“approvable” plan by September 6, 2016. EPA may grant extensions of up to two years, until September 6, 2018. If EPA grants an extension, the state must submit a progress report by September 6, 2017. States may submit individual plans or multi-state plans, as described in greater detail below. A “Federal Implementation Plan” will be finalized for any state (with covered EGUs) that EPA determines has not submitted an approved Section 111(d) plan by the designated compliance date.

Two Approaches

The CPP provides guidelines for the development and implementation of state plans to achieve interim and final CO2 emissions rates for EGUs. States can choose between two types of plans: an “emissions standards” approach or a “state measures” approach. An emissions standards approach imposes federally determined standards directly on affected EGUs. In contrast, a state measures approach allows states to achieve state-wide, rather than facility-specific, emissions reductions.

The emission standards approach will measure emissions in pounds of CO2 emissions per megawatt-hour (MWh) of electricity generation. This approach includes source-specific requirements.[20] If a state chooses the emission standards approach, it would implement specified emission rate standards for all affected EGUs in the state. This approach could involve multiple states and allows for the creation of an emission-rate trading system.

A state measures approach allows a state to achieve the equivalent of the CO2 emission standards approach by using some combination of federally enforceable standards for EGUs and elements that would be enforceable only under state laws. Examples of such elements include renewable energy and/or energy efficiency requirements that could be applied to affected EGUs or other entities. States opting for this approach will be required to use a mass-based target to ensure that the proposed state measures achieve overall emission reductions. Options for cutting emissions include investing in renewable energy, energy efficiency, natural gas and nuclear power, and shifting away from coal-fired power.

The CPP paves the way for states to design compliance strategies that are “trading ready,” and gives states the option to work with other states in multi-state approaches to reduce emissions, including via regional emissions trading platforms or exchanges. As a result, out-of-state ERCs or allowances would likely be used by states and regulated EGUs to meet emission reduction requirements. This component of the plan also incentivizes the development of cost-effective renewable energy resources, since regional trading programs would reward clean-burning power sources by providing credits that could be sold to heavy polluters to offset CO2 emissions.

Clean Energy Incentive Program

As part of the CPP, EPA created incentives for future development of renewable energy projects. Specifically, the CPP established the Clean Energy Incentive Program (CEIP), which is expected to be a preferred option for states considering compliance strategies. The CEIP begins on January 1, 2020 and runs throughout 2020 and 2021. States that have expressed interest in participating in this program in their final plans are eligible.

[20] EPA uses the state-specific emission rate targets to calculate equivalent state-specific mass-based targets, measured in metric tons of CO2.

According to EPA, the CEIP is designed “to reward early investments in renewable energy generation and demand-side energy efficiency measures.” A corollary environmental benefit is to limit the growth of natural gas, especially in light of the new CO2 emission limits established by the CPP. Under the CPP, states that invest in wind and solar projects that commence construction after a state’s compliance plan is finalized (to help meet their emission reduction targets) will generate credits for renewable energy generation in the years 2020 and 2021, ahead of the CPP’s 2022 start date. Energy efficiency investments in low-income communities are also incentivized by the CEIP.

Participation in the CEIP is optional. States that act early to cut CO2 pollution, either with renewables or energy efficiency, would be rewarded with emission reduction credits, which they could use to meet their targets or sell to other emitters.

The CEIP sets up a system to award credits to energy efficiency projects in low-income communities and renewable energy projects (only wind and solar) in participating states. The credits are in the form of emission rate credits or emission allowances, depending on whether a state uses an emission rate or mass-based target, respectively. The credits could be sold to or used by an affected emission source to comply with the state-specific requirements. Under the CPP, renewable energy projects would receive one credit (either an allowance or ERC) from the state and one credit from EPA for every two megawatt-hours (MWh) of solar or wind generation. Energy efficiency projects in low-income communities would receive double credits ─ for every two MWh of avoided electricity generation, energy efficiency projects will receive two credits from the state and two credits from EPA.

EPA will match up to 300 million short tons in credits during the CEIP program life. The amount of EPA credits potentially available to each participating state depends on the amount of emission reduction each state is required to achieve compared to its 2012 baseline. As a result, states with greater reduction requirements will have access to a greater share of the EPA credits.

Looking Ahead

A range of legal and legislative challenges await the CPP in 2016, as well as more limited financing options for coal operators. In addition, and as discussed above, initial state plans with requests for an extension or final plans must be submitted to EPA by September 6, 2016.

As of the date of this publication, the Republican Congress has passed bills in both houses of Congress to invalidate the CPP. On December 1, the House of Representatives passed a resolution, previously passed by the Senate, to repeal the CPP. The resolutions would both nullify the CPP and prevent “substantially similar” rules from being introduced in the future. These resolutions, however, are expected to be vetoed by President Obama. It is unlikely that opponents of the CPP will be able to mobilize the votes needed to override a presidential veto in 2016.

Similarly, utility and industry groups, including the coal industry, have commenced legal challenges against the CPP. In addition, a group of 24 states, led by West Virginia, Oklahoma and North Dakota, have also challenged the rule. These challenges allege, among other items, that EPA lacks the authority under the Clean Air Act to mandate carbon emission cuts from EGUs and that EPA is prohibited from issuing rules under Section 111(d) of the Clean Air Act because EGUs are already regulated under Section 112. It is likely that some of these challenges will be heard by the US Supreme Court.

In late November, Morgan Stanley and Wells Fargo announced plans to reduce involvement in, and funding for, coal projects. Morgan Stanley’s “Coal Policy Statement” includes a commitment to decline financing transactions that “directly support the development of new or physical expansions of coal-fired power generation, unless there is sufficient carbon capture and storage equivalent emissions and pollutant reduction technology in place." Morgan Stanley has also committed to "continue to reduce [its] exposure to coal mining globally" and not to provide financing where the "specified use of proceeds would be directed towards" mountaintop removal mining. It also indicated that it would not provide financing to any company that does not have a plan to eliminate existing mountaintop removal operations in the foreseeable future.

Wells Fargo's Environmental and Social Risk Management policy commits the bank to "limit and reduce [its] credit exposure to the coal mining industry." In response to concerns about mountaintop removal mining, Wells Fargo's policy states that its involvement with mountaintop removal mining "is limited and declining."

Conclusion

The CPP is a Clean Air Act initiative to cut CO2 emissions from certain power plants and to spur the development and growth of renewable energy. At its core, it reflects the first uniform effort to reduce CO2 emissions from existing fossil fuel-fired power plants. Under the CPP, states may choose to meet specified CO2 emissions reduction targets or opt to join together in multi-state or regional compacts to find the lowest cost options for reducing CO2 emissions, including via emissions trading programs. No matter the choice, one thing appears clear: CO2 emissions from fossil fuel-fired power plants appear to be on track to decrease significantly by 2022 and are projected to be 32 percent below 2005 emissions levels by 2030.

Additional LNG/CNG Export Projects Get the Green Light

by Donna J. Bobbish

In 2015, the United States Department of Energy's Office of Fossil Energy (DOE/FE) authorized the long-term, large-scale export of US-produced liquefied natural gas (LNG) for four export projects with a cumulative volume of exports totaling some 4.26 billion cubic feet per day (Bcf/d) of natural gas. DOE/FE issued the export authorizations after the Federal Energy Regulatory Commission (FERC) had authorized the construction of facilities to be used for the export of LNG. These approved LNG export projects are Dominion Cove Point LNG, LP (0.77 Bcf/d),[21] Cheniere Marketing, LLC and Corpus Christi Liquefaction, LLC (2.1 Bcf/d),[22] Sabine Pass Liquefaction, LLC Expansion Project (1.38 Bcf/d),[23]and American LNG Marketing LLC (0.008 Bcf/d).[24]

In 2012 and 2014, FERC authorized the construction of LNG export facilities and DOE/FE authorized the long-term, large-scale export of LNG for four LNG export projects with a cumulative volume of exports totaling 5.74 Bcf/d of natural

21 *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331-A, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas from the Cove Point LNG Terminal in Calvert County, Maryland, to Non-Free Trade Agreement Nations (May 7, 2015), *reh'g pending*; and *Dominion Cove Point LNG, LP*, Order Granting Section 3 and Section 7 Authorizations, 148 FERC ¶ 61,244 (Sept. 29, 2014), *reh'g denied*, 151 FERC ¶ 61,095 (May 4, 2015), *petition for review pending*.

22 *Cheniere Marketing, LLC and Corpus Christi Liquefaction, LLC*, DOE/FE Order No. 3638, Final Order and Opinion Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Proposed Corpus Christi Liquefaction Project to Be Located in Corpus Christi, Texas, to Non-Free Trade Agreement Nations (May 12, 2015), *reh'g pending*; and *Corpus Christi Liquefaction, LLC, et al.,* Order Granting Authorization Under Section 3 of the Natural Gas Act and Issuing Certificates, 149 FERC ¶ 61,283 (Dec. 30, 2014), *reh'g denied*, 151 FERC ¶ 61,098 (May 6, 2015), *petition for review pending*.

23 *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3669, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Sabine Pass LNG Terminal Located in Cameron Parish, Louisiana, to Free Trade Agreement Nations (June 26, 2015); and *Sabine Pass Liquefaction Expansion, LLC, et al.*, Order Granting Authorization Under Section 3 of the Natural Gas Act and Issuing Certificates, 151 FERC ¶ 61,012 (Apr. 6, 2015), *reh'g denied*, 151 FERC ¶ 61,253 (June 23, 2015).

24 *American LNG Marketing LLC*, DOE/FE Order No. 3690, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas in ISO Containers Loaded at the proposed Hialeah Facility near Medley, Florida, and Exported by Vessel to Non-Free Trade Agreement Nations (Aug. 7, 2015). FERC did not authorize the construction of the Hialeah Facility.

gas. These projects are Sabine Pass Liquefaction, LLC (2.2 Bcf/d),[25] Carib Energy (USA) LLC (0.04 Bcf/d),[26] Cameron LNG, LLC (1.7 Bcf/d),[27] Freeport LNG Expansion, L.P. (1.4 Bcf/d),[28] and Freeport LNG Expansion L.P. (0.4 Bcf/d).[29]

Also, in October, DOE/FE authorized Emera CNG, LLC to export compressed natural gas (CNG) by waterborne vessels to non-FTA countries up to the equivalent of 0.008 Bcf/d of natural gas for a 20-year term.[30] FERC had determined in 2014 that Emera's proposed facilities and operations would not be subject to FERC's jurisdiction under the Natural Gas Act (NGA).[31] This approval raised the total volume of authorized long-term, large-scale LNG and CNG exports to just over 10 Bcf/d.

Section 3 of the NGA gives FERC exclusive jurisdiction to approve the construction and operation of LNG Terminals, which include natural gas facilities located onshore or in state waters used to receive, unload, load, store, transport, gasify, liquefy or process natural gas that is exported to a foreign country from the US. FERC approves the siting, construction and operation of LNG terminals upon a finding that such activities are not inconsistent with the public interest.

Section 3 of the NGA also gives DOE/FE authority over exports of natural gas. Under Section 3(c) of the NGA, LNG exports to countries with which the US has free trade agreements that require "national treatment" for trade in natural gas are automatically considered in the public interest. Requiring "national treatment" means treating an imported good the

25 *Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.,* Order Granting Section 3 Authorization, 139 FERC ¶ 61,039 (2012), *reh'g denied*, 140 FERC ¶ 61,076 (2012); and Sabine Pass Liquefaction, LLC, DOE/FE Order No. 2961-A, Final Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations (Aug. 7, 2012), *reh'g dismissed*.

26 *Floridian Natural Gas Storage Company, LLC*, Order Amending Certificate, 140 FERC ¶ 61,167 (2012); and *Carib Energy (USA) LLC*, DOE/FE Order No. 3487, Final Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural gas in ISO Containers by Vessel to Non-Free Trade Agreement Nations in Central America, South America or the Caribbean (Sept. 10, 2014).

27 *Cameron LNG, LLC, et al.,* Order Granting Authorization Under Section 3 of the Natural Gas Act and Issuing Certificates, 147 FERC ¶ 61,230 (June 19, 2014), *Cameron LNG, LLC, et al.,* 148 FERC ¶ 61,073 (July 29, 2014) (Notice Rejecting Request for Rehearing and Dismissing Request for Stay); and *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Cameron LNG Terminal in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations (Sept. 10, 2014), *reh'g denied*.

28 *Freeport LNG Development, L.P., et al.,* Order Granting Authorizations Under Section 3 of the Natural Gas Act, 148 FERC ¶ 61,076 (July 30, 2014); *reh'g denied*, 149 FERC ¶ 61,119 (Nov. 13, 2014), petition for review pending, and *Freeport LNG Expansion, L.P., et al.,* DOE/FE Order No. 3282-C, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (Nov. 14, 2014).

29 *Freeport LNG Expansion, L.P., et al.,* DOE/FE Order No. 3357-B, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (Nov. 14, 2014).

30 *Emera CNG, LLC*, DOE/FE Order No. 3727, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Compressed Natural Gas by Vessel From a Proposed CNG Compression and Loading Facility at the Port of Palm Beach, Florida, to Non-Free Trade Agreement Nations (Oct. 19, 2015).

31 *Emera CNG, LLC*, Order on Petition for Declaratory Order, FERC Docket No. CP14-114-000, 148 FERC ¶ 61,219 (Sept. 19, 2014).

same as a locally produced good once it enters a market. Applications to export gas to such countries must be approved without modification or delay. The US currently has such free trade agreements with Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore.

Authorization to export LNG to countries without such free trade agreements requires DOE/FE to find that the proposed exports are not inconsistent with the public interest. In making this determination, DOE considers the domestic need for the natural gas proposed to be exported, whether the proposed exports pose a threat to the security of domestic natural gas supplies and other factors bearing on the public interest. DOE also must review the potential environmental effects of the proposed export under the National Environmental Policy Act.

In 2011, DOE/FE engaged the US Energy Information Administration (EIA) and NERA Economic Consulting (NERA) to conduct a two-part study of the economic impacts of LNG exports. The two studies were published in 2012.[32] EIA examined the impact of two DOE/FE prescribed levels of assumed natural gas exports (at 6 Bcf/d and 12 Bcf/d) under numerous scenarios which included a variety of supply, demand and price outlooks. EIA generally found that LNG exports will lead to higher domestic natural gas prices, increased domestic natural gas production, reduced domestic natural gas consumption and increased natural gas imports from Canada via pipeline. The NERA study analyzed the potential macroeconomic impacts of LNG exports under a range of global natural gas supply and demand scenarios, including scenarios with unlimited LNG exports. For every market scenario examined, NERA found that net economic benefits to the US increased as the level of LNG exports increased.

According to DOE/FE, the total approved export volume of 10.01 Bcf/d of natural gas for the 10 final export authorizations issued from 2012 through 2015 is within the range of scenarios analyzed in the EIA and NERA studies, in which NERA found that in all such scenarios—assuming either 6 Bcf/d or 12 Bcf/d of export volumes—the US would experience net economic benefits.

It is expected that during the first quarter of 2016, FERC and DOE will issue final authorizations for the construction of LNG export facilities and long-term, large-scale exports of LNG for Jordan Cove Energy Project LP (2.0 Bcf/d)[33] and Magnolia LNG, LLC (1.08 Bcf/d).[34] FERC issued final Environmental Impact Statements for both projects in the third quarter of 2015, and DOE/FE had granted Jordan Cove conditional authorization to export LNG to non-FTA countries in 2014.

32 EIA published its study, *Effect of Increased Natural Gas Exports on Domestic Energy Markets*, in January 2012. DOE published the NERA Study, *Macroeconomic Impacts of LNG Exports from the United States*, in December 2012.

33 *See* FERC Docket No. CP13-483-000 and FE Docket No. 12-32-LNG

34 *See* FERC Docket No. CP14-347-000 and FE Docket No. 13-132-LNG.

PJM Restructures Its Capacity Market Design

by Donna J. Bobbish

In 2015, PJM Interconnection, L.L.C. (PJM), the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia, began implementing significant reforms to its capacity market construct, as well as corresponding changes to its energy markets. These actions were taken to ensure that committed capacity resources will perform when called upon to meet the reliability needs of the PJM region. Since 2007, PJM's capacity market construct, the Reliability Pricing Model (RPM), has utilized a three-year forward capacity market to ensure resource adequacy at a reasonable cost through the use of an annual auction, the "Base Residual Auction," and subsequent Incremental Auctions closer to the delivery year.

In filings made with the Federal Energy Regulatory Commission (FERC) in December 2014, PJM argued that its capacity market design has failed to keep pace with the level of resource commitments required, has not adequately ensured actual performance and has failed to provide adequate incentives for resource performance. PJM argued that these flaws can threaten the reliable operation of the PJM system and force consumers to pay for capacity without receiving commensurate reliability benefits.

In order to address these problems, PJM proposed a new capacity product, the "Capacity Performance Resource," to provide greater assurance of the delivery of energy and reserves during emergency conditions. PJM further proposed charges for poor performance, credits for superior performance and a must-offer requirement for Capacity Performance Resources.

In June 2015, FERC generally approved PJM's proposed market reforms, finding that PJM had demonstrated the need for reforms to ensure the long-term reliability of electric supply in the PJM region.[35] FERC's order on PJM's market reform proposal came a year after it approved similar reforms of the ISO New England Inc. Forward Capacity Market design.[36]

PJM will procure all of the region's capacity requirements in the form of Capacity Performance Resources beginning with the 2020-21 delivery year. As a transition to the Capacity Performance Resource product, PJM established a separate, interim capacity product with a lower performance expectation, a "Base Capacity Resource," for the 2018-19 and 2019-20 delivery years. For those delivery years, PJM intends to procure at least 80 percent of the region's capacity requirement in the form of Capacity Performance Resources, with the remainder composed of Base Capacity Resources. For delivery years 2016-17 and 2017-18, for which the Base Residual Auction has already been conducted, PJM will procure a portion of Capacity Performance Resources through two Transition Auctions.

[35] *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,208 (2015), *reh'g pending* (the "June 9 Order").

[36] *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014), *reh'g denied*, 153 FERC ¶ 61,223 (2015).

In light of the D.C. Circuit Court of Appeals' decision in 2014 vacating FERC's final rule on demand response compensation in wholesale energy markets,[37] PJM's proposal, as approved by FERC in the June 9 Order, did not permit demand response and other non-generation resources to participate in the Transition Auctions. In an order issued on July 22, 2015, FERC granted a request for rehearing of that aspect of the June 9 Order, finding that such exclusion is unjust, unreasonable and unduly discriminatory, and requiring PJM to allow non-generation resources to participate in the Transaction Auctions if they are technically capable of providing the capacity service to be procured through those auctions.[38]

Capacity Performance Resource

PJM has replaced its existing capacity products with the new Capacity Performance Resource. The Capacity Performance Resource must be capable of sustained, predictable operation that allows the resource to be available to provide energy and reserves whenever PJM determines an emergency condition exists, but is not required to operate during all hours of a delivery year.

All annual Capacity Resources will be eligible to offer as Capacity Performance Resources unless they qualify for an exemption from PJM's must-offer requirement. In order to offer as a Capacity Performance Resource, an External Generation Capacity Resource must demonstrate that it meets, or will meet by the start of the delivery year, the criteria for an exception to the Capacity Import Limit.

Capacity Storage Resources, Intermittent Resources, Energy Efficiency Resources and Demand Resources are permitted to submit stand-alone Capacity Performance sell offers in a megawatt (MW) quantity consistent with their average expected output during peak-hour periods. In addition, Demand Resources, Energy Efficiency Resources, Capacity Storage Resources, Intermittent Resources and Environmentally-Limited Resources (defined as a resource which has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability on either a temporary or long-term basis) may submit aggregated offers as a Capacity Performance Resource. Aggregated resources may either be owned by or under contract to the seller submitting the offer, including resources obtained through bilateral contract and reported to PJM through its capacity accounting system.

PJM also established, on a phased-in-basis, an Annual Demand Resource product to replace its existing demand response capacity products and requires that Annual Demand Resources conform with the standards applicable to a Capacity Performance Resource. Annual Demand Resources are permitted to aggregate with other eligible resource types to submit a Capacity Performance offer.

Instead of delineating specific eligibility requirements for a Capacity Performance Resource, PJM's proposal to FERC had included a requirement that a market seller submitting a Capacity Performance offer make a good faith representation that (i) it has made, or will make, the necessary investment to ensure that its resource has the capability to provide energy when

[37] *EPSA v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *cert. granted*, Nos. 14-840 and 14-841.

[38] *PJM Interconnection, L.L.C., et al.*, 152 FERC ¶ 61,064 (2015), *reh'g pending* (the "July 22 Order").

called upon; (ii) the resource meets the operational requirements and performance obligations applicable to Capacity Performance Resources; and (iii) the seller's offer contemplates the physical delivery of the Capacity Performance Resource no later than the commencement of the applicable delivery year. Fossil-fueled generation resources would be required to make an additional good faith representation that they have obtained and hold, or reasonably expect to obtain and hold, the contractual and other rights necessary to ensure firm fuel supply to each of their affected units during the delivery year. FERC, however, rejected PJM's proposed good-faith representation requirement, finding it to be inappropriately vague, and could cause well-performing resources to elect not to participate in the capacity market to avoid the risk of sanctions. Among other things, FERC noted that PJM will be authorized to review Capacity Performance Resource sell offers in order to mitigate speculative participation in PJM's capacity market.

PJM also revised its milestone requirements to obligate a planned generation resource to execute a Facilities Study Agreement in order to submit an offer into PJM's Base Residual Auction.

Under its revised market design, PJM, in consultation with the Market Monitor, has discretion to reject a sell offer if it determines that the relevant resource does not qualify as a Capacity Resource; that is, if the resource cannot reasonably be relied on to perform, as required, during emergency conditions, is purely speculative or would otherwise undermine the intent of PJM's Capacity Performance construct. However, PJM may only reject an offer when a resource fails to demonstrate that it can reasonably be expected to meet Capacity Performance obligations, consistent with the resource's offer, by the relevant delivery year.

On an interim basis, PJM will reclassify its existing capacity market product as a Base Capacity product. Base Capacity Resources will include internal and external capacity resources; Intermittent Resources; Capacity Storage Resources; Annual Demand Resources; Base Capacity Demand Resources; and Base Capacity Efficiency Resources. Base Capacity Resources will be permitted to participate in PJM's capacity auctions in the 2018-19 and 2019-20 delivery years. Summer-only resources seeking to submit offers as Base Capacity Resources must demonstrate that they are, or will be, physically incapable of meeting the year-round performance expected of a Capacity Performance Resource.

Market Mitigation

Beginning with the 2018-19 delivery year, the installed capacity of every Generation Capacity Resource located in the PJM region that is capable, or that reasonably can become capable, of qualifying as a Capacity Performance Resource must be offered as a Capacity Performance Resource, subject to applicable demand-equivalent forced outage rate (EFORd) and Unforced Capacity determinations, and an exceptions process.

PJM has revised its market power mitigation rules to allow for sell offers that will cover the seller's expected new costs of improving their resources' performance, and the perceived risks of non-performance. In its December 2014 filing with FERC, PJM had proposed a default offer cap for Capacity Performance Resources equal to Net Cost of New Entry (Net CONE). PJM subsequently amended its proposal to provide for a default offer cap set at the product of Net CONE times the average of the Balancing Ratios in the three consecutive calendar years that precede the Base Residual Auction for the delivery year. PJM also will allow resources with high avoidable costs to submit unit-specific offer caps that detail all Avoidable Cost Rate components, including a quantifiable risk premium. A Market Seller Offer Cap may, at the election of the seller, exceed the Net CONE default offer cap, subject to an Avoidable Cost Rate that will permit the costs of natural gas transportation, other gas service and a risk premium. FERC approved PJM's amended proposal, finding that "[a]ny Capacity Performance offer below the default offer cap can properly be deemed competitive, and any offer above that level will be scrutinized by the Market Monitor and PJM to ensure that it is based on legitimate costs and reasonable estimates of unit-specific performance and system parameters."

Non-Performance Charges

PJM established a new Non-Performance Charge, applicable to Capacity Performance Resources, which is based on the expected performance of each Capacity Resource, as compared to its actual performance during an Emergency Action declared by PJM. Emergency Actions are defined as locational or system-wide capacity shortages, including Voltage Reduction Warnings, Manual Load Dump Warnings, Voltage Reduction Actions and Manual Load Dump Actions, that cause pre-emergency mandatory load management reductions or a more severe action. PJM will measure Capacity Resources' performance during Performance Assessment Hours, which will be triggered when PJM declares an Emergency Action. The measure of expected performance and actual performance will differ based on the resource type at issue and PJM's existing rules governing those resources. If a Capacity Resource's actual performance falls short of its expected performance, its shortfall will be subject to the Non-Performance Charge, absent a valid excuse or the application of a stop-loss limit.

Capacity Performance Resources will be subject to Non-Performance Charges, but will not also be subject to PJM's Peak Season Maintenance Compliance Charge or Peak-Hour Period Availability Charge. Base Capacity Resources will be subject to a Non-Performance Charge if they fail to perform under emergency conditions during the months of June through September.

PJM will base the Non-Performance Charge rate on Net CONE divided by 30, the assumed number of Emergency Action hours per year.

PJM also established "stop-loss" limits on the total Non-Performance Charges it may assess. In the June 9 Order, FERC accepted PJM's proposed annual Non-Performance Charge stop-loss limit equal to 1.5 times annual Net CONE, but conditioned its acceptance on the elimination of PJM's proposed monthly stop-loss limit equal to 0.5 times annual Net CONE.

A Capacity Resource will be not be assessed Non-Performance Charges if it was not scheduled by PJM because it was on an approved planned or maintenance outage, or was scheduled down based on PJM's determination that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM region. A Capacity Resource will be assessed Non-Performance Charges if it otherwise would have been scheduled by PJM's Office of Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to any operating parameter limitation submitted in the resource's offer, or the seller's submission of a market-based offer higher than its cost-based offer.

PJM also has revised its tariff to limit the circumstances under which market participants are excused from performing their obligations. Beginning with the 2018-19 delivery year, an event classified by the North American Electric Reliability Corporation (NERC) as "outside management control" will be treated as a forced outage for the purpose of calculating a forced outage rate or peak-hour period penalties.

Performance Bonus Payments

Revenue collected by PJM from payment of Non-Performance Charges will be distributed, as a bonus, to resources that perform above expectations, based on the ratio of the relevant resource's bonus performance level to the total bonus performance from all resources over the same Performance Assessment Hour. Specifically, PJM will distribute Non-Performance Credits for a Performance Assessment Hour to each Market Participant—whether or not such Market Participant committed capacity for that hour—that provided energy or load reductions above the levels expected for such resource during such hour. Unlike the approach taken by ISO-NE, PJM's mechanism will assess performance during Emergency Actions rather than only during shortage or scarcity conditions.

Financial Security Requirements

Previously, PJM's tariff required that sellers of certain Capacity Resources provide credit support prior to an RPM Auction equal to the product of the MW to be offered times an RPM Auction Credit Rate determined using Net CONE for the relevant delivery year. PJM has revised the Auction Credit Rate for sellers submitting offers for a Capacity Performance Resource to be the greater of (i) 0.5 times the Net CONE for the relevant delivery year or (ii) $20/MW-day times the number of days in that delivery year.

For the period following the posting of the Based Residual Auction Result, the Auction Credit Rate for Capacity Performance Resources will be the number of days in the delivery year times the greater of (i) $20/MW-day; or (ii) 0.2 times the capacity resource clearing price (MW-day); or (iii) the lesser of 0.5 times Net CONE or 1.5 times Net CONE minus the applicable capacity resource clearing price for the resource (MW-day).

Following posting of the Base Residual Action results, planned resources that cleared the Capacity Performance Auction are required to provide credit support equal to the greater of (i) 0.2 times the Base Residual Auction Clearing price for the Locational Deliverability Area within which the resource is located; (ii) $20/MW-day; and (iii) the lesser of (a) 0.5 times Net CONE and (b) 1.5 times Net CONE minus the Base Residual Auction clearing price for the Locational Deliverability Area within which the resource is located.

For a seller seeking to offer in an Incremental Auction a Capacity Performance Resource that has not been committed previously for a delivery year, the Auction Credit Rate will be the greater of (i) 0.5 times Net CONE or (ii) $20/MW-day, times the number of days in such delivery year. The Auction Credit Rate for Capacity Performance Resources committed in the Incremental Auction will be the number of days in that delivery year times the greater of (i) 0.2 times the Incremental Auction clearing price for the relevant delivery year of $20/MW-day, or (ii) the lesser of 0.5 times the Net CONE for the relevant delivery year, or 1.5 times Net CONE for the relevant delivery year minus the Incremental Auction Clear Price.

Sellers of Planned Generation Capacity Resources may incrementally reduce their credit obligations after achieving certain project development milestones and the project moves toward being placed in-service. In addition, the initial RPM Credit Requirement for resources that have secured financing or had full funding available prior to the start of the 2015 Base Residual Auction is equal to half the product of the RPM Auction Credit Rate times the MW offered and may be further reduced upon achieving certain project development milestones.

Energy Market Revisions

Operating Parameters

PJM also revised its energy market rules to require market-based offers for Capacity Resources to be based on the specific physical characteristics of that resource, rather than on economic and budgetary considerations, under circumstances that would typically precede an emergency event (known as "parameter limited"). If a resource cannot actually be operated within these more flexible parameters, then it must inform PJM of the parameters to which it is capable of being operated. PJM's Office of Interconnection will determine the unit-specific achievable operating parameters for each individual resource on the basis of its operating design characteristics and other constraints, including the actual operational limitations of the relevant resource type. These unit-specific values will apply for the generation resource unless it is operating pursuant to an exception from those values meeting the minimum parameters.

Resources may recover, through make-whole payments, the costs incurred if a resource operates within its actual constraints and not only within its unit-specific parameter limits based on its physical characteristics. A resource would only be deemed ineligible for make-whole payments if it operates outside any actual constraints faced by the resource, not only limitations based on the resource's physical constraints. A resource that operates outside of its unit-specific parameter limits can seek to justify such operation to PJM as the result of actual constraints, rather than the exercise of market power. If the resource provides adequate justification, it would be eligible for any appropriate make-whole payments for that operating interval.

PJM also established a standardized start-up and notification time of 24 hours or less for Capacity Performance Resources bidding into PJM's energy markets, absent the issuance of a hot or cold weather alert. When a weather alert has been issued, the combined notice and start-up time would not be permitted to exceed 14 hours.

Force Majeure

PJM revised its Operating Agreement to include a new defined term, "Catastrophic Force Majeure," which includes only actions or events in which there has been a systematic failure in all or substantially all of the PJM areas of either the transmission system or the fuel delivery network. It also narrowed its existing force majeure provisions, as applicable to all market transactions, to apply only in the event of a Catastrophic Force Majeure. Performance of any obligation arising under the Operating Agreement will not be excused or suspended because of an event of force majeure, unless the event constitutes an event of Catastrophic Force Majeure, and that event of Catastrophic Force Majeure was not caused by the member's fault or negligence. PJM's broader, existing force majeure protections will continue to apply to non-market, bilateral arrangements, such as interconnection service agreements.

Generator Outages

PJM has revised its energy market rules to prohibit a Generator Maintenance Outage from proceeding unless it has been submitted to PJM for approval and has been approved prior to the outage start date. PJM may withhold approval, or withdraw a prior approval, to "ensure adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures." PJM must give notice to the seller at least 72 hours prior to requiring the generator to return to normal operation. If PJM withholds, withdraws or rescinds approval for an outage, it will work with the seller to reschedule the outage at the earliest practicable time.

With respect to Generator Planned Outages, PJM revised its rules to require a seller seeking approval for such an outage to provide PJM with an estimate of the amount of time it needs to return to service. PJM will use this information to facilitate a voluntary solution should emergency conditions approach, or arise, that may need to return the resource to service.

Maximum Emergency Offers

PJM has revised its tariff to clarify the day-ahead energy market obligation for Generation Capacity Resources. Any capacity that is designated by a Generation Capacity Resource as a Maximum Emergency Offer and not dispatched by PJM because of its use of a Maximum Emergency Offer should be considered non-performing for purposes of applying Non-Performance Charges.

Status of Approval of PJM's Market Restructuring

FERC's June 9 and July 22 Orders are subject to rehearing and, potentially, judicial review. In July and October 2015, PJM made filings in compliance with FERC's June 9 and July 22 Orders, which filings currently are pending review by FERC.

In December 2015, PJM made an informational filing to inform FERC that for the 2016-2017 delivery year, which commences on June 1, 2016, PJM plans to implement its Capacity Performance rules as accepted by FERC and clarified in PJM's compliance filings. In order to allow PJM to make any necessary adjustments prior to June 1, PJM asked FERC to issue an order addressing the pending requests for rehearing of the June 9 and July 22 Orders as well as PJM's compliance filings by February 1.

Transition Auctions

In 2015, PJM conducted two Transition Auctions under its new capacity market requirements. The first, held August 26-27, procured 95,096.6 megawatts of resources at $134 per megawatt-day for 60 percent of capacity needs for the 2016-2017 delivery year.[39] The second Transition Auction, held September 3-4 to procure Capacity Performance resources for 70 percent of capacity needs for the 2017-2018 delivery year, procured 112,195 megawatts of power resources at $151.50 per megawatt-day, below the offer cap.[40]

[39] PJM News Release, "PJM Capacity Performance Transitional Auction Ensures Availability of Resource to Maintain Reliable Power Supplies for 2016-2017," Aug. 31, 2015.

[40] PJM News Release, "Second PJM Capacity Performance Transitional Auction Ensures Power Supplies for 2107-2018," Sept. 9, 2015.

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