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INTEGRATED RESOURCE PLAN

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OPPD

Omaha Public Power District

FEBRUARY 2017

DISCLOSURE

This plan may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed.

Acknowledgement

Resource planning is an ongoing process at the Omaha Public Power District (OPPD). By design, the integrated planning process evaluates low-cost supply and demand-side options to meet forecasted electrical demands for OPPD's service territory. The planning process aligns OPPD's resources with its Board's strategic directives – policies designed to guide efforts to address current and future challenges, mitigate risks, pursue strategic opportunities, and optimize service to the District's customer-owners. Specifically, the planning process supports the following Directives:

Strategic Directive 1: Strategic Foundation
Strategic Directive 2: Competitive Rates
Strategic Directive 4: Reliability
Strategic Directive 7: Environmental Stewardship
Strategic Directive 9: Resource Planning
Strategic Directive 11: Economic Development
Strategic Directive 13: Stakeholder Outreach & Communication
Strategic Directive 15: Enterprise Risk Management

OPPD prepares, files, and publishes an Integrated Resource Plan (IRP) every five years with the Western Area Power Administration (WAPA) as a result of OPPD's long-term contract to receive hydroelectric power from WAPA. OPPD expects that the experience gained over the next few years will likely modify the long-term outlook as the industry experiences rapid change in a compressed period of time. As part of the process, OPPD invited customer-owner participation and delivered that feedback to Management and the Board of Directors. OPPD values the knowledgeable input, comments and discussion provided by the customer-owners and other stakeholders collected during the process. Beyond this report, OPPD looks forward to continuing the ongoing resource planning process collaboratively with our stakeholders. You can learn more about OPPD's resource planning process here.

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Acronyms

AEG - Applied Energy Group, Inc.
CAA - Clean Air Act of 1970
Capacity - Nameplate Capacity
CCCT - Combined-Cycle Combustion Turbine
CCR - Coal Combustion Residual
CCS - Cass County Station
CPP - Clean Power Plan
CO2 - Carbon Dioxide
CREB - Clean Renewable Energy Bonds
CREF - Certified Renewable Export Facility
CSAPR - Cross State Air Pollution Rule
CT - Combustion Turbine
CVR - Conservation Voltage Reduction
CWA - Clean Water Act
DA - Day Ahead Market
DER – Distributed Energy Resource
DOE - Department of Energy
DSM - Demand-Side Management
EE - Energy Efficiency
EIA - Energy Information Administration
EPA - Environmental Protection Agency
EV - Electric Vehicles
FCS - Fort Calhoun Station
FEMA - Federal Emergency Management Agency
FERC - Federal Energy Regulatory Commission
FLISR – Fault Location, Isolation, and Service Restoration
GADS - Generating Availability Data System
GWh - Gigawatt-Hour
Hg - Mercury
IM - Integrated Marketplace
IRP - Integrated Resource Plan
ITC - Investment Tax Credit
JSS - Jones Street Station
kWh - Kilowatt-Hour
kW - Kilowatt
LB - Nebraska Legislative Bill
MATS - Mercury and Air Toxics Standard
MMBtu - One Million British Thermal Units

MRO - Midwest Reliability Organization
MUD - Metropolitan Utilities District
MWh - Megawatt-Hour
MW - Megawatt
NC1 - Nebraska City Station Unit No. 1
NC2 - Nebraska City Station Unit No. 2
NCS - Nebraska City Station
NERC - North American Electric Reliability Corporation
NO1, NO2, NO3, NO4 and NO5 - North Omaha Station Units 1, 2, 3, 4 and 5
NOS - North Omaha Station
NOx - Nitrogen Oxide
NPA - Nebraska Power Association
NPRB - Nebraska Power Review Board
NPV - Net Present Value
NRC - U.S. Nuclear Regulatory Commission
NREL - National Renewable Energy Laboratory
O&M - Operation and Maintenance
OATT - Open Access Transmission Tariff
OPPD - Omaha Public Power District
PHEV - Plug-In Hybrid Electric Vehicle
PSDAR - Post Shutdown Decommissioning Activities Report
PPA - Power Purchase Agreement

PTC - Production Tax Credit
PV - Photovoltaic
REC - Renewable Energy Certificate
RES - Renewable Energy Standard
RFP - Request for Proposal
RH BART - Regional Haze Best Available Retrofit Technology
ROP - Reactor Oversight Process
RPS - Renewable Portfolio Standard
RT - Real Time Market
RTO - Regional Transmission Organization
SAFSTOR - Safe Storage
SAIDI - System Average Interruption Duration Index
SCCT - Simple-Cycle Combustion Turbine
SCED - Security-Constrained Economic Dispatch
SCR - Selective Catalytic Reduction
SCS - Sarpy County Station
SD - Strategic Directives

SEC - Securities Exchange Committee
SNCR - Selective Non-Catalytic Reduction
SIP - State Implementation Plan
SO2 - Sulfur Dioxide
SPP - Southwest Power Pool
USACE - United States Army Corps of Engineers
US - United States
VVO - Volt-Var Optimization
WAPA - Western Area Power Administration

1.0 Summary

1.1 Introduction

The utility industry is experiencing a time of monumental change driven by the emergence of new technologies, new regulatory legislation and changing customer preferences. Omaha Public Power District understands that it must embrace innovation to deliver on its mission to provide customer-owners with affordable, reliable and environmentally sensitive energy services, *now and into the future*. The 2016 Integrated Resource Plan (IRP) presents an analysis of various resource options available to OPPD to serve electrical demand.

As OPPD transforms itself through this period of dynamic change, it also understands that many of the assumptions made in the 2016 IRP will continue to evolve over time as regulation, technology and customers' preferences evolve. In light of this fluid environment, OPPD is committed to being ever-vigilant in its planning efforts to capture the declining costs of renewable resources and the emerging opportunities enabled by technology at the *pace of value for our customer-owners*. As the market evolves, OPPD recognizes that its portfolio will need to be more flexible, adaptable and responsive than ever to continue to drive the historical value we have provided to our customer-owners.

1.2 OPPD Board of Directors Strategic Directives

With a focus on enhancing its governance processes and practices, the OPPD Board of Directors established Strategic Directives in 2015 to provide clear and transparent performance expectations for OPPD Management. These policies and directives guide the organization's efforts to effectively and efficiently address current and future challenges, mitigate risks, pursue strategic opportunities and optimize services for the District's customer-owners. Specifically, the Board of Directors and Management believe these directives are critical in maintaining the value of public power for customers-owners. As a result, the 2016 IRP supports these policies, and aligns closely with the following directives:

SD-1 Strategic Foundation – OPPD's mission is to provide affordable, reliable and environmentally sensitive energy services to its customer-owners. Through its strategic initiatives and broader planning efforts, OPPD will strive to "Lead The Way" it powers the future.

SD-2 Competitive Rates - OPPD has established a rate target of 20% below the West North Central Regional average published rates on a system average basis. Accordingly, OPPD uses a low-cost optimization approach to its resource planning.

SD-4 Reliability - Generation and delivery systems must perform at a high level to provide reliable service to customer-owners. The directive identifies the key metrics of unit availability, system average interruption duration index (SAIDI) and requires a reliable transmission and distribution system. As the composition of OPPD's generation portfolio shifts away from fossil generation to renewable generation and other demand-side solutions, the resource planning process remains sensitive to maintaining reliability.

SD-7 Environmental Stewardship - The Board is committed to operate OPPD in an environmentally sensitive manner. The Board established that a long-term goal of at least 30% of retail energy sales shall be supplied from renewable energy sources. In addition, OPPD shall:

- Conduct its business in a manner that meets all environmental regulatory standards and enhances natural resource conservation and stewardship;
- Participate and provide leadership in the development of national, state, and regional environmental policies and initiatives that support OPPD's mission;
- Promote the efficient use of energy as a Company and by its customer-owners; OPPD shall, at the pace of value or in response to actual or anticipated environmental regulatory requirements, incorporate renewable generation into its generation portfolio;
- Proactively engage its customer-owners and other stakeholders in meeting this directive.

SD-9 Resource Planning - The Board of Directors recognizes that OPPD will have to adapt to the rapidly changing electric utility environment. As a result, OPPD's resource planning organization will provide the resources and analytical capability to adequately assess OPPD's Integrated Resource Portfolio (or Supply and Demand Portfolio) to ensure reliable, competitive, cost-effective and environmentally sensitive service for our customers.

To attain this directive, OPPD shall:

- Periodically assess, for strategic and integrated resource plans, OPPD's mix of generation assets, demand-side management programs, purchased power agreements and renewable energy resources.
- Utilize multiple scenarios to properly evaluate the range of risks posed by varying future assumptions such as, but not limited to, fuel costs, economic growth, regulations and emerging technologies.
- Ensure all integrated resource strategic plans support and align with OPPD's Strategic Directives.

SD-11 Economic Development - A critical component of a region's growth is low-cost and reliable electricity delivery. As a result, OPPD deploys a low-cost optimization approach to its resource planning to partner to facilitate the growth of current customers as well as attract prospective customers looking to locate in the service territory.

SD-13 Stakeholder Outreach and Communication - As a publicly owned utility, OPPD is committed to providing its customer-owners and other stakeholders with important educational information to assist with energy management and promote energy efficiency and safety. OPPD shall:

- Provide ongoing education to its customer-owners on the efficient use of energy.
- Seek input from its stakeholders on important company initiatives through a formalized stakeholder process, which will include input from stakeholders across its service territory.
- Provide various communication and community outreach methods that reflect the diversity of OPPD's customer-owners and other stakeholders. OPPD is committed to continually research more effective ways to communicate and share important information.
- Commit to continually research more effective ways to communicate and share important information.

SD-15 Enterprise Risk Management – In support of OPPD's Enterprise Risk Management efforts, the IRP team performed stochastic modeling and established well-reasoned, risk-based parameters to identify, understand and mitigate risks.

1.3 Stakeholder Process

OPPD engages stakeholders in important matters that support our mission to provide affordable, reliable and environmentally sensitive energy services to our customers. OPPD also operates its business around a number of strategic directives, including SD-13 Stakeholder Outreach and Communication. Through this directive, we are committed to providing stakeholders with important information and feedback opportunities.

As part of the 2016 IRP, OPPD utilized electronic, written and in-person efforts to engage stakeholders and customer-owners and proactively solicit feedback on the process and the results. Four sample portfolios were modeled and analyzed (Blue, Yellow, Orange and Pink). Specifically, the 30-day outreach efforts included information on portfolio changes that OPPD made since its last IRP was produced in 2011.

The portfolios had unique attributes, from varying levels of renewable generation types, to different renewable generators, to incorporation of utility-scale battery technology. Each of these portfolios had unique attributes of cost and emissions that were core features presented during the stakeholder process. An explanation of OPPD's robust 300MW Demand Side Management program was also highlighted in the stakeholder materials.

Through the stakeholder process, OPPD communicated IRP information through social media, OPPD websites and content marketing sites, customer newsletters and open houses, which included access to subject-matter experts. Through these efforts, OPPD was able to educate and collect feedback from a number of customer-owners. Specific results of the stakeholder process are discussed in greater detail in Section 6.0, Stakeholder Engagement.

1.4 Renewable Energy

A cornerstone in OPPD's mission is to provide environmentally sensitive energy. In pursuit of this objective, OPPD has continually invested in renewable energy resources. In 2010, renewable generation served only 4% of OPPD's total retail sales. In 2016, as a percentage of retail sales, renewable generation served 16% of OPPD's total customer load demands, and this percentage is expected to grow to 30% by the end of 2018. The 2016 IRP considers additional renewable generation into OPPD's portfolio that could increase renewable generation to 50% of OPPD's total retail sales by 2021.

OPPD has sought to adopt renewable resources at the *pace of value* for customers and has added renewable resources according to the economic potential. Principally, renewable additions to OPPD's portfolio have included wind generation due to Nebraska's high wind potential. The 2016 IRP evaluates the expected impact of adding new wind generation, as well as new utility scale solar generation, into OPPD's resource portfolio. OPPD is currently evaluating a potential, participation-based, community solar project. Preliminary details on this project can be found in Section 2.10 Community Solar Project, of this report.

1.5 Fort Calhoun Station Retirement

At its June 16, 2016 meeting, the Board of Directors approved Management's recommendation that OPPD cease operations at Fort Calhoun Station (FCS) by the end of 2016. The recommendation to cease operations at FCS was the outcome of a detailed assessment that demonstrated continued operation of FCS would result in costs materially in excess of the cost of obtaining power from other sources. Management's recommendation stated that the cessation of operations at FCS will mitigate the need for further general rate increases through 2021 and will have significant favorable financial implications to OPPD, including an improved competitive position, increased financial liquidity, stable debt service coverage and reduced regulatory and operational risks. This decision will better position OPPD to maintain flexibility, as well as reduce its cost and operational risk.

OPPD ceased electricity generation at FCS on October 24, 2016, and completed the defueling outage in November 2016. To address the lost accredited capacity from closing FCS, OPPD has sourced a number of capacity contracts from other SPP participants and retained the use of NO1, NO2, and NO3 units on natural gas for capacity accreditation purposes. Currently, OPPD is working to submit its decommissioning plan to be filed with the Nuclear Regulatory Commission (NRC) as a part of OPPD's Post Shutdown Decommissioning Activities Report (PSDAR).

1.6 Portfolio Analysis and Findings

The development of the 2016 IRP is supported by a rigorous quantitative analysis that optimizes OPPD's future resource portfolio under a large number of possible future market conditions. The analysis builds on 'best-in-class' generation dispatch modeling software with innovative approaches to capture future market risks. In support of the analysis, OPPD engaged Pace Global, Inc. (PACE), a subsidiary of Siemens, Inc. to support modeling efforts of the 2016 IRP using the Aurora XMP modeling software.

The analysis consisted of development of modeling assumptions, including the valuation of future carbon for Clean Power Plan (CPP) purposes, portfolio optimization, detailed deterministic modeling and stochastic modeling to better understand portfolio risks. The analysis focused on many, diverse future environments by deliberately introducing meaningful levels of volatility to OPPD's cost of fuels, which varied resultant power prices, as well as varying levels of system load over more than 200 portfolio iterations. After all the modeling iterations, OPPD measured cost, emissions and financial risk to customer-owners.

The results of the 2016 IRP analysis indicate that continued investment in renewable resources, specifically in wind generation, will provide OPPD with a lower average operating cost and a lower financial risk portfolio. During the IRP period from 2017 to 2021, any potential accredited capacity shortfalls due to the early retirement of Fort Calhoun Station are most economically satisfied with near-term capacity contracts and of the availability of North Omaha Station Units 1-3 on natural gas fuel.

OPPD is cognizant that its planning efforts will need to become increasingly flexible, integrated and holistic as technology advances and the grid becomes more complex as a result of changing customer preferences and growing participation levels of distributed energy resources. The assumptions made in planning analysis will be reevaluated and refined on a regular basis.

2.0 OPPD Past and Present

2.1 Omaha Public Power District Background

OPPD was created in 1946 under the authority of the Enabling Act as a public corporation and political subdivision of the State of Nebraska (State). The laws of the State provide that OPPD, either alone or jointly with other entities lawfully empowered to do so, may acquire, by purchase, lease or otherwise, and may operate, improve and extend electric properties and facilities and otherwise carry on the business of generating, transmitting and distributing electric power and energy within or beyond the boundaries of OPPD, and may also do such other things as are necessary for carrying on a fully integrated electric power business.

OPPD provides electric service in the city of Omaha, Nebraska, and adjacent territory comprising all of Douglas, Sarpy and Washington counties. It also serves portions of Cass, Saunders, Dodge, Otoe, Nemaha, Johnson, Pawnee, Richardson, Burt and Colfax counties. The service territory also includes the community of Carter Lake, Iowa, which is served directly from OPPD's Omaha distribution system. The service area is approximately 5,000 square miles with an estimated population of 819,752 as of December 31, 2016. Omaha, with an estimated population of 443,885, from a 2015 Census Population Estimate, is the largest city in the State. OPPD also serves 47 cities and villages at retail and five municipalities at wholesale.

For the 12 months ending December 31, 2016, the average number of customers served by OPPD was 364,790, which included 323,784 residential, 45,537 commercial, 164 industrial and 15 customers located outside of OPPD's service area (i.e., off-system customers). For the 12 months that ended December 31, 2016, OPPD's approximate retail revenue (i.e., excluding wholesale and off-system customers) was derived from 44% of sales to residential customers, 34% from sales to commercial customers and 22% from sales to industrial customers.

2.2 Transmission and Distribution System

OPPD maintains a network of transmission lines that interconnect its generating stations and adjacent utilities to the various transmission and distribution substations serving the load of OPPD. In general, this network provides at least two alternate sources of supply to each load point on the system. A summary of the various transmission lines, as of December 31, 2016, making up this network are as follows:

Table 1 - OPPD Transmission System

Voltage	Number of Circuit Miles
345 kV	418
161 kV	420
69 kV	489
Total	1,327

The distribution system includes approximately 6,851 miles of overhead distribution lines, 854 miles of street light overhead circuits, 4,762 miles of underground cable, 1,791 miles of street light underground circuits and 279 miles of underground conduit system, which delivers power to OPPD's retail customers. The distribution system includes overhead and underground lines, low-voltage transformers, meters and service facilities for operating and maintaining the system.

The distribution system support facilities include service centers located in Papillion, Elkhorn, Syracuse and Omaha. These service centers are supported by area offices throughout OPPD's service territory and include office, garage, storeroom and service facilities.

OPPD is subject to oversight by the North American Electric Reliability Corporation (NERC), which ensures the reliability and protection of OPPD's transmission and distribution system. Regarding compliance to the NERC Reliability Standards, no potential violations or mitigation plans are currently being reviewed by OPPD's Regional Entity, the Midwest Reliability Organization (MRO).

OPPD is part of a network of transmission lines known as the Eastern Interconnection. OPPD's transmission facilities are physically interconnected to the transmission facilities of the neighboring utilities. These connections are managed under interconnection agreements with each utility. These interconnections are capable of supplying capacity under emergency conditions in excess of the capacity of North Omaha Station (NOS) and Nebraska City Station (NCS). In addition to emergency energy service, OPPD can utilize these interconnections to provide for firm and participation power purchases and sales, short-term power and interchange of energy, and transmission and ancillary services. These services can be purchased under an Open Access Transmission Tariff or under an enabling agreement. The tariff or enabling agreement specifies the terms and conditions of purchases or sales and allows transactions to take place at market based prices.

2.3 Southwest Power Pool

The Southwest Power Pool (SPP) is based in Little Rock, Ark., and was created in 1941 to provide electric reliability and coordination for 11 regional power companies. SPP has since expanded its scope of services and was approved as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC) in 2004. The services that SPP currently provides for its membership include (1) transmission tariff administration; (2) transmission expansion planning; (3) reliability coordination; (4) wholesale energy market operations and Integrated Marketplace; (5) consolidated balancing authority; and (6) generation reserve sharing. In 2016, SPP celebrated its 75th anniversary and today employs approximately 600 employees and operates a system footprint spanning across 14 states.

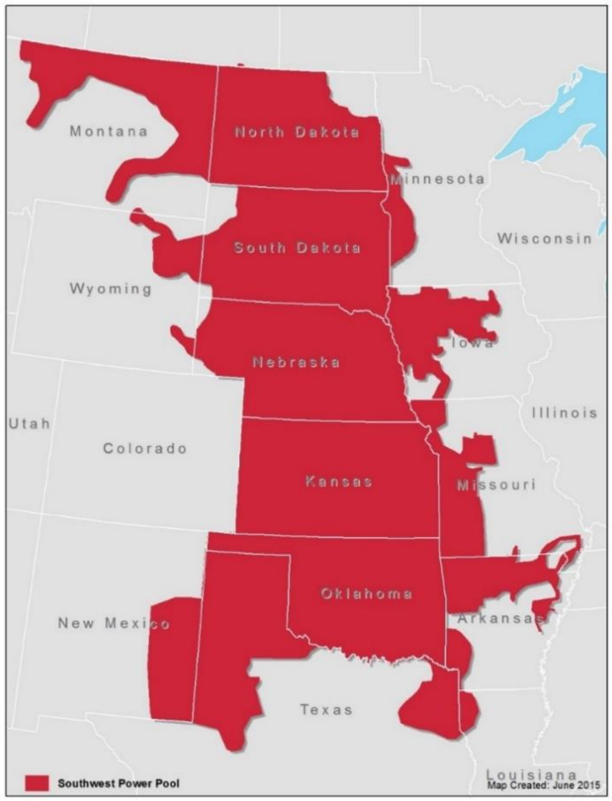


Figure 1- SPP Integrated Marketplace as of October 2015

On April 1, 2009, OPPD became a transmission-owning member of the Southwest Power Pool. OPPD actively participates in SPP working groups to develop improvements and amendments to SPP governing documents and to provide assistance in the development of transmission system study models for transmission expansion planning. At the time of joining, all of OPPD's transmission facilities were placed under the SPP Open Access Transmission Tariff. OPPD no longer grants new transmission service requests under its own transmission tariff. Transmission services granted prior to becoming a member of SPP remain on OPPD's tariff as 'Grandfathered Agreements' for the original term of service. Any extension of service will be under the SPP Tariff. New generation interconnection requests to connect to OPPD's transmission facilities must be submitted to SPP for approval.

In addition to OPPD, there are two Nebraska utilities (Lincoln Electric System and Nebraska Public Power District) that have membership in SPP, and these utilities' transmission systems are also under the SPP RTO authority. The SPP transmission planning process identifies new transmission projects across Nebraska and the SPP footprint that are expected to relieve congestion on the region's transmission system, improve reliability on the nation's energy grid and support future generation additions. These transmission additions should contribute to making additional wind generation feasible with regards to deliverability to OPPD's system.

SPP regional transmission expansion planning studies include consideration of large-scale renewable energy integration, which is intensified by the extension of the federal production tax credits and the projected EPA Clean Power Plan impacts on the system.

The SPP regional transmission planning process evaluates an array of potential futures with more recent studies examining the status quo, a low-carbon emissions future using aspects of the EPA's Clean Power Plan and a future with reduced baseload capacity. Some futures are better satisfied with the addition of renewables. Recent studies are incorporating lower load growth forecasts that are widely shared by SPP members, as well as the tremendous growth already experienced in renewable generation.

This process has identified the need for a 180-mile, 345kV power transmission line known as the Midwest Transmission Project that was built by OPPD, Transource Missouri and Kansas City Power and Light. This transmission project, spanning from a substation at the NCS to Sibley, Mo., was energized and placed in-service December 2016. The project will receive funding under the SPP Open Access Transmission Tariff (OATT). Another project identified in the SPP transmission planning process includes the Nebraska 'r' Plan, which is an approximately 270- mile new 345kV transmission line in west and north-central Nebraska that is projected to be in-service by fall of 2018.

The SPP transmission planning process has also identified the need for a 161kV transmission line interconnecting OPPD's transmission system to the City of Fremont, Neb. The need is driven by long-term load growth served by the City of Fremont and the load served by OPPD in the Fremont area. OPPD will design and construct the 18 miles of transmission and assume full ownership of the transmission line following construction, which is scheduled for completion in 2019. OPPD and the city of Fremont will share the costs of the line, estimated to be $35 million. OPPD's share will be approximately $14 million or 40% of the total cost. Additionally, OPPD will receive reimbursement for one-third of its costs under the SPP OATT approved tariff. This reimbursement will occur over a 32-year period.

2.4 SPP Integrated Marketplace

OPPD participates as a Market Participant in the SPP Integrated Marketplace and offers its generation resources and bids its load into the market. The SPP Integrated Marketplace seeks to utilize the most economical generation resources to serve the electric system load in the SPP footprint while maintaining system reliability. The Integrated Marketplace has both a Day-Ahead (DA) Market and a Real-Time (RT) Market. For the subsequent day, market participants offer generation resources into the DA Market based on cost and availability, and bid in load based on forecasted demand. The SPP DA market engine simulates grid flows and generation resource commitments to most economically and reliably serve the load, resulting in binding financial obligations. In real time, generation resources are physically committed based on real-time system conditions to most economically and reliably serve the actual system load. Real-time system conditions may differ from projections entered into and settled in the DA Market. Generation and load deviations between the DA Market and the RT Market are charged or credited to Market Participants at the RT Market price. Generally speaking, OPPD's fossil and renewable assets are very competitive within the SPP Integrated Marketplace.

2.5 Summary of Generating Facilities

OPPD's power requirements are provided from its generating facilities, leased generation and purchases of power. OPPD's all-time peak load is 2,468,300 kW, set on August 1, 2011. The following table reflects the preliminary results of OPPD's generation facilities displayed by energy source as of December 31, 2016.

Table 2- OPPD Generation Summary

	Initial Date in Service	Capability[1] (kW)	% of Total	Net Production[2] Amount (MWh)	Net Production[2] % of Total	Availability Factor[2]
Coal:						
Nebraska City Station Unit 1	1979	655,900	20.0	4,025,318.1	24.1	81.1
Nebraska City Station Unit 2[3, 5]	2009	664,200	20.2	5,060,879.9	30.2	98.4
North Omaha Station[4]	multiple	264,600	15.6	2,029,760.3	12.1	73.4
Subtotal Coal		1,584,700	55.8	11,115,958.3	66.4	
Nuclear:						
Fort Calhoun Station	1973	482,800	14.6	3,423,068.7	20.5	87.0
Oil/Natural Gas:						
Cass County Station	2003	322,800	9.9	28,253.0	0.2	88.7
Jones Street Station	1973	122,600	3.7	(123.2)	0.0	95.3
North Omaha Station[4,8]	multiple	137,200	3.5	19,630.8	0.1	73.4
Sarpy County Station[6]	multiple	316,500	9.6	52,766.6	0.3	95.0
Subtotal Oil/Natural Gas		899,100	26.7	100,527.2	0.6	
Other:						
Elk City Station (Methane Gas)		6,280	0.2	49,199.0	0.3	
Total Owned Accredited Generation		2,972,880	97.3	14,688,753.2	87.8	
Purchased/Leased Generation:						
City of Tecumseh, Nebraska (Oil)		6,500	0.2	332.5		
Western Area Power Administration (Hydro)		82,000	2.5	379,194.0		
Subtotal Purchased/Leased Generation		88,500	2.7	379,526.5	2.3	
Total Accredited Generation		3,061,380	100.0	15,068,279.7		
Wind[7]						
Valley (OPPD-owned)		660		770.8		
Ainsworth		10,000		29,740.1		
Broken Bow I		18,000		70,261.8		
Crofton Bluffs		13,600		57,221.2		
Elkhorn Ridge		25,000		81,252.4		
Flat Water		60,000		216,682.9		
Petersburg		40,500		162,133.0		
Broken Bow II		43,900		199,821.4		
Prairie Breeze		200,600		841,240.7		
Total Non-accredited Generation		412,260		1,659,124.3	9.9	
Total Generation Produced				16,727,404.0	100.00	

(1) Maximum 2016 summer accredited net capability.
(2) Actual net production and availability factor as of December 31, 2016.
(3) 50% of the output is sold to seven participating utilities through long-term Participation Power Agreements.
(4) Station consists of five units placed in service in 1954, 1957, 1959, 1963 and 1968. North Omaha Units 1, 2, and 3 have been converted to natural gas fired peaking units.
(5) Nebraska City Station Unit 2 capacity derated approximately 27,000 kW after turbine failure and rotor modification.
(6) Station consists of five units placed in service in 1972, 1996 and 2000.
(7) Nameplate capacity. Wind accredited summer 2016 capability is 33.8MW.
(8) North Omaha Station additional summer capability using natural gas. In 2016 OPPD had a firm natural gas contract to provide limited accredited capability.

2.5.1 Nebraska City Station

Nebraska City Station (NCS), located approximately five miles southeast of Nebraska City, Neb., consists of two, coal-fired steam generator units, NCS Unit No. 1 (NC1), and NCS Unit No. 2 (NC2).

NC1 consists of coal pulverizers, subcritical reheat boiler, wall-fired low NOx coal burners, natural gas and fuel oil igniters, steam turbine, steam condenser supplied by once through cooling with river water, air preheaters, electrostatic precipitators for emissions control, dry sorbent injection for flue gas conditioning and emissions control, and activated carbon injection for mercury emissions control.

NC2 consists of coal pulverizers, subcritical reheat boiler, wall-fired low NOx coal burners, natural gas and fuel oil igniters, steam turbine, steam condenser supplied by cooling water from a cooling tower, air preheaters, SCR with ammonia injection for NOx emissions control, dry scrubber for SO_2 emissions control, and activated carbon injection for mercury emissions control.

OPPD retrofitted NC1 with dry sorbent injection and activated carbon injection emissions control systems in 2016 to comply with the Mercury and Air Toxics Standards (MATS).

NC2 was removed from service on November 28, 2014, due to significant vibration on the High Pressure/Intermediate Pressure (HP/IP) section of the turbine which was caused by failure of the 10th stage stationary diaphragm. After opening the HP/IP turbine it was discovered that rotating stages 9 through 11 of the IP turbine were severely damaged, along with significant damage to the adjacent stationary diaphragms. The IP turbine was repaired and the unit was returned to commercial operation on March 12, 2015. In order to facilitate a timely return to service, the damaged rotor was repaired with significant modifications. The modified design has resulted in a 27MW reduction in capability. OPPD is planning to replace the repaired turbine during a planned outage in 2017 in order to restore the lost capability.

OPPD owns, operates, and maintains NC2. Fifty percent of the station's output is used by OPPD to meet customer load requirements. OPPD has executed long-term Power Purchase Agreements (PPAs) with seven public power and municipal utilities, known as the Participants, located in Nebraska, Missouri and Minnesota for the remaining 50% of the unit output.

The Participants and their percentage share of NC2's output are as follows:

Table 3 - Nebraska City Unit 2 Participant Shares

Participants	Percentage Share
Central Minnesota Municipal Power Agency	2.17
City of Grand Island, Nebraska, Utilities Department	5.00
City of Independence, Missouri, Power & Light Department	8.33
Falls City, Nebraska, Utilities	0.83
Missouri Joint Municipal Electric Utility Commission	8.33
Nebraska City, Nebraska, Utilities	1.67
Nebraska Public Power NPPD	23.67
Participants' Total	50.00
Omaha Public Power OPPD	50.00
NC2 Total	100.00

2.5.2 North Omaha Station

North Omaha Station (NOS), located in the north section of the City of Omaha, consists of five steam generator units equipped for coal and natural gas firing. All five units have coal pulverizers, subcritical reheat boilers, coal burners (low NOx burners on NO5), natural gas igniters and burners, steam turbines, steam condensers supplied by once through cooling with river water, air preheaters, and electrostatic precipitators for emissions control. Several maintenance and inspection outages were completed at NOS during 2015 and 2016 to improve station safety, efficiency and reliability.

In June 2014, OPPD's Board of Directors approved changes to its generation portfolio, including NOS. The Board of Directors approved the retirement of NOS Units 1, 2 and 3 (NO1, NO2 and NO3, respectively) in 2016. NO1, NO2, and NO3 were retired from coal operation in April of 2016, and all coal supply-related equipment was disconnected from the units. As a result of the Board of Directors action related to Fort Calhoun Station in June 2016, OPPD is using existing natural gas generating capability for NO1, NO2, and NO3 for capacity accreditation purposes.

Retrofitting of NO4 and NO5 with dry sorbent injection and activated carbon injection emissions control systems was completed on April 16, 2016. This retrofit was completed to comply with the MATS rule.

2.5.3 Fort Calhoun Station

Fort Calhoun Station (FCS) is a retired and defueled nuclear electric generating station with a pressurized water reactor situated along the Missouri River, approximately 20 miles north of the city of Omaha in the vicinity of Fort Calhoun, Neb.

OPPD ceased electricity generation at FCS on October 24, 2016, and completed the defueling outage in November 2016. Currently, OPPD is working to submit the Post Shutdown Decommissioning Activities Report, which will outline OPPD's plan to decommission the facility.

2.5.4 Elk City Station

The Elk City Station, located near Elk City, Neb., is a renewable energy facility that uses methane gas from the Douglas County Landfill to produce electricity. The capacity of the Elk City Station methane gas facility is 6.4MW and the facility has an accredited net capability of 6.28 MW.

2.5.5 Peaking Stations

In addition to the converted units at North Omaha, OPPD owns three oil/natural gas peaking stations that provided less than 1% of net generation in 2016 while accounting for approximately 25% of OPPD's system accredited capacity.

Cass County Station. Cass County Station (CCS), located near Murray, Neb., consists of two combustion turbine units equipped for natural gas firing, primarily used for peaking purposes. The combustion turbine units are tied into two natural gas transportation pipeline systems enhancing competition between fuel suppliers.

Jones Street Station. Jones Street Station (JSS), located near downtown Omaha, consists of two combustion turbine units equipped for oil firing and is primarily used for peaking purposes and during situations when natural gas is not available to the other peaking stations.

Sarpy County Station. Sarpy County Station (SCS), located in Bellevue, Neb., consists of five combustion turbine units equipped for oil or natural gas firing, primarily used for peaking purposes. The ability to operate SCS on fuel oil provides fuel diversity in situations when natural gas may not be available.

2.5.6 Wind Facilities

OPPD's total nameplate wind capacity was 412.26MW as of December 2016. On or before July of 2017, OPPD will begin purchasing generation from the Grande Prairie wind facility with a nameplate capacity of 400MW. The majority of this generation is provided through OPPD's participation in 20-year and 25-year PPAs to purchase output from the wind facilities listed below. As of December 2016, OPPD has the following commitment amounts for its purchase power agreements:

Table 4- OPPD Existing Purchased Power Wind Agreements

Wind Facility	Location	Initial Contract Year	Total Size (kW)	OPPD's Share (kW)	2016 Capacity Factors	Contract Type	Final Year
Ainsworth[1,2]	Ainsworth, NE	2005	59,400	10,000	33.9%	Take-or-pay[3]	2025
Elkhorn Ridge[1]	Bloomfield, NE	2009	80,000	25,000	37.0%	Take-and-pay[4]	2029
Flat Water	Humboldt, NE	2010	60,000	60,000	41.1%	Take-and-pay	2030
TPW Petersburg	Petersburg, NE	2011	40,500	40,500	45.6%	Take-and-pay	2031
Crofton Bluffs[1]	Crofton, NE	2012	42,000	13,600	47.7%	Take-and-pay	2032
Broken Bow I[1]	Broken Bow, NE	2012	80,000	18,000	44.4%	Take-and-pay	2032
Broken Bow II[1]	Broken Bow, NE	2014	75,000	43,900	51.8%	Take-and-pay	2039
Prairie Breeze	Petersburg, NE	2014	200,600	200,600	47.8%	Take-and-pay	2039

Ainsworth. OPPD purchases wind energy from a 10MW (16.8%) share of the 59.4MW NPPD wind energy facility near Ainsworth, Neb. This facility began commercial operation on September 15, 2005.

Elkhorn Ridge. OPPD began receiving wind energy from Elkhorn Ridge wind facility in March 2009, adding 25MW to OPPD's renewable portfolio. The total facility is sized at 80MW nameplate capacity and is near Bloomfield, Neb., in Knox County. The Elkhorn Ridge wind facility is owned by NRG Energy. NPPD subcontracts OPPD's share along with the other participants' shares. The facility began commercial operation March 1, 2009, and is composed of 27, 3MW sized Vestas turbines.

Flat Water. The Flat Water Wind facility is a 60MW facility comprised of 40, 1.5MW GE turbines. OPPD is the sole purchaser. Flat Water is located in OPPD's service territory in southwest Richardson County, Neb., near State Highway 105 and interconnects with OPPD's 161 kV transmission system. The facility is owned by Gestamp Wind. Commercial operation began December 21, 2010.

TPW Petersburg. The Petersburg Wind Facility began commercial operation on November 1, 2011. OPPD has an agreement with Gestamp Wind to purchase 40.5MW of nameplate wind energy. Petersburg Wind Facility is located near the city of Petersburg, Neb. The

1OPPD is a participant with Nebraska Public Power (NPPD).

2In the event another power purchaser defaults, OPPD is obligated, through a step-up provision, to pay a share of any deficit in funds resulting from the default. In the event NPPD receives any financial incentive payments from the United States Department of Energy (DOE") pursuant to the Renewable Energy Production Incentive (REPI") program, OPPD will be entitled to its share of such payments.

3OPPD is obligated under the agreement to make payments for purchased power even if the power is not available, delivered to, or taken by OPPD.

4OPPD is obligated under the agreement to make payments for purchased power only when the power is made available to OPPD.

facility is composed of 27, 1.5MW GE turbines. OPPD is the sole purchaser of the energy from this wind facility.

Crofton Bluffs. The 22–turbine Crofton Bluffs Wind Facility, located southwest of Crofton, Neb., began commercial operation on November 1, 2012. Two turbines have a maximum capacity of 3.0MW, and 20 turbines have a maximum capacity of 1.8MW for a total of 42MW. NPPD subcontracts OPPD's share along with the other participants' shares. The participants in the wind facility are: Nebraska Public Power District (21MW); Omaha Public Power District (13.65MW); the Municipal Energy Agency of Nebraska (4MW); and Lincoln Electric System (3MW).

Broken Bow I. The 50–turbine Broken Bow I Wind Facility in Custer County began commercial operation on December 1, 2012. The facility is currently owned by NRG Energy. Each turbine has a maximum capacity of 1.6MW for a total of 80MW. NPPD subcontracts OPPD's share along with the other participants' shares. The participants in the wind facility are: Nebraska Public Power District (51MW); Omaha Public Power District (18MW); Lincoln Electric System (10MW); and the City of Grand Island (1MW).

Broken Bow II. The 43–turbine Broken Bow II Wind Facility is located near Broken Bow, Neb. Maximum capacity is 75MW. NPPD subcontracts OPPD's share along with the other participant's shares. Nebraska Public Power District has committed to buy the total 75MW and will keep 30MW but sell 45MW to OPPD. OPPD purchases the remaining capacity of 43.9MW. Commercial operation began October 1, 2014.

Prairie Breeze. The 118-turbine Prairie Breeze 1 Wind Facility is located near Elgin, Neb. The facility is owned by Sun Edison and has a maximum capacity is 200.6 MW. OPPD is the sole purchaser of the energy from the Prairie Breeze 1 facility, and commercial operation began May 1, 2014.

Grande Prairie. Grande Prairie Wind Facility is owned by Berkshire Hathaway Energy (BHE) Renewables and is located near O'Neill, Neb., in Holt County. It consists of 200 2MW turbines and has a maximum capacity of 400MW. The 400MW from Grande Prairie will be sold to OPPD on July 1, 2017, or sooner if firm transmission can be acquired. Commercial operation began December 1, 2016.

Valmont Valley Prototype. In addition to the wind facilities discussed above, OPPD's first renewable energy project was the installation of a 6.6MW Vestas Wind Turbine in a joint project with Valmont Industries. This turbine was put into commercial service on December 21, 2001, at a site near Valley, Neb. Initially, it involved a prototype tower and lift system designed by Valmont with the goal of making utility wind projects more economical by reducing construction and maintenance costs. The prototype tower was replaced with a new structure and returned to operation in June 2003. Currently, the Valmont Valley Prototype has ceased operations and will be decommissioned.

2.5.7 Future Generating Facilities

OPPD entered into a 20-year PPA with Grande Prairie Wind Energy, LLC in January 2014 to purchase up to 400MW of wind generated energy from the Grande Prairie Wind Facility located northeast of O'Neill, Nebraska. The new facility was operational in December of 2016 and OPPD is obligated to purchase the output no later than July 1, 2017.

The completion of the Grande Prairie Wind Facility will increase OPPD's renewable capability to 818.6MW and is expected to increase renewable energy to approximately 30% of retail sales by the end of 2018. That percentage surpasses all of OPPD's previously announced corporate goals and will also position OPPD as one of the top utilities in the region for percentage of retail sales from renewable resources.

2.6 Fuel Supply

OPPD currently utilizes three primary fuel sources (coal, natural gas and fuel oil) for current traditional generation resources. With the closure of Fort Calhoun Station, OPPD will no longer procure nuclear fuel. This section provides more detailed information on each fuel source. OPPD's fuel supply risk is managed with a combination of inventories, company-owned rail lines, and contractual agreements with railroad, coal mining, and natural gas utility and pipeline companies.

2.6.1 Coal. OPPD currently has term contracts with Peabody Coal Sales and Arch Coal Sales, expiring in 2019 and 2018, respectively. The bankruptcy filing of Peabody Coal Sales and Arch Coal Sales are not expected to adversely affect coal supply operations to OPPD. Rail transportation services are provided under a contract with Union Pacific Railroad Company for the delivery of all coal through 2020. OPPD owns 57 miles of rail line extending from NCS to Lincoln, Neb (Rail Spur). The Rail Spur provides competitive access to NCS from Union Pacific Railroad Company and Burlington Northern Santa Fe Railroad Company. In order to maintain the Rail Spur, OPPD has a rail maintenance contract with Kelly Hill Company through 2020.

OPPD targets an approximate 42-day coal supply for its NCS. The average price per ton for coal delivered and the total amount delivered to OPPD's NCS for 2014 and 2015 were as follows. At the time of this report, 2014 and 2015 information are the latest available.

Table 5 - 2014 and 2015 Average Delivered Coal Price, Nebraska City Station

Year Ended	Average Price	Tons
2015	$23.10	4,861,801
2014	$23.45	5,461,443

OPPD also targets an approximate 42-day coal supply for its NOS. The average price per ton for coal delivered and the total amount delivered to OPPD's NOS for 2014 and 2015 were as follows. At the time of this report, 2014 and 2015 information are the latest available.

Table 6 - 2014 and 2015 Average Delivered Coal Price, North Omaha Station

Year Ended	Average Price	Tons
2015	$22.17	2,061,835
2014	$22.14	1,980,628

The coal for both NCS and NOS is delivered to the sites by seven OPPD-owned unit trains totaling 1,018 coal cars.

2.6.2 Natural Gas. Natural gas from the Metropolitan Utilities District (MUD) is available on an interruptible basis for power station fuel at NOS and SCS. Firm natural gas contracts have been negotiated for the start-up process at NOS and to generate electricity at NO1, NO2, and NO3 for the summers of 2017 and 2018. CCS and NCS are located outside of MUD's service territory and therefore do not receive natural gas services from MUD. CCS is connected to two natural gas transportation pipeline systems, Northern Natural Gas Company and Natural Gas Pipeline Company of America, adjacent to the CCS site. These interconnections enhance competitive pricing between the two pipeline systems. OPPD has both firm and interruptible natural gas transportation contracts for CCS. The firm natural gas contract for CCS is for summer months only, with the exception of the 2016-2017 winter season when firm gas for one unit was obtained. This was to ensure OPPD met its capacity requirements through the winter after the FCS closure. A natural gas pipeline was constructed and placed in operation from Nebraska City Utilities to NCS to provide fuel for start-up in lieu of fuel oil. In addition, OPPD contracts natural gas storage for hedging purposes.

2.6.3 Fuel Oil. As of December 31, 2016, OPPD had approximately 213,698 gallons of No. 2 fuel oil in storage at the JSS and approximately 694,835 gallons of No. 2 fuel oil in storage at the SCS. The oil in storage provides sufficient fuel to operate OPPD's oil burning peaking units at their full load of 436.4MW (summer net capability) for approximately 25 hours at SCS and 16 hours at JSS. OPPD has access to pipeline terminals in the area for immediate replenishment, if needed. Fuel oil consumption is expected to be less than one million gallons per year with the addition of the NCS natural gas pipeline discussed in Section 2.6.2 Natural Gas. It is anticipated that less than 1% of the energy generated by OPPD for each of the next 10 years will be produced with fuel oil.

2.6.4 Nuclear. Due to the decommissioning of FCS, OPPD is pursuing the termination of all nuclear fuel acquisition contracts.

In June 1983, OPPD and the Department of Energy (DOE) entered into a contract for the disposal of OPPD's spent nuclear fuel. Under the adjusted terms of the contract, OPPD is subject to a fee of one mill ($0.001) per kWh on net electricity generated and sold from FCS. This one mill fee is paid on a quarterly basis to the DOE. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit entered an order requiring the Secretary of Energy to submit to Congress a proposal to reduce the nuclear waste fund fee levy to zero until such a time as either (1) the Secretary completes a fee adequacy study that complies with the Nuclear Waste Policy Act or (2) Congress enacts an alternative waste management plan. The DOE temporarily ceased collection of the one mill per net kWh fee effective May 16, 2014. To date, the total amount paid to the DOE is $113,990,000.

Spent fuel disposal costs are included in OPPD's nuclear fuel amortization rate and are collected from customers as part of fuel costs. It is unclear, at this time, when a DOE spent fuel disposal facility will be operational. OPPD is responsible for the storage of spent fuel until the government takes delivery. OPPD completed construction of an on-site dry cask storage facility to meet interim storage needs for the spent fuel bundles. This facility can be expanded and, along with the existing spent fuel pool storage racks, will provide the necessary on site storage.

2.7 Renewable Energy

In June 2007, OPPD established the Sustainable Energy & Environmental Stewardship Division (now merged into the Energy Production & Marketing Business Unit). One of the primary objectives of the Division was incorporation of environmentally friendly generating resources into OPPD's generation portfolio. In January 2009, OPPD announced a voluntary plan to increase the utilization of renewable generation resources and to reduce overall energy demand. The plan included a goal to produce 10% of the energy provided to OPPD's retail customers with renewable generation resources by 2020. By 2014, OPPD met its 10% goal with the additions of the Broken Bow II and Prairie Breeze wind facilities.

In January 2014, OPPD entered into a 20-year purchase power agreement with Grande Prairie Wind Energy, LLC to purchase up to 400MW of wind generated energy from the Grande Prairie Wind facility located northeast of O'Neill, Neb. The new facility commenced commercial operations on December 1, 2016, and OPPD is obligated to purchase the output no later than July 1, 2017. The completion of the Grande Prairie Wind Facility will increase OPPD's renewable capability to 818MW and increase renewable energy to approximately 30% of OPPD retail sales.

Currently, OPPD has 418MW of renewable generation nameplate capacity, primarily through power agreements. Total renewable generation as a percentage of retail sales was 16% as of the end of 2016. During 2016, OPPD's wind portfolio operated at over a 45% capacity factor.

Further, the Elk City Station, located near Elk City, Neb, is another renewable energy source that uses methane gas from the Douglas County Landfill to produce electricity. The capacity of the Elk City Station methane gas facility is 6.4MW, and the facility has an accredited net capability of 6.28MW.

OPPD also partnered with Creighton University in 2010 on an alternative energy project, using solar and wind energy collectors, which provides 0.120MW of power.

2.8 Demand-Side Management Programs

In June of 2014, the OPPD Board of Directors made a generation portfolio decision to begin a 300MW Demand Side Management program. The DSM measures selected for the 300MW target were a subset of energy and demand reduction measures identified in the Applied Energy Group, Inc. (AEG) potential study completed in 2014. The measures were selected based on their cost-effectiveness and customer preference with a focus on programs to reduce peak energy usage. This objective places emphasis on Demand Response (DR) programs, such as interruptible rates and direct load control, as well as programs that promote high-efficiency HVAC equipment.

Given the DSM objective of delaying future capacity and limiting rate impacts, the cost-benefit test chosen to screen DSM programs is the Ratepayer Impact Measure (RIM) as shown below:

$$\frac{Avoided\ Cost\ of\ Capacity + Avoided\ Cost\ of\ Energy}{Utility\ Costs + Revenue\ Reduction}$$

Although other tests are available to measure the cost effectiveness of a potential DSM program, the RIM measures what will happen to rates in relation to changes in revenues and costs associated with the programs. If a program's revenues exceed its costs, rates will decrease. This test assures that programs selected support OPPD's strategic objectives.

The DSM programs selected to reduce peak demand by 300MW are shown in Table 7. The table includes the name of the program, a brief description, the vintage (whether it is a new program, an existing program that is being expanded or a past program that is being reinitiated) and the year the program will commence. The estimated cost to achieve this reduction in peak demand is $157 million.

Table 7 - Descriptions of Planned DSM Programs

DSM Program	Description	Vintage	Planned Start Year
Residential Efficient HVAC	Provides incentives for high-efficiency HVAC equipment and operational optimization.	New	2015
Residential Income Qualified	Provides home-management education and fully subsidized energy-efficiency measures to income-qualified customers through existing local and regional agencies.	New	2015
Residential Direct Load Control	Achieves demand reductions by cycling and curtailing central AC units by way of a remote-controlled switch.	Expanded	2015
School Kit	Seeks long-term energy savings through enhanced education and awareness of energy efficiency among 5th grade students within OPPD's service territory.	Reinitiated	2018
Appliance Recycling	Offers a bounty payment to customers to remove their old, inefficient refrigerators, freezers and room AC.	Reinitiated	2018
Residential Multi-Family	Efficiency incentives and engagement options for two hard-to-reach populations: multi-family renters and multi-family landlords/property owners.	New	2018
Small Business Direct Load Control	Achieves demand reductions by cycling and curtailing central AC units by way of a remote-controlled switch.	New	2017
Business Prescriptive	Provides customer incentives to implement energy-efficient measures that have predetermined electrical demand-reduction values.	Expanded	2015
Business Custom	Provides incentives to qualifying projects based upon measures where electrical demand reductions are unique to their specific deployment.	Expanded	2015
Business Interruptible Rates	Firm interruptible tariffs with customers for periodic curtailments at times of system peak demand.	Expanded	2015
Business Curtailment Agreements	Firm contractual agreements for automated DR where pre-selected load-reduction strategies are automatically applied at customer site with no or little intervention.	New	2018
Direct Install	A suite of targeted, highly cost-effective measures to small businesses in a quickly deployable delivery mechanism, along with education and product support to help business customers reduce their energy bills.	New	2018

The cumulative peak demand savings for each of the DSM programs planned for the years 2015-2023 is shown in Figure 2. The estimated peak demand savings in 2015 is 98.2MW, reaching 310.3MW in 2023.

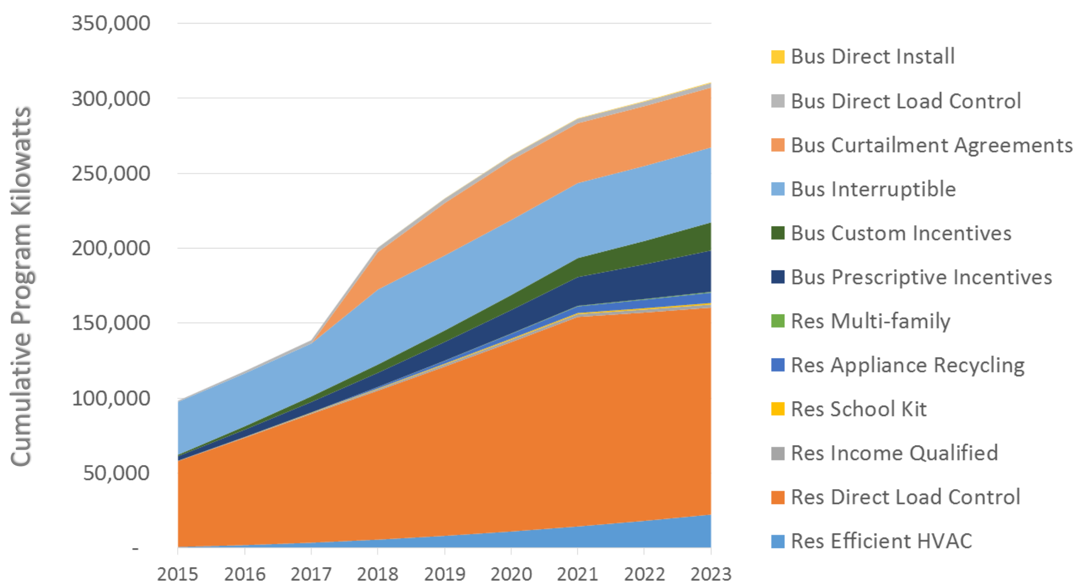


Figure 2 - Cumulative Peak Demand Savings (kW) for OPPD DSM Programs

The cumulative energy savings for each of the DSM programs planned for the years 2015-2023 is shown in Figure 3. The cumulative energy savings in 2015 is 11,874 MWh, reaching 173,020 MWh in 2023.

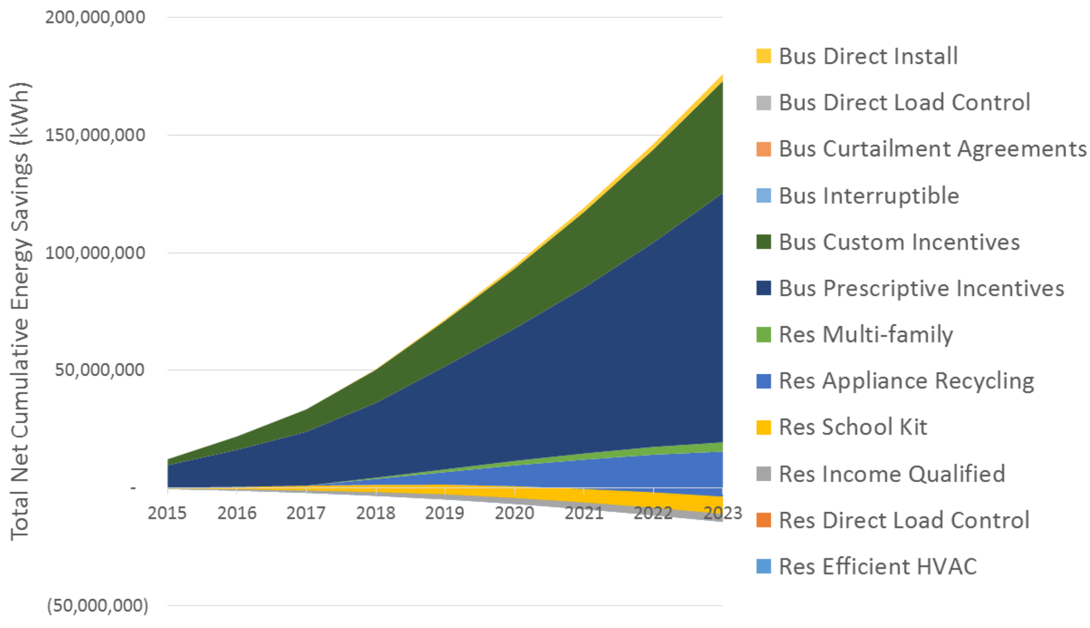


Figure 3 - Cumulative Energy Savings for OPPD DSM Programs

The estimated cost for each of the DSM programs planned for the years 2015-2023 is shown in Figure 4.

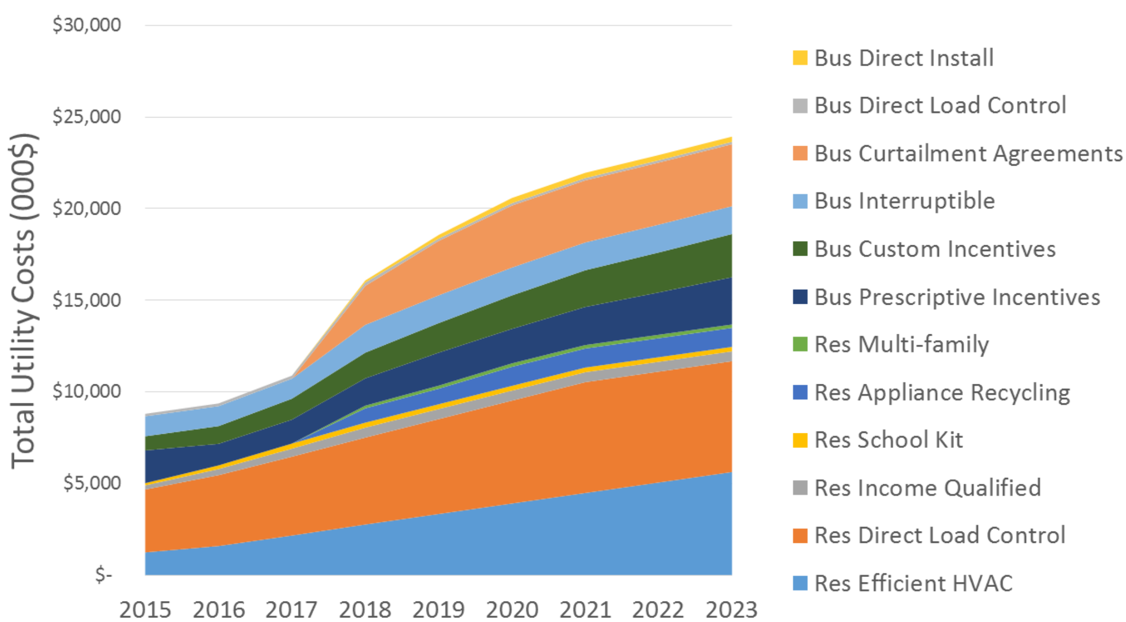


Figure 4 - Total Utility Costs for DSM Programs

2.9 Grid Modernization and Smart Grid Study

OPPD has evaluated, piloted and deployed automation technologies for the past two decades. In 2010, OPPD undertook a full-scale study to understand the complexities, costs and benefits of many different 'Smart Grid', behind the meter and other enabling technologies as shown below in Table 8.

Table 8- 2011 Smart Grid Study Technologies and Enablers

Advanced Distribution Management System	IT/OT Integration
Behind the Meter Devices	Meter Data Management System
Billing System Upgrades	Mobile Computing / GPS
Communication Infrastructure	Rate Strategies
Customer Portal	Smart Line Devices / Distribution Automation (DA)
DER and Renewable Integration	Smart Meters / Automated Meter Infrastructure (AMI)
EVs and Charging Stations	Substation Automation
Home Area Networks	

Through the study process in 2011, OPPD determined that a system-wide deployment of Smart Grid technologies was not warranted or cost effective at that time. However, it was recommended that OPPD pursue a Distribution Automation (DA) project to test Fault Location, Isolation, Service Restoration (FLISR) and Volt-Var Optimization (VVO) functionality as Phase I of Smart Grid at OPPD.

The Phase I project includes a 4-square mile area in northeast Omaha with just under 10,000 customers, served largely by overhead distribution surrounded by mature trees. DA equipment including bi-directional reclosers, intelligent capacitor controls and communicating fault indicators have been installed on five 13.8 kV distribution circuits from two substations. In addition, a small number of AMI meters have been installed. The communication technology deployed includes both a utility-owned mesh radio network (5.8 GHz, 2.4GHz, 900MHz) as well as secured VPN over public carrier (cellular).

The FLISR functionality will both speed restoration through automation and provide increased visibility for Distribution System Operations. The VVO functionality is expected to decrease losses and provide a method for demand reduction using Conservation Voltage Reduction (CVR). The project will be fully functional in early 2017 and the reliability improvement, demand reduction and O&M savings will be measured and tracked to provide insight for any future deployments.

2.10 Community Solar Project

In response to growing interest in solar-powered generation from customer-owners, OPPD evaluated the incorporation of utility-grade solar into the analysis discussed in article 5.2.2 as well as the exploration of a potential community solar project.

The community solar project team at OPPD is currently evaluating a number of attributes for a potential community solar project. Those attributes include, but are not limited to, technology selection, location, financing, nameplate capacity and rate making. In parallel to the analysis of these attributes, OPPD will be executing a stakeholder process to collect customer feedback on the project options. While OPPD may not be able to incorporate all feedback into the final project, OPPD wants to prioritize Strategic Directive 13 – Stakeholder Outreach and Communication in the most meaningful way by incorporating feedback during project planning.

3.0 Environmental and Regulatory

The 2016 Integrated Resource Plan considers and selects resource options to meet the forecasted demand with an acceptable level of reliability. Among the largest uncertainties when planning for future generation is change in environmental regulations and market conditions. Current and future environmental regulations will have a significant impact on the selection and operation of future power supply resources. OPPD will consider all resource alternatives available to develop a least-cost plan.

Important environmental considerations under the Clean Air Act, other potential water and solid waste rule-making and potential carbon (or climate change) legislation or regulatory rule-making are discussed in this section.

3.1 Federal Energy Policy

The 114th Congress completed its two-year legislative session in December 2016. Several bills were considered that could have had implications for energy and environmental policy that will more than likely be reintroduced in the 115th Congress (2017-2018). Below is a more in-depth summary of those issues that can impact OPPD operations.

3.1.1 Tax-Exempt Financing

There have been repeated budget proposals that include provisions that would impose a 28 percent “cap” on the tax value of municipal bond interest, a surtax on municipal bonds, or other onerous proposals to alter the use of tax-exempt financing. For more than 200 years, state and local governments and governmental entities, including OPPD, have relied on municipal bonds as a means of financing. Interest on these bonds issued by state and local governments (OPPD is a political subdivision of the state of Nebraska) have always been exempt from federal income tax. Historically, Congress has never taxed interest on municipal debt. Furthermore, the existing rules and regulations under the Internal Revenue Code and the Securities and Exchange Commission (SEC) appear sufficient to prevent abuse and have enforcement programs to ensure compliance. OPPD, like other public utilities, utilizes tax-exempt financing to fund the construction of electric generation, transmission and distribution assets, as well as other related facilities necessary to provide low-cost, reliable electric service to our ratepayers. Although OPPD will need to continue to adequately plan and serve its customers regardless of any changes to tax-exempt financing, new restrictions on tax-exempt financing of municipal bonds could lead to higher future debt service costs and, therefore, impact the rates paid by OPPD’s customers.

3.1.2 Renewable Electricity Tax Credits

During the 114th Congress, the Consolidated Appropriations Act of 2016 was signed into law. This legislation addressed energy tax issues important to OPPD. The bill extends three renewable power tax credits, including a 2.3 cent per kilowatt hour wind energy production tax credit (PTC), a 30% solar property investment tax credit (ITC), and a 30% residential energy efficient property credit that can apply to solar electric property. Specifically, the bill extended the PTC for wind energy at expired law levels through 2016 (having expired at the end of 2014). The credit would then be phased out as follows: 80% of credit value for 2017; 60% for 2018; and 40% for 2019. The credit would expire after 2019. The PTC has been important to the growth and development of renewable electricity resources, particularly wind. Although OPPD is a tax-exempt entity and only taxable entities can claim the PTC, OPPD is able to benefit from the PTC through PPAs with taxable entities. The taxable entities own the wind energy resources and pass through the PTC in the PPA. Long-term certainty regarding the PTC is crucial for utility operation planning purposes.

3.1.3 Comprehensive Energy Legislation

During the 114th Congress, the U.S. Senate passed S. 2012, the Energy Policy Modernization Act, a major energy bill with provisions addressing energy efficiency, critical infrastructure, energy supplies, and energy financing and markets among other topics. The U.S. House of Representatives passed H.R. 8, the North American Energy Security and Infrastructure Act of 2015. H.R. 8 addressed many similar topics, including energy efficiency, infrastructure and energy markets. The two bills went to a conference committee to resolve the differences between the two energy bills, but they were unable to reach an agreement and were not enacted into law. However, several of the provisions in both bills will be reintroduced in the 115th Congress. OPPD has interest in some of the provisions in those bills. For instance, there was language addressing energy-efficiency provisions, 21st Century energy workforce language, and a provision addressing vegetation management around transmission lines. OPPD will continue to track these and other legislation that may be introduced.

3.1.4 Environmental Legislation

There were several pieces of legislation introduced in the 114th Congress focusing on environmental issues like the Administration's Clean Power Plan, the Waters of the U.S. -rule (WOTUS) promulgated by the EPA and U.S. Army Corps of Engineers, the management of coal combustion residuals (CCRs) legislation, regional haze and other similar bills that OPPD followed. The only environmental legislation that was enacted into law addressed CCRs. The language that was enacted would allow for implementation of the federal CCR rule through a state- or federal-based permit program instead of having enforcement by citizen suits.

OPPD expects several environmental/regulatory relief bills to be introduced in the 115th Congress. OPPD will monitor these pieces of legislation as they move through the legislative process.

3.2 Environmental Protection Agency

The U.S. Environmental Protection Agency continues to pursue more stringent regulations of fossil fuel generation resources.

Existing and potential new environmental regulations could affect the operations of OPPD's electric power generating stations, in particular its coal-fired units.

OPPD has identified mitigation steps and costs for complying with current and probable future environmental regulations to be used in its evaluation of alternative resource plans.

3.2.1 Planned Generation Changes for Environmental Compliance

OPPD continually monitors local, state and federal agencies for environmental rules that may change the operations of, or require modifications to, OPPD's facilities. As a result, OPPD performed an extensive assessment of its resources due to the elevated impact and uncertainty surrounding current and expected future environmental issues and related regulations. Several resource options and portfolios were evaluated to comply with existing and future environmental requirements. OPPD's Board of Directors received a briefing on the resource options evaluation in May 2014. Management then recommended a portfolio option that includes: retiring NO1, NO2 and NO3, and retrofitting NO4, NO5 and NC1 with dry sorbent injection and activated carbon injection in 2016; continuing additional load reductions through demand-side management and energy efficiency to achieve a 300MW total reduction by 2023; and refueling NO4 and NO5 to natural gas in 2023. OPPD's Board of Directors reviewed and approved this recommendation in June 2014. As of April 2016, dry sorbent injection and activated carbon injection were installed and in operation for NO4 and NO5 as well as NC1. As a result of the Board action related to FCS in June 2016, OPPD will use existing natural gas generating capability for NO1, NO2, and NO3 through at least 2018 to provide capacity during peak demand periods.

3.2.2 Air Quality and the Clean Air Act Amendments

The following includes Environmental Protection Agency (EPA) rules that recently have been finalized or proposed and their projected impact on OPPD:

> *Greenhouse Gas Regulation.* On October 23, 2015, the EPA published a final rule regulating the emission of carbon dioxide (CO_2) from existing fossil fuel-fired electric generating units under Section 111 of the Clean Air Act. Also on October 23, 2015, the EPA published a final rule for new, modified, or reconstructed fossil fuel-fired electric utility generating units under Section 111 of the Clean Air Act. These regulations in the aggregate are known as the Clean Power Plan. The CPP requires states to meet interim and final emissions targets on a state-wide basis starting in 2022. The goal is to reduce CO_2 emissions from electric generating units by 32% below 2005 levels by the year 2030. In addition, the EPA issued a proposed rule that provides two possible programs to be used by states for compliance: a mass-based program or a rate-based program. States could allow their fossil fueled generating units to use a number of measures to meet those goals, such as heat rate improvements, unit retirements and renewable energy.
>
> Numerous legal challenges to the CPP have been filed and consolidated in the United States Court of Appeals for the District of Columbia Circuit. On February 9, 2016, the U.S. Supreme Court entered an order staying the implementation of the CPP pending further proceedings. This ruling blocks the implementation of the CPP pending the disposition of the petitions for review in the United States Court of Appeals for the District of

Columbia Circuit. OPPD will continue to monitor this situation and evaluate compliance options. The cost of compliance will not be known until judicial proceedings have been concluded and OPPD can evaluate the final regulatory requirements and its options related thereto.

Cross-State Air Pollution Rule. The EPA published the Cross-State Air Pollution Rule (CSAPR) requiring 28 designated states, including Nebraska, to significantly improve air quality by reducing generating station emissions contributing to ozone and fine particle pollution in other states. Specifically, the rule, effective January 1, 2015, requires significant reductions in sulfur dioxide (SO2) and nitrous oxide (NOx) emissions crossing state lines.

The final CSAPR rule established a cap-and-trade system with state and unit specific allowance allocations to achieve the desired emission reductions for SO2 and NOX. Implementation of Phase I of the final rule began in 2015 and implementation of Phase II begins in 2017. As a result of NO1, NO2, and NO3 ceasing coal-fueled generation, OPPD will likely not need to purchase additional allowances to comply with CSAPR.

Mercury and Air Toxics Standard. The EPA issued the MATS, which places strict limitations on emissions of mercury, non-mercury metallic hazardous air pollutants and acid gases. Compliance with the new rule was necessary by April 16, 2015, for NC2. Compliance was achieved with minor changes including a new mercury monitoring system and increasing the Activated Carbon Injection (ACI) rate from the originally permitted injection rate. At NO4, NO5, and NC1, compliance was necessary by April 16, 2016. OPPD retrofitted NO4, NO5, and NC1 with Dry Sorbent Injection and ACI. In June 2014, the Board of Directors approved changes to its generation portfolio to comply with existing and future environmental regulations. During the June 2014 meeting, the Board approved the retirement of NO1, NO2, and NO3 in 2016. As a result of the Board action to cease operations at FCS in June 2016, OPPD will use existing natural gas generating capability for NO1, NO2, and NO3 through at least 2018 to provide capacity during peak demand periods, and as such, these units will not be subject to the MATS regulation.

National Ambient Air Quality Standard (NAAQS) for Ozone. On October 1, 2015, the EPA announced that the new ozone standard would be set at 70 parts per billion (ppb) from 75 ppb. Nebraska and the Omaha metro area will continue to remain in attainment with the new standard and the reduced standard is not expected to have any impact on OPPD or its compliance strategy.

National Ambient Air Quality Standard for one-hour SO2. On June 2, 2010, the EPA strengthened the NAAQS for SO2. Following long delays in issuing the area designations, the EPA was sued and on March 2, 2015, the U.S. District Court for the Northern District of California accepted as an enforceable order an agreement between the EPA and Sierra

Club and Natural Resources Defense Council to resolve litigation concerning the deadline for completing the designations. The court's order directed the EPA to complete designations in three additional rounds: the first round by July 2, 2016, the second round by December 31, 2017, and the final round by December 31, 2020.

In the second round of area designations to be completed by December 31, 2017, the EPA identified NCS as one of the sources in Nebraska as meeting the criteria established in the court's order. On August 19, 2015, OPPD submitted modeling protocol information to the Nebraska Department of Environmental Quality (NDEQ) for NCS SO2 emissions. The State of Nebraska used this information to perform modeling, which indicated that Otoe County is in attainment with the SO2 NAAQS. The State of Nebraska submitted this information to the EPA on September 18, 2015, recommending that Otoe County be designated as attainment. On July 1, 2016, the EPA published the final designations and agreed with the state of Nebraska recommendation.

Douglas County met the criteria established by the court order however there were questions by EPA R7 as to proper siting of the existing SO_2 Monitor. OPPD worked with NDEQ, Douglas County and EPA Region 7 to establish an acceptable ambient SO2 monitor near NOS to satisfy ambient monitoring requirements. In late December 2016, a new monitor was placed in operation near NOS.

Regional Haze. The NDEQ has drafted its required Regional Haze State Implementation Plan (SIP) Five Year Progress Report on emission reductions to remedy visibility impairments at Class I areas such as the Badlands and Wind Cave National Parks in South Dakota. The draft Five Year Report claims sufficient progress based on the existing emission reductions from OPPD units. This includes the staged shutdown of NO1, NO2, and NO3 from coal generation in 2016, the retrofit of NO4 and NO5 with MATS controls and their refueling to natural gas by 2023. The Five Year Progress Report also takes credit for the use of best available retrofit technology (BART) for NC1 based on the installation of low NOX burners with over fire air technology in 2010, existing controls for particulate matter, and the continued use of low sulfur coal for SO2 control. The Five Year Progress Report also references the existing emission controls at NC2 operational since 2009. The final Five Year Progress Report was due to be submitted to EPA in August 2016. Since the Nebraska SIP was partially approved and partially disapproved by EPA on July 6, 2012, EPA Region 7 has advised the NDEQ to defer submitting the Progress Report until the portions of the SIP that were disapproved can be resolved. Once the SIP issues are resolved, it is not expected to require any changes or additions to the commitments OPPD has made to meet these regulatory requirements.

EPA Information Request and Notice. In 2010, OPPD received a request for information issued under the federal Clean Air Act from the EPA's Region 7 regarding projects undertaken at NC1 and NOS since 1987. OPPD has responded to the initial and subsequent information requests. By a letter dated August 28, 2014, EPA Region 7 sent a Notice of Violation (NOV) to OPPD alleging that OPPD violated the Clean Air Act by undertaking certain equipment replacement projects at NC1. OPPD believes it has complied with all regulations relative to the projects in question. The EPA would have to establish the allegations in the NOV in court. In general, if EPA establishes a Clean Air Act violation in court, the remedy can include civil penalties and a requirement to install pollution-control equipment. OPPD cannot determine at this time whether it will have any future financial obligation with respect to the NOV.

3.2.3 Hazardous and Toxic Materials Regulations

Chemical Reporting. The electric utility industry is subject to the Emergency Planning and Community Right to Know Act (EPCRA), the Toxic Substances Control Act (TSCA) regulations and the Resource Conservation & Recovery Act (RCRA), including applicable programs delegated to the NDEQ by the EPA. OPPD conducts environmental audits to monitor compliance with these regulations in conjunction with the proper management and disposal of applicable hazardous, toxic and low-level radioactive wastes.

The four major provisions of the EPCRA are emergency planning, emergency release notification, hazardous chemical storage reporting requirements, and toxic chemical release inventory. The emergency planning section of the law is designed to help communities prepare for and respond to emergencies involving hazardous substances. Specifically, OPPD annually reports the presence, location and amount of hazardous substances at its facilities to local emergency responders and to local and state emergency planning committees. OPPD also annually reports the amounts of EPCRA chemicals that it releases to the environment at its coal fired electric generating facilities to the State Emergency Response Commission and the EPA via the Toxics Release Inventory (TRI). The TRI is a publicly available EPA database that contains information on toxic chemical releases and other waste management activities reported annually by certain covered industry groups as well as federal facilities. Accidental or emergency releases of EPCRA chemicals above threshold amounts are reported to local agencies and the National Response Center.

OPPD manages TSCA waste (mainly asbestos and polychlorinated biphenyls from electrical transmission and distribution equipment) through a process involving reporting, sampling and analysis, and appropriate waste management to ensure compliance. RCRA waste is managed by characterizing, packaging and shipping radioactive and solid wastes to OPPD’s approved waste vendors to ensure compliance and minimize liability associated with waste disposal. In order to ensure compliance, OPPD remains active in reviewing applicable regulatory changes and modifying facility environmental management plans accordingly. Pollution-prevention efforts have been effective in reducing environmental liabilities and reducing operating costs.

3.2.4 Clean Water Act

On May 19, 2014, the EPA issued the final rule under Section 316(b) Rule of the Clean Water Act. The final rule went into effect in October 2014. Facilities are required to choose one of seven options to reduce fish impingement. The cost impact of the final rule is being assessed. Facilities will also need to study the effects of entrainment and develop compliance strategies. OPPD received new National Pollution Discharge Elimination System (NPDES) permits effective January 1, 2016, which dictated the compliance schedule and studies necessary to comply with the rule. OPPD commenced Entrainment Characterization Studies at FCS, NOS, and NCS on April 4, 2016. Studies necessary to determine the Best Technology Available will occur over the next 42 months and cost for compliance is not thought to be substantial at this time.

3.2.5 Solid Waste

On April 17, 2015, the EPA promulgated technical requirements for *Coal Combustion Residuals (CCR) Regulations* landfills and surface impoundments for the safe disposal of coal combustion residuals under Subtitle D of the RCRA. The regulations provide design criteria, operating criteria, groundwater monitoring requirements, closure requirements, and recordkeeping and notification requirements associated with CCR landfills and surface impoundments. The regulation became effective on October 19, 2015, and OPPD is in compliance with the requirements. OPPD continues to assess and implement compliance strategies associated with this regulation by required dates. The cost of compliance with this regulation is not expected to be substantial.

3.3 U.S. Army Corps of Engineers Oversight of Missouri River

During the spring and summer of 2011, all three of OPPD's baseload stations were threatened by prolonged, flood stage, water levels on the Missouri River as the Corps drained record Missouri River basin runoff from the six mainstem reservoirs. Gavins Point Dam releases were at or above 160,000 cubic feet per second (cfs) for 74 continuous days. The prior highest rate of release from Gavins Point was 80,000 cfs. Management of water storage in the reservoir as authorized in the Corps' Master Manual received much scrutiny in the media and in public forums during and after the flooding. The year 2011 highlighted the level of disruption the Missouri River can present to the operation of OPPD's stations and to all enterprises located in the river's historical flood plain. Contrarily, in drought years, low river levels may also lead to constriction in power generation limits.

3.4 Nebraska Power Review Board

In 1963, the Nebraska Legislature enacted Chapter 70, Article 10, Reissue Revised Statutes of 1943 of Nebraska, as amended, establishing the Nebraska Power Review Board (NPRB). The NPRB consists of five members appointed by the Governor subject to approval by the Legislature. The statute declares that it is the policy of the State to avoid and eliminate conflict and competition between retail suppliers of electricity and to facilitate the settlement of rate disputes between suppliers of electricity at wholesale. Subject to approval of the NPRB, retail suppliers of electricity in adjoining areas are authorized to enter into written agreements with each other, specifying either the service area or customers that each shall serve. Where agreements cannot be reached, the NPRB will determine the matter after a hearing. With NPRB approval, OPPD has entered into service area agreements with all other suppliers whose territories adjoin that of OPPD. The construction of any transmission lines or related facilities outside OPPD's service territory generally carrying more than 700 volts or the construction of most electric generation facilities is subject to the approval of the NPRB. Since the establishment of the NPRB, OPPD has received NPRB approval for the construction of all facilities requiring such approval.

3.5 Nebraska Legislation

3.5.1 C-BED

The Rural Community Based Energy Development Act of 2007 (LB-629), or commonly referred to as C-BED, has led to the development in Nebraska of 80MW of wind in 2009. C-BED projects are privately financed and require payments (no less than one-third of the power purchase payments) to flow to owners with in-state interests or to local communities. These projects can be up to 80MW in size and not require Nebraska Power Review Board approval (see LB-561 discussion for changes). Instead, renewable projects under 80MW can qualify under federal PURPA guidelines, which supersede Power Review Board statutory authority. Projects do need a buyer for the delivered energy (including transmission costs) so the energy must be competitively priced. Since C-BED wind energy facilities are being funded wholly or partially by private sector monies, the energy produced by these facilities will be eligible for federal renewable tax credits (see PTC discussion under Section 3.1.2).

3.5.2 LB-561 Revisions to C-BED and Renewable Generation Statutes

In 2009 the Nebraska Legislature revised portions of the C-BED statutes and further revised NPRB statutes as they pertain to renewable electrical generation. In LB-561, power districts were given the authority to agree to limit their exercise of the power of eminent domain to acquire a wind project. The NPRB shall approve applications for wind and other renewable projects which supply but do not exceed 10% of the producers total energy sales if the applicant's governing body holds at least one public hearing on the renewable project. Under this statute revision, C-BED projects may apply in similar fashion if they establish a purchase power agreement exclusively with a Nebraska electric utility or utilities with a term of at least 20 years. With this revision, it appears that wind projects larger than 80MW will be allowed to be constructed in Nebraska as long the project meets the revised statutes. LB-561 also enacted an exemption to strict adherence to the financing requirements of C-BED statutes through the date of December 31, 2011.

3.5.3 LB-436 Net Metering and LB 65 of 2003

LB 436 passed during 2009 and is a net metering law. This allows a local distribution company to pay owners of customer owned generation for that customer's electrical generation exported to the grid. For electrical energy in excess (sent to the grid) of the customer's own load requirements, the distribution company pays their avoided cost of electric supply to the customer. A qualified facility for net metering must use either methane, wind, solar, biomass, hydro or geothermal resources and have a rated capacity below 25 kW. OPPD added a specific rate for net metering in October 2009; several customers are participating. OPPD has a netting settlement with the customer at the completion of each month

Passage of LB 65, a bill supported by OPPD, by the 2003 Legislature allows a Nebraska utility to build and generate up to 10MW of renewable and emerging technology generation facilities without meeting the least-cost option criteria. Applications for such projects must, however, show some public benefit and receive approval from the Nebraska Power Review Board. The passage of C-BED and LB-561 in 2009, along with the improving economics of wind generation, has reduced the usefulness of LB 65 with respect to wind projects. However, the law retains its usefulness for other less affordable renewable technologies.

3.5.4 LB-1115 Nebraska Renewable Energy Export Study

The "Nebraska Renewable Energy Export Study" was prepared in response to the passage LB-1115 in 2014 and the associated NPRB Request for Proposal (RFP), RFP NPRB-1115. As specified in the RFP, the objective of this report is to identify the opportunities and challenges that impact the capability and desirability of developing 5,000 to 10,000MW of renewable generation capacity in Nebraska for export purposes and to provide options that the Nebraska Legislature can consider for meeting its policy objectives.

The scope specifically included: 1) the review of current state, regional, and national transmission infrastructure and policy; 2) the identification of future needs for transmission infrastructure and policy; 3) the assessment of market availability, opportunities and barriers to the construction of generation facilities using renewable resources in Nebraska primarily designed to export electricity outside the State of Nebraska; and 4) analyzing the implications on the rates and service to Nebraska's electricity consumers and utilities.

3.5.5 LB-1048 Certified Renewable Export Facilities

During the 2010 session of the Nebraska legislature, the Unicameral passed a bill with provisions to allow further wind to be developed in Nebraska without needing to meet the basic need statutes of the Nebraska Power Review Board. The bill allows for solar, biomass or landfill gas-produced electrical energy and wind. Some key criteria must be met. At least 90% of the wind facility energy output must be exported to customer(s) located outside the state of Nebraska. If the facility is larger than 80MW, 10% of the wind facility's output will be made available by offer to Nebraska electric suppliers such as OPPD. All or some of the electric suppliers may choose not to take the wind. Specifically for wind-generating facilities, the bill exempts the facility from property tax. Instead, the equipment will be subject to a nameplate capacity tax that is set at a level to be competitive with taxes imposed on wind facilities in other states.

3.5.6 LB-824 Privately Developed Renewables Exemption

LB 824 removes the requirements of a Certified Renewable Export Facility (CREF) and the power purchase agreement requirement and eliminates the language regarding stranded assets. A privately developed renewable energy generation facility is exempt from the NPRB requirements and regulations. The private entity has no eminent domain rights and the facility cannot be condemned by another entity under eminent domain. The private entity will comply with any decommissioning requirements by the local government entity having jurisdiction and all costs of decommissioning will be paid by the private entity. LB-824 was signed by the Governor of Nebraska on April 19, 2016.

4.0 Load and Market Forecasts

The 2016 IRP models are based on inputs and forecasts for system load, fuel prices, technology costs, environmental regulation and operational costs for existing assets. Projections for these values form the basis for OPPD's understanding of the future market environment. Forecasts are produced from an aggregation of publicly available, proprietary and vendor-provided sources.

4.1 System Load Requirements

Peak demand and total system energy consumption forecasts are fundamental elements in the IRP modeling process. Forecasts for these elements determine the volume of resources OPPD must maintain to support a reliable system and meet the energy needs of its customers. OPPD derives forecasts for these values using MetrixND, an ITRON company software and a sophisticated load forecasting tool used across the electric utility industry.

The 2017-2036 Peak Demand and Net System Requirements forecasts are provided in Appendix A. Compared to forecasts developed for previous IRP submissions, 2016 forecasts have been revised downward to reflect increased energy efficiency and revised projections for population growth within OPPD's service territory. The load forecasts used in the 2016 IRP are considerably lower in both the short-term and long-term when compared to the 2011 IRP. Table 9 shows the differences from the 2011 IRP to the 2016 IRP. Figure 5 includes a comparison of the official annual forecasts developed in 2010 through 2016 for peak demand levels.

Table 9- 2011 vs 2016 Peak Load Forecast

Load Forecast, Annual Peak Demand (MW)			
Year	**2011 IRP**	**2016 IRP**	**Change**
2017	2,705	2,417	-288
2018	2,753	2,454	-299
2019	2,800	2,458	-342
2020	2,835	2,445	-390
2021	2,891	2,456	-435
2022	2,939	2,455	-484
2023	2,988	2,449	-539
2024	3,031	2,434	-597
2025	3,094	2,440	-654
2026	3,148	2,436	-712
2027	NA	2,435	NA
2028	NA	2,425	NA
2029	NA	2,435	NA
2030	NA	2,437	NA
2031	NA	2,438	NA

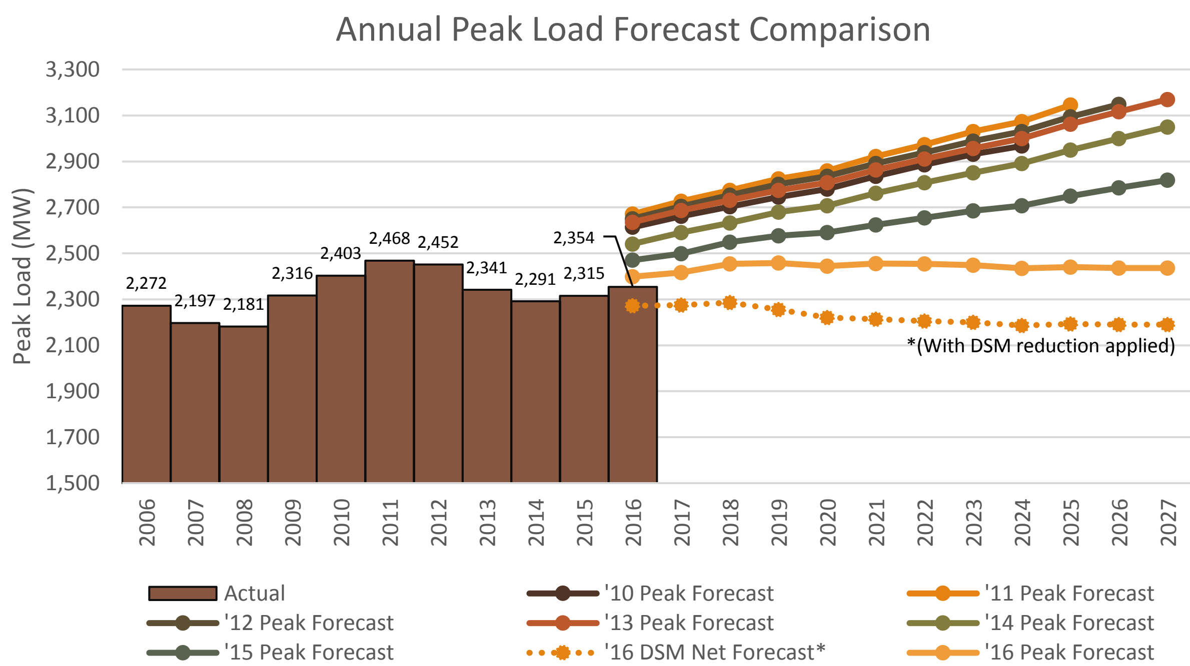


Figure 5 - 2010 vs 2016 Peak Load Forecast

OPPD monthly peak demand and load forecasts include each of the three rate classes modeled: residential, commercial and industrial.

Residential and commercial sales forecasts are developed by using econometric models for average energy use and the total number of customers within OPPD's service territory. Average energy use estimates are developed using the Statistical Adjusted End-Use modeling technique. In this method, device saturation and energy efficiency trends are developed using data from the Energy Information Administration (EIA).

The industrial forecast is developed through both econometric models within MetrixND as well as individual large customer load growth forecasts.

OPPD load shapes, along with the energy forecast, are used to develop a system hourly forecast that includes the OPPD system peak.

4.1.1 Distributed Generation

Distributed generation is a growing trend across the utility industry. This trend is especially true for areas with high solar potential, such as the southwest United States, as well as in areas with significant state and local tax incentives. Though distributed generation has not grown as rapidly in OPPD's service territory as compared to other areas of the country, OPPD does anticipate that the number of distributed generation projects will continue to grow.

OPPD customers who generate renewable energy with generators located behind their service meter are eligible for net metering rates. As of December 2015, OPPD had 45 customers with 64 net metering-qualified facilities and a total generating capacity of 423 kilowatts. In 2015, the total estimated amount of energy produced by customer-owned distributed generation assets was 605,670 kWh. The net energy produced in excess of customer load was 25,975 kWh. At the end of 2016, OPPD had 59 customers with 80 net metering-qualified facilities and a total generating capacity of 538 kilowatts. In 2016, the total estimated amount of energy produced by these customer owned distributed generation assets was 755,406 kWh. The net energy produced in excess of customer load was 32,857 kWh.

At its current participation levels, distributed generation has not materially reduced OPPD's current load forecasts. Although OPPD does not having enough objective historical data to meaningfully project net metering (Distributed Energy Resources) into the future, it expects distributed generation to increase as technology costs decrease and customer preferences change. Accordingly, OPPD will continue to monitor the trend of distributed generation participation as it develops ongoing future resource plans.

4.1.2 Electric Vehicles

OPPD has prepared for expanding consumer use of electric vehicles (EV) within its service territory. In 2010, OPPD completed the Electric Vehicle Readiness Project to support the creation of an EV market and developed a strategic plan for the successful integration of EVs with its power supply infrastructure. Throughout the project's two-year timeline, OPPD engaged various stakeholders, including vehicle vendors, property owners and government entities. The project developed programs to support EV vendors and owners. OPPD also conducted an analysis of all the steps required for a customer to achieve "plug-in-readiness" should they purchase an EV. The emphasis was to make the process simple and convenient for the customer by leveraging partnerships within the community.

OPPD was also one of more than 40 utilities across North America to receive and test a Chevrolet Volt Extended Range Electric Vehicle from the Electric Power Research Institute (EPRI) and General Motors. The objective of the project was to prepare the utility industry for adoption of plug-in electric vehicles (EV) and to provide the technological foundation for integration of the vehicles into utility metering and other grid systems. The project gathered information about driving behavior and charging data and gave participating utilities more experience with this type of EV. The program was funded with a $30.5 million grant from the Transportation Electrification Initiative administered by the U.S. Department of Energy through the American Recovery and Reinvestment Act.

Though the District owns a number of electric vehicles, adoption of the technology has been much slower than originally expected in 2010. According to the Nebraska Energy Office, there were 253 EVs registered in the state of Nebraska at the end of 2015. OPPD is also aware of the following data as it relates to the potential impact of EVs on its load forecasting:

Electric Vehicles Market Share. One of the challenges of preparing for the arrival of EVs is the difficulty in predicting how fast the market will grow and how large it will become. In the 2016 International Energy Agency Global EV Outlook, market share of electric cars in the United States was estimated at 0.7%, and motor vehicle registrations for EVs declined between 2014 and 2015. In their 2017 Annual Energy Outlook reference case, the EIA has forecasted EV sales increasing from less than 1% to 6% of total light-duty vehicles sold in the United States over 2016 to and 2040.

Federal Incentives. On the federal level, Qualified Plug-in Electric Drive Motor Vehicles, including passenger vehicles and light trucks purchased in or after 2010, are eligible for a federal income tax credit of up to $7,500. The credit varies based on the battery used to power the vehicle and will begin to phase out to 50% of the full amount once a manufacturer has sold 200,000 Plug-In Hybrid Electric Vehicles (PHEVs) and battery EVs.

In 2015, the Fixing America's Surface Transportation (FAST) Act reauthorized the tax credit for EV charging supply equipment until December 31, 2016. If a charging station is considered personal property, the tax credit is the smallest of 30% of the station's cost or $1,000; if the charging station is considered business property, the credit is worth the smallest of 30% of the station's cost or $30,000.

Nebraska State Incentives. The Nebraska Energy Office administers the Dollar and Energy Saving Loan Program, which provides low-cost loans for a variety of alternative fuel projects. Projects include the replacement of conventional vehicles with Alternative Fuel Vehicle (AFV); the purchase of new AFVs; the conversion of conventional vehicles to operate on alternative fuels and the construction or purchase of a fueling station or equipment.

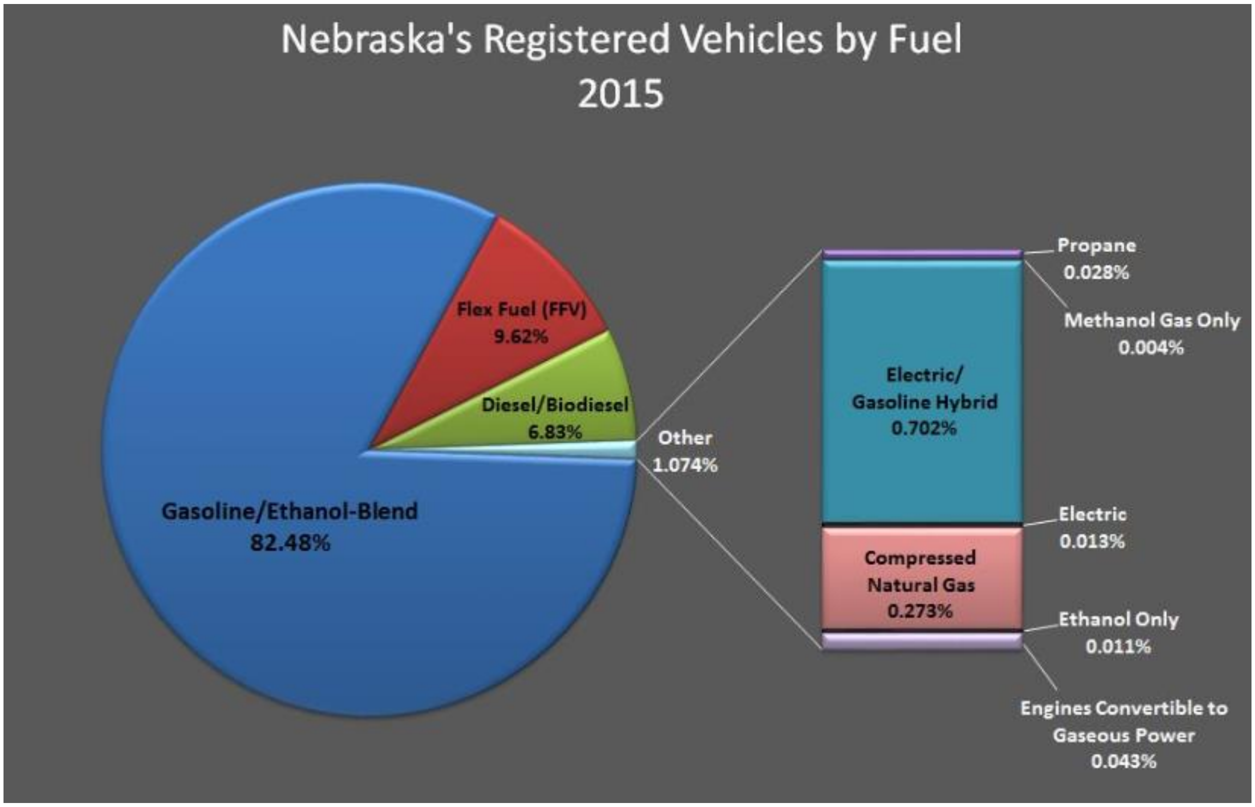


Figure 6 - Nebraska Registered Vehicles by Fuel Type, 2015 Source: Nebraska Energy Office (http://www.neo.ne.gov/statshtml/196.htm).

4.1.3 Energy Efficiency

OPPD integrates two types of energy efficiency projections into its load forecast. The first type is based on data from the EIA Energy Outlook Reference case for the West North Central region. The energy projections contain estimates for energy usage intensities, device saturation rates, device energy efficiency and projected square footage for building structures. The second type of projection includes OPPD's 300MW Demand Side Management Program that includes energy efficiency measures unveiled in 2014. The program is also discussed in section 5.2.3.

4.2 Fuel Forecasts

4.2.1 Natural Gas Forecast

Natural gas prices have historically impacted the market price of power in SPP more than any other fuel type. As a result, OPPD regularly calculates site-specific natural gas cost for budgeting and modeling purposes. The forecast for future natural gas prices is very important in the evaluation of resources in the 2016 IRP. The price of natural gas is driven by weather, storage levels, consumer demand, production levels and production costs. OPPD developed the natural gas price forecast used in the 2016 IRP using an aggregation of proprietary vendor forecasts and forward market prices.

Compared to the 2011 IRP, both short-term and long-term natural gas prices have been revised downwards. This trend is a result of increased U.S. production of natural gas due to improvements in the efficiency of production. According to EIA data, U.S. production of natural gas has grown 19.6% from 2011 to 2015. Robust production from shale gas is expected to continue the downward pressure on natural gas prices in the near-term. Natural gas prices are expected to increase in the long-term as a result of growth of U.S. liquefied natural gas export capability and increasing demand from electric utilities.

Historically, natural gas prices have shown significant volatility. OPPD has modeled significant uncertainty around natural gas forecasts in the stochastic modeling process used to evaluate financial risks of the portfolios included in the 2016 IRP.

4.2.2 Coal Forecast

Like natural gas, coal costs are evaluated regularly for budgeting and modeling purposes. Coal forecasts are developed using 1) an aggregation of multiple, long-term proprietary vendor forecasts specific to delivered coal costs in Nebraska and 2) coal contracts OPPD already has committed to in the near-term.

Though OPPD's forecast does expect a modest recovery in coal prices over the next few years, coal prices are expected to see continued downward pressure as a result of a protracted period of oversupply, lower natural gas prices and an aging coal generation fleet.

4.3 Power Prices

Forward price expectations are derived from proprietary market forecasts and futures obtained from SNL Financial, ABB and IHS Markit, with some adjustments made to ensure 'best fit' across the vendor forecasts. SNL futures were used for the first two years of the market projection and then blended with the average of the long-term forecasts of ABB and IHS Markit for years three and four. For year five and beyond the average of the ABB and IHS Markit forecast was used.

Natural gas prices are an important determinant impacting wholesale power prices. Therefore, one can assume that the lower a given forward price forecast, the lower the gas prices in the forecaster's assumptions. Another important factor in the wholesale power prices is the increase in wind facility capacity across the SPP footprint. According to the "SPP Wind Overview, January 2017," in 2011 there was approximately 5,256MW of installed wind capacity in the SPP footprint; by the end of 2016 there is expected to be 16,354MW. Future generation additions (and retirements) are implicit in the forward price curves. The pricing of this energy reflects the supply and demand balances in the entire Midwest region. These prices are based on the incremental fuel cost of the generating units, which perform the load-regulating duty during on-peak periods and are usually natural gas-fueled combustion turbines or combined cycle units.

SPP initiated its Integrated Marketplace in 2014, which was also the start of the Day Ahead Market in SPP. In the Day Ahead Market, all members offer their generation facilities into the market. This has led to a more efficient dispatch of generation and an overall, lower wholesale market price. Generally speaking, OPPD generators are considered “low cost” and compete well within the SPP Day Ahead Market.

4.4 General Economic Assumptions

Forecasting of economic assumptions such as economic growth, inflation and interest rates, as well as other economic variables, impact generation portfolio decisions. The major economic assumptions used in developing the forecasts for the 2016 IRP, which include generation costs estimates and the load forecast, include an inflation estimate of approximately 2.0% provided by IHS Markit. An annual interest rate of 4.80% was used for OPPD’s cost to secure long-term financing. The discount rate, which is the marginal opportunity cost associated with the capital secured and used to equate streams of revenue requirements to a present value equivalent (i.e., time value of money), was 6.0%.

5.0 Portfolio Analysis and Results

The objective of the Integrated Resource Plan analysis is to determine the optimum combination of resources from a full range of alternatives, which include supply-side, demand-side and energy storage. Resources are selected to meet OPPD's forecasted system demand at an acceptable level of reliability, while also focusing on environmental stewardship at the lowest possible cost to the customer-owner.

This integrated process encompasses many variables, both quantitative and qualitative, that impact utility operations. The plan takes into account necessary standards for system operation, such as system capacity and transmission reliability, as well as other financial considerations like projected total net present value of portfolio costs and portfolio financial risks. To support this process, specialized optimization software is used that models operation of the electricity grid based on forecasted assumptions for system load, system resources and fuel prices. These models provide a comprehensive, quantitative assessment of supply-side and demand-side resource options.

The final plan must be flexible enough to respond to opaque, but expected, future changes in the utility industry, with consideration given to the following subjects: cost and availability of fuel, cost and performance improvements in mature and emerging technologies, economic up- and down-turns and environmental regulations.

5.1 Analysis Methodology

The rapid changes occurring within the utility industry present both opportunities and uncertainties that must be evaluated as OPPD makes forward-looking decisions. To better calculate these risks and opportunities, OPPD engaged Pace Global, Inc. (PACE), a subsidiary of Siemens, Inc., to support modeling efforts of the 2016 IRP. PACE has developed innovative methods by employing industry-trusted software with cloud computing to allow for advanced and extensive modeling of risk and uncertainties.

The process of developing and evaluating the sample portfolios presented in the 2016 IRP consisted largely of four separate activities. These activities include the development of assumption inputs, portfolio optimization, deterministic analysis and stochastic analysis. The optimization, deterministic and stochastic analysis of this process are heavily dependent on the use of market simulation software. PACE used AURORAxmp as the market simulation engine within their framework, and a work stream of the process is included in Figure 7 below.

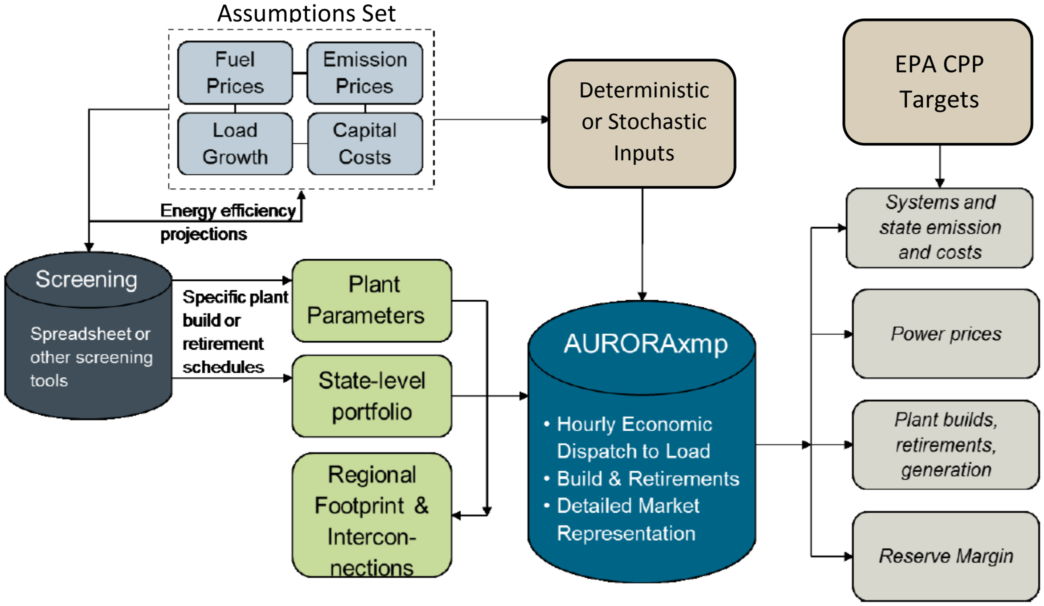


Figure 7- Pace Modeling and Risk Analysis Framework

The modeling software AURORAxmp is described below, in addition to a summary of the four stages of the modeling process:

AURORAxmp. AURORAxmp, developed by EPIS, LLC, is a fundamental electricity market modeling tool that uses economic and transmission constrained dispatch to simulate the future dynamics of the grid. This modeling simulates the hourly generation of each unit in the Southwest Power Pool and calculates projected hourly market power prices. AURORAxmp is a widespread and accepted fundamental tool for modeling the utility grid.

AURORAxmp considers:

- Individual power station characteristics including heat rates, start-up costs, ramp rates, capacities, variable production costs and other technical characteristics
- Fixed annual operational costs for OPPD facilities
- Transmission line interconnections, ratings, losses and tie-line limits
- Forecasts of technology costs, resource additions and fuel costs over time

- Forecasts of loads for load across the SPP region
- Emissions constraints and regulations

The operation of existing and future resources is based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions and operating characteristics of new resources. Algorithms are used in unit dispatch, unit commitment and regional pricing logic. The algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load. Multiple electricity markets, zones and hubs can be modeled using AURORAxmp. OPPD models the entire SPP system when evaluating the various resource portfolios for the IRP.

Assumptions Development. Prior to starting the IRP analysis, OPPD updated all market, operational and technology assumptions used in the modeling process based on the best available information from industry forecasts and from historical operational generating station data. The AURORAxmp model is preconfigured with general operational assumptions for all units within SPP. This preconfigured database is then updated with more detailed information for OPPD generation facilities to improve the level of modeling accuracy and to provide a more calibrated view of expected OPPD generator operations within SPP. General market and technology assumptions are listed in Appendix B.

Portfolio Optimization. The AURORAxmp tool is used for optimized system capacity expansion. The advanced logic of this tool uses market economics to determine an optimized long-term resource mix under varying future conditions including fuel prices, generation technology costs, environmental constraints, future system energy requirements and other modeling constraints. This modeling considers all capital, fixed, and variable costs of resources to derive portfolios with the lowest expected operating cost. The tool produces capacity expansion and retirement schedules, while simultaneously selecting economic demand-side resource options.

Deterministic Modeling. Deterministic modeling allows for higher-resolution simulations of portfolios under specific sets of market conditions. This modeling requires significantly greater computational time than the optimization process, as it directly solves for the economic dispatch of each generating resource within SPP for each hour of the 20-year modeling period. Each deterministic model can require four to eight hours to solve using modern, high-performance computers. The cost results of these detailed simulations are used in development of the net present value costs of each portfolio.

Stochastic Modeling. Each portfolio is tested under a large number of differing market conditions in a process known as stochastic modeling. This process provides an understanding of the distribution of possible financial outcomes for each proposed resource mix. For each set of market conditions, a full deterministic model is run, and the results of these runs are compiled to create a distribution of cost outcomes. The distribution of cost outcomes is then analyzed to evaluate the financial risk of the portfolio. In the stochastic process used for the 2016 IRP, a set of 200 market conditions were used for each of the four sample portfolios created. Because each deterministic analysis requires four to eight hours of computational time on a high-performance computer, the large number of scenarios used in the stochastic modeling required the use of cloud computing to generate all of the results in a timely manner. The differing market conditions used in this process are generated using forward mean forecasts, projections for future market volatility and the potential impacts caused by technology disruptions. The mathematical techniques used include Geometric Brownian Motion, Quantum Distributions and serial correlations, among others.

5.2 Technology Options and Forecasts

The 2016 IRP considers a full range of alternatives, including both supply-side generation options and demand-side options. Supply-side options include a range of applicable conventional and renewable technologies, as well as emerging battery storage technologies. Both new construction and PPAs were considered for supply-side options. Demand-side options include both identified energy efficiency and demand response programs. Both demand-side and supply-side alternatives were considered on an equal basis within the modeling and portfolio optimization process.

5.2.1 Resource Characteristics

Different resource options have different characteristics. Understanding the value provided by different types of resources is crucial to understanding how the right mix of resources is required to provide for electric reliability at the lowest cost. Different types of assets play different roles in delivering energy to meet OPPD's system energy demands. Principally, each type of supply-side technology has differing capital costs, fixed costs, variable costs, accredited capacity percentages, ramping abilities and environmental impacts, among other factors. All of these factors were considered in the resource modeling undergone in the 2016 IRP and are discussed in detail below:

Capital Costs: Capital costs include the up-front cost of construction or procurement of a resource. OPPD incurs debt to pay for capital costs and must continue to pay its debt obligations regardless of the level of use of the asset(s).

Fixed Costs: Fixed costs are costs which must be paid regardless of how much energy is produced by a resource. These costs include all regular operations and maintenance of a resource, such as all staffing costs, property maintenance expenses and equipment-related maintenance expenses.

Variable Costs: Variable costs of production are the incremental costs for each incremental MWh of energy produced by a resource. For traditional fossil fuel resources, this cost is dependent on the market price of fuel, transportation costs of fuel, the fuel efficiency of the unit and the cost of any additional materials consumed to reduce emissions.

Accredited Capacity: Accredited generation capacity is the rated power output level of a resource that can be dependably and predictably relied upon to meet system peak demand. SPP, of which OPPD is a member, requires that each member maintain enough accredited generation capacity to serve a utility's peak load, plus an additional 12% buffer called the Reserve Margin. This is required to ensure overall electric reliability across the SPP region. Traditional resources like coal and natural gas are typically accredited with capacities near 100% of their nameplate capacity. These resources can be turned on and off to meet system energy requirements, a characteristic known as dispatchability. Resources that are non-dispatchable and cannot be turned on and off to meet system load, such as wind and solar, do not receive this level of accreditation.

Ramping Abilities: Ramping ability is the ability of a resource to vary its output generation in response to changing system demands. The rate of ramp of a resource is determined by the change in energy production divided by the time required for the change in output. Ramping ability supports system reliability and is crucial for integration of renewable resources, which have intermittent generation. As OPPD adopts a higher percentage of renewables into its portfolio into the future, more value could be placed on quick-ramping resources.

Environmental Impact: Environmental impact includes traditional and greenhouse gas air pollutants released by resources. Carbon dioxide emissions are quantified by the tons of emissions created per MWh of energy produced. OPPD also considers other, harder-to-quantify environmental impacts, such as water use, life-cycle emissions, wildlife and habitat, land use and hazardous material use that may be involved with a particular generation source or technology.

5.2.2 Supply-Side Options

Limited load growth, declining costs of renewables and lower wholesale power prices frame the context for what types of resources were considered in the 2016 IRP. Low load growth in particular precluded the necessity for additional large, baseload-type facilities to be included in the modeling as they have been in previous Integrated Resources Plans.

Though the costs of traditional supply-side options are constantly evolving, Table 10 provides a high-level, practical summary of the different operating characteristics of each type of the supply-side resource options. Details on the values used for modeling and the long-term forecasts are contained in Appendix C.

Table 10- Resource Comparison Summary Table. Source: OPPD Technology Cost Forecasts. See Appendix C.

Resource Type	Fuel Source	Capital Costs	Fixed Costs	Variable Costs	Accredited Capacity	Ramping Abilities	Environmental Impact	Included in Analysis
		($/kw)	($/kw-yr)	($/MWh)	Percent of Nameplate	(MW/s)	Tons CO2/MWh	Yes/No
Combustion Turbine	Natural Gas	Low	Low	High	100%	High	Medium	Yes
Combined Cycle	Natural Gas	Medium	Medium	Medium	100%	Medium	Medium	Yes
Reciprocating Engines	Natural Gas	Med-Low	Low	Medium	100%	Very High	Medium	Yes
Wind Turbine	Wind	High	Low	Very Low	~15%	None	None	Yes
Solar PV	Solar	Very High	Low	Very Low	~25%	None	None	Yes
Long Duration Battery	Market Power	High	Low	Medium	100%	Very High	Low	Yes
Advanced Nuclear	Uranium	Very High	Very High	Low	100%	Minimal	Low	No
Pulverized Coal	Coal	High	High	Low	100%	Low	High	No
Integrated Gasification Combined Cycle	Coal	Very High	High	Low	100%	Low	Medium	No

Natural Gas

In general, natural gas technologies provide generation flexibility with fast-ramping abilities and lower capital construction costs. The fast-ramping ability of natural gas technology complements renewable resources by accommodating rapid changes in output from intermittent resources, while also supporting system reliability. As a fuel source, natural gas produces roughly half the amount of greenhouse emissions per unit of energy as coal (https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11).

Combustion Turbine. Combustion turbines are the lowest capital cost per unit of capacity considered in the Integrated Resource Plan modeling. This technology is among the fastest-ramping, currently installed technologies available in the SPP system and serves both peaking and reliability roles. Though not as fuel efficient as other natural gas technology, such as a combined cycle, these units are typically used during short intervals where fuel efficiency is not as significant of a contributor to the overall economics of the unit as capital costs.

Combined Cycle. Combined cycle technology includes the addition of a steam cycle to combustion turbine technology to improve total unit efficiency. This option is at a higher operational and capital cost than combustion turbines, while not having as high of ramping ability. A high concentration of combined cycle stations are located in the southern SPP footprint as a result of a closer proximity to gas resources. Additionally, coal transportation costs are higher relative to more northern states.

Reciprocating Engines. Reciprocating engines are gaining in popularity due to their fast-ramping ability, relatively good fuel efficiencies and modular nature, as they are typically sized between 9MW and 18MW. This technology provides a fuel efficiency between combustion turbines and combined cycles, while having significantly faster ramping capabilities than either. This technology has the optionality of being installed in distributed, relatively small increments across OPPD's service territory or in centralized locations. As both the concentration of renewables grows in the OPPD generating portfolio and the participation in distributed energy resources increase, more value could be placed on this technology.

Renewable

Renewable power has provided a major portion of all new electric generating capacity in the Midwest. The maturation of renewable resources is evident in declining costs and widespread deployment across the U.S. Federal incentives provided by the Production Tax Credits and Investment Tax Credits have been crucial to the economics of these resources. Though not directly available to OPPD as a government entity, these benefits may be passed down to OPPD via procurement of renewable resources through PPAs.

Wind. Declining costs of wind technology, the benefits of federal tax credits and Nebraska's high wind potential have made wind generation the lowest levelized cost source of energy evaluated in the 2016 IRP. Wind generation is currently seeing rapid growth throughout the SPP region. The wind potential of the SPP region and of Nebraska can be seen in Figure 8, which shows average wind speeds across the continental United States. The costs used in modeling additional wind generation are reflective of PPA prices offered to OPPD during a competitive Request for Proposal process conducted by OPPD in the spring of 2016.

As an intermittent resource, wind must still be supported by dispatchable forms of capacity to ensure system reliability. SPP accredits approximately 15% of the nameplate capacity of a wind facility towards system capacity, depending on actual generation during peak loading after the first three years of operation.

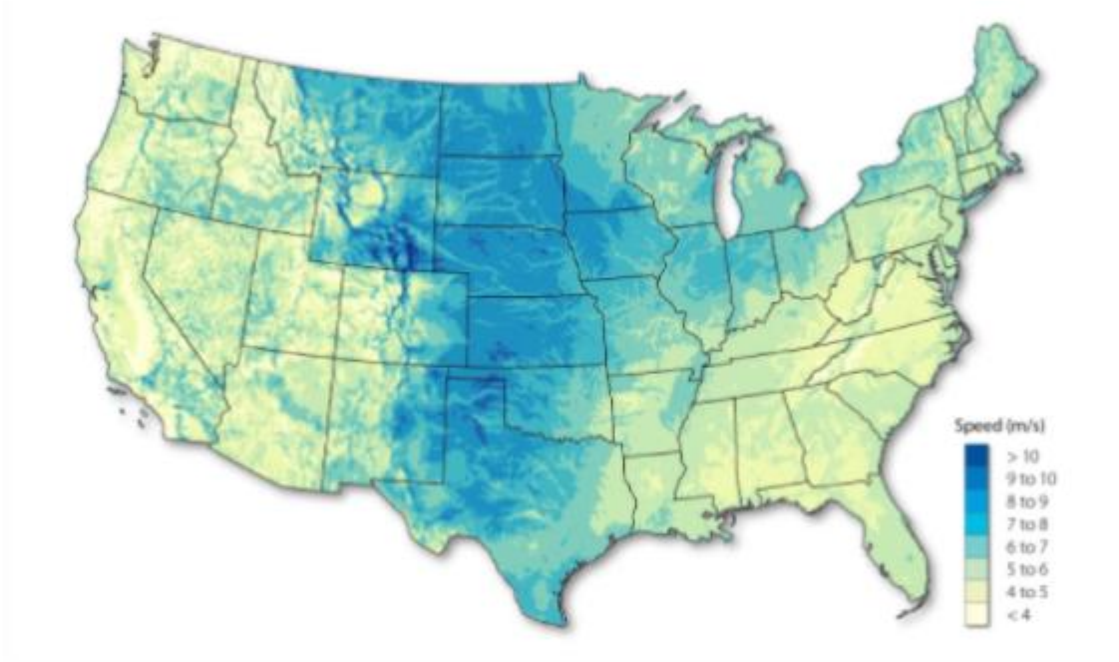


Figure 8- Average 80m wind speeds. Source: DOE Wind Vision

Solar. Solar costs have declined rapidly in recent years, and OPPD expects these costs to continue to decline for the next several years. Supporting the reduction in cost for this technology is the Investment Tax Credit, which provided a 30% credit for solar installations installed prior to 2016 and will provide a 10% credit for installations after 2016. A wide variety of solar technology was considered in the 2016 IRP modeling including fixed, single-axis and multi-axis photovoltaic sources at the residential scale, community scale and utility scale. Of these technologies, utility-scale solar was identified to provide the best economic value of any of the solar technologies considered. Installation and maintenance costs for smaller scale solar were significantly higher.

When compared to other areas of the U.S., solar generation in eastern Nebraska is disadvantaged by sub-optimal solar irradiance levels and the higher land values of agricultural crop land. Though the costs of solar are expected to decline, the total cost of solar generation is projected to be at a material premium when compared to other forms of renewable generation in the region, such as wind generation. Solar potential across the continental United States can be seen in Figure 9, which shows average annual solar irradiance.

Currently, SPP accredits approximately 25% to 30% of the nameplate capacity of a solar facility towards accredited capacity after the first three years of operation. This is dependent on the location, direction, and actual effectiveness of the solar installation. As an intermittent resource, solar generation must be supported by dispatchable forms of energy to ensure system reliability.

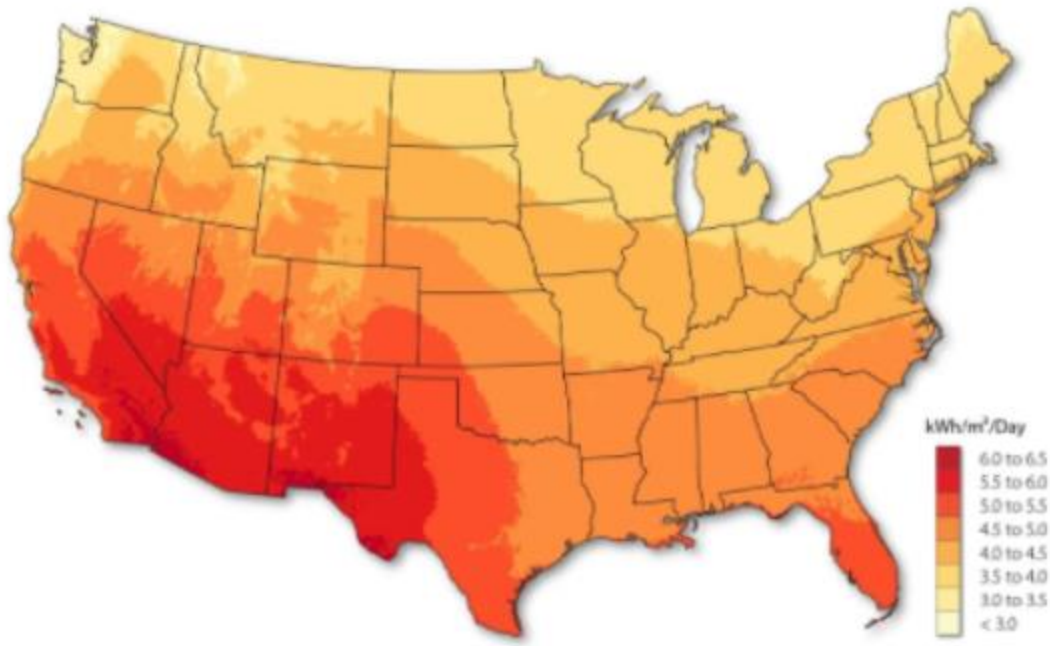


Figure 9 - Average annual solar irradiance. Source: NREL

Storage Technologies

Traditional grid-scale energy storage technologies such as pumped hydro and compressed air energy storage have the ability to provide value to the market in numerous ways including meeting system capacity requirements; shifting off-peak generation to peak periods; providing frequency regulation and voltage support and providing ramping abilities. Newer technologies such as battery storage provide even more opportunity in that they are modular and can be distributed to relieve transmission congestion and defer transmission and distribution investments. An alternative to energy storage is the use of peaking generators.

Long Duration Battery Storage. Battery storage is the most promising form of energy storage available to OPPD due to the declining technology costs, deployment flexibility and number of services the technology is capable of providing. The costs of battery storage have seen significant decreases in the past few years, and several large scale projects have recently been completed or are in the process of being completed in the U.S. This technology may become particularly relevant to the Upper Midwest as higher levels of wind penetration are reached in the marketplace.

Excluded Options

Due to technical limitations arising from the complexity of optimizing the portfolio over many years with many different resource options, not all of the resource options were simultaneously modeled. Those resources that were excluded are noted below, along with the justification for their exclusion.

Advanced Nuclear. While having low fuel costs and no greenhouse gas emissions from generation, nuclear technology remains challenged by very high capital costs, operational costs and regulatory burden. The low and increasingly volatile wholesale power prices resulting from renewables penetration in SPP creates a significant obstacle for nuclear technology, which has limited operational flexibility. The technology's inability to quickly modulate its level of power production reduces its ability to support high levels of renewable penetration.

Integrated Gasification Combined Cycle (IGCC). IGCC has few full-scale operational examples. The few examples that do exist have had cost overruns exceeding one billion dollars. Though this technology allows for the use of local high sulfur coal in other regions of the U.S., OPPD already has access to low sulfur coal due to its proximity to the Powder River Basin. The very high capital and operational costs make this option an uneconomic alternative.

Pulverized Coal. Traditional and advanced coal technologies were excluded from the analysis due to high capital and operational costs relative to market power prices, as well as risks due to uncertainty around future load growth and environmental regulations. The increased greenhouse gas emissions from such a facility would also challenge compliance with proposed environmental legislation.

Compressed Air Energy Storage and Pumped Hydro Energy Storage. The economics of both compressed air energy storage and pumped hydro storage are heavily dependent on geology and terrain. These resources have been evaluated in past OPPD studies and have not proven economic. Though these technologies are relatively mature and are not expected to have significant decreases in cost through the study period, the costs of alternative forms of energy storage like long duration batteries are projected to decrease significantly. The decreasing costs and increased flexibility and capability of long-duration battery storage make it a better option for OPPD than compressed air energy storage and pumped storage hydro.

Flywheel Energy Storage. Flywheel energy storage technology is well suited for applications involving power quality, fast regulation and rapid frequency response. However, this technology is a more expensive form of energy storage than long duration batteries. At this time, OPPD has not experienced poor power quality issues that would require use of the technology. The technology may be evaluated in the future as OPPD's generation mix changes.

5.2.3 Demand-Side Options

In 2014, OPPD committed to pursuing a total of 300MW of peak load reduction by 2023 through energy efficiency and demand response programs. Programs were identified and selected through a DSM potential study conducted by Applied Energy Group, Inc., a third-party consultant. As of December 2016, approximately 124MW of the targeted 300MW DSM have already been implemented. The 2016 IRP assumes all existing DSM programs will continue through the study period. It re-evaluates planned, future demand response programs within the context of updated market and technology assumptions.

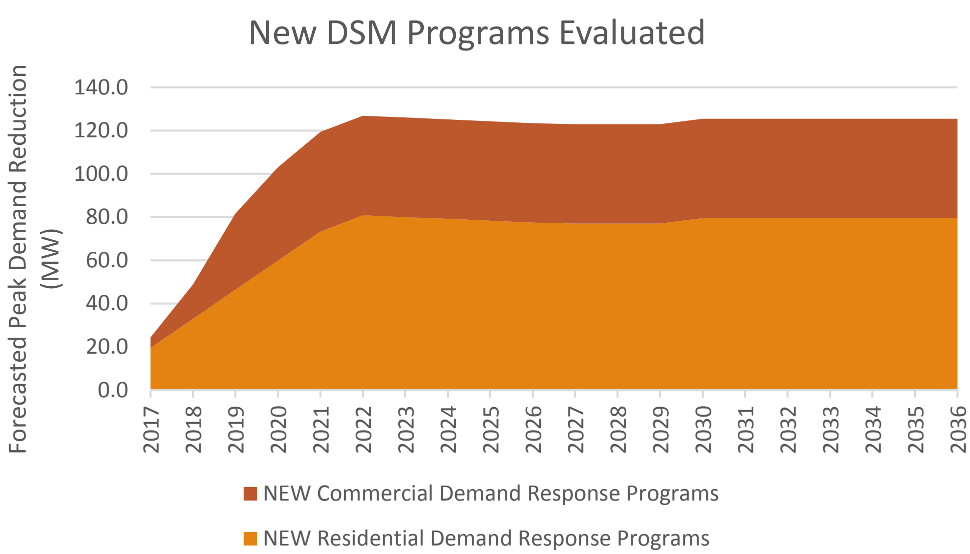


Figure 10 - Peak Demand Impact of DSM Programs Evaluated

Greater detail of these programs and the selection process used in 2014 can be found in Section 2.8 Demand-Side Management Programs. The DSM programs and megawatt capacity values re-evaluated are listed Appendix C. OPPD's DSM program is relatively new and based on a study completed in 2014 by the aforementioned Applied Energy Group, Inc. OPPD plans to update the DSM study in the future, incorporating actual DSM program results. The DSM potential study is complex and costly; it evaluates DSM program costs, consumer behaviors, appliance saturation rates and actual consumer energy use to derive estimated program participation rates and costs. In addition to updating the comprehensive DSM potential study, OPPD re-evaluates and modifies DSM programs to make sure they are cost effective (given current cost estimates and market conditions) and relevant to customers.

5.3 Portfolio Optimization

The portfolio optimization process used the AURORAxmp optimization tool to simultaneously consider the resource options listed in section 5.2 to meet OPPD's future capacity and energy needs. This process also considers the retirement and replacement of existing OPPD generation assets. By design, the optimization results in the lowest total system cost portfolio for the given set of resource alternatives and the constraints imposed on the modeling process.

5.3.1 Modeling Constraints

Modeling constraints were applied during the optimization to prevent the tool from arriving at portfolio solutions that were not compliant with regulations or were financially or operationally undesirable.

Capacity Reserve Margin. SPP imposes a requirement that each load serving utility within the SPP footprint maintains a 12% capacity reserve margin. This means that each utility must have accredited capacity totaling the peak demand of their load service territory, plus an additional 12% buffer. This buffer ensures total system reliability by maintaining enough capacity to serve load under extreme events.

Net OPPD Energy Position. To limit OPPD's market and financial risks, a 30% limit was placed on total energy generation, in excess of OPPD's projected retail sales. This 30% threshold limits OPPD from assuming speculative market positions where OPPD would rely on market sales to subsidize total system costs.

Renewables Limits. OPPD has set both a lower and upper limit on the percentage of intermittent renewable resources to be integrated into its system over the next five years. The lower limit is 30%, which is in alignment with Strategic Directive 7 set by OPPD's Board of Directors. The upper limit is set to 50% of OPPD's total retail load. In 2016, 16% of OPPD's total retail sales were provided by renewable generation resources. As its system materially changes, with the addition of renewable resources in a relatively short period of time, OPPD wants to ensure the system can operate reliably and predictably. In practical terms, an upper limit allows OPPD to gain the operational experience necessary to support reliable system operation as more renewables are added. The concentration of renewables will be continually re-evaluated in light of OPPD's strategic directives with considerations given to system reliability, the evolving transmission and distribution system, cost and market conditions.

North Omaha Station. North Omaha was constrained to be maintained in its current state until 2018. This allows OPPD to react to any potential recommendation to cease operations at the facility and allows for a better understanding of power flows on the north side of its service territory with the closure of Fort Calhoun Station.

Clean Power Plan Regulations. All modeling and optimization includes impacts and compliance with the EPA's Clean Power Plan (CPP), as currently written. The projected impacts of this rule resulted in the suppression of coal generation to allowable limits, as prescribed by the CPP. This method economically suppresses high -emitting units in favor of generation from lower carbon sources.

5.3.2 Portfolio Results

The optimization process resulted in a single, fully optimized portfolio. To better understand and convey the impacts of alternative portfolios, additional constraints were included to arrive at an increased number of portfolios beyond the single, fully optimized portfolio. The following sections describe the resource changes produced by the optimization over the next five years.

Blue Portfolio. The Blue Portfolio represented the fully optimized resource mix, which resulted in the lowest projected cost of the sample portfolios and resulted in 50% of projected retail electric sales coming from renewable resources. This portfolio maintained all current existing assets through the five-year period, recommended the procurement of an additional 426MW of wind generation and indicated that a 46MW portion of the 300MW demand-side management target was uneconomic, relative to alternative sources of capacity. The total DSM target of 300MW would remain the same while the District identified another program or augmented an existing program to replace the 46MW identified as uneconomic.

Yellow Portfolio. The Yellow Portfolio retained the renewable threshold of 50% of retail energy sales by renewable sources through an additional 426MW of incremental wind energy. An additional constraint was applied to Portfolio Yellow, requiring a 10MW long-duration battery storage asset. Similar to the Blue Portfolio, the analysis recommended 46MW of Business Direct Load Control DSM be replaced with another, more economical program.

Orange Portfolio. Similar to both the Yellow and Blue Portfolios, the Orange Portfolio also included 50% of retail electric sales supplied by renewable resources. Unlike Yellow and Blue, Orange included 100MW of utility scale solar generation and 326MW of incremental wind generation.

Pink Portfolio. The Pink Portfolio reduced the limitation constraint on renewables as a percentage of retail electric sales from 50% to 40% of OPPD system requirements. As a result, only 160MW of incremental wind energy would be sourced.

5.4 Deterministic Results

The deterministic modeling process is a more detailed simulation than the process used for optimization of portfolios. Each of the optimized portfolios are modeled deterministically to calculate expected total system production costs. These system production costs are then used to determine the portfolio net present value calculation. The basis for the net present value calculation is the 20-year study period from 2017 to 2036. This 20-year duration captures the life of the renewable generation purchased power agreements considered and extends far enough into the future to account for the uncertainty of projected market changes.

5.4.1 Net Present Value Results

The deterministic results indicate the Blue Portfolio to be the lowest cost resource mix of the portfolios evaluated. The Blue Portfolio was followed by the Yellow Portfolio, the Orange Portfolio and then the Pink Portfolio in order of increasing cost. The Blue Portfolio was fully optimized and was expected to be the lowest-cost option. This portfolio added 426MW of nameplate wind capacity over the next five years.

The Yellow Portfolio cost was marginally higher than the Blue Portfolio. This was driven by the uneconomic addition of 10MW of battery storage included, which was the only resource difference between the Blue and Yellow Portfolios.

The Orange Portfolio included 100MW of utility-grade solar and was a substantially higher total portfolio cost than the Blue Portfolio. The modeling outcome of this scenario indicated that, at this time, the cost of a combination of wind and solar would be materially higher than a portfolio which attained the same level of renewables through wind only.

The total cost of the Pink Portfolio, which had a 40% limit on renewables, was significantly higher than the blue portfolio, which had a 50% limit on renewables. The cost differential between these portfolios was due to the fact that wind power could presently be procured at a lower cost than the average wholesale price of power forecasted throughout the study period. Portfolio Pink confirmed that wind energy was economically favorable to the portfolio. However, any incremental wind beyond the 426MW recommended by the analysis would introduce energy in excess of the 30% constraint above projected retail sales, and thus expose OPPD to higher levels of market risk. Figure 11 below aggregates the net present value cost of operating various portfolios as well as the incremental costs between the sample portfolios.

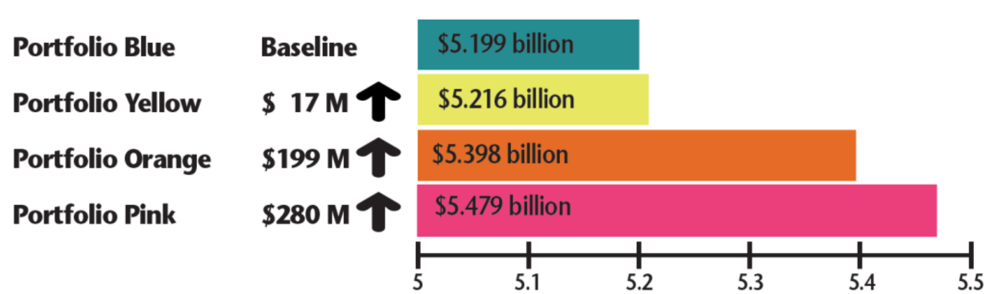


Figure 11- Portfolio Deterministic Results

5.4.2 Generation Results

In each of the portfolios, OPPD's future generation mix will be composed of significantly more renewable resources than it has been historically. OPPD's shift to renewable resources can clearly be seen in Figure 12. The focus of this Integrated Resource Plan is between 2017 and 2021. OPPD plans to continually revisit generation options and its future generation mix as both technology matures and as customer preferences evolve. As OPPD revisits it generation planning efforts, it will continue to strive toward its mission of affordable, reliable and environmentally sensitive energy.

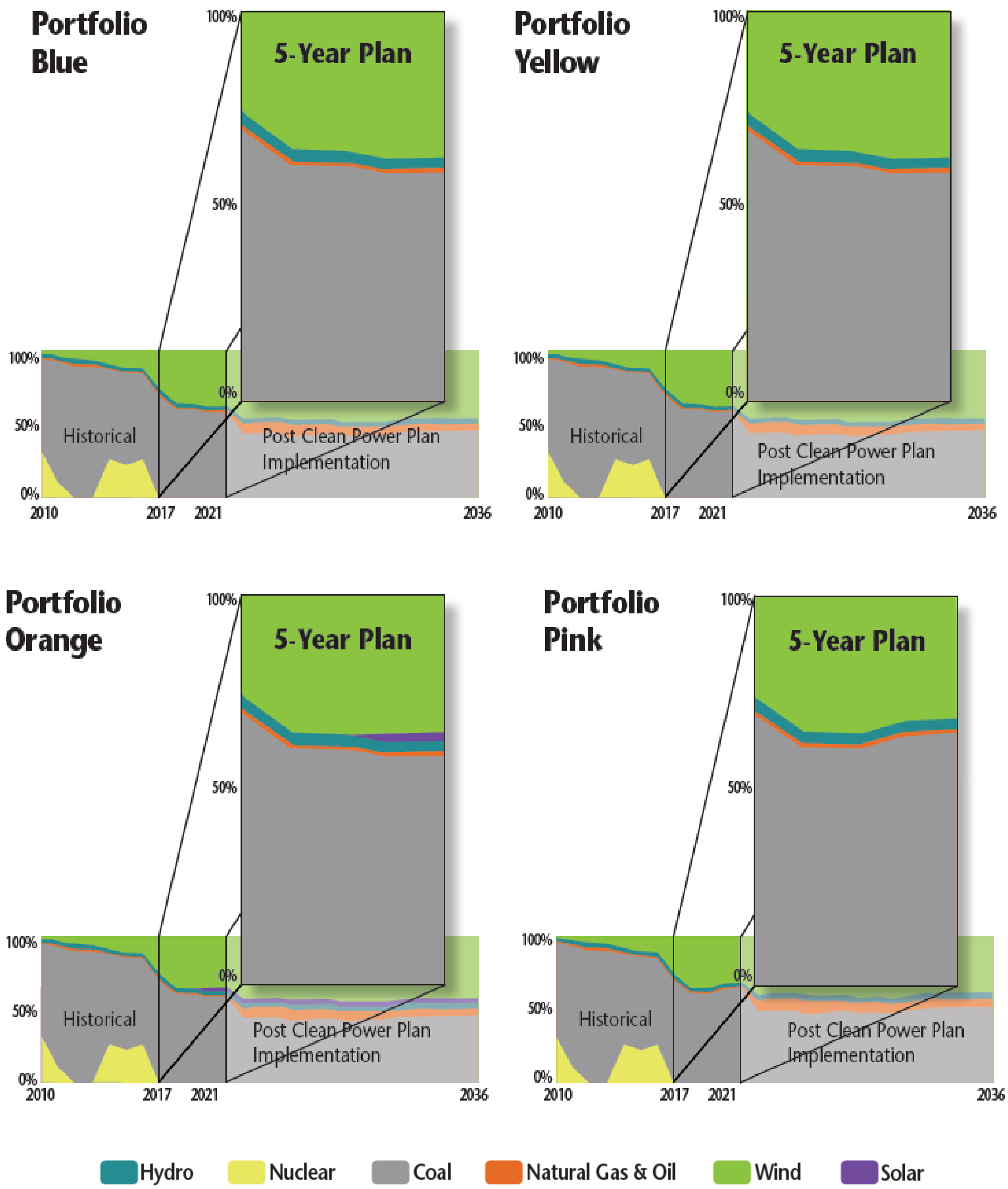


Figure 12- Portfolio Generation by Year. Source: Historical: OPPD Corporate Operating Plan, Future: PACE Deterministic Modeling

5.4.3 Emissions Results

Emissions reductions are comparable across the portfolios. OPPD continues to proactively protect the environment and meet or exceed all regulatory requirements. The installation and operation of emission controls equipment in 2016 at North Omaha Units 4 & 5 and Nebraska City Unit 1 has resulted in dramatic reductions in mercury emissions. The conversion of three coal units to natural gas at NO1, NO2 and NO3 will also continue to reduce emissions by meaningful levels. Depiction of emissions is based on CPP requirements and shown in Figure 13 below.

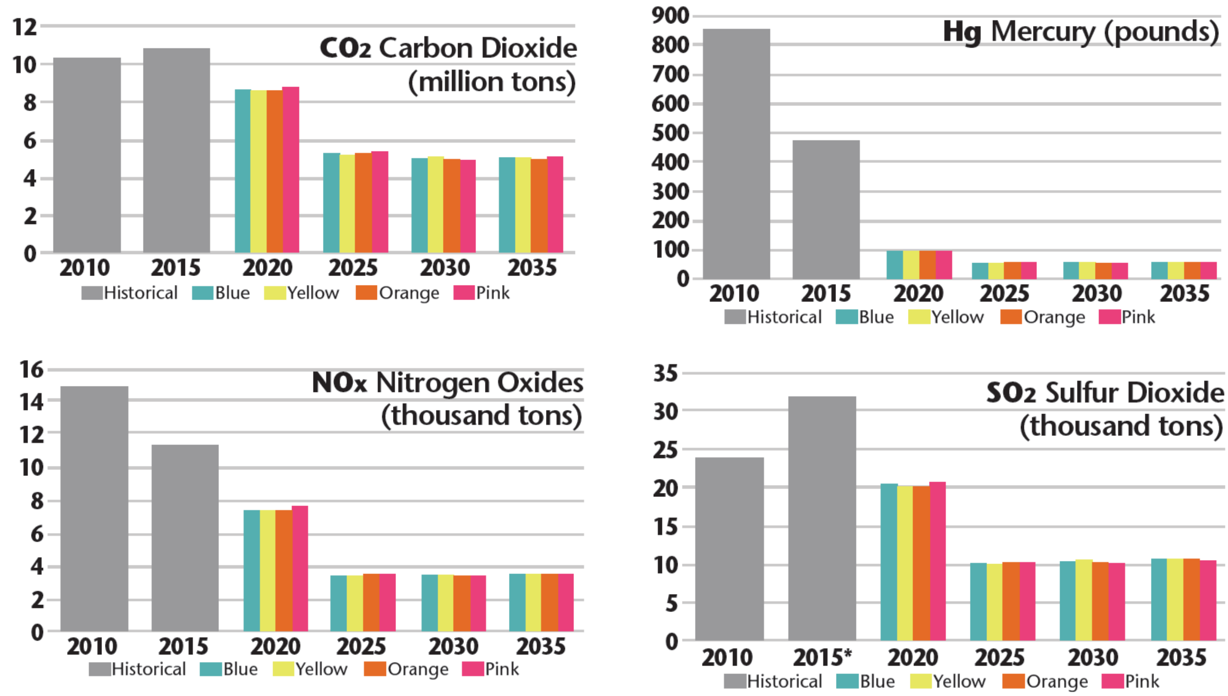


Figure 13- Emissions Timelines. Source: OPPD Environmental Affairs.

5.5 Stochastic Results

Building on the deterministic analysis, a stochastic analysis was conducted to evaluate the resilience of each portfolio under changing market conditions. The stochastic analysis tested each portfolio under a set of 200 unique market conditions using AURORAxmp within a cloud computing environment. The distribution of financial results from each of these 200 iterations was then analyzed to better understand the potential long-term market risks associated with each portfolio. This process helped ensure that OPPD would make long-term investment decisions that continued to fulfill its mission of affordable energy in the event of many possible future market environments. The market conditions used in this process were derived from historical and expected future volatility of fuels, projections for future market volatility and the potential impacts caused by technology disruptions and declining technology costs. Distributions for market forecasts used in this analysis are contained in Appendix B.

Risk quantification using CVAR$_{90}$. Financial risks were quantified using Conditional Value at Risk at the 90th percentile (CVAR$_{90}$). This measure was computed as the mean of the net present value of all iterations exceeding the 90th percentile for each set of stochastic outcomes. The measure was an indication of the 'tail risk' of portfolio outcomes. This metric helped answer the question "How costly could this portfolio be on average under its worst set of market conditions?" As an example, this would be calculated as the mean of the top 20 most costly iterations of a set of 200 iterations. Figure 14 below is a comparison between the Mean NPV cost (average cost) to operate the portfolio on the y-axis, and the x-axis features the CVAR$_{90}$ (financial risk) value. "Baseline" denotes the ongoing operations of FCS within the OPPD portfolio, while "Rebalanced" signifies the decision to cease operations at FCS. The remaining four colored portfolios denote the four sample portfolios developed as part of the IRP process.

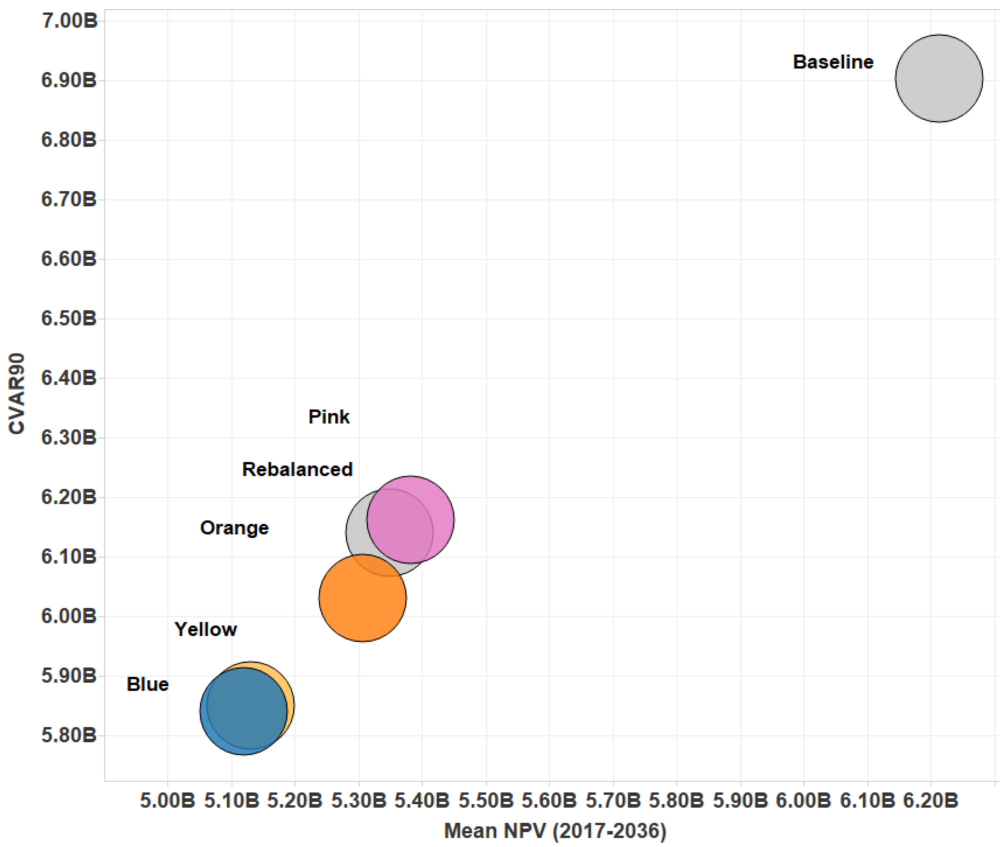


Figure 14 - Stochastic Analysis Results. The "Baseline" and "Rebalanced" Portfolios reflect the studies conducted during the Fort Calhoun Station Analysis. Values above are expressed in billions of 2016 dollars. Source: PACE Stochastic Modeling.

The stochastic analysis indicated that both average cost and financial risk have been lowered in the optimized portfolios, as compared to portfolios analyzed earlier in 2016 that included continued operation of Fort Calhoun Station. The fully optimized Blue Portfolio was projected to be both the lowest average cost and lowest financial risk portfolio of the portfolios evaluated. This was a result of current wind PPA prices located at the very lowest reaches of the expected future price distribution.

Though the results of the stochastic analysis indicated that even more investment in wind would result in a lower cost and lower financial risk portfolio, there are also operational risks that must be evaluated and understood as the portfolio increases reliance on intermittent renewable resources. The Blue Portfolio was the lowest cost and risk portfolio, satisfying the 50% renewable limit placed on the portfolio over the next 5 years. Accordingly, OPPD incurs the lowest average cost to operate the portfolio and incurs the lowest financial risk, which supports Strategic Directive 2 – Competitive Rates.

5.6 Analysis Conclusions

The analysis conducted in the 2016 IRP indicated the Blue Portfolio to be the lowest cost and lowest financial risk resource mix over the next 20 years. This portfolio represents continued investment in wind generation, up to 50% of OPPD's retail energy requirements.

As the lowest cost and lowest financial risk portfolio maximizes the 50% renewable constraint, further analysis is needed to evaluate the means of integration of higher levels of renewables, while ensuring high system reliability. OPPD must also continue to evaluate both the financial and operational risks associated with a transition to such a portfolio.

OPPD anticipates that its resource plan will be continually re-evaluated and will continue to evolve as the industry undergoes an extended period of dynamic change.

6.0 Stakeholder Engagement

OPPD engages stakeholders in important matters that support our mission to provide affordable, reliable and environmentally sensitive energy services to customers. OPPD is also aligned around a number of strategic directives, including SD-13: Stakeholder Outreach and Communication. Through this directive, we are committed to providing stakeholders with important information and feedback opportunities.

In 2014, OPPD launched a comprehensive initiative to establish stakeholder expectations and objectives related to resource generation. At that time, OPPD held numerous open houses and created an online meeting and feedback forum, *oppdlistens.com*, for garnering feedback.

In 2016, the WAPA filing, although not requiring a board vote, presented an opportunity for OPPD to re-engage stakeholders. Outreach focused on education of the modeling results and gathering feedback on the process and options presented.

Objectives of the outreach were clearly defined as follows:

1. Assess OPPD's generation mix and make a recommendation to the OPPD Board of Directors
2. Present portfolios that support OPPD strategic directives and take into consideration cost, environmental impact, financial risk, reliability and ability to adapt to changing climate
3. Create multiple forums for communicating to and gathering feedback from stakeholders
4. Use research and feedback to create OPPD's future integrated resource plan
5. Meet regulatory requirements by submitting the plan to WAPA in February 2017

6.1 Outreach Efforts and Results

OPPD outreach included multiple facets. The sections listed below will provide an overview of efforts and the results of each.

6.1.1 OPPD Board of Directors Meetings

The process, timing and outreach efforts, specifically related to the WAPA filing, were initially introduced to the public at the November 2016 OPPD Board of Directors meeting. Meetings are heavily attended by local media and special interest groups. They are also livestreamed throughout the OPPD service territory.

Research and outreach were conducted over the next month, and OPPD returned to the Board of Directors in December 2016 with a recommendation and outreach results.

6.1.2 Research

The process included qualitative and quantitative research conducted by an industry leader, Market Strategies International, and was performed in 2014. This phase included residential and commercial customer focus groups and gauged impressions on 15 portfolio options.

Additionally, an online survey was conducted across OPPD customer groups to gather feedback. OPPD collected more than 400 surveys from across OPPD's territory. During this phase, the trade-offs of potential resource attributes and options were evaluated. The significant community preferences included generation sources that provided affordability, had renewable features, reduced conventional emissions and greenhouse gases and provided customer energy efficiency programs.

From this research, OPPD also learned the following insights and took these customer preferences into the 2016 IRP 30 day stakeholder process:

- Customers are willing to trade off a slight increase in cost to reduce emissions and increase renewables
- The tipping point was low and significant bill increases (above 10%) for higher reductions were not acceptable
- Stakeholders trust OPPD to make the right decisions

6.1.3 Open House Events

Three open houses were held across the service territory on November 29-30 and December 1 to engage the Omaha metro and rural customers to the north and south. Open houses provided a forum for customers to walk through a series of educational banners, speak with subject matter experts about the process and provide feedback on options presented.

Figure 15- Open house event held at University of Nebraska, Omaha on November 29, 2016

Stations included education on public power, our relationship with WAPA and the Southwest Power Pool, resource planning efforts to date, the modeling process, resource options, economics, environmental compliance, demand-side management and research approaches.

The open houses were attended by 46 OPPD customers, and ten feedback forms were completed. The open house format was well-received, and feedback included comments on timing, visibility to the actual report and modeling details, information on additional technologies (i.e. distributed energy resources and hydrogen storage) and inquiries on the economics and implementation of solar.

6.1.4 Electronic Efforts

OPPD electronic efforts were concentrated on use of its content marketing site, oppdlistens.com, social media and an email campaign.

OPPDListens.com – This site resides within oppd.com, and is used for sharing information on industry and utility discussions, as well as listening and seeking to understand customer issues and concerns. During outreach, the site received 1,561 page views and 1,281 of those were unique views. OPPD also received comments and requests for information from 22 customers via the site, to which written responses were provided.

OPPDtheWire.com – This is OPPD's content marketing site, and its stories help provide more context and transparency around company efforts, as opposed to most traditional websites. A story on the integrated resource planning and outreach efforts received 577 page views; 550 of those being unique views.

Social Media – Customers following OPPD on Facebook and Twitter received several posts and 11 tweets promoting the process and OPPD outreach efforts. On Facebook, OPPD reached 2,997 customers, with 143 video views. Twitter impressions reached 248,000, with 85 click-throughs to web pages.

Email Campaign – More than 200 emails were sent to elected officials and community leaders. This group included state senators, congressional representatives, mayors, city council members, county commissioners, area chambers of commerce and environmental partners.

Figure 16 - Sharing on social media

6.1.5 Written Efforts

OPPD written efforts included OPPD's monthly customer newsletter, Outlets, as well as press releases and posters advertising area open houses.

Outlets – OPPD's newsletter is distributed with customer bills and reaches 365,000 customers. It was used to promote *oppdlistens.com* as a source for more information and a forum to provide feedback.

Press Releases – Two press releases were sent to 65 media outlets. OPPD's process and outreach were covered by the Omaha World-Herald, KETV, KMTV, KBLR and the Washington County Pilot-Tribune & Enterprise.

Posters/Banners – Posters and banners were displayed at open house venues to promote upcoming open houses. The University of Nebraska at Omaha (UNO) also posted the same information on their community engagement website.

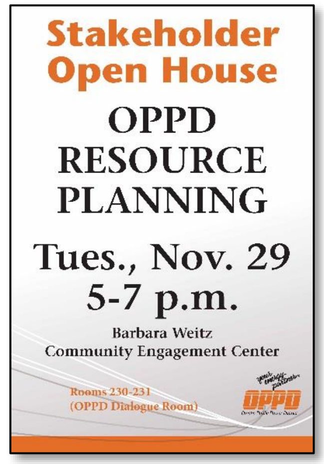


Figure 17 - Open house event flyer

Through the qualitative and quantitative research performed by Market Strategies International in 2014, stakeholders trust OPPD to make the right decisions regarding generation; they want electricity to be affordable, but are willing to pay a slight premium (although at a low tipping point) for renewable generation and emissions reductions; they encourage DSM programs and want reductions in environmental emissions. Stakeholders were not in favor of short-term retrofitting or refueling of uneconomic facilities.

Overall, customer expectations are aligned with OPPD's stated mission of providing affordable, reliable and environmentally sensitive energy services to our customers. This process thoroughly evaluated feasible options where OPPD considered stakeholder input and provided the Board of Directors with a fair, equitable and informed recommendation. This recommendation included the commitments to DSM, retirement and refueling activities described above.

Additionally, the Integrated Resource Plan is a public document, and the public is invited to offer their input on an ongoing basis by visiting OPPDlistens.com. OPPD's Board of Director meetings are also open to the public, and input is encouraged. These processes meet the requirements of the Federal Energy Planning and Management Program.

7.0 The OPPD Plan

7.1 OPPD 5-Year Plan

As a result of the Integrated Resource Plan, the analysis conducted by OPPD supported a number of relatively definitive conclusions. First, the analysis and forward-looking models concluded that wind is an economical energy source now and into the future. Second, OPPD identified that 46MW of its existing Demand-Side Management Program is uneconomical. Specifically, it is OPPD's intent that the Business Direct Load Control program identified as uneconomic would be replaced by another, soon-to-be-determined program. The program would be economical relative to other capacity options and would be used to keep the total, 300MW DSM program intact. Third, low cost natural gas generators are the most optimized way for OPPD to increase its capacity in the event that prices rise from the existing spot market. Further, with the advent of scarcity pricing promulgated by FERC and SPP, quick-fire natural gas generators may provide added value to OPPD's customer-owners. OPPD will continue its evaluation of those generators as its capacity needs increase beyond 2021.

7.2 Wind Generation Additions

The 2016 IRP includes the addition of 426MW of new nameplate wind generation capacity in addition to the 400MW Grande Prairie project, which will become part of OPPD's portfolio on or before July 1, 2017. This new wind acquisition is expected to be procured in two separate contracts over the next five years. With the inclusion of the wind energy from these projects, OPPD expects to obtain approximately 50% of its total retail energy sales from renewable resources.

7.3 Capacity Contracts and Delayed Unit Retirement

In 2016, OPPD procured multiple capacity contracts to support system capacity requirements over the next five years. In part, these capacity contracts replace the generation capacity of FCS. Assuming transmission margin remains, OPPD expects that short term capacity contracts will be the lowest cost solution to fulfill OPPD's accredited capacity requirements. In the event capacity contract prices rise or transmission would be unavailable, OPPD would evaluate building capacity or expanding its Demand-Side Management program—or both, depending on market conditions.

The generation plan produced in 2014 recommended that North Omaha Units 1-3 be retired in 2016. At the end of the analysis to cease operations at FCS in mid-2016, it was determined that refueling North Omaha Units 1-3 on natural gas would be the most cost-effective solution for maintaining system accredited capacity over the next five years. These units have been permanently retired from coal operation and are expected to operate on natural gas fuel, only at very high peak periods of system demand or during extreme events to support grid reliability. North Omaha Units 1-3 are among the oldest in OPPD's fleet and their continued, reliable operation will be an important factor in future life extension decisions.

7.4 Necessary System Features

The IRP takes into account necessary features for system operation including portfolio diversity, reliability, and dispatchability, as well as other risk factors.

7.4.1 Diversity

The primary objective of portfolio diversity is the reduction of long-term risks associated with both cyclical and secular changes in the marketplace. Such risks include unanticipated long-term shifts in fuel prices, unanticipated regulatory changes, and unanticipated disruptions in the market caused by technology breakthroughs. OPPD has a goal of integrating meaningful diversity into its resource portfolio to ensure it can continue to deliver its mission of affordability, reliability, and environmental sensitivity under a wide spectrum of possible future scenarios.

By making the decision to decommission Fort Calhoun Station, OPPD has greatly reduced its exposure to regulatory risks associated with the ongoing operation of a nuclear facility. These risks include the large capital cost which may have been required in the future to comply with evolving safety and operations regulations driven by the Nuclear Regulatory Commission. OPPD has found that this regulatory cost burden of compliance has only increased with time. The decision to shut down and decommission Fort Calhoun Station has also reduced the amount of net energy OPPD sells into the SPP integrated marketplace. This reduction in net surplus energy reduces OPPD's exposure to market power prices.

OPPD continues to invest in wind generation, which it receives through fixed price, purchased power agreements. This investment reduces OPPD's overall direct sensitivity to fuel price volatility by adding energy resources that are not impacted by commodity prices of fuels. Further, this investment better positions OPPD's portfolio for future environmental regulatory requirements such as those proposed by the Clean Power Plan.

7.4.2 Reliability

The OPPD 5-Year Plan will provide a minimum capacity reserve margin of 12%, as required by the SPP. The 12% margin is established by SPP stakeholder planning groups and is critical in maintaining continuous electricity deliverability to regional customers as well as the Eastern Interconnection.

As non-dispatchable resources, such as wind generation continues to grow in OPPD's portfolio, OPPD will continue to study grid modernization projects and will evaluate the need for fast-ramping resources to continue to support system reliability as time progresses.

7.4.3 Dispatchability

Through 2021, OPPD plans to maintain four dispatchable coal units, ten dispatchable natural gas units, and two dispatchable oil units. OPPD has a combined accredited capacity of 1,584.7MW from coal generation (including all of NC2), with a target of 42 days' worth of fuel supply located onsite. OPPD's dispatchable natural gas capacity, during the summer season, is 932.1MW, and its dispatchable oil capacity is 122.6MW.

7.4.4 Other Risk Factors

In addition to diversity, reliability and dispatchability, the 2016 IRP does acknowledge risks associated with the growing penetration of renewables in SPP North. Specifically, OPPD is aware of the growing need for resources with fast ramping and frequency response abilities to support system reliability and a high quality of power.

In addition to the growing need of fast-ramping generator technologies, OPPD is also monitoring the ongoing saturation of wind levels within SPP's northern region and the potential impact on regional pricing. In the event abnormal pricing events occur due to higher concentration of winds generation, OPPD would advocate for a number of remediating actions, including the potential construction of new transmission facilities.

7.5 Ongoing Planning Efforts

OPPD's energy load forecast exhibits little growth over the next five years. However, the addition of any sizeable customer loads to OPPD's service territory may require additional accredited capacity to be obtained. To support such future capacity needs, OPPD will evaluate available capacity options at the time needed. In addition to unanticipated load changes within OPPD's service territory, emerging technologies create the need for OPPD to re-evaluate its resource portfolio as part of an ongoing planning process. Within this ongoing planning process, DERs and portfolio flexibility will be of central importance in the coming years.

7.5.1 Distributed Energy Resources

DERs include small-scale generation, storage and demand response devices and are typically located at the point of end-use. These technologies are enabled by declining costs in technology and modernization of electric grid infrastructure. DERs represent an opportunity to both OPPD and to the customer through decreased customer energy bills, differed or mitigated distribution capacity and enhanced system reliability and resiliency. DERs also represent a challenge to OPPD because they can require complex integration with the existing electricity grid. As OPPD conducts future resource planning efforts, it will continue to evaluate the benefits of, and programs for, implementation of DERs within OPPD's service territory.

7.5.2 Resource Flexibility

OPPD has identified portfolio flexibility as a crucial aspect in ensuring it continues to provide the best value to customers as market conditions change. As part of this flexible strategy, OPPD has purchased capacity contracts and maintained NO1, NO2, and NO3 to defer large investments in long-term assets. Deferring large investments creates the financial flexibility required for capturing the value provided by emerging technology breakthroughs. Deferment of large, long-term assets also reduces the risk of overbuilding if future energy consumption is lower than current forecasts.

Appendix A – System Load and Capability

Summer Load and Capability

Summer Conditions (June - September)

	2017	2018	2019	2020	2021
1. Seasonal System Demand					
Base Peak (Aug 2015 LF)	2417	2454	2458	2445	2456
Efficiency (included in Base Peak)	0	0	0	0	0
DSM Applied to Base Peak as of June 1	-120	-128	-133	-137	-142
Total	2297	2326	2325	2308	2314
2. Annual System Demand	2297	2326	2325	2308	2314
3. Firm Power Purchases - WAPA	82	82	82	82	82
4. Firm Sales					
Wholesale Towns (a)	14	14	14	15	15
(blank)	0	0	0	0	0
Total	14	14	14	15	15
5. Seasonal Adj. Net Demand (1-3+4)	2229	2259	2257	2240	2247
6. Adjusted Net Demand (2-3+4)	2229	2259	2257	2240	2247
7. Net Generating Capability					
Fort Calhoun					
Nebraska City #1	656	656	656	656	656
Nebraska City #2	664	676	676	676	676
North Omaha	557	557	557	557	557
Sarpy County	317	317	317	317	317
Jones Street	123	123	123	123	123
Cass County	323	323	323	323	323
Elk City Landfill Gas	6	6	6	6	6
Future Baseload Capacity	0	0	0	0	0
Future Peaking Capacity	0	0	0	0	0
Total	2646	2657	2657	2657	2657
8. Participation Purchases					
Tecumseh (leased)	7	7	7	7	7
Wind Energy	60	82	82	122	122
Capacity Purchase	240	190	140	75	75
Total	307	279	229	204	204
9. Participation Sales					
Nebraska City #2 Participants	332	338	338	338	338
(blank)	0	0	0	0	0
City of Gardner Kansas	20	20	0	0	0
MJMEUC	35	0	0	0	0
Total	387	358	338	338	338
10. Accredited Capability (7+8-9)	2565	2578	2548	2523	2523
11. Net Reserve Capacity Obligation (6 X 12%)	268	271	271	269	270
12. Total Firm Capacity Obligation (5+11)	2497	2530	2528	2509	2516
13. Surplus or Deficit Capacity (10-12)	68	48	20	14	7
14. Reserve Margin (10/5 -1), SPP>12%	15.1%	14.1%	12.9%	12.6%	12.3%
15. Capacity Margin ((1-5/10), SPP>10.7%	13.1%	12.4%	11.4%	11.2%	11.0%

(a) Consists of the projected demands of the Nebraska towns and entities of Elk Creek, Greenwood, Syracuse, Tecumseh and Boys Town. All are served at wholesale by the District.

Winter Load and Capability

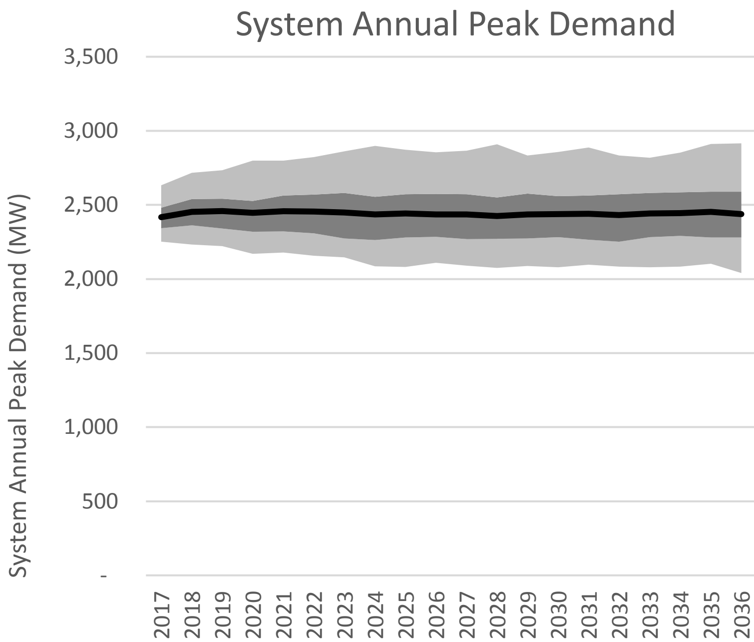
Winter Conditions (December - March)

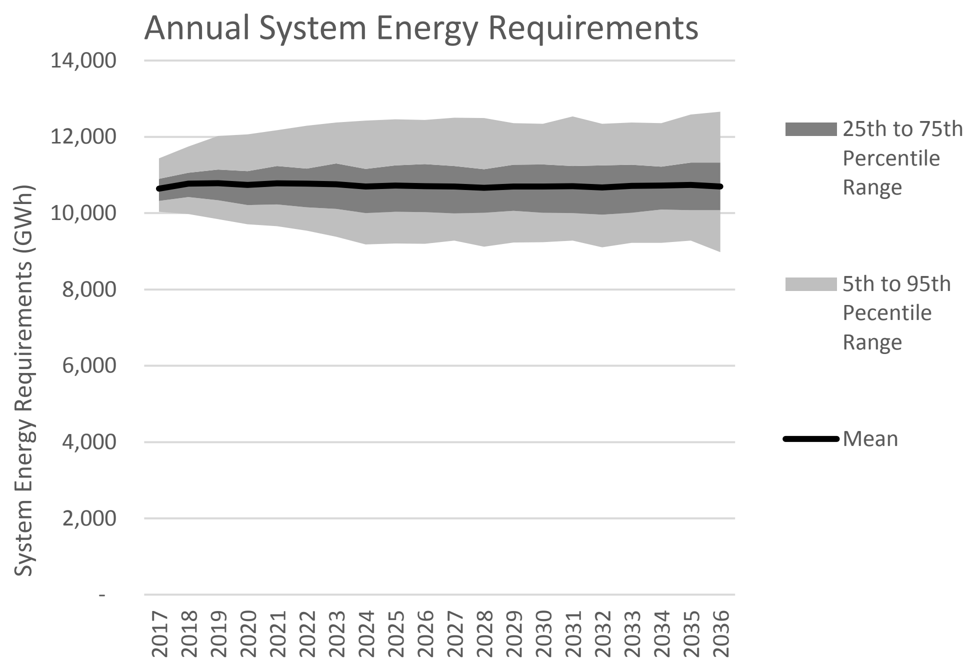
	17/18	18/19	19/20	20/21	21/22
1. Seasonal System Demand					
Base Peak (Aug 2015 LF)	1640	1643	1593	1661	1659
DSM, Winter	0	0	0	0	0
(blank)	0	0	0	0	0
Total	1640	1643	1593	1662	1660
2. Annual System Demand	2297	2326	2325	2308	2314
3. Firm Power Purchases - WAPA	42	42	42	42	42
4. Firm Sales					
Wholesale Towns (a)	10	10	10	10	10
Total	10	10	10	10	10
5. Seasonal Adj. Net Demand (1-3+4)	1608	1612	1561	1630	1628
6. Adjusted Net Demand (2-3+4)	2265	2295	2293	2276	2282
7. Net Generating Capability					
Fort Calhoun					
Nebraska City #1	656	656	656	656	656
Nebraska City #2	664	676	676	676	676
North Omaha	287	287	287	287	287
Sarpy County	317	317	317	317	317
Jones Street	123	123	123	123	123
Cass County	0	0	0	0	0
Elk City Landfill Gas	6	6	6	6	6
Total	2052	2064	2064	2064	2064
8. Participation Purchases					
Tecumseh (leased)	7	7	7	7	7
Wind Energy	102	102	142	142	142
Capacity Purchase	240	190	140	75	75
Total	348	298	288	223	223
9. Participation Sales					
Nebraska City #2 Participants	332	338	338	338	338
(blank)	0	0	0	0	0
City of Gardner Kansas	20	0	0	0	0
MJMEUC	35	0	0	0	0
Total	387	338	338	338	338
10. Accredited Capability (7+8-9)	2013	2024	2014	1949	1949
11. Net Reserve Capacity Obligation (6 X 12%)	193	193	187	196	195
12. Total Firm Capacity Obligation (5 + 11)	1801	1805	1748	1826	1823
13. Surplus or Deficit Capacity (10 - 12)	212	219	266	123	126
14. Reserve Margin (10 / 5), SPP>12%	25.2%	25.6%	29.0%	19.6%	19.7%
15. Capacity Margin ((1-5/10), SPP>10.7%	20.1%	20.4%	22.5%	16.4%	16.5%

(a) Consists of the projected demands of the Nebraska towns and entities of Elk Creek, Greenwood, Syracuse, Tecumseh and Boys Town. All are served at wholesale by the District.

North Omaha Winter	17/18	18/19	19/20	20/21	21/22
North Omaha 1	0	0	0	0	0
North Omaha 2	0	0	0	0	0
North Omaha 3	0	0	0	0	0
North Omaha 4	111.8	111.8	111.8	111.8	111.8
North Omaha 5	174.8	174.8	174.8	174.8	174.8
Total	286.6	286.6	286.6	286.6	286.6

System Load Ranges for Stochastic Analysis



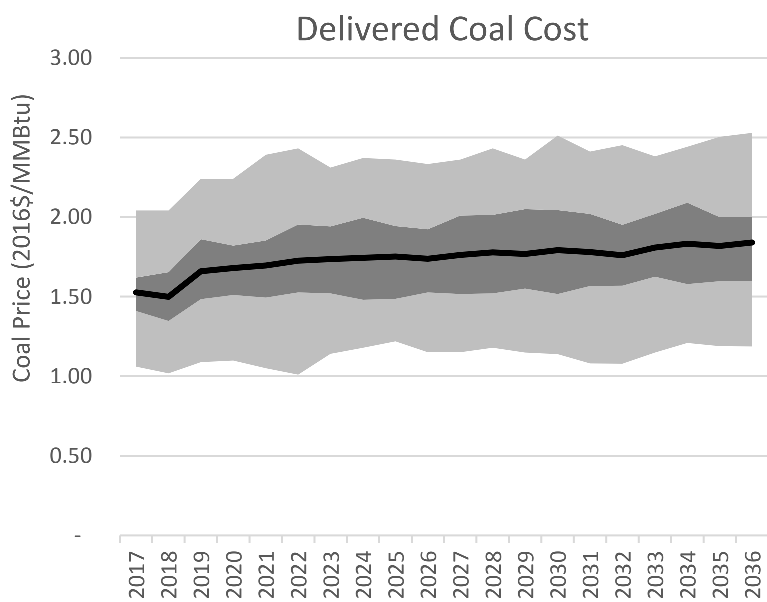


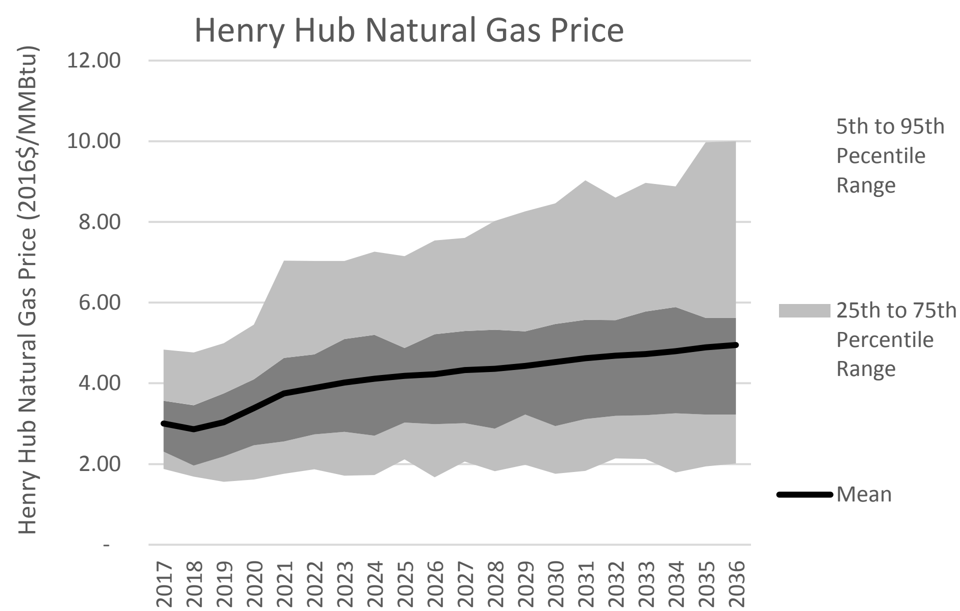
Peak Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
5th Percentile	2,253	2,232	2,221	2,170	2,179	2,156	2,146	2,086	2,081	2,109	2,091	2,075	2,089	2,079	2,096	2,085	2,079	2,085	2,103	2,040
25th Percentile	2,344	2,363	2,342	2,319	2,322	2,308	2,275	2,264	2,281	2,284	2,270	2,272	2,273	2,282	2,266	2,252	2,283	2,292	2,281	2,281
Mean	2,417	2,454	2,459	2,446	2,457	2,455	2,449	2,435	2,441	2,437	2,436	2,426	2,437	2,439	2,441	2,431	2,442	2,445	2,452	2,439
75th Percentile	2,481	2,539	2,541	2,526	2,564	2,570	2,582	2,555	2,571	2,574	2,573	2,550	2,577	2,560	2,564	2,571	2,580	2,584	2,589	2,589
95th Percentile	2,632	2,716	2,735	2,800	2,798	2,823	2,861	2,899	2,873	2,854	2,865	2,908	2,834	2,858	2,888	2,834	2,817	2,853	2,911	2,916

System Energy Requirements (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
5th Percentile	10,038	9,981	9,845	9,711	9,660	9,538	9,378	9,179	9,206	9,200	9,279	9,121	9,231	9,241	9,282	9,104	9,220	9,222	9,282	8,977
25th Percentile	10,323	10,421	10,333	10,211	10,226	10,155	10,110	10,000	10,033	10,023	9,996	10,006	10,063	10,015	10,006	9,960	10,006	10,095	10,080	10,080
Mean	10,642	10,771	10,785	10,736	10,779	10,773	10,754	10,700	10,721	10,706	10,701	10,664	10,696	10,702	10,706	10,672	10,711	10,722	10,743	10,697
75th Percentile	10,900	11,060	11,141	11,097	11,238	11,171	11,304	11,157	11,255	11,287	11,234	11,152	11,270	11,279	11,233	11,249	11,265	11,221	11,325	11,325
95th Percentile	11,433	11,750	12,021	12,069	12,173	12,291	12,379	12,424	12,456	12,443	12,505	12,494	12,359	12,338	12,537	12,339	12,379	12,363	12,584	12,659

Appendix B – Market Forecasts

Fuel Prices for Stochastic Analysis

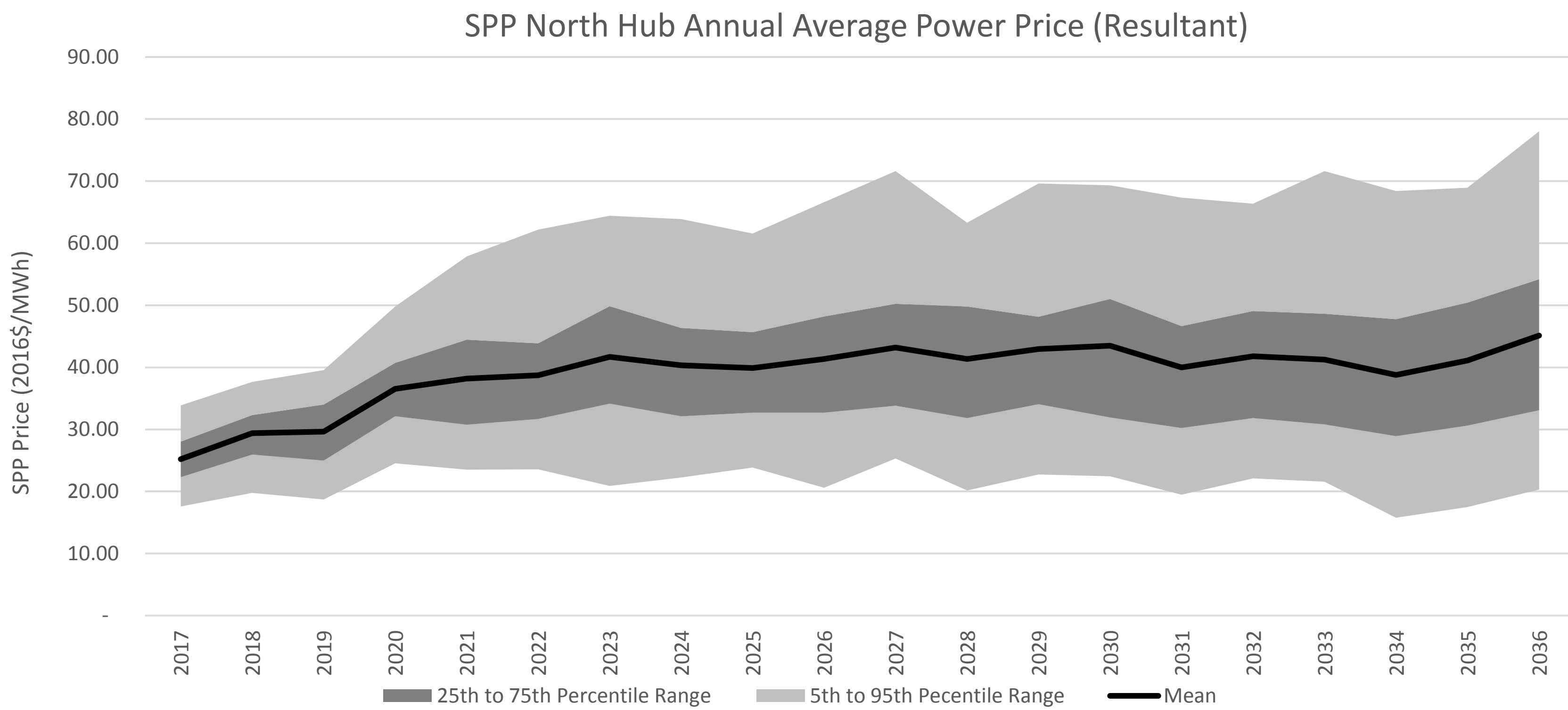




Coal ($/MMBtu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
5th Percentile	1.06	1.02	1.09	1.10	1.05	1.01	1.14	1.18	1.22	1.15	1.15	1.18	1.15	1.14	1.08	1.08	1.15	1.21	1.19	1.19
25th Percentile	1.41	1.35	1.49	1.51	1.50	1.53	1.52	1.48	1.49	1.53	1.52	1.52	1.55	1.52	1.57	1.57	1.63	1.58	1.60	1.60
Mean	1.53	1.50	1.66	1.68	1.69	1.73	1.74	1.74	1.75	1.74	1.76	1.78	1.77	1.79	1.78	1.76	1.81	1.83	1.82	1.84
75th Percentile	1.62	1.65	1.86	1.82	1.85	1.95	1.94	2.00	1.94	1.92	2.01	2.01	2.05	2.04	2.02	1.95	2.02	2.09	2.00	2.00
95th Percentile	2.04	2.04	2.24	2.24	2.39	2.43	2.31	2.37	2.36	2.33	2.36	2.43	2.36	2.51	2.41	2.45	2.38	2.44	2.50	2.53

Henry Hub Natural Gas ($/MMBtu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
5th Percentile	1.88	1.68	1.56	1.61	1.76	1.87	1.71	1.72	2.11	1.67	2.06	1.83	1.98	1.76	1.83	2.14	2.12	1.79	1.94	2.01
25th Percentile	2.31	1.96	2.19	2.46	2.56	2.74	2.80	2.71	3.03	2.99	3.01	2.88	3.22	2.94	3.11	3.19	3.21	3.26	3.23	3.23
Mean	3.00	2.86	3.04	3.39	3.75	3.89	4.02	4.11	4.19	4.23	4.33	4.36	4.43	4.53	4.62	4.69	4.72	4.80	4.89	4.95
75th Percentile	3.56	3.46	3.75	4.10	4.63	4.72	5.10	5.20	4.88	5.21	5.30	5.33	5.29	5.47	5.58	5.56	5.78	5.89	5.63	5.63
95th Percentile	4.83	4.77	4.99	5.45	7.04	7.03	7.03	7.26	7.16	7.54	7.61	8.03	8.26	8.46	9.03	8.60	8.97	8.88	9.98	10.00

SPP Market Prices from Stochastic Analysis



SPP North Annual Average Power Prices ($/MWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
5th Percentile	17.59	19.80	18.70	24.52	23.50	23.56	20.90	22.25	23.87	20.60	25.29	20.18	22.73	22.46	19.46	22.09	21.58	15.77	17.49	20.31
25th Percentile	22.30	25.95	24.98	32.10	30.75	31.68	34.18	32.13	32.70	32.68	33.80	31.83	34.08	31.93	30.23	31.80	30.80	28.90	30.63	33.09
Mean	25.20	29.41	29.65	36.52	38.18	38.71	41.70	40.34	39.89	41.36	43.20	41.37	42.93	43.48	39.99	41.80	41.24	38.76	41.08	45.12
75th Percentile	28.05	32.33	34.00	40.70	44.45	43.85	49.85	46.35	45.65	48.20	50.23	49.78	48.15	51.00	46.65	49.08	48.65	47.78	50.45	54.20
95th Percentile	33.86	37.68	39.55	49.81	57.87	62.21	64.41	63.91	61.54	66.61	71.63	63.31	69.61	69.34	67.33	66.36	71.63	68.42	68.95	78.03

Appendix C – Resource Options

Technology Cost Summary

Technology Details

Technology	Advanced Nuclear	Integrated Gasification Combined Cycle	Pulverized Coal without Carbon Capture	Pulverized Coal with Carbon Capture	Convential Combined Cycle	Advanced Combined Cycle	Conventional Combustion Turbine	Advance Combustion Turbine	Reciprocating Engine	Reciprocating Engine	Wind	Solar PV	Battery
Fuel Type	Uranium	Coal	Coal	Coal	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	N/A	N/A	Market Power
Description	Large baseload technologies screend out due to low load growth forecasts.				2 Large Frame CT + Steam Cycle	1 Large Frame CT + Steam Cycle	Small Frame CT	Large Frame CT	112.5 MW Facility	225 MW Facility	Onshore	Utility Scale Single Axis	Long-Duration 4-hr Composite
FL Heat Rate, HHV, Btu/kWh					6615.6	6749	9067.59	9974.46	8565	8565	na	na	na
FOM, 2016$/kW-yr					10.5	13.77	16	9.25	8.5	8.5	23.5	11.5	57.00
VOM, 2016$/MWh					2.75	2.10	5	8.75	5.4	5.4	na	na	na
Life, Years					30	30	25	25	25	25	25	20	14
Expected Capacity Factor					35%	35%	5%	5%	15%	15%	46%	27%	5%

Capital Construction Cost by Year (2016$/kW)

Year of Forecast	Advanced Nuclear	Integrated Gasification Combined Cycle	Pulverized Coal without Carbon Capture	Pulverized Coal with Carbon Capture	Convential Combined Cycle	Advanced Combined Cycle	Conventional Combustion Turbine	Advance Combustion Turbine	Reciprocating Engine	Reciprocating Engine	Wind	Solar PV	Battery
2016	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,185	$ 1,048	$ 741	$ 956	$ 854	PPA	PPA	$ 1,487
2017	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,048	$ 741	$ 956	$ 854	PPA	PPA	$ 1,472
2018	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,048	$ 741	$ 956	$ 854	PPA	PPA	$ 1,432
2019	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,048	$ 741	$ 956	$ 854	PPA	PPA	$ 1,166
2020	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,048	$ 741	$ 956	$ 854	PPA	PPA	$ 900
2021	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 956	$ 854	PPA	PPA	$ 858
2022	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 956	$ 854	$ 1,626	$ 1,631	$ 816
2023	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 956	$ 854	$ 1,610	$ 1,579	$ 774
2024	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 956	$ 854	$ 1,594	$ 1,529	$ 732
2025	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 956	$ 854	$ 1,578	$ 1,481	$ 690
2026	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 956	$ 854	$ 1,562	$ 1,434	$ 648
2027	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 955	$ 854	$ 1,546	$ 1,389	$ 606
2028	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 955	$ 854	$ 1,531	$ 1,346	$ 564
2029	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 955	$ 854	$ 1,515	$ 1,304	$ 522
2030	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,038	$ 1,184	$ 1,047	$ 741	$ 955	$ 854	$ 1,500	$ 1,284	$ 480
2031	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,037	$ 1,184	$ 1,047	$ 741	$ 955	$ 854	$ 1,496	$ 1,265	$ 480
2032	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,037	$ 1,184	$ 1,047	$ 741	$ 955	$ 854	$ 1,491	$ 1,246	$ 480
2033	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,037	$ 1,184	$ 1,047	$ 741	$ 955	$ 854	$ 1,487	$ 1,227	$ 480
2034	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,037	$ 1,183	$ 1,047	$ 741	$ 955	$ 854	$ 1,482	$ 1,209	$ 480
2035	$ 6,670	$ 7,663	$ 3,329	$ 5,736	$ 1,037	$ 1,183	$ 1,047	$ 741	$ 955	$ 854	$ 1,478	$ 1,191	$ 480

Note: Values are based on an aggregation of multiple industry sources including publicly available information from the National Renewable Energy Laboratory, the Lazard Levelized Cost of Energy Study 9.0 and other proprietary vendor supplied technology cost forecasts. Care was taken to reflect the most current and best cost projections for emerging technologies including solar, wind, and batteries. Costs are overnight construction costs and do not include site specific infrastructure costs. Site specific infrastructure costs were considered in addition to the costs shown above. Purchased Power Agreement (PPA) values for wind and Solar were solicited through a competitive Request for Proposal process in 2016 and reflect the best available cost information for this technology.

DSM Programs Evaluated

DSM PROGRAMS	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
EXISTING Residential DR																				
Capacity, MW	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80	57.80
NEW Residential DR																				
Capacity, MW	19.44	32.91	46.39	59.86	73.34	80.84	79.99	79.14	78.29	77.44	76.94	76.94	76.94	79.49	79.49	79.49	79.49	79.49	79.49	79.49
EXISTING Commercial DR																				
Capacity, MW	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30	54.30
NEW Commercial DR																				
Capacity, MW	4.83	15.98	35.16	43.08	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00	46.00

Note: New Residential Demand Response and New Commercial Demand Response are programs identified in the 2014 AEG study as part of OPPD's 300MW DSM target but are not yet implemented.

Appendix D – Outreach Materials

Leading the Way We Power the Future

As a public power utility, OPPD engages stakeholders in important matters that support our mission to provide affordable, reliable and environmentally sensitive energy services to our customers.

OPPD is committed to providing stakeholders with important information and feedback opportunities – as a matter of fact, it's one of our strategic directives.

In early 2017, OPPD is required to submit an Integrated Resource Plan (IRP) to one of our energy partners, the Western Area Power Administration (WAPA). This plan is prepared every five years as part of our contractual commitment to WAPA for hydroelectric power.

This handout gives you an overview of OPPD's progress over the years and a comparative look at the four portfolios that were a result of our study when preparing the WAPA filing. Our research shows you trust us to make the right decisions – but it's also important to us that you are educated, understand the reasoning behind those decisions and are able to provide feedback.

What is an Integrated Resource Plan (IRP)?

The plan is a road map for meeting OPPD's mission. It helps us determine how we will generate power in the future. We utilize a comprehensive, forward-looking decision support tool for evaluating resource options to meet our objectives at the lowest cost. The process considers supply-and-demand resource options, risk and fuel, power and technology costs associated with various resource plan outcomes.

OPPD's Resource Planning Practices

The utility industry is experiencing dynamic change at an accelerated pace. For that reason, OPPD regularly reviews resource options (and will continue to do so). In addition, the IRP is conducted every five years as part of the formal filing with WAPA. All reviews are based on market conditions, load requirements, legislation, research and pace of value for our customers.

Since our last formal IRP, our regular review and planning resulted in the decisions below:

- In 2014, we added nearly 200 megawatts of wind (Prairie Breeze) and announced plans for an additional 400 megawatts of wind (Grand Prairie) to come online in 2017.
- In 2014, we announced plans to retire North Omaha Units 1-3 (our three oldest coal-generation units) and we refueled to natural gas in 2016. We also announced the addition of emission controls on North Omaha Units 4-5 and Nebraska City Unit 1.
- In 2016, we began the decommissioning of our Fort Calhoun Nuclear Station because it was no longer economically feasible to operate.

What's next?

As part of this year's planning, OPPD has several near-term decisions to make. We will be submitting a 5-year plan to WAPA, focusing on the short-term. We will revisit our options once we know the final legal status of the Clean Power Plan (CPP), a set of Federal regulations limiting carbon emissions and expected to be enacted in the coming years. For OPPD, planning and decisions for future years will be revisited once there is more clarity around those regulations.

Why change now?

Change takes time, preparation and years to implement. Doing nothing now will cost more in the long-run. OPPD must make changes to its portfolio to ensure compliance with the possible CPP regulations and to ensure long-term low rates.

Stakeholder Outreach

OPPD listens. As a customer-owner, your opinion matters and your feedback is welcome – 24/7 – at **OPPDListens.com**. This site also provides other content, such as frequently asked questions, open house schedules and more.

Thank you for helping us shape your future generation.

Where We've Been

	RENEWABLES	COAL	NUCLEAR	NATURAL GAS & OIL
2010	4%	65%	30%	1%
2015	13%	63%	23%	1%

Fuel source as a percent of total generation (rounded, based on full-year data)
Source: OPPD Production Engineering

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Omaha Public Power District
November 2016

Where We're Headed

Four portfolios were selected as a result of our study. As part of the modeling process, we applied some assumptions:

- **Ensure reliability**
  To maintain an adequate capacity margin, the Southwest Power Pool (SPP) requires a minimum reserve margin of 12 percent. SPP is comprised of several utilities, generators and transmission companies for the purpose of ensuring reliability across the region. OPPD has been a member of SPP since 2009.
- **Limit market exposure and operational risk**
  Total energy generation not to exceed 30 percent above OPPD's retail load.
- **Include renewables**
  OPPD is dedicated to renewable generation per our strategic directive. By 2018, OPPD expects approximately 30 percent of its retail sales to come from renewable energy – predominantly wind power with a small landfill gas operation.

Portfolio comparisons reflect a more restrictive regulatory environment than today, conservatively ensuring our compliance with the Clean Power Plan.

Proposed Generation Additions (5 year)

In 2014, OPPD held a robust stakeholder process regarding our generation portfolio. That portfolio is in effect today and the proposed additions are listed below.

Portfolio Blue

This is the "Rebalanced Portfolio" identified during the recent Fort Calhoun Station analysis. It is the most economical and includes up to 50% renewables.*

- **Wind:** 426 MW

Portfolio Yellow

Includes up to 50% renewables* and expands the rebalanced portfolio to include 10 MW of battery storage. As technology cost improves, this option would enable us to better understand how batteries could be used.

- **Battery Storage:** 10 MW
- **Wind:** 426 MW

Portfolio Orange

Expands the rebalanced portfolio by evaluating the economics of 100 MW of utility-grade solar. Like Blue and Yellow, it also includes up to 50% renewables.*

- **Solar:** 100 MW
- **Wind:** 326 MW

Portfolio Pink

In comparison to the rebalanced portfolio, this portfolio caps renewable energy at 40%* and also allows a more moderated inclusion of renewables.

- **Wind:** 160 MW ↓

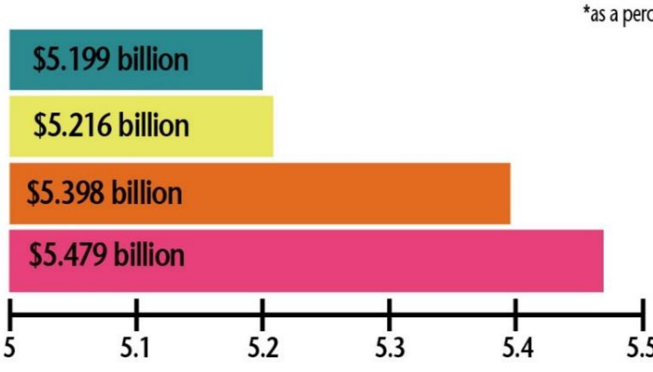
*as a percent of retail sales

Economics

Remember, OPPD has committed to no general rate increase through 2021.

Amounts are compared on a Net Present Value basis over a 20-year period.

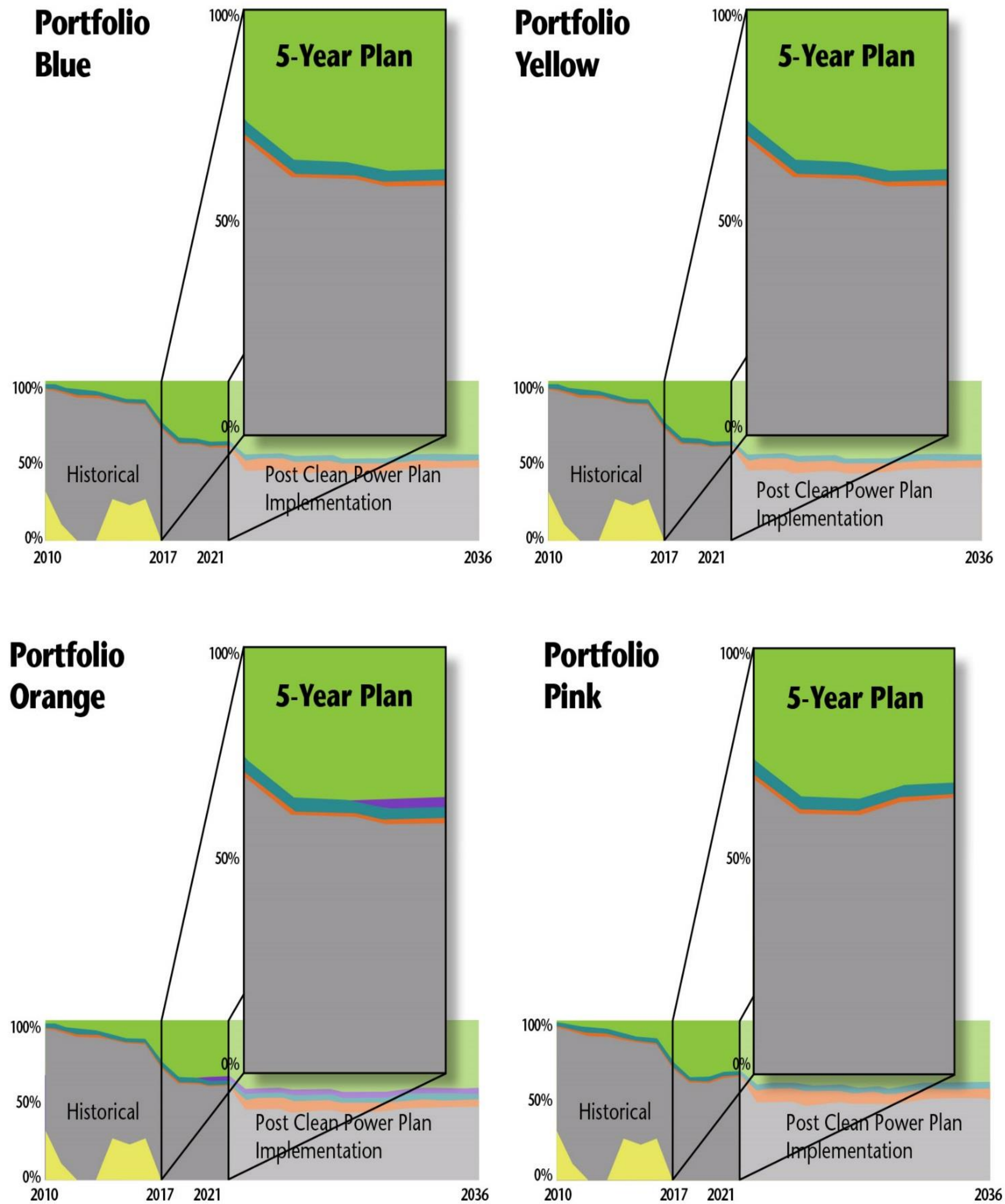
Portfolio Blue	**Baseline**
Portfolio Yellow	**$ 17 M ↑**
Portfolio Orange	**$199 M ↑**
Portfolio Pink	**$280 M ↑**



Generation Diversity

Hydro Nuclear Coal Natural Gas & Oil Wind Solar

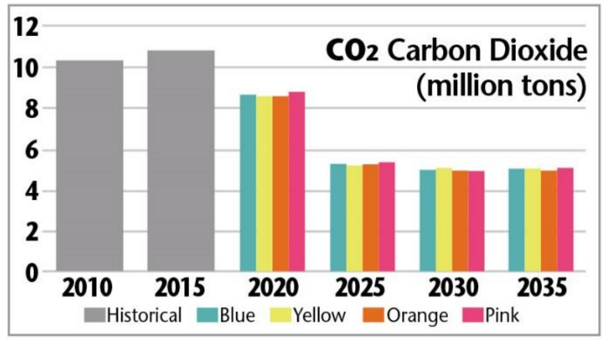
This IRP primarily focuses on 2017–2021. OPPD plans to continually revisit generation options as technology matures and as we learn more about the Clean Power Plan (CPP).



Source: OPPD Corporate Operating Plan

Emission Timelines

At right, you will notice that emission reductions are comparable across the portfolios. OPPD continues to proactively protect the environment and meet or exceed all regulatory requirements. The installation and operation of emission controls in 2015 at North Omaha Units 4 & 5 and Nebraska City Unit 1 has resulted in dramatic reductions in mercury emissions. The conversion of three coal units to natural gas will also continue to reduce emissions. Depiction of emissions is based on CPP requirements.
Source: OPPD Environmental Affairs.

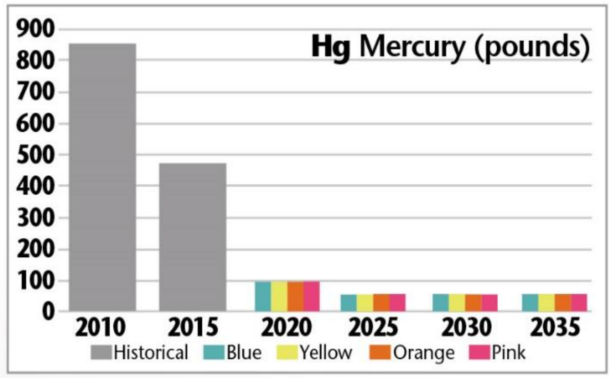


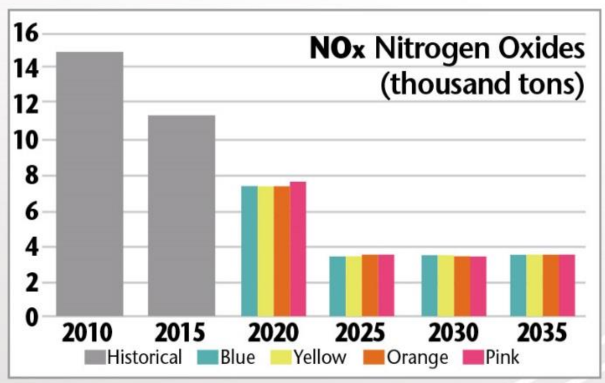
Demand-Side Management (DSM) and Energy Efficiency

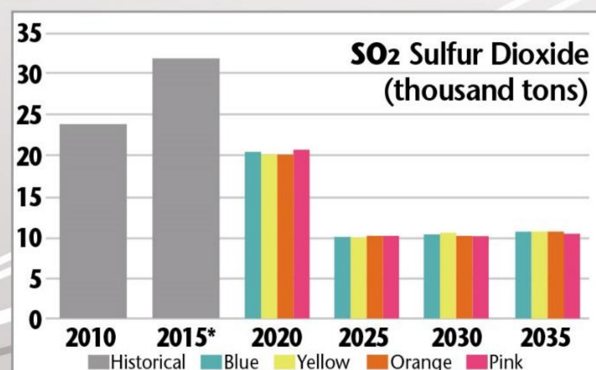
Demand-side management programs are designed to reduce energy consumption and/or peak load by incenting customers to invest in energy-efficient equipment or incenting customers to reduce their usage during periods of high electricity demand.

All four portfolios concluded that 46 MW of the planned 300 MW DSM programs are uneconomical and should be re-evaluated at this time. The DSM megawatt reduction was solely related to a planned commercial demand-response program not yet implemented.

OPPD's intent is to continue with existing commercial and residential programs, which promote demand response and energy efficiency. In addition to existing programs, OPPD will continue to seek innovative and cost effective demand side management programs that can provide sustainable alternatives.







*SO_2 emissions were increased in 2015 because of extended outage on Nebraska City Unit 2 (OPPD's lowest emission unit), which required temporary increased usage of higher emitting units.

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FAQs and Definitions - OPPD's Integrated Resource Plan
Updated November 30, 2016

Integrated Resource Planning

(1) Q: What is an Integrated Resource Plan (IRP)?
The plan is a road map for meeting OPPD's mission and is required by the Western Area Power Administration (WAPA). It helps us determine how we will generate power in the future. We utilize a comprehensive, forward-looking decision support tool for evaluating resource options to meet our objectives at the lowest cost. The process considers supply-and-demand resource options, risk and fuel, power and technology costs associated with various resource plan outcomes.

As Management completes the IRP, there are a number of strategic directives that must be considered; SD-2 Competitive Rates, SD-4 Reliability, SD-7 Environmental Stewardship, SD-9 Resource Planning, SD-11 Economic Development, SD-13 Stakeholder Outreach and Communication and SD-15 Enterprise Risk Management.

(2) Q: What is WAPA?
WAPA stands for Western Area Power Administration. WAPA is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit wholesale electricity from multi-use water projects. The service area encompasses a 15-state region of the central and western U.S.

WAPA sells power to customers such as Federal and state agencies, cities and towns, rural electric cooperatives, public utility districts, irrigation districts and Native American tribes. These customers, in turn, provide retail electric service to millions of consumers in the West. As a component of their energy delivery contract, WAPA requires an Integrated Resource Plan be filed every 5 years for hydroelectric power.

(3) Q: OPPD has several energy partners. Why does OPPD only supply an integrated resource plan to WAPA and not the others?
WAPA is OPPD's only Federal energy partner and the only partner who requires an IRP as part of our contractual commitment to them. The other partners do not require a plan.

(4) Q: How often does OPPD review generation needs?
The utility industry is experiencing dynamic change at an accelerated pace. For that reason, OPPD regularly reviews resource options based on market conditions and our contractual commitment to the Western Area Power Administration (WAPA). We assess generation mix, Purchase Power Agreements (PPA) and Demand Side Management Programs to evaluate supply-and-demand resource options.

All reviews are based on market conditions, load requirements, legislation, research and pace of value for our customers.

Portfolio Clarification

(5) Q: Portfolios refer to megawatts (MW) – please help me understand the impact of the megawatts discussed in each portfolio.
Portfolios refer to 160-426 MW of wind and 100 MW of utility grade solar.

To put that in perspective, 400 MW of electricity can power approximately 120,000 average Nebraska homes. Additionally, 1MW of utility grade solar requires approximately 6 acres of land or about 6 football fields.

(6) Q: What is Utility Grade Solar?
A utility grade solar facility generates solar power on a large scale, as opposed to residential solar.

(7) Q: How does battery storage work?
Utility scale battery storage can serve multiple roles supporting the electricity grid including both energy storage and regulation support. Energy storage allows for the storage of electrical generation during times of excess generation (or low usage) and the use of the stored energy during periods of high demand or constrained generation. An example of this would be storage of excess wind generation during the night at a time of low energy usage and the use of that energy during the day when energy usage is at its highest. Regulation support allows for greater control of the quality of power by balancing intermittent resources such as wind or solar.

(8) Q: Why does the Pink Portfolio cost more if that portfolio is adding the least amount of generation?
Portfolio pink has a higher net present value cost due to the fact that there is less renewable generation added compared to the other portfolios. As a result of adding less generation, there is less energy available for sale into the Southwest Power Pool market. In this scenario, having less energy available for sale increases the total cost of operating the portfolio.

(9) Q: What is the reliability of each portfolio?
Each portfolio meets the Southwest Power Pool's (SPP) system capacity reserve requirements. This ensures that each of the portfolios has the ability to serve OPPD's maximum system demand, plus an additional 12% reserve margin.

(10) Q: If OPPD is committed to no general rate increase for 5 years, why shouldn't we just go with solar?
OPPD is committed to no general rate increase for five years, from 2017-2021 (SD-2 Competitive Rates). As part of that commitment, OPPD believes it can achieve its environmental stewardship goal of 30% of retail sales coming from renewable sources (SD-7 Environmental Stewardship). In accordance with each initiative, the District believes the optimal decision is to incorporate lowest cost renewables in order to achieve both goals at the same time (SD-2 and SD-7). If OPPD were to select higher cost renewable generations sources (solar), it would be in direct conflict with SD-2 to achieve rates 20% below the regional average.

(11) Q: What do the periodic table symbols mean? (Mercury, Sulfur, Carbon, Nitrogen Oxide)

- Carbon dioxide is represented with the symbols **C** for carbon and **O2** for oxygen as "**CO2**."
- Mercury is represented by the periodic table symbol for elemental mercury as "**Hg**."
- Nitrogen dioxide is represented with the symbols for nitrogen, **N**, and oxygen, **O2**, as "**NO2**."
- Sulfur dioxide is represented with the symbol **S** for sulfur and **O2** for oxygen as "**SO2**.".

(**12) Q: How is the IRP related to the resource planning OPPD did for Fort Calhoun Station?** OPPD's resource planning that resulted in ceasing operations at FCS was a subset of the larger, more integrated process required to produce the IRP. At its core, the IRP is a continuation of the FCS analysis that specifically incorporates the rest of the OPPD generation assets, PPA agreements and Demand Side Management programs. OPPD expects the IRP process to be both more important and more visible as the utility industry experiences dynamic change in a compressed period of time.

(**13) Q: Since the Board voted on Fort Calhoun Station, why aren't they voting on this?** This is an Integrated Resource Plan that will be filed with WAPA as part of our contractual relationship. The FCS decision also required accounting changes as well as short term capacity additions. When we bring the next phase of addition (i.e. Wind contracts), the Board will be voting on those contracts.

(14) Q: How is OPPD meeting its 300 MW DSM goal?
In 2014, OPPD made the commitment to proceed down the path of pursuing 300 MW of demand side management (DSM) options by 2023. Our 300 MW DSM goal remains intact, and we continue to offer programs like Residential AC Management, Residential HVAC Rebates, Residential Low Income energy assistance and training programs, Commercial and Industrial Prescriptive Rebates, Commercial and Industrial Customer Rebates, and Commercials and Industrial Interruptible programs. During the 2016 IRP process, it was determined that approximately 46 MW of DSM capacity for commercial and industrial customer have higher projected implementation costs than other options available to OPPD, and we're working to identify other solutions. OPPD remains committed to DSM programs and continues to research other options to achieve our DSM goals cost effectively.

(15) Q: Have you considered distributed generation options?
Distributed generation was not included in our modeling at this time. To date, we've seen very limited participation in our net metering rate program; fewer than 100 of our approximately 360,000 customer-owners currently participate in net metering. We continue to monitor energy trends and look ahead to solutions that will provide the most cost-effective, reliable and environmentally sensitive options for our customer-owners. Distributed generation will likely grow in prominence and scalability in the future, and we'll continue to evaluate its fit in our portfolio.

Future Outlook

(16) Q: How will the Clean Power Plan affect these portfolios?
The environmental regulatory future remains highly uncertain and ever-changing. Due to the uncertainty, the portfolios were modeled with a conservative approach that anticipates further regulation on the coal-fired electric generation; the most significant of these regulations is called the Clean Power Plan.

On October 23, 2015, the EPA published a final rule regulating the emission of carbon dioxide ("CO_2") from existing fossil-fuel fired electric generating units under section 111 of the Clean Air Act.

Also on October 23, 2015, the EPA published a final rule for new, modified, or reconstructed fossil fuel-fired electric utility generating units under section 111 of the Clean Air Act.

These regulations in the aggregate are known as the Clean Power Plan ("CPP"). The CPP requires states to meet interim and final emissions targets on a state-wide basis starting in 2022. The goal is to reduce CO_2 emissions from electric generating units by 32% below 2005 levels by the year 2030.

In addition, the EPA issued a proposed rule which provides two possible programs to be used by states for compliance, a mass-based program, or a rate-based program. States could allow their fossil fueled generating units to use a number of measures to meet those goals, such as heat rate improvements, unit retirements, and renewable energy.

Numerous legal challenges to the CPP have been filed and consolidated in the United States Court of Appeals for the District of Columbia Circuit. On February 9, 2016, the U.S. Supreme Court entered an order staying the implementation of the CPP pending further proceedings. Oral arguments were heard before the District of Columbia Circuit Court on September 27, 2016. The cost of compliance will not be known until judicial proceedings have been concluded and the District can evaluate the final regulatory requirements and its options related thereto.

(17) Q: Why is OPPD focusing on the 5-year plan?
OPPD has important near-term decisions to make. We are committed to continually revisiting generation options. As energy technologies mature and as we learn more about the legal status of the Clean Power Plan, we will be able to adjust accordingly.

(18) Q: What happens after the 5-year no general rate increase?
After the five years, no general rate increase period concludes and OPPD would continue its efforts to provide affordable, reliable and environmentally sensitive energy services to our customers. This effort would include avoiding future rate increases whenever possible but ultimately would depend on regulations, customer usage patterns, technology costs and a variety of other macroeconomic factors.

(19) Q: Is OPPD still committed to demand-side management (DSM) programs?
Yes. Demand-side management programs are designed to reduce energy consumption and/or peak load by incenting customers to invest in efficient equipment or reduce their usage during periods of high electricity demand.

All four portfolios concluded that 46 MW of the planned 300 MW DSM programs are uneconomical and should be re-evaluated at this time. The DSM megawatt reduction was solely related to a planned commercial demand-response program not yet implemented.

OPPD's intent is to continue with existing commercial and residential programs, which promote demand response and energy efficiency. In addition to existing programs, OPPD will continue to seek innovative and cost effective demand side management programs that can provide sustainable alternatives.

Residential:

- ***CoolSmart:*** Achieves demand reductions by cycling and curtailing central AC units by way of a remote- controlled switch. As of September 2016, OPPD has 40,340 active switches and can control 57.8 MW, when needed.
- ***HVACSmart***: Provides incentives for high efficiency HVAC equipment and Certified High Performance Homes (HERS scores (home energy rating system) of 65 or lower (lower the better).
- ***SmartSteps***: Provides home management education and subsidized energy efficiency measures to income-qualified customers.

Commercial and Industrial:

- ***Custom Rebates***: Provides incentives to qualifying projects based upon measures where electrical demand reductions are unique to their specific deployment.
- ***Prescriptive Rebates:*** Provides customer incentives to purchase energy efficient measures that have predetermined electrical demand reduction values.
- ***Business Interruptible Rates:*** Firm interruptible tariffs with customers for periodic curtailments at times of system peak demand.

(20) Q: What is OPPD's commitment to solar?

OPPD's Integrated Resource Plan has shown that utility grade solar (>100 MW) is not economically competitive with other generation sources at this point in time and the inclusion of utility grade solar would be contrary to SD-2 at this time.

OPPD plans to keep solar as an option in our perpetual resource planning going forward and will look at solar at the pace of its value.

Definitions

Base load - The minimum amount of electric power delivered or required over a given period of time at a steady rate. (EIA glossary)

Battery storage – A battery (or cell) used for storing electrical energy. A voltaic battery consisting of two or more storage cells.

Capacity - The maximum electric output that a generator is capable of reliably producing in a given hour when needed. OPPD's capacity includes its own fleet of generators, along with purchase agreements for additional capacity from other generators. - From "Role of Natural Gas" on OPPDtheWire.com

Clean Power Plan - The final rule promulgated by EPA on October 23, 2015, that provides Carbon Pollution Emission Guidelines for Existing Stationary Sources for Electric Utility Generating Units.

Combined cycle unit - An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbines(s). (EIA)

Combustion turbine - A gas turbine, also called a combustion turbine, is a type of internal combustion engine. It has an upstream rotating compressor coupled to a downstream turbine, and a **combustion** chamber in-between.

Demand-side management (DSM) - A utility customer action that reduces or curtails end-use equipment or processes. DSM is often used in order to reduce customer load during peak demand and/or in times of supply constraint. DSM includes programs that are focused, deep, and immediate such as the brief curtailment of energy-intensive processes used by a utility's most demanding industrial customers, and programs that are broad, shallow, and less immediate such as the promotion of energy-efficient equipment in residential and commercial sectors. (EIA)

Distributed resources – Distributed energy resources (DER) are smaller power sources that can be aggregated to provide power necessary to meet regular demand.

Electricity generation – The process of producing electric energy or the amount of electric energy produced by transforming other forms of energy. It is commonly expressed in kilowatt hours (kWh) or megawatt hours (MWh). (EIA)

Energy – The actual generated megawatt-hours (MWh) utilized to meet customer needs. - From "Role of Natural Gas" on OPPDtheWire.com)

Fuel mix – The combination of fuels (coal, wind, natural gas, nuclear, hydropower, fuel oil, geothermal, landfill gas, biomass) or other technologies used to generate electricity. Fuel diversity helps ensure stability and reliability in electric supply. Worldwide, utilities' fuel mixes vary based on availability and procurement costs in their geographic locations.

Generation – Electricity generated from fossil fuels, nuclear power plants, hydro power plants (excluding pumped storage), geothermal systems, solar panels, biofuels, wind, etc.

MATS – Mercury and Air Toxics Standard - These rules set technology-based emissions limitation standards under sections 111 (new source performance standards) and 112 (toxics program) of the 1990 Clean Air Act amendments for mercury and other toxic air pollutants.

PPA – Purchase Power Agreement - A bilateral, legally binding agreement between two parties where one party buys power and the other party provides power over an extended period of time.

SPP – Southwest Power Pool - A bilateral, legally binding agreement between two parties where one party buys power and the other party provides power over an extended period of time.

Appendix E – PACE Letter

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OVERVIEW OF OMAHA PUBLIC POWER DISTRICT'S GENERATION PORTFOLIO ANALYSIS FOR INTEGRATED RESOURCE PLANNING

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The Omaha Public Power District (OPPD) has retained Pace Global to support its integrated resource planning process by performing a comprehensive analysis of the operation and overall cost of various generating portfolio options. Performing this study allows OPPD to measure the relative cost and risk implications of a variety of portfolio alternatives including the increased reliance on renewables as well as the potential inclusion of both solar and battery storage technologies in its portfolio. Details of Pace Global's approach, models, and assumptions used for this study are detailed herein.

Portfolios Considered

In support of OPPD's integrated resource planning process, Pace Global modeled various portfolios with distinct attributes. The study covered the time period of 2017 through 2036. Although uncertainty remains over the timing and ultimate structure of the future regulation of carbon emissions, the modeling did assume a more restrictive regulatory environment than today in an effort to position OPPD's generation portfolio for compliance with the Clean Power Plan. A summary of these portfolios is provided in the table below.

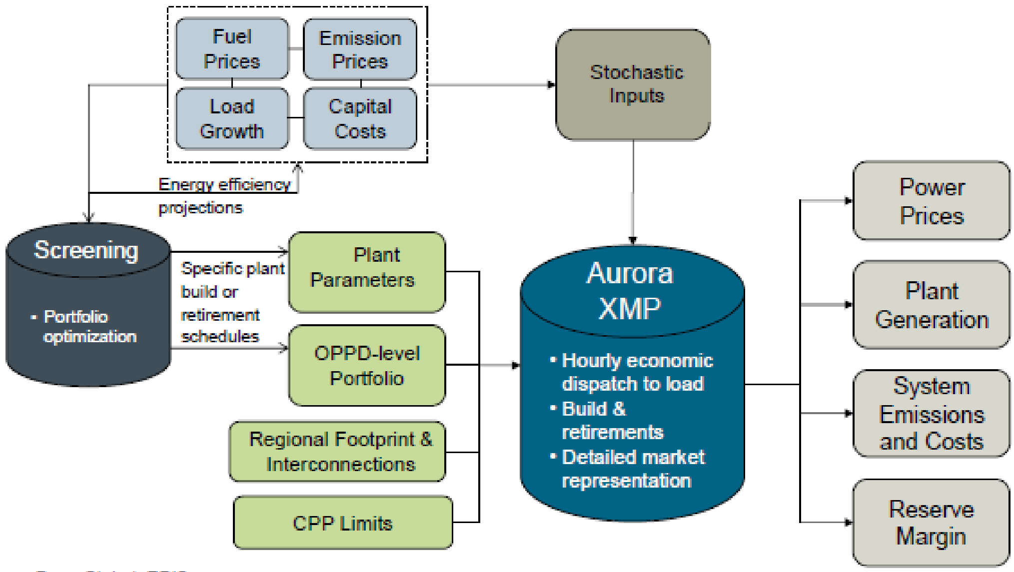
Portfolios	Portfolio Attributes
Blue	The Blue portfolio is a full optimization of OPPD's portfolio and is comparable to the "Rebalanced Portfolio" that was discussed at the conclusion of the FCS analysis. This portfolio provides up to 50% of retail sales from renewable generation sources.
Yellow	Like portfolio Blue, the Yellow portfolio provides that 50% of retail sales are from renewable generation sources and Yellow also includes the addition of 10 MW of battery storage technology.
Orange	In addition to the Blue and Yellow portfolios, the Orange portfolio provides that 50% of retail sales are from renewable generation sources. It also assumes the inclusion of 100 MW of utility grade solar.
Pink	The Pink portfolio takes a more tempered approach to the growth of renewables and provides up to 40% of retail sales from renewable generation sources.

Model and Approach

Pace Global deploys AURORAxmp[1], an hourly chronological dispatch model to simulate the economic dispatch of power plants. This industry standard tool was run for the entire Southwest Power Pool (SPP) and surrounding zones to assess not only OPPD's system but how the broader market operates and impacts OPPD's resources (i.e. accounting for market sales and purchases). Exhibit 1 presents an overview of AURORAxmp model inputs and outputs.

[1] Licensed by EPIS

Exhibit 1: AURORAxmp Overview



Source: Pace Global, EPIS

Pace Global used a three-step process to fully analyze OPPD's generation portfolio options.

- **Step 1: Portfolio Optimization** – For defining the optimized portfolio and to backfill for additional supplies when needed, Pace Global used AURORAxmp portfolio optimization tool to select from OPPD resource options to determine the optimal generation mix. This process allowed for existing generating resources to drop out and/or alternate technologies, including conventional, renewable and battery storage options to be added. Accounting for the minimum requirements of maintaining the SPP reserve margin of 12% and not allowing total energy produced to exceed 30% of retail sales, the optimizer selected the low cost portfolio composition.
- **Step 2: Base Case Dispatch Analysis** – Next, using reference case assumptions that are discussed in more detail below, Pace Global deployed AURORAxmp dispatch model to simulate the operation and costs of alternative OPPD portfolios. Outputs of this modeling include portfolio and regional generation by technology, total system costs, fuel consumption and emissions. OPPD portfolios were compared based on calculating the net present value of costs over the 20-year time horizon.
- **Step 3: Risk Integrated Dispatch Analysis** – To test how the defined OPPD portfolios would perform under a variety of plausible future market conditions, Pace Global performed a risk-based analysis, also referred to as stochastic analysis. The reason for conducting stochastic analyses is to expose each portfolio to the full range of plausible future market conditions. Pace Global stochastic projections are based upon a combination of historical market volatility and market fundamental analyses. Stochastic distributions of key market drivers, including fuel costs, technology costs, and load were developed based on historical volatility and considering current and future market conditions that would deviate from historical trends. These assumptions were randomly drawn for a 200-iteration dispatch analysis. While the composition of each OPPD portfolio being considered was fixed, the model would retire existing units in the market or make new supply decisions in response to the market conditions seen in each iteration. The range of outcomes and distributions around the mean offered a measurement of risk in the overall cost of the portfolio.

Key Assumptions

Pace Global provided reference assumptions for the following market drivers:

- Fuel (coal, gas) prices
- Technology capital costs (gas, wind, solar, etc.)
- SPP load projections
- Carbon prices

OPPD provided other key assumptions including:

- Existing unit performance and fuel costs
- Existing demand side program specifications
- Existing energy purchase and sale contract specifications
- OPPD system projected load

The base case, "deterministic," dispatch analysis assumed reference outlook for key assumptions. The risk integrated dispatch analysis varied key market drivers based on stochastic distributions for load, fuel costs, and capital costs.

Pace Global Corporate Overview

Pace Global, A Siemens Business, is a leading provider of strategic energy consulting services. For nearly 40 years, Pace Global has provided innovative services to support the execution of business strategies, complex energy transactions, asset development, and operations focusing on select markets in the Americas. Our leadership team's average number of years of experience in the energy business exceeds 20 years. This experience enables Pace Global to offer a sophisticated and insightful perspective on energy markets, assets, value, and risk drivers. Pace Global has extensive experience in supporting utility resource planning activities and considering Clean Power Plan compliance in its analyses.