VOLUME 1

EXECUTIVE SUMMARY

KCP&L GREATER MISSOURI OPERATIONS COMPANY (GMO)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.010

APRIL, 2018

KCP&L
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SECTION 1: INTRODUCTION

The fundamental objective of the resource planning process shall be to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest and is consistent with state energy and environmental policies. This objective requires that the utility shall:

- Consider demand-side resources, renewable energy, and supply-side resources on an equivalent basis
- Use minimization of the present worth of long-run utility costs as the primary selection criterion
- Identify and where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process

1.1 IRP REPORT STRUCTURE

Nine (9) separate volumes comprise this IRP filing:

1. Volume 1: Executive Summary
2. Volume 2: Missouri Filing Requirements including an index of Rule compliance
3. Volume 3: Load Analysis and Load Forecasting
4. Volume 4: Supply-Side Resource Analysis
5. Volume 4.5: Transmission and Distribution Analysis
6. Volume 5: Demand-Side Resource Analysis

7. Volume 6: Integrated Resource Plan and Risk Analysis

8. Volume 7: Resource Acquisition Strategy Selection

9. Volume 8: Filing Schedule and Requirements

1.2 IRP DEVELOPMENT

In developing the IRP filing, KCP&L Greater Missouri Operations Company (GMO) has endeavored to meet all requirements of Missouri's IRP rules covered under 4 CSR 240-22. GMO's IRP spans the 2018-2037 planning horizon. Data necessary to complete evaluations were derived from recognized industry sources, consultants, publications and other sources as appropriate. Data sources are noted in the text of the report or in the appendices of a volume.

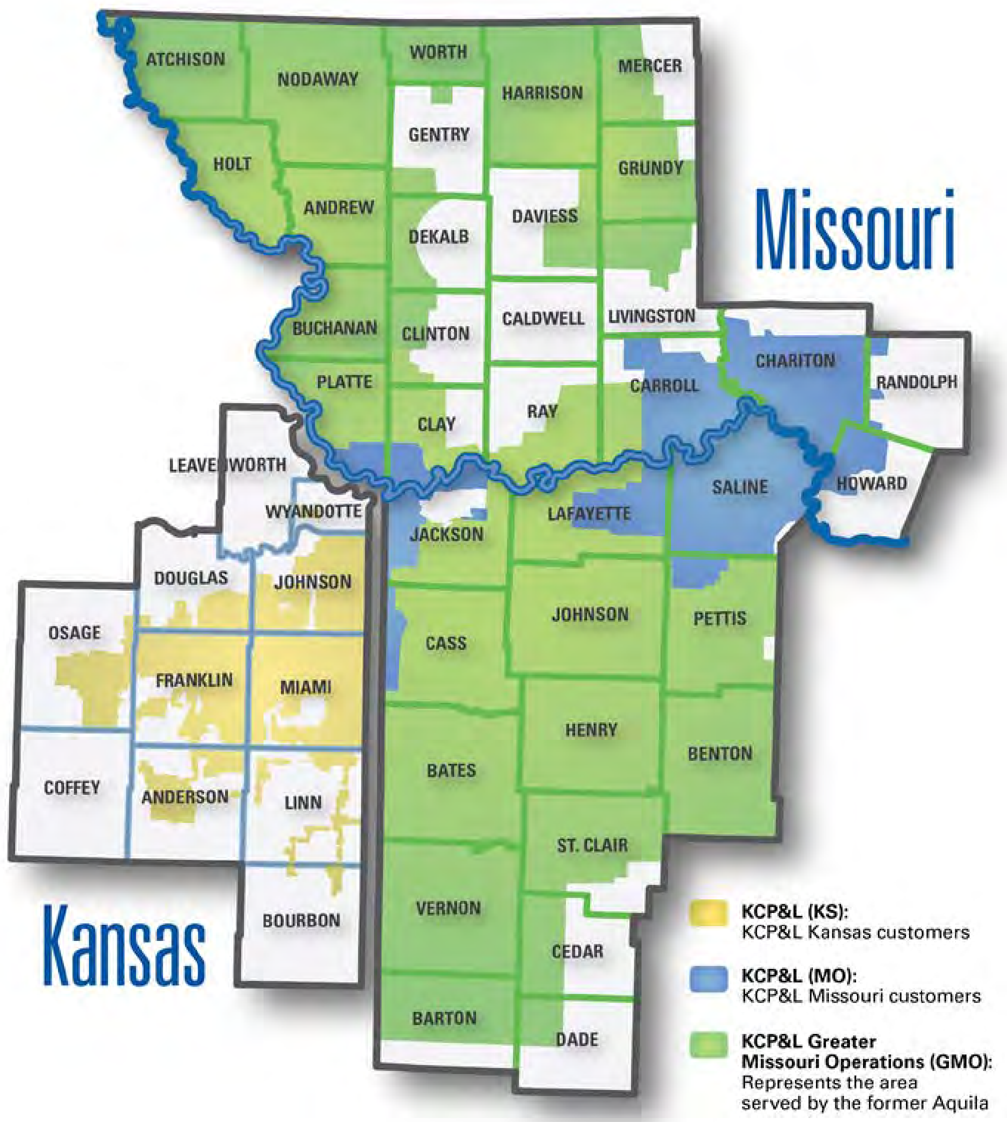
Several distinct tasks are included in the planning process:

- A detailed forecast of future demand and energy requirements
- An assessment of Supply-Side resource alternatives
- An assessment of Demand-Side resource alternatives
- An assessment of Transmission and Distribution alternatives
- Integrated Analysis evaluates the economics of various combinations of demand-side and supply-side alternatives that are developed as alternative resource plans over the planning timeline
- Risk Analysis provides a comparison of the range of economic results for the alternative resource plans due to identified critical uncertain factors
- The adoption and executive approval of a Resource Acquisition Strategy that includes a preferred resource plan, implementation plan, and contingency plans

SECTION 2: GMO SYSTEM OVERVIEW

GMO is an integrated, mid-sized electric utility serving portions of Northwest Missouri including St. Joseph and several counties south and east of the Kansas City, Missouri metropolitan area. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. A map of the Great Plains Energy (GPE) service territory which includes GMO is provided in Figure 1 below:

Figure 1: GPE Service Territory



GMO is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 1 provides a snapshot of the number of customers served, estimated retail sales and peak demand.

Table 1: 2017 Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
GMO	**322,143**	**8,084,554**	**1,910**

GMO owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. In the third quarter, 2017, GPE signed Power Purchase Agreements for two wind generation facilities totaling 444 MW. The wind facilities, both located in Kansas, are expected to be commercially operational by June, 2019. Table 2, Figure 2 and Figure 3 below reflect GMO's generation assets including all executed wind PPAs and announced unit retirements.

Table 2: Capacity and Energy By Resource Type

Capacity By Fuel Type	Capacity (MW)	% of Total Capacity	Estimated Annual Energy (MWh)	% of Annual Energy
Coal	457	21.2%	2,893,443	53.6%
Oil	60	2.8%	-	0.0%
Nat. Gas	1,012	46.9%	90	0.0%
Wind	625	29.0%	2,484,255	46.1%
LFG	1.6	0.1%	11,773	0.2%
Solar	3	0.1%	4,709	0.1%
Total	**2,159**	**100.0%**	**5,394,270**	**100.0%**

Figure 2: Capacity By Resource Type

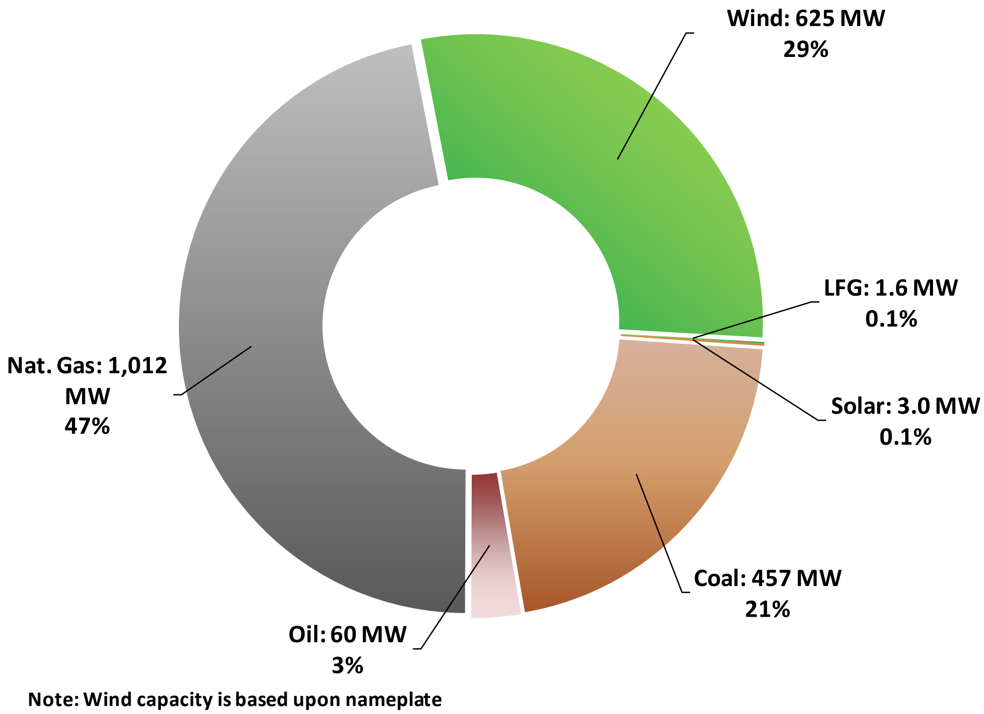
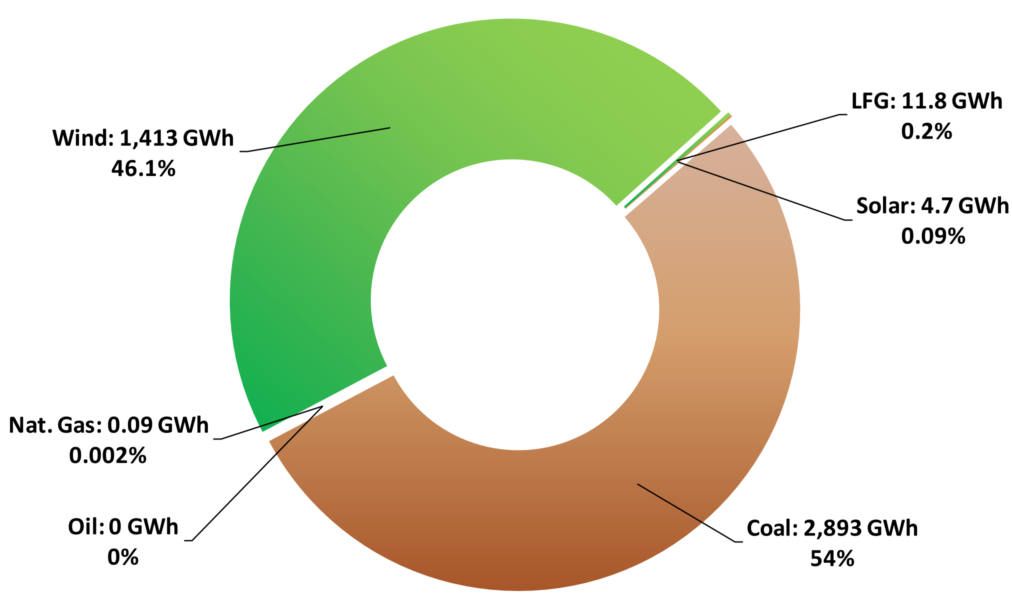


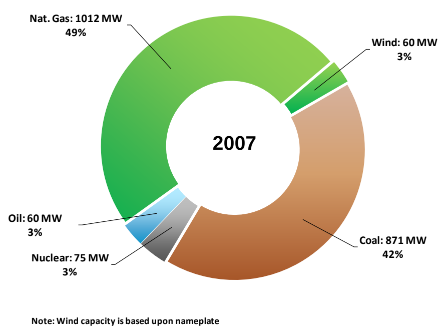
Figure 3: Energy By Resource Type

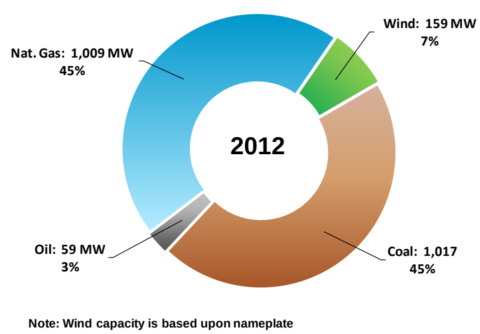


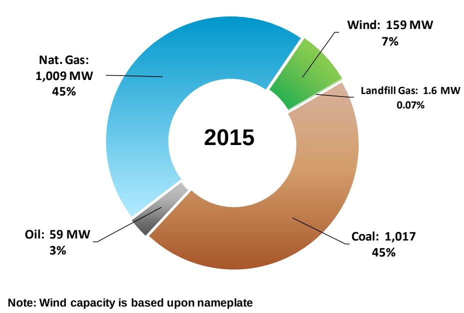
Additionally, GPE owns and operates a delivery system consisting of 3,700 miles of transmission lines, 22,400 miles of distribution lines, and 400 substations.

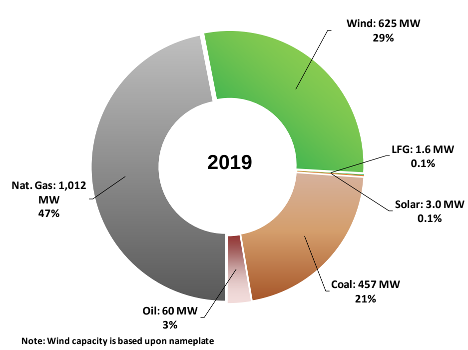
2.1 CONTINUED COMMITMENT TOWARDS RENEWABLES

More than a decade ago, GMO began increasing their generation portfolio makeup with renewable generation resources while retiring coal and gas fired generators. In 2005, only 3% of the GMO's total capacity was from a renewable resource, whereas in 2019, it is expected that approximately 29% of total capacity will be sourced from renewables. The following pie charts illustrates this shift from the GMO's generating fleet consisting primarily of coal and gas generation to a diversified portfolio consisting of substantial renewable generation.









SECTION 3: PREFERRED PLAN SELECTION

3.1 ALTERNATIVE RESOURCE PLANS AND SELECTION OF THE PREFERRED PLAN

3. A summary of the preferred resource plan to meet expected energy service needs for the planning horizon, clearly showing the demand-side resources and supply-side resources (both renewable and non-renewable resources), including additions and retirements for each resource type;

Alternative Resource Plans were developed using a combination of various supply-side resources, demand-side resources and resource addition timing.

In total, fourteen Alternative Resource Plans were developed for integrated resource analysis. Each plan is detailed in Volume 6 of the IRP submittal. Based on determination of the lowest 20-year net present value revenue requirement (NPVRR), the Preferred Plan for the 20-year planning period is shown in Table 3 below:

Table 3: GMO Preferred Plan

Year	CT (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)
2018	0	146		78	406
2019	0	120		72	97
2020	0			124	
2021	0			153	
2022	0			168	
2023	0			182	
2024	0			200	
2025	0			217	
2026	0			232	
2027	0			246	
2028	0		10	245	
2029	0			240	
2030	0			238	
2031	0			233	
2032	0			231	
2033	0			234	
2034	0			238	
2035	0			244	
2036	0			250	
2037	0			256	

Based in part upon current Missouri RPS rule requirements, the Preferred Plan includes 10 MW of solar additions and 266 MW of wind additions over the twenty-year planning period. The 266 MW of wind additions are from two power purchase agreements (PPA) executed in 2017. The one wind project consisting of 244 MW of total capacity is currently expected in to be in-service in 2018. The second wind project consisting of 200 MW of total capacity is currently expected to be in service by June, 2019. The total capacity of each wind facility is shared between KCP&L and GMO. The DSM resources included in the Preferred Plan consist of a suite of six residential and eight commercial programs three of which are demand response programs, two are educational programs, and nine are energy efficiency programs.

The Preferred Plan also includes retiring 406 MW of coal generation at Sibley Station by 2019 and a 97 MW natural gas unit at Lake Road. Key drivers that contribute to these retirement decisions are a lower SPP reserve margin requirement which has been reduced from 13.6% to 12%, higher wind resource accreditations, and a reserve margin requirement based upon normal weather peak load rather than actual peak. Additionally, continued low long-term gas price forecasts, low long-term peak load forecasts, and more wind capacity additions in the SPP region have reduced the economic value of these units. Also, environmental regulations including Ozone National Ambient Air Quality Standards (NAAQS), PM NAAQS, Clean Water Act Section 316(a) and (b), Coal Combustion Residuals Rule, Effluent Guidelines, Clean Power Plan increase the projected cost of operating these units, further reducing their economic value.

The Preferred Plan was not the lowest cost plan from a Net Present Value of Revenue Requirement (NPVRR) perspective. The lowest cost Alternative Resource Plan (ARP) was $4 Million lower over the twenty-year planning period. The single difference between the Preferred Plan and the lowest cost ARP was due to the difference in DSM assumptions between the plans. The Preferred Plan maintains the current level of DSM programs at a slight cost above the lowest cost plan evaluated. To reduce certain programs at this time would cause a disruption to some currently participating customers. GMO continually strives to minimize the cost of the DSM programs to maximize cost effectiveness. In addition, the MEEIA stakeholders will have an opportunity to provide input and recommendations on budgets, energy savings targets, and peak demand reduction targets when GMO makes its next application for MEEIA Cycle 3 later this year.

The Preferred Plan meets the fundamental planning objectives as required by Rule 22.010(2) to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.

The Preferred Plan including ongoing or potential environmental initiatives is shown in Table 4 and existing and new capacity additions are shown in Table 5 below.

Table 4: GMO Preferred Plan Graphic

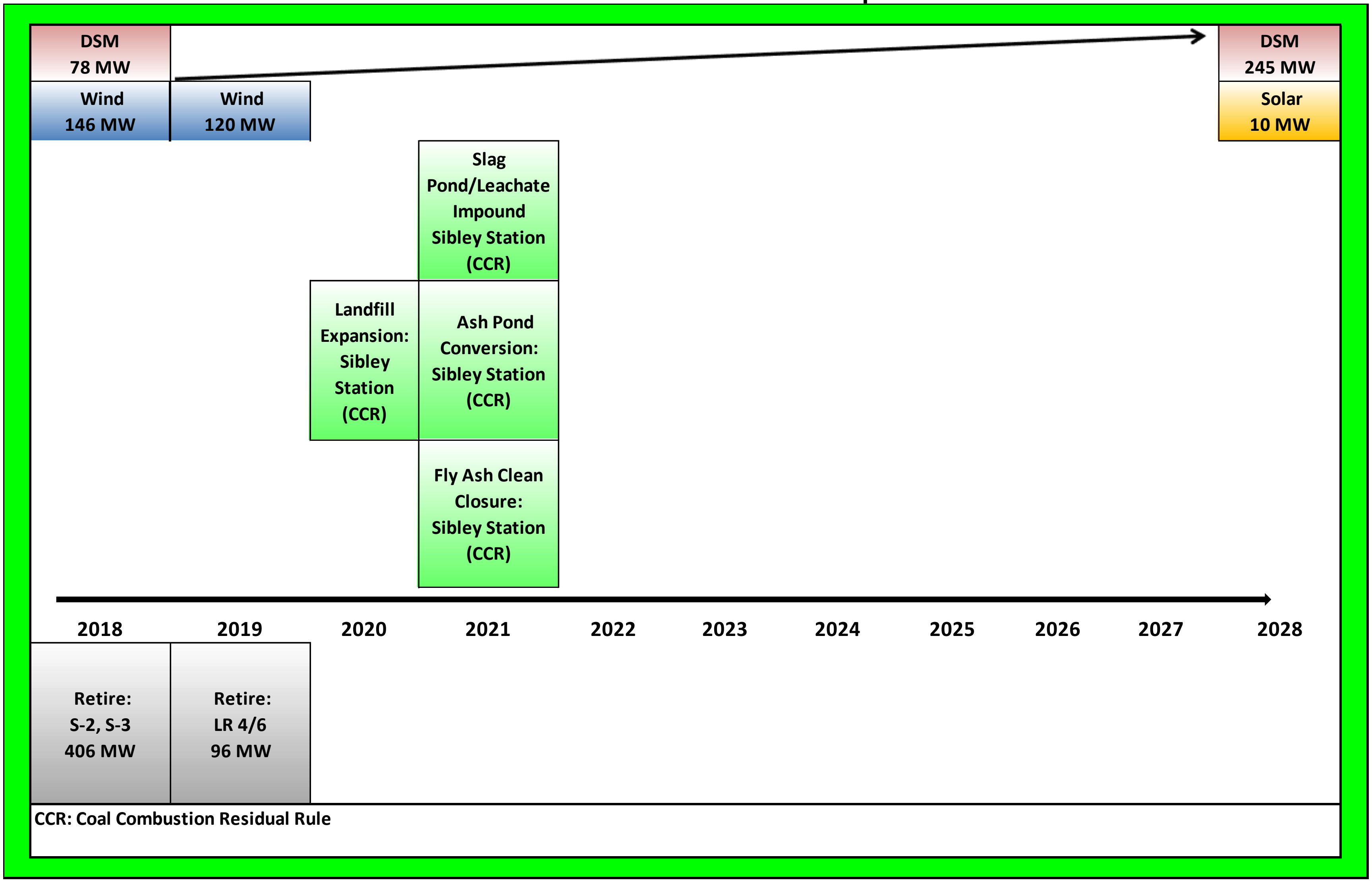
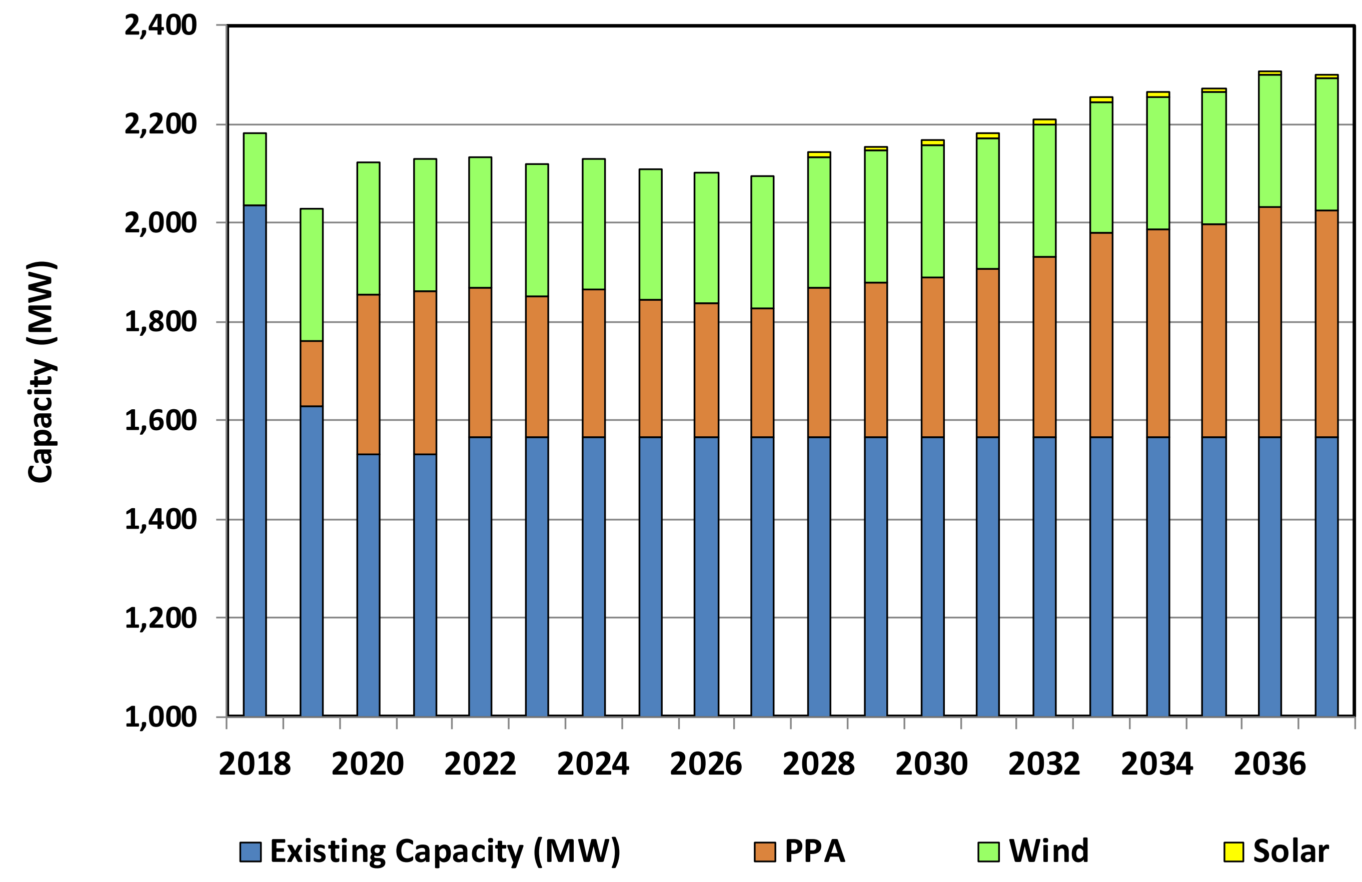


Table 5: 2018 Preferred Plan Capacity Outlook



SECTION 4: CRITICAL UNCERTAIN FACTORS

4. Identification of critical uncertain factors affecting the preferred resource plan;

The ranges of critical uncertain factors are calculated by finding the value at which the critical uncertain factor needs to change in order for the Preferred Resource Plan to no longer be preferred. The values of the NPVRR for the Preferred Resource Plan and the lowest cost plan under extreme conditions are compared and by using linear interpolation a crossover point value is found and expressed as a percent of the range of the critical uncertain factor. These percentages are superimposed on the forecast levels for each critical uncertain factor to develop the resulting ranges.

The values of the top two ARPs NPVRR under each of these risks are detailed in the following table.

Table 6: Alternative Plans for Each Uncertain Factor

Assuming No CO_2 Tax						
NPVRR ($MM)	High Load	High NG	No CO_2 Tax	EV	Low NG	Low Load
GAAFC	9,708	9,616	9,463	9,594	9,332	9,220
GAAGC	9,712	9,619	9,467	9,598	9,337	9,225
Assuming CO_2 Tax						
NPVRR ($MM)	High Load	High NG	CO_2 Tax	EV	Low NG	Low Load
GAAFC	10,047	9,921	9,777	9,594	9,649	9,511
GAAGC	10,050	9,924	9,781	9,598	9,653	9,515

The top two ARPs rank consistently in those positions across all uncertainty endpoint/scenario sensitivities. Because of this, no crossover point value is found and expressed as a percent of the range of the critical uncertain factor. The differences represented in Table 6 are due to the accelerated DSM programs of the Preferred Plan. Load, natural gas prices and CO_2 uncertainties represented in the remaining ARPs do not produce a crossover point for expression of those ranges.

Additional information for the range of uncertain factors can be found in Volume 7, Section 2.

SECTION 5: PERFORMANCE MEASURES

5. For existing legal mandates and approved cost recovery mechanisms, the following performance measures of the preferred resource plan for each year of the planning horizon:

A. Estimated annual revenue requirement;

B. Estimated level of average retail rates and percentage of change from the prior year; and

C. Estimated company financial ratios;

Data for the Preferred Plan is provided in the table below. This information is also provided in the Company response to Rule 240-22.060(4)(C)1. in Volume 6.

It should be noted that the IRP analysis for determining estimated annual revenue requirement; estimated level of average retail rates and percentage of change from the prior year; and estimated company financial ratios assumes perfect ratemaking.

Of note, the analysis does not take into consideration other factors such as Company commitments and determinations from Commission Orders in other dockets that may impact the rate increase depicted each year in the table below.

As such, rate increase percentages reflected in the various years of analysis should not be interpreted as actual planned rate increase requests anticipated by the Company.

Table 7: Financial Performance - Preferred Plan

Year	Revenue Requirement ($MM)	Revenue Requirement Without DSM Performance Incentive ($MM)	Levelized Annual Rates ($/kW-hr)	Levelized Annual Rates Without DSM Performance Incentive ($/kW-hr)	Rate Increase	Rate Increase Without DSM Performance Incentive	Times Interest Earned	Debt to Capital	Internal Cash to Construction Expense
2018	812	812	0.09	0.09	0.00%	0.00%	3.34	47.70	1.43
2019	799	799	0.09	0.09	-1.69%	-1.69%	3.18	47.70	1.12
2020	814	809	0.09	0.09	1.86%	1.21%	3.18	47.70	1.28
2021	835	830	0.10	0.09	2.67%	2.69%	3.11	47.70	1.08
2022	845	845	0.10	0.10	0.81%	1.44%	3.01	47.70	1.12
2023	868	864	0.10	0.10	2.28%	1.77%	2.91	47.70	1.04
2024	890	886	0.10	0.10	2.07%	2.08%	2.93	47.70	1.08
2025	902	902	0.10	0.10	1.16%	1.66%	2.81	47.70	1.02
2026	962	959	0.11	0.11	6.08%	5.75%	2.83	47.70	1.08
2027	984	981	0.11	0.11	1.75%	1.75%	2.83	47.70	0.93
2028	996	996	0.11	0.11	0.28%	0.59%	2.77	47.70	1.19
2029	1,019	1,016	0.11	0.11	1.52%	1.28%	2.77	47.70	1.19
2030	1,035	1,032	0.11	0.11	0.87%	0.87%	2.75	47.70	1.12
2031	1,057	1,057	0.11	0.11	1.44%	1.67%	2.73	47.70	1.12
2032	1,079	1,078	0.12	0.12	1.21%	1.09%	2.72	47.70	1.07
2033	1,107	1,106	0.12	0.12	1.99%	1.99%	2.67	47.70	1.07
2034	1,138	1,138	0.12	0.12	1.90%	2.02%	2.66	47.70	1.06
2035	1,170	1,170	0.12	0.12	1.94%	1.89%	2.66	47.70	1.10
2036	1,203	1,203	0.12	0.12	1.80%	1.80%	2.66	47.70	1.09
2037	1,232	1,232	0.13	0.13	1.66%	1.71%	2.65	47.70	1.10

SECTION 6: COMPANY FINANCIAL RATIOS

6. If the estimated company financial ratios in subparagraph (2)(E)5.C. of this rule are below investment grade in any year of the planning horizon, a description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting performance measures of the preferred resource plan;

The Company calculated performance measures for all studied alternative plans including the Preferred Plan. The expected values of alternative plan performance ratios do not materially change below current conditions. The expectation is that the investment rating of the Company is not at risk from the choice of any particular Alternative Resource Plan.

SECTION 7: RESOURCE ACQUISITION INITIATIVES

7. Actions and initiatives to implement the resource acquisition strategy prior to the next triennial compliance filing; and

7.1 DEMAND-SIDE MANAGEMENT PROGRAMS

The current schedules for ongoing and planned DSM programs are shown in Table 8 and Table 9 below. GMO will file an application under the Missouri Energy Efficiency Investment Act (MEEIA) in mid-2018 requesting Commission approval of demand-side programs for a program implementation period beginning in 2019. Additional detail regarding the implementation plan for the DSM Preferred Plan can be found in Volume 5, Demand-Side Analysis.

Table 8: DSM Program Schedule – Existing Programs

Program Name	Program Type	Segment	Program Implemented	Annual Report	Program Duration	EM&V Completed and draft report available
Home Lighting Rebate	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Online Home Energy Audit	Educational	Residential	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Whole House Efficiency	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Home Energy Report	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Residential Programmable Thermostat	Demand Response	Residential	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Energy Efficiency Rebate - Standard	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Energy Efficiency Rebate - Custom	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Strategic Energy Management	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Block Bidding	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Online Business Energy Audit	Educational	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Small Business Direct Install	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Commercial Programmable Thermostat	Demand Response	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year
Demand Response Incentive	Demand Response	C&I	Apr., 2016	90-days following Plan Year	3-Years	1-Yr following Plan Year

Table 9: DSM Program Schedule – Planned Programs

Program Name	Program Type	Segment	Projected Tariff Filing Date	Projected Approval Date	Projected Implementation Date	Annual Report
Home Lighting Rebate	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Home Energy Report	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Income-Eligible Home Energy Report	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Online Home Energy Audit	Educational	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Whole House Efficiency	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Income-Eligible Weatherization	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Residential Smart Thermostat w DLC	Demand Response	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Central AC DLC Switch	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Water Heating DLC Switch	Energy Efficiency	Residential	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Business Energy Efficiency Rebate - Standard	Energy Efficiency	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Business Energy Efficiency Rebate - Custom	Energy Efficiency	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Strategic Energy Management	Educational	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Retrocommissioning	Energy Efficiency	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Block Bidding	Demand Response	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Online Business Energy Audit	Demand Response	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Small Business Targeted	Demand Response	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Business Smart Thermostat w DLC	Demand Response	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year
Demand Response Incentive	Demand Response	C&I	June, 2018	Oct., 2018	Apr., 2019	90-days following Plan Year

7.2 UNIT RETIREMENT PLANNING

Based on the 2018 Preferred Plan, Sibley Units 2 and 3 and Lake Road 4/6 are expected to be retired by 2019, and 2020 respectively. Post-Sibley Station retirement activities includes but are not limited to disconnection, de-energization, cleanout and tasks to secure the units rendering the site safe until dismantlement can occur. Selected dismantlement is expected for the chimney and other selected items to render the site safe. Post-Lake Road Unit 4/6 retirement activities includes but not limited to disconnection, de-energization, cleanout that will render the unit safe until dismantlement can occur. Draft schedules of the major milestones expected to be undertaken for the retirement of Sibley Station and Lake Road 4/6 within the next three years are provided in the following tables:

Table 10: Sibley Station Retirement Milestones

Milestone Description	Date Range
Selection of Owner's Engineer	Oct, 2017 - Nov, 2017
Phase 1: Initial Study - Cost and MHA*	Nov, 2017 - Mar, 2018
Phase 2: Develop isolation plans, specs, etc	April, 2018 - June, 2018
Bid process and selection	July, 2018 - Dec, 2018
Isolation activities	Dec, 2018 - Dec, 2019
Sibley Units Fully Retire	By Dec 31, 2018
Sibley Staff - post retire assignments	Jan 1, 2019
Sibley 3 Chimney Demolition	7/2019 - 12/2020
Sibley Post Isolation activities	5/2019 - 12/2020
Sibley Full Demolition	TBD
* Material Hazard Analysis	

Table 11: Lake Road 4/6 Retirement Milestones

Milestone Description	Date Range
Notified SPP of anticipated plant closure	June 2, 2017
Selection of Owner's Engineer	Oct, 2017 - Nov, 2017
Phase 1: Initial Study - Cost and MHA*	Nov, 2017 - Mar, 2018
Phase 2: Develop isolation plans, specs, etc	April, 2018 - June, 2018
Bid process and selection	July, 2019 - Dec, 2019
Isolation Activities	Dec, 2019 - Dec, 2020
Lake Road 4/6 retires	By Dec 31, 2019
Asbestos Removal	Jan, 2020 - Dec, 2021
Lake Road Post isolation activities	May, 2020 - Dec, 2021
* Material Hazard Analysis	

7.3 WIND RESOURCE ADDITIONS

As described above, 266 MW of wind additions are from two power purchase agreements (PPA) executed in 2017. One wind project, Pratt Wind consists of 244 MW of total capacity and is currently planned to be in-service in 2018. GMO is expected to be allocated 146 MW of the 244 MW facility. Pratt Wind is located in Pratt County, Kansas and owned by NextEra.

The second wind project, Prairie Queen, consists of 200 MW of total capacity and is currently planned to be in service by June, 2019. GMO is expected to be allocated 120 MW of the 200 MW facility. Prairie Queen is located in Allen County, Kansas and owned by EDP Renewables.

SECTION 8: MAJOR RESEARCH PROJECTS

8. A description of the major research projects and programs the utility will continue or commence during the implementation period;

8.1 LOAD FORECASTING

GMO plans to conduct its next Residential Appliance Saturation Survey during the implementation period. GMO is also looking at implementing the results from the last commercial and industrial survey in the 2019 update. The last residential survey was completed in 2016. The expected timeline for the Residential Appliance Saturation Survey has not yet been determined.

GMO plans to conduct a price elasticity study during the implementation period.

8.2 DEMAND-SIDE MANAGEMENT MARKET POTENTIAL STUDY

Pursuant to 4 CSR 240-3.164 (2) (A), the current market potential study shall be updated no less frequently than every four (4) years. Therefore, in compliance with this requirement and as part of GMO's ongoing research efforts, GMO plans to initiate the next market potential study in 2019 with an estimated completion date of early 2020.

8.3 ELECTRIC POWER RESEARCH INSTITUTE

GMO financially supports research conducted by the Electric Power Research Institute (EPRI). GMO has access to the EPRI library of energy efficiency and demand response research and data that is available to program participants.

More information about the EPRI energy efficiency and demand response program research can be found on their website, www.epri.com. Additional specific EPRI energy efficiency and demand response programs recently and/or currently supported by GMO are summarized below.

8.3.1 EPRI SUPPLEMENTAL PROJECT: ANALYSIS AND EVALUATION OF KCPL CLEAN CHARGE NETWORK

KCP&L began installing 1,000 plug-in electric vehicle (PEV) charging stations (2,000 ports) to serve 10k – 12k PEV's in 2015. The first two years expect low utilization of the charging stations with years two and three seeing PEV dealers and manufacturers catching up with supply. Year three is expected to see significant increases in charge station utilization with increased PEV adoption rates. KCP&L is among the first utilities in the US to establish a large-scale utility-owned and operated PEV charging network prior to receiving regulatory direction or approval. This project seeks to quantify the value of KCP&L's 'Clean Charge' PEV charging network (CCN) and related programs. The data collected and analyzed on top of the mainstream customer profile may be invaluable to stakeholders across the US who are considering utility-owned PEV charging networks as possible levers to increase PEV adoption and impact on the utility, local consumer, PEV driver, etc. This supplemental study seeks to achieve the following:

- PEV Adoption Scenarios
- Outline PEV Charging Technology Trends and Challenges
- Define PEV Unmanaged Charging Profiles
- Define PEV Managed Charging Profiles
- Assess Generation-Level Impact
- Assess Distribution Grid System Level Impacts
- Assess Distribution Grid Neighborhood Impacts
- Evaluate Rate Payer Impact
- Environmental Benefits of EV Adoption

8.3.2 EPRI PROGRAM 170: ENERGY EFFICIENCY AND DEMAND RESPONSE

GMO continues its participation in this EPRI research program. This program is focused on the assessment, testing, demonstration, deployment, and technology transfer of energy-efficient and demand-responsive end-use technologies to accelerate their adoption into utility programs, influence the progress of codes and standards, and ultimately lead to market transformation. The program also develops analytical frameworks essential to utility application of energy efficiency and demand response (DR) in order to enable the Integrated Power System, with particular focus on end-use load research and data analytics.

This program provides the following:

- Objective, independent technical assessment, testing, and demonstration of emerging end-use technologies for energy efficiency and the enablement of DR technologies.
- Framework to evaluate the readiness of emerging end-use technologies for utility programs along a research continuum spanning: technology scouting; assessment and lab testing; field testing and demonstration; field pilots; technology transfer; and full program rollout.
- World-class laboratory facilities to test emerging end-use technologies in simulated environmental conditions, thereby mitigating members' technical risk for field demonstrations and larger-scale deployments or programs.
- Multilevel assessment of enabling technologies for DR: components, sensors, and devices; systems for home and building energy management; and program integration into retail and wholesale markets.
- Development of analytical frameworks to help members characterize end-use load profiles, extract insights from smart meter data and other customer databases.

- Characterization of the grid impacts of customer interaction with emerging energy technologies and development of platforms for their integration as resources to enable an Integrated Power System.
- Technical staff with expertise in heating, ventilating, and air conditioning (HVAC); lighting; water heating; motors; power electronics; data centers; building energy management systems and controls; smart end-use systems; and analytical frameworks for energy efficiency and demand response.

This program advances the efficient use of energy, helping to keep electric service affordable for customers and environmentally responsible for society through resource conservation and avoided emissions. It also facilitates the connected customer getting more value from their utility service.

8.3.3 EPRI PROGRAM 170 SUPPLEMENTAL: EVALUATING SMART THERMOSTATS' IMPACT ON ENERGY EFFICIENCY AND DEMAND RESPONSE

GMO continues its participation in this EPRI supplemental research project. The EPRI smart thermostat project is a collaborative of 18 utilities seeking to understand more about smart thermostats in terms of customer perceptions, EE and DR impacts, and industry trends. To date the pilot has involved seven pilots projects, contributions to connected device-related specifications, technology assessments, lessons learned analyses, secondary research reviews, and multiple multi-stakeholder workshops. Pilot results to date suggest annual EE savings ranging from 5% to an increase in usage of 1%; summer DR reductions range from 0.7 to 1.2kW. KCP&L contributed a pilot project that is being evaluated to explore how thermostat-level data can be used for various use cases, including predicting EE and DR savings potential, as well as for alternative EE and DR impact evaluation methods. The overall project, including the KCP&L-specific evaluation, is expected to be completed in July 2018.

8.3.4 EPRI SMART THERMOSTAT COLLABORATIVE PROJECT

EPRI's Smart Thermostat Collaborative consists of 15 member utilities with an interest in evaluating smart thermostats for energy efficiency and demand-response benefits for both the utility and its customers. Estimates based on current growth trends project that smart thermostats, defined as customer-programmable communicating devices that can be remotely controlled via a signal from a utility, will constitute over half of the thermostats sold in the United States by 2017. The objective of this report is to summarize the state of the market and to give an account of the status of technological features provided by smart thermostats. It includes an historical overview of the evolution of customer and utility interest in programmable and smart thermostats.

Consumer desire for increasing levels of comfort, convenience, and control has recently driven a significant spike in purchases of smart thermostats. These devices present a new paradigm of consumer-facing technologies that includes new market delivery channels which utilities have not traditionally used. This paradigm-shift is creating new opportunities for utilities to deliver energy efficiency and demand-response programs via devices procured through delivery channels such as retail; security; and heating, ventilating, and air conditioning (HVAC) system providers. The electricity industry is beginning to identify potential grid-related and customer benefits of deployments of smart thermostats. In addition to energy efficiency and demand-response programs, example benefits to the utility include customer preference identification and segmentation, added opportunities to reach utility customers, customer event targeting, HVAC tune-up programs, home-energy audits, and passive storage using the thermal mass of residential buildings for load-shifting purposes. The report also addresses barriers to the deployment of smart thermostats, such as limited third-party empirical studies quantifying and verifying energy, demand, and the societal impacts of smart thermostats; lack of historical baselines for smart thermostat measurement and verification; interoperability restrictions between these connected devices and other residential and utility systems; security and privacy concerns; and challenges connected with the need for new partnerships between the utility and product providers.

The researchers investigated emerging features of smart thermostats that utilities can use for both grid and customer benefits. They also conducted a survey of smart thermostat manufacturers and service providers to gain enhanced insights into their current product offerings. Finally, they discussed utility interest in and ways to effectively leverage data collected from smart thermostats and other consumer devices.

8.3.5 EPRI PROGRAM 174: INTEGRATION OF DISTRIBUTED ENERGY RESOURCES

Increased amounts of distributed energy resources (DER) in the electric grid brings a number of challenges for the electric industry. Utilities may face large numbers of interconnection requests; distributed generation on some circuits will exceed the load; and many operating challenges involving feeder voltage regulation, hosting capacity limits, inverter grid support options are brought to bear. Furthermore, providing reliable service as DER penetrations increase can also add economic challenges to the technical ones.

This Program addresses the aforementioned challenges with project sets that assess feeder impacts, inverter interface electronics, interconnection and communication standards, and integration analytics. The Program provides insights into utility interconnection practices and strategies related to future integration approaches. It also evaluates economic impacts and values of DER integration. Many of these activities support EPRI's "The Integrated Grid" initiative.

Finally, the Program includes laboratory and field evaluations and demonstrations of improved DER power management and communications. A primary objective of the work in the field is to expand utility hands-on knowledge for managing distributed energy resources—without reducing safety, reliability, or asset utilization effectiveness.

8.3.6 EPRI PROGRAM 182: UNDERSTANDING ELECTRIC UTILITY CUSTOMERS

GMO continues its participation in this EPRI research program. Customers are growing more and more sophisticated, with increasing expectations of value, speed, and reliability based on service interactions in multiple business sectors, such as home entertainment, business computing and communications, and the Internet of Things. These expectations are carrying over to the electricity sector. At the same time, customers are beginning to consider options related to electricity supply and use, with choices often coming from third parties, not their utility. Technology advances are giving customers more choice and control over when and how they use electricity, including smart appliances and thermostats, plug-in electric vehicles, and options for local generation, such as rooftop solar photovoltaics. The choices customers make are already having recognizable impacts on the electricity system, particularly on energy consumption and load shapes, and these impacts will continue to grow.

Customer choice and control can enhance the value of electricity service to the individual customer and to customers as a whole. Because utilities have established relationships with their customers, they can be very effective change agents toward offering customers choices that align with both customer and utility objectives. Utilities have opportunities to meet customer expectations and to dynamically integrate customers and their choices into the power system. However, with the increasing sophistication of customers, new and diverse strategies to integrate customers are needed going forward. For example, utilities can learn from competitive industries' methods for understanding their customers. Businesses have developed detailed knowledge of their customers' preferences and behaviors over decades of gathering information. They apply this knowledge of customer interests and values to devise products and services that meet diverse demands, and then they make appropriate offers to targeted customers. Similarly, utilities need strategies for creating and offering compelling choices for electricity service.

EPRI's Understanding Electric Utility Customers research is focused on providing utilities with insights and tools to understand and to take action with their customers to offer choices that are aligned with customer preferences as well as utility and societal objectives of providing reliable, affordable, and environmentally-responsible power.

8.3.7 EPRI SUPPLEMENTAL: DISTINGUISHING DEMAND RESPONSE CANDIDATES THROUGH LOAD VARIABILITY ANALYSIS

GMO began participation in this EPRI supplemental research project in 2018. Studies on dynamic pricing programs among commercial and industrial (C&I) customers reveal a wide range of responses, which vary by type of pricing experiment and by customer segment. Even customers within the same segment exhibit different responses to dynamic pricing. Previous research reveals that a small portion of participants in dynamic pricing pilots deliver most of the load impact. However, identifying these highly responsive customers is a challenge that is not well understood. This lack of understanding contributes to the uncertainty and unpredictability of price-based demand response (DR) in the eyes of utilities, policy makers, and other stakeholders.

An emerging hypothesis is that variability in customer baseline load patterns may be a key indicator of DR potential, and therefore a means of differentiating and targeting high-value DR program participants. The theory suggests that customers with highly variable load patterns on normal days are more capable of altering their usage in response to price changes or other inducements. For example, in the Korean Critical Peak Pricing (CPP) pilot experiment in 2013 for C&I customers, KEPCO Research Institute (KEPCO RI) determined that variability of pre-enrollment load patterns was a significant predictor of DR impact. Customers in relatively low-variability clusters provided limited to no response, whereas customers in relatively high-variability clusters consistently delivered large DR impacts, accounting for most of the program level peak reductions. In that pilot, high-variability customer clusters represented 29% of program participants but delivered 70% of the program's peak reduction.

The objective of this project is to develop and apply a cost-effective and reliable method to identify potential highly responsive DR participants based on the variability of their electricity usage from pre-enrollment load data and other key variables such as electricity cost and demographics. This project will leverage the methodology and findings of the KEPCO RI CPP pilot using U.S.-based DR pilot data.

Although KEPCO RI's results offer a consistent interpretation of the effect of load variability on DR performance under CPP, it is unclear whether that will hold for other types of DR tariffs or segments beyond C&I. This project aims to assess the applicability of the variability measure to other pricing structures, such as time of use (TOU) and real-time pricing (RTP), as well as to the residential segment.

In addition, this project aims to provide normative insights into the design of dynamic pricing plans by employing a behavioral econometric model of electricity demand that accounts for customers' pre-enrollment load variability.

8.4 DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM (DERMS)

GMO is expected to commence on a new project to explore the value of an integrated distributed energy resource management system (DERMS). This software platform could have the potential to reach across many utility assets including demand response, electric vehicles, battery storage, distributed renewable generation to increase grid efficiency, reduce operating costs and improve customer satisfaction through service reliability and choice. A potential first phase of this project could specifically look at bringing demand response resources (dispatchable thermostats, controlled commercial load, etc.) together in a concerted fashion to better manage the coordination and impact of demand response events from these various assets.