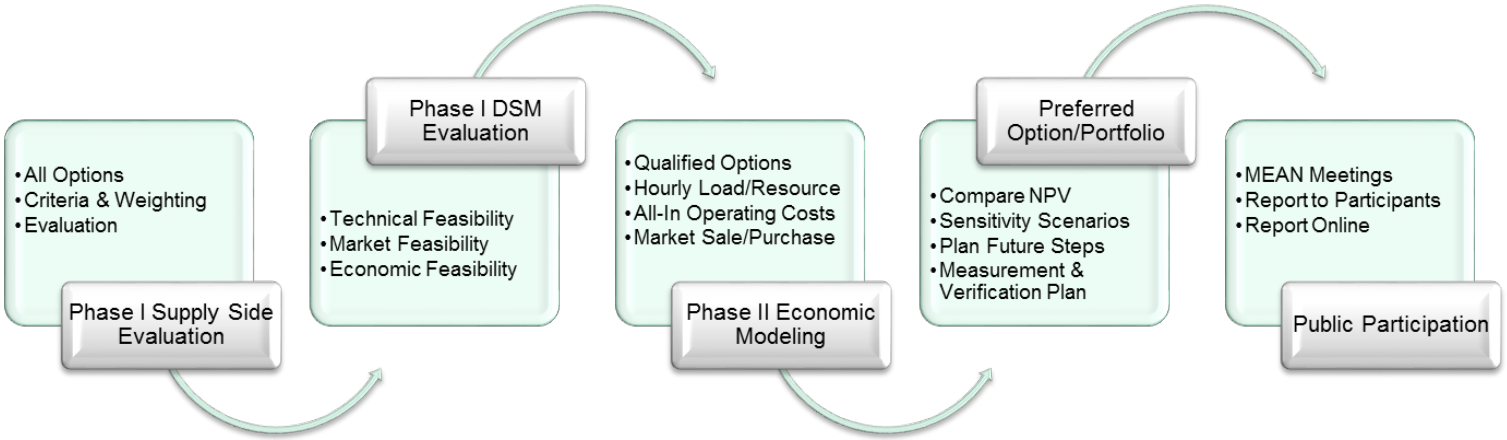


Figure III-1

D. MEAN Overview

The Municipal Energy Agency of Nebraska ("MEAN") is a body corporate and politic under the laws of the State of Nebraska. MEAN was created on June 22, 1981 under the Municipal Cooperative Financing Act, Sections 18-2401 through 18-2485, Reissue Revised Statutes of Nebraska (the "Act"). MEAN was created for the purpose of planning, acquiring, financing and operating facilities to generate and transmit electric power and energy.

MEAN's power supply system consists of ownership and contractual rights and interests in various electric generating and transmission resources and supplies (the "Power Supply System"). MEAN uses the Power Supply System to provide wholesale power supply, transmission and ancillary services to its participating municipal utilities ("Participants"). MEAN's services include power supply, dispatching, energy load forecasting, wheeling arrangements, load research, limited political action, demand-side management, load factor improvement, training, community development, and energy cost analysis. Through its professional staff, MEAN also provides planning, engineering, financing, regulatory, and governmental affairs services to its Participants.

The Municipal Cooperative Financing Act ("The Act") authorizes MEAN to plan, construct, operate, participate in or acquire facilities, within or outside the State of Nebraska, for the generation, transmission or distribution of electric power and energy, solely or in common with others. Under the Act, MEAN may sell or exchange excess capacity of any project or electric power or energy owned, purchased, or leased by MEAN not required by its Participants. The Act authorizes MEAN to issue its bonds, notes and other evidences of indebtedness. In the acquisition of property, MEAN may exercise the power of eminent domain.

E. MEAN Membership

MEAN's 69 Participants currently include 41 municipalities and one public power district in Nebraska, 14 municipalities and one joint action agency in Colorado, two Wyoming municipalities and 10 Iowa municipalities. Each of the Participants owns and operates an electrical utility system that provides electric service to consumers. 61 of the Participants (the *"Total Requirements Participants"*) receive "total-requirements" electric supply services from MEAN, exclusive only of their allocations of firm power and energy from the Western Area Power Administration of the U.S. Department of Energy (*"WAPA"*), except for certain generating facilities of Waverly Utilities (a municipal utility of the City of Waverly, Iowa) (*"WU"*) and Aspen, Colorado. Additional municipalities may become Participants of MEAN with the approval of the Management Committee of MEAN.

Together, the Total Requirements Participants provide electric utility service at retail to approximately 97,712 residential, commercial, institutional, agricultural and industrial customers, representing a total population of approximately 174,400. Participants' total energy usage for MEAN's fiscal year ended March 31, 2017 was 2,423,503 MWh (which includes 364,458 MWh of Participant WAPA allocations).

MEAN's participant communities are mapped in *Figure III-3*.

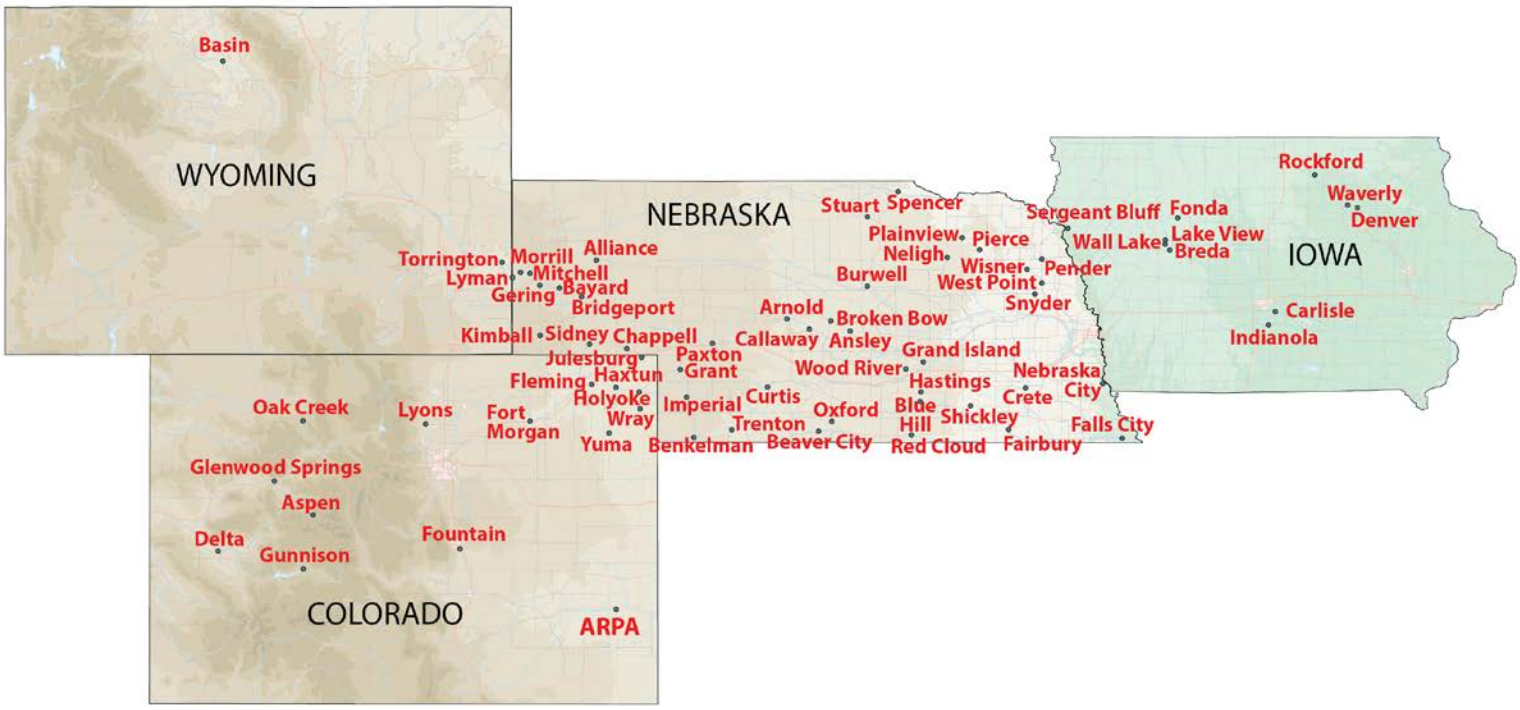


Figure III-2

Participants may take additional steps to become members of MEAN (*"Members"*) under the Act by making application with the Nebraska Power Review Board. Each Member appoints and is represented by a director on the MEAN Board of Directors, as described below. MEAN currently has 54 Members, which are indicated in *Figure III-2*.

MEAN PARTICIPANTS AND MEMBERS

COLORADO	PARTICIPANT	MEMBER	**NEBRASKA (CONT.)**	PARTICIPANT	MEMBER
Arkansas River Power Authority	X		Burwell	X	X
Aspen	X	X	Callaway	X	X
Delta	X	X	Chappell	X	X
Fleming	X	X	Crete	X	X
Fort Morgan	X	X	Curtis	X	X
Fountain	X	X	Fairbury	X	X
Glenwood Springs	X	X	Falls City	X	X
Gunnison	X	X	Gering	X	X
Haxtun	X	X	Grand Island	X	
Holyoke	X		Grant	X	X
Julesburg	X	X	Hastings	X	
Lyons	X	X	Imperial Public Power District	X	X
Oak Creek	X		Kimball	X	X
Wray	X	X	Lyman	X	X
Yuma	X	X	Mitchell	X	X
IOWA			Morrill	X	X
Breda	X	X	Nebraska City	X	X
Carlisle	X		Neligh	X	X
Denver	X		Oxford	X	X
Fonda	X		Paxton	X	
Indianola Municipal Utilities	X	X	Pender	X	X
Lake View*	X		Pierce	X	X
Rockford	X		Plainview	X	
Sergeant Bluff	X	X	Red Cloud	X	X
Wall Lake	X	X	Shickley	X	X
Waverly Municipal Electric Utility	X	X	Sidney	X	X
NEBRASKA			Snyder	X	
Alliance	X	X	Spencer	X	
Ansley	X	X	Stuart	X	X
Arnold	X	X	Trenton	X	
Bayard	X	X	West Point	X	X
Beaver City	X	X	Wisner	X	X
Benkelman	X	X	Wood River	X	X
Blue Hill	X	X	**WYOMING**		
Bridgeport	X	X	Basin	X	X
Broken Bow	X	X	Torrington	X	X

Figure III-3

*Lake View, Iowa submits an Integrated Resource Plan specific to their community and separate from MEAN's IRP.

Each of the Participants has entered into the Electrical Resources Pooling Agreement (the *"ERPA"*) with MEAN. The ERPA includes various service schedules under which MEAN provides power supply services to the Participants on varying terms. A Participant may elect to become a Total Requirements Participant, in which case it receives all power and energy from MEAN (exclusive only of its firm power and energy allocations from WAPA). Alternatively, a Participant may elect to become a Service Schedule Participant, in which case it retains full responsibility for meeting its power and energy requirements and may enter into buy/sell power and energy or other transactions with MEAN.

Fifty-four of the Participants (the *"Long-Term Total Requirements Participants"*) have entered into Service Schedule M of the ERPA (the *"Long-Term Power Supply Contracts"*). The Long-Term Total Requirements Participants, with the limited exception of Aspen, Colorado and Waverly Utilities, have agreed to purchase all their firm electric requirements from MEAN, exclusive of any firm power and energy allocated to such Long-Term Total Requirements Participants by WAPA. The term of the Long-Term Power Supply Contracts currently extends to at least January 1, 2041. Waverly and Aspen have certain external contracts for renewable energy.

Seven of the Total Requirements Participants (sometimes referred to herein as the *"Limited-Term Total Requirements Participants"*) have contracted with MEAN for "total-requirements" electric supply services by entering into a Supplemental Agreement to Service Schedule J of the ERPA (*"Service Schedule J Participants"*) or Service Schedule K or K-1 of the ERPA (*"Service Schedule K and K-1 Participants"*). Such Participants have agreed to purchase all their electric requirements from MEAN, exclusive of any firm power and energy allocated to such Limited-Term Total Requirements Participants by WAPA. These agreements vary in length, but generally have terms of five to ten years. Collectively, the Long-Term Total Requirements Participants and the Limited-Term Total Requirements Participants are referred to herein as the "*Total Requirements Participants*."

Eight of the Participants (the *"Service Schedule Participants"*) do not receive "total-requirements" electric supply services from MEAN, and instead may enter into buy/sell power and energy or other transactions with MEAN from time to time. Three of the Service Schedule Participants currently receive only agent and scheduling services from MEAN with respect to transactions in the Southwest Power Pool (*"SPP"*) Integrated Marketplace (*"IM"*). MEAN also enters into other agreements and interchange sales with non-Participant electric utilities and organizations such as SPP and Midcontinent Independent System Operator (*"MISO"*) markets.

F. MEAN Organization

MEAN is governed by a board of directors (the *"Board of Directors"*) consisting of one director for each of the Members, appointed by the mayor or chair of each Member, and approved by the governing body of each Member. Each director serves for a three-year term, or until his or her successor is appointed, and is entitled to one vote. A director may be removed for any cause at any time by the governing body of the Member that such director represents. The removal of an officer requires an affirmative vote by two-thirds of the Members. Amending the MEAN charter requires an affirmative vote of a majority of the Members. Most other actions require the approval of a majority of the Members present.

In addition, MEAN has a management committee that serves as the "operator" for MEAN (the *"Management Committee"*). The Management Committee reviews Service Schedule K and K-1 rates and charges and Service Schedule J contracts, as well as operational issues. Each Participant

designates one representative to serve on the Management Committee. Each representative is entitled to one vote, unless weighted voting is requested.

The Act authorizes the Board of Directors to create one or more project committees to which the Board of Directors may delegate such powers and duties with respect to a project as the Board of Directors shall specify. The Board of Directors has created the following committees: Executive Committee, Services Committee, Finance Committee, Risk Oversight Committee and Ad Hoc Committee. In addition, pursuant to the ERPA, the Management Committee has created the Power Supply Committee. Oversight of the IRP process falls under the purview of the Power Supply Committee.

The officers of MEAN are elected each January by the Board of Directors of MEAN to serve terms of one year beginning April 1.

G. NMPP Energy

MEAN, Nebraska Municipal Power Pool, Public Alliance for Community Energy and National Public Gas Agency comprise a coalition referred to by the trade name NMPP Energy pursuant to a Joint Operating Committee Agreement. MEAN and the other participating organizations share administrative resources and staff, allowing them to more efficiently run their operations and their systems. The coalition provides substantial benefits to MEAN and the other participating organizations, including: (i) the development and utilization of a highly skilled and professional staff with specialized technical expertise in business management, administration, engineering, finance, accounting, governmental affairs, law, and other disciplines; (ii) achieving economies of scale and the sharing of facilities and overheads; (iii) the development and execution of projects, plans, and services that benefit multiple organizations; and (iv) the sharing of institutional experience through the Joint Operating Committee. MEAN and each of the other organizations included in NMPP Energy is an independent financial entity. None of the organizations are financially liable for the debts or obligations of any other associated organization.

H. Regional Energy Markets and Coordination

MEAN's regional footprint stretches from Central Iowa across Nebraska and into Colorado and Wyoming. Due to this footprint, MEAN is required to operate in two regional transmission organizations, MISO and SPP. Both MISO and SPP operate day-ahead and real-time energy markets. Market participants must pay for costs to serve load and receive revenue for their electrical generation. MEAN also operates in the western United States through the Western Electricity Coordinating Council (*"WECC"*).

SPP was founded in 1941, incorporated as a nonprofit entity in 1994 and became a FERC-approved Regional Transmission Organization in 2004. SPP's members, including investor-owned utilities, municipalities, cooperatives, state power agencies, independent power producers, power marketers, independent transmission companies and federal agencies, serve over 18 million people. SPP provides transmission services on more than 60,000 miles of transmission lines in 14 states: Nebraska, Kansas, Missouri, Oklahoma, Arkansas, New Mexico, Texas, Louisiana, Iowa, Minnesota, Montana, North Dakota, South Dakota and Wyoming.

The SPP Integrated Market (*"IM"*), which was launched on March 1, 2014, replaced the Energy Imbalance Service (*"EIS"*) market that SPP had operated since 2007. The IM restructured the EIS market by establishing a day-ahead market along with a real-time energy and operating reserve market. Consolidating 16 balancing authorities into a single SPP-operated balancing authority was

designed to maximize energy efficiency and reduce transaction costs. The IM also utilizes locational-marginal pricing, transmission congestion rights, and virtual transactions.

MEAN became a member of SPP on October 20, 2015. As a member, MEAN works with other SPP members to identify ways to improve market operations and overall organizational effectiveness.

MISO is an independent organization whose purpose is to ensure the reliability of its integrated, regional electrical transmission system, to facilitate a regional wholesale marketplace, to provide non-discriminatory access to the transmission system and to maintain and improve system reliability. Its members include vertically-integrated utilities, stand-alone transmission owners, load-serving entities, energy marketers, state regulatory authorities and independent power producers.

MEAN became a non-transmission owning member of MISO on October 22, 2015.

MEAN also operates in the western United States through WECC. For operations in WECC, MEAN enters into other agreements and transactions with various electric utilities that are not MEAN Participants pursuant to which such electric utilities may purchase power and energy from MEAN or sell power and energy to MEAN.

IV. Uncertainties/Limitations

There are many parameters that impact the inputs to the IRP analysis. Many of these parameters have been calculated or assigned with certain assumptions. Should these assumptions be incorrect or prove to change over time, the outcome of the analysis could potentially change as well. This section explores some of the uncertainties and limitations underlying these variable inputs to the analysis.

A. Environmental Legislation

Electric utilities are subject to continuing environmental regulation. Various environmental permits and approvals from state and federal agencies are necessary in order to operate the Power Supply System. To date, MEAN reports that all environmental permits and approvals necessary for the operation of the Power Supply System have been obtained. However, federal, state, and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that the Power Supply System and the utility facilities owned or operated by the Participants will remain subject to the regulations currently in effect or indefinitely maintain current compliance status. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of individual electric generating units not in compliance.

There is increased concern by the public, the scientific community, and Congress regarding environmental damage resulting from the use of fossil fuels. There are a number of pending or recently enacted legislative proposals in Congress that may affect the electric utility industry. Increased environmental regulation has created and may create additional barriers to new facility development and modification of existing facilities. The additional costs, including time, human resources, uncertainty and delay, could increase the cost of electricity from affected resources. This type of legislation may ultimately have significant influence on nationwide or regional resource mixes and market operations as some types of resources experience increased costs of compliance or artificial carbon prices while other types of resources avoid such costs or receive financial incentives for generation, thereby effecting the feasibility of resource retirement and new construction.

In March of 2017, President Trump signed the Energy Independence Executive Order, directing federal agencies to submit plans to the White House to propose measures to revise or rescind regulatory barriers to energy independence and regulations that place unnecessary or costly burdens on the energy industry. The Executive Order also rescinded several policies relating to climate change enacted by the Obama administration. On May 12, 2017 the American Public Power Association ("*APPA*"), in response to a Federal Register notice published by the EPA on April 13, reported to the Environmental Protection Agency (*"EPA"*) that many regulations issued in recent years are burdensome to electric utilities and have costs that outweigh their benefits. The APPA recommended that certain rules should be repealed or modified. Specific arguments stated by the APPA are described as applicable below.

1. Renewable Portfolio Standards

Some states are now implementing renewable portfolio standards (*"RPS"*) which typically require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date. As of the date of this Official Statement, Iowa has adopted a renewable portfolio standard for investor owned utilities. Colorado has adopted a renewable portfolio standard affecting investor-owned utilities, electric

cooperatives and municipal utilities, except municipal utilities serving less than 40,000 customers. For affected Colorado municipalities, the RPS requires that the municipality provide the following percentages of renewable or recycled energy: 6% of retail electricity sales for each year until 2019 and 10% of retail electricity sales beginning in year 2020 and for each year thereafter. Presently, this RPS is not affecting MEAN's Colorado Participants. Nebraska and Wyoming have not adopted an RPS.

For the IRP base case scenario, it is assumed that RPS requirements will remain as currently mandated.

2. Clean Air Act

The 1990 Amendments to the Clean Air Act seek to improve the ambient air quality throughout the United States by reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x), emissions caused by electric utility power plants, particularly those fueled by coal. This is administered through a cap and trade system of emission allowances. Currently, all of MEAN's coal-fired generation resources meet the NO_X compliance requirements. Based on current projections, MEAN has sufficient allowances for SO_2 emissions to cover the electric power needs of its customers through 2018. SO_2 and NO_X emissions are monitored continuously and reported quarterly in compliance with EPA regulations.

On August 3, 2015, EPA released its final Clean Power Plan under Section 111(d) of the Clean Air Act (the *"Clean Power Plan"*) which sets performance standards for existing power plants to reduce carbon dioxide (CO_2) emissions. The Clean Power Plan requires each state to reduce its CO_2 emissions rate from existing fossil fuel plants relative to 2005 emission levels to meet state-specific standards starting in 2022, with a final rate for 2030 and beyond. The Clean Power Plan outlines several methods by which emission reductions can be achieved, but does not prescribe specifically to states which methods to employ. Following the release of the Clean Power Plan, 27 states and state agencies, together with various coal companies and utilities, filed a lawsuit in the U.S. Court of Appeals for the District of Columbia Circuit (the *"DC Circuit"*) challenging the Clean Power Plan on constitutional and other grounds. On February 9, 2016, the U.S. Supreme Court issued a stay of the Clean Power Plan, effective immediately, while litigation proceeds. A ten-judge panel of the DC Circuit heard oral arguments on the Clean Power Plan on September 27, 2016. In April 2017, the DC Circuit granted a request for pause in litigation, holding the case in abeyance for 60 days while the EPA reviews the regulation.

MEAN expects the impacts of the Clean Power Plan should be mitigated by MEAN's ownership of recently constructed coal facilities.

The APPA included in its May 2017 report to the EPA its belief that the Clean Power Plan's rule for existing plants would have "created economic inefficiency; imposed inequitable distributed costs on consumers; threatened the reliability of the electricity system; and forced a risky over-reliance on a single fuel – natural gas – to generate electricity." The report offered principles upon which a revised rule must be based. The APPA also stated that the rule on new plants does not set emission limits that adequately justify the benefits or the costs and called for a replacement of that rule as well.

3. Cross-State Air Pollution Rule

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (*"CSAPR"*), which would require the reduction of NO_x and SO_2 in 28 targeted states in the eastern and mid-western United States by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Under CSAPR, EPA sets a pollution limit (referred to as a "budget") for each state covered by the rule. CSAPR allows sources in each state to determine how to meet the emission budgets, including unlimited trading of emissions allowances between power plants in the same state and limited interstate trading under certain conditions.

The timing of CSAPR's implementation has been affected by a number of court actions. Ultimately, Phase I of CSAPR took effect January 1, 2015 and states subject to CSAPR must now comply with the Phase I emission budgets set by EPA. Phase II emission budgets were scheduled to take effect January 1, 2017.

Nebraska is among the 28 states that are subject to CSAPR's requirements to reduce annual emissions of NO_x and SO_2. MEAN believes its generating resources are well positioned to meet any requirements relating to CSAPR's implementation. MEAN does not anticipate that CSAPR will have a material impact on the Power Supply System or its generating resources.

4. Mercury and Air Toxics Standards

On December 16, 2011, the EPA issued final rules titled "Mercury and Air Toxics Standards" (*"MATS"*). The rules establish national emission standards for mercury and other hazardous air pollutants from coal- and oil-fired power plants. They require significant reductions in mercury and acid gas emissions from coal-fired power plants, and apply to electric generating units greater than 25 MW.

MEAN's impacted facilities are all currently MATS compliant. WSEC 4 was originally constructed with emissions controls which enable the plant to comply with MATS. Included with the purchase of the Air Quality Control System for WEC 2 was the necessary equipment to use activated carbon injection as a control of mercury emission to enable compliance with MATS. Wygen Unit I's current emission control equipment enables the plant to comply with MATS. Laramie River Station completed installation of equipment in order to meet a June 2015 compliance deadline to comply with MATS. Ongoing compliance with MATS must be demonstrated by each affected facility.

5. Reciprocating Internal Combustion Engine Subpart ZZZZ

Beginning in May of 2013, the National Emissions Standards for Hazardous Air Pollutants (*"NESHAP"*) for Stationary Reciprocating Internal Combustion Engines (*"RICE"*) (40 CFR, Part 63, Subpart ZZZZ) were updated by the EPA. The RICE NESHAP update included a required reduction of emissions of hazardous air pollutants from covered engines located at major sources of hazardous air pollutant emissions such as power plant sites. For most of the effected units, this required the installation of an oxidation catalyst on the exhaust stack to reduce the emissions of carbon monoxide (CO). In addition, a monitoring system was required to verify and report the performance of the catalyst. All of MEAN's applicable Committed Facilities have installed the required catalyst and monitoring equipment. MEAN staff worked extensively with participants to ensure that all necessary policies and procedures were adopted and continues efforts to assist participants in compliance with the RICE NESHAP regulations.

6. Regional Haze Rule

The EPA's Regional Haze Rule requires emissions controls using best available retrofit technology (*"BART"*) for industrial facilities emitting air pollutants that impair visibility in Class I areas (national parks and wilderness areas). Such pollutants include fine particulate matter ($PM_{2.5}$) and compounds that contribute to $PM_{2.5}$ such as NOx, SO_2, certain volatile organic compounds, and ammonia. Each state is required to submit a State Implementation Plan (*"SIP"*) to demonstrate compliance.

Nebraska, as a CSAPR-affected state, will be able to substitute CSAPR for any requirements related to the Regional Haze Rule. WEC 2 is well positioned to meet any requirements relating to CSAPR's implementation. Based on a determination by the state of Iowa, WSEC 4 is not subject to the Regional Haze Rule.

In 2014 the EPA issued a final ruling on the Wyoming state implementation plan for Laramie River Station that required installation of SCR technology for all three units at Laramie River Station. The estimated Regional Haze Rule compliance date for Laramie River Station is 2020. The Wyoming Department of Environmental Quality and coal plant operators evaluated various options for Laramie River Station compliance and ultimately negotiated a settlement with the EPA. The current plan is to install selective noncatalytic reduction controls on two units and SCR control on one unit, rather than SCR controls on all. This results in a significant cost reduction over installing all SCR technology. Plans have been initiated for the installation of this equipment with final completion scheduled for 2019. Wygen Unit I is not currently subject to CSAPR, though it is well positioned to meet any requirements relating to CSAPR's implementation.

In May 2017, the APPA communicated to the EPA its argument that the rule should be revised to modify the methodology for setting emission reduction levels and give more discretion to states "in determining the course for achieving visibility goals."

7. National Ambient Air Quality Standards

The EPA promulgated final rules and guidance for fine particulate matter, known as the $PM_{2.5}$ Standard, under the National Ambient Air Quality Standards (*"NAAQS"*), which regulates particles less than 2.5 microns in diameter. No county in Colorado, Iowa, Nebraska or Wyoming has been included in the EPA's list of $PM_{2.5}$ "non-attainment" areas, *i.e.*, not in compliance with air quality standards.

In 2008, the EPA promulgated new primary and secondary national ambient air quality standards for ozone, with revised NAAQS for ground-level ozone becoming effective in 2015. The revision set stricter standards and requires modeling and low ambient air testing to confirm compliance. Based on current data and public information, all areas of Colorado, Iowa, Nebraska and Wyoming are either in attainment or are unclassifiable.

8. Greenhouse Gas and Climate Change Issues

In April 2009, the EPA issued final findings that the current and projected concentrations of the mix of six key greenhouse gases (*"GHG"s*)—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride—in the atmosphere threaten the public health and welfare of current and future generations.

On May 13, 2010, the EPA issued a final rule that requires Prevention of Significant Deterioration (*"PSD"*) and Title V operating permits to be obtained by stationary sources,

including power plants. PSD permitting requirements for compliance with GHG emission criteria require a "best available control technology" (*"BACT"*) analysis. WEC 2, WSEC 4 and Wygen Unit I are all operated under BACT standards. WEC 2, WSEC 4, Wygen Unit 1, and Laramie River Station currently have the necessary Title V operating permits and acid rain permits.

On August 3, 2015, the EPA finalized performance standards for new, modified and reconstructed fossil fuel-fired electric generating units. Under the rule, new coal-fired power plants will be required to employ partial carbon capture and sequestration technology to meet emission standards for carbon dioxide. For new natural gas-fired units, EPA has concluded that compliance should be achievable without additional controls. The performance standards will not apply to existing plants.

There have been numerous other judicial and legislative challenges to the EPA's efforts to regulate GHGs that may impact the regulatory status outlined above.

9. Coal Combustion Residuals

The "Disposal of Coal Combustion Residuals from Electric Utilities" rule under the Resource Conservation and Recovery Act (*"RCRA"*) provides a comprehensive set of requirements for the safe disposal of coal combustion residuals (*"CCRs"*) from coal-fired power plants. The CCRs Final Rule regulates CCRs under Subtitle D of the RCRA as non-hazardous solid waste. The CCRs Final Rule establishes guidelines and new minimum standards for the disposal of CCRs in landfills and surface impoundments. As of the date of this report, MEAN facilities are currently compliant.

In its May 2017 communication to the EPA, the APPA advocated for the modification and repeal of certain provisions of this rule, saying that is costs exceed its benefits. The APPA argued the CCR rule should be modified since other regulations establish methods to implement the CCR rule through state or EPA permit programs. The APPA also called for changes to the CCR rule to allow for tailoring corrective action programs based on site-specific conditions and the extension of the deadlines due to coordination between the CCR rule and the Effluent Limitation Guidelines rule. In September, the EPA responded to requests from the power industry and environmentalists, agreeing to "reconsider specific revisions" of the rule.

10. Effluent Limitation Guidelines

The EPA has in recent years considered adopting more stringent limits for new pollutants and parameters for individual wastewater streams generated by steam electric power plants, with a particular focus on coal-fired power plants. The Effluent Limitation Guidelines rule established wastewater limits for heavy metals from coal combustion residual products. Under the rule, new requirements for existing power plants will be phased in between 2018 and 2023. Operators of MEAN's facilities are completing the necessary planning to ensure compliance.

The APPA recommended that the EPA modify the rule due to its costs and effect on jobs. The recommendation suggested flexibility in the applicability date to allow additional time for the development and testing of treatment technologies. The APPA also requested an exemption for units under 400 MW.

11. Water Quality

The Federal Clean Water Act regulates the discharge of process wastewater and certain storm water under the National Pollutant Discharge Elimination System permit program. WSEC 4 is not impacted by the Clean Water Act. WEC 2, Wygen Unit I and Laramie River Station have proper permitting in place under the Clean Water Act.

In 2015, the act was revised with regard to the regulatory definition of the term "waters of the United States." However, later that year the US Court of Appeals for the Sixth Circuit issued a stay on the revision. In response, federal agencies reverted to the prior definition for enforcement. In February 2017, the President issued an executive order directing the EPA and Army Corps of Engineers to review and revise or rescind the 2015 rule. This review is ongoing. The manner in which this term is defined will impact requirements for wastewater discharge from power plants located upstream of community water sources.

12. Future Legislation and Rules

Previous to the current administration, various Congressional bills were introduced in both the House of Representatives and the Senate that would require the further reduction of emissions of sulfur dioxides, nitrogen oxides, mercury and carbon dioxide from coal-fired electric generating units. However, environmental initiatives look to be stalled under the current administration and congressional control. In recent months, a bill has been proposed to initiate tax credits for carbon capture and sequestration technologies, which could incentivize investments in cleaner fossil fuel power generation. It is uncertain if or when any of these previous Congressional bills may be reintroduced or enacted into law upon a change in executive or legislative control and what effect, if any, such legislation will have on MEAN, the Power Supply System or the Participants.

MEAN cannot predict at this time whether any additional legislation or rules will be enacted in the future that will affect the operations of the Power Supply System, MEAN or the Participants, and if such laws or rules are enacted, what the costs to MEAN and the Participants might be in the future because of such action.

MEAN is continually monitoring, and evaluating the best ways to meet, the requirements of current federal and state air quality and other environmental laws.

B. Load Forecast

MEAN employs a robust statistical method for forecasting load. As fully described in Section V. System Load Forecast, a number of input variables are used to formulate a forward-looking equation to calculate the monthly peak demand and monthly energy usage for each participant community for the entirety of the study period. The individual participant load forecasts are combined to result in a total load forecast for each region. However, the statistical analysis is dependent upon several variables, such as weather data, population, and income. Changes in any of these factors will impart changes in the load forecast.

In addition to the variables identified as inputs to the load forecast calculation, throughout the MEAN footprint, demand side management (*"DSM"*) measures are being adopted by utilities and end-use customers in participant communities. DSM measures act to reduce either the peak demand for electricity or the total electricity consumption. Consumers are gaining interest and knowledge in the control and reduction of their energy consumption and carbon footprint. As such, we can expect the deployment and adoption of DSM to continue and likely increase in the future,

leading to a decrease in load. This effect is fully explored in the Demand Side Management section of this report, although the actual future use of DSM is difficult to accurately forecast.

In addition to controlling and reducing their energy consumption, some customers also have interest in providing for their own energy supply. Distributed Generation (*"DG"*) is customer and/or community ownership of generating assets to serve end use load. DG, particularly in terms of wind, solar, and combined heat and power, are becoming more popular "behind the meter" installations. Each installation of DG removes energy consumption from the MEAN system and thereby decreases the resource need, either on a capacity or energy basis depending on the timing of DG energy supply. The future rate of DG installation and therefore its impact on load projections is unknown.

Recent years have seen an emphasis on energy efficiency and energy conservation on all levels: residential, commercial, and industrial. From improved performance of household appliances to the use of energy efficient materials in building construction to conscious selection of efficient HVAC systems, customers are making choices to decrease their energy usage and cost. The widespread use of these practices has led to a decrease in the growth rate of electric loads, and is a trend which is likely to continue, but at a pace that is difficult to predict.

C. Future Load Acquisition

MEAN maintains a goal toward strategic growth to benefit the membership and the long-term health of the organization. This means adding new load when it can be economically served. When Requests for Proposals for energy supply are released, MEAN conducts a statistical analysis to determine the cost at which the load can be served by the existing Power Supply System or future resources if needed. Adding load, particularly when new resources are not required, benefits the remainder of the total requirements participants as MEAN's fixed costs are allocated among more communities.

Obviously, although load addition is a priority for MEAN, it cannot be accurately forecast. Therefore, this represents an unknown potential change in MEAN's load and resource balance and timing of future resource needs.

D. Energy Markets

In the integrated markets, loads are served and resources dispatched according to market dynamics and the balance of bids and offers in an attempt to cost effectively optimize the pool of resources. In addition, the Transmission Congestion Rights markets give participants a financial hedge against the market price fluctuations that occur due to transmission congestion.

Within the integrated markets, market prices are determined by variable costs of generating units throughout the entire market. Therefore, the construction of new units and retirement of existing units has the potential to change the order of economic dispatch of resources and, as a result, marginal pricing. The integration of non-dispatchable, renewable generation into the resource mix impacts the operation of other resources, particularly peaking units dispatched in response to supply fluctuations and cycling coal plants.

Since the establishment of the SPP and MISO Integrated Markets, several changes have been introduced that have changed the way resources are designated to load, the way resources are dispatched into the marketplace, and energy prices and cost recovery for generation resources. Given the fast pace of developments in the markets, it is likely that changes will continue in the future.

In recent years, transmission providers in the west have been contemplating joining together to form a Mountain West RTO and possibly integrate into the SPP IM. This will undoubtedly impose changes on load and resource interaction in the west. The effects of these structural changes would be seen not only in the western region, but in SPP as well.

The existing markets and potential creation of future markets present significant opportunity for uncertainty.

E. Fuel Pricing

1. Natural Gas

Recent natural gas pricing has been low compared to historical pricing and has seen less volatility in the last two to three years. However, within the past 20 years there have been several periods of elevated pricing and high volatility, as shown in *Figure IV-1*.

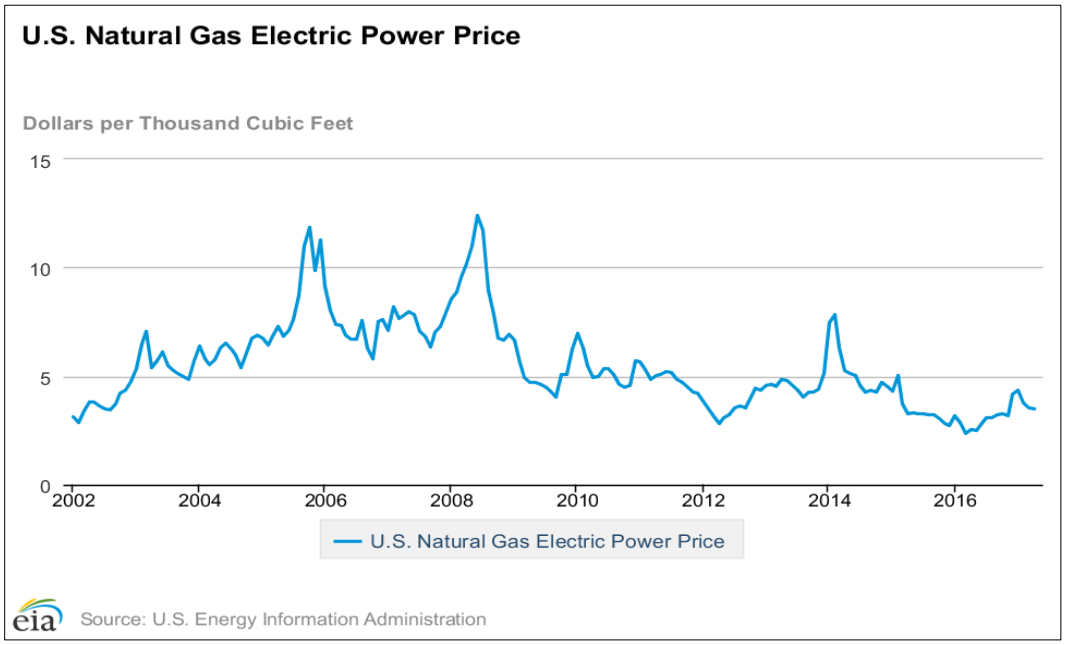


Figure IV-1

Future pricing projections indicate that this current depressed pricing is likely to be sustained. Various sources predict a low growth rate for natural gas pricing for the foreseeable future. *Figure IV-2* compares future natural gas pricing projections under various scenarios as published by the U.S. Energy Information Administration. *Figure IV-3* shows how the EIA reference case projections have decreased over the past six years.

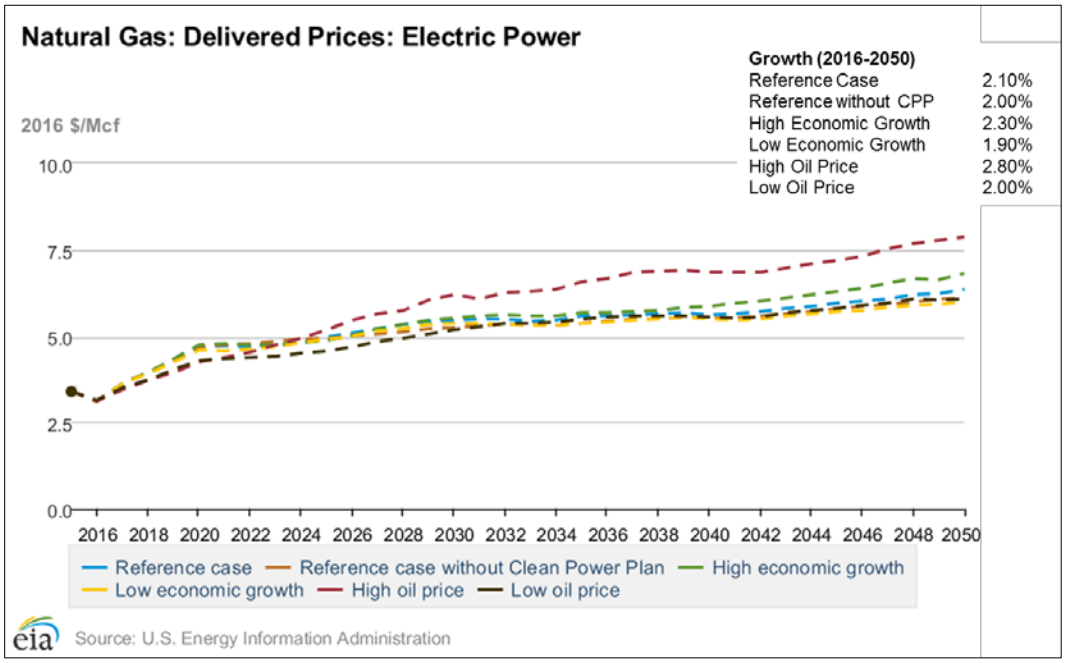


Figure IV-2

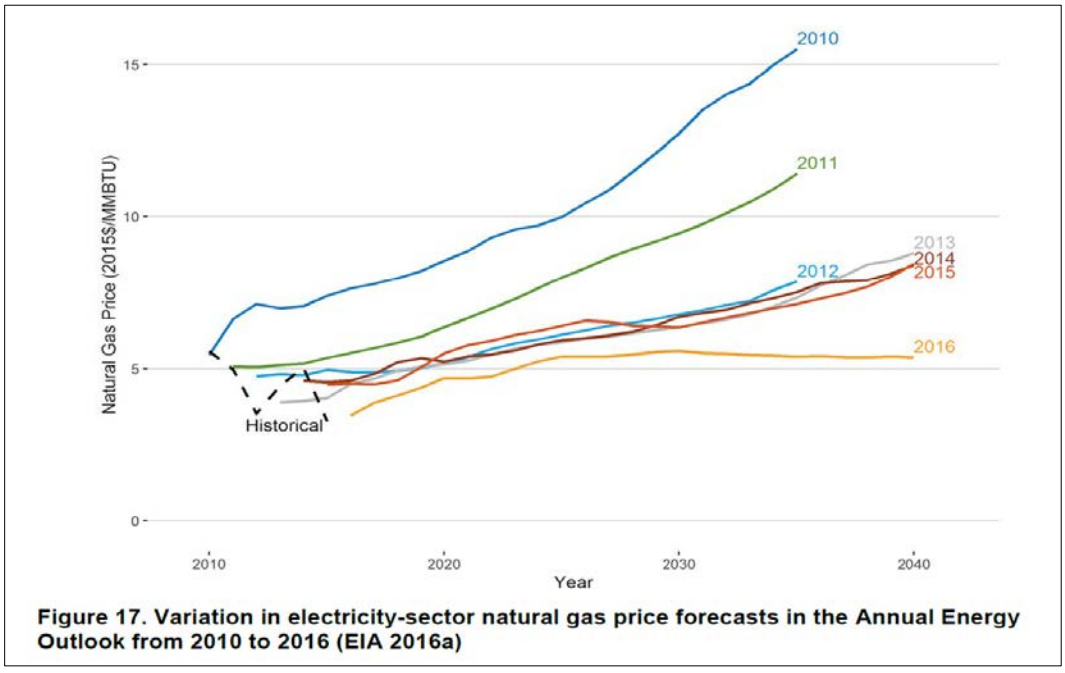


Figure 17. Variation in electricity-sector natural gas price forecasts in the Annual Energy Outlook from 2010 to 2016 (EIA 2016a)

Figure IV-3

The reduction in current pricing is in large part due to an increase in domestic production facilitated by the proliferation of hydraulic fracturing. The alleged environmental risks of fracking may lead to future regulations, which may in turn affect the boon in production and thereby pricing.

As a global resource, natural gas is also subject to the influence of global supply and demand. This relationship carries with it the risk of price fluctuations in response to market occurrences elsewhere. Fuel pricing projections assume low pricing and low volatility into the future. However, this contains inherent uncertainty.

2. Coal

Although Appalachian coal prices experienced a peak about ten years ago, more recently prices have stabilized and remained relatively low. Coal in most regions has seen flat or declining pricing over the past five years, illustrated in *Figure IV-4*.

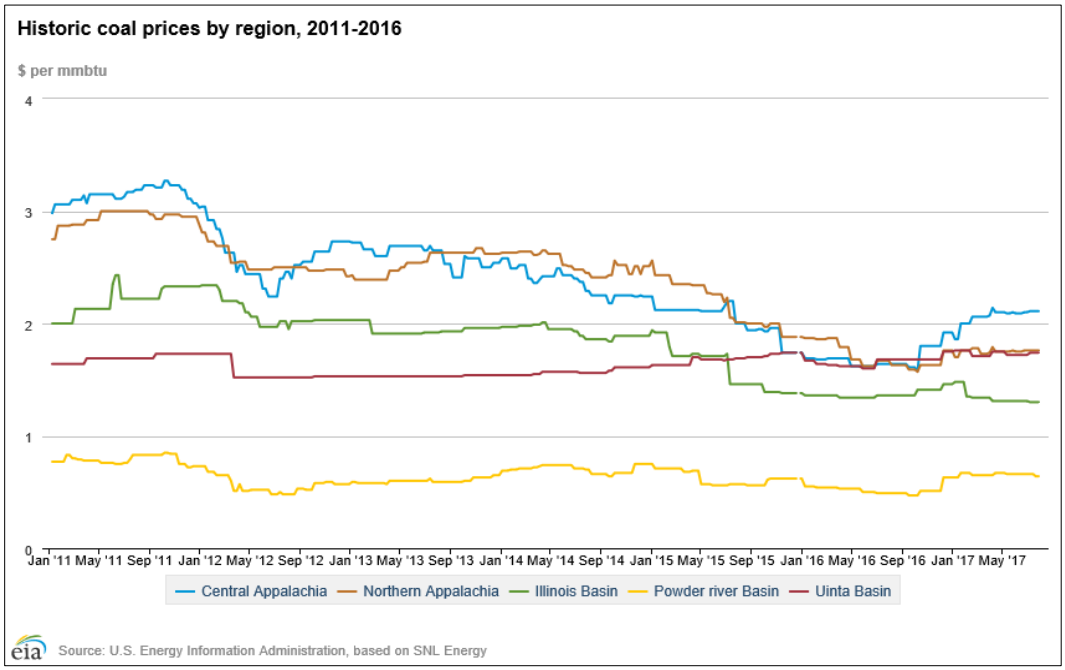


Figure IV-4

The EIA coal delivered price projections for several possible conditional cases shows a consensus of low price increases into the future. The reference case for the coal supply delivered price for electric power end use indicates a growth rate of 0.3% from 2016 to 2050. These projections are shown in *Figure IV-5*.

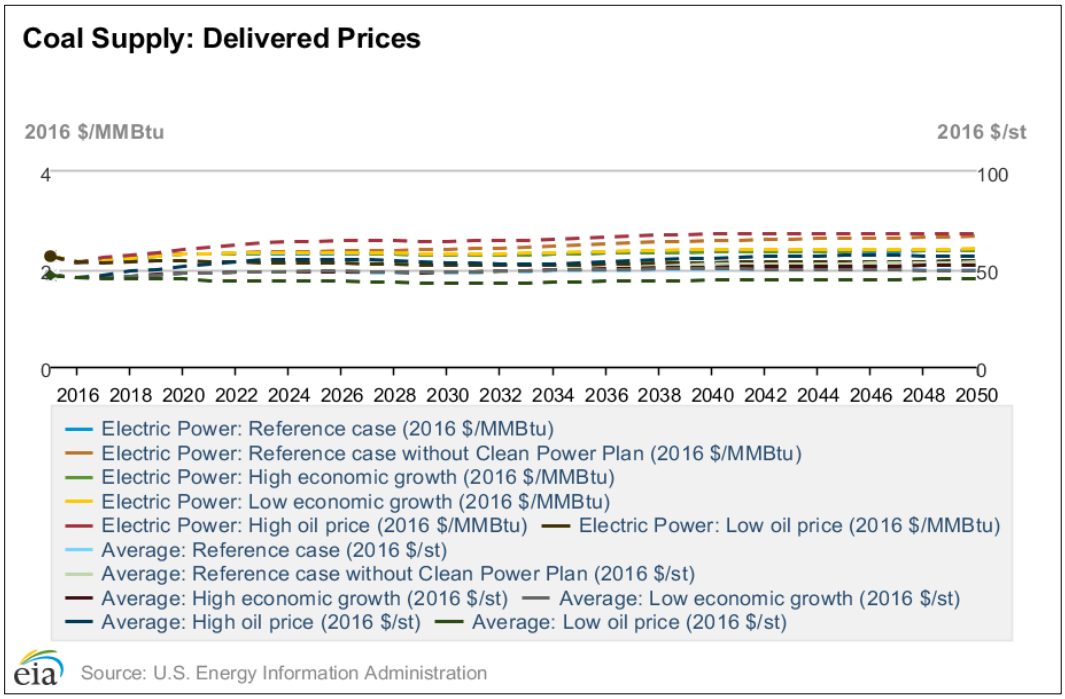


Figure IV-5

F. Other Factors

In addition to these items described above, a number of other factors are having or may have significant impacts on the electric utility industry generally and on the financial and operating condition of individual utilities. These factors include, among other things:

- the development and impact of alternate energy sources, and government changes to tax credits and grants for renewable energy projects;
- the lack of a comprehensive national energy policy;
- effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions and strategic alliances of competing electric and natural gas utilities and from transmission of less expensive electricity from greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity;
- increased competition from independent power producers and marketers, brokers and federal power marketing agencies;
- changes in state regulations that determine the pricing and incentives for "distributed generation" (solar, microturbines, fuel cells, etc.), including net metering rate structures;
- volatility in the price of energy purchased on the wholesale market that may occur in times of high peak demand;
- unavailability of or substantial volatility in the cost of coal or natural gas used as fuel for generation facilities; and
- local, regional and national economic conditions.

It is not possible to predict what impact these and other factors will have on the financial and operating position of MEAN or the Participants. The foregoing discussion is a general summary of complex matters. This discussion is not comprehensive or definitive and the matters discussed are subject to change.

V. System Load Forecast

A. Methodology

1. Non-Coincident Peak Demand

MEAN employed multiple regression analysis to forecast the non-coincident peaks for each of its Total Requirement Participants for FY 2017-2018 (annual forecast) thru FY 2032-33 (15-year forecast). The annual forecast model utilized the daily peak demand data from 2006 to 2016 as a dependent variable, while the 15-year forecast model used monthly peak demand data of the same period. Both models took into consideration three main factors as independent variables: economic factors such as population growth and income growth; temperature factors such as average daily temperature, heating degree days (*"HDD"*) and cooling degree days (*"CDD"*); and calendar factors such as weekdays and month. Historical average daily temperatures, HDD and CDDs were gathered from NOAA station data, historical population data were gathered from the U.S. Census Bureau, and historical income data was sourced from the Bureau of Labor Statistics. The estimated population and income data used for the forecast were calculated from separate simple linear regressions.

To ensure that monthly peak demand was forecasted under normalized weather conditions for each town, actual weather data from the past ten years was used, and ten sets of monthly peak demand were forecasted. The median was used as the normalized peak demand of the town for the given month. Non-coincident peak demand was then calculated by summing all the normalized peak demands of each town for each month.

2. Energy for load forecast

The same methodology used in 15-year peak demand forecast was used for energy forecasts for each town. The only difference was the change of the dependent variable from monthly peak demand to monthly energy usage. All the data was obtained from the same resources as in the demand forecast, and the same weather normalization process used in the demand forecast was used in the energy forecast.

3. Coincident Peak Forecast

The coincident peak forecast is calculated as MEAN's non-coincident peak multiplied by the coincidence factor. The coincidence factor was forecasted based upon regression analysis of the difference between the mean temperature and the max temperature at the time of historical peaks. The historical weather data used in the regression was based on NOAA station data. The historical coincidence factor used for regression was derived by using the dates and times of historical peak. In the detailed regression analysis, a stepwise selection procedure was used and two variables, Max Temperature Differential and Mean Temperature Differential, were selected to define the equation for the coincidence factor.

To arrive at the expected weather normal coincidence peak, MEAN looked at historical mean temperature differences and the max temperature differences for all the dates and times of historical peaks. The medians were then calculated and reinserted into the regression equation to find the expected coincidence factor. The final expected coincident factor was 95.49%, with 95% confidence intervals of 93.75% and 97.23%.

The regression analysis also resulted in the below statistical output:

- Model description and fit
- Residual Analysis
- Variance Inflation Factors (Collinearity Analysis)
- ANOVA (Analysis of Variance)
- Confidence Intervals
- Forecast Evaluation Statistics

4. Annual Participant Load Survey

To validate the load forecast statistical calculations, MEAN conducts an annual load survey to all participants. MEAN presents the results of its 15-year forecast for the participant community and asks the representatives to review it against their knowledge of the community's peak load and energy consumption. Specifically, the survey asks if there are any recent or planned additions to load or losses of load. Any information collected in response to the survey are then incorporated into the community's load forecast and the regional and system-wide forecasts are corrected accordingly.

B. Factors Affecting Load Growth

MEAN Participants and their end-use customers are implementing demand side management (*"DSM"*) measures to reduce peak demand and/or energy use. MEAN administers DSM programs to control peak demand to avoid the addition of future resources. Participant utilities adopt DSM programs to decrease their peak demand in an effort to lower the Fixed Cost Recovery Charge paid to MEAN, which is based on the 3-year historical average peak. End-use customers participate in DSM programs to reduce their utility bill. Although the actual impact of these measures is often difficult to measure or predict, successful DSM programs will ultimately slow the rate of load growth into the future.

Growing awareness of energy issues and pricing has increased customer interest in owning generation to serve their own load. As technologies become more available and affordable, MEAN Participants and their end-use customers will have more incentive to install distributed generation assets. From residential rooftop solar to industrial combined heat and power to community wind and solar, distributed generation is being aggressively marketed and eagerly adopted. These assets ultimately decrease the load obligation that MEAN has to serve by increasing behind-the-meter capacity.

Energy efficiency and energy conservation are widely promoted initiatives and are becoming easier to integrate into everyday life. As electricity rates increase, the economic benefit of efficiency and conservation gives consumers, businesses, and institutions ample reason to adopt behaviors and make purchases with the goal of reducing energy consumption. This has a long-term effect on all load profiles.

C. Recent Developments

Since the submittal of the 2012 IRP, MEAN's load has been impacted by a few changes to the organization's membership.

1. Load Loss

From 2012 to 2017, five service contracts totaling approximately 105 MW of peak load expired. This included the following participant communities: Buffalo, Iowa; Wood River, Nebraska; Fountain, Colorado; Gillette, Wyoming; and Sargent, Nebraska.

In addition to expired service contracts, some MEAN participants have recently lost large loads within their communities. MEAN and NMPP continually work with the membership to prevent and mitigate negative impacts of such load loss.

Furthermore, planned installations of local generation have been announced, which will have the effect of decreasing MEAN's service loads in the host communities. Specifically, a large industrial customer within a participant community is planning to install a 6 MW cogeneration facility to serve its operations. This project, planned to come online in 2018, has already been included in the load forecast.

2. Load Additions

Between 2012 and 2017, MEAN has added four new limited term service contracts for a total peak load of approximately 15 MW. This includes the communities of: Wray, Colorado; Lakeview, Iowa; Snyder, Nebraska; and Trenton, Nebraska.

As opportunities are announced via Requests for Proposals, MEAN engages in deliberate analysis to determine the benefits and costs of service additions and responds to all viable requests. MEAN continues to pursue additional load, through the initiation of new contracts and assisting existing communities with economic development to grow loads within their territories.

D. MISO

MEAN's peak demand, annual energy consumption, and load factor for all participants located in the MISO footprint are listed in *Figure V-1*, with both historic and projected future values included.

MISO Region Load Forecast						
Year	Load(kW)		Energy(MWh)		Load Factor (%)	
	Summer	Winter	Summer	Winter	Summer	Winter
2006-2007	47,651	25,593	93,702	48,275	44.77%	43.18%
2007-2008	42,535	33,286	95,877	92,621	51.32%	63.70%
2008-2009	51,439	37,761	104,395	103,731	46.21%	62.89%
2009-2010	53,152	56,050	105,720	127,409	45.29%	52.04%
2010-2011	90,629	66,631	199,707	188,303	50.17%	64.70%
2011-2012	98,133	62,676	206,163	183,633	47.83%	67.08%
2012-2013	98,430	64,498	209,794	186,985	48.53%	66.37%
2013-2014	92,361	70,005	201,680	199,220	49.72%	65.15%
2014-2015	84,836	66,860	194,111	188,555	52.10%	64.56%
2015-2016	93,208	65,745	194,689	173,756	47.56%	60.51%

2016-2017	90,369	63,365	198,895	183,633	50.11%	66.35%
2017-2018	86,772	63,425	192,292	181,108	50.46%	65.37%
2018-2019	86,844	63,484	191,858	180,757	50.30%	65.19%
2019-2020	86,916	63,544	191,423	180,406	50.15%	65.00%
2020-2021	86,988	63,604	190,989	180,055	49.99%	64.81%
2021-2022	81,638	58,547	183,298	167,269	51.12%	65.41%
2022-2023	81,632	58,573	179,665	166,793	50.11%	65.19%
2023-2024	81,627	58,599	179,083	166,316	49.95%	64.98%
2024-2025	81,622	58,626	178,501	165,839	49.79%	64.76%
2025-2026	81,616	58,652	177,920	165,362	49.63%	64.55%
2026-2027	81,611	58,678	177,338	164,886	49.48%	64.33%
2027-2028	81,605	58,704	176,757	164,409	49.32%	64.12%
2028-2029	81,600	58,730	176,175	163,932	49.16%	63.90%
2029-2030	81,594	58,757	175,593	163,455	49.00%	63.69%
2030-2031	81,589	58,783	175,012	162,979	48.84%	63.47%
2031-2032	81,583	58,809	174,430	162,502	48.68%	63.26%
2032-2033	81,578	58,835	173,848	162,025	48.52%	63.05%

Figure V-1

As shown in *Figure V-2*, for the period of 2017 to 2032, the summer peak demand for MISO is expected to drop from 86,772 kW to 81,578 kW, and the winter peak demand will drop from 63,425 kW to 58,835 kW. A slight decrease in peak demand will occur for both summer and winter demand in 2021 due to the contract expiration of Lake View (if not renewed).



Figure V-2

As show in *Figure V-3*, for the period of 2017 to 2032, the summer season energy requirement for MISO is expected to drop from 192,292 MWh to 173,848 MWh, and the winter energy requirement will drop from 181,108 MWh to 162,025 MWh. A slight energy requirement decrease will occur in both summer and winter season in 2021 due to the contract expiration of Lake View (if not renewed).

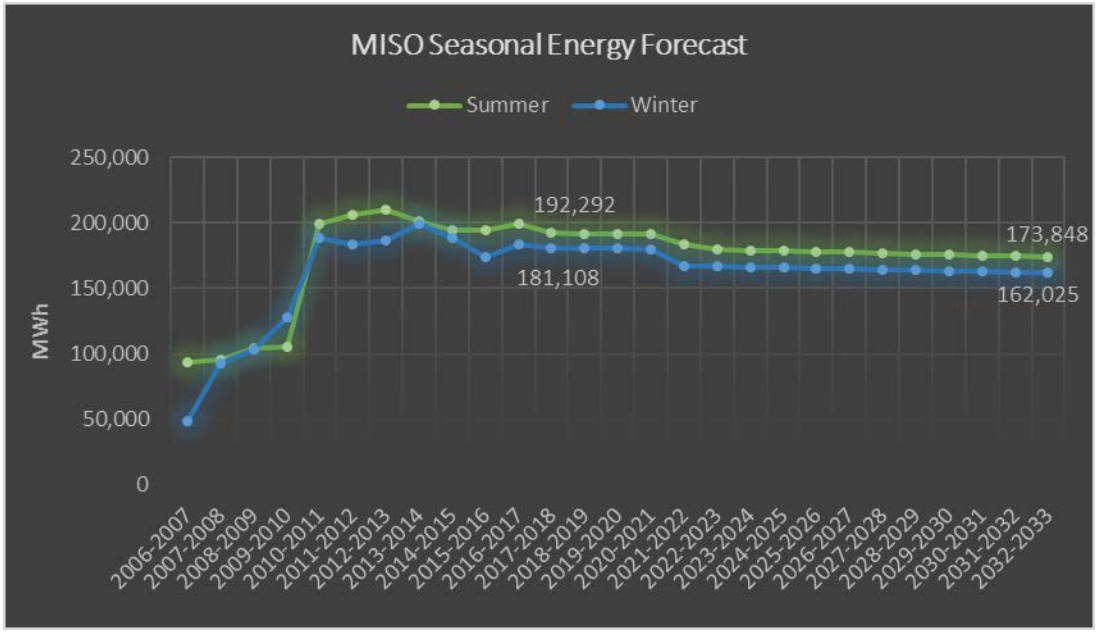


Figure V-3

The table in *Figure V-4* summarizes the MISO participant contracts that were initiated or are set to expire from the date of the previous IRP submittal through the end of the study period.

MISO Region Participants Schedule Start Dates 2006-2028			
Town	Schedule	RTO	Schedule Start Date
Buffalo	K	MISO	1/1/2005
Breda	M	MISO	1/1/2008
Wall Lake	M	MISO	1/1/2008
Indianola	M	MISO	4/1/2009
Sergeant Bluff	M	MISO	4/1/2009
Waverly	M	MISO	2/1/2010
Denver	M	MISO	7/1/2010
Lake View	J	MISO	6/1/2016
MISO Region Participants Schedule End Dates 2006-2028			
Town	Schedule	RTO	Schedule End Date
Buffalo	K	MISO	12/31/2014
Lake View	J	MISO	5/31/2021

Figure V-4

E. SPP

MEAN's peak demand, annual energy consumption, and load factor for all participants located in the SPP footprint are listed in *Figure V-5*, with both historic and projected future values included.

SPP Region Load Forecast						
Year	Load(kW)		Energy(MWh)		Load Factor (%)	
	Summer	Winter	Summer	Winter	Summer	Winter
2006-2007	156,974	132,420	362,537	367,314	52.59%	63.50%
2007-2008	151,125	139,078	367,191	388,973	55.32%	64.03%
2008-2009	150,042	150,832	362,696	397,998	55.04%	60.41%
2009-2010	145,580	152,097	356,432	413,319	55.75%	62.21%
2010-2011	159,143	154,861	378,232	405,376	54.11%	59.93%
2011-2012	165,632	137,798	375,504	384,747	51.62%	63.92%
2012-2013	171,093	142,639	398,623	401,972	53.05%	64.52%
2013-2014	160,180	153,918	388,937	425,228	55.29%	63.25%
2014-2015	156,293	148,194	374,285	405,367	54.53%	62.62%
2015-2016	155,751	140,400	370,269	382,910	54.13%	62.44%
2016-2017	161,225	147,534	378,783	399,107	53.49%	61.93%
2017-2018	162,660	147,200	385,404	408,489	53.95%	63.53%
2018-2019	163,484	148,150	387,606	410,787	53.98%	63.48%
2019-2020	164,309	149,100	389,808	413,086	54.02%	63.43%
2020-2021	165,134	150,049	392,010	415,385	54.05%	63.38%
2021-2022	164,331	146,946	391,676	408,902	54.27%	63.71%
2022-2023	162,767	147,919	387,456	409,386	54.20%	63.36%
2023-2024	163,614	148,892	389,547	411,122	54.21%	63.21%
2024-2025	163,127	148,595	389,110	410,719	54.31%	63.28%
2025-2026	163,957	149,547	391,193	412,876	54.32%	63.21%
2026-2027	164,786	150,499	393,275	415,033	54.34%	63.13%
2027-2028	165,615	151,450	395,357	417,190	54.35%	63.06%
2028-2029	166,445	152,402	397,439	419,347	54.37%	62.99%
2029-2030	167,274	153,354	399,521	421,504	54.38%	62.93%
2030-2031	168,103	154,306	401,604	423,661	54.40%	62.86%
2031-2032	168,933	155,258	403,686	425,818	54.41%	62.79%
2032-2033	169,762	156,210	402,768	427,976	54.02%	62.72%

Figure V-5

As shown in *Figure V-6*, for the period of 2017 to 2032, the summer peak demand for SPP is expected to increase from 162,660 kW to 169,762 kW, and the winter peak demand will increase from 147,200 kW to 156,210 kW. If not renewed, the contracts of Sargent, Snyder, Trenton, and Paxton will expire in 2017, 2021, 2021, and 2024 respectively, but they don't have a major influence on the SPP total demand. MEAN's service contract with Trenton began in January 2017.



Figure V-6

As shown in *Figure V-7*, the energy requirement for SPP is higher in winter than in summer. For the period of 2017 to 2032, the summer season energy requirement is expected to increase from 385,404 MWh to 402,768 MWh, and the winter energy requirement will increase from 408,489 MWh to 427,976 MWh.

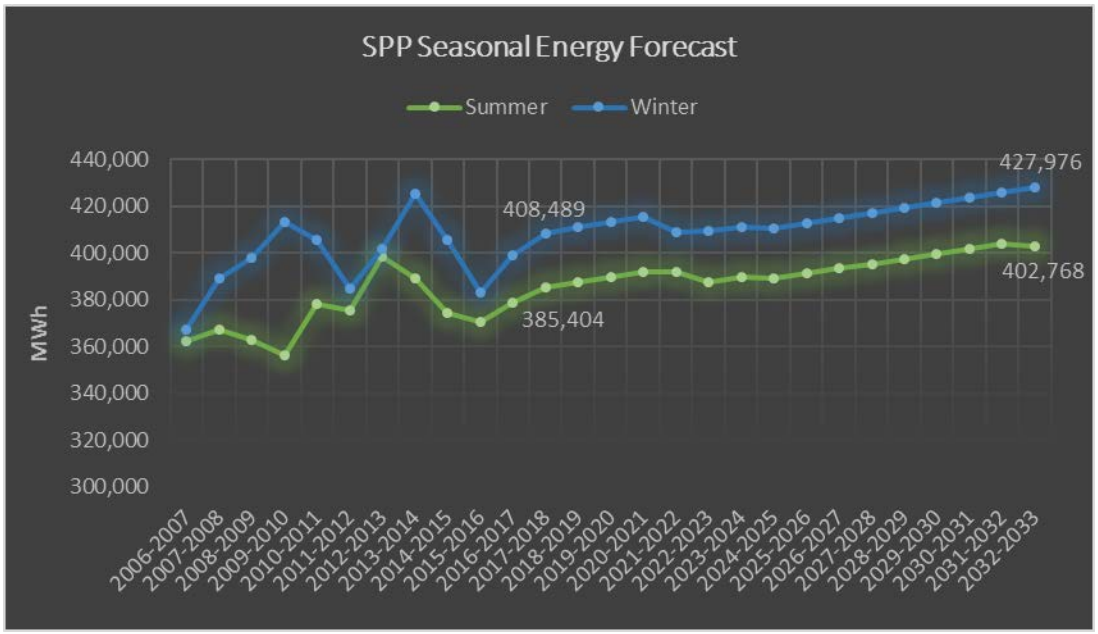


Figure V-7

Figure V-8 summarizes the SPP participant contracts that were initiated or are set to expire from the date of the previous IRP submittal through the end of the study period.

SPP Region Participants Schedule Start Dates 2006-2028			
Town	Schedule	RTO	Schedule Start Date
Rockford	M	SPP	9/1/2007
Wisner	M	SPP	9/1/2007
Julesburg	M	SPP	10/1/2007
Stuart	M	SPP	12/1/2007
Grant	M	SPP	2/1/2008
Pender	M	SPP	2/1/2008
Ansley	M	SPP	2/1/2008
Spencer	M	SPP	6/1/2008
Pierce	M	SPP	4/1/2009
Plainview	M	SPP	10/1/2011
Paxton	K	SPP	3/1/2014
Snyder	J	SPP	6/1/2016
Trenton	J	SPP	1/1/2017
SPP Region Participants Schedule End Dates 2006-2028			
Town	Schedule	RTO	Schedule End Date
Wood River	K	SPP	2/28/2015
Sargent	K	SPP	2/28/2017
Snyder	J	SPP	5/31/2021
Trenton	J	SPP	12/31/2021
Paxton	K	SPP	2/28/2024

Figure V-8

F. West

MEAN's peak demand, annual energy consumption, and load factor for all participants located in the west region footprint are listed in *Figure V-9*, with both historic and projected future values included.

West Region Load Forecast						
Year	Load (kW)		Energy (MWh)		Load Factor (%)	
	Summer	Winter	Summer	Winter	Summer	Winter
2006-2007	260,864	229,056	611,799	649,273	53.40%	64.89%
2007-2008	257,484	244,883	598,547	665,004	52.93%	62.17%
2008-2009	263,308	264,135	614,860	687,302	53.17%	59.57%
2009-2010	252,436	266,240	611,748	719,449	55.18%	61.86%
2010-2011	272,610	263,866	640,425	710,943	53.49%	61.68%
2011-2012	284,070	246,920	650,631	707,955	52.15%	65.64%
2012-2013	297,152	255,596	682,325	718,471	52.28%	64.35%
2013-2014	287,970	270,613	679,062	740,774	53.69%	62.67%
2014-2015	294,032	281,900	651,116	743,994	50.42%	60.42%
2015-2016	236,991	181,543	555,812	545,546	53.40%	68.80%
2016-2017	204,605	178,289	502,831	542,751	55.96%	69.69%
2017-2018	194,215	175,368	487,864	548,728	57.19%	71.63%
2018-2019	189,670	176,572	491,228	551,669	58.97%	71.53%

2019-2020	190,619	177,764	494,591	554,610	59.08%	71.43%
2020-2021	191,462	178,861	497,955	557,551	59.22%	71.37%
2021-2022	192,252	179,912	501,319	560,492	59.37%	71.32%
2022-2023	193,121	181,032	504,683	528,655	59.50%	66.86%
2023-2024	171,215	159,787	444,513	498,182	59.11%	71.38%
2024-2025	172,086	160,905	447,841	501,131	59.25%	71.30%
2025-2026	172,946	162,012	451,168	504,080	59.40%	71.23%
2026-2027	173,777	163,093	454,496	507,029	59.55%	71.17%
2027-2028	174,608	164,174	457,824	509,978	59.70%	71.12%
2028-2029	175,439	165,256	461,152	512,927	59.85%	71.06%
2029-2030	176,271	166,337	464,480	515,876	60.00%	71.00%
2030-2031	177,102	167,419	467,807	518,825	60.14%	70.95%
2031-2032	177,933	168,500	471,135	521,774	60.29%	70.89%
2032-2033	178,773	169,589	474,463	524,723	60.43%	70.84%

Figure V-9

As shown in *Figure V-10*, for the period of 2017 to 2032, the summer peak demand for the west is expected to decrease from 194,215 kw to 178,773 kW, and the winter peak demand will also decrease from 175,368 kW to 169,589 kW. If the contracts are not renewed, decreases will occur in both summer and winter demand due to the contract expiration of Wray and Holyoke in 2018, and of Glenwood Springs in 2022.

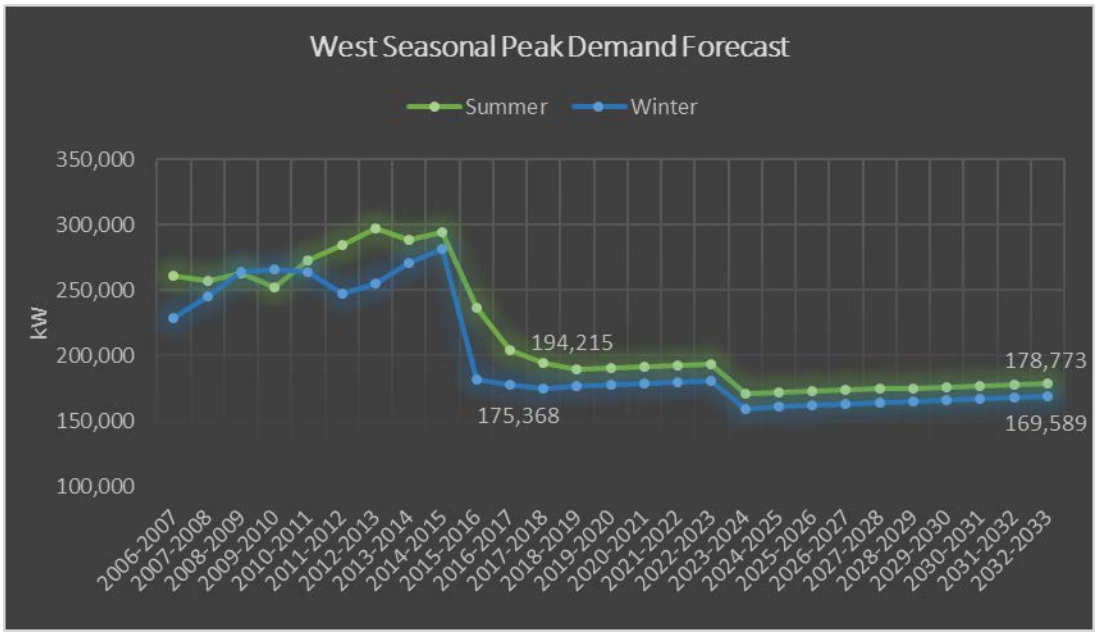


Figure V-10

As shown in *Figure V-11*, The energy requirement for the west is higher in winter than in summer. For the period of 2017 to 2032, the summer season energy requirement is expected to decrease from 487,864 MWh to 474,463 MWh, and the winter energy requirement will also decrease from 548,728 MWh to 524,723 MWh. Decreases will occur in both summer and winter energy requirement due to the contract expiration (if not renewed) of Wray and Holyoke in 2018, and of Glenwood Springs in 2022.

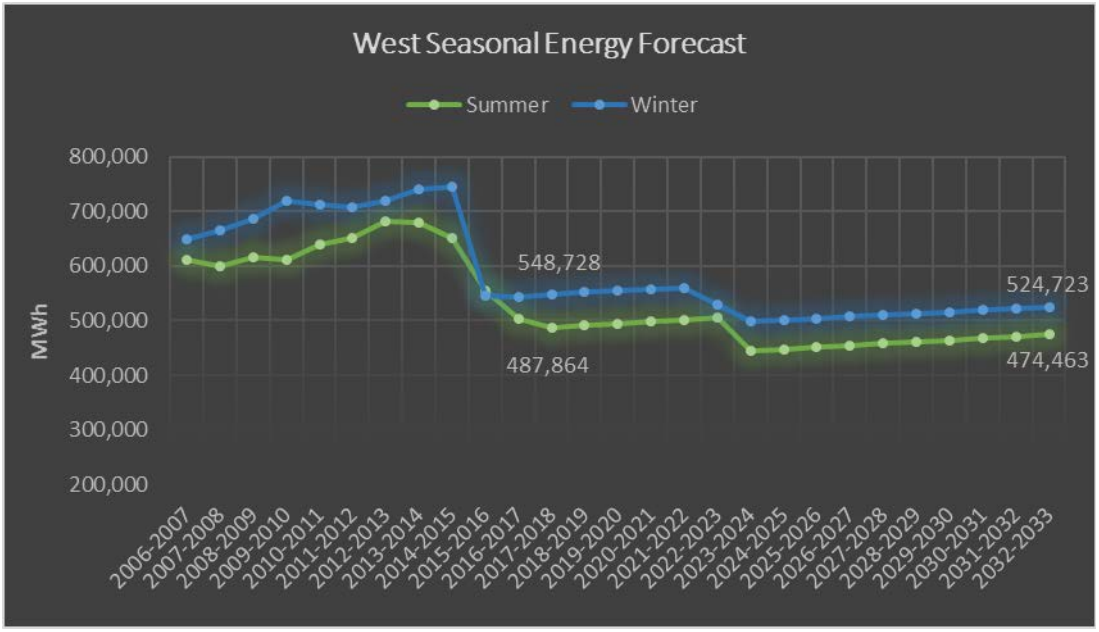


Figure V-11

Figure V-12 summarizes the west region participant contracts that were initiated or are set to expire from the date of the previous IRP submittal through the end of the study period. [At the time of this report, MEAN is in discussions with the communities of Wray and Holyoke regarding renewal of their current contracts.]

West Region Participants Schedule Start Dates 2006-2028			
Town	Schedule	RTO	Schedule Start Date
Basin	M	West	1/1/2006
Torrington	M	West	1/1/2008
Sidney	M	West	2/1/2008
Fort Morgan	M	West	7/1/2009
Delta	M	West	10/1/2012
Glenwood Springs	K	West	1/1/2013
Wray	J	West	7/1/2013
West Region Participants Schedule End Dates 2006-2028			
Town	Schedule	RTO	Schedule End Date
Gillette	J	West	3/31/2015
Fountain	J	West	6/30/2015
Wray	J	West	6/30/2018
Holyoke	J	West	9/30/2018
Glenwood Springs	K	West	12/31/2022

Figure V-12

G. MEAN System

MEAN's peak demand, annual energy consumption, and load factor for all participants throughout the entire footprint are listed in *Figure V-13*, with both historic and projected future values included.

MEAN System Load Forecast						
Year	Load (kW)		Energy (MWh)		Load Factor (%)	
	Summer	Winter	Summer	Winter	Summer	Winter
2006-2007	465,489	387,069	1,068,038	1,064,862	52.24%	62.98%
2007-2008	451,144	417,247	1,061,615	1,146,598	53.58%	62.91%
2008-2009	464,789	452,728	1,081,951	1,189,031	53.00%	60.13%
2009-2010	451,168	474,387	1,073,900	1,260,177	54.20%	60.82%
2010-2011	522,382	485,358	1,218,364	1,304,622	53.10%	61.54%
2011-2012	547,835	447,394	1,232,298	1,276,335	51.22%	65.31%
2012-2013	566,675	462,733	1,290,742	1,307,428	51.86%	64.69%
2013-2014	540,511	494,536	1,269,679	1,365,222	53.48%	63.20%
2014-2015	535,161	496,954	1,219,512	1,337,916	51.88%	61.64%
2015-2016	485,950	387,688	1,120,770	1,102,212	52.51%	65.09%
2016-2017	456,199	389,188	1,080,509	1,125,491	53.93%	66.21%
2017-2018	443,647	385,993	1,065,560	1,138,325	54.69%	67.52%
2018-2019	439,998	388,206	1,070,692	1,143,213	55.41%	67.42%
2019-2020	441,844	390,408	1,075,822	1,148,102	55.44%	67.33%
2020-2021	443,584	392,514	1,080,954	1,152,991	55.48%	67.25%
2021-2022	438,221	385,405	1,076,293	1,136,663	55.92%	67.52%
2022-2023	437,520	387,524	1,071,804	1,104,834	55.78%	65.27%
2023-2024	416,456	367,278	1,013,143	1,075,620	55.39%	67.05%
2024-2025	416,835	368,126	1,015,452	1,077,689	55.47%	67.02%
2025-2026	418,519	370,211	1,020,281	1,082,318	55.51%	66.93%
2026-2027	420,174	372,270	1,025,109	1,086,948	55.55%	66.84%
2027-2028	421,828	374,328	1,029,938	1,091,577	55.59%	66.76%
2028-2029	423,484	376,388	1,034,766	1,096,206	55.63%	66.68%
2029-2030	425,139	378,448	1,039,594	1,100,835	55.68%	66.59%
2030-2031	426,794	380,508	1,044,423	1,105,465	55.72%	66.51%
2031-2032	428,449	382,567	1,049,251	1,110,094	55.76%	66.43%
2032-2033	430,113	384,634	1,051,079	1,114,724	55.64%	66.35%

Figure V-13

As shown in *Figure V-14*, the system demand in summer is higher than in winter. For the period 2017 to 2032, the system summer demand will decrease from 443,647 kW to 430,113 kW, and the system winter demand will also decrease from 385,993 kW to 384,634 kW.

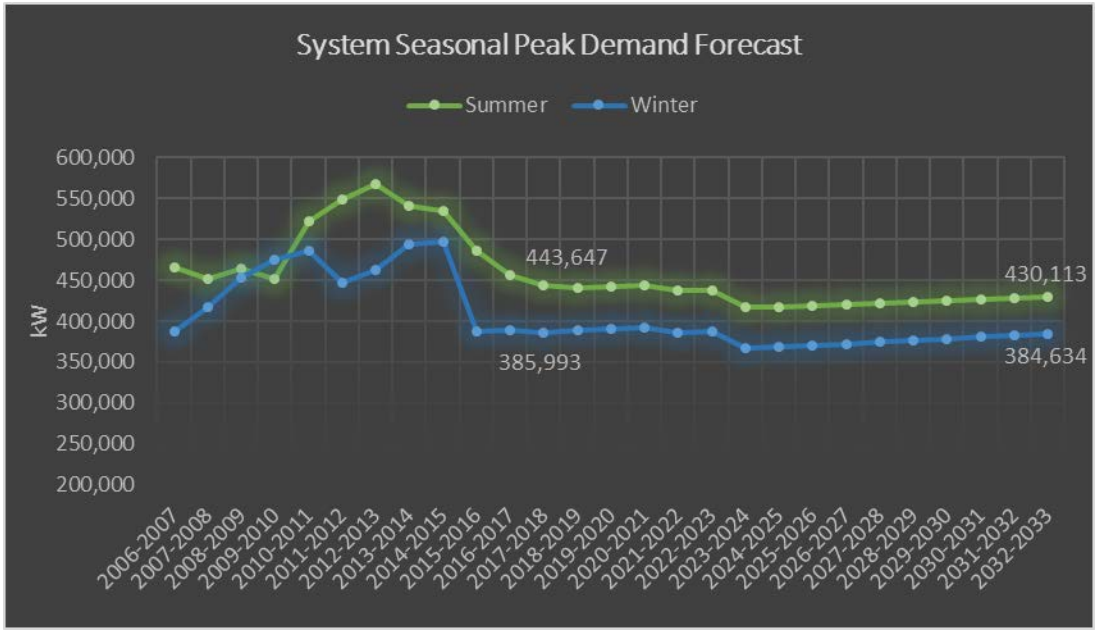


Figure V-14

As shown in *Figure V-15*, the system energy requirement is higher in winter than in summer. For the period 2017 to 2032, the system energy requirement in summer will decrease from 1,065,560 MWh to 1,051,079 MWh, and the system energy requirement in winter will also decrease from 1,138,325 MWh to 1,114,724 MWh.

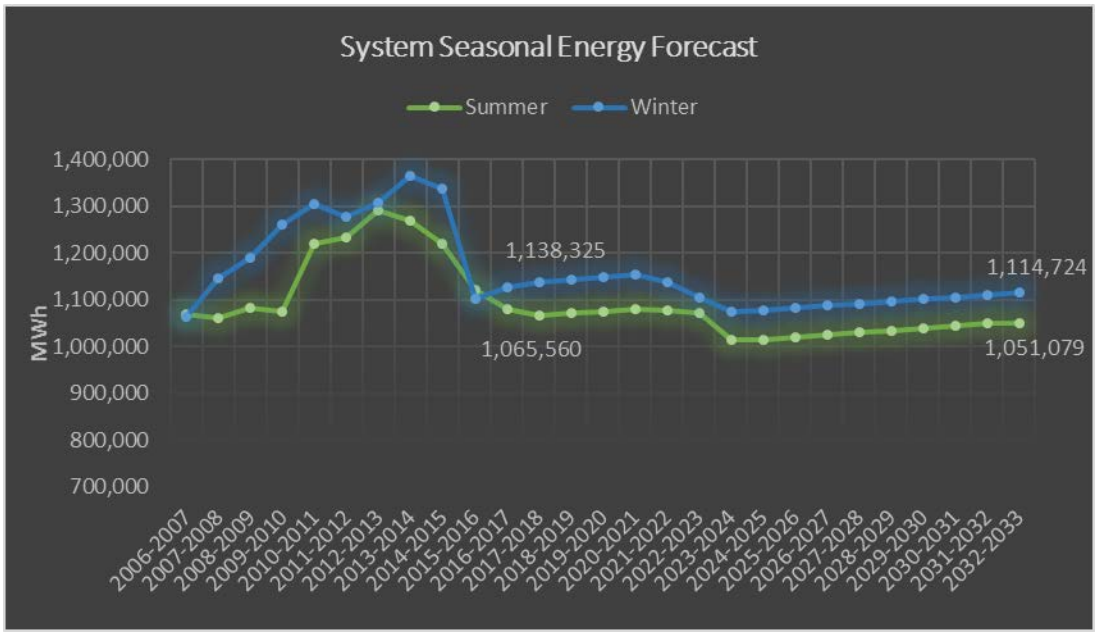


Figure V-15

As shown in *Figure V-16*, MEAN's total annual energy requirement will decrease from 2,203,885 MWh in 2017 to 2,165,803 MWh in 2032.

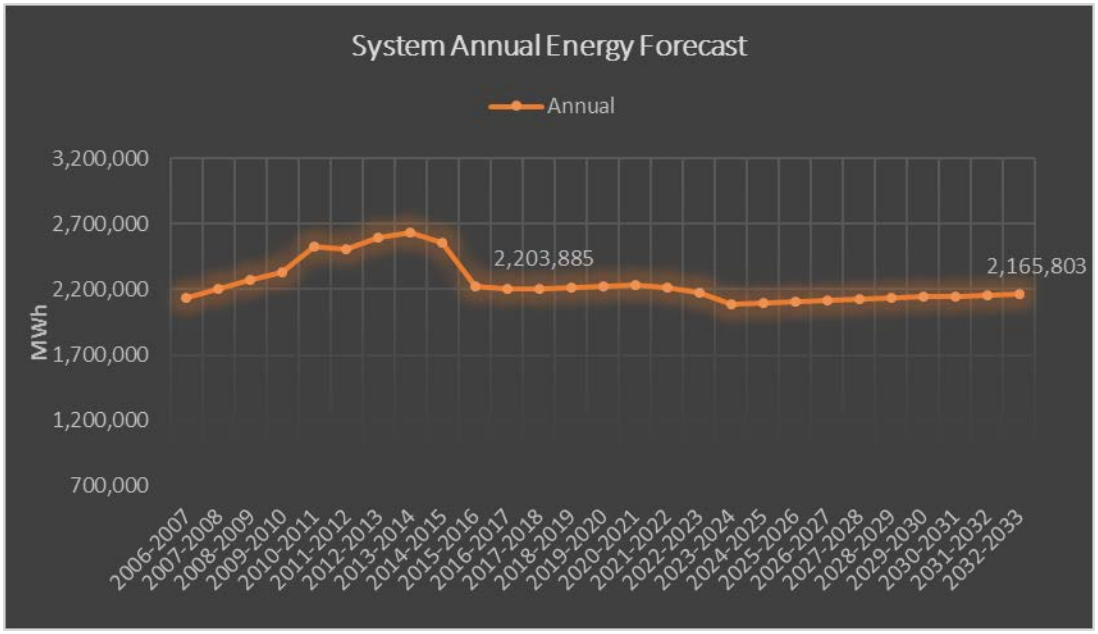


Figure V-16

H. Reserves and Transmission Losses

MEAN must maintain capacity to serve not only the forecasted load in each region, but the total resource obligation which adds to the peak demand a reserve margin and transmission losses.

1. Reserve Margin

The SPP and MISO market constructs require each load serving entity to maintain a designated percentage of reserve capacity in addition to the entity's forecasted peak load.

In SPP, the established required Capacity Margin is 12%. However, a tariff modification is being considered by FERC to replace this with a 12% Planning Reserve Margin, which translates to a 10.7% Capacity Margin. In SPP, Capacity Margin shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.

In MISO, the required Planning Reserve Margin (*"PRM"*) is calculated such that the Loss of Load Expectation for the next planning year is one day in 10 years. The minimum amount of capacity above Coincident Peak Demand in the MISO region required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region. For the 2017/18 planning year, the PRM is 15.8%. As the MISO definition of the PRM is specific to the operation of the upcoming year, the PRM changes annually.

For loads and resources in the west, there is no prescribed reserve margin. MEAN incorporates a 12% reserve margin in addition to forecasted load when determining the load and resource balance in the west.

MEAN adds the required margins to the forecasted peak demand to determine the total obligation for service in each region.

2. Transmission Losses

MEAN's total obligation for service must also include the losses that occur throughout the transmission system. The rate of loss depends on the transmission system, and is typically reported to MEAN on an annual basis. However, MEAN does not have to provide for transmission loss on WAPA allocations. Therefore, this amount is deducted from the calculations. In total, MEAN serves network load on six transmission systems.

VI. System Resources

A. Summary

The Power Supply System consists of owned, leased and purchased power supply resources as well as transmission system arrangements used to transmit resources to the Total Requirements Participants. MEAN receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnected System (the *"Western Interconnection"*).

MEAN adheres to a strategic and integrated resource plan that includes a variety of resources providing stable and economical power and energy to the Participants. MEAN has a policy in place which endeavors to have no more than 15% of MEAN's capacity from a single generating unit. In the event that a generation unit does represent more than 15% of MEAN's capacity, MEAN will investigate potential exchanges or insurance products to reduce the potential cost impacts and disruption of service that could be caused by a major unit outage. The Risk Management Committee and the Power Supply Committee will continue to evaluate this policy as the MEAN portfolio evolves to ensure that it still reflects participant goals and provides adequate protection to MEAN's financial position.

Figure VI-1 summarizes MEAN's long-term power supply resources as of the date of this report:

Resource	MEAN Nameplate Capacity	Primary Energy Source	Market Region[(1)]	% of Capacity
Total Requirements Committed Facilities (Participant Owned Generation)	136 MW	Oil/Gas	MISO (77 MW), SPP (47 MW), WEST (12 MW)	22.9%
WAPA[(2)]	124.5 MW	Hydroelectric	MISO (7.5 MW), SPP (30 MW), WEST (87 MW)	21.0%
Whelan Energy Center Unit 2[(3)]	82 MW	Coal	SPP	13.8%
Walter Scott Energy Center Unit 4	59 MW	Coal	MISO	10.0%
NPPD Multi-Unit Participation	50 MW	Coal/Nuclear	SPP	8.4%
Laramie River Station Unit 1	9 MW	Coal	SPP	1.5%
Laramie River Station Unit 2 & Unit 3	19 MW	Coal	WECC	3.2%
Wygen Unit I	20 MW	Coal	WECC	3.4%
Neil Simpson Unit 2	10 MW	Coal	WECC	1.7%
Wygen Unit III	10 MW	Coal	WECC	1.7%
Wind Project at Kimball[(4)]	10.5 MW	Wind	WECC	1.8%
Wessington Springs Wind Project	10 MW	Wind	SPP	1.7%
NPPD Elkhorn Ridge Wind Plant	8 MW	Wind	SPP	1.3%
NPPD Laredo Ridge Wind Project	8 MW	Wind	SPP	1.3%
Louisa Generating Station	8 MW	Coal	MISO	1.3%
DMEA Shavano Falls/Drop 4 & Drop 6	7.6 MW	Hydroelectric	WECC	1.3%
NPPD Ainsworth Wind Energy Facility	7 MW	Wind	SPP	1.2%
Whelan Energy Center Unit 1	5.3 MW	Coal	SPP	0.9%
Waste Management Landfill Gas Facility	4.8 MW	Landfill Gas	MISO	0.8%
NPPD Crofton Bluffs Wind Project	4.2 MW	Wind	SPP	0.7%
TOTAL	592.9 MW			

(1) Resources located in MISO and SPP are dispatched by MISO and SPP.

(2) Comprised of approximately 109.5 MW of participant allocations, 6.7 MW of MEAN allocation, and 8.0 MW of Kansas Tribal allocation.

(3) Comprised of MEAN's Entitlement Share under its Participation Agreement with PPGA (80 MW) and purchase from Hastings Utilities (currently 2 MW). Under a power sales agreement dated June 9, 2008, between Hastings Utilities and MEAN, Hastings Utilities has agreed to sell capacity and associated energy from its Entitlement Share under its Participation Agreement with PPGA at cost through April 2018.

(4) Existing 10.5 MW Kimball Wind Farm owned by MEAN is being replaced by a PPA for energy output of a 30 MW wind farm at the same location. Commercial operating date is projected to be in Q1 2018.

Figure VI-1

The table in *Figure VI-2* shows the amounts of energy obtained by MEAN from its principal power supply resources (in Gigawatt-hours and as percentages of MEAN's total power supply), for MEAN'S last five fiscal years:

ENERGY SUPPLY FOR FISCAL YEAR ENDED MARCH 31
(GWH AND % OF TOTAL)

	2017		2016		2015		2014		2013	
Participant Owned Generation	1.4	0.1%	1.2	0.0%	1.3	0.0%	2.5	0.1%	1.7	0.1%
WAPA[1]	187.8	7.7%	200.7	7.3%	222.7	7.2%	218.6	7.0%	287.6	9.2%
Whelan Energy Center Unit 2[2]	349.8	14.4%	460.1	16.7%	446.7	14.5%	576.9	18.5%	536.9	17.2%
Walter Scott Jr. Energy Center Unit 4[3]	259.8	10.6%	405.1	14.7%	379.5	12.3%	413.0	13.3%	413.7	13.3%
NPPD Multi-Unit Participation	320.3	13.1%	345.8	12.5%	352.8	11.4%	405.3	13.0%	365.8	11.8%
Laramie River Station	188.7	7.7%	186.4	6.7%	170.2	5.5%	200.7	6.5%	188.9	6.1%
Wygen Unit I	167.9	6.9%	175.7	6.4%	175.2	5.7%	164.4	5.3%	159.9	5.1%
Wygen Unit III and Neil Simpson Unit 2	171.8	7.0%	170.9	6.2%	238.5	7.7%	257.0	8.3%	245.0	7.9%
Wind Project at Kimball	8.7	0.4%	19.8	0.7%	27.5	0.9%	30.1	1.0%	30.3	1.0%
Wessington Springs Wind Project	42.4	1.7%	39.2	1.4%	41.7	1.4%	42.2	1.4%	39.1	1.3%
NPPD Elkhorn Ridge Wind Plant	25.7	1.1%	25.5	0.9%	26.5	0.9%	27.1	0.9%	26.7	0.9%
NPPD Laredo Ridge Wind Project	32.6	1.3%	31.6	1.1%	34.4	1.1%	36.5	1.2%	34.9	1.1%
Louisa Generating Station	42.0	1.7%	36.4	1.3%	54.6	1.8%	49.8	1.6%	57.6	1.9%
DMEA Shavano Falls/Drop 4 & 6[4]	30.0	1.2%	23.4	0.8%	-	-	-	-	-	-
NPPD Ainsworth Wind Energy Facility	20.7	0.8%	21.3	0.8%	23.2	0.8%	24.0	0.8%	20.1	0.6%
Whelan Energy Center Unit 1	18.9	0.8%	16.3	0.6%	25.0	0.8%	29.1	0.8%	29.6	0.9%
Waste Management Landfill Gas Facility[5]	38.8	1.6%	38.8	1.4%	39.2	1.2%	3.6	0.1%	-	-
NPPD Crofton Bluffs Wind Project[6]	17.4	0.7%	17.3	0.6%	17.8	0.6%	17.6	0.6%	6.7	0.2%
All Others[7]	515.8	21.2%	546.8	19.9%	809.3	26.2%	612.5	19.6%	663.9	21.4%
TOTAL	2,440.7	100.0%	2,762.3	100.0%	3,086.1	100.0%	3,110.9	100.0%	3,108.4	100.0%

(1)Comprised mostly of Participant allocations with respect to which MEAN serves only as agent.

(2)Includes MEAN's participation in Public Power Generation Agency (PPGA) and power sales agreement between MEAN and Hastings Utilities.

(3)Includes MEAN ownership interest and assignment from Waverly Utilities.

(4)Began commercial operation in May 2015.

(5)Began commercial operation in March 2014.

(6)Began commercial operation in November 2012.

(7)Includes economy and short term firm purchases.

Figure VI-2

B. Description of Resources

Participant Owned Generation.



By execution of the ERPA and a firm power service agreement under the applicable service schedule, 19 Total Requirements Participants commit to MEAN all of the output of all existing compliant generation facilities owned by them for the common benefit of the Total Requirements Participants, except the power and energy generated by three hydroelectric plants owned or contracted by Aspen, Colorado, and by three hydroelectric plants and three wind turbines owned by Waverly Utilities. The aggregate capacity of the generating facilities that the Total Requirements Participants have committed to MEAN (the "Participant Owned Generation") under the ERPA as of the date of this report is 136 MW. All of Participant Owned Generation units are fueled by natural gas and/or fuel oil.

Under the ERPA, each of these Total Requirements Participants is required, upon MEAN's request, to supply to MEAN the total committed capacity of its Participant Owned Generation. Each such Total Requirements Participant is required to maintain its Participant Owned Generation in good operating condition. The MEAN Board voted at the May quarterly meeting to approve a new requirement for Participants to exercise the Participant Owned Generation at least quarterly, with MEAN paying for the fuel consumed during these exercises. Scheduled outages must be coordinated with MEAN. Each Total Requirements Participant retains the right to retire its Participant Owned Generation from service with proper notice as defined in the ERPA.

The Participant Owned Generation units are primarily electric generators that are located within the service areas of the Total Requirements Participants. Three facilities totaling 77 MW of nameplate capacity are located in MISO. Fourteen facilities totaling 47 MW of nameplate capacity are located in SPP. Three facilities totaling 12 MW of nameplate capacity are located in the Western Interconnect. The hydroelectric and wind generating facilities owned by Aspen, Colorado and Waverly Utilities as described above are not Participant Owned Generation under the Participant's ERPA but are part of the respective Participant's overall resource mix as exceptions to the general rule of leasing all power production back to MEAN as part of the Long-Term Power Supply Contracts.

Western Area Power Administration.

WAPA is one of four power marketing administrations within the U.S. Department of Energy. WAPA's role is to market and transmit wholesale electricity from multi-use water projects. WAPA's service area encompasses a 15-state region of the central and western U.S. where WAPA's more than 17,000 circuit mile transmission system carries electricity from 56 hydropower plants operated

by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. WAPA also markets power from the Navajo Generating Station coal-fired plant near Page, Arizona. Together, these plants have an installed capacity of 10,504 megawatts. WAPA sells power to preference customers such as federal and state agencies, cities and towns, rural electric cooperatives, public utility districts, irrigation districts and Native American tribes. These entities provide retail electric service to millions of consumers in the West.



MEAN has an allocation from the U.S. Department of Energy, through WAPA, of firm power under contract from Loveland Area Projects hydroelectric plants of approximately 7 MW. MEAN recently executed an extension of this contract through 2054.

MEAN has entered into Benefit Crediting Agreements with WAPA and four Native American Tribes. Under these Agreements MEAN manages the allocations which represent 8 MW from the Loveland Area Projects. MEAN receives the energy from WAPA in exchange for providing a financial credit to the tribes.

MEAN has also signed a Capacity and Energy Displacement Agreement ("WAPA Displacement Agreement") whereby WAPA provides to MEAN additional allocations of approximately 62 MW of capacity and 237,097 MWh of energy in the LAP footprint, and MEAN provides equivalent capacity and energy to WAPA eastern interconnection customers in Nebraska and Kansas. MEAN commits 46 MW of behind-the-meter participant owned generation and 16 MW of capacity from Cooper Nuclear Station ("NPPD Multi-Unit Participation Agreement") to the WAPA Displacement Agreement.

The Total Requirements Participants have allocations through WAPA totaling approximately 109.5 MW. Electric capacity and energy generated by WAPA has been and continues to be a low cost capacity and energy resource for the Total Requirements Participants. WAPA reviews its energy rates annually to ensure that such rates generate sufficient revenues to cover its operating and other expenses.

MEAN acts only as an agent with respect to Participant WAPA allocations. MEAN provides these services on a cost pass-through basis to the Total Requirements Participants and has no beneficial interest in the Total Requirements Participants' power allocations as the power allocations are retained by the Total Requirements Participants, and the Total Requirements Participants are financially responsible for paying all costs associated with their power allocation(s). MEAN has contracted to collect payments for WAPA capacity and energy purchased by certain Total Requirements Participants and remits these payments to WAPA. Since MEAN is only acting as an agent, these amounts are not reflected as revenue or expense in MEAN's financial statements.

Participants receiving WAPA allocations are located in the WAPA Rocky Mountain Region ("RMR") Marketing Area, the WAPA Upper Great Plains ("UGP") Marketing Area, and the WAPA Colorado River Storage Project ("CRSP") Management Center. The WAPA UGP Marketing Area contracts extend until December 2020. A thirty-year term extension of the UGP contracts has been proposed by WAPA through its 2021 Power Marketing Initiative. Existing allocation contracts in the RMR Marketing Area, which serves customers with power from the Loveland Area Projects ("LAP"),

extend until September 2024. The Rocky Mountain 2025 Power Marketing Initiative proposes to extend the LAP Firm Electric Service contracts for 30 years beyond the current expiration date. Existing allocation contracts in the CRSP Management Center, which serves customers with power from the Salt Lake City Area ("SLCA") integrated projects, extend until September 2024. Through the CRSP 2025 Power Marketing Plan, WAPA has proposed an extension of 40 years from the date of contract execution for SLCA customers.

Whelan Energy Center Unit 2.



MEAN is a participant in the Public Power Generation Agency ("PPGA") which was created solely for the purpose of owning, financing, acquiring, constructing and operating the Whelan Energy Center Unit 2 ("WEC2"). WEC2 is a nominally rated 220 MW pulverized coal-fired steam electric generating facility and related electric interconnection, transmission, rail car storage, and other facilities located near Hastings, Nebraska. Its commercial operation began in May, 2011. The unit includes pollution control equipment, a cooling tower, water treatment facilities, material storage facilities, control and administrative buildings, and other ancillary facilities. The unit is connected to the regional transmission grid through a network of 115 kV transmission lines. Hastings Utilities is the operating agent for WEC 2.

MEAN holds a 36.36% Entitlement Share of WEC2 representing approximately 80 MW of output of WEC2. Under its Participation Agreement with PPGA, MEAN has agreed to pay a corresponding percentage of all of PPGA's costs of owning and operating WEC2, including debt service on PPGA's bonds, regardless of whether or not WEC2 or any portion thereof is completed, operable, or operating, and notwithstanding suspension, interruption, interference, reduction or curtailment of the WEC2 output or services of the WEC2. Payments to PPGA pursuant to the Participation Agreement are included in MEAN's operating expenses. In addition to MEAN's Entitlement Share under its Participation Agreement with PPGA, under a power sales agreement dated June 9, 2008, between Hastings Utilities and MEAN, Hastings Utilities has agreed to sell capacity and associated energy from its Entitlement Share under its Participation Agreement with PPGA at cost through April 2018. Hastings Utilities retains primary responsibility under its Participation Agreement for payment of all amounts due to PPGA with respect to its full Entitlement Share. The amount of project output sold under the power sales agreement is currently 5 MW and decreases to 2 MW on May 1, 2017.

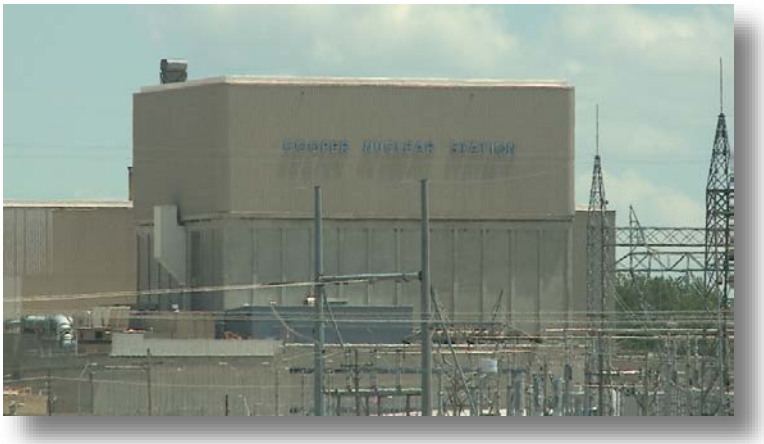
Walter Scott, Jr. Energy Center Unit 4.



MEAN entered into a Joint Ownership Agreement with MidAmerican Energy Company ("MEC") and other entities to develop, design, construct, own and operate Walter Scott, Jr. Energy Center Unit 4 ("WSEC 4"), a 790 net MW super-critical, coal-fired steam electric generating plant fueled with low-sulfur coal located near the city of Council Bluffs, Iowa. The plant began commercial operation in June 2007. MEC is the majority owner, developer and operator of WSEC4. MEAN originally owned an undivided 6.67% interest in WSEC4. In 2012, MEAN acquired an additional 0.25% interest in WSEC4, for a total undivided interest of 6.92%, or 56 MW. In addition, Waverly Utilities granted MEAN a partial assignment of Waverly Utilities' interest in WSEC4, which includes rights to receive 0.4% (approximately 3 MW) of the output from WSEC4 and continues through the term of Waverly Utilities' Long-Term Power Supply Contract with MEAN.

MEAN's ownership interest and partial assignment of interest in WSEC4 provides MEAN with approximately 59 MW of capacity and energy, providing MEAN with a long-term, cost-based source of power and energy.

Nebraska Public Power District Multi-Unit Participation.



MEAN and NPPD entered into a Multi-Unit Participation Agreement that became effective January 1, 2011 (the "NPPD Agreement"). Under the NPPD Agreement, NPPD provides MEAN with 50 MW of capacity and related energy. NPPD's obligation to deliver capacity and related energy to MEAN pursuant to the NPPD Agreement is contingent on availability and operation of NPPD's Gerald Gentleman Station Units No. 1 (12 MW) and No. 2 (12 MW) located near Sutherland, Nebraska, and NPPD's Cooper Nuclear Station (26 MW) located near Brownville, Nebraska. The NPPD Agreement is effective through December 31, 2023. In the event NPPD and MEAN participate in the same new baseload generation unit prior to December 31, 2023, MEAN has the right, but not the obligation, to terminate the NPPD Agreement upon the commercial operation of such unit.

Laramie River Station.



In 1982, MEAN and Lincoln Electric System ("LES") entered into two agreements (the "Laramie River Agreements") which collectively provide for the sale to MEAN of a portion of LES's undivided interest in the Laramie River Electric Generating Station ("Laramie River Station") and an associated transmission system. Laramie River Station is a coal-fired steam-electric generating station that consists of three units totaling 1,697 MW. It is located in Platte County, Wyoming on the Laramie River and is owned by LES and five other utilities, as tenants in common. The three units of the Laramie River Station began commercial operation in 1980 and 1982. MEAN began making purchases of electric power and energy under its original agreement with LES on June 1, 1982. MEAN's total interest in Laramie River Station is 1.67% or 28 MW. Basin Electric Power Cooperative operates and maintains the Laramie River Station.

MEAN pays to LES: (1) MEAN's proportionate share of operation and maintenance costs, capital improvements, repairs, administrative costs, and all other fixed costs relating to ownership interest in Laramie River Station; (2) the costs related to the production of energy in proportion to the energy scheduled and produced from Laramie River Station for MEAN during each month; and (3) any costs incurred by LES directly related to the scheduling and dispatching of MEAN's power and energy generated by Laramie River Station. Laramie River Station Unit 1 is dispatched by SPP while Laramie River Station Unit 2 and Unit 3 are in the Western Interconnection.

Under a Displacement Contract dated as of July 1, 1986, between MEAN and Basin Electric Power Cooperative, MEAN receives scheduling and delivery rights in the Western Interconnection for Laramie River Station's West Side units (known as "West Allotment") and delivery rights in the associated transmission system. MEAN's West Allotment entitles MEAN to schedule and deliver up to 8.3% of the LES entitlement of power and energy from Laramie River Station.

Wygen Unit I.

In 2009, MEAN acquired an undivided 23.5% interest in the Wygen Unit I which provides MEAN approximately 20 MW of capacity and energy. The Wygen Unit I, located in Campbell County, Wyoming, near the town of Gillette, is an approximately 85 MW coal-fired electric generating plant fueled with low-sulfur Powder River Basin Coal. Wygen I is collocated with the Wyodak coal mine, which supplies fuel to the plant. Black Hills Wyoming, Inc. developed, designed, constructed and operates the Wygen Unit I, which began commercial operation in February 2003, and owns the remaining 76.5% of the Wygen Unit I.

Neil Simpson Unit 2 and Wygen Unit III.

MEAN has entered into a Power Purchase Agreement with Black Hills Power, Inc. ("Black Hills Power") that became effective April 1, 2010. The Power Purchase Agreement is unit contingent on Neil Simpson Unit 2 and Wygen Unit III. Under the Power Purchase Agreement, Black Hills Power will provide MEAN with the capacity and related energy output in the following amounts:



CONTRACT YEAR	CAPACITY (MW)
4/1/2010 – 5/31/2018	20 MW (10 MW from Wygen Unit III and 10 MW from Neil Simpson Unit 2)
6/1/2018 – 5/31/2020	15 MW (10 MW from Wygen Unit III and 5 MW from Neil Simpson Unit 2)
6/1/2020 – 5/31/2022	12 MW (6 MW from Wygen Unit III and 6 MW from Neil Simpson Unit 2)
6/1/2022 – 5/31/2023	10 MW (5 MW from Wygen Unit III and 5 MW from Neil Simpson Unit 2)

Louisa Generating Station.

MEAN purchases the power and energy associated with Waverly Utilities' interest in the Louisa Generating Station, a coal-fired generating unit which began commercial operation in October 1983. The power sales agreement includes rights to receive 1.1% or approximately 8 MW of the output from the Louisa Generating Station and continues for the term of Waverly Utilities' Long-Term Power Supply Contract.



Delta-Montrose Electric Association Shavano Falls/Drop 4 and Drop 6.

MEAN entered into a 22-year power purchase agreement with Delta-Montrose Electric Association ("DMEA") for the purchase of renewable hydro energy from the Shavano Falls hydro project. MEAN's share of the project includes 2.8 MW from Drop 6 and 4.8 MW from Drop 4. The project began commercial operation in May 2015.



Whelan Energy Center Unit 1.

Pursuant to the Participation Power Sales Agreement between MEAN and the City of Hastings, Nebraska, MEAN purchases 6.95%, or approximately 5.3 MW, of the electric power and energy generated by Whelan Energy Center Unit 1, a 77 MW coal-fired steam electric generating station operated by Hastings Utilities and located in Adams County, Nebraska (the "Whelan Energy Center"). The Participation Power Sales Agreement terminates on the later of the date of (i) the final maturity of the indebtedness incurred by Hastings to pay the costs of the Whelan Energy Center or capital additions thereto, which date is now January 1, 2019, or (ii) the date Hastings removes the Whelan Energy Center and/or its associated transmission system from commercial operation.



Waste Management Des Moines Landfill Gas Facility.

MEAN has entered into a long term Power Purchase Agreement with Waste Management for the total output of the facility, which has 4.8 MW total nameplate capacity, until March 2034.



Wind Resources.



The following is a summary of MEAN's owned or purchased wind resources:

- *Wind Project at Kimball.*

MEAN previously owned and operated a 10.5 MW wind project located near Kimball, Nebraska, which began commercial operation on October 1, 2002. This project is scheduled to be decommissioned during the summer of 2017. MEAN has signed a 20-year Purchase Power Agreement with Kimball Wind LLC to purchase the energy output of a new 30 MW wind farm to be constructed on the same and adjacent site. The new wind farm is scheduled for commercial operation in January 2018.

- *Wessington Springs Wind Project.*

Heartland Consumers Power District purchases all the output of the 51.15 MW Wessington Springs Wind Project and resells 19.55% (10 MW) of the output to MEAN under the agreement, which expires February 2029.

- *NPPD Elkhorn Ridge Wind Plant.*

MEAN purchases from NPPD 10.0% of the output of the Elkhorn Ridge Wind Plant, or approximately 8 MW of the 80 MW nameplate capacity, under a contract ending March 2029.

- *NPPD Laredo Ridge Wind Project.*

MEAN purchases from NPPD 10.0% of the output of the Laredo Ridge Wind Project, or approximately 8 MW of the 80 MW nameplate capacity, under a contract ending February 2031.

- *NPPD Ainsworth Wind Energy Facility.*

MEAN purchases from NPPD 11.78% of the output of the Ainsworth Wind Energy Facility, or approximately 7 MW of 60 MW nameplate capacity, under a contract ending October 2025 which may be extended for terms of 5 years each or until the end of the operational life of the facility.

- *NPPD Crofton Bluffs Wind Project.*

MEAN purchases from NPPD 10.0% of the output of the Crofton Bluffs Wind Project, or approximately 4.2 MW of 42 MW nameplate capacity, under a contract ending November 2032.

Market Purchases.

MEAN utilizes a combination of short term purchases and medium to long term resources with sufficient capability to meet MEAN's load and reserve obligations. MEAN enters into purchase and sale transactions in the MISO, SPP and WECC markets.

Ruedi/Maroon Creek



The City of Aspen, Colorado owns and operates the Ruedi hydroelectric plant under a permit issued by the Federal Energy Regulatory Commission ("FERC") with a rated capacity of 5 MW and a hydroelectric project known as Maroon Creek with a rated capacity of 0.5 MW. These projects are used to supply capacity and energy to Aspen for resale to its customers. MEAN and the City of Aspen have executed an agreement whereby Aspen's energy purchases from MEAN are reduced by the output of Ruedi, and the generation is treated similar to a WAPA allocation. The term of the Ruedi agreement between Aspen and MEAN is concurrent with Aspen's Total Requirements contract with MEAN.

For resource planning purposes therefore, Ruedi and Maroon Creek are counted as resources to credit against Aspen's load.

Ridgway

Aspen has acquired an interest in a portion of the output of the Ridgway Hydropower Project ("Ridgway"). Specifically, Aspen has rights to all of the plant's capacity and energy during the months of October through May. Aspen has assigned to MEAN the exclusive responsibility for scheduling and managing the City's share of the Ridgway output. MEAN uses and schedules 4.5 MW of the Ridgway output as a designated network resource for MEAN's designated network load on the Tri-State transmission system. For resource planning purposes therefore, Ridgway is counted as a resource and included in resource mix allocations. Aspen's contract with Tri-County Water Conservancy District for the Ridgway output extends to 2034.

C. Regional Energy Markets and Coordination

The SPP Integrated Market (*"IM"*), which was launched on March 1, 2014, replaced the Energy Imbalance Service (*"EIS"*) market that SPP had operated since 2007. The IM restructured the EIS market by establishing a day-ahead market along with a real-time energy and operating reserve market. Consolidating 16 balancing authorities into a single SPP-operated balancing authority that was designed to maximize cost-effectiveness of generation and reduce transaction costs. The IM also utilizes locational-marginal pricing, transmission congestion rights, and virtual transactions.

The IM allows generators to submit offers to sell energy and operating reserves. Additionally, it allows load serving entities to submit bids to purchase energy. After day-ahead submissions, SPP clears the offers and bids via security-constrained unit commitment and security-constrained economic dispatch algorithms. A financially binding schedule matches sale offers with demand bids to meet operating reserve requirements.

Financial transmission rights (termed Transmission Congestion Rights (*"TCRs"*) in SPP and Financial Transmission Rights (*"FTRs"*) in MISO) are used to mitigate variances between Location Marginal

Prices (*"LMPs"*) at load locations and LMPs at generation locations due to transmission congestion. Long-Term Congestion Rights (*"LTCRs"*) and Auction Revenue Rights (*"ARRs"*) are awarded to market participants based on firm transmission rights on the SPP network. Transmission congestion rights are automatically converted from awarded LTCRs and can be converted from awarded ARRs.

The SPP IM is the latest and most complex step in SPP's approach to adding market functionality and coordinating next-day generation across the region. The IM maximizes cost-effectiveness, provides participants with greater access to reserve energy, improves regional balancing of electricity supply and demand, and facilitates the integration of renewable resources.

Like SPP, MISO allows generators to submit offers to sell energy and operating reserves and load serving entities to submit bids to purchase energy, after which MISO clears the offers and bids via security-constrained unit commitment and economic dispatch algorithms. The end product is a financially binding schedule that matches sale offers with demand bids and satisfies operating reserve requirements. Similar to SPP, MISO also operates auction revenue rights and a financial transmission rights auction.

MEAN also operates in the western United States through WECC. For operations in WECC, MEAN enters into other agreements and transactions with various electric marketers and power suppliers that are not MEAN Participants pursuant to which such electric utilities may purchase capacity and energy from MEAN or sell capacity and energy to MEAN.

D. Resource Mix by Fuel Type

1. Capacity

When presenting resource mix metrics, resource capacity is listed according to unit nameplate. This is notable in relation to intermittent resources, namely existing wind contracts. "Participant Oil/Gas" represents Participant Owned Generation.

In the west region the majority of the existing capacity, 63%, is provided by WAPA allocations and the WAPA Displacement Agreement. This means only 29% of the west capacity is fossil fueled, from coal resources and participant owned generation, a much lower percentage than in other regions. 8% of capacity in the west is renewable, comprised of wind and hydro. In the 2030 snapshot, the total WAPA capacity decreases dramatically due to the expiration of the WAPA Displacement contract. The coal share also decreases with the termination of the Black Hills PPA. Renewable capacity increases with the replacement of the Kimball Wind Farm. This leaves 21% of the required capacity to be supplied by future resources.

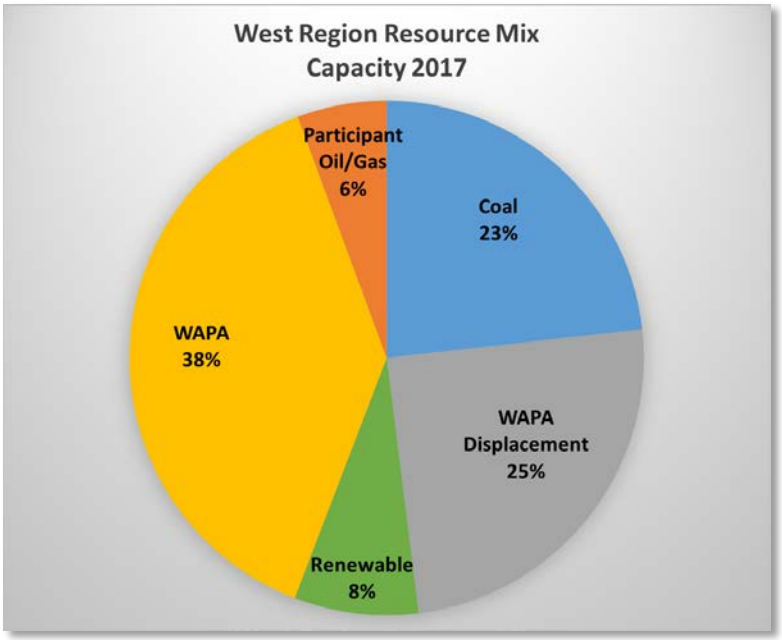


Figure VI-3

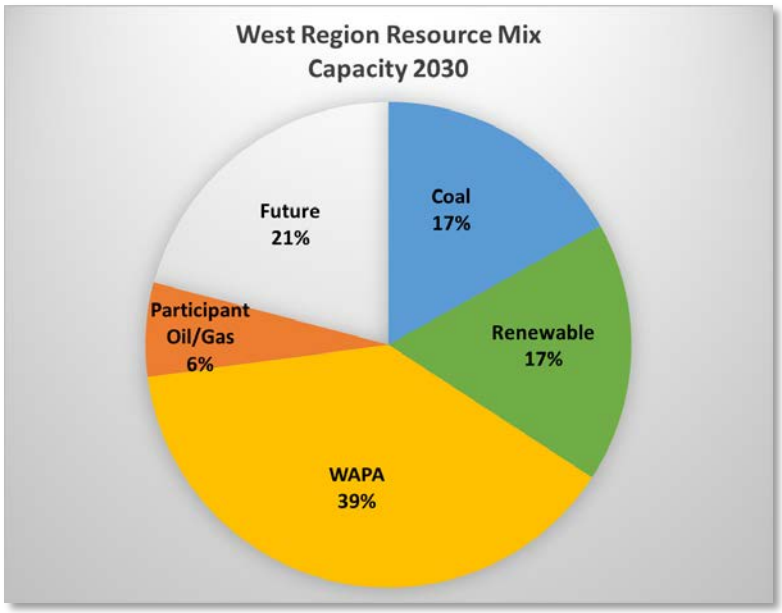


Figure VI-4

SPP capacity is supplied largely by fossil fuel resources. Coal and participant owned generation account for a total of 71% of the capacity in 2017. (This participant owned generation includes 40 MW imported from MISO.) In SPP, WAPA allocations total only 9% of the region's capacity. The wind farms provide renewable capacity of 16%. Lastly, because a portion of Cooper Nuclear Station (included in the NPPD Multi-Unit Participation Agreement) is designated to the WAPA Displacement Agreement, the remainder totals only 4% of the SPP capacity. In 2030, the coal proportion decreases due to the expiration of the NPPD Multi-Unit Participation Agreement. The total of participant owned generation designated to MEAN increases when the WAPA Displacement

Agreement ends and that capacity is no longer used for the Kansas load. Other WAPA allocations see little change, providing 10% of the future capacity. Renewable capacity reduces to only 2% of the total as most of the wind PPAs will have expired by this year. Therefore 17% of the required 2030 capacity must be furnished by future resources.

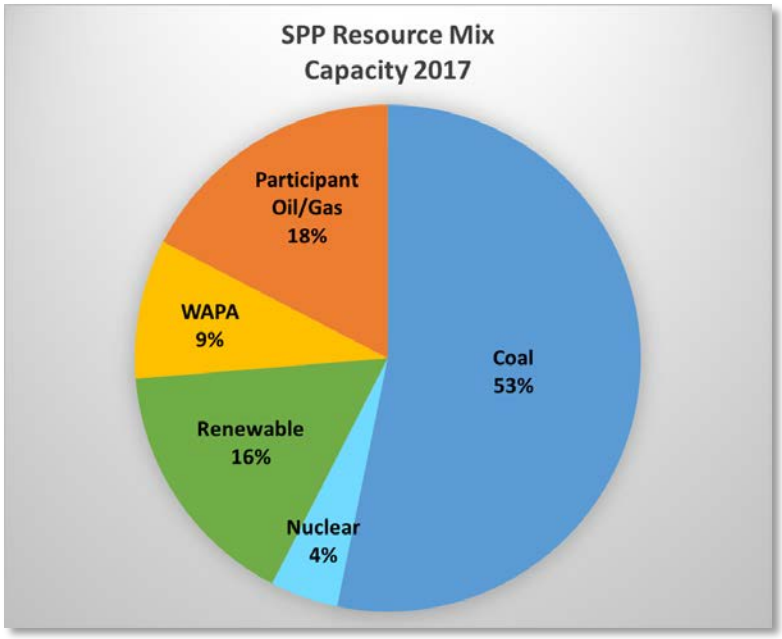


Figure VI-5

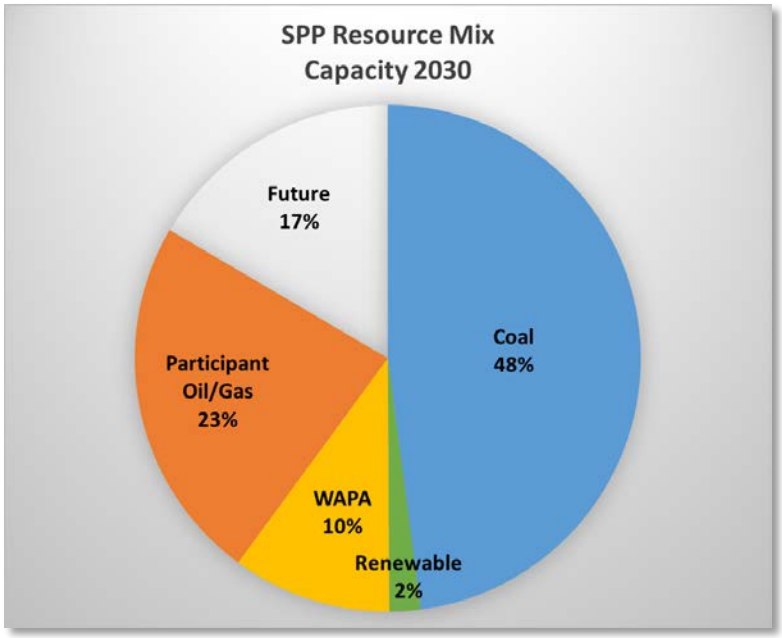


Figure VI-6

With coal at 58% and participant owned generation at 31%, MISO capacity is largely fossil fueled. Only 7% of capacity is provided by WAPA allocations and 4% by renewable resources. This picture changes very little in the future. Behind the Meter Generation accounts for slightly less with minor contract changes. The total in WAPA allocations decreases with the expiration of one of the participant service contracts. MEAN has no resource need in MISO during the study period.

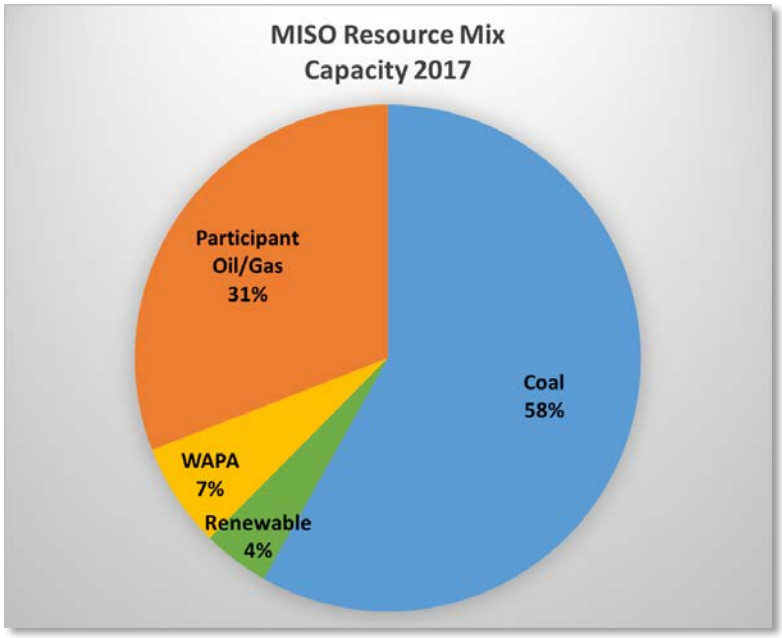


Figure VI-7

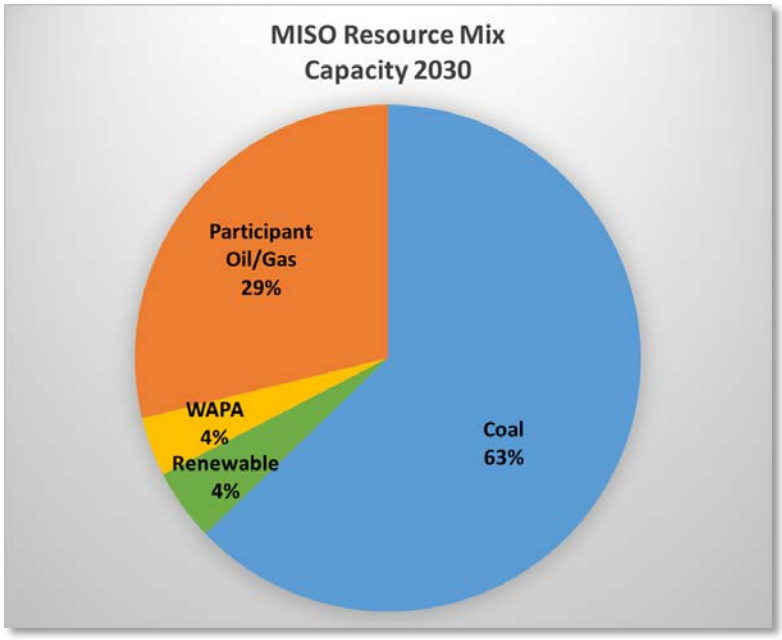


Figure VI-8

In 2017, 57% of MEAN's resource mix is provided by fossil fueled resources, divided between coal and participant owned generation. WAPA allocations and the Displacement agreement supply 31% of the total. Renewable resources, including wind, small hydro, and landfill gas, account for only 10% of MEAN's capacity. 2% of MEAN's mix is nuclear powered. In the future, the percentage of fossil fueled capacity remains at 57%. WAPA power is still at 21%, but the Displacement agreement has expired, and the renewable total is reduced to 9%. In total, 13% of MEAN's required resources in 2030 will be contributed by future resources.

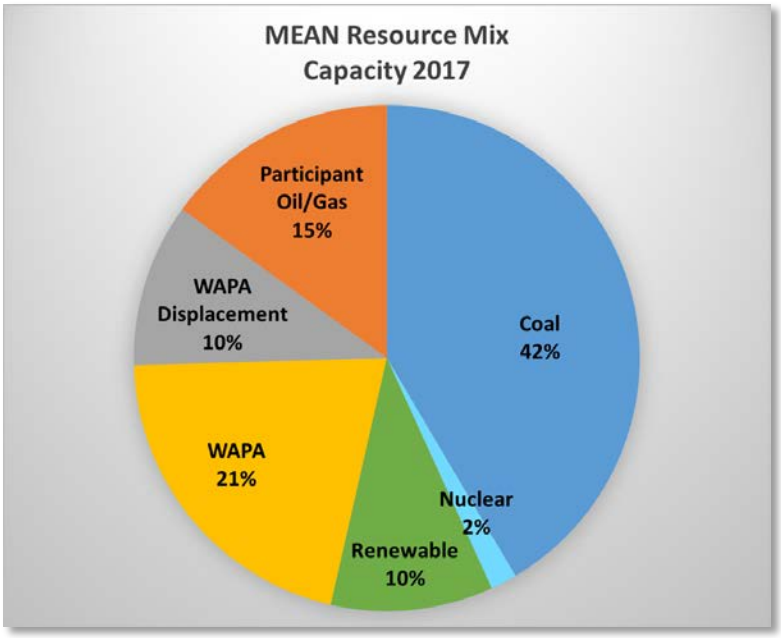


Figure VI-9

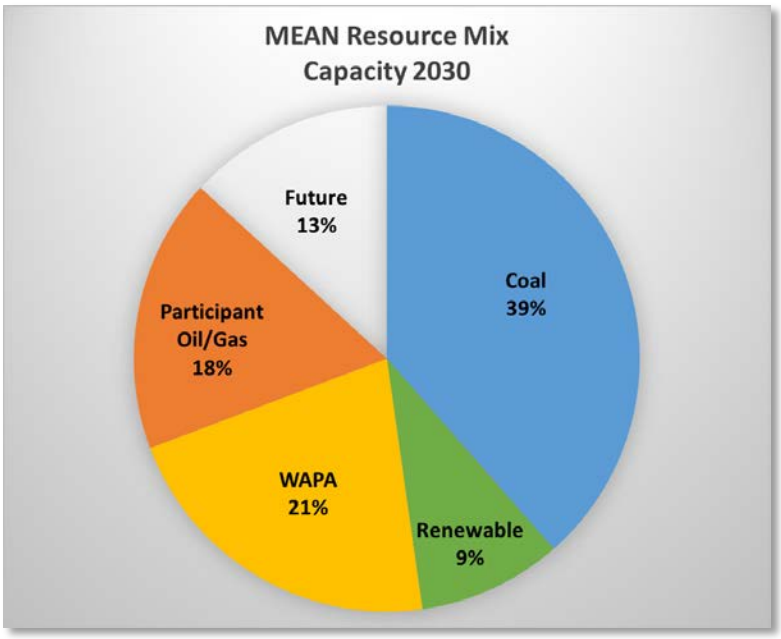


Figure VI-10

2. Energy

In terms of energy, future energy production is based in large part on historical operation as defined by annual capacity factor. In some cases, this value is adjusted due to resources that have recently initiated market dispatch as opposed to self-commitment in the past. As the total resource mix of each market changes, the operation of MEAN's resources may change from the projected profiles.

The energy proportions in the west show the contribution of baseload coal units. Due to the high capacity factor of these units, the 44% of MEAN energy produced by the coal resources is a larger percentage than MEAN's coal capacity. Conversely, WAPA resources operate at a lower capacity factor, and therefore WAPA provides a smaller percentage of energy than capacity. The intermittent nature of renewable resources is also reflected in the low amount of energy produced relative to the capacity. Participant owned generation is generally not called to operate many hours of the year, and therefore does not produce a notable amount of energy. In the future, the energy resource mix in the west looks very balanced between coal, WAPA, and renewables. 23% of future energy needs are to be filled with future resources.

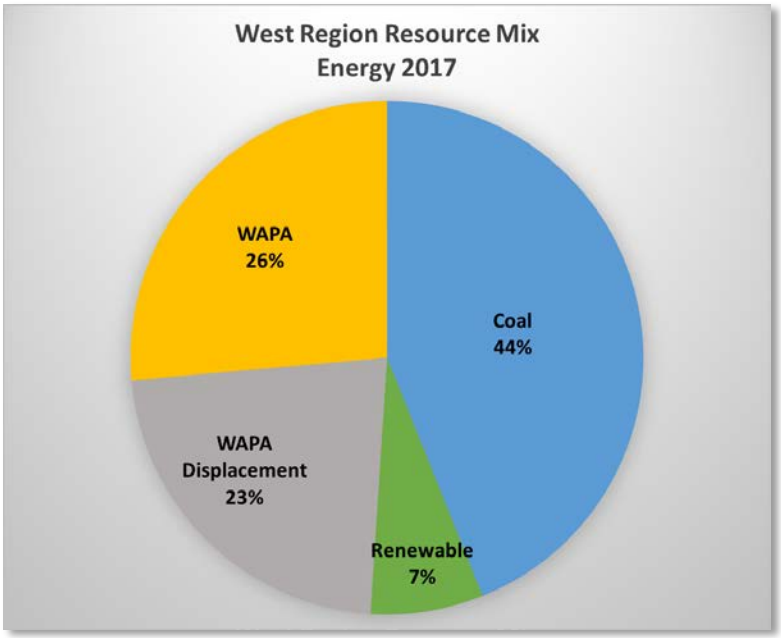


Figure VI-11

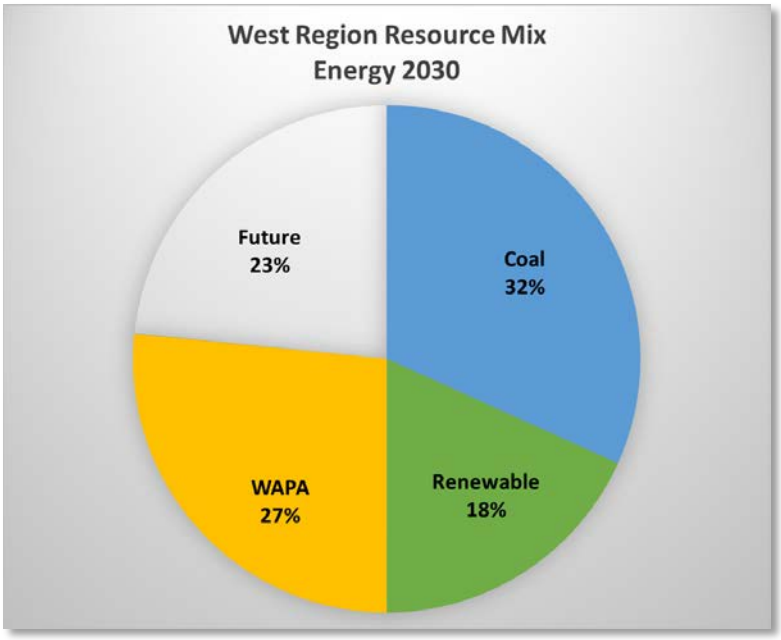


Figure VI-12

The baseload operation of coal and nuclear assets in SPP is evident in the high percentage of energy generated by these units. In total, 81% of MEAN's SPP energy is produced by these resources. WAPA hydro operates at a lower capacity factor as shown by the relative contribution to the total energy at only 7%. The renewable resources in SPP consist of wind turbines, which also achieve a lower annual capacity factor. Again, the behind the meter participant owned generation contributes virtually no energy on an annual basis. In the future, as the nuclear contract is discontinued and the wind PPAs expire, coal generation becomes a larger percentage of the SPP energy. The WAPA energy changes little. The amount of energy to be produced by future resources is approximately 15%.

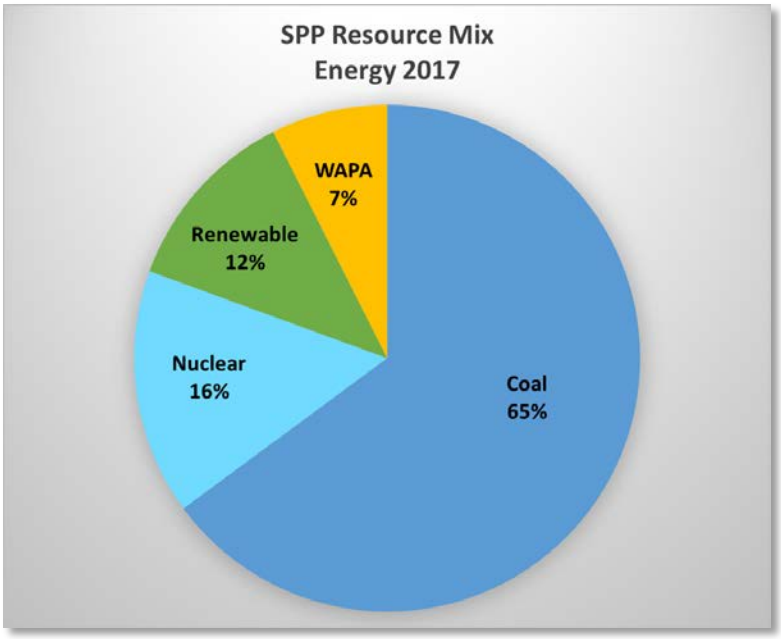


Figure VI-13

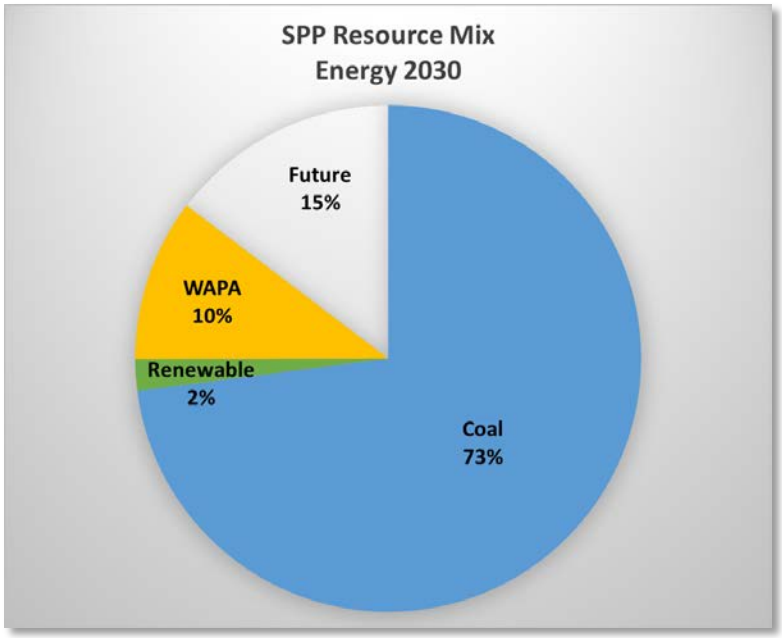


Figure VI-14

In MISO, an overwhelming majority of the MEAN energy generated is sourced from coal units. Only 14% of the total energy comes from non-fossil fueled sources, with 7% from WAPA allocations and 7% from renewables. These values see very little change into the future. The proportion of WAPA allocations decreases with the expiration of one of the participant service contracts. There is no need for energy from future resources.

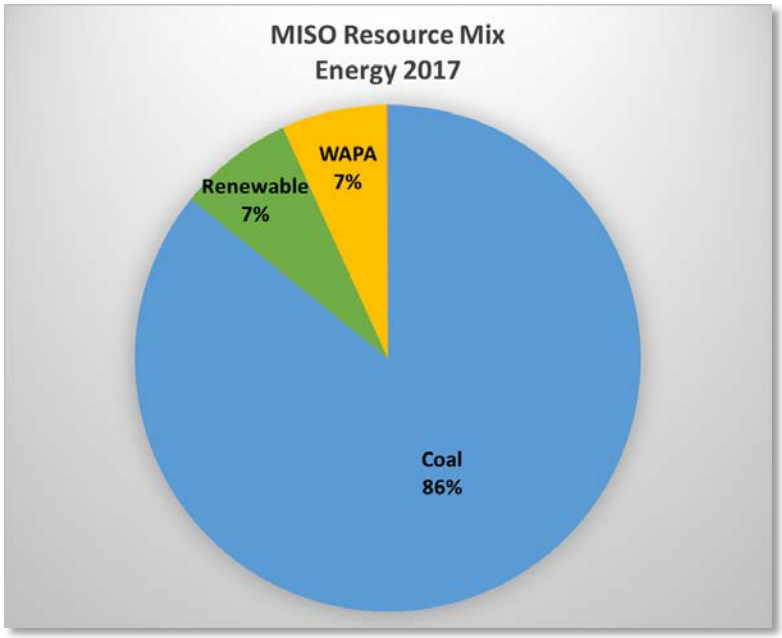


Figure VI-15

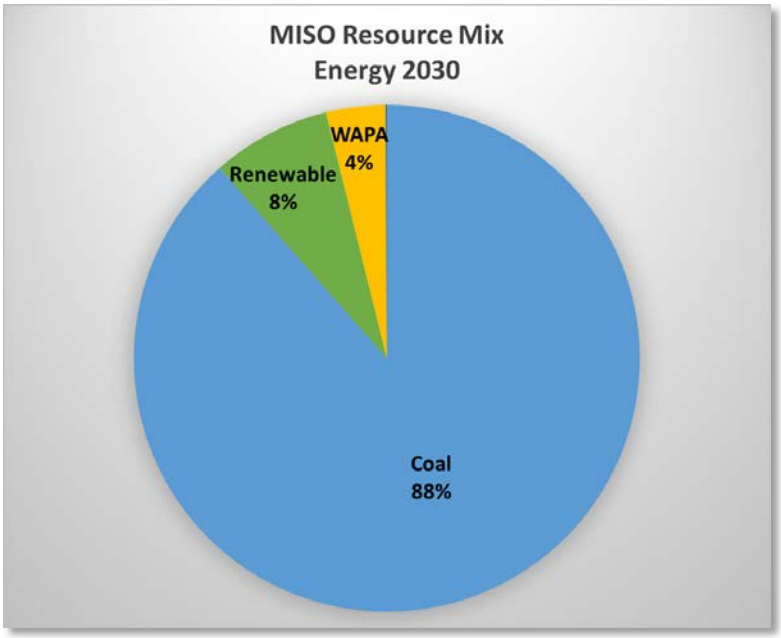


Figure VI-16

MEAN's resource mix in 2017 in terms of energy generation capability shows that the largest contribution comes from coal resources, at 61% of the total. Non-emitting resources make up the remaining 39%. 23% of the total energy is supplied by WAPA allocations and the Displacement agreement, 9% of MEAN's energy is renewable, and 7% is generated by a nuclear resource. Into the future, the energy capability of coal resources increases to 64% of the total, the contribution of WAPA allocations increases to 17%, and the renewable resource percentage increases slightly to 11%. Only 8% of MEAN's total energy must be generated by future resources. However, as energy is generally not transferred between regions, the regional mixes present a more accurate picture of future energy needs.

Again, the future energy mix is a projection based on not only the availability of resources, but the operation based on historical capacity factors and contract energy requirements. Changes in market dynamics and the introduction of an integrated market in the west could substantially alter the actual energy production.

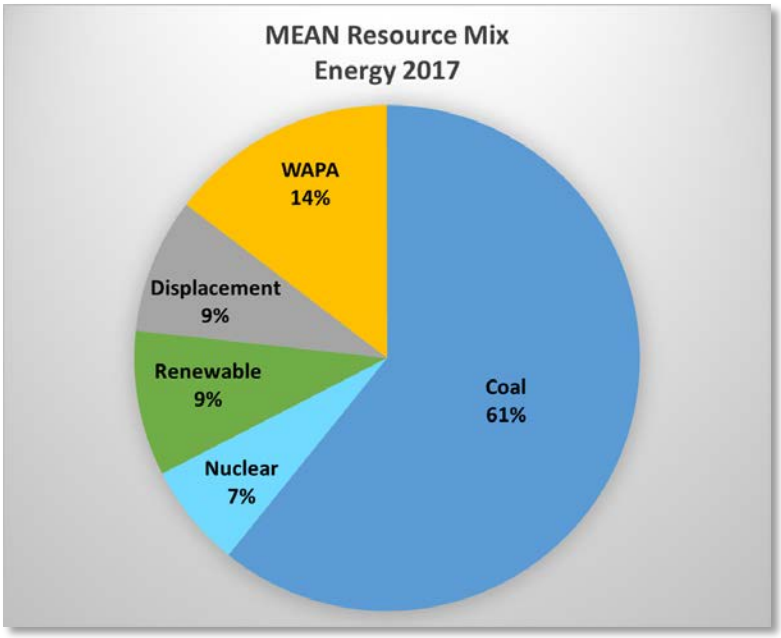


Figure VI-17

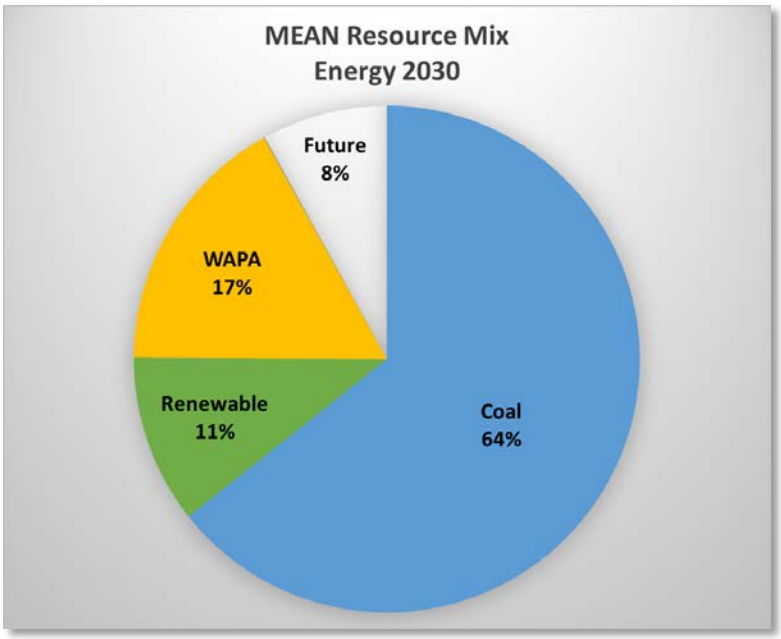


Figure VI-18

E. Resource Mix by Contract Type

MEAN's resource portfolio consists of assets obtained through various contract vehicles. The rights to the capacity and energy of a given unit as well as the way costs are incurred is dependent upon whether the contract is an ownership or a Power Purchase Agreement (*"PPA"*). In addition, WAPA provides allocations that are applied directly to load, separate from ownership or power purchase.

1. Capacity

In terms of nameplate capacity, 34% of MEAN's resource portfolio is controlled through an ownership interest, 22% of the total portfolio is assigned to MEAN as an allocation,

and 29% is contracted via a PPA. For purposes of this illustration, the WAPA Displacement Agreement is considered a Power Purchase Agreement.

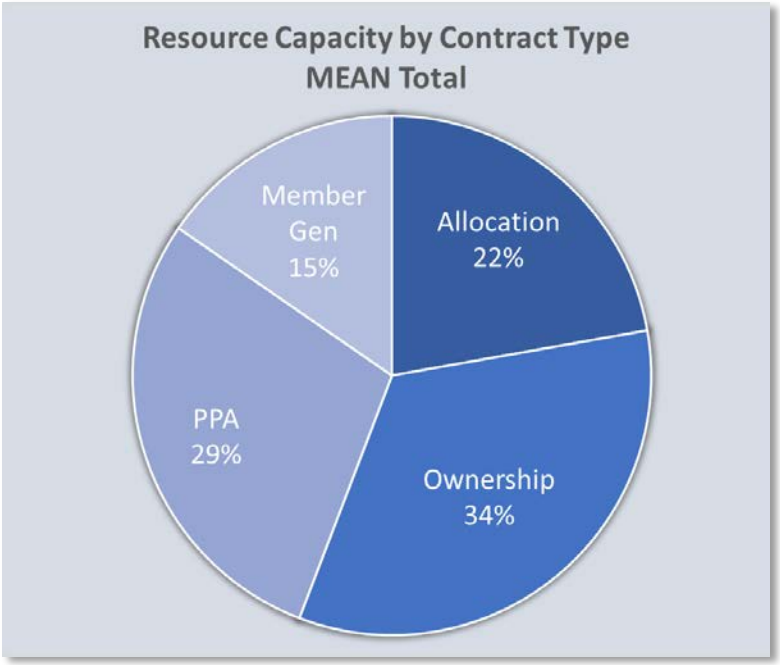


Figure VI-19

2. Energy

In total, 49% of the energy generated by MEAN's resource portfolio is controlled through an ownership interest, 15% of the total portfolio is assigned to MEAN as an allocation, and 36% is contracted via a PPA (including the WAPA Displacement Agreement.)

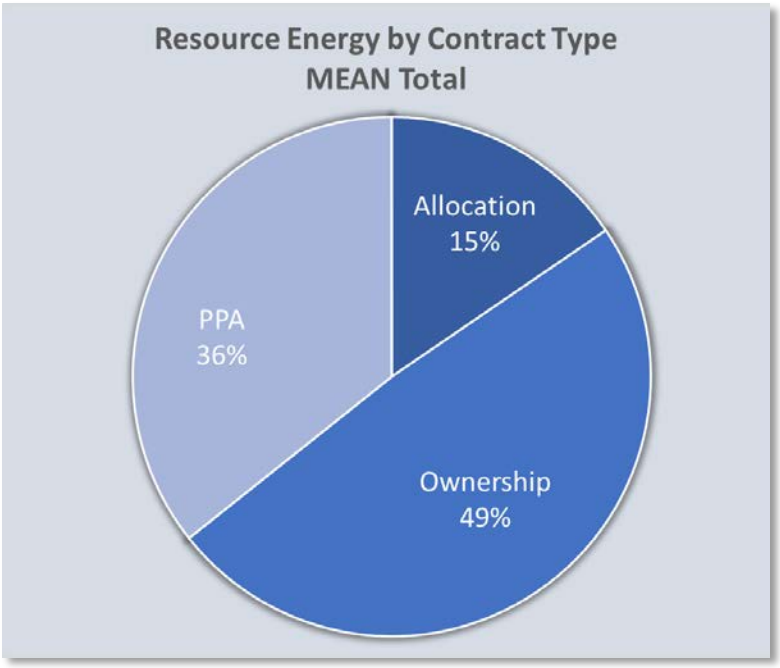


Figure VI-20

F. Market Purchases/Exposure

During discussions at the Power Supply Committee meeting in January 2017, the committee members expressed an interest in investigating a resource portfolio strategy that intentionally leaves a portion of the energy supply to be sourced from the market. In the integrated market construct, MEAN ultimately purchases all energy for load from the market, but the actual operating or contract pricing of MEAN's assets acts as a hedge against fluctuations in market conditions. The committee communicated that MEAN's portfolio should perhaps contain a percentage of energy needs that are provided by market purchases for which MEAN does not maintain a hedge with owned or contracted energy. To gather more input on this possibility, the question was presented as part of the online participant survey in April 2017. The results shown in *Figures VI-21* and *VI-22* indicate that a large majority of respondents approve of this strategy, with an average recommended market exposure of 21.3% of MEAN's energy portfolio.

This approach carries a certain amount of risk. Current market prices are low, and therefore market energy purchases are favorable. However, in the case that market prices increase, MEAN would see a negative financial impact.

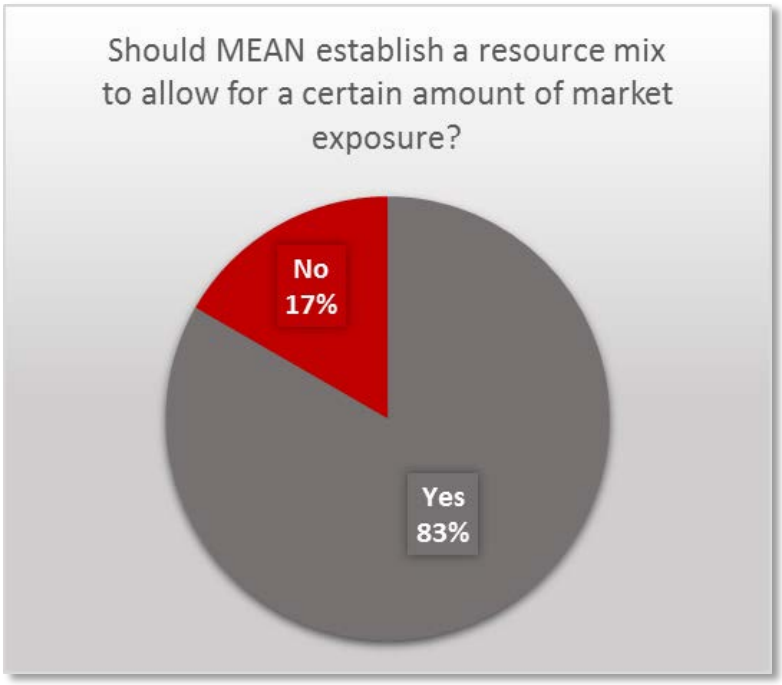


Figure VI-21

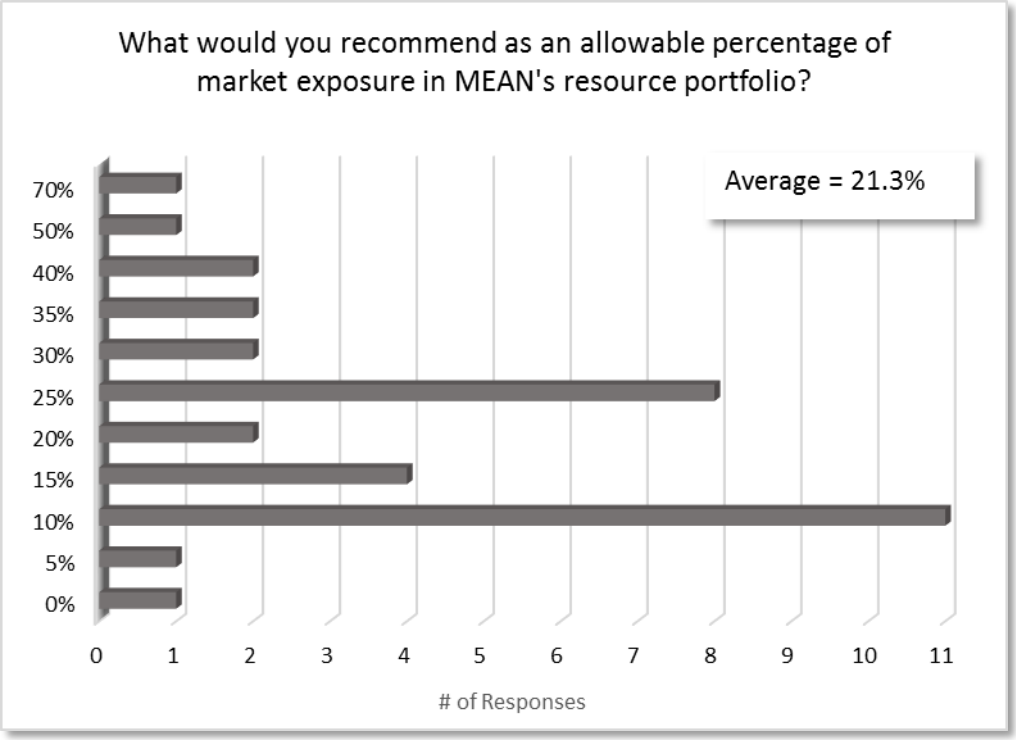

What would you recommend as an allowable percentage of market exposure in MEAN's resource portfolio?
Average = 21.3%
70%
50%
40%
35%
30%
25%
20%
15%
10%
5%
0%
0
1
2
3
4
5
6
7
8
9
10
11
of Responses

Figure VI-22

VII. Distributed Generation

A. Renewable Distributed Generation Policy

MEAN adopted a Renewable Distributed Generation Policy (the *"DG Policy"*) in 2016 that, in limited amounts and in certain circumstances, allows the Participants that have committed to purchase all of their electricity requirements from MEAN to (a) permit their retail customers to utilize output from renewable generation resources to supply all or a portion their own loads, (b) purchase output from renewable generation resources owned by their retail customers, and (c) subject to a cap set forth in the DG Policy, own and operate renewable generation resources, including community solar projects, to offset a portion of their total requirements purchases from MEAN. The DG Policy includes provisions to mitigate any adverse economic impacts of renewable generation resources purchased or undertaken by an individual Participant on MEAN and its other Participants. MEAN anticipates that the DG Policy will be revised from time to time to reflect developments in distributed and renewable generation, including any applicable regulatory requirements.

The existing policy limits Participants to installation of a distributed renewable generating resource capable of generating 2% of the Participant's average annual energy needs. The type of resource determines the capacity factor, and therefore the allowable capacity of the installed resource. For a small community with a low annual energy consumption, the installation of a high capacity factor resource would mean the resource would have to be of a very small capacity to generate the energy allowable under the 2% cap.

The Board heard proposals at the May quarterly meeting to modify the DG Policy language to limit the installation to the larger of 2% of annual energy or a given nameplate capacity size. Ultimately, at the August quarterly meeting, the MEAN Board approved a change to the policy to allow for the installation of renewable distributed systems that generate up to 2% of a participant's annual energy consumption or have a nameplate capacity up to 75 kW. This will allow smaller Participants to consider installation of a high capacity factor resource in a more practical size.

B. Existing Distributed Generation

In 2016, MEAN conducted a Participant survey in preparation for the creation of the DG Policy to determine the installed DG in each community. This serves as a baseline of "grandfathered" distributed generation which will not be counted against the Participant's 2% cap if the asset is community-owned. This installed capacity is already reflected in the historical load values, and therefore is also included in future load forecasts.

The survey found that throughout the entire MEAN footprint, there is a total installed grandfathered DG capacity of 2,875 kW. Of this total, 71 kW are located in SPP, 739 kW are located in MISO, and 2,065 kW are located in the west.

C. Ultimate Impact of DG

Installed behind-the-meter DG reduces the energy that Participant utilities supply to end users and consequently, the energy MEAN supplies to Participants. An increase in DG installations has the potential to reduce revenue for both the Participants and MEAN. There are a number of costs, on the other hand, that do not decrease proportionally with lower energy sales. There is a portion of costs that are avoided with a reduced energy supply, but many of MEAN's costs remain.

Fortunately, MEAN has designed the rate structure to directly bill for a portion of fixed costs on a basis that includes the capacity of DG. Because MEAN must maintain the Power Supply System to provide for the Participants' load even when the DG units are not generating, some fixed costs are allocated on this basis. This ensures that MEAN maintains a system capable of supplying firm power to our Participants under full load conditions. MEAN has performed deliberate calculations of its avoided costs throughout the footprint for application in distributed generation installations and continues to evaluate this calculation as conditions change.

VIII. Existing Demand Side Management

A. Existing DSM Programs

1. MEAN Programs

MEAN has conducted several Demand Side Management (*"DSM"*) programs in the past, with varying degrees of adoption and impact. The newest DSM program currently administered by MEAN is the LED Lighting Upgrade Program. The ENERGYsmart commercial LED lighting program includes cash incentives paid directly to commercial customers to help cover the cost of lighting upgrades and replacements. The program covers:

- Indoor high/low bay lighting
- LED exit signs
- Linear replacement or retrofit lighting
- Fluorescent freezer/refrigerator case lighting
- Incandescent replacement (150 watts or less)
- Customized requests

Converting to more efficient lighting can have a favorable impact on a business's bottom line. Interior lighting accounts for about 30 percent of a commercial business's total energy use. Lighting technologies, such as LEDs, can help cut lighting costs while improving output, visibility and reducing environmental impacts.

The MEAN Board of Directors approved the program for all long-term MEAN participants, with a maximum of $2,500 per customer/owner per year. The program is available to commercial businesses of MEAN long-term power participants. Incentives are allocated in the order that applications are received and approved and will be continued until the annual limit of $75,000 is exhausted.

The program year coincides with MEAN's fiscal year and runs April 1 through March 31. The program was initiated in FY16-17 and has been renewed for FY17-18 and FY18-19.

The funding is distributed according to the schedule in *Figure VIII-1*:

Application	New LED Wattage	Incentive
High Bay, Low Bay	9-65 watts 66-130 watts 131-240 watts	$25 $50 $75
LED Exit Signs	under 8 watts	$10
Linear Replacement or Retrofit	11-22 watt LED 23-45 watt LED 46-68 watt LED 69-90 watt LED	$7 $14 $21 $28
Fluorescent Freezer/Refrigerator Case Lighting	4', 5', or 6' Strips	$30
Replace Incandescent 150 watts or less	LED 40 watts or less	$5

Figure VIII-1

2. Community Programs

MEAN conducts an annual survey of our participants to compile data on existing community DSM programs. Each participant provides descriptions, timelines, and performance data on DSM programs that have already been implemented or are in the planning stages.

The 2016 survey revealed a total of 26 communities with 42 DSM programs in place. The non-coincident sum of the demand and energy savings from these DSM programs is 15.15 MW and 6,988 MWh. Of this total, a large portion of the available demand savings is in the form of interruptible load supplied to irrigation wells. The projected annual savings of the community DSM programs is summarized in *Figure VIII-2*.

Region	# of Communities	# of Programs	Demand Savings (kW)	Energy Savings (kWh)
MISO	7	15	1,167	307,533
SPP	10	13	13,226	5,846,040
West	9	14	762	834,931

Figure VIII-2

B. Historical Results

1. MEAN Programs

For FY16-17, the LED Lighting Upgrade program served 64 approved projects totaling $77,949 in funding. 20 of MEAN's long term total requirements communities participated. Of these recipients, 2 were communities in Colorado, 2 in Iowa, and 16 in Nebraska. 13 of the communities used the program for multiple projects. In total 8,730 fixtures were retrofitted. A breakdown of projects by type is illustrated in *Figure VIII-3*:

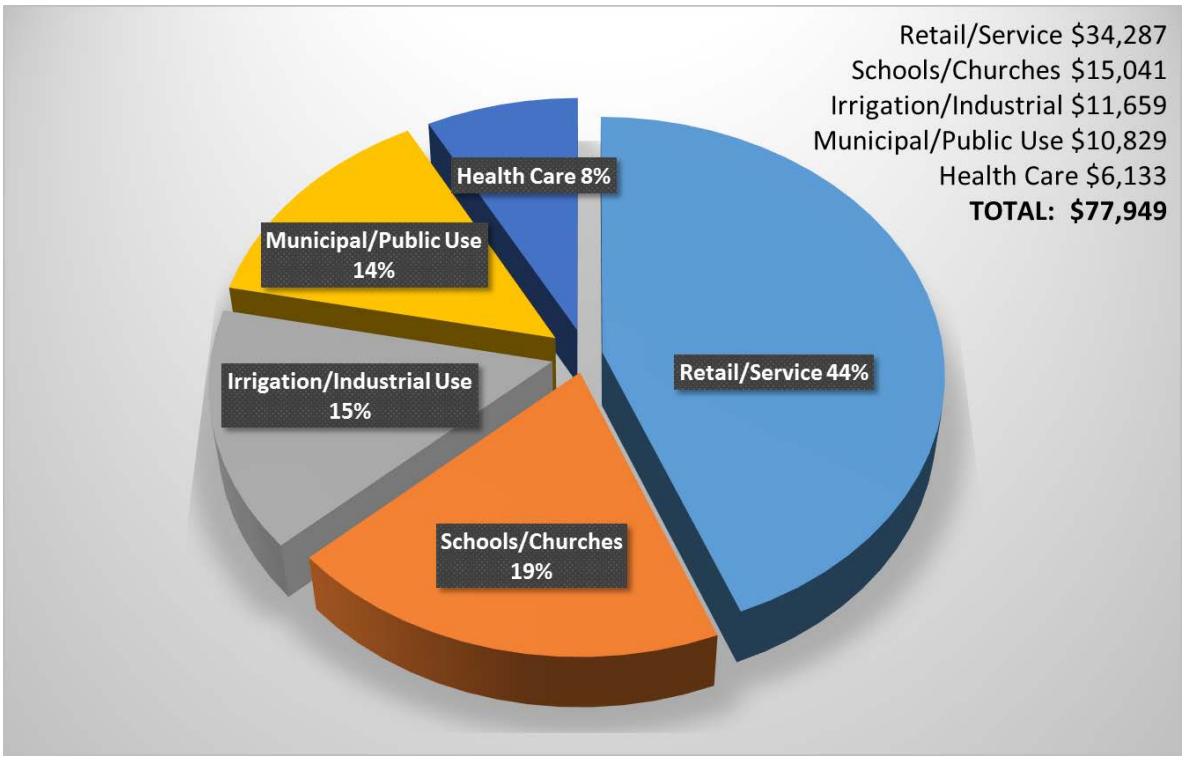


Figure VIII-3

The total annual energy savings achieved by the program is projected to be 1,131 MWh. The peak demand savings is projected to be 209 kW. Detailed results are shown in *Figure VIII-4*:

Equipment Info (Conversion)	Sum of Quantity	KW Savings	Hours ran (annual)	Coincidence	Annual KWh Savings	KW Savings
High Bay - 10-70 watts	431	17.24	4160	95%	71718	16.4
High Bay - 141-203 watts	181	18.1	4160	95%	75296	17.2
High Bay - 71-140 watts	32	2.08	4160	95%	8653	2.0
LED Exit	8	0.16	8672	99%	1388	0.2
LED Refrigerator	14	0.56	8672	99%	4857	0.6
Customized Application Fixtures (Linear)	326	9.128	5200	95%	47466	8.7
Linear Replace/Retrofit - 17-24 watts LED	5,472	98.496	5200	95%	512179	93.6
Linear Replace/Retrofit - 25-48 watts LED	1,114	22.28	5200	95%	115856	21.2
Linear Replace/Retrofit - 49-72 watts LED	76	2.66	5200	95%	13832	2.5
Linear Replace/Retrofit - 73-96 watts LED	193	9.65	5200	95%	50180	9.2
Replace Incand.	883	44.15	5200	85%	229580	37.5
Grand Total	**8,730**	**225**			**1,131,004**	**209**

Figure VIII-4

The total cost of the LED Lighting Program per kW of savings is $373. This compares very favorably to even the most economical supply side option for additional resources, making DSM the lowest cost alternative to meet MEAN's future resource needs in terms of capacity.

C. Continuing DSM Programs

1. MEAN Programs

The following established MEAN DSM programs will be continued as part of MEAN's overall resource portfolio:

LED Lighting Upgrade Program: The NMPP Board has approved the continuance of the LED Lighting Upgrade program through FY17-18. In fact, 10 projects in 6 communities have been applied for and pre-approved to date, totaling $10,654. Similar results in energy and demand savings are expected. These savings are reflected in the current load forecast. In addition, the NMPP Services Committee has recommended extension of the program into FY18-19.

Infrared Energy Audits: This service identifies abnormal heat in electrical and mechanical systems, helps predict equipment trouble and revenue loss. These valuable audits are beneficial to large account customers to lower their electricity costs and increase system reliability in order to maximize their bottom line.

ENERGYsmart Vending Miser Bulk Purchasing Program: All MEAN participant communities are eligible to purchase at discount prices Vending Miser vending machine units to save money by improved energy conservation of non-perishable item vending machines.

Member Exclusive Education Sessions: Workshops, retreats and forums are held throughout the year covering a variety of topics geared for member communities and their development. These sessions can be held in any participant community in accordance with interest and requests. Past workshop topics included:

- Load management
- Smart grid operations
- Grant funding opportunities
- Building community leadership
- Fostering employee pride
- Net Metering issues
- Legislative guidelines
- Accounting practices
- Energy efficiency training
- Economic development basics
- Business retention and expansion

Essent Newsletter Subscription: All members of NMPP receive complimentary copies of the monthly Essent newsletter. The newsletter covers news pertinent to the membership of NMPP. The newsletter also includes news about other members as well as ideas from energy efficiency to economic development tips.

2. Community Programs

The participant DSM survey did not indicate any intentions to discontinue any existing DSM programs administered within MEAN communities. Therefore, it is assumed that all existing programs will continue into the future. The rate of growth in demand and energy savings is unknown. Some of the programs were newly implemented and therefore did not have estimates of savings. Therefore, it is expected that the actual savings attributable to these programs will be further quantified in future years.

IX. Renewable Energy Resources

A. MEAN Renewable Goals

MEAN has not previously defined a requirement or goal dictating the amount of renewable energy in the resource portfolio. There is no existing state or federal legislation that requires MEAN to maintain a renewable portfolio standard. Should this change in the future, external forces will exert control over this policy decision.

To determine whether renewable goals should be a consideration of MEAN's long-term planning strategy, this question was asked in the April 2017 online survey. Of the respondents, 81% agreed that MEAN should establish a renewable energy goal. Of those answering in support of such a goal, the average recommended target percentage was 26%. The most common answer was 20%. Survey results are shown in *Figures IX-1* and *IX-2*.

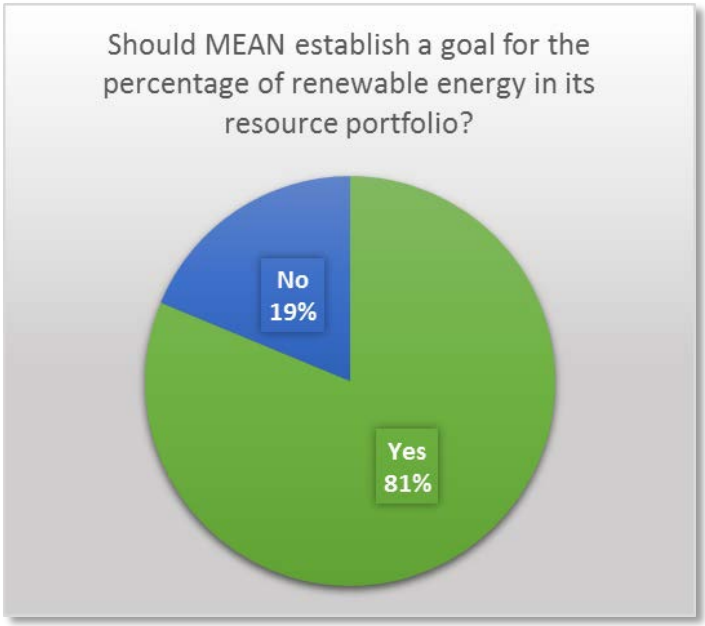


Figure IX-1

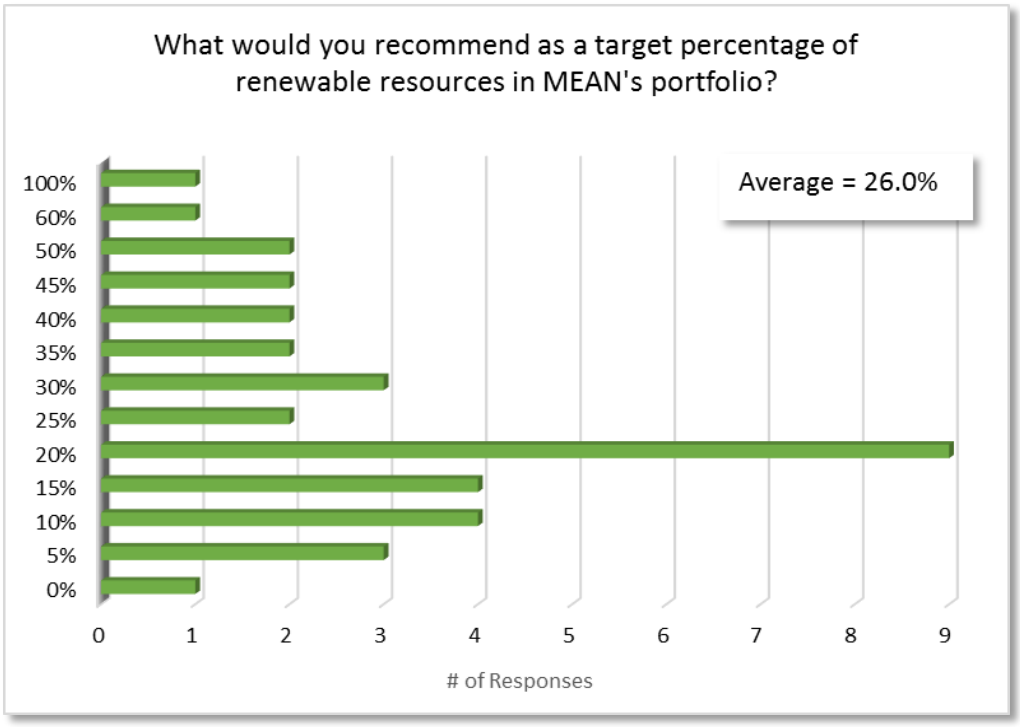


Figure IX-2

To explore the upper bounds for this goal in addition to a lower bound, a second question was posed to determine the preference for also establishing a maximum limit for renewable energy. In this instance, 60% of respondents were against setting an upper limit. However, of the respondents in favor of a limit, the average recommended maximum target was 30.3%. Survey responses are graphed in *Figures IX-3* and *IX-4*.

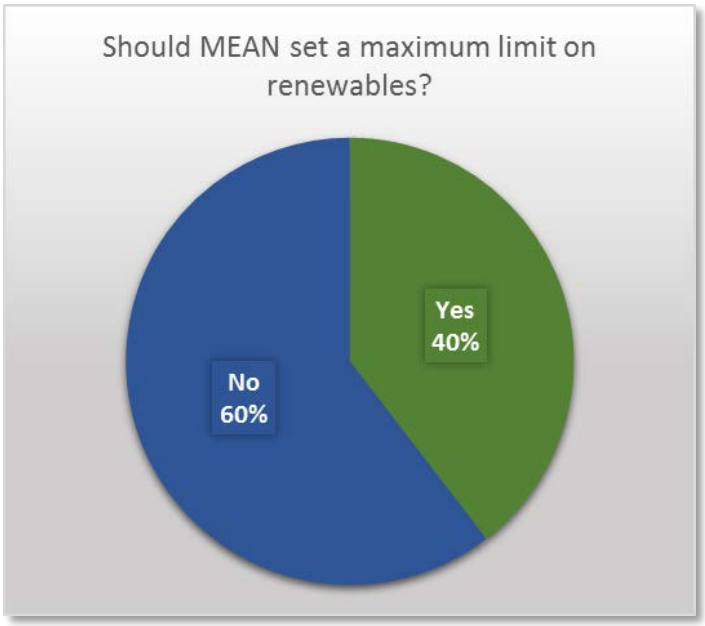


Figure IX-3

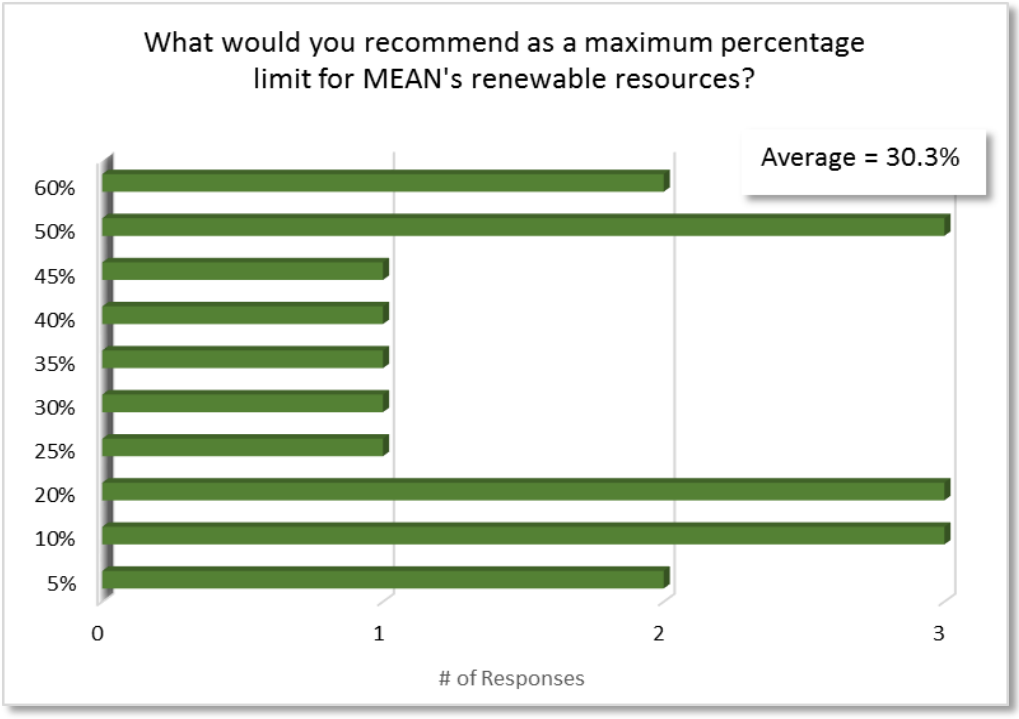


Figure IX-4

This question combined with the previous indicate that MEAN's participants would like to plan for a future resource portfolio that contains between 20-30% renewable energy.

B. Renewable Resource Mix

A review of Section VI.D. shows the current and future resource mix, specifically the percentage of renewable energy in each region's mix and MEAN's overall mix. In some contexts, existing hydropower administered by WAPA is not considered renewable energy due to the size of the resources and their environmental impact. However, small hydro units with less than 30 MW capacity are categorized as renewable. Since MEAN is considering an internal renewable goal, WAPA allocations may or may not be included. However, in the case of a legislated RPS, the target would have to be met exclusive of WAPA allocations.

The table in *Figure IX-5* summarizes the regional and total percentages of renewable resources (on a nameplate basis), both including and excluding WAPA:

Region	2017 Renewable Capacity (including WAPA)	2017 Renewable Capacity (excluding WAPA)	2030 Renewable Capacity (including WAPA)	2030 Renewable Capacity (excluding WAPA)
West	71%	8%	56%	17%
SPP	25%	16%	12%	2%
MISO	11%	4%	8%	5%
MEAN	**42%**	**10%**	**31%**	**9%**

Figure IX-5

C. Existing Renewable Resources

MEAN's current portfolio contains the following renewable resources:

- Kimball Wind Farm
- Shavano Falls Hydro
- Ridgway Hydro
- Ainsworth Wind Farm
- Crofton Bluffs Wind Farm
- Elkhorn Ridge Wind Farm
- Laredo Ridge Wind Farm
- Wessington Springs Wind Farm
- Waste Management Des Moines Landfill Gas

D. Renewable Resource Costs/Incentives

Certain investment or production incentive exist to subsidize the generation and investment in renewable energy resources. In December of 2015, Congress extended the Investment Tax Credit (*"ITC"*) for solar energy projects. This legislation allows a federal tax credit of 30% of the capital invested in solar generation installed through 2019. The ITC will decrease to 26% in 2020, 22% in 2021, and remain permanently at 10% beginning in 2022. The Production Tax Credit (*"PTC"*) for wind projects, which was extended at the same time as the solar ITC, will provide a ten year $23/MWh credit for all wind generated energy for projects initiated in 2016. For projects that begin construction in 2017, the PTC will decrease by 20% and see the same decrease each year through 2020.

Geothermal, landfill gas, marine energy, and incremental hydro projects were previously eligible for a PTC, but this option expired at the end of 2016.

X. Load and Resource Balance

A. Capacity/Demand Balance

Previous sections of this report have quantified the load forecast that MEAN expects to serve in future years as well as the capacity available to MEAN for service of this load. To determine the timing and magnitude of MEAN's future resource needs, the annual peak demand must be compared to the resource capacity available during the peak.

For the calculation of load and resource balance, resources will be quantified according to accredited capacity, or the maximum capacity that is expected to be available during the system peak load. For baseload and dispatchable resources, the accredited capacity is most typically equal to the nameplate capacity. However, intermittent or non-dispatchable resources cannot be depended on to supply nameplate capacity at any given hour, but are subject to the availability of irregular occurrences such as wind and solar irradiance. SPP has provided an equation to determine the accredited capacity of such resources, which MEAN utilizes in this analysis.

The peak demand as shown in the load and resource balance in the total service obligation, which includes not only the forecasted peak load, but also the required reserve margin and the expected transmission losses. Resource capability in terms of capacity and energy is classified by fuel type. Behind-the-Meter-Generation ("BTMG") designates Participant Owned Generation.

1. MEAN System

The graph in *Figure X-1* shows the balance of peak demand and resource capacity for MEAN's entire footprint. Available capacity is sufficient to serve load until 2024. At that point, MEAN has a slowly growing resource need into the future.

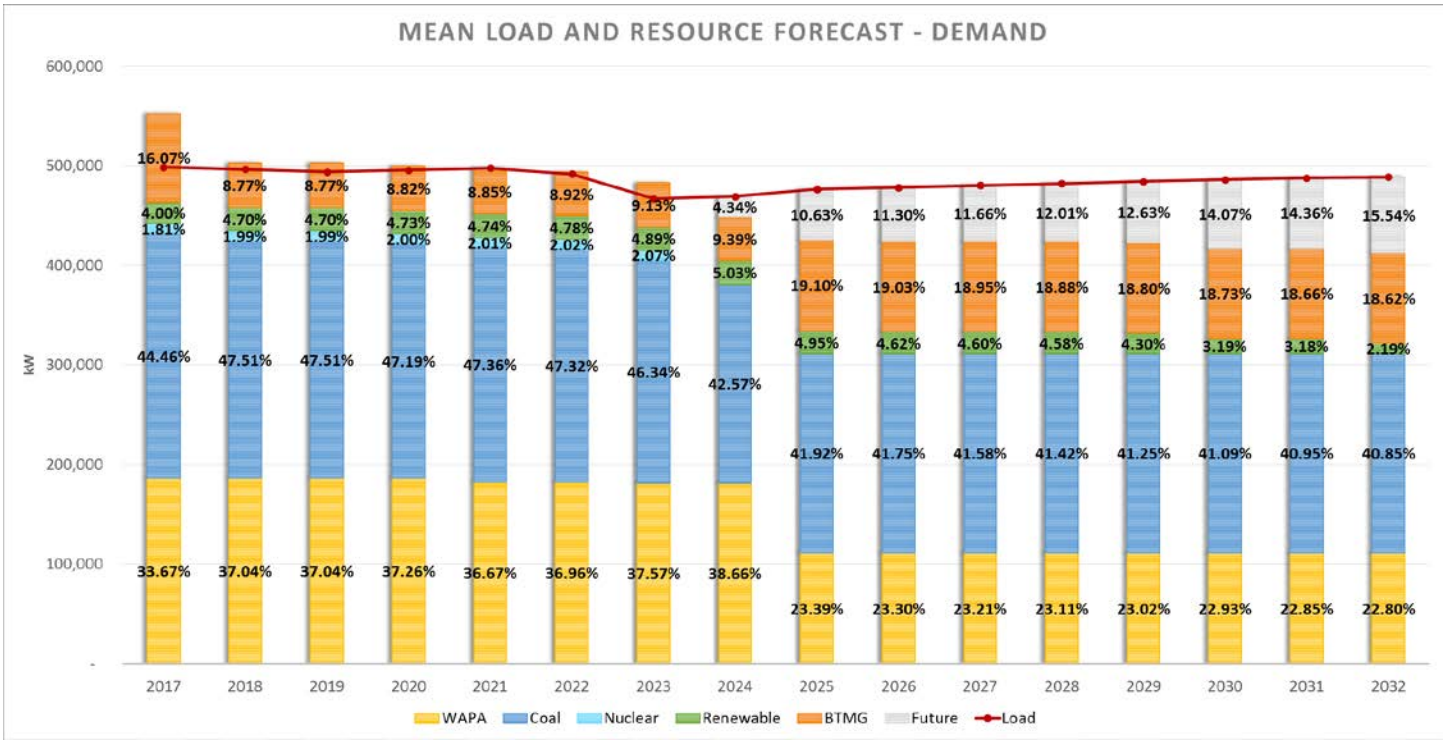


Figure X-1

However, since MEAN serves load and designates resources in each individual region, the load and resource balance must be divided by region to determine the course of future resource acquisition.

2. West Region

The graph in *Figure X-2* shows the peak demand and resource capacity balance for the west region. The major changes on the load side occur in 2018 with the expiration of the limited term contracts with Wray and Holyoke and in 2022 with the expiration of the Glenwood Springs service contract.

On the resource side, the Black Hills PPA steps down over the next few years and finally terminates in 2023, and the WAPA Displacement contract is set to expire on the last day of September 2024. The west region resources include the increased capacity of the new Kimball Wind PPA.

The west region is long on capacity until 2025. At that point, the region has a deficit of 21.9% of the load obligation. This continues through the remainder of the study period.

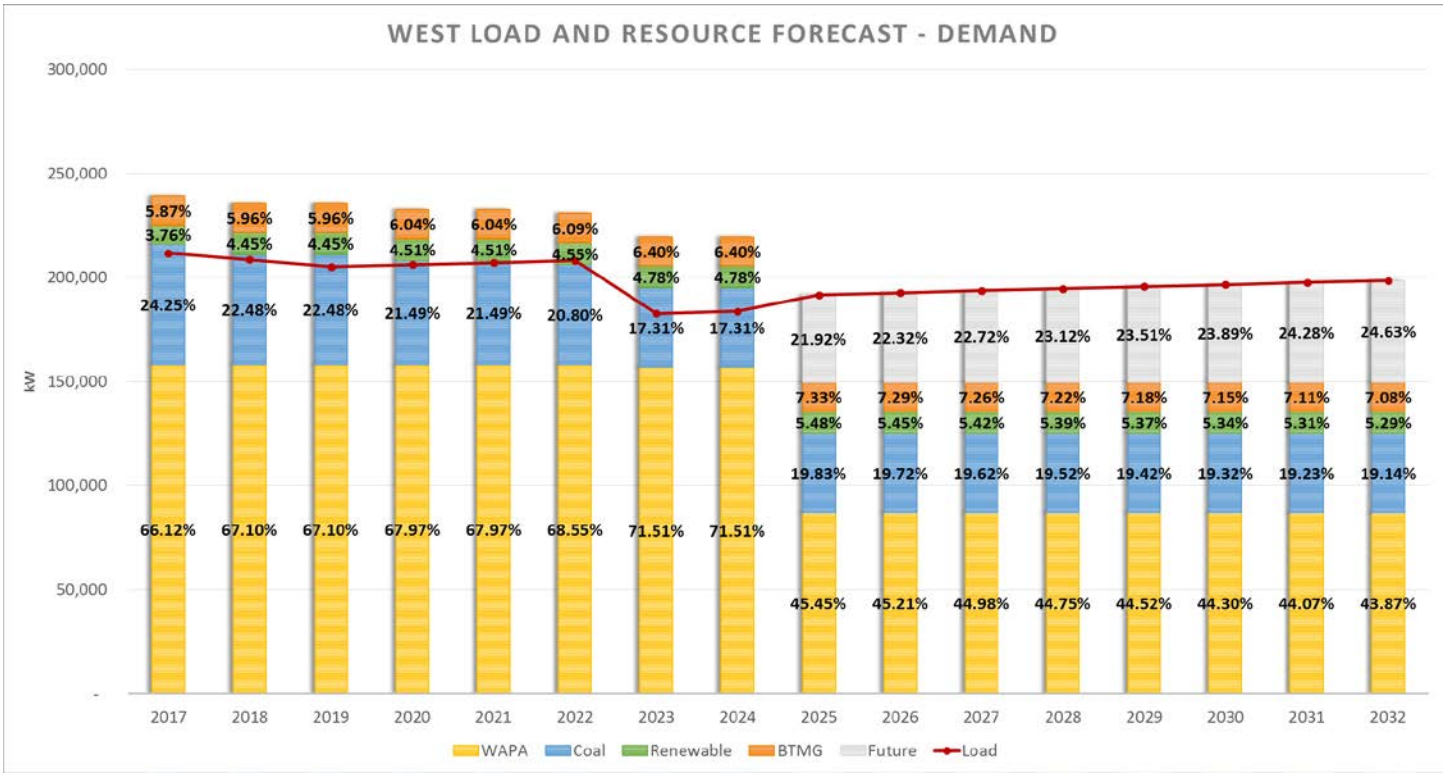


Figure X-2

3. SPP Region

The graph in *Figure X-3* illustrates the peak demand and resource capacity balance for SPP. In 2017, capacity remains adequate to cover the service obligation. However, with the termination in 2018 of the Generation Agent Arrangement with Indianola Municipal Utilities (*"IMU"*) and Waverly Utilities (*"WU"*) contracting excess participant owned generation, SPP capacity is no longer sufficient to meet the load. The termination of the NPPD PPA in 2023 is evident in the further reduction of resource levels after that year. In 2025, the WAPA Displacement Agreement ends, allowing the capacity dedicated to that

contract to be again applied to MEAN's load. However, this does not recover enough capacity to remove the deficiency through the rest of the study period.

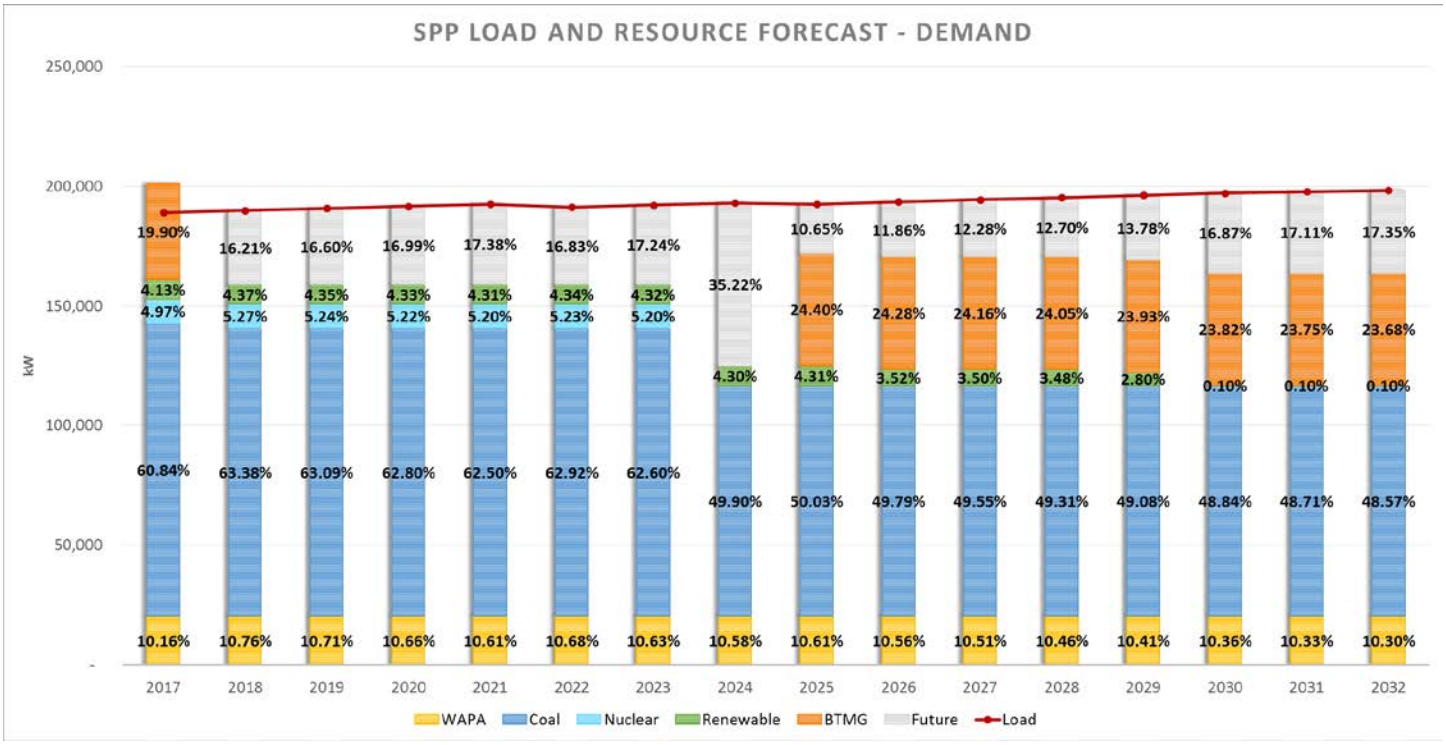


Figure X-3

4. MISO Region

Throughout the study period, MEAN has sufficient capacity in MISO, as shown in *Figure X-4*. There are very few changes in resources or load during this time. There is a slight decrease in load when the limited term contract with Lake View expires. Resource levels are constant, with the exception of the end of the Generation Agent Arrangement with IMU and WU that ends following the peak season of 2018. There is no resource deficiency in terms of capacity in MISO.

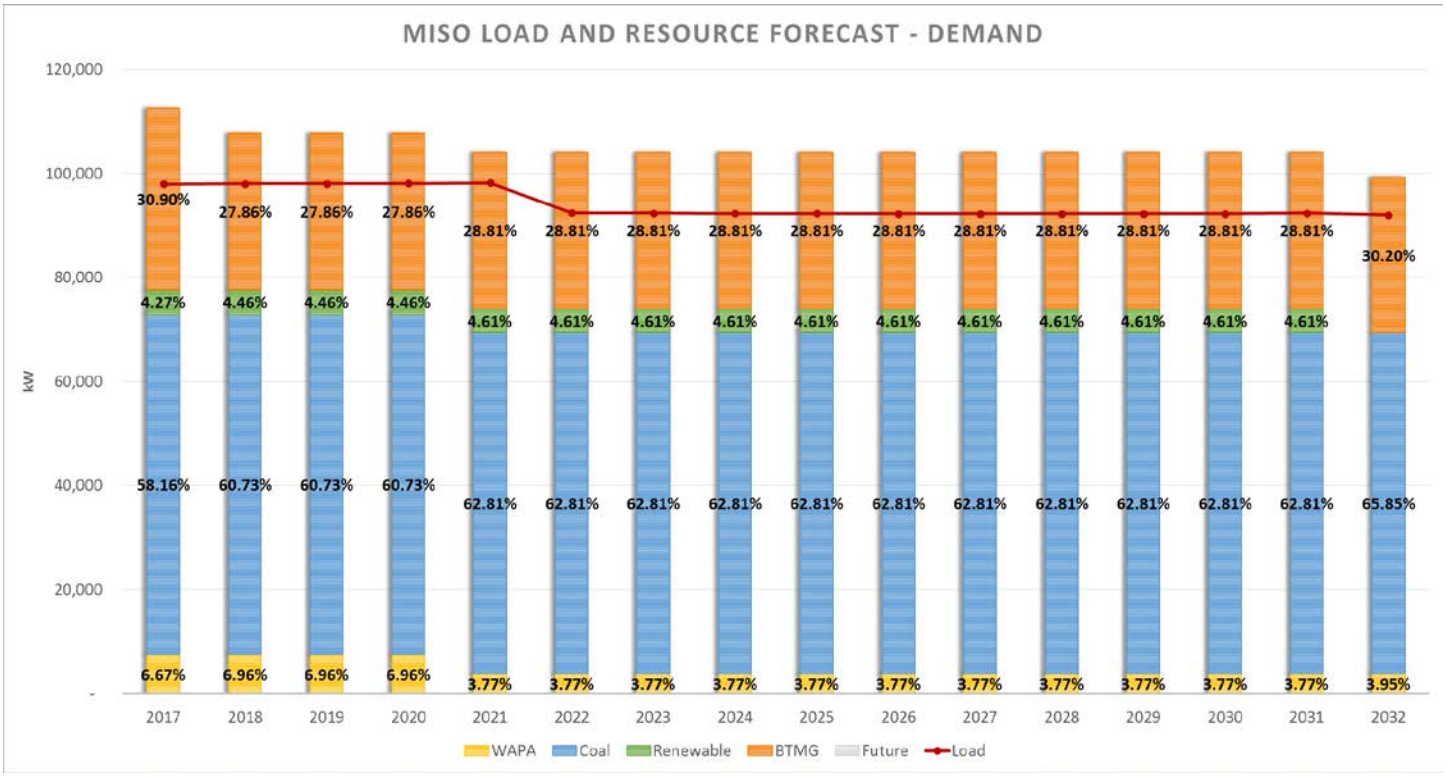


Figure X-4

A. Monthly Balance

The graphs in *Figures X-5* through *X-7* show the regional load and resource capability balance on a monthly basis to illustrate the periodic change in the balance.

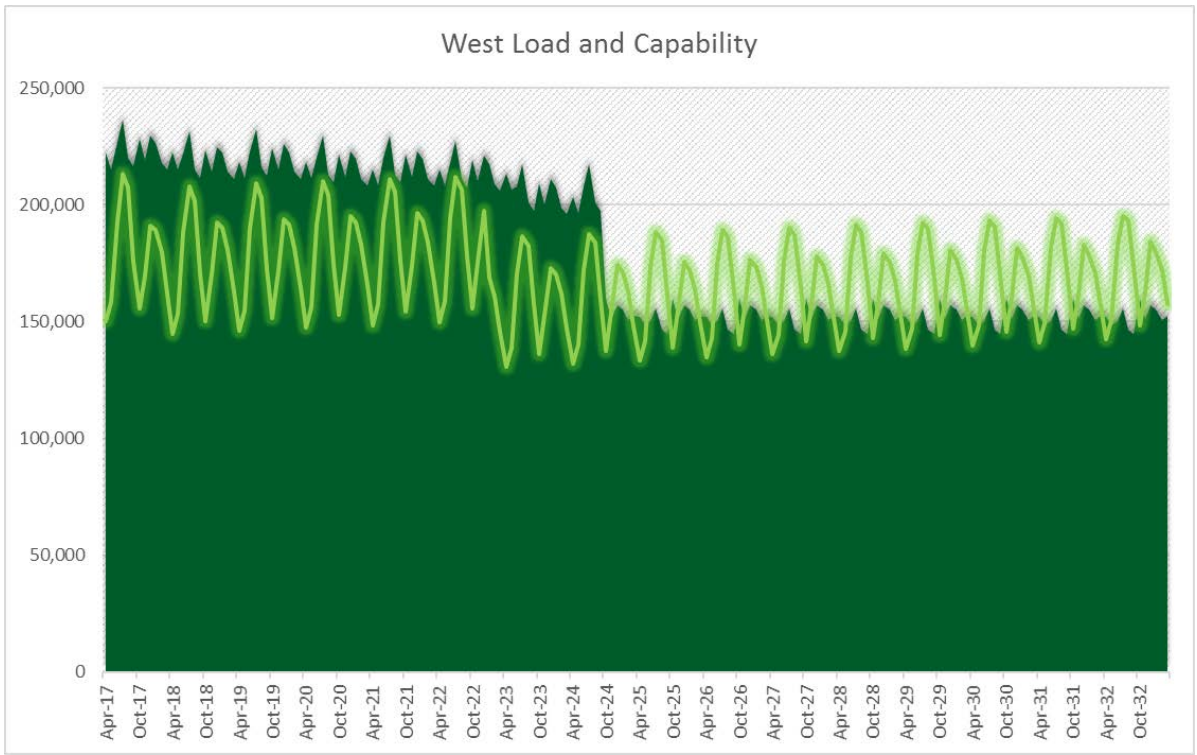


Figure X-5

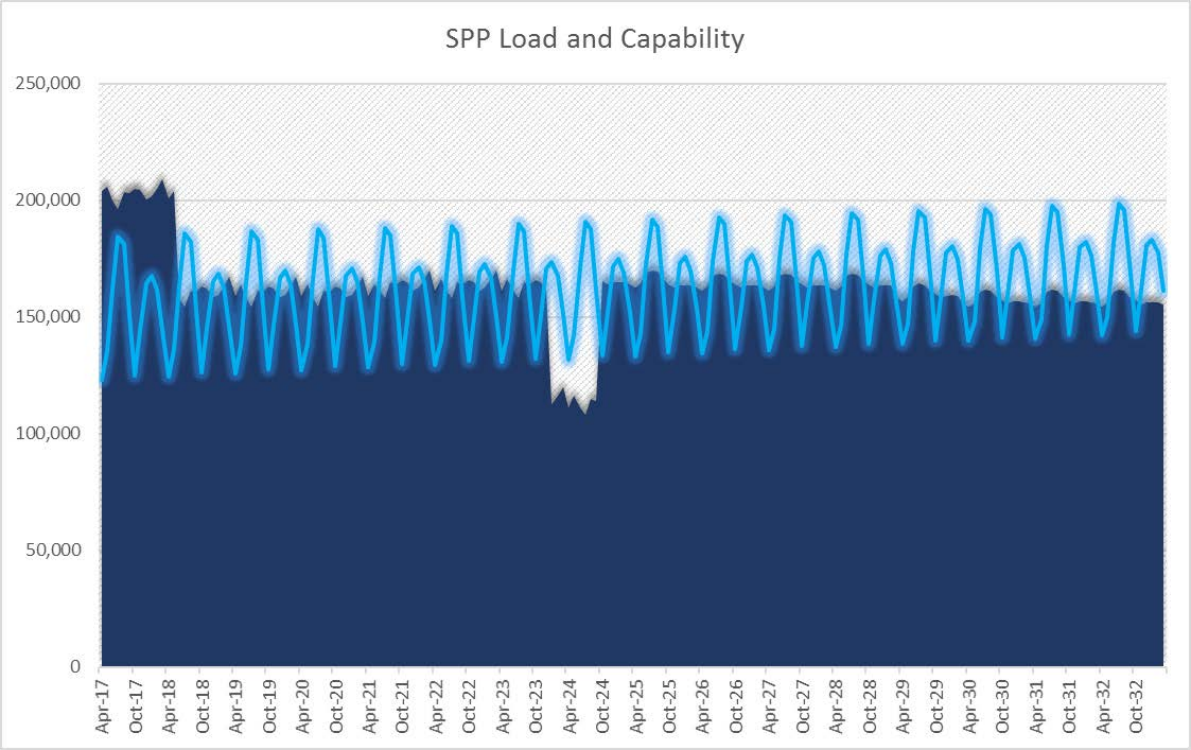


Figure X-6

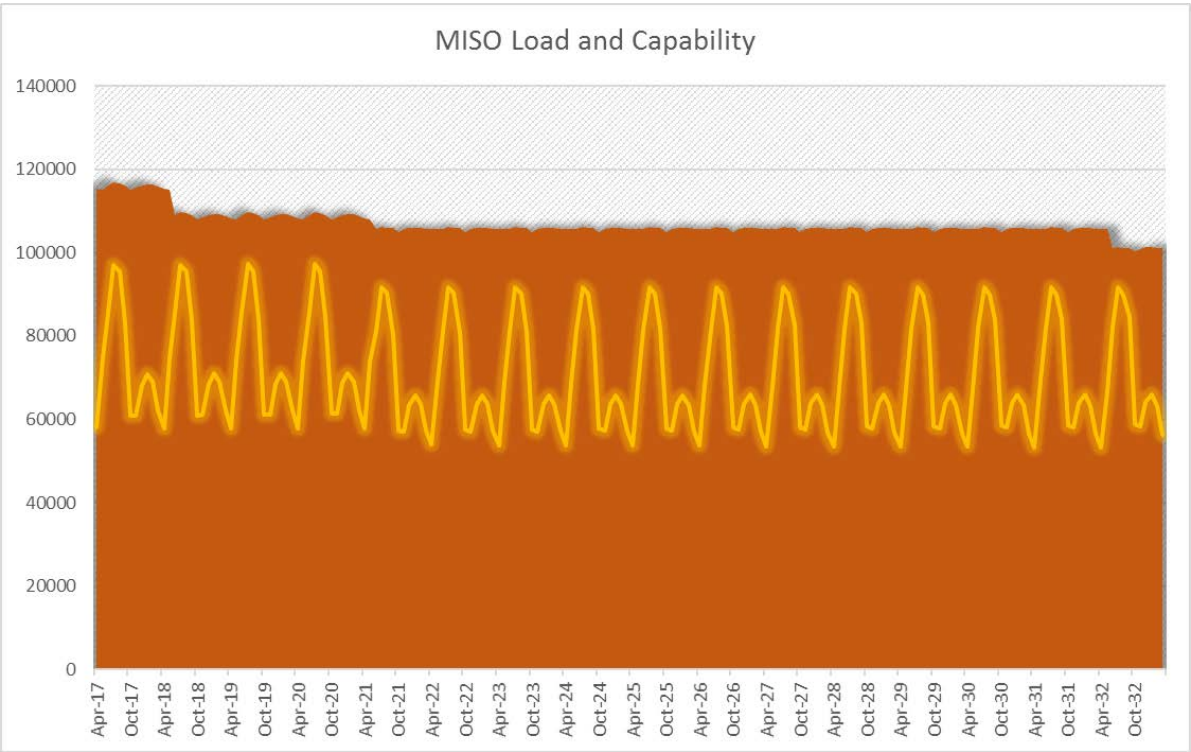


Figure X-3

B. Energy/Load Balance

When showing future energy output of MEAN resources for purposes of quantifying the balance of load and capability, expectations are based on total unit capability as well as historical operation and energy production. Depending on market conditions, real load, and unit maintenance, actual production can vary from the predicted values.

1. MEAN System

Due to the number of high capacity factor resources throughout the Power Supply System, MEAN is long on energy throughout the first half of the study period. As shown in *Figure X-8*, there is a small energy deficiency starting in 2025.

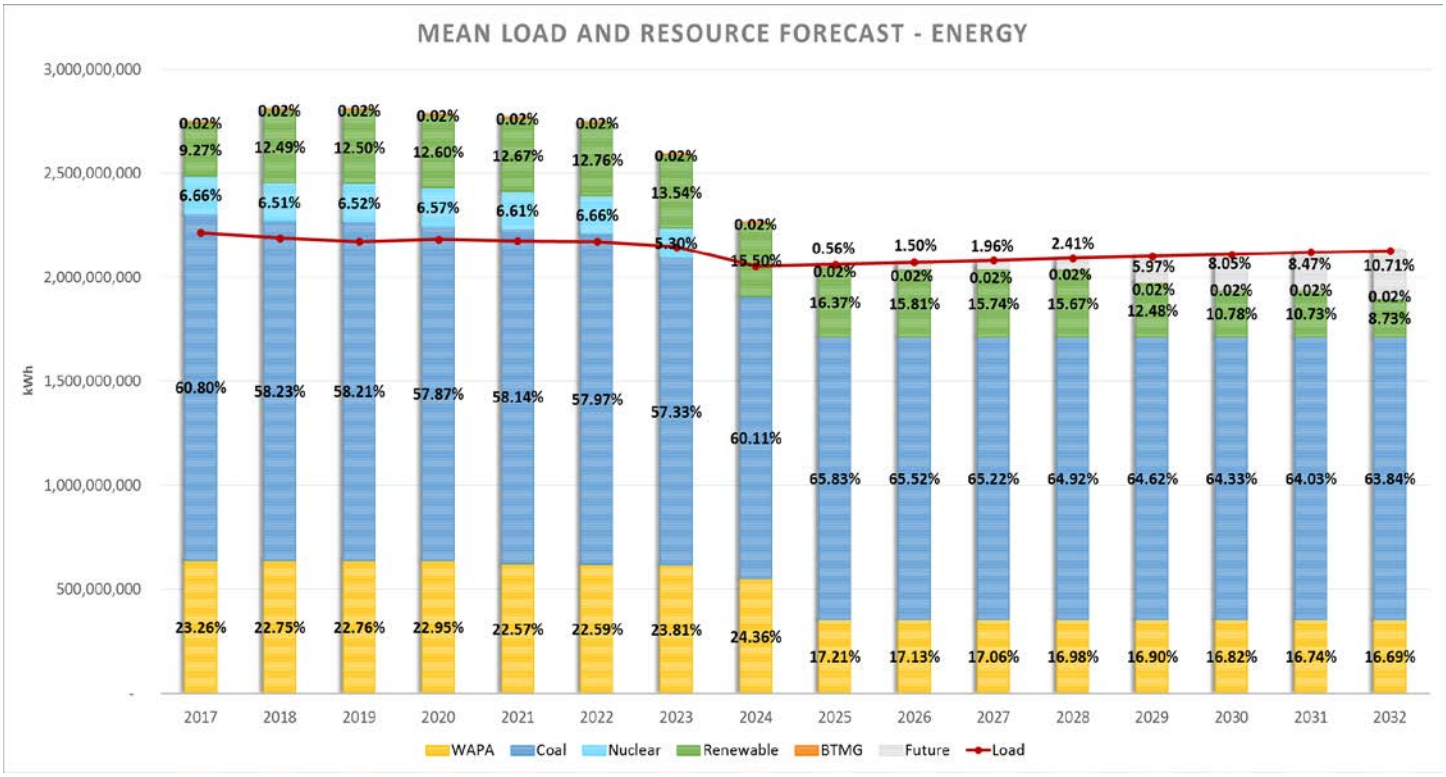


Figure X-4

However, as noted previously, MEAN serves load and designates resources per region, and therefore the level of energy generation in comparison to load must be analyzed for each region.

2. West Region

The energy position in the West looks similar to the capacity position, but the extent to which MEAN is long on energy is a larger margin. This is primarily due to the fact that MEAN's coal resources operate at very high capacity factors, while the load factors of the towns are much less. In fact, the historical capacity factors at the west coal plants have been 80-97%, and the average load factor for participants in the west is 61%. Resources in the west are not operated according to market conditions, rather many are self-committed based on bilateral arrangements and individual contracts, maintaining an incentive to run at high capacity factors.

In the west, the projected annual energy consumption exceeds the available energy generation in 2025. This value increases slightly each year for the rest of the study period. *Figure X-9* shows the long-term balance.

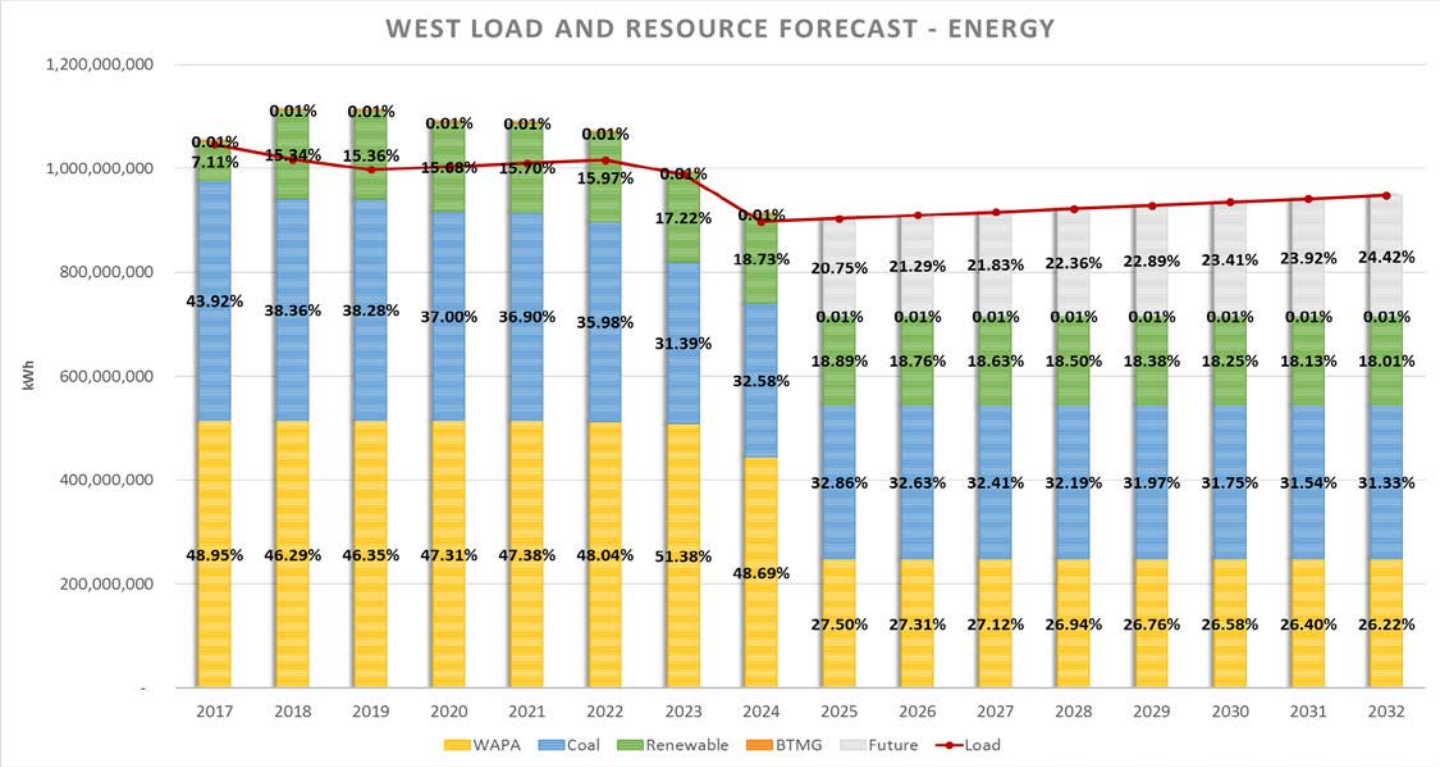


Figure X-5

3. SPP Region

The expected available energy in SPP would be sufficient to cover MEAN's annual energy needs until 2026. In fact, MEAN is quite long on energy through 2023. Again, this is a function of high capacity factor resources and lower load factor for participants in SPP. The baseload coal and nuclear resources in SPP run at capacity factors between 70% and 96%, but the average SPP participant load factor is 56%. The long-term energy balance for SPP is shown in *Figure X-10*.

This imbalance has the potential to change with the possible economic dispatch of WEC2. WEC2 began limited economic dispatch in the spring of 2017, and is investigating the impact of continuing this operational approach. If WEC2 permanently enters economic dispatch, the capacity factor would likely drop, which would reduce the excess energy in SPP. Looking at the graph, this operational modification could even move the energy deficiency ahead to 2024.

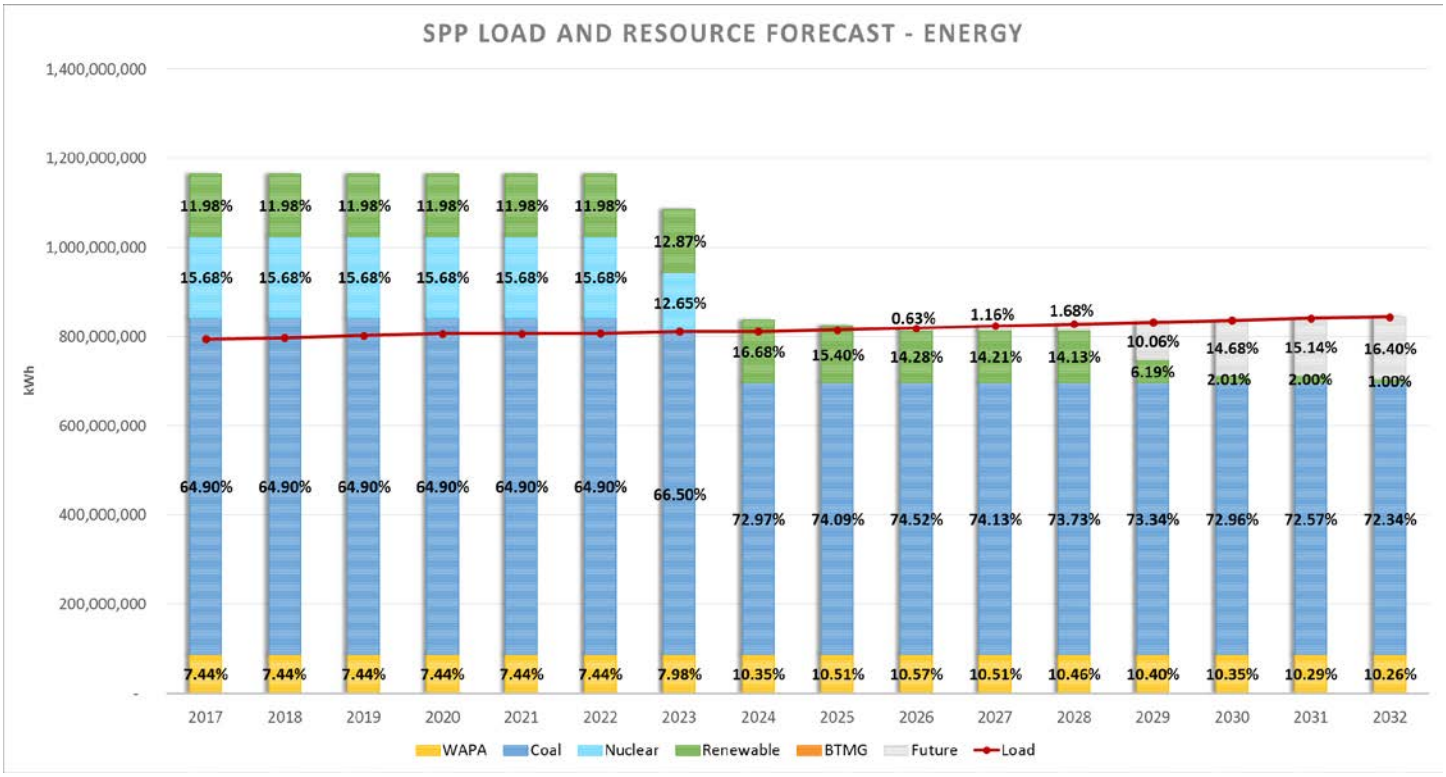


Figure X-6

4. MISO Region

Throughout the entirety of the study period, the MISO region is long on energy with no resource needs in terms of energy. As in the other regions, the coal resources in MISO have been historically operated at high capacity factors, while the average participant load factor in MISO is 48%. Again, it should be noted that the resource values shown in the graph below represent the operation of resources in recent years. This balance is illustrated in *Figure X-111*.

Historically, WSEC4 was operated in self-commit status, wherein unit operation was determined by the owner regardless of economics. However, starting in the fall of 2016, WSEC4 entered into market commitment status, wherein if it is not economic for the unit to run relative to market conditions, the market will shut the unit down. This dropped the capacity factor from an average of 80% down to 63%. If the unit continues to be operated in this manner, the available energy will reduce to more closely match the load and provide less excess.

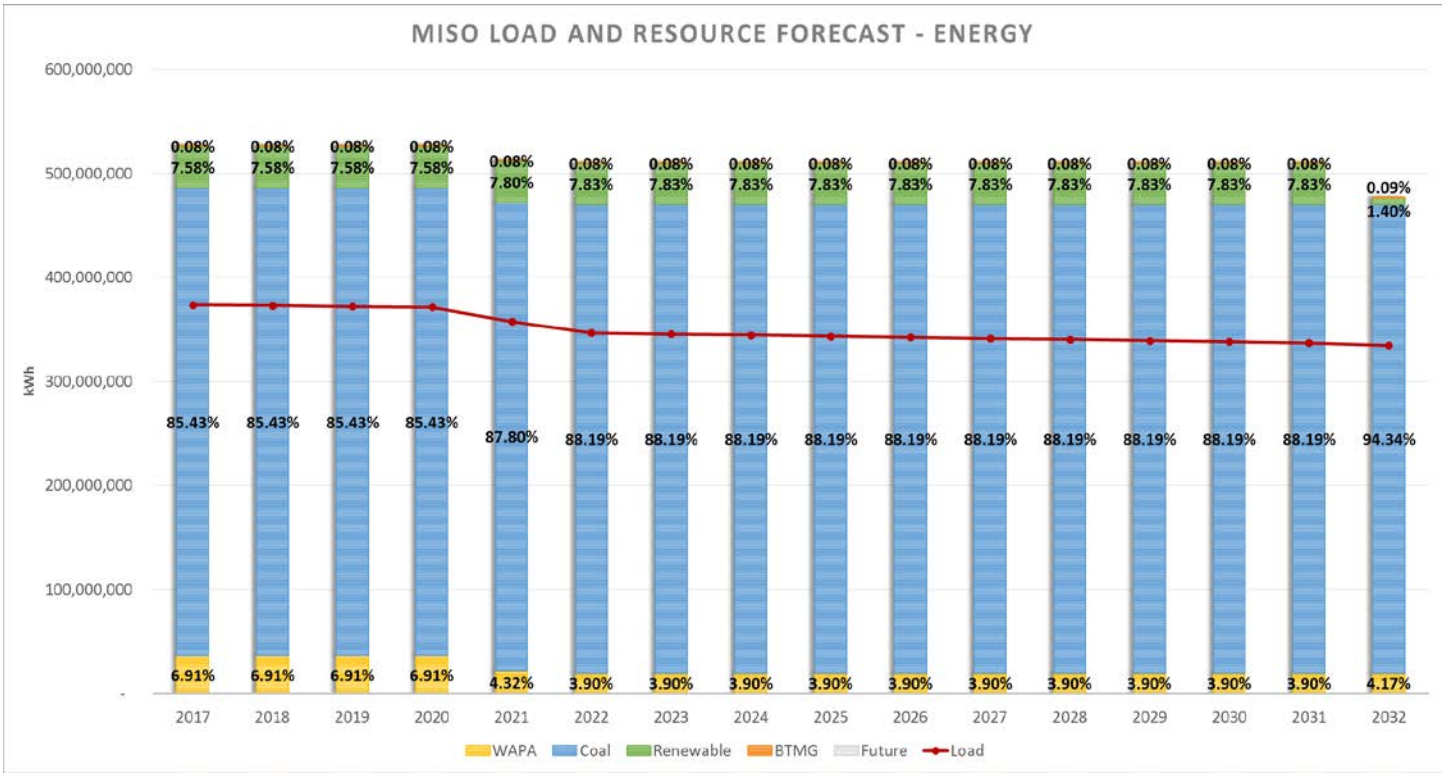


Figure X-7

If WSEC4 continues to operate at a lower capacity factor due to economic dispatch, the MISO load and resource balance on an energy basis changes as shown in *Figure X-12*. The region still has an overabundance of energy in to the future, but not to the extent of recent years.

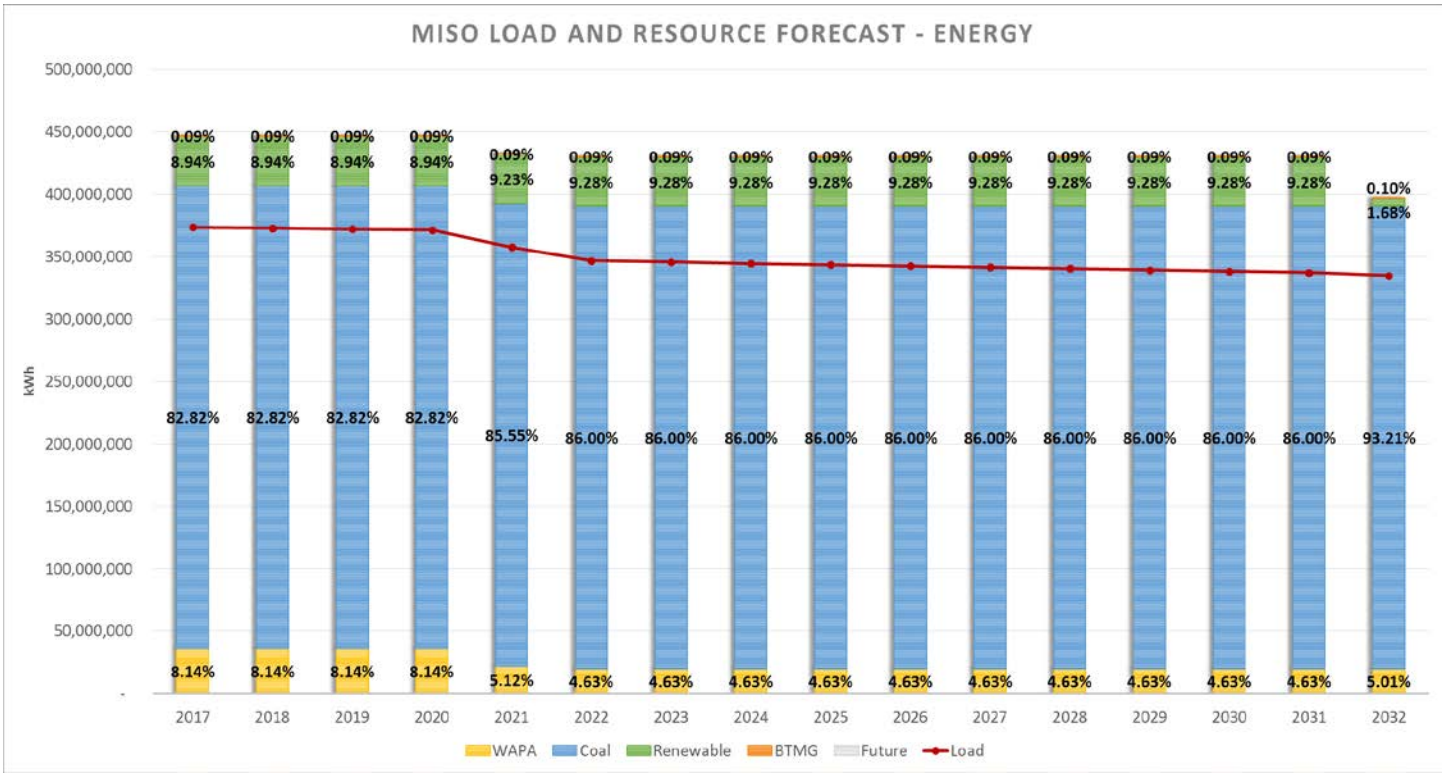


Figure X-8

C. Next Anticipated Resource Addition

It is important to clearly identify MEAN's future resource needs in terms of timing and scale in order to move forward with an evaluation to select the preferred resource portfolio. *Figure X-13* summarizes MEAN's total future needs.

MEAN's need for additional resources begins in 2019 with a capacity deficit that lasts the duration of the study period and increases throughout. In all, MEAN has a minimum resource need of 31 MW starting in 2019 and a maximum resource need of 78 MW at the end of the study period.

MEAN's energy needs, however, do not begin until 2025. The required resource capacity factor, if a resource were acquired to provide for the entirety of MEAN's energy needs, ranges between 28% and 45%.

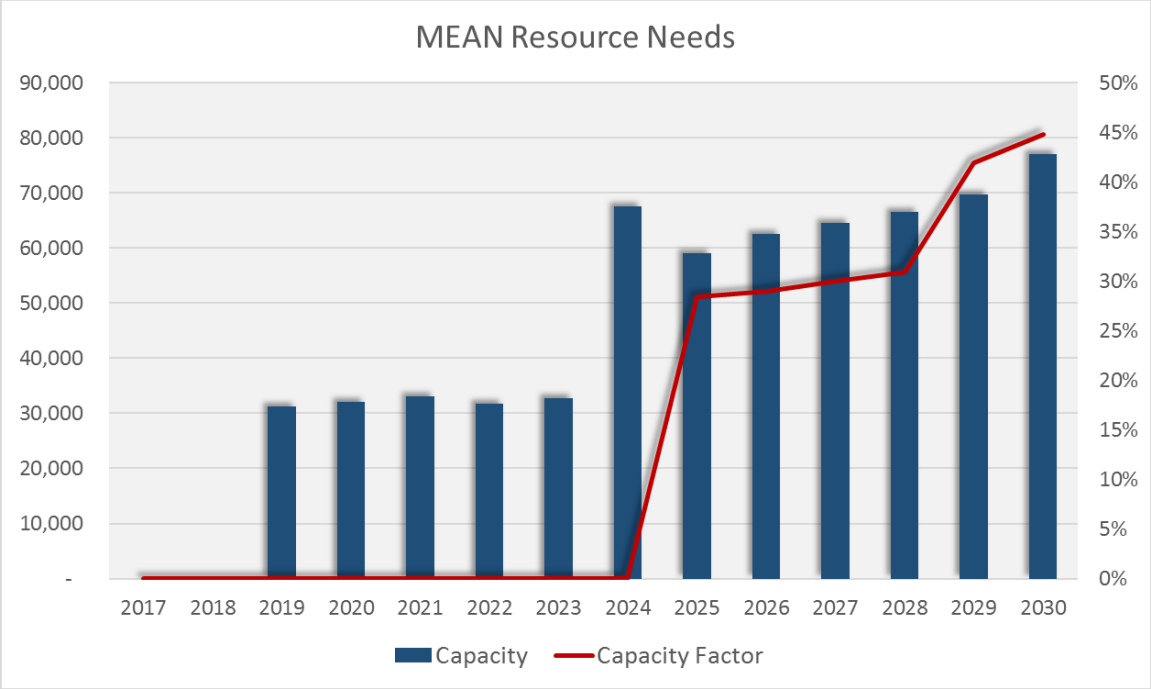


Figure X-9

Although the total numbers for MEAN's system are instructive, it is most useful to utilize the regional values and projections for planning purposes as resources are typically restrained within regional boundaries. *Figure X-14* shows the regional breakdown.

In the West region, MEAN has a resource need starting in 2025. In terms of capacity, the deficit is approximately 45 MW. There is a need for capacity and energy during the remainder of the study period. An intermediate type or even an intermittent resource would fulfill the energy needs in the west.

In SPP, the initial resource need occurs in 2019 when the first capacity shortfall of about 33 MW appears. However, at that time there is no need for additional energy. In 2024, there is a much larger deficit of capacity due to contract timing, but MEAN still has adequate energy capabilities. Then in 2026, SPP has a shortage of capacity and energy. The capacity deficit reaches approximately the same 33 MW level by the end of the study period. Either an intermediate resource or a combination of peaking and intermediate resources could meet the energy need.

In MISO, there is adequate capacity and energy available from currently contracted resources to meet the projected load with reserve margin and transmission losses throughout the study period. No additional resources are required in this region.

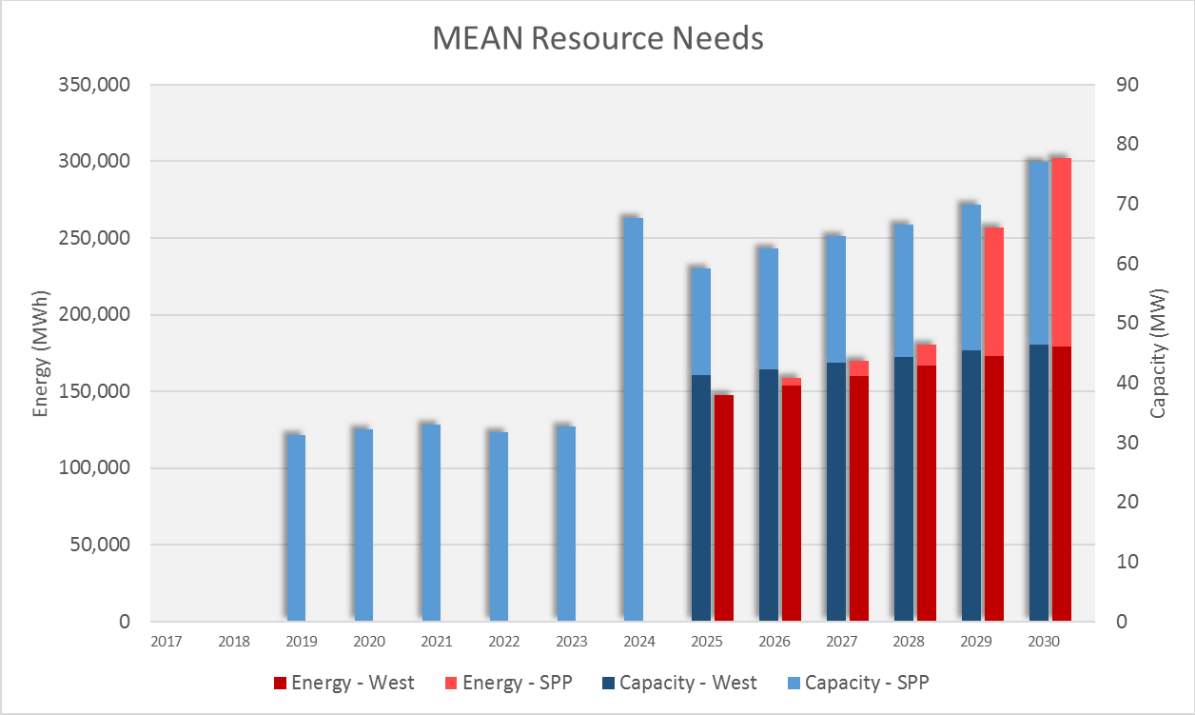


Figure X-10

XI. Transmission

MEAN is a transmission-dependent utility and receives transmission services provided by SPP, MISO and multiple transmission providers in the Western Interconnection. Transmission costs include network integration transmission service and point-to-point transmission service. Transmission costs also include the impact of auction revenue rights and transmission congestion rights in SPP and auction revenue rights and financial transmission rights in MISO. These financial instruments were primarily designed to allow firm transmission customers the opportunity to offset price differences due to transmission congestion costs between resources and loads.

MEAN has also contracted to collect payments for transmission service purchased on behalf of certain Participants and remits these payments to the respective providers. Since MEAN is only acting as an agent, these amounts are not reflected as revenue or expense in MEAN's financial statements.

A. SPP and MISO

SPP and MISO each have integrated, regional electrical transmission systems and facilitate a regional wholesale marketplace. Network and point-to-point transmission service agreements provide MEAN with sufficient access to transmission facilities to deliver energy to the MEAN Participants, to participate in the SPP and MISO energy markets and to sell excess generation and purchase replacement energy when generation is not available or it is economically beneficial. These MISO and SPP agreements are valid as long as MEAN continues to be the power supplier for the loads in the MISO or SPP market, as applicable. MEAN utilizes a Transmission Agreement for Point to Point service on NPPD's transmission system that goes between SPP and MISO. This allows MEAN to take advantage of price differentials between the markets to serve load at the better price. MEAN also has a 50 MW Point to Point transmission path from MISO to SPP, which is now used to transfer 40 MW of participant owned generation capacity from Indianola Municipal Utilities and Waverly Utilities contracted under the Generation Agent Arrangement.

MEAN has experienced significant increases in transmission costs since it began participating in the EIS market, which transitioned into SPP's IM in 2014. Such increased transmission costs are the result of transmission congestion caused by the increased dispatch of generation resources in newly integrated balancing areas, which raises the price to serve load, and increased transmission expansion in response to congestion. The increased costs are exacerbated by the fact that MEAN, as a transmission dependent utility, does not receive revenues from transmission expansion projects that transmission owners (*"TOs"*) receive which offset the higher costs.

B. Black Hills Common Use System

MEAN has several agreements with Black Hills Power which provide for firm point-to-point transmission service and non-firm point-to-point transmission service for use in making deliveries to Participant loads, resource deliveries to adjacent transmission networks as well as energy sales to other regional utilities. The agreements have varying expiration dates, and have rollover provisions to optimize future resource arrangements.

C. WAPA-RMR

WAPA-RMR provides network integration transmission service to Participants connected to the WAPA-RMR transmission system under Contract Number 08-RMR-1811. WAPA-RMR provides this service to MEAN under a transmission tariff that is not subject to FERC jurisdiction. The NITSA

provides rights across the DC tie to serve Participants in the west with lower priced energy in the east and vice versa. MEAN's PTP transmission service agreement with WAPA-RMR permits electricity produced from the resources of Black Hills and Laramie River Station to be moved to the transmission networks of other providers. The agreement continues through December 31, 2018.

D. Other

MEAN owns proportionate transmission rights in the transmission facilities associated with the Laramie River Station, WSEC 4, and WEC2 pursuant to the Laramie River Agreements, WSEC 4 Agreements, and the WEC2 Agreement, respectively.

XII. Phase I Supply Side Resource Evaluation

A. Phase I Supply Side Evaluation Objectives

Phase I is a preliminary evaluation undertaken with the goal of examining a comprehensive list of supply side options and focusing this list down to fewer qualified options that prove to be feasible potential additions to the MEAN portfolio. The Phase I evaluation is in large part qualitative and based on simplified metrics. A more in-depth economic analysis is reserved for the qualified options in Phase II.

B. Phase I Supply Side Evaluation Process

Phase I begins with the identification of the full list of all supply side options to be considered. These include fossil-fueled resources, non-emitting resources, and storage resources.

A list of criteria on which these options will be evaluated is weighted by the MEAN participants as a way to determine the collective priorities. Each of the options is given a score for each criteria, and the score is weighted according to the ranking received from the participants.

The weighted scores are compared to arrive at the qualified options that will be the subject of the detailed economic analysis in Phase II.

C. Supply Side Options

Figure XII-1 displays the complete list followed by a simple description of the supply side options included in the Phase I evaluation for MEAN's future resource needs.

Supply-Side Resource Options
New Coal Plant*
New Coal IGCC Plant*
Natural Gas Combustion Turbine
Natural Gas Combined Cycle*
Co-Fire (new or retrofit)
Nuclear
Geothermal
Biomass (100%)
Landfill Gas/ MSW
Hydropower
Wind
Utility/Community Solar
Battery Storage
Compressed Air Storage
Pumped Hydropower
*with and without CCS

Figure XII-1

1. New Coal Plant

This option includes capacity and/or energy produced by a new pulverized coal (*"PC"*) plant with SO_2 and NO_x controls to meet with all current environmental and emissions regulations. The assumed unit is 650 MW in nameplate capacity with a heat rate of 8.78 MMBtu/MWh. MEAN would contract for either an ownership stake in the plant or a Purchased Power Agreement for capacity and energy. This option was considered with and without carbon capture and sequestration (*"CCS"*) equipment. Coal plants typically operate as a baseload resource at capacity factors of 60-85%.

2. New Coal IGCC Plant

This option calls for generation from a new integrated gasification combined cycle (*"IGCC"*) coal plant wherein coal as the fuel source is gasified and then fed into a gas turbine in a combined cycle plant configuration. This plant would be equipped with SO_2 and NO_x controls to comply with all current and anticipated environmental and emissions regulations. The assumed unit has a heat rate of 8.37 MMBtu/MWh. MEAN would contract for either an ownership stake in the plant or a Purchased Power Agreement for capacity and energy. This option was considered with and without carbon capture and sequestration (*"CCS"*) equipment. As with a traditional PC coal plant, capacity factor is expected to be 60-85% with baseload operation.

3. Natural Gas Combustion Turbine

This option describes a simple cycle combustion turbine fueled by natural gas. NGCT plants are available as conventional or advanced technologies. For the purposes of this evaluation, the average value was used. Various configurations and turbine classes are available. The heat rate of CT units is assumed for this analysis at 10.0 MMBtu/MWh. NGCT plants can be operated as peaking units with capacity factors expected around the 5% range, or as intermediate units with capacity factors around 48-50%. Again, this option could be contracted as an ownership portion or a power purchase. Natural gas resources are highly flexible resources, enabling them to respond to changes in supply from intermittent resources.

4. Natural Gas Combined Cycle

This option includes power generation from a natural gas fueled combined cycle unit where the combination of a gas turbine and a steam turbine can produce up to 50% more electricity than a simple cycle plant. The waste heat from the combustion turbine is used in a heat recovery steam generator to create steam which is fed into a steam turbine to produce a second energy stream. The heat rate of a combined cycle unit is 6.69 MMBtu/MWh. As the combined cycle is the most economic natural gas plant configuration, it is typically operated as an intermediate or baseload resource. Capacity factors can run from 48 to 87%. The NGCC option was considered with and without a CCS system. Natural gas resources are highly flexible resources, enabling them to respond to changes in supply from intermittent resources.

5. Co-Fire (New or Retrofit)

This option contemplates a new or existing plant that co-fires on coal and biomass. Using biomass as a partial substitute for coal has little impact on boiler efficiency, but has significant environmental advantages and offers opportunities for financial savings and local benefits, depending on location. Retrofitting an existing coal boiler to burn biomass typically has a lower capital cost than construction of a new dedicated biomass-fired plant.

The average heat rate of a new co-fired plant burning 10-15% biomass is 9.88 MMBtu/MWh, and that of a retro-fitted unit is 10.74 MMBtu/MWh. The average capacity factor is 52%.

6. Nuclear

The nuclear option used in this analysis includes a typical advanced nuclear fission-powered plant equipped with the requisite auxiliary systems. Nuclear plants generate electricity similar to other plants, except that the steam is created by the heat produced in the nuclear reaction. Average heat rate for a nuclear power plant is 10.48 MMBtu/MWh. Nuclear plants operate as baseload resources, and for this analysis a capacity factor of 92% was used. This option offers certain benefits as a non-emitting resource.

7. Geothermal

The geothermal option presents two different technologies for generating renewable energy using heat extracted from below the earth's surface. Hydrothermal geothermal plants are a mature technology that injects fluid into naturally occurring reservoirs to create steam to power a turbine. Enhanced Geothermal Systems (*"EGS"*) artificially produce these conditions by fracturing hot rock below the surface for injection and extraction of fluid. For each of these plant types, two energy conversion processes are common: binary (using a heat exchanger to transfer geothermal energy to the steam turbine generator) and flash (creating steam directly from the geothermal fluid through a change in pressure). This analysis includes hydrothermal binary and near field EGS plant configurations. Both of these options operate at an average 80% capacity factor.

8. Biomass (100%)

Biomass plants are similar to coal plants with the exception of the feedstock. This option includes a dedicated plant burning 100% biomass. The cost and operation of a biomass plant are largely location dependent due to variations in fuel supply. The average capacity factor of a dedicated biomass plant is 52%. The typical heat rate is 13.5 MMBtu/MWh. Biomass plants have a lower emissions rate than coal plants and can also offer a local benefit if nearby feedstock supply is abundant.

9. Landfill Gas

Landfill gas (*"LFG"*) is a natural byproduct of the decomposition of organic materials in landfills. LFG is approximately 50% methane and 50% carbon dioxide, with a small amount of other organic compounds. LFG plants capture and convert this naturally occurring gas to be burned in internal combustion engines, turbines, microturbines, or fuel cells to generate electricity. Preventing the escape of methane into the atmosphere is a notable environmental benefit as methane is a more potent greenhouse gas than CO2. LFG plants run at a high capacity factor, averaging 70.2%. The expected heat rate is 7.9 MMBtu/MWh.

10. Municipal Solid Waste

Municipal Solid Waste (*"MSW"*) contains biomass, non-biomass combustible materials, and noncombustible materials. The fuel can be utilized in two forms. Mass burn technology, the most common MSW-to-electricity technology, involves the combustion of unprocessed or minimally processed refuse. Refuse-derived fuel (*"RDF"*) typically consists of pelletized or fluff MSW produced by a resource recovery operation, which

removes non-combustible materials. As the MSW is incinerated, heat from the combustion process is used to generate steam, which is then routed to a steam turbine-generator for power generation. MSW has relatively high carbon emissions factors, but is generally considered a renewable fuel. A typical MSW plant will run at capacity factors around 68-70%.

11. Hydropower

New hydropower resources can be originated either by powering non-powered dams (*"NPD"*) or by construction of a new dam via new stream-reach development (*"NSD"*). These plant types are further defined based on the head and capacity at the specific location. This analysis aimed to be conservative and used values for low head, low capacity units. For the NPD units, a capacity factor of 62% was input, and for the NSD units, a capacity factor of 66% was input. In reality, the capacity factor is a function of actual operation required to meet reservoir management needs using the plant's dispatch capability.

12. Wind

MEAN's service territory is a favorable area for wind resources. Recent years have seen an increase in development of large wind farms across Iowa, Nebraska, Colorado, and Wyoming. Wind resources have a financial benefit in that they qualify for the Production Tax Credit (*"PTC"*), receiving a tax credit for each MWh produced. For projects initiated in 2016, the credit is $23/MWh. This amount decreases by 20% each year. As experience with wind power and wind turbine installation grows, equipment pricing and installation costs continue to decrease. This is a favorable condition, especially as consideration of the PTC end dates starts to impact PPA pricing. In line with recent wind farm operation in the area, the analysis uses a 45.8% capacity factor.

13. Utility or Community Solar

This option investigates a utility-scale photovoltaic solar installation owned by MEAN or a participant community. In fact, discussions among participants have even introduced the concept of several communities jointly owning such an asset. The first quarter of 2017 was the sixth straight quarter in which more than two gigawatts of solar photovoltaics and more than one gigawatt of utility-scale PV was installed. Similar to wind resources, as the rate of adoption increases, material and installation costs continue to fall to new lows. 2017 has seen utility-scale system prices drop below the $1 per watt barrier for the first time. In addition to a decrease in capital costs, the Investment Tax Credit (*"ITC"*) offers a further savings benefit. While not as ideal as the southwest regions, the solar irradiance in the MEAN footprint is at an acceptable level for solar installations. A capacity factor of 20% was used in the calculations for a solar resource. The representative resource is a single axis tracking solar system.

14. Battery Storage

A battery storage system is integrated with a generation source to act as a sink for the electricity when it is not required for load and a source of that same electricity when load levels increase. In this way, battery storage can increase the value of an intermittent resource by dispatching energy to match the timing of the load. There are various battery technologies available for this application, including but not limited to: lead-acid, lithium-ion, sodium-sulfur, nickel-cadmium, sodium-nickel-chloride, and flow batteries. However, the most mature and commonly installed technology for utility-scale storage is the lithium

ion battery. Lithium-ion battery systems have high efficiency and are very flexible, with varying discharge times available. Although energy density and performance characteristics can vary widely among the different technologies, this analysis refers to lithium-ion batteries specific to a renewable integration application. Although lithium-ion batteries currently have a high capital cost, costs are expected to trend downward in the future due to an increase in manufacturing volume, design improvements, and chemistry improvements.

15. Compressed Air Storage

The compressed air energy storage (*"CAES"*) option is another method by which electricity can be created during off-peak hours and dispatched during peak hours. Off-peak electricity is used to compress the air and store it in either an underground or above-ground structure. Then during peak load, the compressed air is mixed with natural gas, burned and expanded in a modified gas turbine. Typical caverns, aquifers, or abandoned mines are used for underground storage. CAES systems have the opportunity for large capacity, but have historically suffered from low round-trip efficiency and geographic limitations. However, recent innovations are increasing the available efficiency of advanced systems. Heat rates for the latest generation of CAES systems are approximately 4.0 MMBtu/MWh. It is assumed that emissions control technology is utilized for the turbine to comply with current regulations.

16. Pumped Hydropower

The pumped hydropower energy storage (*"PHES"*) option represents a mature technology that is widely used throughout the US and the world. In fact, PHES power plants constitute almost 99% of installed electrical storage capacity across the globe. Conventional pumped hydro storage systems use two water reservoirs at different elevations. The system is charged during off-peak hours by pumping water from the lower to the upper reservoir. When loads are sufficiently high, the energy is discharged by releasing water from the upper to the lower reservoir, powering a turbine and generator. There are different options for the upper and lower reservoirs, which can take advantage of local geography. Discharge times can be from hours to days. The efficiency of PHES plants is in the range of 70 % to 85 %. Once constructed, PHES systems enjoy a very long service life. However, opportunities are dependent on location.

17. Thermal Storage

Thermal Energy Storage (*"TES"*) systems are yet another method by which energy demand is shifted from peak hours to off-peak hours. TES systems store thermal energy for peak demand dispatch by heating or cooling a storage medium for use in heating or cooling applications or power generation. Available technologies include sensible heat storage, latent heat storage, and thermo-chemical storage. Sensible heat storage stores energy through a temperature change of the storage medium and are applicable to domestic systems, district heating, and industrial needs. Since these applications are directed to end-use customers, MEAN is unable to administer such options. Latent heat storage stores energy through a phase change of the storage medium. Examples include molten salts in concentrated solar plants. Thermo-chemical storage uses chemical reactions to store and release thermal energy. Examples include adsorption processes and desiccant cooling. Most latent heat and thermo-chemical storage applications are in the development or demonstration phase and are high in cost, and are therefore unlikely to be pursued by MEAN.

D. Criteria

The goal of Phase I was to narrow the complete list of supply side options to a list of qualified options that represent the most feasible supply side resources for MEAN. To select the qualified options, appropriate criteria had to be determined. To this end, MEAN conducted an online survey wherein the participants were asked to rank the following criteria in terms of importance in resource selection:

- Cost: This includes the total cost of energy. In an ownership scenario, this is inclusive of fuel costs, fixed O&M costs, variable O&M costs, and capital cost recovery. In a PPA scenario, this includes the contracted price of energy. Transmission costs would also be added if applicable.

- Fuel Diversity: Fuel diversity of MEAN's resource mix is primarily determined using nameplate capacity, but the percentage of energy provided by each fuel will also be assessed.

- Flexibility/Dispatchability/Market Risk: This factor considers whether a resource is dispatchable (i.e., coal or natural gas) or intermittent (i.e., wind or solar) and whether the resource output can be reduced to a minimum level that allows response to market conditions. A resource's dispatchability is also a measure of its reliability.

- Emissions/Environmental Impact: Measures the resource emissions of NO_x, SO_2, CO_2, and Mercury. Water consumption will also be considered.

- Renewable Fuel: Preference for renewable resources over those using fossil fuels.

- Local Benefit: Locating a resource in or near a participant community to allow for economic development opportunities and/or localized environmental benefits.

- PPA vs. Ownership: Evaluates the impact on MEAN's long-term debt position and resource mix dependent upon whether a resource is acquired in an ownership stake as opposed to a power purchase.

- Environmental Policy Risk: Evaluates whether a resource is vulnerable to increased regulation (and possibly additional costs) as a result of future environmental policy.

The results of the survey indicated that the participants' most important criteria in resource selection is cost. With a score of 4.77 out of 5, Cost was the most highly rated criteria. This was followed by Local Benefit with a score of 4.02 and Flexibility/Dispatchability with a score of 3.92. The lowest priorities were PPA vs. Ownership and Renewable Fuel. The complete results are shown in *Figure XII-2*.

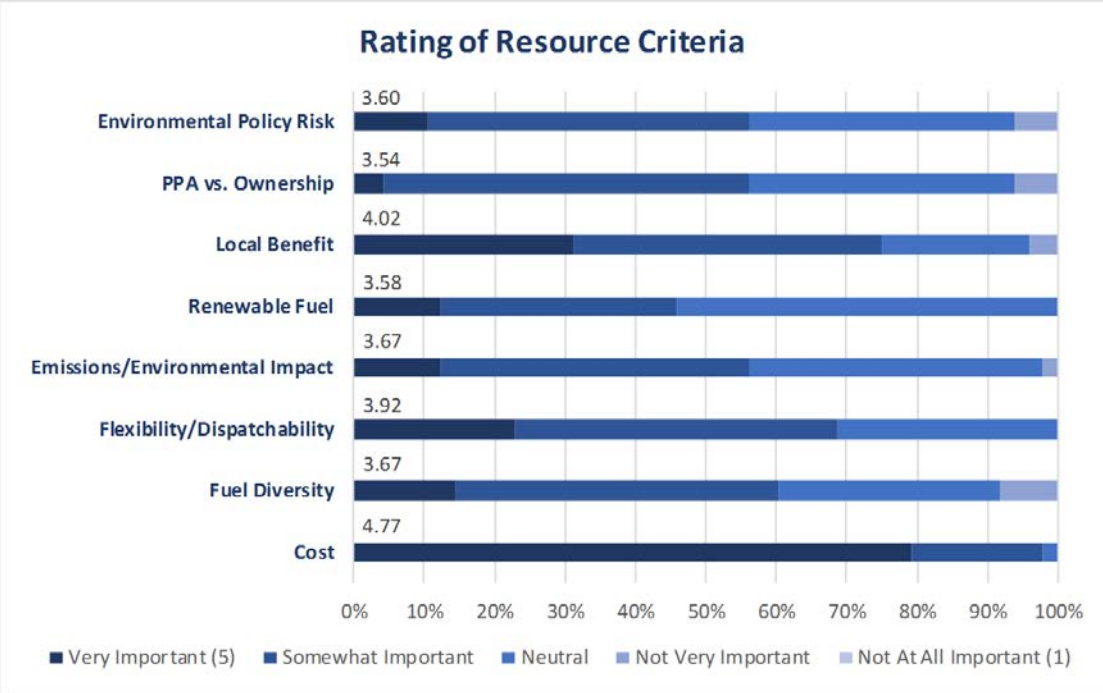


Figure XII-2

E. Input Data

Each of the supply side options was scored on each of the criteria using a variety of metrics obtained from the U.S. Energy Information Administration (*"EIA"*), the National Renewable Energy Laboratory (*"NREL"*), the Department of Energy (*"DOE"*), the Electric Power Research Institute (*"EPRI"*), and other publicly available studies. Specific data used as the scoring values for the Phase I evaluation is shown graphically in Appendix B.

F. Evaluation

The chart in *Figure XII-3* shows the total combined weighted score for each of the supply side options. The individual components of the score are color coded by criteria as described above.

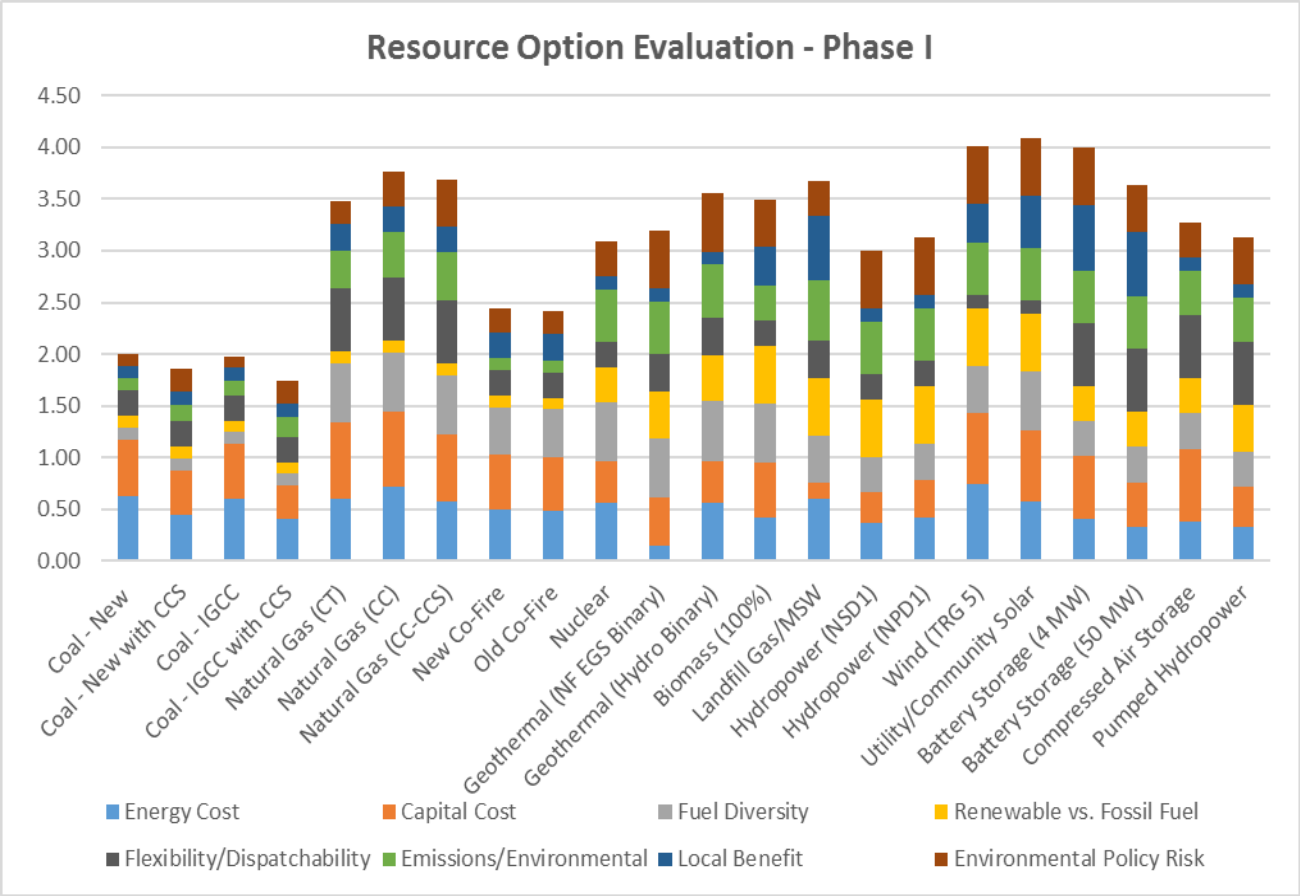


Figure XII-3

G. Qualified Options

1. Evaluation

The Phase I evaluation resulted in final combined weighted scores for each of the supply side options defined at the beginning of the process. Because the criteria were weighted according to the participants' survey, the scores reflect the options most likely to achieve the priorities of the participants. As highlighted in *Figure XII-4*, the top scoring options were:

- Utility/Community Solar
- Wind
- Battery Storage
- Natural Gas Combined Cycle
- Landfill Gas/Municipal Solid Waste

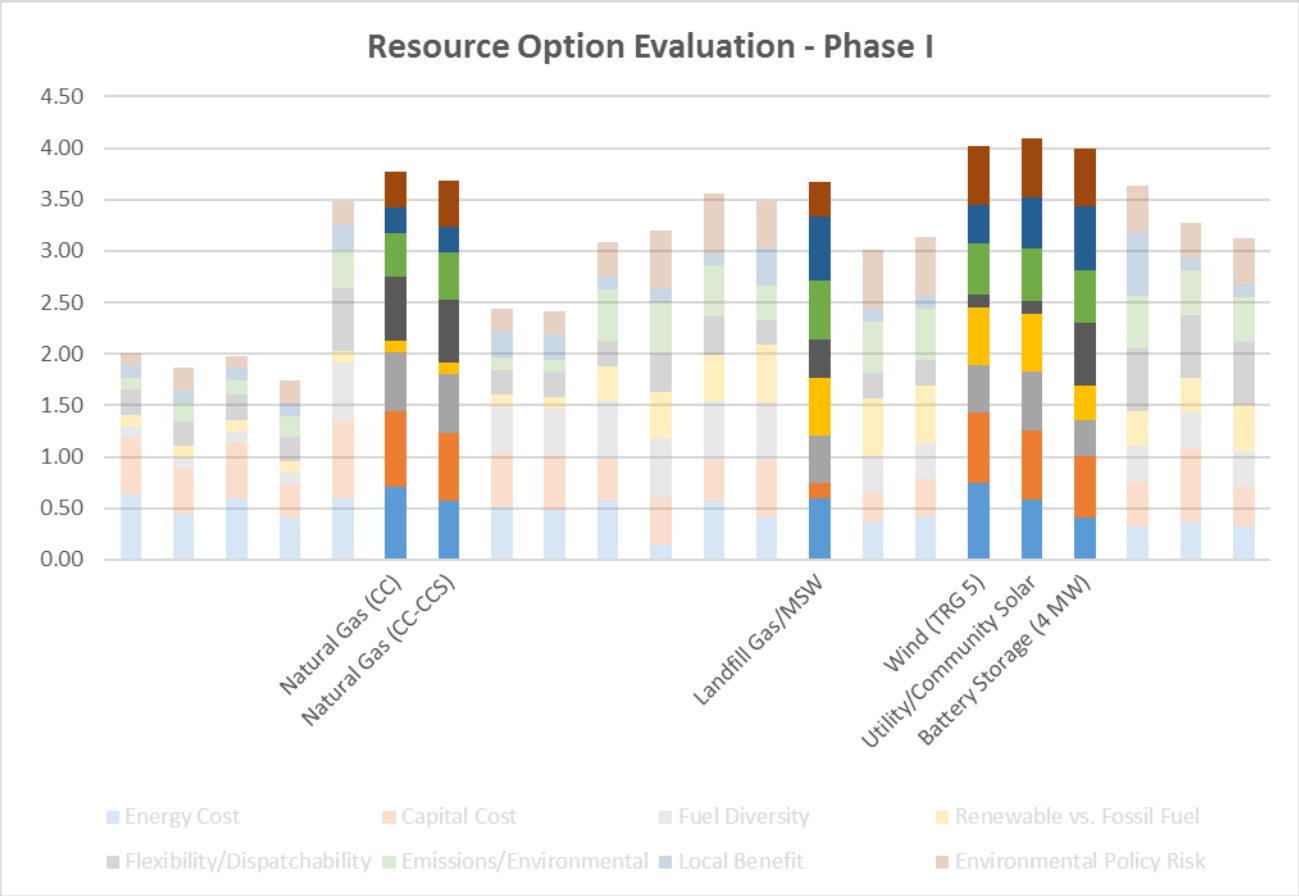


Figure XII-4

2. Public Participation

In discussions at the Power Supply Committee Workshop held in April 2017, participants suggested adding to the qualified options determined by the Phase I evaluation.

Participant Owned Generation: Several workshop attendees favorably discussed the option of allowing participants to install new behind-the-meter generation to their community fleet and add these units to MEAN's portfolio through the same contract by which MEAN leases existing generation. This is an option that would supply capacity and peaking energy while at the same time provide a benefit to a participant community. MEAN would intend to release a Request for Proposals to participants wherein the unit parameters are specified to allow MEAN to control the resource mix and enhance the performance of the participant owned generation fleet.

Extension of PPAs: MEAN is party to several Power Purchase Agreements that are scheduled to expire during the study period. Market dynamics may present an environment in which MEAN can negotiate an extension of these contracts favorable in terms of pricing and operating strategy. Contracts considered were the NPPD Multi-Unit Participation Agreement (GGS 1 and 2 and Cooper Nuclear Station), the Black Hills PPA (Wygen III and Neil Simpson 2), and the NPPD Wind PPAs. The Black Hills PPA was discounted for the lack of flexibility and dispatchability. The NPPD wind contracts were excluded as the assets are expected to be at or near the end of their useful service life when the contracts expire.

Extension of Generation Agent Arrangements: In January 2005, the MEAN Board placed a moratorium on participant owned generation, disallowing any generating unit additions to the committed facilities fleet. When Indianola Municipal Utilities and Waverly Utilities joined MEAN, they operated in their communities significant generating assets that they wished to lease to MEAN. The Board agreed to lift the moratorium to lease 15 MW from each participant under the existing ERPA contract. In addition, MEAN entered in to the Generation Agent Arrangements with each participant whereby the capacity payment due each town would be based on the total owned capacity less the capacity leased under the ERPA at a rate reflective of the annual MISO Capacity Auction price. This agreement includes a total of approximately 47 MW. The contract term extends through the MISO Planning year 2017-18. Of the total behind-the-meter generation of IMU and WU, 40 MW is exported from MISO to SPP. Extension of these contracts would provide SPP with the additional capacity needed in future years.

Creative Energy Solutions: MEAN has entered into discussions with Creative Energy Solutions to purchase the energy generated at CES's planned pyrolysis plant in Colorado. The pyrolysis facility would utilize municipal solid waste and waste tires to produce a synthetic gas, which would then be used to generate electricity via combustion turbines. The pyrolysis equipment processes the feedstock at high temperatures in the absence of oxygen to reduce emissions. This plant would be a 22 MW baseload renewable resource expected to come online sometime in 2019. However, in MEAN's west region load and balance projection, no capacity or energy is needed until the year 2025. MEAN has been working with CES to solicit interest from other utilities to purchase the plant's output until such time that MEAN's load would require it. The Phase II analysis will include an option for a PPA with CES with an effective date coinciding with MEAN's capacity and energy needs in the west.

Battery Storage: Internal MEAN discussions and participant conversations at the April 2017 workshop and the May 2017 Board and Committee Meetings revealed an aversion to the serious consideration of battery storage as a resource option. The deployment of battery storage integrated with renewable resources is a relatively new application with few demonstrations of established and proven installations. MEAN's participants have little appetite for the risk inherent to this option. Therefore, battery storage will not be included in the Phase II analysis.

XIII. Demand Side Evaluation

A. Demand Side Evaluation Process

Just as new a supply side resource can be added to MEAN's portfolio to supply additional energy to meet the demands of the end-user, conversely end-user demand can be decreased to require less energy to be generated by supply side resources. Demand side management (*"DSM"*) programs can be utilized to reduce peak demand and thereby eliminate or delay the need for future capacity additions. Alternately, DSM measures can be designed to lower energy consumption to decrease the energy generation required by existing and future resources. Since MEAN's load and resource balance shows a future deficit in terms of both capacity and energy, both types of DSM are viable solutions.

In an attempt to minimize the required supply side resources to meet MEAN's total obligation, a demand side resource evaluation was performed to determine the value of proposed DSM programs.

B. Demand Side Options

In addition to the established DSM programs that MEAN plans to continue as described in Section VII, a list of potential future programs was compiled for evaluation. The total list for the initial investigation included:

- Energy Efficiency Education
- Commercial/Irrigation Interruptible Service
- Street Lighting Upgrades
- Commercial Lighting Upgrades
- Commercial Appliance Rebates
- Residential Appliance Rebates
- Commercial/Industrial Direct Load Control
- Residential Direct Load Control (Air Conditioners, Water Heaters)
- Commercial High Efficiency HVAC Incentives
- Residential High Efficiency HVAC Incentives

C. Market Feasibility

The first step in the analysis was to determine the market feasibility of the potential programs. In other words, an estimation of the probability that each program would be accepted by the end-user market. In April, MEAN conducted an online survey to ask each community's Board representative to rate the potential implementation of each of the prospective DSM programs. The results of the survey are shown in *Figure XIII-1*.

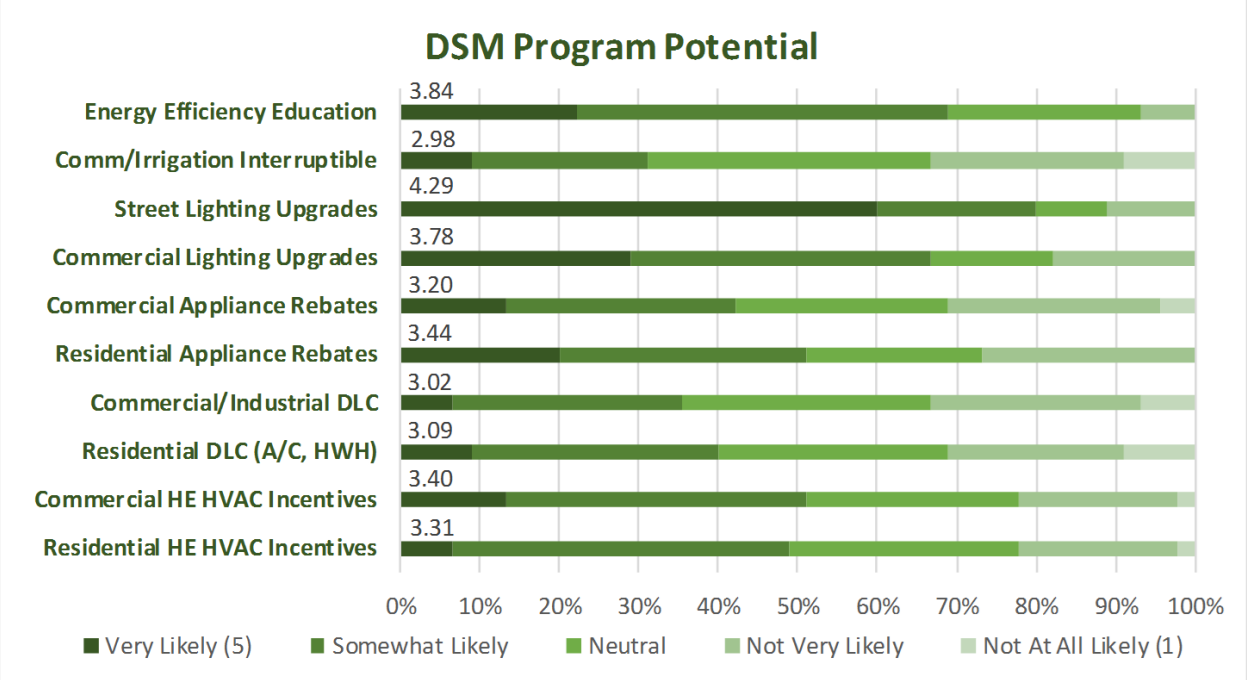


Figure XIII-1

The options with the highest scores for market feasibility were: Street Lighting Upgrades, Energy Efficiency Education, and Commercial Lighting Upgrades. Fortunately, MEAN already has programs in place to administer each of these DSM measures. The survey results show that MEAN's resources are being effectively utilized, and that expansion of these programs should be considered.

The next highest scoring programs were: Residential Appliance Rebates, Commercial High Efficiency HVAC Incentives, Residential High Efficiency HVAC Incentives, and Commercial Appliance Rebates. These were the programs selected for further analysis in the economic feasibility evaluation.

The lowest scoring options were: Residential Direct Load Control, Commercial/Industrial Direct Load Control, and Commercial/Irrigation Interruptible Rates. These programs were eliminated from further consideration.

D. Qualified Options

Based on the results of the Participant survey, the qualified options were broadly categorized as Residential and Commercial Appliance Rebates, and Residential and Commercial High Efficiency HVAC Incentives. In order to perform a more accurate analysis, these categories were studied and more specific programs defined for the next step in the analysis.

To respond to customer interest as indicated by recent programs administered by other regional utilities and to create programs designed to be useful and effective for a minimum 10-year span, the following DSM programs were advanced to the final analysis:

Residential and Commercial Appliance Rebate Programs:

- Refrigerator Rebate
- Freezer Rebate
- Water Heater Conversion (Gas to Electric) Rebate

Residential and Commercial High Efficiency HVAC Incentives:

- Air Source Heat Pump Conversion Incentive
- Room Air Conditioner Upgrade Incentive
- Central Air Conditioner Upgrade Incentive

E. Economic Feasibility

1. Benefit/Cost Ratio Tests

The costs and benefits of the proposed DSM programs will be compared using three different calculation methods, all of which are commonly used by utilities for this purpose. These three tests consider the costs and benefits of the DSM programs from different perspectives. A calculated ratio greater than 1 indicates benefits that exceed costs.

- The Utility Cost Test (*"UCT"*), also called the Program Administrator Cost Test. This test measures cost-effectiveness from the viewpoint of MEAN. If MEAN's avoided supply costs exceed the costs incurred by MEAN in administering the program and paying the incentives or rebates to the end-use customer, the program is a net benefit to MEAN.

- Participant Cost Test (*"PCT"*). This test measures benefits and costs to the end-use customers participating in DSM programs. The test compares net bill savings, considering electric bills and gas bills, against incremental costs of the efficient HVAC equipment or appliance, which are calculated to include the incentive or rebate received from the utility. If the savings exceed the incremental costs, the program provides a positive financial impact to end-use customers.

- Total Resource Cost Test (*"TRC"*). This test examines each program from the viewpoint of the entire MEAN system. The TRC test compares the program benefits of avoided supply costs against the administration costs to the utility and the customer costs of upgrading equipment. The payment of incentives or rebates is a net zero as it is a cost to the utility but a benefit to the end-use customer. A passing score on the TRC indicates a decrease in total resource costs, benefitting MEAN and the customer.

The table in *Figure XIII-2* summarizes the benefits and costs included in the calculations of the ratio.

TEST	BENEFITS	COSTS
Utility Cost Test	Utility Avoided Costs	• Program Administration Costs • Incentives/Rebates Paid
Participant Cost Test	Net Bill Savings	• Incremental Cost of Investment (Net of Incentive/Rebate)
Total Resource Cost Test	Utility Avoided Costs	• Program Administration Costs • Incremental Cost of Investment

Figure XIII-2

2. Market Potential

The first step in quantifying the costs and benefits of the proposed DSM programs is to determine the potential market for each program. MEAN used the 2015 Residential Energy Consumption Survey (*"RECS"*) conducted by the U.S. Energy Information Administration, which details the statistics of appliance and HVAC equipment ownership. Data is available on the number of owned systems by type, age, efficiency rating, and capacity.

MEAN first tabulated the total percentage of regional customers who owned the applicable system or appliance and applied this percentage to the total number of residential meters in the MEAN system. Next, the type and age was considered to determine the number of systems likely to be eligible for replacement. Lastly, an estimate of the expected rate of participation was applied to the number of eligible systems/meters.

The table in *Figure XIII-3* shows the results of the market potential calculations for each program. This total number was distributed evenly over the ten-year assumed span of the program.

DSM PROGRAM	TOTAL METERS	OWNED SYSTEMS	ELIGIBLE SYSTEMS	PARTICIPATION	TOTAL POTENTIAL
Air Source Heat Pump Incentive	78,933	64.02%	28.79%	20%	2,909
Room Air Conditioner Rebate	78,933	26.14%	18.18%	30%	1,125
Central Air Conditioner Incentive	78,933	70.83%	35.61%	30%	5,972
Refrigerator Rebate	78,933	99.24%	11.83%	50%	4,634
Freezer Rebate	78,933	39.39%	27.88%	30%	2,601
Water Heater Conversion Incentive	78,933	60.23%	36.74%	30%	5,240

Figure XIII-3

3. Energy Efficiency Assumptions

To estimate the impact of each DSM program in terms of energy savings, MEAN used Energy Star Life Cycle Cost Estimate calculation tools (U.S. Department of Energy) and the Federal Energy Management Program Energy Cost Calculator for Electric and Gas Water Heaters.

The Air Source Heat Pump program replaces a traditional natural gas forced-air furnace and electric air conditioner with an electric air source heat pump. This replacement results in an overall increase in electric energy consumption, as the annual energy used by the heat pump system exceeds that saved by the elimination of the conventional air conditioner. This is accompanied by a decrease in natural gas consumption with the elimination of the furnace. Therefore, the impact to MEAN's system in terms of energy is a net negative savings.

The Room Air Conditioner program simply replaces a minimum efficiency conventional unit with an Energy Star rated unit with higher efficiency.

The Central Air Conditioner program replaces a minimum efficiency conventional unit with an Energy Star rated unit with higher efficiency.

The Refrigerator program replaces a minimum efficiency standard appliance with an Energy Star rated unit with higher efficiency.

The Freezer program replaces a minimum efficiency standard appliance with an Energy Star rated unit with higher efficiency.

The Water Heater program replaces a natural gas-fired water heater with an electric water heater. This replacement has the effect of an increase in electric energy consumption and a decrease in natural gas consumption. Therefore, the impact to MEAN's system in terms of energy is a net negative savings.

The calculations are included in Appendix C, and the results are tabulated in *Figure XIII-4*.

DSM PROGRAM	ENERGY SAVINGS (MWh/year/unit)	POTENTIAL UNITS	PROGRAM SAVINGS (MWh/year)
Air Source Heat Pump Incentive	-8.35	291	-2,430
Room Air Conditioner Rebate	0.06	113	6.78
Central Air Conditioner Incentive	0.438	597	261.5
Refrigerator Rebate	0.101	463	46.8
Freezer Rebate	0.287	260	74.6
Water Heater Conversion Incentive	-4.75	524	-2,489

Figure XIII-4

4. Costs and Savings

MEAN will incur DSM program costs in two ways. First, MEAN will require staff time to administer the program. It was assumed in this analysis that one staff member could be devoted to administration of all six programs. However, a pro-rated percentage of the staff member's time and salary would be allocated to individual programs. MEAN will also pay the cost of the incentives or rebates received by the end-use customers. Incentive and rebate amounts were projected based on the average offers from regional utilities for similar programs.

From the customer's perspective, the cost incurred is the incremental cost paid for the higher efficiency equipment or appliance as compared to the purchase of a standard unit. This data was calculated in the Energy Star Life Cycle Cost calculation tools as shown in Appendix C. This incremental cost must be adjusted to include the incentive or rebate received from MEAN for participation.

The costs for each program are listed in *Figure XIII-5*:

DSM PROGRAM	ADMINISTRATION COST ($/year)	INCENTIVE/REBATE	INCREMENTAL CUSTOMER COST
Air Source Heat Pump Incentive	$12,500	$500	$1,000
Room Air Conditioner Rebate	$12,500	$25	$50
Central Air Conditioner Incentive	$12,500	$300	$556
Refrigerator Rebate	$12,500	$30	$70
Freezer Rebate	$12,500	$30	$45
Water Heater Conversion Incentive	$12,500	$150	$200

Figure XIII-5

MEAN's benefit is quantified by its avoided cost. Every MWh that is not consumed at the end-use customer level is a MWh that MEAN does not have to generate or purchase. While all of MEAN's costs are not directly attributable to energy production, and therefore not avoided with a decrease in energy consumption, there is a portion of MEAN's costs that is avoided when energy consumption decreases. This is termed MEAN's "avoided cost." MEAN's current calculated avoided cost rate is $0.22, a value that is recalculated with changing system parameters. In the benefit/cost analysis, this cost is escalated at a rate of 2% per year.

The end-use customer's benefit is determined by the net energy bill savings. For the Air Source Heat Pump and Water Heater programs, this is the total of the increase in electric billing costs and the decrease in natural gas billing costs. For this analysis, a seasonal and regional weighted average of $0.076 per kWh with a 1% annual escalation was used for the electric billing rate, and $0.65 per therm with a 2% escalation was used for the gas billing rate.

5. Results

The costs and benefits as described above were applied to the potential market participants for each of the proposed DSM programs. The costs were escalated and summed for a ten-year period. Finally, a Net Present Value was calculated for the annual costs and benefits and this value used to determine the final benefit/cost ratio. The results of the three Benefit/Cost tests are shown in *Figure XIII-6*.

DSM PROGRAM	UTILITY COST TEST (Benefit/Cost)	PARTICIPANT COST TEST (Benefit/Cost)	TOTAL RESOURCE COST TEST (Benefit/Cost)
Air Source Heat Pump Incentive	-0.36	-0.11	-0.36
Room Air Conditioner Rebate	0.01	0.19	0.01
Central Air Conditioner Incentive	0.03	0.14	0.04
Refrigerator Rebate	0.04	0.54	0.05
Freezer Rebate	0.08	1.53	0.10
Water Heater Conversion Incentive	-0.64	-4.03	-1.49

Figure XIII-6

As stated initially, only a ratio greater than 1 would indicate that a program is likely to result in benefits that outweigh its costs and therefore provide a net positive impact to MEAN or the end-use customer, depending on the test.

The results show two programs that resulted in a negative benefit/cost ratio. In these cases, the benefit was the negative value, meaning there was no net benefit, discounting these options.

In total, only one program had a favorable result, and in only one of the tests. Therefore, none of the potential programs would prove beneficial to MEAN and the end-use customer to a point that would compensate for the required costs.

XIV. Phase II Analysis and Results

A. Phase II Supply Side Analysis

The qualified options from the Phase I supply side evaluation are combined with MEAN's existing contracted resources to create a number of future resource portfolios for study. Depending on the capacity and energy potential of each resource, it is studied as either an independent addition or in combination with another resource to provide the capacity and energy required to meet the regional load. The date on which a resource is modeled to begin generation is aligned with the timing of the regional resource deficit as defined in Section X "Load and Resource Balance".

The Phase II analysis aims to investigate the simulated operation of each of the hypothetical MEAN portfolios to calculate the 15-year revenue requirement and thereby determine the least cost option. This option will be integrated with the demand side management measures showing a favorable cost/benefit relationship to arrive at recommended short-term and long-term plans.

B. Impact of DSM Qualified Options

After conducting a survey of Participants to identify the DSM measures most likely to be implemented in the Participant communities and performing a cost/benefit analysis of those qualified options, no new programs are recommended for initiation. The analysis determined that all of the proposed new programs would result in a net cost to both the end used customer and to MEAN. Should cost parameters change in the future, particularly natural gas prices or retail electric rates, these options should be studied again for consideration.

However, MEAN's existing programs and the programs administered by individual Participant communities are quite successful and will be maintained into the future. The effects of these programs in decreasing demand and energy consumption have been quantified where possible and have already been incorporated into the regional load forecasts.

C. Studied Portfolios

The Phase I evaluation determined the following qualified supply side resource options:

- Natural Gas Combined Cycle
- Landfill Gas/Municipal Solid Waste
- Wind
- Utility/Community Solar
- Participant Owned Generation
- Extension of Multi-Unit Participation Agreement (NPPD)
- Extension of Generation Agent Arrangements
- Creative Energy Solutions

As each of these options offers different operational capabilities in terms of capacity factor (the relation of energy generation and nameplate capacity), some can provide the capacity and energy needs of a region, while others can provide only capacity and others primarily only energy. The qualified options were applied to the resource deficits of each region to create portfolios that would offer varying solutions to the needs of each region. The portfolios are as follows:

1. SPP

Portfolio 1: Natural Gas Combined Cycle

MEAN would contract for a partial ownership or a power purchase agreement for 40 MW of a natural gas combined cycle plant. This resource is scheduled to enter MEAN's resource portfolio to coincide with the capacity deficit. The NGCC plant would be operated in SPP's integrated marketplace, subject to economic dispatch, to provide capacity and energy. This portfolio achieves the goal of diversifying MEAN's resource portfolio in terms of fuel source and provides a high degree of operational flexibility.

Portfolio 1D: Identified Natural Gas Combined Cycle

MEAN has been in communication with the owners of an existing natural gas combined cycle plant located in the SPP footprint. MEAN would contract for a partial ownership or a power purchase agreement for 40 MW of this plant. This resource would be scheduled to enter MEAN's portfolio to coincide with the capacity deficit in SPP. This plant is operated by economic dispatch in the SPP integrated marketplace and would provide both capacity and energy to MEAN's load. This portfolio allows MEAN to diversify the fuel sources of its resource portfolio and achieves the goal of resource flexibility.

Portfolio 2: Landfill Gas

MEAN would contract for a partial ownership or a power purchase agreement for 40 MW of one or more landfill gas plants. The LFG plant would be contracted to enter MEAN's portfolio to fulfill the capacity deficit in SPP. Landfill gas plants can be operated as must-run units or can be controlled with limited dispatch flexibility. The Phase II economic model considers the LFG plant dispatched according to marketplace economics to provide capacity and energy. The LFG portfolio increases MEAN's percentage of renewables in SPP in terms of capacity and energy in an attempt to achieve the 20% renewable goal of its participants as determined by the April 2017 online survey. This resource also increases the fuel diversity of MEAN's portfolio.

Portfolio 3: Municipal Solid Waste

This portfolio would add 40 MW of an MSW plant to MEAN's portfolio via a partial ownership contract or a power purchase agreement. The MSW plant would provide capacity and energy to MEAN via economic dispatch in SPP's integrated marketplace. The resource contract would be scheduled to meet the capacity deficit. This portfolio contributes to the renewable percentage in MEAN's SPP portfolio, and creates a more diversified portfolio with regard to fuel source.

Portfolio 4: Wind + Generation Agent Arrangement

This portfolio would extend the existing Generation Agent Arrangement with IMU and WU for participant owned generation in the communities of Waverly and Indianola, Iowa and maintain the import of 40 MW of this capacity to the SPP footprint. The effective date of this contract extension would address the capacity deficit in SPP, but contribute no energy. In addition, MEAN would enter into a power purchase agreement for wind generation when the first energy deficit occurs in SPP. This portfolio adds both renewable and fossil fuel resources to MEAN's SPP mix. Although the wind resource will provide very little accredited capacity, in consideration of nameplate capacity, MEAN would achieve an overall increase in renewable energy in SPP.

Portfolio 5: Solar + Generation Agent Arrangement

This portfolio would also extend the existing Generation Agent Arrangement with IMU and WU for participant owned generation and maintain the import of 40 MW of this capacity to the SPP footprint to prevent the capacity deficit in the near future. In this portfolio, MEAN would enter into a power purchase agreement for utility or community owned solar generation to provide for energy needs in SPP. This portfolio adds both renewable and fossil fuel resources to MEAN's SPP mix. MEAN can approximately half of the solar resources as accredited capacity, and in terms of nameplate capacity, MEAN would see an increase in renewable energy in SPP.

Portfolio 6: Extend Multi-Unit Participation Agreement + Generation Agent Arrangement

Portfolio 6 extends two current contracts to meet the future capacity and energy needs of MEAN in the SPP footprint. The Generation Agent Arrangement granting MEAN 40 MW of capacity of participant owned generation in Waverly and Indianola, is extended past its current expiration to provide capacity needed to meet MEAN's SPP load. This contract is extended only through 2023. At this point, the Multi-Unit Participation Agreement with NPPD that grants MEAN capacity and energy from NPPD's Cooper Nuclear Station and Gerald Gentleman Station, is extended. This portfolio does not improve the SPP resource portfolio in terms of fuel diversity or renewable holdings, raising the percentage of capacity and energy from fossil fuel resources.

Portfolio 7: Generation Agent Arrangement

This portfolio again extends the Generation Agent Arrangement for a total of 40 MW of participant owned generation from IMU and WU, starting at its termination date and extending through the remainder of the 15-year study period. However, this portfolio does not provide any additional energy, relying more on market purchases than other portfolios. This portfolio does not increase MEAN's fuel diversity or renewable percentage in SPP.

Portfolio 8: Wind + New Participant Owned Generation

Portfolio 8 eliminates the projected capacity deficit by increasing the amount of participant owned generation leased to MEAN. This resource would be obtained by the issuance of a Request for Proposals to all participants to solicit bids for generation in a total capacity of 40 MW to meet MEAN's total obligation in SPP. In addition, MEAN would enter into a power purchase agreement for wind generation when the energy deficit first occurs in SPP. This portfolio adds both renewable and fossil fuel resources to MEAN's SPP mix. The wind resource provides little accredited capacity, but when totaling nameplate capacity, MEAN would achieve an overall increase in renewable capacity and energy in SPP.

Portfolio 9: Solar + New Participant Owned Generation

This portfolio provides for the additional requirement for capacity in SPP using 40 MW of added participant owned generation. This leased capacity is acquired through a Request for Proposals submitted to all Participants with the goal of adding generation in a total combined capacity to meet the deficit. To provide the required energy in the later years of the study period, MEAN would sign a power purchase agreement for solar generation. With this portfolio, MEAN adds renewable and fossil fuel resources. Although the accredited capacity of the solar resource would add only about half of the nameplate

capacity to the portfolio, the energy contribution would increase the renewable generation in SPP.

Portfolio 10: Extend Multi-Unit Participation Agreement + New Participant Owned Generation

Portfolio 10 combines existing and new resources to meet the future capacity and energy needs in SPP. To address the more immediate capacity needs, MEAN will add to its fleet of leased participant owned generation via a bid process open to all Participants. At the point where MEAN anticipates an energy shortage, the Multi-Unit Participation Agreement with NPPD that grants MEAN capacity and energy from NPPD's Cooper Nuclear Station and Gerald Gentleman Station, is extended. The exact capacity included in the extension will be matched to actual needs. This portfolio does not improve the SPP resource portfolio in terms of fuel diversity or renewable holdings and increases the total capacity and energy from fossil fuel resources.

2. West Region

Portfolio 1: Natural Gas Combined Cycle

MEAN would contract for a partial ownership or a power purchase agreement for 45 MW of capacity and energy from a natural gas combined cycle plant. This resource is scheduled to enter MEAN's resource portfolio to coincide with the capacity deficit. The NGCC plant would not be operated in a market, and therefore not subject to economic dispatch. However, the plant would be dispatched by the operator when local economics are favorable. This portfolio achieves the goal of diversifying MEAN's resource portfolio in terms of fuel source and provides a high degree of operational flexibility.

Portfolio 2: Landfill Gas

This portfolio involves a partial ownership or a power purchase agreement for 45 MW of capacity and energy from one or more landfill gas plants. The LFG plant contract would enter MEAN's portfolio to fulfill the capacity deficit in the west. A landfill gas plant can be operated as a must-run unit or can be dispatched by operators in response to pricing and demand conditions. The Phase II economic model considers the LFG plant dispatched according to regional economics to provide capacity and energy. The LFG portfolio increases MEAN's percentage of renewables in the west in terms of capacity and energy and increases the fuel diversity of MEAN's portfolio.

Portfolio 3: Municipal Solid Waste

Portfolio 3 would add 45 MW of an MSW plant to MEAN's portfolio via a partial ownership contract or a power purchase agreement. The MSW plant would provide capacity and energy to MEAN with a resource contract scheduled to begin at the time of capacity deficit in the west. This portfolio increases the renewable percentage of MEAN's capacity and energy and contributes to the fuel diversity of MEAN's portfolio.

Portfolio 4: Wind + Natural Gas Combined Cycle

This portfolio adds both renewable and fossil fuel resources to MEAN's resource mix. In Portfolio 4, MEAN would enter into a power purchase agreement for wind generation when the energy and capacity deficit occurs in the west. Although the wind resource will provide very little accredited capacity, in consideration of nameplate capacity, MEAN

would achieve an overall increase in renewable energy. This portfolio would also add a partial ownership or power purchase agreement for 45 MW of capacity and energy from a natural gas combined cycle plant to provide for the remainder of the deficit. The effective date of this contract would occur in 2025 when the deficits begin.

Portfolio 5: Solar + Natural Gas Combined Cycle

This portfolio also adds both renewable and fossil fuel resources to MEAN's west region mix. In this portfolio, MEAN would enter into a power purchase agreement for utility or community owned solar generation to provide for energy needs in the west. MEAN can claim approximately half of the solar resources as accredited capacity, but in terms of nameplate capacity, MEAN would see an increase in renewables. This portfolio would also include MEAN's partial ownership or participation in a power purchase agreement for 45 MW of capacity and energy produced by a natural gas combined cycle plant. Both resources would be added to the portfolio in 2025 when the west experiences a deficit.

Portfolio 6: CES + Natural Gas Combined Cycle

Portfolio 6 combines the Creative Energy Solutions pyrolysis plant as described in Section XII with a natural gas combined cycle plant to provide the required capacity and energy to meet the project deficits in the west. The CES project is expected to be an approximately 22 MW facility operating at a high capacity factor. MEAN would enter into a power purchase agreement with CES. The natural gas combined cycle plant could be contracted as a partial ownership or a power purchase agreement and would be planned for approximately 23 MW to meet the capacity needs projected in the west. This portfolio would increase MEAN's renewables and provide fuel diversity.

Portfolio 7: Wind + New Participant Owned Generation

This portfolio provides for the future requirement for capacity in the west by adding approximately 45 MW of participant owned generation. This leased capacity is acquired through a bidding process available to all Participants with the goal of adding generation in a total combined capacity to meet the deficit. To provide the required energy in the applicable years of the study period, MEAN would sign a power purchase agreement for wind generation. With this portfolio, MEAN adds renewable and fossil fuel resources. Although the accredited capacity of the wind resource would be minimal, the nameplate capacity and the energy contribution would increase MEAN's percentage of renewables.

Portfolio 8: Solar + New Participant Owned Generation

This portfolio also adds both renewable and fossil fuel resources to MEAN's resource mix. Portfolio 8 eliminates the projected capacity deficit by increasing the amount of participant owned generation leased to MEAN by approximately 45 MW. This resource would be obtained by the issuance of a Request for Proposals to all participants to solicit bids for generation in a total capacity to meet MEAN's total obligation in the west. In addition, MEAN would enter into a power purchase agreement for solar generation to provide the required energy. The solar resource provides about half of nameplate as accredited capacity, but in terms of nameplate capacity MEAN would achieve an overall increase in renewable resources in the west.

Portfolio 9: CES + New Participant Owned Generation

Portfolio 9 includes the power purchase agreement with CES for the 22 MW pyrolysis plant as described in Section XII. This resource would add capacity and energy capabilities to MEAN's west portfolio. To supplement this capacity, MEAN would again contract with Participants to lease approximately 23 MW of additional participant owned generation for capacity requirements. MEAN would invite all participants to bid to add generation assets to the portfolio. With this portfolio, MEAN adds renewable capacity and energy and increases its fuel diversity in the west.

D. Hourly Resource Profile

To study each of the proposed portfolios, the model determines the generation of each resource in the portfolio on an hourly basis. This begins with the hourly resource profile, or hourly available capacity.

Available capacity is determined according to season of year, time of day, planned maintenance, forced outage rates, and variable fuel costs. Availability of existing resources is modeled on historical operating data and planned outage schedules.

For proposed new resources, availability is modeled after similar existing resources, known capacity factors, projected planned and forced outage rates, and for intermittent resources, hourly generation profiles of similar technologies in similar locations.

E. Economic System Model

The Economic System Model used for the portfolio analysis is depicted in *Figure XIV-1*:

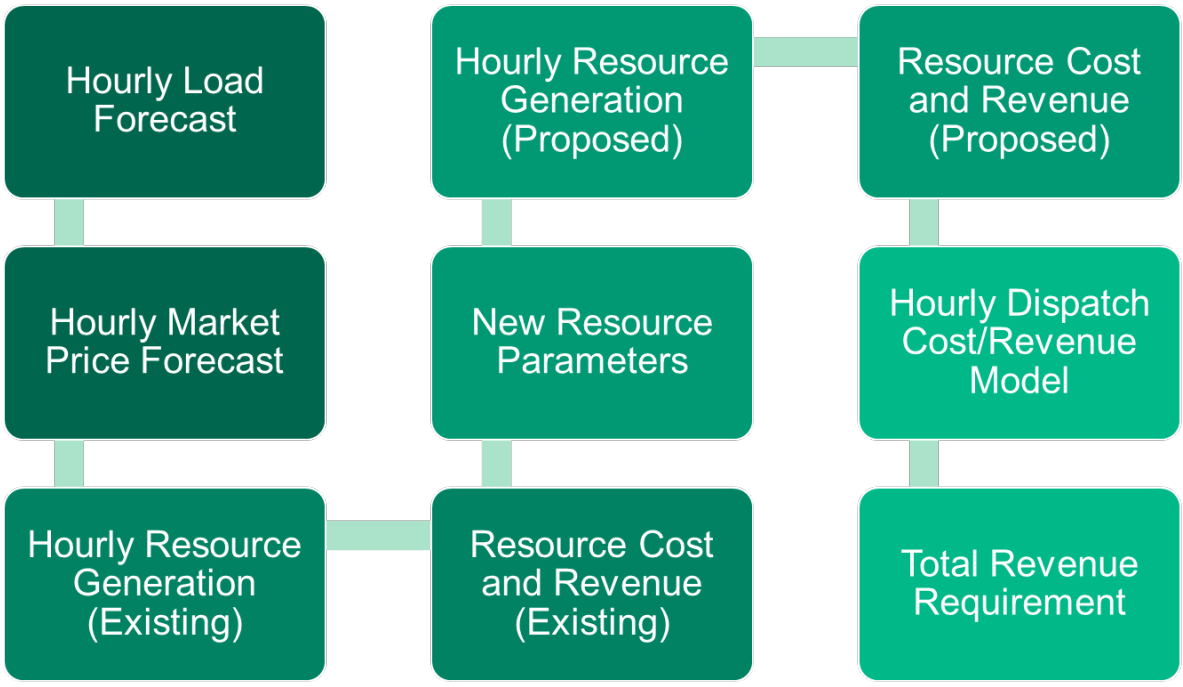


Figure XIV-1

The model calculates the deployment of available capacity, as determined by market and unit economics, to meet anticipated demand on a least-cost basis. Due to regional differences, separate models were created for SPP and the west.

Since market conditions and economics change on an hourly basis, each region's load was calculated hour by hour for the entire 15-year time range. This was accomplished by calculating each town's annual hourly load profile averaged over the last 10 years and applying the hourly profile to the forecasted monthly peak demand and energy consumption and finally summing each region's hourly load.

Hourly market pricing was provided by a third-party consultant. The pricing provided was specific to large regional areas. Since economic dispatch in market constructs is determined in part by the locational marginal pricing, the model needed the individual nodal prices for each MEAN resource as well as a load price. Comparing historical nodal pricing to a historical average regional price on an hourly basis created an hourly profile that related the nodal price to the regional price. This profile was then applied to the forward pricing projections for the larger areas. This calculated pricing per hour for the 15-year study period for each resource and the MEAN load node in SPP. In the west, the regional pricing was used.

For existing resources, current costs of generation were compiled, including fixed operation and maintenance costs, variable operation and maintenance costs, fuel costs, and anticipated capital investment. The escalation rates for future pricing were extracted from past billings and contract terms. In addition, actual operating parameters were recorded, such as heat rates and emissions factors.

Similarly, operating parameters and costs were estimated for new resources. Operating metrics, such as capacity factor, emissions data, outage rates, minimum turndown, etc. were collected primarily from publicly available data from EIA, NREL, and other DOE sources as well as some published studies. From these same sources, the generating costs of the proposed resources were calculated using capital costs, fixed O&M, variable O&M, and fuel costs with a determination of the escalation rate of each cost.

For portfolios that included a specific facility, namely the CES pyrolysis project and an identified natural gas plant in the SPP footprint, actual proposed pricing and operating data was provided and incorporated into the model calculations.

The hourly resource profile as described above only determined when each resource was available to operate, and in the case of existing and intermittent resources, the typical expected generation for each hour. Resource availability, however, does not guarantee resource operation for dispatchable resources. To account for economic dispatch in the SPP market, the variable operating costs of a resource were compared against the nodal locational marginal price on an hourly basis. Only when the variable cost was less than the LMP was the resource considered to be in operation.

Each resource was then categorized according to its operating mode – intermittent resources, must-run resources, WAPA allocations, resources with minimum operating levels, and dispatchable resources. All resources were dispatched into the model against the hourly load according to operating mode. This resulted in a tabulation of the hourly generation, the hourly cost of generation, the hourly revenue from market sales, and the hourly cost of load (in SPP).

All costs and revenues were summed on an hourly basis, then combined on an annual basis, and finally summed for the entire 15-year study period to arrive at the total revenue requirement. Each

portfolio was entered into its regional model, and a total revenue requirement was calculated for each portfolio.

It should be noted that the revenue requirements calculated by the model include only resource-related costs of the components input into the model. These values are not intended to represent MEAN's total revenue requirements.

F. Sensitivity Scenario Analysis

The model was expanded to include the effects of a number of different scenarios. As external conditions change, generation costs and market costs change. This alters the economics of each portfolio in a different way. Two very significant factors that affect generation are natural gas prices and the potential of a carbon tax. Changes in natural gas pricing influence the generation level of natural gas resources, and as a result will affect the generation of other resources to compensate in response to load demand, which in turn affects the pricing of other fuels. In this way, fuel pricing and the overall regional resource mix are interrelated. In the same way, the imposition of a carbon tax will increase the generating cost of some resources, which changes generating levels and fuel costs.

The sensitivity analysis included three levels of natural gas pricing: low (lower than current projections), base (equal to current projections), and high (higher than current projections). Each of these price levels was combined with three possible carbon tax futures: no tax, a medium tax rate, and a high tax rate. Each of these scenarios introduced variations in fuel costs and carbon costs into the variable energy cost of each resource, ultimately affecting the final revenue requirement of each portfolio.

The table in *Figure XIV-2* displays the scenarios under which the model was simulated. Each portfolio was entered into the model for each sensitivity.

Sensitivity Analysis Scenarios

		Natural Gas Price		
		Low	Base	High
CO_2 Tax	No	1	4	7
	Med	2	5	8
	High	3	6	9

Figure XIV-2

G. Model Results

For the model results, Scenario 5, which included the base natural gas pricing and a medium carbon tax, was considered the base case. Other scenarios indicate a variation from the base case conditions.

1. SPP

The chart in *Figure XIV-3* shows the results of the SPP model for all eleven portfolios described in Section XIV.C.1. and all nine scenarios tabulated in *Figure XIV-2*. The dark blue bar represents the base case total revenue requirement for each portfolio. The light blue vertical line shows the positive and negative deviation from the base case, or the range from the maximum revenue requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the "scenario variance".

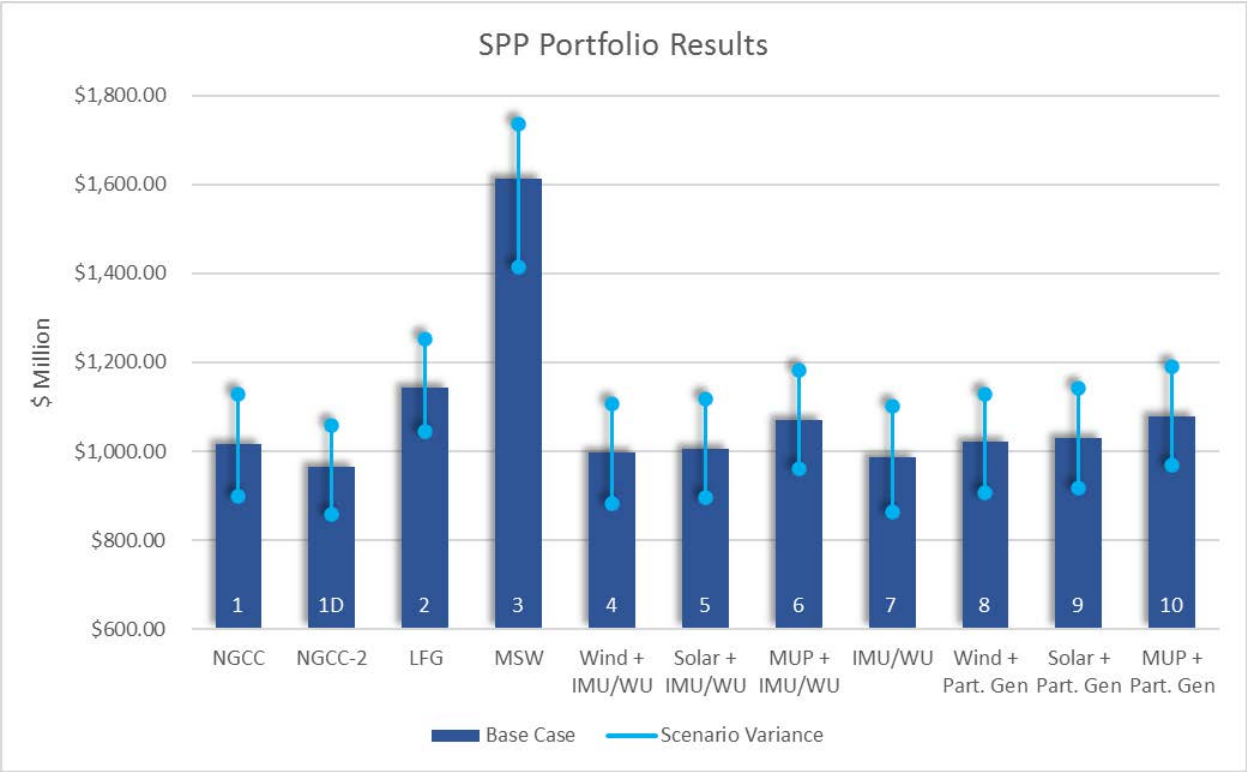


Figure XIV-3

The table in *Figure XIV-4* illustrates the same data with the values displayed and the addition of a metric showing the incremental percentage above the lowest cost portfolio.

Portfolio #	Description	Cost (Base Case)	+/-	Variance
1	NGCC	$1,015,852,691	+5.4%	10.96%
1D	NGCC-2	$963,846,484	--	9.84%
2	LFG	$1,144,257,293	+18.7%	9.52%
3	MSW	$1,611,527,936	+67.2%	7.72%
4	Wind + IMU/WU	$998,390,183	+3.6%	10.79%
5	Solar + IMU/WU	$1,005,032,419	+4.3%	11.15%
6	MUP + IMU/WU	$1,069,721,394	+11.0%	10.47%
7	IMU/WU	$987,129,129	+2.4%	11.64%
8	Wind + Member Gen	$1,021,745,696	+6.0%	10.54%
9	Solar + Member Gen	$1,028,387,932	+6.7%	10.90%
10	MUP + Member Gen	$1,077,687,596	+11.8%	10.39%

Figure XIV-4

The positive variance, or the differential between the maximum scenario revenue requirement and the base case revenue requirement, quantifies the risk inherent in each portfolio relative to possible changes in fuel pricing and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the SPP Portfolios. These metrics are displayed in *Figure XIV-5*.

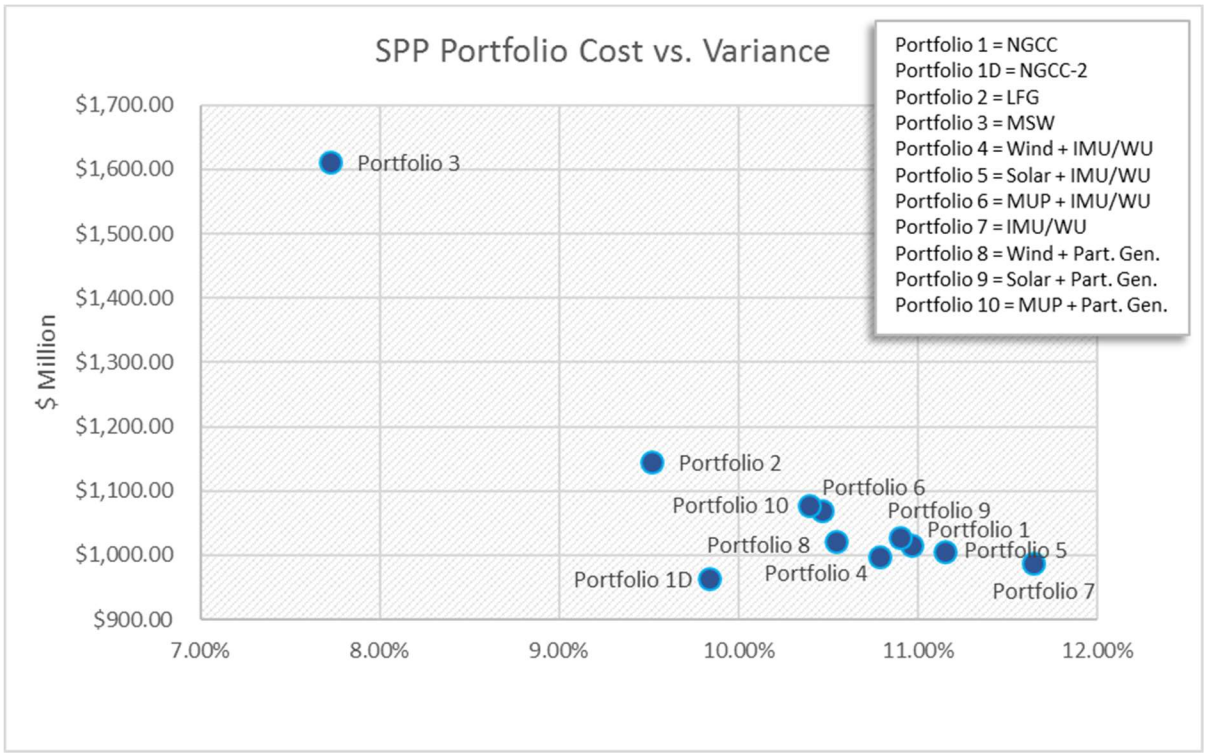


Figure XIV-5

To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in *Figure XIV-6*.

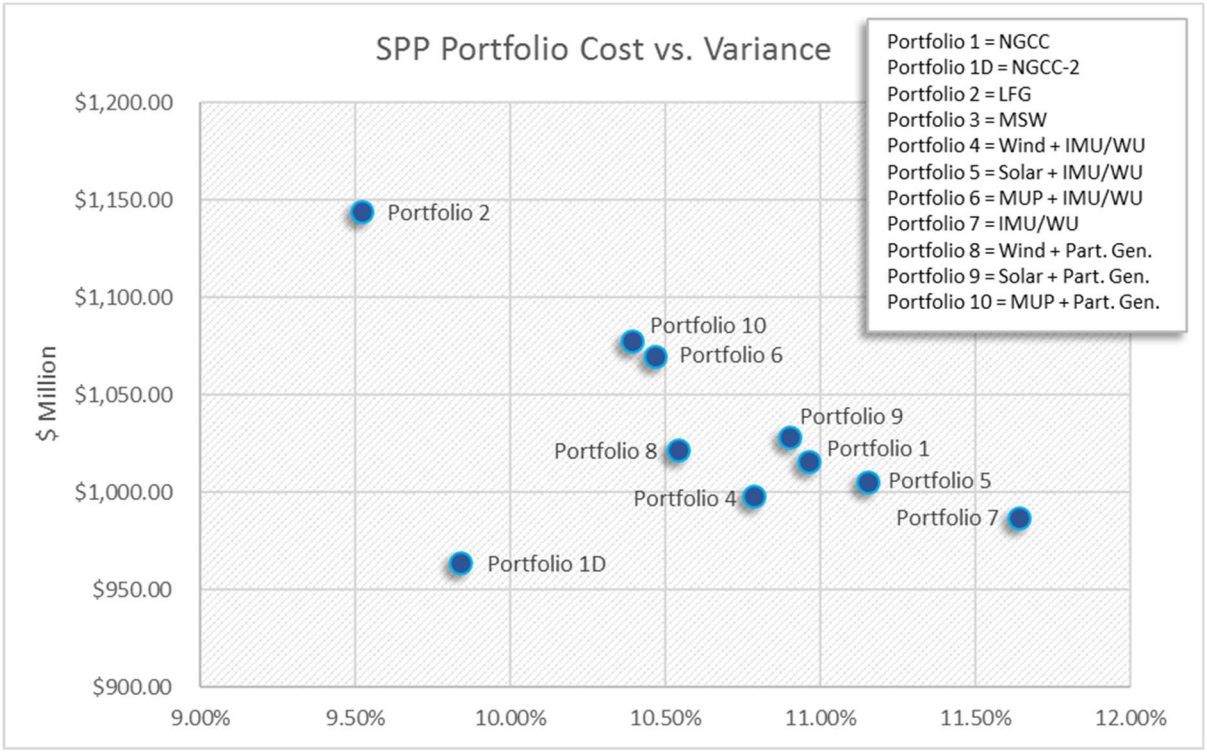


Figure XIV-6

The values and graphical results show that Portfolio 1D, the identified natural gas plant, has the lowest revenue requirement. While Portfolio 2, the landfill gas plant, has the lowest variance, its base case cost is the highest of all options, and the variance of Portfolio 1D is only slightly higher.

2. West Region

The chart in *Figure XIV-7* shows the results of the west model for all nine portfolios and all nine scenarios. The dark green bar represents the base case total revenue requirement for each portfolio. The light green vertical line shows the positive and negative deviation from the base case, or the range from the maximum revenue requirement of the sensitivity scenarios and the minimum revenue requirement of the sensitivity scenarios. This range is termed the “scenario variance”.

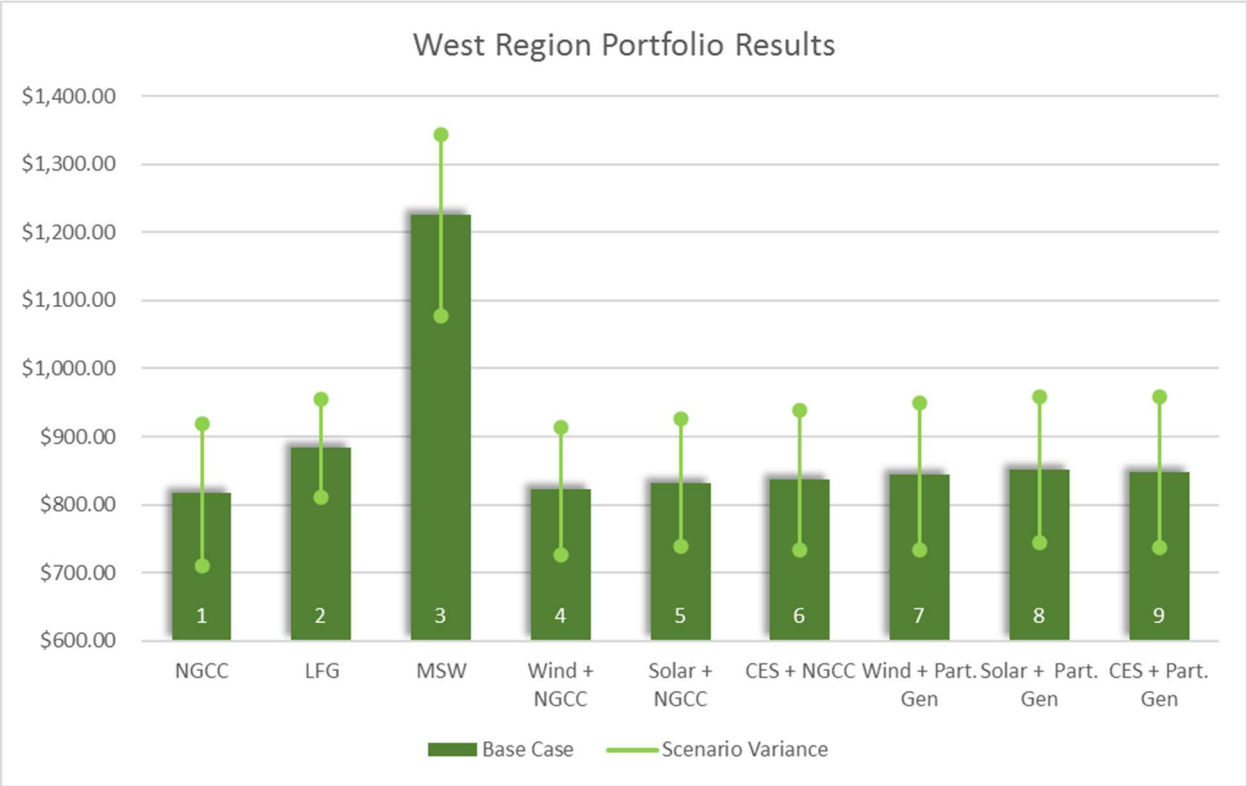


Figure XIV-7

The table in *Figure XIV-8* illustrates the same data with the values displayed and the addition of a metric showing the incremental percentage above the lowest cost portfolio.

Portfolio #	Description	Cost (Base Case)	+/-	Variance
1	NGCC	$817,711,474	--	12.29%
2	LFG	$884,432,526	+8.2%	7.96%
3	MSW	$1,226,420,324	+50.0%	9.52%
4	Wind + NGCC	$822,249,284	+0.6%	11.16%
5	Solar + NGCC	$832,250,149	+1.8%	11.21%
6	CES + NGCC	$836,184,718	+2.3%	12.24%
7	Wind + Member Gen	$844,282,725	+3.2%	12.44%
8	Solar + Member Gen	$851,503,878	+4.1%	12.49%
9	CES + Member Gen	$848,216,639	+3.7%	12.95%

Figure XIV-8

The positive variance, or the differential between the maximum scenario revenue requirement and the base case revenue requirement, quantifies the risk inherent in each portfolio relative to possible changes in fuel pricing and carbon tax levels. Plotting the base case revenue requirement against this variance allows a concurrent view of cost and risk for each of the west Portfolios. These metrics are displayed in *Figure XIV-9*.

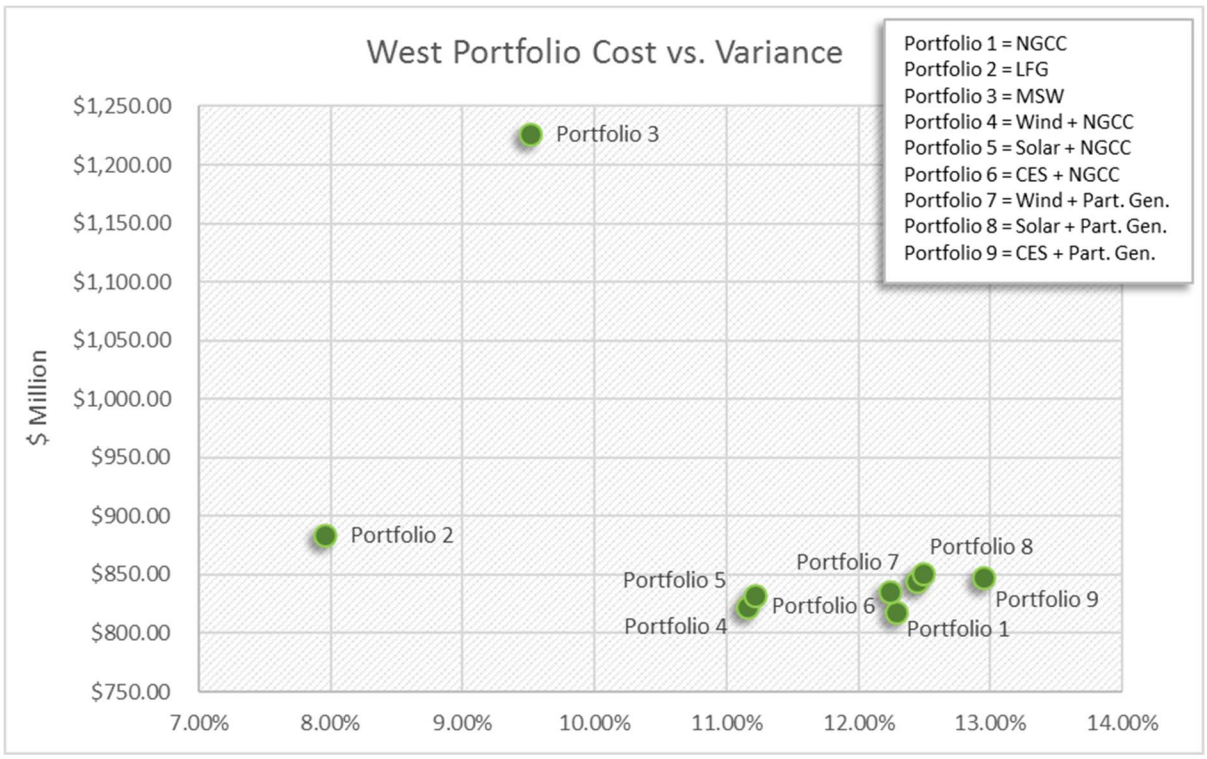


Figure XIV-9

To get a more distinct picture of the relative positions of the portfolios, Portfolio 3 is omitted from the graph in *Figure XIV-10*.

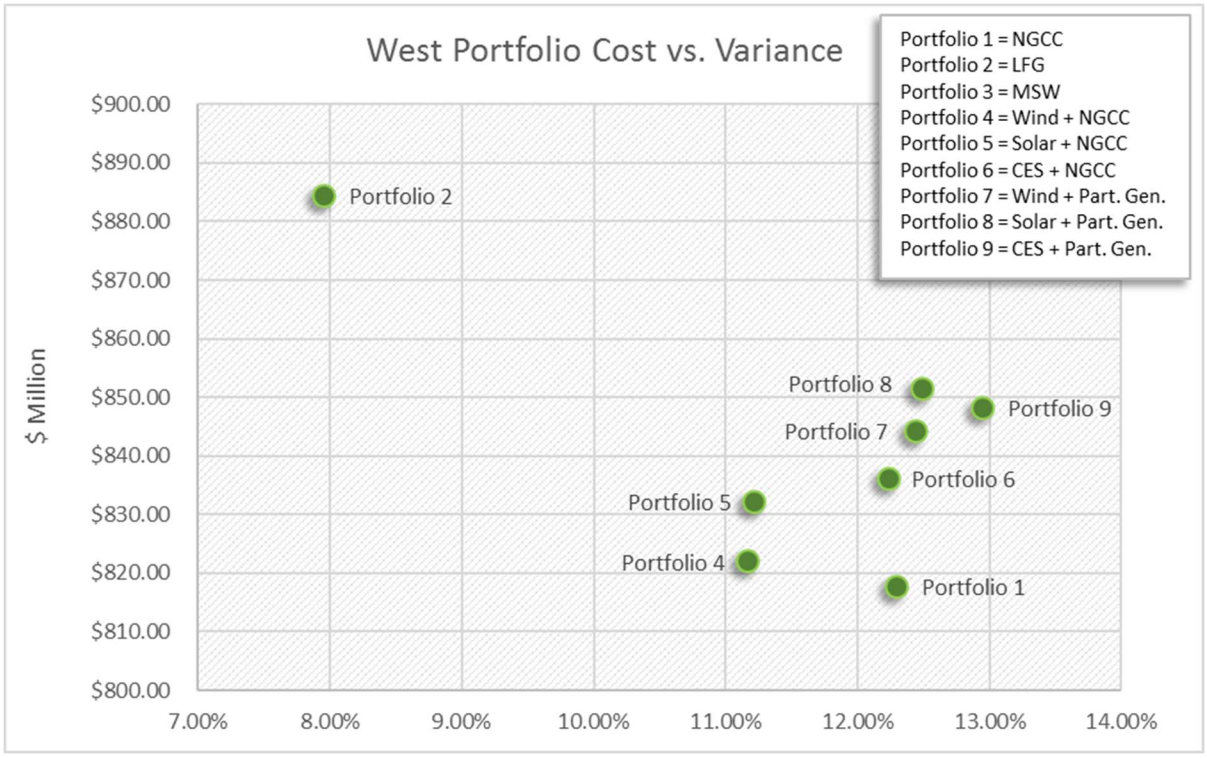


Figure XIV-10

The values and graphical results show that Portfolio 1, the natural gas plant, has the lowest revenue requirement, but not significantly lower than Portfolio 4, the wind resource and natural gas plant. While Portfolio 2, the landfill gas plant, has the lowest variance, its base case cost is the highest of all options.

XV. Environmental Impact

A. Existing Environmental Considerations

MEAN is subject to environmental and other regulations, in varying degrees, at federal, state and local levels. These regulations, as well as MEAN's compliance status, are detailed in Section IV.A.

As part of a long-term strategy, MEAN has invested in environmental regulation compliant base load generating resources expected to provide highly reliable base load generation for the Participants' present and future energy requirements. Wygen Unit I provides stable base load capacity and energy to MEAN from a modern generating station with a state of the art emission control system. Upon commercial operation in 2007, WSEC4 enabled MEAN to substantially reduce the market purchases of energy required to meet the Participants' energy requirements. WEC2 was constructed to provide a hedge against market purchases based on marginal generation from high natural gas prices occurring at the time of its construction.

The proliferation of hydraulic fracturing technology has created low natural gas prices, and the effects of wind generation offers into the RTO markets have kept WSEC4 and WEC2 at minimum generation periodically despite low incremental costs of production. These units have shown flexibility in low priced markets with the ability to turn down to 50% of their full capacity, and the ability to offer in for market dispatch after maintenance outage which provides economic relief when prices are below the offer price and covers the cost of start-up when the unit is ultimately dispatched for generation. MEAN believes the boiler design for WSEC4 and WEC2 is highly reliable, resulting in high operating efficiency and state of the art environmental compliance. As cost-based resources, MEAN believes WSEC4 and WEC2 produce energy at relatively level prices and enhance MEAN's ability to provide long-term price stability to its Participants.

In addition to these state-of-the-art coal facilities and WAPA allocations, MEAN has acquired renewable resources and nuclear capacity. MEAN has considered the addition of new renewable resources as other coal and nuclear agreements expire in the near term.

MEAN also works with Participants that set local standards to develop solutions. The City of Aspen, Colorado expressed a desire to obtain 100% of its power from renewable resources, and MEAN worked with Aspen to develop a solution to achieve this goal in 2015.

B. Supply Side Resource Options Environmental Impact

In the Phase I evaluation of supply side options, environmental impact was considered for all options as part of the scoring process. Two categories reflected the consideration of a resource's current and future effects on the environment. Scoring categories included Emissions/Environmental Impact, which calculated and compared the emissions levels for carbon, SO_2, NOx, and mercury, and Environmental Policy Risk, which estimated the degree to which a resource could be affected by the imposition of future environmental regulations.

In the participant survey, these categories ranked near the middle, and therefore had an average weighting in relation to other criteria. Therefore, the initial round of supply side resource evaluation acted to eliminate resource options that resulted in a high level of environmental impact.

C. Carbon Cost Scenario Impact

The inclusion of the carbon tax sensitivity scenarios provides a method by which the impact of carbon emissions can be quantified for each portfolio as a whole. For each level of natural gas pricing, the results for the scenarios with no carbon tax can be compared against the results for the scenarios with a high carbon tax to show the consequence of high carbon emissions. The average variance resulting from only the carbon tax (holding the natural gas pricing constant) is shown in *Figures XV-1* and *XV-2*.

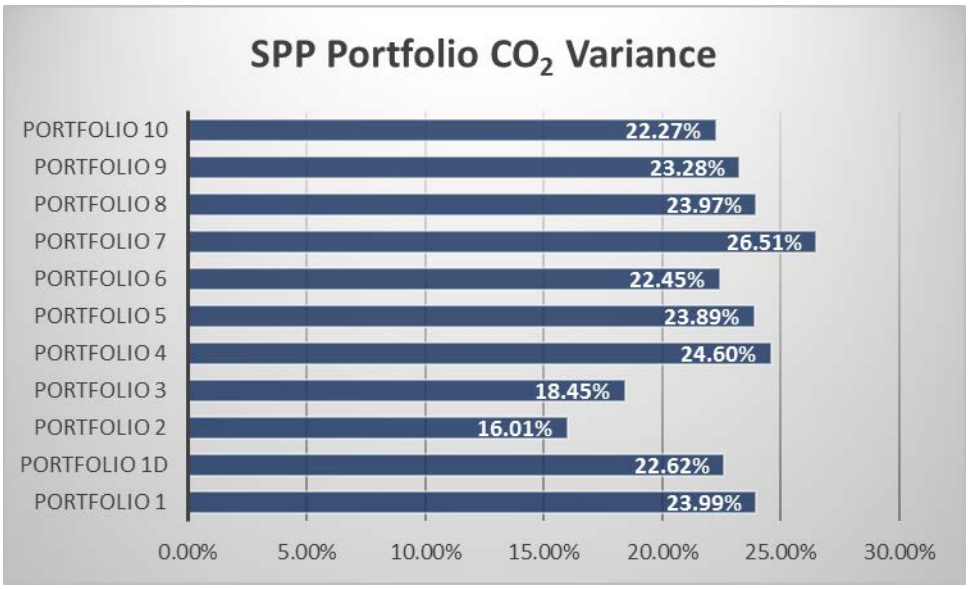


Figure XV-1

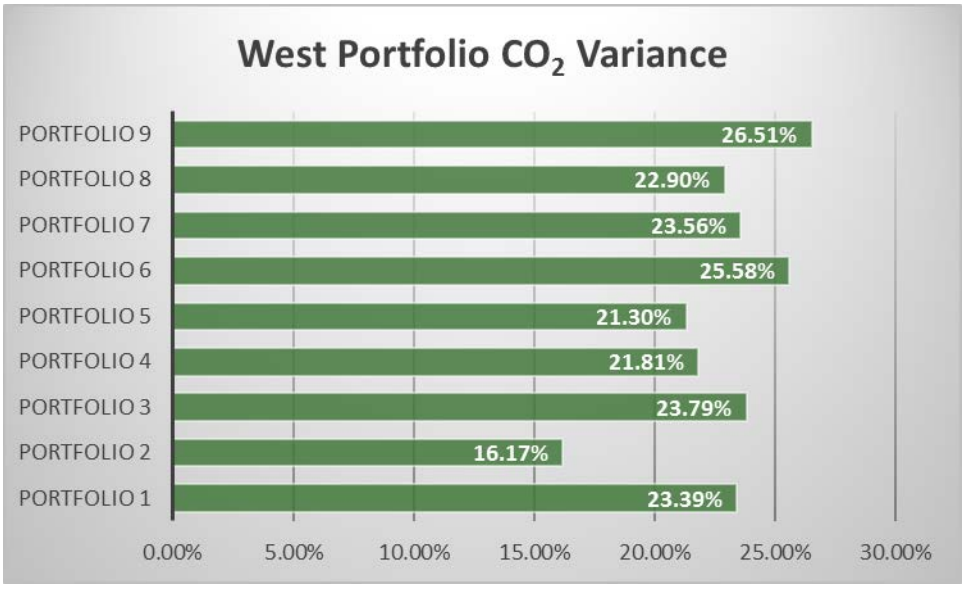


Figure XV-2

These results show an expected relation. Portfolios that include more fossil fueled capacity or more market energy purchases see a higher cost impact from a carbon tax. In this way, higher emitting resources are "penalized" in the model with a higher degree of variance. The effects of carbon emissions were included in the variance factor used in the analysis of the final portfolio results.

XVI. Conclusions and Recommended Action Plan

Based on the data and analysis in this IRP report, MEAN has developed conclusions relative to proposed demand side solutions and supply side solutions.

A. Conclusions

1. MEAN's Future Resource Needs

In the SPP service territory, MEAN has a need for capacity in the near term and throughout the study period. The capacity deficit is approximately 35 MW. The energy deficit does not occur until the end of this period.

In the west region, MEAN has concurrent capacity and energy deficit that occurs in 2025 and remains relatively constant for the remaining period. The capacity deficit is approximately 45 MW.

2. Demand Side Management – Conclusions

New DSM Programs: The costs and benefits of the proposed new DSM programs were compared using three different calculation methods. These three tests consider the costs and benefits of the DSM programs from different perspectives. A calculated ratio greater than 1 indicates that a program is likely to result in benefits that outweigh its costs and therefore provide a net positive impact to MEAN or the end-use customer, depending on the test. In total, only one program had a favorable result, but in only one of the three tests. Therefore, none of the potential programs would prove beneficial to MEAN and the end-use customer to a point that would compensate for the required costs.

LED Lighting Upgrade Program: This program was initiated in FY 2016-17 and was successfully implemented throughout MEAN's system. The total annual energy savings achieved by the program is projected to be 1,131 MWh, and the peak demand savings is projected to be 209 kW. These savings are reflected in the current load forecast. The NMPP Services Committee has approved the continuance of the LED Lighting Upgrade program through FY 17-18.

Other existing MEAN DSM programs to be continued include: Infrared Energy Audits, ENERGYsmart Vending Miser Bulk Purchasing Program, Member Exclusive Education Sessions, and the energy efficiency education content of *Essent* Newsletter subscriptions.

Participant DSM Programs: The 2016 Participant DSM survey revealed a total of 26 communities with 42 DSM programs in place. The non-coincident sum of the demand and energy savings from these DSM programs is 15.15 MW and 6,988 MWh, respectively. These community programs are expected to be maintained in future years. MEAN repeats the DSM survey on an annual basis to track these programs and the impact on MEAN's demand and load.

3. Supply Side Resources – Conclusions

Based on the April 2017 Participant survey, the preferred resource portfolio option should consider low cost as a requisite condition. To reflect this preference, the Phase I evaluation highly weighted the capital cost and energy cost of each option. To further investigate the life cycle cost of each proposed resource portfolio, the Phase II economic analysis calculated the total revenue requirement related to each portfolio's resources

over the 15-year study period. The final results clearly indicate the portfolio options with the lowest cost.

In the course of multiple participant meetings and workshop sessions, MEAN received feedback from participants that signified an inclination toward resource solutions that provide a local benefit or allow for local participation. In fact, this criterion was also scored as the second most important in the participant survey conducted in April 2017. Examples of such resources discussed by participants were: leasing of additional participant owned generation and renewable distributed generation, such as community solar. In response, MEAN heavily weighted the Local Benefit score for each of the supply side options in the Phase I evaluation. In addition, resources were added to the proposed portfolios in the Phase II economic analysis to provide options with local benefit. In particular, both participant owned generation and community solar were included in the analysis.

Internal feedback from MEAN Operations communicated an appeal for resources that allow for operational flexibility. Due to constantly changing market conditions, the ability to schedule the output of a resource in response to changes in load and market price is very valuable. The value of this flexibility often translates into financial value as well, which relates to the priority of cost-effectiveness. As part of the Phase I analysis, Flexibility/Dispatchability was ranked as the third most important of the criteria and was weighted accordingly in the scoring. Also, since the economic model used in the Phase II analysis included both generating costs and market sale and purchase costs, dispatchable resources could operate in response to this differential and either realize financial benefit or avoid disadvantaged pricing, whereas non-dispatchable resources did not operate in this manner.

SPP:

- The proposed portfolio in SPP that best achieved the primary goal of low cost was Portfolio 1D, the addition of capacity and energy from an identified natural gas combined cycle plant located in the SPP footprint. This option also provides for operational flexibility and fuel diversity, but not local benefit.

- The second lowest cost option in SPP was Portfolio 7, the extension of the Generation Agent Arrangement with IMU and WU for lease of their participant owned generation. This option is low cost and provides local benefit. Since these units are typically not run for energy needs, this option relies on market purchases for energy.

- The next best options in terms of cost were Portfolios 4 and 5, the combination of the Generation Agent Arrangement for capacity and the addition of a wind or solar resource for energy needs. These options achieve the low-cost goal, increased fuel diversity, and can be configured for local benefit, but do not allow operational flexibility.

West:

- The proposed portfolio in the west that best achieved the primary goal of low cost was Portfolio 1, the addition of capacity and energy from a natural gas combined cycle plant. This option also provides for operational flexibility and fuel diversity, but not local benefit.

- The next best options in terms of cost were Portfolios 4 and 5, the combination of the natural gas combined cycle plant for capacity and energy and the addition of a wind or solar resource for additional energy needs. These options achieve the low-cost goal and increased fuel diversity, the wind and solar resources can be configured for local benefit, and the natural gas combined cycle plant allows for operational flexibility.

- In response to participant interest in resources with local benefit, MEAN will further investigate more economical ways to include the CES project (to be located in a participant community) and additional participant owned generation into other portfolios.

B. Proposed Future Resource Portfolios

1. Committee Recommendation and Board Approval

Following the presentation of the Phase II Economic Modeling results and the relative revenue requirements and cost variance risk of each proposed portfolio, the Power Supply Committee discussed the portfolios in light of the conclusions described above. Consequently, the Committee recommended to the Board the adoption of the IRP with the incorporation of a plan to pursue the following future portfolios by region:

SPP:

- Portfolio 1D – Identified Natural Gas Combined Cycle Plant
- Portfolio 7 – Extension of Generation Agent Arrangement
- Portfolio 8 – Wind and Participant Owned Generation
- Portfolio 9 – Solar and Participant Owned Generation

West:

- Portfolio 1 – Natural Gas Combined Cycle Plant
- Portfolio 7 – Wind and Participant Owned Generation
- Portfolio 8 – Solar and Participant Owned Generation
- Portfolio 9 – CES and Participant Owned Generation

The Board unanimously voted to approve the resolution to accept this recommendation from the Power Supply Committee.

C. Recommended Action Plans

Based on the above conclusions and Board recommendations, MEAN has determined the following action plans in relation to demand side management resources and supply side resources in response to future projected capacity and energy deficits throughout its service territory.

1. Short-Term Recommended Action Plan (0-5 Years)

MEAN will continue to administer all current DSM programs: LED Lighting Upgrades, Infrared Energy Audits, ENERGYsmart Vending Miser Bulk Purchasing Program, Member Exclusive Education Sessions, and the *Essent* Newsletter subscriptions. MEAN will revisit the proposed new programs upon any significant change in the analysis inputs to reevaluate the benefit to cost ratio. Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities. MEAN will continue to perform the DSM annual survey and include DSM demand and energy savings into the load forecast.

In SPP, MEAN will pursue one of the low-cost portfolio options to prevent the impending capacity shortage. This would involve the initiation of negotiations with the owners of the natural gas combined cycle plant as previously described toward a partial ownership or PPA arrangement, discussions with IMU and WU regarding extension of the Generation Agent Arrangement, or even investigation into additional existing participant owned generation not currently under a lease contract with MEAN that would be available in the near term.

In the west, there is no short term need for supply side resources. MEAN will gather data on potential future resources and maintain a readiness for procurement of new capacity and energy when the projected shortage approaches.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change will trigger a revised resource plan to determine required modifications and future actions.

Throughout MEAN's footprint, continual efforts will be made to acquire additional load. All three served regions have an energy surplus, representing an opportunity for additional energy sales without an immediate expense of additional capacity purchase.

2. Long -Term Recommended Action Plan (5-15 Years)

MEAN will regularly evaluate the impact and implementation of existing DSM programs. Based on the results of the evaluation, MEAN will continue to administer successful programs. MEAN will revisit the proposed new programs on a regular basis to recalculate the analysis inputs and reevaluate the benefit to cost ratio. Programs that receive a favorable ratio should be planned for a trial roll-out in interested communities to verify projected savings prior to widespread execution. Participants will be encouraged to continue existing DSM programs and initiate any new measures welcomed by their communities.

In SPP, depending on the actions taken to relieve the short-term capacity deficit, MEAN will secure a long-term solution for additional capacity and an energy resource for future years. If additional capacity is still required, MEAN will pursue one of the lower cost portfolio options. If not already secured during the short-term action plan, this could involve negotiations with the owners of the previously described natural gas combined cycle plant in pursuit of a partial ownership or PPA arrangement, discussions with IMU and WU regarding extension of the Generation Agent Arrangement, or investigation into additional new or existing participant owned generation. Of course, in future years, MEAN would investigate other natural gas combined cycle plants for comparative terms. For energy requirements, the natural gas combined cycle plant would offer a solution that

could operate at a range of capacity factors, or a wind or solar resource would provide low cost energy and increase MEAN's renewable portfolio.

In the west, MEAN will search out the lowest cost resources for capacity and energy as determined in the analysis. MEAN will explore opportunities to contract with a natural gas combined cycle plant in the region for capacity and energy purchase or a partial ownership arrangement. Concurrently, MEAN will solicit its participants for opportunities to lease new or existing participant owned generation. If terms and costs of this option are favorable in comparison to the natural gas plant, MEAN would require a separate energy source. According to the analysis results, MEAN should explore available wind and/or solar resources, giving preference to community-based installations.

MEAN will continue to monitor actual load for all participant communities and compare against the load forecast and against existing capabilities. Any significant change will trigger a revised resource plan to determine required modifications and future actions.

Throughout MEAN's footprint, continual efforts will be made to acquire additional load and extend terminating contracts. Depending on the load profile in comparison to the rest of MEAN's system load and resource additions made in the short term, there may be opportunity to supply energy without additional capacity investment.

D. Tracking/Measurement Strategy

MEAN will employ the following Measurement Strategies to gauge the progress and impacts of the Recommended Action Plans described above.

METRIC	MEASUREMENT STRATEGY	MEASUREMENT BASELINE
Load vs. Forecast	MEAN will annually compare the actual peak demand and energy consumption against the forecast values. Data will be tracked by participant, region, and system. MEAN also conducts an annual load survey to aid in this measurement.	• Annual Load Forecast • 15-Year Load Forecast • Hourly/Monthly Participant Load Data
Load vs. Capability	On a semi-annual basis, MEAN is required to calculate and present to the Board the upcoming peak season Load and Capability balance for planning purposes. MEAN typically presents a long-term outlook. In this way, changes in the timing of deficits can be foreseen to prepare via resource planning.	• Annual Load Forecast • 15-Year Load Forecast • Resource Contracts • Hourly Resource Generation Data • Current Season Load and Capability Report
DSM Savings/Impact	MEAN conducts an annual DSM survey to all participants to gather data on the programs offered and the expected demand and energy savings. Responses will be compared year-to-year to verify savings. This is valuable in the contemplation of future programs. MEAN also tracks data on its administered Lighting Upgrade Program for estimated power savings.	• Previous Year Hourly Participant Load Data – Peak and Energy Usage • DSM Survey Responses • Energy Star® Energy Efficiency Calculation Tools
Existing Resource Performance	MEAN tracks the operation, performance, and cost of its contracted resources. This is measured against expected and contracted values and can be used to gauge the cost-effectiveness of future resources.	• Resource Contracts • Previous Year Hourly Resource Generation Data • Resource Invoices
New Resource Parameters	MEAN regularly tracks research on the costs and parameters of new resources. Understanding the performance of established and emerging technologies and the total generating cost in relation to market conditions will prepare MEAN for future resource acquisition.	• Resource Data Used for IRP (EIA, NREL, DOE) • Market Pricing
Environmental Regulation	MEAN continually monitors environmental regulations, paying particular attention to future legislation affecting the power supply industry. When changes are proposed or adopted, MEAN projects the impacts on existing or potential future resources. Currently, MEAN is alert for changes in the status of the Clean Power Plan and power resource tax credits.	• Status Quo Regulations • MEAN's current compliance status

Figure XVI-1

Appendix A – Meeting Presentations

A. January 2017 Board and Committee Meetings

POWER SUPPLY COMMITTEE

CALL TO ORDER

Chairman Leroy Frana called the meeting to order at 1:07 p.m. (CT). Pursuant to Section 84-1412 (8) of the Nebraska Open Meetings Act, a current copy of the Open Meetings Act was posted in the meeting room and made available to the public.

ROLL CALL

A quorum was declared with ten of the eleven committee members in attendance.

1. Leroy Frana, Nebraska City
2. James DePue, Wray
3. Duane Hoffman, Oxford
4. Bill Moser, Arnold
5. Wes Olson, Red Cloud
6. Tom Ourada, Crete
7. Mike Palmer, Sidney
8. Chris Rodman, Wall Lake
9. Jeremy Tarr, Burwell
10. Randy Woldt, Wisner

Jeff Wells, Voting Ex-Officio

Absent: Doug Staab, Broken Bow

Others in attendance: Rod Brestel, Gordon Bridges, Barthold Brinkman, Jim Cederburg, Ron Christian, Pat Davison, Brock Domeier, Richard Eymann, Mike Ferguson, Tom Goulette, Bill Hinton, Nate James, Marlene Johnson, Eric Johnson, Gary Jorn, Mike Kalkwarf, Todd Kielkopf, Bill Leners, Bob Lockmon, Lynn Longmore, Brent Nation, Phil Overeynder, John Prettyman, Rick Rigel, Jim Roblyar, Alan Romine, Doug Schultz, Jeff Sprock, Rob Stangel, Adam Suppes, and Darrel Wenzel.

NMPP staff: Beth Ackland, Rich Andrysik, Carol Brehm, Tim Cerveny, Shannon Coleman, Chris Dibbern, Katrinka Dicke, Bruce Doll, Brad Hans, Kara Hunt, Jamie Johnson, Jill Jones, Kyle Kaldahl, Gen Li, Bob Poehling, Joe Rivera, Andrew Ross, Kim Schafers, Armin Sehic, Tim Sutherland, Candy Thomazin, and Kevin Wickham.

BOARD OF DIRECTORS

CALL TO ORDER

Chairman Tom Goulette called the meeting to order at 9:03 a.m. (CT). Pursuant to Section 84-1412(8) of the Nebraska Open Meetings Act, a current copy of the Open Meetings Act was posted in the meeting room and made available to the public.

ROLL CALL

A quorum was declared with 42 of the 54 Directors in attendance.

1. Teresa Bartlett – Beaver City
2. Collin Biesler – Fairbury
3. Rod Brestel – Callaway
4. Ron Carpenter – Haxtun
5. Ron Christian – Aspen
6. Tammy Cooley – Gering
7. Alan Coyne – Julesburg
8. Mike Criss – Chappell
9. Pat Davison – Imperial
10. James DePue – Wray
11. Brock Domeier – Shickley
12. Rick Eymann – Pierce
13. Mike Ferguson – Ansley
14. Tom Goulette – West Point
15. Dana Harris – Grant (Arrived @ 10:05 a.m.)
16. Bill Hinton – Kimball
17. Duane Hoffman – Oxford
18. Nate James – Morrill
19. Wayne Kautz – Bridgeport
20. Jim Kerr – Lyons
21. Bob Lockmon – Stuart
22. Joe McNally – Neligh
23. Robin Millyard – Glenwood Springs
24. Bill Moser – Arnold
25. Wes Olson – Red Cloud
26. Tom Ourada – Crete
27. Bruce Paeper – Pender
28. Mike Palmer – Sidney
29. John Prettyman – Yuma
30. Chris Rodman – Wall Lake
31. Alan Romine – Falls City
32. Doug Schultz – Curtis
33. Jeffry Sprock – Mitchell
34. Rob Stangel – Indianola
35. James Summers – Benkelman
36. Adam Suppes – Delta
37. Jeremy Tarr – Burwell
38. Ed Tvrs – Alliance
39. Jeff Wells – Fort Morgan
40. Darrel Wenzel – Waverly
41. Randy Woldt – Wisner
42. Dana Youtz – Torrington

Board Members not in attendance: Keith Beck, Fleming; Dan Coolidge, Bayard; Greg Cramer, Wood River; Will Dowis, Gunnison; Larry Edgar, Blue Hill; Leroy Frana, Nebraska City; Phil Juillard, Basin; Curtis Mitchell, Fountain; Kim Robb, Lyman; Doug Schultz, Broken Bow; Michael Schwabe, Breda; and Jon Winkel, Sergeant Bluff.

Others in attendance: Barnas, Quinn; Bown, Scott; Bridges, Gordon; Brinkman, Bart; Burdett, Travis; Cederburg, Jim; Classen, Joe; DeLaune, Doug; Exstrum, Brian; Hartwell, Carrie; Johnson, Marlene; Jorn, Gary; Kalkwarf, Mike; Kielkopf, Todd; Leners, Bill; Longmore, Lynn; Morehead, Jim; Nation, Brent; Overeynder, Phil; Pecena, Vicki; Rigal, Rick; and Roblyer, Jim.

NMPP staff: Beth Ackland, Rich Andrysik, Carol Brehm, Tim Cerveny, Shannon Coleman, Chris Dibbern, Katrinka Dicke, Brad Hans, Kara Hunt, Jamie Johnson, Jill Jones, Kyle Kaldahl, Bob Poehling, Joe Rivera, Andrew Ross, Kim Schafers, Tim Sutherland, Candy Thomazin, and Kevin Wickham.

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Integrated Resource Plan

Shannon Coleman

Supervisor of Resource Planning and Analysis

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Integrated Resource Plan

- Purpose
  - IRP mandated by the Energy Policy Act of 1992.
  - Requires all WAPA customers to submit IRP every 5 years.
  - Also must submit annual progress report.
- Requirements
  - Identify and compare energy efficiency and supply resource options.
  - Action plan and timing set by customer.
  - Efforts to minimize environmental effects of new resource acquisitions.
  - Ample opportunity for public participation.
  - Load forecasting.
  - Description of measurement strategies to determine if objectives are being met.



Western Area Power Administration

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Integrated Resource Plan

- Schedule

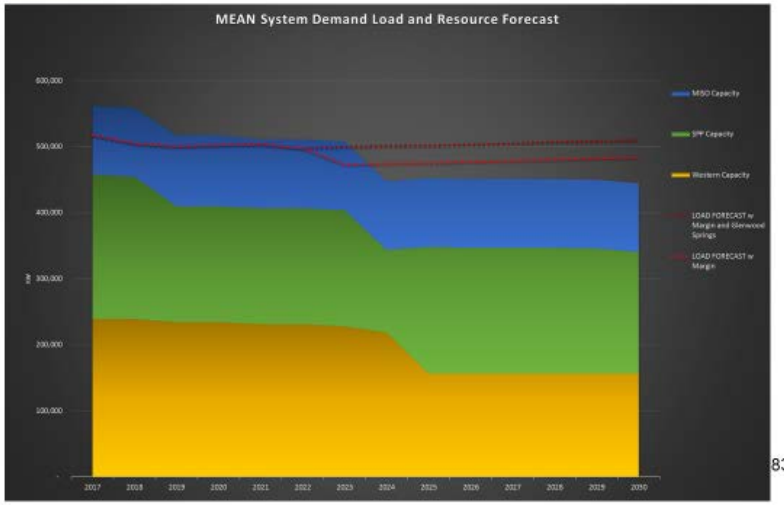
TASK	DATE
Develop Cases and Conduct Analysis	Feb-17
Finalize Preferred Plan	Mar-17
Present Preferred Plan to MEAN Managers	Apr-17
Present Preferred Plan to Risk Department	Apr-17
Draft Report Complete	May-17
MEAN Managers Review of Draft	May-17
Present Draft to Committees/Board for Review *	May-17
Submit Draft to Western for Review	May-17
Present Final to Committees/Board for Approval*	Aug-17
Submit Final to Western	Oct-17

*Fulfills Public Participation Requirement

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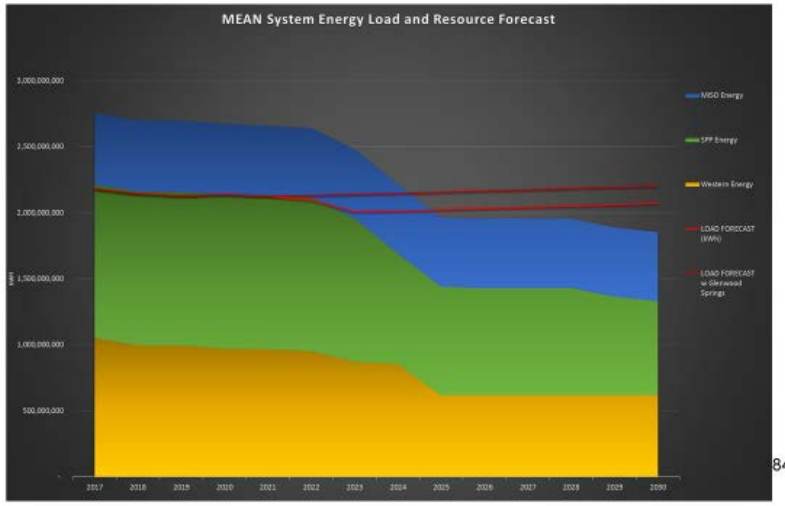
MEAN Demand L&R Forecast



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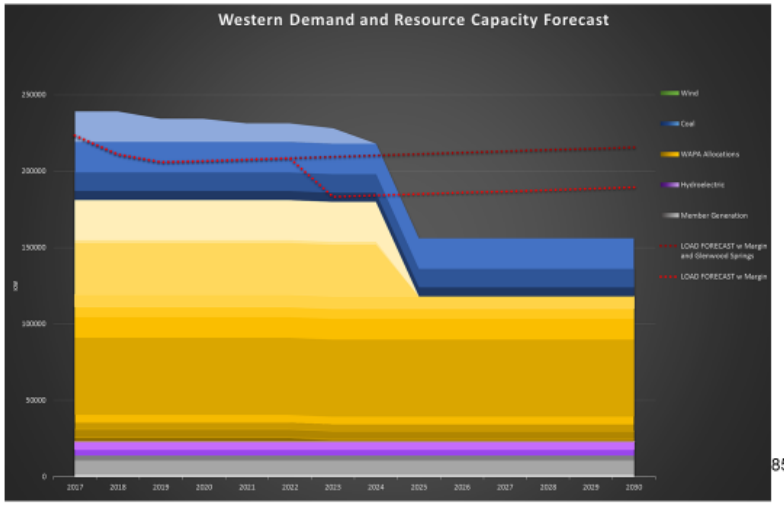
MEAN Energy L&R Forecast



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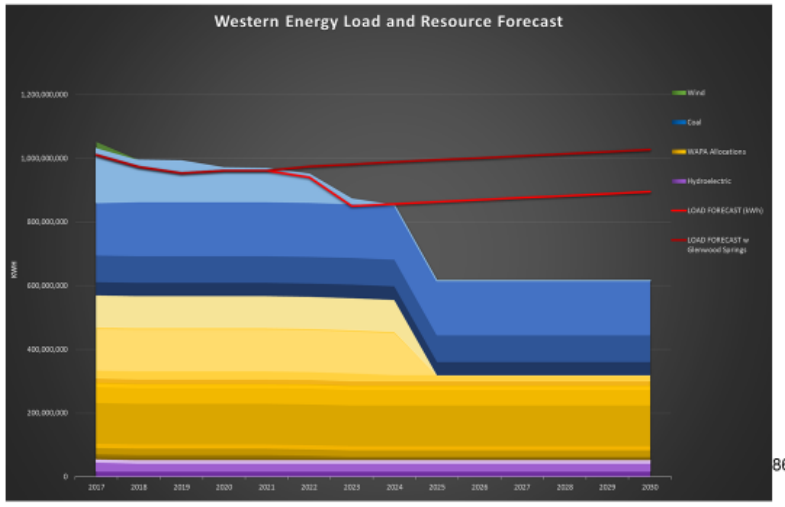
Western Demand L&R Forecast



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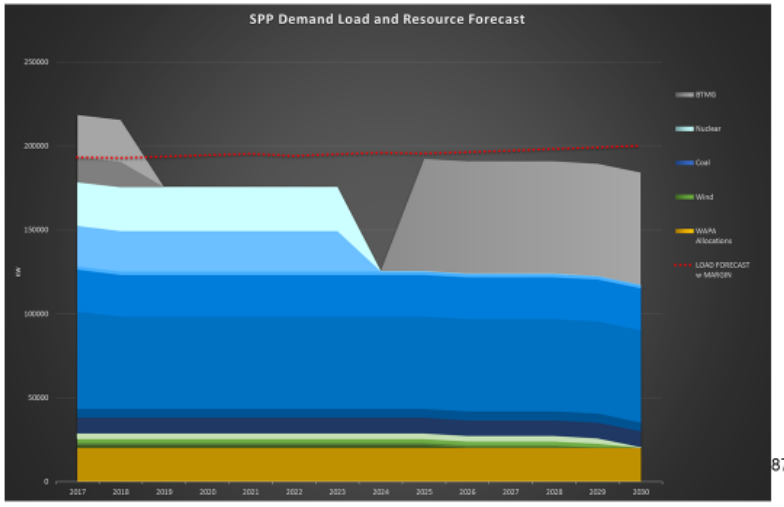
Western Energy L&R Forecast



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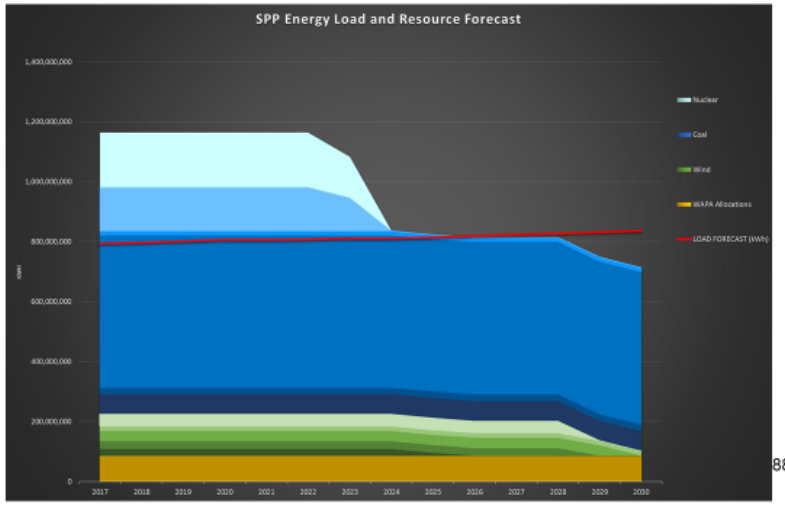
SPP Demand L&R Forecast



87

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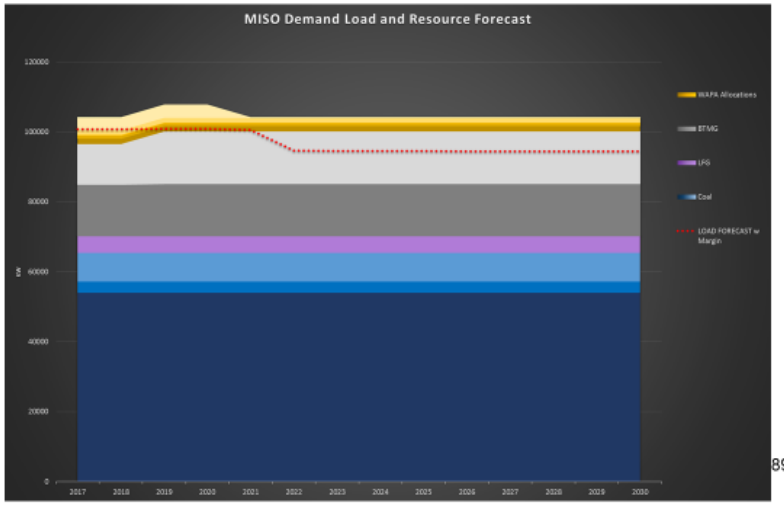
SPP Energy L&R Forecast



88

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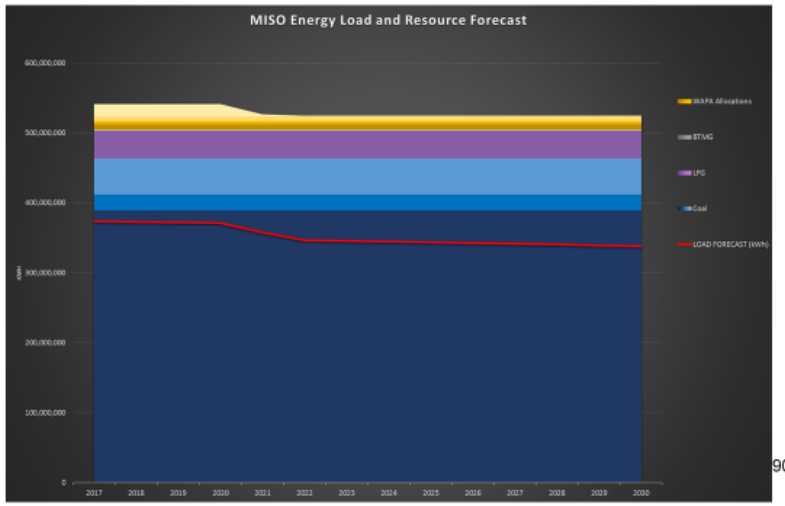
MISO Demand L&R Forecast



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MISO Energy L&R Forecast

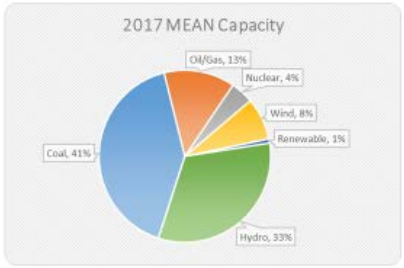


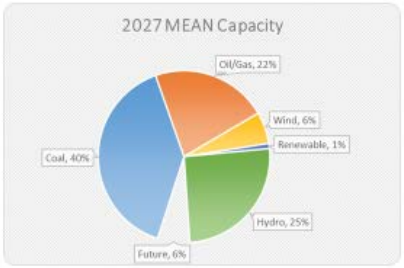
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Integrated Resource Plan

- Current vs. Future Resource Mix - Capacity



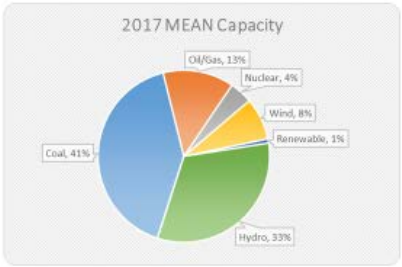


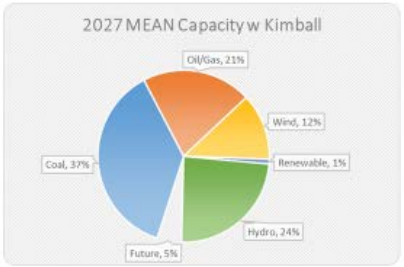
91

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Integrated Resource Plan

- Current vs. Future Resource Mix - Capacity
  - With Kimball Wind PPA



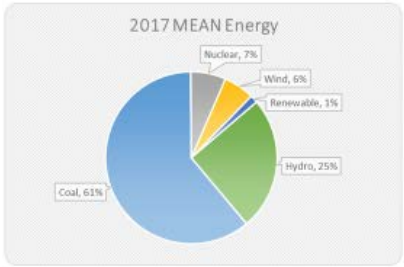


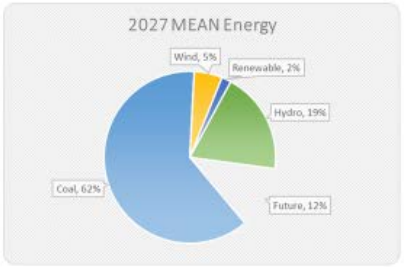
92

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Integrated Resource Plan

- Current vs. Future Resource Mix - Energy



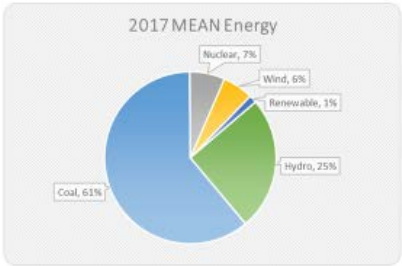


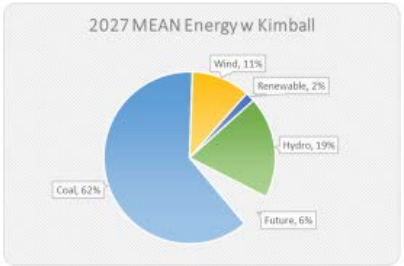
93

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Integrated Resource Plan

- Current vs. Future Resource Mix - Energy
  - With Kimball Wind PPA





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Integrated Resource Plan

- Criteria Discussion
  - Qualitative Review of Options for High Level Evaluation
    - Environmental
    - Ownership vs. PPA
    - Reliability
    - Operational Flexibility
    - Market Participation



  - Quantitative Analysis of Options for Detailed Evaluation
    - Cost
    - Pricing Risk
    - Environmental



  - Committee Discussion

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Integrated Resource Plan

- Next Steps
  - Identify Cases
  - Determine Criteria
  - Qualitative Analysis
  - Quantitative Analysis
  - Present Draft at May Meeting





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B. April 2017 Power Supply Committee Workshop

SIGN-IN SHEET
MEAN AD HOC & POWER SUPPLY COMMITTEE WORKSHOP
April 19, 2017
MUNICIPAL ENERGY AGENCY OF NEBRASKA
Heartland Event Center | Grand Island NE

1.	Randy Woldt	Wisner	31.	Tim S.	Staff
2.	Jeremy Tarr	Burwell	32.	Carol B.	Staff
3.	Jim Poblyen	Burwell	33.	Shannon C.	Staff
4.	Rod Bnestel	Callaway	34.	Tim C.	Staff
5.	Chris DesPlanques	Indianola	35.	Katrinka D.	Staff
6.	Rob Stangel	Indianola	36.	Michell L.	Staff
7.	Chris Rodman	Wall Lake	37.	Chris D.	Staff
8.	Mike Ferguson	Anoka	38.	Jill J.	Staff
9.	Rick Rigel	AMPA	39.	Dave B.	Staff
10.	Leroy FAANA	Neon City	40.	Rich A.	Staff.
11.	Joe Kubala	Town of Lyons	41.	Candy T.	Staff
12.	Jeff Wells	Ft. Morgan	42.	Jamie J.	Staff
13.	Brent Nation	Fort Morgan	43.		
14.	Bill Leners	Lake View	44.		
15.	Bob Lackman	Stuart	45.		
16.	Tom Ourada	Crete	46.		
17.	Mike Kalkwarf	Crete	47.		
18.	Gordon Bridges	Crete	48.		
19.	Mike Palmer	Sidney	49.		
20.	Darrel Wenzel	Waverly	50.		
21.	Lance Terrill	Kimball	51.		
22.	Jim Cederburg	Kimball	52.		
23.	Doug Schultz	Cuming	53.		
24.	Duane Hoffman -	Oxford	54.		
25.	Wes Olson	Red Cloud	55.		
26.	Tom Gaulke	Wahoo	56.		
27.	Kim S.	Staff	57.		
28.	Kane H.	Staff	58.		
29.	Brad H	Staff	59.		
30.	Bob P.	Staff	60.		

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Integrated Resource Plan

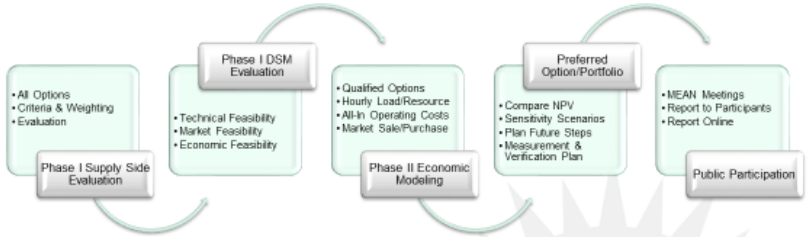
Shannon Coleman

Supervisor of Planning & Analysis

3

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Integrated Resource Plan Process



4

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Integrated Resource Plan

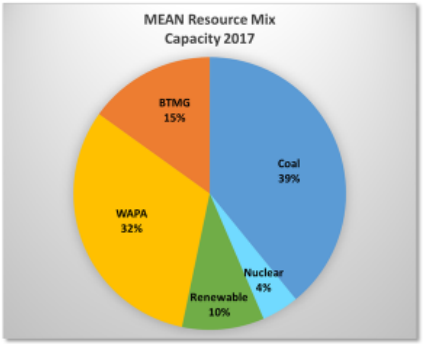
- Assumptions
  - Reserve Margins and Transmission Losses Included in Demand
  - No Retirements of Existing Resources
  - Scheduled Expiration of WAPA Displacement
  - Fairbury Replacement – WEC2?
  - No Clean Power Plan – For Now…
- Unknowns
  - Western Integration into SPP

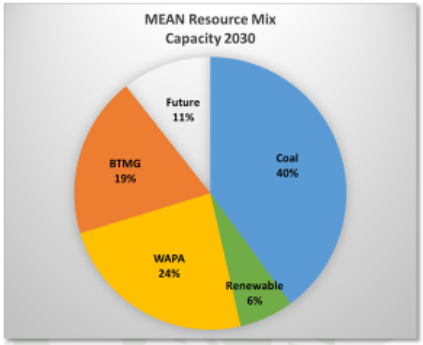


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Resource Mix – MEAN System

[Capacity – Unit Nameplate]

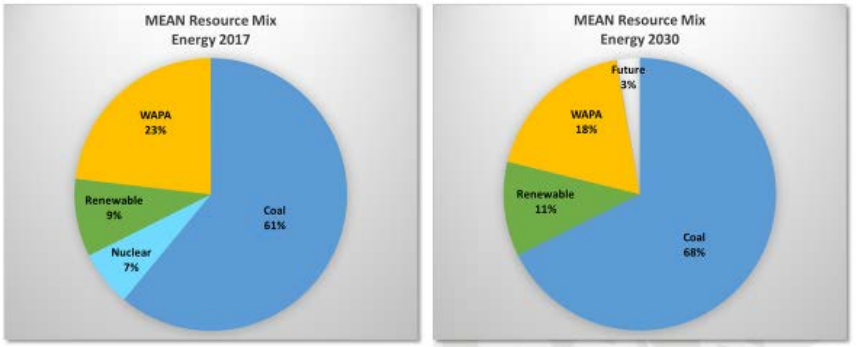




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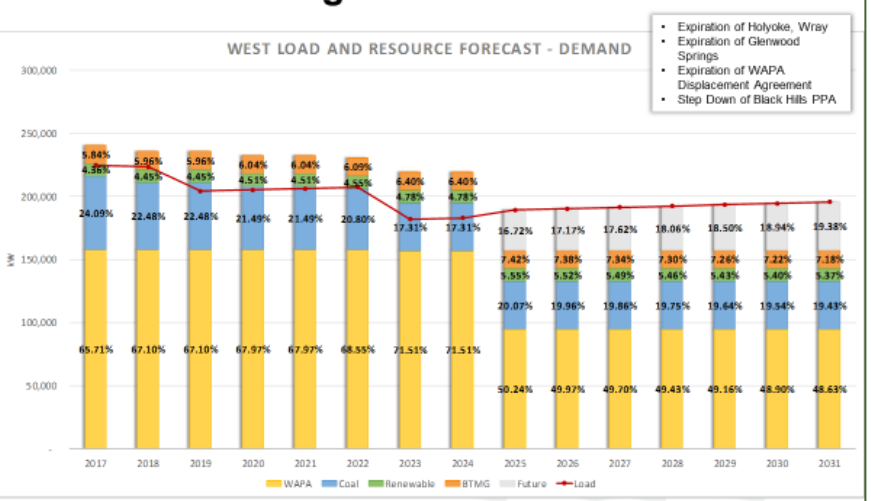
Resource Mix – MEAN System
[Energy]



7

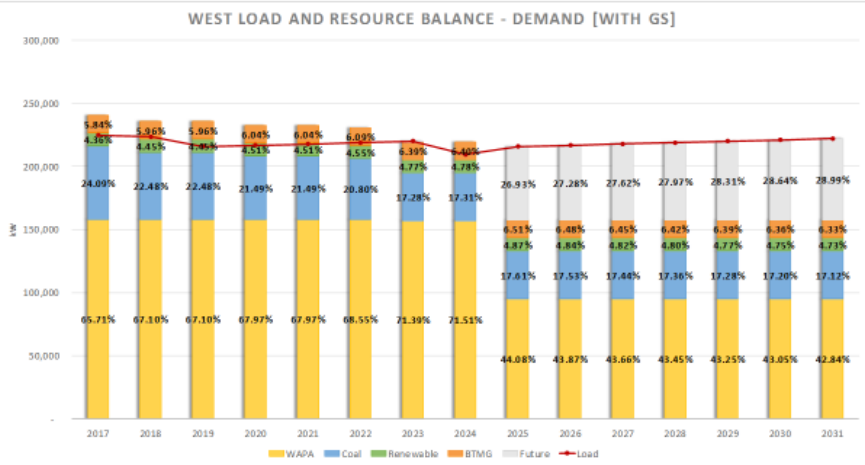
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West Region - Demand



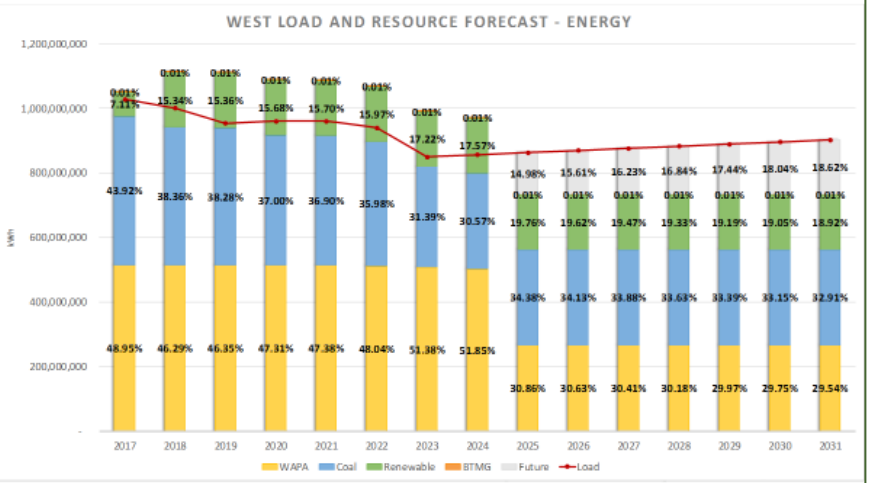
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West Region – Demand [+GS]



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West Region - Energy



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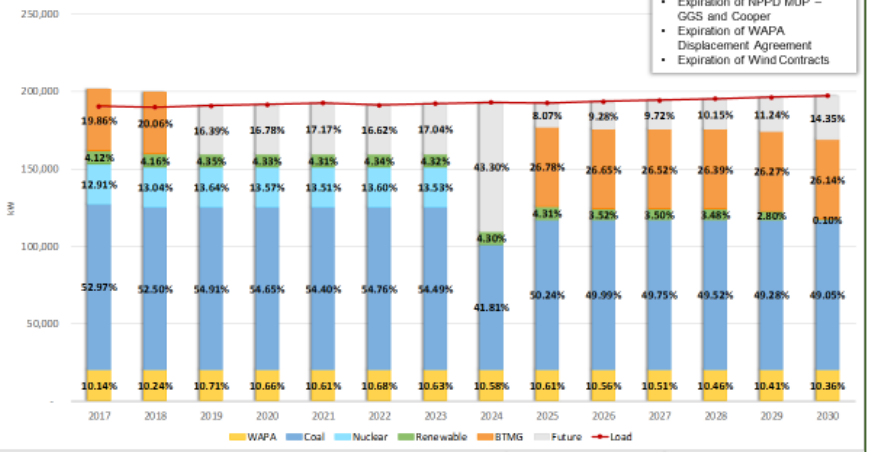
West Region – Energy [+GS]



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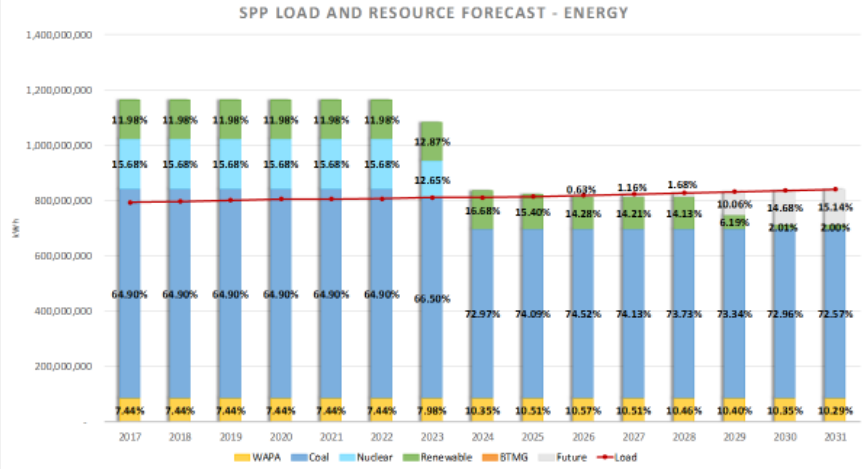
SPP – Demand

- Capacity from WEC2 to replace Fairbury
- Expiration of IMU and Waverly Generation Agent Arrangement
- Expiration of NPPD MUP – GGS and Cooper
- Expiration of WAPA Displacement Agreement
- Expiration of Wind Contracts



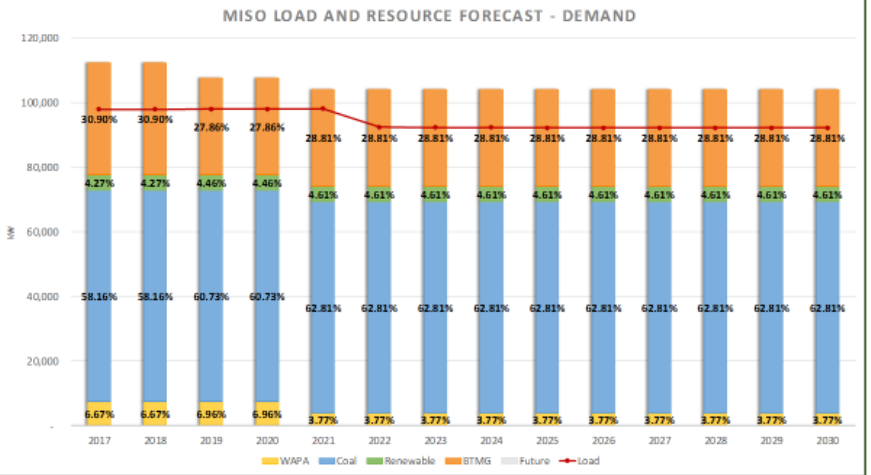
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SPP - Energy



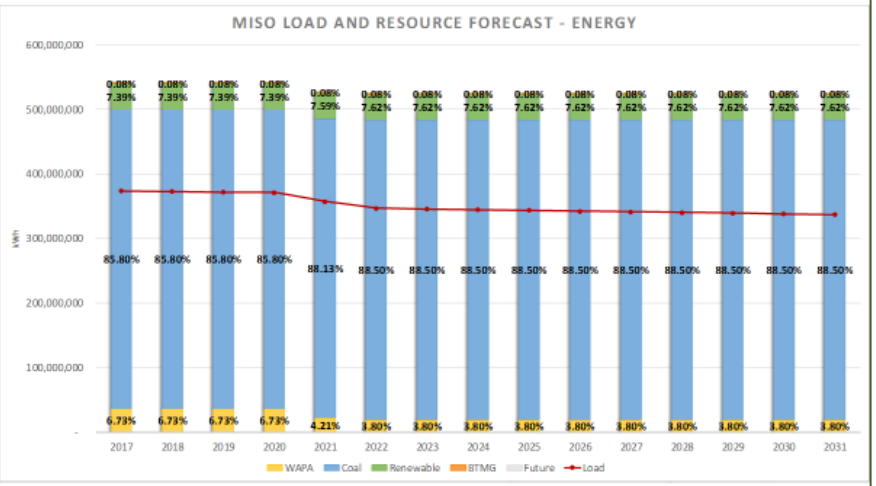
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MISO - Demand



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MISO - Energy



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Discussion Point

- West Region Deficit
  - Capacity (32-38 MW) + Energy in 2025
  - 47-51% Capacity Factor
    - Intermediate
- SPP Region Deficit
  - Capacity (31 MW) in 2019
  - Capacity (16-28 MW) + Energy in 2026
  - 3-50% Capacity Factor
    - Peaking or Intermediate
- MISO Region Deficit
  - None

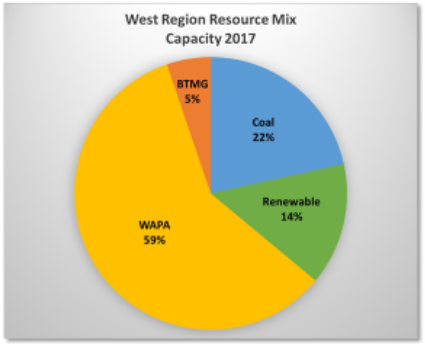


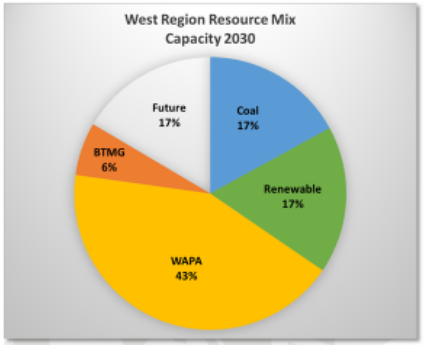
22

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Resource Mix – West Region

[Capacity – Unit Nameplate]



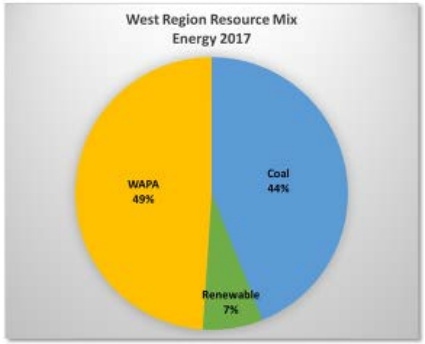


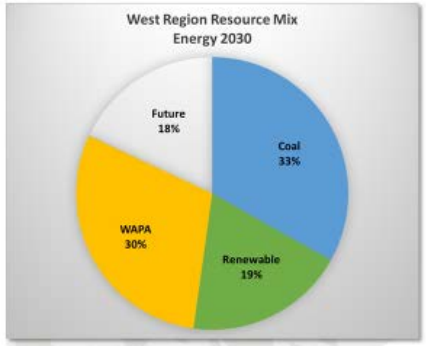
23

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Resource Mix – West Region

[Energy]

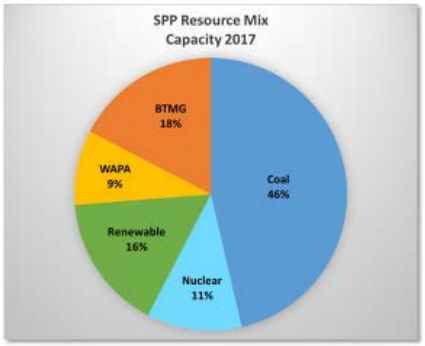


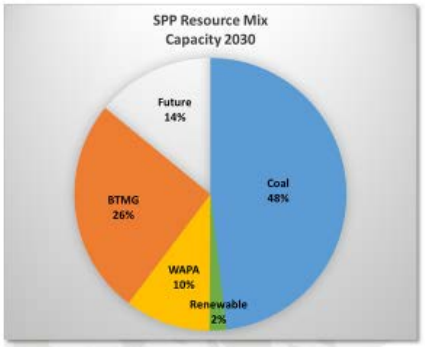


24

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Resource Mix – SPP
[Capacity – Unit Nameplate]

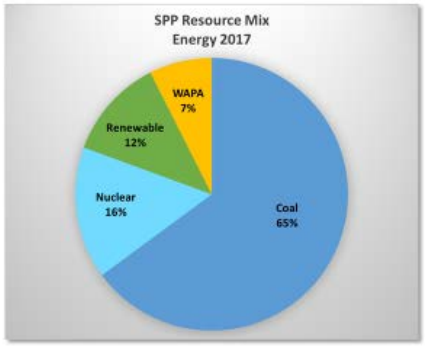


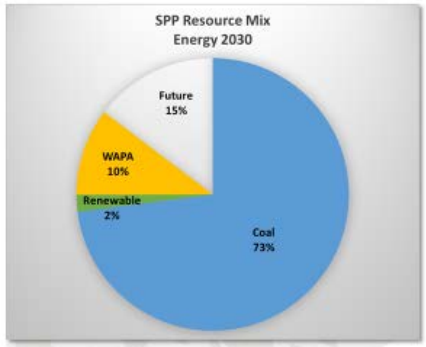


25

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Resource Mix – SPP
[Energy]

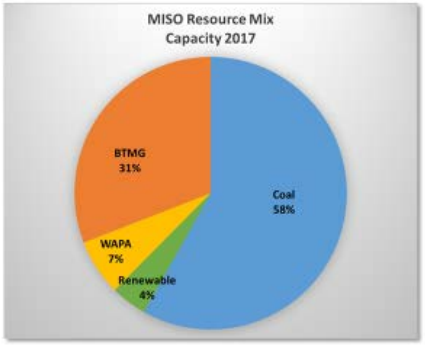


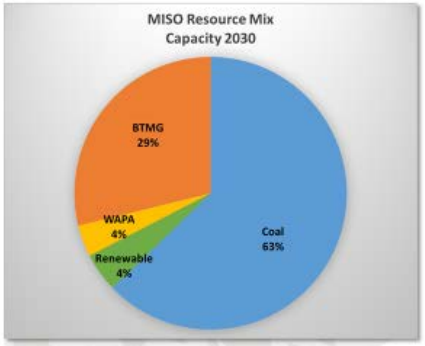


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Resource Mix – MISO
[Capacity – Unit Nameplate]

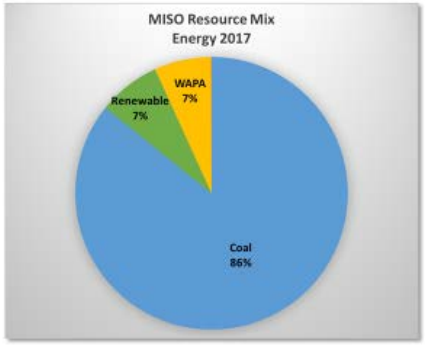


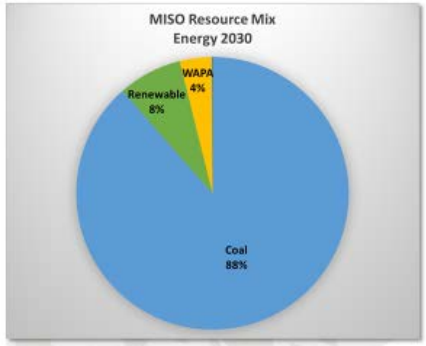


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Resource Mix – MISO
[Energy]

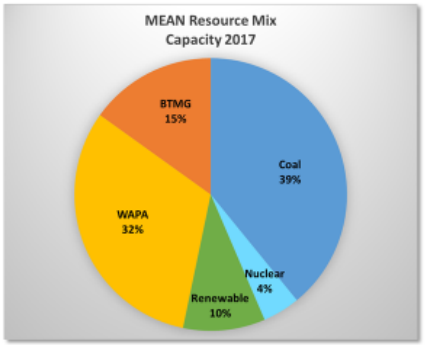


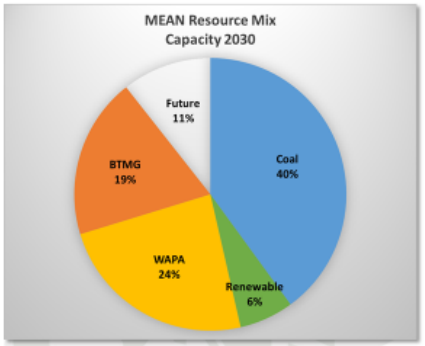


29

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Resource Mix – MEAN System
[Capacity – Unit Nameplate]

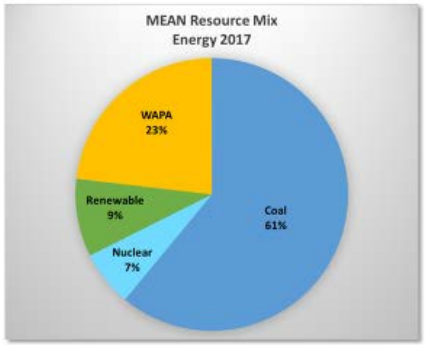


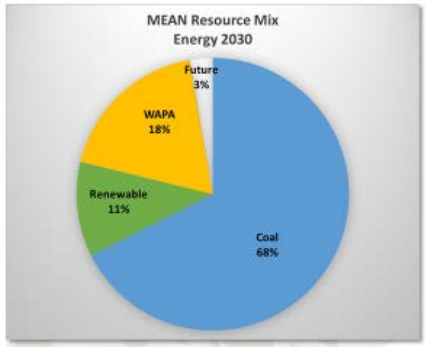


30

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Resource Mix – MEAN System
[Energy]

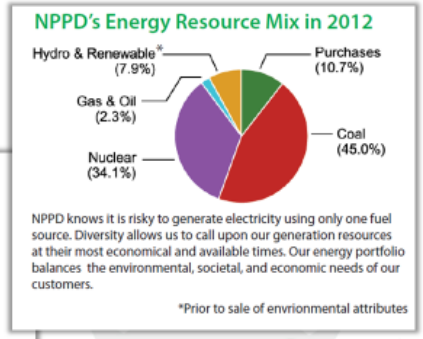




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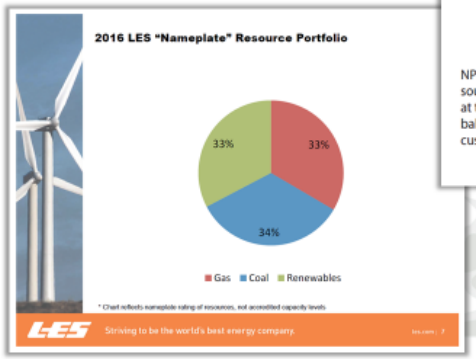
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Resource Portfolios
NPPD and LES



NPPD knows it is risky to generate electricity using only one fuel source. Diversity allows us to call upon our generation resources at their most economical and available times. Our energy portfolio balances the environmental, societal, and economic needs of our customers.

*Prior to sale of envrionmental attributes

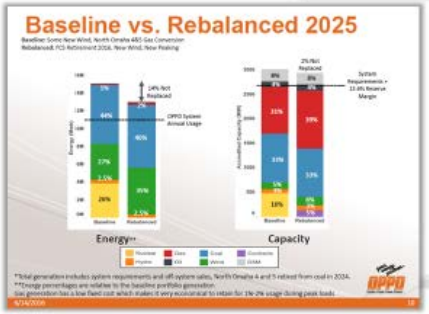


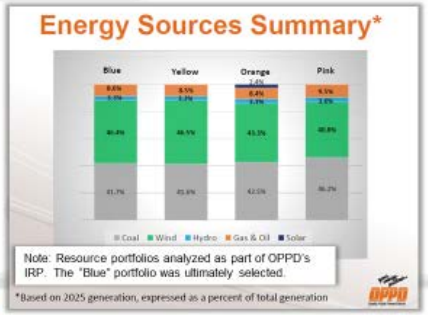
32

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Resource Portfolios
OPPD



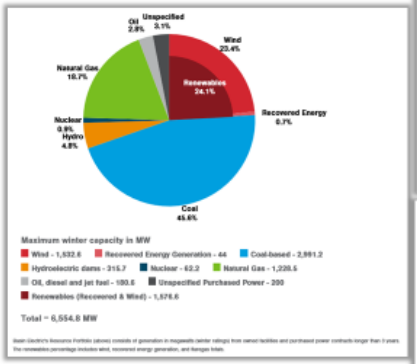


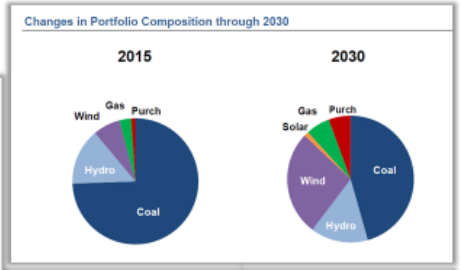


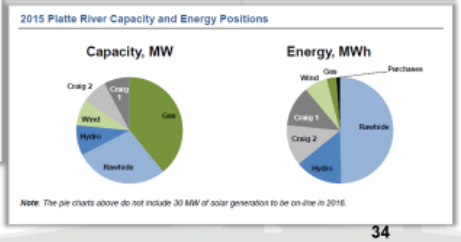
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Resource Portfolios

Basin and PRPA

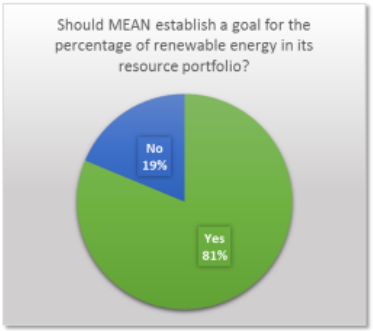


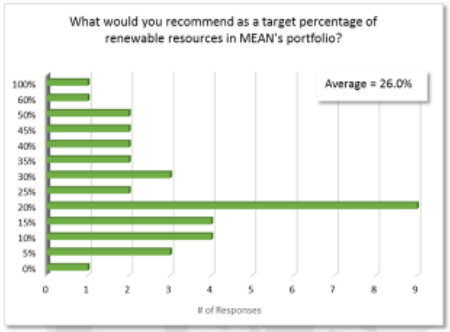




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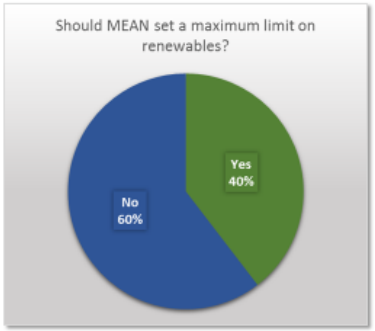
IRP Survey Results

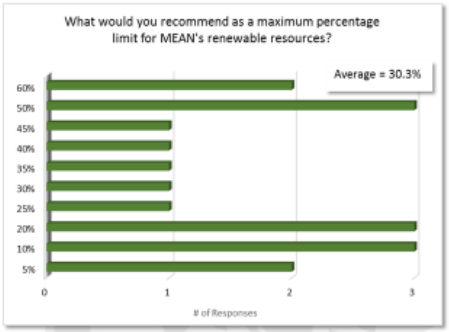




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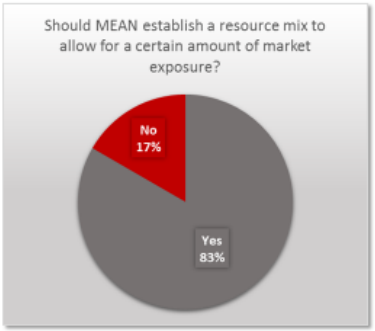
IRP Survey Results

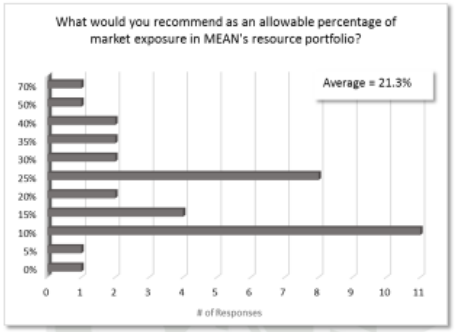




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IRP Survey Results





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Discussion Point

- Renewables
- Market Exposure
- Resource Mix
  - Trade-Off Between Current Low Cost and Potential Future High Cost
  - Baseload vs. Intermediate vs. Renewables (Flexibility)

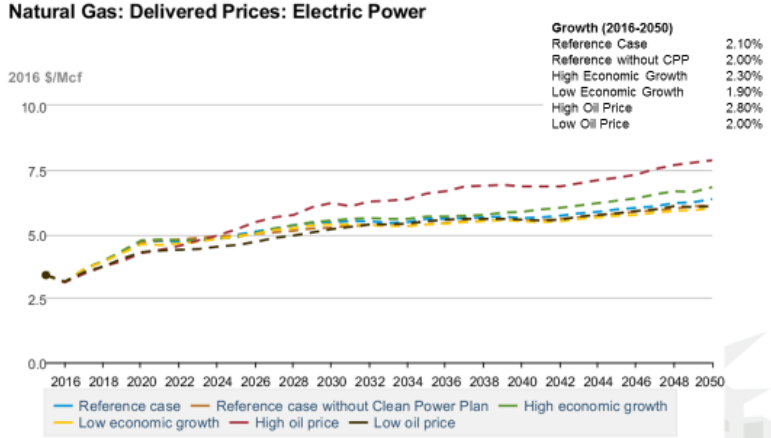


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Natural Gas Pricing

Natural Gas: Delivered Prices: Electric Power



eia Source: U.S. Energy Information Administration

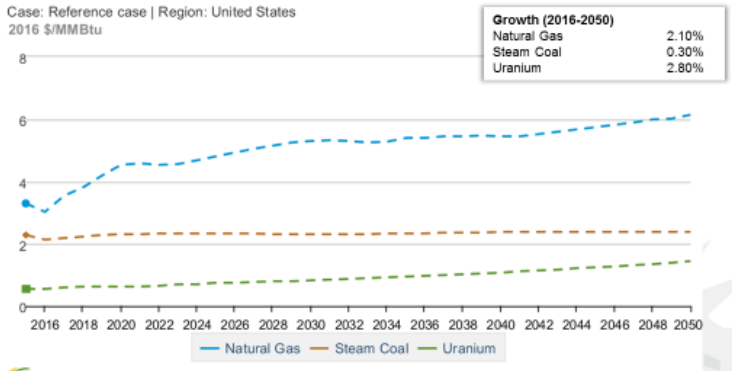
[7] Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.

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Fuel Pricing Comparison

Energy Prices: Electric Power



eia Source: U.S. Energy Information Administration

[7] Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.

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Natural Gas Pricing

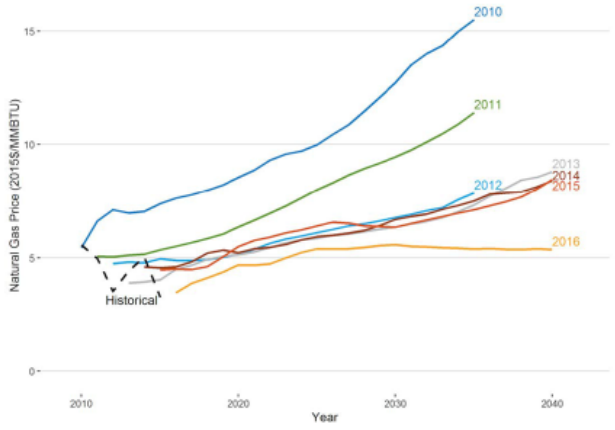


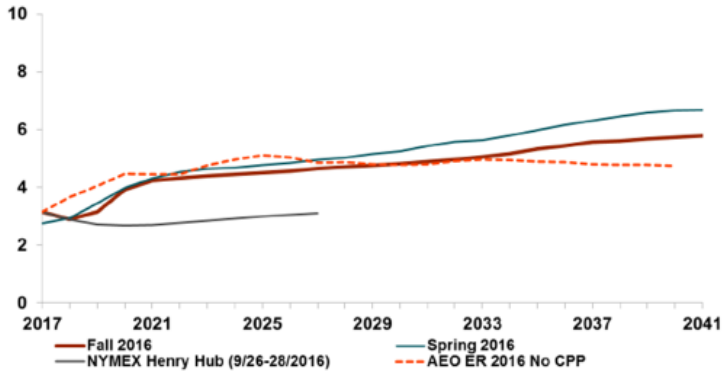
Figure 17. Variation in electricity-sector natural gas price forecasts in the Annual Energy Outlook from 2010 to 2016 (EIA 2016a)

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Natural Gas Pricing

Henry Hub Forecast Comparison (2016 $/MMBtu)



(Source: U.S. Energy Information Administration (EIA), ABB Advisors.)

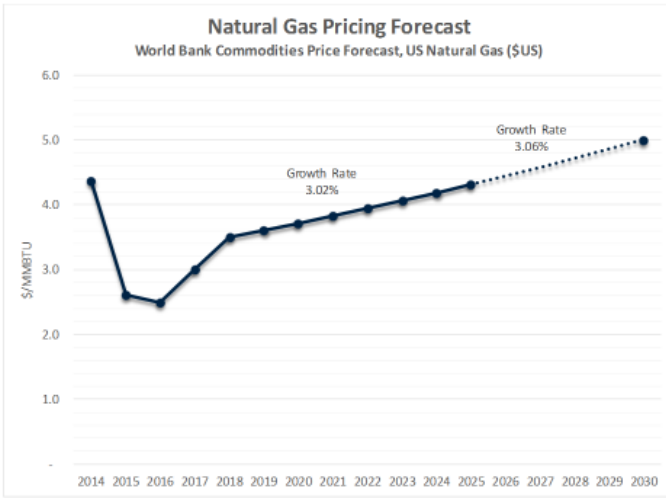
42

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Natural Gas Pricing

Natural Gas Pricing Forecast

World Bank Commodities Price Forecast, US Natural Gas ($US)

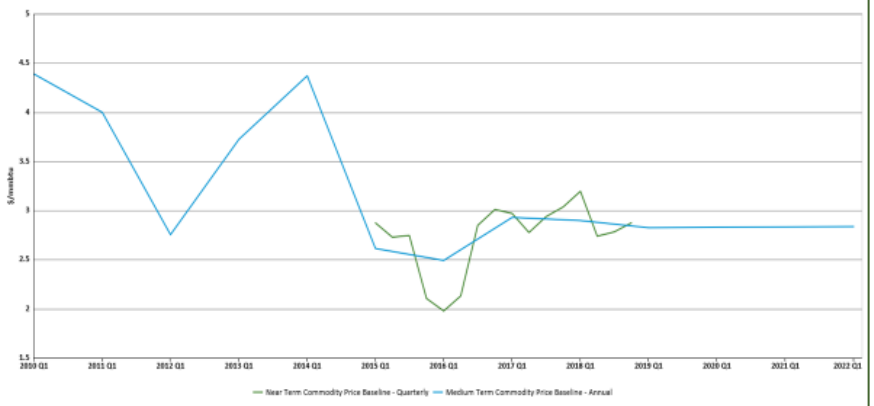


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Natural Gas Pricing

IMF Commodity Pricing Forecast (US Domestic Market, $US)



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Discussion Point

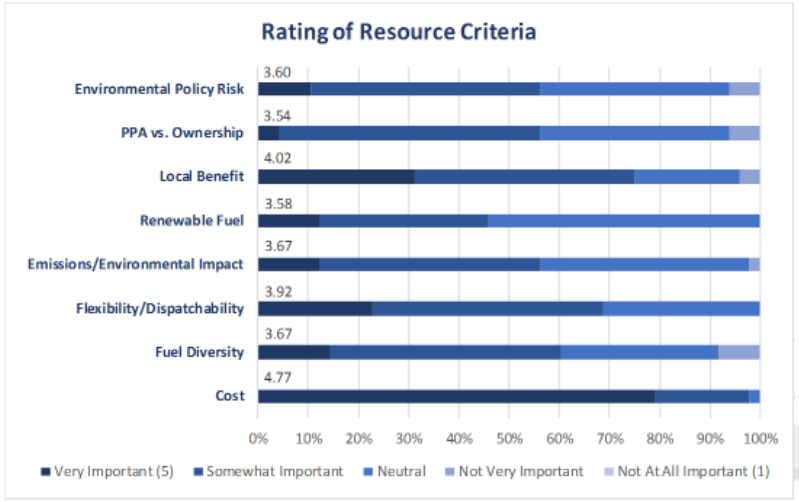
- Fuel Pricing/Diversity
  - Natural Gas
  - Future of Coal
  - Fossil and Nuclear Retirements
  - Future of Renewable Energy Credits
  - Renewable Integration



45

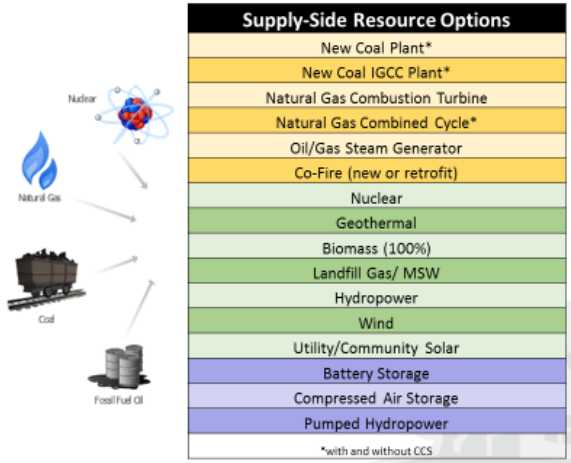
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PSC IRP Survey



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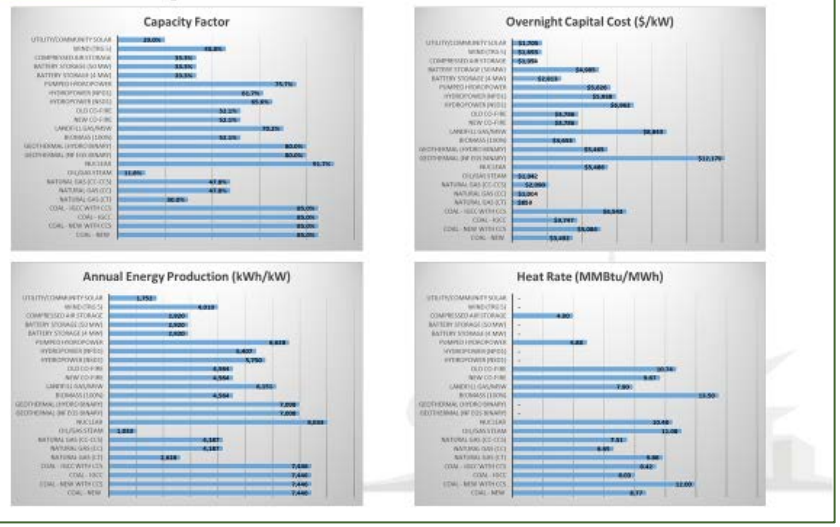
Supply Side Options – Phase I



47

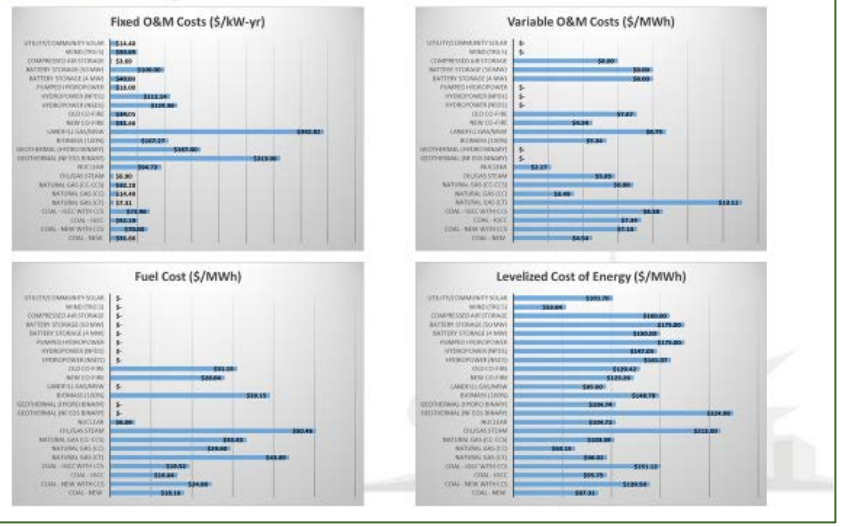
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Options Evaluation – Phase I



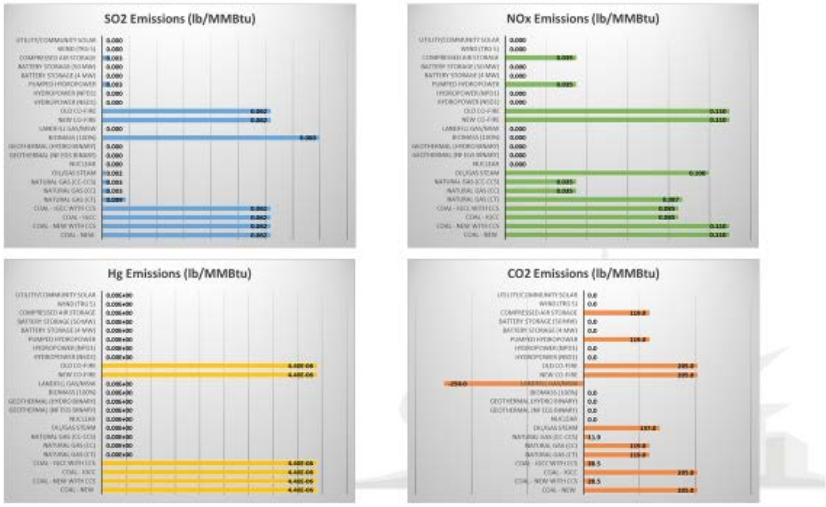
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Options Evaluation – Phase I



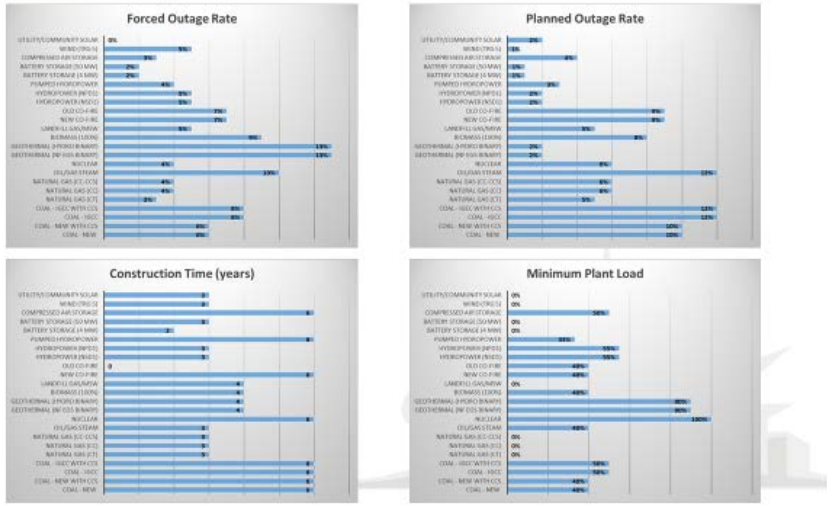
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Options Evaluation – Phase I



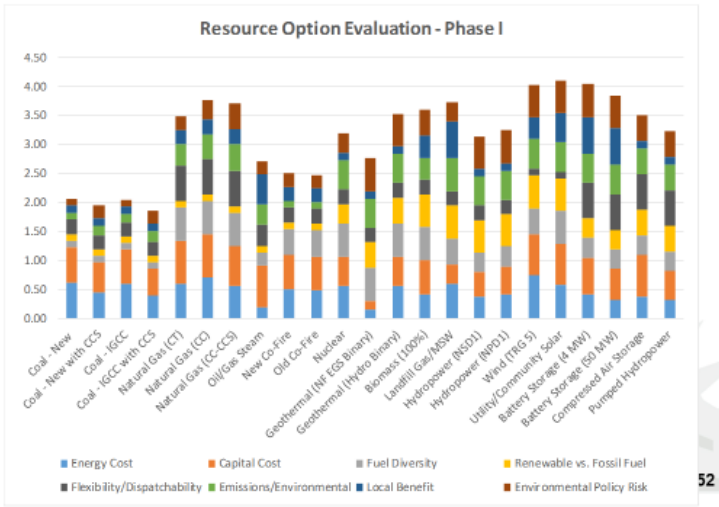
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Options Evaluation – Phase I



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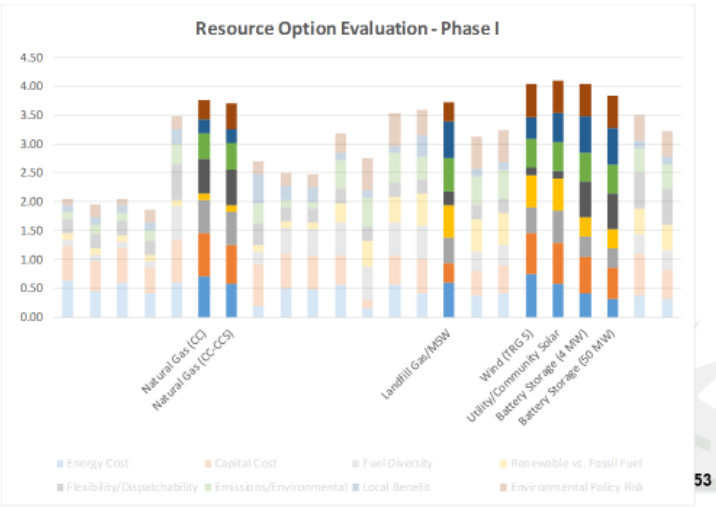
Phase I Evaluation



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Phase I Evaluation



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Discussion Point

- Supply Side Resource Evaluation
  - Resource Options
  - Criteria
  - Renewable Target
  - Market Exposure
  - Qualified Options



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Demand Side Management

- DSM/EE Evaluation
  - 2012 IRP = Load Reduction
  - Qualitative Screening
    - Cost, Customer Preference, Environmental Impact, Market Potential, Ease of Implementation, Availability
    - Scored from 0-3
  - Economic Evaluation
    - Total Resource Cost – MEAN, Utility, Retail Customer
    - Avoided Demand and Energy Cost
    - Lost Retail Revenue
    - NPV Calculation



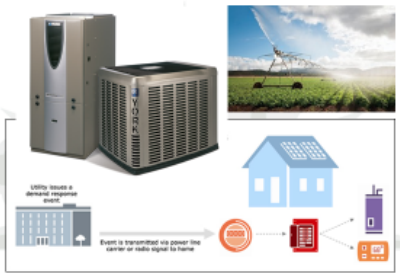




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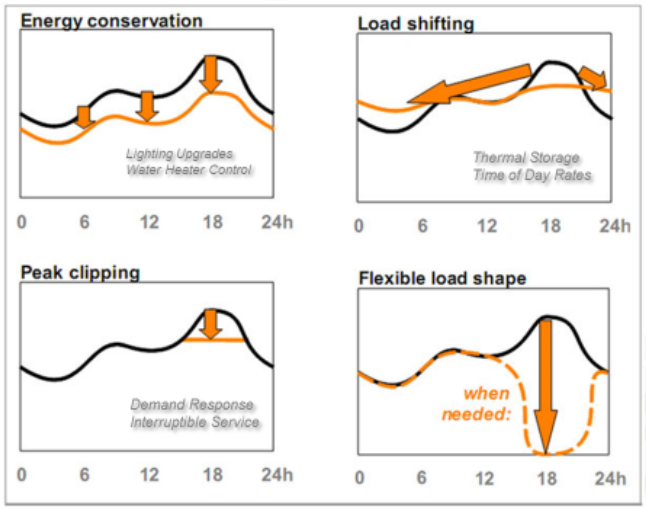
Demand Side Management

- DSM/EE Evaluation
  - 2017 IRP = DSM as Resource?
    - Full Cost to Implement – MEAN, Utility, Retail Customer
    - Benefit – Demand and Energy Reduction (Avoided Cost)
    - Estimate Market Size and Participation Rate
  - Technical Potential
  - Market Potential
    - Survey Results
  - Economic Potential
    - (Cost/Benefit Ratio <1)



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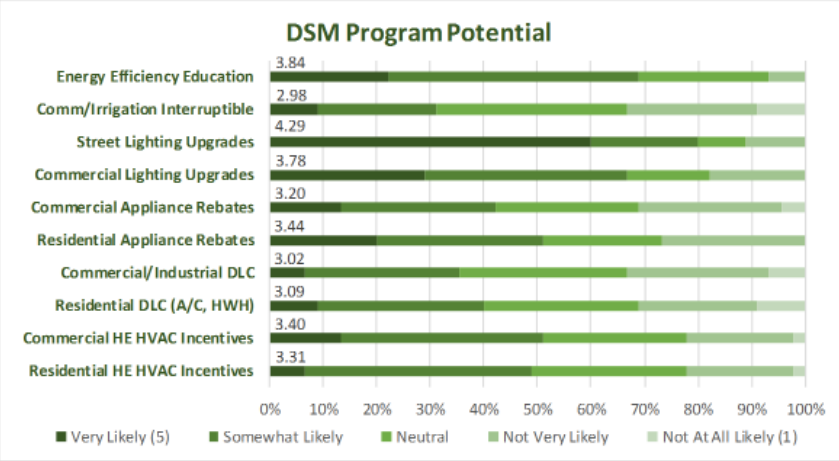
DSM Strategies



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Demand Side Management



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Discussion Point

- Demand Side Management
  - Market Feasibility
  - Technical Feasibility
  - Modeling
  - Other Programs?



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Integrated Resource Plan

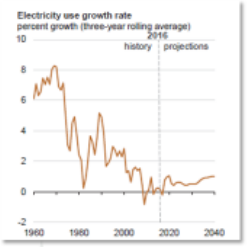
- Phase II Economic Modeling
  - Costs
    - 20 Year Pricing Forecasts (Market Energy, Market Capacity, and Natural Gas)
    - Capital Costs
    - Fuel Costs
    - Fixed O&M, Variable O&M
  - Market Purchase
  - Result = NPV

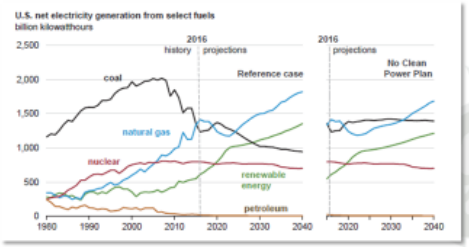
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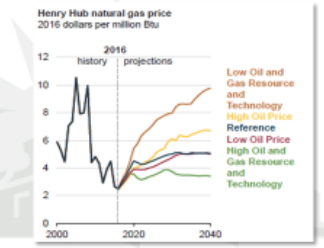
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Integrated Resource Plan

- Scenarios/Sensitivities
  - Fuel Pricing – High or Low
  - Load Forecast – High or Low
  - Environmental – CPP/CO_2 Pricing
  - Others?







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Integrated Resource Plan

- Public Participation
  - PSC Online Survey
  - PSC Workshop
  - Board/Committee Meetings
    - May 2017
    - August 2017
  - Participant Communities
  - MEAN Website
  - Other Suggestions?



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Discussion Point

- Steps Forward
  - Phase II Modeling
  - Sensitivity Cases
  - Public Participation
  - Other Input



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C. May 2017 Board and Committee Meetings

POWER SUPPLY COMMITTEE

CALL TO ORDER

Chairman Leroy Frana called the meeting to order at 10:03 a.m. (CT). Pursuant to Section 84-1412 (8) of the Nebraska Open Meetings Act, a current copy of the Open Meetings Act was posted in the meeting room and made available to the public.

ROLL CALL

A quorum was declared with eight of the nine committee members in attendance.

1. Leroy Frana, Nebraska City
2. James DePue, Wray (arrived at 10:34 a.m.)
3. Duane Hoffman, Oxford
4. Wes Olson, Red Cloud
5. Tom Ourada, Crete
6. Doug Staab, Broken Bow
7. Jeremy Tarr, Burwell
8. Randy Woldt, Wisner (arrived at 10:11 a.m.)

Mike Palmer, Voting Ex-Officio

Absent: Chris Rodman

Others in attendance: Rod Brestel, Jim Cederberg, Mike Criss, Pat Davison, Dan Dean, Will Dowis, Tom Goulette, Bill Hinton, Nate James, Marlene Johnson, Mike Kalkwarf, Joe Kubala, Bob Lockmon, Lynn Longmore, Todd Mahin, Brent Nation, Mike Palmer, Rick Rigel, Jim Roblyer, Alan Romine, Doug Schultz, Jeffry Sprock, Rob Stangel, James Summers, Adam Suppes, Lance Terrill, Ed Tvrs, Jeff Wells, Darrel Wenzel, and Justin Zweibel.

NMPP staff: Rich Andrysik, David Beard, Carol Brehm, Tim Cerveny, Shannon Coleman, Chris Dibbern, Katrinka Dicke, Brad Hans, Kara Hunt, Jill Jones, Sarah Jones, Kyle Kaldahl, Michelle Lepin, Jennifer McCoy, Ryan Olsen, Bob Poehling, Kim Schafers, Robin Spady, Tim Sutherland, Candy Thomazin, and Kevin Wickham.

BOARD OF DIRECTORS

CALL TO ORDER

Chairman Tom Goulette called the meeting to order at 9:02 a.m. (CT). Pursuant to Section 84-1412(8) of the Nebraska Open Meetings Act, a current copy of the Open Meetings Act was posted in the meeting room and made available to the public.

ROLL CALL

A quorum was declared with 35 of the 54 Directors in attendance

1. Ed Tvrs – Alliance
2. Mike Ferguson – Ansley
3. James Summers – Benkelman
4. Nancy Janssen – Breda
5. Doug Staab – Broken Bow
6. Jeremy Tarr – Burwell
7. Lynn Longmore – Callaway
8. Mike Criss – Chappell
9. Tom Ourada – Crete
10. Doug Schultz – Curtis
11. Adam Suppes – Delta
12. Alan Romine – Falls City
13. Jeff Wells – Fort Morgan
14. Tammy Cooley – Gering
15. Robin Millyard – Glenwood Springs
16. Dana Harris – Grant (Arrived 9:41 a.m.)
17. Will Dowis – Gunnison
18. Pat Davison – Imperial
19. Rob Stangel – Indianola
20. Bill Hinton – Kimball
21. Joe Kubala – Lyons
22. Jeffry Sprock – Mitchell
23. Nate James – Morrill
24. Leroy Frana – Nebraska City
25. Joe McNally – Neligh (Arrived at 9:40 a.m.)
26. Duane Hoffman – Oxford
27. Rick Eymann – Pierce
28. Wes Olson – Red Cloud
29. Mike Palmer – Sidney
30. Bob Lockmon – Stuart
31. Mike Varney – Torrington
32. Darrel Wenzel – Waverly
33. Tom Goulette – West Point
34. Randy Woldt – Wisner
35. James DePue – Wray

Board Members not in attendance: Beck, Keith; Bielser, Collin; Carpenter, Ron; Coolidge, Dan; Coyne, Alan; Cramer, Greg; Domeier, Brock; Edgar, Larry; Hornbacher, Dave; Jorgensen, Grant; Kuckkahn, Rick; Lesher, Stacey; Mitchell, Curtis; Moser, Bill; Paeper, Bruce; Prettyman, John, Rodman, Chris; Thomas, Allan; and Winkel, Jon.

Others in attendance: Burdett, Travis; Cederberg, Jim; Classen, Joe; Dean, Dan; Exstrum, Brian; Johnson, Marlene; Kalkwarf, Mike; Lent, Andrew; Mahin, Todd; McKain, Wendy; Nation, Brent; Pecena, Vicki; Rigel, Rick; Roblyer, Jim; Rundel, John; Terrill, Lance; and Zweibel, Justin.

NMPP staff: Beth Ackland, Rich Andrysik, David Beard, Carol Brehm, Tim Cerveny, Shannon Coleman, Chris Dibbern, Katrinka Dicke, Brad Hans, Mandy Hansen, Kara Hunt, Jill Jones, Sarah Jones, Michelle Lepin, Jennifer McCoy, Ryan Olsen, Bob Poehling, Andrew Ross, Kim Schafers, Robin Spady, Tim Sutherland, Candy Thomazin, and Kevin Wickham.

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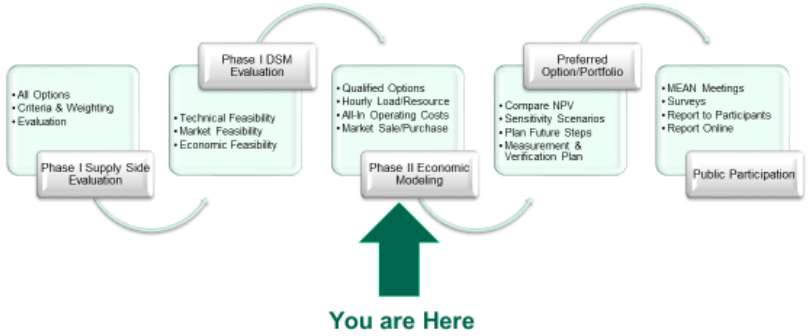
Integrated Resource Plan

Shannon Coleman

Supervisor of Resource Planning and Analysis

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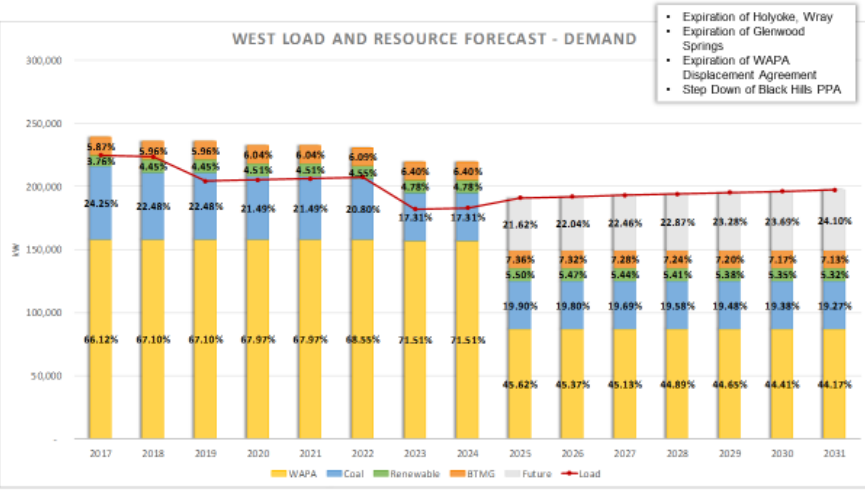
Integrated Resource Plan Process



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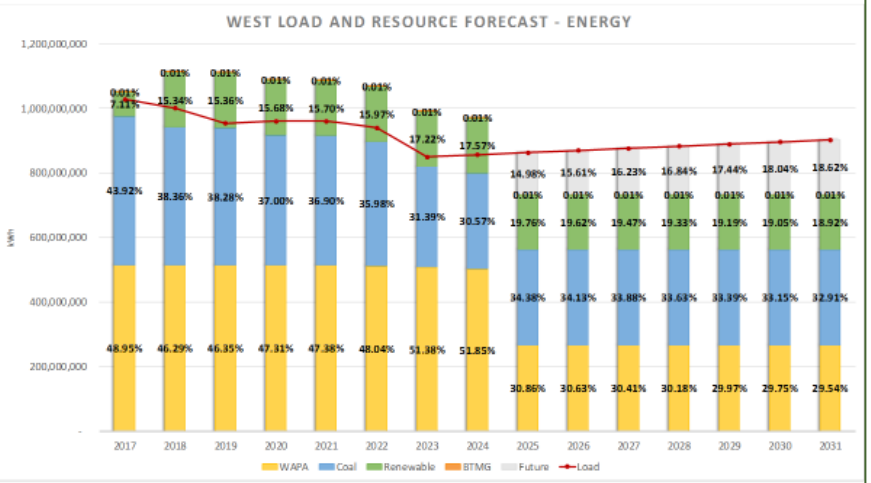
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West Region - Demand



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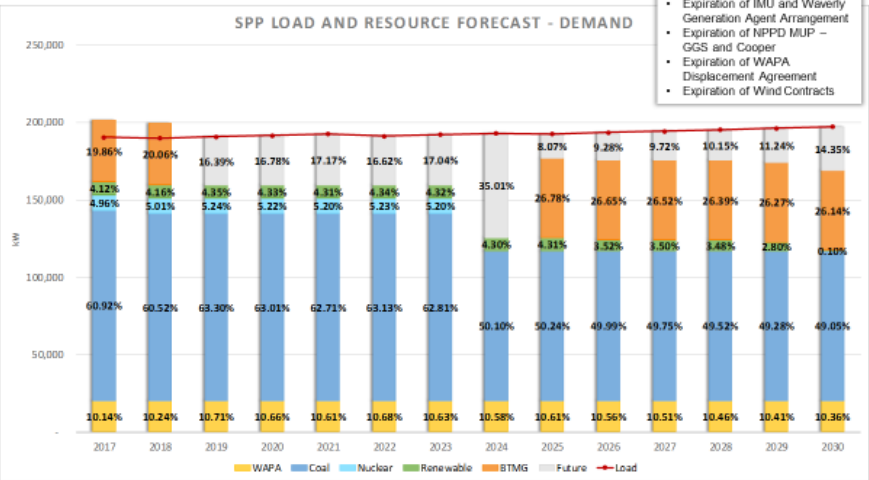
West Region - Energy



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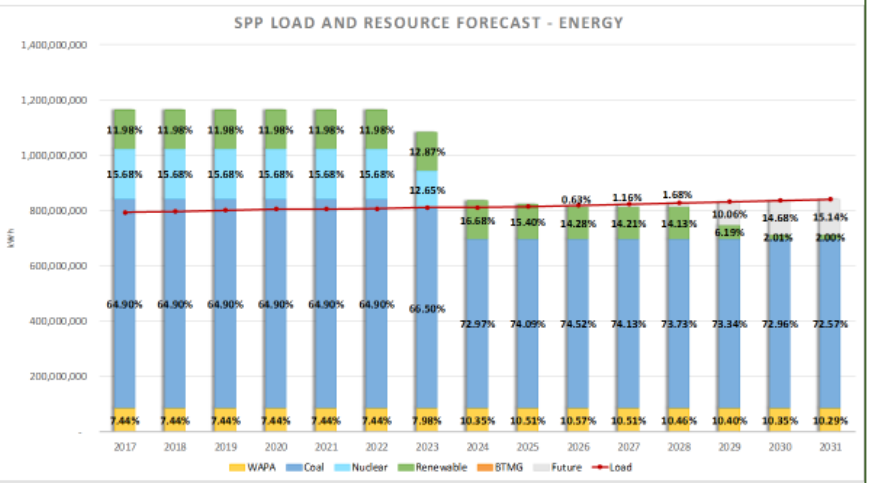
SPP – Demand

- Capacity from Cooper to replace Fairbury
- Expiration of IMU and Waverly Generation Agent Arrangement
- Expiration of NPPD MUP – GGS and Cooper
- Expiration of WAPA Displacement Agreement
- Expiration of Wind Contracts



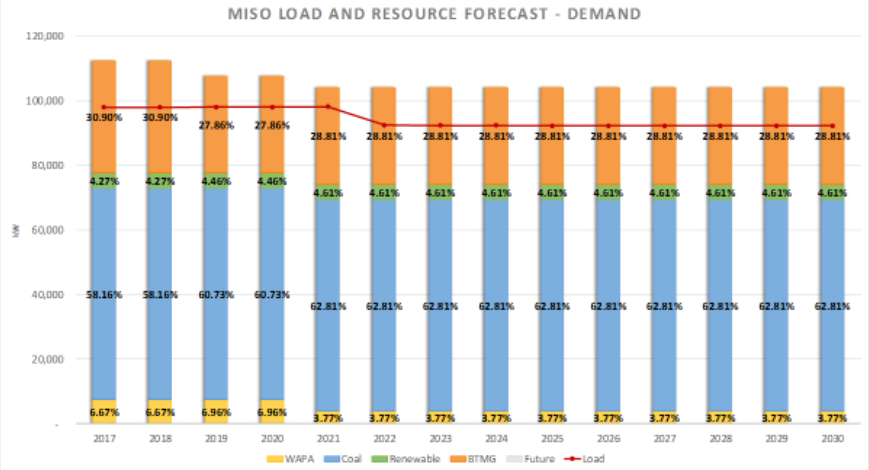
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SPP - Energy



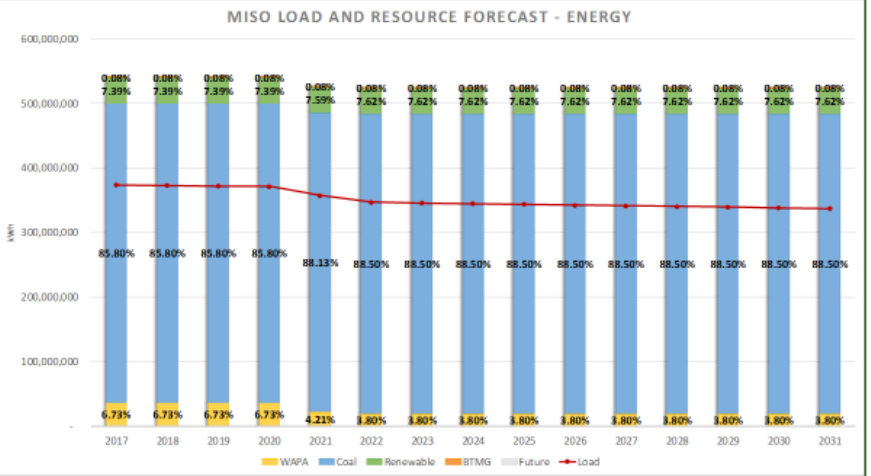
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MISO - Demand



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MISO - Energy



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Summary of Resource Needs

- West Region Deficit
  - 2025 Capacity (40-46 MW) + Energy
  - 47-51% Capacity Factor
    - Intermediate
- SPP Region Deficit
  - 2019 Capacity (31 MW)
  - 2026 Capacity (16-28 MW) + Energy
  - 3-50% Capacity Factor
    - Peaking or Intermediate
- MISO Region Deficit
  - None

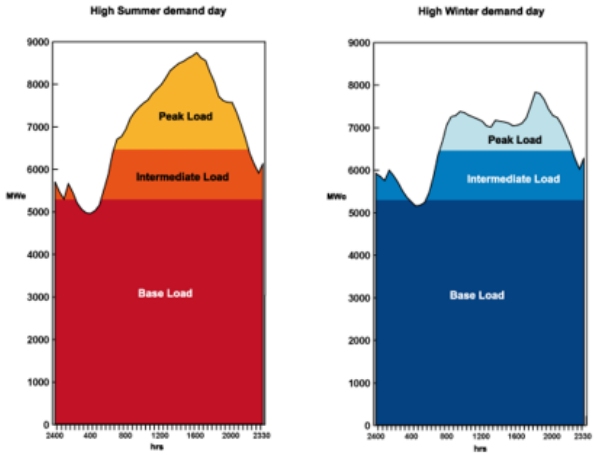


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Market Dispatch

Load curves for Typical electricity grid

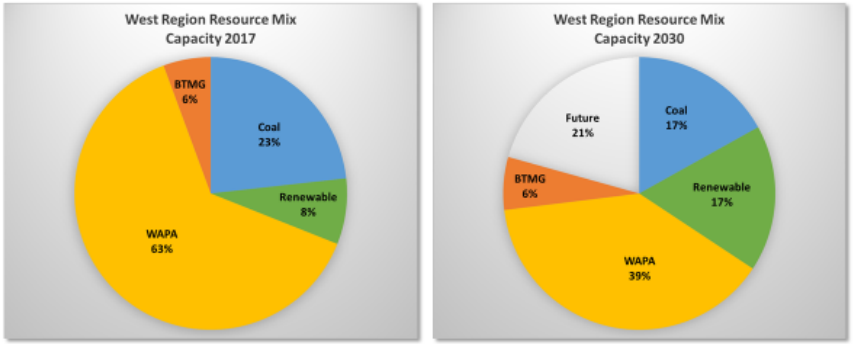


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Resource Mix – West Region

[Capacity – Unit Nameplate]

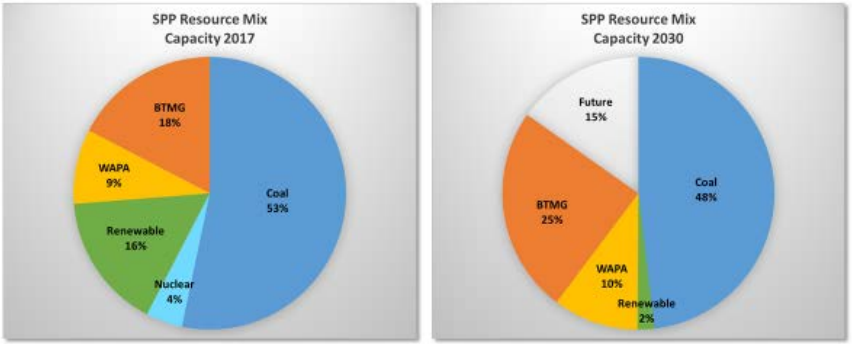


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Resource Mix – SPP

[Capacity – Unit Nameplate]

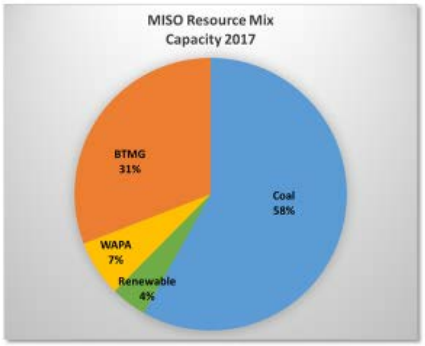


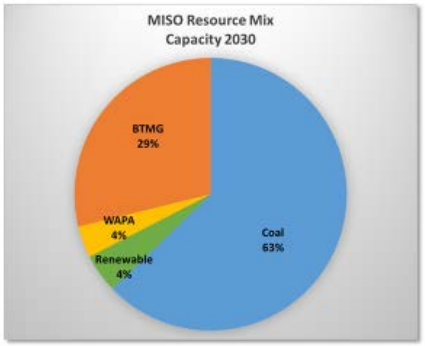
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Resource Mix – MISO

[Capacity – Unit Nameplate]



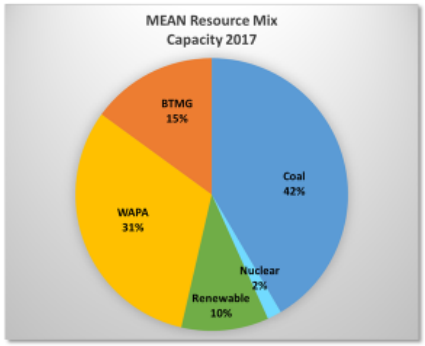


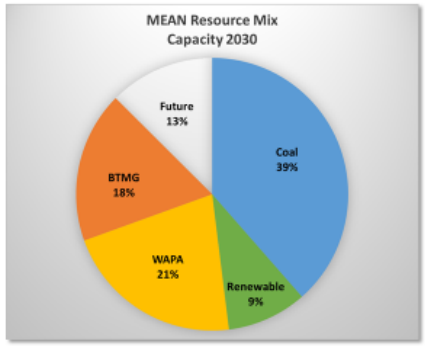
64

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Resource Mix – MEAN System

[Capacity – Unit Nameplate]



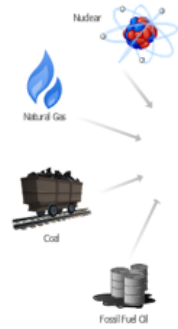


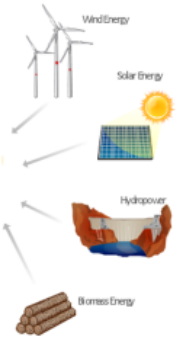
65

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Supply Side Options – Phase I

Supply-Side Resource Options
New Coal Plant*
New Coal IGCC Plant*
Natural Gas Combustion Turbine
Natural Gas Combined Cycle*
Oil/Gas Generator
Co-Fire (new or retrofit)
Nuclear
Geothermal
Biomass (100%)
Landfill Gas/ MSW
Hydropower
Wind
Utility/Community Solar
Battery Storage
Compressed Air Storage
Pumped Hydropower
*with and without CCS

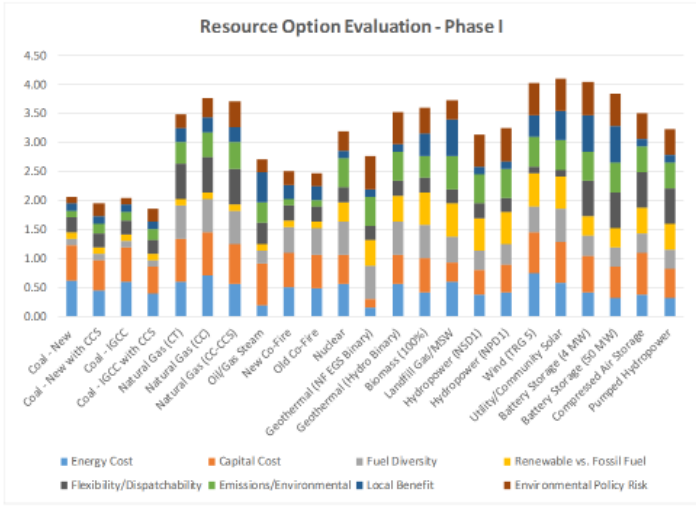




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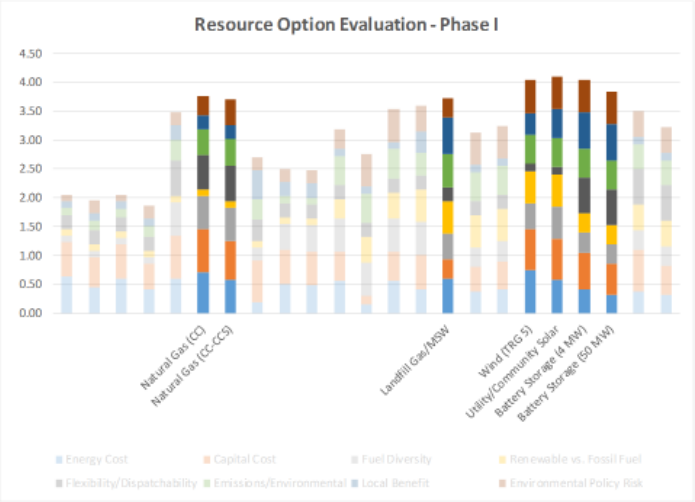
Phase I Evaluation



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Phase I Evaluation

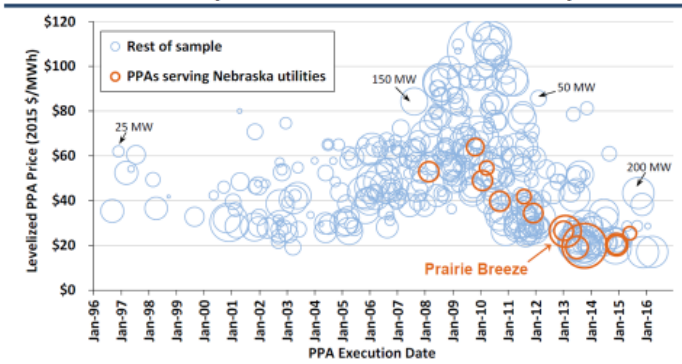


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Wind PPA Price Trends

Nebraska wind PPAs have followed a similar pattern as the rest of the sample



"[Prairie Breeze] is comparable in cost to other OPPD generation and therefore there is no impact on OPPD rates. OPPD simply backs down other generation resources when the wind is blowing and replaces it with similarly priced energy from the Prairie Breeze Wind Project."
– Minutes from OPPD Board of Directors meeting on January 17, 2013

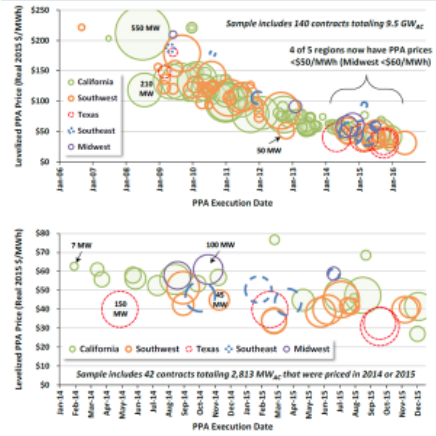
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Solar PPA Price Trends

Combination of falling installed prices and better project performance enables lower PPA prices



- PPA prices are levelized over the full term of each contract, after accounting for escalation rates and/or time-of-delivery factors, and are shown in real 2015 dollars
- Top graph shows the full sample; bottom graph shows a sub-sample of PPAs signed in 2014 or 2015
- CA and the Southwest dominate the sample, but 2014 and 2015 saw a broadening of the market to TX, AR, AL, FL, GA — ***and even MN and MI, with 3 projects priced around $60/MWh***
- Steady downward price trend since 2006 to **<50$/MWh in 2015**
- Smaller projects (e.g., 20-50 MW) seemingly no less competitive

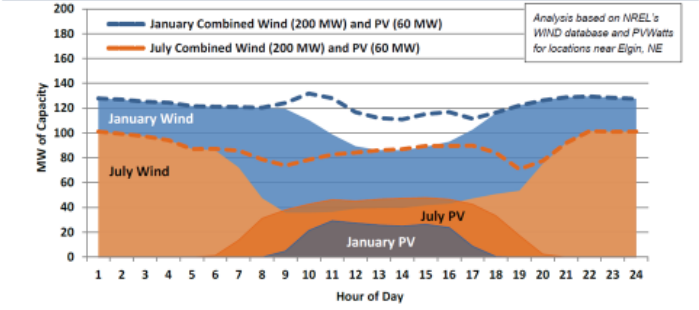
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Wind and Solar Integration

Solar and wind are diurnal and seasonal complements in Nebraska



- Solar is better correlated with wholesale power prices (SPP North Hub), thus providing more wholesale market value than wind — but solar is also more expensive
- Assuming the 200 MW of wind is priced at $22.50/MWh and the 60 MW of PV is priced at $60/MWh, the combination of the two is a blended price of $27.4/MWh
  - Is the flatter combined generation profile worth the incremental ~$5/MWh over wind alone?
  - This incremental premium will decline as the cost of solar continues to fall

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Other Supply Options

- Extension of Generation Agent Agreement
  - Waverly and Indianola
- Extension of Existing PPAs
  - NPPD Multi-Unit Participation – GGS and Cooper Nuclear Station
  - Black Hills PPA – Renegotiated Pricing
  - NPPD Wind PPAs – Renegotiated Pricing
- Additional Member Generation
  - RFP
  - Natural Gas
  - Heat Rate Requirement






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Phase II Analysis Process

Load
- Hourly per Town
- Hourly per RTO

Resource Availability
- Hourly for Existing
- Hourly for Proposed Options

Resource Operation
- Non-Dispatchable
- Must-Run and Minimums
- Dispatchable

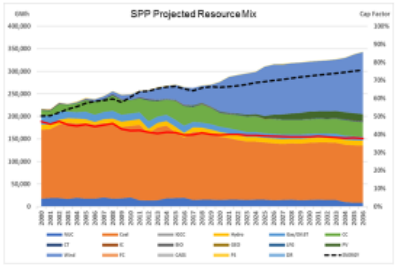
Resource Cost
- Actual/Contract Pricing for Existing
- Calculated Cost for New Options
- Projected Market Pricing

NPV
- For Each New Proposed Option
- Sensitivity Scenarios

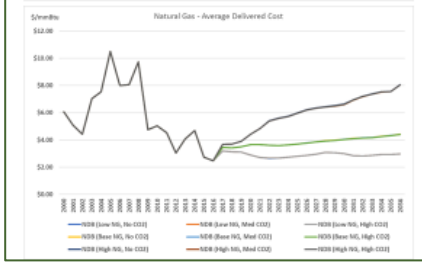
75

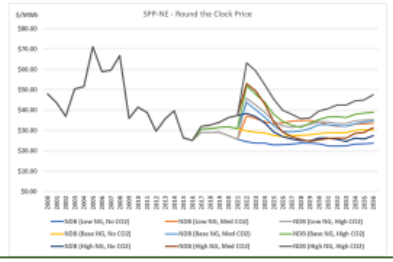
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Phase II Analysis Inputs



HORIZONS ENERGY





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Future Expectations

Phase I	• Input from PSC – Workshop and Survey • Draft Review by PSC
Phase II	• Input from PSC – Workshop and Survey • Draft Review by PSC
Final Draft	• Review by Board • **Public Distribution** • WAPA Review
Board Approval	• Board Meeting Vote

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D. August 2017 Power Supply Committee Workshop

SIGN-IN SHEET
MEAN AD HOC & POWER SUPPLY COMMITTEE WORKSHOP
August 2, 2017
MUNICIPAL ENERGY AGENCY OF NEBRASKA
Lincoln, Nebraska

1.	Doug Staab-Broken Bow	31.	Kyle-Staff
2.	Jeff Wells-Fort Morgan	32.	Rich-Staff
3.	Darrel Wenzel -Waverly, IA	33.	Dianne-Staff
4.	Chris Rodman-Wall Lake	34.	Joe-Staff
5.	Duane Hoffman-Oxford	35.	Candy-Staff
6.	Pat Davison-Imperial	36.	Bruce-Staff
7.	Tom Goulette-West Point	37.	
8.	Adam Suppes-Delta	38.	
9.	Tom Ourada-Crete	39.	
10.	Todd Kielkopf-Carlisle	40.	
11.	Chris DesPlanques-Indianola	41.	
12.	Mike Kalkwalf-Crete	42.	
13.	Gordon Bridges-Crete	43.	
14.	Phil Overender-Aspen	44.	
15.	Adam-staff	45.	
16.	Dave-Staff	46.	
17.	Armin-Staff	47.	
18.	Jill-Staff	48.	
19.	Michelle-Staff	49.	
20.	Gen-Staff	50.	
21.	Bob-Staff	51.	
22.	Tim S. Staff	52.	
23.	Kara-Staff	53.	
24.	Kim-Staff	54.	
25.	Brad-Staff	55.	
26.	Jamie J.-Staff	56.	
27.	Shannon-Staff	57.	
28.	Tim C.-Staff	58.	
29.	Chris-Staff	59.	
30.	Katrinka-Staff	60.	

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Integrated Resource Plan

Shannon Coleman

Supervisor of Planning & Analysis

4

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Agenda

- What is the IRP again?
- Why do we prepare and submit an IRP?
- What is the intent of the IRP?
- Long-Term Resource Needs
- Current and Potential Resource Mix
- How to Choose a Resource
- Modeling Process for IRP
- Results



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The IRP

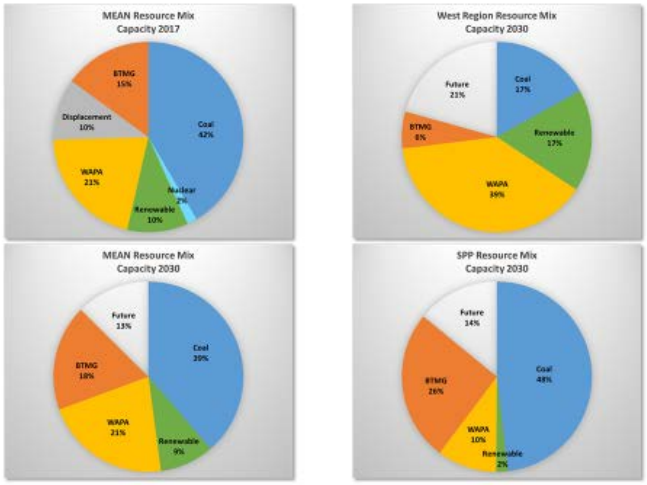
Western Area Power Administration

- Requirement of WAPA – Allocations
- Establish Long-Term Plan for Meeting Load
  - Supply Side Resources
  - Demand Side Resources
- The IRP must **evaluate the full range of alternatives** to provide adequate and reliable service to a customer's electric consumers at the customer's or member's **lowest system cost.**
- Robust **public involvement** should be a part of the process, as well, allowing the utility to share upcoming challenges with its consumers and to get their **input on solutions** that best address the community's diverse wishes and concerns.
- MEAN's Strategic Plan

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Resource Portfolios

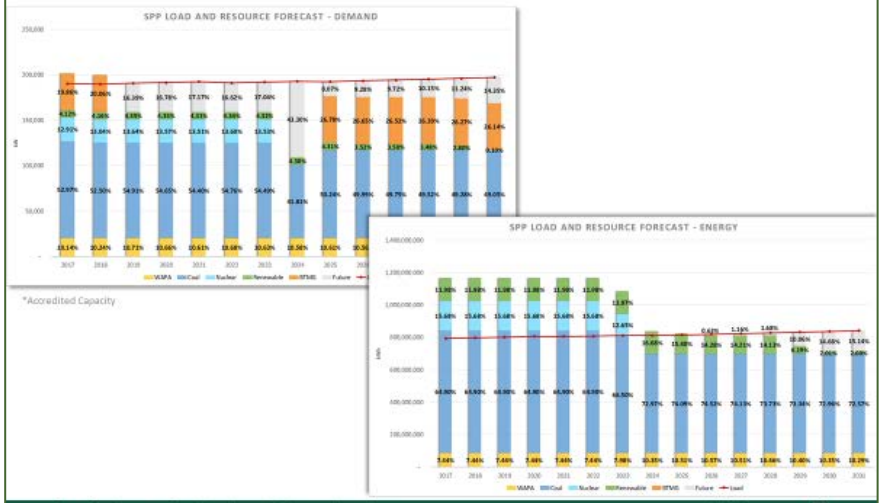


*Nameplate Capacity

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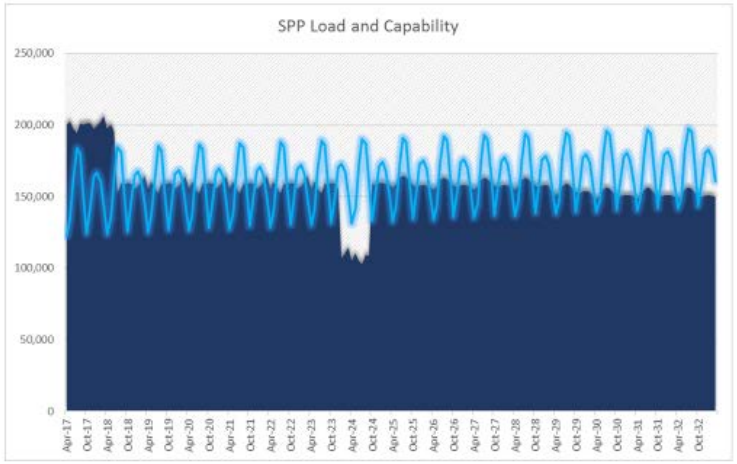
Resource Needs



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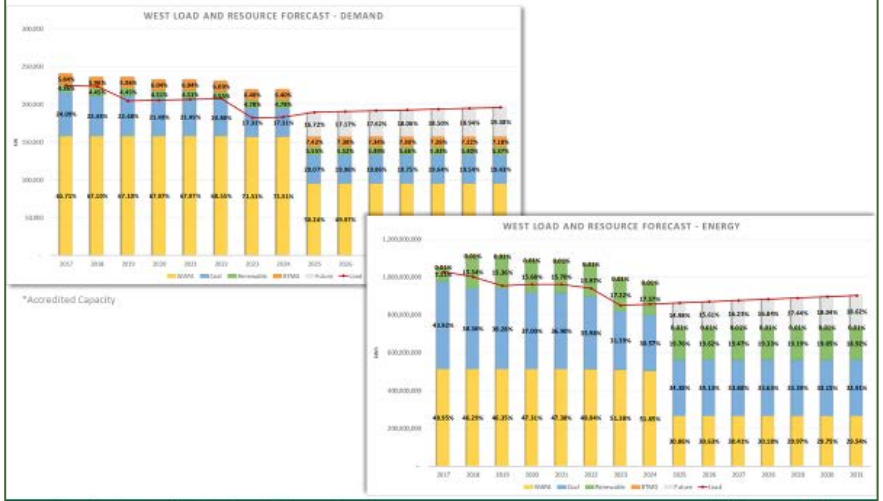
SPP Load and Resource Balance



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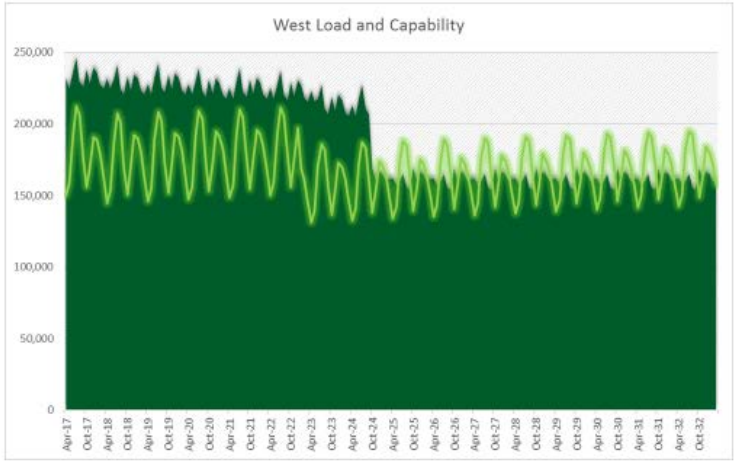
Resource Needs



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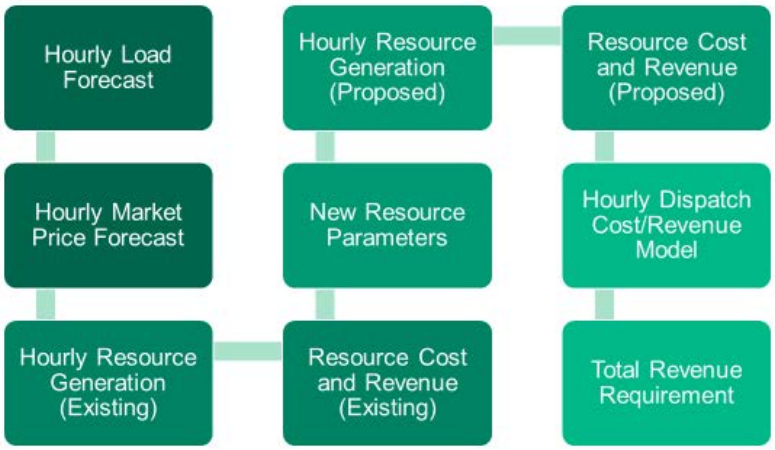
West Region Load and Resource Balance



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Modeling Process



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Sensitivity Analysis

Scenarios

CO2 Tax	Natural Gas Price: Low	Base	High
No	1	4	7
Med	2	5	8
High	3	6	9

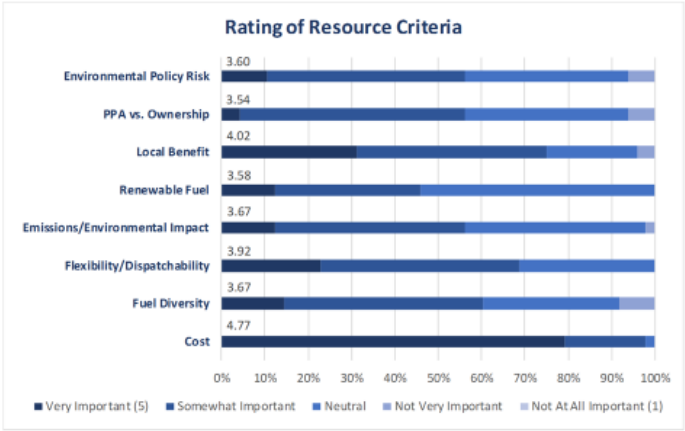
Variables:

- Market Price
- Fuel Price
- CO2 Tax

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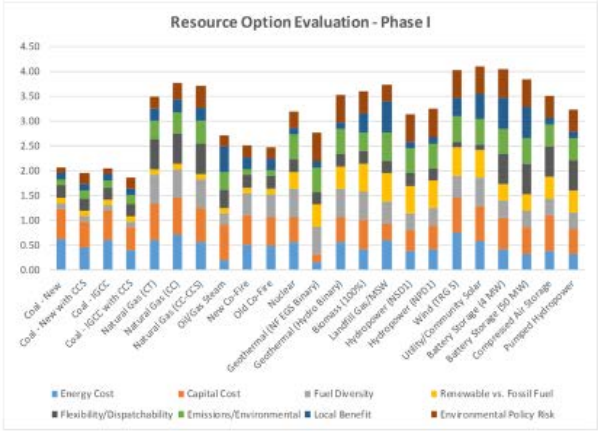
Resource Selection Criteria



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Phase I Supply Side Resource Evaluation



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Phase I Supply Side Resource Evaluation



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SPP Portfolios

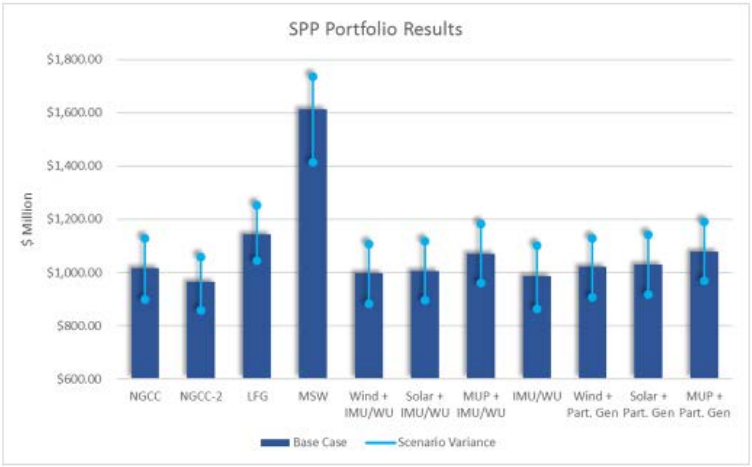
- Portfolio 1 = Natural Gas Combined Cycle
- Portfolio 1D = Identified Natural Gas Combined Cycle Plant
- Portfolio 2 = Landfill Gas
- Portfolio 3 = Municipal Solid Waste
- Portfolio 4 = Wind + Extend Generation Agent Arrangement
- Portfolio 5 = Solar + Extend Generation Agent Arrangement
- Portfolio 6 = Extend MUP + Extend Generation Agent Arrangement
- Portfolio 7 = Extend Excess Agent (Market Energy)
- Portfolio 8 = Wind + New Participant Generation
- Portfolio 9 = Solar + New Participant Generation
- Portfolio 10 = Extend MUP + New Participant Generation

Increased Fuel Diversity Increased Renewables

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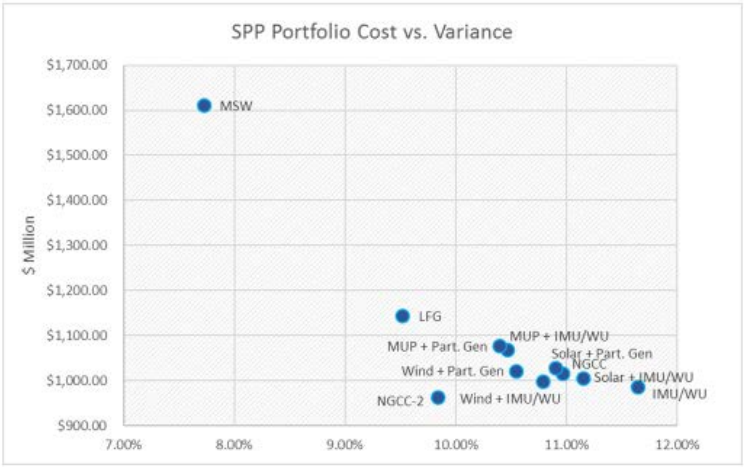
SPP Portfolio Revenue Requirements



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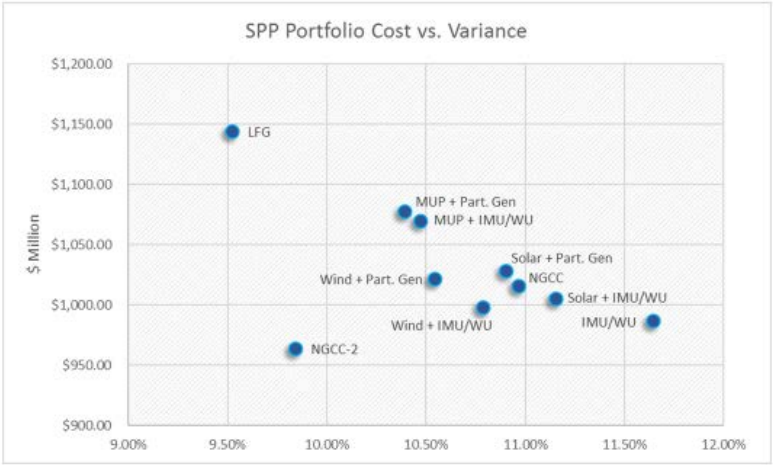
SPP Portfolio Cost vs. Variance



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SPP Portfolio Cost vs. Variance



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SPP Portfolio Cost and Variance

Portfolio #	Description	Cost (Base Case)	+/-	Variance
1	NGCC	$1,015,852,691	+5.4%	10.96%
1D	NGCC-2	$963,846,484	--	9.84%
2	LFG	$1,144,257,293	+18.7%	9.52%
3	MSW	$1,611,527,936	+67.2%	7.72%
4	Wind + IMU/WU	$998,390,183	+3.6%	10.79%
5	Solar + IMU/WU	$1,005,032,419	+4.3%	11.15%
6	MUP + IMU/WU	$1,069,721,394	+11.0%	10.47%
7	IMU/WU	$987,129,129	+2.4%	11.64%
8	Wind + Member Gen	$1,021,745,696	+6.0%	10.54%
9	Solar + Member Gen	$1,028,387,932	+6.7%	10.90%
10	MUP + Member Gen	$1,077,687,596	+11.8%	10.39%

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West Portfolios

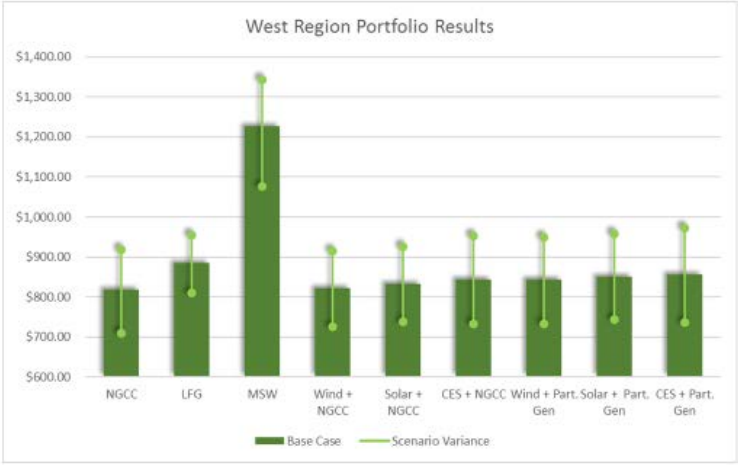
- Portfolio 1 = Natural Gas Combined Cycle
- Portfolio 2 = Landfill Gas
- Portfolio 3 = Municipal Solid Waste
- Portfolio 4 = Wind + Natural Gas Combined Cycle
- Portfolio 5 = Solar + Natural Gas Combined Cycle
- Portfolio 6 = CES + Natural Gas Combined Cycle
- Portfolio 7 = Wind + New Participant Generation
- Portfolio 8 = Solar + New Participant Generation
- Portfolio 9 = CES + New Participant Generation

Increased Fuel Diversity Increased Renewables

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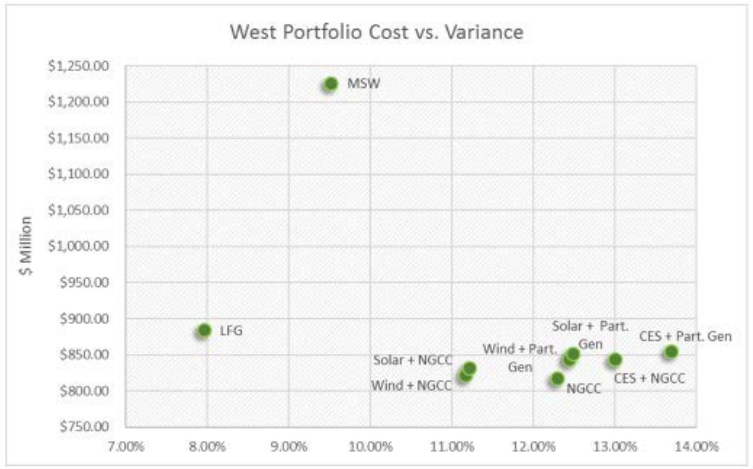
West Portfolio Revenue Requirements



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West Portfolio Cost vs. Variance



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West Portfolio Cost vs. Variance



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West Portfolio Cost and Variance

Portfolio #	Description	Cost (Base Case)	+/-	Variance
1	NGCC	$817,711,474	--	12.29%
2	LFG	$884,432,526	+8.2%	7.96%
3	MSW	$1,226,420,324	+50.0%	9.52%
4	Wind + NGCC	$822,249,284	+0.6%	11.16%
5	Solar + NGCC	$832,250,149	+1.8%	11.21%
6	CES + NGCC	$843,498,058	+3.15%	13.00%
7	Wind + Member Gen	$844,282,725	+3.25%	12.44%
8	Solar + Member Gen	$851,503,878	+4.1%	12.49%
9	CES + Member Gen	$855,529,979	+4.6%	13.69%

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Conclusion/Recommendation

- Lowest Cost Portfolio
  - SPP = NGCC-2, IMU/WU Extension
  - West = NGCC
- Lowest Variance
  - SPP = LFG, NGCC-2
  - West = LFG, Wind + NGCC
- Other Factors?
- PSC Recommendation?

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E. August 2017 Board and Committee Meetings

POWER SUPPLY COMMITTEE

CALL TO ORDER

Chairman Leroy Frana called the meeting to order at 11:08 a.m. (CT). Pursuant to Section 84-1412 (8) of the Nebraska Open Meetings Act, a current copy of the Open Meetings Act was posted in the meeting room and made available to the public.

ROLL CALL

A quorum was declared with ten of the eleven committee members in attendance.

1. Leroy Frana, Nebraska City
2. Pat Davison, Imperial
3. James DePue, Wray
4. Bill Hinton, Kimball
5. Duane Hoffman, Oxford
6. Tom Ourada, Crete
7. Chris Rodman, Wall Lake (arrived at 11:15 a.m.)
8. Jeremy Tarr, Burwell
9. Ed Tvrs, Alliance
10. Randy Woldt, Wisner

Mike Palmer, Voting Ex-Officio

Absent: Doug Staab

Others in attendance: Rod Brestel, Gordon Bridges, Dan Dean, Chris DesPlanques, Will Dowis, Rich Eymann, Tom Goulette, Reece Jensen, Mike Kalkwarf, Wayne Kautz, Joe Kubala, Bob Lockmon, Lynn Longmore, Todd Mahin, Margaret Medellin, Brent Nation, Mike Palmer, John Prettyman, Rick Rigel, Jim Roblyer, Alan Romine, Doug Schultz, Jeff Sprock, Adam Suppes, Jeff Wells, and Darrel Wenzel.

NMPP staff: Rich Andrysik, David Beard, Carol Brehm, Tim Cerveny, Shannon Coleman, Chris Dibbern, Katrinka Dicke, Bruce Doll, Brad Hans, Kara Hunt, Jamie Johnson, Jill Jones, Sarah Jones, Kyle Kaldahl, Michelle Lepin, Bob Poehling, Joe Rivera, Kim Schafers, Robin Spady, Tim Sutherland, Candy Thomazin, and Kevin Wickham

BOARD OF DIRECTORS

CALL TO ORDER

Chairman Tom Goulette called the meeting to order at 9:03 a.m. (CT). Pursuant to Section 84-1412(8) of the Nebraska Open Meetings Act, a current copy of the Open Meetings Act was posted in the meeting room and made available to the public.

ROLL CALL

A quorum was declared with 32 of the 54 Directors in attendance.

1. Brestel, Rob – Callaway
2. Cooley, Tammy – Gering
3. Davison, Pat – Imperial
4. DePue, Wray – Wray
5. DesPlanques, Chris – Indianola
6. Dowis, Will – Gunnison
7. Eymann, Rich – Pierce
8. Ferguson, Michael – Ansley
9. Frana, Leroy – Nebraska City
10. Goulette, Tom – West Point
11. Hinton, Bill – Kimball
12. Hoffman, Duane – Oxford
13. Kautz, Wayne – Bridgeport
14. Kubala, Joe – Lyons
15. Lockmon, Bob – Stuart
16. Mahin, Todd – Red Cloud
17. McNally, Joe – Neligh
18. Millyard, Robin – Glenwood Springs
19. Ourada, Tom – Crete
20. Palmer, Mike – Sidney
21. Prettyman, John – Yuma
22. Rodman, Chris – Wall Lake
23. Romine, Alan – Falls City
24. Schultz, Doug – Curtis
25. Sprock, Jeff – Mitchell
26. Summers, James – Benkelman
27. Suppes, Adam – Delta
28. Tarr, Jeremy – Burwell
29. Tvrs, Ed – Alliance
30. Wells, Jeff – Fort Morgan
31. Wenzel, Darrel – Waverly
32. Woldt, Randy – Wisner

Absent: Beck, Keith; Bielser, Collin; Carpenter, Ron; Coolidge, Dan; Coyne, Allen; Cramer, Greg; Criss, Mike; DeLaune, Doug; Domeier, Brock; Edgar, Larry; Harris, Dana; Hornbacher, Dave; Jorgensen, Grant; Lesher, Stacey; Mitchell, Curtis; Paeper, Bruce; Schmidt, Janine; Schwabe, Michael; Staab, Doug; Thomas, Allan; Varney, Mike; and Winkel, Jon.

Others in attendance: Travis Burdett, Dan Dean, Brian Exstrum, Gordon Bridges, Reece Jensen, Mike Kalkwarf, Todd Kielkopf, Chris Linder, Lynn Longmore, Wendy McKain, Margaret Medellin, Brent Nation, Rick Rigel, Jim Roblyer, and John Rundel.

NMPP staff: Rich Andrysik, Carol Brehm, Tim Cerveny, Shannon Coleman, Chris Dibbern, Katrinka Dicke, Bruce Doll, Brad Hans, Kara Hunt, Jamie Johnson, Jill Jones, Sarah Jones, Kyle Kaldahl, Michelle Lepin, Bob Poehling, Joe Rivera, Andrew Ross, Kim Schafers, Robin Spady, Tim Sutherland, Candy Thomazin, and Kevin Wickham.

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Integrated Resource Plan Results (To Date)

Public Hearing

Shannon Coleman
Supervisor of Planning & Analysis

Attachment B

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Agenda

- What is the IRP again?
- Why do we prepare and submit an IRP?
- What is the intent of the IRP?
- Long-Term Resource Needs
- Current and Potential Resource Mix
- Demand Side Management Analysis
- How to Choose a Supply Side Resource
- Modeling Process for IRP
- Results



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The IRP

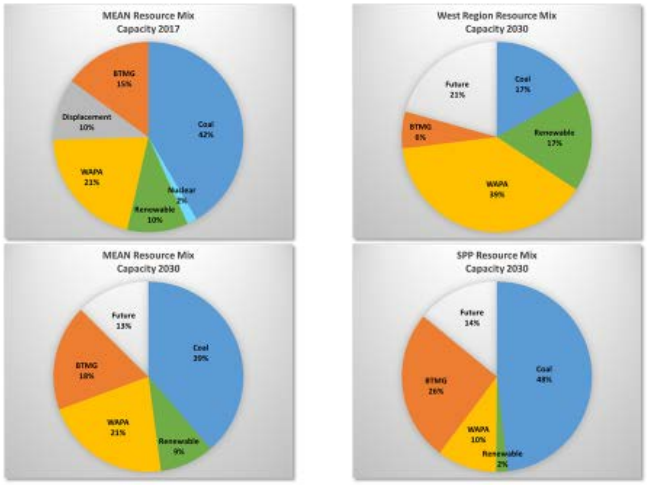
Western Area Power Administration

- Requirement of WAPA – Allocations
- Establish Long-Term Plan for Meeting Load
  - Supply Side Resources
  - Demand Side Resources
- The IRP must **evaluate the full range of alternatives** to provide adequate and reliable service to a customer's electric consumers at the customer's or member's **lowest system cost.**
- Robust **public involvement** should be a part of the process, as well, allowing the utility to share upcoming challenges with its consumers and to get their **input on solutions** that best address the community's diverse wishes and concerns.
- MEAN's Strategic Plan

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Resource Portfolios

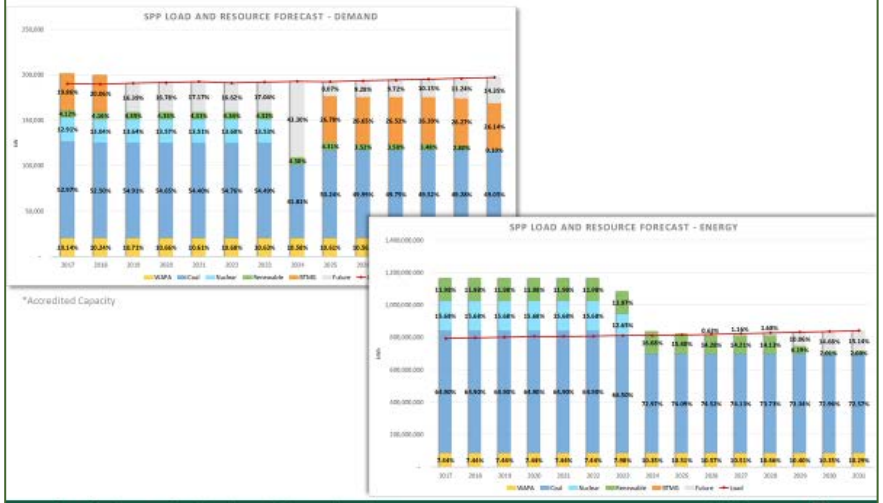


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*Nameplate Capacity

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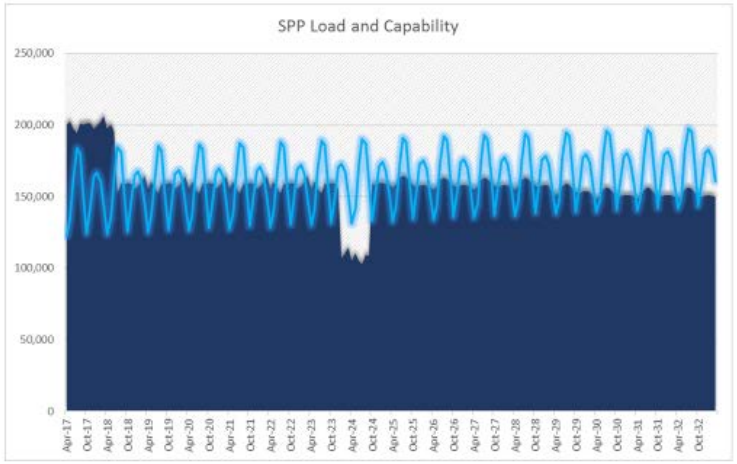
Resource Needs



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SPP Load and Resource Balance

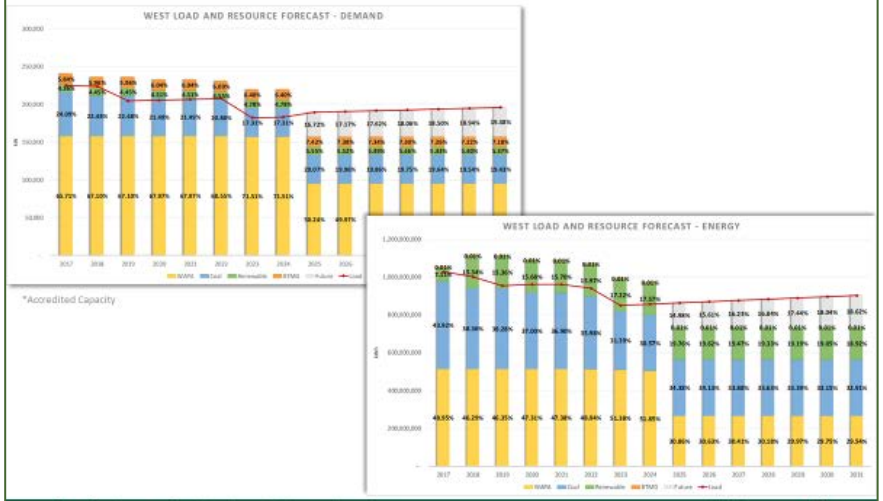


48

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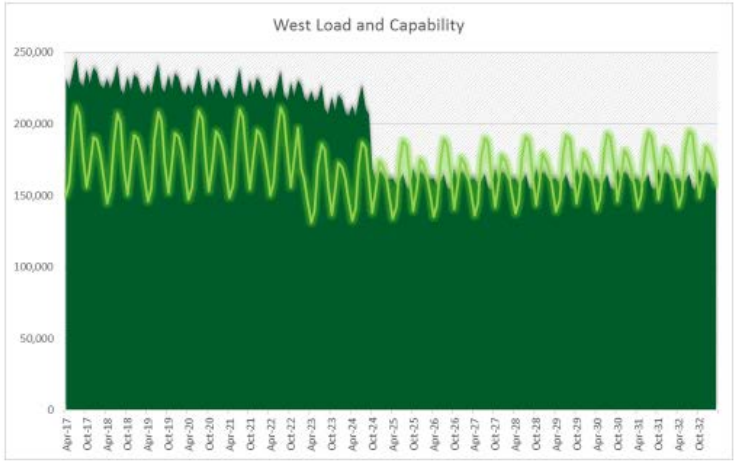
Resource Needs



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West Region Load and Resource Balance

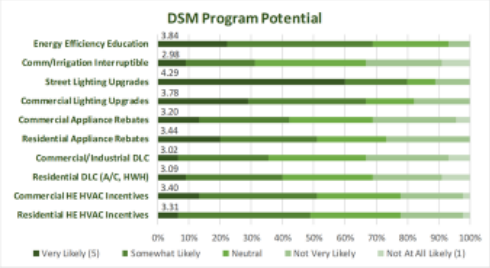


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Demand Side Management Analysis



Qualified Options:

- Appliance Rebates
  - Refrigerator Upgrades
  - Freezer Upgrades
  - Water Heater Conversion
- High Efficiency HVAC Incentives
  - Air Source Heat Pump Conversion
  - Room Air Conditioner Upgrade
  - Central Air Conditioner Upgrade

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Demand Side Management Analysis

- Three Benefit/Cost Ratio Tests
  - Utility Cost Test
  - Participant Cost Test
  - Total Resource Cost Test

TEST	BENEFITS	COSTS
Utility Cost Test	• Utility Avoided Costs	• Program Administration Costs • Incentives/Rebates Paid
Participant Cost Test	• Net Bill Savings	• Incremental Cost of Investment (Net of Incentive/Rebate)
Total Resource Cost Test	• Utility Avoided Costs	• Program Administration Costs • Incremental Cost of Investment (Net of Incentive/Rebate)

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Demand Side Management Analysis

Benefit/Cost Ratio Test Results

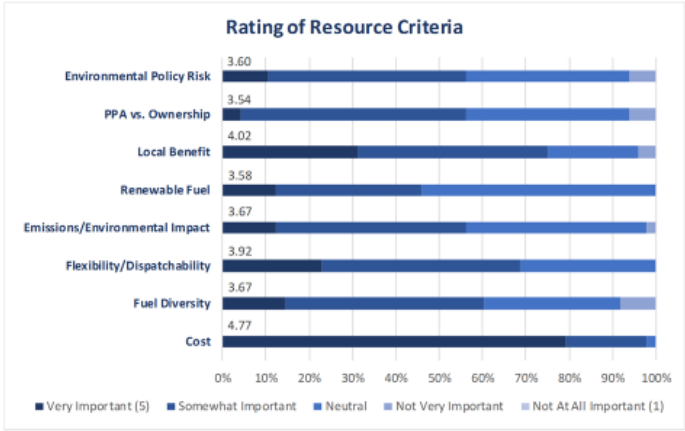
DSM PROGRAM	UTILITY COST TEST (Benefit/Cost)	PARTICIPANT COST TEST (Benefit/Cost)	TOTAL RESOURCE COST TEST (Benefit/Cost)
Air Source Heat Pump Incentive	-0.36	-0.11	-0.36
Room Air Conditioner Rebate	0.01	0.19	0.01
Central Air Conditioner Incentive	0.03	0.14	0.04
Refrigerator Rebate	0.04	0.54	0.05
Freezer Rebate	0.08	1.53	0.10
Water Heater Conversion Incentive	-0.64	-4.03	-1.49

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Resource Selection Criteria

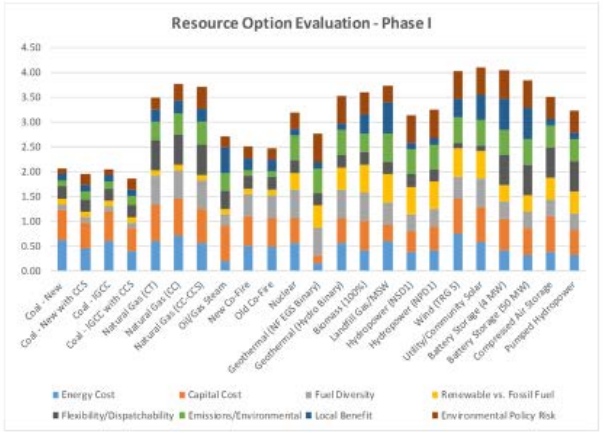


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Phase I Supply Side Resource Evaluation

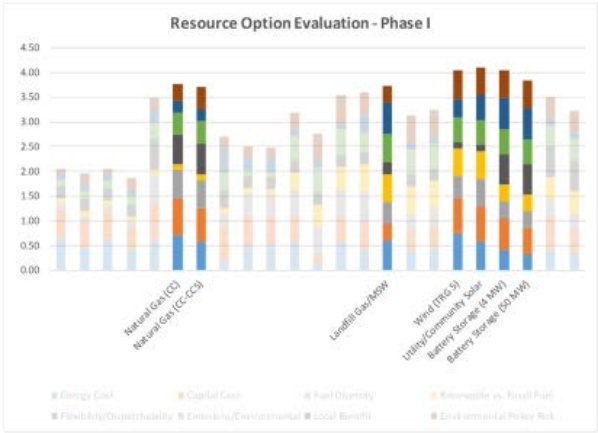


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Phase I Supply Side Resource Evaluation

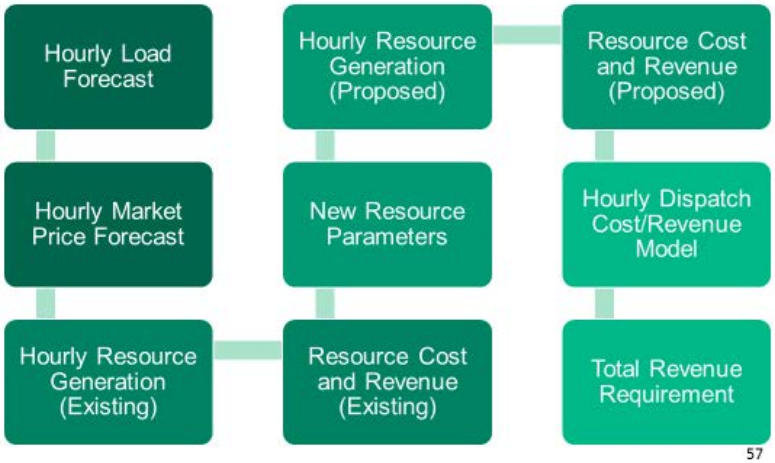


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Modeling Process



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Sensitivity Analysis

Scenarios

CO2 Tax	Natural Gas Price: Low	Natural Gas Price: Base	Natural Gas Price: High
No	1	4	7
Med	2	5	8
High	3	6	9

Variables:

- Market Price
- Fuel Price
- CO2 Tax

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SPP Portfolios

- Portfolio 1 = Natural Gas Combined Cycle
- Portfolio 1D = Identified Natural Gas Combined Cycle Plant
- Portfolio 2 = Landfill Gas
- Portfolio 3 = Municipal Solid Waste
- Portfolio 4 = Wind + Extend Generation Agent Arrangement
- Portfolio 5 = Solar + Extend Generation Agent Arrangement
- Portfolio 6 = Extend MUP + Extend Generation Agent Arrangement
- Portfolio 7 = Extend Excess Agent (Market Energy)
- Portfolio 8 = Wind + New Participant Generation
- Portfolio 9 = Solar + New Participant Generation
- Portfolio 10 = Extend MUP + New Participant Generation

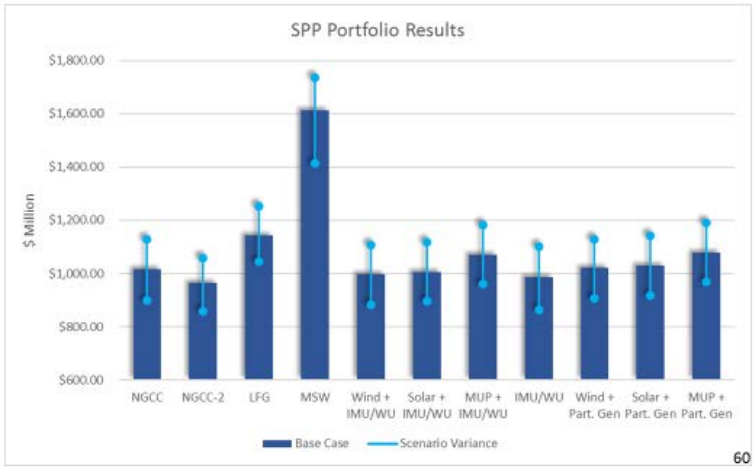
Increased Fuel Diversity Increased Renewables

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SPP Portfolio Revenue Requirements

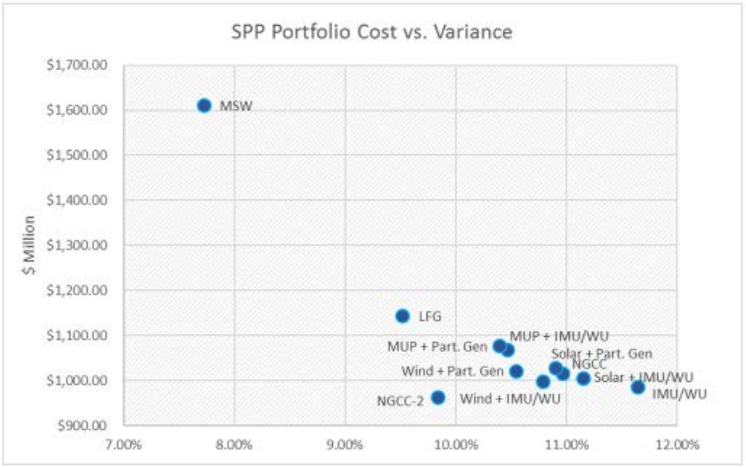


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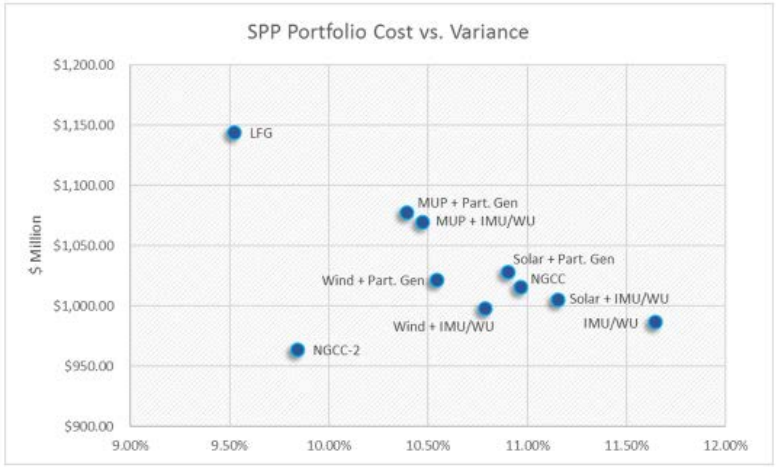
SPP Portfolio Cost vs. Variance



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SPP Portfolio Cost vs. Variance



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SPP Portfolio Cost and Variance

Portfolio #	Description	Cost (Base Case)	+/-	Variance
1	NGCC	$1,015,852,691	+5.4%	10.96%
1D	NGCC-2	$963,846,484	--	9.84%
2	LFG	$1,144,257,293	+18.7%	9.52%
3	MSW	$1,611,527,936	+67.2%	7.72%
4	Wind + IMU/WU	$998,390,183	+3.6%	10.79%
5	Solar + IMU/WU	$1,005,032,419	+4.3%	11.15%
6	MUP + IMU/WU	$1,069,721,394	+11.0%	10.47%
7	IMU/WU	$987,129,129	+2.4%	11.64%
8	Wind + Member Gen	$1,021,745,696	+6.0%	10.54%
9	Solar + Member Gen	$1,028,387,932	+6.7%	10.90%
10	MUP + Member Gen	$1,077,687,596	+11.8%	10.39%

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West Portfolios

- Portfolio 1 = Natural Gas Combined Cycle
- Portfolio 2 = Landfill Gas
- Portfolio 3 = Municipal Solid Waste
- Portfolio 4 = Wind + Natural Gas Combined Cycle
- Portfolio 5 = Solar + Natural Gas Combined Cycle
- Portfolio 6 = CES + Natural Gas Combined Cycle
- Portfolio 7 = Wind + New Participant Generation
- Portfolio 8 = Solar + New Participant Generation
- Portfolio 9 = CES + New Participant Generation

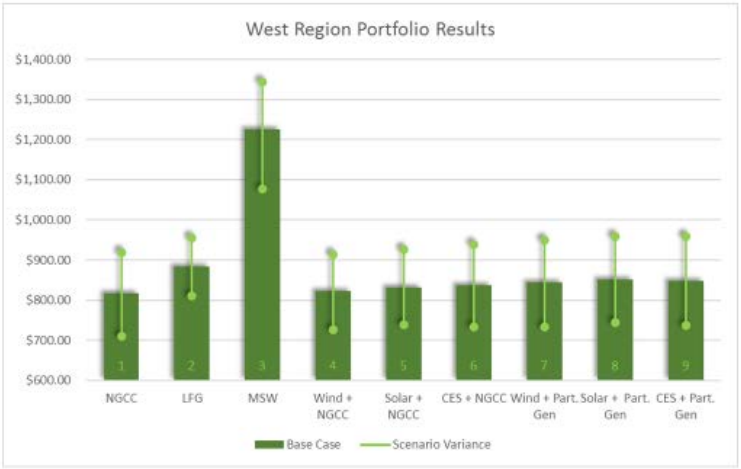
Increased Fuel Diversity Increased Renewables

64

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West Portfolio Revenue Requirements

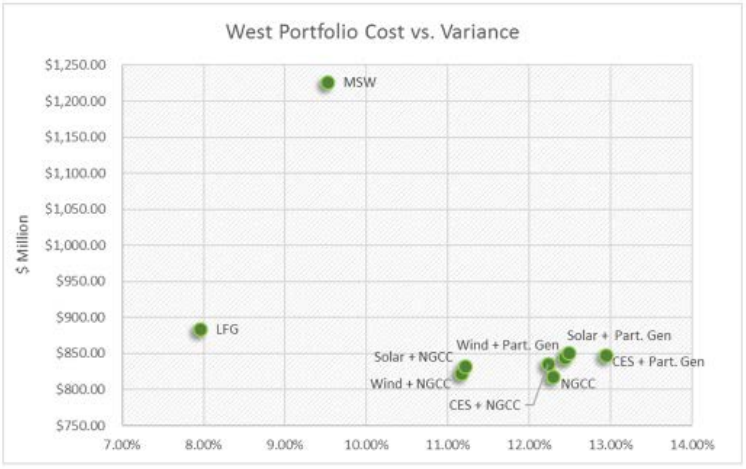


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West Portfolio Cost vs. Variance

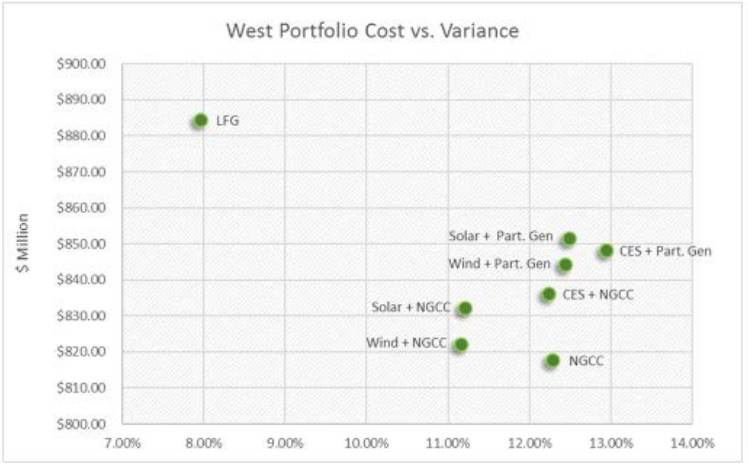


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West Portfolio Cost vs. Variance



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West Portfolio Cost and Variance

Portfolio #	Description	Cost (Base Case)	+/-	Variance
1	NGCC	$817,711,474	--	12.29%
2	LFG	$884,432,526	+8.2%	7.96%
3	MSW	$1,226,420,324	+50.0%	9.52%
4	Wind + NGCC	$822,249,284	+0.6%	11.16%
5	Solar + NGCC	$832,250,149	+1.8%	11.21%
6	CES + NGCC	$836,184,718	+2.3%	12.24%
7	Wind + Member Gen	$844,282,725	+3.25%	12.44%
8	Solar + Member Gen	$851,503,878	+4.1%	12.49%
9	CES + Member Gen	$848,216,639	+3.7%	12.95%

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Conclusion/Recommendation

- Lowest Cost Portfolio
  - SPP = NGCC-2, IMU/WU Extension
  - West = NGCC
- Lowest Variance
  - SPP = LFG, NGCC-2
  - West = LFG, Wind + NGCC
- Other Factors
  - Cost
  - Local Benefit
  - Flexibility/Dispatchability
- PSC Recommendation



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Public Participation

Questions and Answers

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Board –The MEAN Power Supply Committee recommends the MEAN Board of Directors approve the IRP as presented and direct staff to submit the IRP to Western Area Power Administration on behalf of the Total Requirements Participants.
1. Yes 30
2. No 0
3. Abstain 0
71
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NMPPenergy.org

From: Kim Schafers
To: [redacted]
Subject: MEAN Integrated Resource Plan (IRP) Process
Date: Monday, August 14, 2017 2:57:00 PM
Attachments: ATTACHMENT B-2017 MEAN IRP_DRAFT.pdf

ATTENTION CITY CLERKS-PLEASE FORWARD TO YOUR MEAN REPRESENTATIVES
Please Note: The attached information will be referenced during the MEAN Committee and Board meetings this Wednesday and Thursday, August 16-17, 2017 in Kearney, Nebraska.

Sent on behalf of Tim Sutherland via email
August 14, 2017

Subject: MEAN Integrated Resource Plan (IRP) Process

MEAN Board of Directors and Management Committee:

As we discussed in our email dated April 12, 2017, describing the steps in developing our Integrated Resource Plan, we have attached the Draft IRP for your review and the review of your community. We are asking that you consider the following:

- This is a draft version, which should be complete with exception to any additional recommendations made at the Power Supply Committee, Board meeting or other revisions made in response to review comments and final formatting.
- Please make the document publicly available in your community and invite public review and comment. This can be done via your community website or by making a hard copy available in a public building.
- Please send comments to MEANIRP2017@nmppenergy.org.
- Comments should be sent by September 8, 2017. This will provide time to incorporate comments and corrections in time for the submittal to WAPA on October 15, 2017.

We are encouraging all Participants and their communities to be actively involved in this process to provide valuable feedback to shape the IRP, which lays out a path to guide our strategic plan and resource decisions in the future.

We look forward to working through this process and your involvement in shaping future resource needs. If you have any questions or would like more information, please don't hesitate to contact me at (402) 474-4759.

Sincerely,

Tim Sutherland

Tim Sutherland
Director of Wholesale Electric Operations

NMPP | MEAN | NPGA | ACE

8377 Glynoaks Drive | Lincoln, NE 68516
Direct 402-473-8220 | Office 402-474-4759 | Cell 402-641-0134 | nmppenergy.org

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PUBLIC NOTICE

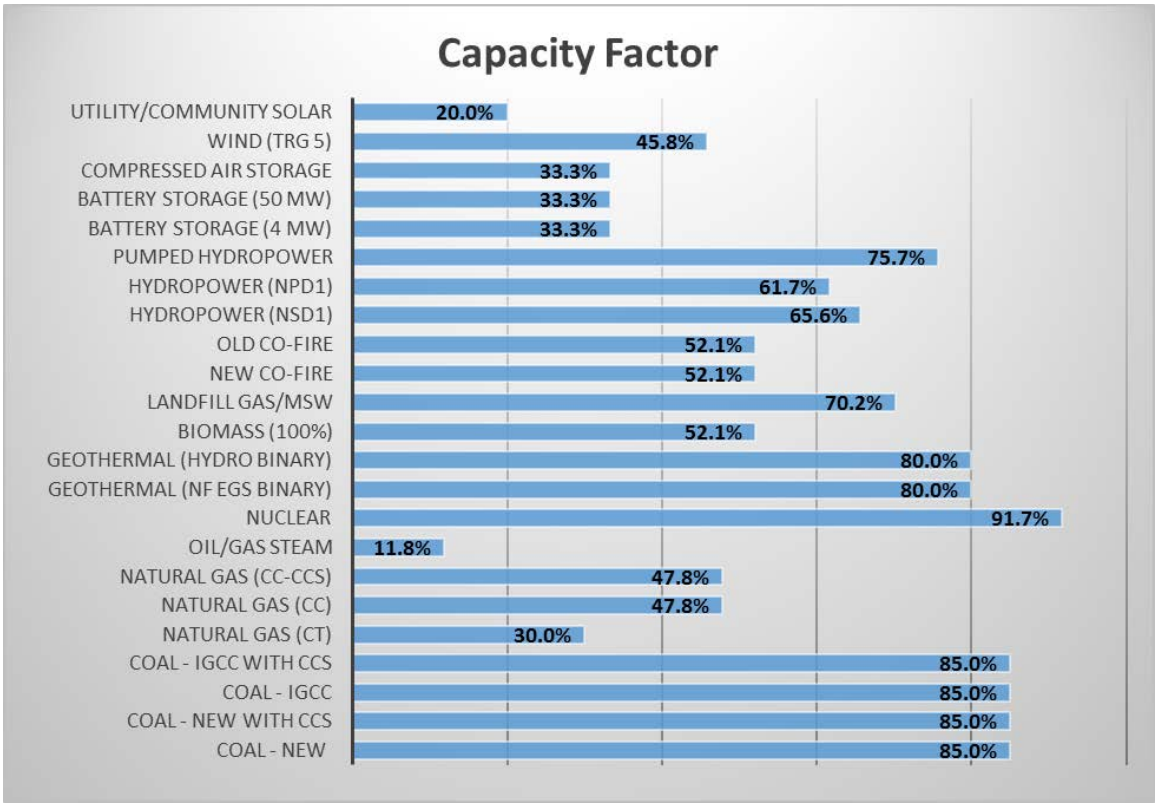
NOTICE IS HEREBY GIVEN that a joint meeting of the Board of Directors and Management Committee of the Municipal Energy Agency of Nebraska will be held Thursday, August 17, 2017, at 9:00 a.m. (CT), at the Younes Conference Center, Kearney, Nebraska.

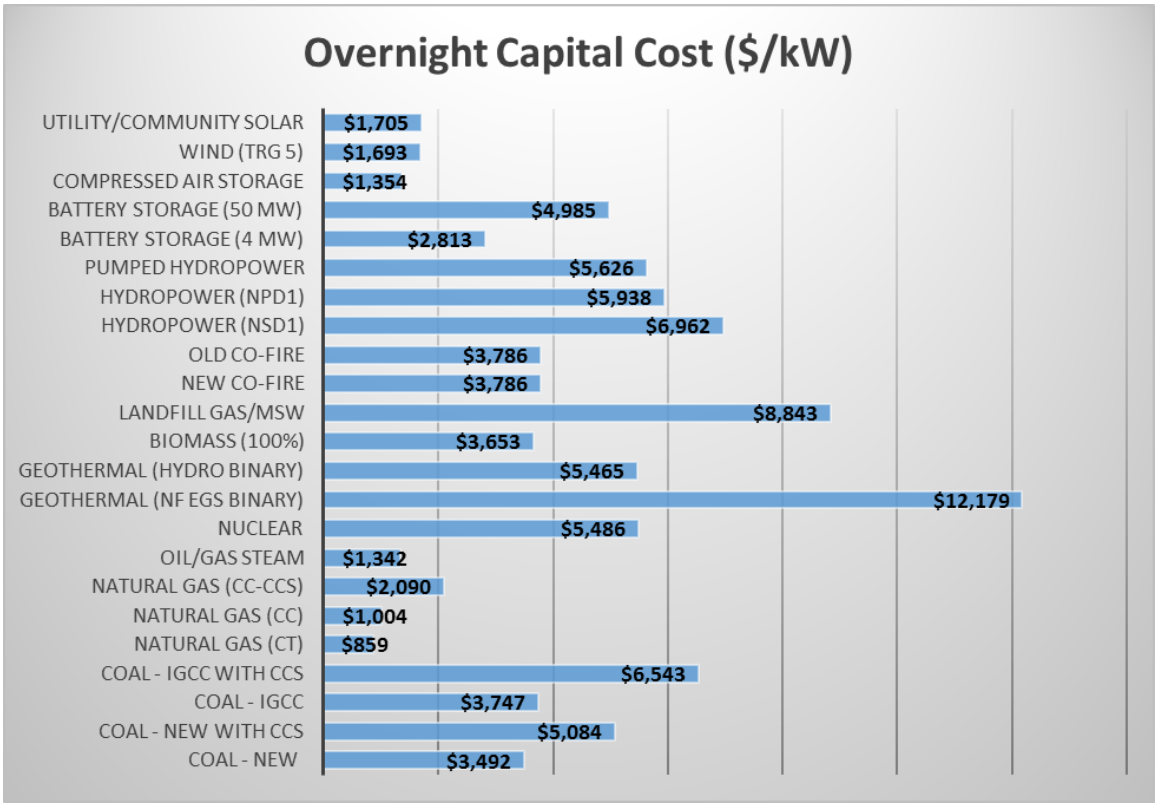
The agenda includes review and approval of the proposed draft Integrated Resource Plan (IRP). The purpose of the hearing is to provide for public participation in the development of the IRP, which will be submitted to Western Area Power Administration as part of the Energy Planning and Management Program. A copy of the proposed IRP will be available at the meeting and the Municipal Energy Agency of Nebraska (MEAN) will consider comments it receives at the public hearing prior to submittal to the MEAN Board of Directors for approval at the August 17, 2017 meeting.

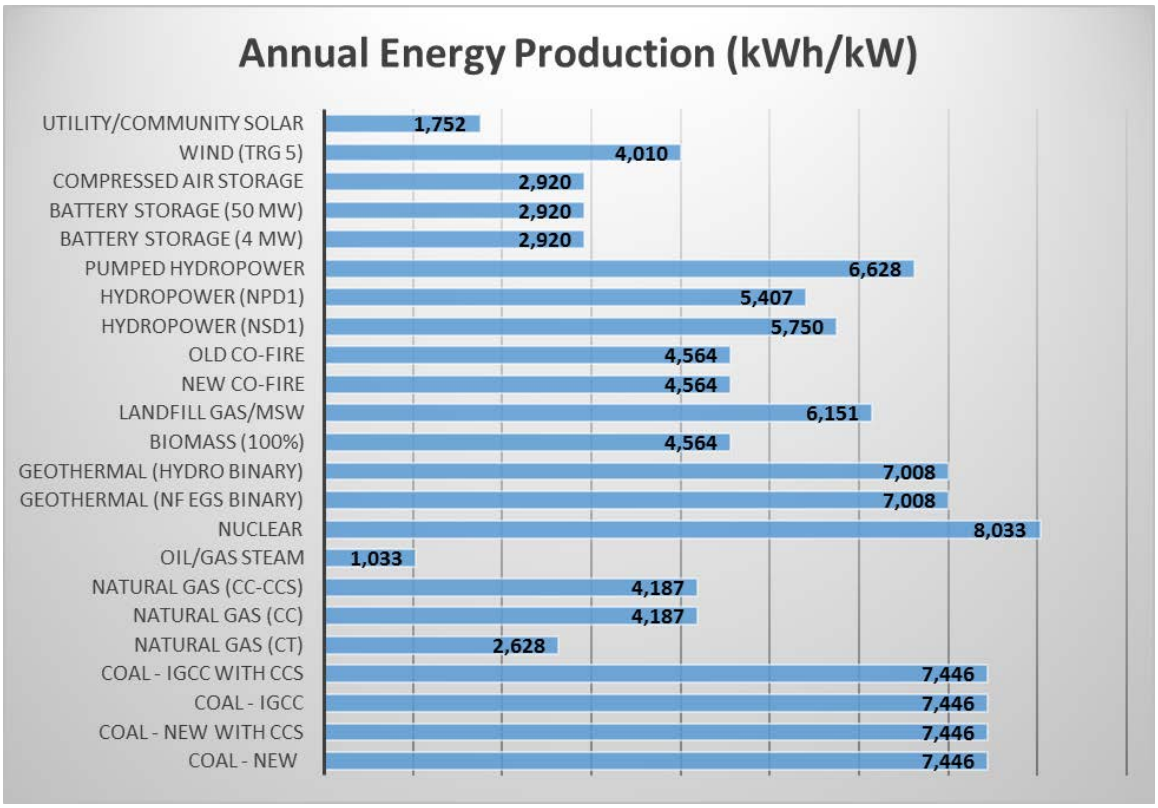
If you are unable to attend the hearing, but would like to review the proposed draft IRP, a copy of the proposed draft IRP is located for public review at MEAN's business office located at 8377 Glynoaks Drive, Lincoln, NE 68516. A copy of the proposed IRP is also posted for public review at all municipal offices of MEAN participants. Comments may be submitted by mail to Municipal Energy Agency of Nebraska, Attn. Shannon Coleman, 8377 Glynoaks Drive, Lincoln, NE 68516 or by email to MEANIRP2017@nmppenergy.org no later than September 8, 2017.

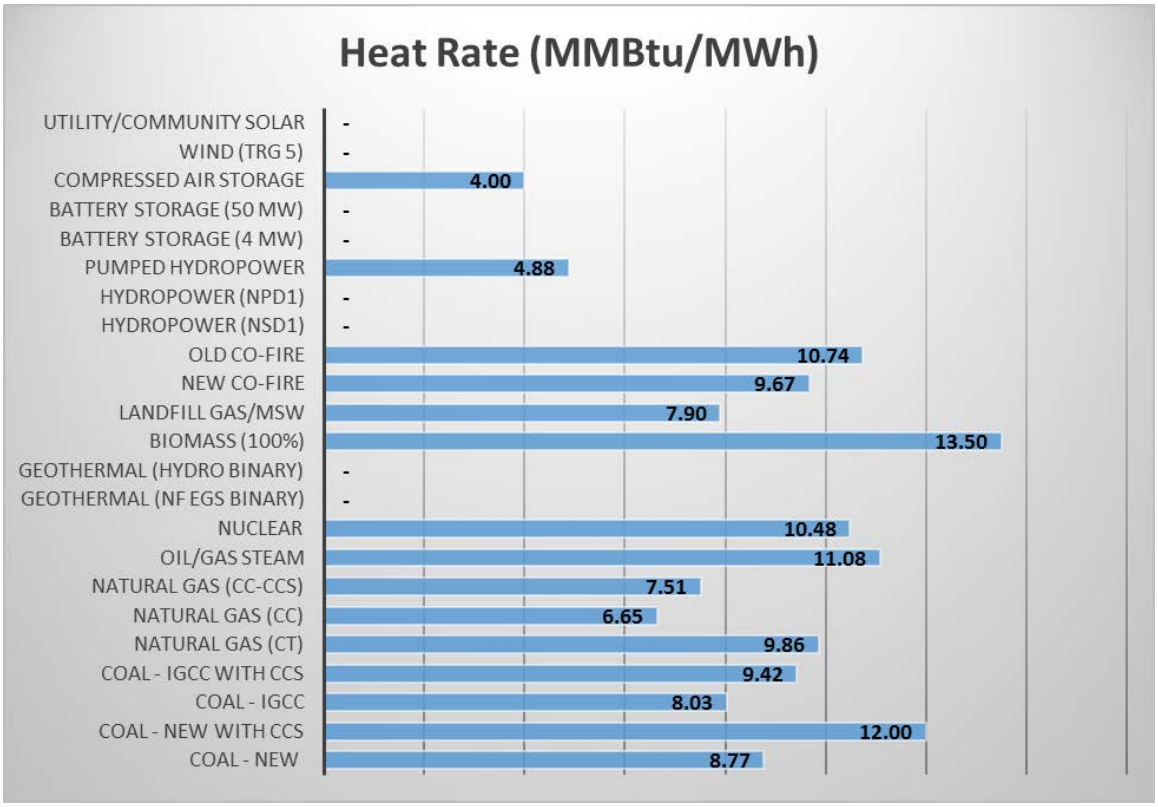
A copy of the agenda is posted upon issuance, kept continually current, and is available for public inspection at the NMPP Energy office, located at 8377 Glynoaks Drive, Lincoln, Nebraska. The meeting is open to the public. If you require special accommodations in order to attend the meeting, please contact Kim Schafers at 402-474-4759.

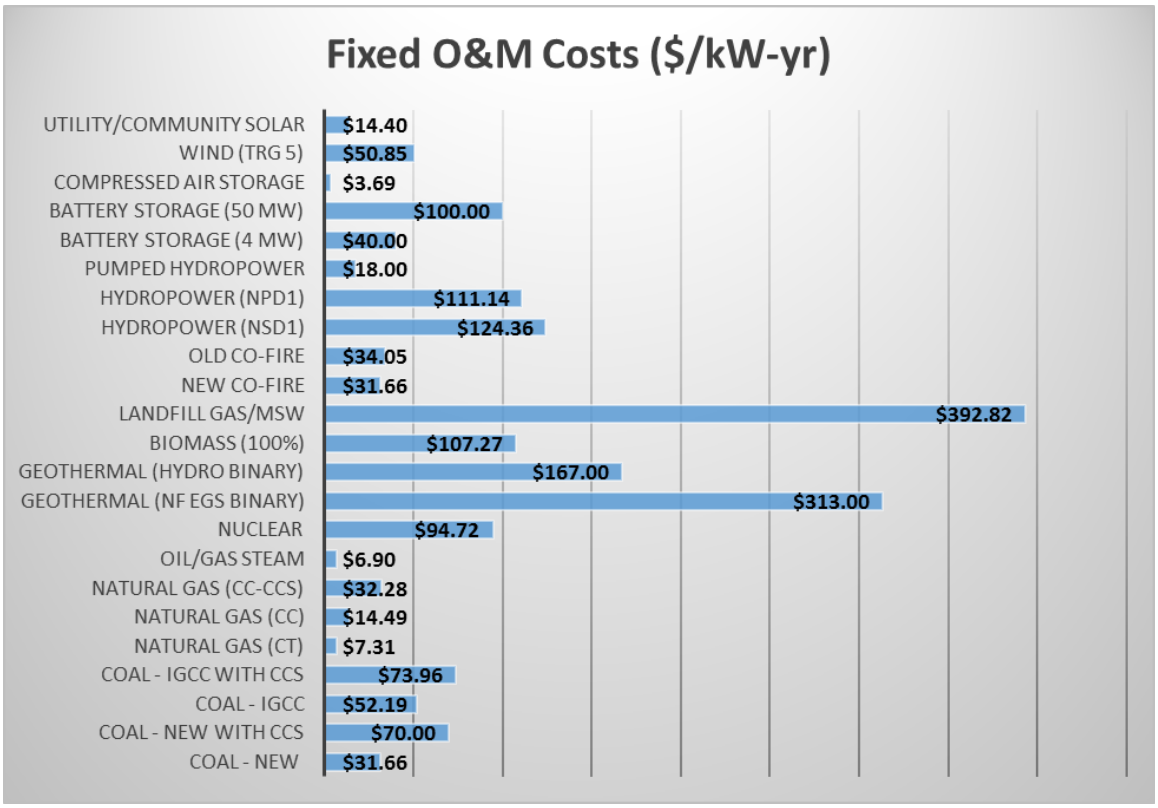
Appendix B – Phase I Supply Side Option Data

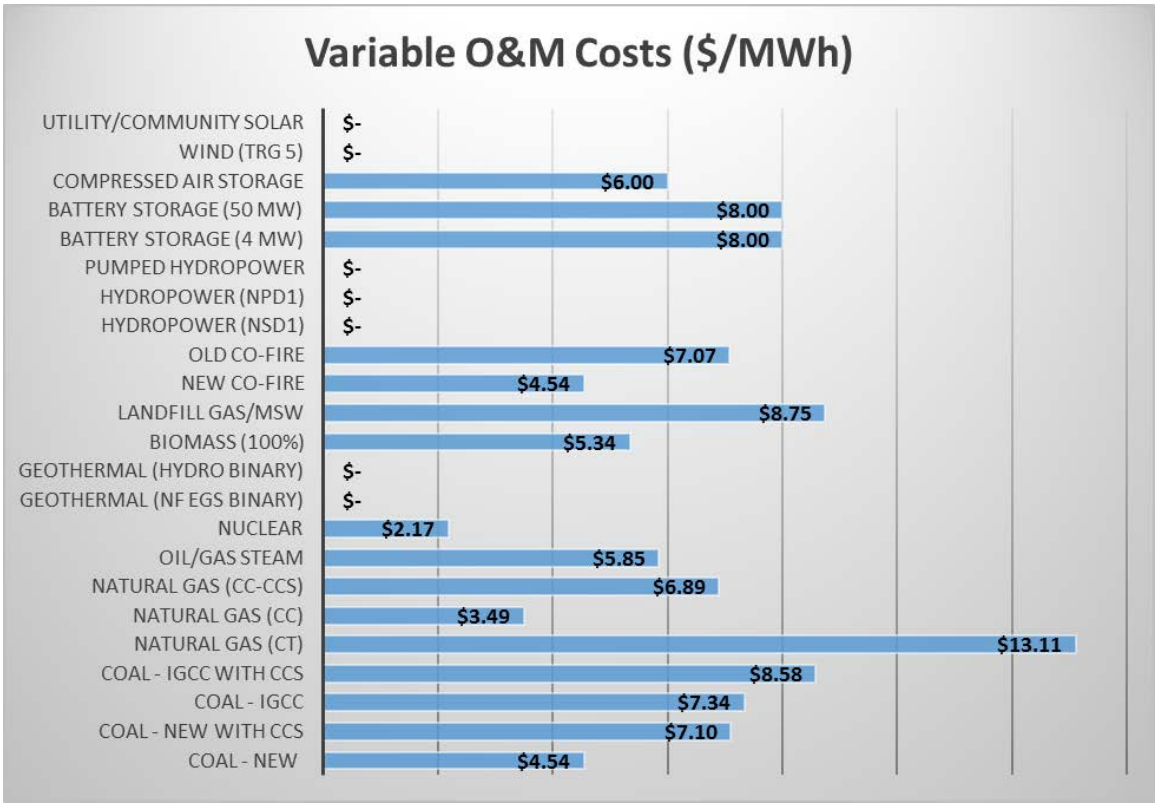


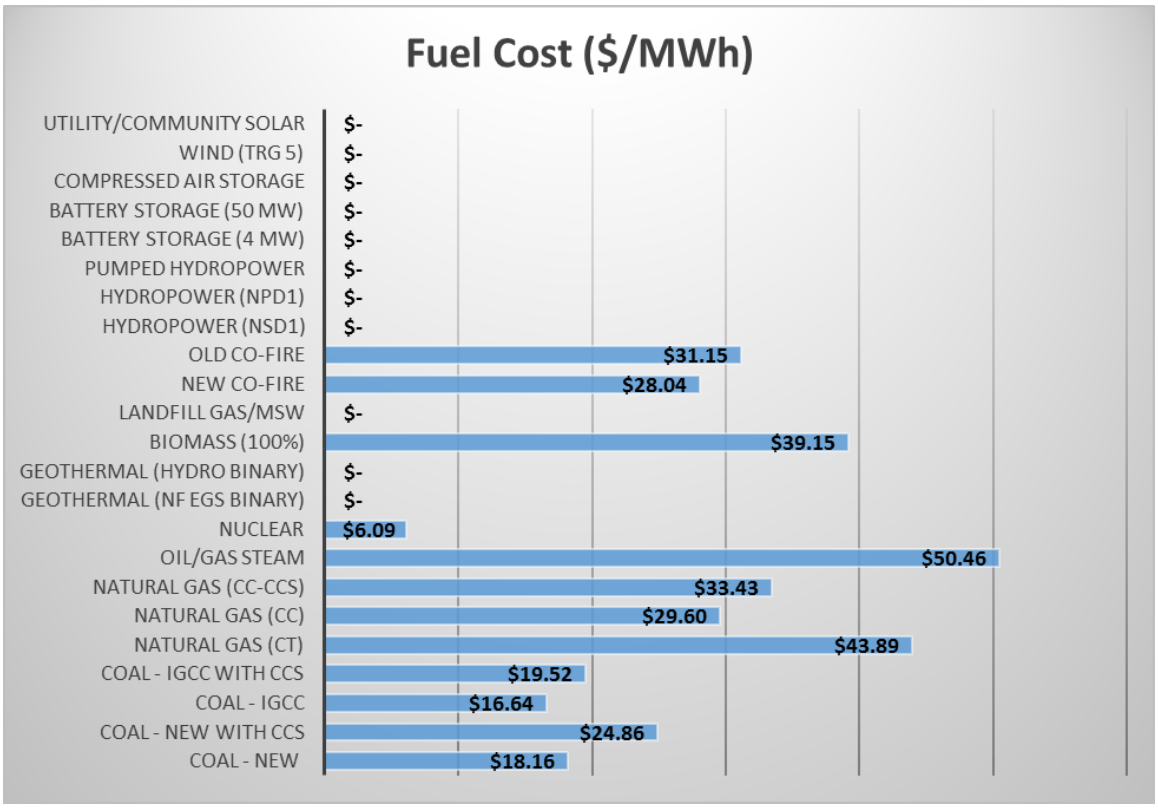


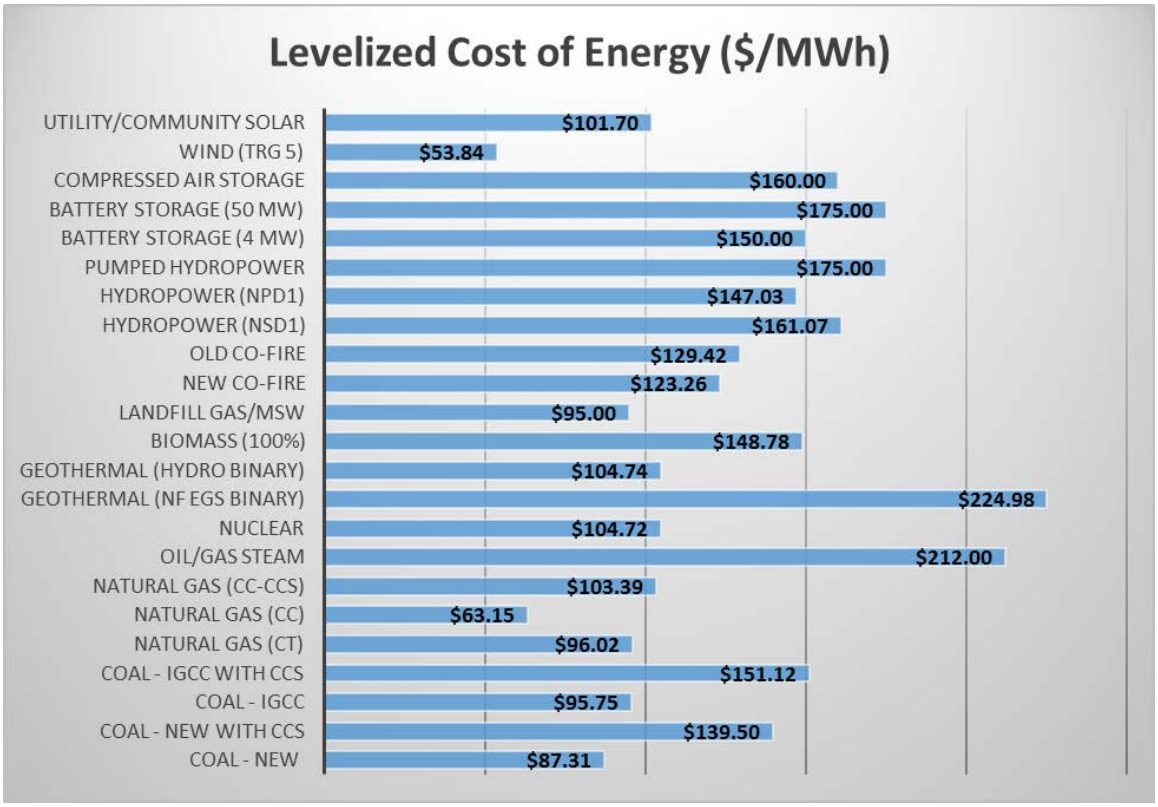

Annual Energy Production (kWh/kW)
UTILITY/COMMUNITY SOLAR 1,752
WIND (TRG 5) 4,010
COMPRESSED AIR STORAGE 2,920
BATTERY STORAGE (50 MW) 2,920
BATTERY STORAGE (4 MW) 2,920
PUMPED HYDROPOWER 6,628
HYDROPOWER (NPD1) 5,407
HYDROPOWER (NSD1) 5,750
OLD CO-FIRE 4,564
NEW CO-FIRE 4,564
LANDFILL GAS/MSW 6,151
BIOMASS (100%) 4,564
GEOTHERMAL (HYDRO BINARY) 7,008
GEOTHERMAL (NF EGS BINARY) 7,008
NUCLEAR 8,033
OIL/GAS STEAM 1,033
NATURAL GAS (CC-CCS) 4,187
NATURAL GAS (CC) 4,187
NATURAL GAS (CT) 2,628
COAL - IGCC WITH CCS 7,446
COAL - IGCC 7,446
COAL - NEW WITH CCS 7,446
COAL - NEW 7,446

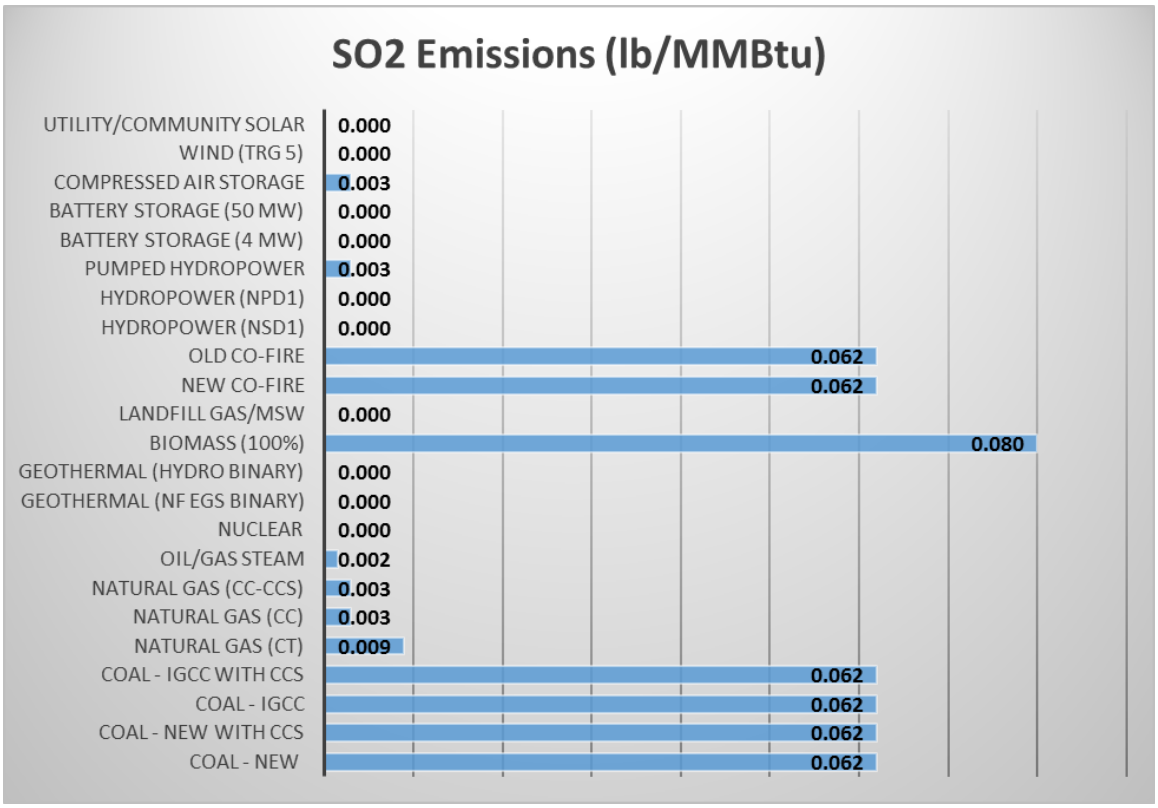

Heat Rate (MMBtu/MWh)
UTILITY/COMMUNITY SOLAR -
WIND (TRG 5) -
COMPRESSED AIR STORAGE 4.00
BATTERY STORAGE (50 MW) -
BATTERY STORAGE (4 MW) -
PUMPED HYDROPOWER 4.88
HYDROPOWER (NPD1) -
HYDROPOWER (NSD1) -
OLD CO-FIRE 10.74
NEW CO-FIRE 9.67
LANDFILL GAS/MSW 7.90
BIOMASS (100%) 13.50
GEOTHERMAL (HYDRO BINARY) -
GEOTHERMAL (NF EGS BINARY) -
NUCLEAR 10.48
OIL/GAS STEAM 11.08
NATURAL GAS (CC-CCS) 7.51
NATURAL GAS (CC) 6.65
NATURAL GAS (CT) 9.86
COAL - IGCC WITH CCS 9.42
COAL - IGCC 8.03
COAL - NEW WITH CCS 12.00
COAL - NEW 8.77

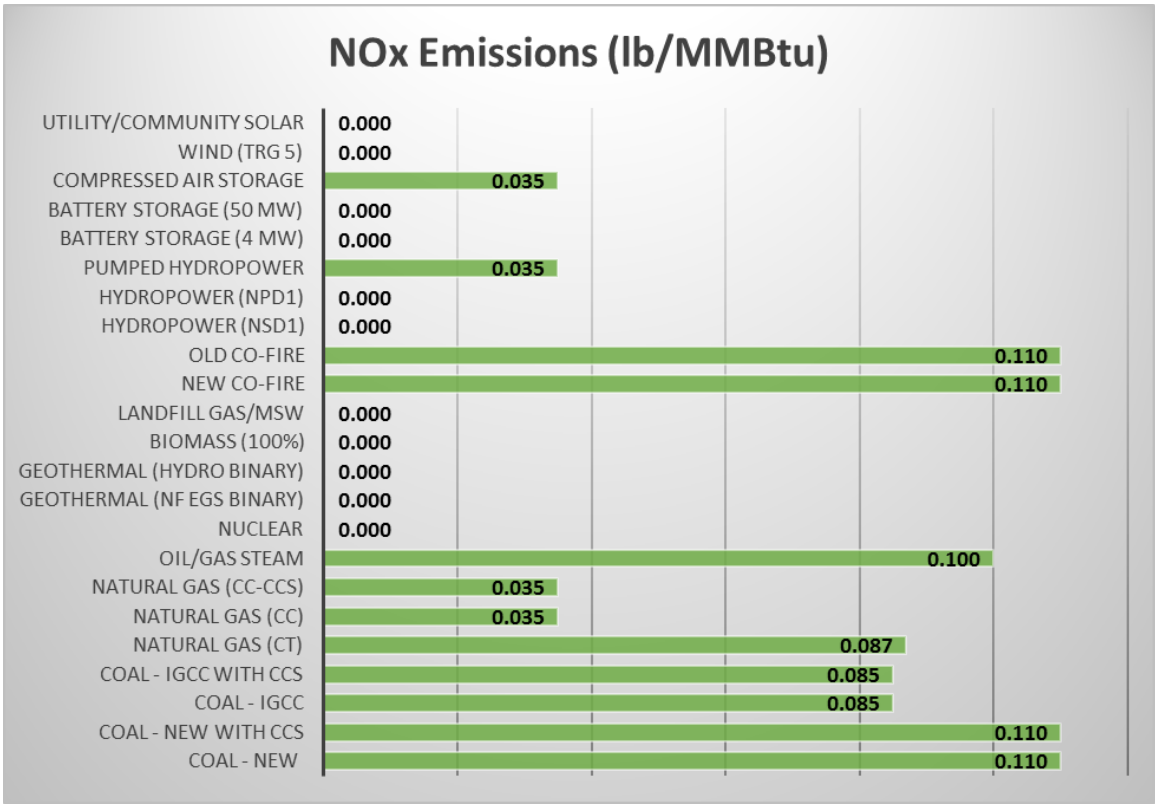

Fixed O&M Costs ($/kW-yr)
UTILITY/COMMUNITY SOLAR $14.40
WIND (TRG 5) $50.85
COMPRESSED AIR STORAGE $3.69
BATTERY STORAGE (50 MW) $100.00
BATTERY STORAGE (4 MW) $40.00
PUMPED HYDROPOWER $18.00
HYDROPOWER (NPD1) $111.14
HYDROPOWER (NSD1) $124.36
OLD CO-FIRE $34.05
NEW CO-FIRE $31.66
LANDFILL GAS/MSW $392.82
BIOMASS (100%) $107.27
GEOTHERMAL (HYDRO BINARY) $167.00
GEOTHERMAL (NF EGS BINARY) $313.00
NUCLEAR $94.72
OIL/GAS STEAM $6.90
NATURAL GAS (CC-CCS) $32.28
NATURAL GAS (CC) $14.49
NATURAL GAS (CT) $7.31
COAL - IGCC WITH CCS $73.96
COAL - IGCC $52.19
COAL - NEW WITH CCS $70.00
COAL - NEW $31.66

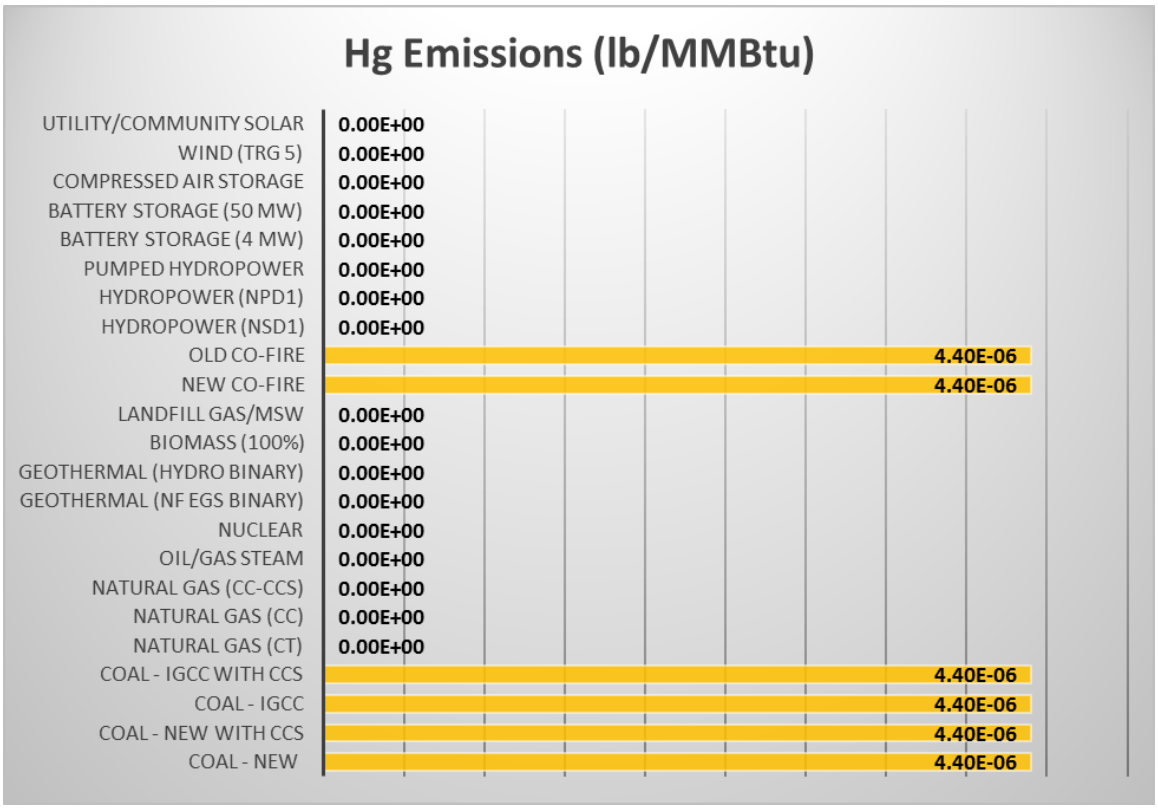

Variable O&M Costs ($/MWh)
UTILITY/COMMUNITY SOLAR $-
WIND (TRG 5) $-
COMPRESSED AIR STORAGE $6.00
BATTERY STORAGE (50 MW) $8.00
BATTERY STORAGE (4 MW) $8.00
PUMPED HYDROPOWER $-
HYDROPOWER (NPD1) $-
HYDROPOWER (NSD1) $-
OLD CO-FIRE $7.07
NEW CO-FIRE $4.54
LANDFILL GAS/MSW $8.75
BIOMASS (100%) $5.34
GEOTHERMAL (HYDRO BINARY) $-
GEOTHERMAL (NF EGS BINARY) $-
NUCLEAR $2.17
OIL/GAS STEAM $5.85
NATURAL GAS (CC-CCS) $6.89
NATURAL GAS (CC) $3.49
NATURAL GAS (CT) $13.11
COAL - IGCC WITH CCS $8.58
COAL - IGCC $7.34
COAL - NEW WITH CCS $7.10
COAL - NEW $4.54

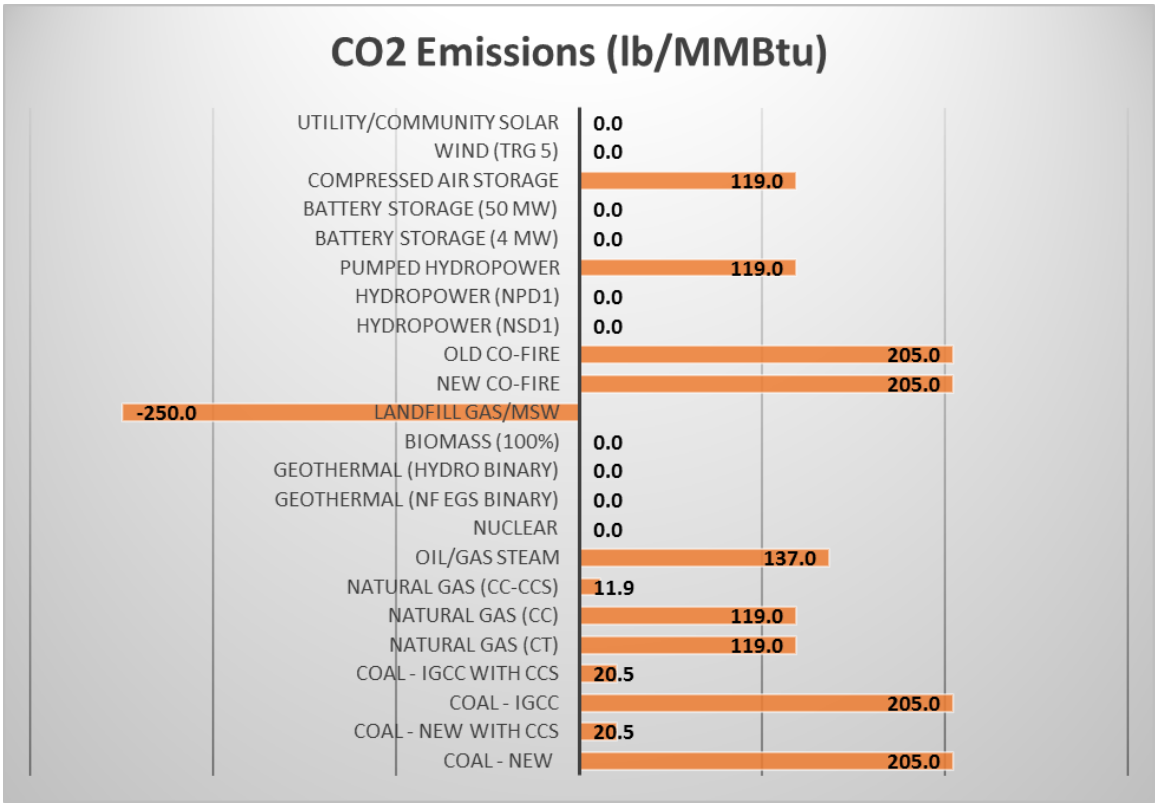

Fuel Cost ($/MWh)
UTILITY/COMMUNITY SOLAR $-
WIND (TRG 5) $-
COMPRESSED AIR STORAGE $-
BATTERY STORAGE (50 MW) $-
BATTERY STORAGE (4 MW) $-
PUMPED HYDROPOWER $-
HYDROPOWER (NPD1) $-
HYDROPOWER (NSD1) $-
OLD CO-FIRE $31.15
NEW CO-FIRE $28.04
LANDFILL GAS/MSW $-
BIOMASS (100%) $39.15
GEOTHERMAL (HYDRO BINARY) $-
GEOTHERMAL (NF EGS BINARY) $-
NUCLEAR $6.09
OIL/GAS STEAM $50.46
NATURAL GAS (CC-CCS) $33.43
NATURAL GAS (CC) $29.60
NATURAL GAS (CT) $43.89
COAL - IGCC WITH CCS $19.52
COAL - IGCC $16.64
COAL - NEW WITH CCS $24.86
COAL - NEW $18.16

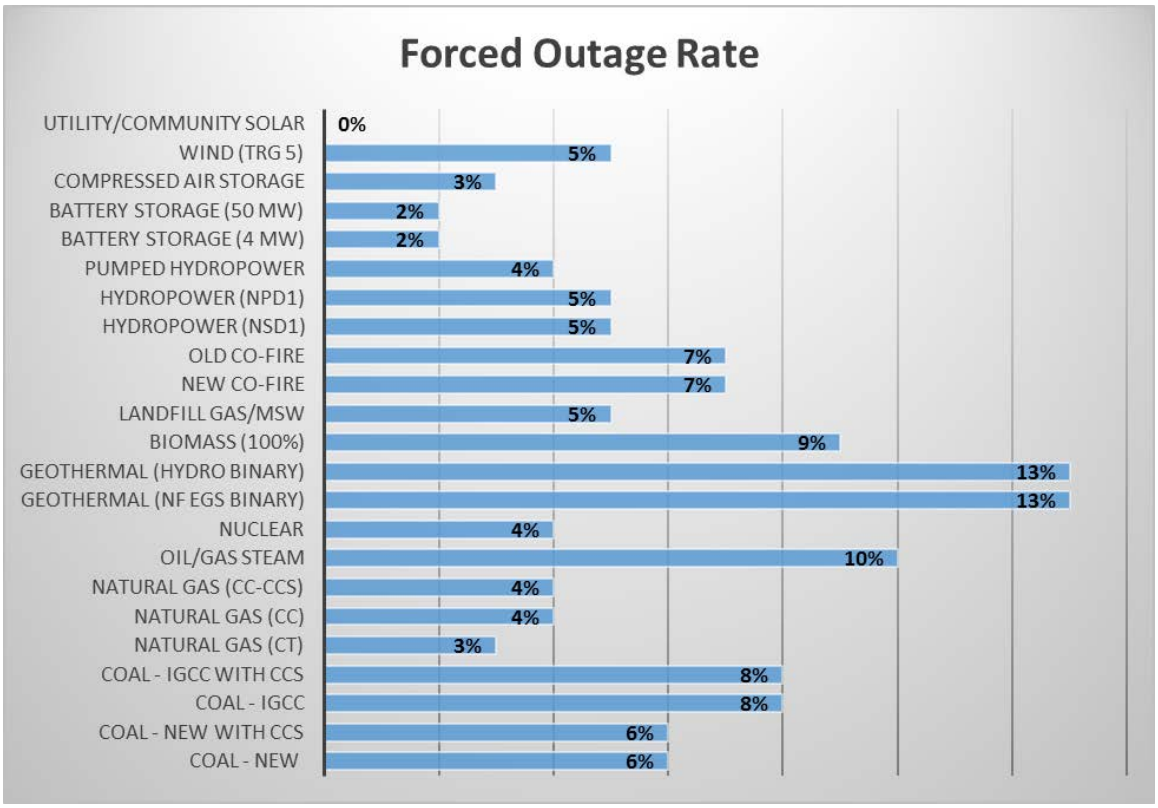

Levelized Cost of Energy ($/MWh)
UTILITY/COMMUNITY SOLAR $101.70
WIND (TRG 5) $53.84
COMPRESSED AIR STORAGE $160.00
BATTERY STORAGE (50 MW) $175.00
BATTERY STORAGE (4 MW) $150.00
PUMPED HYDROPOWER $175.00
HYDROPOWER (NPD1) $147.03
HYDROPOWER (NSD1) $161.07
OLD CO-FIRE $129.42
NEW CO-FIRE $123.26
LANDFILL GAS/MSW $95.00
BIOMASS (100%) $148.78
GEOTHERMAL (HYDRO BINARY) $104.74
GEOTHERMAL (NF EGS BINARY) $224.98
NUCLEAR $104.72
OIL/GAS STEAM $212.00
NATURAL GAS (CC-CCS) $103.39
NATURAL GAS (CC) $63.15
NATURAL GAS (CT) $96.02
COAL - IGCC WITH CCS $151.12
COAL - IGCC $95.75
COAL - NEW WITH CCS $139.50
COAL - NEW $87.31

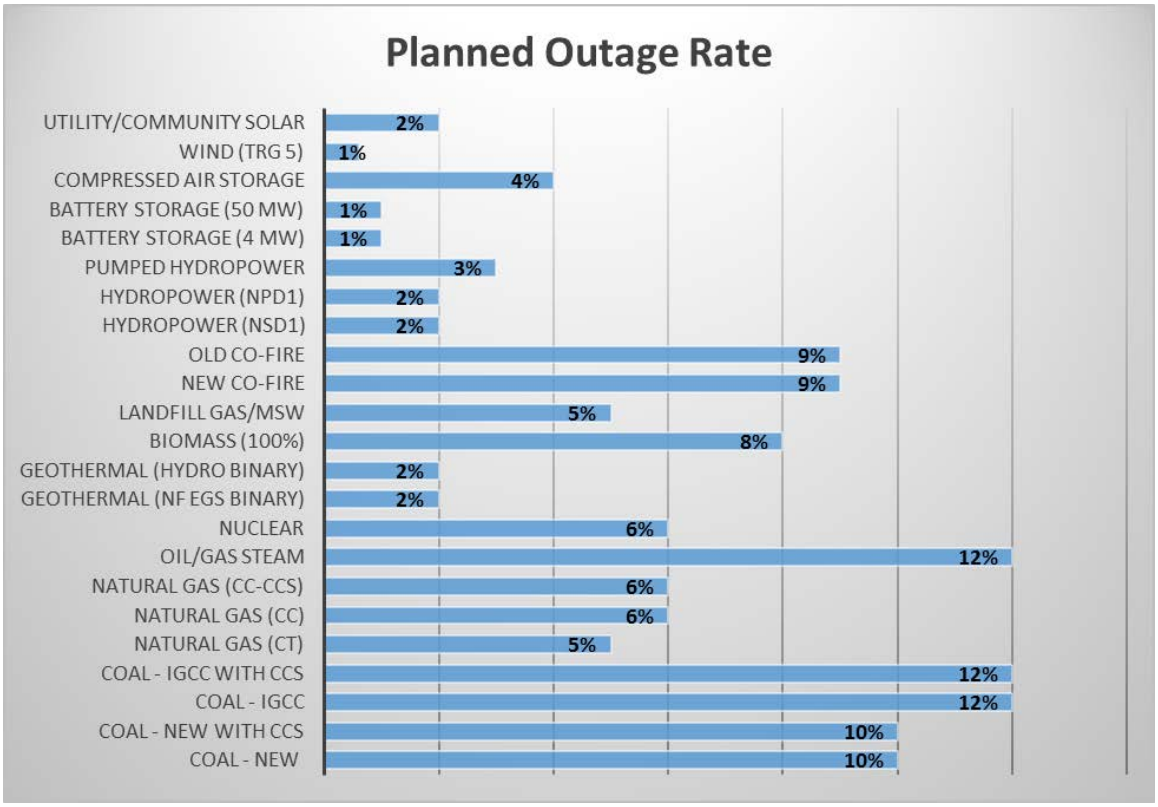

SO2 Emissions (lb/MMBtu)
UTILITY/COMMUNITY SOLAR 0.000
WIND (TRG 5) 0.000
COMPRESSED AIR STORAGE 0.003
BATTERY STORAGE (50 MW) 0.000
BATTERY STORAGE (4 MW) 0.000
PUMPED HYDROPOWER 0.003
HYDROPOWER (NPD1) 0.000
HYDROPOWER (NSD1) 0.000
OLD CO-FIRE 0.062
NEW CO-FIRE 0.062
LANDFILL GAS/MSW 0.000
BIOMASS (100%) 0.080
GEOTHERMAL (HYDRO BINARY) 0.000
GEOTHERMAL (NF EGS BINARY) 0.000
NUCLEAR 0.000
OIL/GAS STEAM 0.002
NATURAL GAS (CC-CCS) 0.003
NATURAL GAS (CC) 0.003
NATURAL GAS (CT) 0.009
COAL - IGCC WITH CCS 0.062
COAL - IGCC 0.062
COAL - NEW WITH CCS 0.062
COAL - NEW 0.062

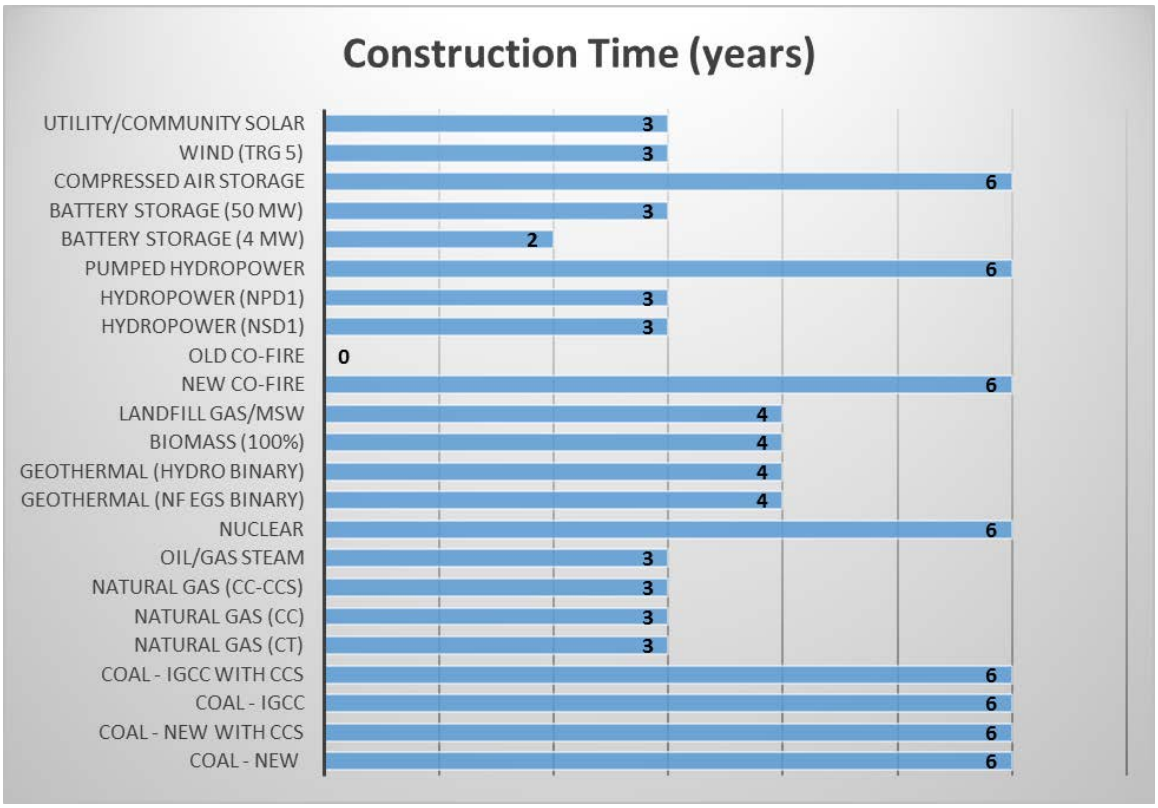

NOx Emissions (lb/MMBtu)
UTILITY/COMMUNITY SOLAR 0.000
WIND (TRG 5) 0.000
COMPRESSED AIR STORAGE 0.035
BATTERY STORAGE (50 MW) 0.000
BATTERY STORAGE (4 MW) 0.000
PUMPED HYDROPOWER 0.035
HYDROPOWER (NPD1) 0.000
HYDROPOWER (NSD1) 0.000
OLD CO-FIRE 0.110
NEW CO-FIRE 0.110
LANDFILL GAS/MSW 0.000
BIOMASS (100%) 0.000
GEOTHERMAL (HYDRO BINARY) 0.000
GEOTHERMAL (NF EGS BINARY) 0.000
NUCLEAR 0.000
OIL/GAS STEAM 0.100
NATURAL GAS (CC-CCS) 0.035
NATURAL GAS (CC) 0.035
NATURAL GAS (CT) 0.087
COAL - IGCC WITH CCS 0.085
COAL - IGCC 0.085
COAL - NEW WITH CCS 0.110
COAL - NEW 0.110

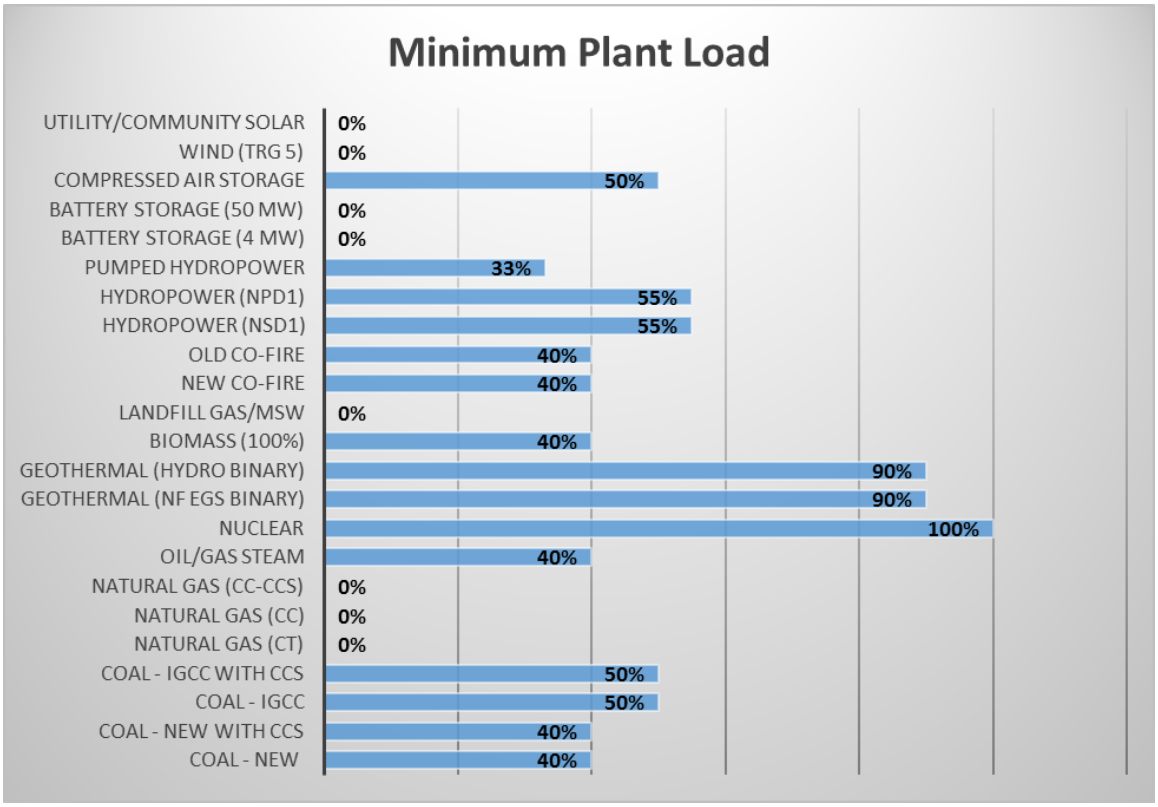

Hg Emissions (lb/MMBtu)
UTILITY/COMMUNITY SOLAR 0.00E+00
WIND (TRG 5) 0.00E+00
COMPRESSED AIR STORAGE 0.00E+00
BATTERY STORAGE (50 MW) 0.00E+00
BATTERY STORAGE (4 MW) 0.00E+00
PUMPED HYDROPOWER 0.00E+00
HYDROPOWER (NPD1) 0.00E+00
HYDROPOWER (NSD1) 0.00E+00
OLD CO-FIRE 4.40E-06
NEW CO-FIRE 4.40E-06
LANDFILL GAS/MSW 0.00E+00
BIOMASS (100%) 0.00E+00
GEOTHERMAL (HYDRO BINARY) 0.00E+00
GEOTHERMAL (NF EGS BINARY) 0.00E+00
NUCLEAR 0.00E+00
OIL/GAS STEAM 0.00E+00
NATURAL GAS (CC-CCS) 0.00E+00
NATURAL GAS (CC) 0.00E+00
NATURAL GAS (CT) 0.00E+00
COAL - IGCC WITH CCS 4.40E-06
COAL - IGCC 4.40E-06
COAL - NEW WITH CCS 4.40E-06
COAL - NEW 4.40E-06


CO2 Emissions (lb/MMBtu)
UTILITY/COMMUNITY SOLAR 0.0
WIND (TRG 5) 0.0
COMPRESSED AIR STORAGE 119.0
BATTERY STORAGE (50 MW) 0.0
BATTERY STORAGE (4 MW) 0.0
PUMPED HYDROPOWER 119.0
HYDROPOWER (NPD1) 0.0
HYDROPOWER (NSD1) 0.0
OLD CO-FIRE 205.0
NEW CO-FIRE 205.0
-250.0 LANDFILL GAS/MSW
BIOMASS (100%) 0.0
GEOTHERMAL (HYDRO BINARY) 0.0
GEOTHERMAL (NF EGS BINARY) 0.0
NUCLEAR 0.0
OIL/GAS STEAM 137.0
NATURAL GAS (CC-CCS) 11.9
NATURAL GAS (CC) 119.0
NATURAL GAS (CT) 119.0
COAL - IGCC WITH CCS 20.5
COAL - IGCC 205.0
COAL - NEW WITH CCS 20.5
COAL - NEW 205.0


Forced Outage Rate
UTILITY/COMMUNITY SOLAR 0%
WIND (TRG 5) 5%
COMPRESSED AIR STORAGE 3%
BATTERY STORAGE (50 MW) 2%
BATTERY STORAGE (4 MW) 2%
PUMPED HYDROPOWER 4%
HYDROPOWER (NPD1) 5%
HYDROPOWER (NSD1) 5%
OLD CO-FIRE 7%
NEW CO-FIRE 7%
LANDFILL GAS/MSW 5%
BIOMASS (100%) 9%
GEOTHERMAL (HYDRO BINARY) 13%
GEOTHERMAL (NF EGS BINARY) 13%
NUCLEAR 4%
OIL/GAS STEAM 10%
NATURAL GAS (CC-CCS) 4%
NATURAL GAS (CC) 4%
NATURAL GAS (CT) 3%
COAL - IGCC WITH CCS 8%
COAL - IGCC 8%
COAL - NEW WITH CCS 6%
COAL - NEW 6%


Planned Outage Rate
UTILITY/COMMUNITY SOLAR 2%
WIND (TRG 5) 1%
COMPRESSED AIR STORAGE 4%
BATTERY STORAGE (50 MW) 1%
BATTERY STORAGE (4 MW) 1%
PUMPED HYDROPOWER 3%
HYDROPOWER (NPD1) 2%
HYDROPOWER (NSD1) 2%
OLD CO-FIRE 9%
NEW CO-FIRE 9%
LANDFILL GAS/MSW 5%
BIOMASS (100%) 8%
GEOTHERMAL (HYDRO BINARY) 2%
GEOTHERMAL (NF EGS BINARY) 2%
NUCLEAR 6%
OIL/GAS STEAM 12%
NATURAL GAS (CC-CCS) 6%
NATURAL GAS (CC) 6%
NATURAL GAS (CT) 5%
COAL - IGCC WITH CCS 12%
COAL - IGCC 12%
COAL - NEW WITH CCS 10%
COAL - NEW 10%


Construction Time (years)
UTILITY/COMMUNITY SOLAR 3
WIND (TRG 5) 3
COMPRESSED AIR STORAGE 6
BATTERY STORAGE (50 MW) 3
BATTERY STORAGE (4 MW) 2
PUMPED HYDROPOWER 6
HYDROPOWER (NPD1) 3
HYDROPOWER (NSD1) 3
OLD CO-FIRE 0
NEW CO-FIRE 6
LANDFILL GAS/MSW 4
BIOMASS (100%) 4
GEOTHERMAL (HYDRO BINARY) 4
GEOTHERMAL (NF EGS BINARY) 4
NUCLEAR 6
OIL/GAS STEAM 3
NATURAL GAS (CC-CCS) 3
NATURAL GAS (CC) 3
NATURAL GAS (CT) 3
COAL - IGCC WITH CCS 6
COAL - IGCC 6
COAL - NEW WITH CCS 6
COAL - NEW 6


Minimum Plant Load
UTILITY/COMMUNITY SOLAR 0%
WIND (TRG 5) 0%
COMPRESSED AIR STORAGE 50%
BATTERY STORAGE (50 MW) 0%
BATTERY STORAGE (4 MW) 0%
PUMPED HYDROPOWER 33%
HYDROPOWER (NPD1) 55%
HYDROPOWER (NSD1) 55%
OLD CO-FIRE 40%
NEW CO-FIRE 40%
LANDFILL GAS/MSW 0%
BIOMASS (100%) 40%
GEOTHERMAL (HYDRO BINARY) 90%
GEOTHERMAL (NF EGS BINARY) 90%
NUCLEAR 100%
OIL/GAS STEAM 40%
NATURAL GAS (CC-CCS) 0%
NATURAL GAS (CC) 0%
NATURAL GAS (CT) 0%
COAL - IGCC WITH CCS 50%
COAL - IGCC 50%
COAL - NEW WITH CCS 40%
COAL - NEW 40%

Appendix C – Demand Side Management Data

Release date: February 2017

Table HC7.7 Air conditioning in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Air-conditioning equipment							
Use air-conditioning equipment	103.1	18.0	4.3	13.7	24.3	16.7	7.6
Do not use air-conditioning equipment	15.1	3.0	1.3	1.7	2.0	1.4	0.6
Type of air-conditioning equipment used (more than one may apply)							
Use central air-conditioning equipment	77.1	7.6	1.6	6.0	18.7	12.5	6.2
Without a heat pump	56.5	6.1	1.3	4.8	16.9	11.4	5.5
With a heat pump	20.5	1.6	0.4	1.2	1.8	1.1	0.7
Use individual air-conditioning units	31.6	11.2	2.8	8.4	6.9	5.1	1.8
With 1 unit	15.7	4.6	1.2	3.3	4.0	2.8	1.2
With 2 units	9.4	3.7	0.9	2.8	2.1	1.6	0.5
With 3 or more units	6.5	2.9	0.7	2.2	0.7	0.6	Q
Do not use air-conditioning equipment	15.1	3.0	1.3	1.7	2.0	1.4	0.6
Central air-conditioning equipment age							
Less than 2 years old	8.5	0.8	Q	0.7	1.9	1.4	0.5
2 to 4 years old	11.9	1.1	Q	0.9	2.2	1.5	0.8
5 to 9 years old	22.5	2.4	0.4	2.0	5.1	3.4	1.7
10 to 14 years old	17.4	1.6	0.5	1.1	4.5	2.9	1.7
15 to 19 years old	9.3	1.0	0.4	0.6	2.7	1.9	0.8
20 or more years old	7.4	0.8	Q	0.7	2.2	1.5	0.7
Do not use central air-conditioning equipment	41.1	13.4	4.0	9.4	7.7	5.6	2.1
Have thermostat for central air-conditioning equipment							
Yes	75.7	7.5	1.6	5.8	18.5	12.3	6.2
Programmable thermostat	48.5	5.2	1.1	4.1	11.6	8.0	3.6
Non-programmable thermostat	27.3	2.2	0.5	1.7	7.0	4.4	2.6
No	1.3	Q	Q	Q	0.2	0.1	Q
Do not use central air-conditioning equipment	41.1	13.4	4.0	9.4	7.7	5.6	2.1

U.S. Energy Information Administration
2015 Residential Energy Consumption Survey: Housing Characteristics Tables

Table HC7.7 Air conditioning in homes in the Northeast and Midwest regions, 2015[1]

	Number of housing units (million)						
		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Central air-conditioning equipment control							
Set one temperature and leave it there most of the time	34.4	3.1	0.5	2.6	8.6	5.7	2.9
Manually adjust the temperature at night or when no one is at home	19.9	1.8	0.4	1.4	4.1	2.7	1.5
Program the thermostat to automatically adjust the temperature during the day and night at certain times	13.9	1.6	0.3	1.3	4.1	2.8	1.3
Turn equipment on or off as needed	8.9	1.1	0.5	0.6	1.8	1.3	0.5
Household does not have control over the equipment	Q	N	N	N	N	N	N
Do not use central air-conditioning equipment	41.1	13.4	4.0	9.4	7.7	5.6	2.1
Most-used individual air-conditioning unit age							
Less than 2 years old	6.2	1.8	0.6	1.2	1.1	0.7	0.4
2 to 4 years old	9.9	3.0	0.6	2.4	2.3	1.7	0.6
5 to 9 years old	9.6	4.1	1.0	3.1	2.0	1.6	0.4
10 to 14 years old	3.6	1.3	0.3	1.0	0.9	0.7	0.2
15 to 19 years old	1.2	0.5	Q	0.4	Q	Q	Q
20 or more years old	1.0	0.3	Q	0.3	0.3	Q	Q
Do not use individual air-conditioning units	86.6	9.8	2.8	7.0	19.5	13.0	6.5
Most-used individual air-conditioning unit control							
Set one temperature and leave it there most of the time	9.6	2.9	0.8	2.1	2.5	1.9	0.6
Manually adjust the temperature at night or when no one is at home	5.8	1.7	0.4	1.3	1.6	1.1	0.5
Program the thermostat to automatically adjust the temperature during the day and night at certain times	1.6	0.7	Q	0.5	0.2	Q	Q
Turn equipment on or off as needed	14.3	5.8	1.4	4.4	2.7	2.0	0.6
Some other way	Q	Q	Q	N	N	N	N
Do not use individual air-conditioning units	86.6	9.8	2.8	7.0	19.5	13.0	6.5

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Table HC7.7 Air conditioning in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Summer indoor daytime temperature when someone is home							
69 degrees or less	20.0	5.1	1.6	3.5	5.2	3.9	1.3
70 degrees	17.4	3.0	0.9	2.1	4.3	3.1	1.2
71 to 73 degrees	20.6	3.6	0.7	2.9	5.4	3.7	1.7
74 to 76 degrees	26.4	4.4	0.7	3.7	6.2	4.2	2.1
77 to 79 degrees	13.0	1.0	Q	0.9	2.4	1.3	1.1
80 degrees or more	5.7	0.9	0.3	0.6	0.8	0.6	0.2
Do not use air-conditioning equipment	15.1	3.0	1.3	1.7	2.0	1.4	0.6
Summer indoor daytime temperature when no one is home							
69 degrees or less	14.1	3.3	1.0	2.3	3.9	2.9	1.1
70 degrees	12.8	2.2	0.6	1.6	3.2	2.2	1.0
71 to 73 degrees	14.5	2.4	0.4	2.0	4.3	2.8	1.4
74 to 76 degrees	25.8	5.1	1.2	3.8	6.7	4.7	2.0
77 to 79 degrees	15.9	1.7	0.2	1.5	3.3	2.2	1.1
80 degrees or more	20.1	3.4	0.8	2.5	3.0	1.9	1.1
Do not use air-conditioning equipment	15.1	3.0	1.3	1.7	2.0	1.4	0.6
Summer indoor temperature at night							
69 degrees or less	25.8	5.8	1.9	3.9	6.4	4.8	1.5
70 degrees	20.0	4.0	0.9	3.0	4.7	3.3	1.4
71 to 73 degrees	19.3	3.0	0.6	2.4	5.2	3.3	1.8
74 to 76 degrees	23.6	3.8	0.7	3.1	5.4	3.5	1.9
77 to 79 degrees	10.3	1.0	Q	0.9	2.0	1.2	0.8
80 degrees or more	4.2	0.4	Q	Q	0.7	0.5	Q
Do not use air-conditioning equipment	15.1	3.0	1.3	1.7	2.0	1.4	0.6
Air-conditioned basement							
Yes	14.1	2.1	0.3	1.8	8.0	4.6	3.4
No	17.7	7.2	2.0	5.2	6.4	4.7	1.8
Not asked (air-conditioned homes with no basement)	39.9	1.8	0.5	1.3	3.8	3.0	0.9
Not asked (un-air-conditioned homes, apartments, and mobile homes)	46.5	9.9	2.8	7.0	8.1	5.8	2.3

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2015 Residential Energy Consumption Survey: Housing Characteristics Tables

Table HC7.7 Air conditioning in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Air-conditioned attic							
Yes	1.7	0.6	Q	0.4	0.5	0.3	Q
No	40.0	6.1	1.4	4.7	9.6	6.5	3.1
Not asked (air-conditioned homes with no attic)	30.1	4.5	1.2	3.2	8.2	5.5	2.7
Not asked (un-air-conditioned homes, apartments, and mobile homes)	46.5	9.9	2.8	7.0	8.1	5.8	2.3
Air-conditioned, attached garage							
Yes	1.0	Q	Q	Q	0.2	Q	Q
No	41.4	5.7	1.3	4.4	10.9	7.3	3.7
Not asked (air-conditioned homes with no attached garage)	29.3	5.3	1.5	3.8	7.1	4.9	2.3
Not asked (un-air-conditioned homes, apartments, and mobile homes)	46.5	9.9	2.8	7.0	8.1	5.8	2.3
Dehumidifier usage							
Use a dehumidifier	16.6	5.3	1.6	3.7	7.0	5.1	1.9
Less than 4 months	5.8	2.1	0.8	1.3	2.4	1.8	0.5
4 to 6 months	6.5	1.7	0.5	1.2	3.2	2.3	0.9
7 to 9 months	2.0	0.7	Q	0.6	0.7	0.5	0.2
10 to 11 months	Q	Q	Q	Q	Q	Q	Q
Turned on all 12 months	2.1	0.7	Q	0.5	0.7	0.5	0.2
Do not use a dehumidifier	101.6	15.7	4.1	11.7	19.4	13.0	6.4
Use an evaporative or swamp cooler (asked only in arid areas)							
Yes	2.8	N	N	N	N	N	N
No	54.8	N	N	N	N	N	N
Not asked	60.6	21.0	5.6	15.4	26.4	18.1	8.3

U.S. Energy Information Administration
2015 Residential Energy Consumption Survey: Housing Characteristics Tables

Table HC7.7 Air conditioning in homes in the Northeast and Midwest regions, 2015[1]

	Number of housing units (million)						
		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Fan types used (more than one may apply)							
Ceiling fans	85.4	12.3	3.0	9.3	19.9	13.5	6.3
Floor, window, or table fans	54.3	10.9	3.5	7.4	13.9	9.5	4.3
Whole house fans	6.1	0.9	Q	0.8	1.5	0.9	0.5
Attic fans	8.7	1.8	0.2	1.6	2.1	1.2	0.8
Number of ceiling fans used							
0	32.8	8.7	2.6	6.0	6.5	4.6	2.0
1	21.2	3.8	0.9	2.8	5.4	3.8	1.6
2	18.9	3.1	0.8	2.3	4.6	3.2	1.4
3	15.1	2.4	0.7	1.7	3.6	2.5	1.1
4 or more	30.2	3.1	0.5	2.6	6.2	4.1	2.2

[1]Housing characteristics data were collected between August 2015 and April 2016.

[2]Total U.S. includes all primary occupied housing units in the 50 states and the District of Columbia. Vacant housing units, seasonal units, second homes, military houses, and group quarters are excluded.

Q = Data withheld because either the Relative Standard Error (RSE) was greater than 50% or fewer than 10 households responded.

N = No cases responded.

Notes: Because of rounding, data may not sum to totals. See RECS Terminology for definition of terms used in these tables.

Source: U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457A and EIA-457C of the 2015 Residential Energy Consumption Survey.

U.S. Energy Information Administration
2015 Residential Energy Consumption Survey: Housing Characteristics Tables

Release date: February 2017

Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Stoves (units with both an oven and a cooktop)							
Have a stove	108.1	19.9	5.3	14.5	24.9	17.2	7.7
1	105.8	19.1	5.1	14.0	24.3	16.7	7.5
2 or more	2.3	0.8	0.3	0.6	0.6	0.4	Q
Do not have a stove	10.1	1.1	0.3	0.8	1.5	0.9	0.6
Most-used stove fuel							
Electricity	65.7	8.7	3.0	5.7	15.0	9.3	5.7
Natural gas	35.9	9.4	1.5	7.9	8.6	7.1	1.6
Propane	5.4	1.5	0.7	0.8	1.1	0.7	0.4
Dual fuel	1.0	0.3	Q	Q	Q	Q	Q
Do not have a stove	10.1	1.1	0.3	0.8	1.5	0.9	0.6
Most-used stove usage: cooktop part							
0 times per week	3.4	0.4	Q	Q	0.8	0.5	0.3
1 to 3 times per week	16.8	2.1	0.4	1.7	4.0	2.9	1.1
4 to 7 times per week	50.6	9.5	2.6	6.9	11.9	8.1	3.7
8 to 14 times per week	23.9	4.6	1.4	3.2	5.4	3.5	1.9
15 or more times per week	13.4	3.2	0.7	2.4	2.8	2.2	0.6
Do not have a stove	10.1	1.1	0.3	0.8	1.5	0.9	0.6
Most-used stove usage: oven part							
0 times per week	18.2	3.2	0.6	2.7	3.0	2.1	0.9
1 to 3 times per week	56.8	10.7	2.9	7.8	13.5	9.2	4.3
4 to 7 times per week	28.3	5.2	1.6	3.6	7.2	5.1	2.1
8 to 14 times per week	3.7	0.4	Q	0.3	1.0	0.6	0.3
15 or more times per week	1.1	0.3	Q	Q	0.2	Q	Q
Do not have a stove	10.1	1.1	0.3	0.8	1.5	0.9	0.6
Separate cooktops							
Have a separate cooktop	17.0	2.5	0.7	1.8	2.5	1.5	1.0
1	16.7	2.4	0.7	1.7	2.4	1.4	1.0
2 or more	0.3	Q	N	Q	Q	Q	N
Do not have a separate cooktop	101.2	18.5	4.9	13.6	23.8	16.6	7.2
Most-used separate cooktop fuel							
Electricity	9.5	1.2	0.3	0.9	1.4	0.7	0.7
Natural gas	6.5	1.1	Q	0.9	1.0	0.8	0.2
Propane	1.1	Q	Q	Q	Q	Q	Q
Do not have a separate cooktop	101.2	18.5	4.9	13.6	23.8	16.6	7.2

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Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Most-used separate cooktop usage							
0 times per week	2.1	0.4	Q	Q	0.3	Q	Q
1 to 3 times per week	3.1	0.5	Q	0.4	0.5	0.3	Q
4 to 7 times per week	6.6	0.9	Q	0.7	1.0	0.6	0.4
8 to 14 times per week	3.4	0.5	Q	0.3	0.5	0.3	0.2
15 or more times per week	1.9	0.2	Q	Q	0.2	Q	Q
Do not have a separate cooktop	101.2	18.5	4.9	13.6	23.8	16.6	7.2
Separate wall ovens							
Have a separate wall oven	14.0	1.6	0.4	1.1	2.1	1.3	0.8
1	10.0	1.2	0.3	0.9	1.5	1.0	0.5
2 or more	3.9	0.4	Q	Q	0.6	0.3	0.3
Do not have a separate wall oven	104.2	19.4	5.2	14.3	24.2	16.8	7.5
Most-used separate wall oven fuel							
Electricity	12.0	1.2	0.3	0.9	1.9	1.2	0.8
Natural gas	1.8	0.3	Q	0.3	0.2	0.2	Q
Propane	Q	Q	Q	N	Q	N	Q
Do not have a separate wall oven	104.2	19.4	5.2	14.3	24.2	16.8	7.5
Most-used separate wall oven usage							
0 times per week	2.0	0.3	Q	Q	Q	Q	Q
1 to 3 times per week	6.2	0.7	Q	0.5	1.0	0.7	0.3
4 to 7 times per week	4.6	0.4	Q	0.3	0.7	0.4	0.3
8 to 14 times per week	0.8	Q	Q	Q	0.2	Q	Q
15 or more times per week	0.3	Q	N	Q	Q	Q	Q
Do not have a separate wall oven	104.2	19.4	5.2	14.3	24.2	16.8	7.5
Frequency of hot meals cooked							
No hot meals cooked	0.8	Q	Q	Q	Q	Q	Q
Less than once a week	2.4	0.4	Q	Q	0.6	0.3	0.3
About once a week	2.6	0.3	Q	Q	0.4	0.3	Q
A few times each week	19.9	3.0	0.6	2.4	4.2	2.9	1.3
Once a day	36.0	7.0	2.3	4.8	8.6	5.9	2.8
2 times a day	38.3	7.1	1.7	5.4	8.8	5.9	2.9
3 or more times a day	18.1	3.1	0.8	2.3	3.6	2.7	0.9

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Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Microwave ovens							
Have a microwave oven	113.6	19.6	5.4	14.2	25.7	17.6	8.1
1	108.8	18.6	5.0	13.6	24.4	16.7	7.7
2 or more	4.8	1.0	0.4	0.6	1.3	0.9	0.4
Do not have a microwave oven	4.6	1.4	0.2	1.2	0.7	0.5	0.2
Microwave oven usage							
0 times per week	1.6	0.3	Q	Q	0.3	0.3	Q
1 to 3 times per week	10.5	2.0	0.6	1.4	2.0	1.3	0.7
4 to 7 times per week	38.8	7.0	1.7	5.3	8.2	6.0	2.3
8 to 14 times per week	27.8	4.7	1.6	3.1	6.6	4.7	1.9
15 or more times per week	34.8	5.6	1.4	4.2	8.6	5.4	3.1
Do not have a microwave oven	4.6	1.4	0.2	1.2	0.7	0.5	0.2
Outdoor grills and fuel							
Use an outdoor grill	69.4	11.6	3.2	8.4	17.5	12.0	5.5
Natural gas	4.2	1.0	Q	0.9	0.9	0.6	0.3
Propane	42.3	8.7	2.8	5.9	10.7	7.2	3.6
Charcoal	22.2	1.8	0.3	1.5	5.6	4.0	1.5
Some other fuel	0.7	Q	N	Q	0.3	0.2	Q
Do not use an outdoor grill	48.8	9.4	2.4	7.0	8.9	6.1	2.8
Small kitchen appliances used at least once each week (more than one may apply)							
Toaster	74.2	13.2	3.7	9.5	18.3	12.4	5.9
Toaster oven	28.9	6.9	2.1	4.8	4.4	3.1	1.3
Coffee maker	76.1	13.5	3.8	9.7	17.7	12.3	5.4
Slow cooker	33.5	4.9	1.1	3.8	8.7	5.9	2.8
Food processor	12.4	2.3	0.6	1.7	2.3	1.6	0.6
Rice cooker	14.4	2.3	0.4	1.8	2.2	1.7	0.5
Blender or juicer	30.8	5.4	1.1	4.3	5.8	4.2	1.6
Some other small kitchen appliance[3]	12.4	2.0	0.4	1.7	3.1	2.0	1.1
Refrigerators							
Use a refrigerator	117.4	20.8	5.6	15.2	26.2	18.0	8.3
1	82.0	14.3	4.0	10.3	17.2	12.1	5.1
2 or more	35.4	6.5	1.6	4.9	9.0	5.9	3.1
Do not use a refrigerator	0.8	Q	Q	Q	Q	Q	Q

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Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Most-used refrigerator size							
Half-size or compact	0.9	Q	N	Q	Q	Q	Q
Small (less than 17.6 cubic feet)	6.7	1.6	0.5	1.1	1.2	0.9	0.4
Medium (17.6 to 22.5 cubic feet)	59.2	11.0	3.0	8.0	13.5	9.2	4.2
Large (22.6 to 29.5 cubic feet)	48.8	7.9	2.0	5.9	11.2	7.6	3.5
Very large (more than 29.5 cubic feet)	1.8	0.3	Q	Q	0.2	Q	Q
Do not use a refrigerator	0.8	Q	Q	Q	Q	Q	Q
Most-used refrigerator type							
Half-size/compact	0.9	Q	N	Q	Q	Q	Q
One door	9.4	2.0	0.6	1.4	2.0	1.2	0.7
Two doors, top freezer	51.5	10.8	2.6	8.2	11.9	8.4	3.5
Two doors, bottom freezer	15.5	3.1	1.1	2.0	3.9	2.6	1.2
Two doors, side by side	37.2	4.5	1.2	3.2	7.8	5.4	2.4
Three or more doors	2.9	0.3	Q	0.3	0.5	0.3	0.2
Do not use a refrigerator	0.8	Q	Q	Q	Q	Q	Q
Most-used refrigerator age							
Less than 2 years old	15.8	3.0	1.0	2.1	3.2	2.3	0.9
2 to 4 years old	26.2	4.2	1.4	2.8	5.4	3.7	1.7
5 to 9 years old	41.0	7.2	2.0	5.3	9.0	6.2	2.8
10 to 14 years old	22.2	4.0	0.8	3.2	5.5	3.7	1.8
15 to 19 years old	7.4	1.4	0.2	1.2	1.9	1.3	0.7
20 or more years old	4.7	0.9	0.2	0.7	1.2	0.9	0.3
Do not use a refrigerator	0.8	Q	Q	Q	Q	Q	Q
Most-used refrigerator through-the-door ice service							
Yes	41.8	5.0	1.4	3.6	8.6	5.8	2.8
No	75.6	15.8	4.2	11.6	17.6	12.2	5.4
Do not use a refrigerator	0.8	Q	Q	Q	Q	Q	Q
Second refrigerator							
Use a second refrigerator	35.4	6.5	1.6	4.9	9.0	5.9	3.1
Do not use a second refrigerator	82.8	14.5	4.0	10.5	17.3	12.2	5.2
Second refrigerator size							
Half-size or compact	8.2	1.5	0.5	0.9	2.0	1.2	0.8
Small (less than 17.6 cubic feet)	5.5	0.9	Q	0.7	1.4	1.0	0.4
Medium (17.6 to 22.5 cubic feet)	14.6	2.8	0.5	2.3	3.9	2.6	1.3
Large (22.6 to 29.5 cubic feet)	6.9	1.3	0.3	1.0	1.8	1.1	0.7
Very large (more than 29.5 cubic feet)	0.2	N	N	N	Q	N	Q
Do not use a second refrigerator	82.8	14.5	4.0	10.5	17.3	12.2	5.2

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Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Second refrigerator type							
Half-size or compact	8.2	1.5	0.5	0.9	2.0	1.2	0.8
One door	5.8	0.7	Q	0.6	1.4	0.9	0.6
Two doors, top freezer	14.4	3.2	0.6	2.6	4.1	2.9	1.2
Two doors, bottom freezer	1.1	0.3	Q	Q	0.2	Q	Q
Two doors, side by side	5.7	0.8	Q	0.6	1.2	0.8	0.4
Three or more doors	Q	N	N	N	Q	Q	N
Do not use a second refrigerator	82.8	14.5	4.0	10.5	17.3	12.2	5.2
Second refrigerator age							
Less than 2 years old	2.8	0.4	Q	Q	0.5	0.3	0.2
2 to 4 years old	5.1	1.0	Q	0.7	1.2	0.8	0.4
5 to 9 years old	9.8	1.7	0.4	1.4	2.3	1.3	1.0
10 to 14 years old	9.3	1.7	0.4	1.2	2.6	1.8	0.7
15 to 19 years old	4.8	1.0	0.2	0.8	1.3	0.9	0.4
20 or more years old	3.6	0.7	0.2	0.5	1.2	0.8	0.4
Do not use a second refrigerator	82.8	14.5	4.0	10.5	17.3	12.2	5.2
Second refrigerator location							
Basement	6.8	2.3	0.7	1.6	2.9	1.8	1.2
Garage	16.1	2.2	0.3	1.9	4.1	3.0	1.1
Outside	1.8	0.3	Q	Q	Q	Q	Q
Main floor of house	8.9	1.1	0.4	0.7	1.5	0.8	0.7
Some other location	1.7	0.6	Q	0.5	0.4	0.3	Q
Do not use a second refrigerator	82.8	14.5	4.0	10.5	17.3	12.2	5.2
Separate freezers							
Use a separate freezer	38.1	6.0	1.3	4.7	10.4	6.7	3.8
1	34.3	5.4	1.1	4.3	9.3	6.2	3.1
2 or more	3.8	0.6	0.2	0.4	1.1	0.5	0.7
Do not use a separate freezer	80.1	15.0	4.3	10.7	16.0	11.4	4.5
Most-used separate freezer size							
Half-size or compact	3.2	0.4	Q	Q	1.0	0.6	0.4
Small (less than 17.6 cubic feet)	11.9	2.0	0.4	1.6	2.8	1.9	1.0
Medium (17.6 to 22.5 cubic feet)	15.2	2.4	0.6	1.8	3.9	2.4	1.5
Large (22.6 to 29.5 cubic feet)	7.2	1.1	0.2	0.9	2.4	1.7	0.8
Very large (more than 29.5 cubic feet)	0.5	Q	N	Q	0.2	Q	Q
Do not use a separate freezer	80.1	15.0	4.3	10.7	16.0	11.4	4.5

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Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Most-used separate freezer type							
Upright	17.8	2.9	0.6	2.3	4.4	2.9	1.4
Chest	20.3	3.0	0.7	2.3	6.1	3.7	2.3
Do not use a separate freezer	80.1	15.0	4.3	10.7	16.0	11.4	4.5
Most-used separate freezer age							
Less than 2 years old	3.7	0.7	Q	0.5	0.9	0.6	0.3
2 to 4 years old	6.1	0.8	0.2	0.6	1.3	0.7	0.5
5 to 9 years old	11.1	1.8	0.3	1.4	3.1	2.1	1.0
10 to 14 years old	8.2	1.2	0.3	0.9	2.3	1.5	0.8
15 to 19 years old	4.1	0.7	Q	0.6	1.1	0.6	0.5
20 or more years old	4.9	0.8	Q	0.6	1.8	1.2	0.6
Do not use a separate freezer	80.1	15.0	4.3	10.7	16.0	11.4	4.5
Dishwashers and usage							
Have a dishwasher	80.1	12.0	3.2	8.8	17.1	11.2	5.9
Used 0 times per week	15.9	2.0	0.5	1.6	2.3	1.8	0.5
Used 1 time per week	13.6	2.2	0.5	1.7	2.8	1.7	1.1
Used 2 to 3 times per week	25.8	3.9	1.2	2.7	6.1	4.2	1.9
Used 4 to 6 times per week	15.4	2.6	0.7	1.9	3.9	2.3	1.6
Used 7 or more times per week	9.4	1.3	0.3	1.0	2.0	1.3	0.7
Do not have a dishwasher	38.1	9.0	2.4	6.6	9.2	6.9	2.4
Dishwasher age							
Less than 2 years old	11.3	1.6	0.5	1.1	2.3	1.5	0.8
2 to 4 years old	16.3	2.0	0.6	1.4	3.4	2.3	1.2
5 to 9 years old	27.0	4.0	1.1	3.0	5.8	4.0	1.8
10 to 14 years old	16.6	2.7	0.6	2.2	3.7	2.2	1.5
15 to 19 years old	5.1	0.9	0.2	0.6	1.1	0.7	0.4
20 or more years old	3.9	0.7	0.2	0.5	0.8	0.5	0.2
Do not have a dishwasher	38.1	9.0	2.4	6.6	9.2	6.9	2.4
Most-used dishwasher cycle type							
Normal or default cycle *without* heated dry	14.6	2.4	0.7	1.7	3.1	1.8	1.2
Normal or default cycle *with* heated dry	37.3	5.5	1.5	4.0	8.9	5.8	3.1
Heavy or "pots and pans" cycle	5.1	0.9	Q	0.8	1.1	0.8	0.4
Light or delicate cycle	1.8	0.3	Q	Q	0.3	0.2	Q
Energy saver	5.4	0.9	0.3	0.6	1.4	0.9	0.5
Do not have or use a dishwasher	54.0	11.0	2.9	8.1	11.6	8.6	2.9

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Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Clothes washers							
Have a clothes washer at home	97.6	15.0	4.1	10.8	22.0	15.0	7.0
Top-loading	73.8	11.1	2.9	8.2	16.9	11.6	5.2
Front-loading	23.9	3.9	1.2	2.7	5.2	3.4	1.8
Do not have a clothes washer at home	20.6	6.0	1.5	4.5	4.3	3.1	1.2
Clothes washer age							
Less than 2 years old	15.1	2.8	0.7	2.1	2.9	2.1	0.8
2 to 4 years old	22.1	3.0	1.0	2.0	4.6	3.0	1.5
5 to 9 years old	34.8	4.9	1.2	3.7	7.7	5.1	2.6
10 to 14 years old	17.2	2.7	0.7	2.1	4.8	3.3	1.5
15 to 19 years old	5.5	1.0	0.3	0.7	1.4	1.1	0.3
20 or more years old	3.0	0.5	Q	0.3	0.7	0.5	0.3
Do not have a clothes washer at home	20.6	6.0	1.5	4.5	4.3	3.1	1.2
Clothes washer usage							
0 loads per week	1.2	Q	Q	Q	0.3	Q	Q
1 to 4 loads per week	59.8	9.2	2.4	6.7	12.7	8.6	4.1
5 to 9 loads per week	27.3	4.6	1.4	3.2	6.4	4.6	1.9
10 to 15 loads per week	8.0	1.0	0.3	0.7	2.3	1.5	0.8
More than 15 loads per week	1.3	0.2	Q	Q	0.3	0.2	Q
Do not have a clothes washer at home	20.6	6.0	1.5	4.5	4.3	3.1	1.2
Usual water temperature setting for the wash cycle							
Hot	6.5	1.0	0.2	0.8	1.2	1.0	0.3
Warm	47.8	7.2	1.8	5.4	12.0	8.2	3.9
Cold	42.1	6.7	2.1	4.6	8.5	5.7	2.8
Do not have or use a clothes washer at home	21.7	6.1	1.5	4.6	4.6	3.3	1.3
Usual water temperature setting for the rinse cycle							
Hot	2.3	0.3	Q	Q	0.3	0.2	Q
Warm	23.2	3.4	0.8	2.5	5.1	3.3	1.8
Cold	71.0	11.2	3.2	8.0	16.4	11.4	5.0
Do not have or use a clothes washer at home	21.7	6.1	1.5	4.6	4.6	3.3	1.3

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2015 Residential Energy Consumption Survey: Housing Characteristics Tables

Table HC3.7 Appliances in homes in the Northeast and Midwest regions, 2015[1]

Number of housing units (million)

		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Clothes dryer and fuel							
Have a clothes dryer at home	95.3	14.3	4.0	10.3	21.9	14.9	7.0
Electricity	75.7	10.0	3.3	6.7	15.3	9.2	6.1
Natural gas	18.2	3.8	0.5	3.3	6.2	5.3	0.9
Propane	1.4	0.4	0.2	Q	0.5	0.4	Q
Do not have a clothes dryer at home	22.9	6.7	1.6	5.1	4.4	3.2	1.2
Clothes dryer age							
Less than 2 years old	11.7	2.0	0.5	1.4	2.2	1.5	0.7
2 to 4 years old	20.2	2.6	0.8	1.8	4.2	2.9	1.4
5 to 9 years old	33.9	4.8	1.5	3.3	7.7	5.2	2.5
10 to 14 years old	19.1	2.9	0.7	2.3	5.2	3.6	1.6
15 to 19 years old	6.3	1.2	0.3	0.9	1.5	1.1	0.4
20 or more years old	4.0	0.8	0.2	0.5	1.1	0.6	0.5
Do not have a clothes dryer at home	22.9	6.7	1.6	5.1	4.4	3.2	1.2
Clothes dryer usage							
0 loads per week	2.1	Q	Q	Q	0.3	Q	0.2
1 to 4 loads per week	57.0	8.4	2.3	6.1	12.5	8.4	4.1
5 to 9 loads per week	26.6	4.2	1.3	3.0	6.5	4.6	1.9
10 to 15 loads per week	8.3	1.2	0.4	0.8	2.3	1.5	0.8
More than 15 loads per week	1.4	Q	N	Q	0.3	0.2	Q
Do not have a clothes dryer at home	22.9	6.7	1.6	5.1	4.4	3.2	1.2

[1]Housing characteristics data were collected between August 2015 and April 2016.

[2]Total U.S. includes all primary occupied housing units in the 50 states and the District of Columbia. Vacant housing units, seasonal units, second homes, military houses, and group quarters are excluded.

[3]Some other small kitchen appliance includes stand mixers, bread makers, waffle makers, electric can openers, sandwich makers, coffee grinders, and many other reported appliances.

Q = Data withheld because either the Relative Standard Error (RSE) was greater than 50% or fewer than 10 cases responded.

N = No cases responded.

Notes: Because of rounding, data may not sum to totals. See RECS Terminology for definition of terms used in these tables.

Source: U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457A and EIA-457C of the 2015 Residential Energy Consumption Survey.

Release date: February 2017

Table HC8.7 Water heating in homes in the Northeast and Midwest regions, 2015 [1]

	Number of housing units (million)						
		Northeast Census Region			Midwest Census Region		
	Total U.S.[2]	Total Northeast	New England	Middle Atlantic	Total Midwest	East North Central	West North Central
All homes	118.2	21.0	5.6	15.4	26.4	18.1	8.3
Fuel used by main water heater							
Natural gas	56.9	10.8	2.1	8.7	15.9	11.2	4.6
Electricity	53.6	6.5	2.0	4.5	9.0	5.8	3.2
Propane	4.6	1.0	0.4	0.6	1.5	1.0	0.4
Fuel oil/kerosene	2.8	2.5	1.1	1.4	N	N	N
Some other fuel	0.3	Q	Q	Q	Q	N	Q
Size of main water heater							
Small (30 gallons or less)	15.0	1.8	0.5	1.3	3.1	2.1	1.0
Medium (31 to 49 gallons)	52.4	8.1	2.3	5.8	12.5	8.7	3.8
Large (50 gallons or more)	31.6	4.3	0.9	3.4	6.6	4.2	2.4
Tankless	3.0	0.8	0.4	0.3	0.7	0.5	0.2
Central water heater in an apartment building	16.2	6.1	1.5	4.6	3.5	2.6	0.9
Age of main water heater							
Less than 2 years old	16.1	3.4	1.0	2.4	3.6	2.6	1.0
2 to 4 years old	23.7	3.7	1.4	2.3	4.9	3.4	1.5
5 to 9 years old	37.6	6.6	1.5	5.1	8.2	5.7	2.5
10 to 14 years old	23.3	3.5	0.7	2.8	5.4	3.6	1.8
15 to 19 years old	8.9	1.4	0.4	1.0	2.3	1.7	0.6
20 years or more	8.6	2.2	0.5	1.7	2.0	1.1	0.9
Fuel used by secondary water heater							
Natural gas	1.8	Q	Q	Q	0.3	Q	0.2
Electricity	2.1	0.2	Q	Q	0.1	Q	Q
Some other fuel	0.4	Q	Q	Q	Q	Q	Q
Do not have a secondary water heater	97.7	14.5	4.0	10.5	22.3	15.2	7.1
Not asked (central water heater in an apartment building)	16.2	6.1	1.5	4.6	3.5	2.6	0.9

[1]Housing characteristics data were collected between August 2015 and April 2016.

[2]Total U.S. includes all primary occupied housing units in the 50 states and the District of Columbia. Vacant housing units, seasonal units, second homes, military houses, and group quarters are excluded.

Q = Data withheld because either the Relative Standard Error (RSE) was greater than 50% or fewer than 10 households responded.

N = No cases responded.

Notes: Because of rounding, data may not sum to totals. See RECS Terminology for definition of terms used in these tables.

Source: U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457A and EIA-45C of the 2015 Residential Energy Consumption Survey.

U.S. Energy Information Administration

2015 Residential Energy Consumption Survey: Housing Characteristics Tables

DSM Program Participation Calculations

Air Source Heat Pump	
Estimated Residential Customers	70,352
Estimated Appliance Saturation	64.02%
Market Eligibility	28.79%
Adoption Rate	20.00%
Estimated Convertable Units	2,593

Room Air Conditioner	
Estimated Residential Customers	70,352
Estimated Appliance Saturation	26.14%
Market Eligibility	18.18%
Adoption Rate	50.00%
Estimated Convertable Units	1,672

Central Air Conditioner	
Estimated Residential Customers	70,352
Estimated Appliance Saturation	70.83%
Market Eligibility	35.61%
Adoption Rate	30.00%
Estimated Convertable Units	5,323

Refrigerator	
Estimated Residential Customers	70,352
Estimated Appliance Saturation	99.24%
Market Eligibility	11.83%
Adoption Rate	70.00%
Estimated Convertable Units	5,783

Freezer	
Estimated Residential Customers	70,352
Estimated Appliance Saturation	39.39%
Market Eligibility	27.88%
Adoption Rate	40.00%
Estimated Convertable Units	3,091

Water Heater	
Estimated Residential Customers	70,352
Estimated Appliance Saturation	100.00%
Market Eligibility	24.22%
Adoption Rate	50.00%
Estimated Convertable Units	8,518

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CHANGE FOR THE BETTER WITH ENERGY STAR

Life Cycle Cost Estimate for 1 ENERGY STAR Qualified Air Source Heat Pump(s)

This simple energy savings calculator was developed by the U.S. EPA and U.S. DOE and is provided for estimating purposes only. Actual energy savings may vary based on use and other factors. For a more sophisticated estimate, use the ENERGY STAR HVAC Investor software or a bin-hour tool.

Enter your own values in the gray boxes or use our default values.

Number of units	1
Electric Rate ($/kWh)	$0.113
City	
Choose your city from the drop-down menu	NE-North Platte

	ENERGY STAR Qualified Unit	Conventional Unit
Initial Cost per Unit (estimated retail price)	$6,700	$5,700
Heating Seasonal Performance Factor (HSPF) rating	8.2	7.7
Seasonal Energy Efficiency Ratio (SEER) rating	15	13
Heat Pump Capacity (Btu/hr)	36,000	36,000
Use with programmable thermostat (Yes/No)	Yes	No

Annual and Life Cycle Costs and Savings for 1 Air Source Heat Pump(s)

	1 ENERGY STAR Qualified Units	1 Conventional Units	Savings with ENERGY STAR
Annual Operating Costs*			
Energy cost	$1,142	$1,467	$325
Energy consumption (kWh)	*10,124*	*13,007*	*2,883*
Maintenance cost	$0	$0	$0
Total	**$1,142**	**$1,467**	**$325**
Life Cycle Costs*			
Operating costs (energy and maintenance)	$10,717	$13,770	$3,052
Energy costs	$10,717	$13,770	$3,052
Energy consumption (kWh)	*121,484*	*156,085*	*34,601*
Maintenance costs	$0	$0	$0
Purchase price for 1 unit(s)	$6,700	$5,700	-$1,000
Total	**$17,417**	**$19,470**	**$2,052**
		Simple payback of initial additional cost (years)†	**3.1**

** Annual costs exclude the initial purchase price. All costs, except initial cost, are discounted over the products' lifetime using a real discount rate of 4%. See "Assumptions" to change factors including the discount rate.*

† A simple payback period of zero years means that the payback is immediate.

Summary of Benefits for 1 Air Source Heat Pump(s)

Initial cost difference	**$1,000**
Life cycle savings	**$3,052**
Net life cycle savings (life cycle savings - additional cost)	**$2,052**
Simple payback of additional cost (years)	**3.1**
Life cycle energy saved (kWh)	**34,601**
Life cycle air pollution reduction (lbs of CO_2)	**53,286**
Air pollution reduction equivalence (number of cars removed from the road for a year)	**5**
Savings as a percent of retail price	**31%**

Assumptions for Air Source Heat Pumps

Category	Value		Data Source
Power			
ENERGY STAR Qualified Unit			
Initial Cost Per Unit	$6,700		Industry Data 2008
Heating Seasonal Performance Factor (HSPF) rating	8.2		The HSPF criteria for ENERGY STAR qualified residential air-source heat pumps are ≥ 8.2 for split systems and ≥ 8.0 for single package equipment.
Seasonal Energy Efficiency Ratio (SEER) rating	14.5		ENERGY STAR Specification: The SEER criteria for ENERGY STAR qualified residential air-source heat pumps is ≥ 14.5
Heating Capacity of Air Source Heat Pump (Btu/hr)	36,000	Btu/hr	Assumption
Lifetime	12	years	LBNL 2007
Conventional Unit			
Initial Cost Per Unit	$5,700		Industry Data 2008
Heating Seasonal Performance Factor (HSPF) rating	7.7		NAECA
Seasonal Energy Efficiency Ratio (SEER) rating	13		NAECA
Heating Capacity of Air Source Heat Pump (Btu/hr)	36,000	Btu/hr	Assumption
Lifetime	12	years	LBNL 2007
Maintenance			
Labor cost (per hour)	$20		EPA 2004
Labor time (hours)	0		EPA 2004
Usage	Cooling	Heating	
Full-Load Cooling/Heating Hours for Selected Location	640	2,403	EPA 2002
NE-Grand Island	851	2288	EPA 2002
NE-Lincoln	899	2284	EPA 2002
NE-Norfolk	801	2437	EPA 2002
NE-North Platte	640	2403	EPA 2002
NE-Omaha	890	2327	EPA 2002
NE-Scottsbluff	647	2365	EPA 2002
Discount Rate			
Commercial and Residential Discount Rate (real)	4%		A real discount rate of 4 percent is assumed, which is roughly equivalent to the nominal discount rate of 7 percent (4 percent real discount rate + 3 percent inflation rate).
Programable Thermostat Discount Rate	17%		LBNL 2007 (Based on minimum estimated savings)
Energy and Water Prices			
Commercial Electricity Price	$0.0962	$/kWh	National average: US Department of Energy, Annual Energy Outlook 2013 (Early Release edition), (converted from 2011 to 2012 dollars)
Residential Electricity Price	$0.1128	$/kWh	
Carbon Dioxide Emissions Factors			
Electricity CO_2 Emission Factor	1.54	lbs CO_2/kWh	EPA 2013
CO_2 Equivalents			
Annual CO_2 emissions per average passenger car	11,244	lbs CO_2/yr	EPA Greenhouse Gas Equivalencies Calculator, 2013

If you have questions, comments or suggestions, please write to calculators@energystar.gov
Calculator last updated April 2009, utility and emission rates updated 2013

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CHANGE FOR THE BETTER WITH ENERGY STAR

Life Cycle Cost Estimate for 1 ENERGY STAR Qualified Room Air Conditioner(s)

This energy savings calculator was developed by the U.S. EPA and U.S. DOE and is provided for estimating purposes only. Actual energy savings may vary based on use and other factors.

Enter your own values in the gray boxes or use our default values.

Number of units	1	
Electricity Rate ($/kWh)	$0.109	
Choose your city from the menu at right	NE-North Platte	
	ENERGY STAR Qualified Unit	**Conventional Unit**
Initial Cost per Unit (estimated retail price)	$220	$170
Energy Efficiency Ratio (EER)	10.8	9.8
Cooling Capacity of Air Conditioner (Btu/hr)	10,000	10,000

Annual and Life Cycle Costs and Savings for 1 Room Air Conditioner(s)

	1 ENERGY STAR Qualified Unit(s)	1 Conventional Unit(s)	Savings with ENERGY STAR
Annual Operating Costs*			
Energy cost	$65	$71	$7
Energy consumption (kWh)	*593*	*653*	*60*
Maintenance cost	$0	$0	$0
Total	**$65**	**$71**	**$7**
Life Cycle Costs*			
Operating costs (energy and maintenance)	$480	$529	$49
Energy costs	$480	$529	$49
Energy consumption (kWh)	*5,333*	*5,878*	*544*
Maintenance costs	$0	$0	$0
Purchase price for 1 unit(s)	$220	$170	-$50
Total	**$700**	**$699**	**-$1**
		Simple payback of initial additional cost (years)†	**7.6**

** Annual costs exclude the initial purchase price. All costs, except initial cost, are discounted over the products' lifetime using a real discount rate of 4%. See "Assumptions" to change factors including the discount rate.*

† A simple payback period of zero years means that the payback is immediate.

Summary of Benefits for 1 Room Air Conditioner(s)

Initial cost difference	**$50**
Life cycle savings	**$49**
Net life cycle savings (life cycle savings - additional cost)	**-$1**
Simple payback of additional cost (years)	**7.6**
Life cycle energy saved (kWh)	**544**
Life cycle air pollution reduction (lbs of CO_2)	**838**
Air pollution reduction equivalence (number of cars removed from the road for a year)	**0**
Air pollution reduction equivalence (acres of forest)	**0**
Savings as a percent of retail price	**0%**

Assumptions for Room Air Conditioners

Category	Value	Data Source
Power		
ENERGY STAR Qualified Unit		
Initial Cost Per Unit	$220	Average retail price of a qualified model in 2008 from national retail data
Energy Efficiency Ratio (EER)	10.8	ENERGY STAR Criteria
Cooling Capacity of Air Conditioner (Btu/hr)	10,000 Btu/hr	Typical room air conditioner size, April 2009
Lifetime	9 years	Appliance Magazine, September 2008
Conventional Unit (Manufactured After 1994)		
Initial Cost Per Unit	$170	Average retail price of a non-qualified model in 2008 from national retail pricing
Energy Efficiency Ratio (EER)	9.8	DOE Federal Test Procedure 10 CFR 430, Appendix F
Cooling Capacity of Air Conditioner (Btu/hr)	10,000 Btu/hr	Typical room air conditioner size, April 2009
Lifetime	9 years	Appliance Magazine, September 2008
Maintenance		
Labor cost (per hour)	$20	EPA 2004
Labor time (hours)	0	EPA 2004
Usage		
Full-Load Cooling Hours		
Full-Load Cooling Hours for Selected Location	640	EPA 2002
NE-Grand Island	851	EPA 2002
NE-Lincoln	899	EPA 2002
NE-Norfolk	801	EPA 2002
NE-North Platte	640	EPA 2002
NE-Omaha	890	EPA 2002
NE-Scottsbluff	647	EPA 2002
Discount Rate		
Commercial and Residential Discount Rate (real)	4%	A real discount rate of 4 percent is assumed, which is roughly equivalent to the nominal discount rate of 7 percent (4 percent real discount rate + 3 percent inflation rate).
Energy Prices		
Commercial Electricity Price	$0.0953 $/kWh	US Department of Energy, Annual Energy Outlook 2011 (Early Release), (converted from 2009 to 2010 dollars), http://www.eia.gov/forecasts/aeo/er/
Residential Electricity Price	$0.1089 $/kWh	
Carbon Dioxide Emissions Factors		
Electricity Carbon Emission Factor	1.54 lbs CO_2/kWh	EPA 2011
CO_2 Equivalents		
Annual CO_2 sequestration per forested acre	10,347 lbs CO_2/yr	EPA's Greenhouse Gas Equivalencies Calculator, http://www.epa.gov/cleanenergy/energy-resources/calculator.html
Annual CO_2 emissions per average passenger car	11,244 lbs CO_2/yr	

If you have questions, comments or suggestions, please write to calculators@energystar.gov
Calculator last updated April 2009, utility and emission rates updated July 2011

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CHANGE FOR THE BETTER WITH ENERGY STAR

Life Cycle Cost Estimate for 1 ENERGY STAR Qualified Central Air Conditioner(s)

This energy savings calculator was developed by the U.S. EPA and U.S. DOE and is provided for estimating purposes only. Actual energy savings may vary based on use and other factors.

Enter your own values in the gray boxes or use our default values.

Choose your city from the menu at right: NE-North Platte

Enter your own values in the gray boxes or use our default values.

Number of units	1
Electric Rate ($/kWh)	$0.113

	ENERGY STAR Qualified Unit	Conventional Unit
Initial Cost per Unit (estimated retail price with installation)**	$3,413	$2,857
Seasonal Energy Efficiency Ratio (SEER) rating	14.5	13.0
Cooling Capacity of Air Conditioner (Btu/hr)	3 ton	3 ton
Use with programmable Thermostat (Yes/No)	Yes	No

Annual and Life Cycle Costs and Savings for 1 Central Air Conditioner(s)

	1 ENERGY STAR Qualified Units	1 Conventional Units	Savings with ENERGY STAR
Annual Operating Costs*			
Energy cost	$151	$200	$49
Energy consumption (kWh)	*1,335*	*1,772*	*438*
Maintenance cost	$0	$0	$0
Total	**$151**	**$200**	**$49**
Life Cycle Costs*			
Operating costs (energy and maintenance)	$1,590	$2,112	$521
Energy costs	$1,590	$2,112	$521
Energy consumption (kWh)	*18,686*	*24,812*	*6,126*
Maintenance costs	$0	$0	$0
Purchase price for 1 unit(s)	$3,413	$2,857	-$556
Total	**$5,003**	**$4,969**	**-$34**
		Simple payback of initial additional cost (years)†	**11.3**

** Annual costs exclude the initial purchase price. All costs, except initial cost, are discounted over the products' lifetime using a real discount rate of 4%. See "Assumptions" to change factors including the discount rate.*

† A simple payback period of zero years means that the payback is immediate.

Summary of Benefits for 1 Central Air Conditioner(s)

Initial cost difference	**$556**
Life cycle savings	**$521**
Net life cycle savings (life cycle savings - additional cost)	**-$34**
Simple payback of additional cost (years)	**11.3**
Life cycle energy saved (kWh)	**6,126**
Life cycle air pollution reduction (lbs of CO_2)	**9,434**
Air pollution reduction equivalence (number of cars removed from the road for a year)	**1**
Savings as a percent of retail price	**-1%**

Assumptions for Central Air Conditioners

Category	Value	Data Source
Power		
ENERGY STAR Qualified Unit		
Initial Cost Per Unit		
2.5 ton	$3,252	DEER Database 2008
3 ton	$3,413	DEER Database 2008
3.5 ton	$3,574	DEER Database 2008
4 ton	$3,735	DEER Database 2008
5 ton	$4,057	DEER Database 2008
Seasonal Energy Efficiency Ratio(SEER) rating	14.5	EPA 2009
Cooling Capacity of Air Conditioner (Btu/hr)	36,000 Btu/hr	Calculated
Lifetime	14 years	EPA 2006
Conventional Unit		
Initial Cost Per Unit		
2.5 ton	$2,696	DEER Database 2008
3 ton	$2,857	DEER Database 2008
3.5 ton	$3,018	DEER Database 2008
4 ton	$3,179	DEER Database 2008
5 ton	$3,501	DEER Database 2008
Seasonal Energy Efficiency Ratio(SEER) rating	13	EPA 2007
Cooling Capacity of Air Conditioner (Btu/hr)	36,000 Btu/hr	Calculated
Lifetime	14 years	EPA 2006
Maintenance		
Labor cost (per hour)	$20	EPA 2004
Labor time (hours)	0	EPA 2004
Usage		
Full-Load Cooling Hours		
Full-Load Cooling Hours for Selected Location	640	ARI Unitary Directory, August 1, 1992 - January 31, 1993
Discount Rate		
Commercial and Residential Discount Rate (real)	4%	A real discount rate of 4 percent is assumed, which is roughly equivalent to the nominal discount rate of 7 percent (4 percent real discount rate + 3 percent inflation rate).
Programable Thermostat Discount Rate	16%	LBNL 2007 (Based on minimum estimated savings)
Energy and Water Prices		
Commercial Electricity Price	$0.0962 $/kWh	National average: US Department of Energy, Annual Energy Outlook 2013 (Early Release edition), (converted from 2011 to 2012 dollars)
Residential Electricity Price	$0.1128 $/kWh	
Carbon Dioxide Emissions Factors		
Electricity Carbon Emission Factor	1.54 lbs CO_2/kWh	EPA 2013
CO_2 Equivalents		
Annual CO_2 emissions per average passenger car	11,244 lbs CO_2/yr	EPA Greenhouse Gas Equivalencies Calculator, 2013
Usage		
Full-Load Cooling Hours		
Full-Load Cooling Hours for Selected Location	640	EPA 2002
NE-Grand Island	851	EPA 2002
NE-Lincoln	899	EPA 2002
NE-Norfolk	801	EPA 2002
NE-North Platte	640	EPA 2002
NE-Omaha	890	EPA 2002
NE-Scottsbluff	647	EPA 2002

If you have questions, comments or suggestions, please write to calculators@energystar.gov
Calculator last updated April 2009, utility and emission rates updated 2013

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CHANGE FOR THE BETTER WITH ENERGY STAR

Life Cycle Cost Estimate for 20 ENERGY STAR Qualified Residential Refrigerator(s)

This energy savings calculator was developed by the U.S. EPA and U.S. DOE and is provided for estimating purposes only. Actual energy savings may vary based on use and other factors.

Enter your own values in the gray boxes or use our default values.

Number of units	20	
Electricity Rate ($/kWh)	$ 0.106	
Choose the type of refrigerator	1-Manual Defrost Refrigerators	
	ENERGY STAR Qualified Unit	**Conventional Unit**
Initial cost per unit (estimated retail price)	$1,100	$1,070
Refrigerator Fresh Volume (ft^3)	18	18
Refrigerator Freezer Volume (ft^3)	5	5
Refrigerator Total Volume (ft^3)	23	23

Annual and Life Cycle Costs and Savings for 20 Residential Refrigerator(s)

	20 ENERGY STAR Qualified Unit(s)	20 Conventional Unit(s)	Savings with ENERGY STAR
Annual Operating Costs*			
Energy costs	$862	$1,015	$152
Total	**$862**	**$1,015**	**$152**
Life Cycle Costs*			
Energy costs	$8,612	$10,132	$1,520
Energy consumption (kWh)	*105,869*	*124,551*	*18,683*
Purchase Price for 20 unit(s)	$22,000	$21,400	-$600
Total	**$30,612**	**$31,532**	**$920**
		Simple payback of initial additional cost (years)†	**3.9**

* *Annual costs exclude the initial purchase price. All costs, except initial cost, are discounted over the products' lifetime using a real discount rate of*

† *A simple payback period of zero years means that the payback is immediate.*

Summary of Benefits for 20 Residential Refrigerator(s)

Initial cost difference	**$600**
Life cycle savings	**$1,520**
Net life cycle savings (life cycle savings - additional cost)	**$920**
Simple payback of additional cost (years)	**3.9**
Life cycle energy saved (kWh)	**18,683**
Life cycle air pollution reduction (lbs of CO_2)	**28,771**
Air pollution reduction equivalence (number of cars removed from the road for a year)	**2.39**
Air pollution reduction equivalence (acres of forest)	**2.97**
Savings as a percent of retail price	**4%**

Assumptions for Residential Refrigerators

Category	Value	Data Source
Power		
ENERGY STAR Qualified Unit		
Initial cost per unit	$1,100	DOE 2004
Refrigerator Fresh Volume	18 ft^3	DOE 2004
Refrigerator Freezer Volume	5 ft^3	DOE 2004
Adjusted Volume	26.15 ft^3	DOE 2004
Lifetime	13 years	DOE 2004
Annual Unit Energy Consumption		
For Selected Refrigerator Type	407 kWh	Calculated.
1-Manual Defrost Refrigerators	407 kWh	DOE 2004
2-Partial Automatic Defrost Refrigerators	407 kWh	DOE 2004
3-Top Mount Freezer without through-the-door ice	452 kWh	DOE 2004
4-Side Mount Freezer without through-the-door ice	541 kWh	DOE 2004
5-Bottom Mount Freezer without through-the-door ice	492 kWh	DOE 2004
6-Top Mount Freezer with through-the-door ice	529 kWh	DOE 2004
7-Side Mount Freezer with through-the-door ice	570 kWh	DOE 2004
Conventional Unit (New Unit)		
Initial cost per unit	$1,070	DOE 2004
Refrigerator Fresh Volume	18 ft^3	DOE 2004
Refrigerator Freezer Volume	5 ft^3	DOE 2004
Adjusted Volume	26.15 ft^3	DOE 2004
Lifetime	13 years	DOE 2004
Annual Unit Energy Consumption		
For Selected Refrigerator Type	479 kWh	Calculated.
1-Manual Defrost Refrigerators	479 kWh	DOE 2004
2-Partial Automatic Defrost Refrigerators	479 kWh	DOE 2004
3-Top Mount Freezer without through-the-door ice	532 kWh	DOE 2004
4-Side Mount Freezer without through-the-door ice	636 kWh	DOE 2004
5-Bottom Mount Freezer without through-the-door ice	579 kWh	DOE 2004
6-Top Mount Freezer with through-the-door ice	623 kWh	DOE 2004
7-Side Mount Freezer with through-the-door ice	670 kWh	DOE 2004
Usage		
Number of operating hours per day	24 hours/day	DOE 2004
Number of operating days per year	365 days/year	DOE 2004
Number of operating hours per year	8,760 hours/year	Calculated.
Discount Rate		
Commercial and Residential Discount Rate (real)	4%	A real discount rate of 4 percent is assumed, which is roughly equivalent to the nominal discount rate of 7 percent (4 percent real discount rate + 3 percent inflation rate).
Energy Prices		
2006 Commercial Electricity Price	$ 0.0952 $/kWh	EIA 2008
2006 Residential Electricity Price	$ 0.1059 $/kWh	EIA 2008
Carbon Emissions Factors		
Electricity Carbon Emission Factors	1.54 lbs CO_2/kWh	EPA 2008
CO_2 Equivalents		
Annual CO_2 sequestration per forested acre	9,700 lbs CO_2/acre-yr	EPA 2007
Annual CO_2 emissions for "average" passenger car	12,037 lbs CO_2/acre-yr	EPA 2007

If you have any questions, please contact: ESCalcs@cadmusgroup.com.
Calculator last updated: 08/08

Products that earn the ENERGY STAR prevent greenhouse gas emissions by meeting strict energy efficiency guidelines set by the U.S. Environmental Protection Agency and the U.S. Department of Energy.
www.energystar.gov

CHANGE FOR THE BETTER WITH ENERGY STAR

Life Cycle Cost Estimate for 1 ENERGY STAR Qualified Commercial Refrigerator(s)

This energy savings calculator was developed by the U.S. EPA and U.S. DOE and is provided for estimating purposes only. Actual energy savings may vary based on use and other factors.

Enter your own values in the gray boxes or use our default values.

Number of units	1	
Electricity Rate ($/kWh)	$0.071	
	ENERGY STAR Qualified Unit	**Conventional Unit**
Initial cost per unit (estimated retail price)	$1,500	$1,000
Volume (ft^3)	43.5	43.5
Unit energy consumption (kWh/year)	2,332	4,300

Annual and Life Cycle Costs and Savings for 1 Commercial Refrigerator(s)

	1 ENERGY STAR Qualified Units	1 Conventional Units	Savings with ENERGY STAR
Annual Operating Costs*			
Energy cost	$166	$305	$140
Maintenance cost	$0	$0	$0
Total	**$166**	**$305**	**$140**
Life Cycle Costs*			
Operating cost (energy and maintenance)	$1,343	$2,476	$1,133
Purchase price for 1 unit(s)	$1,500	$1,000	-$500
Total	**$2,843**	**$3,476**	**$633**
		Simple payback of initial additional cost (years)†	**3.6**

** Annual costs exclude the initial purchase price. All costs, except initial cost, are discounted over the products' lifetime using a real discount rate of 4%. See "Assumptions" to change factors including the discount rate.*

† A simple payback period of zero years means that the payback is immediate.

Summary of Benefits for 1 Commercial Refrigerator(s)

Initial cost difference	**$500**
Life cycle savings	**$1,133**
Net life cycle savings (life cycle savings - additional cost)	**$633**
Simple payback of additional cost (years)	**3.6**
Life cycle energy saved (kWh)	**19,674**
Life cycle air pollution reduction (lbs of CO_2)	**28,133**
Air pollution reduction equivalence (number of cars removed from the road for a year)	**2.43**
Air pollution reduction equivalence (acres of forest)	**3.84**
Savings as a percent of retail price	**42%**

Assumptions for Commercial Refrigerators

Category	Value	Data Source
Power		
ENERGY STAR Qualified Unit		
Initial cost per unit (estimated retail price)	$1,500	Food Service Technology Center (FSTC) 2004
Volume	43.5 ft^3	FSTC 2004
Unit Energy Consumption	2,332 kWh/year	Calculated
Lifetime	10 years	FSTC 2004
Conventional Unit		
Initial cost per unit (estimated retail price)	$1,000	FSTC 2004
Volume	43.5 ft^3	FSTC 2004
Unit Energy Consumption	4,300 kWh/year	Calculated
Lifetime	10 years	FSTC 2004
Maintenance		
Labor cost (per hour)	$20	EPA 2004
Labor time (hours)	0	EPA 2004
Usage		
Number of operating hours per day	24 hours/day	FSTC 2004
Number of operating days per year	365 days/year	FSTC 2004
Number of operating hours per year	8,760 hours/year	Calculated.
Discount Rate		
Commercial and Residential Discount Rate (real)	4%	A real discount rate of 4 percent is assumed, which is roughly equivalent to the nominal discount rate of 7 percent (4 percent real discount rate + 3 percent inflation rate).
Energy Prices		
2004 Commercial Electricity Price	$ 0.071 $/kWh	EPA 2004
2004 Residential Electricity Price	$ 0.085 $/kWh	EPA 2004
Carbon Dioxide Emissions Factors		
Electricity Carbon Dioxide Emission Factors	1.43 lbs CO_2/kWh	EPA 2003
CO_2 Equivalents		
Annual CO_2 sequestration per forested acre	7,333 lbs CO_2/yr	EPA 2003
Annual CO_2 emissions for "average" passenger car	11,560 lbs CO_2/yr	EPA 2003

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The simple choice for energy efficiency.

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Your Information

Model:	16.5-18.9 Cubic Feet Chest Freezer
Electricity Rate:	$0.1058
Annual Cost:	$65.70
Annual kWh:	621 kWh

Flip Your Fridge Savings

$152 over five years

496 lbs of carbon pollution over five years

10,509 lbs more of carbon pollution when you properly recycle your old refrigerator

Learn more, including information on refrigerator rebates in your area.

LEARN MORE →

ENERGY STAR refrigerators and freezers are independently certified to save energy. Special offers may be available in your area.

REBATE FINDER → PRODUCT FINDER →

This Flip Your Fridge calculator is designed to provide an estimate of the savings associated with replacing or removing an old refrigerator or freezer with a new ENERGY STAR certified model. Actual savings may vary based on use, upkeep, and other factors. Assumptions are based on a combination of historical data (adjusted for degradation based on the age of the refrigerator/freezers) and calculations cited in the ENERGY STAR specifications.

If you have trouble using this tool, please contact appliances@energystar.gov

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Energy Cost Calculator for Electric and Gas Water Heaters

Vary equipment size, energy cost, hours of operation, and /or efficiency level.

INPUT SECTION		
Input the following data (if any parameter is missing, calculator will set to default value).		*Defaults*
TYPE OF WATER HEATER	Gas	*Electric*
AVERAGE DAILY USAGE (GALLONS PER DAY)*	64 gallons	*64**
ENERGY FACTOR†	0.61	*0.92 (electric) 0.61 (gas)*
ENERGY COST	$0.65 / therm	*$0.06 per kWh $.60 per therm*
QUANTITY OF WATER HEATERS TO BE PURCHASED	1 unit(s)	*1 unit*

* See assumptions for various daily water use totals.
† The comparison assumes a storage tank water heater as the input type. To allow demand water heaters as the comparison type, users can specify an input EF of up to 0.85; however, 0.66 is currently the best available EF for storage water heaters.

Calculate | Reset

OUTPUT SECTION				
PERFORMANCE PER WATER HEATER	YOUR CHOICE	BASE MODEL	FEMP RECOMMENDED LEVEL	BEST AVAILABLE
NEW ENERGY FACTOR	0.61	0.59	0.62	0.85
ANNUAL ENERGY USE therm	244	253	241	175
ANNUAL ENERGY COSTS	$159 <>	$164	$157	$114
LIFETIME ENERGY COSTS	$1649	$1701	$1628	$1182
LIFETIME ENERGY COST SAVINGS	$52	$0	$73	$519
LIFETIME ENERGY COST SAVINGS FOR 1 WATER HEATER(S)	$52	$0	$73	$519

Your selection of a gas water heater using 64 gallon(s) per day will have a $ 52 energy cost savings per water heater over an estimated 13 year life expectancy compared to the base model.

Assumptions

FEDERAL ENERGY MANAGEMENT PROGRAM

- "Base model" has an efficiency that just meets the national minimum standard for gas and electric water heaters.
- Lifetime energy cost is the sum of the discounted value of the annual energy costs based on assumed water heater life of 13 years.
- Future electricity price trends and a discount rate of 3.2% are based on Federal guidelines.
- $0.09 per kWh for electricity is the Federal average price in the U.S.
- $0.93 per therm for gas is the Federal average price in the U.S.
- Hot water usage estimates:
  - Average shower (8 minutes) = 10 gallons of hot water
  - Average clothes washer (one load) = 7 gallons of hot water
  - Average dishwasher (one load) = 6 gallons of hot water
  - Average kitchen faucet flow = 2 gpm
  - Average bathroom faucet flow = 0.5 gpm
  - Average daily usage = 64 gallons of hot water.

Disclaimer

This cost calculator is a screening tool that estimates a product's lifetime energy cost savings at various efficiency levels. Maintenance and installation costs do not vary significantly among the same product having different efficiencies; so, these costs are not included in this calculator tool. For a detailed life cycle cost analysis, the Federal Energy Management Program has developed a tool called Building Life Cycle Cost (BLCC). This downloadable tool allows the user to vary interest rates, installation costs, maintenance costs, salvage values, and life expectancy for a product or an entire energy project.

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Energy Cost Calculator for Electric and Gas Water Heaters

Home » Products & Technologies » Cost Savings Calculators » Energy Cost Calculator for Electric and Gas Water Heaters

Vary equipment size, energy cost, hours of operation, and /or efficiency level.

INPUT SECTION		
Input the following data (if any parameter is missing, calculator will set to default value).		*Defaults*
TYPE OF WATER HEATER	Electric	*Electric*
AVERAGE DAILY USAGE (GALLONS PER DAY)*	64 gallons	*64**
ENERGY FACTOR†	0.92	*0.92 (electric) 0.61 (gas)*
ENERGY COST	$0.06 / kWh	*$0.06 per kWh $.60 per therm*
QUANTITY OF WATER HEATERS TO BE PURCHASED	1 unit(s)	*1 unit*

* See assumptions for various daily water use totals.
† The comparison assumes a storage tank water heater as the input type. To allow demand water heaters as the comparison type, users can specify an input EF of up to 0.85; however, 0.66 is currently the best available EF for storage water heaters.

Calculate Reset

OUTPUT SECTION				
PERFORMANCE PER WATER HEATER	YOUR CHOICE	BASE MODEL	FEMP RECOMMENDED LEVEL	BEST AVAILABLE
NEW ENERGY FACTOR	0.92	0.86	0.92	0.95
ANNUAL ENERGY USE kWh	4750	5082	4750	4600
ANNUAL ENERGY COSTS	$285 <>	$305	$285	$276
LIFETIME ENERGY COSTS	$2767	$2962	$2767	$2680
LIFETIME ENERGY COST SAVINGS	$195	$0	$195	$282
LIFETIME ENERGY COST SAVINGS FOR 1 WATER HEATER(S)	$195	$0	$195	$282

Your selection of a electric water heater using 64 gallon(s) per day will have a $ 195 energy cost savings per water heater over an estimated 13 year life expectancy compared to the base model.

Assumptions

FEDERAL ENERGY MANAGEMENT PROGRAM

- **"Base model" has an efficiency that just meets the national minimum standard for gas and electric water heaters.**
- **Lifetime energy cost is the sum of the discounted value of the annual energy costs based on assumed water heater life of 13 years.**
- **Future electricity price trends and a discount rate of 3.2% are based on Federal guidelines.**
- **$0.09 per kWh for electricity is the Federal average price in the U.S.**
- **$0.93 per therm for gas is the Federal average price in the U.S.**
- **Hot water usage estimates:**
  - **Average shower (8 minutes) = 10 gallons of hot water**
  - **Average clothes washer (one load) = 7 gallons of hot water**
  - **Average dishwasher (one load) = 6 gallons of hot water**
  - **Average kitchen faucet flow = 2 gpm**
  - **Average bathroom faucet flow = 0.5 gpm**
  - **Average daily usage = 64 gallons of hot water.**

Disclaimer

This cost calculator is a screening tool that estimates a product's lifetime energy cost savings at various efficiency levels. Maintenance and installation costs do not vary significantly among the same product having different efficiencies; so, these costs are not included in this calculator tool. For a detailed life cycle cost analysis, the Federal Energy Management Program has developed a tool called Building Life Cycle Cost (BLCC). This downloadable tool allows the user to vary interest rates, installation costs, maintenance costs, salvage values, and life expectancy for a product or an entire energy project.

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Demand Side Management
Benefit/Cost Analysis

Assigned Values			
Discount Rate	(%)		4.39%
Utility Avoided Cost Rate	($/MWh)	$ 22.00	2%
Customer Electrical Retail Rate	($/MWh)	$ 65.00	2%
Customer Natural Gas Retail Rate	($/therm)	$ 0.65	2%

Air Source Heat Pump Conversion

Cost/Benefit Component	Unit	Escalation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV
Energy Savings	(MWh/yr/unit)	--	-8.352	-8.352	-8.352	-8.352	-8.352	-8.352	-8.352	-8.352	-8.352	-8.352	
Participants	(#/yr)	--	291	291	291	291	291	291	291	291	291	291	
Utility Avoided Cost	($/yr)	2%	$ (53,455)	$ (53,455)	$ (54,525)	$ (55,615)	$ (56,727)	$ (57,862)	$ (59,019)	$ (60,200)	$ (61,404)	$ (62,632)	($454,350)
Utility Administrative Cost	($/yr)	3%	$ 12,500	$ 12,875	$ 13,261	$ 13,659	$ 14,069	$ 14,491	$ 14,926	$ 15,373	$ 15,835	$ 16,310	$112,817
Utility Incentive Rate	($/unit)	--	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	
Utility Incentive Cost	($/yr)	--	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$1,157,249
Customer Incremental Cost	($/unit)	--	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	
Customer Incremental Cost	($/yr)	--	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$ 145,462	$1,157,249
Customer Electrical Bill Savings	($/yr)	2%	$ (161,095)	$ (161,095)	$ (164,317)	$ (167,604)	$ (170,956)	$ (174,375)	$ (177,862)	$ (181,420)	$ (185,048)	$ (188,749)	($1,369,244)
Customer Natural Gas Bill Savings	($/yr)	2%	$ 163,572	$ 166,843	$ 170,180	$ 173,584	$ 177,055	$ 180,596	$ 184,208	$ 187,893	$ 191,650	$ 195,483	$1,414,965

Program Administrator Cost Test = A ÷ (B+C)	-0.3577
Customer Cost Benefit Test = (E+F) ÷ D	0.0395
Total Resource Cost Test = A ÷ (B+D)	-0.3577

Room Air Conditioner Rebate

Cost/Benefit Component	Unit	Escalation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV
Energy Savings	(MWh/yr/unit)	--	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	
Participants	(#/yr)	--	113	113	113	113	113	113	113	113	113	113	
Utility Avoided Cost	($/yr)	2%	$ 149	$ 149	$ 152	$ 155	$ 158	$ 161	$ 164	$ 167	$ 171	$ 174	$1,263
Utility Administrative Cost	($/yr)	3%	$ 12,500	$ 12,875	$ 13,261	$ 13,659	$ 14,069	$ 14,491	$ 14,926	$ 15,373	$ 15,835	$ 16,310	$112,817
Utility Incentive Rate	($/unit)	--	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	
Utility Incentive Cost	($/yr)	--	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$22,381
Customer Incremental Cost	($/unit)	--	$ 50	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	
Customer Incremental Cost	($/yr)	--	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$ 2,813	$22,381
Customer Electrical Bill Savings	($/yr)	2%	$ 448	$ 448	$ 457	$ 466	$ 475	$ 485	$ 494	$ 504	$ 514	$ 524	$3,805
Customer Natural Gas Bill Savings	($/yr)	2%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0

Program Administrator Cost Test = A ÷ (B+C)	0.0093
Customer Cost Benefit Test = (E+F) ÷ D	0.1700
Total Resource Cost Test = A ÷ (B+D)	0.0093

Central Air Conditioner Rebate

Cost/Benefit Component	Unit	Escalation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV
Energy Savings	(MWh/yr/unit)	--	0.438	0.438	0.438	0.438	0.438	0.438	0.438	0.438	0.438	0.438	
Participants	(#/yr)	--	597	597	597	597	597	597	597	597	597	597	
Utility Avoided Cost	($/yr)	2%	$ 5,755	$ 5,755	$ 5,870	$ 5,987	$ 6,107	$ 6,229	$ 6,354	$ 6,481	$ 6,611	$ 6,743	$48,914
Utility Administrative Cost	($/yr)	3%	$ 12,500	$ 12,875	$ 13,261	$ 13,659	$ 14,069	$ 14,491	$ 14,926	$ 15,373	$ 15,835	$ 16,310	$112,817
Utility Incentive Rate	($/unit)	--	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	
Utility Incentive Cost	($/yr)	--	$ 179,168	$ 179,168	$ 179,168	$ 179,168	$ 179,168	$ 179,168	$ 179,168	$ 179,168	$ 179,168	$ 179,168	$1,425,405
Customer Incremental Cost	($/unit)	--	$ 556	$ 556	$ 556	$ 556	$ 556	$ 556	$ 556	$ 556	$ 556	$ 556	
Customer Incremental Cost	($/yr)	--	$ 152,890	$ 152,890	$ 152,890	$ 152,890	$ 152,890	$ 152,890	$ 152,890	$ 152,890	$ 152,890	$ 152,890	$1,216,346
Customer Electrical Bill Savings	($/yr)	2%	$ 17,343	$ 17,343	$ 17,690	$ 18,044	$ 18,405	$ 18,773	$ 19,148	$ 19,531	$ 19,922	$ 20,320	$147,409
Customer Natural Gas Bill Savings	($/yr)	2%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0

Program Administrator Cost Test = A ÷ (B+C)	0.0318
Customer Cost Benefit Test = (E+F) ÷ D	0.1212
Total Resource Cost Test = A ÷ (B+D)	0.0368

Demand Side Management
Benefit/Cost Analysis

Refrigerator Rebate

Cost/Benefit Component	Unit	Escalation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV
Energy Savings	(MWh/yr/unit)	--	0.101	0.101	0.101	0.101	0.101	0.101	0.101	0.101	0.101	0.101	
Participants	(#/yr)	--	463	463	463	463	463	463	463	463	463	463	
Utility Avoided Cost	($/yr)	2%	$ 1,025	$ 1,025	$ 1,045	$ 1,066	$ 1,087	$ 1,109	$ 1,131	$ 1,154	$ 1,177	$ 1,201	$8,710
Utility Administrative Cost	($/yr)	3%	$ 12,500	$ 12,875	$ 13,261	$ 13,659	$ 14,069	$ 14,491	$ 14,926	$ 15,373	$ 15,835	$ 16,310	$112,817
Utility Incentive Rate	($/unit)	--	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	
Utility Incentive Cost	($/yr)	--	$ 13,902	$ 13,902	$ 13,902	$ 13,902	$ 13,902	$ 13,902	$ 13,902	$ 13,902	$ 13,902	$ 13,902	$110,600
Customer Incremental Cost	($/unit)	--	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	
Customer Incremental Cost	($/yr)	--	$ 18,536	$ 18,536	$ 18,536	$ 18,536	$ 18,536	$ 18,536	$ 18,536	$ 18,536	$ 18,536	$ 18,536	$147,467
Customer Electrical Bill Savings	($/yr)	2%	$ 3,088	$ 3,088	$ 3,150	$ 3,213	$ 3,277	$ 3,343	$ 3,410	$ 3,478	$ 3,547	$ 3,618	$26,248
Customer Natural Gas Bill Savings	($/yr)	2%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0

Program Administrator Cost Test = A ÷ (B+C)	0.0390
Customer Cost Benefit Test = (E+F) ÷ D	0.1780
Total Resource Cost Test = A ÷ (B+D)	0.0335

Freezer Rebate

Cost/Benefit Component	Unit	Escalation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV
Energy Savings	(MWh/yr/unit)	--	0.287	0.287	0.287	0.287	0.287	0.287	0.287	0.287	0.287	0.287	
Participants	(#/yr)	--	260	260	260	260	260	260	260	260	260	260	
Utility Avoided Cost	($/yr)	2%	$ 1,644	$ 1,644	$ 1,677	$ 1,711	$ 1,745	$ 1,780	$ 1,815	$ 1,852	$ 1,889	$ 1,926	$13,975
Utility Administrative Cost	($/yr)	3%	$ 12,500	$ 12,875	$ 13,261	$ 13,659	$ 14,069	$ 14,491	$ 14,926	$ 15,373	$ 15,835	$ 16,310	$112,817
Utility Incentive Rate	($/unit)	--	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	
Utility Incentive Cost	($/yr)	--	$ 7,803	$ 7,803	$ 7,803	$ 7,803	$ 7,803	$ 7,803	$ 7,803	$ 7,803	$ 7,803	$ 7,803	$62,078
Customer Incremental Cost	($/unit)	--	$ 45	$ 45	$ 45	$ 45	$ 45	$ 45	$ 45	$ 45	$ 45	$ 45	
Customer Incremental Cost	($/yr)	--	$ 3,902	$ 3,902	$ 3,902	$ 3,902	$ 3,902	$ 3,902	$ 3,902	$ 3,902	$ 3,902	$ 3,902	$31,039
Customer Electrical Bill Savings	($/yr)	2%	$ 4,955	$ 4,955	$ 5,054	$ 5,155	$ 5,258	$ 5,363	$ 5,471	$ 5,580	$ 5,692	$ 5,805	$42,115
Customer Natural Gas Bill Savings	($/yr)	2%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0

Program Administrator Cost Test = A ÷ (B+C)	0.0799
Customer Cost Benefit Test = (E+F) ÷ D	1.3568
Total Resource Cost Test = A ÷ (B+D)	0.0971

Electric Water Heater Conversion

Cost/Benefit Component	Unit	Escalation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV
Energy Savings	(MWh/yr/unit)	--	-4.750	-4.750	-4.750	-4.750	-4.750	-4.750	-4.750	-4.750	-4.750	-4.750	
Participants	(#/yr)	--	573	573	573	573	573	573	573	573	573	573	
Utility Avoided Cost	($/yr)	2%	$ (59,920)	$ (59,920)	$ (61,119)	$ (62,341)	$ (63,588)	$ (64,860)	$ (66,157)	$ (67,480)	$ (68,830)	$ (70,206)	($509,298)
Utility Administrative Cost	($/yr)	3%	$ 12,500	$ 12,875	$ 13,261	$ 13,659	$ 14,069	$ 14,491	$ 14,926	$ 15,373	$ 15,835	$ 16,310	$112,817
Utility Incentive Rate	($/unit)	--	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	
Utility Incentive Cost	($/yr)	--	$ 86,010	$ 86,010	$ 86,010	$ 86,010	$ 86,010	$ 86,010	$ 86,010	$ 86,010	$ 86,010	$ 86,010	$684,269
Customer Incremental Cost	($/unit)	--	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	
Customer Incremental Cost	($/yr)	--	$ 28,670	$ 28,670	$ 28,670	$ 28,670	$ 28,670	$ 28,670	$ 28,670	$ 28,670	$ 28,670	$ 28,670	$228,090
Customer Electrical Bill Savings	($/yr)	2%	$ (180,578)	$ (180,578)	$ (184,190)	$ (187,873)	$ (191,631)	$ (195,463)	$ (199,373)	$ (203,360)	$ (207,427)	$ (211,576)	($1,534,839)
Customer Natural Gas Bill Savings	($/yr)	2%	$ 94,296	$ 96,182	$ 98,105	$ 100,067	$ 102,069	$ 104,110	$ 106,192	$ 108,316	$ 110,482	$ 112,692	$815,697

Program Administrator Cost Test = A ÷ (B+C)	-0.6389
Customer Cost Benefit Test = (E+F) ÷ D	-3.1529
Total Resource Cost Test = A ÷ (B+D)	-1.4940

Appendix D – Board Resolution

From the minutes

CONSIDER AND APPROVE 2017 INTEGRATED RESOURCE PLAN | PUBLIC HEARING

Chairman Goulette reported that as part of the Western Area Power Administration Energy Planning and Management Program, under the firm power contract, MEAN is required every 5 years to prepare and submit an Integrated Resource Plan (IRP) on behalf of MEAN and its Total Requirements Participants. A copy of the proposed draft IRP was previously distributed via email; and was made available in the back of the room at its August 17, 2017 meeting; and was available at MEAN's offices in Lincoln, Nebraska as well as at the municipal offices of MEAN's 61 Total Requirements Participants as posted in the Lincoln Journal Star and public posting processes of the Total Requirements Participants.

He further noted that as part of the IRP process, MEAN is also required to allow for public participation and accomplishes this by conducting a public hearing. He stated that the public hearing is scheduled today (August 17, 2017) in conjunction with the regularly scheduled meeting of the MEAN Board of Directors.

Goulette declared the public hearing to comment on MEAN's draft IRP open at 9:57 a.m. (CT).

Shannon Coleman, Supervisor of Resource Planning & Analysis, provided an overview of the MEAN IRP draft report. She further noted that comments may be submitted by September 8, 2017 by mail to the Municipal Energy Agency of Nebraska, 8377 Glynoaks Drive, Lincoln, Nebraska 68516, or email to MEANIRP2017@nmppenergy.org. Portions of Coleman's overview addressed the following items:

1. IRP Requirements
2. System Load Forecast
3. System Resources
4. Load and Resource Balance
5. Phase I Supply Side Resource Evaluation
6. Demand Side Evaluation
7. Phase II Analysis and Results
8. Conclusions and Recommended Action Plan

Coleman stated that the IRP is due to WAPA on October 15, 2017.

Public Comments and questions were solicited. There being no questions or comments, the public hearing was declared closed at 10:30 a.m. (CT).

At its August 16, 2017 meeting, the Power Supply Committee recommended that the MEAN Board of Directors approve as presented the following portfolios for the Southwest Power Pool (SPP) region and the West region:

- SPP: Portfolio 1D, 7, 8, & 9
- West: Portfolio 1,7,8 & 9

Staff recommended the MEAN Board of Directors approve the following resolution as presented.

Motion: *Jeff Sprock moved to approve the IRP as presented and directed staff to submit the IRP to Western Area Power Administration on behalf of the Total Requirements Participants. Mike Palmer seconded the motion, which carried unanimously on roll call vote. (Todd Mahin and Jeremy Tarr did not vote).*

MEAN BOARD OF DIRECTORS RESOLUTION

WHEREAS, Western Area Power Administration ("WAPA") requires its customers to prepare and submit an Integrated Resource Plan ("IRP") every five years, and

WHEREAS, MEAN has prepared an IRP for submission to WAPA in 2017 to comply with the requirements of the WAPA Energy Planning and Management Program for MEAN and its total requirements participants.

NOW, THEREFORE, BE IT RESOLVED by the MEAN Board of Directors that the Integrated Resource Plan is approved as presented, utilizing the following Portfolios for the Southwest Power Pool ("SPP") region and the West region:

- *SPP: Portfolio 1D, 7, 8, & 9*
- *West: Portfolio 1,7,8 & 9*

BE IT FURTHER RESOLVED by the MEAN Board of Directors that staff is hereby authorized and directed to submit the IRP to WAPA in 2017 on behalf of MEAN and its total requirements participants.

BE IT FURTHER RESOLVED by the MEAN Board of Directors that the Board of Directors reserves the right to modify the 2017 IRP to take into account changed circumstances and operational and economic considerations.