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Tuesday, July 2, 2013

Obama plan may raise coal retirement estimates

ANALYSIS While many of the points in President Barack Obama's recent energy speech may be a repackaging of existing administration initiatives, the administration's re-invigorated push on reducing greenhouse gas emissions from power plants could result in an increase in estimates of coal plant retirements.

The administration already had a GHG reduction plan under way in the form of the Environmental Protection Agency's New Source Performance Standards. And the EPA had already laid out NSPS rules for new power plants, even though the finalization of those rules had stalled. The EPA also was working on NSPS rules for existing power plants.

"What really happened in the president's speech is not that he said what he is going to do, but that he said what he is not going to do. He is not going to punt on climate change,"

(continued on page 16)

EPA mum on details of 'new' carbon rules

REGULATION The Environmental Protection Agency confirmed Monday that it has taken the next step toward implementing President Barack Obama's recently announced plan to combat climate change by curbing carbon-dioxide emissions from power plants.

In a statement, EPA said it has sent a "new proposal" to curb CO2 emissions from not-yet-built power plants to the White House Office of Management and Budget, which reviews all such regulations before they are publicly issued.

"EPA is moving forward on the president's plan to address carbon pollution from power plants using the same Clean Air Act tools that have protected Americans' health and environment from air pollution for a generation," the agency said. "As part of

(continued on page 17)

NU will keep 1,100 MW of generation in N.H.

GENERATION Northeast Utilities is balking at the idea of spinning off 1,100 MW of generation assets into an unregulated affiliate, despite a recommendation to do so by New Hampshire regulatory staff.

NU subsidiary Public Service of New Hampshire rejected the idea Friday, saying it has no interest in re-entering the competitive generation business after exiting it in 2005.

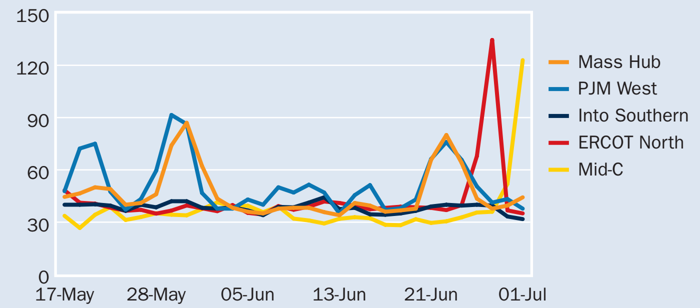
The utility wants to continue owning the portfolio as a regulated asset.

However, competitive generators and environmentalists are pressing for the utility to sell or spin-off the plants. Mostly coal-fired generation and hydro, the portfolio is among the last utility-owned generation in the restructured New England states.

Staff of the Public Utilities Commission last month

(continued on page 18)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Jul 2 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	39.82	42.38	27.01	28.82
NYISO	36.90	74.24	26.40	39.94
PJM	35.10	46.10	21.69	27.36
MISO	28.07	34.41	20.33	22.41
ERCOT	36.50	50.26	24.66	25.58
CAISO	79.17	94.03	33.47	38.62

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 Jul 2

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	44.25	11737	17.86	14.09	6.55	-0.99	-12.30
N.Y. Zone-A	37.00	10931	13.31	9.92	3.15	-3.62	-13.78
PJM/MISO							
PJM West	37.75	11503	14.78	11.50	4.93	-1.63	-11.48
Indiana Hub	33.00	9244	8.01	4.44	-2.70	-9.84	-20.55
Southeast & Central							
Southern, Into	31.75	9071	7.25	3.75	-3.25	-10.25	-20.75
ERCOT, North	35.02	10180	10.94	7.50	0.62	-6.26	-16.58
West							
Mid-C	122.96	73519	111.25	109.58	106.24	102.89	97.87
SP15	100.00	26178	73.26	69.44	61.80	54.16	42.70

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

NORTHEAST MARKETS

Dailies rise on steady demand

Daily power prices in the Northeast edged up Monday with demand expected to be fairly steady and spot natural gas prices higher. Forward prices were mainly down while the NYMEX August natural gas futures contract settled at $3.577/MMBtu Monday, 1.2 cents higher than Friday's close.

ISO New England forecasted peak load on Monday near 21,700 MW and 21,430 MW Tuesday. High temperatures for Boston are forecast in the upper 70s Tuesday.

Algonquin city-gates spot natural gas added about 11 cents, going to $3.74/MMBtu and Transco Zone 6 New York was up 5 cents to $3.65/MMBtu.

Mass Hub on-peak for Tuesday gained $4, going to the mid-$40s/MWh, as off-peak edged up slightly into the low $30s/MWh.

The New York ISO projected peak load for Monday at 25,669 MW and 26,552 MW Tuesday. High temperatures in New York state are forecast in the upper 70s on Tuesday.

New York Zone A peak for Tuesday was steady in the upper $30s/MWh. New York Zone G peak edged up about $2.50 to the upper $40s/MWh.

Day-ahead auction prices in ISO-NE peeled back Monday as demand was expected to ease a bit. Internal Hub peak was off more than $9, clearing around $41.57/MWh, while off-peak fell $2.13 to $28.56/MWh.

Connecticut peak lost more than $9 to $42.38/MWh, as off-peak was down $2.15 to $28.82/MWh. Maine peak gave up $8.18, clearing at $39.82/MWh, while off-peak decreased $1.75 to $27.01/MWh. Vermont peak gave up $9.21, clearing at $41.90/MWh, as off-peak was down $1.90 to $28.73/MWh.

Day-ahead auction prices in NYISO were mostly up Monday, with demand expected to move up slightly. Long Island was the exception, as peak dropped $22.87 to $74.24/MWh and off-peak fell $3.61 to $39.94/MWh.

Hudson Valley peak was up nearly $1 to just more than $48/MWh, as off-peak was up 29 cents to $30.62/MWh. New York City peak gained $1.80 to $52.39/MWh, as off-peak was 35 cents higher to $31.57/MWh. West zone peak added $1.20 to $36.90/MWh, while off-peak moved up 33 cents to $27.43/MWh.

Northeast term power prices mostly weakened Monday despite a small rise in natural gas futures. Mass Hub on-peak August financial futures slipped 50 cents, with bids at $50.75/MWh and offers at $51.50/MWh on the IntercontinentalExchange at about 2:30 p.m. EDT. Mass Hub fourth-quarter slipped 10 cents to $51.65/MWh and January-February futures dropped 75 cents to $43.25/MWh.

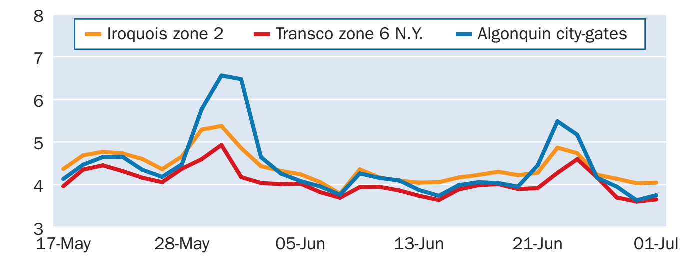
In New York, the market was focused on the west. New York Zone-A on-peak August financial futures moved down 25 cents to $45.50/MWh on ICE. Zone A Q4 came off 25 cents to $38.90/MWh and January-February futures were unchanged at about $43.25/MWh.

Northeast day-ahead bilateral indexes for Jul 2 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	44.25	4.75	41.88	11737
N.Y. Zone-G	48.00	2.50	46.75	12476
N.Y. Zone-J	52.50	3.25	50.88	13645
N.Y. Zone-A	37.00	0.00	37.00	10931
Ontario*	28.00	0.00	28.00	6735
Off-Peak				
Mass Hub	30.50	1.00	30.00	8090
N.Y. Zone-G	30.75	0.50	30.50	7992
N.Y. Zone-J	31.50	-0.25	31.63	8187
N.Y. Zone-A	27.50	0.50	27.25	8124
Ontario*	20.50	0.50	20.25	4931

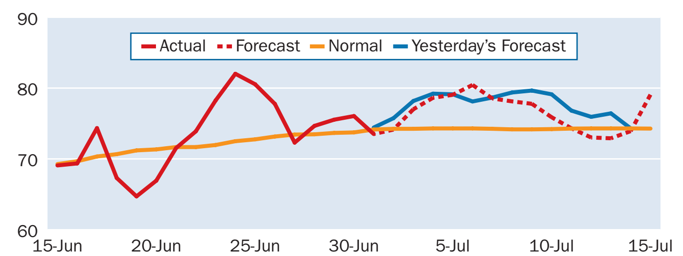
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO average temperature (°F)



Source: Custom Weather

Northeast load and generation mix forecast (GWh)

	Actual 30-Jun	%Chg	% Chg Year-ago	Forecast 01-Jul	02-Jul	03-Jul	04-Jul	05-Jul
ISONE								
Load	396	2	2	382	397	424	452	456
Generation								
Coal	17	-2	39	15	15	18	20	23
Gas	167	8	-8	169	173	180	187	191
Nuclear	111	0	-7	111	111	111	111	111
NYISO								
Load	487	-1	1	530	526	543	556	557
Generation								
Coal	21	-2	86	21	26	31	34	35
Gas	193	3	-11	213	208	209	214	216
Nuclear	135	0	9	134	135	135	135	135

Source: Bentek

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ISONE day-ahead LMP for Jul 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	41.57	0.00	-0.04	-9.18	46.16	11180
Connecticut	42.38	0.00	0.77	-9.12	46.94	10940
NE Mass-Boston	41.57	0.00	-0.04	-9.06	46.10	11180
SE Mass	41.23	0.00	-0.38	-8.84	45.65	11090
West-Central Mass	41.85	0.00	0.25	-9.12	46.41	11258
Rhode Island	40.83	0.00	-0.78	-8.58	45.12	10982
Maine	39.82	0.00	-1.79	-8.18	43.91	9950
New Hampshire	41.57	0.00	-0.04	-9.17	46.16	10387
Vermont	41.90	0.00	0.29	-9.21	46.51	10470
Off-Peak						
Internal Hub	28.56	0.00	0.10	-2.13	29.63	7837
Connecticut	28.82	0.00	0.36	-2.15	29.90	7509
NE Mass-Boston	28.43	0.00	-0.04	-2.18	29.52	7799
SE Mass	28.39	0.00	-0.08	-2.12	29.45	7788
West-Central Mass	28.76	0.00	0.30	-2.13	29.83	7892
Rhode Island	28.50	0.00	0.04	-1.94	29.47	7821
Maine	27.01	0.00	-1.46	-1.74	27.88	6780
New Hampshire	28.35	0.00	-0.12	-1.88	29.29	7116
Vermont	28.73	0.00	0.27	-1.90	29.68	7213

NYISO day-ahead LMP for Jul 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	42.67	-0.23	2.53	2.66	41.34	11460
Central Zone	40.16	-0.15	0.10	1.57	39.38	11864
Dunwoodie Zone	49.16	-4.31	4.94	1.14	48.59	12783
Genesee Zone	38.49	-0.02	-1.43	1.38	37.80	11371
Hudson Valley Zone	48.06	-3.32	4.83	0.96	47.58	12497
Long Island Zone	74.24	-28.21	6.13	-22.87	85.68	19306
Millwood Zone	49.08	-4.21	4.97	1.13	48.52	12764
Mohawk Valley Zone	41.68	-0.34	1.44	1.70	40.83	11706
N.Y.C. Zone	52.39	-7.17	5.32	1.79	51.50	13624
North Zone	37.80	0.00	-2.10	1.26	37.17	9445
West Zone	36.90	-0.02	-3.03	1.20	36.30	10902
Off-Peak						
Capital Zone	29.50	0.00	1.72	0.22	29.39	7973
Central Zone	28.05	0.00	0.26	0.30	27.90	8318
Dunwoodie Zone	30.71	0.00	2.92	0.29	30.57	8041
Genesee Zone	27.62	0.00	-0.16	0.33	27.46	8192
Hudson Valley Zone	30.62	0.00	2.83	0.29	30.48	8016
Long Island Zone	39.94	-8.37	3.78	-3.61	41.75	10457
Millwood Zone	30.68	0.00	2.89	0.30	30.53	8032
Mohawk Valley Zone	28.59	0.00	0.80	0.37	28.41	8088
N.Y.C. Zone	31.57	-0.56	3.22	0.35	31.40	8265
North Zone	26.40	0.00	-1.39	0.14	26.33	6628
West Zone	27.43	0.00	-0.36	0.33	27.27	8134

Generation unit outage report

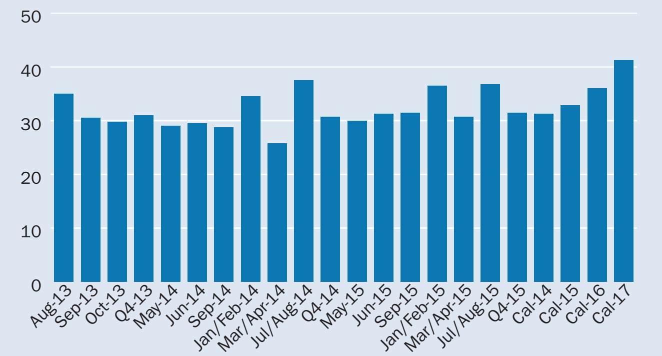
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-8/Bruce	822	n	Ont.	Unk	Unk	06/28/13
Pickering-1/OPG	500	n	Ont	MO	Unk	06/07/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13

Northeast Platts-ICE Forward Curve, Jul 1 ($/MWh)

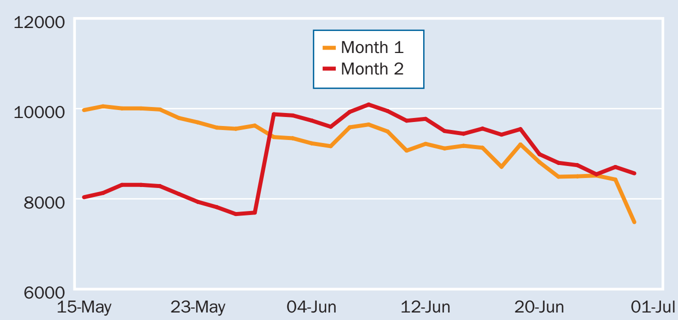
Prompt month: Aug 13	On-peak	Off-peak
Mass Hub	51.25	34.50
N.Y. Zone G	60.50	39.50
N.Y. Zone J	66.50	42.50
N.Y. Zone A	45.50	32.75
Ontario*	35.00	23.75

*Ontario prices are in Canadian dollars

Ontario*: Forward curve on-peak ($/MWh)



Ontario*: Marginal heat rate on-peak (Btu/kWh)



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Bal-week	06/28	42.00-44.00
Next-week	06/28	54.50-56.50

*Ontario prices are in Canadian dollars.

Daily generation outage references

MO	unplanned maintenance outage	RF	refueling outage
PMO	planned maintenance outage	Unk	unknown
OA	offline/available		

Fuels: Nuclear=n; Coal=c; Natural gas=g; Hydro=h ; Wind=w

Sources: Generation owners, public information and other market sources.

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SOUTHEAST MARKETS

ERCOT dailies down on lower temperatures

Daily power prices in the Electric Reliability Council of Texas came down Monday with lower temperatures and demand. Forward prices were mixed while the NYMEX August natural gas futures contract settled at $3.577/MMBtu Monday, 1.2 cents higher than Friday's close.

ERCOT North Hub next-day on-peak physical power fell $1.75 to trade between $35 and $35.75/MWh for Tuesday delivery on IntercontinentalExchange.

Spot natural gas at Houston Ship Channel slipped fell about 11 cents to $3.494/MMBtu on ICE. High temperatures across the ERCOT region were forecast slip from the 90s into the 80s in Houston and Dallas.

System load in ERCOT was forecast to peak at 54,649 MW Tuesday, down about 10,000 MW from the end of last week.

Wind generation was forecast to peak near 2,300 MW wround 5 p.m. CDT Monday and about 2,700 MW late Tuesday night. ERCOT expects wind generation to drop to about 800 MW mid-day Monday and Tuesday.

North Hub bal-week on-peak futures traded at $35.50 and $36.25/MWh on ICE, nearly level with dailies. North Hub Next-week on-peak futures traded at $41 and $43/MWh.

In the Southeast, dailies dropped Monday with cooler weather in the region. Into Southern next-day on-peak power markets dropped more than $7 to about $32/MWh for Tuesday delivery on ICE.

Spot natural gas at Transco Zone-3 slipped 1.5 cents to about $3.49/MMBtu on ICE. High temperatures in Atlanta were forecast to stay in the low-80s until the holiday, remaining more than 5 degrees below the seasonal average.

ERCOT day-ahead auction clearing prices were mixed Monday with prices already down for the weekend after last week's heat and high prices. The West Zone remained the highest priced on-peak settlement point moving up 96 cents to $50.26/MWh for Tuesday delivery. Congestion remained substantial, with West Hub clearing at an average of $37.63/MWh for on-peak hours.

The North Hub on-peak average rose 93 cents to $36.50/MWh

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for Jul 2 ($/MWh)

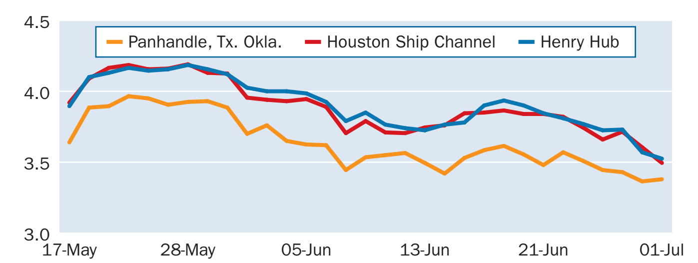
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	33.25	-2.50	34.50	9185
Southern, Into	31.75	-1.50	32.50	9071
Florida	33.00	1.50	32.25	8250
TVA, Into	32.00	-2.50	33.25	9008
Entergy, Into	34.00	-3.00	35.50	9749
Southeast Off-Peak				
VACAR	24.00	1.75	23.13	6630
Southern, Into	23.75	2.75	22.38	6786
Florida	24.00	-1.50	24.75	6000
TVA, Into	23.25	2.00	22.25	6545
Entergy, Into	22.00	2.25	20.88	6308
ERCOT On-peak				
ERCOT, North	35.02	-1.73	35.89	10180
ERCOT, Houston	36.50	-6.75	39.88	10466
ERCOT, South	36.00	-7.00	39.50	10435
ERCOT, West	35.00	-2.75	36.38	10167
ERCOT Off-Peak				
ERCOT, North	24.25	0.75	23.88	7049
ERCOT, Houston	24.50	1.00	24.00	7025
ERCOT, South	24.50	1.00	24.00	7101
ERCOT, West	24.25	1.25	23.63	7044
SPP/MRO On-peak				
MAPP, South	33.00	-4.25	35.13	9270
SPP, North	32.00	-6.75	35.38	9467
SPP/MRO Off-Peak				
MAPP, South	20.50	0.75	20.13	5758
SPP, North	21.50	1.25	20.88	6361

Southeast load and generation mix forecast (GWh)

	Actual 30-Jun	%Chg	% Chg Year-ago	Forecast 01-Jul	02-Jul	03-Jul	04-Jul	05-Jul
ERCOT								
Load	1045	-10	0	940	947	958	976	996
Generation								
Coal	365	-14	18	352	371	386	400	413
Gas	533	-6	-14	437	378	360	373	396
Nuclear	123	0	-3	123	123	123	123	123
SPP								
Load	694	-5	-5	662	652	638	655	677
Generation								
Coal	416	-4	13	408	413	420	427	436
Gas	182	-8	-29	159	145	140	150	168
Nuclear	47	17	-4	48	49	49	49	49

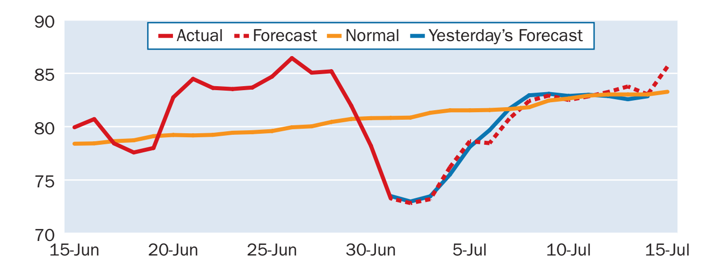
Source: Bentek

Southeast & Central spot natural gas prices ($/MMBtu)



Source: Platts

ERCOT & SPP average temperature (°F)



Source: Custom Weather

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ERCOT average day-ahead LMP for Jul 2 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	36.98	0.32	36.82	10681
Hub Average	37.33	-0.02	37.34	10782
Houston Hub	38.00	-1.19	38.60	10853
North Hub	36.50	0.93	36.04	10602
South Hub	37.20	-0.16	37.28	10756
West Hub	37.63	0.34	37.46	10915
AEN Zone	38.52	0.36	38.34	11175
CPS Zone	38.06	-0.49	38.31	11019
LCRA Zone	37.65	-0.13	37.72	10900
Rayburn Zone	36.58	0.98	36.09	10625
Houston Zone	38.16	-1.14	38.73	10898
North Zone	36.54	0.90	36.09	10615
South Zone	38.60	-1.55	39.38	11160
West Zone	50.26	0.96	49.78	14580
Off-Peak				
Bus Average	24.68	-1.82	25.59	7065
Hub Average	24.71	-1.83	25.63	7072
Houston Hub	24.70	-1.98	25.69	6918
North Hub	24.66	-1.78	25.55	7136
South Hub	24.69	-1.81	25.60	7074
West Hub	24.78	-1.75	25.66	7160
AEN Zone	24.82	-1.81	25.73	7174
CPS Zone	24.82	-1.97	25.81	7169
LCRA Zone	24.76	-1.82	25.67	7151
Rayburn Zone	24.66	-1.78	25.55	7136
Houston Zone	24.70	-2.00	25.70	6919
North Zone	24.66	-1.78	25.55	7136
South Zone	24.73	-1.92	25.69	7085
West Zone	25.58	-1.57	26.37	7393

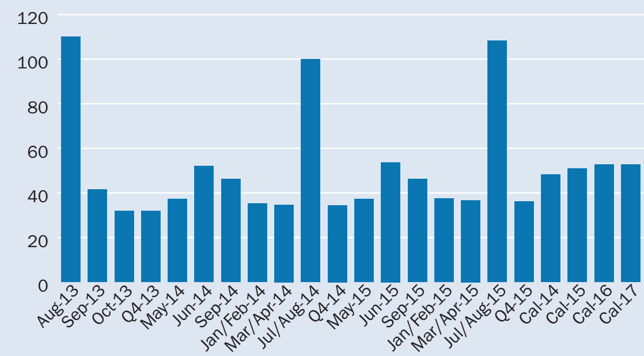
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	06/25	38.00-38.50
Bal-month	06/25	38.00-38.50
Next-week	06/25	39.00-39.50
ERCOT, North		
Bal-week	06/25	78.00-80.00
Bal-month	06/27	62.00-85.00
Bal-month (off-peak)	06/26	23.50-24.50
Next-week	07/01	41.00-43.00
Next-week	06/27	38.75-39.25
ERCOT, Houston		
Bal-week	06/25	80.50-83.00

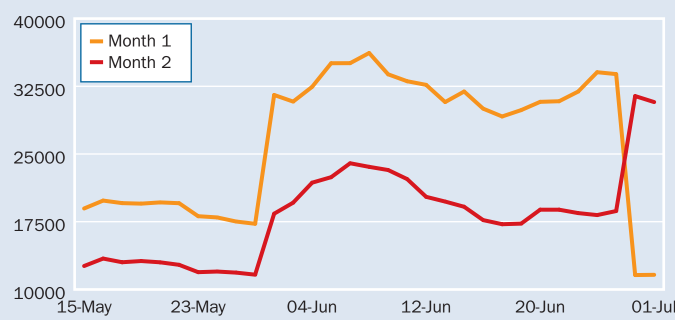
Southeast & Central Platts-ICE Forward Curve, Jul 1 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
Southern Into	37.00	28.50
Entergy Into	36.25	26.25
ERCOT North	107.00	31.25
ERCOT Houston	106.25	31.25
ERCOT West	110.00	31.25
ERCOT South	106.75	32.25

ERCOT West: Forward curve on-peak ($/MWh)



ERCOT West: Marginal heat rate on-peak (Btu/kWh)



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
Arkansas-1/Entergy	903	n	Ark.	PMO	08/01/13	03/25/13
Bowen-1/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Crystal River-3/Progress	838	n	Fla.	NA	Retired	09/26/09
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13

Holiday notice

Megawatt Daily will not publish Thursday, July 4, because of the Independence Day holiday. Assessments based on electricity trading Wednesday, July 3, will be published in the Friday, July 5, issue. Flows dates for power traded Wednesday vary among markets and will be specified in published tables.

Additional information on data and analysis:

For more information on data and analysis from Bentek Analytics, including five-day load and generation mix forecasts and relative load normalized by temperature, email power@bentekenergy.com, or call 303-988-1320. Average on-peak and off-peak LMP and marginal heat-rate data is available via Platts Market Data. More detailed, hourly LMP and marginal heat-rate data is available from Bentek Analytics.

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WEST MARKETS

Dailies surge; terms also gain ground

Most western dailies were up sharply Monday morning with continuing high temperatures, a lingering nuclear outage, and greater demand expected in California on Tuesday. Terms spiked, and the NYMEX August natural gas futures contract posted a preliminary settlement price of $3.577/MMBtu, 1.2 cents higher than on Friday.

SP15 next-day on-peak added around $28.75 to trade between $92 and $120/MWh. SP15 day-ahead off-peak was down $11.50 to about $36.50/MWh. SP15 bal-month was bid at $55 and offered at $60/MWh, an increase of around $3.50. NP15 day-ahead on-peak was up more than $34.75 to trade between $100 and $130/MWh. NP15 day-ahead off-peak gained $3.25 to about $38/MWh. NP15 bal-month was bid at $51.75 and offered at $57/MWh, up more than $5.25.

Amid the persistently hot temperatures and ongoing Diablo Canyon-1 nuclear outage so a leaking reactor weld could be repaired, the California Independent System Operator urged power conservation in Northern California on Monday.

Sacramento, California, expected highs near 110 Tuesday, about 15 degrees above normal, and lows around 75. Forecasts for Burbank were cooler, with highs in the low 90s and lows around 70 on Tuesday.

Cal-ISO projected peak demand to hit 46,119 MW on Monday and 47,922 MW on Tuesday. Renewables were 3,082 MW and wind was about 1,100 MW at 7 a.m. PDT on Monday.

In the desert Southwest, Palo Verde next-day on-peak was up about $37 to trade between $110 and $130/MWh. Palo Verde day-ahead off-peak was down about $6 to trade between $21 and $23.75/MWh.

Phoenix expected highs approaching 110 Tuesday, down about five degrees from the weekend, and lows in the low 90s.

In the Northwest, Mid-Columbia day-ahead on-peak was up about $14.50 to trade between $60 and $165/MWh for delivery on Tuesday. Mid-C day-ahead off-peak was down more than $1.50 to trade between $10.25 and $14.25/MWh on IntercontinentalExchange. The Mid C on-peak balance-of-the month package traded between $44 and 46.50/MWh, up about $4.75. Portland, Oregon's forecast highs were near 95, more than 15 degrees above normal, and expected lows were around 66 through Tuesday.

The Bonneville Power Administration's wind at 7 a.m. PDT Monday was 400 MW and its hydropower was 12,464 MW.

Next day natural gas prices rose in the Rockies and California. Opal was up 3.6 cents to $3.404/MMBtu, PG&E city-gate added 19.1 cents to $3.921/MMBtu, and SoCal city-gate gained 10.6 cents to $3.966/MMBtu.

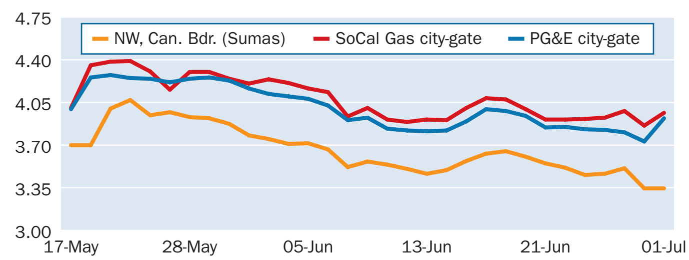
Day-ahead on-peak prices were down in the California Indepdent System Operator auction Monday afternoon. SP15 on-peak fell $6.07 to $81.87/MWh and SP15 off-peak dropped $1.31 to $33.85/MWh. NP15 on-peak lost $5.97 to $94.03/MWh

(continued on page 10)

Western day-ahead bilateral indexes for Jul 2 ($/MWh)

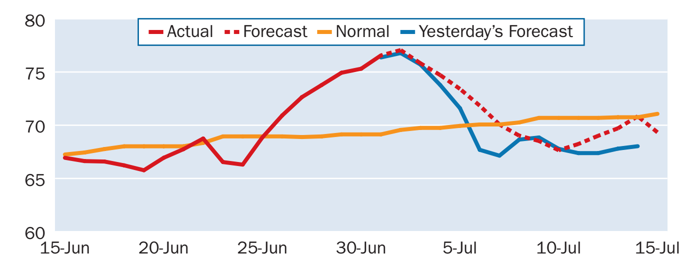
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	148.78	84.02	106.77	43125
Mid-C	122.96	70.98	87.47	73519
Palo Verde	122.33	39.55	102.56	33653
Mead	145.75	56.50	117.50	38154
Mona	115.00	31.50	99.25	33923
Four Corners	120.71	35.46	102.98	34988
NP15	108.00	35.00	90.50	27551
SP15	100.00	24.00	88.00	26178
Off-Peak				
COB	17.18	-1.55	17.96	4980
Mid-C	12.07	-1.30	12.72	7217
Palo Verde	23.25	-5.75	26.13	6396
Mead	27.75	-6.00	30.75	7264
Mona	25.00	2.50	23.75	7375
Four Corners	26.50	-1.11	27.06	7681
NP15	37.75	3.00	36.25	9630
SP15	36.50	-11.50	42.25	9555

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO average temperature (°F)



Source: Custom Weather

Western load and generation mix forecast (GWh)

	Actual 30-Jun	%Chg	% Chg Year-ago	Forecast 01-Jul	02-Jul	03-Jul	04-Jul	05-Jul
CAISO								
Load	812	-3	2	833	867	864	867	842
Generation								
Gas	331	4	3	304	342	372	381	369
Nuclear	28	0	-7	28	29	33	41	48

Source: Bentek

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CAISO average day-ahead LMP for Jul 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	94.03	9.75	-1.04	3.03	92.52	23956
SP15 Gen Hub	81.87	1.77	-5.21	-6.07	84.91	21404
ZP26 Gen Hub	79.17	-1.21	-4.93	-3.03	80.69	20699
Off-Peak						
NP15 Gen Hub	38.62	4.42	-0.69	-1.72	39.48	10221
SP15 Gen Hub	33.85	0.05	-1.09	-1.31	34.51	9117
ZP26 Gen Hub	33.47	-0.08	-1.35	-1.13	34.04	9014

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	07/01	44.00-45.00
Bal-month	06/28	40.00-41.00
Bal-month	06/25	36.75-37.25
Bal-month (off-peak)	06/25	21.50-23.00
Next-week	06/26	46.00-47.00

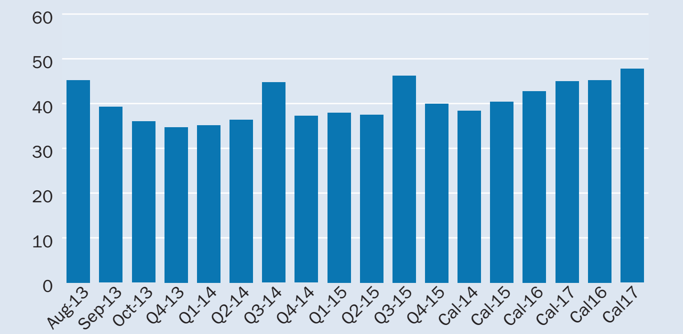
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Contra Costa-6/NRG	337	g	Calif.	MO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
Diablo Canyon-1/PG&E	1150	n	Calif.	PMO	Unk	06/26/13
Huntington Beach-3/AES	225	g	Calif	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif	PMO	Unk	04/14/13
Los Esteros/Calpine	188	g	Calif.	PMO	Unk	05/27/13
Mexcali/Sempra	180	g	Calif.	MO	Unk	05/02/13
Ocotillo/Pattern	265	w	Calif.	MO	Unk	05/16/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12
Tracy/Highstar	332	g	Calif.	MO	Unk	06/30/13

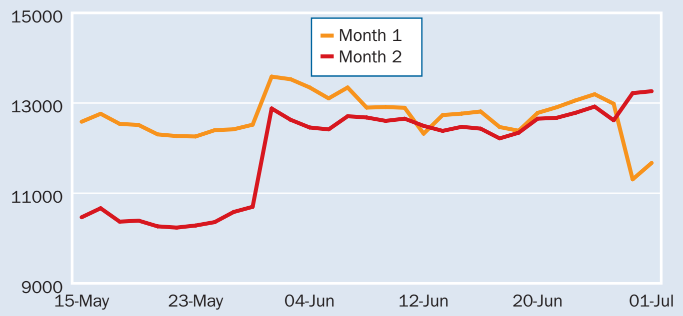
Western Platts-ICE Forward Curve, Jul 1 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
Mid-C	45.75	31.75
Palo Verde	45.25	28.75
Mead	47.50	30.50
NP15	52.50	36.75
SP15	56.75	38.00

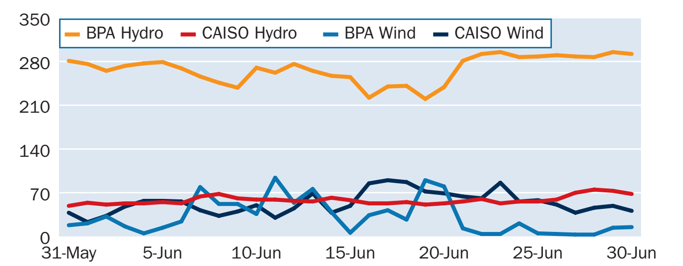
Palo Verde: Forward curve on-peak ($/MWh)



Palo Verde: Marginal heat rate on-peak (Btu/kWh)



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

Market coverage

Platts provides a detailed methodology related to its coverage of North American electricity markets at: http://platts.com/MethodologyAndSpecifications/ElectricPower. Questions can be directed to Mike Wilczek, Market Editor, (202) 383-2246, Mike_Wilczek@platts.com.

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PJM & MISO MARKETS

Dailies retreat despite demand, spot gas gains

Daily power prices in the Mid-Atlantic and Midwest dipped Monday, even with peak demand expected to creep up a bit and spot natural gas edging higher. Forward prices were down while the NYMEX August natural gas futures contract settled at $3.577/MMBtu Monday, 1.2 cents higher than Friday's close.

PJM Interconnection forecasted peak demand for Monday at 118,014 MW and 118,857 MW Tuesday. High temperatures across the PJM region are expected to be in low 70s to low 80s Tuesday.

Spot gas in the region gained about 4 cents, with Texas Eastern M-3 at $3.48/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Tuesday fell about $5, going to the upper $30s/MWh, as off-peak was down slightly, staying in the mid-$20s/MWh.

Daily prices in the Midcontinent ISO peeled back even as regional spot gas remained firm. Chicago city-gates spot gas added about 1 cent to reach $3.59/MMBtu.

Indiana Hub peak was down about $5, going to the low $30s/MWh, as off-peak moved down slightly in the low $20s/MWh.

Dailies in the Midwestern portion of PJM eased with the nearby markets peeling back. AEP-Dayton Hub peak was down about $3 to the mid-$30s/MWh, with off-peak steady in the mid-$20s/MWh. Northern Illinois Hub peak fell about $2.50, going to the low $30s/MWh, as off-peak edged down $1 to $19/MWh.

Day-ahead auction prices in PJM were mostly higher Monday, with steady demand in the outlook. BG&E peak was the exception, going down $1.63 to $45.21/MWh, while off-peak edged up 45 cents to $26.96/MWh. Pepco peak added 87 cents, going to $43.42/MWh, as off-peak was 51 cents higher, reaching $26.58/MWh.

Western Hub peak jumped more than $3 to $41.19/MWh, while Eastern Hub peak added $2.72 to $46.10/MWh. ATSI zone peak was up $5.17 to $40.25/MWh and ATSI Gen Hub peak was up $5.03 to $40.01/MWh. PSEG peak added $1.65, going to $45.07/MWh and JCPL was up $2.58 to $44.60/MWh. Chicago Hub peak added $3.75 to $35.87/MWh and ComEd peak gained $3.76 to $35.78/MWh.

MISO day-ahead auction clearing prices moved down Monday for on-peak hours. The Indiana Hub on-peak average fell $5.53 to $29.29/MWh for Tuesday delivery and the Indiana Hub off-peak average slipped 16 cents to $22.01/MWh. Illinois Hub on-peak average fell $3.14 to $28.07/MWh and the Michigan Hub on-peak average moved down $2.83 to $30.23/MWh. The Minnesota Hub on-peak average dropped $3.07 to $34.41/MWh.

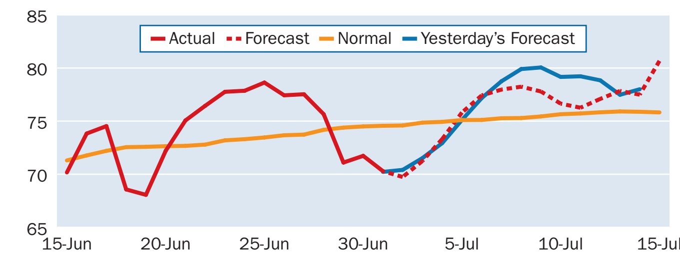
Mid-Atlantic forward prices slipped Monday even as natural gas futures moved up. PJM West on-peak August financial futures fell 25 cents, with bids at $53.50/MWh and offers at $53.80/MWh on ICE at about 2:30 p.m. EDT. PJM West on-peak fourth-quarter was steady at about $40.85/MWh and January-February futures were unchanged at $44.25/MWh.

Midwest May forwards moved down Monday with weaker

PJM & MISO day-ahead bilateral indexes for Jul 2 ($/MWh)

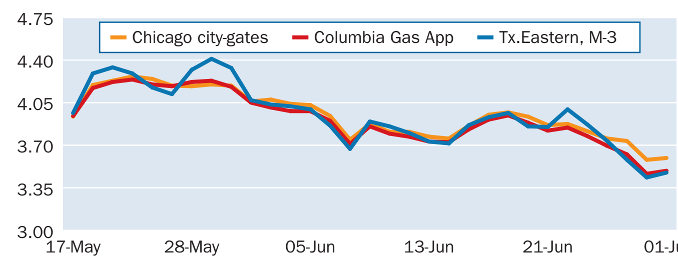
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	37.75	-5.50	40.50	11503
Dominion Hub	37.50	-6.00	40.50	10549
AD Hub	34.50	-3.00	36.00	9031
NI Hub	31.75	-2.25	32.88	8832
PJM Off-Peak				
PJM West	25.00	-1.00	25.50	7618
Dominion Hub	24.75	-1.00	25.25	6962
AD Hub	24.75	0.75	24.38	6479
NI Hub	19.00	-1.00	19.50	5285
MISO On-peak				
Indiana Hub	33.00	-5.00	35.50	9244
Michigan Hub	31.00	-3.00	32.50	8300
Minnesota Hub	35.00	3.50	33.25	9504
Illinois Hub	29.00	-6.50	32.25	8072
MISO Off-Peak				
Indiana Hub	22.00	0.00	22.00	6162
Michigan Hub	22.50	-0.50	22.75	6024
Minnesota Hub	21.00	0.00	21.00	5703
Illinois Hub	20.50	-1.75	21.38	5706

PJM & MISO average temperature (°F)



Source: Custom Weather

PJM & MISO spot natural gas prices ($/MMBtu)



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 30-Jun	%Chg	% Chg Year-ago	Forecast 01-Jul	02-Jul	03-Jul	04-Jul	05-Jul
PJM								
Load	2136	-2	2	2120	2276	2367	2441	2502
Generation								
Coal	1023	-2	13	984	1034	1085	1129	1159
Gas	287	-1	-22	310	365	398	407	406
Nuclear	750	-2	1	750	750	750	750	750
MISO								
Load	1224	-5	0	1418	1426	1421	1467	1503
Generation								
Coal	1043	-5	9	1184	1221	1214	1215	1234
Gas	38	1	-45	72	98	113	129	133
Nuclear	193	0	-11	193	193	193	193	193

Source: Bentek

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MISO average day-ahead LMP for Jul 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	29.29	-1.36	-0.09	-5.53	32.06	8204
Michigan Hub	30.23	-1.14	0.63	-2.83	31.65	8095
Minnesota Hub	34.41	3.33	0.34	-3.07	35.95	9335
Illinois Hub	28.07	-1.72	-0.94	-3.14	29.64	7809
Off-Peak						
Indiana Hub	22.01	0.30	0.26	-0.16	22.09	6218
Michigan Hub	22.41	0.23	0.73	-0.30	22.56	6038
Minnesota Hub	20.86	-0.17	-0.42	0.37	20.68	5677
Illinois Hub	20.33	-0.62	-0.51	-0.35	20.51	5685

PJM & MISO near-term bilateral markets ($/MWh)

Package	Trade date	Range
PJM West		
Bal-week	06/28	43.00-45.00
Bal-week	06/25	51.25-52.25
Bal-month	07/01	56.00-57.00
Bal-month	06/27	55.00-56.00
Bal-month (off-peak)	06/27	32.00-33.00
Next-week	07/01	60.00-62.00
Next-week	06/28	57.00-59.00
Next-week	06/27	43.50-44.50
Next-week	06/25	44.00-45.00
NI Hub		
Bal-week	06/28	35.00-36.00
Next-week	06/28	47.00-49.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Braidwood-2/Exelon	1166	n	Ill.	MO	Unk	06/28/13
Davis-Besse/FirstEnergy	971	n	Ohio	MO	Unk	06/29/13
Kewaunee/Dominion	581	n	Wis.	NA	Retired	05/07/13
Monticello/Xcel	666	n	Minn.	PMO	07/03/13	03/02/13

PJM average day-ahead LMP for Jul 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	36.55	-1.65	-2.38	3.68	34.71	10379
AEP-Dayton Hub	37.95	-1.49	-1.13	3.70	36.10	10779
ATSI Gen Hub	40.01	-0.83	0.26	5.03	37.50	11674
Chicago Gen Hub	35.10	-3.39	-2.09	3.65	33.28	9756
Chicago Hub	35.87	-3.15	-1.55	3.75	34.00	9971
Dominion Hub	40.97	0.77	-0.38	3.76	39.09	11518
Eastern Hub	46.10	3.07	2.46	2.72	44.74	13012
New Jersy Hub	44.73	2.44	1.72	2.01	43.73	12628
Northern Illinios Hub	35.51	-3.28	-1.78	3.67	33.68	9872
Ohio Hub	38.19	-1.47	-0.91	3.69	36.35	10634
West Internal Hub	39.83	-0.24	-0.51	4.63	37.52	12139
Western Hub	41.19	0.40	0.22	3.05	39.67	12556
AEP Zone	38.09	-1.42	-1.07	3.80	36.19	10816
Allegheny Power Zone	39.35	-0.73	-0.50	3.85	37.43	11422
Atlantic Elec Zone	44.45	1.86	2.02	2.22	43.34	12548
ATSI Zone	40.25	-0.79	0.47	5.17	37.67	11745
BG&E Zone	45.21	2.82	1.82	-1.63	46.03	13323
ComEd Zone	35.78	-3.20	-1.59	3.76	33.90	9947
Dayton P&L Zone	38.53	-1.54	-0.50	4.18	36.44	10792
Delmarva P&L Zone	45.93	3.22	2.13	2.79	44.54	12964
Dominion Zone	41.51	0.91	0.02	3.71	39.66	11671
Duke Zone	36.87	-1.44	-2.27	3.72	35.01	10327
Duquesne Light Zone	37.84	-1.26	-1.47	4.47	35.61	11529
JCPL Zone	44.60	2.46	1.57	2.58	43.31	12591
MetEd Zone	42.99	2.11	0.31	2.05	41.97	12200
PECO Zone	43.45	1.87	1.00	1.79	42.56	12329
Pennsylvania Elec Zone	41.51	-0.03	0.96	4.14	39.44	12567
PEPCO Zone	43.42	1.80	1.05	0.87	42.99	12798
PPL Zone	42.45	1.73	0.15	1.03	41.94	12046
PSEG Zone	45.07	2.65	1.85	1.65	44.25	12723
Rockland Elec Zone	45.10	2.61	1.91	1.47	44.37	12730
Off-Peak						
AEP Gen Hub	24.47	0.09	-1.25	0.38	24.28	6995
AEP-Dayton Hub	25.23	0.34	-0.74	0.25	25.11	7211
ATSI Gen Hub	26.01	0.31	0.07	0.55	25.74	7627
Chicago Gen Hub	21.69	-2.37	-1.57	1.20	21.09	6055
Chicago Hub	22.11	-2.22	-1.30	1.11	21.56	6171
Dominion Hub	26.08	0.43	0.02	0.61	25.78	7345
Eastern Hub	27.24	0.39	1.22	0.46	27.01	7754
New Jersy Hub	27.18	0.36	1.19	0.19	27.09	7738
Northern Illinios Hub	21.88	-2.35	-1.40	1.10	21.33	6108
Ohio Hub	25.37	0.42	-0.68	0.19	25.28	7112
West Internal Hub	25.74	0.30	-0.18	0.55	25.47	7882
Western Hub	26.24	0.32	0.30	0.64	25.92	8036
AEP Zone	25.29	0.30	-0.64	0.33	25.13	7229
Allegheny Power Zone	25.86	0.27	-0.04	0.51	25.61	7554
Atlantic Elec Zone	27.10	0.33	1.14	0.31	26.95	7715
ATSI Zone	26.07	0.29	0.15	0.59	25.78	7646
BG&E Zone	26.96	0.34	0.99	0.45	26.74	7996
ComEd Zone	22.03	-2.27	-1.32	1.14	21.46	6150
Dayton P&L Zone	25.23	0.13	-0.52	0.47	25.00	7128
Delmarva P&L Zone	27.12	0.39	1.10	0.44	26.90	7721
Dominion Zone	26.24	0.40	0.20	0.58	25.95	7388
Duke Zone	24.33	0.08	-1.38	0.38	24.14	6874
Duquesne Light Zone	25.18	0.23	-0.68	0.53	24.92	7706
JCPL Zone	27.04	0.33	1.08	0.35	26.87	7698
MetEd Zone	26.44	0.34	0.47	0.35	26.27	7559
PECO Zone	26.73	0.33	0.77	0.28	26.59	7642
Pennsylvania Elec Zone	26.74	0.32	0.79	0.65	26.42	8160
PEPCO Zone	26.58	0.34	0.62	0.51	26.33	7884
PPL Zone	26.30	0.30	0.37	0.32	26.14	7519
PSEG Zone	27.36	0.41	1.33	0.04	27.34	7790
Rockland Elec Zone	27.34	0.40	1.31	-0.02	27.35	7783

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prices to the east. Indiana Hub on-peak August financial futures came off about 25 cents, with bids at $44.25/MWh and offers at $45.75/MWh. Indiana Hub on-peak fourth-quarter was unchanged at $34.15/MWh. AD Hub on-peak August financial futures fell 25 cents, with bids at $47.75/MWh and offers at $48.50/MWh. AD Hub on-peak fourth-quarter was unchanged at $37.25/MWh and January-February futures held at about $39/MWh.

Southeast markets ... *from page 4*

and the North Zone on-peak average rose 90 cents to $36.54/MWh. Houston Hub on-peak average fell $1.19 to $38/MWh and the Houston Zone on-peak average was down $1.14 to $38.16/MWh. Clearing prices for off-peak hours averaged between $24.50 to $26/MWh, down about $1.80.

South Central on-peak terms were mixed at the front of the curve Monday, as August NYMEX gas futures edged up. ERCOT North on-peak August tumbled $2 to about $107/MWh, September rose 25 cents to about $41/MWh, and the fourth quarter crept up 15 cents to about $32.75/MWh. Heat rates were up about 20 Btu/kWh on ICE at about 2:30 p.m. EDT.

Into Entergy on-peak August fell 25 cents to about $36.25/MWh, September surged 50 cents to about $34.50/MWh, and Q4 fell 25 cents to about $32.75/MWh.

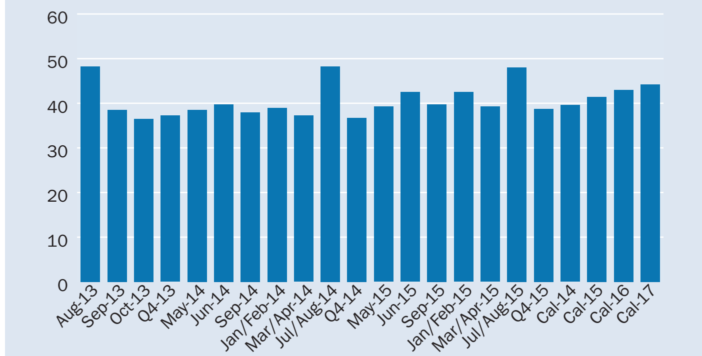
Southeast US on-peak August was unmoved Monday, as August NYMEX gas futures rose. Into Southern August stayed at about $37/MWh, September gained 50 cents to about $35.75/MWh, and Q4 fell 25 cents to about $34.50/MWh.

Advertisement

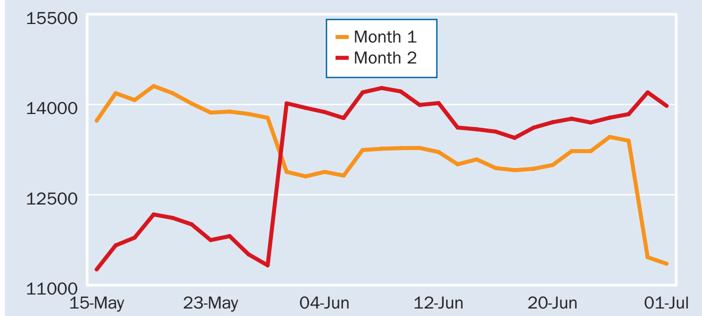
PJM & MISO Platts-ICE Forward Curve, Jul 1 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
PJM West	53.75	31.75
AD Hub	48.25	29.00
NI Hub	46.50	26.00
Indiana Hub	45.00	26.50

Ad Hub: Forward curve on-peak ($/MWh)



AD Hub: Marginal heat rate on-peak (Btu/kWh)



West markets ... *from page 6*

while NP15 off-peak dipped $1.72 to $38.62/MWh. ZP26 on-peak retreated $3.03 to $79.17/MWh as ZP26 off-peak also declined $1.13 to $33.47/MWh.

In the Northwest term markets, Mid-Columbia on-peak August added $1.75 with bids at $45.50 and offers at $46.25/MWh on ICE around 2:30 p.m. EDT. September surged $1.50 to about $39.75/MWh, and the fourth quarter was virtually unchanged at about $35.90/MWh. In California, SP15 on-peak August financial terms advanced $1.75 with bids at $56.50 and offers at $57.25/MWh. September sprang up $1.50 to about $52.50/MWh, and Q4 rose 25 cents to about $46/MWh. NP15 August jumped $2.50 to about $52.50/MWh, and Q4 skipped up rose cents to about $43/MWh. Palo Verde August rose 50 cents to about $45.25/MWh, September skipped up $1.50 to about $39.25/MWh, and Q4 fell 35 cents to about $34.75/MWh.

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NEWS

Day-ahead prices in California top $100/MWh

For the first time since July 2008, day-ahead spot power prices in Northern California cracked the $100/MWh-mark Monday as high temperatures in the state's interior are expected to remain near or above 100 degrees all week.

Day-ahead spot prices for NP15 in Northern California were at about $108/MWh at 7 a.m. PDT Monday. As the state was heading into the day's peak demand period, real-time prices were creeping up to about $41/MWh, according to the California Independent System Operator's website.

The heat, along with the continued outage of Pacific Gas & Electric's 1,150-MW Diablo Canyon-1 nuclear unit, led the ISO on Sunday to call on consumers to conserve energy between noon and 7 p.m. PDT on Monday and Tuesday and warn that local power outages are possible.

Sacramento, which has already seen several days of high temperatures in triple digits, is expected to see a high of 108 Monday and 109 on Tuesday and Wednesday.

The ISO also forecasted peak demand at to be about 500 MW above the 47,413 MW-mark it had previously estimated to be the record for the summer.

Still, the grid operator believes there is enough generation in the state to meet a peak demand of more than 51,000 MW.

— Martin Coyne

California generation up 8.3% since June 2012

California generated and imported 20.8 million MWh in June, up 8.3% from 19.2 million MWh in the same month last year, with renewable resources continuing to represent a larger part of the overal fuel mix, according to data released Monday by the state's grid operator.

Renewable generation in June was about 3.4 million MWh, up from 2.5 million MWh a year ago. Renewables last month accounted for 16.5% of generation, up from 13.1% in June 2012.

Renewable output has grown steadily from 9.5% of generation since 2011 as California moves closer to complying with its renewable portfolio standard that says 33% of the generation consumed in the state must come from renewable resources by 2020.

The roughly 5,900 MW of wind capacity installed in the California Independent System Operator's territory, has been hitting record hourly levels this year. In April, wind output passed the 4,000-MWh mark, setting a record of 4,196 MWh on April 7, according to the ISO.

Wind led all renewables in June with 1.6 million MWh, up from 934,609 MWh a year ago. Solar power followed wind with 451,609 MWh, up from 396,768 MWh in June 2012.

Hydro generation was 1.8 million MWh in June, down from 2 million MWh last year and 3.4 million MWh in the same period of 2011. Water levels in 2011 and 2012 were especially high in the Pacific Northwest, which exports a significant amount of hydropower to California.

The ISO is in a water conservation mode because California snowpack levels were 17% of normal for the 2012-13 winter, according to the California Department of Water Resources.

Thermal generation accounted for 7.9 million MWh in June, compared with 7.5 million MWh last year. Of that total, nuclear generation was 1.5 million MWh, compared with 1.1 million MWh in June 2012.

Power imports were 6.1 million MWh in June, compared with 6.5 million MWh last year and 5.9 million in 2011.

— Martin Coyne

Coal-fired generation tops PJM fuel mix

Coal remained the most-used fuel source for generation in the PJM Interconnection, according to the latest fuel mix information from the grid operator.

Coal-fired generation represented about 43% of the fuel mix in May, about flat from the previous month and almost 2 percentage points higher than May 2012.

Natural gas-fired generation contributed about 17% of the fuel mix in May, about 1 percentage point higher than April, but about 3 percentage points below the same period in 2012.

Nuclear generation was slightly above 35%, about a half of percentage point above last month and almost one percentage point higher than May 2012.

Wind generation contributed slightly more than 2% to the May fuel mix, almost one percentage point lower than April, but almost one percentage point higher than May 2012.

— Eric Wieser

Enernoc claims DR not fully evaluated by utility

A Kentucky Power official said Monday that a preliminary analysis showing conversion of the 278-MW Unit 1 at the utility's Big Sandy coal-fired plant to burn natural gas to be the least-cost option was not unfair to Enernoc.

But Enernoc is complaining about its treatment in the utility's request for proposals process. Enernoc is asking the Kentucky Public Service Commission to ensure its bid is "adequately considered" as part of Kentucky Power's 250-MW RFP issued March 28.

The solicitation sought several options to possibly retiring Big Sandy 1, including switching the unit to gas. Kentucky Power already has announced plans to retire Big Sandy Unit 2, an 800-MW baseload coal unit, in 2015 to comply with new Environmental Protection Agency rules.

In late May, Kentucky Power filed with the PSC a partial settlement reached with the Sierra Club and Kentucky Industrial Utility Customers that potentially affects the RFP. The accord, which still must be approved by the PSC, allows Kentucky Power to acquire half of the 1,560-MW Mitchell baseload coal plant in West Virginia from fellow American Electric Power subsidiary Ohio Power at a book value of $536 million, convert Big Sandy

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Unit 1 to gas and release an RFP for 100 MW of wind power.

Enernoc contends that the deal short-circuited the RFP process, in effect forcing Kentucky Power to make a rushed decision in which Enernoc's bid to aggregate load as part of a demand response proposal was not adequately considered. "Enernoc has a special interest in ensuring its responsive bid is evaluated, analyzed and considered because it believes its bid can be part of the least-cost alternative for a greater number of Kentucky Power's ratepayers," the company told the PSC.

"In addition, Enernoc's proposal will bring economic development value throughout the Kentucky Power territory by providing revenue to the commercial, industrial and institutional customers who participate in demand response programs through aggregation."

Enernoc attorney Jeremiah Byrne said that the company's bid should be "considered by the commission and hopefully Kentucky Power."

Details of Enernoc's bid were not publicly disclosed, and other company officials did not return a call by press time Monday.

Ranie Wohnhas, Kentucky Power director, regulatory and finance, said in an interview the utility attempted to be fair to all bidders before concluding its own proposal to convert Big Sandy Unit 1 to gas was the least-cost option. Because the utility is attempting to keep the Mitchell asset transfer case moving forward at the PSC, the RFP analysis "was done quickly and results indicated the gas plant would be least cost," he said.

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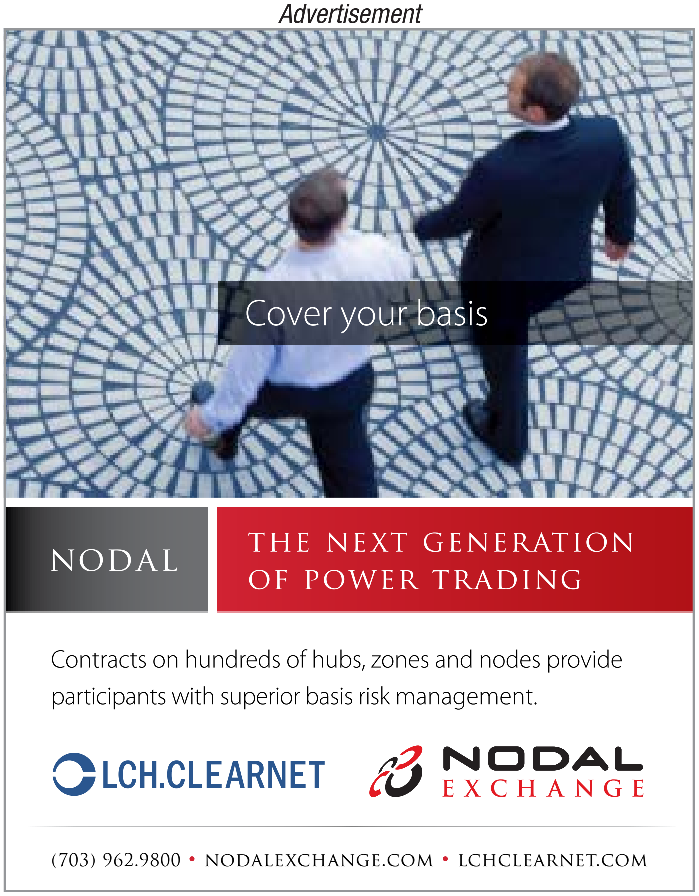

Daily CSAPR allowance assessments, Jul 1

CSAPR ($/st)	2013 Range	Mid	2014 Range	Mid
SO_2 Group 1	5.00-35.00	20.00	5.00-25.00	15.00
SO_2 Group 2	25.00-75.00	50.00	25.00-65.00	45.00
NOx Annual	40.00-70.00	55.00	30.00-70.00	50.00
NOx Seasonal	20.00-90.00	55.00	20.00-80.00	50.00

All prices in $/st

Daily CAIR allowance assessments, Jul 1

	$/allowance	Change	$/st
S02 2013	0.67	0.00	1.34

For methodology, visit www.emissions.platts.com. Full coverage of SO2 and NOx emissions markets now appears in Platts Coal Trader. For information on Coal Trader, contact support@platts.com or call 1-800-PLATTS-8.

RGGI carbon allowance futures, Jun 28 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.53	0	Dec13	1.97	0
Dec13 V11	3.53	0	Dec14	1.97	0
Dec13 V12	3.53	0			
Dec13 V13	3.40	0			
Dec14 V10	3.53	0			
Dec14 V11	3.53	0			
Dec14 V12	3.53	0			
Dec14 V13	3.40	0			
Dec15 V10	3.53	0			
Dec15 V11	3.53	0			
Dec15 V12	3.53	0			
Dec15 V13	3.40	0			

The Regional Greenhouse Gas Initiative is a carbon cap-and-trade program for power generators in nine Northeast and Mid-Atlantic US states. One RGGI allowance is equivalent to one short ton of CO2. The volume listed is the number of futures contracts traded. Each futures contract represents 1,000 RGGI allowances.

Now, however, Kentucky Power intends to "go back and take another look at the numbers to make sure everything is proper," he added. "We would not have done this quickly, but we were trying to make sure the Mitchell plant transfer remains on track" at the PSC.

Wohnhas said Kentucky Power intends to develop a "short list" of bidders in the RFP sometime this summer, although he could not be more specific on the timing. According to the original RFP, a short list was expected by mid-July.

"This is not a knock against Enernoc. This is not trying to keep them out of the loop," he said.

— Bob Matyi

Penelec details efficiency target shortfall

Pennsylvania Electric Company will fall 11% short of the energy usage reduction targets it had to meet by May 31 if changes are not made to its energy efficiency and conservation plan, the company told state regulators last week.

In a report issued to the PUC in mid-April, the utility said it had reached 103% of its energy savings target and 117% of its peak load compliance target, both of which are mandated by state law. But savings were recalculated in such a way that they could

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have been overstated by about 11%, and the company could be required to make up the deficit, the FirstEnergy utility said.

Penelec's required energy consumption savings by May 31 under the state law, Act 129, was 431,979 MWh. Its peak load reduction requirement was 108 MW. The targets had to be met under a spending cap of $22.9 million, or 2% of the company's 2006 revenue. Utilities can be fined for not meeting the targets.

The 11% deficit is a result of several factors, including a key underlying savings assumption that was changed to eliminate a transmission and distribution loss factor, the company said. The statewide evaluator and the Public Utility Commission's bureau of conservation economics and energy planning also said savings projections should be calculated at the retail level for Act 129 compliance purposes, but at the system generation level for total resource cost test purposes, the company said.

"As a result, all of the savings projections included in the current plan are overstated by approximately 11%," the utility told the PUC.

Changes proposed by the company would recalculate projected savings and would make up the 11% deficit, the company said. The changes were proposed in May, and without them the utility is in jeopardy of not meeting the targets, Penelec said.

The plan is part of a back-and-forth with PUC officials on the final calculation of savings Penelec attained under the program, Scott Surgeoner, a company spokesman, said. "We have a lot of programs and we're now trying to make sure that the data is verified for the years those programs ran," he said.

The company plans to issue a preliminary report on its energy savings in August and a final report in November, Surgeoner said.

Certain programs are performing below levels originally anticipated because of the downturn in the economy, lower customer participation levels and other changes, the company said.

Penelec proposed a number of changes that could help make up the 11% shortfall, including shifting funds from underperforming programs to more successful programs. and enhanced funding for large commercial and industrial programs. The utility proposed increasing the budget for a large commercial and industrial demand response program by $2.6 million to boost the energy savings of that program. Changes to the incentives for large C&I customer lighting programs also were proposed.

Penelec wants savings from small C&I customers to count toward the peak demand reduction target. It also proposed modifying the incentive structure for lighting portion of the small C&I program.

Other plans call for a new program targeting strip malls, small grocery stores and restaurants, all of which are high energy users, the utility said.

— Mary Powers

ERCOT to alter rules to keep exemption

The Electric Reliability Council of Texas must change more rules to ensure its transactions are exempt from Commodity Exchange Act regulation, stakeholders learned via email Monday.

On March 28, the Commodity Futures Trading Commission approved a final order exempting financial transmission rights, energy, forward capacity transactions and reserve or regulation transactions when administered by an independent system operator.

Under the exemption order terms, ERCOT had to meet certain conditions, including establishing risk and credit practices that at least substantially comply with relevant Federal Energy Regulatory Commission rules, which required changing certain ERCOT protocols.

"Although ERCOT has met each of the conditions for the exemption, the exemption does not necessarily apply to all entities currently transacting in the ERCOT market," stakeholders were told via email Monday. "The CEA provides that any CFTC-ordered exemption applies only to transactions occurring between 'appropriate persons,' which term is defined to include only certain kinds of financial institutions."

But the CEA authorized the CFTC to expand the definition of appropriate persons, which CFTC has done to include "eligible contract participants" under the CEA and entities that are "in the business of generating, transmitting or distributing electric energy, or providing electric energy services that are necessary to support the reliable operation of the transmission system."

To ensure all ERCOT market participants meet these standards, ERCOT must change its protocols by September 30 to incorporate the CFTC "appropriate persons" definition, the ERCOT email states.

ERCOT staff therefore plans to submit a nodal protocol revision request addressing the issue and to seek urgent status so that it can get final approval at the ERCOT board of directors' September 17 meeting, the email states.

— Mark Watson

CFTC's Jill Sommers to leave agency July 8

Commodity Futures Trading Commissioner Jill Sommers said Monday that her final day will be July 8.

Sommers first announced her resignation in January but decided to stay through the first quarter to vote on rules governing swap-execution facilities, among others.

Sommers, a Republican who has held her seat since August 2007, said Monday that "it has been a unique time at the commission." She has played a role in formulating agency rules after the passage of the 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, and she led the CFTC's investigation into the failure of brokerage MF Global.

On July 20, 2009, Sommers was nominated by President Obama to serve a five-year second term. The Senate confirmed her on October 8, 2009.

The CFTC can still vote on key matters with her seat vacant as the five-member commission requires only a three-vote majority for passage of rules.

Her vote will be noticeably absent as the commission determines the cross-border rules governing swap transactions, a heavily debated issue.

CFTC Chairman Gary Gensler has announced his intent to hold a vote on those final rules before a no-action relief letter

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expires July 12. The letter has been providing the swaps industry guidance on the transactions while the CFTC deliberates the proposed rules.

Holding a vote now appears less likely given Sommers' impending departure and the fact that Commissioner Scott O'Malia is on a two-week vacation.

According to a source close to the agency, J. Christopher Giancarlo, executive vice president at GFI Group, will likely be nominated for Sommers' seat.

But her replacement is not expected to be announced until after the Obama administration decides the fate of Gensler and Commissioner Bart Chilton, whose terms officially expired in April.

— *Christopher Tremulis*

Hydro leads list of new RPS capacity in June

In June, hydroelectric facilities represented the largest source of new generation eligible to satisfy renewable portfolio standards in at least one PJM state, according to an analysis of data provided by the grid operator.

There was a net growth of 54 MW of eligible capacity from hydro generators. The facilities involved were located in New York (43 MW) and Pennsylvania (11 MW).

The amount of new generation in the PJM tracking system does not necessarily equate to recently completed projects. Some facilities wait to become RPS-eligible for a variety of reasons.

A capacity update can instead be seen as a bellwether of renewable energy certificate supply. The addition of RPS-eligible facilities indicates more RECs will be entering the market.

By technology, the next biggest addition in June came from solar photovoltaic, which added roughly 48 MW. New Jersey was responsible for the bulk of that increase.

It is common for capacity to decrease in a given month as certain projects drop out of the PJM tracking system if they lose their RPS eligibility status.

In June, there was a net decrease of 120 MW in wind capacity. The wind farms involved were located in Indiana and Illinois.

Another parameter used to quantify renewable capacity is RPS eligibility. From this perspective, megawatts can be counted more than once when a project is qualified in multiple states.

The biggest changes in June were Pennsylvania Tier I (262.2 MW), Illinois Solar (48.8 MW), Maryland Tier I (47.8 MW), New Jersey Solar (46.8 MW), District of Columbia Tier I (22.8 MW), Pennsylvania Tier II (11 MW), Maryland Solar (5.1 MW), Ohio Renewable (3.2 MW) and Ohio Solar (3 MW).

New Jersey Tier I saw a net decrease of 120 MW, presumably stemming from the loss of those wind farms in Illinois and Indiana.

Projects generate renewable energy certificates that can be sold to load-serving entities. The LSEs need the RECs to comply with state-mandated renewable portfolio standards.

The PJM states with a mandatory RPS are Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania and West Virginia. The District of Columbia also has one.

— *Geoffrey Craig*

FERC rejects MISO transmission proposal

Federal energy regulators on Friday rejected a proposal to raise the minimum amount of time for certain uses of firm point-to-point transmission service within the Midcontinent Independent System Operator, saying that the ISO did not sufficiently justify the proposal.

But the Federal Energy Regulatory Commission in the Friday order (Docket No. ER13-1094) left the door open to MISO submitting a more robust proposal, saying that it rejected the plan "without prejudice to MISO, in a future [Federal Power Act] section 205 filing, substantiating the problems it alleges here and proposing a remedy that is narrowly tailored to addressing them and is consistent with or superior to the *pro forma* [open access transmission tariff]."

Specifically, FERC rejected a March 14 MISO proposal to raise from one day to one year the minimum term for firm point-to-point transmission service in MISO when "both the receipt and the delivery are within MISO's transmission system."

The ISO argued that the use of short-term firm point-to-point service in load pockets by behind-the-meter generation assets could be frustrating the development of a more robust transmission system, according to FERC's order. Also, raising the threshold for firm point-to-point service would assure that behind-the-meter generation assets "will be treated similarly to long-term firm point-to-point and network integration transmission service customers that have supported necessary upgrades and expansions of the system."

"MISO states that increasing the minimum term to one year for firm point-to-point transmission service within MISO's transmission system will place all users of internal firm point-to-point transmission service on the same basis by triggering the need for a system impact study to correctly identify load pockets that cannot be efficiently redispatched to resolve congestion," FERC said in its order.

And while service transmission owners within MISO, including Ameren Illinois, Duke Energy Indiana and MidAmerican Energy, backed the change, the Michigan Public Power Agency and others in comments argued that MISO had failed to provide evidence to support its proposal or demonstrate that a problem existed.

MPPA in particular argued that "the proposal would eliminate an important service for municipal utilities with Behind the Meter Generation and force those customers to incur higher cost transmission charges for service they do not need or use (i.e., network service), or require them to take inferior service (i.e., non-firm transmission service)," according to the order.

And in rejecting MISO's proposal, FERC noted that MISO pointed to only two examples to support its arguments regarding behind-the-meter generation operating within load pockets using short-term service "to import power into the customer's system on a basis functionally equivalent to network integration transmission service."

Said FERC, "We cannot find that, based on only two examples for which MISO did not provide supportive data, it is just and reasonable for MISO to eliminate all short-term firm point-to-

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point transmission service internal to MISO of less than one year for all transmission customers."

FERC further rejected MISO's argument that the changes would address discriminatory pricing, noting that FERC previously concluded that MISO's tariff was just and reasonable. The commission also said that "MISO has failed to demonstrate that its market operations justify these specific modifications."

In response to the order, a MISO spokesperson said that they are evaluating the impact of the decision.

— Bobby McMahon

CEC staff lists concerns with IGCC plant

California Energy Commission staff is raising major concerns about a proposed 431-MW integrated gasification combined cycle plant with carbon capture technology that SCS Energy intends to bring online by early 2018.

CEC staff's review "has revealed significant, and for the most part, unresolved issues" with the application for the coal-fired project near Bakersfield, California, according to a preliminary staff assessment and draft environmental impact statement issued Friday by the CEC and the Department of Energy.

DOE proposed to provide up to $408 million to SCS Energy, based in Concord, Massachusetts, for the project, which is expected to cost about $4 billion. The funding would come from DOE's Clean Coal Power Initiative, a program that aims to boost IGCC technology.

Several years ago, during a period of relatively high natural gas prices and the expectation that there would be federal greenhouse gas regulation, IGCC projects were proposed around the US. Since then, some have been cancelled while others have been more expensive to build than initially planned.

In California, BP Alternative Energy North America and Rio Tinto Hydrogen Energy proposed the Hydrogen Energy California project in mid-2008 by. The two companies spent about $110 million on the project before SCS Energy, a power plant developer, bought the project in 2011.

The project is designed to capture up to 90% of the facility's carbon dioxide emissions and use them for enhanced oil recovery at a nearby oil field. The plant would also make fertilizer.

CEC staff said the project would lead to a "significant, unavoidable" effect on the Blunt Nosed Leopard Lizard, which is fully protected under California law. The Fish & Wildlife Service is also reviewing the project's effect on endangered species.

The project may deplete groundwater supplies faster than they can by replenished, the CEC staff said. SCS Energy is proposing to use 7,500 acre-feet of water a year for the project, which is "significantly" more water intensive than recently approved projects, CEC staff said, noting that there is evidence that the water could be used for other, more beneficial, purposes. As a result, staff is examining the possibility of dry-cooling for the project, which would cut its water use by 90%.

The CEC and DOE are taking comments on the preliminary assessment in preparation for issuing a final assessment. After public comments and a hearing, staff will issue a final assessment and an EIS, which will be used by the CEC when it makes a decision on the project.

If approved, SCS Energy intends to begin building the plant in January and bring it online four years later. The plant is slated to connect to the power grid at Pacific Gas & Electric's Midway substation via a 230-kV Midway-Wheeler Ridge transmission line and a new PG&E switching station.

SCS Energy did not return requests for comment.

Meanwhile, CEC staff Friday issued a preliminary assessment for the 500-MW Palen solar power project proposed by BrightSource Energy and Abengoa Solar. The roughly $2 billion project was approved in December 2010, but the developers have proposed switching the project from trough technology to solar towers. The developers also reduced the project footprint by about 25% to 3,800 acres. The initial assessment found several shortfalls in the application that require more information or discussion.

The Bureau of Land Management is preparing an EIS for the project.

BrightSource bought the Palen project from bankrupt Solar Trust of America last year.

— Ethan Howland

ISO-NE proposes winter reliability measures

ISO New England would like to implement several changes it believes will help the region avoid reliability problems this winter, according to a Friday filing with the Federal Energy Regulatory Commission.

The proposal includes payments to oil and dual-fuel generators to maintain oil inventories and the creation of a winter demand response program.

The ISO developed the proposed changes to address challenges related to the region's growing dependence on natural gas, which are exacerbated during extended cold-weather periods when gas demand by local distribution companies increases pipeline constraints.

Those challenges were highlighted this last winter, when the ISO was forced to commit additional generating resources during a January cold snap and a February blizzard due to the inadequacy of generator fuel arrangements and the uncertainty created. The ISO said it needed to commit resources in key locations to manage the volatility of transmission, generation and customer outages in hard-hit areas from the blizzard. The resources were committed out-of-economic-merit order and contributed to significant uplift costs to consumers, according to the ISO.

"A number of 'lessons learned' from the winter of 2012-13 led the ISO to conclude that the region could not wait for [longer-term solutions], and that a stop-gap measure would be needed to maintain reliability in winter 2013-14," ISO-NE and the New England Power Pool said in their filing with FERC. "Although [last] winter was mild, there were operational events that caused concerns about reliability during a colder winter."

Given those concerns, the ISO is proposing four main changes that it hopes to have in place by December 1: creating a winter demand response program, paying oil and dual fuel

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generators to maintain oil inventories, paying for tests to see if dual fuel units with oil inventories are able to switch fuel sources in five hours or less and allowing dual fuel generators to bid using their higher-cost energy during the winter (Docket No. ER13-1851).

The proposal would allow the ISO to procure up to 2.4 million MWh between December 1 and February 28, 2013 from demand response resources, and oil and dual fuel resources that have committed to maintain oil inventories, according to the ISO's filing. The total cost of the changes if put in place for this winter is estimated to be $16 million to $43 million and will be paid by regional network load.

The demand response program will be open to up to 200 new or existing assets that can provide additional capacity. Resources enrolled in the program would need to be available between 5 a.m. and 11 p.m. but would not be required to respond more than 10 times over a winter. Resources in the program would be paid based on their bid price but would be subject to non-performance penalties.

The second key part of the proposal is payments to oil and dual fuel generators that agree to maintain a specified level of oil inventory throughout the winter. Generators would be paid based on what the price they bid in to provide this service, but would face penalties if they are unavailable or fail to maintain their oil inventories.

In selecting demand response resources and generators offering to maintain oil inventories, the ISO would consider the bid cost, the resource's historical availability and performance, the resources ability to respond to contingencies, the diversity of locations and system constraints and dual fuel capabilities.

The proposal would allow ISO-NE to use Net Commitment Period Compensation payments to compensate dual fuel generators for demonstrating that they are able to switch fuel sources in five hours or less.

Finally, the proposal would also alter market monitoring rules to allow dual fuel generators to make energy bids based on their higher-cost fuel during the winter.

Because ISO-NE needs to have the changes in place by December 1, it did not pursue proposals that would require significant software or market design changes, according to the filing. But the ISO noted that it is also working on longer-term solutions, such as implementing a fuel-neutral, winter-based reliability product for 2014 through 2018 and adding a pay-for-performance mechanism to its forward capacity market.

The proposed changes were approved with about 86% support from the NEPOOL Participants Committee on Thursday and were approved with about 66% support from the NEPOOL Markets Committee on June 13, according to the filing.

ISO-NE asked FERC to approve to make the changes effective by August 27. In a Friday blog post, ISO-NE said it plans to begin accepting bids from demand response and oil resources on July 1. Pending the FERC order, ISO-NE said it plans finalize its selection of bids by early September.

— Juliana Brint

Obama plan may raise coal retirements

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Benjamin Salisbury, an analyst with FBR Capital Markets, said in an interview.

The common wisdom in the environmental community was that the president was not providing the necessary leadership on climate change issues, Salisbury said. He argues that the plan Obama put in motion with his speech is designed to alleviate those concerns and galvanize support among voters under age 35. In polls, that demographic group places environmental issues high on their list of concerns, even above the economy.

So while the president’s plan to address climate change may not have a lot of new initiatives, it does light a fire under policies that have stalled or slowed by setting deadlines.

Following the flood of comments it received when it issued its NSPS for new plants in April 2012, EPA was in the process of issuing new rules. The president has now directed EPA to issue those revised rules by September 20.

EPA was also working on NSPS rules for existing power plants. The president’s plan imposes deadlines on those efforts. The rules for existing plants must be issued by June 1, 2014, and finalized by June 1, 2015. The president also directed EPA to include in those rules a June 30, 2016, deadline by which states must submit their implement plans to EPA.

Salisbury, citing a report by the National Resources Defense Council, said that the administration’s renewed push on GHG limits for power plants could result in another 50 GW of coal plant retirements in addition to the 30 GW already expected as a result of the pending, year-end 2015 deadline for compliance with the EPA Mercury and Air Toxics Standards.

FBR estimates that MATS could result in 50 GW of coal plant retirements, but has not issued a retirement estimate based on GHG limits following the president’s speech.

Christine Tezak, an analyst with ClearView Energy Partners, estimates that implementation of GHG restrictions on power plants will lead to an incremental 70 GW of coal plant retirements by 2020 over and above the 40 GW of retirements already announced as a result of MATS. Tezak’s number is a “back-of-the-envelope” estimate based on NRDC’s 1,500 pounds CO_2/MWh figure as a starting point.

The 1,500 lb. figure is the benchmark that NRDC uses for coal plant CO_2 emissions to set 2020 target emissions rates. NRDC uses 1,000 lb. CO_2/MWh for gas-fired plants. Based on that number, NRDC estimates that the nation’s fossil generating fleet could reduce CO_2 emissions by 26% from 2005 levels by 2020 at an annualized cost of $4 billion in 2020 and with benefits of $25 billion to $60 billion in saved lives and the reduced risk of catastrophic climate change. NRDC puts the value of reducing CO_2 pollution at $26 to $59 per ton.

Black & Veatch, which has consistently been the consulting firm at the high end of coal plant retirement estimates, has not released a new estimate based on the president’s speech. B&V is in the process of updating its coal retirement estimate, but expects it will end up in the 63 GW to 65 GW range. At the beginning of last year, B&V had an estimate of 62.7 GW of coal retirements.

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MATS is the real driver on coal retirements, B&V analyst Neil Copeland said, adding that right now there is not enough detail on how the NSPS rules will be written or implemented.

As Tezak noted, the fate of existing coal plants is going to depend on the final shape of EPA's NSPS rules and, depending on the mechanism used, that could reduce the expected number of coal plant retirements.

In a research report issued this week, Bernstein analyst Hugh Wynne outlined the approaches EPA can take — both at the unit level and fleet wide. The unit level approach could be accomplished via carbon capture technology that Wynne notes would impose an "unsustainable cost" on existing coal plants. The other unit-specific approach would be to mandate heat rate improvements, but the potential for such improvements is so limited it is "almost inconsequential," he wrote.

Wynne leans toward a fleet-wide approach to reducing CO2 emissions that would use a cap and trade program or some form of CO2 allowances. Using such an approach would imply a price of $18 per ton of CO2 avoided. He estimates the cost of using unit-specific CO2 capture at as $75 per ton of CO2 avoided.

In his speech, the president may be signaling that EPA will take the fleet-wide approach with some form of emissions averaging/trading scheme approach by advocating a flexible solution to the problem and by emphasizing state-specific remedies .

As Wynne noted, California already has a CO2 cap and trade program and the nine member states of the Regional Greenhouse Gas Initiative have a CO2 trading program.

By directing the EPA to use section 111(b) and 111(d) of the Clean Air Act, the administration could be setting the stage for a national CO2 trading program. And that may be what is really new in the president's energy plan.

Section 111(d) has almost never been used as a road map for emissions policy, Salisbury noted. Section 111(d) has been viewed as particularly problematic with respect to CO2 regulation because it calls for the use of best "system" for CO2 mitigation. "The plain reading until 2012" was that "system" meant technology, Salisbury said.

In a December report, the NRDC argues that a system could mean a scheme to trade CO2 allowances. It is the same report in which NRDC puts out the 1,500 lb CO2/MWh benchmark.

— Peter Maloney

EPA mum on details of 'new' carbon rules

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this process, EPA has sent the new proposal [for new power plants] for interagency review."

Obama, in outlining his broad plan last week, called on EPA to issue a new proposal to curb GHG emissions from new power plants by September 20. It is not uncommon for OMB to take several months or more to complete the interagency review process, so it is not surprising that EPA submitted its proposal so soon after Obama's speech.

But the details of EPA's proposal to regulate GHG emissions from new power plants remained unclear Monday. Julia Valentine, an EPA spokeswoman, declined to comment when asked if the proposal would still prohibit the construction of coal-fired power plants that lack carbon-capture technology, which is extremely expensive and largely unproven on a commercial scale.

EPA effectively ruled out the construction of non-carbon-capture coal plants in the regulations that it proposed last year but never finalized, saying new plants could not emit more than 1,000 pounds of CO2 for every megawatt-hour of electricity they generate.

Valentine would not say if EPA's new proposal still contains the 1,000 pounds/MWh limit.

Nor did Valentine say if EPA's proposal contains another key provision of last year's never-finalized regulations: allowing newly built coal plants to emit higher levels of GHGs for their first 11 years of operations, but then forcing them to sharply ratchet down emissions over the next 19 years by installing carbon-capture systems. The idea behind allowing generators to "average out" their GHG emissions over a 30-year period is that carbon-capture technology, while expensive now, would become more economical down the road.

Some power-sector attorneys have told Platts in recent months that EPA's carbon standards for new power plants would be legally vulnerable if the agency does not add a secondary, more lenient standard that would allow the construction of coal-fired power plants without carbon-capture systems.

A number of lawmakers have made a similar argument, telling Obama in a recent letter that EPA should formally declare in its forthcoming GHG rules that "supercritical" coal-fired power plants are "the performance standard for new coal-based electricity."

"We urge you to consider an alternative approach to address GHG emissions in a way that will not harm our economy or endanger our electricity supply," said the letter, which was signed by Senator Roy Blunt, a Missouri Republican, and other GOP lawmakers.

But attorneys from environmental groups that have close ties to EPA say they have seen no evidence that the agency is going to backtrack and allow the construction of coal-fired power plants that lack carbon-capture systems.

EPA, for its part, said in its statement Monday that its revised proposal "will ensure that carbon pollution standards for new power plants reflect recent developments and trends in the power sector." The agency did not specify which "developments and trends" it has in mind, although it should be noted that EPA has said quite a bit in recent years about electricity generators shifting from coal to natural gas.

EPA said it will take public comments on its proposal, once it is issued. The agency received more than 2.5 million public comments on the GHG standards for new power plants that it never finalized.

After EPA sets the first-ever GHG standards for new power plants, the agency will endeavor to set carbon standards for the US' more than 5,000 existing power plants. Obama has called on EPA to proposes those standards by June 1, 2014, and to finalize them by June 1, 2015.

— Brian Hansen

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NU will keep 1,100 MW of generation

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recommended that the utility produce a proposal to transfer the plants into an unregulated affiliate at net book value.

But PSNH said the staff report misses the mark and avoids dealing with the larger "alarming" issue plaguing New England's supply: an overreliance on natural gas-fired generation and severe pipeline constraints.

"In fact, the region's overreliance on gas-fired generation was relegated to a footnote in the report," PSNH said in comments filed with the PUC. PSNH contends that its portfolio acts as a safety net for its customers should natural gas prices spike or if the fuel grows scarce. "In a region dominated by an overreliance on gas-fired generation, PSNH's generating assets provide significant system integrity value as a result of fuel diversity," PSNH said.

The utility said that another idea put forward by staff – retiring the plants – also is "not worthy of any further consideration."

"Merely shuttering the plants will not eliminate ongoing costs such as taxes, security, insurance, etc., and the remaining net book value of the plants would have to be recovered from customers. Instead of mitigating costs, retirement of the assets would merely exacerbate those costs," PSNH said.

PSNH also challenged assertions by staff that its default service rates are likely to remain well above market, saying the report failed to provide data backing up those assertions.

"It is also important to remember how difficult it is to predict the future of the energy market," PSNH said. "As history has repeatedly demonstrated, any forecast of energy and commodity prices must recognize the limitations inherent in predictions related to an extremely volatile and perpetually cyclical market."

The New England Power Generators Association, however, continued to press for spinoff of the assets, saying "urgent action is needed" in comments it filed on Friday.

The utility's default service rates are the highest in New England – 15% over the state average and 18% over the regional average, according to NEPGA. The generation group and others who support the spinoff warn that the high rates are driving more customers away from PSNH to competitive suppliers. This leaves a smaller customer base at PSNH to cover more and more of the plant costs.

The organization contends that PSNH investors, not ratepayers, should shoulder this cost. All other coal-fired plants in New England are owned by competitive generators, NEPGA said.

A final decision on how to proceed rests with the PUC.

NEPGA recommended that the PUC require that the utility submit a proposal to transfer the assets into an affiliate in July or August. Stakeholders would then consider associated issues through December.

Next, the PUC and Legislature would take any necessary action by June 2014. For the remainder of 2014, the parties would determine the value of the generation assets. The assets would then be unbundled and either transferred to an affiliate or sold to a third party.

Meanwhile, PSNH argued that no decision should be made about the future of the plants until the state produces its energy strategy, which was mandated in recently passed legislation (S.B. 191). The legislation requires a draft of the strategy by May 2014 and a final version by September 2014.

— Lisa Wood

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