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Industrial Consumers Concerned by Efforts to Expand LNG Exports

By Michael Brooks and Rich Heidorn Jr.


Loading of the first commissioning cargo at Sabine Pass LNG Terminal in February 2016 | *Cheniere Energy*

The U.S. is becoming a net exporter of natural gas for the first time since 1958, a boon to the nation's balance of trade and a bragging point for the Trump administration but a source of concern for industrial gas customers for whom cheap gas has sparked a resurgence in U.S. chemical production.

The historic shift is the result of both increased pipeline shipments to Canada and Mexico and the expansion of LNG export capacity.

The opening in February 2016 of Cheniere Energy's Sabine Pass LNG export terminal in Louisiana — the first export facility in the lower 48 states — helped push the country from being a net importer of natural gas to a net exporter for four of the first six months of 2017, according to the U.S. Census Bureau.

The U.S. ranked 16th in LNG exports in 2016, with only a 1.1% market share. But

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Texas PUC Praises Harvey Restoration Efforts

By Tom Kleckner

Texas regulators last week praised the response of the state's utilities, ERCOT and first responders during discussion of a preliminary report on restoration efforts in the wake of Hurricane Harvey.

Speaking during an Aug. 31 open meeting of the Public Utility Commission of Texas, Commissioner Ken Anderson noted the "remarkable" restoration effort in flood-stricken Houston, especially when compared to Hurricane Ike's aftermath in 2008.

Brandy Marty Marquez, the PUC's other commissioner, described a road trip she took a day earlier to the deep-sea fishing community of Port Aransas. Port A, as South Texans refer to the beach town, was devastated by Harvey's 130-mph winds.

"I saw linemen with all different uniforms [on the way]. It was very inspiring," Marquez

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California Agencies, Utilities Prep for Climate Change

By Jason Fordney

California utilities and state agencies are cooperating on developing plans to manage the effects of global climate change on the electricity grid, an issue that looms especially large for the state.

Rising sea levels, reduced snowpack, more wildfires and extreme weather events such as drought and severe rain are predicted for California, which experts say will be more affected by global warming than other states because of its warm climate and extensive coastline.

Partnership between state officials, local government and utilities was the theme at a workshop last week hosted by the California Energy Commission. Participants discussed the physical impacts of climate change on the grid, geophysical changes, temperature trends and the challenges facing vulnerable populations.

State law requires the CEC to assess and forecast the state's energy production, supply and demand, and develop policies that conserve resources. The agency is studying climate change impacts on the energy grid as part of its 2017 Integrated Energy Policy Report process, which is updated every year and adopted every two years.

Pacific Gas and Electric is a critical infrastructure company with 16 million customers and a "critical responsibility," said Melissa Lavinson, vice president of federal affairs and policy. The company is getting more requests from local governments for information on its efforts to prepare for climate change, she said.

PG&E favors a regional approach to the issue that would help with coordination, rather than going community by community. The utility has proposed a "climate resilience clearing house" to aggregate information and a regional governing body to

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In This Week's Issue

CAISO NEWS

Aliso Canyon Measure Clears California Assembly Committee

By Jason Fordney

SACRAMENTO, Calif. — A key California State Assembly committee on Wednesday advanced a Senate bill requiring publicly owned utilities in the Los Angeles Basin to support deployment of distributed energy resources and energy storage.

The Committee on Appropriations approved SB 801, which now goes to the full Assembly for a vote.

The legislation was drawn up by State Sen. Henry Stern (D) in response to the 2015 leak that resulted in the closure of the Aliso Canyon natural gas storage facility. Many area residents are trying to get the facility closed permanently, but owner Southern California Gas recently resumed gas withdrawals after a court battle. (See *Aliso Canyon Resumes Injections*.)

Stern noted that investor-owned utilities Southern California Edison and San Diego Gas & Electric deployed energy storage quickly after the blowout, which threatened to compromise fuel deliveries to the region's gas-fired generators.

"However, publicly owned utilities in the area have not yet adopted the same aggressive approach to clean energy storage and other safe reliability solutions in response to Aliso Canyon," Stern said.

If passed, the measure would require the Los Angeles Department of Water and Power (LADWP), which serves 250,000 customers, to make data available that would help DER providers identify solutions to increase reliability in the region. It also requires LADWP to maximize use of demand response, renewables and energy efficiency in the area where reliability has been impacted by the Aliso Canyon outage.

The bill would allow LADWP to offset any ratepayer expenses with fines or fees levied over the leak against SoCalGas and its parent company Sempra Energy.

It would also require LADWP to study deployment of 100 MW of energy storage and oblige SCE to deploy 20MW of storage by June 1, 2018.

Stern has called the reopening of Aliso Canyon "premature and unnecessary." California Energy Commission Chairman Robert Weisenmiller has said the facility should be closed permanently.

The committee also suspended until Friday a vote on SB 100, which mandates that the state's utilities procure 100% of their electricity from zero-carbon resources by 2045. The Senate in May approved the legislation introduced by Senate President pro Tempore Kevin de León, a Los Angeles Democrat. (See *California Senate Passes Bill Mandating 100% RPS*.)

Power Sellers, LSEs Question CAISO ROR Designation

By Jason Fordney

Generation owners in CAISO are urging changes in an ISO reliability proposal for determining which unprofitable generators are eligible to receive payments in order to remain operational.

The power sellers were commenting on the ISO's Capacity Procurement Model Risk-of-Retirement (CPM ROR) initiative, which is due to be reviewed by the Board of Governors on Nov. 1. The ISO is proposing to open timing windows each year — in April and November — for three types of ROR designations. (See *CAISO Seeks Changes to Boost Retirement Program*.)

CAISO earlier this month included 20 changes to its revised straw proposal. It added a requirement for applicants in the April window to demonstrate that their resource is unlikely to receive an annual resource adequacy (RA) contract in early fall for the upcoming RA compliance year.

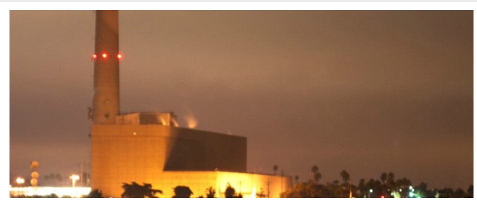
CAISO has proposed that a resource may not submit an ROR request in the April window unless its costs exceed the CPM soft offer cap. The ISO reasons that higher costs indicate the resource will likely not be chosen as an RA resource. It said it wants the CPM ROR payment to be based on cost of service and that the resource should be the only one that could meet an identified reliability need.

NRG Energy in its comments said the requirement effectively means that a resource with costs below the soft offer cap must wait until the November window.

"Forcing generator owners to wait until November to seek a CPM ROR designation effectively negates one of the primary reasons why resource owners sought a change in the ROR process, namely, to provide for a longer 'runway' with regards to seeking, and the CAISO evaluating and granting, an ROR designation prior to the end of a calendar year, to allow for better planning and coordination," NRG said. "As a result, this new proposed requirement calls into question the value of this initiative."

San Diego Gas & Electric said it did not believe that a resource's costs need to be above the current CPM soft offer cap to receive a ROR designation.

"CAISO should not filter out less expensive



Encina Power Station in San Diego | © *RTO Insider*

but similarly qualified resources from the CPM ROR process," the utility said, adding it sees no reason to keep more expensive resources online over less expensive ones. It said it supports requiring resources to justify costs even if below the soft offer cap.

Pacific Gas and Electric said it understands the CAISO position that the CPM ROR payment be based on cost of service.

"However, if a resource is granted a conditional CPM in April, it does not have an incentive to bid competitively when it knows it can receive cost-of-service recovery," the company said in its comments.

Earlier this year, market participants said the CPM ROR initiative does not address the fact that CAISO's energy market can no longer adequately compensate generation resources that are needed for reliability. (See *CAISO Stakeholders Question Risk-of-Retirement Initiative*.)

CAISO NEWS

CAISO Considering Transmission Charge Changes

By Jason Fordney

CAISO is moving forward with a proceeding that could result in changes to how it allocates transmission costs to participants in its wholesale markets, meant to better reflect increased adoption of distributed generation and other factors.

The grid operator is considering a proposal to replace its current method, which utilizes end-use metered load to bill a volumetric transmission access charge (TAC). That method does not reflect the role of DG in reducing transmission costs.

CAISO is analyzing whether to reduce TAC charges in transmission owner service areas for load that is offset by DG output, and how best to do so. It also is considering a demand-based charge instead of — or in addition to — its volumetric charge, or one based on time-of-use pricing.

The ISO last week held a stakeholder working group on the proposed TAC changes outlined in a June 30 issue paper. Neil Millar, CAISO executive director of infrastructure development, said during the meeting that because transmission charges are applied both to energy provided from central stations and DG, the cost of delivering energy is ignored, creating an inefficient market.

"It distorts cost allocation, distorts energy markets [and] costs money," Millar said. Transmission costs are also rising, making dealing with the issue a "political necessity."

CAISO also considered changing another settlement process that uses a volumetric rate for wheeling power to loads off the ISO-controlled grid, but it put it on hold after talking with stakeholders and deciding the initiative had "a number of complex and controversial issues."

Moving the point where transmission usage is measured would solve a lot of the issues, according to Millar. To address the issue, the ISO is considering a Clean Coalition proposal that would rely on gauging hourly net load at each transmission-distribution interface substation, referred to as "transmission energy downflow."

In an effort to place some boundaries on the proposal, CAISO plans to remove some other topics that are broad in scope regarding the TAC. Among those initiatives were an assessment of current regional and local transmission charges that are recovered through a postage-stamp rate and an analysis of the ISO's role in collecting the TAC. Other topics to be postponed are alternative types of transmission service. CAISO said it would study other regions and some other proposals put forth by stakeholders.

CAISO plans to issue a straw proposal on the TAC changes by Oct. 31, followed by a Nov. 15 stakeholder call. A final proposal will be submitted to the ISO Board of Governors sometime in 2018.

The grid operator earlier developed a proposal to allocate transmission costs over an expanded balancing area if the ISO integrates new members such as PacifiCorp. (See *CAISO Floats Latest Cost Allocation Plan for Expanded Balancing Area*.) That proposal has been shelved until CAISO expands into other regions of the West.

Calif. Agencies, Utilities Prep for Climate Change

Continued from page 1

coordinate local governments.

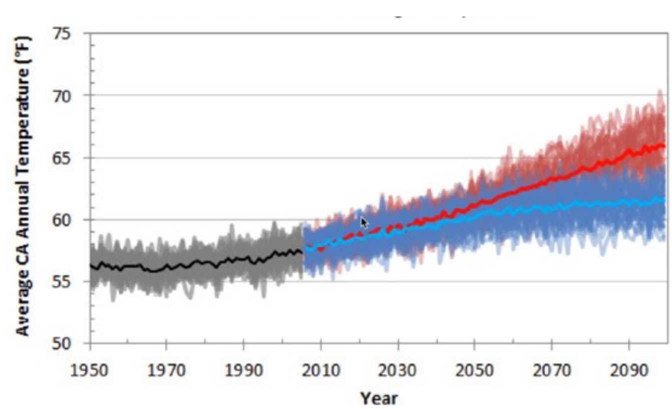
"We are far from the end of this process. We are at the beginning of this journey," she said.

San Diego Gas & Electric is in the midst of a "Climate Vulnerability and Adaptation Options" study consisting of both electric grid and natural gas tracks, Sempra Energy Meteorologist Brian D'Agostino said. The electric analysis looks only at the effect of the rising water level and flooding on the coast where many of the company's power plants are located, while the natural gas program also looks at climate hazards inland. The report also highlights downstream impacts on customers, electricity demand and the economy.

PG&E is working with the University of California, Berkeley and the California Department of Water Resources on a program to deploy wireless remote sensors to study moisture, temperatures and snowpack and more effectively manage hydro assets, said Gary Freeman, the company's principal hydrologist. The company closely studies weather and increasing "atmospheric rivers," which are columns of moisture that occur in the atmosphere and can dump large amounts of rain.

Atmospheric rivers hundreds of miles wide occur in California because of the Pacific Ocean and mountains that cool the air as it travels inland. The formations provide up to 50% of the annual precipitation on the West Coast, and their increasing activity is another example of how climate change affects grid planning and reliability in a region with extensive hydroelectric capacity.

Gov. Jerry Brown in April 2015 signed an executive order that set 2030 greenhouse gas reduction targets that were recently codified into law. (See *California Lawmakers Extend Cap-and-Trade*.) The state has also developed online tools providing climate change data, including climateconsole.org and cal-adapt.org.



California statewide average temperature | *California Energy Commission*

CAISO NEWS

Berkshire Companies Seek EIM Rate Authority

By Jason Fordney

Berkshire Hathaway Energy subsidiaries PacifiCorp and NV Energy on Thursday asked FERC to lift bidding restrictions placed on them in the Western Energy Imbalance Market (EIM) and allow them to offer energy at market-based rates.

In a joint filing with FERC, the companies said the bid limits are "no longer appropriate" because they both meet criteria for EIM participation established in previous commission orders (ER17-2392, ER17-2394). Both utilities are currently restricted to using a cost-based default energy bid (DEB) when offering into the market, which they told FERC is "both contrary to organized market design and presents risks of unrecovered costs in some market intervals."

A November 2015 FERC order found that the Berkshire companies' request for EIM market-based rate authority had included a "deficient" analysis that failed to disprove their horizontal market power. The order also questioned CAISO's ability to mitigate such power outside its own balancing area.

In establishing the bid limits, the commission pointed to potential intertie constraints between NVE and CAISO, as well as between the PacifiCorp West and PacifiCorp East balancing authorities. Arizona Public Service is also separately subject to the bid limits.

The commission last year denied the companies' request for rehearing on that decision, saying that future market power studies must provide analysis of potential power in EIM submarkets stemming from transmission constraints, not just the market as a whole. (See *Berkshire Denied Rehearing on Market Power*.)

The companies' latest filing relies on analysis performed by Charles River Associates (CRA) showing that, since the entry of NVE into the EIM, there has been little congestion between balancing authority areas, so they should not be considered "submarkets," and that the ability of third-party resources to balance the system mitigates market power concerns. CAISO has also implemented market measures that mitigate prices back to the DEB when competing supplies cannot reach a constrained area, the Berkshire companies said.

According to the filing, the companies "are not asking to charge market-based rates without mitigation. Rather, their bids will be subject to the CAISO tariff-based mitigation instead of the current blanket, seller-specific mitigation."

The Berkshire companies said the CRA findings are backed by an assessment produced by CAISO's own internal Market Monitor, which in July said transfer capacity in the EIM footprint is now sufficient to justify removing bid limits that are in effect for PacifiCorp, NVE and APS. (See *CAISO Monitor Says EIM Bid Limits No Longer Needed*.) The Department of Market Monitoring said it would support the companies' request to FERC for market-based rates.

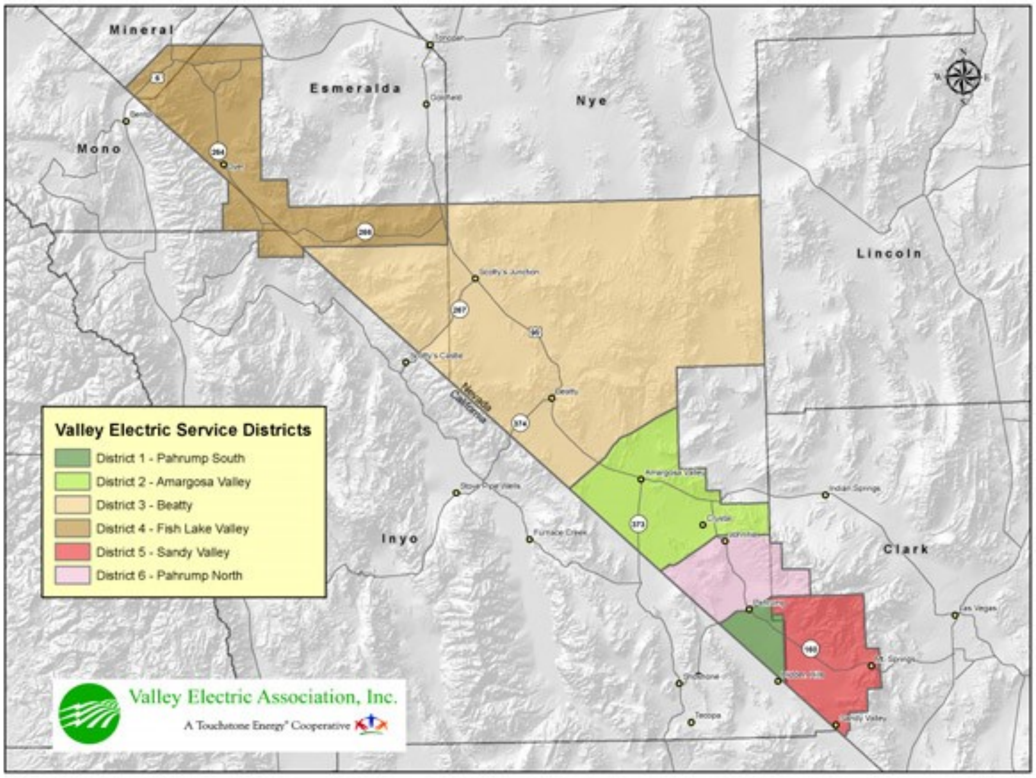
PacifiCorp was the first utility to participate in the EIM when the market became operational in November 2014. NVE applied to join the EIM in March 2015 and began participation in December 2015.

PacifiCorp operates 71 thermal, hydroelectric, wind-powered generating and geothermal facilities in California, Idaho, Wyoming, Washington, Utah and Oregon. NVE subsidiaries include vertically integrated utilities Nevada Power and Sierra Pacific Power.

CAISO NEWS

FERC Rejects CAISO Small TO Interconnection Plan

By Jason Fordney



FERC on Friday voted 2-1 to reject a CAISO proposal intended to prevent small transmission owners from shouldering the costs for network upgrades needed to interconnect generation serving load outside of their service territories.

The proposal was designed specifically to address the circumstances of Nevada-based Valley Electric Association, the California grid operator's only out-of-state member. The electric cooperative serves 45,000 customers and peak demand of 135 MW within a 6,800-square-mile territory straddling the California-Nevada border.

FERC's decision means Valley Electric's ratepayers potentially face the cost of interconnecting almost 4,000 MW of solar resources that would help support California's renewable portfolio standard. The cooperative has 25 requests totaling 3,952 MW of new capacity in its interconnection queue.

CAISO conducted a seven-month stakeholder process to develop the proposal to certify Valley Electric as a small participating transmission owner (PTO) and distribute its interconnection costs across the broader ISO. (See *Board Approves CAISO Small TO Generator Interconnection Plan*.)

The rule changes would have folded low-voltage generator interconnection costs into high-voltage transmission revenue requirements, spreading costs among the ISO's entire ratepayer base. San Diego Gas & Electric had cited a concern that CAISO's solution did not meet FERC cost allocation rules and Southern California Edison opposed the proposal.

"In the past, CAISO has justified its cost allocation methodology by explaining, with supporting evidence, that low-voltage facilities generally support local service and that the high-voltage transmission facilities perform a backbone function that supports regional flows of bulk energy," FERC said (ER17-1432).

The ISO was now asserting "without supporting evidence" that low-voltage upgrades on Valley Electric's system — but not those on the systems of Pacific Gas and Electric, SCE and SDG&E — benefit customers throughout the region, the commission said.

"CAISO's proposal is inconsistent with the commission's cost causation principles because it shifts costs from a single PTO to all load in CAISO without providing evidence that CAISO transmission system users being allocated such costs benefit from the network upgrades to Valley Electric's low-voltage transmission system," FERC said.

"Of additional concern is CAISO's proposal to allow stakeholders to decide whether to grant alternative certified small PTO rate treatment; stakeholders are interested parties that may be impacted by the determination that a PTO should become a certified small PTO."

Commissioner Cheryl LaFleur dissented in the ruling.

"It is simply unfair to require the 0.27% of CAISO's customer base in Nevada to bear the costs of these interconnections, which are not remotely commensurate with the benefits they receive," she said. "Rather, I believe the customers in California, whose policies are driving the costs, should largely bear the burden of these costs. The CAISO proposal achieves that objective in a pragmatic way."

In June, FERC staff sent CAISO a deficiency letter asking for a better definition of CAISO's criterion for designating a certified small PTO and how transmission customers will benefit from low-voltage interconnection network upgrades in Valley Electric's service territory.

CAISO did not immediately respond to a request for comment. In comments previously filed with FERC, the ISO said Valley Electric faced the risk of being allocated all of the costs for network upgrades necessitated by other utilities' procurement efforts, and that similarly situated small TOs potentially could face the same situation.

ERCOT NEWS

Texas PUC Briefs

PUC Approves Preliminary Order in Oncor-Sharyland Asset Swap

The Public Utility Commission of Texas last week gave preliminary approval to Oncor's and Sharyland Utilities' proposed swap of $400 million in assets.

The order lists a set of 27 issues to be discussed before the PUC renders a decision, which is due by Feb. 1, 2018 (Docket 47469).

Oncor and Sharyland filed a settlement agreement early last month, asking the PUC to expedite the case by deciding it without referring it to the State Office of Administrative Hearings (SOAH). The companies said Sharyland's current retail customers will receive "substantial rate relief" under the transaction, in which Sharyland will take over 258 miles of 345-kV transmission from Oncor in exchange for Sharyland's distribution network and retail delivery customers.

"The hard work that's gone into this is going to significantly change people's lives," said Commissioner Brandy Marty Marquez. "I'm happy this is all proceeding."

Among those signing on to the settlement agreement are commission staff, the Office of Public Utility Counsel (OPUC), the Steering Committee of Cities Served by Oncor, the Alliance of Oncor Cities, numerous other Texas cities and various electric retailers. The Texas Industrial Energy Consumers (TIEC), the Targa Pipeline Mid-Continent WestTex and Golden Spread Electric Cooperative chose not to oppose the settlement.

An administrative law judge set today as the deadline to request a hearing in the docket.

The settlement would also resolve Sharyland's separate applications to deploy an advanced metering system (Docket 44361) and requests for rate relief and a certificate of convenience and necessity (Docket 45414), and Oncor's application to change its rates (Docket 46957).

"This will ultimately solve a lot of problems for a lot of folks," said Commissioner Ken Anderson.

Commissioners Undecided on LP&L's Contested-Rate Case Request

The PUC postponed a decision on how to process Lubbock Power & Light's request to move 430 MW of its load from SPP into ERCOT. The commission is considering whether to treat the request as a contested case or refer it to SOAH, where it would be heard before an ALJ.

The commissioners will announce their decision during their Sept. 28 meeting, after reviewing a draft preliminary order (Docket 45633).

"I'm fine going to SOAH," Anderson said. "The other tradeoff, in terms of time, is SOAH may be able to handle getting the facts. It handles much of discovery anyway."

"If we send it to SOAH, the judge won't do much of anything until the preliminary order comes out," Marquez said.

LP&L is hoping for a decision before March 2018, which will enable it to maintain its plan to integrate with ERCOT by June 2021. The municipality announced its intention in 2015 to disconnect its load from SPP and join ERCOT in June 2019. That that date has since slipped, but LP&L extended a power purchase agreement with Southwestern Public Service through May 2021.

The preliminary order will allow the PUC to decide policy questions over load migrations "by putting a framework around what needs to be decided," Anderson said.

"A 'Hotel California' clause in the order might be appropriate," he said, referring to the Eagles' lyric, "You can check out any time you like, but you can never leave!"

"Going back and forth between ERCOT and other regions is, at best, disruptive, not to mention expensive," Anderson said.

ERCOT, SPP Agree to Rayburn Country Migration Studies

Rayburn Country Electric Cooperative representatives told the commissioners they are comfortable with ERCOT's and SPP's proposed scope and timeline for their studies of the East Texas co-op's proposed transfer of much of its SPP transmission facilities and load into ERCOT (Docket 47342).

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ERCOT NEWS

Texas PUC Briefs

Continued from page 7

The grid operators said they would conduct individual studies using a common scope and assumptions, including an analysis of system impacts, expected changes in production costs and avoided projects. ERCOT and SPP also plan to conduct a reliability review of the transfer using power flow and system contingency analysis.

ERCOT and SPP said they expect to complete their studies on the move by February.

"It's time to get started," Marquez said.

Rayburn Country is an SPP member, but only about 150 MW (less than 20% of its load) and 160 miles of its transmission sit in the Eastern Interconnection. ERCOT has said it will cost $38 million to connect the SPP load with the Texas grid.

SWEPCO Seeks to Reduce Wind Catcher Costs

The commissioners consented to a list of 36 issues to be contested before an ALJ related to Southwestern Electric Power Co.'s costs associated with parent American Electric Power's massive Wind Catcher project. (See *AEP to Spend $4.5B on Largest Wind Farm in US*.)

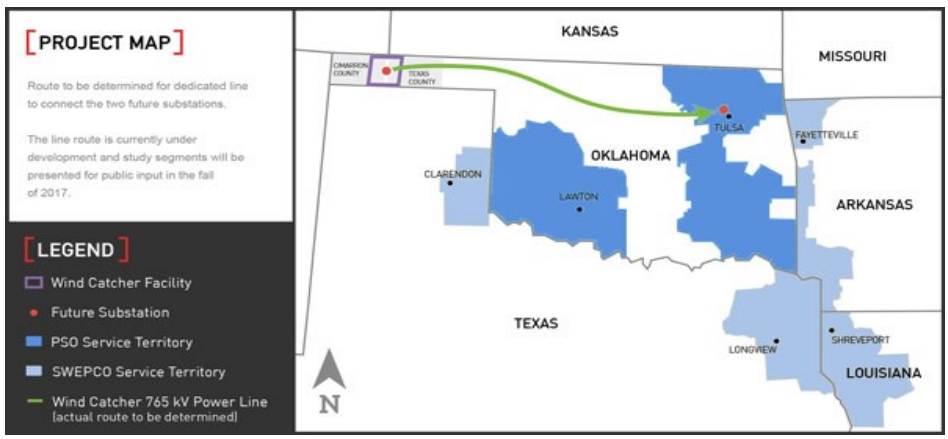
SWEPCO has filed a request with the PUC (Docket 47461) that its costs associated with the Oklahoma wind farm and EHV transmission line — $2 billion and $1.1 billion, respectively — be treated as an eligible fuel expense, and that the federal production tax credit be treated as a credit against it. The utility has estimated $1.1 billion is jurisdictional, and it wants to credit the PTC's value against its fuel expenses, until the project can be included in base rates.

SWEPCO also wants to defer for ratemaking purposes a portion of the PTC into a regulatory liability that would be credited back to ratepayers 11 years after Wind Catcher's planned 2020 in-service date. This would avoid a large increase in rates once the PTC expires, the company said.

The PUC referred SWEPCO's request to SOAH early last month. OPUC, TIEC and Golden Spread have filed motions to intervene and contributed to the list of issues. That list includes accounting and cost allocation questions and whether SWEPCO needs the additional capacity.

AEP plans to build 350 miles of 765-kV lines to connect the 2,000-MW wind farm in the Oklahoma Panhandle to its SWEPCO and Public Service Company of Oklahoma subsidiaries. SWEPCO services northeastern Texas. The wind farm would be the largest in the nation.

— Tom Kleckner



AEP

ERCOT NEWS

Texas PUC Praises Harvey Restoration Efforts

Continued from page 1

said. "We have a long way to go, but you can't mess with Texas. We'll be fine. This is a big test for us, but everyone's risen to the occasion."

PUC Executive Director Brian Lloyd became visibly emotional as he talked about the 10,000 utility workers from around the country who have descended to help Texas with the restoration.

Taking a few seconds to regain his composure, Lloyd told the commissioners, "It's great to see that work."

Bill Barnes, NRG Energy

"As an industry, we should be very proud of what has happened in the response," said NRG Energy Director of Regulatory Affairs Bill Barnes. "We have a lot of friends to thank across this industry."

American Electric Power, CenterPoint Energy, Entergy Texas and Texas-New Mexico Power reported just more than 200,000 combined customer outages Aug. 31, down from about 278,000 the day before. That number had dropped to almost 78,000 by Sunday afternoon.

"Other than the areas with extensive damage and flooding, a good chunk of this will be back online this weekend," Lloyd said.

'This is Personal'

ERCOT filed a status report with the commission Aug. 30 indicating that two of the six 345-kV lines that Harvey knocked out of service have yet to be restored. Another 55 high-voltage transmission lines in the storm-affected areas were still out of service as of Friday morning, the ISO said.

Most of those outages are in the Coastal Bend area between Corpus Christi and Houston, which took the full brunt of high winds when Harvey made landfall as a Category 4 storm. AEP Texas said Thursday that more than 4,600 workers have spent 14- to 16-hour days restoring power.

The bulk of those without power — about 40,000 — are in the Rockport-Victoria-Aransas Pass area. AEP Texas estimates it will take until Sept. 8 to complete its restoration work in the region.

Barnes offered a note of caution to the PUC: Just because it's stopped raining doesn't mean Harvey's damage is over.

"What we're dealing with is something that is very devastating and will have a lasting impact," he said. "This is going to take a significant amount of time to recover from. A lot of people have had their lives changed forever as a result of this. That includes our employees, our families, our friends.

"The Corpus Christi-Victoria area is our backyard; Houston is our home. So this is personal."

Barnes told the commissioners that NRG and its retail electric providers would halt disconnect notices through Sept. 30 for its customers in affected areas, and provide "direct financial relief" in the form of payment extensions, late fee and deposit alternatives or waivers, and increased funding of bill payment assistance programs.

The companies will also provide more than $2 million in disaster relief resources, including donating money to relief agencies and deploying a mobile generation station and disaster relief command center for affected communities, according to a filing with the PUC.

TXU Energy said it would also be waiving late fees through Sept. 30, along with extending payment due dates with no down payment required, and reducing down payments and deferring balances over five equal installments.

Anderson commended the retailers for their actions, saying, "It's a good example for the rest of the retail industry."

Generation, Demand Down

ERCOT also reported Friday that 7,500 MW of generation remains unavailable or operating at reduced capacity. The loss does not represent a reliability concern, and the ISO expects to have sufficient generation for the "foreseeable future."

System demand has been down significantly since shortly before the storm made landfall Aug. 25, ranging between 41 and 48 GW, approximately 15 to 20 GW lower than normal. Demand has started to increase as service is restored and temperatures begin to rise, with projected peaks over the weekend of 56 GW. (ERCOT had predicted a peak of 73 GW this summer.)

The South Texas Project nuclear plant in Bay City, 90 miles southwest of Houston, remained online during the storm. Like other plants in the area, operators at the 2,760-MW double-unit facility were "literally locked in [the] plant for days," Marquez said.

Barnes agreed. "Road access was flooded," he said, referring to the situation at other NRG plants. The company is one of STP's co-owners.

MISO NEWS

FERC Approves MISO Plan to Share Generator Gas Data

By Amanda Durish Cook

FERC last week approved a MISO pilot program allowing the RTO to share information on power plants' gas use with pipeline operators (ER17-1556-001).

Starting in December, MISO will share day-ahead hourly burn estimates from gas-fired generators with a trio of gas operators: Northern Natural Gas, ANR Pipeline and DTE Energy. The RTO says the program will help ensure adequate fuel supplies for gas plants.

FERC agreed that the program complies with the communications permitted in Order 787.

"We find that MISO's proposal to extend the information sharing provisions to LDCs [local distribution companies] and intrastate natural gas pipeline operators will help ensure and optimize the reliable operation of the grid, particularly during the winter months where demand for natural gas is strongest," the commission said.

The commission noted that Order 787 encouraged grid operators to make Tariff filings "to facilitate greater sharing of nonpublic, operational information with entities such as local distributions companies."

"We note that the proposed revision will improve communication and coordination among MISO and operating personnel of the interstate natural gas pipeline companies in the MISO region to ensure that MISO and interstate natural gas pipeline control room operators have better information on which to base operating decisions," FERC said.

The acceptance comes after FERC in June issued MISO a deficiency letter in response to an earlier version of the proposal. The letter noted that the pilot lacked a no-harm clause and that the RTO failed to justify its reason for sharing confidential information with LDCs, which FERC must approve on case-by-case basis. (See *FERC: MISO Gas Data Sharing Plan Falls Short*.)

In response, MISO amended its filing with language borrowed from PJM that expressly states that any shared information will not be used "to the detriment of any natural gas and/or electric market." MISO also contended communication with LDCs is crucial because about 25% — or 12,511 MW — of the RTO's gas-fired capacity is served by the companies.

FERC accepted both responses, saying that MISO's use of nondisclosure agreements and restrictions placed on shared data "minimizes the opportunity that the information can be used in an unduly discriminatory or preferential manner by the recipient or to the detriment of the market."

The commission rebuffed Indianapolis Power and Light's protest against the pilot. The utility asked that MISO not be allowed to "grant itself the ability to provide proprietary data to anyone without the expressed consent of the generation owner." FERC, however, noted that Order 787 did not require "three-way communications" for such programs.

Some MISO stakeholders earlier this year voiced opposition to the pilot, saying it could affect reliability if participating gas operators make burn rate decisions relying solely on partial day-ahead data. (See *MISO Stakeholders Question Electric-Gas Info Sharing*.)

DTE's Washington 10 complex near Detroit | *DTE Energy*

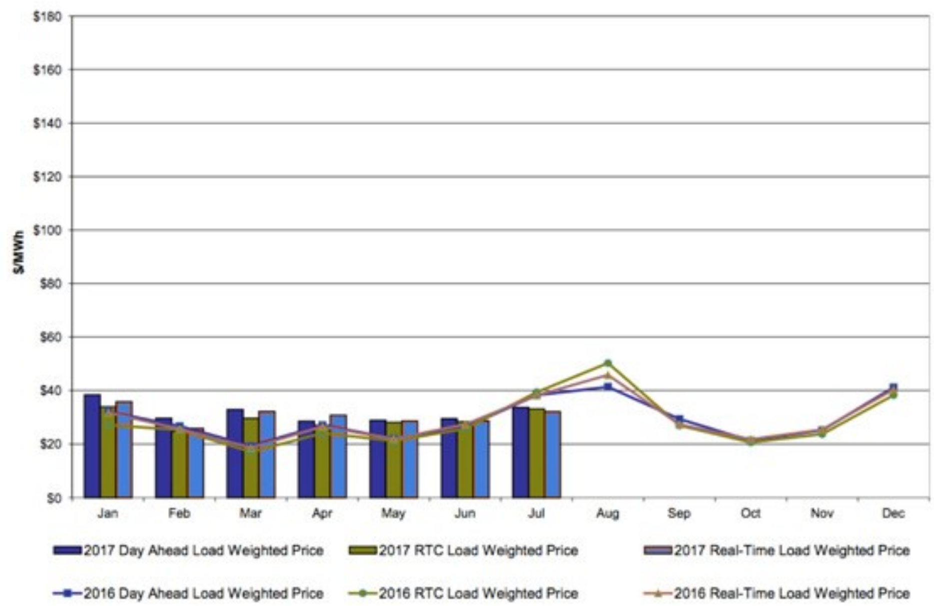
NYISO NEWS

Management Committee Briefs

LBMPs up 12% for Year, Tracking Gas

NYISO locational-based marginal prices (LBMPs) have averaged $36.35/MWh for the year through July, a 12% increase from a year earlier, COO Rick Gonzales told the Management Committee during its Aug. 30 meeting. Natural gas prices were up 13.1% over the same period.

LBMPs averaged $35.84/MWh during July, up 13% from June and down 10% from July 2016. Last month's daily sendout averaged 498 GWh/day, compared with 532 GWh/day a year earlier.



NYISO monthly average internal LBMPs, 2016-2017 | *NYISO*

July natural gas prices and distillate price averages gained from the previous month, with Transco Z6 NY gas up 4% to $2.44/MMBtu, jet kerosene Gulf Coast up 9% to $10.49/MMBtu and NY Harbor ultra-low sulfur No.2 diesel up 7% to $10.85/MMBtu. Distillate prices increased 11.1% from the same period a year ago.

Average uplift costs — not including NYISO cost of operations — were down to -43 cents/MWh for the month, compared with -37 cents/MWh in June. The local reliability share fell 4 cents to 11 cents/MWh. The statewide share of -54 cents/MWh came in 2 cents below June. July's total uplift costs were also lower than in June.

The monthly peak load of 29,699 MW occurred July 19, far short of the all-time summer peak of 33,956 MW recorded on July 19, 2013.

NYISO Evaluates Energy Market Offer Cap

The ISO is continuing to evaluate its energy market offer cap to prevent differences in regional offer caps from interfering with economic and reliability-driven interchange scheduling, according to a report presented by NYISO Senior Vice President for Market Structures Rana Mukerji.

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NYISO NEWS

Management Committee Briefs

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Under FERC Order 831 issued last November, NYISO is required to cap each resource's incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer, and cap verified cost-based incremental energy offers at $2,000/MWh when calculating LBMPs. The grid operator last December filed a request for clarification/rehearing on the issue with FERC and submitted a compliance filing in May.

Mukerji also noted that the ISO is working to improve forward horizon coordination of real-time constraints (RTC) and real-time dispatch (RTD). NYISO aims to improve modeling consistency between RTC and RTD and evaluate improvements in look-ahead evaluations to facilitate more efficient scheduling and price convergence.

Pending issues include possible proposals to allow market participants to buy and sell reserves and regulation service between NYISO and adjacent control areas and to develop a market mechanism to assign external parties with the costs associated with congestion rent shortfalls resulting from external transmission outages.

NYISO control room | *NYISO*

The ISO is also examining the reciprocal elimination of fees on export transactions in order to increase interregional transmission scheduling efficiency. Rate pancaking between NYISO and ISO-NE has already been eliminated.

Interconnection Queue Improvements Approved

The committee approved steps intended to improve the efficiency of the interconnection queue process while maintaining needed reliability evaluations.

The proposed changes clarify and update existing practices and procedures, except for the transmission interconnection procedures, which are still pending FERC acceptance. Transitional rules would allow projects currently in the interconnection process to benefit from the proposed changes. (See "Committee Advances Interconnection Queue Improvements," *NYISO Business Issues Committee Briefs: Aug. 9, 2017*.)

NYISO expects to file associated Tariff changes with FERC in late September following board approval.

New York Easily Handles Solar Eclipse

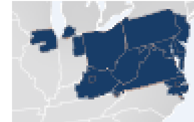
NYISO easily met operational reliability criteria throughout the solar eclipse Aug. 21, despite a 1,010-MW reduction of net load that exceeded predictions by nearly 300 MW, according to a report from NYISO Vice President of Operations Wes Yeomans.

The ISO did not experience the slight projected load increase early in the eclipse, possibly because of lower loss of behind-the-meter solar than originally anticipated, as well as public reaction to the event. He attributed the higher-than-expected net load increase later in the eclipse to high humidity.

New York experienced a partial solar eclipse from 2:30 to 2:45 p.m., with peak obscuration ranging from 80% in Chautauqua County, to 75% in New York City and Long Island and 67% in Clinton County.

— Michael Kuser

PJM NEWS



PJM Stakeholders Hash out Capacity Repricing Triggers

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM appears headed toward implementing a capacity construct that would reprice auction results to address the influence of subsidized generation offers.

The RTO's Capacity Construct/Public Policy Senior Task Force (CCPPSTF) met last week for the sixth time in August to focus on determining what circumstances would trigger auction repricing.

Repricing, which would filter subsidized offers out of auction results to mitigate suppression of the clearing price, is a key mechanism in five of the nine capacity redesign proposals. NRG Energy, LS Power, Exelon, PJM and Old Dominion Electric Cooperative all included it. (See *Stakeholders Seek to Trim PJM Capacity Construct Options*.)

CCPPSTF attendees have identified 18 components that the repricing trigger should address, including a subsidy's financial significance in supporting a resource and the scale of a resource's impact on the market. The discussion has delved into the details of how states could potentially issue subsidies, including through yearly allotments or a one-time lump-sum payment for performance over an expected lifespan.

Sorting the Details

Avangrid's Kevin Kilgallen suggested that repricing should be triggered only by subsidies provided during an auction's delivery year. Calpine's David "Scarp" Scarpignato added that lump-sum subsidies that include the delivery year in their amortization should also be a trigger. The distinction was initially lost on some participants.

"There are two different issues here," Kilgallen said. "I'm saying only subsidies that may or will be or are expected to be applicable during the delivery year should be considered. … I think [Scarp's is] a separate issue, whether or not there's a trigger for a resource that may or may not receive [in that year] a subsidy that it's eligible for."

Scarp later suggested that subsidies that incentivize the pricing of carbon emissions should be exempted. EnerNOC's Katie Guerry questioned the suggestion as ostensibly supporting a controversial tenant of Exelon's proposal that would effectively exempt nukes that are receiving subsidies from triggering repricing. Scarp clarified that his suggestion was specific to subsidies that would monetize emissions instead of subsidize units that have a related beneficial attribute, such as being emissions-free. His proposal wouldn't exempt a unit that received a subsidy elsewhere, he said.

Guerry said carbon pricing creates an entirely separate market that's not involved with the capacity market.

"Carbon pricing is something completely separate, and it's in and of itself a solution … that would obviate the need to do anything in the capacity market," she said. "If you have something like carbon pricing, there's not a question of exempt or not exempt. It's the solution that we pursued outside of the capacity market."

Scarp pointed out that subsidies could affect either the capacity or the real-time energy markets, which introduced a new concept for the group as all discussion had previously focused only on subsidies in the capacity market.

"If PJM institutes carbon pricing, you don't think it will affect your energy [market] revenues? It will," Scarp said.

State Actions Only

Stakeholders also debated whether a resource that received a subsidy in the past should always be considered subsidized, and whether federal subsidy programs should remain outside the CCPPSTF's scope.

While the task force's charter is limited to state programs, Exelon's Jason Barker asked if PJM's eventual FERC filing on the issue would also remain limited to state programs. PJM's Dave Anders, who facilitates the group's meetings, declined to speculate about the RTO's plans.

"The problem statement we've got is limited strictly to state actions. What happens at FERC, happens at FERC," he said.

Direct Energy's Marji Philips argued that federal actions weren't the issue.

"The difference between a federal action is all states are impacted by it and have to price it in," she said. "If it's a state law, it only impacts — or should only impact — the citizens of that state, and that's what this exercise is. It's not to tell a state what it can or can't do. It's to make sure that other customers from other states don't pay for what one state wants that another state might not want."

Exelon's Sharon Midgley responded that such programs can still impact auction prices. "While a federal program may have the same impact across the entire footprint, it still has the potential to suppress [prices, even if it does so] uniformly," she said.

Stakeholders are also considering how to write rules that address potential future scenarios in which states decide to offer financial incentives for demand-side resources or certain existing programs expand to other states, such as the Illinois program offering zero-emissions credits to nuclear units.

"I think there are a number of parties who would say, 'I'm OK with the status quo. My concern is what's coming down the pike,'" Guerry said. "Preference for the status quo by some might be dictated by what happens or may not happen in the future."

'Non-repricing' Alternatives

While the meeting focused on repricing, stakeholders have also suggested additional redesigns beyond the five repricing proposals. The Independent Market Monitor has proposed extending the existing minimum price offer rule indefinitely to any subsidized unit that doesn't qualify for several specific exemptions.

Three "non-repricing" proposals would reduce the role of the auction in PJM's capacity acquisition procedures. John Horstmann at Dayton Power & Light proposed to expand the RTO's existing fixed resource requirement (FRR) option to allow utilities to meet capacity obligations with any combination of FRR and auction results.

A proposal by the Sustainable FERC Project

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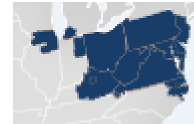
PJM NEWS



PJM Stakeholders Hash out Capacity Repricing Triggers

Continued from page 13

would reduce the capacity requirement to off-peak season needs and allow seasonal resources to account for the additional demand during the peak season. American Municipal Power (AMP) is still finalizing the details of a proposal that would emphasize the use of long-term bilateral contracts over a single auction.

Polling Controversy

With his company's proposal unfinished, AMP's Ed Tatum expressed concern about a planned PJM poll to measure the relative popularity of the proposals. He was particularly displeased with an opening section that asked respondents to opine on how each proposal addressed specific issues.

"Is this something we're going to do regardless of how people feel about it?" Tatum asked. "It looks like you've got 11 good questions. The first one is a bit broad and the categories elusive. … We need to make sure the poll results are meaningful and we'll get something good and useful out of it."

"We are trying valiantly to get some additional information out to people to see what people are thinking," Anders said. "I feel like we're in full attack mode against this poll before we've even seen it."

Tatum was not alone in his concerns about the poll. Barker noted that the poll doesn't address repricing triggers, "which is quite possibly the most important part, which is why we've registered our concerns." As part of his instructions to stakeholders at the end of the meeting, Anders later asked those who submitted proposals to attend the next meeting prepared to define the triggers they plan to include in their proposal.

GT Power Group's Tom Hyzinski requested adding to the first question whether each proposal "insulates other states or other jurisdictions against the actions of a state, because I think there's only one that actually does that, and that's the IMM's proposal. Any of the others, there's actions that can be taken in one small place that affect the pricing and market signal in every other section of PJM."

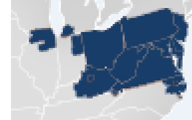
Barker said that Hyzinski was "pretty shrewd" to provide his answer with the question.

"Similarly, we could ask for questions about whether or not the application [of the proposal] is discriminatory, much like the IMM's proposal, where it proposes to exempt certain resources but not others that may have the same dollar-for-dollar impact," Barker said.

Anders said that he is anticipating at least one more round of polling and feedback before moving to a recommendation vote. "We'll just have to see how things mature after [the polling]," he said.

PJM staff planned to distribute the poll to the CCPPSTF task force list last week and differentiate between member and non-member responses. Staff are seeking to receive responses this week in order to prepare results for the next CCPPSTF meeting on Sept. 11.

PJM NEWS



Consensus Fades on PJM Incremental Auction Solution

By Rory D. Sweeney

"My belief is that more supply will be coming from market participants than from PJM in future years. We've seen a lot of excess from PJM due to very high load forecasts in the BRA."

Bruce Campbell, CPower

A consensus that appeared to be coalescing for how to revise PJM's Incremental Auction process and address replacement capacity issues seems to have dissipated.

Stakeholders had been combining ideas into joint packages, but PJM's Jeff Bastian announced at last week's meeting of the Incremental Auction Senior Task Force that the packages had separated back into five individual proposals.

The first proposal from PJM staff focused on giving Base Residual Auction sellers confidence that their commitment can be replaced in an IA "with little likelihood of economic loss and in fact a high likelihood of profit."

"We changed our proposal around quite a bit as we thought through this," Bastian said. "It's not the objective of this package to force the Incremental Auction clearing prices toward the clearing price … but it is the intent to correct what we think are existing design flaws which force just the opposite to happen, especially when it comes to the PJM sellback of excess."

GT Power Group's Jeff Whitehead disagreed with PJM's proposal to allocate excess commitment credits (ECCs) to load-serving entities.

"That logic ignores the fact that LSEs bear the risk of, and pay for, any excess capacity that underlies ECCs on behalf of their customers, and it is the terms of retail contracts with those customers that determine whether that excess capacity risk gets passed through to customers," he said in an email to *RTO Insider*. "To the extent excess capacity risk is passed through by an LSE to its customers, then it follows that the proceeds associated with ECC sales should be passed through as well. If the excess capacity risk is not passed through to customers, and borne by the LSE, then it follows that the LSE would retain the proceeds of ECC sale. PJM's proposal to not allocate ECCs to LSEs is unprecedented in that it incorrectly presumes the terms of retail contracts and deprives LSEs and their customers of the option to monetize the excess capacity for which they have paid."

PJM argues that the current allocation system incents anyone looking to purchase replacement capacity to "hold out for a 'better deal' from a party that may be allocated ECC megawatts" rather than purchase PJM excess capacity during an IA.

Calpine's David "Scarp" Scarpignato agreed with Whitehead's argument, but pointed out that the allocations help the entire system. "When you get into individuals making decisions, that doesn't work. It has to be a systemwide decision," he said.

Whitehead agreed.

The Independent Market Monitor's proposal is also focused on addressing IA clearing prices that are well below BRA clearing prices, but it differs on implementation. Both PJM and the Monitor envision just two IAs, with the RTO releasing capacity only in the final one. The current schedule has the BRA and three IAs for each delivery year. However, the Monitor would have the changes implemented with the third 2018/2019 IA, while PJM is targeting the 2021/2022 delivery year.

Direct Energy said it reintroduced its proposal based on concerns expressed at the IASTF's last meeting. The package differs from PJM in that it puts a "collar" around the variable resource requirement (VRR) demand curve.

"With no collar, the possibility exists that all third-party suppliers sell at a price just below the BRA price, pushing any excess PJM [megawatts] out of the market," Direct Energy's proposal reads. "The result is that load still pays for the excess capacity and actually increases load's scaling factors — increasing the overall cost of capacity."

CPower's Bruce Campbell offered a proposal "intended to maximize the benefit of Incremental Auctions to load interests with minimal changes to the current structure." Described as "a compromise of stakeholder positions," Campbell said it meets most of the preferences from initial polling, including maintaining three annual auctions between the BRA and the delivery year and having PJM sell excess capacity in each of them.

"My belief is that more supply will be coming from market participants than from PJM in future years. We've seen a lot of excess from PJM due to very high load forecasts in the BRA," Campbell said. "I think PJM has taken substantive steps to address that, and I expect that most excess supply that's available in Incremental Auctions will now come from market participants rather than PJM."

The proposal offered by Gregory Pakela of DTE Energy Trading would set a different type of collar: a minimum sell offer at 50% of the BRA clearing price and a maximum at 100%. PJM would offer all its excess capacity in each of three IAs. Pakela offered research and analysis for his proposal, which led him to conclude, like Campbell, that PJM is unlikely to sell off a large quantity of commitments ever again. The corresponding reduction in sell offers will increase IA clearing prices, they say.

Scarp said the proposal neglected to account for the fact that capacity within a locational deliverability area must be replaced by other capacity in that LDA.

"PJM, I think, did a good job of addressing their sell offer, which everybody agrees is a major problem, probably the biggest problem," Scarp said. "But there's still other problems."

"PJM, I think, did a good job of addressing their sell offer, which everybody agrees is a major problem, probably the biggest problem."

David "Scarp" Scarpignato, Calpine

SPP NEWS

Overheard at the GCPA SPP Regional Conference

IRVING, Texas — The Gulf Coast Power Association's fourth annual SPP Regional Conference last week drew more than 130 registrations, but most from the Houston area and those involved in Hurricane Harvey restoration efforts were unable to attend, cutting the audience by almost 20%. GCPA Executive Director **Tom Foreman** said the organization refunded registration fees to those from Houston.

GCPA Executive Director Tom Foreman chats with SPP Board Chair Jim Eckelberger. | © *RTO Insider*

"My heart, prayers and concerns go out to all of our friends, family and colleagues in Houston and South Central Texas," said Foreman, a Houston native. "They are still in the midst of a truly historic and devastating event. Please know that all of us at GCPA wish you well and hope you remain safe."

SPP Chairman: 'Green Revolution' Faces Unknown Future

Referring to the SPP region as the "Saudi Arabia" of wind, SPP Board Chair Jim Eckelberger focused his keynote presentation on the RTO's ample wind and solar resources, and the challenges they present.

He pointed to slides that listed the 17.9 GW of wind capacity currently in service and the 43.8 GW of additional capacity in all stages of development. That includes 36.8 GW in the generation-interconnection queue and 7.1 GW with signed interconnection agreements. SPP's queue also has 7.7 GW of solar projects.

But that's not all. Eckelberger said the Great Plains states of Kansas, Nebraska, New Mexico and Oklahoma, along with the Texas Panhandle, may produce up to 90 GW of wind capacity — almost double SPP's current peak demand of 52 GW.

On April 24, Kansas wind farms generated more energy (3,712 MW) than the state's load (3,507 MW). Oklahoma came close that same day, producing 5,054 MW of wind energy while the state's load was 5,682 MW.

"There's a future that's really unknown. That unknown future is a dilemma for what this green revolution is," Eckelberger said. "All this is happening, not because of the Clean Power Plan, and not because of government-subsidized wind and solar. It's about science moving forward, technology moving forward and the market itself. That's what pricing does."

The wind revolution has resulted in more than 20,000 industry-related jobs, more than $23 billion in capital investments and more than $40 million in annual lease payments to landowners within SPP's footprint, Eckelberger said.

© *RTO Insider*

"This is why governors say, 'Don't export wind to my state. I want that development to myself and bring those jobs to my state,'" Eckelberger said. "What a national energy policy would do is have us move this immense wind energy from west to the east. It would really make sense to be in that mode, but we don't have a national energy policy. It's not going to happen, at least in the foreseeable future."

Asked why he is so pessimistic about a national energy policy, Eckelberger told *RTO Insider* some of the blame lies with "parochial [state] governors" protecting their states' interests.

"I sense from the states they feel the same way," he said. "There's not a lot of oomph for a national energy policy. Of course, not much is getting done in Washington anyway."

Can SPP Withstand More Negative Prices?

Bruce Rew, SPP's vice president of operations, said wind energy is fast replacing natural gas as the RTO's No. 2 fuel resource, and surpasses coal at times as the No. 1 fuel source.

"Gas is pretty much a secondary resource," Rew said. "It's still important for short-term reliability commitments."

Khai Le, senior vice president for energy software provider Power Costs Inc., noted that SPP's Integrated Marketplace has pushed almost 5 GW of less efficient capacity out of the dispatch stack most days, which has resulted in lower production costs. Le said the market's prices "are rational and consistent with gas costs."

However, he also said no market has more negative day-ahead and real-time LMPs than SPP. The Integrated Marketplace cleared about 160 negative five-minute

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SPP NEWS

Overheard at the GCPA SPP Regional Conference

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intervals in 2016.

"With greater wind output and low gas prices, 70 to 80% of coal units are offered as must-run resources, so 20 to 30% of coal is out of the money," Le said. "SPP will need more quick-start peakers, but under current SPP protocols, peakers do not receive sufficient reliability unit commitment make-whole payments to cover their full production costs."

Still, Le said, he has yet to come across a market participant who wants to leave the SPP market. "If you talk to most market participants, they give a fairly high score to SPP," he said. "Somewhere between an A- to an A."

Golden Spread Electric Cooperative's Mike Wise, the company's senior vice president of regulatory and market strategy, said the region will have to decide what to do with the potential wind energy to come, given SPP's lack of load growth.

"SPP is the renewable breadbasket of energy for the U.S., but we're an island," Wise said. "We're throwing more and more renewable energy into this island, with very little capability to push this out. Can a market consistently continue with negative pricing long-term? This problem, or opportunity, is going to get deeper and deeper as you go on.

"[Our] congested areas have a large amount of renewable energy in those pockets and significantly high amounts of negative pricing. We need units able to operate and provide services necessary to support a reliable grid. Coal plants are paying to put coal-fired energy in the market. With that in mind, we need flexible units and the ability for market signals to encourage and bring on those units with short, quick-start capability."

Improvements to SPP-MISO Interregional Process

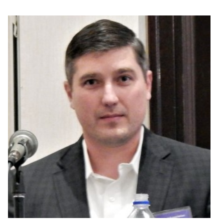
SPP members offered recommendations to improve the interregional transmission planning process with MISO, which has yet to result in a project between the two organizations. MISO last month told stakeholders it was no longer considering the first transmission project to result from a coordinated study with SPP. (See SPP Glum as MISO Axes Last Interregional Project.)

American Electric Power's **Jim Jacoby** said the RTOs should align their study processes and timelines, noting that MISO only allocates costs for 345 kV or higher, while SPP allocates down to the 115-kV level. He also pointed to a 2,500-MW export capability with MISO, "which isn't much when SPP has a 50-GW system and MISO a 150-GW system."

"AEP thinks that's a problem. It thinks lower-level kV projects can be valuable," Jacoby said. "[Aligning the study requirements] might help incent some of these projects get built."

"We classify projects as purely reliability or purely economic or public policy, but it's very unusual to see a project selected for reliability that doesn't have economic benefits as well," said ITC Holdings' **Alan Myers**. "We need to be less limiting in our thinking.

"Bottom line, our traditional planning has focused on reliability and incremental fixes to the detriment of the overall system," he said, emphasizing that ITC is not advocating less focus on reliability. "We're in the midst of a green revolution and a rapidly evolving shift in load. All of this calls for, and demands, a new approach to the planning system, and bigger picture things across the seams."



Jesse Moser, MISO's director of transmission planning, promised his audience changes are coming. He said the two RTOs are working to resolve the differences in cost allocation and expect a FERC filing next year with an effective date for the 2019 planning cycle.

"We did get a push from FERC as a result of a complaint on the MISO-PJM seam," said Moser, referring to the commission's 2016 order on a complaint by Northern Indiana Public Service Co. (See FERC Signals Bulk of NIPSCO Order Work Complete.)

"If we don't make those changes, we'll probably get a complaint on the other side. We're trying to get in front of that and be the masters of our own destiny. Hopefully, we'll get a team effort with SPP."

"If there's an interregional solution to a regional problem, that's what we think is very important," said Missouri Public Service Commissioner **Steve Stoll**, who chairs SPP's Regional State Committee. "So far, we haven't come up with any [interregional solutions], but that doesn't mean there won't be any in the future."

Political Uncertainty Cast Cloud over Market

Wise set the stage for a discussion of Lubbock Power & Light's intended migration of 430 MW of load from SPP to ERCOT by asking what compels a load to switch grid operators.

"They've been served reliably [by SPP] for many, many years," he said. "It's not really a reliability issue. It's purely economics. What are those compelling reasons loads would seek to move?"

Wise answered the question himself, saying that unlike SPP, ERCOT does not have capacity or firm transmission requirements. Transmission costs also are allocated differently in the SPP system. The Texas grid regionally allocates costs of service equally under "less intrusive" requirements than SPP in its base plan funding and highway/byway processes, he said.

"Those are the facts, and they're undisputable," Wise said, paraphrasing a line from the movie "A Few Good Men." "Now we'll have to spend time with what those facts mean. [The Public Utility Commission of Texas] will be dealing with those facts extensively over the next few months." (See "Commissioners Undecided on LP&L's Contested-Rate Case Request," *Texas PUC Briefs*, p.??.)

Asked by Wise why ERCOT didn't simply build a DC tie as a cheaper option to

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SPP NEWS

FERC Again Rejects SPP's Resource Adequacy Revision

By Tom Kleckner

FERC last week rejected SPP's proposed Tariff revisions requiring load-responsible entities (LREs) to maintain sufficient capacity and planning reserves (ER17-1098).

The commission found SPP's filing "inadequate in several respects" and said key elements must be addressed to help ensure successful implementation of a resource adequacy requirement (RAR).

At the same time, the commission offered the RTO guidance to help it "fully develop its proposal" for future submission. A quorum-less FERC in May also found SPP's initial Tariff revision to be deficient. (See *Waiting on FERC, SPP Members Cut Reserve Margin*.)

"We expect to work with our stakeholders in assessing FERC's suggestions," Lanny Nickell, SPP's vice president of engineering, said Friday. "We will continue efforts to incorporate a comprehensive set of resource adequacy requirements in our Tariff."

SPP submitted the Tariff revision in March under Section 205 of the Federal Power Act. Nearly two dozen SPP members intervened in the proceeding.

In January, the RTO's board and stakeholders approved a package of policies that included reducing its planning reserve margin from 13.6% to 12%, which translates to a 10.7% capacity margin. A task force spent more than two years developing the package, which is projected to reduce SPP's capacity needs by about 900 MW and save members $1.35 billion over 40 years. (See "Stakeholders Endorse 12% Planning Reserve Margin, Policies," *SPP Markets and Operations Policy Committee Briefs*.)

Included in the package was a proposed Tariff revision stipulating that an LRE — an asset owner serving load in SPP's markets — maintain sufficient firm capacity to serve its peak load and maintain a predetermined planning reserve margin.

Under the revision, an LRE's net peak demand is defined as the forecasted highest demand for energy, including transmission losses, plus the volume of megawatts subject to firm power sales contracts. The revision defines firm power as power sales and purchases deliverable with firm transmission service, where the seller assumes the obligation to serve the purchaser's load with capacity, energy and planning reserves that must be continuously available in a manner comparable to power delivered to native load customers.

FERC noted that it has previously ruled that power purchase agreements be backed by verifiable capacity in order to serve as capacity resources. It pointed to a 2008 order in which it said it did not consider a market participant's statements "to be sufficient to constitute verification" and required that MISO be given a copy of a PPA to verify the capacity backing the agreement. The commission said SPP's proposal lacked such requirements.

"As such, SPP's proposal fails to ensure that LREs that rely on power purchase agreements are providing sufficient capacity to meet their net peak demand plus planning reserve margin on the same basis as LREs that self-supply their own capacity, and therefore could result in unjust, unreasonable and unduly discriminatory determinations of deficiencies and assessments of deficiency payments," FERC said.

The commission also said SPP's proposed treatment of firm power purchases and sales in determining net peak demand could result in undue discrimination. It pointed to intervenors' arguments that if the purchaser under the contract is an LRE located in SPP, but the seller is an entity located outside the footprint, then no entity would have the obligation to demonstrate to the RTO that there is sufficient capacity and planning reserves to meet the load in SPP served by the firm power contract. It said that LREs that purchase from an external seller should be responsible for meeting SPP's RAR for the load served by the purchase.

FERC also found that SPP did not show that its proposal to post publicly which LREs have not met their RAR to be just and reasonable, and said that SPP failed to provide justification for "creating a new information asymmetry between deficient LREs and potential sellers of capacity."

The commission noted that SPP's market for bilateral capacity is "relatively net long" compared to the 12% reserve margin.

"As the amount of uncommitted capacity and the number of potential sellers shrink over this period, concerns over the potential exercise of market power could arise," FERC said.

Overheard at the GCPA SPP Regional Conference

Continued from page 17

connect Lubbock's load, **Jeff Billo**, the ISO's senior manager of transmission planning, said the alternative was never studied. ERCOT and SPP have determined in separate joint studies that LP&L's proposed transition would cost the two nearly $370 million. (See *Load Migrations Put SPP's Focus on Retention*.)

"Their request seemed to be, 'We want to be in the ERCOT market and ERCOT regulatory construct,'" Billo said.

The studies considered the differences between the two grids' market and regulatory structures.

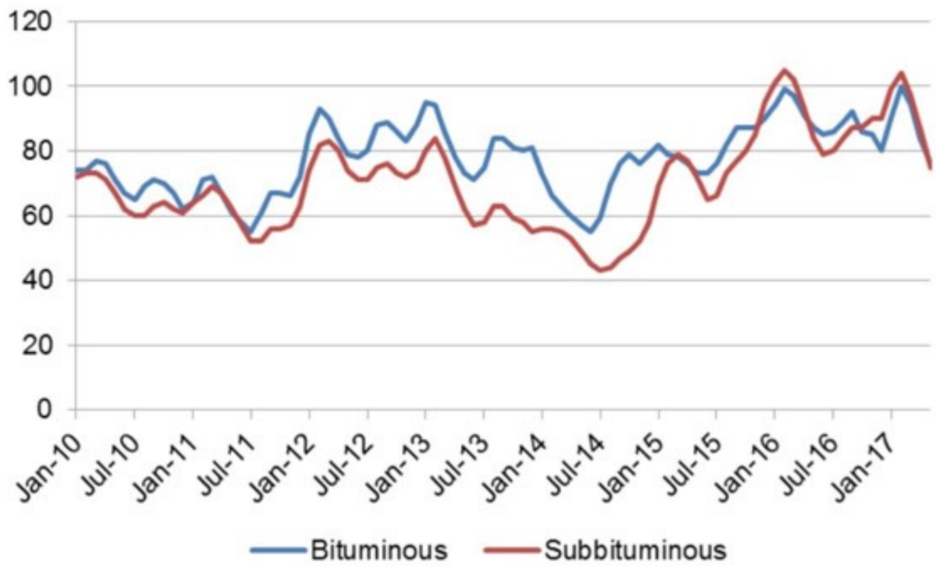
"At the end of the day, the study results would not be apples to oranges, but apples to apples," Billo said. "More like Jonathan apples to Gala apples."

SPP's Antoine Lucas (left) and Golden Spread's Mike Wise discuss Lubbock's potential move from SPP to ERCOT. | © *RTO Insider*

— Tom Kleckner

Echoing DOE Report, Industry Study Touts Coal 'Resiliency'

By Amanda Durish Cook



Days of stockpiled coal burn | *ACCCE*

A new study prepared for the American Coalition for Clean Coal Electricity (ACCCE) spotlighting the "resiliency" of coal-fired generators echoes the findings of a U.S. Department of Energy report released earlier this month.

Although the study by PA Consulting Group concludes that "no single electricity resource has all of the attributes necessary for a reliable and resilient grid" and that "a mix of resources is the best strategy," it lauds coal generation for its "many critical attributes," including stable fuel prices and an on-site fuel supply that can act as a hedge against potentially volatile natural gas prices, interruptible fuel deliveries and intermittent renewable and demand response resources.

The study's release may prove to be an early salvo in the possible "fuel wars" predicted by one former senior FERC official who said that new FERC commissioners could break with agency tradition by each acting as advocates for favored types of resources. (See *Coal Seeks 'Resiliency' Premium; FERC 'Fuel Wars' Coming?*)

The study ranked generation resources on 11 attributes, giving coal high marks in all but black start capability.

The report is effectively a response to a study done by The Brattle Group for the American Petroleum Institute (API), which concluded that gas-fired generation is "relatively advantaged" in all but one of the 12 attributes identified in that study. (See *NG Lobby Goes on Offensive vs Coal, Nukes*.)

The API/Brattle report ranked coal as only "neutral" on two categories for which ACCCE claimed a full score — frequency response and ramp rates (referred to as "ramp capability" by ACCCE).

API did not score three categories in which ACCCE said coal had an advantage over gas: on-site fuel supply, reduced exposure to a single point of disruption and price stability.

"This new report shows the coal fleet is essential to help maintain the reliability and resilience of the electricity grid," said ACCCE CEO Paul Bailey. "For that reason, we are especially supportive of DOE's recent recommendation that policymakers need to establish criteria to value attributes, such as on-site fuel, that help protect the grid against low probability events that have extreme consequences."

Bailey said he looked forward to "working with policymakers to implement DOE's recommendation as quickly as possible" that RTOs begin valuing on-site fuel storage as a measure of "resiliency." (See *Perry Grid Study Seeks to Aid Coal, Nuclear Generation*.)

Natural Gas Criticisms

The report took particular aim at natural gas-fired generation, coal's biggest competitor. According to the report, coal generators on average stockpiled 82 days of bituminous coal and 73 days of subbituminous coal on site over the last five years. It compared that to the position of "vulnerable" gas-fired plants, which last year on average had about 60 days of fuel in storage reserves and rely on interruptible deliveries via pipeline.

It also pointed out that low-probability, high-impact events like earthquakes can cause supply shocks in the gas distribution network. More than 50% of gas storage capacity is located in five states — Michigan, Texas, Louisiana, Pennsylvania and California — PA Consulting warned, and 18 states in the continental U.S. have "no material storage capability," including New England and North Carolina, South Carolina, Georgia and Florida.


Worldcoal.org

The study also said that because most U.S. coal is used for electricity, coal-fired generation "does not compete with higher-priority uses" and will not have to be forcibly curtailed. It also pointed out that "all but two lignite coal-fueled plants [in the U.S.] source their coal from mines within 30 miles of the plant."

The popularity of gas-fired generators relies on the continuation of low-cost shale natural gas, the study contends.

"The current investment boom in natural gas-fired plants is driven in part by an expectation of continued low natural gas prices of approximately $3-4/MMBtu," the study said. The 77 GW of gas-fired capacity built since 2009 might be a result of an "over-focus on short-term price signals," the authors contend.

Over the last decade, monthly average natural gas prices have "repeatedly seesawed" from $3/MMBtu to more than $12/MMBtu, reaching $100/MMBtu in some markets during the so-called "polar vortex" of 2014, the study noted. It also pointed to dramatically fluctuating gas prices during 2015's Aliso Canyon leak and an extreme cold front in Texas in 2011 that caused 193 generating plants to either fail outright or experience weak output.

"Retaining existing coal-fueled power plants can help insulate ratepayers against rising and possibly volatile natural gas prices," the report said.

Clean Line Seeks Rehearing on Grain Belt Rejection

By Tom Kleckner

Clean Line Energy Partners has filed a rehearing request with the Missouri Public Service Commission, which earlier this month rejected the company's request for a certificate of convenience and necessity for a portion of its $2.3 billion Grain Belt Express transmission project.

The company said Friday the request is a procedural step necessary to preserve the right to appeal the PSC's decision to the state courts. It is one of several options Clean Line mulled over following the PSC's second rejection in three years. (See *Clean Line Ponders Options After Grain Belt Rejection*.)

"Clean Line continues to believe that the Grain Belt Express project is too important not to pursue and is therefore exploring many options to move the project forward," Clean Line spokesperson Sarah Bray told *RTO Insider*. "The Grain Belt Express would be the largest clean energy infrastructure project in Missouri's history and would save Missouri ratepayers more than $10 million annually."

Four of the commission's five members said in a concurring opinion Aug. 16 that the project is needed, economically feasible and beneficial to the public. However, they referenced a March state appeals court ruling on an unrelated case involving Ameren Transmission Company of Illinois, which found that infrastructure projects must first secure approvals from each county it crosses.

The project developers said the PSC's decision that it could not "lawfully issue a CCN" until they could prove they had obtained the necessary county assents was in error. In their filing, they asserted the appeals court ruling interprets a statutory provision that was never invoked in and is not relevant to this case, and that "there are particular legal and factual distinctions" between the two cases.

"The commission's findings of fact and conclusions of law are not supported by substantial and competent evidence on the record as a whole and are grounded in legal error," the filing contends.

Clean Line was unable to gain permission to construct the line through Caldwell County. However, the project has approvals from all other Missouri counties and from the neighboring states of Kansas and Illinois.

The project would deliver approximately 4,000 MW of wind power from western Kansas through Missouri and Illinois to the Indiana border over 780 miles of HVDC lines. Clean Line expects the Grain Belt Express to enable about $7 billion of new, renewable energy projects to be built.

State Could Reject Ameren Illinois Efficiency Target Reset

By Amanda Durish Cook

Ameren Illinois may have hit a roadblock in its efforts to lower its energy efficiency targets prescribed under a new law.

Illinois Commerce Commission Administrative Law Judge Jan Von Qualen last week issued a preliminary order (17-0311) denying the utility's request to lower its energy efficiency goals established under the state's recently enacted Future Energy Jobs Act (FEJA). The ICC is expected to render a final decision on the request by mid-September.

Under the law, Ameren is required to meet 9.8% in cumulative annual energy savings by 2021, but the utility is planning for 8.24% in savings. The utility has allocated $114 million per year for the program, the maximum budget under the law, but claimed it still could not meet the savings goal. A maximum budget triggers the ICC's authority to reduce annual incremental savings goals.

"Based on the record, the commission finds that [Ameren] should modify its plan in a manner that ensures cost efficiencies and serves the customers, including low-income customers, to the maximum extent practicable throughout its service territory," Von Qualen said. "The commission will not modify the [annual savings] goal absent a showing that every attempt has been made to meet the goal and it cannot be met."

The Illinois Clean Jobs Coalition, along with other environmental and consumer activists, last month held a press conference to criticize Ameren for setting low energy efficiency goals and to urge state regulators to reject the utility's four-year efficiency and demand response plan. (See *Ameren Illinois Criticized for Lowered Energy Efficiency Goals*.)

Von Qualen said the state attorney general's office — as well as the Citizens Utility Board, Environmental Defense Fund and the Natural Resources Defense Council — provided multiple suggestions in testimony regarding how Ameren could meet its annual savings goal "while staying within the budget cap."

The judge suggested that Ameren reallocate its optional $6 million per year efficiency research and development spending to programs that actually lower costs per kilowatt-hour. She also said the utility could use a portion of the $4.7 million budgeted for air conditioners on more cost-effective programs. The judge directed Ameren to work with the Illinois Energy Efficiency Stakeholder Advisory Group, the Economically Disadvantaged Advisory Committee and the Illinois Home Weatherization Assistance Program to make better use of its required $8 million in spending on third-party energy efficiency implementation programs, instead of using national retailers and online stores.

She did approve other aspects of Ameren's plan, including savings goals for its gas program and riders for the recovery of electric energy efficiency costs.

Ameren: No Change

Ameren defended its plan and said it has no plans to change its filing in light of the proposed order.

"We have put forth the right plan to help working families in our territory save energy and we look forward to making our case with the Illinois Commerce Commission," Ameren Illinois spokesperson Marcelyn Love told *RTO Insider*.

Ivan Moreno, communications director of the Natural Resources Defense Council, said Ameren has been heavily lobbying state legislators to lean on the ICC to approve the plan.

"This is unusual given that legislators have already debated and voted on this issue through the Future Energy Jobs Act," Moreno said, adding that he expects Ameren to escalate efforts to get the ICC to approve the plan "despite the proposed order."

The Illinois Clean Jobs Coalition welcomed the preliminary ruling: "As the Illinois Clean Jobs Coalition has said from the start, Ameren should be able to deliver energy efficiency programs that serve low-income communities and — at the same time — achieve the energy efficiency targets that the company agreed to under FEJA. We are hopeful that members of the Illinois Commerce Commission will agree with the judge in this case."

The group said it looked forward to working with Ameren on a new plan "that meets the goals set forth in FEJA which can create jobs, savings and better health across Illinois and, in particular, deliver benefits to economically disadvantaged communities throughout the state."

COMPANY BRIEFS

Cost Containment Discussion Suspended for PJM Doc Review

PJM on Wednesday announced that it is canceling a Sept. 8 special session of the Planning Committee focused on cost-containment provisions in competitive bidding for transmission projects.

PJM's Susan McGill said in an email that staff needs "to conduct a detailed review of the governing documents and manuals and consider where the cost capping principles should be added to the planning process" before the group can move forward. She committed to publishing draft language by Sept. 18 in preparation for the group's next session on Oct. 9.

Stakeholders are asked to submit any comments by Sept. 7 to rtep@pjm.com.

Xcel to Retire 2 Units At Comanche Plant

Citing economics, Xcel Energy last week announced plans to retire two of three units at its coal-fired Comanche Generating Station in Colorado.

Xcel will retire Unit 1, built in 1973, and Unit 2, built in 1975, before 2022 and 2025, respectively. The units represent 660 MW of generation. The company will continue to operate its cleaner coal-fired Unit 3, which came online in 2010 and has a capacity of 750 MW.

The utility will request competitive bids before the end of the year for 1,000 MW of additional wind, 700 MW of solar and 700 MW of natural gas power generation under its "Colorado Energy Plan."

More: *The Denver Post*

Amazon Unveils NJ's Largest Rooftop Solar System

Amazon last week unveiled at its Carteret, N.J., warehouse what it says is the state's largest rooftop solar system in addition to being one of the largest in the U.S.

The 22,000-panel system, which sits on a 30-acre roof, can create up to 7.5 MW of power and will power everything in the facility, which operates 24 hours a day.

More: *NJ Advance Media*

Battery Startup Raises $30M in Financing; $65M in Orders Lined Up

Electric vehicle and stationary energy storage battery startup Romeo Power announced it has raised $30 million in seed financing.

The company, which launched in 2015 and is headed by former SpaceX, Tesla, Apple, Amazon and Samsung designers and engineers, also said it has $65 million in initial orders scheduled for delivery in 2018.

The company is currently building a 113,000-square-foot manufacturing facility, scheduled for completion by the end of this year. It plans to produce its own cylindrical lithium-ion cells for mobility and a product named Powerstack for stationary energy storage based on the same battery pack design.

More: *Energy Storage News*

BNSF Workers Back on Job as Coal Volumes Rise

BNSF Railway has called back about 4,000 of its 5,000 workers who were furloughed last year due, in part, to a rise in coal volumes.

"We have seen an increase in coal due mainly to increased natural gas prices and higher electricity demand driven by seasonal trends," spokesman Zak Andersen said. He said BNSF anticipates the trend to decline in the long term.

More: *Reuters*

Microgrids Keeping Houston Supermarkets Open

Hurricane Harvey is serving as a "proof of concept" for natural gas-powered microgrids in Texas, according to the CEO of Houston-based microgrid company Enchanted Rock.

Thanks to microgrids, at least 18 Houston-area H-E-B supermarkets are open for business, with 100% of the electricity they need, while power may be out in the surrounding area, Thomas McAndrew said.

Enchanted Rock installed the technology at the stores over the past year. On Aug. 25, it disconnected H-E-B's microgrid stores from the main power grid and switched over to on-site generators fed by underground natural gas pipelines.

More: *Houston Business Journal*

Osram Buys Smart-Lighting Startup Digital Lumens

Multinational lighting manufacturer Osram has purchased Digital Lumens, a startup with a sensored, networked LED lighting platform in a deal that is reportedly in the "mid-double-digit million-dollar" range.

In February, Digital Lumens started offering customers access to data from a range of sensors — including temperature, humidity, motion and light — as well as an energy management solution that monitors, measures and controls non-lighting electrical loads.

The deal, announced Wednesday, is Osram's second acquisition since it announced in the spring that it planned to spend up to $530 million on companies to fill out its portfolio.

More: *Greentech Media*

Duke Takes Pass on VC Summer Project

Duke Energy has declined to invest in the stalled V.C. Summer nuclear plant expansion.

Duke was one of a small number of companies approached by South Carolina Gov. Henry McMaster about the possibility of investing in the project or buying state utility Santee Cooper as part of his effort to raise money to salvage the project.

Duke announced Friday that it is seeking to cancel development of its Lee Nuclear plant. It cited the recent bankruptcy of Westinghouse Electric as its reason.

More: *Charlotte Business Journal; Blue Ridge Now*

FEDERAL BRIEFS

States Blast EPA over 'Legally Incorrect' Guidance

Fourteen Democratic attorneys general and officials from six cities and counties blasted EPA on Thursday for what they described as a "legally incorrect" letter stating they do not need to comply with the Clean Power Plan.

The guidance, sent by EPA Administrator Scott Pruitt to states on March 30, said that because the legal case involving the Obama-era regulation is on hold, states and other interested parties are not expected to work toward meeting the compliance dates.

State officials said the regulation remains in force and called upon Pruitt to retract his letter.

More: *Reuters*

EPA's New Midwest Leader Scrubbed Climate Info from Internet


Stepp

The Trump administration has named Wisconsin's top environmental regulator — who instructed her department last year to remove mentions of human contributions to climate change from its website — to lead EPA's Midwest regional office.

Cathy Stepp, who heads the state's Department of Natural Resources, will be the principal deputy administrator for EPA's Region 7 office, which is responsible for Missouri, Kansas, Nebraska and Iowa.

Stepp is the second regional administrator EPA has named under Trump. Last week, EPA named Trey Glenn, Alabama's former environmental regulator, to lead the Southeast office.

More: *The Hill*

Navajo's First Utility-Scale Solar Project Now Producing Electricity

The first utility-scale solar project for the Navajo Nation has begun producing electricity for the tribe, as it braces for closure of the coal-fired Navajo Generating Station in December 2019.

The Kayenta Solar Facility in Arizona is producing enough electricity to power about 13,000 Navajo homes.

Federal solar investor tax credits allowed the tribe to avoid passing on the $60 million cost of the plant to customers, said Glenn Steiger, project manager for the solar farm. He said a two-year power purchase and renewable energy credit agreement with the Salt River Project will cover loan repayments for the plant's construction.

More: *The Associated Press*

TVA Investigating High Arsenic Levels at Allen Plant

The Tennessee Valley Authority is installing a network of wells to identify the source and extent of unprecedented levels of arsenic at its 58-year-old coal-fired Allen Fossil Plant.

Arsenic concentrations at well No. 203, which was installed within roughly the past year, ranged from 2,890 to 4,140 parts per billion — more than 400 times the federal standard. Four other wells also showed arsenic above the federal drinking water maximum of 10 parts per billion.

TVA officials said the arsenic levels in well No. 203 are so high that they likely point to sources other than coal ash.

More: *The Commercial Appeal*

EPA Ends Sponsorship of Climate Leadership Awards

EPA announced Friday it will no longer sponsor an awards program honoring voluntary corporate actions to combat global warming.

Since 2012, EPA has been the lead sponsor of the Climate Leadership Awards program and conference, which recognizes companies that reduce greenhouse gas emissions in their internal operations and supply chains.

In an email Friday, EPA did not explain why it was eliminating the program but apologized for doing so in the middle of the awards application process. Awards were slated to be given out between Feb. 28 and March 2, 2018.

More: *Reuters*

DOE Asks Scientists to Scrub 'Climate Change' Language

Two scientists on projects the Energy Department approved for funding were asked Thursday to remove climate change-related language from the descriptions of their research.

Jennifer Bowen, of Northeastern University, received the request via email one day after her grant to study how carbon is stored in salt marshes was announced. Ecologist Scott Saleska, of the University of Arizona, was asked the remove the language from a description of his research on effects of decomposing plant material on permafrost.

A colleague in Bowen's study said the request appeared only to apply to the abstract of the proposal, and there was no indication that their final report should avoid language related to climate change.

More: *InsideClimate News*

STATE BRIEFS

CALIFORNIA

SCE Agrees to Seek New Location for San Onofre Waste

Southern California Edison last week agreed to seek a new location for 3.55 million pounds of nuclear waste that have accumulated at its San Onofre Nuclear Generating Station.

The settlement was approved by a Superior Court judge, ending litigation filed by two San Diego-area plaintiffs who sued after the Coastal Commission in 2015 approved a 20-year permit for SCE to bury nuclear waste in concrete bunkers.

The agreement calls for SCE to make "commercially reasonable" efforts to relocate the waste to sites in New Mexico, Texas or Arizona. Officials from Arizona Public Service, which operates the Palo Verde Nuclear Generating Station, say they won't take it.

More: *The San Diego Union-Tribune*; *The Republic*

DELAWARE

Governor Creates Group to Advance Offshore Wind

Gov. John Carney last week authorized the creation of a working group to advance offshore wind in the state.

The group, which will consist of 17 members, including at least three from the energy industry, will study how the state can participate in development and leverage economic opportunities.

It will deliver a report to the governor by Dec. 15 with short- and long-term strategies.

More: *Renewable Energy World*

MICHIGAN

Snyder Orders Review Of Enbridge Line 5

Gov. Rick Snyder on Wednesday ordered an accelerated and "aggressive" review of Enbridge Energy's operations and maintenance procedures after the company revealed that two sections, with a possible third section, of its Line 5 pipeline running under the Straits of Mackinac are missing a protective coating.

According to Enbridge spokesman Ryan Duffy, raw metal from the pipeline sections directly touches the Great Lakes water, but there is no damage to the pipe. One section measures 3-inches-by-one-half-inch. Enbridge would not disclose the size of the second section and is still investigating the possible third area of exposed metal.

Enbridge plans to notify EPA, the state Department of Environmental Quality and the U.S. Pipeline and Hazardous Materials Safety Administration, and make repairs after a study is completed in the next several days.

More: *The Detroit News*

NEW MEXICO

Proposal Calls for Cuts to Carbon Dioxide Emissions

The state attorney general's office and consumer advocates are petitioning state regulators to consider a new energy standard calling for electric utilities to reduce carbon dioxide emissions from power plants that serve customers in the state by 4% a year through 2040.

Steve Michel, the energy policy chief with the environmental group Western Resources Advocates, presented the proposal Wednesday to the Public Regulation Commission.

A spokesman for Public Service Company of New Mexico, the state's largest electric provider, said the utility would not comment on the standard until a final version of the proposed rule is drafted.

More: *The Associated Press*

UTAH

Solar Industry, RMP Reach Agreement on Net Metering

The state's solar industry and Rocky Mountain Power have reached a compromise on how net metering in the state should move forward.

The agreement calls for current net metering customers to be grandfathered at a rate of about 10 cents/kWh until 2035, while allowing a rate of 9.2 cents/kWh for new customers after Nov. 15. That rate for new customers stays in effect for three years while the state, Rocky Mountain Power and other stakeholders assess solar's cost/benefit framework and construct a permanent solution.

The Public Service Commission is expected to vote on the proposal at its Sept. 19 meeting.

More: *pv magazine*; *Deseret News*

Industrial Consumers Concerned by Efforts to Expand LNG Exports

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about half of global export capacity under construction is in the U.S.

Sabine Pass and the only other existing export terminal in the U.S., ConocoPhillips' Kenai LNG Plant in Nikiski, Alaska, have a combined capacity of 2.3 Bcfd. An additional 11 other terminals with a combined capacity of 16.4 Bcfd have been approved, and 14 terminals (25 Bcfd) have pending applications or are in the prefiling stage, according to FERC.

The Trump administration has pushed to expand LNG exports, particularly to European Union countries dependent on Russian gas, continuing an Obama-era policy to counter Russian influence. Russia supplied more than one-third of Europe's gas in 2016 and is expected to remain its biggest supplier through 2035.

Although some government strategists find U.S. shale gas wealth appealing as a geopolitical lever, economists say exporting too much gas could expose U.S. consumers, industrial users and electric generators to much higher world prices. Australia's surge in LNG exports provides a cautionary tale. The country, which exported 62% of its production last year, was hit with a February heat wave that resulted in gas shortages and blackouts.

But there is no agreement on what is the tipping point for the U.S. or how soon we could get there. The answer depends on at

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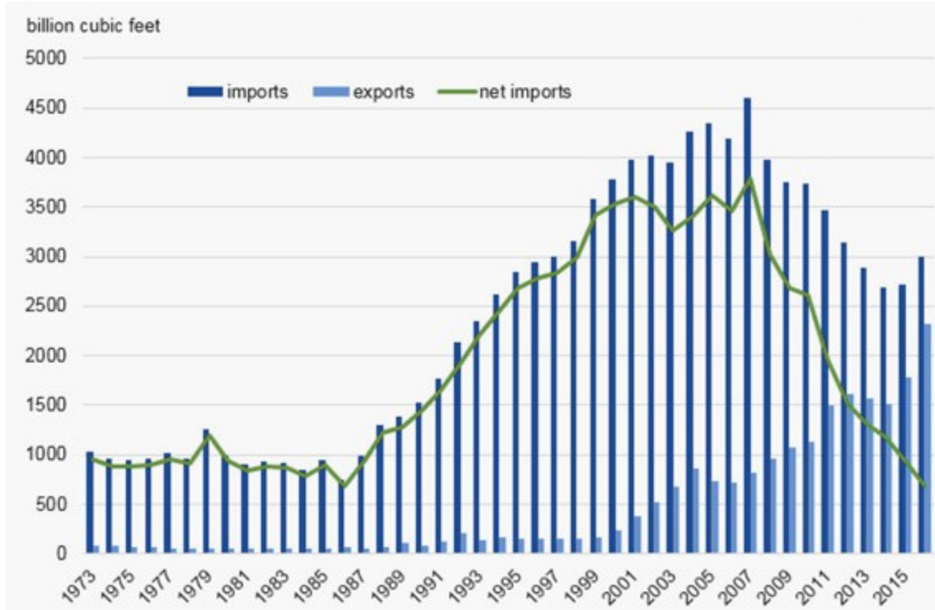
least three variables: How big is the U.S. supply? How much demand is there for U.S. exports? And what will be the impact of increasing exports on U.S. gas prices? (See related story, *No Agreement on Tipping Point for LNG Exports*, p.26.)



U.S. natural gas net imports fell to a record low in 2016. | *EIA*

Chris McGill, vice president of policy analysis for the American Gas Association, which represents more than 200 gas utilities, is unconcerned.

"We have not believed that incremental elements of demand — like LNG growing over time, like more gas for power generation — destroy the market for small volume users," he said. "In fact, if you look at the recent history, and particularly since the shale revolution, we have a market that's been demand-constrained, not supply-constrained."

John Shelk, CEO of the Electric Power Supply Association, said independent power producers aren't concerned by an increase in exports influencing electricity prices either. "We agree with our producer colleagues that the supply curve is so flat that any increased demand from LNG exports going up can be met without a meaningful uptick in prices," he said.

But the Industrial Energy Consumers of America (IECA) is alarmed by the trend. The group, which represents companies with 2,600 facilities and 1.7 million employees, issued a statement in July disputing Trump's boast that the U.S. is "sitting on massive" energy reserves. It called for a moratorium on further approvals of LNG exports to countries without free-trade agreements (FTAs) with the U.S.

Citing EIA data, IECA President Paul N. Cicio claimed "56% of all natural gas resources will be consumed" by 2050. The claim that the U.S. has a 100-year supply of gas, he says, "is a myth."

Regulation of Exports, Terminals

Under the Natural Gas Act of 1938, the U.S. Department of Energy must approve any requests to import or export gas based on whether it is in the "public interest" — a term it has never precisely defined.

The Energy Policy Act of 1992 stipulates that trades with countries that have FTAs with the U.S. are automatically considered "consistent with the public interest and granted without modification or delay," according to the department.

Two bills introduced in the Senate in June would expand that blanket authorization to countries without FTAs, except those under U.S. sanctions: the License Natural Gas Now Act, proposed by Sen. Bill Cassidy (R-La.), and the Natural Gas Export Expansion Act, by Sen. Ted Cruz (R-Texas). Cassidy said his bill is supported by industry groups including the American Petroleum Institute and the Natural Gas Supply Association. IECA said it opposes the Cassidy bill.

Last week, DOE proposed automatic approvals of gas export applications of up to 140 Mcfd as long as the applications do not require an extensive environmental review.

DOE has delegated to FERC the authority to conduct environmental and safety reviews of proposed LNG facilities, but not to block exports on broader policy grounds.

Industrial Growth Threatened?

In April 2016, the American Chemistry Council (ACC) called the U.S. "the most attractive place in the world to make chemicals," saying cheap gas was responsible for 264 U.S. chemical industry projects totaling $164 billion. By 2023, the group said, the spending would result in 69,000 new chemical industry jobs, 357,000 jobs in supplier industries and 312,000 jobs in neighboring communities. By contrast, IECA notes that LNG export terminals only employ a few hundred employees each.

Notably, 55% of the projects cited by the ACC were then in the planning phase, making them vulnerable to cancellation if gas prices rise too high.

Unlike IECA, however, the chemicals group expresses no fear of LNG exports.

The ACC told *RTO Insider* last month that it stands by its 2013 statement opposing any new export bans or restrictions on LNG export terminals and supporting "free-market policies that promote the export of American-made goods, including" LNG.

"Where there is not a clear consensus among the membership is on the question of whether the Natural Gas Act's 'public interest' requirement should be further defined in export permitting to non-FTA countries," the group said. It said its Executive Committee would continue discussions to seek a consensus and monitor "issues that could affect the competitive position of our industry in the future, such as infrastructure development and access to energy resources."

The industrials group is aware that ACC's position seems to undermine its concerns.

"IECA is often asked why other large manufacturing trade associations like the National Association of Manufacturers, the U.S. Chamber, the American Chemistry Council and the Business Roundtable do not raise concerns about excessive LNG exports," it says. "The answer is that 100% of IECA member companies are manufacturing com-

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panies. Other trade associations have company membership which includes the oil and natural gas industry, and prevents them from addressing these concerns."

According to EIA, power generation led the demand for U.S. natural gas in 2016, responsible for 36% of consumption. Industrial consumption was second (28%), with demand driven by petrochemical producers — who use natural gas as a feedstock in the production of methanol, ammonia and fertilizer — and other energy-intensive industries that use natural gas for heat and power.

EIA predicts gas use in power production will briefly decline because of growth in renewables and price competition with coal, before increasing after 2020.

The increase is based in part on the scheduled expiration of renewable tax credits in the mid-2020s. However, the reference case also included fuel switching to gas because of EPA's Clean Power Plan, which President Trump has vowed to cancel. Natural gas consumption in the electric power sector is about 6% higher in the reference case in 2040 than the "No CPP" case.

Defining the 'Public Interest'

Neither Congress nor the DOE has defined the "public interest" for making decisions on exports to non-FTA countries; instead, the department has used guidelines developed in 1984 for LNG imports, according to a 2014 Government Accountability Office report.

The industrials say the department should define the public interest to recognize job impacts. IECA says using natural gas in manufacturing creates eight times more jobs than exporting it. Domestic industrial use is worth twice the direct value added per year and 4.5 times the direct construction jobs, IECA says.

"The most glaring omission and failure of the Obama administration [public interest] studies was to cumulatively account for increased LNG exports to both NFTA and FTA countries. The studies only considered the impact for volumes to NFTA countries. More than twice the volume is approved for FTA countries and these volumes, in addition to domestic demand, were not included in any of the studies," IECA said.

IECA Recommendations

The group recommends the government allow existing LNG export terminals approved for shipment to non-FTA countries to become operational and determine if the gas industry can increase production, pipeline transportation and storage capacity without price increases or supply shortages that would damage the U.S. economy.

"DOE should implement its authority under the Natural Gas Act (NGA) to establish a process of ongoing monitoring of economic impacts of LNG export volumes, and with the ability to reduce LNG export volumes for purposes of establishing a safety valve for U.S. consumers and the economic welfare of the country," IECA said.

No Agreement on Tipping Point for LNG Exports

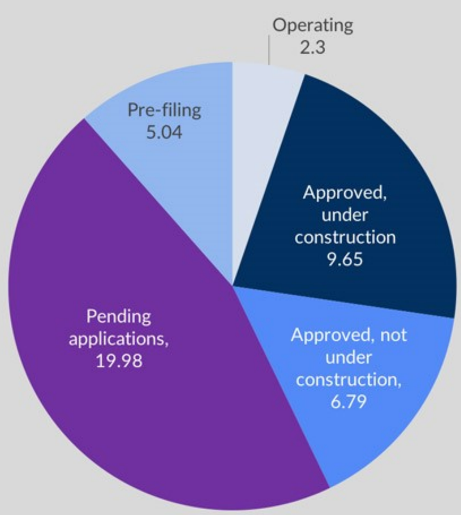
By Michael Brooks and Rich Heidorn Jr.

There is wide agreement among economists that exporting too much U.S. natural gas could expose U.S. consumers, industrial users and electric generators to much higher world prices. But there is no agreement on what is the tipping point, and how soon could the U.S. get there. The answer depends on at least three variables: How big is the U.S. supply? How much demand is there for U.S. exports? And what will be the impact of increasing exports on U.S. gas prices?

Below, *RTO Insider* summarizes the current data and the projections on these variables.

Supply Debate

According to the U.S. Energy Information Administration, there was about 2,355 trillion cubic feet (Tcf) of technically recoverable gas in the U.S. as of Jan. 1, 2015. "Technically recoverable" gas includes proved (gas expected to be produced under current economic conditions) and unproved reserves (gas that is recoverable based on current technology, without regards to economics).



U.S. LNG export capacity by license status (Bcfd) | *EIA*

The reference case of its 2017 Annual Energy Outlook (AEO) projects gas production to grow at almost 4% annually through 2020, about equal to the growth since 2005. After 2020, EIA projects a 1% annual production growth rate as net export growth moderates and domestic consumers more efficiently use their gas.

In July, the Potential Gas Committee — a group of scientists from industry, academia and government — said that recoverable gas is about 20% higher than EIA's estimate. The committee's biennial report put the figure at 2,817 Tcf as of Dec. 31, 2016.

The PGC's new estimate represents a 12% increase over its previous report, the fifth consecutive increased projection. The group attributed the increase largely to a re-evaluation of production and development of shale gas plays across the country, with the Appalachian Basin plays — which include the Marcellus and Utica — especially having much more than previously thought.

Alexei Milkov, professor of geology and director of the Potential Gas Agency at the Colorado School of Mines, presented the report in July at American Gas Association headquarters in D.C. He said the lopsided increase in the Appalachian plays is because it is more economic for gas producers to explore existing sites, rather than drill new wells. Producers also are drilling longer laterals when fracking and increasing their use of "slick water" — water with added chemicals that reduces friction, allowing for more efficient gas production.

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Consumption

Last month, EIA reported that the U.S. has enough natural gas to last about 86 years, or about 2101, based on the 2015 consumption rate of about 27.3 Tcf per year.

"The actual number of years will depend on the amount of natural gas consumed each year, natural gas imports and exports, and additions to natural gas reserves," the agency said.

EIA actually projects consumption rising to almost 40 Tcf by 2050, an average annual increase of almost 1.2%. The 2017 AEO reference case projects a total consumption of 1,227.2 Tcf from 2016 to 2050. This figure includes a maximum of 4.4 Tcf annually (about 12 Bcfd) in net LNG exports.

Assuming consumption increases continue at about 1.2%/year after 2050, the U.S. would actually run out of gas in 2075, based on EIA's supply estimate.

Using the PGC's total reserve estimate and the same consumption increase extends supply to 2083.

The Industrial Energy Consumers of America (IECA) has been sounding alarms about growing exports, noting in June that EIA's projections show the U.S. will exhaust 56% of its supply by 2050. (See related story, *Industrial Consumers Concerned by Efforts to Expand LNG Exports*, p.1.)

The group's estimate subtracted from EIA's 2016 reserve estimate the supply from Alaska, a reduction of almost 7%. It did this because those Alaskan "resources are not available to consumers in the lower 48 states," it said. This would put the lower 48 on track to run completely out by 2072.

IECA says the Energy Department has approved exports of 20.6 Bcfd to non-FTA countries, almost equal to U.S. industrial gas consumption and almost three-quarters of the amount burned for power generation. "The U.S. should never agree to ship LNG to countries that subsidize their manufacturers and power plants," the group said.

Exports Growing

U.S. natural gas exports jumped 30% to 6.35 Bcfd in 2016, a record high, according to EIA. Almost 92% of exports were via pipelines to Mexico (up 29% from 2015) and Canada (up 10%). Exports to Mexico, which have more than doubled since 2013, are expected to continue growing with the completion of pipeline projects currently under construction and as demand from new natural gas-fired generators in Mexico increases.

Mexico, Canada and four other countries with free-trade agreements with the U.S. — Chile, South Korea, Jordan and the Dominican Republic — accounted for 44% of LNG exports in 2016, according to IECA. The remaining 56% was consumed by 13 non-FTA countries, led by India, China, Argentina and Japan.

Exports to Canada have been increasing steadily since 2000, when the 1.3-Bcfd Vector pipeline began shipping gas from Chicago. The trend has accelerated since 2011 as several pipelines that had been importing gas from Canada were reversed in the Midwest and Northeast.

LNG export terminals along the Gulf of Mexico | *EIA*

As of March 2017, U.S. natural gas exports to Canada were 3.21 Bcfd and those to Mexico averaged 4.04 Bcfd.

Although the U.S. remained a net importer of natural gas in 2016 — buying 685.3 Bcf more than it sold — net imports dropped 27% from 2015 and 50% from the previous five-year average (2011-15).

In its AEO reference case, EIA projects LNG exports to exceed pipeline exports by the early 2020s, rising steadily before leveling at 4.4 Tcf in 2035.

The two U.S. export terminals in operation — Cheniere Energy's Sabine Pass LNG Terminal in Louisiana and ConocoPhillips' Kenai LNG Plant in Alaska — have a combined capacity of 2.3 Bcfd.

According to FERC, 11 other terminals with a combined capacity of 16.4 Bcfd have been approved, all but four of which have commenced construction. An additional 14 terminals with total capacity of 25 Bcfd have pending applications or are in the prefiling stage, the commission says.

"After 2020, U.S. exports of LNG grow at a more modest rate as U.S.-sourced LNG becomes less competitive in global energy markets," EIA predicts. Currently, most LNG is traded under oil price-linked contracts, but this is expected to change as the global LNG market expands, EIA said.

However, the reference case also included fuel switching to gas because of EPA's Clean Power Plan, which has been stayed by the Supreme Court and which Administrator Scott Pruitt is trying to rewrite. Natural gas consumption in the electric power sector is about 6% higher in the reference case in 2040 than the "No CPP" case.

Consumption: How Much Demand Is There?

Some analysts say the rush to build export facilities threatens to create a glut.

"Just as the U.S. terminals are ramping up capacity, the global LNG market is entering a period of oversupply and weak spot LNG prices across the major gas importing regions," Columbia University's Center on Global Energy Policy said in a November 2016 report. "In this new market environment, it seems increasingly uncertain whether America's new flexible LNG export capacity will be fully utilized toward the end of the decade."

For exports to be economic, the report notes, the delivered cost of LNG must be lower than the target market's spot price. This "arbitrage window" is still open, but

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narrow, in the European and Asian markets — "quite remarkable, given how much spot natural gas prices have fallen in both regions over the last two years," the report said. The two benchmark spot prices for the European (U.K.) and Asian (Japan/South Korea) markets had fallen to $4.69/MMBtu (down 40%) and $6.08/MMBtu (down 60%), respectively, as of Sept. 30, 2016, it said.

"By adding a vast supply of flexible uncommitted LNG into the global natural gas market, U.S. LNG is already changing gas market dynamics around the world in profound ways," the report concludes. "Whether the world will want to buy all that gas, however, will depend on even small changes in a number of key variables, with significant consequences for future investment, technological and commercial innovation, and global gas trade."

Price Impact

The economics for exporting LNG, like those for converting to gas-fired power generation, are the product of the U.S. shale gas revolution that has dramatically reduced prices and increased supply.

But EIA predicts a steady increase in prices under all its future scenarios:

- In its reference case, EIA forecasts Henry Hub prices nearly doubling from $2.50/MMBtu to $4.90/MMBtu between 2016 and 2020. Average delivered prices rise a more modest 48% over the same period.
- Under EIA's high oil price scenario, Henry Hub prices increase 75% by 2020, with average delivered prices rising 37%. The scenario assumes a barrel of Brent crude oil — currently priced at about $50/barrel — reaches $226 by 2040, compared to $109 in the reference case and $43 in the low oil price case.
- The high oil and gas resource and technology case — which models lower gas costs and higher supplies than in the reference case — predicts a 60% increase in Henry Hub prices and 31% in average prices by 2020. The lower prices increase domestic consumption and exports.
- In comparison, in the low oil and gas resource and technology case, "prices near historical highs drive down domestic consumption and exports." Henry Hub prices rise by 131% by 2020, while average delivered prices rise by about two-thirds.

Henry Hub, long the benchmark for U.S. gas contracts, is increasingly helping to set international prices. In the first six months of 2017, the volume of Henry Hub futures traded outside of typical U.S. trading hours jumped 31% compared with the same period last year, according to the New York Mercantile Exchange.

Kenneth Medlock, senior director of Rice University's Center for Energy Studies, says added LNG exports will not have a substantial impact for almost a decade because the large amount of LNG supply coming online globally will prevent the U.S. from exporting more than 12 Bcfd before 2025.

Medlock coauthored with Oxford Economics an October 2015 study for the Energy Department on the macroeconomic impact of increased LNG exports. It concluded LNG exports raised domestic prices somewhat and lowered prices globally, with Asia most sensitive to price movements.

It projected that if LNG exports met a global demand of 20 Bcfd, it would only increase U.S. GDP by 0.03 to 0.07%, or $7 billion to $20 billion at today's prices.

Australia's Lesson

Australia's surge in LNG exports provides a cautionary tale for the U.S. The country, which exported 62% of its production last year, was hit with a February heat wave that resulted in domestic shortages, spiking prices to as high as $17/MMBtu and leading to blackouts. It was responsible for 17% of LNG exports in 2016, second only to Qatar (30%).

Such a crisis is unlikely soon in the U.S.: The country would need to ship about 45 Bcfd — seven times its current rate at current production levels — to match Australia's exports as a share of total production.

ATC Fined over Improper FERC Reporting

By Amanda Durish Cook

American Transmission Co. has agreed to pay a federal fine and undergo a year of monitoring after failing to properly report more than 60 agreements and transactions to FERC over the past 16 years.

Under an agreement reached with FERC's Office of Enforcement, Milwaukee-based ATC will pay a civil penalty of $205,000 to the U.S. Treasury and submit semi-annual compliance monitoring reports for one year detailing any further violations (IN17-5).

The office found that ATC repeatedly failed to seek approval to merge or acquire FERC-jurisdictional facilities and to file "timely" contracts and agreements relating to rates and charges for jurisdictional service.

"Enforcement determined that, although ATC's violations did not result in quantifiable market harm, they created a lack of transparency in the market by failing to have all of ATC's jurisdictional agreements on file with the commission, and by consummating purchases of commission-jurisdictional assets without commission authorization," the commission said.

In an internal review of its filing processes during 2014 and 2015, ATC discovered 63 instances in which it failed to either properly report or file information starting in 2001.

Those include several agreements that it failed to file pursuant to Federal Power Act obligations, relating to operations, transmission design on shared 345-kV projects, pole replacements, repairs on jointly owned substations, transmission line relocation and ownership, and cost-sharing for jurisdictional facilities. ATC in some cases also neglected to file notices to terminate existing agreements. The company has already paid $1.4 million to several affected parties in time-value refunds.

The company also identified 21 jurisdictional facilities it acquired without gaining FERC approval. The facilities range in value from $1,513 to $1.2 million. FERC retroactively approved each transaction after ATC sought permission between 2014 and 2015.

Section 203 of the FPA requires public utilities to file for FERC authorization to merge or acquire jurisdictional facilities, and Section 205 requires public utilities to file "all contracts which in any manner affect or relate to such [jurisdictional] rates, charges, classifications and services."

FERC said that, since discovering the violations, ATC has taken steps to "strengthen its compliance policies and procedures and to prevent noncompliance in the future regarding jurisdictional agreements," holding employee training seminars, updating training documents and developing an internal review process to make sure the company has proper authorization.