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Witness:	Kavita Maini
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2024-0261
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BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in Its Missouri Service Area	)))))	**File No. ER-2024-0261**

Surrebuttal Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

September 17, 2025

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

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TABLE OF CONTENTS

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Surrebuttal Testimony of Kavita Maini

INTRODUCTION

Q. Please state your name and occupation.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. Please state your business address.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. Are you the same Kavita Maini that previously filed Direct and Rebuttal Testimony in this case?

A. Yes, I filed direct testimony and rebuttal testimony on behalf of the Midwest Energy Consumers Group ("MECG"). I provided recommendations regarding Empire District Electric Company d/b/a Liberty's ("Liberty" or "Company") class cost of service study ("COSS"), revenue allocation to classes and rate design on its Large General Service ("NS- LG", "TC-LG") Large Power Service ("LP") and Transmission Service ("TS") Schedules respectively.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the Company and Commission

Staff witnesses regarding COSS methodology, revenue allocation, and rate design related matters. The fact that I do not address any particular issue should not be interpreted as my implicit approval of any position taken by Staff or any other party on that issue.

I. COST OF SERVICE

A. Production Cost Allocator

Q. Which production cost allocator did you recommend in your direct testimony?

A. I recommended the Average and Excess ("A&E") 4NCP allocator.

Q. Did the Company support this approach?

A. Yes, Company witness Mr. Timothy Lyons agreed that it was appropriate to modify from the Company's A&E-8NCP to MECG's A&E-4NCP allocator.[1]

Q. Please comment on the Company's response.

A. I appreciate the Company's recognition and acceptance of MECG's A&E-4NCP allocator.

Q. What was Staff's response to your recommendation?

A. Staff opposes the A&E method for renewable generation. Staff witness Ms. Sarah Lange asserts that wind generation related fixed costs should be allocated to customer classes using an energy allocator. Her assertion is that it is not reasonable to allocate capital costs of wind and solar generation on a measure of class demands and to allocate revenues from wind and solar generation on a measure of class energy. In support of her argument, she asserts that for customer classes that utilize more energy, they also

[1] See Mr. Timothy Lyons Rebuttal Testimony on page 7.

receive more revenues from wind generation compared to other classes that use less energy while at the same time they are allocated lesser capital costs due to a lower demand allocator. She also indicates that since peak loads driving capacity investments do not currently coincide with the times of peak wind output, this means wind generation related fixed production plant related costs should be allocated based on an energy allocator.

Q. Do you agree with Ms. Lange's rationale?

A. No, I do not support her rationale for the following reasons:

First, as a practical matter and as explained in my rebuttal testimony, the allocation of fixed production plant should be predicated on load characteristics of the Company's system, not the operating characteristics of any one or more generation resources. The cost causative drivers or need for acquiring a resource have not changed and continue to be based on load profile, energy usage and demand needs. These drivers are included in the development of the A&E allocator which once again incorporate the maximum demands, load factor and <u>energy use.</u> Contrary to Staff's perspective, Liberty's participation in the SPP market does not invalidate the fact that the primary reasons it built or acquired generation capacity is sized to meet system peak demands and the type of capacity that was built is primarily a function of the load characteristics of the system. Therefore, it remains reasonable to use the A&E allocator to allocate all types of fixed production plant cost including wind generation.

Second, I believe Ms. Lange's assertions of inconsistency between allocation of wind generator revenues and wind generation costs in isolation does not provide a complete picture. Important issues come to mind which do not appear to be addressed in her analysis and render it inconclusive:

1. Her analysis is speculative. She does not explain on a year by year basis whether the utility is short or long on an hourly basis. She overlooks important details regarding whether the hourly generator revenues are more than offset by the costs to serve load which would imply no generator revenues to spread to classes. Thus, her analysis is speculative and incomplete and does not conclusively demonstrate the need to change from the A&E production allocation.
2. Assuming for the sake of argument that it is reasonable to allocate the wind generation capital investment based on an energy allocator thereby requiring customers with energy intensive operations to disproportionately pay for the fixed costs, then on the fuel cost side, it should also be ensured that such customers also get the benefit of being allocated the "fuel" cost savings associated with wind generation. However, since the fuel costs are not time differentiated on a broad level or on a granular hourly basis but rather allocated to classes using a flat energy allocator, the customers with the energy intensive operations would also end up paying a disproportionate level of fuel costs because they do not receive the "fuel" savings benefit. This would not be a reasonable outcome.

Third, Ms. Lange asserts that peak loads driving capacity investments do not currently coincide with the times of peak wind output. She argues, therefore, that it would not be valid to allocate wind using the A&E allocator. However, it is worth noting that while Ms. Lange tends to rely on the SPP market design principles when it comes to incorporating generator revenues, she ignores SPP's methodology used to assign accredited capacity to renewable generation. The Company's response to MECG 2.2 shows differing accredited capacity value for wind generation for summer and winter respectively. Therefore, by using an energy allocator, she ignores the capacity value attributable to these resources thereby deviating from cost causation.

Fourth, as indicated by Ms. Lange in her direct testimony, it is the participation in the SPP market that resulted in Staff's view of differentiating generation based on operating characteristics. However, note that none of the investor-owned utilities in Missouri have changed their methodology to classify and allocate fixed production plant since participating in organized markets. They continue to recognize the reasonableness and validity of the A&E methodology for all resources notwithstanding participation in the SPP or MISO market.

For all these reasons, I continue to oppose Staff's production plant allocation methodology based on generation operating characteristics and continue to recommend the A&E allocation method for all resources. Further, I believe that MECG's A&E-4NCP allocator is a reasonable allocator for allocation of all fixed production plant related costs. As discussed above, this view is also supported by the Company who has agreed to adopt MECG's allocator.

B. Distribution Plant Related Classification and Allocation

Q. Do you continue to support the Company's methodology to classify and allocate equipment related costs booked in FERC accounts 364-368?

A. Yes, I do. I reviewed Mr. Lyons' assessment and response to Staff's analysis and understand from his rebuttal testimony that Staff did not consider certain notable factors such as updating costs using the Handy Whitman index and excluded supporting costs such as guys, anchors, and fixtures. Further, considering that 40% of the investment was based on the zero intercept methodology which has no load, Staff's concerns about load carrying capability seems to be misplaced. As noted in my direct testimony, I continue to believe that the Company made a concerted effort to be conservative by using the lower percentage between the minimum system and zero intercept methods where the Company could reasonably calculate two estimates for certain distribution equipment. Thus, I continue to believe that the Company's approach for classifying distribution equipment booked in FERC accounts 364-368 to be reasonable. Further, I am supportive of the Company view of allocating the demand related classified costs on the basis of 1-NCP as opposed to Staff's 12-NCP allocation. As explained in my rebuttal testimony, Staff's use of class contribution to 12 coincident peaks to allocate distribution plant is inconsistent with cost causation

II. REVENUE REQUIREMENT ALLOCATION

A. Revenue Requirement Increase to Classes

Q. What was your revenue requirement recommendation in direct testimony?

A. My revenue allocation recommendations in direct testimony were directionally consistent with MECG's COSS results meaning that:

- Customer classes with negative ROR at present rates received the highest increase and customer classes with the highest ROR (in double digits) at present rates received the lowest increase.
- Customers classes with below system average ROR at present rates receive an above system average increase; and

- Customer classes with above system average ROR at present rates receive a below system average increase.

Further, in terms of the specific allocations, I relied on the relative RORs at present rates to get classes closer to cost while recognizing that moderation is necessary given the double digit increase. My recommendations were presented in terms of a class multiplier to the average system increase as has been used by Evergy in the last two most recent rate cases.

Q. Did Staff have concerns regarding my methodology?

A. Yes. Staff witness Ms. Maria Gonzales finds it unreasonable that I gave two classes with different cost of service based results the same multiplier. For instance, she indicates that the Small Primary Service NS and TC cost of service results are different but are both assigned the same multiplier.

Q. How do you respond to Staff's assertions?

A. As summarized above, I endeavored to be clear in my direct testimony regarding the various factors I considered in recommending MECG's revenue allocation. I made efforts to temper the rate impacts for certain classes while also recognizing that it is important to make movement towards getting classes closer to cost. I used the class relative rates of return at present rates to smoothen the revenue allocation curve further than what the cost of service study results would suggest. Then, I attempted to develop multipliers for certain rate schedules that were different within the class in some cases because the cost of service study suggested significant variations in the relative ROR at present rates. As mentioned in my direct testimony, the multiplier approach is not new, and Staff is well aware of this method due to the experience in the recent Evergy base rate cases.

Q. Did Staff highlight other concerns with your approach?

A. Yes. Staff would prefer the same increase for rate schedules within a class.

Q. Do you have an alternative recommendation which results in the same rate increase for all rate schedules within a class?

A. Yes, I do. Figure 1 below shows the major classes with the same multiplier applicable to all rate schedules within the class.

Figure 1: MECG Alternative Revenue Allocation at Class Level

Class	MECG COSS Increase Percent	COSS Multiplier (Class Increase/Overall Increase)	MECG Recommended Multipliers At Class Level	Class Impacts with Company's Average Increase of 29.64% using MECG Multipliers
Residential Class	42.40%	1.43	1.147	34.0%
General Service Class	10.40%	0.35	0.780	23.1%
Large General Service	32.30%	1.09	1.002	29.7%
Small Primary Service	-1.50%	-0.05	0.682	20.2%
Large Power Service	5.60%	0.19	0.759	22.5%
Transmission Service	10.40%	0.35	0.780	23.1%
Lighting Service	11.80%	0.40	0.823	24.4%
Overall Increase	29.64%	1.00	1.000	

These multipliers are similar in large part to the multipliers I had by rate schedule except I moved some classes closer to cost than my original recommendation, while retaining moderation for other classes. I made some modifications to move classes closer to cost because based on Staff's revenue requirement analysis, it is very likely that the final revenue requirement will be lower than the Company's initial revenue requirement.

For instance, the Small Primary Class has a lower multiplier compared to my recommendation in direct testimony meaning further movement to cost of service for this class. I also recommend the same multiplier for General Service as Transmission Service since they have the same cost-based multiplier. My proposed recommendation is generally consistent with bringing all classes 30 percent closer towards the costs to serve. While I believe the revenue allocation recommendation in my direct testimony is reasonable and can be adopted, in the interest of narrowing the issues in this case, with regards to applicability of the rate increase to classes, I can support the same increase to the rate schedules within each class. The last column in Figure 1 shows the percent increases at the class level assuming the same revenue requirement increase as the Company's original proposal to provide an apples-to-apples comparison.

Q. Please provide a comparison of the class cost of service related multipliers to the multipliers derived for the Company and Staff recommendations.

A. Figure 2 below shows both the cost of service study related multipliers and revenue allocation multipliers for Staff, the Company and MECG.

Figure 2: Comparison of Cost of Service Related Multipliers with Revenue Allocation Multipliers

	Staff COSS Multiplier	Staff Option 1 Revenue Allocation Multiplier	Staff Option 2 Revenue Allocation Multiplier	Company COSS Multiplier	Company Revenue Allocation Multiplier	MECG COSS Multiplier	MECG Revenue Allocation Multiplier
Residential Class	1.52	0.85	1.13	1.46	1.04	1.43	1.15
General Service Class	0.59	1.15	0.67	0.40	0.94	0.35	0.78
Large General Service	0.84	1.15	0.94	1.00	1.00	1.09	1.00
Small Primary Service	0.46	1.15	0.54	-0.01	0.90	-0.05	0.68
Large Power Service	0.89	1.15	0.97	0.18	0.92	0.19	0.76
Transmission Service	1.43	1.15	1.36	0.34	0.94	0.35	0.78
Lighting Service	1.22	1.15	1.15	0.54	0.95	0.40	0.82
Overall Increase	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Comparing Staff's Option 1 to the Staff's own CCOS result, it is clear that Staff's Option 1 is not cost of service based and should be rejected. Further, while Staff's Option 2 directionally follows its cost of service study, I have previously explained the flaws in that approach and so I recommend Staff's Option 2 revenue allocation be rejected as well.

The Company and MECG's cost of service study results are very similar. However, compared to MECG on revenue allocation. the Company makes very little movement towards its cost of service study results while focusing more on mitigating the rate impacts for certain classes. While I recognize that tempering the rate increase for certain classes is very necessary and important given the magnitude of the increase, we must also promote fairness by making meaningful movement towards costs – after all, by recommending that some classes pay less than the costs to serve, we are asking other classes to pay more than it costs for their service, thereby creating a tradeoff between moderation and fairness that should be carefully considered. I believe that my revenue allocation draws a better balance between considering rate mitigation and fairness compared to the Company's proposal, I therefore recommend that the Commission adopt MECG's revenue allocation multipliers for application to the final rate increase.

B. Allocation of Income Eligible Rate Discount for Residential Customers

Q. Did OPC witness Dr. Geoff Marke recommend a new program aimed at residential customers?

A. Yes. Dr. Marke recommended a program aimed at low-income residential customers. His proposal consists of waiving the customer charge for income eligible customers above a certain threshold as explained on page 10 of his direct testimony.

Q. Assuming that Dr. Marke's proposal is accepted, how should the costs associated with this program be allocated?

A. Given that the program is aimed at residential customers, the related costs associated with this program should be allocated within the residential class.

Q. Based on its rebuttal testimony, Staff suggests allocating these costs to all classes based on an energy allocator. Do you support this approach?

A. No, I am not supportive of Staff's proposal. Non-residential customers do not cause any costs associated with or realize any benefit from this program. Therefore, cost recovery within the residential class would be consistent with cost causation principles.

Also, as a secondary matter, as it relates to Staff's preferred rate design, the residential program appears to be focused on income eligible customers which would be more closely related to revenue and not energy use in how it should be recovered.

III. RATE DESIGN

A. Response to Staff Regarding Recovery from Demand and Energy Components

Q. Generally speaking, what was your main concern regarding the Company's proposed increases in the energy and demand charges for LGS and LPS rates?

A. My main concern was that the Company's rate design proposals aimed at commercial and industrial customers such as the LGS and LPS classes were largely ignoring cost of service guidance regarding appropriate recovery from demand charge components. That is, there is over recovery of fixed costs from energy charges and under recovery of such costs from demand charges thereby resulting in inefficient rate design[2]. My recommendations in direct testimony generally consisted of making no changes to the tail block energy rates and increasing the recovery from the billing demand charges. I

[2] I discussed economic efficiency in rates within my direct testimony at pages 5-6.

had additional feedback regarding narrowing the difference in the summer and winter demand charges for the LPS class.

Q. What was Staff's response to your recommendations?

A. Staff witness Ms. Maria Gonzales opposes my recommendation on the basis that there is little to no relationship between customers' non coincident peak ("NCP") and coincident peak ("CP"). Since customers are billed based on NCP demand and not CP demand, customers that use most of their energy during the off peak would be potentially penalized. She concludes that it is not reasonable to increase the cost recovery of NCP charges and to further bill customers who use most of their energy in off peak hours.[3]

Q. How do you respond?

A. I respond with the following:

I share Ms. Gonzales' concern regarding the discouragement of off peak use. Indeed, the most direct way to affect off peak usage is by making concerted efforts to lower the fixed cost recovery from the tail block of the energy rates. The tail energy block usage represents off peak usage.[4] Therefore, the most direct way to address discouraging off peak usage is to ensure in this case that there is no increase in the already high tail block rates which are recovering fixed costs. Therefore, my recommendation to make no changes to the tail block rates should actually address staff's concerns as it pertains to discouraging off peak energy usage.

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[3] See Ms. Maria Gonzalez rebuttal testimony on page 5.

[4] See for instance, Ms. Sarah Lange's direct testimony in docket ER-2024-0189, page 4 where she discusses the daytime shift, second shift and overnight third shift within the context of hours use rate design.

Further, as it relates to Staff's concerns regarding the lack of correlation of monthly NCP and monthly CP demands, I believe that there is a high correlation for large customers because of the relatively high load factor profile of such customers. A high load factor profile means customer's demand is relatively stable and consistent throughout the day which implies that, generally speaking, one would not expect a high variation between demand during the day versus nighttime hours. Figure 3 shows the monthly CP and NCP for the LP class. This graph generally shows that there is not a wide variation between the monthly NCP and CP demands for the class.

Figure 3: Monthly CP and NCP for the Large Power Class

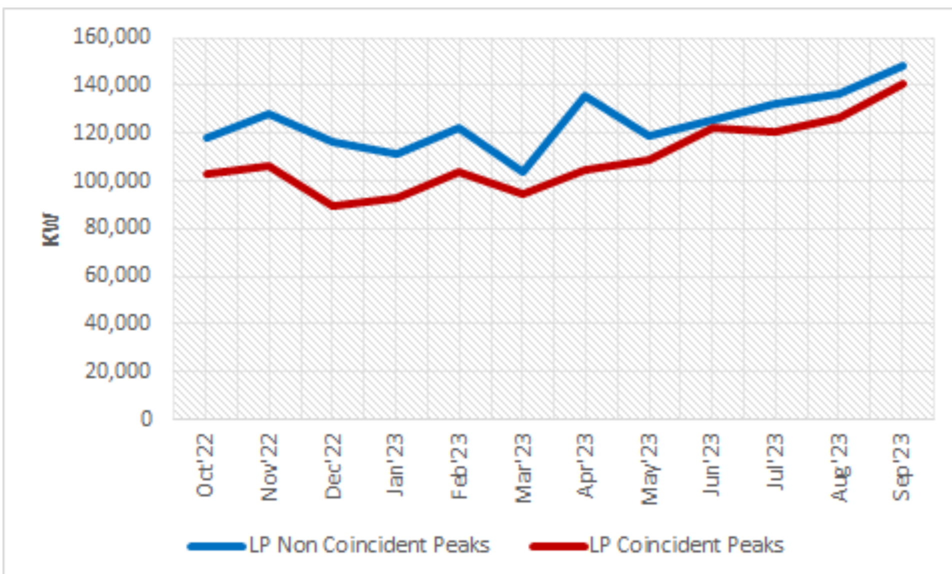

Figure 4 shows the ratios of CP demand to NCP demand by month. A range of 77% - 95% for the ratio of CP to NCP demand would suggest a reasonably high correlation.

Figure 4: Ratio of Monthly CP to NCP for the Large Power Class

	Oct'22	Nov'22	Dec'22	Jan'23	Feb'23	Mar'23	Apr'23	May'23	Jun'23	Jul'23	Aug'23	Sep'23
CP / NCP Ratio	88%	83%	77%	84%	85%	91%	77%	91%	97%	91%	93%	95%

If the goal is to determine commercial and industrial coincident peak demand focused on a narrow set of hours in the summer and winter, then additional analysis will be necessary. In a recent investigation to develop time differentiated rates in Kansas, Evergy's analysis showed a 0.92 ratio between commercial and industrial demand in a four hour window in the summer with the non-coincident peak demand for the same time period. Other utilities such as those in Wisconsin I am familiar with have a 12-hour time window for setting the billing demand, which would result in a higher ratio due to the larger time window. The main point is that, as it relates to setting time differentiated billing demand, the time windows vary based on the objectives of the rate design and it would be incorrect to assume that there is no correlation between CP and NCP demand.

Thus, while it is valid to suggest that a monthly CP demand would provide the purest pricing signal, the NCP demand is not unreasonable and captures an appropriate signal to indicate that capacity is not cheap. Therefore, it is more economically efficient to recover fixed costs from NCP demands as opposed to continuing to propagate the problem of sending erroneous signals by recovering such charges through volumetric rates.

Notwithstanding the discussion above, I also believe it is important to introduce well-vetted and well-designed time differentiated rates applicable to the large commercial and industrial customers that are fully developed and not introduced in a piecemeal fashion. I support the development of such rates applicable to large customers to improve the current rate design applicable to LGS, SP and LP classes respectively. In this regard, I recommend that the Company work with interested parties to develop such rates, preferably in advance of its next rate case.

B. Response to Company Regarding Recovery from Demand and Energy Components

Q. What was the Company's response to your recommendations regarding the allocation of the increase between demand and energy charge components?

A. Company witness Mr. Timothy Lyons agreed with my concerns in part regarding the under recovery of fixed cost through demand charges. He addressed the under recovery from demand charges by recommending an increase of 1.25 times the overall class increase, with the remaining revenue requirement not recovered in the demand charges recovered through a uniform percentage increase in customer and kWh charges.

Q. Do you support the Company's recommendation?

A. In part. I appreciate the Company's efforts to address the under recovery of demand charges and support the proposed increases to the demand charges. In addition, however, I continue to recommend no changes to the tail block energy charges for reasons discussed in my direct testimony and in responding to Ms. Gonzales above. Therefore, as described in my direct testimony, I recommend that the increases being allocated to the energy tail block should instead be recovered from the winter and summer billing demand charges. Figures 5 (a) and 5 (b) below show that the incremental increase to the Company's proposed winter and summer billing demand charges is \$0.60/KW-month and \$0.91/KW-month respectively. The same changes should be made to the TC LG rate as well since the rates for both these classes are designed with the same increase and using the same billing determinants.

Figure 5 (a): Removal of Company Proposed Increases to NS Large General Service Rate Energy Tail Block Rate

Rate Design Component	Company Proposal	MECG Proposal	Redirect Recovery to Billing Demand Charges
All Additional - Winter Tail Block	6,482,082	$5,103,307	$1,378,775
All Additional - Summer Tail Block	4,976,600	$3,918,050	$1,058,550

Figure 5 (b): Incremental Increase to Company Proposed Increases to NS Large General Service Rate Billing Demand Charge

	Company's Proposed $/KW-month Billing Demand Charge	MECG $/KW-Month Increase to Company Proposal	MECG $/KW-Month Total Billing Demand Charge
Winter Billing Demand Charge	$9.57	$0.60	$9.70
Summer Billing Demand Charge	$12.28	$0.91	$12.58

Q. Does the Company recommend the same approach for the rates applicable to the SP class as discussed above for the LGS class?

A. Yes. The Company has recommended the same percent increases to the demand charges for the SP class as the LGS class. While I did not provide any recommendations for the SP class in my direct testimony, the SP rates have the problem of under recovering fixed costs from demand based rates. Therefore, I support the Company's approach while also recommending the same method of retaining the existing energy tail block charge while raising the winter and summer billing demand charges to recover the costs that would have been recovered by increasing the energy tail block rate.

Q. Does the Company recommend the same approach for the rate applicable to the LP class as discussed above for the LGS class?

A. Yes.

Q. Do you support the Company's proposal?

A. Not for the LP class. The reason is that the Company's proposal does not address the wide differential between the summer and winter demand charges. Considering that Liberty is a dual peaking utility, it would make sense to narrow this differential. Further, it is also worth noting that in the current LGS and SP rates, the demand charge differentials are narrower where winter demand charges are roughly 78% of summer demand charges. My recommended changes presented in direct testimony changes the current ratio of 55% in the LP rate to 78% while also imposing no increases to the tail energy block rate as recommended for the other rates. Thus, I continue to have the same recommendations as submitted in direct testimony for the LP class.

C. Response to Staff Regarding Interruptible Credits

Q. What was your recommendation regarding interruptible credits provided in Schedule TS?

A. I had recommended an increase in the interruptible credit from $4.01/KW-month to $6/KW-month, to equitably compensate the interruptible load, so that it is commensurate with the increase in value.

Q. What was Staff's response to your recommendation?

A. Staff witness Mr. Randall Jennings opposes my recommendation to increase the credit. I summarize his rationale for opposing the increase in credits as follows:

1. It would have been cheaper to procure the energy market instead of paying the interruptible credit.
2. The interruptible credit is a discount because of the very few times that the customer was interrupted.
3. The Company has not requested an increase in the interruptible credit.
4. The avoided cost of a combined cycle is more appropriate.
5. Staff does not agree to increasing the interruptible credit to benefit the one at the cost of the many.

I respond to each of Staff's assertions below from a technical standpoint. Further, Mr. Richard Nelson, Director, Energy Management – Linde Inc.'s North Division, has submitted surrebuttal testimony and provides real world perspective as an industrial customer operating in a highly competitive environment that made the business decision to manage its costs in part by taking non-firm service. Linde Inc. is the only customer on Schedule TS.

Q. Mr. Jennings asserts that it would have been cheaper to procure power from the energy market in lieu of paying the interruptible credit. How do you respond?

A. Mr. Jennings misunderstands the objective of the interruptible rate. This rate is capacity based and gives compensation to the interruptible load for being available during emergency events when the Company has need or experiences a capacity shortage. The rate is not aimed at compensating the customer for economic interruptions. The main reason why the Company is able to rely on the interruptible load as a resource for resource adequacy purposes is because it is available to be interrupted and can be relied on to respond to capacity based emergency events.

Q. Mr. Jennings asserts that the interruptible credit is a discount because of the very few times that the customer was interrupted. How do you respond?

A. Once again, the interruptible credit is provided to the customer for being available to interrupt and is not a function of the actual number of interruptions. Mr. Jennings seems to imply that just because Liberty has not initiated curtailments often that the interruptible load provides no value to the Company or its customers and is akin to a discount. On the contrary, the interruptible load provides valuable capacity as insurance to Liberty and its customers should the Company determine that an interruption is warranted. Ignoring this value would be akin to claiming that buying insurance is of no value if there was not a mishap. Therefore, this is not a discount but rather a credit to compensate interruptible customers for forgoing firm service thereby avoiding acquiring capacity for this load and being available for curtailment. Further, as Mr. Richard Nelson describes in his testimony Linde has made investments to enable its commitment as an interruptible customer which the customer would not be investing in, if as Ms. Randall Jennings puts it "the odds are not likely it [meaning interruption] will happen, and any credits received is more akin to a discount"[5].

Q. Mr. Jennings explains that the Company has not requested an increase in the interruptible credit. How do you respond?

A. While the Company did not request an increase in the interruptible credit, the Company does not oppose such as increase either. Indeed, Mr. Tim Lyons provides support for the increase by describing the benefit in reducing the Company's resource adequacy requirements.[6] Furthermore, as discussed in my direct testimony, responses

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[5] See Mr. Randall Jennings testimony on page 5.
[6] See Mr. Timothy Lyons Rebuttal Testimony on page 24.

to discovery questions indicate that the Company has highlighted the uncertainty associated with the many changes in SPP's resource adequacy construct and appreciates the benefit of having interruptible load as a hedge.

Q. Mr. Jennings claims that the cost of a combined cycle is more appropriate to use as a proxy for avoided capacity cost. How do you respond?

A. Mr. Jennings does not appear to account for the capital cost associated with calculating the proxy for avoided costs, which is the main component used to calculate such costs. Further, a review of the public version of Liberty's most recent IRP shows the capital costs in terms of $/KW-year for combined cycle and combustion turbines to be around $150/KW-year which equates to $12.5/KW-month ($150/12).[7] Therefore, using this proxy instead of the SPP CONE reference of $7.13 per KW-month would actually result in arguments for a higher credit than what I recommend here.

Q. Mr. Jennings does not agree with increasing the interruptible credit to benefit the one at the cost of the many. How do you respond?

A. Mr. Jennings seems to be suggesting that it is reasonable to ignore the proper value of the interruptible load and not pay the compensation that is commensurate with the value it provides or alternatively what the Company would charge for acquiring a supply side resource. The Company has indicated that it is facing high uncertainty from a resource adequacy perspective which means that it is important for the Company to retain this load and it would therefore make sense to compensate the resource adequately. Based on response to MECG 3.1, it is my understanding that the Company needs to treat demand response resources on an equivalent basis as supply side resources to be consistent with the Policy Objectives as stated in Commission Rule 20 CSR 4240-

[7] See Figure 1-8. Page 1-30, Liberty's 2025 Resource Plan.

22.010 (2) (A). On this basis, the interruptible rate should be compensated at $7.13/KW-month or arguably $12.5/KW-month as the avoided cost for a combustion turbine from the Company's IRP. However, in my view, in order to ensure that interruptible load is more cost effective than supply side resources, I continue to recommend a credit at $6/KW-month. Contrary to Mr. Jennings assertions, the increase in the interruptible credit is a win-win proposition as it will benefit all customers to acquire a cheaper resource to address SPP's resource adequacy needs and the customer providing interruptible load receives an increase in compensation to recognize its value and ensure that it can continue to make the business case to remain an interruptible load.

Q. Does this conclude your Surrebuttal testimony?

A Yes.