MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

CLASS COST OF SERVICE

APPENDIX 2

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2021-0240

Jefferson City, Missouri
September 2021

Appendix 2

Average and Peak – The Average and Peak is a type of Embedded Cost, Energy Weighted, study method. It can be based on any number of peaks, typically from 1 to 12 non-coincident peaks. In studies performed by Staff it was found to replicate the results of the "Capacity Utilization" method, while requiring significantly less data and effort to complete than the specific Capacity Utilization method employed by Staff at that time. The Peak and Average method initially allocates average costs to each class, then reallocates the entire peak usage to the classes that contribute to the peak. In Case No. ER-2010-0036 the Commission stated "Thus, the classes that contribute a large amount to the average usage of the system but add little to the peak, have their average usage allocated to them a second time. Thus, the Peak and Average method double counts the average system usage, and for that reason is unreliable."

Average and Peak method variations are discussed in the 1992 NARUC Manual[1] and the 2019 Regulatory Assistance Project ("RAP") Manual.[2]

Average and Excess – The Average and Excess is a type of Embedded Cost, Energy Weighted, study method. It can be based on any number of peaks, typically from 1 to 6 non-coincident peaks.[3] Only Average and Excess 4 NCP studies have been relied upon by the Commission in the period studied. The method relies on annual maximum and average demands for each customer class and the system load factor. While this relatively low data requirement facilitates the study to be conducted easily, given the relatively few data points relied upon, any concerns with data reliability are amplified in the results. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. This component is multiplied by the remaining proportion of production plant and then added to the first component to obtain the total allocator. The A&E methods assume that energy costs are the same amount regardless of the hour of consumption or the source of the energy, and/or do not consider the operating characteristics of plants, and assume that capacity costs are equal among types of plants. This approach would produce the same classification of plant for a system that was entirely composed of gas-fired combustion turbines (with low capital costs and high fuel costs) or of coal-fired plants (with high capital costs to produce lower fuel costs), which illustrates its inability to reflect the offsetting capital costs and operating expenses of different types of generating facilities. The method is also based entirely on load characteristics without consideration of generation characteristics, which would result

[1] NARUC Manual https://pubs.naruc.org/pub.cfm?id=53A3986F-2354-D714-51BD-23412BCFEDFD
[2] RAP Manual https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/
[3] See NARUC Manual, page 50, "if your objective is – as it should be – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."

in customers receiving a proportionate allocation of a suboptimally-constituted fleet as an optimally-constituted fleet.

Average and Excess method variations are discussed in the 1992 NARUC Manual. It is referenced as a "legacy" allocator and "essentially just a peak allocator" in the 2019 RAP Manual.

Base Intermediate and Peak – The Base Intermediate and Peak is a type of Embedded Cost, time differentiated, study method.[4] The Commission implicitly relied on KCPL's Base Intermediate Peak study performed by Paul M. Normand ("Normand BIP"). Although it is not discussed in the Commission's order, it appears to have been the basis of a stipulation that was opposed in the KCPL case but approved in the companion GMO case. The Normand BIP Study did not specifically conform to the NARUC BIP definition and was an Energy-Weighted study. (The NARUC BIP definition is summarized below)

Base-Intermediate-Peak (BIP) Method: The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only. There are several methods that may be used for allocating these categorized costs to customer classes. A shortcoming of all embedded cost methods, including the BIP, is reliance on the assumption that the utility fleet has been designed and built to most efficiently serve its native load, as opposed to maximizing profits for its participation in an integrated energy market.

Variations on the Base Intermediate and Peak method are discussed in the 1992 NARUC Manual and the 2019 RAP Manual.

Detailed BIP - The detailed BIP is a type of embedded cost, time differentiated cost allocation method. This variation on the BIP method is described in the RAP Manual as the "Base-Peak" Method. The Commission has found, when compared to variations on the A&E and the A&P, that the detailed BIP method most reasonably recognizes the relationship between the cost of the plant required to serve various levels of demand and energy requirements and the cost of producing energy.[5] The Detailed BIP method uniquely recognizes the tradeoffs that exist between the cost of installing a plant, the generation capabilities of a plant, and the cost of obtaining energy from that plant, and takes into consideration the differences in the capacity costs associated with units that run at a stable level much of the year, versus the capacity costs associated with units that quickly dispatch only a few hours a year, as well as those units that have a cost and operation characteristic in between those extremes. The Detailed BIP method also considers the inverse relationship between the cost of capacity and the cost of energy produced by base, intermediate, and peaking units. Unlike other common CCOS methods, the Detailed BIP method assumes that some plants will run virtually year round (base), only part of the year (intermediate), and rarely during the year (peak). A shortcoming of all embedded cost methods, including the detailed BIP, is reliance on the assumption that the utility fleet has been designed and built

[4] See KCPL Case No. ER-2012-0174.

[5] See the Commission Report and Order findings in Case No. ER-2014-0351 (Empire) and ER-2016-0285 (KCPL).

to most efficiently serve its native load, as opposed to maximizing profits for its participation in an integrated energy market.

Variations on the BIP are found in the NARUC manual, and the method is described in the RAP Manual as the Base-Peak method.

Capacity Utilization – This method was developed by Staff professionals in the 80s and 90s. It is a type of time differentiated study. During the studied period it is discussed in Orders but not relied upon. It is very data intensive and relied on software that is no longer available.

Assigned Capacity – This is a variation of a time differentiated study that applies a utility's participation in an integrated energy market to the allocation of its revenue requirement.[6] Of currently available methods, it most accurately reflects the economic circumstances of a utility and its customers with regard to the costs and expenses of a utility participating in regional transmission organizations, selling energy at wholesale, and obtaining energy at wholesale to serve its customers, It also facilitates design of complex rate schedules such as time-of-use and/or seasonal rates. A current complication to its application is the lack of liquid capacity markets, which may be compensated by a variation in the application of an equivalent peaker method which is explained below. It has been presented in recent cases.

The NARUC Manual describes five Peak Demand Methods. For brevity, this document will generally describe the Peak Demand Method without breaking out each of the separate methods – 1. Single Coincident Peak Method, 2. Summer and Winter Peak Method, 3. The Sum of the Twelve Monthly Coincident Peak Method, 4. Multiple Coincident Peak Method, 5. All Peak Hours Approach. Generally, under these methods each class's contribution to a defined number of peaks is used to allocate the cost of production capacity. The All Peak Hours Approach may take on the results of a time differentiated approach. These methods have not been widely used in Missouri for allocating generation, but are widely used for distribution and transmission. Their suitability for generation would depend on the characteristics of a utility's load and generation fleet. Given Missouri's climate, methods 1 and 2 would tend to overallocate to lower-load factor classes and underallocate to higher-load factor classes, while methods 3 and 4 could tend to underallocate to lower-load factor classes and over-allocate to higher load factor classes.

The NARUC Manual describes four Energy Weighting Methods:

> **Average and Excess** was discussed above.
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> **Equivalent Peaker** - In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related. A variant of the above approach is to do the equivalent peaker

[6] An earlier application of this approach was denominated "Market Based".

cost evaluations based only on the variable generation alternatives available to the utility at any point in time. This method may require significant deference to expert judgement.

Base and Peak - The objective of the base and peak method is to reflect in cost allocation the argument that an on-peak kilowatt-hour costs more than an off-peak kilowatt-hour and that the extra cost should be borne by the customers imposing it. This approach first identifies the same production plant cost components as the equivalent peaker cost method, and allocates demand-related production plant costs in the same way. The difference is that, using the base and peak method, the energy-related excess capital costs are allocated on the basis of the classes' proportions of on-peak energy use.

Judgmental Energy Weightings – This method recognizes that energy loads are an important determinant of production plant costs, and require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand.

The NARUC Manual describes Time-Differentiated Methods:

Production Stacking Methods - The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. The generating units identified as baseload are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

LOLP Production Cost Method - LoLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

Probability of Dispatch Method - The probability of dispatch ("POD") method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

The NARUC Manual provides options for various Marginal Production Cost studies, permutations of which are derived from various methods of calculating and applying Marginal Energy Costs, and various methods of calculating and applying Marginal Capacity Costs. Marginal Costs developed under these methods can be allocated to time periods and or customer groups in varying permutations. Thus, the four methods described below can be combined to create approximately 16-32 additional study methods.

Production Cost Modeling Study – is a method of costing Marginal energy costs derived from running a computer simulation of a fleet's response to load under specified circumstances to determine the cost of producing an additional unit of energy in each of specified time periods.

Historical Marginal Energy Cost Study – is a method of costing Marginal Energy costs derived from reviewing experienced system efficiency. The NARUC manual cautions that system efficiency may change rendering historical studies unreliable for forecasting.

Peaker Deferral Method – is a method of costing Marginal Capacity Costs that assumes, for study purposes, the addition of a peaking plant as the measure of cost to meet additional capacity requirements. The peaker deferral method compares the present worth cost of adding a peaker in the test year to the present worth cost of adding a peaker one year later.

Generation Resource Plan Expansion Method – is a method of costing Marginal Capacity Costs that takes the utility resource plan and increase or decrease the load forecast on which the plan was based. The resulting revision to the generation resource plan captures the effect of the change in customer usage.