MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

A WORKING CASE TO EXPLORE

EMERGING ISSUES IN UTILITY REGULATION

FILE NO. EW-2017-0245

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I. Executive Summary

On March 24, 2017, Staff filed an *Agenda and Request for Workshop Docket* noting "[u]tility regulation is constantly affected by new advancements in technology and the law", and identifying five emerging areas of interest. On April 6, 2017, the Commission issued its *Order Opening a Working Proceeding Regarding Emerging Issues, and Scheduling a Workshop Meeting* for May 18, 2017. Interested stakeholders were invited to submit information, including examples from other states, legal implications, and answers to various questions posed by Staff, by May 1, 2017. Several stakeholders submitted comments and information, and participated in the May 18 workshop. This Staff Report provides a summary of the information provided, and includes recommendations for further actions. Specifically, Staff recommends additional workshops to:

- Address potential revisions to the following Commission rules: Cogeneration (4 CSR 240-20.060), Filing Requirements for Electric Utility Cogeneration Tariff Filings (4 CSR 240-3.155), and Net Metering (4 CSR 240-20.065), with discussions related to methodologies of calculating avoided costs; standardized Public Utility Regulatory Policies Act ("PURPA") contracts; net metering excess generation credits; and disconnect standards.

- After progress has been made in discussing avoided cost methodologies, evaluate the needs of the value of distributed resource study.

- Explore policy questions related to modified rate design proposals and collect data to the extent available.

Staff suggests it would be beneficial if the Commission provided feedback on these issues that may provide guidance to Staff, the utilities, and other interested stakeholders when approaching the workshops related to these topics. Similar requests for Commission feedback have been made in other states. Feedback from the Minnesota Commission was recommended as part of the Minnesota e21 Initiative. Similarly, the Chairman of the California Public Utilities Commission recently released an Action Plan titled - “a roadmap for where we want to go with [distributed energy resources]”.

II. <u>What is the Commission’s role in shaping the solar landscape?</u>

A. <u>General summary of workshop and filed comments</u>

The solar landscape portion of the workshop consisted of two presentations followed by stakeholder discussions. The first presenter, David Bunge with Cypress Creek Renewables, spoke on the benefits of a vibrant Qualifying Facility market and compared the implementation of PURPA in Missouri to that of North Carolina. The next presentation’s hosts were Laura Chapelle with Varnum Law and Karl Rabago with the Pace Energy and Climate Center who spoke on utility obligations under PURPA, avoided cost calculation methodologies, and on Michigan’s ongoing PURPA implementation.

Numerous stakeholders voiced interest in competitive options for renewable energy, an evaluation of avoided costs calculation methodologies, and a value of solar (or value of distributed resource) study. Many stakeholders also expressed interest in reevaluating the Commission’s implementation of PURPA in the cogeneration rules.

The written comments by many of the non-utility parties echoed the stakeholder discussion regarding revisions to the Commission’s rules implementing PURPA, studying the value of solar (or distributed resources), and touched on related topics such as net metering.

Parties who provided written comments on the Commission's role in shaping the solar landscape were: Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri"), Missouri Division of Energy ("DE"), Kansas City Power and Light and KCP&L Greater Missouri Operations (collectively, "KCP&L"), Brightergy, the Empire District Electric Company ("Empire"), Missouri Solar Energy Industries Association ("MOSEIA"), Renew Missouri Advocates ("Renew Missouri"), Sierra Club and the Natural Resource Defense Council ("NRDC"), Sun Solar, and the Office of the Public Counsel ("OPC"). The comments covered a broad range of solar-related topics and nuanced viewpoints. Staff's summarization here focuses on the main issues that were raised by stakeholders. Staff will instead briefly discuss the comments related to the following subtopics which appeared to generate the most interest: the Commission's implementation of PURPA, net metering, value of solar (or DER) studies, and utility-led programs.

<u>Commission's implementation of PURPA:</u>

Renew Missouri provided clear recommendations regarding the Commission's implementation of PURPA though multiple stakeholders also voiced general interest in reviewing the Commission's Cogeneration rule. Specifically, Renew Missouri suggested the following:

- Implement a fixed term for qualifying facility ("QF") contracts to give independent power producers ("IPPs") long-term certainty;
- Increase the size limit for the standard QF rate (currently the standard contract is set at 100 kW which is the size limit for net metering);
- Include a standard QF contract as part of the utility's tariffs;
- Specify a time frame for utility response to QF applications (such as 60 days); and
- Consider avoided cost methodologies using an objective third-party.

Net metering:

The comments regarding the net metering statute were primarily from members of the solar industry and revolved around the statute being too restrictive. Additionally, various stakeholders showed an interest in evaluating the compensation for excess generation of net metered systems. Although many of the comments would need to be addressed by modification of the Net Metering and Easy Connection Act, Sierra Club suggested the statute sets a floor, not a ceiling on compensation for excess generation. [1] Staff will note that the topic of compensation for excess generation is directly related to avoided cost calculation methodologies because the Commission's current net metering rule defines avoided fuel costs as "avoided costs… used to calculate the electric utility's cogeneration rate." [2] Staff also received comments regarding the disconnect standards and a recommendation to consider Arkansas' Net Metering Rules, Section 3.1.

KCP&L noted in its written comments that it believes the Commission's current net metering rule is working as the applicable statue intended. KCP&L also pointed out the potential for cost-shifts between customer groups where wide-scale increases of solar adoption occurred, such as California, Hawaii, Nevada, and Arizona.

Value of Distributed Generation Study:

DE voiced interest in interested stakeholders evaluating the value of distributed generation, whereas, Renew Missouri suggests a neutral third party should conduct the study.

[1] Section 386.890 5.(3) RSMo Supp. 2008, states in part: "shall be credited an amount at least equal to the avoided fuel cost of the excess kilowatt-hours generated during the billing period";
4 CSR 240-20.065(1)(A) states in part: Avoided fuel cost means avoided costs… used to calculate the electric utility's cogeneration rate"
4 CSR 240-20.065(7)(C) states in part that the excess generation rate "is calculated from the electric utility's avoided fuel cost"

[2] 4 CSR 240-20.065(1)(A) states in part: Avoided fuel cost means avoided costs… used to calculate the electric utility's cogeneration rate".

OPC suggests that any such study should also inform the Commission as to which customers benefit. Karl Rabago noted in response to a question from DE that further discussion regarding avoided costs would also inform a future value of distributed resource study and notes a cost-benefit study should be done before rate-design.

Utility-led Programs:

Ameren Missouri specifically referenced the solar pilot program cases (Case Nos. EA-2016-0207 and EA-2016-0208) for its understanding of the Commission's position regarding the regulation of solar energy. KCP&L commented that the Commission should remain supportive of its efforts to integrate solar and other renewables.

Empire provided general written comments and noted that many of the technologies and trends on the workshop agenda may be grouped into one category: grid modernization. Further, Empire commented that, "The Commission should have a pivotal role in defining the appropriate economic and societal value of a unit of energy at any given point in a day, season, or year."

Sierra Club pointed to the importance of not restraining models to select a limited quantity of solar used in integrated resource plans and using accurate and current cost figures for solar and other renewables. Sierra Club also recommends the Commission require requests for proposals for utility-scale solar projects; Staff understands that this has been done for past utility scale projects by the investor-owned utilities ("IOUs").

Renew Missouri specifically recommends the Commission order every utility to design and offer community solar programs to be available to their customers within the next two years.

Renew Missouri also commented that the Ameren Missouri "Subscriber Solar" is a suitable model for the other utilities to use as a model. [3]

OPC provided questions the Commission should ask in evaluating when a utility adds new generation.

B. <u>Additional workshops</u>

Staff recommends additional workshops to develop revisions to the following Commission rules: Cogeneration (4 CSR 240-20.060), Filing Requirements for Electric Utility Cogeneration Tariff Filings (4 CSR 240-3.155), and Net Metering (4 CSR 240-20.065). As a part of the additional workshops, Staff recommends the stakeholders focus on the following topics:

- Methodologies of calculating avoided costs
- Standardized PURPA Contracts
    - Size limit
    - Contract term length
    - Utility response time
- Net metering excess generation credits
- Disconnect standards

Because a value of distributed resource study would be informed by a thorough avoided cost discussion, Staff recommends a separate workshop evaluating the needs of the value of distributed resource study after progress has been made in discussing avoided cost methodologies.

Staff appreciates Renew Missouri's interest in seeing additional utility-led community solar programs being offered. However, Staff would prefer to wait for Ameren Missouri's reporting on its subscriber pilot to begin[4] before the Commission issues an order encouraging

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[3] *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Subscriber Solar Program and File Associated Tariff.* Case No. EA-2016-0207.

[4] See Page 10 of the Non-unanimous Stipulation and Agreement in EA-2016-0207.

additional community solar programs. This reporting would provide Staff and other interested stakeholders an improved understanding of customer interest and utility management of a subscriber program.

III. What is the Commission's role related to the installation of advanced metering infrastructure?

A. Summary of workshop and filed comments

DE supports investments in advanced metering infrastructure ("AMI") that provide benefits to consumers through opportunities such as demand-response programs and enhanced time-differentiated rate designs. DE also supports AMI deployment by natural gas and water utilities. DE recommends the Commission direct parties to investigate potential synergies through co-delivery options and joint estimates of customer efficiency savings that could be attained between utility AMI programs.

Brightergy suggests large-scale information gathering and data analytics will have an increasingly important role in the energy industry. Brightergy comments that it will be a significant challenge for the Commission to balance the various interests in having access to customer data with the privacy concerns of individual customers, noting that for every customer that declines to participate, data becomes less useful.

Ameren Missouri states it is still developing its views on AMI-related issues, and KCP&L refers stakeholders to the testimony of KCPL witness Mr. Tim Rush in Case No. ER-2016-0285 for its perspective on AMI.

At the workshop, Mr. Daniel I. Beck, on behalf of Staff, provided comments, including that Empire has analog meters, that Ameren Missouri has made significant investment in identifying some concerns with automated meter reading, and that KCPL has deployed AMI to over 90 percent of its service territory, with more rural areas to be addressed in the future.

Mr. Beck stated that Staff has received consumer inquiries related to health concerns (such as radiofrequency radiation); safety concerns (such as fires at the advanced meters); and, privacy concerns. He also referenced electric utility opt-out provisions that resulted from recent Commission cases. Stakeholders engaged in a discussion of advanced metering, noting: 1) It was a cost-effective means for outage control and monitoring outages; 2) It is a way to address safety concerns for utility workers because advanced metering gets the workers out of the field; 3) Data is important to customers wanting to interact with appliances, etc.; and, 4) The need for education on the benefits and perceived harms of advanced meters. Ultimately, the utilities indicated they were not experiencing significant calls or issues from ratepayers related to advanced metering. The electric utilities commented that even with the ability to "opt-out", very few customers had expressed an interest. It was suggested the Commission may need to revisit customer notice requirements of Chapter 13 or in the Commission's rules, since advanced metering provides the opportunity for remote disconnects.

B. Additional workshops

No significant issues were identified during the comment period or as part of the workshop discussions; therefore, Staff does not recommend additional workshops on this topic at this time. However, as part of its general rule review in File No. AW-2017-0336, Staff recommends the Commission consider whether changes to the Chapter 13 notices requirements are necessary to accommodate AMI.

IV. What is the Commission's role in shaping the availability of Property Assessed Clean Energy (PACE) and Pay as You Save® (PAYS®) programs?

A. Summary of workshop and filed comments

Seven parties filed comments on the topic of the Commission's role in shaping the availability of PACE and PAYS® programs.

Ameren Missouri did not opine on what the Commission's role should be, but mentioned that along with its recently approved on-bill financing pilot program, Ameren Missouri will also be conducting a feasibility study of PAYS® and will continue to explore customer financing options and how they can maximize participation in utility programs and best meet customer preferences.

KCP&L recommended interested stakeholders review testimony supplied by Company witness Mr. Brian File in Case No. ER-2016-0285. While KCP&L did not provide an opinion on the Commission's role in shaping the availability of PACE and PAYS® programs, Mr. File's testimony in the referenced case gave a brief background of KCP&L's involvement with PACE and PAYS® and added that, "Properly developed financing vehicles should have a positive impact on the participation of energy efficiency programs as well as increasing the overall customer value. However, the ultimate benefits may not outweigh the costs and risks associated with setting up utility on-bill financing programs, especially when there are additional options for funding that are available to all customers. For example, utility financing research from the American Council for an Energy-Efficiency economy ("ACEEE") found that 'homeowner financing programs historically draw low participation rates and tend to attract educated and higher income-level homeowners who are the least in need of financing opportunities. Financing for those who are most in need, people with low or fixed incomes and poor credit, has had low success.'"[5][6]

DE expressed support of PACE, on-bill financing and other financing opportunities and noted that the discussion of on-bill financing should not be limited only to PAYS®. DE also states that while PACE financing is provided at the discretion of local governments that

[5] http://aceee.org/topics/energy-efficiency-financing
[6] Rebuttal Testimony of Brian A. File, Case No. ER-2016-0285, EFIS No. 156, Filed December 30, 2016.

participate in Clean Energy Districts and not entities regulated by the Commission, utilities can promote diverse financing options for customers. DE concluded by recommending the Commission order parties to consider how to encourage utilities to offer a broad variety of financing options for customers to make energy-related improvements.

MOSEIA stated that PACE is a financing vehicle appropriately subject to oversight by the local jurisdictions and the energy districts under which they are enabled by state law and local ordinance or resolution. Also, as it is a financing tool and has little or nothing to do with the public infrastructure of the transmission and distributive grid, or investor owned utilities, MOSEIA believes that the Commission should not be involved in PACE.

Renew Missouri expressed its support for PACE financing programs and stated that the Commission can support PACE by encouraging its integration with utility-sponsored energy efficiency and demand-side management programs under the Missouri Energy Efficiency Investment Act ("MEEIA"). Renew Missouri also expressed its support for the PAYS® model as well as other on-bill financing models and stated that the Commission has the authority under MEEIA to facilitate the creation of PAYS® programs.

Sun Solar offers both residential and commercial PACE financing to its clients where PACE financing is available. Sun Solar also states that while PACE is only statutorily authorized to finance clean energy projects, its oversight comes not from financial regulators but the technologies that are being financed themselves and are already regulated by the Commission where applicable. It is Sun Solar's belief that it is not the place of the Commission to regulate the means that customers use to finance their clean energy projects and thus PACE should not play a role in Commission decisions.

OPC states that PACE financing does not fall under the Commission's oversight and made no formal recommendation to the Commission regarding PACE financing. However, OPC believes PACE financing can best be understood as a complementary financing tool to promote energy efficiency programs and, where available, supports the use of PACE as a financing option to enable upgrades in energy efficiency related activities. OPC mentions the role it has taken in researching and investigating the appropriateness of offering a PAYS® tariff to ratepayers. OPC has been actively promoting third-party feasibility analyses for each of Missouri's electric investor-owned utilities to inform dialogue moving forward.

During the PACE and PAYS® portion of the workshop, Mr. Bill Davis from Ameren Missouri and Mr. Josh Campbell from Missouri Energy Initiative presented. Mr. Davis spoke about Ameren Missouri's recently approved on-bill financing pilot program and a feasibility study on PAYS® that Ameren Missouri will be conducting. Mr. Campbell gave an update on the current status and future outlook of PACE in Missouri.

On April 13, 2017, the Commission issued its *Order Approving Non-Unanimous Stipulation and Agreement Regarding Use of R&D Funds and Modification of Measure Incentives* in Case No. EO-2015-0055, which allowed for Ameren Missouri to use no more than $25,000 of its MEEIA Cycle 2 Research & Development ("R&D") budget to hire an independent third-party consultant to perform a feasibility study of PAYS® to be completed by June 2018. On May 17, 2017, the Commission issued its *Order Approving Stipulation and Agreement Regarding DSM Tariffs* in Case No. ER-2016-0023, which allowed for Empire to utilize no more than $50,000 of its total budget for the program year beginning in 2017 to hire an independent third-party consultant to perform a feasibility study of PAYS® and other on-bill financing to be completed by May 31, 2018. KCP&L is currently working with Ameren Missouri and Empire to determine how to collaborate, if possible, on a feasibility study of PAYS®. The details of this collaboration have not yet been determined; however, KCP&L has committed to spending some amount of its MEEIA Cycle 2 R&D budget on the feasibility of PAYS® and on-bill financing during its MEEIA Cycle 2. The feasibility study will inform stakeholders and provide further guidance on the likelihood and availability of implementing such a tariff.

B. Additional workshops

Since the utilities are already moving forward on PACE and PAYS® initiatives, Staff recommends no further workshops on PACE and PAYS® at this time.

V. What is the Commission's role in implementing modified rate design proposals?

A. General summary of workshop and filed comments

Commenters from various areas of regulatory interest emphasized that Time of Use ("ToU") and Inclining Block ("IBR") rates should not be viewed as mutually exclusive features of a particular utility's rate design; rather that a utility could have both sets as options for a rate class. DE suggested use of shadow billing to provide customers with customer-specific pricing of what their total bill would be under alternative rate designs, as well as a "hold harmless" provision so that a customer electing to switch to an alternative rate design would have some period of time to undo a rate switch that resulted in an unexpected bill increase for that customer. Industrial intervenors stated a belief that, in general, there is limited, if any, cost basis for IBR rates, but there may be cost basis for ToU rate designs.

The impacts of IBR and ToU rate designs on low income customers, electric vehicle charging, company revenue, and customer bill stability were raised by the stakeholders as concerns to be further considered in the future.

B. Additional workshops

Staff recommends additional workshops to explore the following policy questions related to modified rate design proposals.

(i) Impact of IBR and ToU rate designs on low income households and households with significant electric use associated with medical equipment;

1. Include further study on revenue impact of changes to rate design based on existing customer billing information at a company level;
2. Include further study of bill impact to specific customers on a monthly, seasonal, or annual basis;
3. Identify any further customer segmentation that may be necessary for purposes of annualizations and normalizations due to alternative rate designs;

ii) Impact of IBR and ToU on at-home electric vehicle charging and commercial facilitation of electric vehicle charging;

1. Include further study on the impact of the rate design as it varies with the severity of the rate design;

iii) Effectiveness of bill design versus rate design to facilitate communication of price signaling and enhance customer understanding;

1. Identify benefits and costs of establishing a shadow billing program that would provide customers with an indication of what that customer's bill would be under other rate design options, to educate customers on rate design options, if applicable;

iv) Impact of IBR and ToU rate designs on company incentives and behaviors;

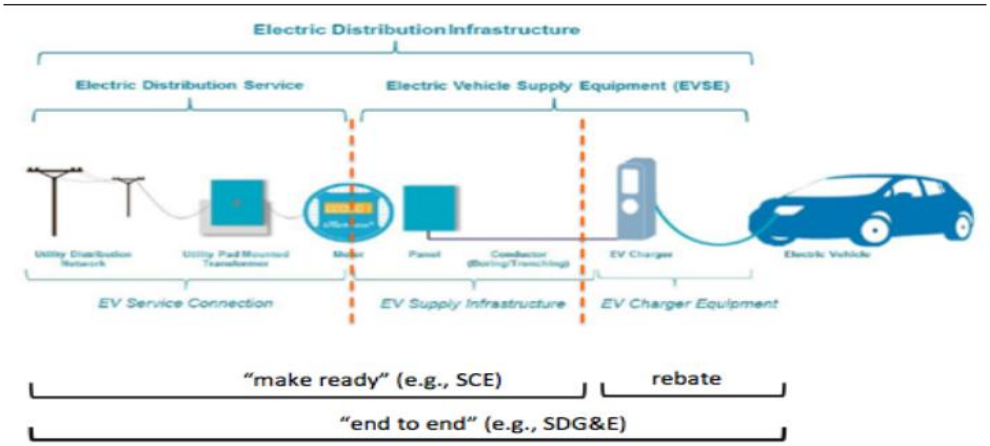
1. Include further study of impact of different capacity positions of utility on cost-effectiveness of rate design incentives;
2. Include further study or discussion of cost-based or policy-driven methods of establishing the relative size of the blocks in terms of level of kWh for each block, and in terms of $/kWh variability by block;

3. Include further study of hold-harmless provisions during implementation of any significant changes to rate design or presentation of significantly different rate design options.

VI. What is the Commission's role in promoting a competitive market for plug-in electric vehicles?

A. Summary of workshop and filed comments

The final session of the workshop was performed by Mr. Noah Garcia of NRDC. Mr. Garcia started the presentation with an explanation of the three models and addressed ownership, operations and maintenance of each type of electric vehicle charging station. As exhibited below, Mr. Garcia characterized these models as; make ready, rebate and end to end.



Mr. Garcia in his presentation made the following statements, including emphasis, with respect to what the Commission could do to promote a competitive market for plug-in electric vehicles:

> The Commission should recognize that *utility procurement of charging hardware and software can promote competition* among third-party charging service providers.
>
> The Commission should also recognize that *electricity pricing at charging stations may require regulatory oversight* due to unique characteristics of electric vehicle charging service markets.

Mr. Garcia also recommended that the Commission, Staff and stakeholders review the Illinois Citizens Utility Board, "ABCs of EVs, A Guide for Policy Makers and Consumer Advocates".[7]

The quote below was in Mr. Garcia's presentation.

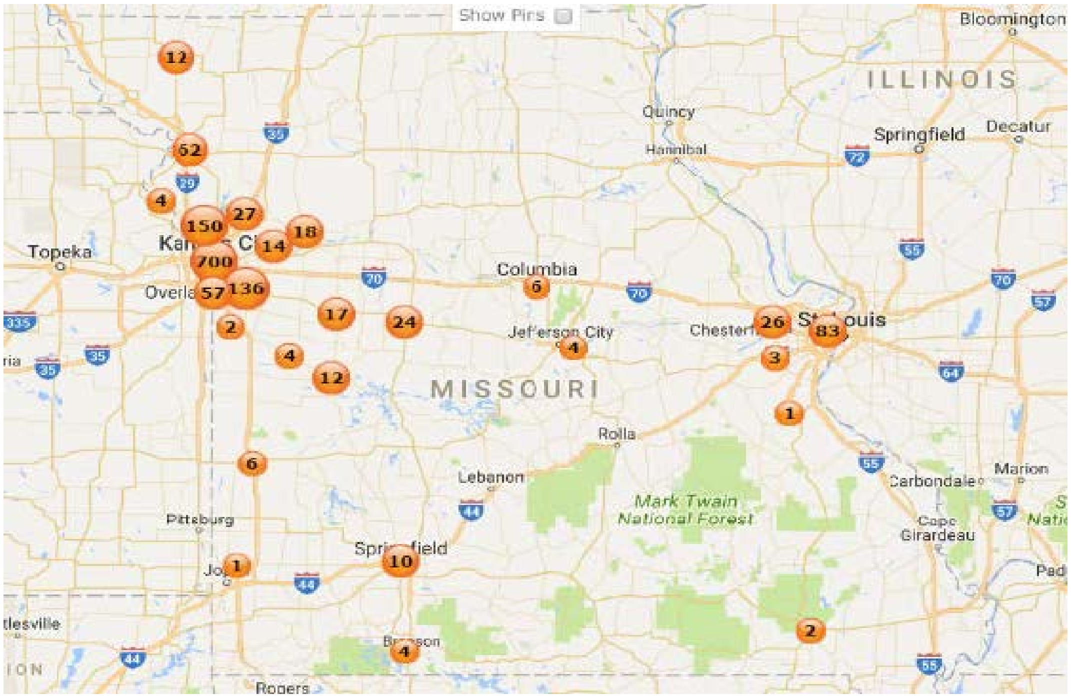
> The electrification of transportation presents a rare opportunity to achieve gains for all stakeholders affected by electricity regulatory policy. The right set of policies can help achieve the traditional regulatory goals — safe, reliable, and affordable service — while advancing new goals of sustainability, efficiency, and customer choice.

According to Mr. Garcia's presentation, the most significant impact the Commission can have in promoting a competitive market for plug-in electric vehicles is clarifying that public charging stations for electric vehicle are not considered the resale of electricity service, which would be a violation of Missouri law. According to Mr. Garcia, to achieve this, the Commission must direct the IOUs to revise their tariffs to allow for the resale of electricity from electric vehicle charging stations that are available to the public.

ChargePointComments

ChargePoint, Inc., ("ChargePoint") submitted written comments on April 30, 2017. ChargePoint has more than 34,000 Level 2 EV and DC fast charging ("DCFC") locations around the country, including 744 public and private stations in Missouri. A map of the charging locations is featured below:

[7] *See*: https://citizensutilityboard.org/wp-content/uploads/2017/04/2017_The-ABCs-of-EVs-Report.pdf



ChargePoint makes the following recommendations for the Commission to consider:

- Establish guidelines for a utility role in EV charging that supports innovation, competition, and customer choice in equipment and services.

- Ensure equitable access to the benefits of transportation electrification. Evaluate how smart, connected charging stations can be utilized to optimize grid benefits from EV charging; and,

- Consider alternative rate structures for fast and high-speed charging sites.

ChargePoint encourages the Commission to consider issuing guidelines to shape utility engagement similar to those approaches that have been taken in California, Oregon, Massachusetts, and New York.

ChargePoint suggests the Commission can incent smart and connected charging to provide the greatest benefits to the grid and enable more tools for grid management and reliability.

As EV adoption increases, load created by EV charging will impact the electrical grid. ChargePoint suggests it will be important for utilities to work with stakeholders and the

Commission to establish programs and rate structures that encourage off-peak charging through load management, demand response, and increase charging when it is most beneficial to the grid.

ChargePoint encourages consideration of residential EV- only ToU rates that leverage the embedded metrology within connected home EV charging stations, in lieu of adding a second utility meter to measure EV load. ChargePoint recommends that utilities establish pilots to gather data on how connected charging stations can be leveraged to allow residential customers in Missouri to subscribe to an EV-Only ToU rate while avoiding the additional costs of deploying new meters at every charging station.

Based on ChargePoint's comments, utilities use peak demand to properly size electrical facilities for their individual customers, guarantee adequate generating capacity is available for all customers, and ensure cost recovery. Demand charges to commercial customers are typically based on the highest average 15 minutes in a monthly billing cycle. Unfortunately, high-speed DC fast charging stations are currently characterized by having a low load factor with sporadic instances of very high energy use due to a limited, but growing number of vehicles in the market. This means that in the near term, site hosts face high demand charges, which could amount to hundreds of thousands of dollars annually, due to the few peak charging sessions that occur each month. The risk of high operating costs creates a barrier to EV infrastructure deployment, limiting EV adoption and grid benefits.

ChargePoint recommends that the Commission evaluate alternative rate structures for high energy use charging stations to capture costs. ChargePoint suggests several options to consider, that would still allow utilities to recover all costs, while at the same time encourage sites to operate fast chargers. Examples include:

- Demand charges could be replaced with or paired with higher volumetric pricing to provide greater certainty for charging station operators with low

> utilization. This rate could be scaled based on utilization or load factor as charging behavior changes over time with increased EV adoption.
>
> The bank of charging stations could be put on a separate meter in order to use a unique “EV charging” rate that is designed to reflect charging needs.
>
> A pilot rate could be developed specifically for fleet operators, particularly those that operate electric bus fleets that may charge overnight and provide time of use benefits to the grid.
>
> The utility could consider pricing signals to the station operator, such as time-of-use or critical peak pricing.
>
> Utilities should factor in the overall EV load from all vehicles in their service territory and that load’s benefit to the grid. With increased EV adoption, there will be increased load, which could lead to greater grid benefits in the future.[8]

Comments of the Sierra Club & NRDC

The Sierra Club and NRDC stated that the jurisdiction of the Commission, based on the origination statutes of the Commission, is limited as it relates to electric vehicle service equipment (“EVSE”).

The most fundamental issue is the question of the Commission’s jurisdiction over utility and non-utility owners or operators of EVSE. Similarly critical is establishing the standard of review for proposed utility investments in EVSE and/or supporting infrastructure. Sierra Club and NRDC offered examples from other states which have considered and resolved these two issues. See Attachment A for the suggested examples.

The Sierra Club and NRDC also suggest the Commission may need to consider and resolve a number of related and separate questions, ranging from whether the installation of EVSE is subject to permitting, regulation or standards under Missouri law, to the type of evidence needed for regulators to make EV policy decisions. According to the Sierra Club and

[8] Comments of ChargePoint. May 5, 2017.

NRDC, the full range of these issues is well summarized in the previously referenced report by the Citizens Utility Board of Illinois, entitled "The ABCS of EVs: A Guide for Policy Makers and Consumer Advocates." The Guide provides information on the potential impacts of EVs. The excerpt below is from the Executive Summary.

> An EV in the garage could increase the electricity consumption of an average household by 40%—and millions of them could require costly expansion of electric system delivery and generation capacity. But if EVs and EV infrastructure are managed as distributed energy resources, the rise of transportation electrification can lead to lower—not higher—electric rates for all consumers.

The Guide is intended to help policymakers forge local and regional strategies designed to capture the potential of EV growth to contribute to system optimization. The Guide identifies factors favoring EV market penetration; assesses its ramifications for the electric grid and the consumers who depend on it; advances a set of principles to protect the interests of electricity customers; describes proceedings and initiatives underway in a number of jurisdictions; and lays out options for state regulatory action.

The Office of the Public Council Comments

According to OPC, whenever competition is feasible, for all its imperfections, it is superior to regulation as a means of serving the public interest. OPC maintains its original position of supporting free market competition and believes that government intervention is not warranted and inhibits EV promotion. Both ratepayers and drivers are best served by a competitive market for charging services rather than a regulated monopoly. According to OPC, Missouri's electric investor-owned utilities' *regulated* services can best enable the promotion of EV adoption by offering well-formed, time-of-use (ToU) rates on an opt-in basis that encourages charging during low-cost, off-peak hours. At this initial stage, OPC states, this can best be promoted by educating customers and vehicle dealers on the value proposition of current and future rates.

The Division of Energy Comments

Based on the Commission's recent decisions, DE states that it is unclear how resale provisions apply to electric vehicle charging and how the Commission can play a role with regard to electric vehicle-specific rate designs, since Commission decisions as to these topics would cover "charging services" as opposed to electricity sales. DE, in its comments, expresses concerns that the Commission's decision not only limits future regulatory options, but could limit the electric vehicle charging market from becoming truly competitive.

B. Consumer protections for fair and reasonable rates/site host accountability/reliability

Due to the fact that the Commission determined it does not have jurisdiction over the EV charging station networks, consumers of electricity from EV charging stations will be dependent upon the IOUs to develop rates that are fair and reasonable.

Site host accountability and reliability is the responsibility of the owners of the charging stations. The IOUs that develop networks of EV charging stations will be fully responsible for the maintenance and operation of the charging stations. The site host will be required to sign a contract with the owner of the equipment (IOUs) and to maintain access to the charging station and inform the owner (IOUs) if there is a problem with the EV charging equipment.

C. Other States' Efforts to Develop EV Infrastructure

Xcel Energy Electric Vehicle Fee Structure

Pricing Plan Summary from the Xcel Energy tariff:

> Our special EV Rate plan makes it easy for owners of electric vehicles to save on charging costs. Customers who participate will get a reduced rate for the electricity they use to charge their vehicle during off-peak hours (between 9:00 p.m. and 9:00 a.m. on weekdays, or anytime on weekends and holidays).

Metering Set-Up	Monthly Charge	Off-Peak (9 p.m.–9 a.m., holidays & weekends)	On-Peak (9:00:01 a.m.–8:59:59 p.m.
EV Rate	Separate Meter for the EV Only $4.95	$0033/kWh	$014170/kWh other month $0.17564/kWh (June–Sept.)

> *Rates apply to single phase – secondary voltage use only. Rates are subject to resource and/or fuel adjustments, city fees and taxes where applicable. Rates may change upon PUC approval. Rates include the Variable Fuel Cost Charge. The average fuel cost for August 2014 through July 2015 was $0.02723.

The tariff is available for viewing in Attachment B.

An article titled *"How Leading Utilities are Embracing Electric Vehicles"* provides information Staff found relevant on the efforts of IOUs to develop ToU rates for EV charging. As of June, 2015, at least 28 utilities (see Attachment C) across the country offered special EV rates to their customers. In addition, over 200 utilities offer ToU rates to their residential customers, which could help to encourage off-peak charging of EVs.[9]

As discussed previously, ToU rates can be beneficial to utilities by increasing demand for electricity during off-peak hours when there is significant underutilized generating capacity. ToU rates can also be economically beneficial to EV owners who take advantage of less expensive electricity prices during off-peak hours. While switching from a gasoline vehicle to an EV has already been proven to result in reduced operating costs (even at only $2 per gallon of gas), the additional savings offered by ToU rates provides a small additional incentive to EV adoption.

[9] How Leading Utilities are Embracing Electric Vehicles, Mike Salisbury and Will Toor, February 2016, June 22, 2017. *See*: http://www.swenergy.org/data/sites/1/media/documents/publications/documents/How_Leading_Utilities_Are_Embracing_EVs_Feb-2016.pdf,

For example, customers at NV Energy and APS (both of which have special EV-specific ToU rates) can save $245 and $446 each year respectively by charging their vehicles during off-peak hours compared to using the regular residential rates. On the other hand, utilities that do not offer a ToU rate and also have tiered electricity pricing (the more you use, the more you pay) will create a mild financial disadvantage to EV owners. For example, customers of Xcel Energy in Colorado (which has tiered rates during summer months but does not offer a ToU or special rate) would pay an additional $46 annually to charge their EV, compared to the situation with a flat rate.[10]

An article in the Public Utilities Fortnightly online magazine titled, *Electric Vehicle Charging: Tariffs and Tradeoffs* from the March 2015 edition explains the need for tariffs that incent charging at specific times. The article examines various types of charging strategies and infrastructure available today and reports on the experienced gleaned from structures for EV charging now being offered at four different utilities in the southwest. The report's findings are summarized below:

- **ToU Pricing.** All utilities should have time-of-use electricity pricing available for EV owners;
- **High-Voltage Charging.** Availability of fast-charging options at high voltages will place significant new demand on the grid and should be subject to marginal cost pricing, including appropriate demand charges;
- **At-Home Charging.** Rates that incentivize at-home, off-peak charging (as compared to daytime charging, such as at place of employment) will remain essential - and to achieve this goal, public and commercial charging stations should similarly reflect ToU pricing in their user pricing;
- **First Steps.** To answer the "chicken/egg" problem (build infrastructure first, or wait for widespread EV acceptance?) The regulators should introduce both charging stations and rate structures together;

[10] Id.

- **EVs as Gen Resources.** Smart vehicle-to-grid technology, including direct load control capability, should be encouraged for charging stations with higher voltages;
- **Consumer Education.** Utilities should educate EV owners about options for ToU rate structures and why charging off-peak is economically and environmentally optimal.11

    i. Line extension tariffs

In the State of Missouri, the costs related to extension tariffs (Attachment D) are already being captured by the IOUs for full cost recovery of all cost associated with installation of the EV charging stations as authorized by state law and the Commission.

The line extension tariffs of IOUs set the parameters for the installation of infrastructure for IOUs and third party vendors for the connection of EV charging stations to the grid. The tariffs explain the cost anticipated for the connection of the charging stations to the grid. The cost includes estimated installed cost of any line extensions and/or modifications and enlargements of the IOU's distribution system, and will include the total cost of all labor and materials, easements, licenses, permits, cleared right-of-way and all other incidental costs, including indirect costs. The indirect costs will include, where applicable, the cost of engineering, supervision, inspection, insurance, payments for injury and damage awards, taxes, Allowance for Funds Used During Construction ("AFUDC"), legal and administrative and general expenses associated with the extension of the IOU's distribution system. The percentage used for indirect costs reflects the IOU's historical indirect cost experience. The IOU's distribution extension allowances and charges are based on normal, pre-construction and unobstructed conditions. Cost estimates relative to revenue guarantees or customer contributions are based on the conditions prevailing at the time the estimate is made.

[11] "Electric Vehicle Charging: Tariffs and Tradeoffs." *Fortnightly*. N.p., n.d. Web. 14 June 2017.

It is imperative to understand the requirements of the IOUs for extending the distribution system to the pedestal of the EV charging station. The "Make Ready Model" that the Commission inquired about consists of the extension of the distribution system up to the charging station pedestal. The demarcation point can be found at this position in the system.

A third party vendor would own the pedestal, meter and charging station itself. The IOU owns the portion of the distribution system up to the pedestal of the charging station; the point of demarcation.

The State of Colorado is serviced by two investor-owned utilities - Black Hills Energy and Public Service Company of Colorado, also known as Xcel Energy. The Public Service Company of Colorado Electrical Service Lateral Extension and Distribution Line Extension Tariff are presented as Attachment E.

D. <u>Additional workshops</u>

At this time, Staff does not recommend additional workshops specific to electric vehicle charging stations, but recommends the Commission include the EV issues in any modified rate design discussions.

VII. <u>Update on other states</u>

The online magazine, "Utility Dive", released an article on November 28, 2016 titled, "The Top 10 Utility Regulatory Commission Issues of 2016". The article illustrates the top efforts of various state Public Utility Commissions to modernize the grid and provide incentives to utilities in "the utility regulatory model" to encourage greater adoption of distributed resources, energy storage and EV infrastructure development. The article has been included as Attachment F for convenience. Listed below are the highlights of other state activities.

1. New York, Illinois and Ohio – Reforming the Energy Vision (Grid Modernization, DER Disincentives and Performance-Based regulation)
2. California – California Reforms (DER Disincentives and ToU)
3. Multiple States – Mergers and Acquisitions
4. Pennsylvania, Illinois, Colorado and Texas – Customer Access to Analytics
5. California, Colorado, Nevada and Arizona – Alternative Rate Designs
6. Arizona – Residential Demand Charges
7. Rhode Island, Minnesota and Massachusetts – Grid Modernization
8. California, Massachusetts and Texas - Energy Storage Mandates
9. California – Electric Vehicle Charging Stations
10. Multiple States – Renewable Portfolio Standards

The Colorado State University, Center for the New Energy Economy, State Policy Opportunity Tracker – "SPOT" for clean energy, provides policy profiles for each individual state. The website has a downloadable policy brief available as well as a Gap Analysis of vehicle charging infrastructure incentives for each state and a comprehensive spreadsheet of renewable energy policies[12]. The document is extensive showing the current policies in each individual state.

Current status of Minnesota's e21

The Great Plains Institute, a nonprofit organization, with the Center for Energy and Environment has published its Phase II report of the e21 Initiative. The e21 Initiative ("e21" stands for 21st Century Energy System) is a diverse and collaborative group of Minnesota leaders assembled to recommend ways to realign and update Minnesota utility regulation by:

> 1) Shifting away from a utility business model that provides customers few options (everyone gets the same grid electricity produced largely with coal, natural gas, or nuclear power at large central stations) toward one that offers customers more options in how and where their energy is produced and how and when they use it; and

[12] "SPOT." *The State Policy Opportunity Tracker (SPOT) for Clean Energy*. N.p., n.d. Web. 20 June 2017. See: https://spotforcleanenergy.org/

> 2) Shifting away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that rewards utilities for achieving an agreed-upon set of performance outcomes that the public and customers want (e.g., energy efficiency, reliability, affordability, emissions reductions, predictable rates, etc.).[13]

The e21 Phase I Report, concerning the plan for Phase II, stated that

> "e21 participants understood from the beginning of the project in February 2014 that evolving Minnesota's 100-year-old-plus regulatory framework would be neither simple nor fast. The initial recommendations outlined in this Phase I Report propose a new blueprint for regulating utilities in Minnesota. But as with any blueprint, the building still needs to be built. That is what e21's second phase will be about. Phase II begins the hard work of 'sweating the details' to place Minnesota on a predictable, step-wise path toward implementing e21's recommendations.[14]
>
> "In its second phase, the e21 Initiative expects to work with the Commission, Department, e21 stakeholders, and others to further develop the implementation strategies and details for Phase I recommendations and tackle issues raised in Phase I but not yet fully addressed by e21. Multi-interest stakeholder processes, such as e21, should be used in the near-term to work out the details of implementing the multi-year, performance-based regulatory framework recommended in this report, including but not limited to:
>
> 1. Identification of performance metrics that are quantifiable, verifiable, and align with e21 Principles and Outcomes;
> 2. The percentage of a utility's revenue that should be tied to achieving these performance metrics, and any penalties for failing to achieve them, or additional incentives for exceeding them;
> 3. Additional questions raised by the proposed Integrated Resource Analysis; and
> 4. The planning needed to identify grid modernization investments or new services that would facilitate achieving e21 Principles and Outcomes."[15]

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[13] Phase I e21 Report, page 1.
[14] Phase I e21 Report, page 23.
[15] Phase I e21 Report, page 23.

The Phase II report consists of a series of whitepapers that build on the recommendations established in Phase I of the initiative. The Institute prepared separate whitepapers for the areas of Performance-based Compensation, Integrated Systems Planning, and Grid Modernization. The complete Phase II summary with identified options and objectives for future action for each whitepaper area is presented as Attachment G.

As part of the workshop process, interested stakeholders were invited to submit information, including examples from other states, legal implications, and answers to various questions posed by Staff, by May 1, 2017. Several stakeholders submitted comments and participated in the May 18 workshop. Based on input received from the stakeholders, as delineated in the Executive Summary and throughout this Report, Staff provides recommendations for further actions.

VIII. ATTACHMENTS

Attachment A - State Decisions on EV

Attachment B - Excel EV Fee Structure

Attachment C - Special Rates for EV

Attachment D - Missouri IOU Tariffs

Attachment E - Colorado Line Ext Tariff

Attachment F - Top 10 State Regulatory Issues

Attachment G - e21

Sierra Club and NRDC Joint Comments Appendix A: State Examples of Jurisdictional Decision for EV Charging and Standards of Review for Utility Programs

State	New York
Decision	*Declaratory Ruling on Jurisdiction Over Publicly Available Electric Vehicle Charging Stations*, Case 13- E-0199, In the Matter of Electric Vehicle Policies (filed November 22, 2013), New York Public Service Commission (emphasis added).
Core statutory terms	"The term 'electric plant,' when used in this chapter, includes all real estate, fixtures and personal property operated, owned, used or to be used for or in connection with or to facilitate the generation, transmission, distribution, sale or furnishing of electricity for light, heat or power; !and any conduits, ducts or other devices, materials, apparatus or property for containing, holding or carrying conductors used or to be used for the transmission of electricity for light, heat or power."
	The term "electric corporation," when used in this chapter, includes every corporation, company, association, joint-stock association, partnership and person, their lessees, trustees or receivers appointed by any court whatsoever (other than a railroad or street railroad corporation generating electricity solely for railroad or street railroad purposes or for the use of its tenants and not for sale to others) owning, operating or managing any electric plant… .
Holding	"The Public Service Law does not provide the Commission with jurisdiction over (1) publicly available electric vehicle charging stations; (2) the owners or operators of such charging stations, so long as the owners or operators do not otherwise fall within the Public Service Law's (PSL) definition of "electric corporation;" or, (3) the transactions between the owners or operators of publicly available electric vehicle charging stations, which do not otherwise fall within the PSL's definition of "electric corporation," and members of the public."

State	Massachusetts
Decision	*Order on Department Jurisdiction Over Electric Vehicles, The Role of Distribution Companies in Electric Vehicle Charging and Other Matters*, DPU 13-182-A, Investigation by the Department of Public Utilities upon its own Motion into Electric Vehicles and Electric Vehicle Charging (filed August 4, 2014), Massachusetts Department of Public Utilities.
Core statutory terms	Chapter 164 defines "distribution company" in pertinent part as: "a company engaging in the distribution of electricity or owning, operating or controlling distribution facilities." Chapter 164 defines "electric company" in pertinent part as: "a corporation organized under the laws of the commonwealth for the purpose of making by means of water power, steam power or otherwise and for selling, transmitting, distributing, transmitting and selling, or distributing and selling, electricity within the commonwealth, or authorized by special act so to do….".
Holding	"An owner/operator of EVSE that provides EV charging service is not a distribution company or an electric company within the meaning of G.L. c. 164, § 1; an EVSE owner/operator is selling a service and not electricity within the meaning of G.L. c. 164; and the provision of EV charging service is not within the Department's jurisdiction under G.L. c. 164." "[D]istribution companies subject to the Department's jurisdiction may recover costs associated with ownership and operation of electric vehicle supply equipment only as provided herein."

State	California
Case	*Decision in Phase 1 On Whether a Corporation or Person That Sells Electric Vehicle Charging Services To the Public Is a Public Utility*, D.10-07-044 (filed July 29, 2010), California Public Utilities Commission.
Core statutory terms	“Electric plant” defined to include “all real estate, fixtures and personal property owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, or furnishing of electricity for light, heat, or power, and all conduits, ducts, or other devices, materials, apparatus, or property for containing, holding, or carrying conductors used or to be used for the transmission of electricity for light, heat, or power.” "Electrical corporation" defined to include “every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others.”
Holding	“We conclude that the legislature did not intend that this Commission regulate providers of electric vehicle charging services as public utilities pursuant to §§ 216 and 218.” “To the extent an investor-owned utility provides electric vehicle charging services, provision of such services will not affect the utility’s status as a public utility.”

Examples of Standards of Review for Proposed Utility Investments in Vehicle Charging Infrastructure

State	Massachusetts
Decision	*Order on Department Jurisdiction Over Electric Vehicles, The Role of Distribution Companies in Electric Vehicle Charging and Other Matters*, DPU 13-182-A, Investigation by the Department of Public Utilities upon its own Motion into Electric Vehicles and Electric Vehicle Charging (filed August 4, 2014), Massachusetts Department of Public Utilities.
Holding	“[T]he Department may grant cost recovery for distribution company EVSE ownership and operation in response to a company proposal. For Department approval and allowance of cost recovery, any proposal must: be in the public interest; meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market; and not hinder the development of the competitive EV charging market.” [Note: In January 2017, a nearly identical form of this standard was codified by the legislature].

State	California
Decision	*Phase 1 Decision Establishing Policy to Expand the Utilities’ Role in Development of Electric Vehicle Infrastructure*, D.14-12-079 (filed July 29), 2010), California Public Utilities Commission.
Holding	The Commission opted to evaluate future utility applications on a “case-specific basis,” using a balancing test to weigh the benefits of utility ownership of EV charging infrastructure against the competitive limitation that may result from

	that ownership. The Commission's "case-specific" evaluation of utility bids for participation would, at a minimum, evaluate: (1) the nature of the program (for instance, whether the utility proposed to own the EV service equipment); (2) the degree to which the market into which the utility program would enter is competitive, and at what level of concentration; (3) the identification of unfair utility advantages; and (4) if the potential for the utility to unfairly compete is identified, what conditions or regulatory protections may effectively mitigate those unfair advantages.! [Note: This test is applied in addition to the state's ratepayer interest test].

State	Oregon
Source	S.B. 1547 (2016)
Core statutory provisions	In reviewing utility proposals for programs and investments in vehicle charging infrastructure, the Commission is obliged to consider whether a given investmen will be: prudent; used and useful; reasonably expected to support the electric company's electrical system; reasonably expected to improve the electric company's system efficiency and operational flexibility, including integration of variable generating resources; and reasonably expected to stimulate innovation, competition and choice in the vehicle charging and services market.

Xcel Energy Electric Vehicle Fee Structure

PUBLIC SERVICE COMPANY OF COLORADO — COLO. PUC No. 8 Electric

P.O. Box 840 — First Revised Sheet No. 31

Cancels

Denver, CO 80201-0840 — Original Sheet No. 31

ELECTRIC RATES	RATE
RESIDENTIAL DEMAND SERVICE	
SCHEDULE RD	
APPLICABILITY Applicable to Residential Service at Secondary Voltage. Not applicable to Customers that own and operate generation connected in parallel with the Company's electric system that do not receive service under Net Metering Schedule NM of this Electric Tariff. Not applicable to Standby, Supplemental or Resale Service.	
AVAILABILITY Available to Customers receiving service under this rate schedule as of December 31, 2016, after which no new Customers shall be served under this rate schedule.	
MONTHLY RATE	
Service and Facility Charge:	$ 12.01
Production Meter Charge:	3.65
Load Meter Charge:	3.65
Demand Charge:	10.08
All Kilowatts of Billing Demand, per kW	7.76
Summer Season..	
Winter Season	0.01974
Energy Charge:	
All Kilowatt-Hours used, per kWh	
The Summer Season shall be from June 1 through September 30. The Winter Season shall be from October 1 through May 31.	
MONTHLY MINIMUM The Service and Facility Charge plus the Demand Charge plus the Production Meter Charge if applicable. Applicability for the Production Meter Charge can be	

found under the Net Metering Service Schedule.

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this Electric Tariff.

(Continued on Sheet No. 31A)

ADVICE LETTER NUMBER

1736

ISSUE DATE

February 21, 2017

DECISION/ PROCEEDING NUMBER

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE March 24, 2017

ELECTRIC RATES	RATE
RESIDENTIAL DEMAND SERVICE	

SCHEDULE RD

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fourteen (14) business days from date of bill. A business day for purposes under this Payment and Late Payment Charge section is all non-Holiday weekdays. Residential Customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of thirty (30) calendar days from the scheduled due date of the current bill. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive Months. A maximum late payment charge of one percent (1.0%) per Month shall be applied to all billed balances for Commission jurisdictional charges that are not paid by the billing date shown on the next bill unless the balance is fifty dollars ($50) or less.

The Company will remove the assessment of a late payment charge for one (1) billing period, but not more frequently than once in any twelve (12) Month period, at Customer's request. The late payment charge will not apply to a billed security deposit, or in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the Customer, or where a Customer is current on an active payment arrangement.

DETERMINATION OF BILLING DEMAND

Billing Demand, determined by meter measurement, shall be the maximum fifteen (15) minute integrated Kilowatt Demand used during the Month.

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve (12) consecutive Months and Monthly thereafter until terminated. If service is no longer required by Customer, service may be terminated on three (3) days' notice.

PRODUCTION METER INSTALLATION

The Company shall install, own, operate and maintain the metering to measure the electric power and energy supplied by the Customer's generation. For Customers who are net metered, the applicability of the Production Meter Charge can be found under the Net Metering Service Schedule.

LOAD METER INSTALLATION

The Company shall install, own, operate and maintain the metering to measure the electric power and energy supplied by the Customer's generation under this schedule and determine the full load obligations of the Customer. For Customers who are net metered, the applicability of the Load Meter Charge can be found under the Photovoltaic Service Schedule.

(Continued on Sheet No. 31B)

ADVICE LETTER NUMBER

1736

ISSUE DATE

February 21, 2017

DECISION/ PROCEEDING NUMBER

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE March 24, 2017

ELECTRIC RATES | RATE

RESIDENTIAL DEMAND SERVICE

SCHEDULE RD

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with the Commission and the following special condition:

1. Customers that own and operate generation connected in parallel with the Company's electric system that do not receive service under Net Metering Schedule NM of this Electric Tariff must take service under a buy-all, sell-all scenario where all power and energy used by the Customer shall be provided by the Company under a Residential Service rate schedule and all power and energy produced by the Customer's generation shall be separately metered and purchased by the Company under the terms and conditions set forth in the Small Power Production and Cogeneration Facility Policy in this Electric Tariff.

ADVICE LETTER NUMBER

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C16-1075

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE January 1, 2017

ELECTRIC RATES	RATE
RESIDENTIAL DEMAND-TIME DIFFERENTIATED RATES SERVICE	

SCHEDULE RD-TDR

APPLICABILITY

Applicable to Residential Service at Secondary Voltage. Applicable to Supplemental Service. Not applicable to Standby or Resale Service.

AVAILABILITY

In 2017, service under this rate schedule shall be limited to the first 10,000 Residential Customers electing to receive service. This total participation cap will increase to 14,000 Residential Customers in 2018 and 18,000 Residential Customers in 2019. Upon notification by a Customer that Customer is requesting service, the Company will install the proper Service Meter to allow the Company to measure service hereunder. The Company shall install a Service Meter and begin billing service hereunder within sixty (60) days of the Customer's request or sooner if practicable. As set forth in the General Definition Section of the electric tariff, Customers taking Service under this Schedule and under Schedule Net Metering (Schedule NM) will not be subject to the requirements of Supplemental Service. Service under this schedule is available until January 1, 2022.

MONTHLY RATE

Service and Facility Charge:	$ 5.39
Production Meter Charge:	1.15
Demand Charge:	
All Kilowatts of Billing Demand, per kW	
Distribution Demand:	3.65
Generation and Transmission Demand - Summer Season............	9.73
Generation and Transmission Demand - Winter Season	6.81

DEFINITION OF

SEASONS Summer Season

The Summer Season shall be from June 1 through September 30.

Winter Season The Winter Season shall be from October 1 through May 31. (Continued on Sheet No. 32A)	

ADVICE LETTER NUMBER

1739

ISSUE DATE

March 30, 2017

DECISION/ PROCEEDING NUMBER

C17-0248

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE April 1, 2017

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ELECTRIC RATES	RATE
RESIDENTIAL DEMAND-TIME DIFFERENTIATED RATES SERVICE	

SCHEDULE RD-

TDR MONTHLY RATE – Cont'd

Energy Charge:
All Kilowatt-Hours used, per kWh .... $ 0.00461

MONTHLY MINIMUM

The Monthly minimum shall be the Service and Facility Charge, plus the Demand Charges, plus the Production Meter Charge if applicable.

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this Electric Tariff. Customer's shall be billed the Residential Time-of-Use Electric Commodity Adjustment (ECA).

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fourteen (14) business days from date of bill. A business day for purposes under this Payment and Late Payment Charge section is all non-Holiday weekdays. Residential Customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of thirty (30) calendar days from the scheduled due date of the current bill. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive Months. A maximum late payment charge of one percent (1.0%) per Month shall be applied to all billed balances for Commission jurisdictional charges that are not paid by the billing date shown on the next bill unless the balance is fifty dollars ($50) or less.

(Continued on Sheet No. 32B)

ADVICE LETTER NUMBER

1731

ISSUE DATE

December 8, 2016

DECISION/ PROCEEDING NUMBER

C16-1075

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE
EFFECTIVE January 1, 2017

ELECTRIC RATES	RATE

RESIDENTIAL DEMAND-TIME DIFFERENTIATED RATES SERVICE

SCHEDULE RD-TDR

PAYMENT AND LATE PAYMENT CHARGE – Cont'd

The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve (12) Month period, at Customer's request. The late payment charge will not apply: to a Low Income Customer for two (2) billing cycles so that credits for hold-harmless protections can be applied, to a billed security deposit, in instances where a Company billing error is involved, where complications arise with financial institutions in processing payments that are no fault of the Customer, or where a Customer is current on an active payment arrangement.

DETERMINATION OF BILLING DEMAND

Billing Demand, determined by meter measurement, shall be the maximum sixty (60) minute integrated Measured Demand used during the Month.

Billing Demand for the Generation and Transmission Demand Charge shall be the Measured Demand used between 2:00 p.m. and 6:00 p.m. Mountain Time on all non-Holiday weekdays.

Billing Demand for the Distribution Demand Charge, shall be the Measured Demand used during the Month.

For Supplemental Service, Billing Demand for the Generation and Transmission Demand Charge shall be the Measured Demand used during the Month between 2:00 p.m. and 6:00 p.m. Mountain Time on all non-Holiday weekdays net of the Customer's generation.

For Supplemental Service, Billing Demand for the Distribution Demand Charge shall be the Measured Demand used during the Month net of the Customer's generation.

SERVICE PERIOD

After an initial grace period in which the Customer may opt out of RD-TDR Service prior to the end of the seventh billing cycle, all service under this schedule shall be for a minimum period of twelve (12) consecutive Months and Monthly thereafter until terminated. If service is no longer required by Customer, service may be terminated on three (3) days' notice.

(Continued on Sheet No. 32C)

ADVICE LETTER NUMBER

1731

ISSUE DATE

December 8, 2016

DECISION/ PROCEEDING NUMBER

C16-1075

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE January 1, 2017

ELECTRIC RATES	RATE
RESIDENTIAL DEMAND-TIME DIFFERENTIATED RATES SERVICE	
SCHEDULE RD-TDR	

LOW INCOME PROVISION

Low Income Customers will be held harmless, such that a Low Income Customer will pay the lower of the Customer's monthly bill on Schedule R or Schedule RD-TDR. The Company will implement this protection by either charging the Customer the lower of the two bills under Schedule R or Schedule RD-TDR or by billing the Customer under Schedule RD-TDR and crediting the Customer for any bill savings that would have resulted from the application of Schedule R on the Customer's subsequent bill.

PRODUCTION METER INSTALLATION

The Company shall install, own, operate and maintain the metering to measure the electric power and energy supplied by the Customer's generation to allow for proper billing of the Customer under this schedule. For Customers who are net metered, the applicability for the Production Meter Charge can be found under the Net Metering Service Schedule.

PURCHASE OF CUSTOMER'S EXCESS ENERGY

If a Customer receiving Supplemental Service produces energy exceeding the energy used by the Customer's facility during any Monthly billing period, the energy shall be purchased by the Company either under a Power Purchase Agreement between the Company and the Customer, or at the Energy Charge under this schedule.

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with the Commission.

ADVICE LETTER NUMBER

1731

ISSUE DATE

December 8, 2016

DECISION/ PROCEEDING NUMBER

C16-1075

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE January 1, 2017

ELECTRIC RATES	RATE
RESIDENTIAL ENERGY TIME-OF-USE SERVICE	

SCHEDULE RE-TOU

APPLICABILITY

Applicable to Residential Service at Secondary Voltage. Not applicable to Supplemental, Standby or Resale Service.

AVAILABILITY

Required for any Customer on Schedule R whose meter is switched such that the Customer's energy use can be metered on a time-of-use basis. The meter switch may take place for one of two reasons, either the Customer voluntarily participates in Schedule RE-TOU or the Customer's meter is exchanged and upgraded through an approved meter roll-out. Any Customer whose service is transferred from Schedule R to Schedule RE-TOU as a result of meeting this condition will be notified of the transfer before the first billing to the Customer under Schedule RE-TOU.

In 2017, service under this rate schedule shall be limited to the first 10,000 Residential Customers electing to receive service. This total participation cap will increase to 20,000 Residential Customers in 2018 and 30,000 Residential Customers in 2019. Upon notification by a Customer that Customer is requesting service, the Company will install the proper Service Meter to allow the Company to measure service hereunder. The Company shall install a Service Meter and begin billing service hereunder within sixty (60) days of the Customer's request or sooner if practicable.

MONTHLY RATES

	RATE
Service and Facility Charge:	$ 5.39
Production Meter Charge:	1.15
Energy Charge:	
Summer:	
On-peak Energy Charge, all Kilowatt-Hours used during the Summer On-Peak Period, per kWh	0.13814

Shoulder Energy Charge, all Kilowatt-Hours used during the Summer Shoulder Period, per kWh..	0.08420
Off-Peak Energy Charge, all Kilowatt-Hours used during the Summer Off-Peak Period, per kWh	0.04440
(Continued on Sheet No. 33A)	

ADVICE LETTER NUMBER

1739

ISSUE DATE

March 30, 2017

DECISION/ PROCEEDING NUMBER

C17-0248

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE April 1, 2017

ELECTRIC RATES	RATE
RESIDENTIAL ENERGY TIME-OF-USE SERVICE	
SCHEDULE RE-	
TOU MONTHLY RATE – Cont'd	
Winter:	
On-peak Energy Charge, all Kilowatt-Hours used during the Winter On-Peak Period, per kWh	$ 0.08880
Shoulder Energy Charge, all Kilowatt-Hours used during the Winter Shoulder Period, per kWh	0.05413
Off-Peak Energy Charge, all Kilowatt-Hours used during the Winter Off-Peak Period, per kWh	0.04440
DEFINITION OF SEASONS Summer Season	
The Summer Season shall be from June 1 through September 30.	
Winter Season	
The Winter Season shall be from October 1 through May 31.	
DEFINITION OF BILLING PERIODS	
The Summer and Winter On-Peak, Shoulder and Off-Peak Periods applicable for service hereunder shall be as follows:	
On-Peak Period:	
Summer and Winter weekdays except Holidays, between 2:00 p.m. and 6:00 p.m. Mountain Time.	
Shoulder Period:	
Summer and Winter weekdays except Holidays, between 9:00 a.m. and 2:00 p.m. and between 6:00 p.m. and 9:00 p.m. Mountain Time.	
Summer and Winter weekends and Holidays, between 9:00 a.m. and 9:00 p.m. Mountain Time.	

Off-Peak Period:

Summer and Winter daily, between 9:00 p.m. and 9:00 a.m. Mountain Time.

MONTHLY MINIMUM

The Monthly minimum shall be the Service and Facility Charge, plus the Production Meter Charge if applicable.

(Continued on Sheet No. 33B)

ADVICE LETTER NUMBER

1731

ISSUE DATE

December 8, 2016

DECISION/ PROCEEDING NUMBER

C16-1075

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE January 1, 2017

ELECTRIC RATES	RATE
RESIDENTIAL ENERGY TIME-OF-USE SERVICE	

SCHEDULE RE-TOU

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this Electric Tariff. Customer's shall be billed the Time-of-Use Electric Commodity Adjustment (ECA) for Secondary Voltage, RE-TOU.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fourteen (14) business days from date of bill. A business day for purposes under this Payment and Late Payment Charge section is all non-Holiday weekdays. Residential Customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of thirty (30) calendar days from the scheduled due date of the current bill. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive Months. A maximum late payment charge of one percent (1.0%) per Month shall be applied to all billed balances for Commission jurisdictional charges that are not paid by the billing date shown on the next bill unless the balance is fifty dollars ($50) or less.

The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve (12) Month period, at Customer's request. The late payment charge will not apply: to a Low Income Customer for two (2) billing cycles so that credits for hold-harmless protections can be applied, to a billed security deposit, in instances where a Company billing error is involved, where complications arise with financial institutions in processing payments that are no fault of the Customer, or where a Customer is current on an active payment arrangement.

SERVICE PERIOD

After an initial grace period in which the Customer may opt out of RE-TOU Service prior to the end of the seventh billing cycle, service under this schedule shall be for a minimum period of twelve (12) consecutive Months and Monthly thereafter until terminated. If service is no longer required by Customer, service may be terminated on three (3) days' notice.

Early Adopter Provision An "Early Adopter" is any Customer that meets the Availability requirements of this Schedule RE-TOU prior to the Commission's Decision on an Advice Letter regarding the analysis of the impact of Schedule RE-TOU, which is expected to be filed in December 2019. The Early Adopter period will end at the time the Commission issues a Decision on the Advice Letter. Prior to the end of the seventh billing cycle of becoming an Early Adopter, Customers may opt-out of Schedule RE-TOU by notifying the Company and receive service under Schedule R. Customers electing to opt-out after their meter is exchanged through an approved meter roll-out, but before the end of the Early Adoption period will continue to pay the RE-TOU Service and Facility Charge, with the exception of LEAP participants.	

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January 1, 2017

ELECTRIC RATES | RATE

RESIDENTIAL ENERGY TIME-OF-USE SERVICE

SCHEDULE RE-

TOU SERVICE PERIOD – Cont'd

Early Adopter Provision – Cont'd

Upon notification by the Customer, this change will be effective at the beginning of the Customer's next billing cycle if practical, but no later than the beginning of the billing cycle following the next billing cycle.

LOW INCOME EARLY ADOPTER PROVISION

Low Income Early Adopters will be held harmless, such that a Low Income Customer will pay the lower of the Customer's monthly bill on Schedule R or Schedule RE-TOU. The Company will implement this protection by either charging the Customer the lower of the two bills under Schedule R or Schedule RE-TOU or by billing the Customer under Schedule RE-TOU and crediting the Customer for any bill savings that would have resulted from the application of Schedule R on the Customer's subsequent bill.

PRODUCTION METER INSTALLATION

The Company shall install, own, operate and maintain the metering to measure the electric power and energy supplied by the Customer's generation to allow for proper billing of the Customer under this schedule. Applicability for the Production Meter Charge can be found under the Net Metering Service Schedule.

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with the Commission.

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REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

DATE EFFECTIVE January 1, 2017

UTILITIES OFFERING SPECIAL RATES FOR EV OWNERS[1]

Utility	State
Alabama Power	AL
Arizona Public Service (APS)	AZ
Salt River Project (SRP)	AZ
Tucson Electric Power (TEP)	AZ
Los Angeles Department of Water and Power (LADWP)	CA
Pacific Gas and Electric (PG&E)	CA
Sacramento Municipal Utility District	CA
San Diego Gas and Electric (SDG&E)	CA
Southern California Edison (SCE)	CA
Georgia Power	GA
Hawaiian Electric Companies (HECO)	HI
Indiana Michigan Power	IN
Indianapolis Power and Light (IPL)	IN
Northern Indiana Public Service Company (NIPSCO)	IN
Louisville Gas & Electric (LG&E)	KY
Baltimore Gas & Electric (BGE)	MD
Pepco	MD
Consumers Energy	MI
DTE Energy	MI
Lansing Board of Water and Light (BWL)	MI
Connexus Energy	MN
Dakota Electric	MN
Xcel Energy	MN
Wright Hennepin Cooperative Electric Association (WH)	MN
NV Energy	NV
ConEdison	NY
York Electric Co-op (YEC)	SC
Dominion Virginia Power	VA

[1] Southwest Energy Efficiency Project, Alternative Fuels Data Center. 2015. State Laws and Incentives, *How Leading Utilities Are Embracing Electric Vehicles*, http://www.afdc.energy.gov/laws/state, Page 29.

Missouri Investor Owned Utility Line Extension Tariffs Excerpts

Ameren Missouri Tariff: Sheet No. 112 - General Rules and Regulations, III. Distribution Systems Extensions (Cont'd)

D. DISTRIBUTION EXTENSION COST

The estimated installed cost of any line extensions and/or modifications and enlargements of the Company's distribution system will include the total cost of all labor and materials, easements, licenses, permits, cleared right-of-way and all other incidental costs, including indirect costs. The indirect costs will include, where applicable, the cost of engineering, supervision, inspection, insurance, payments for injury and damage awards, taxes, AFUDC (Allowance for Funds Used During Construction), legal and administrative and general expenses associated with the extension of the Company's distribution system. The percentage used for indirect costs reflects the Company's historical indirect cost experience. The Company's distribution extension allowances and charges are based on normal, pre-construction and unobstructed conditions. Cost estimates relative to revenue guarantees or customer contributions are based on the conditions prevailing at the time the estimate is made. Additional costs due to changes in surface conditions or unanticipated subsurface conditions will be charged to the customer. Company may install a distribution extension of greater length or capacity than initially required for the customer requesting service, due to general engineering, operating, or economic reasons, in which case the additional cost of such increases in distribution system length or capacity shall not be included in the cost of the extension applicable to customer.

A copy of the Company's estimated extension charges, including indirect costs, shall be furnished to the customer upon request prior to construction.

E. OVERHEAD EXTENSIONS TO INDIVIDUAL RESIDENTIAL CUSTOMERS

Company will provide, at no cost, single-phase overhead electric service consisting of a meter, service drop, transformation capacity and up to 1,000 feet of additional distribution facilities, as required, no more than 500 feet of which shall be extended on private property, to the premises of an individual residential customer not located within a residential subdivision.

The portion of any distribution extension applicable to customer in excess of the aforementioned allowance shall be paid for by customer, in advance of construction, at the Company's then current standard construction cost per foot of single phase overhead extensions. Alternatively, at customer's option, Company will provide any distribution facilities in addition to the meter, overhead service drop and transformation capacity referred to above, at no cost to customer provided the annual net revenue estimated to be received by Company from the extension equals or exceeds the installed cost of such additional distribution facilities, estimated at the Company's then current standard construction cost per foot of single phase overhead extensions. Where the annual net revenue estimated to be received by Company is less than the estimated extension cost applicable to customer, said cost in excess of annual net revenue shall be paid by customer to Company in advance of construction.

Ameren Missouri: Sheet No. 114 – III Distribution System Extension (Cont'd)

G. OVERHEAD EXTENSIONS TO NON-RESIDENTIAL CUSTOMERS

Company will provide an overhead distribution extension to individual nonresidential premises at no cost to customer provided the annual net revenue estimated to be received by Company from the distribution extension equals or exceeds the estimated installed cost of the portion of required extension applicable to customer. Where the annual net revenue estimated to be received by Company is less than the estimated extension cost or, in Company's opinion, customer's revenues cannot be accurately projected, or where customer credit standing acceptable to Company cannot be established, customer or other responsible party will be required to enter into a guarantee agreement with Company, as referred to in Section III.P, herein, prior to the commencement of construction by Company.

Ameren Missouri: Sheet No 121 – III Distribution System Extensions (Cont'),

K. Underground Extension (Cont'd)

4. Non-Residential Extensions

a. Application

Where an underground extension is requested by a non-residential customer or required by law, Company will first estimate the cost of equivalent overhead extension and the Company's rules for overhead extensions to individual non-residential customers, Section III.G, shall apply. The underground distribution facilities will be provided at Company's sole discretion following the payment by customer of the Company's estimated excess cost of the underground extension over the cost of an equivalent overhead extension.

Ameren Missouri: Sheet No 122 – III Distribution System Extensions (Cont'),

K. UNDERGROUND EXTENSIONS (Cont'd.)

4. Non-Residential Extensions (Cont'd.)

b. Point of Delivery of Service

Company will designate to customer the point of delivery of the required electric service and customer shall be responsible for the installation, maintenance, replacement, enlargement or relocation of all underground electric service facilities, other than metering, to the Company's designated delivery point.

c. Specifications

Customer will install, maintain, replace, enlarge, or relocate all underground conduit, foundations, manholes, service boxes, transformer pads, switchgear pads, and other surface and sub-surface structures to meet Company specifications which are necessary to contain and/or support Company's electrical primary and secondary cables and equipment within the boundaries of the development. Maintenance, replacement, enlargement, or relocation of such facilities will be done by the Company at the customer's expense once they contain or support energized cables or equipment. Company will provide standard switchgear pads and transformer pads to customer for installation in order to maintain uniformity and quality control of these items. Customer is to provide Company open access to said facilities, and when necessary, remove obstructions, improvements, decorative structures, etc., when Company requires such access for maintenance, replacement, enlargement, etc. When Company requests additional conduits or larger structures for facilities that will serve customers beyond the boundaries of the development, Company will pay the incremental or extra cost of those additional facilities.

L. EXTENSIONS REQUESTED IN ADVANCE OF PERMANENT SERVICE

Where customer requests Company to complete all or a portion of an extension in advance of when said installation is required to provide permanent electric service, and Company agrees to do so, customer shall pay for such advancement of facilities at the monthly rate of 2.0% of the estimated installed cost of the extension being advanced. Such payments shall be non-refundable and shall continue until the permanent metering for the premises is installed by Company and utilized to provide permanent service thereto.

Kansas City Power and Light Company Tariff

Sheet No. 1.14
Rules and Regulation Electric

3. Supplying Electric Service (continued)

3.18 ELECTRIC VEHICLE CHARGING STATIONS: The sale or furnishing of electric vehicle charging services by a customer of the Company to a third party does not constitute the resale of electricity.

Sheet No. 1.30A
Rules and Regulation Electric

9. Extension of Electric Facilities (continued)

9.02 Definition of Terms (Continued)

(D). Construction Charges: That portion of the Distribution Extension’s construction costs for which the Applicant is responsible. The Electric Service Standards and the provisions in this extension policy specify which segments of service shall be furnished by Applicant and which segments are provided by Company at cost to Applicant. These charges may consist of the following components:

1. Nonrefundable charges represent the portion of Construction Charges which are not supported by the expected revenue stream or for non-standard costs associated with the Distribution Extension and will not be reimbursable to Applicant. (Exception: Non-standard costs for Excess Facilities may be recovered on a surcharge basis as mutually agreed to by Applicant and Company and specified in the Facilities Extension Agreement.)

2. Refundable charges represent the portion of Construction Charges that may be reimbursed to the Applicant during the Open Extension Period, dependent upon the Applicant's requisite performance as outlined in the Facilities Extension Agreement.

(E). Distribution Extension: Distribution facilities including primary and secondary distribution lines, transformers, service laterals and all appurtenant facilities and meter installation facilities installed by Company.

(F). Electric Service Standards: Company's Electric Service Standards available upon request to any Applicant, defines Company's uniform standards and requirements for installation, wiring and system design.

(G). Estimated Construction Costs: The Estimated Construction Costs shall be the necessary cost of the Distribution Extension and shall include the cost of all materials, labor, rights-of-way, trench and backfill, together with all incidental underground and overhead expenses connected therewith. Where special items, not incorporated in the Electric Service Standards, are required to meet construction conditions, the cost thereof shall also be included as a non-standard cost.

Sheet No. 1.30 Rules and Regulations Electric
9. EXTENSION OF ELECTRIC FACILITIES (continued)

SECTIONS 9.01 THROUGH 9.11 SHALL BE APPLICABLE TO FACILITY EXTENSION AGREEMENTS EXECUTED ON AND AFTER JANUARY 1, 2018.

SECTIONS 9.12 THROUGH 9.14 SHALL BE APPLICABLE TO FACILITY EXTENSION AGREEMENTS EXECUTED BEFORE JANUARY 1, 2018.

ANY PROVISIONS OF THE FACILITY EXTENSION AGREEMENT, EXECUTED BEFORE JANUARY 1, 2018, SHALL REMAIN IN EFFECT IF THEY CARRY OVER INTO THE NEW POLICY PERIOD.

9.01 Purpose

The purpose of this policy is to set forth the service connection and distribution system extension requirements when one (1) or more applicants request overhead or underground electric service at premises not connected to Company's distribution system or request an alteration in service to premises already connected where such change necessitates additional investment.

Sheet No. 1.30

9.02 Definition of Terms

(A). Applicant: The developer, builder, or other person, partnership, association, firm, private or public corporation, trust, estate, political subdivision, governmental agency or other legal entity recognized by law applying for the construction of an electric Distribution Extension, Extension Upgrade, or Relocation.

(B). Basic Extension Request: A request by Applicant for a Distribution Extension for which Company specified facilities are provided free of charge to the Applicant.

(C).Construction Allowance: The cost of that portion of the Distribution Extension which is for economically justifiable and necessary construction and which is made by Company. The formula used to determine the appropriate Construction Allowance will be based on Company's feasibility model. Generally, the formula used by the feasibility model is the Estimated Margin divided by the Fixed Carrying Cost percentage as measured over the first five (5) year life of the Distribution Extension.

$$CA = \frac{\text{SUM } (EM1 + EM2 + EM3 + EM4 + EM5)}{\text{SUM } (FCC1 + FCC2 + FCC3 + FCC4 + FCC5)}$$

Where, CA = Construction Allowance;
EM = Estimated Margin;
FCC = Fixed Carrying Cost;

Sheet No. 1.30A

9. EXTENSION OF ELECTRIC FACILITIES (continued)

9.02 Definition of Terms (Continued)

(D). Construction Charges: That portion of the Distribution Extension's construction costs for which the Applicant is responsible. The Electric Service Standards and the provisions in this extension policy specify which segments of service shall be furnished by Applicant and which segments are provided by Company at cost to Applicant. These charges may consist of the following components:

1. Nonrefundable charges represent the portion of Construction Charges which are not supported by the expected revenue stream or for non-standard costs associated with the Distribution Extension and will not be reimbursable to Applicant. (Exception: Non-standard costs for Excess Facilities may be recovered on a surcharge basis as mutually agreed to by Applicant and Company and specified in the Facilities Extension Agreement.)
2. Refundable charges represent the portion of Construction Charges that may be reimbursed to the Applicant during the Open Extension Period, dependent upon the Applicant's requisite performance as outlined in the Facilities Extension Agreement.

(E). Distribution Extension: Distribution facilities including primary and secondary distribution lines, transformers, service laterals and all appurtenant facilities and meter installation facilities installed by Company.
(F). Electric Service Standards: Company's Electric Service Standards available upon request to any Applicant, defines Company's uniform standards and requirements for installation, wiring and system design.
(G). Estimated Construction Costs: The Estimated Construction Costs shall be the necessary cost of the Distribution Extension and shall include the cost of all materials, labor, rights-of-way, trench and backfill, together with all incidental underground and overhead expenses connected therewith. Where special items, not incorporated in the Electric Service Standards, are required to meet construction conditions, the cost thereof shall also be included as a non-standard cost.
(H). Estimated Margin: The Estimated Margin will be determined by first multiplying the effective rates for each customer class by the estimated incremental usage – and then subtracting 1) applicable margin allocation for network and infrastructure support costs; and 2) incremental power and energy supply costs.
(I). Extension Completion Date: The date on which the construction of a Distribution Extension, Extension Upgrade or Relocation is completed as shown by Company records.

Sheet No 1.30B
9. EXTENSION OF ELECTRIC FACILITIES (continued)
9.02 Definition of Terms (Continued)
(J). Extension Upgrade: The increase in capacity of existing electric distribution facilities necessitated by Applicant's estimated electric requirements and for which Company determines that such facilities can be reasonably installed.
(K). Facilities Extension Agreement: Written agreement between Applicant and Company setting out the contractual provisions of Construction Allowance, Construction Charges, payment arrangements, the Open Extension Period, etc. in accordance with this extension policy.
(L). Fixed Carrying Cost: Company's cost of capital to provide the requisite return on its investment as well as the costs for depreciation, property taxes and property insurance.
(M). Indeterminate Service: Service that is of an indefinite or indeterminate nature where the amount and permanency of service cannot be reasonably assured in order to predict the revenue stream from Applicant. For purposes of uniform application, "Indeterminate Service" may include such service as may be required for the speculative development of property, mobile buildings, mines, quarries, oil or gas wells, sand pits and other ventures that may reasonably be deemed to be speculative in nature.
(N). Open Extension Period: The period of time, five (5) years, during which Company shall calculate and pay refunds of Construction Charges according to the provisions of this extension policy. The five (5) year period begins on the Extension Completion Date.

(O). Permanent Service: Overhead or underground electric line extensions for primary or secondary service where the use of service is to be permanent and where a continuous return to Company of sufficient revenue to support the necessary investment is reasonably assured.
(P). Temporary Service: Any service that is of a known temporary nature, excluding service for temporary meter sets, and shall not be continued for a period longer than twelve (12) months.

Sheet No. 1.30C

9. EXTENSION OF ELECTRIC FACILITIES (continued)

9.03 General Provisions

(A). Company at its sole discretion, after consideration of Applicant's electric requirements, will designate the class of service requested as Permanent, Indeterminate or Temporary in accordance with the definitions set forth herein.
(B). The determination of facility type and routing will be made by Company to be consistent with the characteristics of an Applicant's requirements and for the territory in which service is to be rendered and the nature of Company's existing facilities in the area.
(C). The facilities provided will be constructed to conform to the Electric Service Standards. Except as otherwise provided (Section 9.09 Excess Facilities), the type of construction required to serve the Applicant appropriately will be determined by Company.
(D). Facilities Extension Agreements will be based upon Company's Estimated Construction Cost for providing the facilities necessary to supply the service requested by Applicant. Company shall exercise due diligence with respect to providing the estimate of total costs to the customer. If it is necessary or desirable to use private, public and/or government rights-of-way to furnish service, Applicant may, at Company's discretion, be required to pay the cost of providing such rights-of way.
All Distribution Extensions, with the exception of service conduits, provided wholly, or in part, at the expense of an Applicant shall become the property of Company once approved and accepted by Company.
(E). Company shall construct, own, operate and maintain new overhead and/or underground feeder lines, service lines and related distribution system facilities only on or along public streets, roads and highways which Company has the legal right to occupy, and on or along private property across which right-of-ways and easements satisfactory to Company have been received.
(F). Rights-of-way and easements which are satisfactory to Company including those as may be required for street lighting, must be furnished by the Applicant in reasonable time to meet construction and service requirements and before Company shall be required to commence its installation; such rights of-way and easements must be cleared of trees, tree stumps, and other obstructions, and graded to within six (6) inches of final grade by Applicant at no charge to Company. Such clearance and grading must be maintained by the Applicant during construction by Company. If the grade is changed subsequent to construction of the distribution system in such a way as to require relocation of any of the electric facilities, the estimated cost of such

relocation shall be paid by the Applicant or its successors as a non-refundable Construction Charge.

Sheet No. 1.32A

10. UNDERGROUND DISTRIBUTION POLICY

SECTION 10 IS APPLICABLE ONLY TO FACILITY EXTENSION AGREEMENTS EXECUTED BEFORE JANUARY 1, 2018

SECTIONS 9.12 THROUGH 9.14 SHALL BE APPLICABLE TO FACILITY EXTENSION AGREEMENTS EXECUTED BEFORE JANUARY 1, 2018, ANY AGREEMENT EXECUTED AFTER JANUARY 1, 2018 SHALL BE GOVERNED BY SECTIONS 9.01 THROUGH 9.11.

NO AGREEMENT EXECUTED AFTER THE EFFECTIVE DATE OF THIS SHEET THROUGH JANUARY 1, 2018 MAY HAVE A TERM TO EXCEED JUNE 9, 2022.

10.01 UNDERGROUND SERVICE CONDUCTORS:

All costs of the Company referenced in the following extension policy shall include applicable material and labor costs including allocation of indirect costs. Indirect costs are comprised of supervision, engineering, transportation, material handling and administrative cost functions that support actual construction. The amount of the allocation of indirect costs is derived by application of unit costs or allocation percentages, determined from historical experience. A copy of the Company's estimate of the cost of construction including direct and indirect costs shall be furnished to the customer upon request prior to construction.

(a) In any area where the Company's existing primary and secondary distribution facilities are of underground construction, only underground service conductors to Commercial and Industrial Customer installations will be permitted.

(i) If the Company's transformer is on the Commercial or Industrial Customer's premise or at his property line, the Commercial or Industrial Customer shall furnish, install and own the concrete pad for the Company's transformer and the Company will terminate, at its expense, the underground primary and secondary conductors to its transformer. The Commercial or Industrial Customer shall furnish, install, own, operate and maintain, at his expense, the underground service conductor from the Company's transformer to the Customer's load facilities.

(ii) If the Company's transformer is not located on the Commercial or Industrial Customer's premise or at his property line, the Commercial or Industrial Customer shall furnish, install, own, operate, and maintain the underground service conductors on his premises and shall extend his underground service conductors to his property line at a point designated by the Company, and shall leave an added length of continuous conductor, as specified by the Company. The Company will purchase from the Commercial or Industrial Customer, and will own, operate, and maintain the added length of continuous conductors, as specified by the Company and will complete, at its expense, the installation of the underground service conductor beyond the Commercial or Industrial Customer's property line.

Sheet No. 1.32B
(iii) The Commercial or Industrial Customer may be required to pay to the Company an amount not to exceed that portion of the Company's estimated cost of such underground construction in excess of the Company ' s estimated cost of overhead construction of such underground service conductors beyond the property line. Each such application will be studied by the Company, as received, and if the expected load requirements of the Commercial or Industrial Customers in such areas and the revenues to the Company therefrom are such as to warrant and justify the Company's assumption of all or any portion of the excess of the underground service conductors beyond the property line of the Customer, the Company may make such arrangements therefor, as the Company may deem appropriate, to reduce the amount thereof to be paid by the Customer

The Empire Electric District Tariff

Chapter 3, Service Specification, Distribution Policy
Sheet No. 17a

B. ELECTRIC DISTRIBUTION POLICY, (Continued)
The developer will make full payment of the estimated charges, in excess of one years estimated revenue for the project, in advance of any construction by the Company. When construction is completed, if the actual costs of the extension are less than the estimated costs, the portion of the customer contribution above the actual costs will be refunded to the customer. If actual costs are higher than the estimated costs the customer will not be required to pay more than the estimate.

Upon request, the Company shall install underground services to each mobile home site from an overhead distribution system in accordance with the terms and provisions of Section B.2.c of the Company's filed Rules and Regulations for electric service. A meter pedestal will be located at each mobile home location. The meter pedestal will be furnished, installed, owned and maintained by the Company for a fee.

e Non-residential Customers:
The Company will provide overhead or underground distribution facilities to serve an individual non-residential customer at no cost to the customer provided the estimated revenue from three (3) years of electric service equals or exceeds the estimated direct and indirect costs of construction. The Company shall require

contributions in aid of construction for the portion of the investment in the total extension of the service to the customer that cannot be supported with the estimated revenues.

If the Company is unable to project estimated revenues, the customer shall be required to pay the entire cost of construction. All contributions in aid of construction may be required before construction is commenced.

When construction is completed, if the actual costs of the extension are less than the estimated costs, the portion of the customer contribution above the actual costs shall be refunded to the customer. If actual costs are higher than estimated costs, the customer shall not be required to pay more than the estimate. At the end of three (3) years, the portion of the construction cost justified by the actual revenue shall be refunded to the customer. Refund totals shall not exceed the original contribution by the customer.

The Company will not be required to obligate funds to secure private right-of-way for the purpose of making extension of distribution pole lines or other facilities to premises of prospective customers.

2. Distribution Services:

The Company's standard construction will be overhead. However, where feasible from engineering, operational, and economic considerations, new electric service to residential and commercial customers may be installed underground.

Installation of facilities shall be made in accordance with the following provisions

a. Temporary Distribution and Service Lines:

The Company shall not be required to provide service to temporary locations, such as for mobile homes, construction sites, etc., even though the line facilities are already in place, unless such customer advances the sum stated in Schedule CA, Credit Action Fees, as a construction payment for the cost of installation and removal of the meter, service, and other necessary facilities. The title to such property shall be and remain in the Company. Should the customer utilize electric service at this location for a period of twelve consecutive months from the date of initial service, the above payment, plus interest as designated by State Law or Commission order, will be refunded to the customer by the Company.

The Company shall not be required to provide electric service to temporary customers at locations that require the extension of the Company's lines unless the full cost of erection and removal, including indirect costs of construction, of the extension be contributed by the customer.

Public Service Company of the State of Colorado Distribution System Extension Tariff

COLO. PUC No. 8 Electric

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840 Denver, CO 80201-0840	Original Colo. PUC No. 8 Cancels Colo. PUC No. 7	Sheet No. R165 Cancels Sheet No.	

RULES AND REGULATIONS

ELECTRIC SERVICE

SERVICE LATERAL EXTENSION AND DISTRIBUTION LINE EXTENSION POLICY

These Rules and Regulations set forth the Service Lateral Extension and Distribution System Line Extension Policy of the Company in all territory served by Company.

GENERAL PROVISIONS

The provisions of this policy are subject to the applicable Rules of the Commission and to Company's Rules and Regulations on file with the Commission.

When one (1) or more Applicants request overhead or underground electric service at premises not connected to the Company's distribution system or request an increase in service to premises already connected where such increase necessitates additional investment, Company, after consideration of Applicant's electric requirements, will designate the service requested as Permanent, Indeterminate, or Temporary in accordance with the definitions hereinafter set forth under Line Extension Plans A, B and C, respectively, and will construct the extension with reasonable promptness in accordance with the terms of the plan or plans applicable.

The determination of facility type and routing will be made by Company to be consistent with the characteristics of the territory in which service is to be rendered and the nature of Company's existing facilities in the area.

In all cases, the facilities provided will be constructed by the Company or its designated agent in accordance with the Company's construction specifications, standards and procedures, and shall be, at all times, the property of the Company on the electric supply side of the Point of Delivery. Distribution Line Extension Contracts and Service Lateral Extension Contracts will be based upon Company's estimate of the cost of constructing and installing the facilities necessary to adequately supply the service requested by Applicant. Such cost will include the cost of all materials, labor, rights-of-way, trench and backfill, environmental remediation, permitting, tree trimming, etc., together with all incidental and overhead expenses connected therewith. Where special items, not incorporated in said specifications, are required to meet construction conditions, including but not limited to frost conditions, rock conditions etc., the cost thereof will also be included, either in the initial estimate or at a time subsequent thereafter as conditions may change as determined by Company.

ADVICE LETTER NUMBER 1731	[signature]	ISSUE DATE December 8, 2016	
DECISION/ PROCEEDING NUMBER C16-1075	REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs	EFFECTIVE DATE January 1, 2017	

RULES AND REGULATIONS

ELECTRIC SERVICE

SERVICE LATERAL EXTENSION AND DISTRIBUTION LINE EXTENSION POLICY

CONSTRUCTION ALLOWANCE AND CONSTRUCTION PAYMENTS – Cont'd

PLAN A – PERMANENT SERVICE – Cont'd

The above allowances are subject to review and appropriate revision by filing of new Construction Allowances with the Commission within thirty (30) days following a final decision in a Company cost allocation and rate design proceeding, based on the appropriate gross distribution investment amounts included in that proceeding.

Regarding Electric Vehicle (EV) Charging Stations, beginning with the effective date of this Electric Tariff and ending December 31, 2018, Applicant or Applicants shall be required to T
pay to Company as a Construction Payment all estimated costs for necessary electric Distribution T
Main Extension and Service Lateral Extension. Regarding additional facilities necessary to serve the EV Charging portion of the EV Charging Station based on the added load in Kilowatts, said Construction Payment may be reduced by an award of Construction Allowance in part or in its entirety, in twenty percent (20%) increments, up to the level of the Construction Allowance that would be awarded for such facility for a period of five (5) Years after the Extension Completion Date. After said five (5) Year period has expired, Construction Allowance shall no longer be available. All non-fueling usage of the EV Charging Station shall be determined by the Company as Permanent, Indeterminate, or Temporary Service as applicable.

The Company may opt to offer Applicant(s) an advance for the Construction Payment by entering into a Construction Payment Agreement. Under this option, the Company shall require the Applicant(s) to make monthly installment payments that will cover the Company's costs of such advance. The Construction Payment Agreement allows the Applicant to have advanced a minimum of $500.00 and thereafter in increments of $100.00 for a one (1), three (3), five (5) or ten (10) Year term. The maximum amount to be advanced under the Construction Payment Agreement will be $5,000 for Residential and $10,000 for Commercial Customers. At the Company's discretion, additional amounts may be advanced with Company written approval, where Applicant's financial condition is determined by the Company to be satisfactory. Applicant retains the option to buy down any portion or all of the remaining Construction Payment Agreement balance at any time.

The Top 10 Utility Regulatory Commission Issues of 2016

By Krysti Shallenberger @klshall
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2016 has been a year to remember — or forget.

One polarizing presidential election aside, the power sector has seen a wave of changes in the form of new policies, more consolidation and new energy technologies.

Over the course of 2016, utilities, regulators and other stakeholders debated changes to rate design, cost recovery, grid modernization and data access, just to name a few.

Maryland, for instance, is taking a comprehensive look at ways to integrate new technologies and update aging infrastructure. Other states, like Kansas and California are tackling pilot programs for electric vehicle charging stations. Still others, like Hawaii, New York and Arizona are debating alternative rates for distributed generation.

Because utilities are regulated on the state level, these debates manifest themselves a bit differently in each jurisdiction. Even so, there are a number of broad policy trends occupying regulators and utilities in a number of states nationwide. To help chronicle them, clean energy trade group Advanced Energy Economy compiled what it says are the top ten commission issues of the year.

1. Reforming the Energy Vision

While it did not begin this year, New York's Reforming the Energy Vision remained a clear choice for a top commission issue this year, AEE experts said during a webinar earlier this month.

Since it was rolled out in 2014, the proceeding has captured the attention of sector observers nationwide with its plan to reform utility revenue models to encourage more adoption of distributed resources.

Under the REV, regulators aim to remove disincentives in the utility regulatory model toward deploying customer-sited solutions like rooftop solar and storage instead grid-scale infrastructure like a new transmission line.

Similar to an air traffic controller, utilities will be transformed into Distributed System Platform Providers that coordinate the interconnection and management of various distributed resources. Instead of earning revenue on their expenditures for the grid, utilities would move toward a model of performance-based ratemaking that would reward them for efficiency gains, customer engagement and a variety of other metrics.

New York regulators split the REV docket into two tracks. Track 1 focuses on the development of distributed resource markets and the utility as the DSP providers. Track 2 of the REV docket focuses on reforming utility ratemaking practices (evolving from traditional cost-of-service) and revenue streams to support the DSPP model.

New York utilities have proposed a variety of pilot projects to test various aspects of DER integration, customer data sharing and third party partnerships.

This year, the REV docket moved out of its theoretical stage, with utilities filing their distribution service plans in June and reporting on the operation of a number of pilot programs, from virtual power plants to online marketplaces for building efficiency.

"We've certainly have laid the groundwork, and this year we're really working on the execution," Zibelman told Utility Dive this summer.

The PSC issued the Track 2 Order in May of this year. Under the order, the regulators outlined how utilities can earn returns linked to meeting system demands with alternative methods, such as using customer-sited solar and demand management instead of new central station capacity.

The order also recommended time-of-use rates — a rate design popular for its precise targeting of pricing, and Earnings Mechanism Adjustment, which allows utilities to also earn a rate of return if they target four areas, such as energy efficiency, system efficiency, interconnection (of DERs) and customer engagement.

It remains to be seen how regulators will evaluate utility distribution system plans and their pilot program performance, but already the idea behind REV is spreading to other states. Commissions in Illinois and Ohio, for instance, have expressed desire to open up similar dockets to explore grid modernization and performance-based regulation.

2. California reforms

While all New York's power sector reforms are folded up in REV, California is the hodgepodge of utility reform, with proceedings ranging from EV charging pilot programs to alternative rate designs and programs designed to test the impact of DER incentives on utilities.

Last year saw a wave of changes in the Golden State. Regulators preserved the retail net metering rate, will try to move to default time-of-use rates by 2019 and boosted the renewable energy standard.

This year, the California Public Utilities Commissioner Michael Florio introduced a draft proposal that outlines a framework to align utility ratemaking processes with increasing demand for distributed energy resources. While it doesn't call for an overhaul of the cost-of-service proceeding, it does share many of the same goals as New York's REV.

Under the proposal, California's investor-owned utilities would deploy DERs at a cost-effective rate. But unlike REV, the proposal would reshape the utility regulatory model to apply incentives for traditional infrastructure to DERs as well.

3. Mergers and acquisitions

After a two-year struggle, the utility sector's biggest merger story appears to be coming to a close.

With its acquisition of mid-Atlantic utility Pepco, Exelon is now the largest utility holding company in the U.S. by customer base. Its completion over raucous protests in Washington is symbolic of a wave of consolidation in the sector, according to Coley Girouard, a utility program associate at AEE.

The consolidation trend is in part spurred by "financial struggles driven by low prices in wholesale markets and increasing penetration of DERs," Girouard said during the webinar.

For the most part, regulators have given the proposed mergers a warm reception. Examples of other successes include Cleco Corps. takeover by a group of international investors and Emera's takeover by Teco Energy.

But other proposed mergers haven't encountered such success. Earlier this year, two very large, high-profile deals were rejected by their respective regulators.

In 2014, NextEra proposed to take over Hawaiian Electric Industries, Hawaii's dominant utility. But after nearly two years of wrangling and concerns over NextEra's commitment of renewable energy, the Public Utilities Commission rejected the deal, saying it wasn't in the public's best interest and failed to meet the state's long-term climate goals.

And in 2015, real estate firm Hunt Consolidated filed for approval to acquire Texas' largest transmission and distributed utility, Oncor, as part of a $17.6 billion deal to spin its parent company Energy Future Holdings out of bankruptcy.

If approved, Hunt would have converted Oncor into a real estate investment trust (REIT). But the deal was dogged by concerns over its impact to ratepayers, and whether a portion of the tax savings would go to ratepayers.

Eventually regulators approved the deal, but attached conditions. As a result, Hunt later withdrew its application and Oncor returned to the auction block.

Now NextEra, after Hawaii's rejection, is pursuing the Texas utility, offering over $18 billion in a proposal insiders say is on steadier ground than either company's earlier courtships.

Other pending mergers include Great Energy Plains $8.6 billion takeover of Westar, which still awaits state and federal regulatory approvals.

4. Customer access to analytics

More and more utilities are turning to data analytics as a means to quantify energy usage. Driven in large part by deploying smart meters, utilities are harnessing the information for input and insight into distributed energy technologies. But some regulators are also searching for ways that customers could leverage the same information for their own energy edification.

In Pennsylvania, Robert Powelson, a commissioner on the Public Service Commission, opened a docket to explore opening access to such data analytics for customers.

"I think the competitive markets in Texas and Pennsylvania have shown we embrace competition and disruptive technologies," Powelson said during AEE's webinar. "And behind that is emerging data analytics and how it's empowering customer's appetite to take a holistic view of energy usage."

How to manage the manage the deluge of data is key to new revenue streams and improved grid operation. But utilities need to find the necessary software tools to integrate multiple grid technologies and handle ever-escalating quantities of information.

AEE noted a number of states undergoing similar discussions. The Illinois Commerce Commission created Green Button Connect, an automated delivery system that allows third parties to access customer data. Also in May, Xcel Energy reached a settlement in Colorado to address issues over customer data access, while agreeing to implement its version of Green Button Connect down the road.

In Texas, the Public Utility Commission opened two dockets for third party authorization to access data and the other on how to govern the web portal, Smart Meter Texas, that would open up data access for customers.

5. Alternative rate designs

Few topics in the power sector get more contentious than rate design debates.

As DERs proliferate, utilities and regulators are battling it out in hearings to come up with the most precise way to align price signals with peak demand to curb usage during those times.

In 2019, California utilities will move to default time-of-use rates after a regulatory order last year. Colorado and Arizona are also debating major rate design changes regarding distributed solar.

Colorado's Xcel Energy hashed out a settlement with solar interests, which included a provision to test two pilot time-of-use projects that would eventually result in default TOU rates for all customers.

Other alternative rate structures are not so popular. Nevada is probably the most notorious example after utility regulators raised fixed charges and slashed retail rates for both existing and new net metering customers. Though the decision was eventually reversed, debates over the proper solar compensation mechanism occupied the commission throughout 2016.

In Arizona, debates have long swirled over how to best compensate rooftop solar users for their excess energy. After Arizona regulators approved a small fixed charge on solar customers in 2013, utilities have repeatedly proposed to slash remuneration rates and increase the fixed charge. Now regulators have opened a docket to examine the value of solar, and among the findings would be a new solar rate.

Meanwhile, some Arizona utilities are mulling mandatory residential demand charges as a more palatable option than even time-of-use rates. Demand charges typically charge customers for their highest usage in a short period during the month. These are more commonly seen with commercial and industrial customers, but lately more companies have proposed them for residential customers.

6. Residential demand charges

Fixed charges continue to be a favorite utility rate reform, with 44 proposals filed in the third quarter alone. But many of these requests have met hefty pushback from regulators and stakeholders, pushing some utilities to turn to a new option: residential demand charges.

In Arizona, two rate cases seeking to implement mandatory demand charges on solar customers and all residents captured the national spotlight this year.

UES Electric filed a rate case last year seeking to implement demand charges on all customers. After solar advocates protested, the utility scaled back its proposal to make demand charges an option for non-rooftop solar customers and mandatory for solar.

In another rate case, Arizona's largest utility, Arizona Public Service Co. is also seeking to apply residential demand charges for its entire service territory. Regulators have staved off a decision until the value of solar docket concludes, but already the proposals have garnered heavy opposition.

Critics say residential demand charges are too complex for the average ratepayer to understand and indirectly punish the customer for scaling back on energy usage. Conversely, they argue time-of-use rates are a more easily understood and more refined way to align pricing with peak demand. How the regulators in Arizona rule on the issue could set the stage for proceedings in other states.

7. Grid modernization

As regulators confront aging infrastructure and a changing energy landscape, ways to modernize and shore up the grid in the wake of natural disasters have never been so pressing.

Several states have opened dockets to take a comprehensive look at grid modernization reforms.

Rhode Island is one state contemplating such measures, and Massachusetts is set to hear proceedings over its utilities' plans this month. And in March, Minnesota released a report outlining its steps to move toward more distributed energy resources while hardening the grid system. The state is also looking at advanced metering infrastructure, time-varying rates and third party aggregation.

With the exception of Minnesota, all the other states contemplating grid modernization are deregulated. Minnesota is vertically integrated, which means utilities own generation as well as transmission and distribution. If regulators can come up with a replicable model for modernization, it could help lay the groundwork for similar proceedings in the Southeast and other vertically-integrated states.

8. Energy storage

As more states demand more renewables from their utilities, the opportunity for energy storage technology grows. California, for instance, passed bills requiring utilities to ramp up their use of energy storage. And Massachusetts has recently implemented a mandate for energy storage as well.

But who will own energy storage? Mateo Jaramillo, vice president of products at Tesla, said in the webinar that the biggest regulatory debate surrounding energy storage is ownership.

"It's its own asset," Jaramillo said. "[Utilities] are deploying storage as generation device and storage device."

Take Texas, he said. The PUCT classified it as a generation resource, making it illegal for a transmission and distribution utility to own it in the state's deregulated market. For

California, the question lies with whether or not utilities can access behind-the-meter storage, a proposition that has historically worried third party developers.

One of the bills, AB 2868, would allow utilities to own an additional 500 MW of storage capacity behind customers' meters, using ratepayer money to finance the investments, in addition to the required 1,325 MW.

Private developers opposed the bill, but it was approved earlier this year. As more states consider energy storage mandates and the technology continues to proliferate, continued debates over storage ownership are expected.

9. Electric vehicle charging stations

Electrifying the transportation sector will do more than just reduce emissions. For utilities, the new electricity demand can post revenues, while cars on the grid can open new demand-side management opportunities.

Utilities have noted the opportunities and some regulatory states are contending with proposals by utilities to build the EV charging stations with ratepayer money.

But those proposals have been met with a lukewarm reception at best. In California, the Public Utilities Commission has allowed the three biggest investor-owned utilities to move forward with pilot charging programs, but later scaled back Pacific Gas and Electric's initial proposal amid worries that the utility could squeeze private developers out of the market.

In Kansas City, Missouri, Kansas City Power & Light requested to ratebase more than 1,000 charging stations as part of its ambitious rollout program. But Kansas regulators nixed the proposal in the parts of the metropolitan area that fell into Kansas.

Even so, utilities have still expressed interest in other states to buildout charging stations. And this month, the U.S. Department of Transportation designated roughly 85,000 miles of highway corridor as a national EV charging network.

10. Renewable portfolio standards

Last but not least, the trend for aggressive renewable portfolio standards has only strengthened.

Last year saw some of the most ambitious renewables targets: Hawaii at 100% by 2045, Vermont at 75% by 2032 and California setting a 50% by 2050 goal.

This year, other states set equally ambitious targets: Oregon pledged to source 50% of its renewables by 2050 and phase out exports of coal generation. Rhode Island and the District of Columbia also expanded their RPS, with the New York regulators adopted a mandate to source 50% of its electricity from renewables by 2050 and support aging nuclear generation.

Other states are now examining their own standards in aims of expanding them.

For example, Arizona Corporation Commissioner Doug Little proposed revisiting the standard and looking at broadening its scope to include DERs. How other states will follow remains to be seen.

Looking ahead

Far from being static, each of these commission debates will bleed over into 2017. AEE's Girouard offered some insight into the big commission issues for next year.

One will likely be REV. "In the past, it's been setting theoretical framework. It will be interesting to see how REV moves into implementation," Girouard said.

California will also inevitably make headlines — likely related to how Florio's proposal will move forward, even though he will leave the commission at the end of the year. Girouard said it could be leverage for a more comprehensive review of the utility business model. And for grid modernization efforts, Girouard pointed to Ohio and Illinois as likely hotspots. Washington D.C. also has a staff report for its grid modernization due in December.

As ever rate design "will continue to be important," he said. Especially interesting will be "to see if utilities will look at other things aside from demand charges and fixed charges … to see if they will look at time-of-use rates and performance based regulation."

e21 Initiative Phase II Report On implementing a framework for a 21st century electric system in Minnesota. www.betterenergy.org

Phase II Report Summary

The three white papers build on phase I and should be considered collectively, as all aspects of the modern grid are interrelated: any discussion of compensating utilities based on their performance in achieving particular outcomes necessarily involves an understanding of what grid enhancements would be necessary for the system to support achieving those outcomes. In addition, any such grid enhancements would require the traditional integrated resource planning process to take those changes into account in planning for the electric grid's long-term needs, grid operation, and revenue requirements for the utilities.

Similarly, consideration of new integrated resource planning processes would be incomplete at best without an understanding of what's driving the need to modernize our grid and how expected changes at the distribution grid level will shape the way we do long-range planning for the electric system. Moreover, evolving the traditional integrated resource planning process toward an integrated systems plan (as proposed by e21) also requires an understanding of how new performance-based utility compensation mechanisms may influence how utilities and third parties meet future electricity needs.

In sum, an understanding of the work by the e21 Initiative in phase II requires that the three white papers be read as a package. To aid in this systems view, the following summaries describe each white paper, its recommendations, and its conclusions, and shows how it relates to the other two.

Performance-based Compensation

A central recommendation of the *e21 Initiative Phase I Report* is the shift to a more performance-based compensation framework, where some portion of the utility earnings is linked to utilities' performance on outcomes valued by customers and supportive of state energy policies. This shift would require updating the manner in which Minnesota regulates utilities in two fundamental ways. As noted above, it would accomplish the following:

> *1. Shift away from a business model that provides customers few options (everyone gets the same grid electricity produced largely with coal, natural gas, or nuclear power at large central stations) toward one that offers customers more options in how and where their energy is produced and how and when they use it, while maintaining fair and competitive pricing, reliability, and minimal environmental impacts*
>
> *2. Shift away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that reasonably compensates utilities for achieving an agreed-upon set of performance outcomes that the public and customers want*

As envisioned in phase I of e21's process, this shift is intended to achieve four core objectives:

a. Utilities become indifferent to how a particular system need is met (e.g., large central generation or distributed generation) and by whom (utility or non-utility). Utilities would evaluate all options and pursue non-utility solutions when they are more cost-effective.
b. Real costs for electricity decline over the long term as utilities and customers are incentivized to make choices that optimize the alignment between generation and load to better utilize the existing system.
c. Financial incentives (positive or negative) drive utility performance. High-performing utilities may earn more than their costs would indicate, and utilities that do not meet performance outcomes may earn less.
d .A more customer-centric framework that meets growing customer expectations regarding service, product, and technology options and includes affordable services to low-income customers.

Through the discussions in phase II, however, it became clear that there are diverging views as to how quickly and how extensively the shift should take place, even though there was agreement among participants that there is value in moving toward a more performance-based model. A sudden and untested shift away from the current risk-reward relationship could potentially have an adverse impact on utilities' ability to make necessary cost-effective investments in the electric system. Similarly, waiting too long to act could be detrimental.

As a result, e21's white paper *Performance-based Compensation Framework* delineates principles, guidelines, potential outcomes, and metrics to support an incremental movement toward a more performance-based model, but does not choose among three identified stages or recommend specifically where Minnesota's regulatory framework should settle. e21 participants acknowledge that there may be other options, but agreed that the three models listed below are illustrative of the choices that utilities and regulators will have:

1. Current cost-of-service model. In this scenario, earnings from capital investment remain the primary driver for utility shareholder value. Any performance- or outcome-based financial incentives would be in addition to the utility's cost-based revenue requirement and considered separately from a rate case.

2. Partial shift to a performance-based compensation framework. In this scenario, the regulator-authorized return on equity is reduced, and utility earnings are driven by a combination of performance outcomes and capital investments. The relative share of earnings coming from each would be determined over time. Shareholder earnings may also include potential new revenue streams from providing new products and services.

3. Shift to performance-based compensation framework. Here, there is no automatic, regulator-authorized return on equity; utilities still recover their costs, but shareholder returns would be earned through a combination of utilities achieving performance goals and possible new product and service revenue opportunities.

In all of these scenarios, it is assumed that utilities would recover their prudently incurred costs, including stranded costs as determined by the Minnesota PUC. Thus, whereas in scenario 1, a utility would get a return on its capital investment and have the ability to earn more if it meets certain milestones (for example, achieving a power plant retrofit under budget, delivering greater grid reliability, or adding more choices for customers on how their electricity is produced, such as from wind), in scenario 3, the utility does not earn anything above its costs unless its performance dictates.

The white paper then goes through a list of nine potential performance outcomes, detailed explanations, and sample metrics for each. The metrics for each outcome are not meant to be exhaustive and would need additional exploration, as would the outcomes themselves. e21 offers the following performance outcomes for consideration:

a. distributed energy resources and grid services are fairly valued and integrated into the electric system in ways that add net benefits and minimize costs

b. utilities have sufficient incentive to manage controllable costs, particularly operations and maintenance

c. the system is made more efficient

d. reductions are achieved in the pollution and carbon emissions in any part of the energy economy in a cost-effective manner beyond what is required in law

e. electricity customers, including low-income customers, have increased access to a wider range of utility and third-party services and products

f. development of efficient, low/no carbon loads (e.g., electric vehicles) is promoted

g. high levels of reliability are ensured as driven by customers, as and where needed

h. customer satisfaction is increased

i. customers are ensured access to basic electricity service that is affordable

The white paper is meant to be a guide for further study as utilities and policymakers seek to implement a performance-based system.

Integrated Systems Planning

In phase I, the e21 participants recommended changes to the resource planning process for utilities that opt in to a performance-based multi-year rate structure. Those utilities opting to file a performance-based multi-year rate plan would revise their traditional approach to the 15-year integrated resource planning regime by focusing more attention on the five-year action plan portion and by streamlining regulatory review of the later years of the resource plan (beyond the action plan period). The phase I report referred to this as an integrated resource analysis.

In addition, the e21 participants recommended including more information about transmission and distribution wire and non-wire alternatives in a resource plan, such as additional demand response capabilities and other distributed resource options. This would enable a more detailed look at the ways to serve load that includes both utility-sited and customer-driven resources.

In phase II, e21 refined its thinking about how the traditional integrated resource planning process might evolve and now recommends transitioning the traditional long-range planning process to an integrated systems plan for *all* utilities rather than only those opting in to a multi-year rate plan, because the need to evolve resource planning to take a broader set of distributed and transmission system alternatives into account is important to everyone affected by the distribution system.

e21 participants believe that the resource planning process has served the needs of Minnesotans well over the years, and they see their proposed changes as simply a continuation of the adaptations that have been made in the past to ensure that this least-cost planning process continues to promote the public interest as the electric sector and utilities evolve to suit 21st century needs.

The key question of the current resource planning process will remain how to ensure that customer needs are met in the least-cost ways to achieve relevant state and federal requirements. In addition, those who are engaged in integrated systems planning will need to begin asking and thinking about answers to the following questions:

a. What is the projection for development of demand-side resources, including both customer-driven generation and customer demand response, that are outside the utility's control?

b. What additional potential exists for customer- and utility-sited distributed energy resources to cost effectively meet system needs? Facilitating that potential may require changes to rate design, procurement programs, and other proactive measures.

c. What are the opportunities for third parties in the provision or aggregated operation of those resources?

d. How might supply-side and demand-side resources interact in real time to optimize past and future investments in order to reduce customer cost impacts over the planning period?

e. How does the integrated systems plan of a given utility meet Minnesota's needs and public policies, as well as coordinate with the plans of other utilities and the Midcontinent Independent System Operator (MISO) electricity market?

To facilitate the answers to the questions above, the e21 participants outlined four main areas of potential improvement to the resource planning process:

a. optimize the length of time during which a plan is processed through the regulatory system, and better manage the administrative burden that is placed on regulators, staff, and other parties

b. expand the scope of the planning process to take more of an end-to-end systems approach (from the bulk transmission level to the distribution grid)

c. include more timely information about utility costs and customer impacts from various approaches to the resource mix, infrastructure investments, and delivery mechanisms

d. improve the balance in the plan review process between reliance on modeling versus policy and strategic considerations

The integrated systems planning white paper sets forth an explanation of the current regulatory process and then, using the above questions and areas of improvement, describes potential modifications. They are:

a. **pre-filing collaboration,** to create understanding and potential agreement around modeling assumptions, resource costs, and planning scenarios and sensitivities. This will help reduce the number of issues that significantly impact the evaluation of resource plan options

b. **standardization of naming conventions,** for what constitutes a base case, a reference case, a preferred plan, and other commonly used terms

c. **identification of best practices,** used by utilities in Minnesota, to be shared on a regular basis

d. **standardization of modeling techniques,** to be used by Minnesota utilities and intervenors, such as how variable and distributed resources, demand response, and energy efficiency resources should be modeled

e. **holding annual/biennial systems planning workshops,** to discuss planning, modeling, and forecasting issues; share best practices; and consider new policies and planning requirements and MISO market impacts

f. **coordination by the Minnesota PUC of the scheduling of rate cases and resource plans**, as a pre-cursor to a utility business plan for those utilities that opt to file a multi-year rate plan

g. **establishment of regulations for utility business plans by 2020,** in order to allow utilities to opt in to such a plan

h. **evaluation of supplemental modeling platforms,** which could provide better near-term integration of demand-side resources and customer-owned generation with supply-side resources

i. **provision of more information about demand-side resources and capabilities,** including better forecasting of resources over the planning period and information about potential interactivity with utility resources

j. **evaluation of the usefulness of potentially outdated planning requirements,** such as the requirement for 50/75% renewable capacity scenario

k. **compliance with the Clean Power Plan,** analyzing how a utility's resource decisions might affect compliance with the plan

l. **determination of the five-year rate impact of key scenarios,** as identified by the pre-filing collaboration. This would be in addition to the overall rate impact of the preferred plan and the traditional comparison of their revenue requirements (measured in present value)

m. **evaluation of innovative options to increase system efficiencies and cost-effectiveness and achieve environmental goals,** including deferred investments, easing of rate impacts over time, value-of-solar pricing, time-of-use rates, dynamic pricing, system efficiencies made possible through grid modernization, and coal ramp-down with renewable ramp-up

Implementing these regulatory changes would help facilitate the goals outlined in e21's phase I report while also being respectful of the role that regulators must play. By encouraging greater collaboration on the resource planning side, these changes will also make it easier to implement the changes proposed in the other white papers and to do so in ways that reflect the myriad interests that are affected by Minnesota energy policy.

These suggested changes do not, however, obviate the need identified in phase I to modify the resource planning process to account for multi-year rate plans lasting up to five years. Again, how this occurs would need to be addressed by the Minnesota PUC in general dockets.

Grid Modernization

The basic design of the electric grid has remained largely the same since the first commercial power plant in the United States went into service in 1882. Electricity has for the most part been generated by large central stations, transmitted large distances over high voltage transmission lines, and then reduced in voltage for local distribution and delivery to customers. The vertically integrated system is now changing, evolving to be cleaner and more efficient and to integrate more renewable resources in a cost-effective manner. In addition, customers are installing their own electricity generation, whether on rooftops or through on-site power plants.

Today, the distribution system needs to be able to manage two-way flows of both electricity and information, taking in power and data generated from these customer sites and coordinating many more actors on the system. A modern grid must adapt to increasing distributed energy resources such as storage, electric vehicles, microgrids, combined heat and power, small wind, demand response, and other sources. In short, we are headed for a much more distributed, networked grid that needs to be able to respond to rapidly changing technologies.

Recognizing that a modernized grid provides many benefits to customers, utilities, and grid operators, the phase I report recommended that Minnesota:

a. develop a transparent, forward-looking process for modernizing the grid (which the Minnesota PUC has underway)

b. identify how to achieve a more flexible distribution system that can efficiently and reliably integrate cost-effective distributed energy resources

c. pursue opportunities to reduce customer and system costs by improving overall grid efficiency and better utilizing existing system assets (improving the grid's load factor)

Toward these ends, the grid modernization white paper does the following: suggests an overall approach and a set of objectives for grid modernization in Minnesota, outlines the functions and technologies needed to achieve those objectives, and offers recommendations and next steps that can usefully complement the Minnesota PUC's on-going grid modernization process. The five grid modernization objectives identified by the e21 group are:

Objective 1: Maintain and enhance the reliability, safety, security, and resilience of a more distributed, dynamic, and complex electric grid, as and where needed, through such things as establishing cost-effective, real-time ways to anticipate and fix problems on the system; mapping where on the distribution grid distributed energy resources can provide the greatest benefit and using price signals to encourage them to locate in those places; and deploying sophisticated communications technology to coordinate all of the actors on the electric grid while protecting privacy and ensuring cybersecurity.

Objective 2: Enable greater customer engagement, empowerment, and options, including the ability to manage and potentially reduce electricity costs for all customers, including through deployment of advanced meters and improved customer access to their own electricity usage data (usage and price).

Objective 3: Enhance the system's ability to integrate distributed energy resources and other new products and services in a cost-effective and timely way, by such means as conducting thorough and regular distributed energy resource “hosting capacity” and “locational value” analyses, improving access to that and other relevant grid-level information, and updating Minnesota’s interoperability standards and interconnection processes.

Objective 4: Improve the environmental performance of electricity services, by creating a physical and information technology platform that can optimize the environmental performance of the electric system as a whole—drawing on all available resources to do so, from large-scale renewable generation to responsive customer loads—integrating more renewable energy into the system and better measuring energy savings from efficiency programs.

Objective 5: Promote optimized and cost-effective utilization of grid assets, through reducing peak demand and utilizing both customer-driven resources and the utility’s resources to meet demand at a given time, without overbuilding the distribution grid or power generation sources.
To further these objectives and manage the complexity of this wide-ranging area, the e21 group makes 14 recommendations, organized into three categories. ***The recommendations are addressed to regulators unless otherwise noted.***

Planning

> **a. Provide guidance on developing standard information sets and platforms for the sharing of hosting capacity**
>
> **b. Review and update Minnesota’s interconnection standards and processes to make the interconnection process more predictable, transparent, timely, and consistent**
>
> **c. Distribution planners employ scenario planning to manage the inherent uncertainty of planning for the unknown number, scale, and location of distributed energy resources on the distribution system**

Customer Services and Engagement

> **d. Use a multi-interest stakeholder process to determine the services and benefits(including environmental benefits) that distributed energy resources receive from the grid and can provide (including environmental benefits) to meet the electric grid’s needs**
>
> **e. Establish price signals and payment options that direct distributed energy resources to optimal locations on the grid and that encourage customers to optimally time their electricity use**
>
> **f. Provide customers with convenient and timely access to as much of their own data as possible in a consistent format to enable customers to make informed decisions about the timing and amount of their electricity use**
>
> **g. The Minnesota PUC takes steps it deems necessary to ensure that utilities implement best practices in all areas of cybersecurity to ensure the availability and confidentiality of information and the integrity and security of the electric system**
>
> **h. Allow utilities to establish a specific budget to conduct research and development, rather than relying solely on pilot programs to innovate**

Operations

i. Ask utilities to adopt cost-effective voltage and volt-ampere reactive optimization appropriate for each utility's system

j. Draw on the existing body of regulation and experience to develop a strategy to utilize smart inverters

k. Establish procedures and tariffs for how and when a distribution grid operator may dispatch and curtail distributed energy resources to enable the near real-time matching of generation and load using both supply-side and demand-side resources

l. Implement appropriate and cost-effective enabling technologies that are prerequisites to achieving grid modernization objectives (e.g., supervisory control and data acquisition, advanced metering infrastructure, and high-speed and high-capacity communication systems)

m. Ensure the use of national standards necessary for effective integration of distributed energy resources and interoperability of the grid's communication systems

n. Use digital, automated communication, and monitoring technologies to more accurately evaluate the environmental impact and effectiveness of efficiency and clean electricity programs

As noted above, the Minnesota PUC has initiated a process to explore grid modernization, and the e21 group wishes to complement and inform its process. To that end, the e21 Initiative will identify opportunities in upcoming dockets to address foundational "no regrets" actions; take up issues for which the PUC's technical workshops would have difficulty fostering ongoing dialogue and feed information back into the commission's process; and take up issues beyond the commission's current focus with the goal of offering definition and depth on topics likely to be considered in the future.

Accomplishing these next steps will require close coordination with PUC commissioners and staff, and will be assisted by the process changes for e21 discussed in Appendix A.