Exhibit No.:	
Issues:	Standby Service Rider
Witness:	Jane Epperson
Sponsoring Party:	Missouri Department of Economic Development – Division of Energy
Type of Exhibit:	Rebuttal Testimony
Case No.:	ER-2016-0179

MISSOURI PUBLIC SERVICE COMMISSION

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

CASE NO. ER-2016-0179

REBUTTAL TESTIMONY

OF

JANE EPPERSON

ON

BEHALF OF

MISSOURI DEPARTMENT OF ECONOMIC DEVELOPMENT

DIVISION OF ENERGY

Jefferson City, Missouri
January 24, 2017

(Rate Design)

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2016-0179

AFFIDAVIT OF JANE EPPERSON

STATE OF MISSOURI **COUNTY OF COLE**	**)** **)** **)**	**ss**

Jane Epperson, of lawful age, being duly sworn on her oath, deposes and states:

1. My name is Jane Epperson. I work in the City of Jefferson, Missouri, and I am employed by the Missouri Department of Economic Development as an Energy Policy Analyst, Division of Energy.
2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of the Missouri Department of Economic Development – Division of Energy.
3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct to the best of my knowledge.

Jane Epperson

Subscribed and sworn to before me this 24th day of January, 2017.

LAURIE ANN ARNOLD
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: April 26, 2020
Commission Number: 16000714

Notary Public

My commission expires: 4/26/20

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name and business address.

A. My name is Jane Epperson. My business address is 301 West High Street, Suite 720, PO Box 1766, Jefferson City, Missouri 65102.

Q. Have you previously filed testimony in this case?

A. No.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Missouri Department of Economic Development – Division of Energy ("DE").

Q. Please describe your educational background and employment experience.

A. I received my Masters of Science in Geology from the University of Missouri – Columbia and my Bachelor of Arts degree in Geology from Stephens College, Columbia, Missouri. I began work with DE in 2014 as an Energy Policy Analyst. In that capacity I have filed testimony in prior rate cases (ER-2014-0370, ER-2014-0351, ER-2014-0258), participated in Missouri Energy Efficiency Investment Act rule revision dockets and various electric and gas collaboratives on docketed issues, contributed to development of the Comprehensive State Energy Plan, and am currently project manager for the development of a statewide Technical Reference Manual. Prior to working with DE, I was employed by the Missouri Department of Conservation as Supervisor of the Policy Coordination Unit, which was responsible for statewide and regional planning, statewide compliance with environmental and cultural resource laws, Missouri, Mississippi, and White River basin interstate coordination, and human dimensions research. Prior to working with the Missouri Department of Conservation, I was employed as a Hydrologist III with the Missouri Department of Natural Resources – Director's Office, focusing on interstate water policy and management issues.

Q. What information did you review in preparing this testimony?

A. In preparation of this testimony I reviewed reports and publications about combined heat and power ("CHP") technology; best practices literature and standby service tariffs of other states; Direct and Surrebuttal Testimony by DE on the same issue in the previous rate case (ER-2014-0258); Direct Testimony filed by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") specific to the proposed Standby Service Rider ("SSR") in this case, and Ameren Missouri's responses to my Data Request Numbers 300–310 in this case. Using Ameren Missouri's proposed standby service tariff structure and the data profile used in their workpapers, I analyzed the impacts of various rate element changes and generation and outage scenarios. I also sought and received input on the proposed SSR impacts from an energy engineer and the U.S. Department of Energy CHP Midwest Technical Assistance Partnership.

Q. What is the purpose of your testimony?

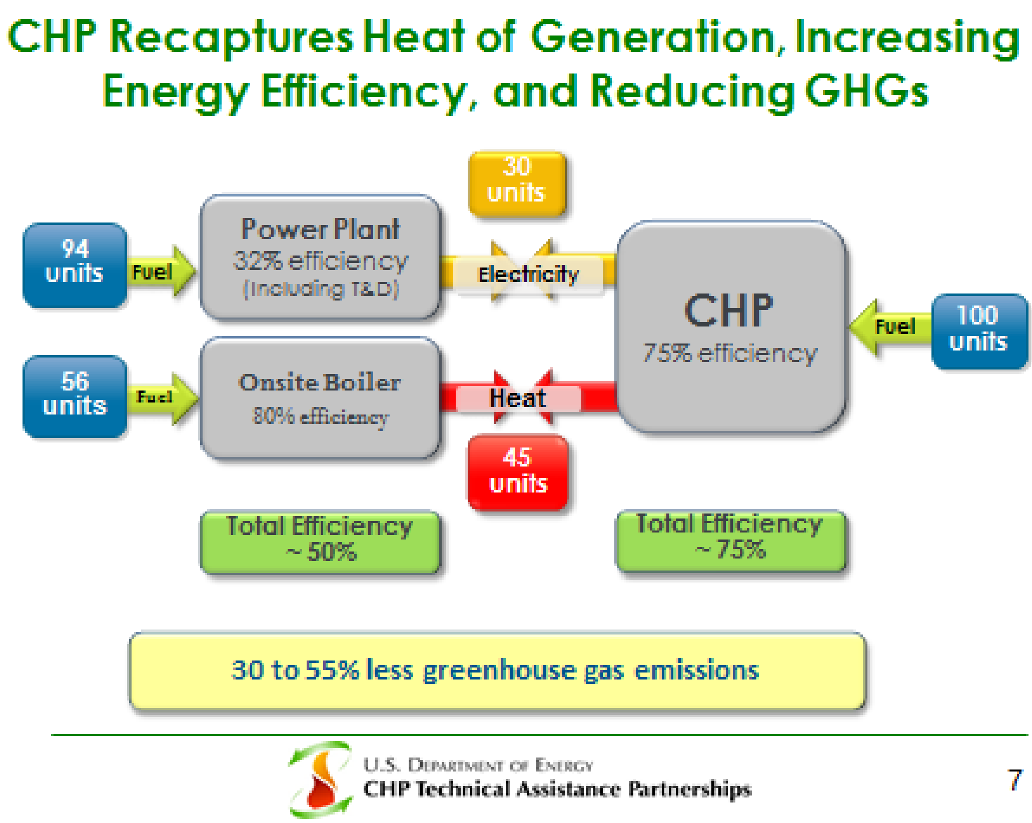
A. The purpose of my testimony is to a) provide a synopsis of the case history on the standby service issue, b) provide an overview of the progress made during the effort to implement the Nonunanimous Stipulation and Agreement Regarding Supplemental Services from Case No. ER-2014-0258, and c) identify problems and recommend improvements to the proposed SSR on the issues of single premises, time of day ("TOD") rates, multiple generators, and supplemental contract capacity.

II. BACKGROUND

Q. What is cogeneration/CHP?

A. CHP, also known as cogeneration, refers to an array of proven technologies that concurrently generate electricity and useful thermal energy from the same fuel source (conventional or renewable). A simple illustration of a separate heat and power system is a typical commercial or industrial building that purchases electricity generated by a utility but has a boiler in the basement that makes hot water to heat the building. Thus, two sources of fuel are burned to meet the building's electric and thermal energy needs. CHP systems utilize one fuel to make both electric and thermal energy. This is done by recovering the otherwise wasted heat from the electric generation process and using it to provide the thermal load of the building. Thus, one source of fuel is used instead of two in a more efficient way (see Figure 1).

Figure 1: Energy Efficiency Comparison of CHP versus Separate Heat and Power Production.[1]



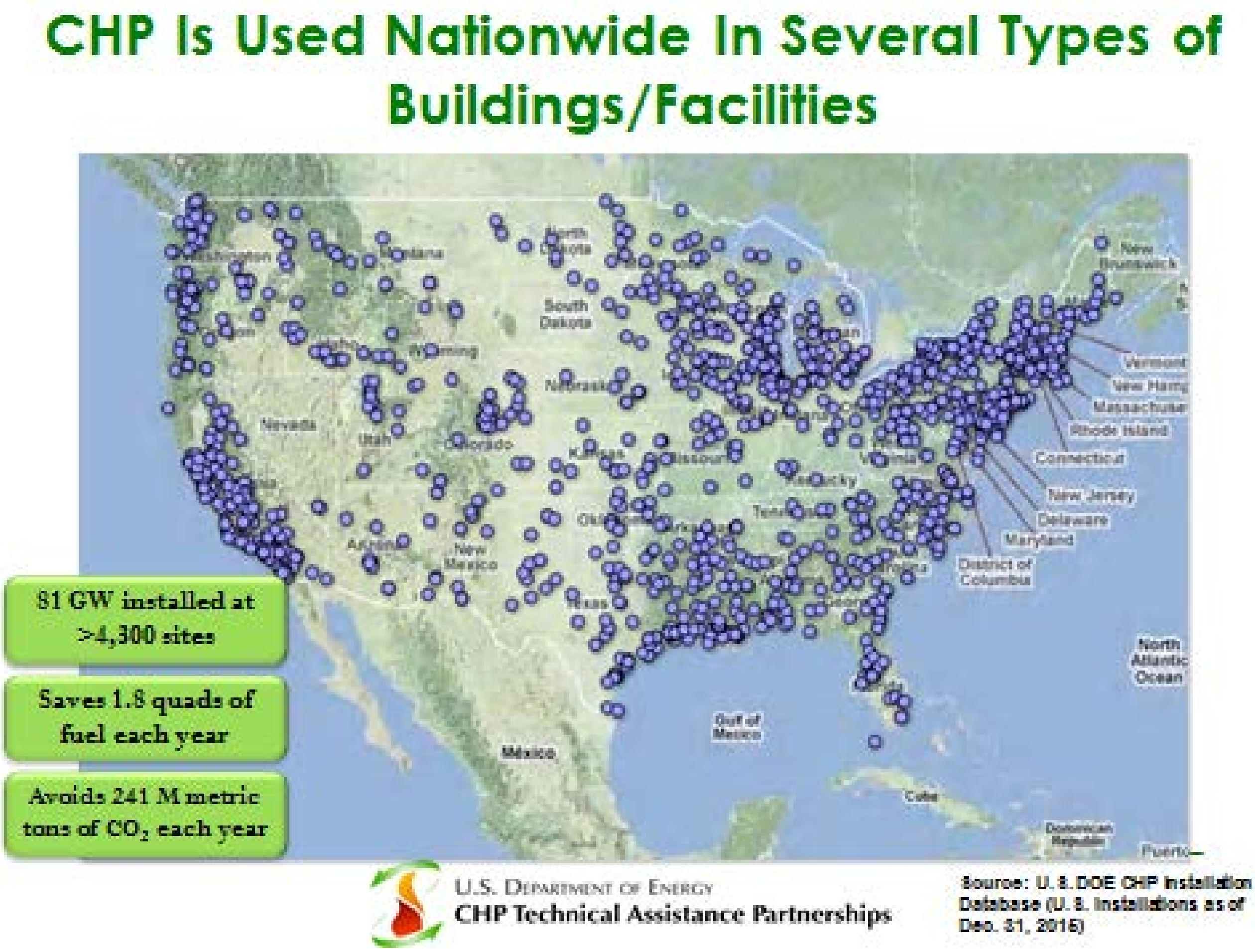
Q. Is CHP new or untested?

A. No. Table 1 and Figure 2 show that CHP is not new, as there are over 4,000 CHP systems that generate over 83,000 megawatts of energy nationally. Gas turbines (64 percent), followed by boiler/steam turbines (32 percent), account for the greatest share of total capacity; however, over half of the total number of CHP applications use

[1] U.S. Department of Energy, Midwest CHP Technical Assistance Partnership.

reciprocating engines. Table 2 provides a list of the 21 known CHP installations in Missouri.[2]

Figure 2: CHP Installations Nationwide.[3]



[2] *Ibid*.
[3] U.S. Department of Energy, Midwest CHP Technical Assistance Partnership.

Table 1. U.S. Installed CHP Sites and Capacity by Prime Mover.[4]

Prime Mover	Sites	Share of	Capacity	Share
Reciprocating Engine	2,194	51.9%	2,288	2.7%
Gas Turbine[5]	667	15.8%	53,320	64.0%
Boiler/Steam Turbine	734	17.4%	26,741	32.1%
Microturbine	355	8.4%	78	0.1%
Fuel Cell	155	3.7%	84	0.1%
Other	121	2.9%	806	1.0%
Total	**4,226**	**100.0%**	**83,317**	**100.0%**

[4] ICF CHP Installation Database, April 2014.
[5] Includes gas turbine/steam turbine combined cycle.

Table 2: Combined Heat and Power Installations in Missouri.

City	Facility Name	Application	Op Year	Prime Mover	Capacity (KW)	Fuel Class-Primary Fuel
Butler	Butler	District Energy	1946	ERENG	13,100	OIL - Distillate Fue
Cape Girardeau	Southeast Missouri State University	Colleges / Univ.	1972	B/ST	6,250	COAL - Coal
Columbia	University Of Missouri Power Plant	Colleges / Univ.	1961	B/ST	99,500	BIOMASS - Biomass
Columbia	Columbia Landfill	Solid Waste Facilities	2008	ERENG	3,000	BIOMASS - LFG
Florissant	Service Merchandise Company, Inc	General Merch. Stores	1985	ERENG	60	NG - Natural Gas
Hannibal	Clemmons Hotel	Hotels	1990	ERENG	150	NG - Natural Gas
Jefferson City	Jefferson City Correction Center	Justice / Public Order	2009	ERENG	3,200	BIOMASS - LFG
Kansas City	Bolling GSA office	General Gov't.	2000	BPST	100	WAST - Steam
Kansas City	Veolia Energy Kansas City	District Energy	2012	B/ST	5,000	BIOMASS - Biomass
Kansas City	Trigen-Kansas City Energy Corporation	District Energy	1990	B/ST	6,000	COAL - Coal
Laddonia	POET Biorefining - Missouri Ethanol	Chemicals	2007	CT	13,000	NG - Natural Gas
Lewistown	Lewistown School District	Schools	2003	MT	60	NG - Natural Gas
Louisiana	Hercules, Inc.	Chemicals	1942	B/ST	15,000	COAL - Coal
Macon	Northeast Missouri Grain	Chemicals	2003	CT	10,000	NG - Natural Gas
Mountain View	Smith Flooring, Inc.	Wood Products	1989	B/ST	500	WOOD - Wood
Neosho	La-Z-Boy Chair Company	Furniture	1984	B/ST	750	WOOD - Wood
North Kansas City	North Kansas City	Agriculture	1987	CC	4,000	NG - Natural Gas
St. Louis	Missouri State Hospital	Hospitals / Healthcare	1977	B/ST	5,000	COAL - Coal
St. Louis	Anheuser-Busch	Food Processing	1939	B/ST	26,100	COAL - Coal
St. Louis	Ashley Plant	District Energy	2000	CT	15,000	NG - Natural Gas
St. Louis	Southwestern Bell Telephone	Communications	1992	ERENG	6,000	OIL - Distillate Fue
St. Louis	Brandonview Building	Office Building	1969	ERENG	4,300	NG - Natural Gas
	Agricultural Facility	Agriculture	2014	ERENG	800	BIOMASS - Digester G

Source: modified from U.S. DOE Combined Heat and Power Installation Database, https://doe.icfwebservices.com/chpdb/state/MO.

As Table 3 shows, compared to other Midwestern states with cost of service regulation, Missouri ranks the lowest in terms of percent of total installed generating capacity from CHP.

Table 3: Total Electric Generating Capacity versus State CHP Capacity.[6]

Regulated State	Number of CHP Installations (#)[1]	State CHP Capacity (MW)[1]	Total Electric Capacity (MW)[2]	CHP as % of Total Capacity (MW)
Iowa	37	739	18,307	4.0%
Indiana	37	2,233	29,708	7.5%
Minnesota	56	937	17,402	5.4%
Wisconsin	98	1,592	19,082	8.3%
Missouri	23	237	23,837	1.0%

Table 4 shows that CHP is not untested technology. Table 4 provides technical detail that underscores the strengths of CHP technology. Note the performance parameters which put numbers to the benefits of high efficiency (55-80 percent), range of capacity (.005 to several hundred MW), high availability (72-99 percent), fuel diversity, and lower emissions of air pollutants.

[6] U.S. DOE Combined Heat and Power Installation Database, 2016 data, https://doe.icfwebservices.com/chpdb/state/MO; U.S. Energy Information Administration, 2015 data, http://www.eia.gov/electricity/data/state/.

Table 4: Comparison of CHP Technology Sizing, Cost, and Performance Parameters.[7]

Technology	Recip. Engine	Steam Turbine	Gas Turbine	Microturbine	Fuel Cell
Electric efficiency (HHV)	27-41%	5-40+%	24-36%	22-28%	30-63%
Overall CHP efficiency (HHV)	77-80%	near 80%	66-71%	63-70%	55-80%
Effective electrical efficiency	75-80%	75-77%	50-62%	49-57%	55-80%
Typical capacity (MWe)	.005-10	0.5-several hundred MW	0.5-300	0.03-1.0	200-2.8 commercial CHP
Typical power to heat ratio	0.5-1.2	0.07-0.1	0.6-1.1	0.5-0.7	1-2
Part-load	ok	ok	poor	ok	good
CHP Installed costs ($/kWe)	1,500-2,900	$670-1,100	1,200-3,300 (5-40 MW)	2,500-4,300	5,000-6,500
Non-fuel O&M costs ($/kWhe)	0.009-0.025	0.006 to 0.01	0.009-0.013	0.009-.013	0.032-0.038
Availability	96-98%	72-99%	93-96%	98-99%	>95%
Hours to overhauls	30,000-60,000	>50,000	25,000-50,000	40,000-80,000	32,000-64,000
Start-up time	10 sec	1 hr - 1 day	10 min - 1 hr	60 sec	3 hrs - 2 days
Fuel pressure (psig)	1-75	n/a	100-500 (compressor)	50-140 (compressor)	0.5-45
Fuels	natural gas, biogas, LPG, sour gas, industrial waste gas, manufactured gas	all	natural gas, synthetic gas, landfill gas, and fuel oils	natural gas, sour gas, liquid fuels	hydrogen, natural gas, propane, methanol
Uses for thermal output	space heating, hot water, cooling, LP steam	process steam, district heating, hot water, chilled water	heat, hot water, LP-HP steam	hot water, chiller, heating	hot water, LP-HP steam
Power Density (kW/m^2)	35-50	>100	20-500	5-70	5-20
NOx (lb/MMBtu) (not including SCR)	0.013 rich burn 3-way cat. 0.17 lean burn	Gas 0.1-.2 Wood 0.2-.5 Coal 0.3-1.2	0.036-0.05	0.015-0.036	0.0025-.0040

[7] U.S. Environmental Protection Agency Combined Heat and Power Partnership, 2015. Catalog of CHP Technologies, p 1-6.

Q. What are some examples of customers that are good candidates for CHP?

A. Customers with a steady demand for both thermal and electrical energy are prime candidates for utilization of CHP generation. Commercial sector candidates include hospitals and nursing homes, public water and wastewater treatment facilities, data centers, hotels, government facilities (federal, state, county, and city), and universities and colleges. Industrial sector candidates include food/beverage distributors as well as manufacturers of chemical, wood, agricultural, and furniture products.

Q. Has the Missouri Public Service Commission ("Commission") provided regulatory guidance with regard to rates for standby service customers?

A. Yes, 4 CSR 240-20.060, the cogeneration rule, was adopted in 1981 (and amended in 2003) for the specific purpose of implementing the Public Utility Regulatory Policies Act of 1978[8] with regard to cogeneration. The stated objective of the rule is to provide "a mechanism to set up a cogeneration program for Missouri for regulated utilities." A qualifying cogeneration facility is defined in 4 CSR 240-20.060(1)(G), consistent with Federal Energy Regulatory Commission regulations, as a generating facility that, "… sequentially produces electricity and other forms of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy." Cogeneration/CHP customers are subject to standby service tariff rates in addition to their otherwise applicable tariffs. Commission regulation 4 CSR 240-20.060(5)(A) requires that rates, "… shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility in comparison to rates for sales

[8] PUBLIC LAW 95-617—NOV. 9, 1978 92 STAT. 3145.

to other customers served by the electric utility. Rates for sales which are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that those rates apply to the utility's other customers with similar load or other cost-related characteristics" (emphases added).

Q. What is the case history on the issue of standby service?

A. DE filed testimony in ER-2014-0258 entitled, "CHP and Ameren Missouri's Rider E." In this testimony, DE described CHP, explained the economic, security, and environmental benefits associated with CHP, and documented the absence of cost-causation and non-discrimination rate principles reflected in Ameren Missouri's Rider E[9]. The issue was addressed through a Nonunanimous Stipulation and Agreement Regarding Supplemental Service Issues in which Ameren Missouri committed to develop and file, in collaboration with the signatories, a Standby Service Tariff by December 31, 2015 (Attachment 1)**.**

Q. Did Ameren Missouri file, in collaboration with the signatories, a SSR by the December 31, 2015 deadline in the Stipulation?

A. No. While the Company worked collaboratively and the effort was productive, the signatories did not reach agreement regarding rate charges. Due to the timing of Ameren Missouri's announcement of its intent to file a rate case, signatories agreed to address the impasse over rate charges through the rate case process.

[9] Direct Testimony of Alex Schroeder on Behalf of Missouri Department of Economic Development-Division of Energy, Missouri Public Service Commission Case No. ER-2014-0258, December 19, 2014.

Q. Has Ameren Missouri demonstrated that the rates contained within the proposed SSR are based on accurate data and consistent system-wide costing principles?

A. No. In response to Data Request No. DED-DE 004, Ameren Missouri stated that no studies have been done or exist that quantify the differences in costs of serving CHP customers compared to firm service customers. In response to Data Request No. DED-DE 009, Ameren Missouri stated that no studies have been done or exist that quantify the difference in cost of providing service to a CHP customer and a non-CHP customer with similar load or other cost characteristics.

Existing class cost of service studies do not reasonably reflect the unique load characteristics associated with cogeneration customers. There exists no tariff that clearly and transparently reflects the actual costs of providing standby service to customers who choose to utilize CHP technology.

Q. Given that the Commission's guidance is clear, why has there been a lack of attention in the area of standby service rates?

A. First, the lower utility rates enjoyed in Missouri currently make CHP generation by customers less economically feasible than in other areas of the country with higher energy. Second, technical expertise and awareness of the benefits of CHP has not been fully realized in the Midwest. For example, CHP utilization on the east and west coasts of the U.S. has proven to be invaluable during natural disasters. While Missouri is not subject to coastal hurricanes, it is vulnerable to tornadoes, thunder storms, ice storms, flooding, and significant earthquake activity. The third reason there has been a lack of attention in the area of standby service rates is that those Missouri customers who are aware and interested in CHP have not pursued such investments because they are discouraged by a) the lack of transparency of the standby service rates and b) the lack of supporting policies and programs.

Q. Why should the Commission take action now to prompt utilities to develop and offer understandable and fair standby service rates which fully comply with the cogeneration regulation (4 CSR 240-20.060)?

A. History suggests that Missouri's utility rates will continue to rise into the future. Regulatory mechanisms must be in place so that, as the economics of cogeneration continue to improve, customers are not impeded from utilizing CHP. It is understandable that utilities are not self-motivated to establish a tariff that results in an earnings reduction for the utility. The Commission should ensure that the opportunities and alternatives provided by CHP technologies can be utilized to increase customer choice, support economic development and competition, and promote efficiency and reliability through distributed generation. Time and effort is necessary to develop fair standby service rates in anticipation of a market that is not yet fully developed in Missouri. This testimony provides clear rationale for necessary revisions to the proposed SSR to ensure that cogeneration customers have available to them non-discriminatory, cost-based rates that accurately reflect the unique use characteristics expressed by the types and sizes of CHP technologies available. DE recommends development and implementation of a deliberate data collection effort from which a future class cost of service study can be performed and used to refine the SSR tariff rates and, perhaps, create additional tariffs reflective of distinct usage parameter ranges.

Q. How would the Company benefit from an uptake in CHP by customers?

A. Insofar as the Company desires to participate in the transformation of the energy sector, CHP applications can:

- Relieve grid congestion;
- Avoid investments in generation and delivery capacity;
- Increase system reliability;
- Serve as the foundation for district energy systems and microgrids;
- Promote economic development through energy technology employment and reduced energy and operating costs, which frees up real capital to invest in business expansion;
- Increase the use of distributed energy resources; and,
- Lower total system energy consumption, costs, and emissions.[10]

III. SUMMARY OF SSR WORKSHOP EFFORT RESULTING FROM CASE NO. ER-2014-0258

Q. Did you participate in the stakeholder effort to develop Ameren Missouri's SSR?

A. Yes, on behalf of DE, I participated in all the stakeholder meetings hosted by Ameren Missouri pursuant to the March 5, 2015, Nonunanimous Stipulation and Agreement Regarding Supplemental Service Issues in an effort to contribute to the clarity and transparency of the tariff and to promote the use of cost-causative and non-discriminatory rate principles.

[10] *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs,* Regulatory Assistance Project, December 2009, Prepared for U.S. Environmental Protection Agency Office of Atmospheric Programs Climate Protection Partnerships Division. p 2.

Q. What were the results of the collaborative effort?

A. The SSR Workshop resulted in productive dialogue and exploration surrounding a methodology intended to guide the development of the tariff. Specifically, the workshop led to the following outcomes:

1. Stakeholders learned that an important concept for evaluating the treatment of onsite generation by partial requirement (standby service) tariff structures is the avoided cost percentage ("ACP"). An ACP above 90 percent of the full service retail rate percentage generally provides adequate savings to support customer investment in onsite generation:

   > Ideally, the reduction in electricity price should be commensurate with the reduction in purchased electricity. If the onsite system reduces consumption by 80 percent, the cost of electricity purchases would also be reduced by 80 percent. The economics are severely impacted if partial requirements rates are structured so that only a small portion of the electricity price can be avoided. The higher the ratio of avoided costs to the full retail average price, the higher the user's savings. [11]

2. The SSR Workshop process led to the development of an annual load profile based upon average customer class data for each of the three classes of service intended to be addressed by the draft SSR. A consistent set of guidelines was used to create generation and outage profiles for each class to use for evaluation. Generation was modeled such that the cogeneration represents 40 percent of the

[11] U.S Environmental Protection Agency, 2009 Standby Rates for Customer-Sited Resources, Issues, Considerations, and Elements of Model Tariffs.

total customer load. Outage rates, intended to represent reasonable levels for common CHP technologies, were assumed at approximately 2 percent for maintenance service and 2 percent for backup service. Maintenance service was assumed to occur during one continuous time period in a non-summer month. Backup service was allocated to multiple forced outages occurring during different months, time of day periods, and was assumed to occur for differing durations of time, as would reasonably be expected in reality. The details of the forced outage occurrences were left to the discretion of Ameren Missouri and are depicted in Table 5.

Table 5. Ameren Missouri's SSR Workshop Model Outage Profile .

Outages	Additional Purchases		Maint hours	FO hours
November 22-28	121275	Maintenance	168	
January 17 for 42 hours	33201	FO		42
June 20 for 42 hours	30940	FO		42
February 17 for 24 hours	18873	FO		24
July 17 for 22 hours	17540	Maintenance	22	
March 28 @ hour ending 4, 7 hours	4815	FO		7
August 28 @ hour ending 11, 7 hours	6020	FO		7
October 28 @ hour ending 11, 7 hours	5796	FO		7
April 3, @12:00 24@3:00 3 hours each	4239	FO		6
May 2, @12:00 24@3:00 3 hours each	4239	FO		6
August 3, @ 12, 3 hours (off peak)	2580	FO		3
September 24@3:00 3 hours	1710	FO		3
December 12@1:00 3 hours	2133	FO		3
Totals	253361		190	150
Percentage of Annual Hours			**2.2%**	**1.7%**

The annual load profiles that were developed by Ameren and based upon average customer class data for each of the three applicable customer classes were then used to evaluate and compare avoided cost percentage for each of the classes on a consistent basis. This evaluation method resulted in an ACP of 84 percent for Large General Service (LGS), 85 percent for Small Primary Service (SPS), and 86 percent for Large Primary Service (SPS), all of which fall below the 90 percent threshold. These below-threshold ACP values suggest that the SSR rate design does not recognize the low probability that CHP customers will experience an outage during peak period.

3. The SSR Workshop also resulted in the review of standby service tariffs from other states, including Minnesota (see Attachment 2) and Iowa (see Attachment 3).

From DE's perspective, the practical tariff rate attributes of simplicity, understandability, and feasibility of application are of paramount importance in developing a standby service tariff for commercial and industrial customers who self-generate a portion of their energy needs.

Q. As stated above, the SSR Workshop ended in an impasse regarding rate charges. Did the Division of Energy offer specific guidance on the rate issue?

A. Yes; please refer to Attachment 4 for documentation of eleven elements that, prior to the conclusion of the SSR Workshop, were articulated by DE as necessary in determining specific rates for the proposed Ameren Missouri Standby Service Rider Tariff.

IV. DE ANALYSIS OF THE PROPOSED SSR

Q. Do you agree with Ameren Missouri Witness Mr. William R. Davis's description of the basic purpose of a SSR?

A. Partially. While a SSR is necessary to recover the fully allocated embedded costs associated with providing backup service, it should be designed in a way that does not create financial barriers to customers who would otherwise benefit from self-generating a portion of their energy requirements. Mr. Davis believes a standby rate should allow self-generating customers access to utility services without unfairly creating costs for other customers. While I agree with this assessment, it is incomplete. Rates should reasonably reflect the system-benefiting attributes of CHP deployment so as not to discourage integration of these technologies into the power system. CHP customers have unique usage characteristics that can benefit other customers through reduced loads on the system, thereby avoiding additional investment in utility infrastructure. Standby rates are critical in determining the feasibility of CHP deployment but have been generally recognized as a barrier to implementation.[12, 13, 14, 15] Standby service rate design should follow the same rate-making objectives that are applied to full requirements customers. Of the eight generally accepted criteria of a desirable rate structure, three stand out as particularly applicable in the development of a SSR:

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[12] American Council for an Energy Efficient Economy, 2011. Chittum, Anna, and Nate Kaufman, *Challenges Facing Combined Heat and Power Today: A State by State Assessement*, Report Number IE111. Pages 22, 51.
[13] American Council for an Energy Efficient Economy, 2013. Chittum, Anna and Kate Farley, Utilities and the CHP Value Proposition, Report Number IE134. Page 4.
[14] [EPA] Environmental Protection Agency. 2009. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*. Washington, D.C.: US Environmental Protection Agency.
[15] Casten, S. and M. Karegianes. 2007. "The Legal Case Against Standby Rates." *The Electricity Journal* 20 (9): 37-46.

1. The practical attributes of simplicity, understandability, public acceptability, and feasibility of application;
2. Fairness of the specific rates in the apportionment of total costs of service among the different consumers; and,
3. Avoidance of undue discrimination in rate relationships.[16]

Standby service customers should not pay for costs that they do not cause to be incurred.

Q. For what services should CHP customers be charged in a SSR?

A. A SSR should reflect the cost of 1) the reservation of the generation, transmission, and distribution services needed to provide power when the customer's generator is not producing due to an unplanned (emergency) energy failure/outage, and 2) energy charges for the incremental amount of electricity provided by the utility resulting from the customer-generator outage.

Q. Please describe your analyses of the rates contained within the proposed SSR.

A. DE's analyses are based on Ameren's workpapers filed in support of the proposed SSR and build upon the SSR Workshop efforts, which ended in impasse regarding the specific rate values. Based on my review, Ameren Missouri's currently proposed SSR tariff reflects only a small reduction in the rates resulting from the SSR Workshop.

The outage scenario presented by Ameren Missouri in this case is very different than the one developed during the SSR workshop and shown previously in Table 4. Instead of varying the frequency and durations of forced outages(FO), a continuous week was

[16] Bonbright, James C. *Principles of Public Utility Rates*. New York: Colombia University Press, 1961. p 291.

modeled. While simpler to run and less representative of a real outage scenario, this outage scenario resulted in more favorable avoided cost percentages.

In order to analyze the rates in the proposed SSR, it was necessary to summarize the applicable rates associated with the proposed SSR tariff. For each customer class, a comparison of tariffs is presented for each season. Tables 6-8 depict summer season rates and Tables 9-11 depict winter season rates. As shown in the tables, LPS customers pay high demand charges and low energy charges under the full-service and supplemental tariff structures. In comparison, SPS and LGS customers pay a lower demand charge and higher energy charges. For SPS and LGS customers, a portion of the demand charge attributable to distribution facilities cost is embedded in energy rates configured into three blocks: a first consumption block at the highest rate, a second consumption block at a lower rate, and a remaining consumption block at the lowest, or base, rate. A significant portion of the embedded demand charges are recovered in the first block of energy usage. For the LPS customer, the proposed SSR tariff shifts a majority of the demand charge from the fixed monthly reservation demand charge into the daily as-used demand charge, which is desirable over paying fixed charges. For the SPS and LGS customers, a much smaller portion of the demand charge is proposed to be shifted into the daily as-used demand charge, which is less desirable for the customer.

The tables also reflect the fact that for all classes in the SSR, the sum of the fixed reservation charge and thirty days of maintenance standby in a month roughly equates to the full demand charge in the applicable full/supplemental tariff. This is illustrated in the tables in red text. Use of backup standby service in lieu of maintenance standby service doubles the as-used charges which motivates customers to maintain reliable operations on peak when they are most likely to incur these back up rates. The cost per kW for 30 days of backup standby for the LPS customer is double the rate of 30 days of maintenance standby. For SPS and LGS, the increase in unit cost is on the order of 12 to 20 percent.

Table 6. Comparison of LPS tariff and the SSR tariff, Summer Season.

		SUMMER SEASON	**LPS**		
			Full Service & Supplemental	Standby	Total Standby 30 day basis
Demand	$/kW	Monthly	$21.98	$3.86	N/A
Demand	$/kW	Maintenance - per day	N/A	$0.60	$21.86
Demand	$/kW	Backup - per day	N/A	$1.21	$40.16
Energy	$/kWh	Block 1	N/A	N/A	N/A
Energy	$/kWh	Block 2	N/A	N/A	N/A
Energy	$/kWh	Block 3/Base	$0.0368	$0.0441 peak*	N/A

Table 7. Comparison of SPS tariff and the SSR tariff, Summer Season.

		SUMMER SEASON	**SPS**		
			Full Service & Supplemental	Standby	Total Standby 30 day basis
Demand	$/kW	Monthly	$4.29	$3.69	N/A
Demand	$/kW	Maintenance - per day	N/A	$0.02	$4.29
Demand	$/kW	Backup - per day	N/A	$0.04	$4.89
Energy	$/kWh	Block 1	$0.1072	$0.1174 peak*	N/A
Energy	$/kWh	Block 2	$0.0807	N/A	N/A
Energy	$/kWh	Block 3/Base	$0.0541	N/A	N/A

* Time-of-Day (TOD) pricing is imposed on SSR customer for standby service, optional for full requirements. Off-peak is less than full requirements base price.

Table 8. Comparison of LGS tariff and the SSR tariff, Summer Season.

		SUMMER SEASON	LGS		
			Full Service & Supplemental	Standby	Total Standby 30 day basis
Demand	$/kW	Monthly	$5.17	$4.57	N/A
Demand	$/kW	Maintenance - per day	N/A	$0.02	$5.17
Demand	$/kW	Backup - per day	N/A	$0.04	$5.77
Energy	$/kWh	Block 1	$0.1107	$0.1245 peak*	N/A
Energy	$/kWh	Block 2	$0.0833	N/A	N/A
Energy	$/kWh	Block 3/Base	$0.0560	N/A	N/A

Table 9. Comparison of LPS tariff and the SSR tariff, Winter Season.

		WINTER SEASON	LPS		
			Full Service & Supplemental	Standby	Total Standby 30 day basis
Demand	$/kW	Monthly fixed	$9.98	$1.42	N/A
		Maintenance - per day	N/A	$0.29	$10.12
		Backup - per day	N/A	$0.57	$18.52
Energy	$/kWh	Block 1	N/A	N/A	N/A
		Block 2	N/A	N/A	N/A
		Block 3/Base	$0.0326	$0.0360 peak*	N/A

* In the proposed SSR, Time-of-Day (TOD) energy pricing is imposed on the SSR customer. TOD is optional for full requirements customers. Off-peak rate is less than full requirements base rate.

Table 10. Comparison of SPS tariff and the SSR tariff, Winter Season.

		WINTER SEASON	SPS		
			Full Service & Supplemental	Standby	Total Standby 30 day basis
Demand	$/kW	Monthly fixed	$1.55	$1.25	N/A
		Maintenance - per day	N/A	$0.01	$1.55
		Backup - per day	N/A	$0.02	$1.85
Energy	$/kWh	Block 1	$0.0675	$0.0714 peak*	N/A
		Block 2	$0.0502	N/A	N/A
		Block 3/Base	$0.0392	N/A	N/A

Table 11. Comparison of LGS tariff and the SSR tariff, Winter Season.

		WINTER SEASON	LGS		
			Full Service & Supplemental	Standby	Total Standby 30 day basis
Demand	$/kW	Monthly fixed	$1.92	$1.62	N/A
		Maintenance - per day	N/A	$0.01	$1.92
		Backup - per day	N/A	$0.02	$2.22
Energy	$/kWh	Block 1	$0.0698	$0.0742 peak*	N/A
		Block 2	$0.0517	N/A	N/A
		Block 3/Base	$0.0407	N/A	N/A

* Time-of-Day (TOD) pricing is imposed on SSR customer for standby service, optional for full requirements. Off-peak is less than full requirements base price.

Because of the low chance of outage, a model SSR would more fairly minimize fixed charges, and consist primarily of relatively high, as-used demand and energy charges. The LPS class, at 82% of the SSR charges reflected as-used energy charges and 12% fixed costs, is more representative of the model rate design. The SPS and LGS customer SSR rates should be distributed similarly between fixed and as-used charges. However, this is not the case in Ameren's proposed SSR for those classes. Table 12 illustrates the disparity between the LPS and SPS/LGS customers' fixed and as-used charges.

Table 12. Portion of the applicable tariff full service demand charge that is shifted to fixed and maintenance charges in proposed SSR.

	Summer Fixed Reservation	Summer Used 30 days maintenance	Winter Fixed Reservation	Winter Used 30 days maintenance
LPS	18%	82%	14%	86%
SPS	86%	14%	81%	19%
LGS	88%	12%	84%	16%

IV. TIME OF DAY RATES ISSUE

Q. Is it appropriate to impose TOD energy rates on the cogeneration customer when it is optional for full requirements customers through the otherwise applicable tariff?

A. No. As shown in Tables 6-11, the Energy Block 1 for the Standby column reflects the on- peak TOD rate. Thus, TOD energy rates are imposed on the SSR customer, whereas these rates are optional for full requirements customers through the otherwise applicable tariffs (LGS, SPS, and LPS). This misalignment creates discriminatory treatment of the SSR customer. This misalignment should be addressed by changing the energy rates in the proposed SSR to reflect the rate of Energy Block 1 and mirror the TOD rate option language from the otherwise applicable tariffs to the SSR. In addition, language should be added to the proposed SSR to clarify that if a customer chooses the TOD option under the otherwise applicable tariff, then the TOD option will apply to the SSR rate as well.

V. SINGLE PREMISES ISSUE

Q. Does the proposed SSR impede cogeneration opportunities by limiting the applicability to single premises?

A. Yes. The SSR tariff limits applicability to a "single premises" with behind the meter distributed generation but does not address situations where multiple meters exist on the premises. Where multiple meters exist, a CHP customer would likely need the ability to aggregate use across those meters on the premises in order to optimally configure his/her CHP system. Restricting SSR to a single premise also precludes CHP from being optimally configured for district energy systems that provide thermal energy to multiple premises. Meter aggregation enables the total power demand and energy sales to determine which customer class and applicable rate schedule to apply, and enable excess power generated at one premise to be utilized at another to serve a concurrent load on an adjacent premises instead of being significantly devalued at "avoided cost" per the standard Ameren Missouri power purchase rates.[17] To eliminate the barrier that currently exists with the term "single premises" the term should be replaced with explicit language clarifying that multiple meters on a single premise can be combined for purpose of billing. Standby Service customers should be allowed to aggregate service under reasonable conditions, including properties owned/operated by the customer within a locality.

[17] https://www.ameren.com/-/media/missouri-site/Files/Rates/UECSheet170EPPQFCogen.pdf

VI. MULTIPLE GENERATING UNITS ISSUE

Q. Does the proposed SSR create unreasonable limitations with regard to treatment of customers with multiple generating units?

A. Yes. It is not unlikely or unreasonable for a customer to choose installation of more than one cogeneration unit. The proposed SSR does not accommodate this possibility. For example, if a customer's average thermal load is approximately half of his/her peak thermal load, he/she might select two generators, one to meet the average demand and the second to meet the peak demand. A customer might also choose a second generating unit for the redundancy function it can provide. The probability that multiple generating units will experience simultaneous outage is significantly less than the probability of a single unit outage. Depending on the specific configuration, there should be opportunity for the customer to pay reduced fixed charges for standby service based on the level of redundancy provided by multiple generating units. Language should be added to the proposed SSR that explicitly reflects this consideration.

VII. DEFINITION OF SUPPLEMENTAL CONTRACT CAPACITY ISSUE

Q. How does the proposed SSR define Supplemental Contract Capacity ("SCC")?

A. The proposed SSR definition of SCC is the maximum peak kW demand for the season, taken through the billing meter without customer generation based on historical or estimated information. Actual demand kW registered at the meter that is less than or equal to the SCC is billed according to the standard tariff rate and demand kW registered at the meter in excess of the SCC is billed according to the SSR tariff rate. The SCC delineation applies to energy charges also.

Q. How does the proposed SSR differ from the standard tariff with respect to SCC?

A. The standard tariff rate applied to a full requirement customer has no ceiling or associated penalty for variability in demand above the level anticipated. The SCC ceiling limits the variability allowed for SSR customer supplemental service that would normally be provided to similar service taken under a full requirement tariff. Defining the SCC for the SSR customer as the "maximum seasonal demand" creates a ceiling by which normal variation of self-generation is impeded. The SSR customer is not able utilize the SSR tariff rates as envisioned. The customer is likely to have more kWh assigned to larger, higher block rates and to incur demand charges under the supplemental tariff that are higher and in addition to the fixed reservation charges the SSR customer is paying whether back up is needed or not. The effect of the SCC is to charge the SSR customer a premium for capacity but limit his/her ability to access the lower demand charges associated with the SSR.

Q. **How was variability evaluated?**

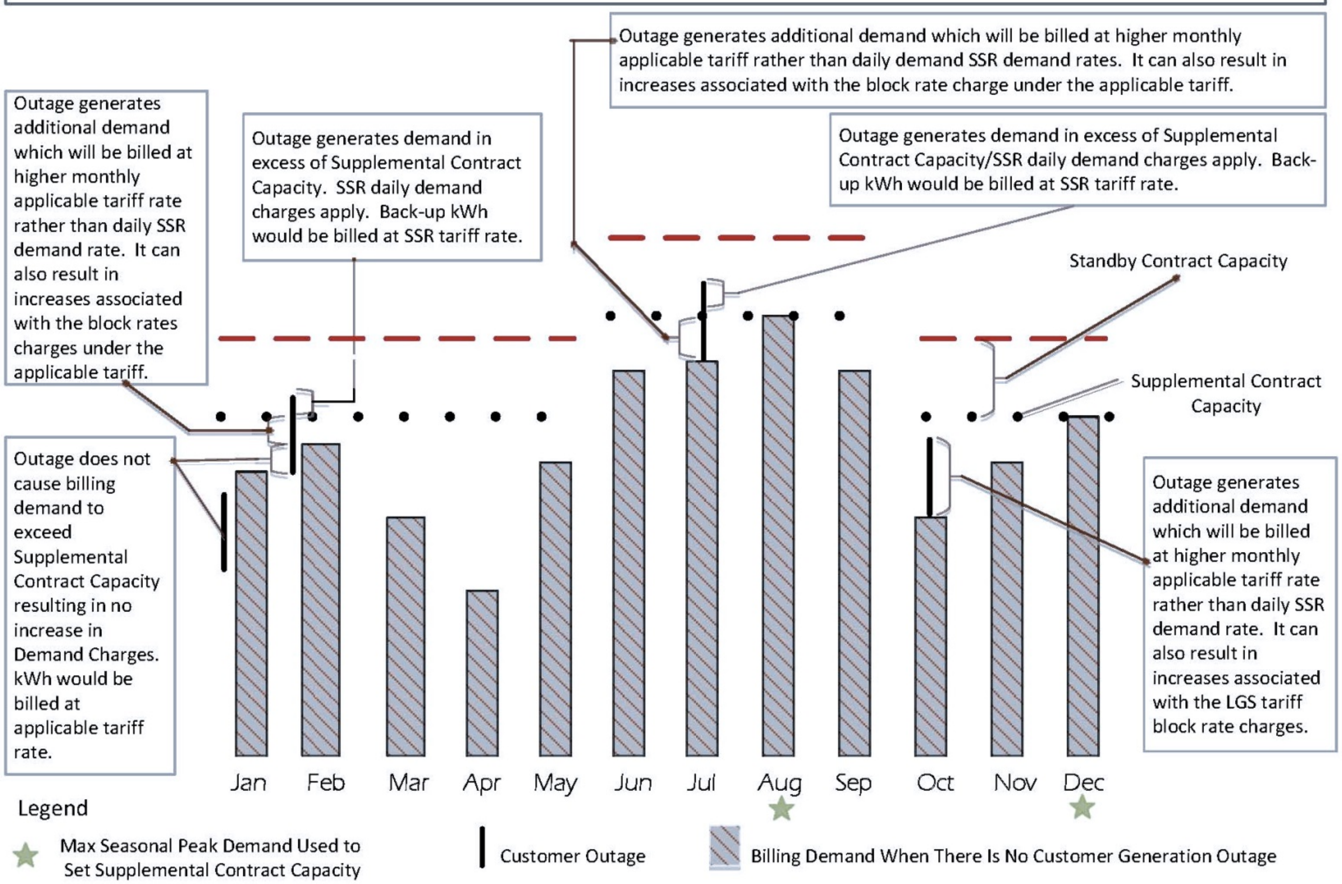
A. To evaluate typical variability, DE studied LPS customer data. Approximately one year of monthly billing data was analyzed for most LPS customers to determine the mean billing demand in kW, and the value of one standard deviation from the mean. Some customers were excluded from the analysis based upon insufficiency or irregularity in their billing data. For example, customers with less than nine months of billing data, or whose data indicated that the minimum demand of 5,000 kW was the billing demand for more than three months during the analysis period, were eliminated from the analysis group. The results of the analysis indicate a standard deviation range of 2 to 22 percent, with the average occurring at about 10 percent. Generally, large institutional customers fell within the higher range and large industrial customers fell within the lower range. Billing data was not available in the Company's workpapers sufficient to conduct a similar analysis for SPS and LGS classes.

Q. Does the proposed SSR remove the allowance of normal use variability that is provided to non co-generating customers?

A. Yes. DE does not disagree with the concept of establishing a supplemental contract capacity above which standby service rates will apply. However, Ameren Missouri's proposal to use the maximum monthly demand to determine the supplemental contract capacity results in 1) taking away from the cogenerator the normal range of variability that is provided under the supplementary portion, and 2) negative impacts on energy charges due to widening of high cost energy blocks. The impacts of this treatment are illustrated in Figure 3.

Figure 3. Impact of Maximum Seasonal Peak Demand Use to Define SCC

The Standby customer pays fixed charges to reserve standby capacity every month whether the capacity is used or not, but does get the full benefit of the associated SSR Daily Demand Charge when the Seasonal Maximum Demand is used to define the Supplemental Contract Capacity.



Q. How could a measure of variability be constructed into the proposed SSR?

A. To resolve the issue of limiting cogeneration normal use variability, DE recommends redefining the supplemental contract capacity to be 90% of seasonal maximum billing demand. This revision would provide a measure of variability similar to that provided to non co-generation customers, as supported by DE's LPS customer study.

VIII. RECOMMENDATIONS

Q. What are DE's specific recommendations?

A. DE recommends that Ameren Missouri should:

1. Add language to the proposed SSR to clarify that if customer chooses the TOD option under the otherwise applicable tariff, then the TOD will apply to the SSR as well. The Company should also revise the energy rates in the proposed SSR to reflect the highest block values and mirror the TOD rate option language from the otherwise applicable tariffs to the SSR;
2. Add language to the proposed SSR that states that, for those customers who choose to install more than one generating unit, there should be opportunity for the customer to pay reduced fixed charges for standby service based on the level of redundancy provided by multiple generating units;
3. Add a clarifying sentence to the SCC definition to specify that the starting point for calculation of the SCC is no more than 90% of the seasonal maximum billing demand; and,
4. Develop and implement a deliberate data collection effort from which a future class cost of service study could be performed and used to improve the SSR tariff rates.

Q. Does this conclude your testimony?

A. Yes.