BRUBAKER & ASSOCIATES, INC. (BAI)

Spring/Summer 2019

ENERGY Update

HELPING OUR CUSTOMERS ACHIEVE THEIR ENERGY GOALS

Proper Allocation of Ramping Costs

By Brian C. Collins, Principal

Overview

As electric utilities, and their customers, continue to invest in renewable generation, it is important to ensure that the costs attributable to renewables are allocated properly to customer rate classes. This is of particular importance with respect to electric utilities in states with high penetrations of renewable energy, such as California – where not only do utilities continue to invest in solar generation, but the state has recently passed legislation that requires all new home construction to include rooftop solar panels beginning in 2020. One utility that has experienced a large amount of solar generation investment on its system is Southern California Edison ("SCE").

Because of the impact of renewable resources on system operations, SCE proposed to separate its generation into both peaking and ramping components, and then allocate each component separately to customer classes (Application 17-06-030).

Ramping costs became significant because of factors which contribute to the so called "duck curve" phenomenon (which will be explained below): (1) falling utility scale solar generation as sunlight fades late in the day, requiring other generators to ramp up relatively quickly to replace the declining solar generation; and (2) net class load changes during the ramping period, which are caused in part by declining solar generation that is behind customers' meters, including residential rooftop solar panels.

For allocating ramping costs, SCE proposed to use average class loads during the ramping period. However, the use of average class loads for allocating all ramping costs does not properly reflect cost causation, because it does not assign costs to the classes responsible for creating the ramping costs.

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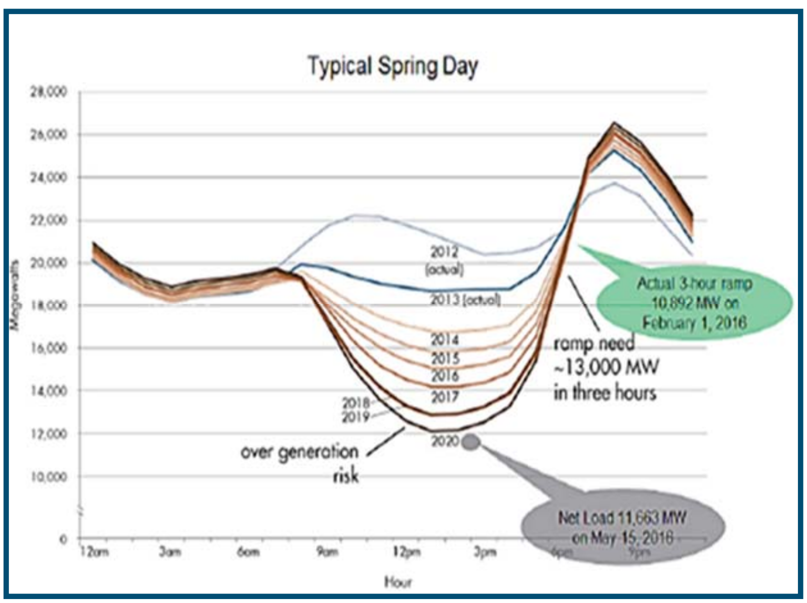
BAI assisted the industrial intervention group, Energy Producers & Users Coalition ("EPUC"), in its challenge of SCE's cost allocation proposal for ramping costs. A stipulation approved by the California Public Utilities Commission ("CPUC") weighted the EPUC proposal equally with SCE's proposal. The result was lower rates for the industrial classes as compared to the proposed rates.

This article will describe SCE's allocation proposal, how it was successfully influenced by EPUC to better reflect cost causation, and how the modification was ultimately reflected in a stipulation approved by the CPUC.

SCE Proposal for Allocating Ramping Costs

In its application, SCE separated generation capacity costs into "peak" and "ramping" components. The peak component refers to the traditional maximum summer levels, and the ramping component refers to what happens when solar generation drops off and class loads also increase. For the allocation of ramping costs, SCE proposed to use average loads for each class across all hours of the ramp period. However, critical analysis revealed two primary causes for the ramp. The first cause is the reduction in output from utility-owned solar generation, as sunlight diminishes in late afternoon; and the second cause is the change in individual customer class loads across the ramp period. The change in net class loads across the ramp period stems from not only the reduction in the output of behind-the-meter generation, including generation from residential rooftop solar panels, but also from the upward ramping of customer gross load requirements over that same time period; that is, these customer loads increase substantially in such periods, aside from any effects of variation in their own generation.

Figure 1
CAISO's Duck Curve Showing Steep Ramping Needs and Over-Generation Risk



SCE's proposal to use class average loads for allocating the ramp component of generation cost does not recognize these factors and, as a result, over allocates costs to customer classes that have more stable loads, such as industrial rate classes. EPUC proposed an alternative allocation method for the ramp related costs that recognizes these factors and, therefore, is consistent with class cost causation.

The "Duck Curve"

The associated ramping stresses placed on the SCE system due to solar generation, both utility solar generation and behind-the-meter customer generation, can be explained by the duck curve phenomenon. The "duck curve" refers to the forecasted system net load shape which, because of increasing levels of solar generation, is expected to have relatively lower mid-day net loads and relatively higher later afternoon and early evening loads. The "neck" of the duck is created by the significant increase (or ramping) as the net load transitions from its midday valley to its evening peak. When viewed graphically (as shown in Figure 1 for California Independent System Operator ("CAISO")), the shape resembles a duck, which has led to the accepted term "duck curve."

As seen in Figure 1, the change in net load from the midday valley to the early evening peak (moving from the belly of the duck to its head) creates a need for a large amount of reliable and fast-ramping dispatchable generation (i.e., non-renewable) capacity capable of providing adequate ramping support. As additional solar generation is added, both utility scale and behind-the-meter, the requisite ramping requirement is expected to increase and, absent additional non-renewable resources, the system could face a severe reliability problem.

The need for reliable ramping support will also increase as dispatchable fossil fuel-fired generation capacity is retired, as such generation is often relied on for ramping purposes.

Contributors to System Stress

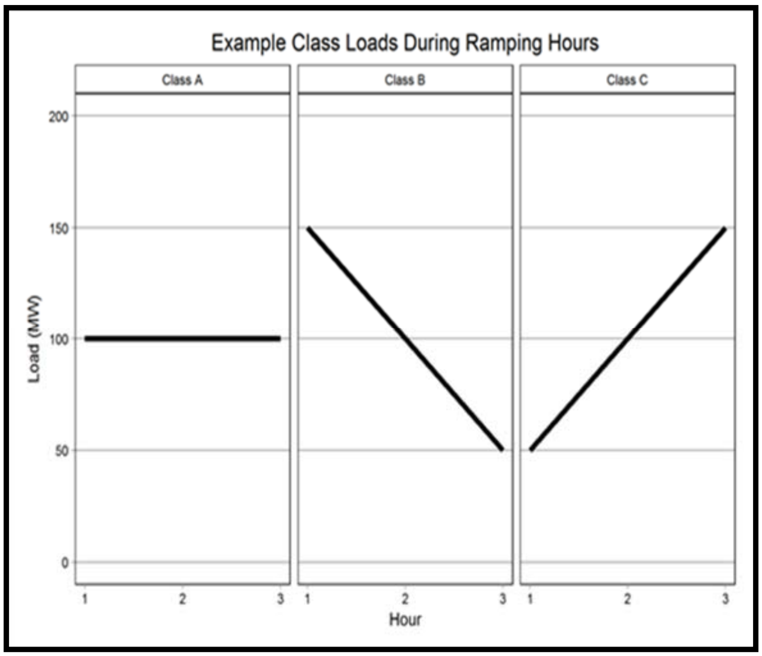
In determining its allocation of generation costs to classes, SCE used the average of four Loss of Load Expectation ("LOLE") studies for the period 2018-2021, for peak and ramp events, to determine the applicable top 100 hours of each event type.

SCE then used an approximate 60/40 split between peak and ramp to weight the cost to be allocated to the various customer classes' contributions to the average load during the top 100 LOLE peak and ramp hours, respectively. This approach, however, does not align cost allocation to cost causation.

With respect to ramping events, SCE identified through its LOLE analysis the top 100 hours when the system was at risk of not being able to serve load, which occurred over a three-hour period. In order to capture the three-hour ramp duration, once the top 100 hours were identified, SCE calculated the average load level in MW for each customer class during the top 100 LOLE hours and the two preceding hours. These class MW levels were then used for purposes of allocating generation costs related to ramping requirements.

This allocation approach for ramping costs ignores the fact that a large contribution to the stress on the system is the change in customer class loads over the ramp period, rather than just the loads themselves. The flaw in SCE's average load allocation is that a customer class with flat (or declining) loads during the stressful system ramping period is not exacerbating system stress, whereas a class that is increasing its net load during the system ramping period is worsening the problem. Simply put, some classes are increasing stress to the system during the ramping period, while other classes are either not contributing to, or are alleviating, the stress. A simple example can illustrate the defect in SCE's proposed method.

Figure 2



In this example, consider three customer classes, Class A, Class B, and Class C, illustrated in Figure 2. If over a three-hour window, Class A used 100 MW per hour constantly for the three hours; Class A has used an average of 100 MW but has not added any ramping requirements because its load has stayed flat. If Class B used 150 MW in hour 1, 100 MW in hour 2 and 50 MW in hour 3, once again the average usage is 100 MW, but Class B has actually reduced system ramping requirements. Finally, if Class C used 50 MW in hour 1, 100 MW in hour 2 and 150 MW in hour 3, yet again the average usage is 100 MW, but Class C has increased system ramping requirements. This is shown graphically in Figure 2. Under SCE's proposed allocation method, each of these three customer classes would be allocated the same amount of ramping related cost. Therefore, this treatment does not adequately reflect cost causation.

How customers use electricity (net of behind-the-meter generation, including residential rooftop solar panels) combined with declining utility solar generation are the drivers behind the "duck curve" and the ramping stress associated with it. Analysis of the SCE system indicated that the solar output falls by about 2,000 MW during the ramping period. This combined with the changes in customer electric usage during the ramping period, creates the total ramping requirement.

Industrial Intervention Group Proposal

A different method to calculate allocation factors for the ramping component of generation cost that better aligns the allocation of ramping capacity with the causes of the ramping requirement was presented in the rate case by EPUC.

As discussed, there are two contributing factors to the system ramping requirement, (i) the reduction in utility scale solar output, and (ii) the change in class net loads. Consequently, the allocation method for ramping costs should recognize and reflect these two causative factors. To do just that, EPUC proposed to derive the two components separately and then combine them into a single allocator.

The first component of the alternative allocation mechanism is the contribution of utility scale solar. Because the utility scale solar is a system benefit, EPUC determined that it was reasonable to use the class proportions of average load during the ramping period (similar to the method as proposed by SCE) to determine class responsibility for this cost.

The second contributing factor to the system ramping requirement is the individual class net load changes during the ramping period, which are partly caused by reduced behind-the-meter solar generation, including residential rooftop solar panels, and by class increases in gross load over the period. The first step is to determine the class load changes during the top 100 LOLE ramp hours over the three-hour ramping window. The second step is to calculate the average three-hour ramp load during the 100 observations for each class. Once these steps are completed, appropriate allocations can be determined for ramping costs.

The overall system ramping requirement is determined by combining the change in the utility scale solar generation output and the change in class loads net of behind-the-meter generation, including customer installed solar generation. Based on this analysis, it was determined that approximately 43% of ramping costs are related to the change in the gross customer loads net of behind-the-meter generation and 57% is related to the reduction in the utility scale solar output. Consequently, the two components are weighted together in these proportions.

Conclusion

The analysis undertaken by EPUC demonstrated that there are two primary causative factors for the ramp period on the SCE system. The first is the reduction in output of the utility scale renewable generation, and the second is the change in net class loads occurring at the same time that the output of the utility scale renewable generation is decreasing. SCE's allocation approach, which uses class average demands across the ramp period, did not reflect either of these causes. The alternative allocation method, which explicitly considers both of these causes, better aligns cost allocation with cost causation.

The settlement stipulation, which was later approved by the CPUC, gave equal weighting to the SCE and EPUC proposals. The issue will be further addressed in statewide workshops beginning this summer.

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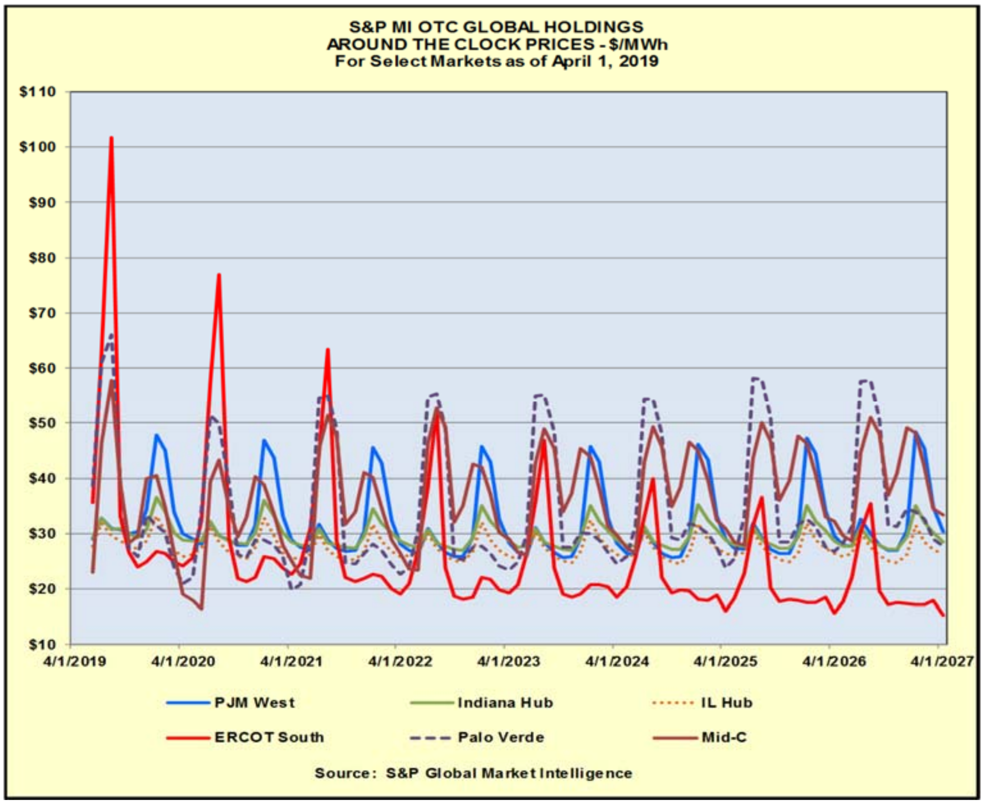
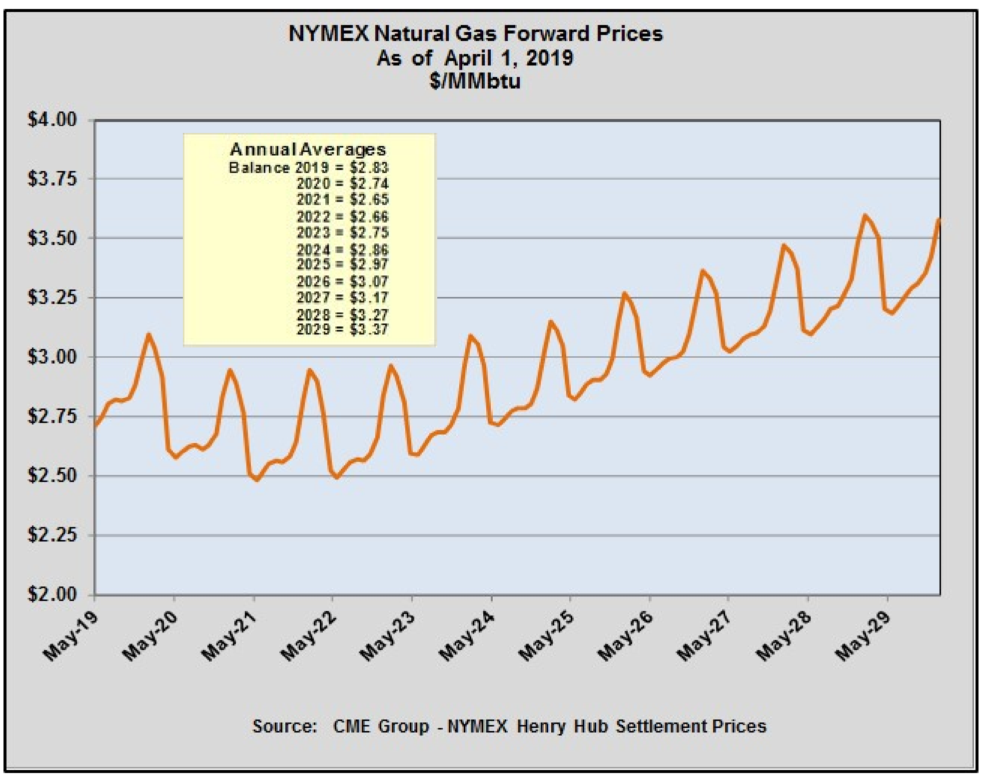
PROJECTED FORWARD POWER PRICES



FORECASTED NATURAL GAS FORWARD PRICES



Looking Ahead at Power and Natural Gas Prices

ERCOT South electricity prices are expected to peak in early 2019 at just over $100 per MWh and then gradually move downward through April 2027. Prices for the other hubs surveyed, remain relatively constant through the first quarter of 2027.

Natural gas forwards have continued to decline over the past 12 months but projections indicate a slow upward movement through the first quarter of 2029.

Check Your Interconnect – Ensuring Distribution Rates Reflect Customers' Unique Interconnection Configurations

By Amanda M. Alderson, Associate

Some large power customers have unique interconnections with their electric distribution utility, and sometimes the distribution tariff rates they pay do not reflect the true cost of service of those unique configurations.

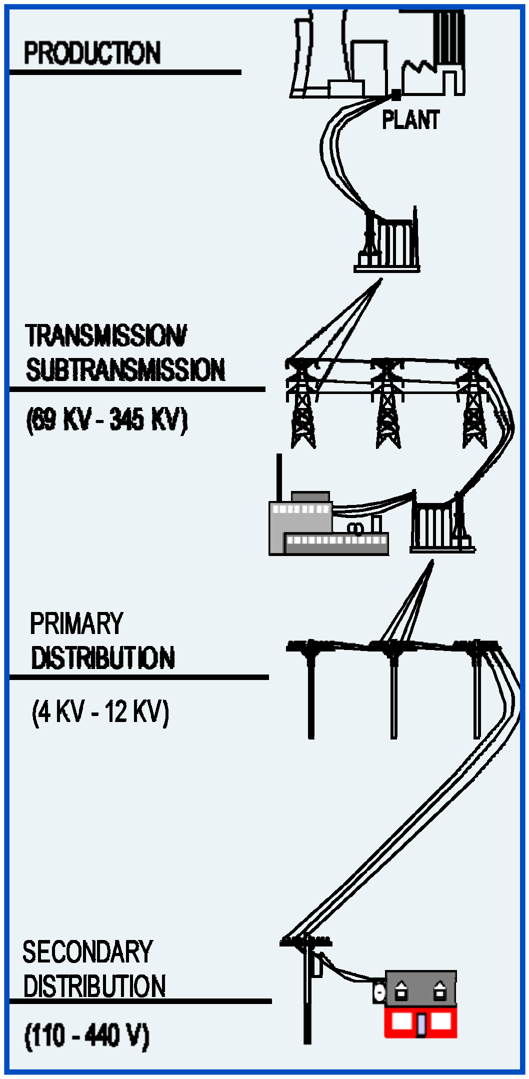
Whether the large customer is paying too much for distribution service depends, in part, on the base tariff rate design applied to the customer, including any offsets or credits. Many utilities, especially large ones with sophisticated rate structures, have in place distribution credits or reduced base rates that account for some types of large customer connection arrangements. For example, the primary metering credit is common, which accounts for the higher metered energy amount on the high side of a distribution transformer – before energy losses occur within the transformer - versus the typical customer metered on the low side of the transformer. Another example is the substation or transformer ownership credit, which should be provided to customers who own or lease the substation necessary to bring the utility service voltage down to the customer's required voltage level. In general, customers who are served at a higher delivery voltage do not make use of, and should not be charged for, lower voltage assets owned by the utility to serve other customers.

Alternatively, these credits may be embedded in the utility's tariff in the form of a lower base distribution rate for customers that take service at a higher voltage level. However, if the large commercial and industrial tariff rate does not incorporate a lower distribution demand charge to higher service voltage customers, then these types of credits are imperative to ensure high voltage customers are not paying more than cost of service.

BAI has investigated these types of rate design issues in numerous cases. In 2016, we assisted a client who owned its own substation in maintaining its transformer ownership credit, despite opposition by the state's Public Service Commission Staff witness. This customer held onto its credit of approximately $50,000 per year because it owned the transformers that converted the utility delivery line voltage of 12.5 kV to the lower voltage used at the customer's plant. Staff testified that its interpretation of the utility tariff made the customer ineligible for the transformer ownership credit. We assisted in persuading the Commission to rule in favor of retention of the credit, by showing that the distribution rates that would have been charged to the customer absent the credit were designed to recover the cost of distribution assets below 12.5 kV that were not used to provide service to this customer. It was discovered during this rate case proceeding that if Staff's interpretation had prevailed, other customers of the utility, and of neighboring utilities in the same state, likely would have become similarly ineligible for the substation ownership credits that they had properly been receiving.

There are other examples of more atypical customer interconnection configurations for which most utilities do not have a rate credit or adjustment to appropriately account. For example, consider a customer which takes service at the sub transmission level and is served directly from the bulk transmission system via a relatively short dedicated subtransmission line owned by the utility. The customer does not utilize any of the utility's remaining subtransmission facilities. In addition, assume the total cost of the dedicated subtransmission line is less than the share of the total cost of the subtransmission system of the customer's utility that would be assigned to the customer under the utility's normal subtransmission service level rates. Given this situation, the customer should clearly be held responsible only for the total cost of the dedicated subtransmission line, rather than being subject to paying a share of the total cost of the subtransmission system of the customer's utility. However, the utility's tariff does not permit this and requires the customer to pay the same subtransmission service rate that all other sub transmission level customers pay. This customer is, therefore, overpaying the utility by being required to pay for subtransmission facilities that are clearly not used to serve it.

In 2018, we assisted such a customer in making its case to design a true cost-based delivery rate, given the unique circumstances of customers like it which are not connected to the utility's broader subtransmission network, but instead are served by a dedicated line. The concept was initially well-received by the utility, but the Commission Staff in that state felt that the resulting rate would be prejudicial to other customers in some fashion. Staff failed to see the rate credit proposal for what it was, that is, a delivery credit like the substation ownership credit or primary metering credit that would apply to any eligible customer that fit the characteristics of the unique interconnection arrangement. The credit was necessary to provide for proper cost-based rates to all customers. The case ended in settlement, and unfortunately did not include the rate credit, valued at over $1 million per year to the customer, meaning that the customer is being charged more than the cost it imposes on the utility.



This same exercise of evaluating unique customer interconnections and the applicable distribution tariff rates can be carried out for natural gas service as well. In 2016, we provided testimony supporting a customer that had several service points, all of which were fed by only one large diameter distribution main. The utility's gas distribution rates recovered the fixed cost of distribution mains through the first-block therm charge. A first-block therm charge is a per-therm rate billed, in this case, for the first 1,000 therms used by the customer in a month. The first-block therm rate acts as a fixed monthly charge for large customers that consistently use well more than 1,000 therms per month.

The subject customer was paying a fixed monthly meter charge and the first-block therm charge for each of its several meters, and was therefore over-paying for distribution main investment, because all of its meters were connected to only one distribution main. We proposed that the utility institute consolidated billing for such customers, and consolidate the total therm usage on all of the customer's meters that are connected to the same main when applying the first-block therm charge. This rate design would appropriately bill the customer the first-block therm charge only once per month, which ensures the customer is not over-paying for distribution main investment. This rate case proceeding also ended in a settlement. Although our proposed consolidated billing tariff language was not adopted in the settlement, the utility agreed to charge the customer only one first-block therm charge per month for some of its accounts, using existing tariff provisions concerning combined billing for multiple meters installed at the convenience of the utility.

These are just a few examples of the types of unique service interconnection arrangements that a large commercial or industrial customer may have with its electric or natural gas distribution utility.

These arrangements should be carefully considered in conjunction with the distribution rates, taking into account a thorough investigation into how the rate levels are set and what utility investment costs are intended to be recovered through each rate component. If a customer is being billed for utility investment costs for delivery system assets that are not used to serve them, or is being over-charged for those costs, a case can be made that the rates should be designed differently.

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ANNOUNCED CAPACITY RETIREMENT

Nearly 44,000 MW of current operating capacity has been announced for retirement over the next 7 years. As outlined in the table below, coal represents the largest percentage of fuel type slated for retirement.

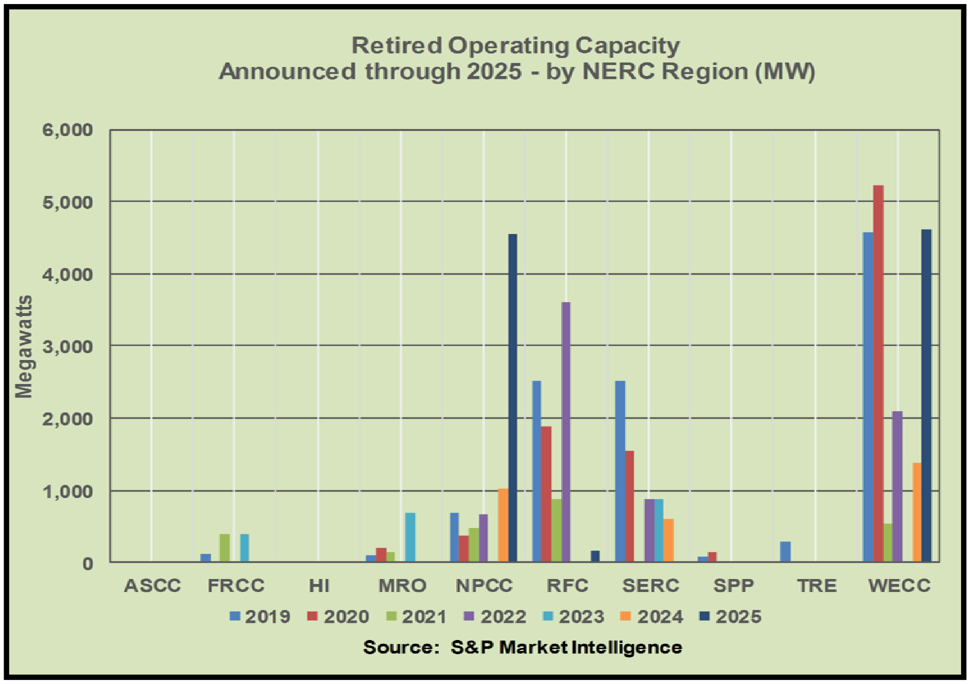
Retirement by Fuel Type (%)

Fuel Type	2019	2020	2021	2022	2023	2024	2025
Coal	63.2	43.5	82.7	73.1	100.0	20.0	39.2
Gas	26.7	50.5	12.1	4.1	0.0	8.9	0.0
Nuclear	6.3	0.0	0.0	20.4	0.0	71.1	60.8
Oil	1.6	0.2	2.0	2.3	0.0	0.0	0.1
Water	0.2	5.0	2.6	0.0	0.0	0.0	0.0
Wind	1.3	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.8	0.7	0.7	0.0	0.0	0.0	0.0

Source: U.S. Energy Information Administration (EIA) and S&P Market Intelligence

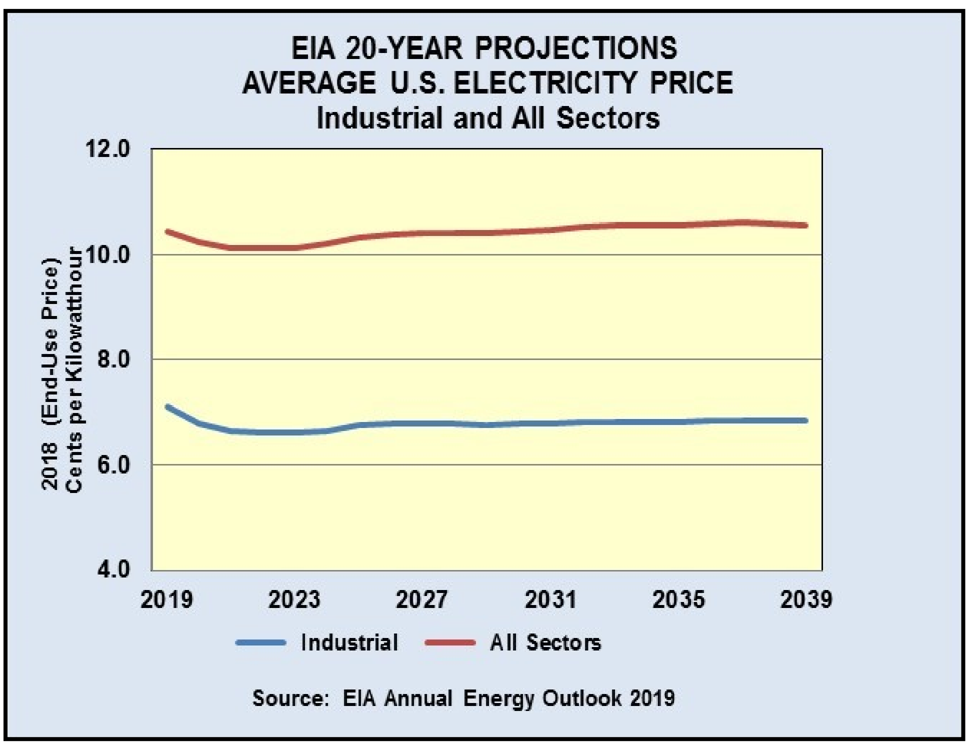
The graph on the following page illustrates future announced retirement capacity by NERC region through year 2025. The WECC region is expected to retire the most capacity between 2019 and 2025, estimated at 18.4 MW with regions RFC and NPCC trailing at 9.1 MW and 7.8 MW, respectively.

RETIREMENTS BY NERC REGION



Retired operating capacity announced to date, is outlined in the adjacent graph. The NERC regions of NPCC, RFC and WECC are expected to retire the largest amounts of capacity over the next seven years.

20-YEAR ELECTRICITY PRICE PROJECTIONS



The U.S. Energy Information Administration ("EIA") has projected industrial electricity prices to average around 7.0 cents per kWh through 2019. Industrial prices are expected to decline slightly in early 2020 and remain between 6.6 cents and 6.8 cents through year-end 2039.

ELECTRIC RATE CASES
AUTHORIZED INCREASES IN 2018 AND 2019 TO DATE

Utility	Order Date	Company Requested ($millions)	Commission Authorized ($millions)
ARKANSAS			
Entergy Arkansas Inc.	12/12/18	189.7	189.7
Oklahoma Gas and Electric Co.	03/06/19	5.8	3.3
COLORADO			
Public Service Co. of CO *	04/26/18	377.9	N/A
CONNECTICUT			
Connecticut Light & Power Co.	04/18/18	337.0	124.7
DELAWARE			
Delmarva Power & Light Co.*	08/21/18	10.9	(6.9)
DISTRICT OF COLUMBIA			
Potomac Electric Power Co.*	08/08/18	26.3	(24.1)
FLORIDA			
Duke Energy Florida LLC	04/02/19	29.2	29.2
Duke Energy Florida LLC	07/10/18	200.5	200.5
GEORGIA			
Georgia Power Co.	03/20/18	(50.0)	(50.0)
HAWAII			
Hawaii Electric Light Co.	06/29/18	19.3	(0.1)
Hawaiian Electric Co.*	06/22/18	125.0	(0.6)
ILLINOIS			
Ameren Illinois*	11/01/18	73.7	73.7
Commonwealth Edison Co.*	12/04/18	(26.1)	(26.1)
INDIANA			
Duke Energy Indiana LLC *	10/09/18	14.3	14.3
Indiana Michigan Power Co.*	05/30/18	192.6	153.4
Indianapolis Power & Light Co.*	10/31/18	88.3	43.9
Northern Indiana Public Service Co.*	11/28/18	15.5	14.8
Northern Indiana Public Service Co.*	05/30/18	12.6	12.6
Southern Indiana Gas & Electric Co.*	12/05/18	3.9	3.9
Southern Indiana Gas & Electric Co.*	05/23/18	1.9	1.9
IOWA			
Interstate Power & Light Co.*	02/02/18	168.0	130.0
KANSAS			
Kansas City Power & Light Co.	12/13/18	32.9	(3.9)
Westar Energy Inc.*	09/27/18	68.3	(50.3)
KENTUCKY			
Duke Energy Kentucky Inc.*	04/13/18	48.6	8.4
Kentucky Power Co.	01/18/18	60.4	12.3
Kentucky Utilities Co.*	04/30/19	112.5	55.9
Louisville Gas & Electric Co.*	04/30/19	34.9	2.1
MARYLAND			
Delmarva Power & Light Co.	02/09/18	19.3	13.4
Potomac Edison Co.	03/22/19	17.6	6.2
Potomac Electric Power Co.	05/31/18	3.3	(15.0)
MASSACHUSETTS			
NSTAR Electric Co.	12/27/18	4.8	31.9
MICHIGAN			
Consumers Energy Co.*	01/09/19	43.9	(24.0)
Consumers Energy Co.*	03/29/18	147.7	72.3
DTE Electric Co.*	04/18/18	212.3	74.4
Indiana Michigan Power Co.*	04/12/18	51.7	49.1
MINNESOTA			
ALLETE (Minnesota Power) *	03/12/18	48.0	12.0
MISSOURI			
Kansas City Power & Light Co.*	10/31/18	16.4	(21.1)
KCP&L Greater Missouri Op. Co.*	10/31/18	19.3	(24.0)

Utility	Order Date	Company Requested ($millions)	Commission Authorized ($millions)
NEW JERSEY			
Atlantic City Electric Co.	03/13/19	130.2	70.0
Atlantic City Electric Co.	07/25/18	99.7	N/A
Public Service Electric & Gas	10/29/18	172.7	88.9
NEW MEXICO			
Southwestern Public Service Co.*	09/05/18	27.3	12.5
NEW YORK			
Central Hudson Gas & Electric	06/14/18	63.4	19.7
Niagara Mohawk Power Corp.	03/15/18	261.0	160.0
Orange & Rockland Utilities Inc.	03/14/19	30.4	13.4
NORTH CAROLINA			
Duke Energy Carolinas LLC*	06/22/18	472.2	(13.0)
Duke Energy Progress LLC *	02/23/18	348.5	194.0
NORTH DAKOTA			
Otter Tail Power Co.	09/26/18	10.1	7.4
OHIO			
Dayton Power & Light Co.	09/26/18	65.8	29.8
Duke Energy Ohio Inc.	12/19/18	15.4	(19.2)
OKLAHOMA			
Oklahoma Gas and Electric Co.*	06/19/18	1.9	(64.0)
Public Service Co. of Oklahoma*	03/14/19	88.5	46.0
Public Service Co. of Oklahoma*	01/31/18	169.7	75.5
OREGON			
Portland General Electric Co.*	12/14/18	75.5	8.6
PENNSYLVANIA			
Duquesne Light Co.	12/20/18	133.8	92.7
PECO Energy Co.	12/20/18	81.9	24.9
UGI Utilities Inc.	10/04/18	7.7	3.2
RHODE ISLAND			
Narragansett Electric Co.*	08/24/18	18.9	28.9
TEXAS			
Entergy Texas Inc.	12/20/18	117.5	53.2
Southwestern Public Service Co.*	12/07/18	32.0	0.0
Texas-New Mexico Power Co.	12/20/18	31.3	22.8
VERMONT			
Green Mountain Power Corp.	12/21/18	23.5	23.5
VIRGINIA			
Kentucky Utilities Co.	05/08/18	6.7	1.8
WASHINGTON			
Avista Corp.*	04/26/18	50.3	10.8
Puget Sound Energy Inc.*	02/21/19	18.9	0.0
WEST VIRGINIA			
Appalachian Power Co.	02/27/19	95.3	44.2
Appalachian Power Co.	08/31/18	94.6	91.6
Monongahela Power Co.	01/02/19	(100.9)	(100.9)
WISCONSIN			
Madison Gas and Electric Co.	09/20/18	(8.0)	(9.2)

NOTES:

(1) *BAI involvement

(2) Includes 2019 electric cases authorized through April, 2019.

(3) Virginia data does not include numerous Rider cases.

Sources: S&P Market Intelligence and various State Regulatory Commissions.

RETAIL ELECTRIC RATE CASES PENDING

Utility	Filing Date	Company Requested Rate Increase ($ millions)
ARKANSAS		
Southwestern Electric Power Co.*	02/28/19	74.5
CALIFORNIA		
Pacific Gas and Electric Co.	12/13/18	924.0
San Diego Gas & Electric Co.	10/06/17	111.5
Southern California Edison Co.	09/01/16	(106.0)
HAWAII		
Hawaii Electric Light Co.	12/14/18	13.4
Maui Electric Co. Ltd	10/12/17	21.2
INDIANA		
Northern IN Public Service Co.*	10/31/18	111.4
Northern IN Public Service Co.*	01/29/19	16.7
Southern Indiana Gas & Electric Co.*	02/04/19	4.1
IOWA		
Interstate Power & Light Co.*	03/01/19	203.3
KANSAS		
Empire District Electric Co.	12/10/18	1.7
LOUISIANA		
Entergy New Orleans LLC*	09/21/18	(20.3)
MAINE		
Central Maine Power Co.	10/15/18	22.9
Emera Maine	03/22/19	15.7
MARYLAND		
Potomac Electric Power Co.	01/15/19	30.0
MASSACHUSETTS		
Massachusetts Electric Co.	11/15/18	132.2
MICHIGAN		
DTE Electric Co.*	07/06/18	248.6
Upper Peninsula Power Co.*	09/21/18	7.1
MONTANA		
MDU Resources Group Inc.*	09/28/18	11.9
NorthWestern Corp.*	09/28/18	34.9

Utility	Filing Date	Company Requested Rate Increase ($ millions)
NEW HAMPSHIRE		
Liberty Utilities Granite State	NA	6.0
Public Service Co. of New Hampshire	NA	33.0
NEW YORK		
Consolidated Edison Co. of NY	01/31/19	485.4
OKLAHOMA		
Oklahoma Gas and Electric Co.*	12/31/18	77.6
SOUTH CAROLINA		
Duke Energy Carolinas LLC	11/08/18	230.8
Duke Energy Progress LLC	11/08/18	68.5
SOUTH DAKOTA		
Otter Tail Power Co.	04/20/18	5.7
WISCONSIN		
Wisconsin Public Service Corp.*	03/28/19	97.3

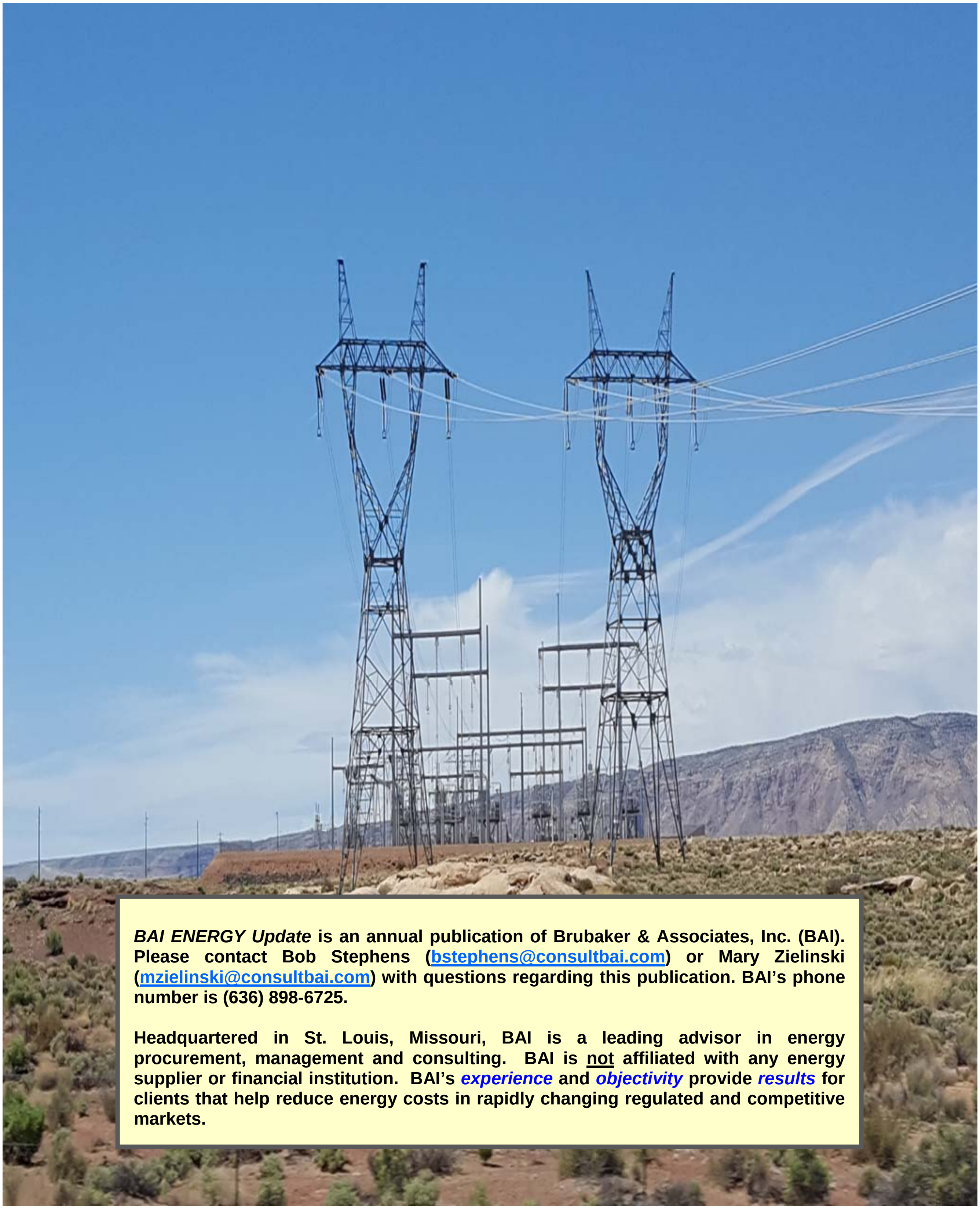
NOTES:

(1) *BAI involvement

(2) Includes 2019 electric cases filed through April, 2019.

(3) Virginia data involving Rider cases is not included.

Sources: S&P Market Intelligence and various State Regulatory Commissions.



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