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Emission deadlines boost coal-gas conversions

ANALYSIS With greater clarity on looming emissions regulations, there has been a steep rise in plans to convert coal-fired generation units to burn natural gas, according to an examination of various company plans.

August saw three companies announce plans to convert coal-fired units to natural gas. Indianapolis Power & Light, owned by AES, said it plans to convert the 427-MW unit 7 at its Harding Street station in Indiana to burn gas.

The utility is already converting units 5 and 6 to burn gas. The conversion of those 100-MW units is expected to be completed by 2016. Unit 7 will stop burning coal in 2016. The start date to burn gas at unit 7 will depend on regulatory approvals, said AES spokeswoman Amy Ackerman.

Also in August, Mississippi Power said it plans to convert units 4

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ISO-NE told to pursue long-term winter program

REGULATION ISO New England needs to work with its stakeholders to develop a "long-term, market-based solution" to ensure reliability during winter months, the Federal Energy Regulatory Commission said Tuesday, as it approved a number of out-of-market steps toward keeping the lights on this coming winter.

"While we accept the 2014-2015 winter reliability program as an out-of-market solution because of its temporary nature, we expect ISO-NE to abide by its commitment to develop a long-term, market-based solution to address winter reliability issues. We therefore require ISO-NE to initiate a stakeholder process by January 1, 2015, to develop a proposal to address reliability concerns for the 2015-2016 winter and future winters, as

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CMP: Transmission line would provide savings

TRANSMISSION A proposed 345-kV transmission line linking northern Maine to the ISO New England grid for the first time would produce regional market savings of $5.9 million, according to an analysis prepared for Central Maine Power, the project's sponsor.

The savings in the ISO-NE market would climb to $146.1 million if 500 MW of additional wind generation were to connect with the line, according to the analysis, filed Monday with the Maine Public Utilities Commission.

Because northern Maine is not part of ISO-NE, the PUC is reviewing various proposals aimed at improving grid reliability in the Northern Maine Independent System Administrator footprint.

CMP hsays the 26-mile Maine Power Connection line, which would cost about $152 mililon, could be the first leg of a longer

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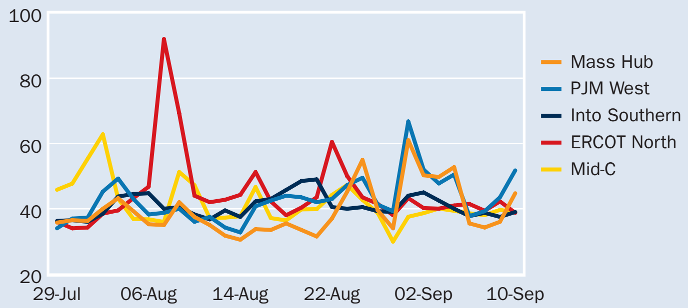
Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Sep 11 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	47.36	58.07	26.07	29.03
NYISO	31.24	54.23	22.26	28.41
PJM	30.71	60.91	18.67	28.66
MISO	31.39	43.94	17.83	29.20
ERCOT	37.22	43.94	27.26	27.61
SPP	21.77	39.16	13.11	29.89
CAISO	49.58	52.46	35.70	36.93

Note: Lows and highs for each ISO are for various hubs and zones. A full listing of average LMPs are availible for the hubs and zones inside this issue.

Day-ahead bilateral indexes and spark spreads for Sep 11

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	44.75	13876	22.18	18.95	12.50	6.05	-3.63
N.Y. Zone-A	37.25	11574	14.72	11.50	5.07	-1.37	-11.03
PJM/MISO							
PJM West	51.75	16155	29.33	26.12	19.72	13.31	3.70
Indiana Hub	36.25	9119	8.43	4.45	-3.50	-11.45	-23.38
Southeast & Central							
Southern, Into	39.00	9861	11.32	7.36	-0.55	-8.46	-20.33
ERCOT, North	38.75	9974	11.56	7.67	-0.10	-7.87	-19.53
West							
Mid-C	38.98	10125	12.03	8.18	0.48	-7.22	-18.77
SP15	51.50	12455	22.56	18.42	10.15	1.88	-10.53

Note: All indexes are on-peak. Spark spreads are reported in ($) and Marginal heat rates in (Btu/kWh). A full listing of bilateral indexes and marginal heat rates are inside this issue.

Inside this Issue

Analysts expect 81-85 Bcf gas storage injection

A consensus of analysts surveyed by Platts expects the US Energy Information Administration on Thursday will estimate a natural gas storage injection of between 81 Bcf and 85 Bcf for the reporting week that ended September 5.

An injection within those expectations would be nearly 20 Bcf above both the 64 Bcf build at this time last year and the 60 Bcf five-year average, according to EIA data.

The wider range of analyst expectations for this Thursday's report spanned from an injection of 65 Bcf to 89 Bcf.

Last week, the EIA reported a 79 Bcf injection that pushed inventories up to 2.709 Tcf. Inventories are still 14.8% below the year-ago level of 3.18 Tcf, and 15.4% below the five-year average of 3.204 Tcf.

The report is expected to continue the summer's trend of higher than average refills as growing production isn't being soaked up by power demand off significant heat.

"Average temperatures in the northern latitudes are declining, providing the framework for higher contributions to storage thanks to continued dry gas production around 70 Bcf/d," Global Hunter Securities analyst Richard Hastings said Wednesday.

INTL FC Stone broker Tom Saal said another number well above-average wouldn't shock traders. "Some of the prognosticators are scratching their heads because they thought it would be 100 [Bcf/d] by now."

"Production out of the Utica is going to show up in this report," Ritterbusch &Associates President Jim Ritterbusch said. "This will be another strong storage report, at least 25 Bcf/d above average."

"The holiday weekend helped push total storage injections higher despite a continuation of the seasonally high temperatures in the eastern half of the country," Bentek Storage and Forecasting analyst Jeff Moore said. "Total demand fell nearly 1.7 Bcf/d from the previous week, with power burn demand accounting for almost 100% of the decline."

Even larger storage builds may be on the horizon, according to BNP Paribas analyst Teri Viswanath. "With cumulative cooling degree days likely to decline next week, the inventory build will likely increase to the mid-90s with the possibility of a triple build either occurring for the week ending September 26 or October 3 as milder weather unfolds," she said Wednesday.

Most analysts continue to predict fall inventories will reach the 3.5 Tcf mark, after plummeting to an 11-year low of 822 Bcf this spring.

The industry has injected 1.887 Tcf since the end of March, or an average of 89.85 Bcf/week over the past 21 reporting weeks. In order to reach an end-October inventory of 3.5 Tcf, another 791 Bcf of refills are needed, or an average of 79.1 Bcf/week over the next 10 reporting weeks.

— Bill Holland

SDG&E seeks supplies to address San Onofre

To help it address the loss of the San Onofre nuclear power plant, San Diego Gas & Electric has issued an all-source request for proposals for 500 MW to 800 MW.

The Sempra Energy utility is seeking at least 300 MW from any source, 175 MW of "preferred" resources such as renewables and 25 MW of energy storage. SDG&E can also seek an additional 300 MW from any source, according to the solicitation, released early this week.

The RFP was issued after the California Public Utilities Commission found that SDG&E would need up to 800 MW by 2022 to help replace the 2,150 MW San Onofre plant and the pending retirement of plants that use once-through cooling technology.

SDG&E has separately asked the PUC to approve a 600 MW bilateral contract with NRG Energy's planned Carlsbad Energy Center. If that deal is approved, 600 MW of SDG&E's need would be filled by the NRG contract and SDG&E would not acquire more gas-fired generation.

However, the utility would still need to procure at least of 200 MW of preferred resources, including at least 25 MW of energy storage.

The proposed Carlsbad PPA is raising concerns from some parties because it was crafted outside a solicitation process and transmission upgrades that are planned may lower the utility's generation needs, according to filings with the PUC.

The California ratepayer advocate's office urged the PUC to wait to see the results of the just-issued RFP before making a decision on the NRG contract to see how prices compare.

In the RFP, SDG&E recommended that bidders submit at least two offers: one to take into account the possibility that the PUC approves the NRG contract and another in case the contract is rejected. The utility is seeking PPAs with terms of at least 20 years.

For energy storage, SDG&E will consider both PPAs and utility-owned offers.

SDG&E will consider offers for energy efficiency, demand response, renewables, combined heat and power, energy storage, conventional resources and distributed generation. Any renewables that the utility procures through the solicitation would count towards SDG&E's renewable portfolio standard requirements.

PA Consulting is the independent evaluator for the solicitation.

Bids are due January 5. SDG&E expects to notify short-listed bidders by June 5 and submit final offers for PUC approval in the first quarter of 2016.

Questions about the solicitation can be emailed to allsourceRFO@semprautilities.com.

— Ethan Howland

Coal-gas conversions jump ...from page 1

and 5 at its Watson coal plant near Gulfport, Mississippi, to burn gas by April 16, 2015, the proximate compliance date for the Environmental Protection Agency's Mercury and Air Toxics Standards rule. The utility also plans to convert units 1 and 2 at its Greene County plant to gas by April 16, 2016, the extended MATS deadline.

NRG Energy announced plans to convert to convert the 1,326-MW Joliet plant in Illinois to burn gas by 2016.

A fourth generation owner, Tennessee Valley Authority, said it plans to shut coal units and not refuel them but replace them with new gas units. TVA is closing three coal-fired units at its 740-MW Allen plant and replacing them with a 1,000-MW combinedcycle gas plant by 2018, and at its Paradise plant TVA is retiring units 1 and 2 and replacing 1,400 MW of coal capacity with a 1,000-MW gas plant due online in 2017.

In all, data compiled by Platts show that there are a total of 13,946 MW of coal-to-gas conversions under way or planned across the US, with most of the conversions expected to be completed by the April 16, 2016, final deadline for MATS compliance. MATS compliance begins on April 16, 2015, but companies can seek an extension.

The total marks a big jump from the conversion plans that were reported by Platts in May 2013, when 3,500 MW of coal-to-gas conversion plans were tallied.

The shift is taking place in the context of a larger shift from coal to gas that is being driven by several factors. In a September 8 report, Sanford Bernstein analyst Hugh Wynne identified four key drivers that could cause coal burn to fall by a quarter of US production and gas burn to rise by nearly a fifth of US gas output.

The four drivers are growth in power demand, the rapid growth of renewable generation, coal retirements driven by the MATS rules and, later in the decade, the effect of EPA's pending rules to reduce carbon dioxide emissions from existing power plants.

Wynne estimates that MATS will drive the retirement of as much as 50 GW of coal capacity between 2013 and 2020.

In terms of conversions, the Bernstein report noted that coal-to-gas conversions could result in fairly high-cost peaking plants with low operational flexibility. So while a conversion might preserve capacity in a location or region where generation is needed, conversions are unlikely to result in the same level of output.

For regulated utilities, converting a plant from coal to gas could be cost-effective way of maintaining reliability requirements, and for a merchant generator in a competitive wholesale market, it could be a cost-effective way of maintaining capacity payments.

NRG appears to be the most eager to get ahead of the regulatory shift in order to take advantage of planned coal retirements. The company has six conversion projects totaling almost 4,000 MW of capacity under way.

Southern Company is the second most active, with seven coal-to-gas conversion projects totaling slightly more than 3,500 MW.

Sixteen other companies, representing a mix of regulated utilities, municipal utilities, private equity players and single asset owners, have conversion projects planned.

Several others companies are waiting in the wings, weighing their options before committing to convert certain facilities. Among them are PacifiCorp, which is waiting for Wyoming to release its implementation plan for CO_2 reductions before deciding what to do with its 700-MW Naughton coal plant near Kemmerer, Wyoming.

Coal-to-gas conversions under way

Owner	Plant	Unit(s)	Coal MW	Gas MW	Online date
NRG Energy	Joliet	6, 7, 8	1,376	1,376	Mid-2016
	Shawville	1, 2, 3, 4	597	597	Jun 2016
	Avon Lake	1 thru 9	753	753	Apr 2016
	Dunkirk	2. 3. 4	435	435	Sep 2015
	New Castle	3, 4, 5	328	328	May 2016
	Big Cajun 2	2	575	575	Apr 2015
Southern Co.	Watson	4, 5	775	775	Apr 2015
	Green County	1, 2	500	500	Apr 2015 or 2016
	Sweatt	1, 2	94	94	TBD
	Yates	6, 7	707	707	Apr 2016
	Barry	1, 2, 3	475	345	Apr 2015 or 2016
	Gaston	1, 2, 3, 4	1,000	1,000	Apr 2015 or 2016
	Gadsen	1, 2	120	120	Apr 2015 or 2016
American Elec. Power	Big Sandy	1	260	278	Early 2016
	Clinch River	1, 2	470	484	Early 2016
SCANA	McMeekin	1, 2	250	250	2015***
	Canadys	1, 2	295	295	2015****
MidAmerican	Riverside	2	137	137	Apr 2016
Duke Energy	WS Lee	3	170	170	Apr 2016
Xcel Energy	Cherokee	4	352	352	2017
Wisconsin Electric	Valley	1, 2	280	280	2014 & 2015
Tucson Electric Power	Wilson Sundt	5	185	185	Dec 2017
Allete	Laskin	1	110	110	Jun 2015
Indianapolis Power & Light	Harding Street	5, 6, 7*	627	627	2016 & TBD
Footprint Power	Salem Harbor	1, 2,3	750	674	Jun 2016**
Upstate New York Power Producers	Cayuga	1, 2	300	300	TBD
Alliant	ML Kapp	2	218	218	Spring 2015
Sunbury Generation	Sunbury	1, 2, 3, 4	347	1,000	2017-2018
Rockland Capital	BL England	1, 2	447	441	2017
Arizona Electric Power Co-op	Apache	1	175	175	Dec 2017
Lakeland Electric	McIntosh	3	365	270-365	TBD
Total			**15,613**	**13,946**	

* Stops burning coal in 2016
** Developer is seeking an extension
*** Gas unit retires in 2018
**** Gas unit retires in 2017

Source: Platts data, company information

Northern States Power is also still undecided on the fate of units 3 and 4 (278 MW) at its Black Dog plant in Burnsville, Minnesota, but the plant is scheduled to stop burning coal in 2015.

Duke Energy, which has a 170-MW conversion under way at its WS Lee plant in South Carolina, is evaluating conversion of the 318-MW unit 6 at its Wabash River station in Vigo County, Indiana, to burn gas, but has yet to make a decision.

Wisconsin Power & Light is still weighing whether to close the 300-MW unit 4 at its Edgewater coal plant in Sheboygin or convert it to burn gas by 2018.

And Lakeland Electric, a municipal utility in Lakeland, Florida, is holding off for now on plans to convert its 365-MW McIntosh plant to burn gas, said Rod Kremmen, the plant manager. The plant likely will be converted to burn gas at some point to give it more operational flexibility, but falling coal prices have delayed plans to make the conversion by 2015, Kremmen said. With gas at $4.10/MMBtu and coal at about $3.50/ton and likely going down to $3.20/ton, it does not make sense to convert right now, he said.

Most of the conversions are being undertaken by large companies that can finance the switch on their balance sheets or through a rate case. But some other companies are also trying to make conversions and their efforts illustrate the potential pitfalls such projects can face.

Footprint Power is converting a 750-MW coal plant Salem, Massachusetts, to a 674-MW gas plant and was on track to have the project completed by June 2016, but a last-minute environmental challenge has prompted the developer to seek a one-year extension for the project's completion date.

Rockland Capital also bought an aging coal plant and is trying to convert it to burn gas, but ran into problems when its proposed path for a gas pipeline through New Jersey's Pine Barrens was shot down. Rockland believes the BL England project is still viable and is working on resolving the problem. Meanwhile, in the second quarter it won an extension from the New Jersey Department of Environmental Protection to continue burning coal at the plant until mid-2017.

Sunbury Generation is trying to convert a 347-MW coal plant at Shamokin Dam, Pennsylvania, to a 1,000-MW gas plant. The plant stopped burning coal in June and is now trying to line up financing with the aim of having the gas plant online by June 2017, in time for PJM's 2017-2018 capacity delivery year, said David Meehan of Sunbury.

— Peter Maloney

ISO-NE told to pursue winter program ...from page 1

necessary," FERC said in its order (ER14-2407).

The approved program compensates natural-gas fired generators that become dual-fuel resources, while also providing incentives for generators to procure liquefied natural gas and oil inventory.

Filings indicate that the total cost of the program could come in at roughly $98 million.

The plan features several attributes of a similar program launched last winter to help ensure reliability, and is one of a batch of programs pursued by RTOs and others to help address gas-electric interdependency and other challenges during the coldest months. The order noted ISO-NE's finding that the program last winter "bridged the reliability gap created by the colder-than-average winter weather," noting that plants burning oil increased their production markedly during cold periods.

ISO-NE said in its proposal that it hoped several market improvements would have obviated the need to continue the out-of-market program, but retirements of non-gas resources, higher-than-expected gas pipeline constraints and difficulties in replenishing oil supplies mid-winter meant that the program should continue. ISO-NE also said that it expects some form of reliability program to be needed each winter until its pay-for-performance plan, which gives incentives for generator performance during key times, is implemented in 2018.

FERC agreed that the program "is necessary to ensure reliability this winter," despite its preference for a longer-term program, while also finding that the program as proposed will help to address ISO-NE's concerns stemming from gas-electric issues. The program "is a just and reasonable solution to help address these risks to reliability by creating incentives for market participants to provide additional reliability services (*i.e.* incremental fuel procurement, incremental demand reductions, or dual-fuel switching capabilities) which they would not have provided absent the program," FERC said.

In doing so, FERC rejected concerns that the rate paid to resources procuring LNG was too low. It also dismissed arguments that the proposal was flawed because it did not compensate all resources that offer firm fuel service, including hydropower and nuclear generation. "It would not be appropriate to make separate payments intended to incent resources to make the same fuel procurement decisions they would have made, and been compensated for, absent the program," the commission said.

Looking beyond this winter, FERC required ISO-NE to convene stakeholder meetings and provide reports back to the commission over the next year on their progress.

— Bobby McMahon