Spring 2016

BAI SUCCESS STORY - MISO CAPACITY AUCTION COMPLAINT

By Ali Al-Jabir, Senior Consultant

NOTE: Due to the results of MISO's auction results published 4/14/16, edits were made to this article on 4/18/16.

Brubaker & Associates, Inc. (BAI) recently assisted the Illinois Industrial Energy Consumers (IIEC) in launching a successful challenge to certain rules that govern the Midcontinent Independent System Operator's (MISO) annual capacity auction. This victory means that capacity prices in southern Illinois are significantly lower in 2016-2017 than they were in 2015-2016.

MISO's resource adequacy mechanism utilizes a voluntary centralized annual capacity auction that incorporates a locational requirement that carves MISO's footprint into nine load resource zones (LRZs). This results in the imposition of rules that require a portion of the acquired capacity for a specific zone to be located within that zone (the local clearing requirement, or LCR). When the LCR binds due to transmission constraints in a particular LRZ, the last offer located in that particular zone that clears the MISO auction sets the clearing price for that zone.

MISO's auction rules also establish an annual initial conduct threshold, or "safe harbor," that is used as a benchmark to determine whether offers submitted in the capacity auction are considered competitive. Capacity offers in excess of this default safe harbor are subject to mitigation by MISO's Independent Market Monitor (IMM) to safeguard against market manipulation and anticompetitive behavior by generation suppliers, unless the supplier can reasonably demonstrate that the offer is entitled to a higher facility-specific conduct threshold. Under MISO's rules, the safe harbor was set based on the opportunity cost of foregone capacity sales into neighboring markets. Specifically, the IMM established the safe harbor based on PJM's Daily Capacity Deficiency Rate, on the assumption that sales into PJM's Capacity Deficiency market are a viable option for generators in the MISO footprint.

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However, the IMM did not fully consider the total depth of that option and the transmission constraints that limit the amount of access there is to that option from the MISO market.

In the 2015-2016 MISO capacity auction, the application of these market rules yielded a very high safe harbor of approximately $155 per MW-day. The combination of this safe harbor and an overstated LCR value enabled a single supplier to set the auction clearing price for LRZ 4 (southern Illinois) at $150 per MW-day. This clearing price represents a 800% increase over the 2014-2015 MISO capacity auction clearing price of $16.75 per MW-day for the same zone and is also substantially higher than the clearing price for the other LRZs in MISO. We estimated that, due to this auction result, a typical large industrial customer in southern Illinois with a Peak Load Contribution (PLC) of 35 MW, whose capacity requirements were met through the MISO auction, would see an increase in its annual cost of electricity of approximately $1.4 million. This dramatic price increase is alarming, particularly given the fact that LRZ 4 possesses local generating capacity well in excess of its local load requirements.

"In the 2015-2016 MISO capacity auction, market rules yielded a high safe harbor of approximately $155 per MW/day"

We analyzed the 2015-2016 MISO capacity auction results and determined that the high clearing price in LRZ 4 was driven by the fact that generation ownership was highly concentrated, to the point that a specific supplier's generating capacity was needed to clear the market (a pivotal supplier[1]). Thus, assuming sufficient foreknowledge, this pivotal supplier had the ability to raise its offer in the MISO auction up to the safe harbor, thereby artificially inflating the auction clearing price and masking the capacity oversupply situation in LRZ 4. We further determined that the problems experienced in the 2015-2016 auction could largely be remedied on a prospective basis by modifying MISO's rules governing the determination of the LCR and the safe harbor.

[1] A pivotal supplier analysis "examines whether the market demand can be met absent the seller during peak times; a seller is determined to be pivotal if demand cannot be met without some contribution of supply by the seller or its affiliates." (*See* Order No. 697-A, FERC Docket No. RM04-7-001, April 21, 2008 at 9.)

In a petition for prospective relief, we assisted IIEC in drafting a complaint, along with supporting technical affidavits, for submission to the Federal Energy Regulatory Commission (FERC) to protest MISO's auction rules. We also appeared in a FERC technical conference to support the arguments set forth in IIEC's protest. The complaint asked the FERC to modify MISO's LCR calculations in a manner that would allow future MISO auctions to produce just and reasonable clearing prices in LRZ 4. IIEC argued that the LCR calculation should be modified to properly reflect the counter flow on the transmission system created by firm capacity sales from resources within each zone to neighboring markets so as to accurately capture the actual transmission capacity available for imports into the MISO zones. This change would lower the LCR in LRZ 4 and allow a greater share of that zone's capacity requirement to be met by resources imported into the zone.

IIEC further argued that the IMM's method of establishing the safe harbor based on the opportunity cost of sales into PJM was unreasonable. In support of its position, IIEC demonstrated that the opportunity to sell MISO capacity into PJM's Capacity Deficiency Market was, in reality, too small to absorb all of the excess generating capacity in LRZ 4 because of the limited amount of actual capacity sales in this PJM market and the limitations on available transmission capacity for exports. These considerations mean that sales into PJM's Capacity Deficiency Market do not constitute a legitimate basis for calculating the safe harbor. To correct this deficiency, IIEC proposed that MISO's safe harbor be set to zero until a more appropriate calculation method can be determined. This had the effect of establishing the offer mitigation threshold for the MISO auction at either a much lower safe harbor or at a facility-specific level determined by each generator's incremental capacity costs.

On December 31, 2015, the FERC issued an order that accepted IIEC's arguments and ordered prospective changes to MISO's LCR and safe harbor calculations that were largely consistent with the modifications proposed by IIEC in its

protest, beginning with the 2016-2017 MISO capacity auction.

Our initial analysis of MISO's modified LCR calculations suggested that the auction rule modifications should lead to a significant reduction in the 2016-2017 MISO capacity auction clearing prices for LRZ 4, which will produce significant savings for industrial customers in southern Illinois who rely on MISO's annual capacity auction to meet their capacity obligations. On April 14, 2016, MISO posted its 2016-2017 capacity auction results, with LRZ 4 prices at $72 per MW-day, less than half of the 2015-2016 clearing price.

The experience of MISO's 2015-2016 capacity auction underscores the importance of thoroughly understanding the wholesale power market rules that apply in the various regions of the U.S. and of remaining active in the process of implementing these rules in order to safeguard against adverse outcomes that can cause significant economic harm to end-use customers.

THE AUTHOR

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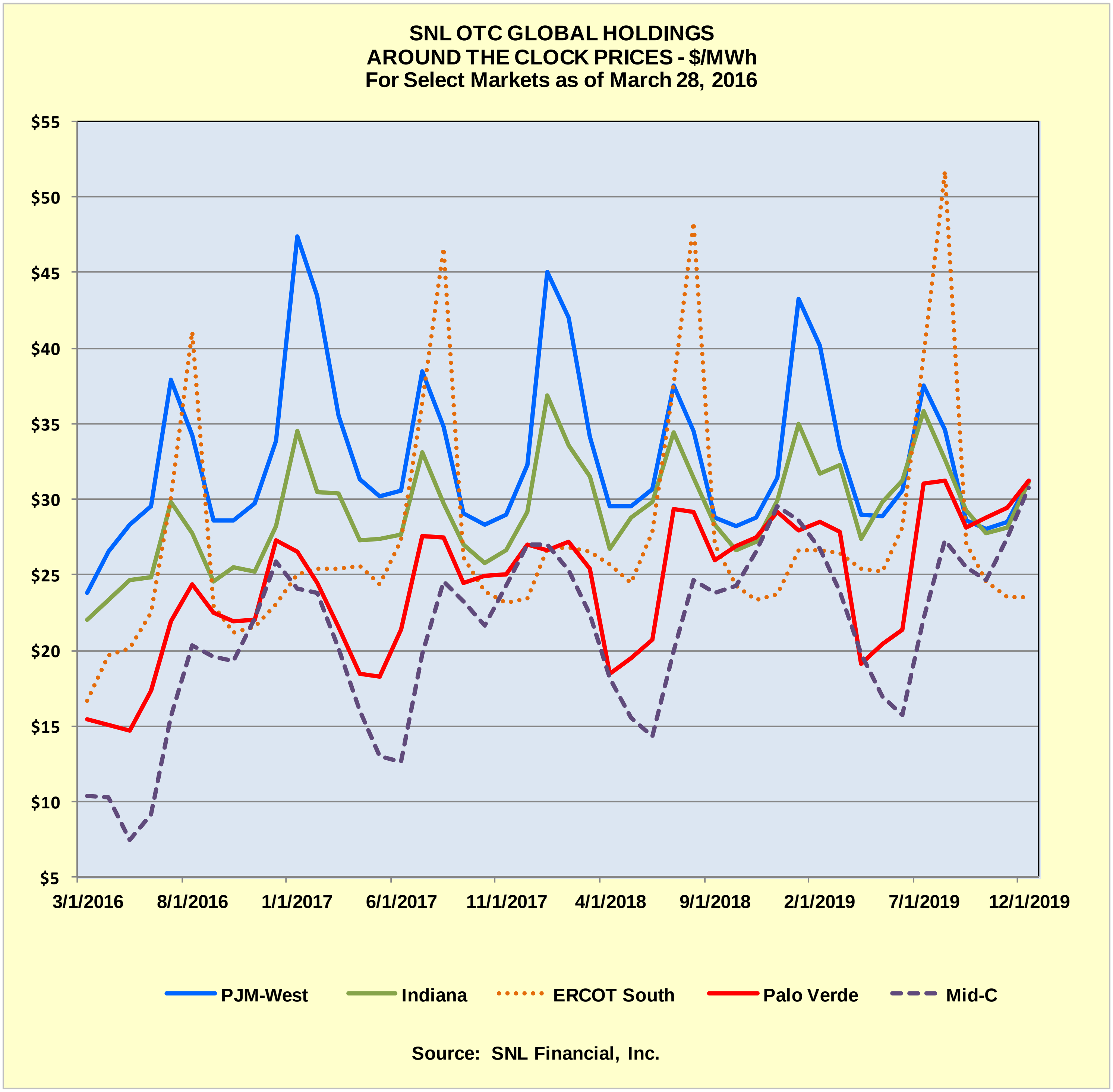
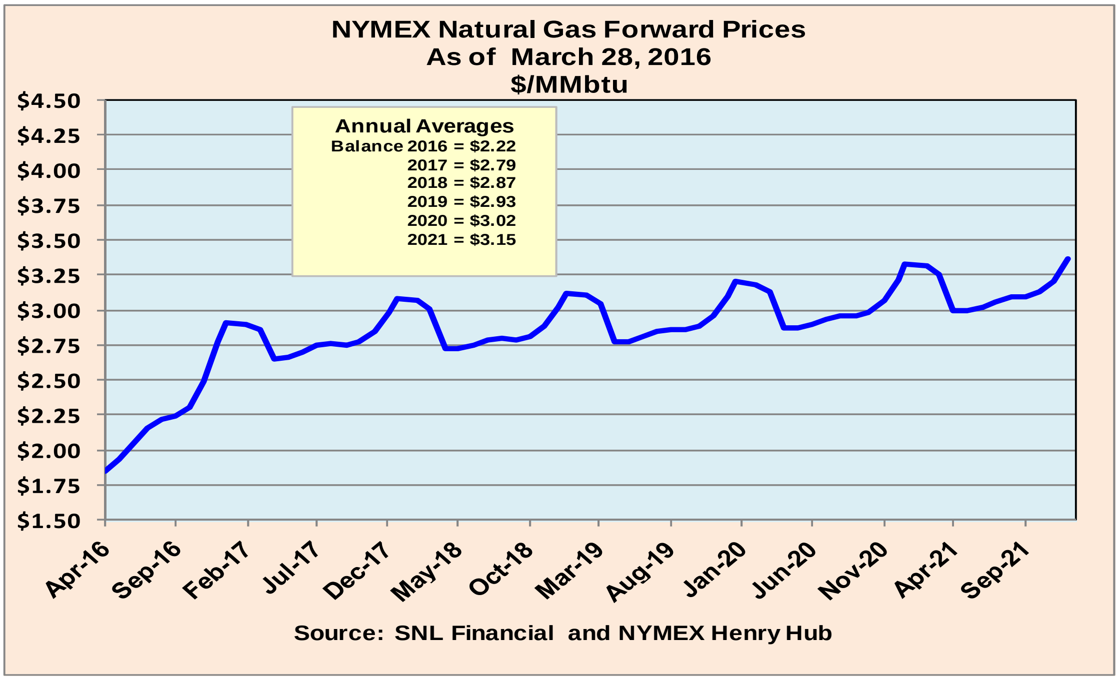
SNL OTC GLOBAL HOLDINGS FORWARD POWER PRICES

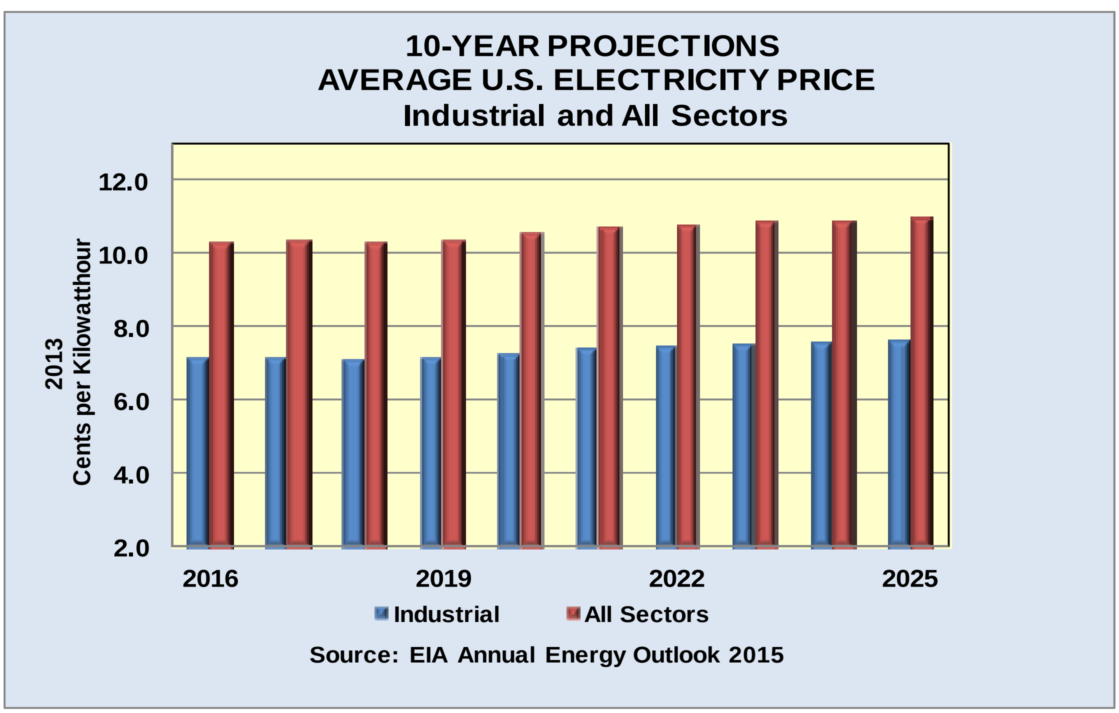


FORECASTED NATURAL GAS AND ELECTRICITY PRICES

The New York Mercantile Exchange ("NYMEX") forecast for natural gas prices projects a slow rise in prices through year-end 2021. As prices move upward, the highest projected peak during 2016 is expected in December at approximately $2.774/MMbtu. Over the five-year outlook, the highest projected peak is expected in December 2021 at $3.366/MMbtu. The lowest price of $1.848/MMbtu is projected for April 2016.



Ten-year price projections from the U.S. Energy Information Administration (EIA) predict industrial electricity prices to remain in the 7.1¢ to 7.6¢/kWh range. An average of 10.3¢ to 11.0¢/kWh is projected for the all sectors group.



ELECTRIC RATE CASES
AUTHORIZED INCREASES in 2015 and 2016 TO DATE

Utility	Order Date	Company Requested ($ millions)	Commission Authorized ($ millions)
ARKANSAS			
Entergy Arkansas Inc.*	2/23/16	268.5	219.7
CALIFORNIA			
Southern California Edison Co.	11/5/15	-120.9	-450.4
COLORADO			
Public Service Company of Colorado*	02/24/15	28.5	-39.4
GEORGIA			
Georgia Power Co.	12/22/15	NA	19.1
IDAHO			
Avista Corp.	12/18/15	26.9	1.7
PacifiCorp*	12/23/15	10.2	10.2
ILLINOIS			
Ameren Illinois *	12/9/15	98.5	95.1
Commonwealth Edison Co.*	12/9/15	-53.8	-65.5
INDIANA			
Indianapolis Power & Light Co.*	03/16/16	67.8	29.6
Northern Indiana Public Service Co.	01/28/16	2.1	0.0
KANSAS			
Kansas City Power & Light Co.	09/10/15	56.3	40.1
Westar Energy Inc.*	09/24/15	250.9	185.3
KENTUCKY			
Kentucky Power Co.	06/22/15	-4.7	-23.0
Kentucky Utilities Co.	06/30/15	153.4	125.0
Louisville Gas & Electric Co.	06/30/15	30.3	0.0
MICHIGAN			
Consumers Energy Co.*	11/19/15	198.6	126.4
DTE Electric Co.*	12/11/15	348.7	242.7
Wisconsin Public Service Corp.	04/23/15	5.7	4.0
MINNESOTA			
Northern States Power Co.	03/26/15	248.1	149.4
MISSISSIPPI			
Mississippi Power Co.	07/07/15	170.5	0.0
Mississippi Power Co. *	12/03/15	272.9	126.1
MISSOURI			
Empire District Electric Co. *	06/24/15	24.3	17.1
Kansas City Power & Light Co. *	09/02/15	112.7	89.7
Union Electric Co. *	04/29/15	181.2	121.5
NEW JERSEY			
Jersey Central Power & Light Co.	03/18/15	11.0	-115.0
NEW MEXICO			
Public Service Co. of New Mexico *	05/13/15	107.4	NA
Southwestern Public Service Co.*	06/24/15	31.5	NA
NEW YORK			
Central Hudson Gas & Electric	06/17/15	40.1	15.3
Consolidated Edison Co. of NY	06/17/15	368.1	0.0
Orange & Rockland Utilities Inc.	10/15/15	33.9	9.3
OKLAHOMA			
Public Service Company of Oklahoma	04/14/15	37.7	-4.8
OREGON			
Portland General Electric Co.	12/15/15	122.3	70.4

Utility	Order Date	Company Requested ($ millions)	Commission Authorized ($ millions)
PENNSYLVANIA			
Metropolitan Edison Co.	04/09/15	168.3	105.7
PECO Energy Co.	12/17/15	190.1	127.0
Pennsylvania Electric Co.	04/09/15	136.8	107.8
Pennsylvania Power Co.	04/09/15	38.0	25.5
PPL Electric Utilities Corp.	11/19/15	167.5	124.0
West Penn Power Co.	04/09/15	114.0	95.2
SOUTH CAROLINA			
South Carolina Electric & Gas	09/23/15	69.6	64.5
SOUTH DAKOTA			
Black Hills Power Inc.	03/02/15	14.6	6.9
Northern States Power Co.	06/15/15	24.6	15.2
NorthWestern Corp.	10/29/15	26.5	40.7
TENNESSEE			
Kingsport Power Co.	12/15/15	12.1	NA
TEXAS			
Cross Texas Transmission	05/01/15	33.2	30.9
Entergy Texas Inc.*	07/20/15	75.9	NA
Southwestern Public Service Co.*	12/17/15	42.1	-4.0
VIRGINIA			
Kentucky Utilities Co.	02/02/16	7.2	5.5
Virginia Electric & Power Co. (Rider B)	02/29/16	21.3	21.0
Virginia Electric & Power Co. (Rider R)	02/29/16	-7.8	-9.3
Virginia Electric & Power Co. (Rider S)	02/29/16	11.5	6.6
Virginia Electric & Power Co. (Rider W)	02/29/16	-15.5	-16.8
Virginia Electric & Power Co. (Rider BW)	04/21/15	60.5	60.5
Virginia Electric & Power Co. (Rider B)	03/12/15	-2.2	-6.4
Virginia Electric & Power Co. (Rider R)	03/12/15	13.5	11.4
Virginia Electric & Power Co. (Rider S)	03/12/15	5.8	5.8
Virginia Electric & Power Co. (Rider W)	02/18/15	36.9	36.9
WASHINGTON			
Avista Corp.*	01/06/16	33.2	-8.1
PacifiCorp	03/25/15	30.4	9.6
WEST VIRGINIA			
Appalachian Power Co.	05/26/15	226.1	123.5
Monongahela Power Co.	02/04/15	212.6	124.3
WISCONSIN			
Northern States Power Co.	12/03/15	27.4	7.6
Wisconsin Public Service Corp.*	11/19/15	96.9	-7.9
WYOMING			
PacifiCorp*	12/30/15	30.0	16.3
PacifiCorp*	01/23/15	32.6	20.2

BAI involvement
Includes 2016 electric cases authorized through March 22, 2016.
Sources: SNL Financial, Regulatory Research Associates and state regulatory commissions.

PENDING RETAIL ELECTRIC RATE CASES

Utility	Filing Date	Company Requested Rate Increase ($ millions)
ARIZONA		
Tucson Electric Power Co.	11/05/15	109.5
UNS Electric Inc.	5/05/15	22.6
CALIFORNIA		
Liberty Utilities LLC	05/01/15	13.6
Pacific Gas & Electric Co.	09/01/15	270.5
San Diego Gas & Electric Co.	11/14/14	91.9
FLORIDA		
Florida Power & Light Co.*	03/15/16	1,337.7
INDIANA		
Northern Indiana Public Service Co.*	10/01/15	126.6
MARYLAND		
Baltimore Gas & Electric Co.	11/06/15	120.9
MASSACHUSETTS		
Fitchburg Gas & Electric Light Co.	06/16/15	3.8
Massachusetts Electric Co.	11/06/15	211.3
MICHIGAN		
Consumers Energy Co.*	03/01/16	225.4
DTE Electric Co.*	02/01/16	344.0
Upper Peninsula Power Co.	09/18/15	6.7
MINNESOTA		
Northern States Power Co.	11/02/15	297.1
Otter Tail Power Co.	02/16/16	19.3
MISSOURI		
Empire District Electric Co.*	10/16/15	33.4
KCP&L Greater Missouri Op Co.* (MPS)	02/23/16	33.7
KCP&L Greater Missouri Op Co.* (L&P)	02/23/16	26.5
Union Electric Co.*	NA	NA
MONTANA		
MDU Resources Group Inc.*	06/25/15	11.8
NEW JERSEY		
Atlantic City Electric Co.	03/22/16	84.4
NEW MEXICO		
El Paso Electric Co.	05/11/15	6.4
Public Service Co. of New Mexico *	08/27/15	123.5
Southwestern Public Service Co.*	10/16/15	45.4

Utility	Filing Date	Company Requested Rate Increase ($ millions)
NEW YORK		
Consolidated Edison Co. of NY *	01/29/16	482.0
NY State Electric & Gas Corp.*	05/20/15	122.3
Rochester Gas & Electric Corp.*	05/20/15	-9.9
OHIO		
Dayton Power and Light Co. *	11/30/15	65.8
OKLAHOMA		
Oklahoma Gas and Electric Co.*	12/18/15	149.5
Public Service Co. of Oklahoma	07/01/15	84.4
TENNESSEE		
Kingsport Power Co.	01/04/16	12.1
TEXAS		
El Paso Electric Co.*	08/10/15	63.3
Southwestern Public Service Co.*	02/16/16	71.9
VIRGINIA		
Virginia Electric & Power Co. (Rider BW)	10/01/15	8.0
Virginia Electric & Power Co. (Rider GV)	07/01/15	41.6
Virginia Electric & Power Co. (Rider U)	12/01/15	24.2
WASHINGTON		
Avista Corp.*	02/19/16	48.9
PacifiCorp	11/25/15	20.3
WEST VIRGINIA		
Appalachian Power Co.	03/01/16	108.3

***BAI involvement**
Includes 2016 electric pending cases as of March 22, 2016
Sources: SNL Financial, Regulatory Research Associates and various state regulatory commissions.

ELECTRIC RETAIL INDUSTRIAL CUSTOMER SHOPPING

As noted in the tables below, a high percentage of large industrial users continue to shop their electric supply. The Northeast, Illinois and Texas, have provided customer choice options for nearly two decades. They remain the dominant areas for electric choice.

STATES WITH FULL CUSTOMER CHOICE

STATE	PERCENT	STATE	PERCENT	STATE	PERCENT
CONNECTICUT		**MASSACHUSETTS**		**OHIO**	
Connecticut Light & Power	N/A	National Grid	86.5%	AEP-Ohio	52.3%
United Illuminating	N/A	Northeast Utilities	99.0%	Cleveland Electric	87.3%
DELAWARE		NStar	79.5%	Dayton Power & Light	73.7%
Delmarva Power & Light	31.1%	UNITIL	88.5%	Duke Energy	69.1%
DISTRICT OF COLUMBIA		**NEW HAMPSHIRE**	N/A	Ohio Edison	78.7%
Potomac Electric Power Co.	34.6%	**NEW JERSEY** (>1,000 kW)		Toledo Edison	87.0%
ILLINOIS		Atlantic City Electric	89.2%	**PENNSYLVANIA**	
Ameren IL (1MW or Greater)		Jersey Central Power & Light	83.2%	Duquesne Light	63.4%
Rate Zone I	88.1%	Public Service Electric & Gas	87.0%	MetEd	85.6%
Rate Zone II	91.7%	Rockland Electric	90.9%	PECO Energy	89.1%
Rate Zone III	87.9%	**NEW YORK** (NonRes LG-TOU)		Penelec	84.7%
ComEd 400 kW & Above	91.6%	Central Hudson	73.9%	Penn Power	97.3%
MAINE (Statewide)	86.9%	Con Edison	89.8%	PPL	89.8%
MARYLAND (Large C&I)		New York State Electric & Gas	78.9%	UGI	38.5%
Baltimore Gas & Electric	94.0%	Niagara Mohawk	70.0%	West Penn Power	89.3%
Delmarva Power & Light	94.3%	Orange & Rockland	28.0%		
Potomac Edison	92.9%	Rochester Gas & Electric	93.6%	**RHODE ISLAND**	
Potomac Electric Power Co.	89.7%			National Grid	N/A
				TEXAS	N/A

STATES WITH LIMITED CHOICE

STATE	PERCENT
MICHIGAN	
Consumers Energy	10% CAP
Detroit Edison	10% CAP
MONTANA	N/A
NEVADA	N/A
OREGON	
Pacific Power & Light	1.4%
Portland General	13.9%
VIRGINIA	N/A
WASHINGTON	N/A

Notes:

- California's Direct Access Load Caps have been met under the adopted utility service area caps.
- Above figures are based on data provided by various state regulatory commission websites.
- Data not available for Connecticut, Montana, New Hampshire, Nevada, Rhode Island, Texas, Virginia and Washington.

KEY CHANGES IN THE FINALIZED CLEAN POWER PLAN

By Colin Fitzhenry, Assistant Engineer

On August 3, 2015, the Environmental Protection Agency (EPA) finalized the Clean Power Plan (CPP) Rule to cut carbon emissions from existing power plants. Under the authority of the Clean Air Act, Section 111(d), the EPA is establishing CO_2 emission guidelines for existing fossil fuel-fired electric generating units (EGUs). The CPP aims to achieve a 32% reduction in CO_2 emissions by the electric power sector by 2030 from 2005 levels. This is a more aggressive target than the 30% reduction in the Proposed Clean Power Plan issued in 2014.

The Final CPP Rule included several significant changes from the Proposed Rule.[1] Most notably, the Best Systems of Emission Reduction (BSER), which provides the methodology for calculating state goals, was altered from the previous version. Several of the building blocks that make up the BSER were changed or eliminated.

Building Block 1, improving heat rate at affected coal fired-steam EGUs, was changed to reflect a more realistic improvement in efficiency. The proposed assumption of a 6% improved efficiency at all coal and oil units is now being reflected as a 2.1%-4.3% improvement, depending on the region.

Similar to Building Block 1, the concept behind Building Block 2 remained relatively unchanged from the Proposed Rule to the Final CPP Rule. Building Block 2 substitutes generation from higher-emitting affected steam generating units to lower-emitting existing natural gas combined cycle units. In the Proposed Rule, the BSER analysis assumed a shift of generation so that natural gas units were running at 70% capacity factor, based on nameplate capacity. Now, the assumption is that natural gas units can be run at 75% capacity factor, based on net summer capacity.

Building Block 3 no longer includes existing or under-construction nuclear power and existing utility-scale renewable energy in the Final CPP Rule. Instead, Building Block 3 solely consists of substituting increased generation from new zero-emitting renewable energy generation for reduced generation from affected fossil fuel-fired generating units. In addition, the EPA has projected significantly more new renewable energy generation in the Final CPP Rule than what was being projected in the Proposed Rule. By 2030, the EPA estimates that the total Building Block 3 generation levels will be about 706,030 GWh.

The former fourth building block of the BSER, demand-side and energy efficiency measures, is no longer being used in calculating a state's Rate-Based or Mass-Based goal. This is primarily due to the EPA's belief that demand-side energy efficiency measures may not be enforceable under Clean Air Act, Section 111.

Based upon the BSER, the EPA has finalized performance rates of 1,305 lb CO_2/MWh for fossil fuel-fired steam generating units, and 771 lb CO_2/MWh for stationary combustion turbines. Both performance rates were initially calculated individually in three different regional interconnects, West, Texas, and East; however, after the calculations were made, it was decided that the least stringent performance rates (Eastern Interconnection) would be used for all three regions. These performance rates were applied to every "Affected EGU," which the EPA defines as Fossil Fuel Fired EGUs and Combined Cycle Stationary Combustion Turbines with the following characteristics:

1. **Must have been in operation or have commenced construction prior to January 8, 2014;**
2. **Capable of selling greater than 25 MW to a utility distribution system; and**
3. **Must have a base load heat input rating greater than 250 MMBtu/h**

Simple cycle combustion turbines are not considered "Affected EGUs" by the EPA, and as such, will not be required to meet the

[1] See BAI Energy Update Spring 2015, for a description of the proposed rule.

performance rates enforced by the EPA. Depending on a state's current mix of fossil fuel-fired steam generating units and Combined Cycle Stationary Combustion Turbines, its final Rate-Based goal will fall somewhere between the two performance rates of 771 lb CO_2/MWh and 1,305 lb CO_2/MWh.

Each state must develop, approve, and then submit its implementation plan to the EPA for approval. The states will determine whether to apply these emissions performance rates to each affected EGU, individually or together, or take an alternative approach and meet either an equivalent statewide Rate-Based goal or an equivalent statewide Mass-Based goal, as provided by the EPA in the final rule. States will also have the option of participating in a Multi-State Joint Plan, where states may aggregate their goals into one goal, or they can participate in a Multi-State Trading Plan, which allows for interstate trading of Emission Rate Credits (ERCs) for Rate-Based Plans or Emission Allowances for Mass-Based Plans. Rate-Based States do not have the option of entering into a Multi-State Trading Plan with Mass-Based States and vice versa. However, the EPA does not preclude the possibility of a group of generators in one state participating in another state's plan or joining a multi-state plan.

The timeline for state compliance plan submittal and the first year the plan goes into effect has also changed in the Final CPP Rule. By September 2016, states will need to either submit a final plan or a partial plan, with a request for an extension. States requesting an extension will have until September 2018 to submit final plans. The EPA will then approve or disapprove a state's plan the year after submission. State plans will have to be either a source-specific plan, or a plan with a list of measures the state will take to reduce CO_2 emissions. The following are additional filing requirements mandated by the EPA:

1. **Description of plan approach and geographic scope;**
2. **Demonstrations that the plan submittal is projected to achieve the state's CO_2 emission goal;**
3. **Description of how reliability was considered in plan development; and**
4. **Must address "Leakage" concerns (shifts in generation to non-affected fossil fuel-fired sources, i.e. new NGCC, that result in increased CO_2 emissions).**

One of the more critical issues that commentators took with the CPP Proposed Rule was the start date of the interim compliance period in January 2020. Specifically, many commentators took issue with the reliability impact of the CPP, citing a lack of electric and gas infrastructure to handle the change in generation resource mix. As a result, the EPA has extended the beginning of the interim compliance period to January 2022. In addition, the EPA has introduced a Reliability Safety Valve. If a catastrophic event were to occur that would cause electric grid reliability issues, states would be given a 90-day period where CO_2 emissions do not count against their annual total.

The EPA has developed a Clean Energy Incentive Program (CEIP) that will take place in 2020 and 2021 to incentivize early adoption of Energy Efficiency and Renewable Energy Technologies. The program works by awarding Emission Rate Credits or Emission Allowances for eligible renewable energy and energy efficiency projects that generate energy or provide energy savings during 2020 and 2021. Some of the criteria for such projects include, but are not limited to, the following:

1. **Projects must be implemented following the submission of a final state plan to the EPA, or after September 6, 2018, for a state that chooses not to submit a complete state plan by that date;**
2. **For renewable energy: Generate metered MWh from any type of wind or solar resources; and**
3. **For energy efficiency: Result in quantified and verified electricity savings through demand-side energy efficiency implemented in low-income communities.**

Any state that chooses not to submit a state plan will be forced to enact the Proposed Federal Plan introduced by the EPA in conjunction with the final version of the CPP. In addition, these states will not be allowed to participate in the CEIP.

States will be required to report CO_2 emissions on an annual basis starting with the interim period in 2022; however, compliance will only be checked following the last year of three reduction

periods, 2022-2024, 2025-2027, and 2028-2029. Following each reduction period, the EPA will check for compliance and require modifications to a state plan if CO_2 targets are not being met. The final target will be verified in 2030 as it was in the Proposed Rule.

Since the release of the CPP, state commissions, utilities, customers, and other state departments are still assessing the impact of such far-reaching regulation. The Midwest Independent System Operator (MISO) recently completed its near-term analysis and preliminary estimates show compliance costs could reach nearly $100 billion over a ten-year period in the MISO region alone. In addition, the Electric Reliability Council of Texas (ERCOT) is projecting a 20%-39% increase in Locational Marginal Prices by 2030 when compared to its Baseline Model, which does not include CPP Impacts. PJM expects to complete an economic compliance analysis including a minimum of three sensitivities by April 30, 2016, and EIA will follow up its analysis of the proposed CPP with an updated analysis of the final CPP sometime in May 2016.

Since the inception of the CPP, the EPA has been in a legal battle with a large number of states that disagree with its legality. On February 9, 2016, the U.S. Supreme Court voted 5-4 in favor of granting a stay of the Clean Power Plan while the D.C. Circuit considers the legal case. The stay effectively halts the enforcement of the CPP until the lower court's decision and the resolution or denial of any subsequent petition of Supreme Court review has been made. The stay was unprecedented, as the Supreme Court had never before granted a request to halt a regulation before review by a federal appeals court. The EPA said it plans to support states that wish to continue developing compliance plans while the case is litigated.

State reaction to the stay has been mixed, as some states have vocalized that they will continue efforts to reduce CO_2 emissions at existing plants, while others vehemently oppose any compliance. Regardless of a state's position concerning the CPP, it is imperative for large electric customers to be involved in the decision making process with their state entities. Billions of dollars in capital and operating costs are at stake with the looming retirement of coal plants, and the decisions on how to replace their generation and capacity.

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