PLATTS
McGRAW HILL FINANCIAL
www.platts.com
[ELECTRIC POWER]
MEGAWATT DAILY
www.twitter.com/plattspower
Tuesday, July 23, 2013

More PJM coal retirements may not lift prices

ANALYSIS Fresh announcements of coal plant retirements in the PJM Interconnection region have raised the possibility of more coal plant retirements, but not necessarily the prospect of higher capacity prices.

Earlier this month FirstEnergy announced plans to close two coal-fired plants totaling 2,080 MW in October, citing the high cost of needed environmental retrofits and low energy and capacity revenues.

FirstEnergy had previously said it planned to retire six plants totaling 3,349 MW, but the recent announcement was notable for the fact that one of the newly announced closures is of a plant previously thought to be safe from retirement.

Many analysts have said that the plants most vulnerable for retirement are older, smaller coal plants.

(continued on page 17)

CFTC, FCA charge trading firm with 'spoofing'

TRADING The Commodity Futures Trading Commission on Monday said it had ordered New Jersey-based trading firm Panther Energy Trading and its principal Michael Coscia to pay $2.8 million to resolve agency charges that the company attempted to manipulate commodity markets.

The agency said the firm engaged in "spoofing," a practice that involves using a computer trading algorithm to illegally place, then quickly cancel, bids and offers in futures contracts. The case is the first brought by the CFTC under Dodd-Frank Wall Street Reform and Consumer Protection Act rules prohibiting the practice.

In a statement, the CFTC said Panther and Coscia engaged in spoofing across a range of commodities from August 8, 2011,

(continued on page 17)

MISO members to vote on hubs tied to IOU move

MARKETS The proposed southern region of the Midcontinent Independent System Operator may have more than one trading hub, depending on a ballot that was slated to be submitted to MISO members July 22.

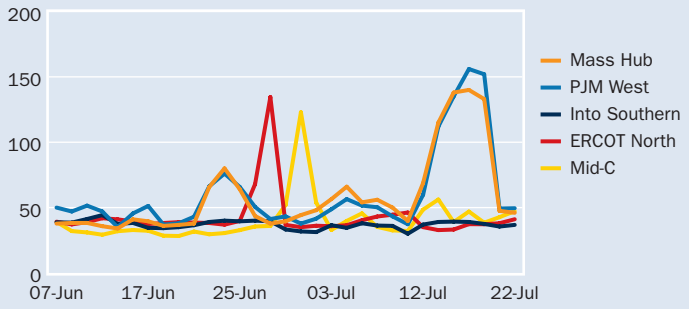
At Monday's MISO Trading Hubs Task Force, the panel decided to have MISO members vote on whether to have one or more than one trading hub serving the Entergy utility territory that the New Orleans-based investor-owned utility hopes to shift to MISO in December.

That territory, known in MISO as the "MISO South" region, incorporates all or parts of Arkansas, Louisiana, Mississippi and Texas.

Also, the panel decided to send a survey to stakeholders in the prospective MISO South region who are not yet members of MISO

(continued on page 19)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Jul 23 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	48.44	51.73	29.84	31.51
NYISO	47.19	104.48	28.83	42.95
PJM	42.11	57.47	24.30	29.96
MISO	38.90	42.87	20.44	25.98
ERCOT	39.27	51.57	25.01	26.54
CAISO	41.84	45.39	32.60	34.86

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 23

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	46.00	11765	18.63	14.72	6.90	-0.92	-12.65
N.Y. Zone-A	41.00	11538	16.13	12.57	5.47	-1.64	-12.30
PJM/MISO							
PJM West	49.50	14163	25.04	21.54	14.55	7.56	-2.93
Indiana Hub	39.50	10576	13.36	9.62	2.15	-5.32	-16.53
Southeast & Central							
Southern, Into	36.75	9980	10.97	7.29	-0.08	-7.44	-18.49
ERCOT, North	41.07	11345	15.73	12.11	4.87	-2.37	-13.23
West							
Mid-C	47.22	13396	22.55	19.02	11.97	4.92	-5.66
SP15	48.50	12814	22.01	18.22	10.65	3.08	-8.28

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 down, following spot gas

Daily power prices in the Northeast were lower Monday with steady demand forecasts and weaker spot natural gas prices. Forward prices dipped as the NYMEX August natural gas futures contract settled at $3.677/MMBtu, down 11.2 cents.

ISO New England forecasted peak load on Monday at 21,400 MW and 21,950 MW on Tuesday. High temperatures for Boston are forecast in the upper 70s Tuesday.

Algonquin city-gates spot natural gas fell about 75 cents to $3.91/MMBtu and Transco Zone 6 New York fell about 8 cents to $3.83/MMBtu.

Mass Hub on-peak for Tuesday eased about $2 to around the mid-$40s/MWh, while off-peak slipped about $8 to the upper $20s/MWh.

The New York ISO forecasted peak load for Monday at 28,500 MW and 28,083 MW on Tuesday. High temperatures in New York state are forecast in the mid-70s to low 80s on Tuesday.

New York Zone A peak for Tuesday traded in the low $40s/MWh, a drop of about $6. New York Zone G peak for Tuesday was valued in the mid-$50s early Monday, about flat.

Day-ahead auction prices in ISO-NE eased Monday with lower expected demand. Internal Hub peak fell $5.37, clearing around $50.21/MWh while Connecticut peak lost $5.75 to $51.73/MWh. Maine peak gave up $5.18 to $48.44/MWh and Vermont peak was off $5.71 to $51.28/MWh. SE-Mass peak gave up $5.22 clearing around $49.80/MWh.

Day-ahead auction prices in NYISO were mixed Monday with demand forecast to be lower Tuesday. West zone peak jumped nearly $24 clearing around $65.73/MWh, while Hudson Valley peak dropped $1.78 clearing at $55.35/MWh. New York City peak was up $1.20 at $64.40/MWh and Long Island peak fell $7.16 to $104.48/MWh.

Northeast term power prices were down Monday, with lower spot power prices and natural gas futures. Mass Hub on-peak August financial futures dropped 75 cents, with bids at $51.60/MWh and $52.75/MWh on the IntercontinentalExchange. The Mass Hub prompt-month package was down as much as $1.75 in early trading. Mass Hub on-peak fourth quarter slipped 75 cents to $52.50/MWh and January-February 2014 fell 25 cents to about $86.25/MWh on ICE.

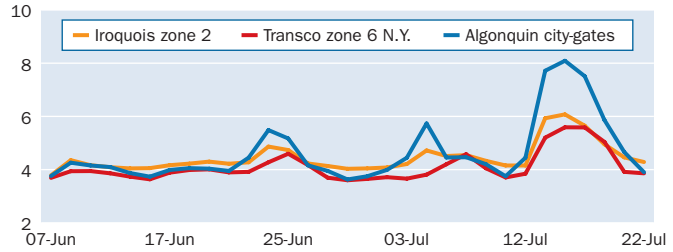
New York Zone A on-peak August financial futures fell 50 cents, with bids at $49/MWh and offers at $49.85/MWh on ICE. The prompt-month package was down as much as $1.75 in morning trading. New York Zone G on-peak August financial futures dropped $3.25 to about $59.75/MWh, without the afternoon bounce seen by other markets.

Northeast day-ahead bilateral indexes for Jul 23 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	46.00	-1.50	71.39	11765
N.Y. Zone-G	55.50	0.50	80.23	13628
N.Y. Zone-J	64.50	3.50	85.88	15838
N.Y. Zone-A	41.00	-6.00	66.66	11538
Ontario*	32.00	-4.00	39.00	7406
Off-Peak				
Mass Hub	29.00	-8.00	37.33	7417
N.Y. Zone-G	33.50	-1.50	37.72	8226
N.Y. Zone-J	40.00	2.00	42.63	9822
N.Y. Zone-A	30.50	-1.50	32.39	8583
Ontario*	23.00	-2.00	22.58	5323

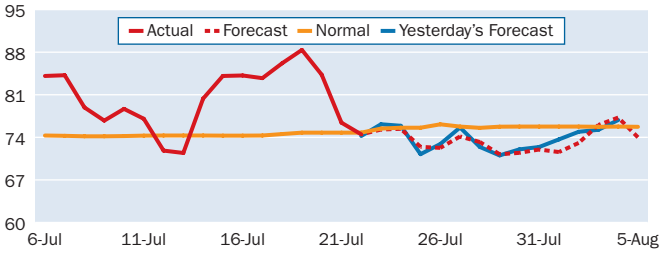
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO average temperature (°F)



Source: Custom Weather

Northeast load and generation mix forecast (GWh)

	Actual 21-Jul	%Chg	% Chg Year-ago	Forecast 22-Jul	23-Jul	24-Jul	25-Jul	26-Jul
ISONE								
Load	416	-19	4	392	410	433	420	400
Generation								
Coal	24	-52	107	16	18	21	21	21
Gas	181	-10	-11	187	182	184	176	169
Nuclear	111	-1	-6	111	111	111	111	111
NYISO								
Load	541	-11	1	552	560	547	518	509
Generation								
Coal	32	-30	102	33	35	35	32	32
Gas	223	-9	-3	225	226	219	208	204
Nuclear	135	0	8	135	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Jul 23 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	50.21	0.00	-0.26	-5.37	68.68	12744
Connecticut	51.73	0.00	1.27	-5.75	70.07	12631
NE Mass-Boston	50.23	0.00	-0.24	-5.23	68.84	12749
SE Mass	49.80	0.00	-0.66	-5.22	68.52	12641
West-Central Mass	50.72	0.00	0.26	-5.45	69.19	12874
Rhode Island	49.21	0.00	-1.25	-5.25	67.75	12491
Maine	48.44	0.00	-2.03	-5.18	63.63	11448
New Hampshire	50.24	0.00	-0.23	-5.31	67.97	11873
Vermont	51.28	0.00	0.81	-5.71	69.23	12119
Off-Peak						
Internal Hub	30.97	0.00	-0.02	0.86	34.90	7130
Connecticut	31.51	0.00	0.52	0.89	35.25	7364
NE Mass-Boston	30.80	0.00	-0.19	0.68	34.85	7093
SE Mass	30.73	0.00	-0.26	0.74	34.94	7076
West-Central Mass	31.22	0.00	0.23	0.86	35.16	7189
Rhode Island	30.97	0.00	-0.02	0.77	35.65	7131
Maine	29.84	0.00	-1.15	0.80	33.24	6893
New Hampshire	30.75	0.00	-0.24	0.82	34.58	7105
Vermont	31.30	0.00	0.31	1.03	35.06	7230

NYISO day-ahead LMP for Jul 23 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	52.49	0.02	2.87	-1.80	60.03	13393
Central Zone	51.45	-1.06	0.76	-0.84	56.69	14383
Dunwoodie Zone	55.52	-0.18	5.70	-1.85	72.17	13578
Genesee Zone	49.60	-0.22	-0.26	-2.68	53.43	13865
Hudson Valley Zone	55.35	-0.13	5.58	-1.77	70.06	13536
Long Island Zone	104.48	-47.56	7.28	-7.16	109.52	25550
Millwood Zone	55.61	-0.17	5.80	-1.80	72.12	13599
Mohawk Valley Zone	51.74	0.02	2.12	-1.89	58.10	13895
N.Y.C. Zone	64.40	-8.88	5.89	1.20	77.15	15750
North Zone	47.19	0.00	-2.45	-2.14	51.62	11152
West Zone	65.73	-17.21	-1.12	23.95	59.50	18375
Off-Peak						
Capital Zone	31.94	0.00	1.75	0.49	34.53	7914
Central Zone	30.56	0.00	0.37	0.47	31.84	8256
Dunwoodie Zone	33.26	0.00	3.08	0.39	35.74	7970
Genesee Zone	30.25	0.00	0.07	0.58	31.27	8174
Hudson Valley Zone	33.15	0.00	2.96	0.45	35.66	7942
Long Island Zone	42.95	-8.76	4.01	5.19	43.34	10292
Millwood Zone	33.23	0.00	3.05	0.39	35.74	7963
Mohawk Valley Zone	31.12	0.00	0.94	0.39	32.63	8118
N.Y.C. Zone	39.80	-6.26	3.36	0.79	41.08	9537
North Zone	28.83	0.00	-1.35	0.31	30.02	6661
West Zone	30.38	0.00	0.19	0.68	30.99	8209

Generation unit outage report

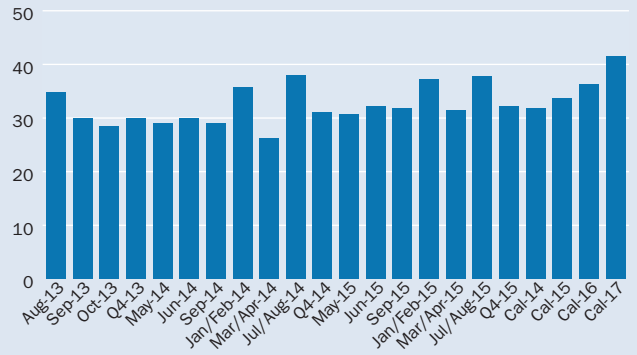
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-1/Bruce Power	750	n	Ont.	Unk	Unk	07/21/13
Bruce-4/Bruce Power	750	n	Ont.	MO	Unk	07/16/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13

Northeast Platts-ICE Forward Curve, Jul 22 ($/MWh)

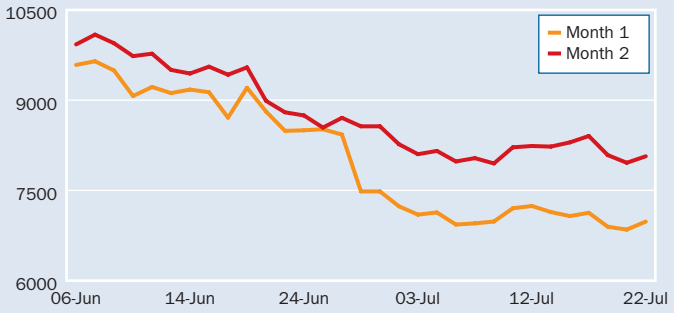
Prompt month: Aug 13	On-peak	Off-peak
Mass Hub	52.00	35.00
N.Y. Zone G	59.75	39.25
N.Y. Zone J	67.00	42.75
N.Y. Zone A	49.25	33.25
Ontario*	34.75	24.25

*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	07/16	149.50-150.50
Next-week	07/16	49.50-50.50

*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.

SOUTHEAST MARKETS

Southeast dailies advance; terms fall

Power prices for Tuesday delivery in the Southeast region advanced Monday, while forwards fell as the NYMEX August natural gas futures contract Monday posted a preliminary settlement price of $3.677/MMBtu, down 11.2 cents, on low seasonal demand due to below-average temperature forecasts for the eastern half of the US.

Electric Reliability Council of Texas dailies for Tuesday delivery were stronger on IntercontinentalExchange Monday morning, with peak load forecast to increase slightly.

Spot natural gas at Houston Ship Channel fell 6.8 cents to trade around $3.620/MMBtu.

ERCOT North Hub next-day on-peak physical power rose about $3 to trade around $41/MWh. Off-peak added around 25 cents to trade around $24.50/MWh. South Hub on-peak gained about $2.75 to trade around $41.50/MWh. Off-peak was bid at $22 and offered at $25/MWh, a loss of roughly 75 cents.

High temperatures across ERCOT's footprint were forecast in the mid-90s Tuesday, with lows in the upper 70s to low 80s. The average July high temperature across the ERCOT region is in the low to mid-90s, with the average low in the mid-70s.

System load in ERCOT was forecast to peak at 59,975 MW Monday and 62,025 MW Tuesday, compared with an actual peak of 53,646 MW Sunday.

Real-time prices averaged $23.75/MWh and were flat from 12:15 to 6 a.m. CDT Monday. Wind generation was forecast to peak at 5,175 MW at midnight CDT Monday and 5,625 MW at 3 a.m. CDT Tuesday.

North Hub balance-of-the-week on-peak packages were bid at $49 and offered at $51. Next-week on-peak was bid at $48 and offered at $51.

In the Southeast, dailies for Tuesday delivery were firmer Monday morning with temperatures forecast increasing slightly. Into Southern next-day on-peak power market was in the mid-$30s/MWh, a slight gain from Friday prices. Spot natural gas at Transco Zone-3 fell 9.4 cents to trade around $3.671/MMBtu.

High temperatures in Atlanta were forecast to rise to the mid-80s Tuesday, with lows expected in the low 70s. The average July

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for Jul 23 ($/MWh)

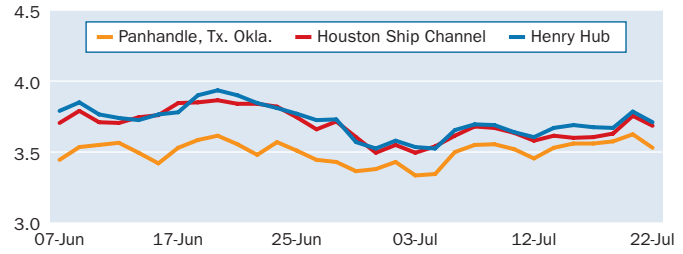
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	40.00	1.00	44.36	10471
Southern, Into	36.75	1.25	35.72	9980
Florida	36.00	1.50	36.27	9461
TVA, Into	37.50	0.75	38.25	10081
Entergy, Into	37.75	0.75	36.64	10286
Southeast Off-Peak				
VACAR	23.50	-0.50	25.77	6152
Southern, Into	21.50	-0.50	24.58	5838
Florida	25.00	0.50	27.09	6570
TVA, Into	22.50	-0.25	24.46	6048
Entergy, Into	19.25	-0.50	22.39	5245
ERCOT On-peak				
ERCOT, North	41.07	3.05	38.07	11345
ERCOT, Houston	41.75	2.50	40.00	11337
ERCOT, South	42.25	3.50	39.55	11720
ERCOT, West	42.00	3.00	39.27	11642
ERCOT Off-Peak				
ERCOT, North	24.45	0.25	23.71	6754
ERCOT, Houston	24.50	0.25	23.91	6653
ERCOT, South	24.50	0.25	23.91	6796
ERCOT, West	24.75	0.25	23.85	6861
SPP/MRO On-peak				
MAPP, South	48.50	1.50	42.39	13126
SPP, North	44.25	1.25	40.47	12535
SPP/MRO Off-Peak				
MAPP, South	21.50	-0.25	23.27	5819
SPP, North	20.50	-0.50	22.85	5807

Southeast load and generation mix forecast (GWh)

	Actual 21-Jul	%Chg	% Chg Year-ago	Forecast 22-Jul	23-Jul	24-Jul	25-Jul	26-Jul
ERCOT								
Load	1024	2	-1	1103	1158	1180	1194	1195
Generation								
Coal	400	2	14	434	449	453	454	454
Gas	463	3	-13	497	511	517	540	552
Nuclear	123	1	-2	123	123	123	123	123
SPP								
Load	727	-3	-3	744	784	779	762	757
Generation								
Coal	427	-3	7	447	464	454	442	435
Gas	219	0	-25	217	230	223	213	206
Nuclear	40	-7	-3	49	49	49	49	49

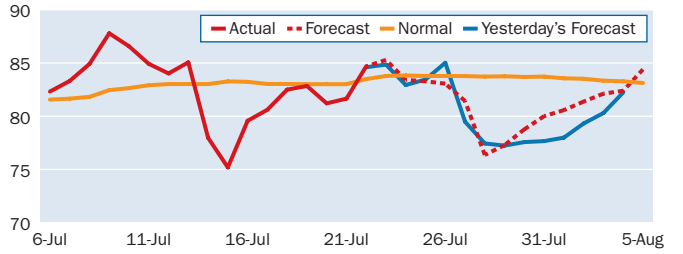
Source: Bentek

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



Source: Platts

ERCOT & SPP average temperature (°F)



Source: Custom Weather

ERCOT average day-ahead LMP for Jul 23 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	39.87	2.51	37.57	10952
Hub Average	39.95	2.53	37.88	10975
Houston Hub	40.00	2.64	38.56	10838
North Hub	39.83	2.54	37.13	10970
South Hub	39.46	2.16	37.85	10892
West Hub	40.51	2.76	37.96	11207
AEN Zone	51.57	4.27	40.76	14268
CPS Zone	41.46	2.20	38.87	11456
LCRA Zone	44.64	3.31	38.95	12334
Rayburn Zone	39.27	2.09	37.04	10817
Houston Zone	40.18	2.66	38.71	10886
North Zone	40.04	2.66	37.26	11030
South Zone	42.86	3.19	39.06	11832
West Zone	47.33	5.36	45.46	13094
Off-Peak				
Bus Average	25.04	0.24	24.16	6781
Hub Average	25.06	0.25	24.16	6785
Houston Hub	25.02	0.20	24.17	6706
North Hub	25.01	0.23	24.15	6789
South Hub	25.14	0.30	24.16	6799
West Hub	25.06	0.25	24.19	6865
AEN Zone	26.54	0.87	24.56	7270
CPS Zone	25.48	0.30	24.30	6927
LCRA Zone	25.58	0.36	24.29	6953
Rayburn Zone	25.01	0.24	24.14	6788
Houston Zone	25.02	0.20	24.17	6706
North Zone	25.01	0.23	24.15	6790
South Zone	25.37	0.29	24.23	6861
West Zone	25.29	0.36	24.51	6927

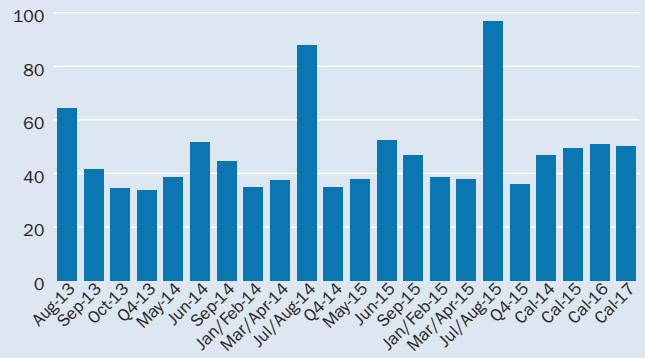
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	07/16	40.75-41.25
Bal-month	07/18	35.75-36.25
Bal-month	07/16	37.75-38.25
Next-week	07/18	36.25-36.75
Next-week	07/16	39.75-40.25
Entergy, Into		
Bal-week	07/19	36.75-37.25
Bal-week	07/16	36.75-37.25
Bal-month	07/19	36.50-37.00
Bal-month	07/18	34.75-35.25
Bal-month	07/16	39.75-40.25
Next-week	07/18	36.75-37.25
Next-week	07/16	36.75-37.25
ERCOT, North		
Next-week	07/18	51.75-52.25
Next-week	07/17	46.00-46.50

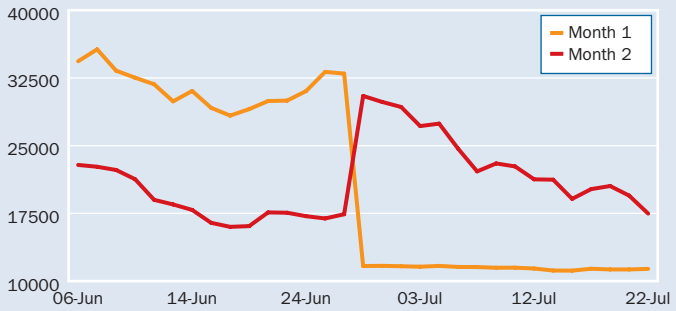
Southeast & Central Platts-ICE Forward Curve, Jul 22 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
Southern Into	36.25	29.00
Entergy Into	35.50	26.75
ERCOT North	64.50	32.00
ERCOT Houston	66.00	32.00
ERCOT West	67.00	32.00
ERCOT South	64.25	33.00

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



ERCOT South: 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	08/15/13	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

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.

WEST MARKETS

Most Western dailies slip; terms move down

Most Western dailies were down Monday, with the move away Sunday peak hours in the off-peak price and lower spot natural gas prices in the region. Terms plunged, and the NYMEX August natural gas futures contract posted a preliminary settlement price of $3.677/MMBtu, down 11.2 cents from Friday's close.

In the Northwest, Mid-Columbia day-ahead on-peak was up more than $4.50 to trade between $43.50 and $57/MWh for delivery on Tuesday. Mid-C day-ahead off-peak fell more than $1.50 to trade between $26 and $27.50/MWh. The Mid C on-peak balance-of-the month package was bid at $39 and offered at $41.25/MWh, down more than $1.75.

Portland, Oregon's forecast highs were for the mid-80s on Tuesday, up slightly from Monday?s projections. Expected lows were for the high 50s.

The Bonneville Power Administration's wind at 7 a.m. PDT Monday was 2,131 MW and its hydropower was 8,420 MW.

In California, SP15 next-day on-peak was down more than $1.50 to trade between $48 and $48.75/MWh. SP15 day-ahead off-peak was down about $3.25 to trade between $34.50 and $36.50/MWh. SP15 bal-month was bid at $48.25 and $49.50/MWh, down more than $1.50. NP15 day-ahead on-peak was down $1 to around $44/MWh. NP15 day-ahead off-peak dropped $3.25 to about $32.50/MWh. NP15 bal-month was bid at $42.75 and offered at $45.75/MWh, down more than $2.50.

Sacramento, California, expected highs near in the low 90s on Tuesday, up about five degrees from Monday's anticipated temperatures, with lows from the high 50s to the low 60s. Forecast highs for Burbank were for the mid-80s through Tuesday and projected lows were for the mid- to high 60s.

Cal-ISO projected peak demand to hit 36,882 MW on Monday and 37,809 MW on Tuesday. Renewables were 2,579 MW and wind was less than 800 MW at 7 a.m. PDT on Tuesday. In the desert Southwest, Palo Verde next-day on-peak was up about $1 to trade between $44.75 and $45.50/MWh. Palo Verde day-ahead off-peak was down around $4.75 to trade between $25 and $27.50/MWh.

Phoenix expected below-normal highs around 101 and normal lows near the mid-80s Tuesday.

Next-day natural gas prices retreated in the Rockies and California. Opal was down 9.2 cents to $3.543/MMBtu, PG&E city-gate also lost 9.2 cents to $3.848/MMBtu, and SoCal city-gate fell 3.8 cents to $3.897/MMBtu.

Most day-ahead prices were down in the California ISO auction Monday afternoon. SP15 on-peak fell $4.46 to $45.39/MWh, and SP15 off-peak was down $4.29 to $34.02/MWh. NP15 on-peak lost 79 cents $41.84/MWh, while NP15 off-peak gained $1.21 to $34.86/MWh. ZP26 on-peak dropped 34 cents to $42.63/MWh, as ZP26 off-peak climbed $1.78 to $32.60/MWh.

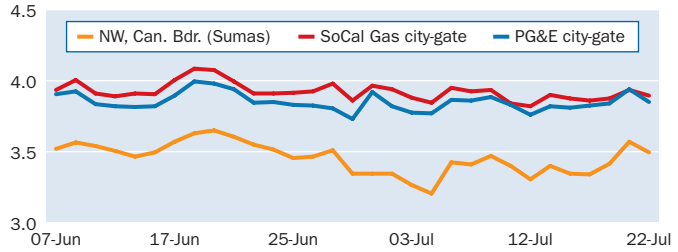
In the Northwest, Mid-Columbia on-peak August shed 75

(continued on page 10)

Western day-ahead bilateral indexes for Jul 23 ($/MWh)

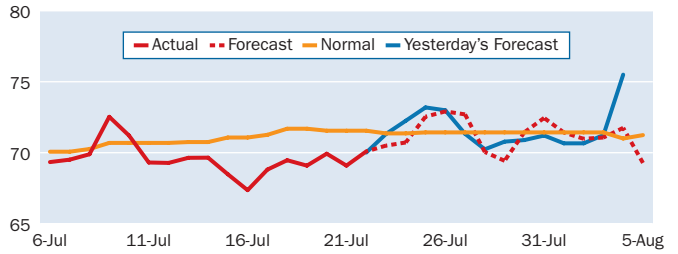
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	53.75	8.35	51.49	14848
Mid-C	47.22	4.55	46.10	13396
Palo Verde	45.07	0.95	50.81	12247
Mead	51.75	0.57	57.53	13672
Mona	49.50	1.50	55.41	14143
Four Corners	50.50	7.00	53.52	14126
NP15	43.25	-1.75	51.74	11234
SP15	48.50	-1.50	53.75	12814
Off-Peak				
COB	27.50	-3.23	21.59	7597
Mid-C	26.71	-1.75	19.18	7577
Palo Verde	25.86	-4.89	27.40	7027
Mead	28.00	-4.00	29.45	7398
Mona	28.50	-4.00	24.95	8143
Four Corners	26.00	-5.00	26.97	7273
NP15	32.50	-3.25	34.53	8442
SP15	35.75	-4.00	36.09	9445

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO average temperature (°F)



Source: Custom Weather

Western load and generation mix forecast (GWh)

	Actual 21-Jul	%Chg	% Chg Year-ago	Forecast 22-Jul	23-Jul	24-Jul	25-Jul	26-Jul
CAISO								
Load	679	-5	2	723	750	760	790	808
Generation								
Gas	293	-1	3	273	279	291	318	338
Nuclear	56	0	-9	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Jul 23 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	41.84	-2.06	-2.02	-0.79	48.56	10868
SP15 Gen Hub	45.39	0.32	-0.85	-4.46	50.18	11992
ZP26 Gen Hub	42.63	-0.41	-2.88	-0.34	45.99	11264
Off-Peak						
NP15 Gen Hub	34.86	0.75	-0.78	1.21	34.42	8891
SP15 Gen Hub	34.02	-0.14	-0.73	-4.29	33.72	8936
ZP26 Gen Hub	32.60	-0.61	-1.70	1.78	31.63	8561

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	07/17	41.00-43.00
Bal-month	07/16	42.00-43.00
Bal-month (off-peak)	07/19	25.75-26.25
SP15		
Bal-month	07/17	49.50-50.50

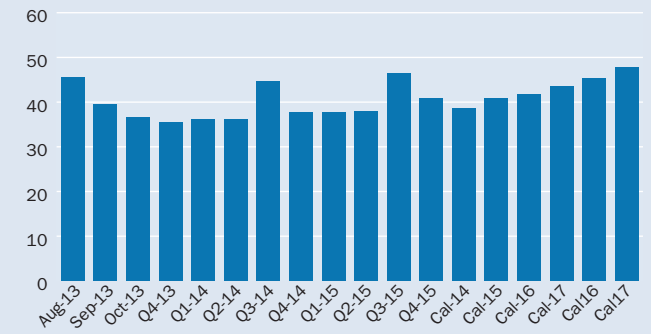
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Alamitos-6/AES	495	g	Calif.	MO	Unk	07/21/13
Contra Costa-6/NRG	337	g	Calif.	PMO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
El Segundo-5-8/NRG	520	g	Calif.	MO	Unk	07/21/13
Huntington Beach-3/AES	225	g	Calif	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif	PMO	Unk	04/14/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Retired	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Retired	01/31/12

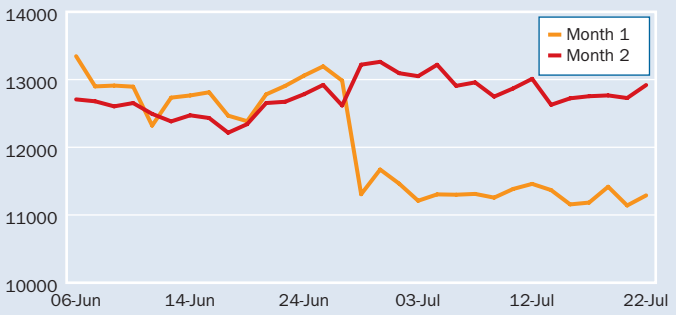
Western Platts-ICE Forward Curve, Jul 22 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
Mid-C	45.50	31.50
Palo Verde	45.50	28.90
Mead	46.75	30.50
NP15	47.50	36.25
SP15	52.75	38.00

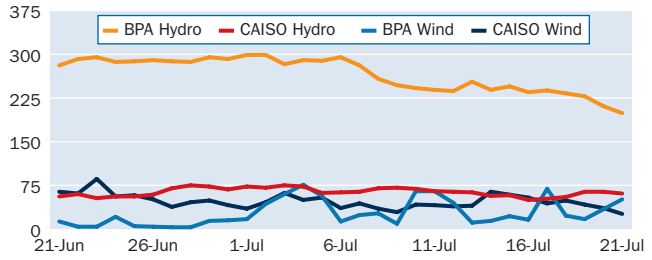
Palo Verde: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

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.

PJM & MISO MARKETS

PJM dailies flat as demand eases

Daily power prices in the Mid-Atlantic were nearly flat Monday, with demand expected to ease slightly, while dailies in the Midwest were mixed or weaker. Forward prices dipped as the NYMEX August natural gas futures contract settled Monday at $3.677/MMBtu, down 11.2 cents.

PJM Interconnection forecasted peak demand for Monday at 136,432 MW and 134,451 MW for Tuesday. High temperatures across the PJM footprint are forecast in the upper 70s to upper 80s on Tuesday.

Spot natural gas in the region was down, with Texas Eastern M-3 down 23 cents to $3.64/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Tuesday were steady in upper $40s/MWh on ICE. PJM West Hub off-peak was also unchanged in the upper $20s to around $30/MWh.

Daily prices in the Midcontinent ISO were mixed Monday, with nearby prices holding steady. Chicago city-gates spot gas fell about 13 cents to $3.74/MMBtu.

Indiana Hub peak for Tuesday eased about $1 to the upper $30s/MWh, as off-peak was unchanged in the mid-$20s/MWh. Minnesota peak for Tuesday gained about $5, going to around $40/MWh.

Dailies in the Midwestern portion of PJM were weaker, with lower temperatures and spot natural gas. AEP-Dayton Hub peak for Tuesday shed about $1.75, going to the low $40s/MWh, as off-peak fell about $1 to the mid-$20s/MWh. Northern Illinois Hub peak was off about $1 to around $40/MWh, as off-peak lost about $7 to the mid-$20s/MWh.

Day-ahead auction prices in PJM were down Monday with lower expected loads and temperatures. Eastern Hub peak lost $5.41 clearing at $52.86/MWh and Western Hub peak shed $1.47 to $52.11/MWh. PSEG peak moved down $7.36 to $54.11/MWh and JCPL peak was down $3.60 to $57.47/MWh.

BG&E peak lost $4.04 clearing around $52.66/MWh and Pepco peak gave up $4.17 clearing near $50.90/MWh. ATSI peak dropped $3.30 at $50.36/MWh and Chicago Hub peak was down $4.76 at $43.07/MWh.

MISO day-ahead auction prices cleared weaker Monday for on-peak periods and mainly stronger for off-peak hours. Michigan remained the highest-priced hub, with on-peak at $42.87/MWh, down $4.33. Off-peak cleared at $25.93/MWh, an increase of 69 cents.

Indiana Hub on-peak cleared at $41.93/MWh, a loss of $3.07. Off-peak cleared at $24.63/MWh, a gain of 30 cents. Illinois Hub on-peak cleared the auction at $40.68/MWh, falling $4.39, while off-peak cleared at $25.98/MWh, adding $2.87. Minnesota Hub maintained its lowest-priced hub position, with on-peak clearing at $38.90/MWh, shedding $6.12, while off-peak cleared at $20.44/MWh, dropping 11 cents.

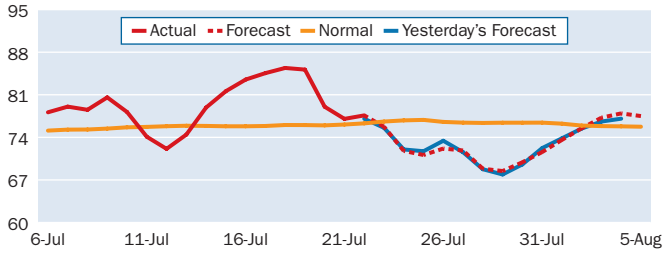
Congestion costs at the hubs ranged from negative $1.82 to $2.07 for on-peak, and from negative $1.85 to $2.74 for off-peak.

Mid-Atlantic forward prices dropped Monday, with rapidly

PJM & MISO day-ahead bilateral indexes for Jul 23 ($/MWh)

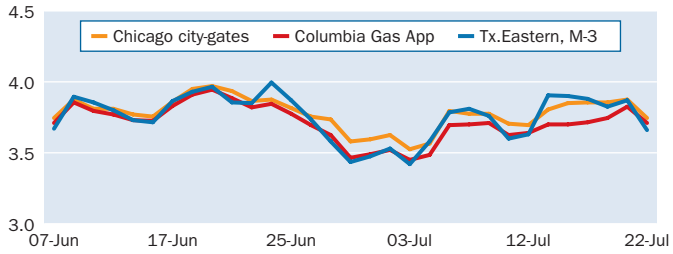
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	49.50	0.25	70.22	14163
Dominion Hub	48.75	8.25	66.14	12948
AD Hub	42.25	-1.75	61.36	11162
NI Hub	40.00	-1.00	57.66	10681
PJM Off-Peak				
PJM West	29.50	-0.50	29.91	8441
Dominion Hub	30.00	-1.00	29.80	7968
AD Hub	26.00	-1.00	27.95	6869
NI Hub	24.00	-7.00	24.63	6409
MISO On-peak				
Indiana Hub	39.50	-1.00	45.83	10576
Michigan Hub	41.00	-3.00	47.17	10466
Minnesota Hub	39.25	3.75	44.84	10397
Illinois Hub	38.75	2.25	43.84	10347
MISO Off-Peak				
Indiana Hub	25.25	0.25	24.34	6760
Michigan Hub	26.25	0.00	25.73	6701
Minnesota Hub	22.00	1.25	22.08	5828
Illinois Hub	24.50	0.50	23.70	6542

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 21-Jul	%Chg	% Chg Year-ago	Forecast 22-Jul	23-Jul	24-Jul	25-Jul	26-Jul
PJM								
Load	2466	-9	2	2571	2563	2438	2302	2290
Generation								
Coal	1125	-11	14	1169	1208	1237	1286	1331
Gas	495	-6	-19	491	486	455	412	404
Nuclear	769	-2	1	775	778	778	778	778
MISO								
Load	1413	-10	-1	1576	1576	1469	1428	1408
Generation								
Coal	1209	-8	8	1331	1349	1288	1255	1254
Gas	114	-21	-44	120	151	139	122	111
Nuclear	189	-3	-11	188	188	189	190	192

Source: Bentek

MISO average day-ahead LMP for Jul 23 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	41.93	2.07	-0.50	-3.70	41.32	11171
Michigan Hub	42.87	1.59	0.93	-4.33	42.98	10896
Minnesota Hub	38.90	-1.82	0.36	-6.12	41.39	10258
Illinois Hub	40.68	1.58	-1.25	-4.39	39.77	10813
Off-Peak						
Indiana Hub	24.63	0.65	0.44	0.30	23.17	6428
Michigan Hub	25.93	0.86	1.53	0.69	24.59	6421
Minnesota Hub	20.44	-1.85	-1.26	-0.11	20.03	5253
Illinois Hub	25.98	2.74	-0.30	2.87	22.38	6724

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

Package	Trade date	Range
PJM West		
Bal-week	07/22	41.75-44.00
Bal-week	07/19	51.75-53.00
Bal-week	07/17	121.00-141.00
Bal-week	07/16	123.25-136.00
Bal-month	07/19	53.75-54.75
Next-week	07/19	55.75-56.75
Next-week	07/18	52.75-54.00
Next-week	07/17	50.00-52.00
Next-week	07/16	51.00-52.50
AD Hub		
Bal-week	07/16	117.50-118.50

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Kewaunee/Dominion	581	n	Wis.	NA	Retired	05/07/13

PJM average day-ahead LMP for Jul 23 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	42.89	-2.53	-2.73	-4.16	52.31	11508
AEP-Dayton Hub	44.99	-2.19	-0.97	-4.17	55.41	12072
ATSI Gen Hub	49.40	0.97	0.28	-3.43	60.54	13521
Chicago Gen Hub	42.11	-3.51	-2.52	-4.78	51.07	11197
Chicago Hub	43.07	-3.31	-1.76	-4.76	52.85	11452
Dominion Hub	47.09	0.54	-1.60	-2.74	60.24	12465
Eastern Hub	52.86	1.58	3.13	-5.41	69.92	14009
New Jersy Hub	54.58	4.02	2.41	-6.03	69.56	14464
Northern Illinios Hub	42.70	-3.37	-2.08	-4.79	52.09	11352
Ohio Hub	45.09	-2.33	-0.73	-4.31	55.63	11870
West Internal Hub	47.76	0.39	-0.77	-4.08	60.46	13577
Western Hub	52.11	4.27	-0.30	-1.47	63.49	14816
AEP Zone	45.32	-1.80	-1.03	-4.03	55.86	12160
Allegheny Power Zone	47.66	0.06	-0.55	-4.14	59.59	13012
Atlantic Elec Zone	49.96	-0.81	2.61	-7.54	67.45	13239
ATSI Zone	50.36	1.50	0.71	-3.30	61.63	13784
BG&E Zone	52.66	3.04	1.47	-4.04	68.02	14495
ComEd Zone	43.02	-3.32	-1.80	-4.75	52.72	11438
Dayton P&L Zone	45.98	-2.25	0.09	-4.15	55.76	12252
Delmarva P&L Zone	52.01	1.22	2.64	-5.34	68.64	13784
Dominion Zone	47.82	0.55	-0.87	-3.86	61.91	12658
Duke Zone	43.87	-2.27	-2.01	-4.10	53.59	11688
Duquesne Light Zone	47.03	0.31	-1.42	-3.76	58.54	13356
JCPL Zone	57.47	6.94	2.37	-3.60	71.29	15229
MetEd Zone	52.57	3.72	0.70	-5.50	65.70	13993
PECO Zone	49.73	-0.04	1.62	-6.21	65.52	13236
Pennsylvania Elec Zone	54.35	5.51	0.70	-1.08	63.63	15664
PEPCO Zone	50.90	2.17	0.58	-4.17	66.04	14012
PPL Zone	55.74	6.78	0.81	-7.08	65.44	14836
PSEG Zone	54.11	3.53	2.43	-7.36	69.23	14341
Rockland Elec Zone	54.99	4.56	2.29	-8.37	68.85	14573
Off-Peak						
AEP Gen Hub	25.88	-0.56	-1.25	-0.60	26.78	6760
AEP-Dayton Hub	26.45	-0.65	-0.58	-0.90	27.89	6910
ATSI Gen Hub	28.03	0.45	-0.10	0.01	28.87	7429
Chicago Gen Hub	24.30	-1.84	-1.55	-0.79	24.38	6298
Chicago Hub	24.89	-1.56	-1.23	-0.64	25.12	6451
Dominion Hub	28.40	0.71	0.00	-0.92	29.20	7366
Eastern Hub	29.53	0.59	1.25	-0.63	30.74	7604
New Jersy Hub	29.58	0.79	1.10	-1.01	31.06	7615
Northern Illinios Hub	24.72	-1.60	-1.36	-0.67	24.90	6407
Ohio Hub	26.51	-0.66	-0.52	-0.94	28.08	6818
West Internal Hub	27.94	0.49	-0.24	-0.29	28.80	7672
Western Hub	28.79	0.86	0.24	-0.18	29.28	7903
AEP Zone	26.57	-0.58	-0.54	-0.81	27.88	6942
Allegheny Power Zone	28.06	0.43	-0.06	-0.42	28.83	7467
Atlantic Elec Zone	29.42	0.54	1.18	-0.74	30.57	7573
ATSI Zone	28.16	0.40	0.07	-0.07	29.03	7463
BG&E Zone	29.32	0.60	1.03	-0.61	30.33	7840
ComEd Zone	24.86	-1.57	-1.26	-0.65	25.06	6443
Dayton P&L Zone	27.06	-0.35	-0.28	-0.46	27.92	7062
Delmarva P&L Zone	29.40	0.60	1.11	-0.58	30.57	7569
Dominion Zone	28.58	0.66	0.24	-0.88	29.39	7415
Duke Zone	25.94	-0.50	-1.25	-0.57	26.87	6770
Duquesne Light Zone	26.97	0.17	-0.89	-0.40	27.95	7393
JCPL Zone	29.43	0.67	1.07	-0.70	30.85	7578
MetEd Zone	28.56	0.56	0.32	-0.40	29.69	7400
PECO Zone	28.98	0.53	0.76	-0.63	30.10	7509
Pennsylvania Elec Zone	29.37	0.99	0.69	-0.16	29.71	8214
PEPCO Zone	28.96	0.59	0.69	-0.64	29.93	7746
PPL Zone	28.79	0.68	0.41	-1.53	29.42	7458
PSEG Zone	29.74	0.93	1.12	-1.40	31.40	7657
Rockland Elec Zone	29.96	1.20	1.06	-1.32	31.29	7712

falling spot power prices and natural gas futures coming down. PJM West on-peak August financial futures moved down $1.25, with bids at $52.60/MWh and offers at $52.85/MWh on ICE. The PJM West prompt-month package was down as much as $2 in early trading. PJM West on-peak fourth-quarter slipped 60 cents to $41.25/MWh. PJM West on-peak January-February 2014 financial futures fell $1 to $44.50/MWh on ICE.

Midwest forwards were down Monday with weaker prices to the east and falling gas futures. AEP-Dayton Hub on-peak August financial futures dropped 75 cents, with bids at $47.45/MWh and offers at $48.85/MWh on ICE. The AD Hub prompt-month package was down as much as $1.75 in morning trading. Indiana Hub on-peak August financial futures were down 75 cents, with bids at $43.25/MWh and offers at $44.25/MWh on ICE.

Southeast markets ... *from page 4*

high temperature in the city is 89. Its average low is 71.

The ERCOT day-ahead auction for Tuesday delivery cleared firmer Monday afternoon, with peak load forecast to increase slightly West Hub moved into the highest-priced hub as South Hub became the lowest-priced hub.

West Hub on-peak cleared in the ERCOT auction at $40.51/MWh, a jump of around $2.75, while off-peak cleared at $25.06/MWh, a gain of about 25 cents.

Houston Hub on-peak cleared in the auction at $40/MWh, a bump of about $7.25, while off-peak cleared at $25.02/MWh, up almost 25 cents. North Hub on-peak cleared the auction at $39.83/MWh, adding roughly $2.50 from Sunday's clearing price, while off-peak cleared at $25.01/MWh, up almost 25 cents.

South Hub on-peak cleared at $39.46/MWh, rising almost $2.25, while off-peak cleared at $25.14/MWh, gaining more than 25 cents. Austin Zone on-peak led the load zones at $51.57/MWh, up about $4.25 from Sunday.

The highest hourly day-ahead price occurred at 5 p.m. CDT in the West Hub at $59.04/MWh and in the Austin Zone at $82.70/MWh. ERCOT system load was forecast to peak at 62,025 MW Tuesday, up 3 % from Monday's expected peak of 59,975 MW.

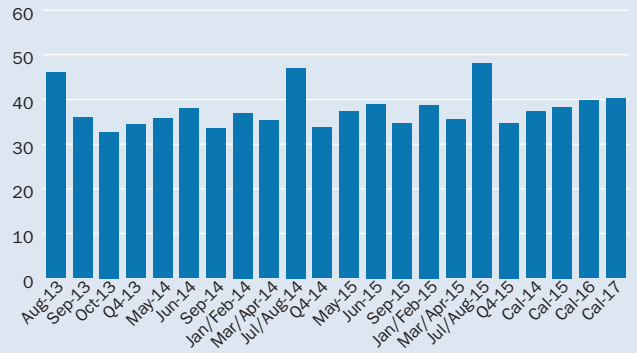
South Central on-peak August terms moved down Monday. ERCOT North on-peak August plunged $9.50 to about $64.50/MWh, September shed $1 cents to about $41/MWh, and the fourth quarter fell 70 cents to about $33.60/MWh. Heat rates were up about 80 Btu/kWh on IntercontinentalExchange around 2:30 p.m. EDT. Into Entergy on-peak August fell 25 cents to about $35.50/MWh, and Q4 skidded 60 cents to about $32.25/MWh.

Southeast on-peak August fell Monday, as did August NYMEX gas futures. Into Southern August fell 25 cents to about $36.25/MWh, September dived 50 cents to about $33.75/MWh, and Q4 slid 60 cents to about $34/MWh.

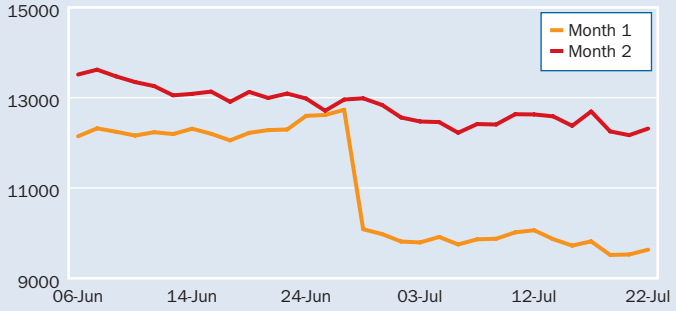
PJM & MISO Platts-ICE Forward Curve, Jul 22 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
PJM West	52.75	32.75
AD Hub	48.00	29.75
NI Hub	46.00	26.00
Indiana Hub	43.75	27.25

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



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



West markets ... *from page 6*

cents with bids at $45 and offers at $45.75/MWh on ICE around 2:30 p.m. EDT. September fell 50 cents to about $39.25/MWh, and Q4 dived 85 cents to about $37.15/MWh. In California, SP15 on-peak August financial terms dropped $1 with bids at $52.50 and offers at $53/MWh. September fell 75 cents to about $51.25/MWh, and Q4 fell 75 cents to about $46.25/MWh. NP15 August skidded $1.50 to about $47.50/MWh, and Q4 fell $1.10 to about $42.75/MWh. Palo Verde August fell 75 cents to about $45.50/MWh, September fell 75 cents to about $39.50/MWh, and Q4 slipped down 85 cents to about $35.40/MWh.

NEWS

FERC, JP Morgan may be nearing settlement

The Federal Energy Regulatory Commission and JP Morgan are nearing a settlement over alleged market manipulation, according to a press report Monday that valued the settlement's penalties at roughly $410 million.

The *Wall Street Journal* report said the agreement, which is not yet final, would likely not include penalties for individual JP Morgan traders.

In its recent record fine, FERC fined both Barclays Bank and four of its former traders for allegedly manipulating power prices in California and other western markets between November 2006 and December 2008.

The Journal also said the settlement could come this week.

FERC declined to comment Monday.

JP Morgan representatives were not immediately available for comment Monday.

FERC has been investigating JP Morgan's bidding practices in California and Michigan, and the company told the Securities and Exchange Commission in May that it "received a Wells-type notice that the FERC staff intends to recommend that the commission bring a possible enforcement action against J.P. Morgan Ventures Energy Corp., ... JPMorgan Chase & Co. and certain firm personnel relating to alleged violations of FERC rules and the rules of certain independent system operators" in March.

The Journal report came as a federal appeals court on Friday put a hold on FERC's challenge to a lower court ruling that rejected the agency's request for access to certain emails between JP Morgan Ventures Energy and its attorneys related to FERC's investigation into alleged market manipulation by JP Morgan.

— *Bobby McMahon*

Project aims to serve Southeast generation

Williams Partners is seeking approval for a 225,000 Dt/d expansion on the Transcontinental Gas Pipe Line system that would help serve growing demand for gas-fired power generation in the southeastern US.

Williams' Transco pipeline filed with the Federal Energy Regulatory Commission for approval of the Mobile Bay South III Expansion Project, designed to provide 225,000 Dt/d of firm transportation service on the Transco Mobile Bay Lateral. It could come online by spring 2015, Williams said in a news release Monday.

The proposed expansion would add compression power at Transco Compressor Station 85 in Choctaw County, Alabama, and bring upgrades at facilities in Washington and Mobile counties in the state. Williams said construction could begin in spring 2014 and the capital cost of the project is around $50 million.

The project would add capacity on the Mobile Bay Lateral from the Station 85 4A pooling point and other receipt points at Transco's Station 85 to interconnections with Florida Gas Transmission and Bay Gas Storage in Mobile County.

"Growing power-generation demand has dramatically increased utilization of Transco's Mobile Bay Lateral in recent years," Frank Ferazzi, general manager of the Transco system, said in the news release. "Our proposed Mobile Bay South III expansion is an efficient way to move additional supply from a well-positioned compressor station in Choctaw County, Ala. to a number of regional storage facilities to growing Southeastern markets."

Power generation is one of the major price drivers in the Transco zone 4 market, where Station 85 is located.

Platts on Monday assessed calendar year 2015 Transco zone 4 packages at a basis of plus 2.75 cents/MMBtu, wider than the calendar year 2014 basis, assessed at plus 1.75 cents/MMBtu.

Florida Gas Transmission zone 3 basis for calendar year 2015 was assessed by Platts at plus 15.5 cents/MMBtu Monday, above the 2014 calendar year for Florida zone 3, assessed at plus 13.75 cents/MMBtu.

Modeled data from Bentek Energy, a unit of Platts, shows Southeastern gas demand for power burn averaging just more than 8 Bcf/d in 2012, up from 6.6 Bcf/d in 2011 and 6.1 Bcf/d in 2010. Year-to-date gas demand for power burn is around 6.9 Bcf/d, according to the Bentek data, reflecting higher gas prices this year as compared with last.

Southeast gas power burn was at about 7.7 Bcf Monday, according to Bentek, making up about 26% of total US gas power burn.

Williams said the project would deliver enough gas to provide service to approximately 1 million homes.

The Transco pipeline is a 10,200-mile pipeline system that provides natural gas transportation and storage services for markets throughout the Northeastern and Southeastern United States. The current system capacity is approximately 9.9 million Dt/d per day, which is enough natural gas to serve the equivalent of 42 million homes.

The final stage of another Transco project, the Mid-South expansion, became operational June 10, boosting the line's capacity by 225,000 Dt/d and adding 23 miles of new pipe to provide incremental firm transport to power plants in North Carolina and Alabama, and to a local distribution company in Georgia.

Additionally, Williams' Virginia Southside Expansion would expand Transco pipeline facilities in southern Virginia by 2015, allowing the pipeline to increase deliveries by 270,000 Dt/d. The project is primarily designed to fuel Dominion Virginia Power's new 1,300-MW power plant planned in Brunswick County, Virginia.

— *Patrick Badgley*

Offshore wind lease auction set for September

Recently With the first-ever lease sale for wind energy in federal waters just over a week away, the Obama administration Monday said the second auction will take place in September.

The second auction, scheduled September 4, will be for nearly 113,000 acres offshore Virginia for commercial wind energy leasing.

“The competitive lease sale offshore Virginia will mark an important transition from planning to action when it comes to capturing the enormous clean energy potential offered by Atlantic

wind," Interior Secretary Sally Jewell said in a statement.

The area, to be auctioned as a single lease, is located 23.5 nautical miles from Virginia Beach and could support more than 2,000 MW of wind generation, according to the Interior Department.

The auction is part of President Barack Obama's recently outlined climate change action plan to add 10,000 MW of energy production on public lands and waters by 2020, Interior said.

Federal and state officials have been working to develop the offshore area for auction for more than two years. Federal regulators have identified eight companies that are eligible to bid in the September auction: Apex Virginia Offshore Wind; Virginia Electric and Power Co.; Energy Management; EDF Renewable Development; Fisherman's Energy; Iberdrola Renewables; Sea Breeze Energy; and Orisol Energy.

"After careful review, [the Bureau of Ocean Enery Management] has determined that these companies are legally, technically and financially qualified to participate in the upcoming lease sale," BOEM Director Tommy Beaudreau said in a statement. "We applaud their leadership and look forward to overseeing a fair and competitive leasing process."

On July 31, Interior also will offer nearly 165,000 acres of federal waters off Rhode Island and Massachusetts for wind-energy development as part of the first renewable energy lease sale on the US Outer Continental Shelf.

The offshore area up for auction covers 164,750 acres, or about 257 square miles, located about nine nautical miles off Rhode Island's coast. BOEM will auction the area as two leases: the North Lease Area, covering 97,500 acres, and the South Lease Area, covering 67,250 acres.

A recent Department of Energy report claimed the North Area has potential for installed capacity of 1,955 MW, while the South Area has potential capacity of 1,440 MW.

— Brian Scheid

Daily CSAPR allowance assessments, Jul 22

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 22

	$/allowance	Change	$/st
SO2 2013	0.64	0.00	1.28

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, Jul 19 ($/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	3.40	0			
Dec13 V13	3.40	385			
Dec14 V10	3.53	0			
Dec14 V11	3.53	0			
Dec14 V12	3.40	0			
Dec14 V13	3.40	0			
Dec15 V10	3.53	0			
Dec15 V11	3.53	0			
Dec15 V12	3.40	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.

Delays in nuclear capacity get closer look

Recently announced delays in the expected online dates for the four 1,100-MW nuclear units now under construction in Georgia and South Carolina—and cost increases associated with the projects—are raising concerns among state regulators, regulatory staff, and a credit rating agency.

However, the delays are not causing any power-supply angst for the utilities involved; all say either that they will have ample reserves until the units come online, or that they expect no difficulty in securing any needed short-term power from the Southeast's capacity-rich market.

Georgia Power and the other entities co-developing two Westinghouse AP1000 units at Plant Vogtle currently expect the new units to begin commercial operation in the fourth quarter of 2017 and the fourth quarter of 2018, respectively, and Georgia Power, which owns 45.7% of the units, has acknowledged that further delays are possible.

Meanwhile, South Carolina Electric & Gas and Santee Cooper, which are co-developing two AP1000 units at their V.C. Summer station, now expect the first new unit to start up in either the fourth quarter of 2017 or the first quarter of 2018, with the second unit to follow in the first half of 2019.

Originally, the developers of the Vogtle and Summer units had expected that their first units would come online in 2016 and their second units to follow in 2017.

Despite the ever-lengthening delays in completing the nuclear units, there is some good news. Georgia Power spokesman Mark Williams said the utility will not need to buy or build any capacity to meet their incremental needs in the 2016-17 period, when it initially had been expecting to start receiving power from the new Vogtle units.

"We believe, as laid out in [Georgia Power's 2013 integrated resource plan], that we have sufficient generating capacity to meet the expected demand" until the new Vogtle units come online, Williams said. During the Georgia Public Service Commission's recently completed review of the IRP, it became known that even with more than 2,000 MW of planned coal-unit retirements, Georgia Power's reserve margin is expected to top 25% for the foreseeable future.

By 2016, the utility also is expected to benefit—at least during daylight hours—from 525 MW of additional solar capacity the PSC has directed Georgia Power to buy.

SCE&G, in turn, may need some incremental power mid-

decade, but is so confident that power will be available for purchase that it last month accelerated the retirement of two older coal units—the 115-MW Canadys-2 and 180-MW Canadys-3—by the end of this year. The utility previously had been planning to convert the units to natural gas firing and retire them in 2018. SCE&G has declined to speculate on how much power SCE&G might need or when it might need it.

SCE&G still plans to convert its McMeekin-1 and -2 coal units—each of which has a capacity of 125 MW—to gas firing by 2016 to keep the utility in compliance with the Environmental Protection Agency's new Mercury & Air Toxics Standards. The converted McMeekin units then would be retired in 2018 when SCE&G's new nuclear capacity starts coming online.

Santee Cooper spokeswoman Mollie Gore said that even before the latest delays at the Summer nuclear project were announced, the utility expected to buy modest amounts of short-term power to help it keep pace with demand through the middle of this decade.

According to Santee Cooper's most recent IRP, which was issued last November, the utility said it expects to need to buy 130 MW in the winter of 2014-15, followed by 330 MW in the winter of 2015-16, 85 MW in the summer of 2016, and 235 MW in the winter of 2016-17.

Gore said Santee Cooper will consider the new online dates for the Summer nuclear units and other factors when preparing its next IRP, which is schedule for release in November. She noted that there appear to be ample amounts of power available for purchase in the Southeast, and that Santee Cooper does not expect any difficulty in securing the power it needs.

While it seems Georgia Power, SCE&G and Santee Cooper will have no trouble keeping pace with power demand, their nuclear projects are facing increasing criticism.

For example, at a July 18 hearing on the Vogtle project, several members of the Georgia Public Service Commission raised concern about project delays and cost increases, most recently Georgia Power's request that the PSC approve a roughly $700 million increase in the $6.1 billion budget for the utility's 45.7% share.

Commissioner Tim Echols suggested that Georgia Power consider reaching a settlement agreement on project costs similar to the one its sister utility, Mississippi Power, reached on its Kemper County integrated gasification combined-cycle project, which is now well over-budget.

In the Kemper settlement, Mississippi Power agreed to cap at $2.4 billion the project costs on which the utility could earn a rate of return on equity. In exchange, the PSC agreed to let Mississippi Power issue up to $1 billion in securitization bonds to help pay for the rest of the project. Echols also questioned whether some of the extra costs that Georgia Power has been incurring were prudently spent.

In South Carolina, the state's Office of Regulatory Staff said in a new report to the South Carolina Public Service Commission that the consortium building the two new Summer units continue to experience "ongoing construction challenges" that threaten the $10 billion project's already-delayed schedule, as well as the project's budget.

The ORS said, "The most significant issue is the delay in the delivery of the structural submodules" that will make up key components of the units. "Despite continuing high-level management and executive focus from Chicago Bridge & Iron, Westinghouse Electric Co. and SCE&G, the delivery and quality associated with the submodules are still not satisfactorily resolved," staff said, noting that delays in submodule delivery "affect almost all critical path sequences in the construction schedule."

SCE&G, which owns 55% of the two planned units, is regulated by the PSC, while state-owned Santee Cooper, which owns the remaining 45%, is not. But Santee Cooper was hit by Fitch Ratings, which on July 18 gave Santee Cooper's credit a "negative" outlook, citing the state-owned utility's "inability" so far to follow through on its plan to roughly halve its Summer-project stake.

Fitch said in a statement that its decision to change Santee Cooper's credit outlook to negative from stable reflects the rating agency's view that the utility "faces a number of challenges over the next several years, including slower growth, a large capital program"—most of it tied to the new nuclear units—"and the ability to manage its excess ownership share of the new Summer nuclear plant expansion project."

Fitch said that Santee Cooper's 45% stake in the new Summer units leaves the utility with "significant excess generating reserves for an extended period and potentially could weaken financial metrics below targeted levels." The rating agency said Santee Cooper's ability to address these challenges in the next 12 to 24 months "will be instrumental in resolving the negative outlook."

Santee Cooper's Gore noted that another rating agency — Standard & Poor's, which like Platts is part of McGraw-Hill Financial — "did just the opposite" on July 16 when it changed its ratings outlook for Santee Cooper to stable from negative. S&P cited the recent extension of the utility's long-term power supply deal with South Carolina's electric cooperatives. Gore added that Santee Cooper is "very actively negotiating" with Duke Energy Carolinas about the possibility of Duke taking part of Santee Cooper's stake in the new Summer units.

— Housley Carr

Group to oppose SCR plans for Wyoming plant

Snake River Alliance, a Boise-based environmental group, intends to oppose plans to add selective catalytic reduction equipment to two units at the 2,120-MW coal-fired Jim Bridger plant in Wyoming, Ken Miller, clean energy program director for the group, said Monday.

The Snake River Alliance, which is active in energy issues in Idaho, would like the plant's owners to retire Jim Bridger by 2020, following examples set by agreements to retire the Boardman plant in Oregon and the Centralia plant in Washington, Miller said. "We're trying to get Idaho Power off coal," he said.

Instead of investing hundreds of millions of dollars in pollution controls for Jim Bridger, the Snake River Alliance believes the plant could be replaced with energy efficiency and

renewable resources, and with natural gas-fired generation if needed, Miller said.

The plant's owners – Idaho Power and PacifiCorp – plan to install SCRs on Jim Bridger units 3 and 4 for about $354 million to cut nitrogen oxide emissions to comply with regional haze rules.

Idaho Power contends that the SCR project is a least-cost, least-risk option compared with switching the plant to natural gas or adding natural gas-fired generation elsewhere, the two options the utility studied.

The Idaho Public Utilities Commission on Friday said it has started to review Idaho Power's request for a certificate of public convenience and necessity for the SCR project, which will cost Idaho Power about $130 million reflecting its one-third ownership interest in the plant. The application also asks the PUC to guarantee cost recovery for the project "because of the magnitude of the investment and the uncertainty surrounding coal-fired generation in today's political and social environment."

The Jim Bridger plant has the lowest dispatch and installed cost of Idaho Power's power plant fleet, according to the utility's CPCN application. "The Jim Bridger plant not only provides highly valuable capacity during periods of peak demand, but also low cost and dispatchable baseload energy," the utility said.

The Environmental Protection Agency in late May recommended approving SCRs for Jim Bridger 523-MW Unit 3 and 530-MW Unit 4 in 2015 and 2016, respectively. "The EPA has indicated it will sign a notice of final rulemaking on November 21, 2013, making these emission reduction requirements at Jim Bridger Units 3 and 4 federally enforceable as well," the utility said. Without the SCRs the plant's owners will have to stop operating the facility, Idaho Power said.

Utah and Wyoming utility commissions in May approved the SCR project for PacifiCorp. Although it operates in Oregon, PacifiCorp has not asked the Oregon Public Utility Commission to approve the project. In a recent PacifiCorp rate case, the Oregon PUC said the utility had made poor management decisions related to a scrubber project at Jim Bridger and denied the utility cost recovery for the investment.

In part, the Snake River Alliance believes it does not make sense to add SCRs to the Jim Bridger plant because it will also require additional investments to reduce mercury, deal with water quality regulations and possibly lower carbon dioxide emissions, Miller said. "If you're going to invest $130 million in two units [for SCRs], you're basically committing your customers to those two units," he said.

The utilities contend they do not have time to wait for other pending regulations to become finalized. "Trying to install multiple controls, which are by themselves generally multi-year projects, within the same short time frames poses a significant risk of noncompliance with penalties that can be substantial," Idaho Power said.

Idaho Power and PacifiCorp plan to add SCRs to Jim Bridger Unit 2 in 2021 and Unit 1 in 2022. However, EPA is taking comments on a plan to speed up the implementation dates for the two units.

Idaho Power asked the PUC to make a decision on its request by November 29. The timeline may be "ambitious," according to the Snake River Alliance's Miller.

The Idaho Conservation League and a group representing Idaho Power industrial customers have asked to intervene in the case.

— Ethan Howland

Need for Mich. gas plant is questioned

A major Michigan business group, pointing to the potential availability of other generation capacity in the state, is questioning whether Consumers Energy's plan to spend $750 million to construct a 700-MW natural gas-fired power plant is truly a least-cost option.

The CMS Energy subsidiary recently applied for a certificate of need from the Public Service Commission to build the Thetford combined-cycle plant in Genesee County, north of Flint. A final PSC order is expected in the spring.

"We understand there are some existing options, and we want to know if they are viable," Robert Strong, attorney for the Association of Businesses Advocating Tariff Equity, said in a Monday interview. ABATE has intervened in the Thetford case at the PSC.

ABATE has roughly 20 members throughout the state, and they include some of Michigan's largest manufacturers.

Those companies, Strong said, typically are heavy users of electricity and are saddled with the highest industrial power rates in the Midwest.

ABATE estimates Thetford would lump an additional 5% or more onto their monthly bills.

As one example, Strong cited the 1,100-MW Covert Generating LLC combined-cycle gas plant in Covert near Lake Michigan in southwestern Michigan's Van Buren County. The plant is owned by New Covert Generating Company LLC, a private equity investment entity managed by Tenaska Capital Management. Tenaska Capital Management is a subsidiary of Omaha, Nebraska-based Tenaska, an independent power generator.

Covert Generating, a merchant facility, was built more than a decade ago.

Strong suggested it may be less expensive for Consumers to purchase power from Covert Generating than to go forward with a new gas project.

Another possibility, he said, is a 652-MW gas-fired plant in Carson City, Michigan. Renaissance Power's four simple-cycle combustion turbines were built by Dynegy in 2002. In February 2010, the plant was sold to New York-based LS Power for $970 million.

Strong said it may be possible and cost-affordable to convert Renaissance's simple-cycle units to combined-cycle units.

"There are things out there that may provide a less expensive option" for Consumers' 1.8 million customers, he said.

Consumers does not agree, however.

"Thetford is the least expensive and most valuable option for Consumers Energy's customers," insisted company spokesman Dan

Bishop. "Unlike existing, much older peaking plants in Michigan, Thetford represents a state-of-the-art, highly efficient technology."

While conceding that Covert Generating fits the bill as a combined-cycle facility, Bishop noted that the plant already is a decade old. "It has 10 years of wear and tear on it, unlike Thetford which would be a brand new facility."

Consumers is playing up both the environmental and economic aspects of the project. Thetford, the company said, will replace seven of the utility's older coal-fired units with a combined generating capacity exceeding 800 MW.

The gas plant project also is expected to create more than 600 construction jobs.

Construction is targeted to start in 2014, with the plant up and running in 2017.

Timothy Sparks, Consumers vice president-energy supply operations, told the PSC that the utility issued a request for proposals in June 2012 seeking power to replace the coal units.

Consumers received two proposals for short-term capacity and five offers for the purchase of existing power plants within Michigan's Lower Peninsula, he said, although the bidders were not identified.

None of the asset sale offers "presented a compelling case to purchase an asset," Sparks said. While some of the offers were comparable to the long-term economics of constructing and operating Thetford, they were all rejected for a variety of reasons.

Those reasons, he said, included "immediate rate impact, reduced flexibility to adjust to changing economic and environmental conditions, the fact that the company does not need any new capacity until 2016, the technology of the generating plants offered for sale, age of those assets, and the lack of Michigan job creation/positive impact on the local economy."

Officials with Tenaska and LS Power could not be reached for comment Monday on whether they were among the unsuccessful bidders and whether they would be willing to enter into a power and/or plant sale arrangement with Consumers.

— Bob Matyi

Pennsylvania utilities top savings targets

All of Pennsylvania's utilities exceeded their legislative requirement to reduce electricity usage 3% and peak demand 4.5% by May 31, according to preliminary reports filed with regulators.

The utilities on Friday filed with the Public Utility Commission progress reports for the period March 1 through May 31, but included the cumulative totals for the four-year savings requirement. A final report that may include additional savings will be filed November 15.

PPL Electric achieved 127% of the energy savings requirement, or 1.45 million MWh/year, the company said. Its compliance target was 1.14 million MWh/year.

PPL achieved 103% of its demand reduction requirement, or 305 MW, which is based on savings during the top 100 peak demand hours of 2012. The peak demand savings had to be achieved during the top 100 peak demand hours, according to the 2008 law known as Act 129. PPL's required savings was 297 MW.

Demand reduction occurring in all hours, not just the top 100 peak demand hours, achieved 126% of the required target, or 375 MW, the PPL report said.

Peco Energy reached 124% of its energy savings target by May 31, or an annual reduction of 1.46 million MWh, the company said.

Peco reached 122% of its demand reduction compliance target, or 459 MW, during the top 100 hours of 2012, the Philadelphia-based utility said.

It achieved 183% of the May 31 energy reduction target for government, nonprofit and institutional customers. Act 129 requires 10% of the total energy savings must come from those customers.

Duquesne Light reached 127% of the May 31 requirement or 536,591 MWh/year. It exceeded its demand reduction requirement of 113 MW by saving 150 MW, or 133% of the requirement.

Pennsylvania Power achieved the greatest excess savings of the four FirstEnergy utilities in Pennsylvania.

The utility reached 119% of its requirement, or 170,397 MWh/year, the company said in its report to the PUC. It reduced peak demand by 49 MW during the top 100 peak demand hours of 2012, or 112% of the legislative mandate. When including all measures installed to date, the company achieved 45 MW of cumulative peak load reductions, the company said.

Pennsylvania Electric achieved 113% of the required total or 489,468 MWh/year. Its required target was 431,979 MWh a year.

Based on preliminary results, Penelec achieved 123 MW of its load reduction at the generator level, or 114% during the top 100 hours of peak demand during 2012, the utility said. The company was required to reduce demand 108 MW during the top 100 hours of peak demand.

Metropolitan Edison achieved 112% of its required savings by May 31, the company said. It saved 501,187 MWh/year. Its requirement was 445,951 MWh/year, the report said.

Met-Ed achieved 132 MW of peak load reductions or 111% of the May 31 demand reduction compliance target, the company said. Its compliance target was 119 MW.

West Penn Power reached 108% of its electricity reduction requirement for the four-year program. It reduced usage 681,084 MWh/year compared with the 628,160 MWh/year required to meet the mandate, the company said.

The utility achieved 204 MW of load reduction during the top 100 hours of 2012, or 130% of the May 31 requirement. The company was required to reduce demand 157 MW during the top 100 hours of peak demand.

Companies faced a stiff penalty for not achieving the mandated savings prescribed by the legislature. Possible fines ranged from $1 million to $20 million.

— Mary Powers

FERC OKs Cal-ISO DR cost allocation plan

The Federal Energy Regulatory Commission has signed off on a demand response cost allocation proposal submitted by the California Independent System Operator.

In December 2011, FERC found that Cal-ISO did not provide adequate support that an allocation directly to the host load

serving entities was consistent with the commission's directive in Order 745 to allocate demand response costs proportionally to the entities that purchase from the energy market in the area where demand response reduced the marginal cost of electricity.

The commission, therefore, determined that Cal-ISO's cost allocation methodology did not comply with FERC's directives in Order 745 and directed CAISO to submit a compliant cost allocation methodology.

FERC in Order 745 directed certain modifications to the compensation of demand response resources in organized wholesale energy markets.

Specifically, Order 745 requires each regional transmission organization and independent system operator to pay a demand response resource the market price for energy, i.e., the LMP, when two conditions are met.

First, the demand response resource must have the capability to balance supply and demand as an alternative to a generation resource. Second, dispatching the demand response resource must be cost-effective as determined by a net benefits test in accordance with Order 745. The net benefits test is necessary to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the costs of dispatching and paying LMP to those resources

Cal-ISO proposed to allocate demand response costs to all load through a real-time energy offset charge because, due to the characteristics of its system, this cost allocation appropriately allocates costs to the load that benefits from the demand reduction, FERC noted. "Thus, the commission finds CAISO's cost allocation method is consistent with Order No. 745 because it allocates the cost to those who benefit from demand response," FERC said in a July 18 order.

"As CAISO explains, load throughout CAISO benefits from demand response through the systemwide energy price and through regional benefits from reduced losses and congestion because demand response resources in different areas of CAISO participate in balancing CAISO's load and supply and impact transmission flows throughout the CAISO system," the order went on to say. Thus, demand response resources impact LMPs throughout the CAISO system.

"Also, CAISO notes that demand response resources are distributed throughout its system, and CAISO predicts that they will continue to be well dispersed. So the price impact of demand response resources will be relatively evenly distributed throughout CAISO," FERC said. Therefore, Cal-ISO proposes to allocate costs to those who benefit from lower prices produced by dispatching demand response, "and we accept CAISO's cost allocation methodology as reasonable."

— *Paul Ciampoli*

EEI, NARUC want rejection of PURPA request

Investor-owned utilities and state regulators urged the Federal Energy Regulatory Commission to reject a request by wind and hydroelectric developers to find that the Montana Public Service Commission is violating the Public Utility Regulatory Policies Act, warning that granting the request would mark a shift from long-standing policy.

The Edison Electric Institute and the National Association of Regulatory Utility Commissioners in separate comments specifically targeted the request of wind and hydro developers in Montana (Docket No. EL13-73), which last month charged that, under MPSC rules, qualifying facilities cannot create a "legally enforceable obligation" under the statute without winning a competitive solicitation process.

Arguing that MPSC's rule nullifies the legally enforceable obligation under PURPA to sell power at avoided cost pricing, the developers said that "a QF must either win a competitive solicitation or it will receive a short-term rate that precludes financing. The QF's right to a LEO is simply immaterial under" the state's rules.

Under PURPA, utilities must buy power from renewable energy providers and other small generators known as QFs under certain rates, which are set at the state commission level. But developers can ask FERC to pursue litigation under the statute over alleged violation of PURPA's requirements.

FERC appears to be facing an uptick in requests for enforcement by developers following its decision to pursue first-of-its-kind litigation in federal district court against the Idaho Public Utilities Commission over how the state commission handled contracts between a local utility and several wind generators (*FERC v Idaho PUC*, 1:13-cv-141). The suit is ongoing, and has not yet reached the oral argument stage.

In response to the developers' petition, MPSC in July 19 comments defended its policies, asking FERC not to act in the case. It noted that QFs in Montana can receive a legally enforceable obligation "that sets an avoided cost rate for a specified time period by winning a competitive solicitation or negotiating with a utility."

"The root of Petitioners' complaint is that QFs, particularly those over 10 MW, are not winning competitive solicitations and have not otherwise been successful in negotiating long-term contracts. Assuming QFs over 10 MW have tried and failed to obtain long-term contracts, there is no basis to blame the MPSC's long-standing approach to implementing PURPA. The Petitioners neglect to present any evidence that they or other QFs have been willing to match winning prices in competitive solicitations or otherwise negotiate prices, terms, and conditions that are competitive with alternatives," MPSC said.

More broadly, MPSC asked FERC to "reaffirm its long-standing commitment to allowing state commissions to rely on competitive solicitations in order to comply with PURPA," a request that was broadly backed in separate comments by EEI and NARUC, both of which asked FERC to reject the developers' request.

In its July 19 comments, EEI argued that the developers' request invites FERC "to unnecessarily and unreasonably interject itself into a state regulatory agency's implementation of PURPA and appears to take the erroneous position that states may not require competitive solicitations to determine avoided cost consistent with the commission's regulations and without violating PURPA."

EEI argued that FERC in a 1988 policy encouraged the use of

competitive processes to determine avoided costs, and that the commission should "continue its policy of consistently giving the states wide latitude" for implementing PURPA.

NARUC as well argued that FERC "has acknowledged the efficiencies of determining avoided cost rates through competitive bidding, which is a well-recognized way of achieving the twin goals of PURPA: to promote renewable power at lowest cost."

"The commission has broadly relied on competition to determine fair rates for electricity and the language of PURPA Section 210 requires that avoided cost rates be just and reasonable to the utility's ratepayers," NARUC said. Section 210 governs PURPA's rules for cogeneration and small power producers.

NARUC also argued that using competitive processes "makes perfect sense in light of later updates to PURPA in pursuit of least-cost integrated resource planning, and also properly reflects the MPSC's jurisdiction to perform integrated resource planning, an authority that exists separate from its jurisdiction to implement the commission's QF rules."

— Bobby McMahon

Retirements may not lift capacity prices ...from page 1

That would be the case with FirstEnergy's 370-MW Mitchell plant, but not with its 1,710-MW Hatfield's Ferry, a supercritical coal plant — meaning that it runs at higher efficiency than a conventional coal plant — and has been running at capacity factors in the 60% to 70% range, according to FirstEnergy.

The Hatfield's retirement raised concerns at UBS where analyst Julien Dumoulin-Smith raised the question of which coal plants did not clear PJM's 2016-17 capacity auction that closed at the end of May.

Dumoulin-Smith noted that nearly 10 GW of coal-fired capacity was offered into the 2016-17 auction but did not clear. He estimated that half of the non-clearing capacity was comprised of FirstEnergy plants and the bulk of the remainder were likely plants belonging to Midwest Generation.

Midwest Gen owns three operating coal plants in Illinois: the 781-MW Waukegan, 1,538-MW Powerton, and 1,334-MW Joliet station.

Spokeswoman Susan Olavarria said Midwest Gen did participate in the PJM auction, but she declined to disclose specifics.

Last year Midwest Gen's corporate parent, Edison International, said it would not invest capital to add environmental controls to the plants. At year-end 2012 Edison Mission Energy and its Midwest Gen subsidiary filed for Chapter 11 bankruptcy court protection.

FirstEnergy's coal fleet in PJM totals 10,057 MW. Backing out the Hatfield's and Mitchell plants and the 885 MW of capacity at the Lake Shore, East Lake and Ashtabula plants that are running under reliability-must-run contracts until early 2015, leaves 7,092 MW.

If UBS' estimation of how many FirstEnergy plants did not clear the auction is right, some of the non-clearing FirstEnergy plants could also be vulnerable for retirement. The most vulnerable might be the smallest in the remaining portfolio, the 240-MW Mansfield station in Pennsylvania. The other plants in FirstEnergy's portfolio are the 2,233-MW W.H. Sammis in Ohio, and three plants in West Virginia: the 1,983-MW Harrison, the 1,300-MW Pleasants and the 1,107-MW Fort Martin.

The announcement of more coal retirements as the 2015 deadline for compliance with the Environmental Protection Agency's Mercury and Air Toxics Standards draws closer could put upward pressure on power prices and bring them to a peak in 2015, Dumoulin-Smith argued.

But as the MATS deadline approaches, new power plants are going to start coming online without further coal retirements and that should lead to lower prices going into 2016 and, longer term, Dumoulin-Smith sees capacity and energy prices falling further in 2017 and 2018.

In a report earlier this month Hugh Wynne at Bernstein Research said that 2015 PJM forward prices are off by $2-3/MWh, but he does not see coal retirements having a big impact on prices, even though he believes there are more retirements to come.

He estimated that on-peak PJM prices could rise to $43/MWh from $41/MWh, off-peak prices could rise to $30/MWh from $29/MWh, and around-the-clock prices could hit $38/MWh from $35/MWh.

The discrepancy arises, he says, from the market imbalance put on prices by power companies that hedge by selling their electric output forward at prices with lower implied heat rates.

Wynne also believes that there are still more coal retirements to be announced. He noted that 13.3 GW of coal plants have already been slated for retirement in PJM by 2015, and he expects a further 2.4 GW of coal plants will retire by 2015.

But even though he sees available capacity in PJM decreasing by 8.6 GW from 194.2 GW in 2012 to 185.6 GW in 2015, he argues that 2015 PJM power prices will be relatively insensitive to coal retirements.

Not only will retirements be offset by 10 GW of new capacity expected online by 2015, Wynne says his modeling shows that flat supply curves and high reserve margins will prevent the retirement of individual plants from materially changing the price of power.

In addition while the retirement of coal plants will shift the demand curve toward higher demand, the growing prevalence of demand response resources in the PJM market will shave peak demand, putting further downward pressure on prices and pushing them "below the level suggested by our model."

Wynne noted that DR resources have been growing steadily in PJM's capacity auction. In the 2012-13 auction cleared DR resources represented 3.8% of peak demand. In the 2015-16 auction cleared DR represented 9% of peak demand.

— Peter Maloney

CFTC, FCA charge firm with 'spoofing' ...from page 1

through October 18, 2011, on CME Group's Globex trading platform. According to the order, Panther engaged in the practice while trading NYMEX WTI crude oil, natural gas and soft commodities such as corn and soybeans.

The CFTC said that under the practice of spoofing, Coscia and

Panther would place a relatively small order to sell futures that they did want to execute, which they quickly followed with several large buy orders at successively higher prices that they intended to cancel.

"By placing the large buy orders, Coscia and Panther sought to give the market the impression that there was significant buying interest, which suggested that prices would soon rise, raising the likelihood that other market participants would buy from the small order Coscia and Panther were then offering to sell," the agency said.

"Although Coscia and Panther wanted to give the impression of buy-side interest, they entered the large buy orders with the intent that they be canceled before these orders were actually executed. Once the small sell order was filled, according to the plan, the buy orders would be canceled, and the sequence would quickly repeat but in reverse — a small buy order followed by several large sell orders. With this back and forth, Coscia and Panther profited on the executions of the small orders many times over the period in question," the CFTC said.

"This is really important because it's the first case under the agency's anti-disruptive practices authority, it shows the CFTC is very much focused on acts that will disrupt the markets, particularly spoofing," said Bob Pease, senior counsel at Bracewell & Giuliani. Most recently, Pease was the counsel to the director in the division of enforcement at the CFTC.

The CFTC approved interpretive guidance regarding their anti-disruptive practices authority during a May 16 public hearing.

The CFTC ordered Panther and Coscia to pay a $1.4 million civil monetary penalty, disgorge $1.4 million in trading profits, and banned Panther and Coscia from trading on any CFTC-registered entity for one year.

CFTC Commissioner Bart Chilton, who has warned about spoofing by high-frequency traders, disagreed with the settlement. "I believe that the type of disruptive trading practice described in the commission's complaint is an egregious violation of the Commodity Exchange Act and warrants the imposition of a much more significant trading ban to protect markets and consumers," Chilton said in a statement.

Separately, the UK's Financial Conduct Authority said it had fined Coscia $900,000 for illegal trading on ICE Futures Europe where he placed thousands of Brent crude, WTI and gas and oil futures orders and the first time the regulator has penalized a high-frequency trading scheme.

The FCA accused Coscia of deliberately engaging in "layering" over a six week period between September 6, 2011 and October 18, 2011 using an algorithmic trading program which he had designed. According to the FCA, Coscia made a net profit of $279,920 during the time period, with a substantial amount of profits coming from WTI trading.

"Although Mr. Coscia did not always make an end of day net profit, the nature of his manipulative trading strategy was such that he caused a detriment to the market," the FCA concluded.

The FCA characterized Coscia as an experienced market participant with 25 years of trading experience, however he was not a member of ICE or an approved person, and traded in the US through a Direct Market Access provider.

Coscia's large orders, which were placed and subsequently canceled when his small orders were executed, were "consistently over 50% of the market depth within five ticks of the best bid and best offer price at the time that they are placed and typically represent 75% of the market depth," according to the FCA during the time in question.

TABB Group estimates that penetration of HFT as a percentage of US futures market volume for 2013 is 61%, including market making activities, which is down from an estimated high of 64% in 2012. TABB Group did not have specific penetration estimates for the energy or commodity markets.

Further, CME Group said it imposed a fine of $800,000 and ordered Coscia and Panther to disgorge about $1.3 million in illegal profits. The exchange also issued a six-month trading ban against the firm and Coscia.

— Christopher Tremulis

MISO members to vote on hubs

...from page 1

because they do not now participate in MISO markets serving the upper Midwest region, in order to gauge their sentiment regarding the number of hubs to serve the existing Entergy footprint.

The ballots and surveys are to be returned by 4 p.m. EDT on July 30.

In a previous meeting, the panel decided to concentrate on two potential trading hubs, one in Arkansas and another in southern Mississippi.

At the Trading Hubs Task Force's August 13 meeting, stakeholders will be able to review the results of the vote and survey. A ballot and survey regarding preferred trading hub locations will be submitted thereafter, said Marka Shaw, Exelon regulatory affairs manager and task force chairwoman.

— Mark Watson

PLATTS
McGRAW HILL FINANCIAL

MEGAWATT DAILY

Volume 18 / Issue 140 / Tuesday, July 23, 2013

ISSN # 1088-4319

Megawatt Daily is published daily by Platts, a division of McGraw Hill Financial. Registered office Two Penn Plaza, 25th Floor, New York, NY 10121-2298

Officers of the Corporation: Harold McGraw III, Chairman, President and Chief Executive Officer; Kenneth Vittor, Executive Vice President and General Counsel; Jack F. Callahan, Jr., Executive Vice President and Chief Financial Officer; Elizabeth O'Melia, Senior Vice President, Treasury Operations.

To reach Platts
E-mail:support@platts.com
North America
Tel:800-PLATTS-8 (toll-free)
+1-212-904-3070 (direct)
Latin America
Tel:+54-11-4121-4810
Europe & Middle East
Tel:+44-20-7176-6111
Asia Pacific
Tel:+65-6530-6430

Manager, Advertisement Sales
Kacey Comstock

Advertising
Tel : +1-720-548-5508