NAVIGANT

DEMAND-SIDE RESOURCE POTENTIAL STUDY REPORT – DEMAND RESPONSE

Prepared for:
Kansas City Power and Light

KCP&L
energizing life

Navigant Consulting, Inc.
1375 Walnut Street
Suite 200
Boulder, CO 80302

(303) 728-2500
www.navigant.com

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1 Executive Summary

This section provides a high-level executive summary of the contents of this report.

1.1 *Introduction and Background*

Kansas City Power and Light (KCP&L) and KCP&L Greater Missouri Operations (KCP&L GMO) ("the Companies") selected Navigant to conduct a Demand Side Management ("DSM") Resource Potential Study in January, 2012. The Study objective was to assess the various categories of electrical energy efficiency and demand response potential in the residential, commercial, and industrial sectors for the Companies' service areas from 2014 to 2033. Portions of the study may be used by the Companies to satisfy some of the demand-side analysis requirements of the Missouri Public Service Commission Regulations for Electric Utility Resource Planning ("MO Planning Regulations").[1] Results of this Study will be used in the Companies' Integrated Resource Planning ("IRP") processes to analyze various levels of energy efficiency related savings and peak demand savings attributable to both energy efficiency initiatives and demand response initiatives at various levels of cost in support of the Companies' efforts to design highly effective potential demand-side programs that broadly cover the full spectrum of cost-effective end use measures for all customer market segments with the ultimate goal of achieving all cost-effective demand-side savings. As part of this study, Navigant also developed a suite of energy efficiency and demand response programs that were designed to achieve the savings deemed per this study to be "realistically achievable."

This document represents the Demand Response (DR) portion of the Demand Side Management ("DSM") Resource Potential Study and specifically presents the potential for peak demand savings attributable to demand response initiatives.

1.2 *Approach*

Navigant conducted the analysis for this study using its Demand Response Simulator (DRSim™) model. This model is designed to identify the critical component variables of peak demand impact, avoided cost estimates, program administration and evaluation costs, one-time startup costs, any incentive costs, and the appropriate population of potential participants. Navigant mirrored the model's approach after the methodology that the Federal Energy Regulatory Commission (FERC) used in its *National Assessment of Demand Response Potential*[2] (NADR), with a number of customizations added to specifically tailor the framework and inputs to the Companies.

Where possible, the analysis used inputs specific to the Companies, gathered through personal communications with the Companies, program documentation from the Companies, and KCP&L-GMO filings with the Missouri Public Service Commission (MO PSC).[3] Other resources referenced or

[1] Rules of Department of Economic Development Division 240—Public Service Commission Chapter 22—Electric Utility Resource Planning (4 CSR 240-22.010) – http://sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf

[2] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

[3] Including Kansas City Power & Light Company. *2012 Integrated Resource Plan*. Case No. EO-2012-0323. April 2012.

incorporated included the Missouri DSM potential study,[4] the Ameren UE DSM potential study,[5] Electric Power Research Institute (EPRI) research,[6] FERC's 2012 DR survey results,[7] and FERC's NADR.[8] In addition to leveraging NADR to inform the model approach, Navigant also used FERC's study as a benchmark for the model's output and to provide model participation, peak demand reduction, and equipment cost inputs that were unavailable through other data sources.

To capture a range of potential DR impacts, Navigant assumed Realistic Achievable Potential and Maximum Achievable Potential DR scenarios. The significance of these scenarios is presented briefly below:

- **Realistic Achievable Potential** means demand savings relative to a utility's baseline demand forecast resulting from expected program participation and realistic implementation conditions. This scenario mirrors FERC's Expanded BAU scenario and represents the approximate peak load reductions that the Companies may achieve through expansion of their current DR initiatives and implementation of some new DR initiatives with "best practice" participation levels[9] and medium-term backend integration with the Companies' AMI to support opt-in time-based rates.
- **Maximum Achievable Potential** means demand savings relative to a utility's baseline demand forecast resulting from expected program participation and ideal implementation conditions. It is considered the hypothetical upper-boundary of achievable demand-side savings potential. This scenario mirrors FERC's Achievable Potential scenario and represents an estimate of the maximum achievable potential for reliability-based DR penetration, based on full-scale deployment of DR programs under ideal implementation conditions, default dynamic pricing tariffs, and accelerated backend integration with the Companies' AMI to support opt-out time-based rates.

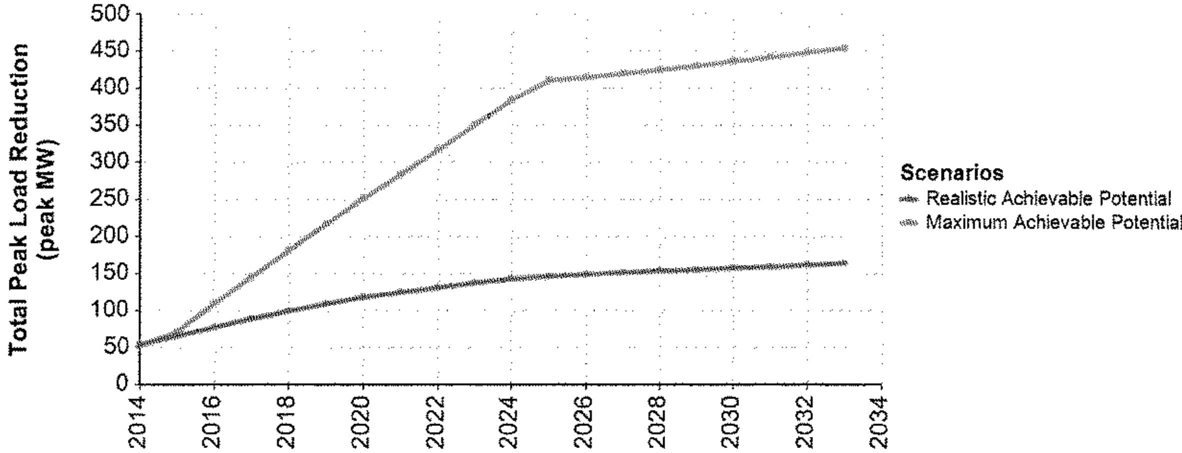
1.3 Results

This section provides a high-level summary of Navigant's estimates of DR potential for KCP&L and KCP&L GMO that the Companies could achieve during reliability-based events. Navigant estimates up to 453 MW in peak load reduction potential for KCP&L-KS, 642 MW for KCP&L-MO, and 840 MW for KCP&L-GMO by 2033 in the Max Achievable scenario, which represents about 21.3, 28.2, and 31.0

[4] "Missouri Statewide DSM Potential Study – Final Report." Published by KEMA Consulting. March 04, 2011.
[5] AmerenUE Demand-side Management (DSM) market Potential Study, Volume 3, prepared by Global Energy Partners, January 2010.
[6] Electric Power Research Institute. *Understanding Electric Utility Customers – Summary Report*. Report #1025856, Final Report, October 2012.
[7] Federal Energy Regulatory Commission, *2012 Survey on Demand Response and Advanced Metering*. Demand Response Survey Data, December 2012.
[8] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009. "National Demand Response Potential Model Guide", prepared for FERC, June 2009.
[9] This analysis uses FERC's interpretation of "best practices," where it refers only to "high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class." Source: Federal Energy Regulatory Commission. *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

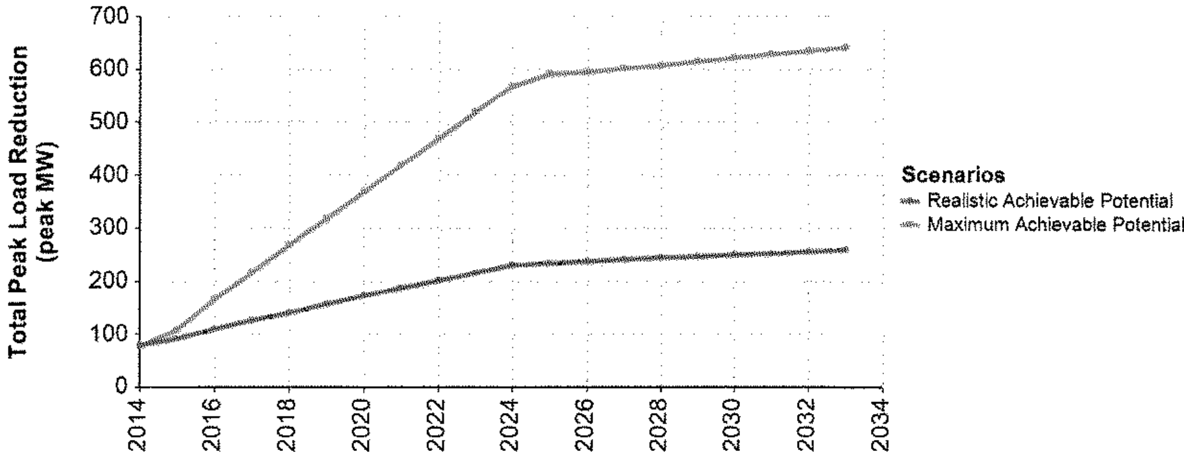
percent of each utility's forecasted peak load for 2033, respectively. The potential in the Max Achievable scenario reflects the peak load reductions that *could* be possible if the Companies were to drive new DR customer participation through targeted program marketing and investment in new infrastructure deployment and integration. These findings are benchmarked against the Realistic Achievable findings in Figure 1-1 through Figure 1-3 and Table 1-1, which show the total peak load reduction potential estimated for KCP&L-KS, KCP&L-MO, and KCP&L-GMO in each scenario.

Figure 1-1. Total Peak Load Reduction Potential by Scenario for KCP&L-KS (peak MW)



Source: Navigant analysis

Figure 1-2. Total Peak Load Reduction Potential by Scenario for KCP&L-MO (peak MW)



Source: Navigant analysis

Figure 1-3. Total Peak Load Reduction Potential by Scenario for KCP&L-GMO (peak MW)

Source: Navigant analysis

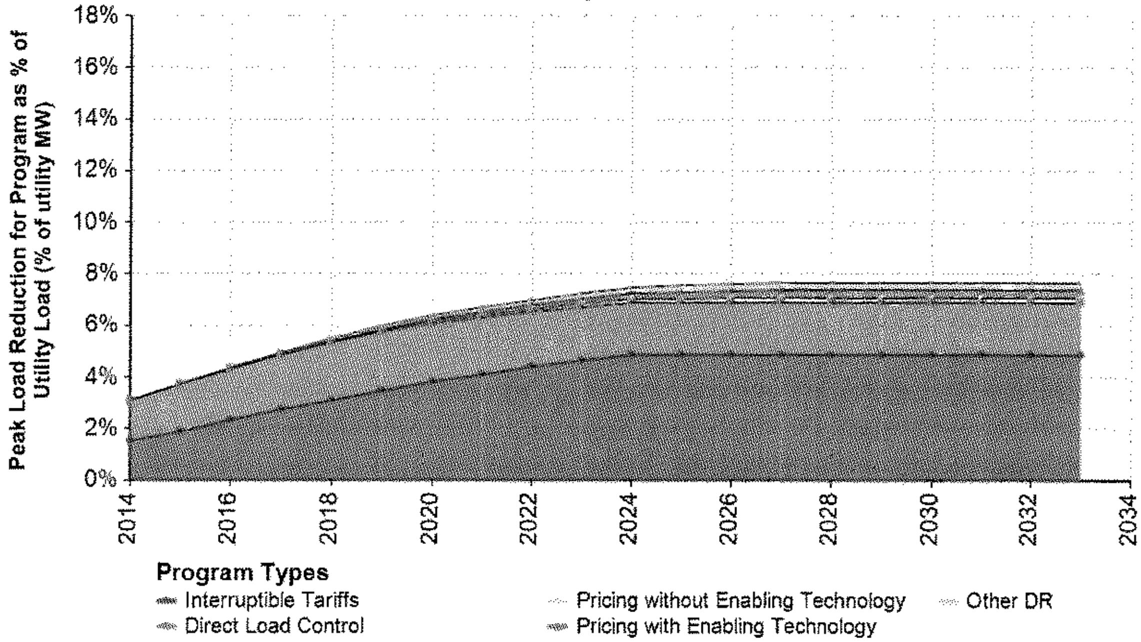
Table 1-1. Total Peak Load Reduction Potential by Scenario for the Companies (peak MW)

Utility	KCP&L-KS		KCP&L-MO		KCP&L-GMO	
Scenario	Realistic Achievable	Max Achievable	Realistic Achievable	Max Achievable	Realistic Achievable	Max Achievable
2014	54	54	78	78	36	36
2015	66	70	91	108	66	75
2016	77	109	110	164	98	117
2017	88	145	125	216	130	158
2018	99	181	141	267	162	226
2019	108	216	156	318	195	294
2020	117	251	172	368	229	361
2021	124	284	187	418	262	428
2022	130	317	201	468	296	497
2023	137	350	215	518	330	565
2024	143	383	230	568	365	636
2025	146	410	233	591	375	672
2026	148	413	237	594	384	710
2027	151	419	241	601	394	750
2028	153	424	243	607	404	760
2029	155	430	246	614	415	777
2030	157	436	249	621	425	792
2031	159	441	252	627	435	808
2032	161	447	255	634	445	824
2033	164	453	258	642	455	840

Source: Navigant analysis

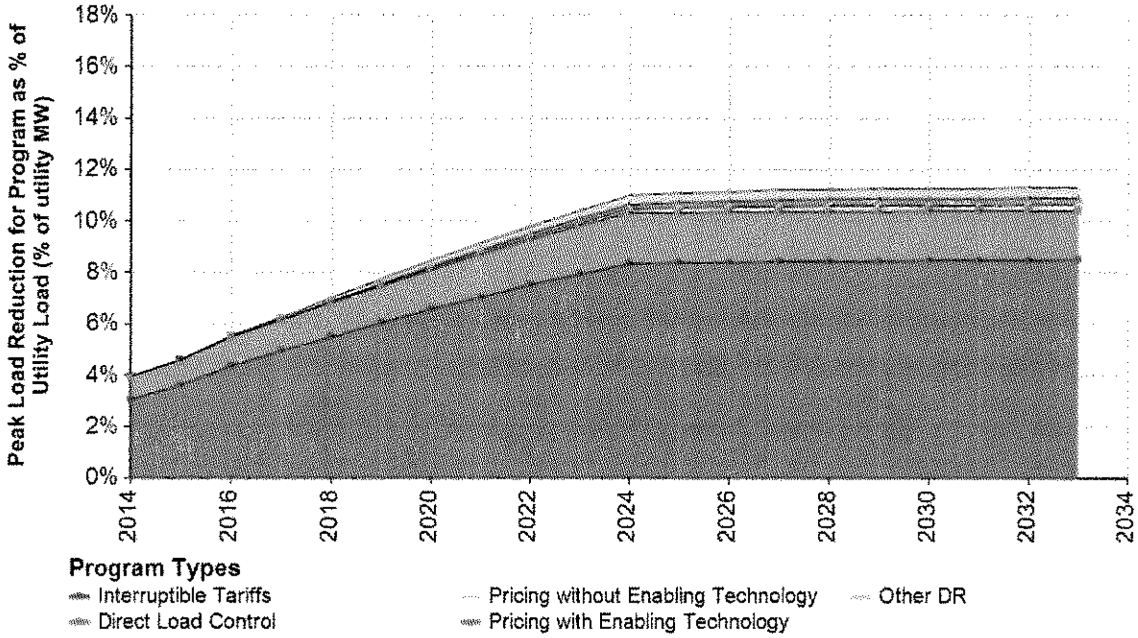
Variations between the three utilities are largely due to differences in total peak load, the mix of customers by rate class, and assumptions about customer load sizes and end uses that impact the amount of load a customer can reduce (e.g., large versus small industrials, higher versus lower air conditioning penetrations, etc.). Figure 1-4 through Figure 1-6 show the peak load reductions estimated in the Realistic Achievable scenarios for each of the Companies as the percentage of system load that could be reduced through different DR program types. This information is shown as tabular results for both the Realistic and Max Achievable scenarios in Appendix C – DR Demand Savings and Costs by Program Type.

Figure 1-4. Peak Load Reduction Potential for KCP&L-KS – Realistic Achievable Scenario (% of utility MW)



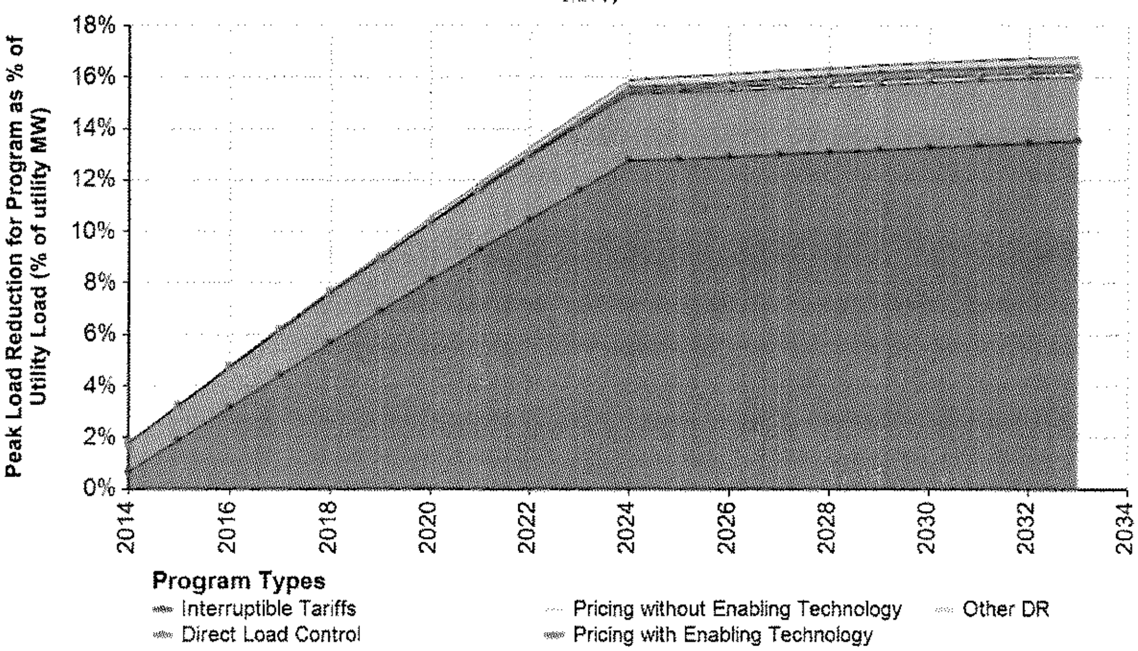
Source: Navigant analysis

Figure 1-5. KCP&L-MO Peak Load Reduction Potential – Realistic Achievable Scenario (% of utility MW)



Source: Navigant analysis

Figure 1-6. KCP&L-GMO Peak Load Reduction Potential – Realistic Achievable Scenario (% of utility MW)



Source: Navigant analysis

All of the scenarios show that significant potential growth still exists for the Companies' MPower Interruptible/Curtailable Tariff programs in the Medium and Large C&I customer segments, particularly in the KCP&L-MO and GMO territories. In contrast, participation rates in the Companies' Energy Optimizer Direct Load Control programs are already close to "best practice," though some additional potential exists. In the case of the pricing programs, the Max Achievable impacts are significantly higher than the Realistic Achievable impacts, which is due to the assumption that the pricing programs are opt-in in the Realistic scenario and opt-out in the Max Achievable scenario. Finally, while the cost effectiveness results suggest that the Other DR program may be cost effective, the potential peak reductions are relatively small.

- **Deployment of pricing programs is predicated on the backend integration of the Companies' AMI systems. While the Companies plan to deploy AMI across most of their service territories before 2020, the Companies do not have explicit plans to invest in the backend integration required to support time-based rates, such as installation of a Meter Data Management System (MDMS), which can add significant upfront costs to the program's deployment.**

- **The analysis includes the estimated costs of installing a MDMS[10] as a one-time startup cost for the pricing programs and finds that the pricing programs are cost effective when analyzed over a long-term horizon (i.e., the 20-year analysis period). However, we note that with relatively low near-term avoided capacity costs projected for the Companies, there is a significant time lag (10-15 years) before the cumulative program benefits surpass the cumulative program costs.**

- **This suggests that the timing of deployment for the pricing programs may warrant monitoring of capacity price forecasts and possibly aligning deployment with capacity price increases (which could shorten the effective payback time).**

Overall, this analysis finds significant potential for cost-effective DR program growth, with as much as 21-31 percent of each utility's peak demand in 2033 met by DR, as compared to less than 5 percent met by the Companies' existing programs. Furthermore, Navigant's cost-effectiveness analysis found that all of the program types are likely to be cost-effective over a 20-year horizon using the Total Resource Cost (TRC) benefit-cost test as a screen for all three of the utilities. These results reflect the estimated benefits from the continued promotion of the Companies' existing MPower and Optimizer programs, as well as investing in the infrastructure needed for backend integration of the Companies' AMI systems to support time-based rate programs.

[10] The MDMS installed cost assumed in this analysis of $1,000,000 is a reasonable initial estimate based on MDMS costs for other independently owned utilities; however, this cost can vary widely depending on the utility's system and functionality requirements, so the actual cost may be relatively uncertain.

2 Introduction

This section provides a brief introduction to the contents of this report, including a background discussion and summary of the study goals. This section also provides a summary of the report organization to facilitate reader navigation of its contents.

2.1 *Background and Study Goals*

Kansas City Power and Light (KCP&L) and KCP&L Greater Missouri Operations (KCP&L GMO) ("the Companies") selected Navigant to conduct a Demand Side Management ("DSM") Resource Potential Study in January, 2012. The Study objective was to assess the various categories of electrical energy efficiency and demand response potential in the residential, commercial, and industrial sectors for the Companies' service areas from 2014 to 2033. Portions of the study may be used by the Companies to satisfy some of the demand-side analysis requirements of the Missouri Public Service Commission Regulations for Electric Utility Resource Planning ("MO Planning Regulations").[11] Results of this Study will be used in the Companies' Integrated Resource Planning ("IRP") processes to analyze various levels of energy efficiency related savings and peak demand savings attributable to both energy efficiency initiatives and demand response initiatives at various levels of cost in support of the Companies' efforts to design highly effective potential demand-side programs that broadly cover the full spectrum of cost-effective end use measures for all customer market segments with the ultimate goal of achieving all cost-effective demand-side savings. As part of this study, Navigant also developed a suite of energy efficiency and demand response programs that were designed to achieve the savings deemed per this study to be "realistically achievable."

This document represents the Demand Response (DR) portion of the Demand Side Management ("DSM") Resource Potential Study and specifically presents the potential for peak demand savings attributable to DR initiatives.

In addition to these efforts, the Companies are currently engaged in DR research with the Electric Power Research Institute (EPRI) and KCP&L-MO's SmartGrid Demonstration Project. This research is also expected to meet some of the MO Planning Regulations. Navigant has collaborated throughout this project with EPRI and the SmartGrid Project and intends for this study to complement those efforts.

2.2 *Stakeholder Involvement*

Navigant involved a broad range of stakeholders throughout the study to ensure opportunity for review and comment of key study assumptions and methods was provided to those where were interested. Navigant invited the following organizations to each meeting and copied each of these stakeholders on correspondence providing key assumption and methodology files. Navigant reviewed and responded to stakeholder comments and distributed final documents to all stakeholders.

[11] Rules of Department of Economic Development Division 240—Public Service Commission Chapter 22—Electric Utility Resource Planning (4 CSR 240-22.010) – http://sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf

Stakeholders:

- KCP&L, KCP&L Greater Missouri Operations
- Missouri Public Service Commission
- Missouri Office of Public Counsel
- Missouri Department of Natural Resources
- National Resources Defense Council
- Empire Electric District
- Renew Missouri
- Ameren

Table 2-1 provides a summary of key stakeholder review meetings and relevant files pertaining to the review process.

Table 2-1. List of Stakeholder Meetings and Relevant Review and Response Files

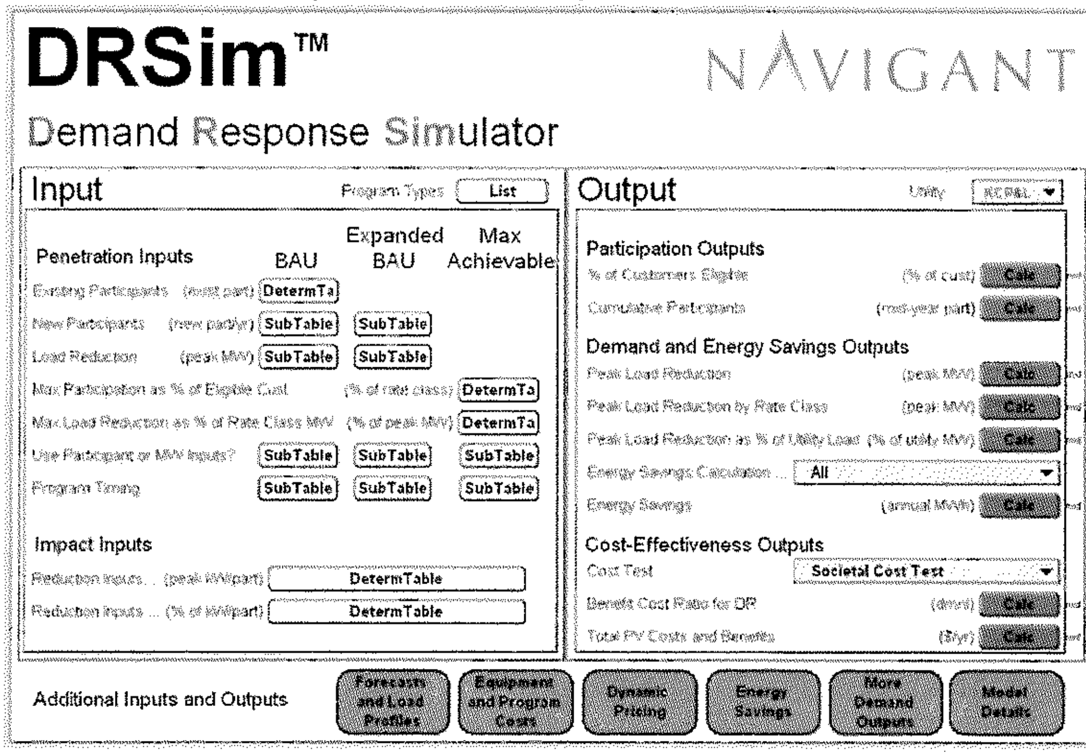
Review Item or Milestone	Review Type	Meeting Date (s)	Final File Date(s)	Relevant File Name(s)
DR Measures/ Approach	File for review	N/A	12/3/2012	KCPL_DR Measures-Approach Memo_07-17-12.docx
List of EE and DR Programs	File for review	N/A	12/3/2012	KCPL GMO Final Programs Matrix Dec 3 2012.docx
EE/DR Modeling Approach	Webinar	12/13/2012	12/13/2012, 01/03/2013, 01/14/2013	KCPL EEDR Demand Side Resource Potential Modeling Methodology 2012_12_13_R2.pdf; Response to KCPL and GMO StakeholderComments_2013_January_03 v4.docx; Response to KCPL and GMO StakeholderComments_2013_January_14;

2.3 *Demand Response Potential Model Description*

Navigant conducted the analysis for this study using its Demand Response Simulator (DRSim™) model. This model is designed to identify the critical component variables of peak demand impact, avoided cost estimates, program administration and evaluation costs, one-time startup costs, any incentive costs, and the appropriate population of potential participants. Navigant mirrored the model's approach after the methodology that the Federal Energy Regulatory Commission (FERC) used in its *National Assessment of Demand Response Potential*[12] (NADR), with a number of customizations added to specifically tailor the framework and inputs to the Companies. Although some DR programs included in this model could be deployed for economic considerations, the model output is intended to reflect the potential for peak load reduction that the Companies could achieve during reliability-based events. Figure 2-1 provides a screen capture of DRSim's graphical user interface.

[12] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

Figure 2-1. DRSim™ Graphical User Interface



Where possible, the analysis used inputs specific to the Companies, gathered through personal communications with the Companies, program documentation from the Companies, and KCP&L-GMO filings with the Missouri Public Service Commission (MO PSC).[13] Other resources referenced or incorporated included the Missouri DSM potential study,[14] the Ameren UE DSM potential study,[15] Electric Power Research Institute (EPRI) research,[16] FERC's 2012 DR survey results,[17] and FERC's NADR.[18] In addition to leveraging NADR to inform the model approach, Navigant also used FERC's study to provide model inputs that were unavailable through other data sources and as a benchmark for the model's output.

[13] Including Kansas City Power & Light Company. *2012 Integrated Resource Plan*. Case No. EO-2012-0323. April 2012.

[14] "Missouri Statewide DSM Potential Study – Final Report." Published by KEMA Consulting. March 04, 2011.

[15] AmerenUE Demand-side Management (DSM) market Potential Study, Volume 3, prepared by Global Energy Partners, January 2010.

[16] Electric Power Research Institute. *Understanding Electric Utility Customers – Summary Report*. Report #1025856, Final Report, October 2012.

[17] Federal Energy Regulatory Commission, *2012 Survey on Demand Response and Advanced Metering*. Demand Response Survey Data, December 2012.

[18] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009. "National Demand Response Potential Model Guide", prepared for FERC, June 2009.

3 Methodology and Key Assumptions

This study leveraged assumptions and inputs from a variety of sources, including several different resources specific to the Companies and FERC's NADR, as discussed below.

3.1 *Demand Response Program Types*

This section provides brief overviews of five different DR program types included in the analysis. These program types are based on those referenced in NADR, as well as on specific initiatives that the Companies are currently considering or implementing. At a high-level, the results for these different program types inform the DR program design efforts Navigant is conducting in parallel with this potential study. These program types are briefly described more below.

Some DR program types, including most time-based rates, require interval data collection and often require two-way communications between the utility and the customer's meter. These functionalities are inherent in advanced metering infrastructure (AMI) meters, but typically require investment in systems like a Meter Data Management System (MDMS) and integration with the utility's billing system. While the Companies plan to deploy AMI across most of their service territories before 2020, the Companies do not have explicit plans to install a MDMS or integrate the AMI with the systems required to support time-based rates. An important assumption within both the Realistic and Maximum Achievable scenarios is that the Companies invest in the additional infrastructure needed to integrate the AMI with the Companies' DR programs and offer time-based rates.

Interruptible/Curtailable Tariffs

FERC defines an interruptible (or curtailable) tariff as a rate structure in which customers agree to reduce consumption to a pre-specified level, or by a pre-specified amount, during system reliability events in exchange for an incentive payment.[19] The analysis limits participation in this program type to Medium and Large C&I customers and assumes that participants do not require additional investments in AMI or other equipment for participation.

This program type represents the Companies' existing MPower peak load reduction programs for commercial and industrial customers, in which the Companies collaborates with customers to curtail (or reduce) their energy use during times of peak electric demand. Events may be called for reliability or economic reasons. Reductions are commonly achieved by reducing lighting and HVAC load, shutting down equipment, or switching facility load to an onsite generator. MPower provides customers with two forms of financial incentives: 1) a monthly "participation payment" for being "on call" to reduce power consumption at the Companies' request, and 2) an additional "event payment" for successfully reducing demand each time they are called upon to do so. Participants must be current electric customers on a non-residential rate, who are able to provide a minimum reduction of 25kW during the specified curtailment season and curtailment hours.

[19] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

Direct Load Control (DLC)

This program type is modeled after the Companies' existing Energy Optimizer programs for Residential and Small Commercial (R&SC) customers. In the Energy Optimizer program, the Companies provide a free programmable thermostat to residential and small commercial customers with peak demand less than 25 kW. The Companies then remotely raise the customer's thermostat setpoint or cycles the A/C equipment without notification to reduce system load on peak summer days.

Because the scope of this analysis is limited, we did not look at the potential for DLC in other end uses, such as water heating or pool pumps, due to the relatively low expected impact. These end uses may provide additional opportunity for peak load reduction beyond that presented here.

Pricing without Enabling Technology

Dynamic pricing refers to the family of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis.[20] Examples of dynamic rates include time of use (TOU),[21] critical peak pricing (CPP), peak time rebates (PTR), and real-time pricing (RTP). Customers without enabling technology are assumed to manually curtail load in response to these dynamic time-varying pricing signals. Pricing signals can be communicated to customers via delivery mechanisms such as text messages, which avoid the need for additional investment in technologies such as in-home displays.

This analysis assumes that integrated AMI must be in place for a customer to be eligible for dynamic pricing. For residential customers, the analysis reflects the program impacts from a TOU rate in the Realistic Achievable scenario and a TOU with CPP rate in the Maximum Achievable scenario. The Companies are particularly interested in assessing TOU potential, given KCP&L-MO's current TOU pilot through the SmartGrid Demonstration Project, so it is specifically explored as part of this study. The program impacts for C&I customers are consistent with those assumed in the FERC NADR study, which does not assume a specific type of pricing.

Pricing with Enabling Technology

In this program type, customers are on a dynamic pricing rate, but also have enabling technology for automatic load curtailment. This analysis defines enabling technology as devices that automatically control load and reduce consumption during high-priced hours. Examples of enabling technology include Programmable Communication Thermostats (PCT), load switches, and Automated Demand Response (Auto-DR).[22] This analysis assumes that:

- The Residential, Small C&I, and Medium C&I customers with enabling technology have a PCT, whereas Large C&I customers have Auto-DR;
- Customer participation requires AMI; and

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[20] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

[21] While FERC's 2009 NADR study does not consider TOU a form of dynamic pricing, other industry definitions of dynamic pricing in more recent reports from EPRI and The Brattle Group include TOU as dynamic pricing. Sources: Electric Power Research Institute, *Understanding Electric Utility Customers – Summary Report*, Report #1025856, Final Report, October 2012. Faruqui, Ahmad, "Dynamic Pricing for Residential and Small C&I Customers", The Brattle Group, Presented to Ohio Public Utilities Commission, March 28, 2012.

[22] Automated Demand Response uses a customer's automated load control systems, such as an energy management system, to participate in DR events without manual intervention.

- Customers are offered the same pricing program types as in pricing without enabling technology.

Other DR

The assumed costs and impacts associated with this program type align with a curtailable load program targeted towards increased Small and Medium C&I customer participation. This new program would be an expansion of the Companies' existing MPower programs to Small and Medium C&I customers and may be a subset within the MPower program. No AMI would be needed to participate. Load curtailment through this program could be used for both economic and reliability-based dispatch.

3.2 *Model Scenarios*

To capture a range of potential DR impacts, Navigant assumed two DR potential scenarios: Realistic Achievable Potential and Maximum Achievable Potential. The primary differences between these scenarios relate to the assumed program participation levels, participant peak load reductions, and expected timing for AMI deployment and backend integration. Key inputs and assumptions for each scenario are discussed further in Sections 3.3 through 3.7.

3.2.1 Realistic Achievable Potential Assumptions

Realistic achievable potential means demand savings relative to a utility's baseline demand forecast, resulting from expected program participation and **realistic** implementation conditions. This scenario mirrors FERC's Expanded BAU scenario and represents the approximate peak load reductions that the Companies may achieve through expansion of their current DR initiatives and implementation of some new DR initiatives with "best practice" participation levels.[23] This scenario assumes that the Companies fully deploy AMI across KCP&L's and KCP&L GMO's territories according to their currently planned deployment schedule (i.e., by 2016 in KCP&L and 2020 in GMO) with at least partial backend integration by 2017 and 2019, respectively, to support opt-in time-based rates (see Table 3-4).

3.2.2 Maximum Achievable Potential Assumptions

Maximum achievable potential means demand savings relative to a utility's baseline demand forecast, resulting from expected program participation and **ideal** implementation conditions. Maximum achievable potential establishes a maximum target for demand-side savings that a utility can expect to achieve through its demand-side programs and may involve incentive or deployment costs that represent a very high portion of total programs costs. Maximum achievable potential is considered the hypothetical upper-boundary of achievable demand-side savings potential, because it presumes conditions that are ideal and not typically observed.

This scenario mirrors FERC's Achievable Potential scenario and represents an estimate of the maximum achievable potential for reliability-based DR penetration, based on full-scale deployment of DR

[23] This analysis uses FERC's interpretation of "best practices," where it refers only to "high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class." Source: Federal Energy Regulatory Commission. *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

programs under ideal implementation conditions and default dynamic pricing tariffs. This scenario assumes backend integration with the Companies' AMI is accelerated to support opt-out time-based rates (see Table 3-4).

3.3 *Market Characterization*

This section discusses the analysis inputs that Navigant collected to define the DR potential market for the Companies. The inputs discussed below include the peak demand forecasts, number of customers forecast, customer load profiles, portion of customers with load suitable for automated control, and AMI deployment forecasts for the Companies.

3.3.1 Peak Demand and Customer Forecasts

This study uses FERC's definition of *peak* and assumes that DR occurs for 4 hours a day during the 15 highest load days of the year. As a result, the DR presented in this analysis reduces peak demand, but not necessarily demand during non-peak times.[24]

To tailor the DR potential estimate to the Companies' service territory, the team collected the peak load[25] and customer forecasts[26] for KCP&L-KS, KCP&L-MO, and KCP&L-GMO through 2033. The peak load forecasts provided by the Companies are without demand-side management (DSM)[27] and serve as the baseline for the analysis. The number of customers informs the maximum penetration of DR programs in the Max Achievable scenario (see Section 3.4.2).

3.3.2 Customer Rate Classes and Load Profiles

Because the potential for DR varies depending on the size and type of customer, the analysis divided the Companies' customers into the following rate classes:

» Residential[28]

» Small C&I (<25 kW)

» Medium C&I (25–200 kW)

» Large C&I (>200 kW)

These rate classes were chosen to maintain consistency with the rate classes used in NADR[29] and with KCP&L's General Service tariffs, which require a minimum demand of 25 kW for Medium General Service and 200 kW for Large General Service. Table 3-1 shows the average customer load profile for each rate class, based on the average peak load per customer under each tariff.

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[24] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009, p. 28.

[25] Maximum monthly load in each year from Coincident Peak Demand By Class (MW) from KCPL Energy Peak Customers.xls and GMO Energy Peak Customers.xls.

[26] Maximum monthly number of customers in each year from "KCPL Energy Peak Customers.xls" and "GMO Energy Peak Customers.xls". Excludes Street Lighting and Sales-for-resale.

[27] Confirmed via phone communications with Joe O'Donnell, GPES, December 17, 2012.

[28] Includes multi-family, as included in GPES's residential tariffs.

[29] FERC's DR potential study actually divides Small and Medium C&I at 20 kW; however, the distinction between 20 kW and 25 kW likely has no significant impact on the analysis.

Table 3-1. Average Customer Load Profiles (peak kW/customer)

Rate Class	Utility		
	KCP&L-KS	KCP&L-MO	KCP&L-GMO [30]
Residential	4.6	3.3	4.0
Small C&I (<25 kW)	3.0	3.9	2.0
Medium C&I (25-200 kW)	39.4	43.0	29.5
Large C&I (>200 kW)	408.7	685.5	456.8

Source: Navigant analysis, based on the Companies' peak demand and number of customer forecasts by rate class.

Table 3-2 shows the portion of customers with load (e.g., cooling load) suitable for participation in programs that require automated load control, such as DLC and pricing with enabling technology.

Table 3-2. Proportion of Customers with Suitable Load

Rate Class	Percentage of Customers with Suitable Load	
	Missouri	Kansas
Residential	87.5%	83.7%
Small C&I (<25 kW)	74%	74%
Medium C&I (25-200 kW)	77%	77%
Large C&I (>200 kW)	40%	40%

Source: Federal Energy Regulatory Commission, A National Assessment of Demand Response Potential. Prepared by The Brattle Group, June 2009.

Finally, Table 3-3 shows the program types that are considered in the DR potential model for each of these rate classes.

[30] Since KCP&L-GMO does not have a Medium General Service tariff, KCP&L-GMO's Small and Large General Service customers and load were divided into these rate classes by using the same proportion of customers and load in each rate class as in KCP&L.

Table 3-3. Overview of DR Program Types and Rate Classes Assessed

Demand Response Programs	Rate Classes R	S	M	L
Interruptible/Curtailable Tariffs			X	X
Direct Load Control	X	X		
Pricing without Enabling Technology	X	X	X	X
Pricing with Enabling Technology	X	X	X	X
Other DR		X	X	

R = Residential, S = Small C&I, M = Medium C&I, L = Large C&I

3.3.3 AMI Deployment Forecast

As discussed in Section 3.1, the analysis assumes that a customer must have access to an AMI meter integrated with the Companies' backend systems to participate in a pricing program. Through discussions with the Companies, Navigant has developed forecasts for when AMI will be deployed across each service territory, as well as a rough estimate of when the Companies might install MDM systems and integrate the AMI to support pricing programs. This forecast appears in Table 3-4 below for both scenarios and is an important driver in the deployment of time-based rates.

Table 3-4. Assumed Timing for AMI Deployment and Backend Integration to Support Time-Based Rates (% of customers)

Scenario	Utility	Year Backend Integration Occurs	AMI Deployment Forecast 2013	2014	2015	2016	2017	2018	2019	2020
Realistic Potential	KCP&L-KS	2017	0%	50%	80%	100%	100%	100%	100%	100%
	KCP&L-MO	2017	*	50%	80%	100%	100%	100%	100%	100%
	KCP&L-GMO	2019	0%	0%	0%	0%	0%	50%	80%	100%
Maximum Potential	KCP&L-KS	2015	0%	50%	80%	100%	100%	100%	100%	100%
	KCP&L-MO	2015	*	50%	80%	100%	100%	100%	100%	100%
	KCP&L-GMO	2017	0%	0%	50%	80%	100%	100%	100%	100%

*Commercial = 0.5%, Residential = 3%

Note: Assumes one MDMS is installed in KCP&L and one is installed in KCP&L GMO.

Source: Based on email and phone communications with Joe O'Donnell, KCP&L, December 2012 and Navigant analysis.

The key differences between the two scenarios are the accelerated meter deployment for KCP&L-GMO and the accelerated backend integration for both utilities in the Maximum scenario, which allow time-based rates to be offered sooner in the Maximum scenario. For comparison, the Achievable Potential scenario in FERC's NADR study, which corresponds to the Maximum Achievable Potential scenario here, assumes full AMI deployment in Kansas and Missouri by 2019.

3.3.4 Customer Program Eligibility

The percentage of customers eligible for each program type is an important constraint on program participation, as described below in Section 3.4. Navigant estimated this percentage using the proportion of customers with load suitable for automated load control from Table 3-2 and customers with integrated AMI meters from Table 3-4. Table 3-5 shows how these constraints are applied to each program type.

Table 3-5. Requirements for DR Program Eligibility

Program Type	Requires Load Suitable for Automated Load Control?	Requires Integrated AMI?
Interruptible/Curtailable Tariffs		
Direct Load Control	Yes	
Dynamic Pricing w/o Enabling Technology		Yes
Dynamic Pricing w/ Enabling Technology	Yes	Yes
Other DR		
Time of Use		Yes

3.4 *Participation Assumptions*

The program participation inputs use a base case participation forecast provided by the Companies as the initial DR penetration in 2014 (see Table 3-6), then assume a maximum penetration of DR program deployment (see Table 3-7) and a number of years it takes to reach that maximum penetration for each scenario.[31] This approach is consistent with the methodology used in NADR.

3.4.1 Base Case Participation Inputs

Table 3-6 shows the participation in each program type at the start of the analysis in 2014, based on the Companies' currently planned DR program forecasts. MPower and Energy Optimizer are the only programs assumed to be available.

[31] The analysis assumes ten years for all program types and scenarios. Source: Oak Ridge National Laboratory, "Eastern Interconnection Demand Response Potential", ORNL/TM-2012/303, DRAFT, October 2012, "NADR-XL7v2s_S_20120710.xlsx." Based on high-case numbers from Faruqui, A. and D. Mitarotonda (2011). "Energy efficiency and demand response in 2020- a survey of expert opinion". Available at http://www.brattle.com/_documents/UploadLibrary/Upload990.pdf.

Table 3-6. Base Case Participation Inputs in 2014 (in kW)

Utility	Interruptible Tariffs	Direct Load Control	All Other Program Types
KCP&L-MO	59,997	18,000	0
KCP&L-KS	26,630	27,000	0
GMO	13,648	22,000	0

Sources:
Interruptible Tariffs: MPower forecast provided by Joe O'Donnell, KCP&L, "KCPL_GMO MPower forecast.xlsx", December 5, 2012.
Direct Load Control: Energy Optimizer forecast provided in National Association of Regulatory Utility Commissioners, Assessment of Demand-Side Resources Survey, Submitted by KCP&L on December 10, 2012.

KCP&L-MO is also currently offering a TOU rate and other residential smart grid DR strategies through its SmartGrid Demonstration Project (the "pilot") for residential customers in its Green Impact Zone. This pilot began in 2012 and will run through 2014. Since the Companies expect program participation to be limited to a few hundred customers, this program is not included in the potential analysis. However, the Companies expect that the pilot will help inform future program deployments, such as the potential deployment of a more widespread residential TOU rate.

3.4.2 Maximum Participation Inputs for Realistic and Maximum Achievable Scenarios

Table 3-7 shows the maximum penetration of DR program deployment, which is estimated as either a percentage of the total peak demand or a percentage of the eligible customers for each rate class, depending on the information available for each program and utility. These estimates are based on the "Expanded BAU" and "Achievable Participation" scenarios in Kansas and Missouri from either FERC's NADR or ORNL's recent update to NADR for the Eastern Interconnection.

Table 3-7. Maximum Participation Inputs for Realistic and Maximum Achievable Potential Scenarios (% of Rate Class MW or Eligible Customers)

Program Type	Participation Input	Scenario	Residential	Small C&I (<25 kW)	Medium C&I (25-200 kW)	Large C&I (>200 kW)
Interruptible Tariffs	% of rate class MW	Both	0%	0%	40%	40%
Direct Load Control	% of customers w/suitable load	Both	21%	20%	20%	20%
Pricing w/o Enabling Technology	% of customers w/AMI	Realistic	5%	5%	5%	5%
		Maximum	75%	75%	60%	60%
Pricing w/ Enabling Technology	% of customers w/suitable load & AMI	Realistic	2.9%	2.9%	2.9%	2.9%
		Maximum	42.7%	42.7%	34.2%	34.2%
Other DR	% of rate class MW	Realistic	0%	1.2%	7.2%	23.4%
		Maximum		20%	20%	

Source for Interruptible, Direct Load Control, and Other DR (Maximum): Oak Ridge National Laboratory, "Eastern Interconnection Demand Response Potential", ORNL/TM-2012/303, DRAFT, October 2012, "NADR-XL7v2s_S_20120710.xlsx." Based on high-case numbers from Faruqui, A. and D. Mitarotonda (2011). "Energy efficiency and demand response in 2020- a survey of expert opinion." Available at http://www.brattle.com/_documents/UploadLibrary/Upload990.pdf.
Source for Dynamic Pricing and Other DR (Realistic): Federal Energy Regulatory Commission. *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.
* All inputs are the same for Kansas and Missouri.
** Estimates presented here do not account for potential overlaps in program participation. Overlap is accounted for in final model output.

The maximum penetrations for the dynamic pricing programs shown in Table 3-7 depend on a variety of inputs, including the percentage of customers that 1) enroll in the programs, 2) are offered an automated load control device (e.g., PCT or load switch), 3) accept the automated load control device, and 4) in the case of pricing without enabling technology, are already enrolled in pricing with enabling technology. This approach leverages the methodology and inputs used in NADR. The relationship between these inputs is shown here for the Maximum Achievable scenario:

Maximum Achievable penetration for pricing with enabling technology:
60–75 percent of eligible customers enroll in dynamic pricing
× 95 percent of eligible customers are offered automated load control device
<u>× 60 percent of eligible customers accept automated load control device</u>
34–43 percent of eligible* customers enroll in dynamic pricing with enabling technology
**Eligible customers must have AMI and load suitable for auto load control.*

Maximum Achievable penetration for pricing without enabling technology:
60–75 percent of eligible customers enroll in dynamic pricing
<u>- 34–43 percent of eligible customers enrolled in dynamic pricing with enabling technology</u>
26–32 percent of eligible* customers enroll in dynamic pricing without enabling technology
**Eligible customers must have AMI.*

Source: Navigant analysis and Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. "FERC_NADR-model.xls." Prepared by The Brattle Group, June 2009.

FERC's assumption that 60–75 percent of eligible customers enroll in dynamic pricing reflects an opt-out enrollment strategy and is based on market research and recent experience in California. The percentages of customers that are offered and accept an automated load control device reflect FERC's assumptions on the likelihood of the average utility and customer to make these decisions.[32]

3.4.3 Adjusting for Overlap in Participation

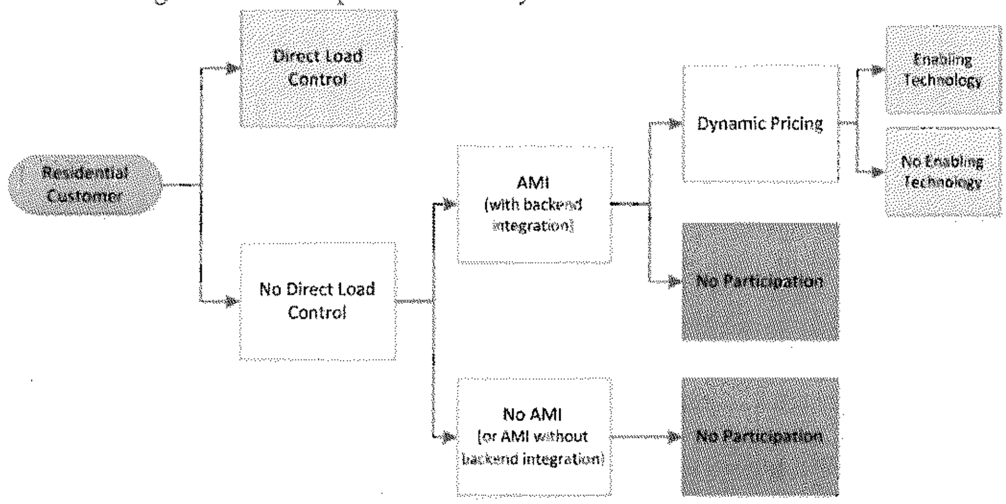
Although the maximum penetration rates shown in Table 3-7 do not account for the potential overlap in program participation across program types and customer segments, the final peak demand reductions are adjusted to account for participant overlap. Figure 3-1 through Figure 3-4 show the hierarchy for determining which program a customer participates in.

In the Realistic scenario, participation in MPower (i.e., Interruptible/Curtailable Tariffs) is the default customer choice for Medium and Large C&I participants and Optimizer (i.e., Direct Load Control) is the default customer choice for Residential Small C&I participants. Participants not enrolled in Interruptible/Curtailable Tariffs or Direct Load Control may choose to participate in either and opt-in Dynamic Pricing program or Other DR, depending on whether or not they have integrated AMI.

In the Maximum scenario, an opt-out pricing program is the default option for participation, assuming the customer has integrated AMI.

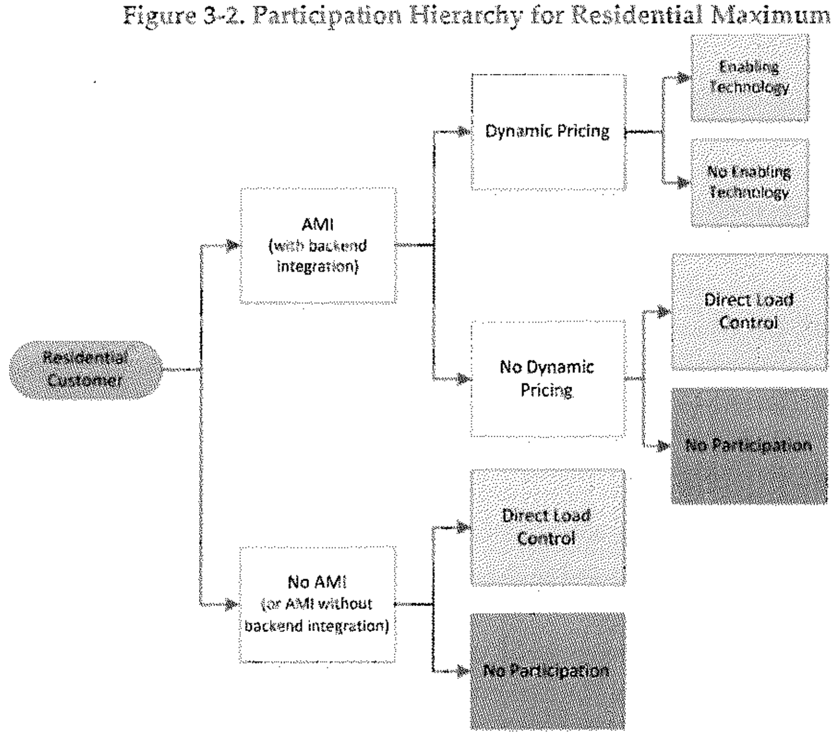
[32] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009, p. 62.

Figure 3-1. Participation Hierarchy for Residential Realistic Achievable Scenario



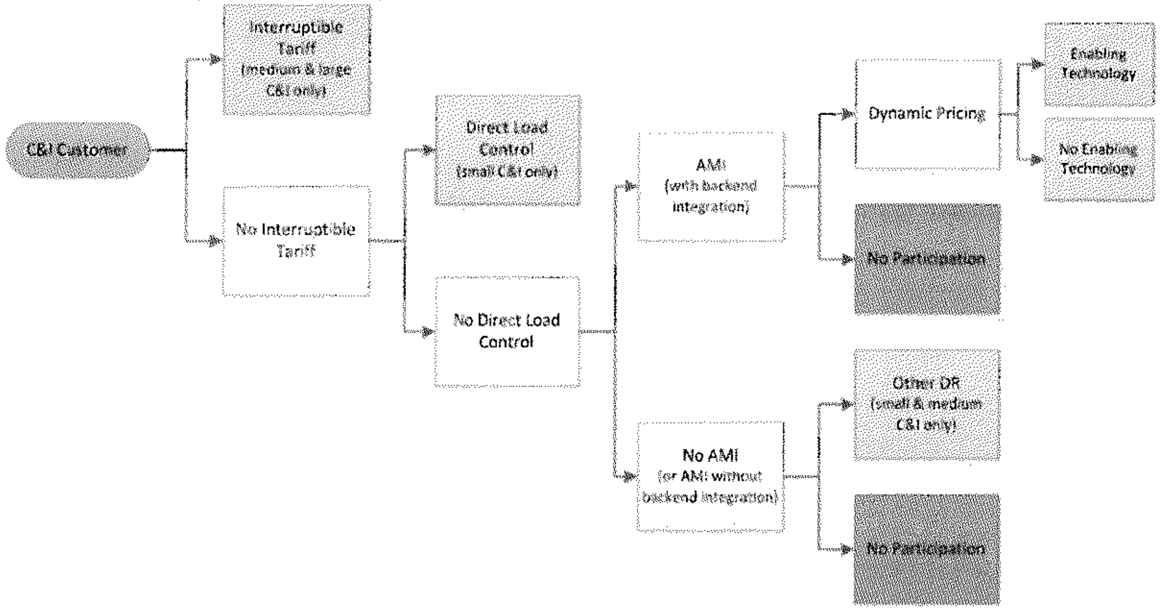
Source: Navigant analysis

Figure 3-2. Participation Hierarchy for Residential Maximum Achievable Scenario



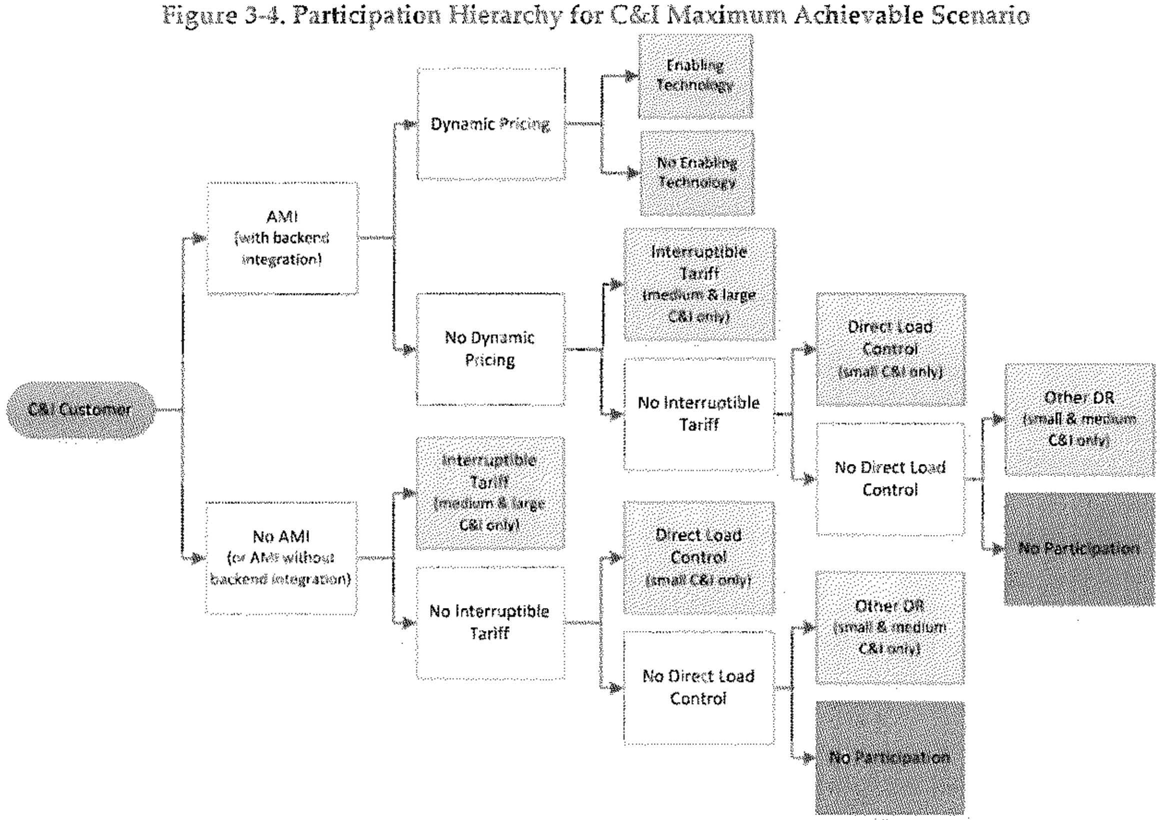
Source: Navigant analysis

Figure 3-3. Participation Hierarchy for C&I Realistic Achievable Scenario



Source: Navigant analysis

Figure 3-4. Participation Hierarchy for C&I Maximum Achievable Scenario



Source: Navigant analysis

3.5 Peak Demand Reduction Assumptions

The amount of peak demand reduced by each participant was calculated as a percentage of the average load profile for that participant's rate class (see Table 3-1). For residential pricing with and without enabling technology, Navigant assumes that the peak demand reductions in the Realistic Achievable scenario are roughly equivalent to the peak demand reductions for a customer on a TOU rate, while the peak demand reductions in the Maximum Achievable scenario are roughly equivalent to that of a TOU with CPP rate. The pricing programs with enabling technology assume peak demand reductions for the same rate types, but with the incremental benefit provided by enabling technologies. Table 3-8 shows the specific rate and demand reduction for each program and scenario, based on the impacts of various residential pricing pilots from EPRI.

Table 3-8. Assumed Peak Demand Reduction and Pricing Type for Each Scenario and Program Type

Program Type	Realistic Achievable	Maximum Achievable
Pricing without Enabling Technology	TOU 7%	TOU with CPP 18%
Pricing with Enabling Technology	TOU + Technology 18%	TOU with CPP + Technology 30%

Source: Based on the averaged load reductions for Residential pricing pilots with and without enabling technology. Electric Power Research Institute, Understanding Electric Utility Customers - Summary Report. Report #1025856, Final Report, October 2012.

For Interruptible Tariffs and Direct Load Control in the Realistic Achievable scenario, Navigant used actual 2012 peak demand reduction values from the Companies' MPower and Optimizer programs by utility. Unless the MPower and Optimizer values were higher than what FERC assumed,[33] Navigant used FERC's NADR assumptions for all other demand reduction inputs in the Realistic and Maximum Achievable scenarios.[34]

3.6 Energy Savings from Demand Response

Navigant conservatively assumes there are no significant energy savings from the Companies' DR programs in any scenario. While some studies have found conservation from DR, this assumption is consistent with typical industry assumptions for dispatchable programs like Direct Load Control and Interruptible Tariffs, as well as some of Navigant's recent findings for utilities with time-based rates, including TOU.[35]

[33] The Companies' actual reductions were slightly higher than FERC's estimated reductions for Large C&I MPower participants in KCP&L-KS and Optimizer participants in KCP&L.

[34] Navigant used FERC's default average participant load reductions from the Achievable scenario, including the price ratio assumptions for dynamic pricing, with minor exceptions.

[35] Email communications with David Walls, Navigant Consulting, Inc., January 2013 regarding energy use with TOU for some DOE Smart Grid Investment Grant recipients.

3.7 *Program Costs and Benefits*

The cost-effectiveness analysis looked at the utility program administration costs; vendor program administration costs; evaluation, measurement, and verification (EM&V) costs; incentive costs; and avoided costs for each DR program type. These costs were included as the following:

- **Ongoing program costs:** An estimated cost per kilowatt of savings ($/kW-year) for each cost category and program type that applies to new and existing program participants.
- **New participant costs:** A cost per new participant ($/new participant), which includes the incremental costs for new participants associated with equipment installation and marketing.
- **One-time costs:** A one-time annual cost ($/yr) for a limited number of startup or capital costs applied within the utility administration cost category.

To distinguish the Companies' in-house administrative costs from outsourced costs, the program administration costs are divided into the utility and vendor administration cost categories. The utility administration costs assumed in this model reflect the up-front costs for program development and MDMS installation; the ongoing in-house costs for implementation and delivery, such as program delivery, marketing, and administration costs; and the marketing for new participants. The vendor administration costs reflect all outsourced costs and include ongoing costs for implementation and delivery, as well as any incremental equipment costs associated with new participants. For the purposes of this analysis, the capital and installation costs associated with equipment installed at the customer site are included in the vendor administration category and treated as costs to the utility and ratepayer, rather than the participant. This assumption is consistent with the current design of the Energy Optimizer program, as well as many other utility DR programs within the industry.

Since the cost structures in the Realistic and Maximum Achievable scenarios for MPower are not expected to change significantly from the base case cost forecasts provided by the Companies, Navigant used the cost estimates provided by the Companies for MPower as the Interruptible Tariffs costs for both scenarios.

This section describes the inputs and assumptions driving the various cost inputs, and how they are applied in more detail below.

Ongoing Program Costs

Table 3-9 below summarizes the ongoing program costs assumed for each cost category and program type.

Table 3-9. Summary of Ongoing Program Costs by Cost Category ($/kW-yr)[1,2]

Program Type	Utility Admin	Vendor Admin	EM&V	Incentive
Interruptible Tariffs	** [redacted]			
Direct Load Control				
Pricing w/o Enabling Technology				
Pricing w/ Enabling Technology				
Other DR				**

1. These are the estimated costs from 2014-2017, with an assumed escalation rate of 2.5 percent per year applied starting in 2018 to be consistent with the cost assumptions in the MPower forecast provided by the Companies.
2. Actual costs in the model vary slightly by utility based on forecasts provided by the Companies.
Interruptible Tariffs: "KCPL_GMO MPower forecast.xlsx" provided by Joe O'Donnell, KCP&L, August 2012.
Direct Load Control and Pricing: Estimated from benchmarking of similar programs.
Pricing and Other DR: Navigant analysis. Global Energy Partners, *Tennessee Valley Authority Potential Study*, Report Number 1360, December 21, 2011.

The assumptions for Direct Load Control *vendor* administration costs were also applied to the pricing programs, since they are assumed to have similar vendor requirements. However, Navigant assumed a slightly higher *utility* administration cost for the pricing programs than for Direct Load Control programs, based on cost estimates from Global Energy Partners (GEP).[36] For Other DR, the vendor administration costs are assumed to be 50 percent higher than the Direct Load Control costs, based on the additional communications and control technologies that would likely be needed for small and medium C&I customers to participate effectively. Finally, the Other DR program's utility administration costs reference GEP's administrative cost estimate for a C&I capacity reduction program of [redacted].

The EM&V costs are based on KCP&L and KCP&L GMO's MPower and Energy Optimizer costs forecasts, and are assumed to be roughly equivalent for all programs except the Other DR program. A slightly higher EM&V cost is assumed for the Other DR program, since it is a less commonly implemented program type within the industry.

Finally, incentive costs are only assumed for Interruptible Tariffs and the Other DR program. The Interruptible Tariffs program uses the forecasted MPower incentive costs provided by the Companies and Other DR references GEP's cost estimates for a C&I capacity reduction program.

[36] Global Energy Partners, *Tennessee Valley Authority Potential Study*, Report Number 1360, December 21, 2011.

New Participant Costs

New participant costs are assumed for all program types except Interruptible Tariffs. The number of new participants each year is based on the annual program growth minus participants that dropped out of the program. The latter is captured through an assumed rate of attrition, which varies between one and five percent each year in this analysis, based on program type and standard industry assumptions.

Under the utility administration cost category, a [redacted] marketing cost is assumed for each new participant in all program types except for Interruptible Tariffs.[37]

Table 3-9 below shows the assumed vendor administration costs for new participants, which largely reflect the installed costs of the equipment required for participation in each program type. No incremental equipment costs are assumed for participation in Interruptible Tariffs or Pricing without Enabling Technology. The Residential and Small C&I costs are based on the estimated installed cost of a controllable thermostat in the Companies' Energy Optimizer programs. These costs are higher than many other assumptions for installed thermostat costs, particularly for Residential, and are thought to be conservative. The Medium and Large C&I costs are reasonable average assumptions, but could be much higher for very large C&I customers.

Table 3-10. Vendor Administration Costs for New Participants by Cost Category and Rate Class ($/new participant)*

Program Type	Residential	Small C&I	Medium C&I	Large C&I
Interruptible Tariffs	[redacted]			
Direct Load Control				
Pricing w/o Enabling Technology				
Pricing w/ Enabling Technology				
Other DR				

* These are the estimated costs from 2014-2017, with an assumed escalation rate of 2.5 percent per year applied starting in 2018 to be consistent with the cost assumptions in the MPower forecast provided by the Companies.
Residential and Small C&I: Based on benchmarking of typical installed cost of controllable thermostats.
Medium C&I: Based on vendor estimates and utility program cost data for the installed cost of programmable communicating thermostats and remotely-controlled switches from programs with similar DR options. Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.
Large C&I: Based on estimated installed cost of automated demand response (Auto-DR) for large C&I customers. Global Energy Partners, *Tennessee Valley Authority Potential Study*, Report Number 1360, December 21, 2011.

One-Time Costs

The analysis includes one-time program development costs for the startup of new programs, as well as the cost of a new MDMS to fully integrate the Companies' AMI meters and support time-based rates. The cost of the AMI meters is not included in the DR cost effectiveness analysis, since it is assumed these meters are deployed independently of the DR programs to provide meter reading benefits.

[37] Navigant analysis for Tucson Electric Power on cost effectiveness of mass market Direct Load Control, 2009. Global Energy Partners, *Tennessee Valley Authority Potential Study*, Report Number 1360, December 21, 2011.

These costs are each incurred once for KCP&L and once for KCP&L-GMO. The model then apportions the costs for KCP&L by state based on the number of KCP&L participants in each state. The assumed program development costs include [redacted][38] for the Other DR program and a single [redacted] cost shared across both Pricing programs in the year the programs begin. No program development cost is applied to the Interruptible Tariff and Direct Load Control programs.

The installed cost of an MDMS is estimated to be around [redacted] based on the estimated cost of Ameren's MDMS,[39] although this cost may vary significantly depending on the selected vendor and choice of options.

Total Program Costs

Table 3-11 through Table 3-13 provide a breakdown, by program, of the forecast cumulative budget from 2014 through 2033. The budget values include the incentive costs, non-incentive costs (i.e., program administration and on-time costs), and EM&V costs presented above. Budgets over the 20-year forecast horizon range from [redacted] depending on the utility. The 10-year average annual budget for each utility is [redacted] for KCP&L-KS, KCP&L-MO, and KCP&L-GMO, respectively. The budgets for the Maximum Achievable Potential scenario are also presented in Appendix C.

[38] Global Energy Partners, *Tennessee Valley Authority Potential Study*, Report Number 1360, December 21, 2011.
[39] Navigant Consulting, Inc. *Advanced Metering Infrastructure (AMI) Future Program Study*. Prepared for FortisBC. March 2011.

Table 3-11. Cumulative Realistic Achievable DR Budget – KCP&L-KS

Year	Interruptible Tariffs	Direct Load Control	Pricing without Enabling Technology	Pricing with Enabling Technology	Other DR	Total
2014	[redacted]					
2015	[redacted]					
2016	[redacted]					
2017	[redacted]					
2018	[redacted]					
2019	[redacted]					
2020	[redacted]					
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					
2026	[redacted]					
2027	[redacted]					
2028	[redacted]					
2029	[redacted]					
2030	[redacted]					
2031	[redacted]					
2032	[redacted]					
2033	[redacted]					

Source: Navigant analysis

Table 3-12. Cumulative Realistic Achievable DR Budget – KCP&L-MO

Year	Interruptible Tariffs	Direct Load Control	Pricing without Enabling Technology	Pricing with Enabling Technology	Other DR	Total
2014	[redacted]					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						

Source: Navigant analysis

Table 3-13. Cumulative Realistic Achievable DR Budget – KCP&L-GMO

Year	Interruptible Tariffs	Direct Load Control	Pricing without Enabling Technology	Pricing with Enabling Technology	Other DR	Total
2014	[redacted]					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						

Source: Navigant analysis

Other Cost-Effectiveness Inputs

In addition to the cost inputs described above, Navigant tailored FERC's assumptions for avoided costs and discount rate to the Companies to determine the cost-effectiveness of each DR program. For consistency, the DR model uses the same discount rate[40] and avoided demand costs[41] as the Demand Side Management Simulator (DSMSim™) model that Navigant created to estimate the Demand Side Management (DSM) potential for the Companies.

Note that the cost-effectiveness analysis does not consider bill reductions or lost revenues because the model does not assume any energy savings and, therefore, does not assume any bill savings to the customer. Externalities are also not considered.

[40] Discount rates assumed to be 3 percent for Societal, 10 percent for Participant, and an After-Tax Weighted Average Cost of Capital of 7.18 and 7.02 percent for KCP&L and KCP&L-GMO in all other tests.
[41] Provided by email communications with Joe O'Donnell, GPES, July 2012. Avoided capacity costs are based on the cost of new entry in the Midwest ISO.

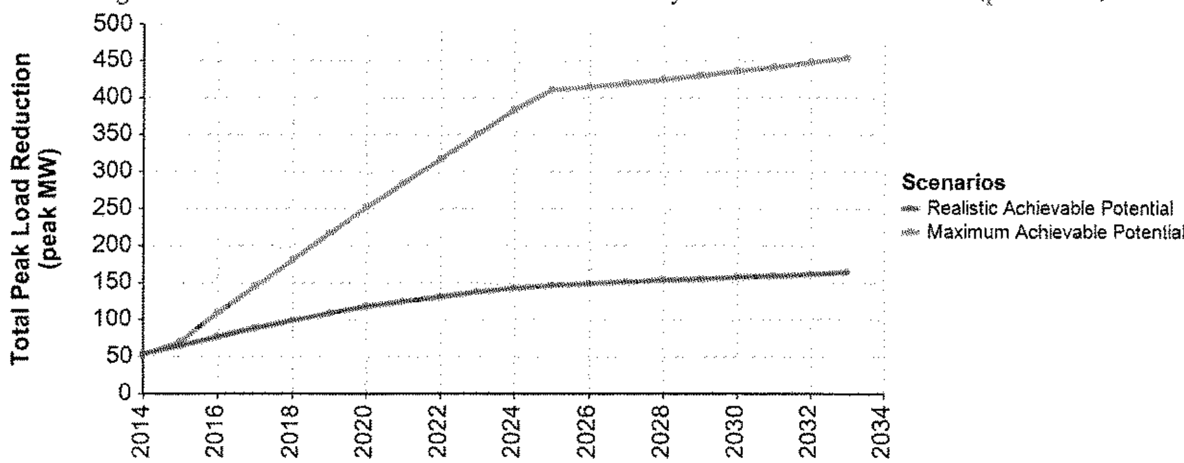
4 Findings

This section presents the results of Navigant's DR potential model for the Companies. This section also compares the Kansas- and Missouri-specific results from NADR with the peak demand reduction potential and cost effectiveness findings of this analysis, and discusses the likely drivers behind major differences in findings.

4.1 Peak Load Reduction Potential

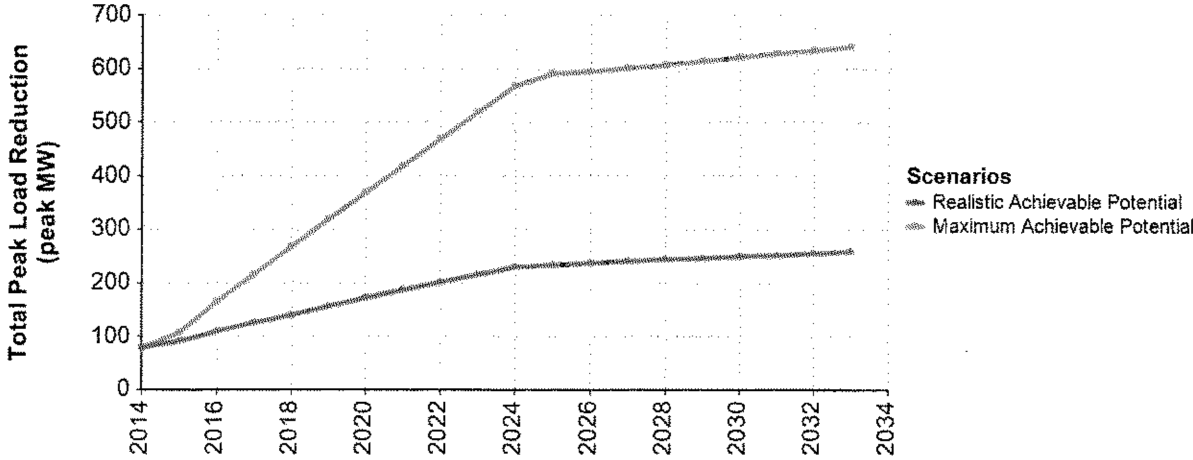
Navigant estimates up to 453 MW in peak load reduction potential for KCP&L-KS, 642 MW for KCP&L-MO, and 840 MW for KCP&L-GMO by 2033 in the Max Achievable scenario, which represents about 21.3, 28.2, and 31.0 percent of each utility's forecasted peak load for 2033, respectively. The potential in the Max Achievable scenario reflects the peak load reductions that *could* be possible if the Companies were to drive new DR customer participation through targeted program marketing and investment in new infrastructure deployment and integration. These findings are benchmarked against the Realistic Achievable findings in Figure 4-1 through Figure 4-3 and Table 4-1, which show the total peak load reduction potential estimated for KCP&L-KS, KCP&L-MO, and KCP&L-GMO in each scenario. Tabular results are shown in Appendix A and Appendix C.

Figure 4-1. Total Peak Load Reduction Potential by Scenario for KCP&L-KS (peak MW)



Source: Navigant analysis

Figure 4-2. Total Peak Load Reduction Potential by Scenario for KCP&L-MO (peak MW)



Source: Navigant analysis

Figure 4-3. Total Peak Load Reduction Potential by Scenario for KCP&L-GMO (peak MW)

Source: Navigant analysis

Table 4-1. Total Peak Load Reduction Potential by Scenario for the Companies (peak MW)

Utility	KCP&L-KS		KCP&L-MO		KCP&L-GMO	
Scenario	Realistic Achievable	Max Achievable	Realistic Achievable	Max Achievable	Realistic Achievable	Max Achievable
2014	54	54	78	78	36	36
2015	66	70	91	108	66	75
2016	77	109	110	164	98	117
2017	88	145	125	216	130	158
2018	99	181	141	267	162	226
2019	108	216	156	318	195	294
2020	117	251	172	368	229	361
2021	124	284	187	418	262	428
2022	130	317	201	468	296	497
2023	137	350	215	518	330	565
2024	143	383	230	568	365	636
2025	146	410	233	591	375	672
2026	148	413	237	594	384	710
2027	151	419	241	601	394	750
2028	153	424	243	607	404	760
2029	155	430	246	614	415	777
2030	157	436	249	621	425	792
2031	159	441	252	627	435	808
2032	161	447	255	634	445	824
2033	164	453	258	642	455	840

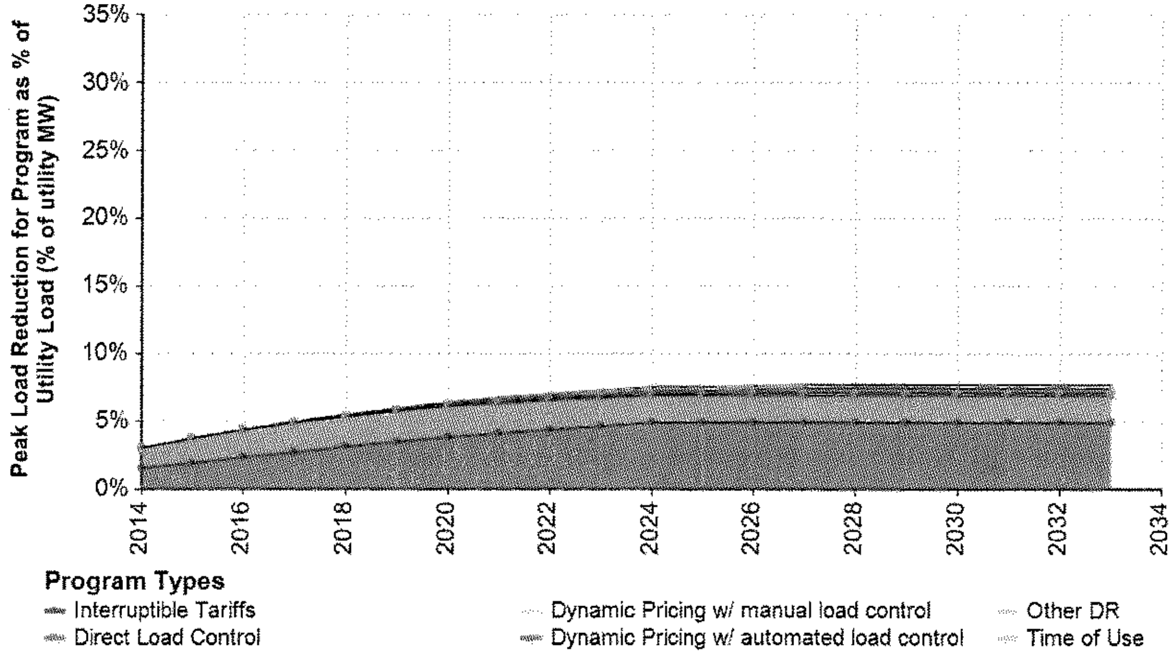
Source: Navigant analysis

For all of the Companies, these figures show significant contrast between the Realistic Achievable scenarios and the Max Achievable scenarios, and suggest that there is significant potential for additional demand reductions through strategic program deployment. Figure 4-4 through Figure 4-9 help identify *which* programs would be most beneficial to target, by showing the peak load reduction potential for each DR program type and scenario as an aggregate percentage of the utility's peak load. In general, KCP&L-KS has lower DR potential than the other utilities, which is primarily due to significantly lower peak load reduction from KCP&L-KS's Interruptible Tariffs program. This is based on current participation in KCP&L's MPower program, where the average peak load reduction for customers in KCP&L-KS is about a third of the average customer's reduction in KCP&L GMO.[42] This also aligns with FERC's assumption that the average Industrial Tariff participant's peak demand reduction in KS (i.e., around 30 percent per participant, on average) is less than a third of the peak demand reduction in MO (i.e., over 90 percent per participant, on average). Additionally, the percentage of peak load from the

[42] Average peak load reductions (i.e., average % load reduced per participant) estimated for 2012 MPower program are around 31 percent in KCP&L-KS, 39 percent in KCP&L-MO, and 92 percent in KCP&L-GMO. Based on 2012 MPower data provided by Joe O'Donnell, GPES, "2012 MPower Active Contracts_12-09-12.xlsx", December 2012.

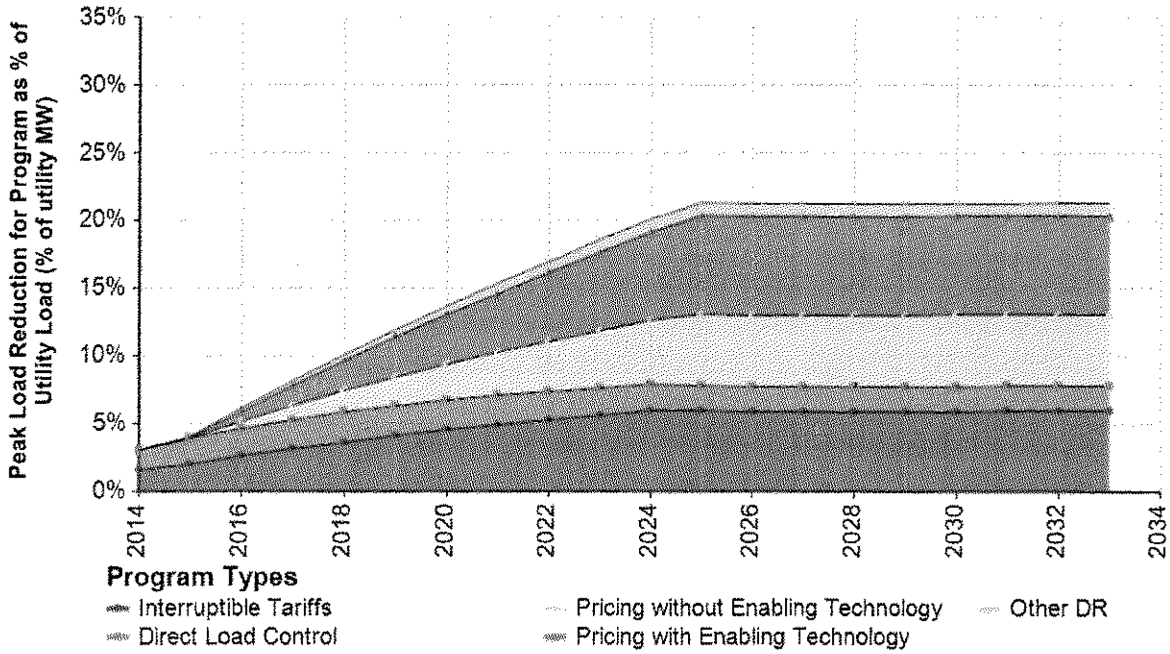
Large C&I customer class is lower in KCP&L-KS relative to the other utilities, which further contributes to the decreased impacts from Interruptible Tariffs.

Figure 4-4. KCP&L-KS Peak Load Reduction Potential – Realistic Achievable (% of utility MW)



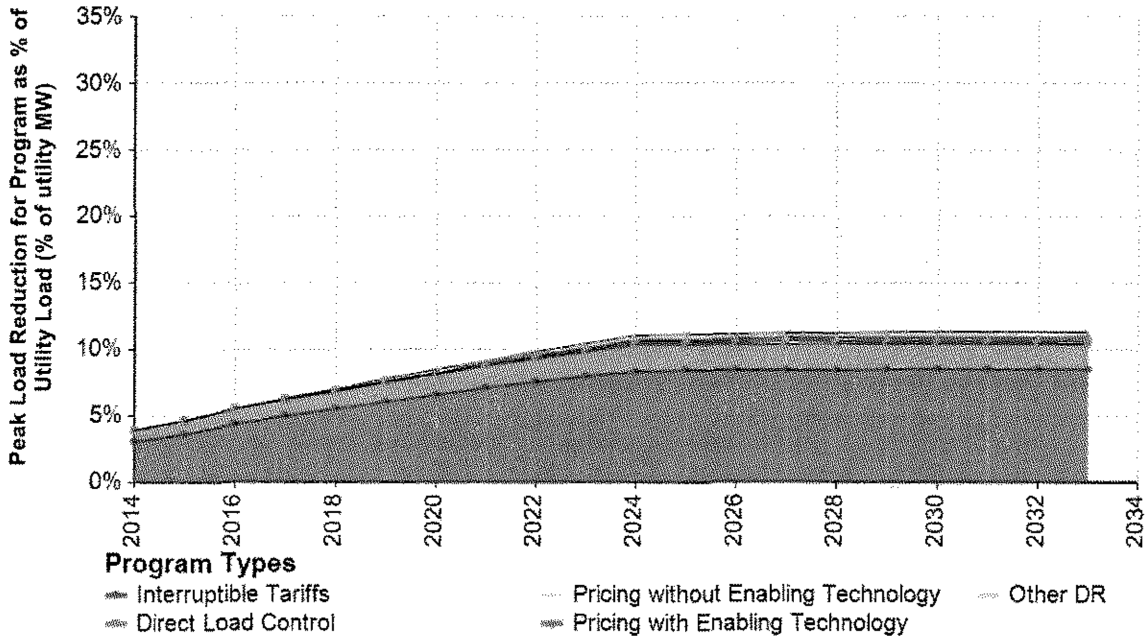
Source: Navigant analysis

Figure 4-5. KCP&L-KS Peak Load Reduction Potential – Max Achievable Scenario (% of utility MW)



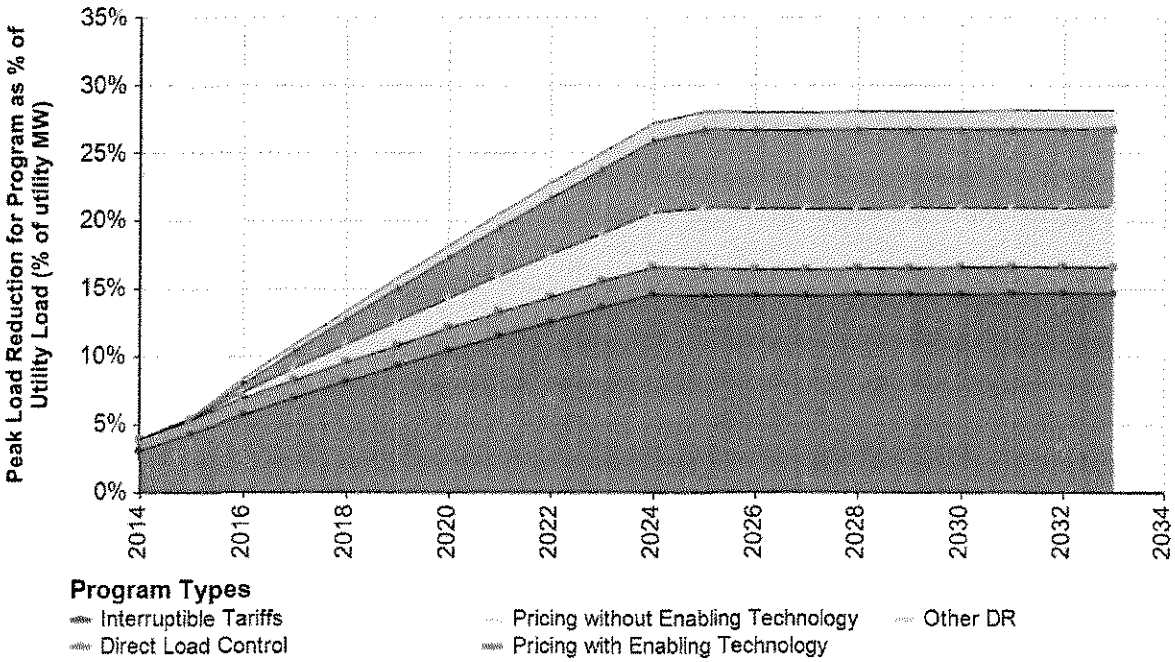
Source: Navigant analysis

Figure 4-6. KCP&L-MO Peak Load Reduction Potential – Realistic Achievable (% of utility MW)



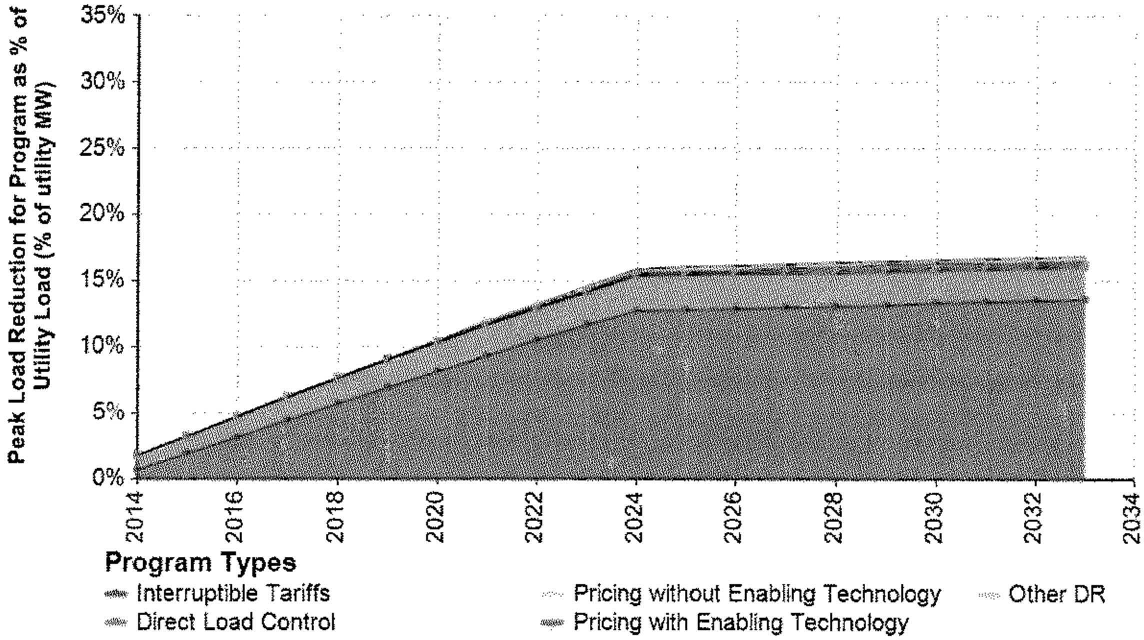
Source: Navigant analysis

Figure 4-7. KCP&L-MO Peak Load Reduction Potential – Max Achievable Scenario (% of utility MW)



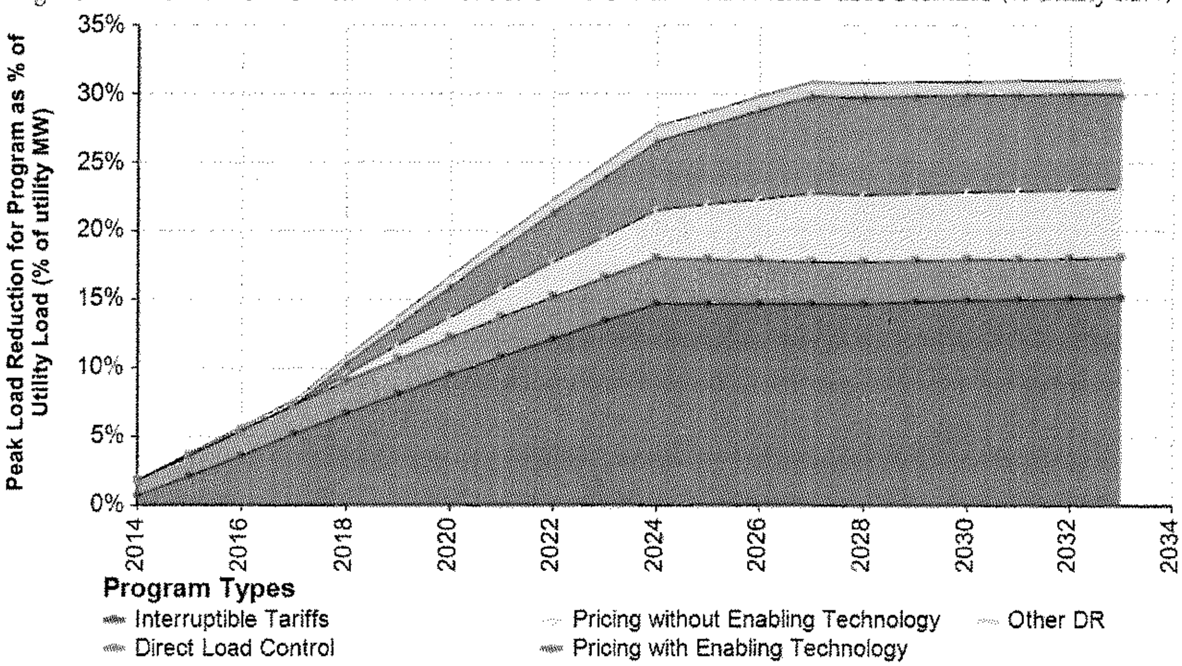
Source: Navigant analysis

Figure 4-8. KCP&L-GMO Peak Load Reduction Potential – Realistic Achievable (% of utility MW)



Source: Navigant analysis

Figure 4-9. KCP&L-GMO Peak Load Reduction Potential – Max Achievable Scenario (% utility MW)



Source: Navigant analysis

4.2 *Energy Savings from Demand Response Potential*

As discussed in Section 3.6, Navigant conservatively assumes there are no significant energy savings from the Companies' DR programs in any scenario.

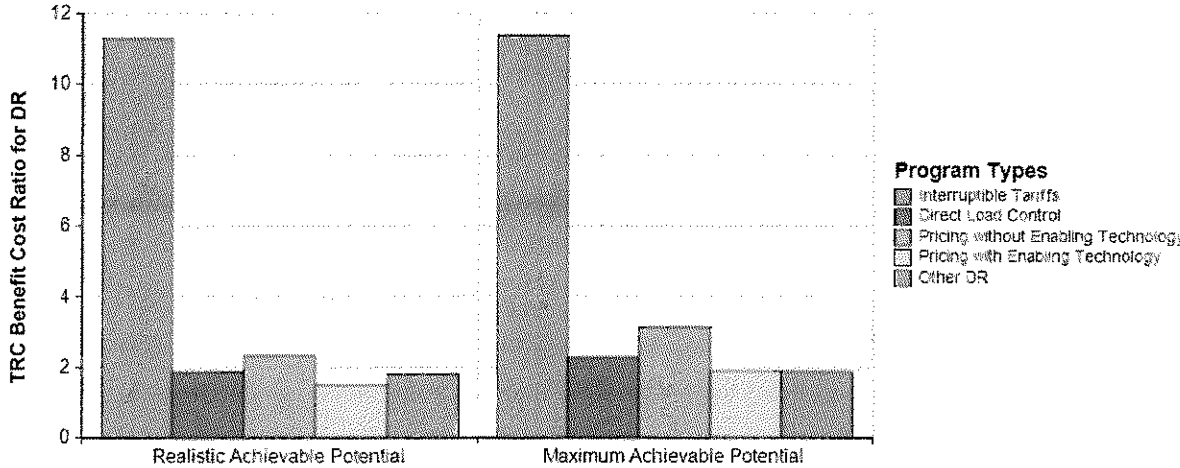
4.3 *Cost-Effectiveness*

This analysis finds almost all DR program types to be cost effective for both scenarios using the Total Resource Cost (TRC), Societal cost, Utility Cost, and Rate Impact Measure benefit-cost tests, as defined in the MO Planning Regulations.[43] The only exception is the Other DR program, where the Utility and RIM test ratios are very close to one. These results represent more cost categories and a more complex methodology than the cost effectiveness analyses in FERC's DR potential study and the Missouri DSM potential study. As such, the benefit-cost ratios in this study are lower, but are likely a better portrayal of actual cost effectiveness.

Figure 4-10 through Figure 4-12 show the results for the TRC test, with all results provided in tabular format in Appendix B – Benefit-Cost Test Ratio Results. As shown in the results, the benefit-cost ratios for the Pricing without Enabling Technology are relatively high, which can be attributed to the lack of equipment and incentive costs needed to participate. However, the potential impacts from this program are also more limited, since participants do not have access to an enabling technology. Similarly, a Direct Load Control program is likely to be more cost effective than Pricing with Enabling Technology, but customer participation rates may ultimately be higher for the Pricing program. Note that incentives are treated as a transfer in the TRC test, which results in a high benefit-cost test ratio for programs where the primary costs are incentives, like the Interruptible Tariffs program.

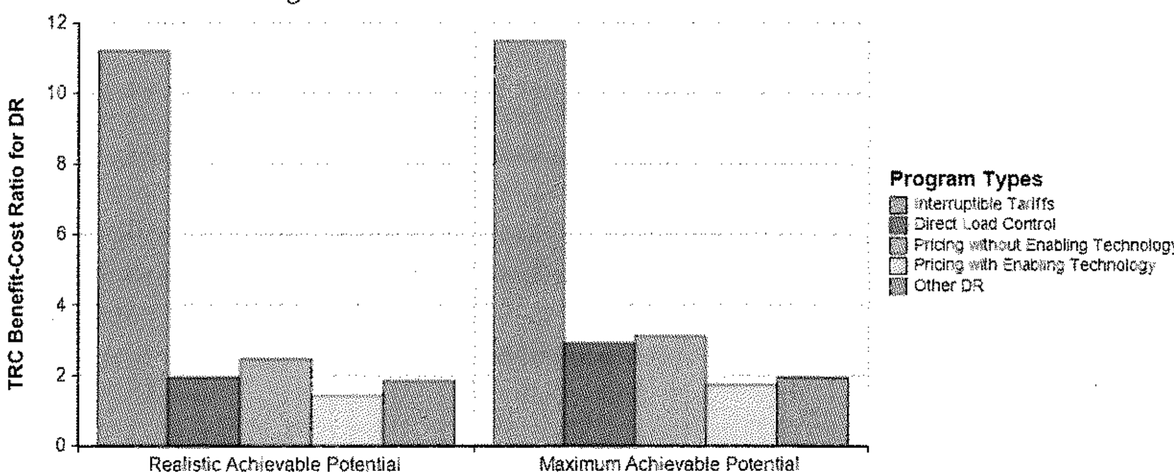
[43] Rules of Department of Economic Development Division 240—Public Service Commission Chapter 22—Electric Utility Resource Planning (4 CSR 240-22.010) – http://sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf

Figure 4-10. TRC Benefit-Cost Test Results – KCP&L-KS



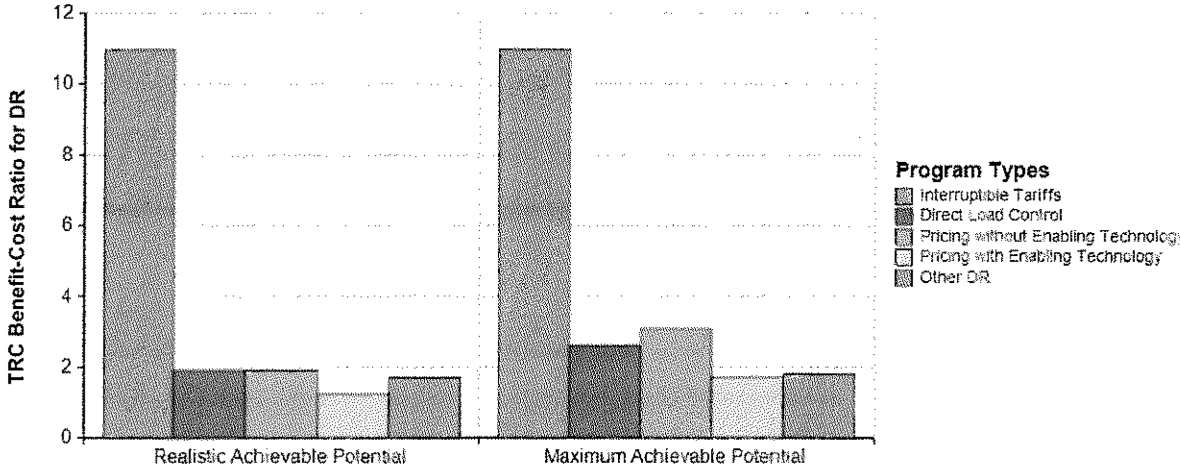
Source: Navigant analysis

Figure 4-11. TRC Benefit-Cost Test Results – KCP&L-MO



Source: Navigant analysis

Figure 4-12. TRC Benefit-Cost Test Results – KCP&L-GMO



Source: Navigant analysis

4.4 Comparison with Findings in FERC's NADR Model

Table 4-2 compares the "Achievable Penetration" scenario findings for Kansas and Missouri from FERC's NADR model with the Maximum Achievable scenario potential estimated in this analysis. The model outputs for 2019 are used to be consistent with the final year of the FERC analysis.

Table 4-2. Comparison of the Companies' Potential Peak Load Reduction from DR in 2019 (% of utility MW)

	KCP&L-KS	KCP&L-MO	KCP&L-GMO
Navigant's Maximum Achievable Scenario	11.9%	15.7%	13.7%
FERC's Achievable Potential Scenario	14.3%*	12.6%**	12.6%**

* For the state of Kansas
** For the state of Missouri

4.5 Summary

All of the scenarios show that significant potential growth still exists for the Companies' MPower Interruptible/Curtailable Tariff programs targeting the Medium and Large C&I customer segments, particularly in the KCP&L-MO and GMO territories. In contrast, participation rates in the Companies' Energy Optimizer Direct Load Control programs are already close to "best practice," though some additional potential exists. While the Other DR program may be cost effective, the potential peak reductions are estimated to be relatively small.

For all utilities in the Max Achievable scenario, the most substantial reductions in 2033 are projected to occur through the Companies' existing MPower programs and pricing with enabling technology. However, in the Realistic Achievable scenario, pricing programs contribute minimal peak load reduction. The Max Achievable impacts from pricing programs are significantly higher than the Realistic

Achievable impacts, which is due to the assumption that the pricing programs are opt-in in the Realistic scenario and opt-out in the Max Achievable scenario. As assumed in FERC's NADR, the pricing program impacts shown in the Max Achievable scenario assumes that the Companies enroll 60 to 75 percent of customers in a pricing program, while the Realistic scenario only assumes that the Companies enroll 5 percent. Even without an opt-out tariff, Navigant expects that a 5 percent enrollment is conservative and impacts under realistic implementation conditions could be higher.

- **Deployment of pricing programs is predicated on the backend integration of the Companies' AMI systems. While the Companies plan to deploy AMI across most of their service territories before 2020, the Companies do not have explicit plans to invest in the backend integration required to support time-based rates, such as installation of a MDMS, which can add significant upfront costs to the program's deployment.**

- **As discussed in Section 3.7, the analysis includes the estimated costs of installing a MDMS as a one-time startup cost for the pricing programs and finds that the pricing programs are cost effective when analyzed over a long-term horizon (i.e., the 20-year analysis period). However, we note that with relatively low near-term avoided capacity costs projected for the Companies, there is a significant time lag (10-15 years) before the cumulative program benefits surpass the cumulative program costs.**

- **This suggests that the timing of deployment for the pricing programs may warrant monitoring of capacity price forecasts and possibly aligning deployment with capacity price increases (which could shorten the effective payback time).**

Overall, this analysis finds significant potential for cost-effective DR program growth, with as much as 21-31 percent of each utility's peak demand in 2033 met by DR, as compared to less than 5 percent met by the Companies' existing programs. Furthermore, Navigant's cost-effectiveness analysis found that all of the program types are likely to be cost-effective over a 20-year horizon using the Total Resource Cost (TRC) benefit-cost test as a screen for all three of the utilities. Navigant also found that almost all program types are cost-effective in the long-term under the Societal, Utility Cost, and Rate Impact Measure benefit-cost tests. These results reflect the estimated benefits from the continued promotion of the Companies' existing MPower and Optimizer programs, as well as investing in the infrastructure needed for backend integration of the Companies' AMI systems to support time-based rate programs.

5 Appendix A – Cumulative Potential Savings and Budget Results

Table 5-1. Cumulative Potential Savings and Budget for KCP&L-KS

	Realistic Achievable Potential			Maximum Achievable Potential		
	Cumulative Energy Savings Potential	Cumulative Peak Demand Savings Potential	Cumulative Budget	Cumulative Energy Savings Potential	Cumulative Peak Demand Savings Potential	Cumulative Budget
Year	(MWh)	(MW)	($)	(MWh)	(MW)	($)
2014	0	54	[redacted]	0	54	[redacted]
2015	0	66	[redacted]	0	70	[redacted]
2016	0	77	[redacted]	0	109	[redacted]
2017	0	88	[redacted]	0	145	[redacted]
2018	0	99	[redacted]	0	181	[redacted]
2019	0	108	[redacted]	0	216	[redacted]
2020	0	117	[redacted]	0	251	[redacted]
2021	0	124	[redacted]	0	284	[redacted]
2022	0	130	[redacted]	0	317	[redacted]
2023	0	137	[redacted]	0	350	[redacted]
2024	0	143	[redacted]	0	383	[redacted]
2025	0	146	[redacted]	0	410	[redacted]
2026	0	148	[redacted]	0	413	[redacted]
2027	0	151	[redacted]	0	419	[redacted]
2028	0	153	[redacted]	0	424	[redacted]
2029	0	155	[redacted]	0	430	[redacted]
2030	0	157	[redacted]	0	436	[redacted]
2031	0	159	[redacted]	0	441	[redacted]
2032	0	161	[redacted]	0	447	[redacted]
2033	0	164	[redacted]	0	453	[redacted]

Note: Conservatively assumes there are no significant energy savings from the Companies' DR programs, which is consistent with typical industry assumptions for dispatchable programs, as well as some of Navigant's recent findings for utilities with time-based rates, including TOU. Results represent both net and gross impacts. Costs are inclusive of incentives, program admin, and EM&V.
Source: Navigant analysis

Table 5-2. Cumulative Potential Savings and Budget for KCP&L-MO

	Realistic Achievable Potential			Maximum Achievable Potential		
Year	Cumulative Energy Savings Potential (MWh)	Cumulative Peak Demand Savings Potential (MW)	Cumulative Budget ($)	Cumulative Energy Savings Potential (MWh)	Cumulative Peak Demand Savings Potential (MW)	Cumulative Budget ($)
2014	0	78	[redacted]	0	78	[redacted]
2015	0	91	[redacted]	0	108	[redacted]
2016	0	110	[redacted]	0	164	[redacted]
2017	0	125	[redacted]	0	216	[redacted]
2018	0	141	[redacted]	0	267	[redacted]
2019	0	156	[redacted]	0	318	[redacted]
2020	0	172	[redacted]	0	368	[redacted]
2021	0	187	[redacted]	0	418	[redacted]
2022	0	201	[redacted]	0	468	[redacted]
2023	0	215	[redacted]	0	518	[redacted]
2024	0	230	[redacted]	0	568	[redacted]
2025	0	233	[redacted]	0	591	[redacted]
2026	0	237	[redacted]	0	594	[redacted]
2027	0	241	[redacted]	0	601	[redacted]
2028	0	243	[redacted]	0	607	[redacted]
2029	0	246	[redacted]	0	614	[redacted]
2030	0	249	[redacted]	0	621	[redacted]
2031	0	252	[redacted]	0	627	[redacted]
2032	0	255	[redacted]	0	634	[redacted]
2033	0	258	[redacted]	0	642	[redacted]

Note: Conservatively assumes there are no significant energy savings from the Companies' DR programs, which is consistent with typical industry assumptions for dispatchable programs, as well as some of Navigant's recent findings for utilities with time-based rates, including TOU. Results represent both net and gross impacts. Costs are inclusive of incentives, program admin, and EM&V.
Source: Navigant analysis

Table 5-3. Cumulative Potential Savings and Budget for KCP&L-GMO

Year	Realistic Achievable Potential			Maximum Achievable Potential		
	Cumulative Energy Savings Potential (MWh)	Cumulative Peak Demand Savings Potential (MW)	Cumulative Budget ($)	Cumulative Energy Savings Potential (MWh)	Cumulative Peak Demand Savings Potential (MW)	Cumulative Budget ($)
2014	0	36	[redacted]	0	36	[redacted]
2015	0	66	[redacted]	0	75	[redacted]
2016	0	98	[redacted]	0	117	[redacted]
2017	0	130	[redacted]	0	158	[redacted]
2018	0	162	[redacted]	0	226	[redacted]
2019	0	195	[redacted]	0	294	[redacted]
2020	0	229	[redacted]	0	361	[redacted]
2021	0	262	[redacted]	0	428	[redacted]
2022	0	296	[redacted]	0	497	[redacted]
2023	0	330	[redacted]	0	565	[redacted]
2024	0	365	[redacted]	0	636	[redacted]
2025	0	375	[redacted]	0	672	[redacted]
2026	0	384	[redacted]	0	710	[redacted]
2027	0	394	[redacted]	0	750	[redacted]
2028	0	404	[redacted]	0	760	[redacted]
2029	0	415	[redacted]	0	777	[redacted]
2030	0	425	[redacted]	0	792	[redacted]
2031	0	435	[redacted]	0	808	[redacted]
2032	0	445	[redacted]	0	824	[redacted]
2033	0	455	[redacted]	0	840	[redacted]

Note: Conservatively assumes there are no significant energy savings from the Companies' DR programs, which is consistent with typical industry assumptions for dispatchable programs, as well as some of Navigant's recent findings for utilities with time-based rates, including TOU. Results represent both net and gross impacts. Costs are inclusive of incentives, program admin, and EM&V.
Source: Navigant analysis.

6 Appendix B – Benefit-Cost Test Ratio Results

The benefit-cost test ratio results are shown below for all DR program types and both scenarios using the Total Resource Cost (TRC), Societal cost, Utility Cost, and Rate Impact Measure benefit-cost tests, as defined in the MO Planning Regulations. Note that incentives are treated as a transfer in the TRC test, which results in a high benefit-cost test ratio for programs where the primary costs are incentives, like the Interruptible Tariffs program.

Table 6-1. Benefit-Cost Test Ratio Results for All Program Types and Scenarios

State	Utility	Benefit-Cost Test	Program Type	Realistic Scenario	Maximum Scenario
KS	KCP&L	Societal Cost Test	Interruptible Tariffs	11.6	11.6
			Direct Load Control	2.1	2.6
			Pricing without Enabling Technology	2.6	3.2
			Pricing with Enabling Technology	1.7	2.0
			Other DR	1.9	2.0
		Total Resource Cost Test	Interruptible Tariffs	11.3	11.4
			Direct Load Control	1.9	2.3
			Pricing without Enabling Technology	2.3	3.1
			Pricing with Enabling Technology	1.5	1.9
			Other DR	1.8	1.9
		Utility Cost Test	Interruptible Tariffs	2.3	2.3
			Direct Load Control	1.9	2.3
			Pricing without Enabling Technology	2.3	3.1
			Pricing with Enabling Technology	1.5	1.9
			Other DR	1.0	1.1
		Participant Cost Test	Interruptible Tariffs	-	-
			Direct Load Control	-	-
			Pricing without Enabling Technology	-	-
			Pricing with Enabling Technology	-	-
			Other DR	-	-
		Rate Impact Measure Test	Interruptible Tariffs	2.3	2.3
			Direct Load Control	1.9	2.3
			Pricing without Enabling Technology	2.3	3.1
			Pricing with Enabling Technology	1.5	1.9
			Other DR	1.0	1.1
MO	KCP&L	Societal Cost Test	Interruptible Tariffs	11.6	11.7
			Direct Load Control	2.1	3.1
			Pricing without Enabling Technology	2.7	3.2
			Pricing with Enabling Technology	1.6	1.9
			Other DR	1.9	2.0
		Total Resource	Interruptible Tariffs	11.2	11.5
			Direct Load Control	1.9	2.9

State	Utility	Benefit-Cost Test	Program Type	Realistic Scenario	Maximum Scenario
		Cost Test	Pricing without Enabling Technology	2.5	3.1
			Pricing with Enabling Technology	1.4	1.7
			Other DR	1.8	1.9
		Utility Cost Test	Interruptible Tariffs	2.2	2.3
			Direct Load Control	1.9	2.9
			Pricing without Enabling Technology	2.5	3.1
			Pricing with Enabling Technology	1.4	1.7
			Other DR	1.1	1.1
		Participant Cost Test	Interruptible Tariffs	-	-
			Direct Load Control	-	-
			Pricing without Enabling Technology	-	-
			Pricing with Enabling Technology	-	-
			Other DR	-	-
		Rate Impact Measure Test	Interruptible Tariffs	2.2	2.3
			Direct Load Control	1.9	2.9
			Pricing without Enabling Technology	2.5	3.1
			Pricing with Enabling Technology	1.4	1.7
			Other DR	1.1	1.1
MO	KCP&L GMO	Societal Cost Test	Interruptible Tariffs	11.1	11.1
			Direct Load Control	2.1	2.9
			Pricing without Enabling Technology	2.2	3.2
			Pricing with Enabling Technology	1.4	1.9
			Other DR	1.8	1.9
		Total Resource Cost Test	Interruptible Tariffs	11.0	11.0
			Direct Load Control	1.9	2.6
			Pricing without Enabling Technology	1.9	3.1
			Pricing with Enabling Technology	1.2	1.7
			Other DR	1.7	1.8
		Utility Cost Test	Interruptible Tariffs	2.2	2.2
			Direct Load Control	1.9	2.6
			Pricing without Enabling Technology	1.9	3.1
			Pricing with Enabling Technology	1.2	1.7
			Other DR	1.0	1.0
		Participant Cost Test	Interruptible Tariffs	-	-
			Direct Load Control	-	-
			Pricing without Enabling Technology	-	-
			Pricing with Enabling Technology	-	-
			Other DR	-	-
		Rate Impact Measure Test	Interruptible Tariffs	2.2	2.2
			Direct Load Control	1.9	2.6
			Pricing without Enabling Technology	1.9	3.1
			Pricing with Enabling Technology	1.2	1.7

State	Utility	Benefit-Cost Test	Program Type	Realistic Scenario	Maximum Scenario
			Other DR	1.0	1.0

Note: The Participant Cost Test is undefined because no costs are assumed on the part of participants.
Source: Navigant analysis

7 Appendix C – DR Demand Savings and Costs by Program Type

The following tables show the demand savings for each DR program type in MW and as a percent of each utility's annual peak demand, as well as the cumulative costs for each program type.

Table 7-1. Peak Load Reduction Potential for the Companies – Realistic Scenario (peak MW)

Utility	KCP&L-KS						KCP&L-MO						KCP&L-GMO					
Prog Type	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total
2014	26.6	27.0	0.0	0.0	0.0	**53.6**	60.0	18.0	0.0	0.0	0.0	**78.0**	13.6	22.0	0.0	0.0	0.0	**35.6**
2015	33.4	32.3	0.0	0.0	0.0	**65.7**	71.0	20.3	0.0	0.0	0.0	**91.2**	37.7	27.9	0.0	0.0	0.0	**65.7**
2016	41.2	35.6	0.0	0.0	0.5	**77.4**	86.7	22.5	0.0	0.0	0.8	**110.0**	64.3	32.6	0.0	0.0	0.7	**97.5**
2017	48.8	38.2	0.0	0.0	1.1	**88.0**	98.7	24.7	0.0	0.0	1.6	**124.9**	91.4	36.9	0.0	0.0	1.3	**129.6**
2018	56.1	40.1	0.4	0.6	1.6	**98.8**	110.5	27.0	0.4	0.6	2.3	**140.8**	119.1	41.0	0.0	0.0	2.0	**162.1**
2019	63.0	41.4	0.7	1.2	2.1	**108.5**	122.0	29.3	0.8	1.1	3.1	**156.4**	147.3	44.9	0.0	0.0	2.7	**194.8**
2020	69.8	42.1	1.1	1.7	2.7	**117.4**	133.1	31.6	1.3	1.7	3.9	**171.5**	175.6	48.4	0.4	0.7	3.4	**228.5**
2021	76.0	41.0	1.5	2.3	3.2	**124.1**	143.9	33.9	1.7	2.3	4.7	**186.5**	204.5	51.1	0.8	1.4	4.1	**261.9**
2022	81.9	40.0	1.9	3.0	3.7	**130.5**	154.3	36.3	2.1	2.8	5.5	**201.1**	234.0	53.9	1.2	2.1	4.8	**296.1**
2023	87.6	39.1	2.3	3.6	4.3	**136.8**	164.5	38.7	2.5	3.4	6.4	**215.5**	263.2	56.9	1.7	2.8	5.5	**330.0**
2024	92.8	38.3	2.6	4.2	4.8	**142.7**	174.3	41.2	2.9	4.0	7.2	**229.6**	293.6	60.0	2.1	3.5	6.3	**365.4**
2025	93.8	38.7	3.1	4.9	5.3	**145.8**	176.0	41.4	3.4	4.6	8.0	**233.4**	300.7	60.7	2.5	4.2	7.0	**375.1**
2026	94.9	39.2	3.5	5.5	5.4	**148.5**	178.0	41.7	3.8	5.2	8.2	**236.9**	307.3	61.5	2.9	5.0	7.2	**383.9**
2027	96.1	39.6	3.9	6.2	5.5	**151.4**	180.2	42.0	4.3	5.8	8.3	**240.6**	315.1	62.3	3.4	5.8	7.3	**393.9**
2028	97.4	40.2	4.0	6.3	5.6	**153.4**	182.4	42.2	4.3	5.9	8.5	**243.3**	322.9	63.1	3.9	6.6	7.5	**404.0**
2029	98.6	40.7	4.0	6.4	5.7	**155.3**	184.8	42.5	4.4	5.9	8.6	**246.2**	331.8	63.9	4.4	7.4	7.6	**415.3**
2030	99.9	41.2	4.1	6.5	5.8	**157.4**	187.1	42.8	4.4	6.0	8.8	**249.1**	340.4	64.7	4.5	7.6	7.8	**425.0**
2031	101.3	41.6	4.1	6.5	5.9	**159.5**	189.4	43.1	4.5	6.0	9.0	**252.0**	348.9	65.5	4.6	7.7	7.9	**434.7**
2032	102.5	42.2	4.2	6.6	6.0	**161.5**	191.5	43.4	4.5	6.1	9.2	**254.7**	358.2	66.3	4.7	7.8	8.1	**445.1**
2033	104.0	42.8	4.2	6.7	6.1	**163.8**	193.9	43.8	4.6	6.2	9.4	**257.8**	366.7	67.2	4.8	7.9	8.3	**454.9**

IT = Interruptible Tariffs, DLC = Direct Load Control, Pricing w/o ET = Pricing without Enabling Technology, Pricing w/ ET = Pricing with Enabling Technology
Source: Navigant analysis

Table 7-2. Peak Load Reduction Potential for the Companies – Maximum Scenario (peak MW)

Utility	KCP&L-KS						KCP&L-MO						KCP&L-GMO					
Prog. Type	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total
2014	26.6	27.0	0.0	0.0	0.0	**53.6**	60.0	18.0	0.0	0.0	0.0	**78.0**	13.6	22.0	0.0	0.0	0.0	**35.6**
2015	35.7	32.6	0.0	0.0	2.1	**70.4**	84.1	20.9	0.0	0.0	3.3	**108.4**	42.4	30.1	0.0	0.0	2.9	**75.4**
2016	45.9	36.2	9.4	12.9	4.2	**108.6**	113.2	23.9	8.9	11.9	6.5	**164.4**	73.8	37.0	0.0	0.0	5.7	**116.6**
2017	55.5	38.4	18.9	26.0	6.2	**145.0**	137.9	26.4	17.9	23.8	9.7	**215.7**	106.0	43.6	0.0	0.0	8.6	**158.1**
2018	64.9	40.0	28.5	39.3	8.2	**180.9**	162.6	28.9	26.9	35.8	12.6	**266.8**	139.0	50.1	10.6	15.3	11.4	**226.4**
2019	73.8	40.8	38.4	52.9	10.1	**216.0**	187.0	31.3	36.1	47.9	15.6	**317.8**	171.7	55.3	21.5	31.0	14.1	**293.6**
2020	82.6	41.1	48.4	66.8	11.9	**250.8**	210.8	33.6	45.3	60.0	18.4	**368.1**	204.3	60.2	32.7	47.1	16.6	**361.0**
2021	90.7	39.7	58.7	80.9	13.7	**283.7**	234.5	35.9	54.7	72.3	21.0	**418.4**	237.4	64.2	44.2	63.6	19.1	**428.5**
2022	98.5	38.4	69.1	95.2	15.3	**316.6**	257.6	38.2	64.2	84.8	23.5	**468.3**	270.9	68.1	56.1	80.5	21.4	**497.0**
2023	106.1	37.3	79.7	110.0	16.9	**350.0**	280.5	40.4	73.8	97.4	25.9	**518.1**	303.7	72.0	68.2	97.8	23.5	**565.3**
2024	113.1	36.3	90.6	125.0	18.4	**383.5**	303.1	42.7	83.5	110.3	28.2	**567.8**	337.7	76.0	80.8	115.7	25.6	**635.7**
2025	113.7	36.1	101.8	140.4	18.1	**410.1**	304.4	42.1	93.5	123.3	27.6	**590.9**	343.8	75.5	93.8	134.1	25.0	**672.2**
2026	114.4	35.8	102.9	142.1	18.2	**413.5**	306.2	41.7	94.3	124.3	27.8	**594.2**	349.3	75.0	107.2	153.0	25.1	**709.6**
2027	115.9	36.3	104.2	143.8	18.5	**418.6**	310.1	42.0	95.1	125.3	28.2	**600.6**	356.0	74.6	121.2	172.6	25.3	**749.7**
2028	117.6	36.8	105.6	145.7	18.8	**424.4**	314.0	42.2	96.0	126.3	28.5	**607.0**	362.6	74.1	123.3	175.3	25.3	**760.5**
2029	119.1	37.2	106.9	147.6	19.0	**429.8**	318.1	42.5	96.8	127.4	29.0	**613.8**	372.5	75.0	125.5	178.1	25.6	**776.6**
2030	120.9	37.7	108.2	149.4	19.3	**435.6**	322.2	42.8	97.7	128.5	29.5	**620.7**	382.0	75.8	127.6	180.8	25.9	**792.0**
2031	122.6	38.1	109.6	151.3	19.5	**441.1**	326.4	43.1	98.6	129.6	29.8	**627.5**	391.5	76.6	129.9	183.6	26.1	**807.6**
2032	124.3	38.6	111.1	153.4	19.8	**447.1**	330.0	43.4	99.6	130.8	30.2	**634.0**	401.7	77.5	132.2	186.4	26.3	**824.1**
2033	126.1	39.1	112.6	155.5	20.1	**453.5**	334.4	43.8	100.6	132.1	30.8	**641.6**	411.3	78.4	134.4	189.3	26.6	**840.0**

IT = Interruptible Tariffs, DLC = Direct Load Control, Pricing w/o ET = Pricing without Enabling Technology, Pricing w/ ET = Pricing with Enabling Technology
Source: Navigant analysis

The following tables show the demand savings for each DR program type and in total as a percent of each utility's annual peak demand. These results are also shown graphically in Figure 1-4 through Figure 1-6 and Figure 4-4 through Figure 4-9.

Table 7-3. Peak Load Reduction Potential for the Companies – Realistic Scenario (% of utility MW)

Utility	KCP&L-KS						KCP&L-MO						KCP&L-GMO					
Prog Type	IT	DLC	Pricing w/o ET	Pricing w/ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total
2014	1.53%	1.55%	0%	0%	0%	**3.08%**	3.04%	0.91%	0%	0%	0%	**3.95%**	0.68%	1.10%	0%	0%	0%	**1.79%**
2015	1.90%	1.84%	0%	0%	0%	**3.74%**	3.59%	1.02%	0%	0%	0%	**4.61%**	1.87%	1.38%	0%	0%	0%	**3.25%**
2016	2.33%	2.01%	0%	0%	0.03%	**4.37%**	4.37%	1.13%	0%	0%	0.04%	**5.54%**	3.14%	1.59%	0%	0%	0.03%	**4.77%**
2017	2.73%	2.14%	0%	0%	0.06%	**4.93%**	4.95%	1.24%	0%	0%	0.08%	**6.27%**	4.41%	1.78%	0%	0%	0.06%	**6.25%**
2018	3.12%	2.23%	0%	0%	0.09%	**5.49%**	5.51%	1.35%	0%	0%	0.12%	**7.02%**	5.66%	1.95%	0%	0%	0.10%	**7.70%**
2019	3.47%	2.28%	0%	0%	0.12%	**5.97%**	6.04%	1.45%	0%	0%	0.16%	**7.75%**	6.89%	2.10%	0%	0%	0.13%	**9.11%**
2020	3.80%	2.29%	0.06%	0.10%	0.15%	**6.40%**	6.56%	1.56%	0.06%	0.08%	0.19%	**8.45%**	8.10%	2.23%	0.02%	0.03%	0.16%	**10.54%**
2021	4.11%	2.22%	0.08%	0.13%	0.17%	**6.70%**	7.05%	1.66%	0.08%	0.11%	0.23%	**9.13%**	9.29%	2.32%	0.04%	0.06%	0.19%	**11.89%**
2022	4.39%	2.14%	0.10%	0.16%	0.20%	**6.99%**	7.50%	1.77%	0.10%	0.14%	0.27%	**9.78%**	10.47%	2.41%	0.06%	0.09%	0.22%	**13.24%**
2023	4.64%	2.07%	0.12%	0.19%	0.23%	**7.25%**	7.94%	1.87%	0.12%	0.16%	0.31%	**10.41%**	11.60%	2.51%	0.07%	0.12%	0.24%	**14.55%**
2024	4.86%	2.01%	0.14%	0.22%	0.25%	**7.48%**	8.35%	1.98%	0.14%	0.19%	0.34%	**11.00%**	12.74%	2.60%	0.09%	0.15%	0.27%	**15.86%**
2025	4.87%	2.01%	0.16%	0.25%	0.28%	**7.56%**	8.37%	1.97%	0.16%	0.22%	0.38%	**11.10%**	12.83%	2.59%	0.11%	0.18%	0.30%	**16.00%**
2026	4.87%	2.01%	0.18%	0.28%	0.28%	**7.61%**	8.39%	1.96%	0.18%	0.24%	0.38%	**11.16%**	12.90%	2.58%	0.12%	0.21%	0.30%	**16.11%**
2027	4.87%	2.01%	0.20%	0.32%	0.28%	**7.67%**	8.41%	1.96%	0.20%	0.27%	0.39%	**11.22%**	12.98%	2.57%	0.14%	0.24%	0.30%	**16.23%**
2028	4.87%	2.01%	0.20%	0.32%	0.28%	**7.67%**	8.43%	1.95%	0.20%	0.27%	0.39%	**11.24%**	13.07%	2.55%	0.16%	0.27%	0.30%	**16.35%**
2029	4.87%	2.01%	0.20%	0.32%	0.28%	**7.67%**	8.45%	1.94%	0.20%	0.27%	0.40%	**11.26%**	13.17%	2.54%	0.18%	0.30%	0.30%	**16.49%**
2030	4.87%	2.01%	0.20%	0.32%	0.28%	**7.68%**	8.47%	1.94%	0.20%	0.27%	0.40%	**11.27%**	13.27%	2.52%	0.18%	0.29%	0.30%	**16.57%**
2031	4.88%	2.01%	0.20%	0.32%	0.28%	**7.68%**	8.49%	1.93%	0.20%	0.27%	0.40%	**11.29%**	13.36%	2.51%	0.18%	0.29%	0.30%	**16.64%**
2032	4.87%	2.01%	0.20%	0.32%	0.28%	**7.68%**	8.49%	1.93%	0.20%	0.27%	0.41%	**11.30%**	13.46%	2.49%	0.18%	0.29%	0.30%	**16.73%**
2033	4.88%	2.01%	0.20%	0.32%	0.29%	**7.68%**	8.51%	1.92%	0.20%	0.27%	0.41%	**11.31%**	13.54%	2.48%	0.18%	0.29%	0.31%	**16.79%**

IT = Interruptible Tariffs, DLC = Direct Load Control, Pricing w/o ET = Pricing without Enabling Technology, Pricing w/ ET = Pricing with Enabling Technology

Source: Navigant analysis

Table 7-4. Peak Load Reduction Potential for the Companies – Maximum Scenario (% of utility MW)

Utility	KCP&L-KS						KCP&L-MO						KCP&L-GMO					
Prog Type	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total
2014	1.53%	1.55%	0%	0%	0%	**3.08%**	3.04%	0.91%	0%	0%	0%	**3.95%**	0.68%	1.10%	0%	0%	0%	**1.79%**
2015	2.03%	1.86%	0%	0%	0%	**4.01%**	4.25%	1.06%	0%	0%	0%	**5.48%**	2.10%	1.49%	0%	0%	0%	**3.73%**
2016	2.59%	2.04%	1%	1%	0.24%	**6.13%**	5.70%	1.20%	0%	1%	0.33%	**8.28%**	3.61%	1.81%	0%	0%	0.28%	**5.70%**
2017	3.11%	2.15%	1%	1%	0.35%	**8.13%**	6.92%	1.32%	1%	1%	0.48%	**10.82%**	5.11%	2.10%	0%	0%	0.41%	**7.63%**
2018	3.61%	2.22%	2%	2%	0.45%	**10.05%**	8.11%	1.44%	1%	2%	0.63%	**13.30%**	6.60%	2.38%	1%	1%	0.54%	**10.75%**
2019	4.07%	2.25%	2%	3%	0.55%	**11.90%**	9.26%	1.55%	2%	2%	0.77%	**15.74%**	8.03%	2.59%	1%	1%	0.66%	**13.73%**
2020	4.50%	2.24%	2.64%	3.64%	0.65%	**13.67%**	10.39%	1.66%	2.23%	2.96%	0.90%	**18.14%**	9.42%	2.78%	1.51%	2.17%	0.77%	**16.64%**
2021	4.90%	2.15%	3.17%	4.37%	0.74%	**15.32%**	11.48%	1.76%	2.68%	3.54%	1.03%	**20.48%**	10.78%	2.91%	2.01%	2.89%	0.87%	**19.46%**
2022	5.28%	2.06%	3.70%	5.10%	0.82%	**16.95%**	12.52%	1.86%	3.12%	4.12%	1.14%	**22.77%**	12.11%	3.05%	2.51%	3.60%	0.96%	**22.23%**
2023	5.62%	1.98%	4.22%	5.83%	0.90%	**18.55%**	13.55%	1.95%	3.56%	4.70%	1.25%	**25.02%**	13.39%	3.18%	3.01%	4.31%	1.04%	**24.93%**
2024	5.93%	1.90%	4.75%	6.56%	0.97%	**20.11%**	14.52%	2.05%	4.00%	5.29%	1.35%	**27.21%**	14.66%	3.30%	3.51%	5.02%	1.11%	**27.59%**
2025	5.90%	1.87%	5.28%	7.28%	0.94%	**21.27%**	14.47%	2.00%	4.45%	5.86%	1.31%	**28.10%**	14.67%	3.22%	4.00%	5.72%	1.07%	**28.68%**
2026	5.87%	1.84%	5.28%	7.29%	0.93%	**21.20%**	14.42%	1.96%	4.44%	5.85%	1.31%	**27.99%**	14.66%	3.15%	4.50%	6.42%	1.05%	**29.78%**
2027	5.87%	1.84%	5.28%	7.29%	0.93%	**21.21%**	14.46%	1.96%	4.43%	5.84%	1.32%	**28.01%**	14.67%	3.07%	4.99%	7.11%	1.04%	**30.89%**
2028	5.88%	1.84%	5.28%	7.29%	0.94%	**21.22%**	14.50%	1.95%	4.43%	5.84%	1.32%	**28.04%**	14.67%	3.00%	4.99%	7.09%	1.02%	**30.78%**
2029	5.88%	1.84%	5.28%	7.29%	0.94%	**21.23%**	14.54%	1.94%	4.43%	5.82%	1.33%	**28.06%**	14.79%	2.98%	4.98%	7.07%	1.02%	**30.83%**
2030	5.89%	1.84%	5.28%	7.29%	0.94%	**21.24%**	14.58%	1.94%	4.42%	5.81%	1.33%	**28.09%**	14.89%	2.95%	4.98%	7.05%	1.01%	**30.88%**
2031	5.91%	1.83%	5.28%	7.29%	0.94%	**21.25%**	14.62%	1.93%	4.42%	5.81%	1.34%	**28.11%**	14.99%	2.93%	4.97%	7.03%	1.00%	**30.92%**
2032	5.91%	1.84%	5.28%	7.29%	0.94%	**21.26%**	14.64%	1.93%	4.42%	5.80%	1.34%	**28.13%**	15.10%	2.91%	4.97%	7.01%	0.99%	**30.97%**
2033	5.92%	1.83%	5.28%	7.29%	0.94%	**21.27%**	14.67%	1.92%	4.41%	5.79%	1.35%	**28.15%**	15.18%	2.90%	4.96%	6.99%	0.98%	**31.01%**

IT = Interruptible Tariffs, DLC = Direct Load Control, Pricing w/o ET = Pricing without Enabling Technology, Pricing w/ ET = Pricing with Enabling Technology

Source: Navigant analysis

Table 7-5. Cumulative DR Budget by Program for the Companies – Realistic Scenario (million $/year)

Utility	KCP&L-KS						KCP&L-MO						KCP&L-GMO					
Prog Type	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total
2014	[redacted]																	
2015	[redacted]																	
2016	[redacted]																	
2017	[redacted]																	
2018	[redacted]																	
2019	[redacted]																	
2020	[redacted]																	
2021	[redacted]																	
2022	[redacted]																	
2023	[redacted]																	
2024	[redacted]																	
2025	[redacted]																	
2026	[redacted]																	
2027	[redacted]																	
2028	[redacted]																	
2029	[redacted]																	
2030	[redacted]																	
2031	[redacted]																	
2032	[redacted]																	
2033	[redacted]																	

IT = Interruptible Tariffs, DLC = Direct Load Control, Pricing w/o ET = Pricing without Enabling Technology, Pricing w/ ET = Pricing with Enabling Technology

Source: Navigant analysis

Table 7-6. Cumulative DR Budget by Program for the Companies – Maximum Scenario (million $/year)

Utility	KCP&L-KS						KCP&L-MO						KCP&L-GMO					
Prog. Type	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total	IT	DLC	Pricing w/o ET	Pricing w/ ET	Other DR	Total
2014	[redacted]																	
2015																		
2016																		
2017																		
2018																		
2019																		
2020																		
2021																		
2022																		
2023																		
2024																		
2025																		
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2028																		
2029																		
2030																		
2031																		
2032																		
2033																		

IT = Interruptible Tariffs, DLC = Direct Load Control, Pricing w/o ET = Pricing without Enabling Technology, Pricing w/ ET = Pricing with Enabling Technology

Source: Navigant analysis