Exhibit No.:	650
Issue:	Demand Response and the Indiana Model
Witness:	Nicholas J. Papanastassiou
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Advanced Energy Management Alliance
Case No.:	ER-2018-0145 ER-2018-0146

MISSOURI PUBLIC SERVICE COMMISSION

CASE NOS.: ER-2018-0145 and ER-2018-0146

REBUTTAL TESTIMONY

OF

NICHOLAS J. PAPANASTASSIOU

ON BEHALF OF

ADVANCED ENERGY MANAGEMENT ALLIANCE

Boston, Massachusetts

August 7, 2018

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	)))	Case No. ER-2018-0145
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority To Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF NICHOLAS J. PAPANASTASSIOU

STATE OF MASSACHUSETTS)
) **ss**
COUNTY OF SUFFOLK)

Nicholas J. Papanastassiou, being first duly sworn on his oath, states:

1. My name is Nicholas J. Papanastassiou. I am employed by EnerNOC as Senior Analyst – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of the Advanced Energy Management Alliance.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct to the best of my knowledge.

NICHOLAS J. PAPANASTASSIOU

Subscribed and sworn to before me this 7th day of August, 2018.

Notary Public

My commission expires: 12/14/23

NINA ESLAMY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
December 14, 2023

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REBUTTAL TESTIMONY

OF

NICHOLAS J. PAPANASTASSIOU

CASE NOS. ER-2018-0125 AND ER-2018-0146

Q: Please state your name and business address.

A: My name is Nicholas J. Papanastassiou. My business address is 1 Marina Park Drive #400, Boston, MA, 02210.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Advanced Energy Management Alliance ("AEMA").

Q: Could you describe AEMA and its interests?

A: AEMA is a nonprofit corporation organized under the laws of the District of Columbia. Additionally, it is a trade association under Section 501(c)(6) of the Federal tax code whose members include national distributed energy resource companies and advanced energy management service and technology providers, including demand response ("DR") providers, as well as some of the nation's largest demand response and distributed energy resources. A list of its members can be found at AEMA's website: http://aem-alliance.org/about/members. AEMA member companies have worked with utilities on DR programs across the Midwestern United States, the Midcontinent Independent System Operator ("MISO") region, and the entire country, and have extensive experience working to align utility and ratepayer needs through proceedings before state regulatory Commissions. AEMA has interest in working with Kansas City Power and Light Company and KCP&L Greater Missouri Operations Company (collectively, "KCP&L") to create and expand demand response and distributed energy resource opportunities as a means to achieving electricity cost savings for consumers, contributing to system reliability and resilience, and hedging against generation retirements and new capacity builds.

Q: **Please state your educational background and describe your professional training and experience.**

A: I received my Bachelor of Arts in Environmental Policy and Economics from Colby College in Waterville, Maine. I began work with EnerNOC in 2015 as a Risk and Compliance Analyst and then as a Senior Analyst of Regulatory Affairs. In that latter capacity I have studied and advocated for demand response (DR) program design matters in numerous North American and international wholesale markets and utility service territories, including in regulatory proceedings in states throughout the Midwest, including Missouri. Prior to EnerNOC, I was employed by EMC Corporation as an Associate Business Operations Analyst, where I was responsible for issues related to supply chain sustainability.

Q: **What are your current responsibilities at EnerNOC?**

A: My responsibilities include managing EnerNOC's regulatory engagements throughout the Midwest, including at both the state and wholesale market level. Additionally, I advise EnerNOC's international market development teams on a variety of DR-related and market design issues. As part of these responsibilities, I research, compile, and manage an online knowledge base of best practices for DR and market design principles across a global scope of programs. This includes research and advocacy on DR cost-effectiveness, market and program attributes that enable customer participation in DR programs, regulatory models that facilitate DR, characteristics that prevent or inhibit DR growth, and more. I have presented on such topics at conferences, workgroups, and panels, as well as advocated for them through written comments submitted in formal and informal proceedings.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to respond to KCP&L's Supplemental Direct Testimony and its interpretation of the Indiana Model for implementing demand response. In doing so, I will summarize how AEMA presented the Indiana Model to the Commission in two oral presentations at Commission-led workshops and in written comments, and how that presentation differs from KCP&L's interpretation. I will also describe how the Indiana Model facilitates the growth of cost-effective demand response. Finally, I will propose a means by which KCP&L can incorporate the best practices from the Indiana Model into its existing DR programs.

Implementing the Indiana Model to pursue all cost-effective DR resources

Q: How did KCP&L interpret the Indiana Model?

A: At pages 9-10 of her Supplemental Direct Testimony, KCP&L witness Kimberly H. Winslow testifies that, in reviewing the Indiana Model, KCP&L reviewed DR tariffs of the five regulated utilities in Indiana: Duke Energy-Indiana ("Duke"), Indianapolis Power & Light ("IPL"), Northern Indiana Public Service Company ("NIPSCO"), Vectren Energy Delivery of Indiana ("Vectren") and Indiana Michigan Power Company ("I&M"). A description of the Indiana Model was further expressed by Burton Crawford at page 4 of his Supplemental Direct Testimony. He described the Indiana Model as "a mechanism utilized to enable DR resource participation in the Midcontinent Independent System Operator ("MISO") and PJM Interconnection ("PJM") RTO markets." While each Indiana utility has multiple DR tariffs, including tariffs that provide them each with capacity resources, the six "market-based demand response" ("MBDR") tariffs that KCP&L reviewed only pertain to consumer participation in wholesale energy and ancillary service markets. These tariffs allow customers who want to participate in the RTO energy or ancillary service markets to do so via their utility in exchange for market-based payments.

KCP&L did not review any Indiana tariff that compensated consumers for the capacity they provide to the utility and/or RTO market, although they exist. This may be because Southwest Power Pool ("SPP"), the RTO in which KCP&L is located, does not have a capacity market. KCP&L stated in its testimony that it intends to include a MBDR tariff, similar to the ones it reviewed from Indiana, as a proposed component of its Business DR program in its upcoming Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 3 filing.

Q: Do you believe that a MBDR program similar to the Indiana utility tariffs reviewed by KCP&L could be advantageous for any of KCP&L's customers?

A: While I agree with Ms. Winslow that some commercial consumers may find value in being able to participate in the SPP energy market,[1] my experience in domestic and international markets suggests that it will only be a very small handful of customers with minimal overall benefit to all KCP&L consumers. Quite simply, demand response participation is minimal in energy-only opportunities, as customers typically require more revenue predictability and certainty before agreeing to participate in demand response programs. We do support KCP&L's development of market-based demand response programs but want to make sure that those programs are worthy of KCP&L staff effort, and deliver benefits for all KCP&L consumers.

Q: Do you believe there are limitations to an MBDR program, as contemplated by KCP&L?

A: Yes. In addition to typically low customer participation in energy only opportunities, the SPP market is challenging for demand response. As Burton Crawford stated at page 5 of his

[1] K.H. Winslow Supplemental Direct at p. 12.

Supplemental Direct Testimony, relative to the MISO and PJM market, "SPP has the fewest and most restrictive criteria for market participation by DR resources." The total amount of DR registered in SPP's wholesale markets – 0 MW in total, according to FERC's 2017 Assessment of Demand Response and Advanced Metering – supports this finding.

The MBDR programs specifically reviewed by Ms. Winslow in Indiana have achieved mixed results. Some of the tariffs reviewed have zero customers enrolled in them. Only the largest and most sophisticated customers that can cope with complex market rules and high upfront program enablement costs tend to participate in these energy/ancillary programs. Given that SPP's rules are more complex, challenging, and costly than MISO's rules, it is unlikely that many, if any, KCP&L customers will be attracted to a MBDR program. KCP&L appears to realize this as well: in its 2018 IRP filing, it stated, "for the time being, it would appear that the company may have greater ability to control and manage its peak demand by self-dispatching its DRRs [demand response resources] rather than submitting demand response offers into the SPP market. This will help to maximize the value of DRR by capturing the value of avoided capacity by reducing its overall system load from SPP's perspective." I agree with this, as does AEMA. Avoiding the complexities of the SPP market will enable KCP&L to develop DR programs that are attractive for the smaller commercial and industrial ("C&I") customers who are crucial for maximizing cost-effective DR potential.

Q: How did AEMA describe the Indiana model to the Commission during the November 20, 2017 and January 9, 2018 workshops and in its October 20, 2017 and March 9, 2018 comments filed in Docket No. EW-2017-0245?

A: In its written comments and presentations on the Indiana Model in Docket No. EW-2017-0245, AEMA specifically referred to I&M's D.R.S.1 tariff, which enables customers to receive compensation based off avoided capacity costs. In the Staff's report on DER recommendations in the same docket, the Indiana Model is defined as "Indiana Michigan Power Company's tariffs, specifically for the PJM territory of its service area." As such, to comply with the Commission's Order from May 4, 2018, KCP&L should be modeling its proposed programs off this capacity-based tariff. This is also what Ameren appears to have done in its MEEIA Cycle 3 filing. Ameren filed for a new, capacity-based DR program to be implemented by a third-party Program Administrator. As discussed further below, these are essential elements of the Indiana Model.

The I&M D.R.S.1 tariff is a capacity-based DR tariff that has been successful at leveraging independent aggregators and reducing I&M's need to build or procure capacity to meet its regional capacity obligations. In using the phrase "Indiana Model" for the rest of this testimony, I will refer only to this tariff.

Best Practices of the Indiana Model

Q: What are the best practices of the Indiana Model?

A: The Indiana Model contains several different elements that help maximize participation of cost-effective DR resources.

First, the tariff allows qualified DR aggregators to recruit customers into the program, and sets clear, equivalent, and non-discriminatory rules for customers participating in the tariff directly or through an aggregator. DR aggregators help maximize customer participation in programs because their specialization, technology, and business models often enable them to reach and attract a broader array of customers than utilities are capable of on their own.

A key service that aggregators provide to customers is allowing them to participate in aggregated portfolios in which their capabilities are combined with those of other customers. Aggregators can then shield individual customers from any risk or penalties associated with program participation by taking on all obligations on behalf of the portfolio. This is crucial for attracting customers and growing a DR program as the risk of out-of-pocket penalties from a missed dispatch can be a huge deterrent to customers. In order for aggregators to provide this service, DR programs must treat aggregated portfolios of customers just like individual customer accounts for the purposes of dispatches, performance calculations, and settlements. The Indiana Model refers to customers and aggregators simply as "participants" and does not differentiate between DR capacity provided by one or the other.

Second, the tariff transparently defines the capacity price and clearly ties it to the long-run avoided cost of capacity. The tariff defines the annual capacity payment as the greater of the 4-year average PJM auction clearing price and 35% of the applicable Net Cost of New Entry ("Net CONE") value. Tying compensation to the prices that attract new supply-side entry to markets ensures that the tariff is aligned with market fundamentals, helps ensure cost-effectiveness, and enables customers to understand the value they provide to a system.

Third, the overall program design enables customer participation. The tariff is based on PJM's wholesale DR capacity products, which have proven successful at attracting thousands of MW of DR (over 8,000 MW of enrolled DR resources for the 2017/2018 delivery year). An essential element of this is a dispatch trigger that only dispatches the program under clearly defined emergency conditions. This ensures that customers, who tend to face very high marginal curtailment costs, are not dispatched before other less expensive energy resources are committed or exhausted in the market.

Fourth, the tariff delivers value to the utility based on the regional resource adequacy construct. I&M uses the tariff to meet its capacity obligation to PJM by qualifying its DR resources directly with the market. However, a utility could also use DR to target its peak load, and thereby reduce its overall capacity obligation to the wholesale market.

Q: Can the Indiana Model work in a region that lacks a capacity market, like SPP?

A: Yes. As stated above, a key component of the Indiana Model is aligning the tariff with the regional resource adequacy construct. In PJM (and MISO), utilities can qualify DR resources as capacity to meet their capacity obligations. In SPP, no such capacity market exists. However, SPP establishes resource adequacy requirements for each load-serving entity equal to its summer season net peak demand plus a planning reserve margin. Net peak demand is defined as the forecasted peak demand less, among other things, the projected impacts of DR programs that are controllable and dispatchable and not registered as a Resource with SPP. Therefore, DR programs can reduce a utility's overall resource adequacy requirement to SPP if designed in a controllable, dispatchable manner that targets summer peak demand. In fact, each MW of demand response is equal to 1.12 MW of generation, as it eliminates the need to procure the reserve margin.

All other elements of the Indiana model – facilitating aggregator participation, transparently aligning program compensation with long-term avoided costs, and creating a program design that fosters customer participation – can be easily applied in any tariff, independent from the regional or wholesale market. Ultimately, the Indiana Model is simply a means to an end of achieving all cost-effective DR resource participation.

Q: Does KCP&L already have DR programs similar to the Indiana Model?

A: In part. In her Supplemental Direct Testimony at pages 3-4, Ms. Winslow describes KCP&L's existing capacity-based DR tariff which is called the Demand Response Incentive ("DRI") program. Versions of this program have existed for the last 20+ years and KCP&L currently has

70 MW of enrolled commercial curtailment capacity for 2018. However, the tariff falls short of the Indiana Model's best practices in key ways. While KCP&L's DRI program has been successful, the Indiana model presents a further opportunity to lead on DR and innovate within the SPP market by aligning the tariff with existing best practices.

Q: **Please describe the shortfalls of KCP&L's DRI tariff when compared to the best practices from the Indiana Model.**

A: The tariff incorporates some elements of the Indiana Model. However, it is missing several critical elements.

First, the KCP&L tariff does not establish clear terms for third party aggregators to participate. The tariff indicates that, for customers contracted through a Company-approved aggregator, the maximum number of curtailment events, the duration of curtailment events, the frequency of curtailment events, and the length of the curtailment season will be all established based on mutual agreement between the Company, the customer, and the aggregator. This creates a risk that aggregators, and their customers, could be subject to different terms than customers who do not participate through an aggregator. It also means that separate negotiations will be required any time an aggregator wishes to add a customer to its portfolio. In other markets and programs, this lack of standardization has dramatically impeded overall program growth.

Second, the tariff does not clearly tie compensation to Net CONE. According to KCP&L's website, the tariff currently provides $32.50/kW-yr in capacity compensation to customers. However, it is not clear how this compensation level is determined. As KCP&L established in its MEEIA Cycle 2 filing, DR programs should be evaluated for cost-effectiveness based on the long-run avoided cost of capacity, similar to supply side options that put "steel in the ground."

Transparently tying compensation to Net CONE will ensure that the tariff remains cost-effective, MEEIA-compliant, and aligned with the costs of adding new capacity to the system.

Third, the tariff does not define the specific conditions under which the program will be dispatched. The DRI tariff explains that curtailments can be requested for operational or economic reasons. While this is fairly common dispatch language for utility programs, it does not provide sufficient transparency as to when dispatches will occur. This transparency is a critical element for attracting and retaining customers into the program, as it enables better forecasting of the quantity and duration of dispatches, and therefore the costs and other burdens that customers will experience while participating in the program.

Fourth, the tariff does not clearly establish a minimum lead time for dispatches. The lead time – the time in which customers must deliver their DR capacity following a dispatch notification – is something that should be specified in the tariff. This helps customers understand their ability to participate in the program as well as any investments they may need to make in order to deliver their curtailment capacity within the required time frame.

It is possible that some of these conditions are included in the standard contract that customers sign as part of their participation in the tariff; I have not been able to find the standard contract online anywhere. However, the minimum terms of participation should be clearly stated and standardized in the tariff, not a contract that has to be negotiated. This is crucial for scaling the program and understanding the benefits it provides to all KCP&L customers.

Q: **Do you believe that fully incorporating the best practices from the Indiana Model would increase customer participation in the DRI tariff?**

A: Yes. Based on my experience, the elements outlined above greatly facilitate customer participation in DR programs, particularly for smaller customers which are critical for scaling a program.

While the DRI program has been successful at attracting 70 MW of DR capacity from customers, the full cost-effective DR potential is likely substantially greater. In its 2018 IRP, KCP&L identified about 160 MW of incremental demand savings under a 'realistically achievable potential' scenario by 2024. In order to achieve these demand savings, and maximize cost-effective DR participation more broadly, DR programs must be suitable for smaller customers who may lack the resources and sophistication of larger customers.

Q: How would you recommend that KCP&L incorporate the Indiana Model into the DRI tariff?

A: KCP&L can incorporate the Indiana Model into the DRI tariff by amending and clarifying the existing terms of the tariff in relatively simple ways. Attached to my testimony as Appendix A is a draft of proposed redlines to KCP&L's existing DRI tariff that incorporate the changes I outline below. AEMA would be glad to discuss these changes with KCP&L in more detail.

First, KCP&L should include language that establishes that utility-approved aggregators who recruit customers into the program are subject to the same rules and sign the same standard contract as customers who participate in the program directly. KCP&L could do this by defining a new term, "participant," that refers to either customers or aggregators and to whom the terms of the tariff apply.

Second, KCP&L should either include the standard contract that tariff participants (customers or aggregators) sign as an appendix to the tariff or clearly link to it from the tariff. Currently, the tariff suggests that the standard contract can be found in a link provided in the tariff, but I have been unable to find it. Making the contract immediately accessible would improve the overall transparency of program terms and avoid potential delays in registering customers in the program.

Third, KCP&L should set annual tariff compensation for DR capacity at 60% of KCP&L's Net CONE. KCP&L's existing DRI program is highly cost-effective, with Total Resource Costs tests of 3.09 and 13.56 in the GMO and KCPL-MO territories, respectively, for Program Year 1 of its MEEIA Cycle 2. This indicates that KCP&L could increase compensation under the program, thereby attracting more customers, while still maintaining cost-effectiveness and delivering net benefits to its system. That KCP&L has indicated that it will file this tariff under MEEIA, the statutory goals of which include achieving all cost-effective demand-side savings, increasing program compensation to attract more customers, while still achieving cost-effectiveness, is fully consistent with the objectives of MEEIA and should be encouraged.

Fourth, KCP&L should define a dispatch trigger in which customers under the tariff are dispatched when KCP&L's load is forecasted to exceed a specific percentage of the peak demand figure used in establishing KCP&L's resource adequacy requirement to SPP. This trigger should be based on an analysis of KCP&L's load shape; other peak shaving programs use a threshold of at least 92%. AEMA would be glad to share its collective experiences from other DR programs with KCP&L to help it establish a threshold appropriate to its system. The program should also be available when emergency conditions exist on KCP&L's system.

Economic curtailments, such as those triggered when KCP&L's marginal cost to produce energy is greater than the price in customers' retail tariffs, should be strictly voluntary. Customers' marginal curtailment costs are typically very high. Even providing a buy-through option for economic curtailments could make participation unattractive for customers, particularly if the buy-through rate is much higher than their retail rate or the quantity of potential economic curtailments is unknown or uncertain.

Fifth, KCP&L should establish a minimum lead time of two hours for curtailment events. This is sufficient for addressing periods of forecasted peak demand and provides KCP&L with sufficient flexibility to address system emergencies while recognizing that some customers have a limited ability to curtail load in less than two hours.

Q: How should KCP&L implement any changes to its DRI tariff?

A: These tariff changes should be reflected in KCP&L's MEEIA Cycle 3 filing. This allows for better coordination and integration of all MEEIA programs and resources and enables KCP&L to file for recovery and incentives for the tariff.

Q: How should KCP&L get recovery for this tariff?

A: KCP&L should get recovery via MEEIA's Demand Side Incentive Mechanism ("DSIM") rider like other MEEIA programs. Approval of cost recovery through the DSIM rider, along with any proposed performance incentives, for the DRI tariff should be predicated on KCP&L incorporating the best practices from the Indiana Model that are outlined above.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

DRAFT PROPOSED REDLINES TO KCP&L'S DEMAND RESPONSE INCENTIVE TARIFF

15.09 DEMAND RESPONSE INCENTIVE

PURPOSE:

This voluntary program is designed to reduce customer load during peak periods to help defer future generation capacity additions and provide for improvements in energy supply. The maximum recurring monthly and/or annual bill credit or incentive payment will not cause the Program's cost to be higher than the benefits realized from the avoided capacity.

AVAILABILITY:

This program is available during the Program Period, and is available to all customers in the classes identified in the Business Demand-Side Management section that also meet Demand Response Incentive provisions. The Customer ~~(or Participant)~~ must have a load curtailment capability of at least 25 kW during the Curtailment Season and within designated Curtailment Hours, and must agree to establish Firm Power Levels as set forth herein. Availability is further subject to the economic and technical feasibility of the installation of required Company equipment. The Company reserves the right to limit the total Curtailable Load determined under this program.

A customer may enroll directly with KCP&L or with a KCP&L-approved Aggregator. A KCP&L-approved Aggregator is an entity, appointed by a customer to act on behalf of said Customer with respect to all aspects of the Program, including but not limited to: a) the receipt of notices from KCP&L under this Program; and b) the receipt of incentive payments from KCP&L.

The term "Participant" as used herein shall mean the customer or KCP&L-approved Aggregator as defined above.

AGGREGATION OF ~~A CUSTOMER'S~~ MULTIPLE ACCOUNTS:

For the purposes of this program ~~only and at the Company's option~~, a Customer with multiple accounts may ~~request that some or all of its accounts be~~ aggregate its accounts ~~d~~ with respect to Estimated Peak Demands, Curtailable Loads and Firm Power Levels, so long as each account in the aggregation is able to provide a Curtailable Load of at least 25 kW. The aggregated account will be treated as a single account for purposes of calculating the Program Participation Payments, Curtailment Occurrence Payments and Penalties.

Multiple Customer electric service accounts, not under common ownership, may be aggregated through a KCP&L-approved Aggregator with respect to Estimated Peak Demands, Curtailable Loads and Firm Power Levels, so long as each account in the aggregation is able to provide a Curtailable Load of at least 25kW. The aggregated account will be treated as a single account under the Participant for purposes of calculating the Program Participation Payments, Curtailment Occurrence Payments and Penalties.

TERM OF CONTRACT:

Contracts under this program shall be a standard contract for each program provision and for all Participants and shall be effective as of the date of contract execution and will expire as indicated in the ~~customer~~ Participant contract but no later than the end of the Program Period. Thereafter, ~~Customers~~ Participants may enter into a new contract subject to the terms and conditions of this program as may be modified from time to time. Written notice by either the Participant or Company to terminate or modify a contract must be given at least thirty (30) days prior to commencement of the Curtailment Season. The Company shall provide Commission Staff and The Office of the Public Counsel with the standard contracts to be used for each program provision. ~~Customers~~ Participants may view standard contract forms at www.kcpl.com/save-energy-and-money/for-business.

KCP&L is not required to curtail all Participants simultaneously and may stagger curtailment events across participating Participants.

PROGRAM PROVISIONS:

This Program may be executed by either of two methods:

Traditional Demand Response Incentive (DRI)

A ~~Participant~~ Customer with load curtailment potential during the Curtailment Season and designated Curtailment hours enrolls directly with KCP&L or KCP&L-approved Aggregator. The Participant (either the Customer or its KCP&L-approved Aggregator) agrees to curtail load at or below their contracted Firm Power Level during a KCP&L Curtailment Event. The Participant ~~or Aggregator~~ receives an event notice from KCP&L and they may manually execute their facility curtailment plan to fulfill their contract. The Participant -receives financial incentives from June through September for Program participation and payments for successful hourly event performance or penalties for non-performance. Participants are notified in advance of scheduled curtailment events and may opt not to participate in an event, but KCP&L reserves the right to assess financial penalties and or contract termination for non-participation as described in ~~Participant's individual contract~~this tariff. An Aggregator delivering the DRI will provide specific terms of participation in Customer's Agreement that may vary from the following Program Provisions, and shall share these terms with the Company upon request~~.~~

Automated Demand Side Management (ADSM)

A ~~Participant~~ Customer with load curtailment potential during the Curtailment Season and designated Curtailment hours enrolls directly with KCP&L or a KCP&L-approved Aggregator. KCP&L or a KCP&L-approved Aggregator then utilizes the ~~Participant's~~ Customer's building energy management system to measure, analyze and report near real time curtailable load capacity. This two-way communication system creates a near real-time bridge between the Program and the Participant's curtailable equipment. The Participant ~~or their Aggregator~~ receives the curtailment event notice from KCP&L then sends the signal to the energy management system to control individual equipment loads to meet necessary kW load reduction. The Participant may override this automated signal before or during an event. Participant receives a financial incentive for participation, but no per event payment. Any limitations on event over-rides or associated penalties are detailed in the Participant's ~~individual~~ contract. The Aggregator delivering the ADSM method will provide specific terms of participation in ~~Participant's~~ Customer's Agreement that may vary from the following Program Provisions.

CURTAILMENT SEASON:

The Curtailment Season shall be ~~determined based upon the method or curtailment, with Customers contracting directly with KCP&L participating in a curtailment season~~the period of June 1 through September 30. The Curtailment Season ~~directly contracted Customers~~ will exclude weekends and ~~independence~~ Independence Day and Labor Day, or the days celebrated as such, as well as other nationally-recognized holidays. ~~Customers contracted with and participating in a KCP&L-approved Aggregator's portfolio shall experience a mutually agreed upon curtailment season pursuant to the terms of the KCP&L-approved Aggregator's contract with the Customer, which may extend the Curtailment Season from January 1 through December 31.~~

~~KCP&L is not required to curtail all Participants simultaneously and may stagger curtailment events across participating Participants.~~

CURTAILMENT LIMITS:

~~The DRI Customer contract shall specify the Maximum Number of Curtailment Events for which the Customer agrees to curtail load during each Curtailment Season. For customers contracting directly with~~of ~~KCP&L Greater Missouri Operations Company~~For each Participant, the Maximum Number of Curtailment Events shall be at least one (1) but shall not exceed ten (10) separate occurrences per Curtailment Season. Each Curtailment Event shall be no more than eight consecutive hours and no more than one occurrence will be required per day. The Company may call a Curtailment Event no more than three consecutive days per calendar week. The cumulative hours of Curtailment Hours per ~~Customer~~ Participant shall not exceed eighty (80) hours in any Curtailment Season.

DISPATCH LEAD TIME

~~Customers~~ Participants shall be dispatched with no less than two hours' notice from KCP&L for Curtailment Events. KCP&L can request curtailments from ~~customers~~Participants with less than two hours' notice, but curtailments will be considered voluntary until two hours after the initial notification. KCP&L will strive to provide ~~customers~~Participants with as much lead time as possible prior to Curtailment Events.

~~CURTAILMENT LIMITS: (continued)~~

~~For Customers contracted through a Company-approved Aggregator, the Maximum Number of Curtailment Events, Duration of Curtailment Events and Frequency of Curtailment Events shall be defined within the Customers contract and mutually agreed upon by Company, the Customer, and the Aggregator.~~

ESTIMATED PEAK DEMANDS:

The Estimated Peak Demand is the average of the Customers Monthly Maximum Demand for Monday through Friday between 12:00 noon and 8:00 p.m. for June 1 through September 30 from the previous year.

The Company may use such other data or methodology as may be appropriate to establish the Estimated Peak Demand.

ESTIMATED PEAK DEMAND MODIFICATIONS:

The Company may review and, if necessary, adjust the ~~Customers~~ Participant's Estimated Peak Demand based on evidence that the ~~Customers~~ Participant's actual peak demand has changed, or will change, significantly from the Estimated Peak Demand currently being used to calculate the ~~Customer's~~ Participant's Curtailable Load. If a change in the ~~Customers~~ Participant's Estimated Peak Demand results in a change in its Curtailable Load, the ~~Customer~~ Participant shall lose and/or be required to repay its curtailment compensation proportional to the number of days curtailment was not available and the change in the Curtailable Load.

FIRM POWER LEVELS:

The ~~Customers~~ Participant's Firm Power Level, which is the maximum demand level to be drawn during a Curtailment Event, shall be set at least 25 Kw less than the ~~Customer's~~ Participant's Estimated Peak Demand.

FIRM POWER LEVEL MODIFICATIONS: (continued)

Additionally, any change in Firm Power Level that decreases Curtailable Load for the ~~Customer~~ Participant shall result in re-evaluation of all curtailment compensation to the ~~Customer~~ Participant including any payment or credits made in advance of the Curtailment Season. The ~~Customer~~ Participant shall repay the Company prior payments/credits made in excess of the curtailment compensation due based on the decreased level of Curtailable Load.

~~Additionally, any change in Firm Power Level that decreases Curtailable Load for the Customer shall result in re-evaluation of all curtailment compensation to the Customer including any payment or credits made in advance of the Curtailment Season. The Customer shall repay the~~

~~Company prior payments/ credits made in excess of the curtailment compensation due based on the decreased level of Curtailable Load.~~

CURTAILABLE LOAD:

Curtailable Load shall be that portion of a ~~Customers~~ Participant's Estimated Peak Demand that the ~~Customer~~ Participant is willing and able to commit for curtailment~~, and that the Company agrees to accept for curtailment~~. The Curtailable Load shall be the same amount for each month of the contract. Under no circumstances shall the Curtailable Load be less than 25 kW. Curtailable Load is calculated as the difference between the Estimated Peak Demand as determined above, and the Firm Power Level.

SELF-GENERATION:

Self-generation as a curtailment method is restricted to customers who can provide documentation validating Compliance pursuant to Environmental Protection Agency ("EPA') regulations (summarized at www.epa.gov/ttn/atw/iceengines/comply.html) that affect the use of reciprocating internal combustion engines.

CUSTOMER COMPENSATION:

~~Customer~~ Participant compensation shall be equal to 60% of KCP&L's Net Cost of New Entry (Net CONE) for the delivery year~~defined within each Customer contract~~. Timing of all payments/credits shall be specified in the curtailment contract with each ~~Customer~~Participant. Payments shall be paid to the ~~Customer (or their Aggregator)~~ Participant by Company in the form of a check or bill credit. ~~as specified in the contract or by a Company-approved Aggregator as defined within the Customers contract~~ The credits shall be applied before any applicable taxes. All other billing, operational, and related provisions of other applicable rates schedules shall remain in effect.

Compensation will include:

PROGRAM PARTICIPATION PAYMENT:

For each Curtailment Season, ~~Customer~~ Participant shall receive a payment/credit based upon the incentive structure outlined within the contract term. The Program Participation Payment for a Curtailment Season is equal to the per kilowatt of Curtailable Load rate as defined in the ~~Customers~~ Participant's contract

The Program Participation Payment will be divided by the number of months in the Curtailment Season and may be applied as bill credits or payments equally for each month of the Curtailment Season or as a combined Participation and Curtailment Event net payment check after the close of the DRI Season.

Curtailment Event Payment: ~~Customers~~ Participants may also receive an Event Payment for each Curtailment Hour during which the ~~Customer's~~ Participant's metered demand is less than or equal to his Firm Power Level.

NEED FOR CURTAILMENT:

Curtailments can be requested for ~~operational~~ peak load, emergency, or economic reasons.

Peak load curtailments

~~Operational~~ Peak load curtailments may occur when KCP&L's peak load is forecasted to exceed xx% of their forecasted peak demand for the current delivery year.

Emergency curtailments

Emergency curtailments may occur when, in the sole judgment of the Company, an emergency condition exists on their system, such that curtailment of load served under this tariff is necessary in order to maintain service to the Company's other firm service customers.

Economic curtailments

~~physical operating parameters approach becoming a constraint on the generation, transmission, or distribution systems, or to maintain the Company's capacity margin requirement.~~ Economic curtailments may occur when the marginal cost to produce or procure energy, or the opportunity to sell the energy in the wholesale market, is greater than the Customer's retail price. These curtailments are voluntary for Participants and will not impact the Customer's base program participation payment.~~,~~

~~ENERGY PURCHASE OPTION:~~

~~At the Company's option and the Customers request, during a Curtailment Event called for economic reasons, the customer may purchase energy above its Firm Power Level from the Company at a price per kilowatt-hour determined at the beginning of a Curtailment Event. A Curtailment Event Payment will not be paid to Customers for Curtailment Events where this option is used. Customer will not have the option to purchase energy during a Curtailment Event called for operational reasons.~~

PENALTIES:

Failure of the ~~Customer~~ Participant to effect load reduction to its Firm Power Level or lower in response to any Company request for peak load or emergency curtailment shall result in the following reduction or refund of Program Participation Payments and Curtailment Occurrence Payments for each such failure as follows:

Reduction of Program Participation Payment: ~~Customer~~ Participant will receive reduced future Program Participation Payments or a bill debit, in an amount equal to 150% of the Program Participation Payment divided by the Maximum Number of Curtailment Event Hours, the result of which is multiplied by the percentage by which the ~~Customer~~ Participant underperformed during a Curtailment Event Hour.

Any ~~Customer~~ Participant who fails to reduce load to its Firm Power Level as described within their ~~Customer~~ Participant Contract may be removed from the program and/or be ineligible for this program for a period of two years from the date of the third failure.

CURTAILMENT CANCELLATION:

The Company reserves the right to cancel a scheduled Curtailment Event prior to the start time of such Curtailment Event. However, if cancellation occurs with less than two hours of the notification period remaining prior to commencement of a Curtailment Event, the canceled Curtailment Event shall be counted as a separate occurrence with a zero-hour duration.

TEST CURTAILMENT:

The Company reserves the right to request a Test Curtailment once each year and/or within three months after a ~~Customers~~ Participant's failure to effect load reduction to its Firm Power Level or lower upon any Company request for curtailment.~~,~~ Test Curtailments shall be limited to one hour in duration and do not count toward the Maximum Number of Curtailment Events. ~~Customers~~ Participants will not be compensated for Test Curtailments.

VOLUNTARY LOAD REDUCTION:

Customers served in this Program also will be served on the Voluntary Load Reduction Rider (Schedule VLR), subject to the paragraph entitled "Special Provisions for Customers Served on Schedule MP.' A separate Contract for service on Schedule VLR is not required for customers served under this Program.

ADDITIONAL VOLUNTARY EVENTS

At any time while the ~~Customer's~~ Participant's contract is in effect, the Company may request a ~~Customer~~ Participant to participate, on a voluntary basis, in additional Curtailment Events. ~~Customers~~ Participants who are asked and who participate in these additional voluntary curtailments will receive Curtailment Event Payments as outlined previously ~~In~~ in this tariff, but will not receive additional Program Participation Payments. This provision applies to all ~~Customers~~ Participants whose contracts are still in force, whether or not they have participated in a number of Curtailment Events equal to their chosen Maximum Number of Curtailment Events.

At its sole discretion, the Company will decide to apply the terms of Voluntary Load Reduction or Additional Voluntary Events for a given Curtailment Event.