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Merchant hedging positions show expectations

ANALYSIS All merchant generators hedge, but not in the same way and not to the same extent and that says a lot about their view of the market, as well as relative advantages conferred by their different types of businesses.

Dynegy has one of the most aggressive approaches. The company is relatively unhedged. In its first quarter earnings call, the company reported that its coal-fired power plants are 68% volumetrically hedged and its gas plants 83% hedged for 2013, but its coal and gas plants are only 26% hedged in 2014.

The company is leaving 2014 "open" with the prospect of capturing the upside if power prices rise.

Dynegy outlines those prospects by giving its earnings sensitivity to commodity prices. For every $1/MMBtu rise in the price of natural gas the company's hedged gas plants could see a

(continued on page 16)

Exelon move highlights merchant softness: analyst

GENERATION A decision by Chicago-based Exelon, the nation's largest nuclear generator, to abandon plans for about 570 MW of uprates at two nuclear plants in Illinois and Pennsylvania underscores the prevailing softness in the US nuclear merchant power sector, a Wall Street energy analyst said Wednesday.

In a Tuesday filing with the Securities and Exchange Commission, Exelon, parent company of Commonwealth Edison, PECO Energy and Constellation Energy, cited "market conditions" for its decision to cancel the previously deferred uprates. The company plans to take an approximately $100 million pre-charge in the second quarter as a result.

Exelon announced the deferrals last September.

(continued on page 18)

NYISO changes approved for external transactions

MARKETS The Federal Energy Regulatory Commission on Tuesday approved a proposal by the New York Independent System Operator to set credit requirements that better capture the risk posed by imports, exports and wheel through transactions.

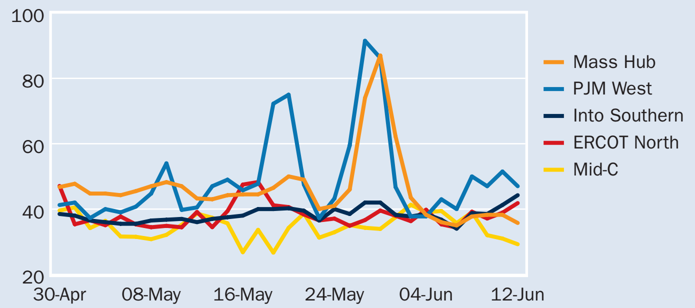
Under NYISO's current system, external transactions are included in the calculation of a market participant's credit requirement for energy and ancillary services, which is based on the market participant's historical purchases and the risks posed by load-serving entities purchasing power to meet obligations.

The ISO argued that this system does not appropriately account for the risks posed by imports, exports and wheel-through transactions.

"In general, a market participant's bids for external

(continued on page 19)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Jun 13 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	34.01	36.04	26.54	28.32
NYISO	31.52	49.72	23.77	28.80
PJM	30.85	64.07	19.81	30.49
MISO	32.24	33.79	20.05	25.66
ERCOT	40.70	56.45	23.62	23.91
CAISO	37.17	39.49	29.13	31.53

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 Jun 13

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	35.75	8871	7.54	3.51	-4.55	-12.61	-24.70
N.Y. Zone-A	33.00	9612	8.97	5.53	-1.33	-8.20	-18.50
PJM/MISO							
PJM West	47.00	12801	21.30	17.63	10.28	2.94	-8.08
Indiana Hub	35.00	9296	8.65	4.88	-2.65	-10.18	-21.48
Southeast & Central							
Southern, Into	44.25	11699	17.77	13.99	6.43	-1.14	-12.49
ERCOT, North	41.84	11377	16.10	12.42	5.07	-2.29	-13.32
West							
Mid-C	29.24	8336	4.69	1.18	-5.84	-12.85	-23.37
SP15	41.50	11111	15.36	11.62	4.15	-3.32	-14.53

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

Inside this Issue

NORTHEAST MARKETS

Dailies lower; terms advance

Power prices for Thursday delivery in the Northeast were lower Wednesday, while forwards advanced as the NYMEX July natural gas futures contract posted a preliminary settlement price of $3.777/MMBtu Wednesday, up 5.3 cents, as the market had been oversold and was due for a technical correction, sources said.

Northeast daily prices are down Wednesday as spot natural gas and peak load forecasts continue to move down. ISO New England forecasted peak load on Wednesday around 16,100 MW and 16,000 MW for Thursday.

High temperatures for the Boston area are forecast to remain in the upper 60s on Thursday. Algonquin city-gates spot natural gas was about 7 cents lower, to $4.08/MMBtu and Transco Zone 6 New York lost about 8 cents to $3.86/MMBtu.

Mass Hub on-peak for Thursday was down $2.50 to the mid-$30s/MWh. Mass Hub off-peak slipped about 75 cents in the mid-$20s/MWh.

The New York ISO forecasted demand on Wednesday around 21,481 MW and 20,156 MW on Thursday. High temperatures in New York state are forecast to be in the low 60s to low 70s Thursday. NY Zone G on-peak for Thursday dropped about $4 to the low $40s/MWh.

Day-ahead auction prices in the ISO New England hardly moved midweek with demand expected to soften slightly. Internal Hub peak shed 10 cents to about $35.49/MWh and off-peak added $1.65 going to $27.92/MWh. Connecticut peak was also down 10 cents to $36.04/MWh and off-peak added $1.68 to $28.23/MWh.

Maine peak moved up 11 cents to $34.01/MWh and off-peak jumped $1.85 to $26.54/MWh. Rhode Island peak added 2 cents to $35.42/MWh and off-peak gained $1.72 to $28.32/MWh.

Day-ahead auction prices in the New York ISO fell Wednesday with demand forecast lower. Peak prices for Dunwoodie, Hudson Valley, Long Island and Millwood all came down more than $4, while other zones saw losses range from 82 cent to $2.73.

Long Island peak fell $4.35 to clear at $49.72/Mwh and off-peak lost 95 cents to $28.80/MWh. New York City peak came down $1.69 to $47/MWh and off-peak shed 80 cents to $27.02/MWh. West peak was down $1.52 to $33.03/MWh and off-peak gave up 93 cents to $24.69/MWh.

North peak fell 82 cents to $31.52/MWh and off-peak decreased 59 cents to $23.77/MWh.

Northeast term power was up Wednesday. In New England, Mass Hub on-peak July financial futures added 25 cents to about $55.75/MWh on the IntercontinentalExchange at about 2:30 p.m. EDT. Mass Hub on-peak August was unchanged at about $51.25/MWh while on-peak fourth quarter rose 25 cents to about $54.85/MWh. Mass Hub off-peak July-August gained 25 cents to about $36.35/MWh.

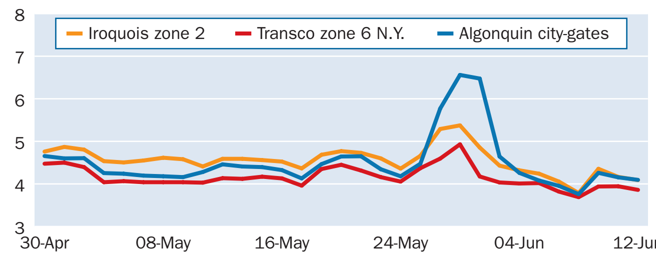
New York Zone G on-peak July-August moved up 15 cents to about $63 /MWh. New York Zone A on-peak July-August climbed 65 cents to about $48.25/MWh.

Northeast day-ahead bilateral indexes for Jun 13 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	35.75	-2.50	40.56	8871
N.Y. Zone-G	42.25	-4.00	45.58	10629
N.Y. Zone-J	47.00	-1.75	49.00	11824
N.Y. Zone-A	33.00	-2.00	35.75	9612
Ontario*	27.00	-1.00	26.94	6503
Off-Peak				
Mass Hub	26.25	-0.50	28.39	6514
N.Y. Zone-G	26.75	-0.75	28.61	6730
N.Y. Zone-J	27.00	-0.75	29.11	6792
N.Y. Zone-A	24.75	-1.00	25.56	7209
Ontario*	18.50	-0.50	18.69	4455

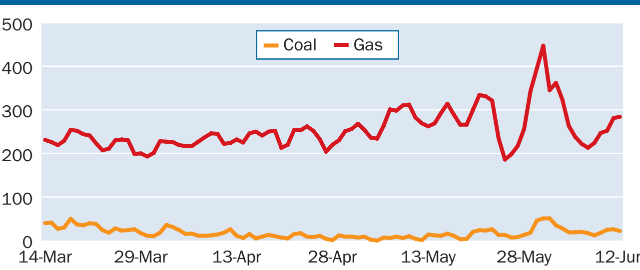
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO gas and coal generation (GWh)



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 11-Jun	%Chg	% Chg Year-ago	Forecast 12-Jun	13-Jun	14-Jun	15-Jun	16-Jun
ISONE								
Load	343	0	3	319	323	324	310	308
Generation								
Coal	8	-11	42	6	4	3	3	4
Gas	132	16	-8	122	123	126	134	140
Nuclear	111	0	-9	111	111	111	111	111
NYISO								
Load	462	4	2	461	420	413	386	384
Generation								
Coal	19	15	93	16	11	9	9	11
Gas	149	9	-11	161	140	126	132	143
Nuclear	135	0	10	135	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Jun 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	35.49	0.00	-0.03	-0.10	38.76	8760
Connecticut	36.04	0.00	0.52	-0.09	39.20	8903
NE Mass-Boston	35.47	0.00	-0.05	-0.01	38.93	8755
SE Mass	35.68	0.00	0.16	-0.05	38.96	8808
West-Central Mass	35.74	0.00	0.22	-0.07	38.97	8822
Rhode Island	35.42	0.00	-0.10	0.03	38.99	8742
Maine	34.01	0.00	-1.51	0.11	36.67	8302
New Hampshire	35.23	0.00	-0.29	-0.01	38.18	8600
Vermont	35.39	0.00	-0.13	-0.17	38.60	8639
Off-Peak						
Internal Hub	27.92	0.00	0.03	1.66	28.16	6729
Connecticut	28.23	0.00	0.35	1.68	28.40	6798
NE Mass-Boston	27.83	0.00	-0.05	1.61	28.06	6709
SE Mass	28.11	0.00	0.23	1.70	28.31	6776
West-Central Mass	28.04	0.00	0.16	1.63	28.29	6759
Rhode Island	28.32	0.00	0.44	1.72	28.52	6827
Maine	26.54	0.00	-1.34	1.84	26.20	6468
New Hampshire	27.57	0.00	-0.32	1.60	27.58	6717
Vermont	27.54	0.00	-0.35	1.45	28.01	6710

NYISO day-ahead LMP for Jun 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	34.84	-0.28	1.42	-1.35	44.19	9727
Central Zone	34.39	-0.46	0.80	-1.20	35.47	10073
Dunwoodie Zone	43.16	-6.35	3.67	-4.24	47.72	10830
Genesee Zone	33.43	-0.33	-0.04	-1.26	34.34	9789
Hudson Valley Zone	42.22	-5.80	3.27	-4.03	47.07	10595
Long Island Zone	49.72	-12.07	4.50	-4.35	68.57	12475
Millwood Zone	43.08	-6.34	3.59	-4.16	47.69	10810
Mohawk Valley Zone	34.93	-0.74	1.05	-1.31	35.99	10514
N.Y.C. Zone	47.00	-9.82	4.04	-1.69	50.13	11794
North Zone	31.52	0.00	-1.62	-0.82	31.95	7696
West Zone	33.03	-0.41	-0.53	-1.51	34.00	9672
Off-Peak						
Capital Zone	25.80	0.00	1.17	-0.84	31.27	7432
Central Zone	24.97	0.00	0.34	-0.76	25.68	7561
Dunwoodie Zone	26.74	0.00	2.12	-0.83	30.64	6608
Genesee Zone	24.58	0.00	-0.05	-0.85	25.15	7445
Hudson Valley Zone	26.68	0.00	2.05	-0.85	30.57	6591
Long Island Zone	28.80	-1.37	2.80	-0.95	33.02	7115
Millwood Zone	26.69	0.00	2.07	-0.86	30.62	6595
Mohawk Valley Zone	25.16	0.00	0.53	-0.76	25.95	8045
N.Y.C. Zone	27.02	0.00	2.39	-0.79	31.13	6675
North Zone	23.77	0.00	-0.86	-0.59	23.95	5791
West Zone	24.69	0.00	0.06	-0.93	25.29	7477

Generation unit outage report

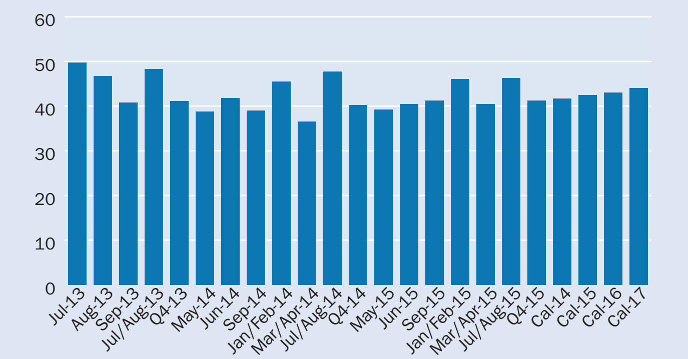
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-3/Bruce Power	820	n	Ont.	MO	Unk	05/24/13
Bruce-8/Bruce Power	822	n	Ont.	PMO	Unk	06/03/13
Pickering-1/OPG	500	n	Ont	MO	Unk	06/07/13
Pickering-4/OPG	500	n	Ont.	MO	Unnk	06/06/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13

Northeast Platts-ICE Forward Curve, Jun 12 ($/MWh)

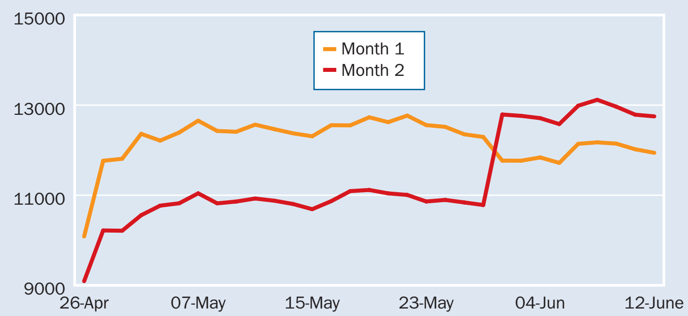
Prompt month: Jul 13	On-peak	Off-peak
Mass Hub	55.75	37.00
N.Y. Zone G	64.25	42.50
N.Y. Zone J	70.75	45.50
N.Y. Zone A	49.75	35.50
Ontario*	41.00	26.75

*Ontario prices are in Canadian dollars

N.Y. Zone A: Forward curve on-peak ($/MWh)



N.Y. Zone A: Marginal heat rate on-peak (Btu/kWh)



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Next-week	06/12	39.50-40.50

*Ontario prices are in Canadian dollars.

Daily generation outage references

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

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

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

SOUTHEAST MARKETS

Dailies and forwards mixed

Power prices for Thursday delivery in the Southeast region were mixed Wednesday, as were forwards in the region. The NYMEX July natural gas futures contract posted a preliminary settlement price of $3.777/MMBtu Wednesday, up 5.3 cents, as the market had been oversold and was due for a technical correction, sources said.

Electric Reliability Council of Texas dailies for Thursday delivery were firmer on IntercontinentalExchange Wednesday morning with peak load forecast increasing.

Spot natural gas at Houston Ship Channel was steady, trading around $3.708 /MMBtu.

ERCOT North Hub next-day on-peak physical power rose about $3 to trade around $42/MWh on ICE, while off-peak rose about $1 to trade around $24.25/MWh. High temperatures across ERCOT's footprint were forecast in the mid-90s Thursday, with lows in the mid-70s. The average June high temperature across the ERCOT region is in the low 90s, with the average low in the low to mid-70s.

System load in ERCOT's footprint was forecast to peak at 58,800 MW Wednesday and 59,850 MW Thursday, compared with an actual peak of 57,025 MW Tuesday.

Real-time prices for ERCOT averaged $22.50/MWh from 12:15 a.m. to 6 a.m. CDT Wednesday.

Wind generation was forecast to peak at 6,525 MW at 1 a.m. CDT Wednesday and 5,525 MW at 2 a.m. CDT Thursday. North Hub on-peak balance-of-the-week packages were bid at $41.25 and offered at $42/MWh. Next-week on-peak was bid at $44.75 and offered at $46/MWh.

In the Southeast, dailies for Thursday delivery were weaker Wednesday morning with temperatures forecast to hold steady. Into Southern next-day on-peak power was bid at $35 and offered at $44/MWh on ICE, a loss of about $1.75. Off-peak was bid at $25 and offered at $28/MWh, a gain of roughly 50 cents.

Spot natural gas at Transco Zone-3 was steady around $3.749/ MMBtu. High temperatures in Atlanta were forecast in the low 90s Thursday, with lows in the mid-70s. The city's average June high

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for Jun 13 ($/MWh)

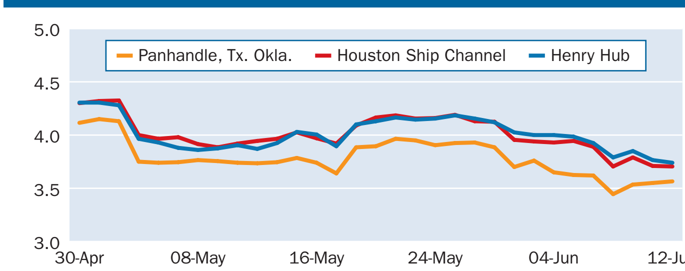
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	45.00	1.25	40.14	11613
Southern, Into	44.25	3.00	38.67	11699
Florida	43.00	3.25	39.42	10374
TVA, Into	42.00	0.00	37.94	10980
Entergy, Into	41.50	-0.50	36.19	11247
Southeast Off-Peak				
VACAR	26.50	0.25	26.31	6839
Southern, Into	26.50	0.50	25.81	7006
Florida	27.25	0.50	28.46	6574
TVA, Into	25.50	0.50	24.77	6667
Entergy, Into	23.25	0.50	21.60	6301
ERCOT On-peak				
ERCOT, North	41.84	2.94	37.87	11377
ERCOT, Houston	43.50	2.25	41.00	11678
ERCOT, South	42.50	2.25	39.33	11369
ERCOT, West	42.25	3.25	37.33	11583
ERCOT Off-Peak				
ERCOT, North	24.30	1.05	24.41	6608
ERCOT, Houston	24.50	0.75	25.23	6577
ERCOT, South	24.50	1.00	24.73	6554
ERCOT, West	24.25	1.25	23.79	6648
SPP/MRO On-peak				
MAPP, Soth	39.00	-3.00	35.78	10512
SPP, North	38.75	-2.75	35.50	10870
SPP/MRO Off-Peak				
MAPP, Soth	22.50	0.25	21.75	6065
SPP, North	22.25	0.25	21.42	6241

Southeast load and generation mix forecast (GWh)

	Actual 11-Jun	%Chg	% Chg Year-ago	Forecast 12-Jun	13-Jun	14-Jun	15-Jun	16-Jun
ERCOT								
Load	1088	3	-1	1057	1106	1121	1069	1034
Generation								
Coal	435	2	20	414	439	451	452	451
Gas	458	4	-15	463	467	467	460	454
Nuclear	123	0	-3	123	123	123	123	123
SPP								
Load	758	11	-4	774	761	765	780	787
Generation								
Coal	461	7	15	466	456	449	450	452
Gas	199	28	-30	209	205	203	209	216
Nuclear	49	0	-4	49	49	49	49	49

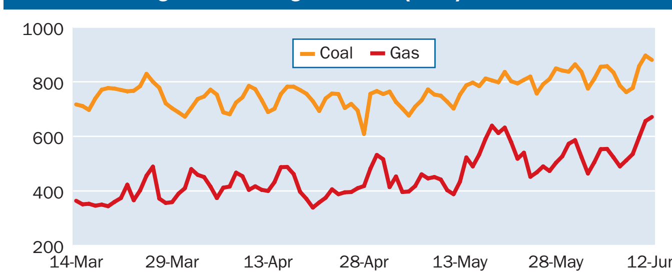
Source: Bentek

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



Source: Platts

ERCOT & SPP gas and coal generation (GWh)



Source: Bentek

ERCOT average day-ahead LMP for Jun 13 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	41.00	1.60	37.04	11071
Hub Average	41.21	1.36	37.51	11128
Houston Hub	41.86	0.07	39.86	11238
North Hub	40.76	2.20	36.12	11072
South Hub	40.76	0.71	38.19	10902
West Hub	41.45	2.44	35.82	11357
AEN Zone	47.00	0.44	43.31	12879
CPS Zone	42.40	0.32	40.61	11410
LCRA Zone	42.63	0.64	39.66	11471
Rayburn Zone	40.70	0.90	36.33	11055
Houston Zone	42.50	-0.12	40.48	11410
North Zone	41.27	2.21	36.70	11211
South Zone	42.40	0.34	41.06	11339
West Zone	56.45	3.21	48.71	15468
Off-Peak				
Bus Average	23.64	0.01	23.63	6385
Hub Average	23.65	0.03	23.64	6387
Houston Hub	23.68	-0.08	23.94	6356
North Hub	23.63	-0.01	23.57	6405
South Hub	23.62	0.01	23.75	6329
West Hub	23.66	0.19	23.29	6485
AEN Zone	23.81	-0.02	23.71	6526
CPS Zone	23.91	-0.39	24.36	6424
LCRA Zone	23.68	-0.05	23.74	6361
Rayburn Zone	23.63	-0.12	23.63	6406
Houston Zone	23.75	-0.08	24.05	6376
North Zone	23.63	-0.05	23.59	6406
South Zone	23.75	0.03	24.07	6362
West Zone	23.85	0.18	23.63	6538

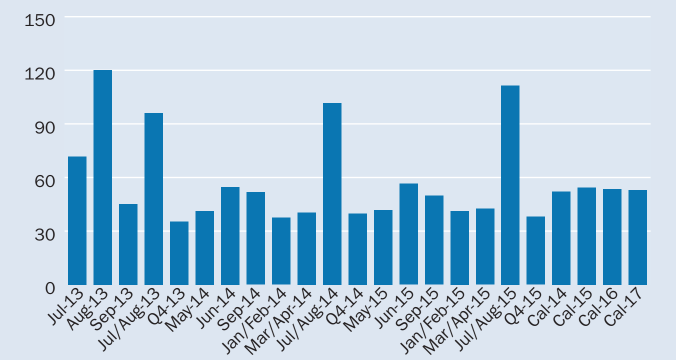
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Entergy, Into		
Bal-week	06/10	35.50-36.00
Bal-month	06/10	35.50-36.00
Bal-month	06/06	34.25-34.75
Next-week	06/10	35.50-36.00
Next-week	06/06	33.75-34.25
ERCOT, North		
Bal-week	06/12	41.25-41.75
Bal-week	06/11	45.00-46.00
Bal-week	06/10	45.00-47.75
Bal-week	06/07	76.00-82.00
Next-week	06/12	54.00-58.00
Next-week	06/11	54.00-58.00
Next-week	06/10	56.75-57.25
Next-week	06/06	53.00-59.75
ERCOT, Houston		
Bal-week	06/07	85.00-85.50
ERCOT, South		
Bal-week	06/07	75.75-76.25

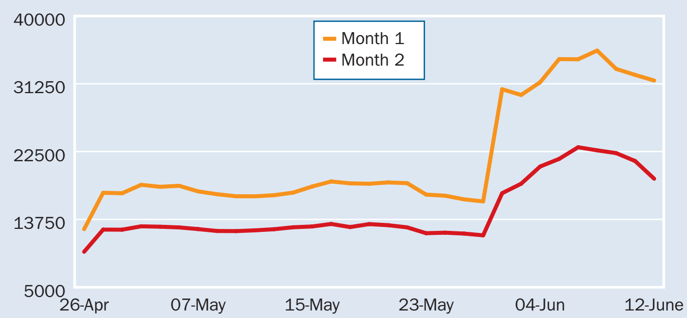
Southeast & Central Platts-ICE Forward Curve, Jun 12 ($/MWh)

Prompt month: Jul 13	On-peak	Off-peak
Southern Into	41.25	29.75
Entergy Into	40.50	27.50
ERCOT North	72.50	32.25
ERCOT Houston	71.75	32.25
ERCOT West	76.50	32.25
ERCOT South	71.75	33.75

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



ERCOT Houston: 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.		Retired	09/26/09
Farley-1/Southern Nuclear	918	n	Ala.	MO	Unk	06/11/13
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11

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

Western dailies go mostly lower; most terms rise

Western dailies were mostly lower Wednesday with lower demand expected in California and mixed spot natural gas prices. Most terms advanced, and the NYMEX July natural gas futures contract posted a preliminary settlement price of $3.777/MMBtu Wednesday, up 5.3 cents from Tuesday's close.

In the Northwest, Mid-Columbia day-ahead on-peak was down about $1.75 to trade between $27.50 and $30/MWh for delivery on Thursday. Mid-C day-ahead off-peak prices fell around $2.50 to trade between $7 and $16.50/MWh. The Mid-C on-peak balance-of-the-month package was bid at $29.75 and offered at $31.75/MWh, down about $1.50.

Portland, Oregon's forecast highs were for the low 60s through Thursday. Expected lows were for the low 50s.

The Bonneville Power Administration's wind at 7 a.m. PDT Wednesday was 1,283 MW, and its hydropower was 12,257 MW.

In California, SP15 next-day on-peak fell more than $1.75 to trade between $41 and $42.75/MWh. SP15 day-ahead off-peak fell around 25 cents to trade between $31.25 and $31.50/MWh. SP15 bal-month traded between $45.25 and $45.75/MWh, down about 50 cents. NP15 day-ahead on-peak lost nearly 25 cents to trade between $38.75 and $39.50/MWh. NP15 day-ahead off-peak was down roughly $1 to about $30.75/MWh. NP15 bal-month was bid at $40.75 and offered at $41/MWh, about flat.

Sacramento, California, expected highs around 85 on Thursday, down slightly. Forecast lows were for the high 50s. Burbank expected highs around 80 and lows in the low 60s.

The California Independent System Operator projected peak demand to hit 34,164 MW on Wednesday and 32,095 MW on Thursday. Renewables were 3,117 MW and wind was about 1,100 MW at 7 a.m. PDT on Wednesday.

In the desert Southwest, Palo Verde next-day on-peak prices were down more than $2.50 to trade between $35 and $37/MWh. Palo Verde day-ahead off-peak lost about $1.25 to trade between $24 and $24.75/MWh. Palo Verde bal-month was bid at $34/MWh.

Phoenix expected highs below 110 on Thursday, down slightly, and lows in the mid-80s.

Next day natural gas were mixed in the Rockies and California. Opal was up 7.1 cents to $3.574/MMBtu, Pacific Gas and Electric city-gate lost 1.2 cents to $3.823/MMBtu, and SoCal city-gate fell 1.9 cents to $3.891/MMBtu.

Day-ahead prices in the California Independent System Operator auction were down Wednesday afternoon following the demand forecast. SP15 on-peak fell $3.02 to $39.41/MWh while SP15 off-peak dropped $3.21 to $29.75/MWh. NP15 on-peak lost $2.88 to $38.13/MWh and NP15 off-peak slid $2.21 to $31.53/MWh. ZP26 on-peak was down $3.39 to $37.17/MWh as ZP26 off-peak declined $3.33 to $29.13/MWh.

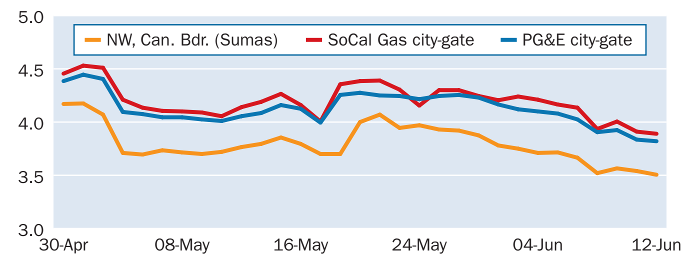
In the Northwest, Mid-Columbia on-peak July was unchanged with bids at $38.50 and offers at $38.95/MWh on

(continued on page 10)

Western day-ahead bilateral indexes for Jun 13 ($/MWh)

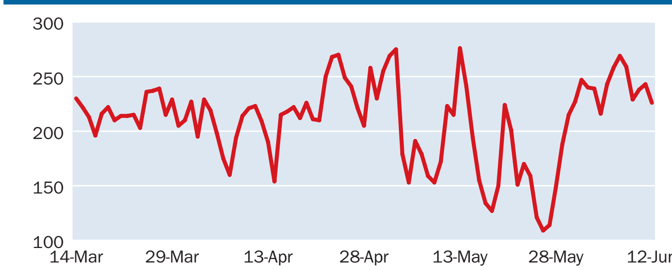
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	30.00	-1.42	37.91	8276
Mid-C	29.24	-1.74	35.81	8336
Palo Verde	35.46	-2.77	39.34	9662
Mead	38.50	-2.17	42.08	10308
Mona	38.00	-3.00	39.70	10780
Four Corners	43.00	-1.95	42.36	11928
NP15	39.00	-0.25	45.02	10209
SP15	41.50	-1.75	49.95	11111
Off-Peak				
COB	15.67	-3.07	23.37	4323
Mid-C	14.49	-2.47	21.11	4131
Palo Verde	24.31	-1.19	28.02	6624
Mead	25.50	-0.95	29.30	6827
Mona	20.00	0.00	21.19	5674
Four Corners	23.05	-0.95	26.41	6394
NP15	30.25	0.75	33.31	7919
SP15	31.50	-0.25	36.17	8434

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO gas generation (GWh)



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 11-Jun	%Chg	% Chg Year-ago	Forecast 12-Jun	13-Jun	14-Jun	15-Jun	16-Jun
CAISO								
Load	695	5	2	667	663	661	628	609
Generation								
Gas	243	2	4	226	215	218	220	219
Nuclear	56	0	-9	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Jun 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	38.13	-0.42	-2.05	-2.88	43.14	9969
SP15 Gen Hub	39.49	-0.05	-1.07	-3.02	47.52	10572
ZP26 Gen Hub	37.17	-0.21	-3.23	-3.39	41.91	9951
Off-Peak						
NP15 Gen Hub	31.53	0.76	-0.51	-2.21	32.96	8228
SP15 Gen Hub	29.75	-0.32	-1.21	-3.21	33.31	7958
ZP26 Gen Hub	29.13	-0.39	-1.77	-3.33	31.42	7791

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	06/10	33.00-33.50
Bal-month	06/07	34.00-34.50
Bal-month (off-peak)	06/12	18.50-19.00
Bal-month (off-peak)	06/11	18.75-20.10
Bal-month (off-peak)	06/10	21.00-22.25
Bal-month (off-peak)	06/07	22.75-23.25
Bal-month (off-peak)	06/06	21.00-22.50
NP15		
Bal-month	06/12	40.75-41.40
SP15		
Bal-month	06/12	45.25-45.90

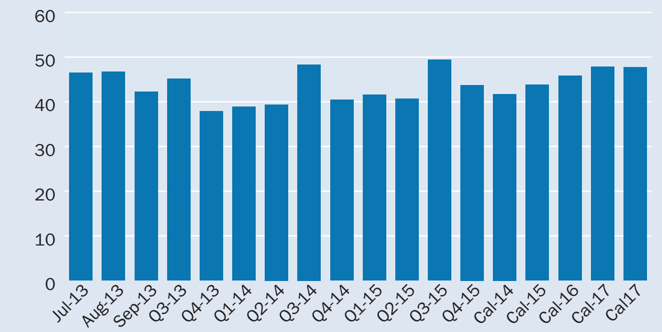
Generation unit outage report

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
Huntington Beach-3/AES	225	g	Calif	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif	PMO	Unk	04/14/13
La Paloma-1/La Paloma	260	g	Calif.	PMO	Unk	05/27/13
La Paloma-4/La Paloma	260	g	Calif.	PMO	Unk	06/10/13
Los Esteros/Calpine	188	g	Calif.	PMO	Unk	05/27/13
Mexicali/Sempra	180	g	Calif.	MO	Unk	05/02/13
Ocotillo/Pattern	265	w	Calif.	MO	Unk	05/16/13
Redondo-8/AES	496	g	Calif.	MO	Unk	06/09/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12

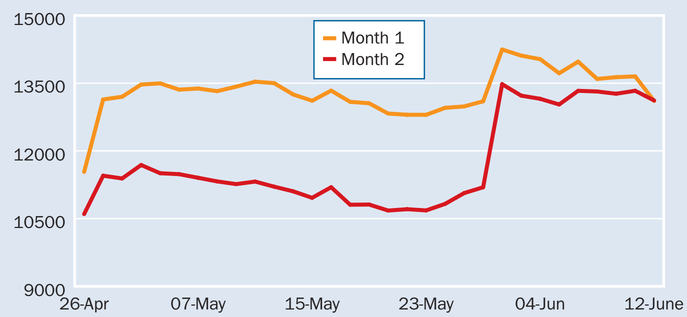
Western Platts-ICE Forward Curve, Jun 12 ($/MWh)

Prompt month: Jul 13	On-peak	Off-peak
Mid-C	38.75	26.75
Palo Verde	44.75	28.50
Mead	46.50	30.25
NP15	48.00	36.50
SP15	54.25	38.25

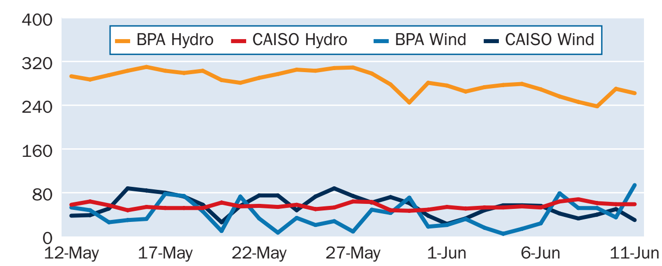
Mead: Forward curve on-peak ($/MWh)



Mead: 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 & MISO dailies lower; terms advance

Power prices for Thursday delivery in the Mid-Atlantic and Midwest were lower Wednesday, while forwards advanced as the NYMEX July natural gas futures contract posted a preliminary settlement price of $3.777/MMBtu Wednesday, up 5.3 cents, as the market had been oversold and was due for a technical correction, sources said.

Mid-Atlantic daily prices retreated Wednesday, with lower demand outlooks and a decline in spot natural gas prices. PJM Interconnection forecasted peak demand for Wednesday at 125,705 MW and 116,209 MW on Thursday.

Temperatures across the PJM region are forecast for highs in the low 70s to mid-90s on Thursday. Spot gas in the region remained weak, with Texas Eastern M-3 losing about 7 cents to $3.78/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Thursday lost more than $5, going to the mid-$40s/MWh. PJM West Hub off-peak peeled back about $1.50 to the mid-$20s/MWh.

Midcontinent Independent System Operator dailies were down Wednesday with temperatures in the MISO region on Thursday forecast in the low 70s to low 80s. Chicago city gates spot gas was holding steady around $3.81/MMBtu. Indiana Hub peak fell about $8.75 to the mid-$30s/MWh and off-peak was steady in the low $20s/MWh.

Dailies in the Midwestern portion of PJM Interconnection also moved lower with the dip in nearby power markets and spot gas prices. AEP-Dayton Hub peak lost about $8.75, going to the upper $30s/MWh and off-peak was down about $1.50 in the mid-$20s/MWh.

Northern Illinois Hub peak dropped about $8.75 to the mid-$30s/MWh. NI Hub off-peak packages lost about $2.50, going to around $18/MWh.

Day-ahead auction prices in the PJM Interconnection were down Wednesday with demand forecast to move down. Eastern hub remained strong, only inching down 24 cents to $64.07/MWh, with the congestion component over $25/MWh, while off-peak lost $10.87, the biggest drop for off-peak prices, to $30.49/MWh. Delmarva P&L zone slipped $1.98 to $58.75/MWh, with congestion above $20/MWh, and off-peak tumbled $9.08 to $29.46/MWh. Western hub peak dropped $9.88 to $40.27/MWh and off-peak shed 86 cents to $26.26/MWh.

BG&E zone peak dropped $10.49 to $53.39/MWh and off-peak lost 86 cents going to $27.63/MWh. Chicago Hub peak was down $9.78 to $31.78/MWh and off-peak gave up $2.70, going to $20.61/MWh.

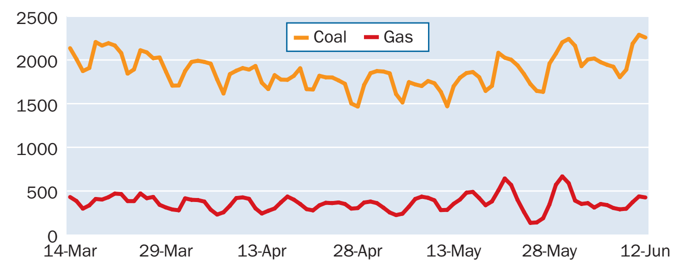
MISO day-ahead auction prices cleared weaker Wednesday. Minnesota became the highest-priced hub, with on-peak clearing at $33.79/MWh, a drop of $3.24. Off-peak cleared at $20.05/MWh, a loss of $2.29.

Indiana Hub on-peak cleared at $33.50/MWh, down $6.71, while off-peak cleared at $22.82/MWh, a drop of 19 cents.

PJM & MISO day-ahead bilateral indexes for Jun 13 ($/MWh)

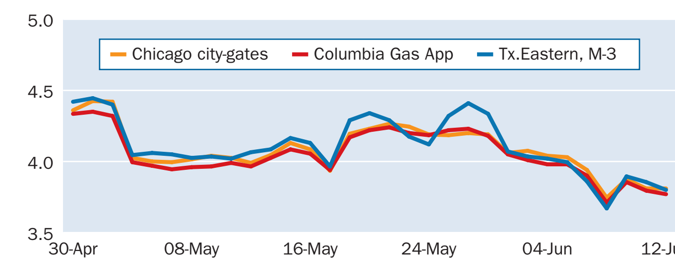
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	47.00	-4.50	44.53	12801
Dominion Hub	51.25	-2.25	44.33	13407
AD Hub	37.75	-8.00	39.53	10107
NI Hub	34.75	-9.00	36.56	9121
PJM Off-Peak				
PJM West	26.00	-0.75	27.06	7081
Dominion Hub	26.75	-0.25	26.97	6998
AD Hub	24.50	-1.00	25.97	6560
NI Hub	18.00	-2.50	20.33	4724
MISO On-peak				
Indiana Hub	35.00	-8.75	35.69	9296
Michigan Hub	33.00	-10.25	37.56	8318
Minnesota Hub	32.00	-10.50	34.81	8654
Illinois Hub	30.00	-12.25	33.50	7890
MISO Off-Peak				
Indiana Hub	22.25	0.00	21.75	5910
Michigan Hub	26.50	1.50	25.92	6679
Minnesota Hub	21.25	2.00	18.36	5747
Illinois Hub	19.50	-0.25	19.72	5128

PJM & MISO gas and coal generation (GWh)



Source: Bentek

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 11-Jun	%Chg	% Chg Year-ago	Forecast 12-Jun	13-Jun	14-Jun	15-Jun	16-Jun
PJM								
Load	2287	4	3	2198	2167	2043	1840	1938
Generation								
Coal	1090	2	13	1023	960	919	882	867
Gas	327	20	-21	333	331	292	280	327
Nuclear	742	2	1	749	749	749	749	749
MISO								
Load	1466	8	1	1497	1432	1345	1237	1309
Generation								
Coal	1199	7	10	1234	1148	1064	1037	1085
Gas	112	11	-43	93	83	74	79	118
Nuclear	193	0	-11	193	193	193	193	193

Source: Bentek

MISO average day-ahead LMP for Jun 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	33.50	-1.02	0.36	-6.71	32.68	8892
Michigan Hub	33.41	-1.43	0.68	-4.80	34.15	8419
Minnesota Hub	33.79	-0.27	-0.11	-3.24	29.75	9143
Illinois Hub	32.24	-1.08	-0.84	-2.90	30.69	8471
Off-Peak						
Indiana Hub	22.82	0.25	0.58	-0.19	21.62	6025
Michigan Hub	25.66	2.88	0.79	-1.39	26.47	6452
Minnesota Hub	20.05	-1.23	-0.71	-2.29	17.22	5446
Illinois Hub	20.62	-0.91	-0.46	0.35	19.96	5411

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

Package	Trade date	Range
PJM West		
Bal-week	06/12	35.75-37.00
Bal-week	06/11	41.00-42.00
Bal-week	06/07	46.50-47.50
Next-week	06/12	46.00-47.00
Next-week	06/11	45.00-46.50
Next-week	06/10	47.50-49.00
Next-week	06/07	53.50-54.25
Next-week	06/06	45.75-48.50

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Kewaunee/Dominion	581	n	Wis.		Retired	05/07/13
Monticello/Xcel	666	n	Minn.	PMO	06/21/13	03/02/13
Palisades/Entergy	778	n	Mich.	MO	Unk	05/05/13

PJM average day-ahead LMP for Jun 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	31.97	-4.50	-1.33	-8.52	37.12	8461
AEP-Dayton Hub	34.33	-3.51	0.05	-8.55	38.53	9087
ATSI Gen Hub	33.77	-4.12	0.09	-8.56	39.91	8949
Chicago Gen Hub	30.85	-5.96	-0.97	-9.22	33.73	8098
Chicago Hub	31.78	-5.59	-0.42	-9.78	34.55	8341
Dominion Hub	44.47	6.86	-0.18	-7.55	42.43	11622
Eastern Hub	64.07	25.04	1.23	-0.24	48.08	16711
New Jersy Hub	37.19	-0.85	0.25	-8.03	43.08	9700
Northern Illinios Hub	31.23	-5.93	-0.64	-9.84	34.06	8196
Ohio Hub	34.74	-3.38	0.33	-8.51	38.70	9090
West Internal Hub	36.75	-0.47	-0.57	-8.60	41.07	9988
Western Hub	40.27	3.23	-0.75	-9.88	42.92	10945
AEP Zone	34.85	-2.85	-0.10	-8.14	38.79	9223
Allegheny Power Zone	35.87	-1.24	-0.68	-9.00	40.33	9622
Atlantic Elec Zone	37.72	-0.52	0.44	-7.56	42.56	9838
ATSI Zone	33.78	-4.23	0.21	-8.65	40.18	8952
BG&E Zone	53.39	14.54	1.06	-10.49	48.56	14233
ComEd Zone	31.56	-5.77	-0.45	-9.76	34.38	8285
Dayton P&L Zone	35.27	-3.93	1.41	-8.89	39.02	9360
Delmarva P&L Zone	58.75	20.19	0.77	-1.98	46.75	15324
Dominion Zone	45.73	7.88	0.06	-7.96	43.10	11952
Duke Zone	33.76	-3.78	-0.25	-8.75	37.74	8960
Duquesne Light Zone	31.22	-5.12	-1.45	-8.34	38.58	8442
JCPL Zone	36.95	-0.98	0.14	-8.01	42.28	9639
MetEd Zone	35.60	-1.66	-0.53	-7.34	41.14	9335
PECO Zone	37.94	0.32	-0.17	-7.39	41.97	9949
Pennsylvania Elec Zone	34.83	-2.48	-0.48	-10.25	41.28	11019
PEPCO Zone	49.05	10.65	0.61	-8.23	46.67	13077
PPL Zone	36.29	-1.04	-0.46	-7.72	41.40	9517
PSEG Zone	37.29	-0.81	0.31	-8.15	43.73	9726
Rockland Elec Zone	36.76	-1.33	0.30	-8.71	43.12	9588
Off-Peak						
AEP Gen Hub	24.36	-0.36	-0.78	-0.50	25.56	6399
AEP-Dayton Hub	25.61	0.29	-0.18	-0.09	26.45	6726
ATSI Gen Hub	25.79	0.39	-0.10	-0.45	27.07	6784
Chicago Gen Hub	20.14	-4.38	-0.97	-2.47	20.58	5287
Chicago Hub	20.61	-4.18	-0.70	-2.70	21.12	5411
Dominion Hub	26.98	1.36	0.12	-0.25	27.28	7010
Eastern Hub	30.49	4.24	0.76	-10.87	29.98	7872
New Jersy Hub	26.89	0.83	0.57	-1.09	28.42	6943
Northern Illinios Hub	19.81	-4.89	-0.80	-3.23	20.51	5200
Ohio Hub	25.87	0.46	-0.09	0.02	26.63	6736
West Internal Hub	25.86	0.60	-0.24	-0.44	26.98	6954
Western Hub	26.26	0.84	-0.08	-0.86	27.44	7062
AEP Zone	25.55	0.24	-0.18	-0.17	26.44	6712
Allegheny Power Zone	25.64	0.38	-0.24	-0.67	27.00	6825
Atlantic Elec Zone	26.90	0.82	0.58	-1.05	28.28	6944
ATSI Zone	25.80	0.33	-0.02	-0.44	27.16	6787
BG&E Zone	27.63	1.42	0.71	-0.86	28.45	7294
ComEd Zone	20.20	-4.58	-0.72	-2.96	20.81	5301
Dayton P&L Zone	25.64	-0.17	0.32	-0.38	26.48	6772
Delmarva P&L Zone	29.46	3.33	0.63	-9.08	29.54	7605
Dominion Zone	27.14	1.44	0.21	-0.49	27.56	7052
Duke Zone	24.69	-0.25	-0.56	-0.38	25.60	6519
Duquesne Light Zone	24.56	-0.04	-0.89	-0.43	26.30	6582
JCPL Zone	26.85	0.81	0.54	-1.10	28.34	6932
MetEd Zone	26.51	0.82	0.19	-1.05	27.91	6892
PECO Zone	26.66	0.83	0.33	-1.06	28.02	6930
Pennsylvania Elec Zone	26.12	0.45	0.17	-1.07	27.70	8790
PEPCO Zone	27.45	1.52	0.44	-0.86	28.18	7248
PPL Zone	26.49	0.78	0.21	-1.04	27.97	6887
PSEG Zone	26.95	0.83	0.62	-1.09	28.54	6957
Rockland Elec Zone	26.90	0.86	0.55	-1.07	28.37	6945

Michigan Hub on-peak cleared the auction at $33.41/MWh, slipping $4.80. Off-peak cleared at $25.66/MWh, losing $1.39.

Illinois Hub dropped to the lowest-priced hub, with on-peak clearing at $32.24/MWh, falling $2.90. Off-peak cleared at $20.62/MWh, adding 35 cents. Congestion costs at the hubs ranged from negative $1.43 to negative 27 cents for on-peak, and from negative $1.23 to $2.88 for off-peak.

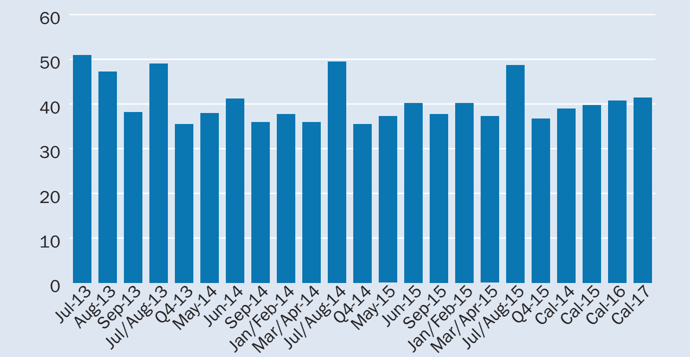
Mid-Atlantic forward prices rose Wednesday with firmer gas futures. PJM West on-peak July financial futures were 75 cents stronger, with bids at $59/MWh and offers at $59.20/MWh on the IntercontinentalExchange at about 2:30 p.m. EDT. PJM West on-peak August climbed 75 cents to $55.75/MWh, while on-peak fourth quarter inched up 15 cents to $42.75/MWh. PJM West off-peak July-August added 25 cents to $34/MWh.

Midwest July forwards made gains Wednesday with stronger gas futures. AEP Dayton Hub on-peak July financial futures increased $1 to $53.25/MWh. Indiana Hub on-peak July climbed 75 cents to $48.75/MWh. Northern Illinois on-peak July rose 50 cents to about $51/MWh.

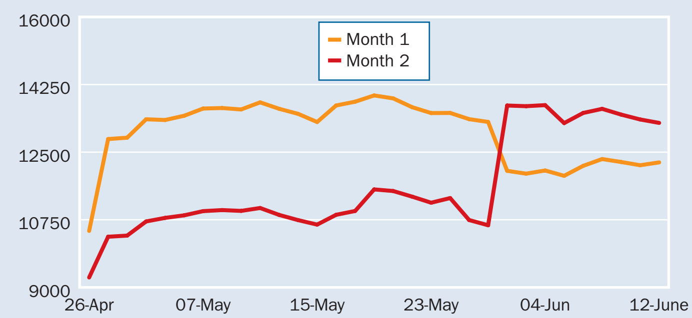
PJM & MISO Platts-ICE Forward Curve, Jun 12 ($/MWh)

Prompt month: Jul 13	On-peak	Off-peak
PJM West	59.00	34.75
AD Hub	53.25	31.75
NI Hub	51.00	28.50
Indiana Hub	48.75	29.00

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



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



Southeast markets *... from page 4*

temperature is 86. Its average low is 68.

The Electric Reliability Council of Texas day-ahead auction for Thursday delivery cleared firmer Wednesday afternoon with peak load forecast increasing. Houston Hub remained in position as the highest-priced hub, while North Hub tied with South Hub for lowest-priced hub.

Houston Hub on-peak cleared in the auction at $41.86/MWh, nearly unchanged, while off-peak cleared at $23.68/MWh, nearly the same as Tuesday.

West Hub on-peak cleared in the ERCOT auction at $41.45/MWh, a jump of almost $2.50, while off-peak cleared at $23.66/MWh, up around 25 cents. South Hub on-peak cleared at $40.76/MWh, a gain of nearly 75 cents while off-peak cleared at $23.62/MWh, steady. North Hub on-peak cleared the auction at $40.76/MWh, an increase of around $2.25 from Tuesday's clearing price, while off-peak cleared at $23.63/MWh, unchanged.

West Zone on-peak led the load zones at $56.45/MWh, a gain of about $3.25 from Tuesday. The highest hourly day-ahead price occurred at 5 p.m. CDT in the Houston Hub at $70.42MWh and in the West Zone at $102/MWh. ERCOT system load was forecast to peak at 59,850 MW Thursday, up 2% from Wednesday's expected peak of 58,800 MW.

South Central July terms were mixed Wednesday. ERCOT North July sank $7.50 to about $72.50/MWh, August fell $1 to about $121/MWh, September fell 25 cents to about $43.50/MWh, and the fourth quarter crept up 20 cents to about $34.60/MWh. Heat rates were down about 200 Btu/kWh on IntercontinentalExchange around 2:30 p.m. EDT. ERCOT Houston had no bids or offers in late trading. Into Entergy July jumped $1 to about $40.50/MWh, August advanced 75 cents to about $37.50/MWh, and September rose 25 cents to about $35/MWh.

Southeast on-peak July went up Wednesday, as did July NYMEX gas futures. Into Southern July surged 75 cents to about $41.25/MWh, August gained 75 cents to about $38.50/MWh, September was up 50 cents to about $36.25/MWh and Q4 rose 25 cents to about $35.65/MWh.

West markets *... from page 6*

IntercontinentalExchange around 2:30 p.m. EDT. The third quarter crept up 10 cents to about $40.25/MWh, and the fourth quarter climbed 50 cents to about $36.75/MWh. In California, SP15 on-peak July financial terms surged 75 cents with bids at $54 and offers at $54.50/MWh. Q3 strengthened by 60 cents to about $54.60/MWh, and Q4 fell 35 cents to about $48.10/MWh. NP15 July stepped up 75 cents to about $48/MWh, and Q3 was up 65 cents to about $48.65/MWh. Palo Verde July rose 25 cents to about $44.75/MWh, Q3 fell 25 cents to about $43/MWh, and Q4 stayed at about $35.50/MWh.

NEWS

SDG&E to pursue PPA after San Onfore decision

Following Southern California Edison's decision to retire the 2,150-MW San Onofre nuclear power plant in southern California, San Diego Gas & Electric plans to repropose a power purchase agreement to buy the output from a planned 305-MW natural gas-fired plant.

"This new [Pio Pico] facility will contribute to local capacity requirements and will be instrumental in maintaining a reliable electrical system," Jennifer Ramp, an SDG&E spokeswoman, said Wednesday.

In a March 21 decision, the California Public Utilities Commission rejected tolling agreements related to the Pio Pico Energy Center, proposed by the Apex Power Group, and the 100-MW Quail Brush Power, proposed by Cogentrix Energy, in part because the commission believed it was unclear that there was an immediate need for the plants. The proposed PPAs grew out of a June 2009 request for proposals issued by SDG&E, a Sempra Energy subsidiary.

The peaking plants were set to start operating by mid-2014, but the ISO does not forecast a shortfall for the San Diego area until about 2018.

Instead of approving the 20-year contracts, the PUC directed SDG&E to procure up to 298 MW of local generation beginning in 2018. The PUC also approved a 25-year, 45-MW PPA between the utility and the Escondido Energy Center, an existing facility that will be expanded by 10 MW under a repowering project. The PUC said it approved the contract due to the project's relative low cost, small size increase, high viability and environmental benefits resulting from a repower.

However, the PUC left the door open to reconsidering the Pio Pico and Quail Brush tolling agreements if they were modified. The PUC directed SDG&E to either issue a new solicitation for the utility's pending shortfall or to resubmit amended Pio Pico and Quail Brush PPAs this year.

Now, SDG&E plans to submit next week a revised contract related to the planned Pio Pico plant, which will be built in San Diego County, Ramp said. Under the new contract, the plant is scheduled to come on line in the fall of 2015 and provide the region with much needed resource adequacy, according to Ramp.

"The need for Pio Pico was determined by the CPUC with [San Onofre] in service and without [the nuclear plant] the need for new resources such as Pio Pico increases," Ramp said. "This new facility will contribute to local capacity requirements and will be instrumental in maintaining a reliable electrical system."

Meanwhile, California has an ample reserve margin heading into the summer, although there are some concerns for local reliability in Southern California, Robert Emmert, California Independent System Operator manager for interconnection resources, said Wednesday during a California Energy Commission meeting.

"We're pretty good in the generation area," Emmert said, noting that the probability of load shedding was about 1%.

Even so, the ISO has concerns for southern Orange County and San Diego, according to Emmert. "Reliability risk is marginally more challenging than last summer," he said.

The operating reserve margin in the ISO footprint is 19.6%, 21.4% in southern California and 21.7% in the north, according to Emmert. A year ago, the ISO forecast for last summer a 22.5% operating reserve margin for its footprint and a 21.5% margin for the south and a 23.7% margin for the north.

Even in an extreme scenario – defined as low imports, 1-in-10 generation and transmission outages, and 1-in-10 peak demand – reserve margins stay above a 3% threshold that would require load shedding, Emmert said.

— Ethan Howland

CEC passes 33% RPS rules for munis

The California Energy Commission approved regulations on Wednesday explaining how publicly-owned utilities will be expected to comply with the state's renewable energy mandate.

The regulations, adopted by a unanimous vote, marks the end of a process stretching back to April 2011 when Governor Jerry Brown signed SBX 1-2, which increased California's renewable target from 20% to one-third by 2020 and placed POUs under the compliance umbrella for the first time.

Passage of the rules comes only six months before the end of the first compliance period, which covers 2011-13, and requires load-serving entities to procure 20% of their retail sales from eligible renewable resources.

The Public Utilities Commission passed its own set of regulations covering investor-owned utilities, competitive retail sellers and community choice aggregators in 2011.

For the CEC, turning the 33% RPS statute into regulations has entailed several drafts, four public workshops and seven rounds of stakeholder comments.

Debate mostly centered on a handful of technical areas defining how renewable energy procurement should count for compliance purposes, with POUs pushing the CEC to adopt rules that would yield greater flexibility and lower costs.

But the proceeding has also exposed opposing views on deeper issues, such as the appropriate role the CEC should play, and whether it is fair to treat POUs differently than IOUs.

These same questions were on display at Wednesday's meeting during public testimony before the vote.

"We think it's important that market rules are the same for POUs and IOUs, which will help everyone who is participating in the marketplace understand the rules," said Valerie Wynn of Pacific Gas & Electric.

IOU customers will otherwise end up paying more than POU customers, she said.

Mike Webster of Los Angeles Department of Water and Power disagreed, saying that it would be wrong to force POUs into the identical RPS compliance framework as IOUs.

Doing so would be as wrong as requiring IOUs to adopt a vertically-integrated utility model, he said.

One of the issues stressed repeatedly by the POUs has been the authority granted over them by their governing boards, rather than the energy commission. The IOU-PUC relationship is not the same as the one between POUs and the CEC, they say.

At Wednesday's meeting, commission staff cast aside that sweeping argument, saying that POUs adopt their own RPS programs, but the energy commission was indeed responsible for compliance.

CEC Chair Robert Weisenmiller said he believed that the approved regulations had struck a balance between the need for POU autonomy and consistent rulemaking.

Another commissioner noted the sensitivities involved where one state agency – the CEC – had an enforcement role over another branch of government.

One specific issue that drew much stakeholder comment, and highlighted these divisions, concerned the rules over the calculation of RPS procurement quantities.

The statute requires load-serving entities reach certain benchmarks leading up to 33% by 2020. These targets are divvied up into three compliance periods. They are 20% (2011-13), 25% (2014-16) and 33% (2017-20).

Load-serving entities must make "reasonable progress" toward the 25% and 33% targets during the intervening years, the statute says, leaving the door open to regulators to interpret the meaning.

The PUC adopted a "stair-step" approach, whereas the CEC originally proposed a "flat trajectory" approach.

Such a bifurcated policy would mean POUs are on the hook to procure smaller quantities of renewable energy than IOUs, according to Pacific Gas & Electric and Southern California Edison.

The POUs said the proposed methodology was better than the PUC's stair-step approach, but contended that the CEC was overstepping its authority in the first place.

Governing boards were responsible for deciding whether POUs make "reasonable progress," they said.

Ultimately, the CEC shifted course and issued last-minute revisions to the regulations. The approved regulations maintain the "flat trajectory" approach in the second compliance period, and a "stair-step" approach during the third compliance period.

— Geoffrey Craig

Daily CSAPR allowance assessments, Jun 12

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, Jun 12

	$/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 11 ($/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	3.38	0			
Dec14 V10	3.53	0			
Dec14 V11	3.53	0			
Dec14 V12	3.53	0			
Dec14 V13	3.45	0			
Dec15 V10	3.53	0			
Dec15 V11	3.53	0			
Dec15 V12	3.53	0			
Dec15 V13	3.45	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.

Maine governor pushes to add Canadian hydro

Maine's governor wants to bring more Canadian hydro into New England. But that's not what's stopping him from signing an omnibus energy bill now on his desk.

Patrick Woodcock, director of the Governor's Energy Office, confirmed in an interview that Governor Paul LePage is holding off on signing (L.D. 1559). But he's holding off in hopes of pressing lawmakers to concede to other energy proposals high on his list – not the hydro provision.

Passed by both branches of the Legislature, the omnibus bill includes measures to lower energy costs through energy efficiency and other means. Before he acts on the bill, LePage wants lawmakers to back his positions on an offshore wind contract and a ratepayer green-energy charge.

Meanwhile, LePage is taking a long-term view when it comes to giving large Canadian hydro – a recent hot topic in New England – a new avenue into Maine, according to Woodcock.

It may not happen this year, but Woodcock believes it will eventually.

“We think there is momentum on a regional level,” Woodcock said. “We hope that Maine joins that effort. We may not be successful this legislative session, but I think there is momentum on our side.”

Restructured New England states for years have disallowed incentives for Canadian hydro, partly out of concern that it would undermine development of a domestic renewables industry. New England generators and environmental groups continue to fight against an influx of Canadian hydro.

But recently, governors from both major parties have taken up the cause for Canadian hydro, including LePage, a Republican, and Democratic governors from two other New England states.

In Connecticut, Governor Dannel Malloy recently signed into law a bill that allows the state to secure 15-year contracts with large Canadian hydro suppliers for up to 5% of the power consumed in the state. Meanwhile, Rhode Island Governor Lincoln Chafee, a Democrat, is pushing a bill that calls for National Grid to issue a solicitation seeking up to 150-MW of Canadian hydro.

Both Malloy and Chafee say they support the Canadian hydro contracts as a way to keep down electricity costs.

LePage proposed a bill this year, L.D. 646, that would let Canadian hydro become a bigger part of the mix by removing a 100-MW cap from the state’s renewable portfolio standard. Currently, projects do not qualify for the RPS unless they are less than 100 MW. The one exception is wind power.

“It is a bit puzzling from a public policy standpoint to have just one type of renewable energy exempt,” Woodcock said.

He described the wind exemption as a “blatant protectionist policy.” If the goal is to grow a renewable energy market in the Northeast, rules should not discriminate or give preference to any particular type of renewable energy, he said.

“We look at these limitations as really a barrier for growing a strong renewable energy market in the Northeast and partnering with the Canadian provinces,” he said.

Others, such as the New England Power Generators Association, question the need to give Canadian hydro any preference through RPS or long-term contracts, and say the resource should be able to compete on its own in the market.

LePage’s hydro bill remains in committee and faces tough going for this year in the Democrat-controlled Legislature. Little time is left. The Legislature plans to adjourn June 21.

Meanwhile, with the clock ticking, LePage is holding off on taking action on the omnibus energy bill, until he sees what lawmakers do on other energy proposals he is pushing.

Passed by the Senate and the House and only awaiting LePage’s signature, the bill aims to reduce energy costs through various means, including energy efficiency and a realignment of some funds the state receives through the Regional Greenhouse Gas Initiative. It also allows the Public Utilities Commission to enter into pipeline capacity contracts for natural gas and reaffirms the state’s participation in RGGI.

Before he signs the omnibus bill, the governor wants lawmakers to take action to bring competition to a contract that the PUC plans to sign with Statoil for floating offshore wind turbines. LePage wants legislation passed that would require the PUC to consider a competing floating wind technology developed at the University of Maine.

The PUC this year approved a term sheet for Statoil’s 12-MW floating offshore wind turbine test project off Maine’s coast. The terms call for Statoil to sell power from the pilot project under the 20-year deal starting at $270/MWh. As a next step, the parties will produce a long-term power purchase agreement that must also win commission approval.

LePage wants legislation passed that would require the PUC to compare the University of Maine’s technology against the Statoil project before moving ahead with a contract.

LePage also take issue with a provision in the omnibus bill that changes how the system benefits charge is set in Maine. The bill shifts control of the charge to the PUC. LePage believes lawmakers should set the charge, which pays for various green energy programs, not “the unelected public utilities commission,” Woodcock said.

While the changes LePage wants cannot be made in the omnibus bill, it is possible for lawmakers to include them in other pending energy legislation, Woodcock said.

The omnibus bill passed the Legislature June 7. The governor has 10 business days from that date to sign it, veto it or allow it to become law without his signature.

— Lisa Wood

MISO, Entergy studying scenarios

If the Midcontinent Independent System Operator can provide sufficient transmission capacity to its proposed new territory in the Entergy footprint, the existing MISO system would need no new thermal generation through 2023.

In a discussion of alternate future scenarios through 2033 if Entergy utilities' territories in Arkansas, Louisiana, Mississippi and Texas are allowed to join MISO, an ISO representative said MISO would need no new thermal capacity through 2023. Thereafter, 7,200 MW of combustion turbine generation would be needed in the existing MISO footprint and an additional 1,200 MW would need to be evenly divided between northeastern Arkansas and central Louisiana.

In this scenario, the existing MISO footprint would need about 8,400 MW of the Entergy footprint's excess capacity.

MISO now serves utilities in Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, South Dakota and Wisconsin.

But in an alternate future with robust economic growth, industrial growth in southeast Texas and along the Louisiana Gulf Coast would require expanding combined cycle natural gas generation in by about 600 MW in northeastern Arkansas, 1,200 MW in the Entergy Texas area, near Alexandria and Baton Rouge, Louisiana, and 600 MW near Jackson, Mississippi.

Entergy and MISO have applied to allow Entergy to join MISO this December. MISO now serves as Entergy's independent coordinator of transmission.

— Mark Watson

SREC prices, solar costs subject of inquiry in N.J.

The price of solar renewable energy certificates in New Jersey and volatility in solar project development costs are the subject of an inquiry by state regulators who are seeking comments on how best to mitigate the problem.

In a request for comment issued Tuesday, the Board of Public Utilities staff said identifying and eliminating the sources of solar development volatility could increase investor confidence, reduce finance costs and help achieve the solar development goal set in the state's renewable portfolio standard. The solar RPS is set at 4.1% by 2027.

The BPU is looking at how fluctuations in the price of SRECs and unexpected changes in the solar market affect development costs. It also is looking at the key indicators that can be used to measure solar market volatility.

Volatility in the market poses risks to solar investors by increasing costs, BPU staff said. "Investors depend on SREC revenue streams and unpredictable swings in value can increase finance costs," staff said.

A number of possible solutions have been identified so far in stakeholder discussions and comments, including a call for increased market transparency by providing more reliable and accurate information on solar projects and prices.

The development of market policies such as feed-in tariffs, a centralized SREC trading platform, an SREC reserve mechanism and an SREC floor price have been identified by participants as possible solutions to the volatility.

But staff also is looking for consensus on the definition of volatility in the market, seeking input on how to define the aspects of solar development volatility that an approach would mitigate. While there is no agreement on how to define solar volatility, there are common themes so far from stakeholders with respect to the relationship between volatility in SREC prices over time and the potential for volatility in the solar installation market, BPU staff said.

SREC prices can serve as a secondary indicator for solar market development volatility, but they are not the primary indicator of volatility in installation activity, staff said.

The Solar Act signed into law last year looked at ways to stabilize the SREC market. The BPU was directed to investigate approaches to mitigate solar development volatility and evaluate techniques used nationally and internationally and to submit a report to the Legislature. The BPU expects to complete its investigation by July 23, 2014.

BPU staff kicked off its proceeding in November and in December initially asked for comments. It expanded the request by asking for help defining and understanding solar development volatility. Comments were filed in February, with Renu Energy saying that volatility refers to frequent, unexpected changes in market conditions that disrupt solar investment decisions.

Quantum Solar noted that the definition of solar development volatility was not in the Solar Act. Market volatility may threaten several important aspects of the law, including provisions for competitive market participation, the company said. It suggested that development of a feed-in tariff and a move to a three-year compliance period for SREC retirement would mitigate solar development volatility.

The Mid-Atlantic Solar Energy Industries said solar development volatility in the Act refers to the pace of constructing solar projects. The group said the New Jersey RPS and SREC market is designed to motivate solar investment and is inherently volatile. The group concluded that in order for SREC supply and demand to be in balance, extreme swings in solar development are necessary, and if solar development is not highly volatile, then the SREC market will swing between under supply and oversupply.

The Solar Energy Industries Association said market stability improves the long-term viability of businesses and contributes to the attainment of the RPS goals.

Comments meant to advance the discussion of ways to mitigate the volatility are due July 1.

— Mary Powers

Correction

An article June 11 about transmission plans being pursued by Atlantic City Electric and PPL misidentified a nuclear power plant. Atlantic City Electric plans to build a 230 kV transmission line to the Orchard substation that converts 500 kV power from the 2,357-MW Salem and the 1,219-MW Hope Creek nuclear power plants to 230 kV. The story incorrectly identified the Hope Creek plant as New Hope.

CHP may be poised for further strides in Texas

An expected petrochemical renaissance along Texas' Gulf Coast, new state laws encouraging combined heat and power projects, and the need for new generating capacity in the Electric Reliability Council of Texas are likely to spur the development of several cogeneration and other CHP plants, industry experts and others said Wednesday.

Texas already is home to more cogeneration and other CHP capacity than any other state, mostly because of its large petrochemical industry, which relies on the availability of natural gas liquids and other feedstock materials, as well as on access to process steam and electricity.

Tommy John, a consulting engineer and owner of Tommy John Engineering of Bandera, Texas, said the huge new supply of natural gas liquids from US shale plays is spurring the development of petrochemical facilities along the Texas and Louisiana coasts.

For example, John said, Exxon Mobil is planning a major expansion of its Baytown, Texas, petrochemical complex, including new steam cracking capacity that will convert ethane, a natural gas liquid, into ethylene, which can then be used to make polyethylene.

Steam cracking facilities planned by Exxon Mobil and others will lead to the development of other petrochemical projects in the area, many of which would benefit from onsite, gas-fired cogeneration facilities that cost-effectively produce process steam and electricity, he said.

John said ERCOT, with its competitive market for power, is a more welcoming place for cogeneration and other CHP projects than most other markets in the US. He added that ERCOT's low reserve margin and need for additional generating capacity — and the resulting likelihood of rising power prices — provides an added incentive to develop new cogeneration plants.

Paul Cauduro, executive director of the Texas Combined Heat and Power Initiative, said his group and other CHP advocates in the state have been successful in reducing or eliminating some of the regulatory and market barriers to developing new cogeneration capacity there.

Cauduro noted that the Texas Legislature in its 2013 session approved three bills supportive of CHP. They include S.B. 385, which allows the use of "property assessed clean energy" financing — that is, long-term financing of CHP and other energy efficiency improvement projects through increased property-tax assessments — by owners of commercial and industrial properties.

H.B. 1864, in turn, directs Texas's State Energy Conservation Office to issue guidelines on how governmental entities should conduct CHP feasibility analyses prior to the construction or renovation of hospitals, data centers and other facilities deemed to be critical for disaster preparedness and response.

Finally, H.B. 2049 permits the owners of cogeneration and other CHP plants to sell electricity to any of their steam hosts. Previously, a cogeneration plant that sold steam to, say, three buyers was allowed to sell electricity to no more than one of them.

"Our hope is that these new laws will help to create more favorable market conditions" for CHP projects, Cauduro said.

Some CHP development is already happening, at least on a small scale. Rentech Nitrogen Partners confirmed Wednesday that it is developing plans for a 15-MW cogeneration plant at its fertilizer products facility in Pasadena, Texas.

According to a company statement, the $30 million cogeneration plant — scheduled to come online by the fall 2014 — will use excess steam from a sulfuric acid unit at the facility to generate electricity, some of which will be used by Rentech itself and the rest of which will be sold into the ERCOT market.

— Housley Carr

Georgia Power details solar solicitation response

Georgia Power received a total of 90 bids from 56 respondents to the utility's May 10 solicitation for 60 MW of utility-scale solar photovoltaic power, the Southern Company subsidiary said Wednesday.

Georgia Power spokesman John Kraft said the utility's largest solar-related request for proposals to date generated a significant amount of interest among prospective bidders.

"More than 500 interested parties registered" at independent monitor Accion Power's website to gain access to RFP-related documents, Kraft said, adding that the company and Georgia Public Service Commission staff responded to "several hundred questions and comments about the RFP." Bids were due June 5.

The solicitation was the first of two 60-MW utility-scale solar RFPs Georgia Power plans to issue as part of the 210-MW "advanced solar initiative" plan approved by the PSC last November.

Under that plan, the utility is authorize to contract for a total of 120 MW of solar projects with capacities of 1 to 20 MW each, as well as a total of 90 MW of distribution-scale projects of less than 1 MW each. The first 45 MW of distribution-scale projects were selected in April; the second 45-MW batch will be picked next spring. Similarly, Georgia Power next spring plans to issue a second 60-MW utility-scale RFP.

In the utility-scale RFPs, the total cost of a solar developer's bid plus any cost of upgrading the grid cannot exceed $120/MWh on a levelized basis. Several observers, including some members of the PSC itself, have indicated that because of falling solar PV panel prices and a heightened competitive atmosphere they expect to see bids at least several dollars/MWh below the $120/MWh cap, and perhaps below $100/MWh.

Georgia Power's Kraft on Wednesday declined comment on whether the utility believes the large numbers of bidder and proposals it received suggest that bid prices will be particularly attractive.

Georgia Power expects a short list of finalists will be determined by September 13; power purchase agreement negotiations will be completed by November 6, and the utility will file the resulting PPAs at the PSC on November 15.

The winners will enter into 20-year PPAs. All winning projects resulting from the first of the two planned utility-scale RFPs must begin commercial operation by January 1, 2015. Projects selected as the winners of next spring's planned utility-scale solicitation will need to come online by January 1, 2016.

Georgia Power said in April that it received nearly 1,000 distinct small- and medium distribution-scale proposals totaling about 600 MW during the March 1-11 submission period, and conducted an April 5 lottery to select 129 proposals totaling 45 MW. As noted, a similar process is planned for next spring.

Participants in the small and medium-scale programs will be paid a flat $130/MWh for the power they provide during their 20-year PPAs. Participants in the medium-scale program can opt to receive an escalating price for power that begin at about 8.5 cents/kWh in 2013 and rises to more than 17 cents/kWh by the end of their 20-year agreements.

— Housley Carr

EIA seen estimating 94-98 Bcf storage injection

A consensus of analysts expect that the Energy Information Administration on Thursday will estimate a natural gas storage injection of between 94 Bcf and 98 Bcf for the reporting week that ended Friday.

Addition to stocks within those expected levels would be above both a 66-Bcf injection seen during the comparable week last year and the five-year-average injection of 84 Bcf, according to EIA data. As a result, both the 616-Bcf deficit to last year and the 69-Bcf deficit to the five-year average should shrink.

The wider range of analyst expectations spanned from injections of between 82 Bcf and 105 Bcf.

EIA estimated a 111 Bcf injection for the week that ended May 31, expanding the overall stocks to 2.252 Bcf.

Bentek Energy's supply/demand model predicts an injection of 94 Bcf for the week that ended Friday, and its pipeline flow model anticipates an addition to stocks at the same level of 94 Bcf. Bentek is a unit of Platts.

Jefferies and Co. analyst Subash Chandra, whose estimate of about 82-Bcf injection is at the lower end of expectations, said the US National Weather Service was forecasting a hotter week, with cooling degree days rising to 42 from 31, which is 7 above last year and 3 above normal.

Citi Futures Perspective analyst Tim Evans, whose estimate of a 105 Bcf injection is at the higher end of expectations, said such addition to stocks could be a "bearish surprise." Evans added that predictions include a wide range of estimates, but most of them are above the five-year average injection level.

— Anastasia Gnezditskaia

Coal's share of ERCOT market makes gains

Coal made gains as natural gas usage fell in the Electric Reliability Council of Texas generation mix for May, according to data released late Tuesday by the grid operator.

ERCOT's 2013 Demand and Energy by Month report shows energy consumption across the grid operator's footprint totaled 27.4 million MWh in May, compared with 28.7 million MWh in May 2012, a 4.4% decrease.

National Weather Service data shows that Austin, which lies near the center of ERCOT's footprint, had 15.30% less cooling-degree days this April than in 2012.

Gas-fired plants provided 35.7% of the power consumed in ERCOT in May, a decrease from 38.8% in April, according to the data. Houston Ship Channel natural gas prices averaged $4.059/MMBtu in May, starting the month at $4.32/MMBtu and falling to end at $3.955/MMBtu.

With the exception of April, natural gas' share of the market has fallen every month this year, starting out the year at 41.3% in January.

Coal-fired facilities generated 36.9% of the energy needed in May, up from 35.8% in April. Nuclear plants provided 13.2% of the electricity consumed in May, a gain from 10% in March.

Wind farms provided 13.5% in May, down from the 15.1% in April. Other sources provided 0.8% of May's energy, up from 0.3% in April.

ERCOT North Hub on-peak prices averaged $38/MWh in May, while off-peak averaged $25.23/MWh. Houston Hub on-peak averaged $39.50/MWh, while off-peak averaged $25.50/MWh. South Hub on-peak averaged $39.25/MWh and off-peak averaged $25.25/MWh. West Hub on-peak prices averaged $37.50/MWh and off-peak averaged $22/MWh.

ERCOT's peak demand in May was the 56,209 MW required on May 31, a 4.6% decrease compared with peak demand of 58,947 MW seen in May 2012. That monthly high took place on May 29, 2012.

— Kassia Micek

Utility output dips 1.3% on year on week: EEI

Utilities generated 76,090 GWh in the week that ended Saturday, down 1.3% from the 77,118 GWh generated in the corresponding week of 2012, the Edison Electric Institute said Wednesday.

The weekly generation output was down slightly from the 76,387 GWh generated in the week that ended June 1, EEI said.

Output for the week compared with last year fell in five of the nine regions tracked by EEI, with drops in the Central Industrial, West Central, Southeast, South Central and Pacific Northwest regions outweighing the gains seen in the New England, Mid-Atlantic, Rocky Mountain and Pacific Southwest.

The West Central region saw the largest percentage drop, with the 5,854 GWh generated in the week that ended Saturday 12% below the corresponding week in 2012, EEI said.

New England saw the largest percentage gain, with the 2,431 GWh generated a 7.8% increase from the same week last year.

Year-to-date utility generation, which includes investor-owned, cooperatives and government-owned utilities, was about 1.696 million GWh, 0.9% above the 1.681 million GWh in the same period of 2012, EEI said.

— Tom Tiernan

Hedging positions show expectations

...from page 1

drop of $14 million in EBITDA, while the same gas price increase would result in only a $4 million drop in EBITDA of its unhedged gas plants.

For Dynegy's hedged coal plants it says a $1 increase in gas prices would result in a $69 million increase in EBITDA while its unhedged coal plants would get a $153 million bump in EBITDA.

Dynegy houses its coal and gas plants in separate business units. Its coal segment has four plants, all in the Midcontinent Independent System Operator region, totaling 2,980 MW. Its gas segment has eight plants in five different markets totaling 6,771 MW.

Toward the other end of the spectrum is FirstEnergy, which takes what it calls a "multi-channel approach" to hedging, meaning that it matches its generation output with a variety of user classes that it serves under contract. Those user groups include customers served through provider of last resort, or POLR, auctions in Ohio and Pennsylvania, customers served through municipal aggregation, mass market customers obtained through mailings, sweepstakes and advertisement, mid-sized commercial and industrial customers, and large commercial and industrial customers.

FirstEnergy uses its own generation to meet its load obligations, spokeswoman Diane Francis, explained. "We don't want to time the market," she said, adding that the company does not want to lock in 2014 prices too early in 2013 so they can take advantage of changes in the market throughout the year.

In 2012 most of FirstEnergy's sales, 51 million MWh for a total of $2.73 billion, were to large commercial and industrial customers. In 2013 FirstEnergy is targeting sales of 54 million MWh for $2.77 billion, of which 99% is already committed. FirstEnergy's second largest channel is sales through government aggregation, which the company is targeting at 21% of sales in 2013. POLR customers are targeted at 15% of sales for 2013, and large commercial and industrial customers are targeted at 52%.

FirstEnergy says that the way its competitive business is set up largely reflects how a regulated utility operates.

FirstEnergy claims there are several advantages to its approach. Arguably the most compelling reason is that by aligning its load obligations with its generating assets the company is better able to fully capture available margin, that is, by essentially selling to itself the company avoids having to pay a third party for services such as load shaping or balancing or renewable attributes. "Our price for power is our cost to produce it," Francis said. "We feel in control of our price."

But while that strategy gives FirstEnergy control over its output, it still leaves the company open to price volatility in its fuel inputs. To reduce that volatility, the company aims to keep fuel costs constant by locking in prices. One of the tools it uses for its coal plants is blending different the types of coal.

FirstEnergy says its nuclear fuel costs for 2012 were $7.60/MWh and are projected to be $8.10/MWh for 2013. Its fossil fuel costs in 2012 were $28/MWh and are projected to be the same in 2013.

At three of its plants – Fort Martin, Mansfield and Sammis – the company says it uses a blend of Northern Appalachian, Western and Illinois Basin coals.

The company also says it is looking at using natural gas at its coal plants and is exploring all options from co-firing with gas to full conversion to gas firing.

About 70% of FirstEnergy's 18,187-MW competitive portfolio is coal fired, and about 22% is nuclear power.

PPL Corp. has retail outlets and owns regulated utilities, but it does not use them to hedge its generation output. It uses standard hedging tools such as swaps and derivatives and manages its hedging within a band on a rolling three-year basis that becomes progressively more open in year three.

In its report on its first quarter earnings, PPL said that its baseload generation is 98% to 100% hedged for 2013, and 62% to 66% hedged in 2014. Three years out, PPL is 0% to 30% hedged.

For its intermediate and peaking plants, however, PPL is currently hedged only 44% and 10% for 2013 and 2014, respectively.

The output of PPL's regulated utilities, such as Kentucky Utilities and Louisville Gas & Electric, do not need to be hedged, but they help the company's hedging efforts because their stable earnings have shored up the company's balance sheet. That enables them to use a variety of hedging tools without overdue concern about credit issues.

The company maintains an $800 million secured energy marketing and trading facility to satisfy collateral posting obligations.

Collateral for hedging is a big issue for merchant generators, particularly those that are not investment grade. Public Service Enterprise Group, in a regulatory filing, noted that if it were to lose its investment grade rating, it could be required to post $675 million of collateral.

The company now has about $5 million net of cash deposited with counterparties and $119 million of letters of credit posted.

PSEG, however, is able to take advantage of hedge that is built in to its home state's regulatory structure by supplying power to retail customers through New Jersey's basic generation service, or BGS, auction.

But there have been major changes in that market in the past several years. In 2012 BGS sales accounted for 35% of PSEG's hedging mix, down from 44% in 2010 and 50% in 2008. And in 2013 PSEG expects BGS to account for only 23% of its hedges.

The declines are the result of the average BGS price moving higher relative to spot prices, which have been pushed down by the combination of low natural gas prices and slack demand. That has allowed retail marketers to enter the market and win away BGS customers.

That has prompted PSEG to adapt its hedging strategy. The company declined to give specifics, except to say that it now incorporates other POLR auctions, such as Maryland's and Pennsylvania's, into its hedging strategy to the extent that they constituted 4% of hedges in 2010 and 8% in 2012. The rest of the fall off has been taken up by traditional hedge, which went from 50% in 2008 to 52% in 2010 and 57% in 2012.

Overall, PSEG says it hedges conservatively. Typically the company is 100% to 75% hedged in current year, 50% to 80% hedged one year out and about 25% hedged two years out.

NRG Energy, on the other hand, does not have an investment grade rating, and that affects its hedging strategy. To mitigate tying up its capital in collateral postings, NRG Energy grants some hedging counterparties first liens on a substantial portion of its assets.

NRG uses first liens to support its obligations under out-of-the-money hedge agreements for forward sales of power or gas used as a proxy for power. If an underlying hedge is in-the-money for NRG the counterparty would have no claim under the lien program.

The lien program limits the volumes that can be hedged, but not the value of underlying positions. Within the program, NRG can hedge up to 80% of its coal and nuclear capacity, excluding plants it acquired from GenOn Energy, and 10% of its other assets, excluding GenOn assets, for the first 60 months.

Even so, NRG puts on some hedges that are not covered by its first lien program. At year-end 2012 it had posted $229 million of collateral. Further, NRG also said at year end that a 50 cent/MMBtu increase in natural gas prices would require posting another $83 million in collateral.

NRG, however, does have the benefit of having a retail service provider. NRG hedges the electric power it sells to customers through its Reliant unit, but because it is an in-house transaction, it does not have to post collateral.

Like several other generators, NRG also hedges on a schedule that leaves further years more open. In 2013, NRG's coal and nuclear output is 96% hedged via natural gas equivalents and 86% hedged via heat rate swaps. In 2014 coal and nuclear is 66% hedged via gas equivalents and 46% via heat rate swaps, and in 2015 its coal and nuclear output is 30% hedged by gas equivalents and 33% hedged with heat rate swaps. NRG also hedges its retail position 80% in 2013, 35% in 2014 and 18% in 2015.

Exelon gained a similar benefit when it bought Constellation Energy in March 2012, obviating its need to put up collateral, as well as having to deal with the margin erosion of bid-ask and liquidity spreads.

As of first-quarter 2013, Exelon expected to have $6 million in open gross margin and, because power prices have been falling, expects $1.2 billion of in-the-money hedges in 2013. For 2013 it is also expecting $350 million of margin from its retail business, as well as $300 million each from its executed and still pending non-power businesses such as wholesale gas delivery, demand response, energy efficiency and rooftop solar installations.

Exelon expects its margin from mark-to-market hedges to decline to $400 million in 2014 and $250 million in 2015 as its hedging level declines from 98% to 101% in 2013 to 70% to 73% in 2014 and 33% to 36% in 2015.

When it comes to hedging, though, Calpine is in a category of its own. The company has no retail outlet and is as close to a pure merchant generator as there is and its fleet is almost entirely comprised of gas-fired plants, leaving it particularly vulnerable to swings in fuel prices.

Like NRG, Calpine uses first liens on its generation assets in lieu of having to post cash collateral. And, like Dynegy, Calpine maintains a relatively aggressive open position that could stand to benefit if power prices rise.

The company is 70% hedged in 2013, but only 34% hedged in in 2014 and 30% hedged in 2015.

— Peter Maloney

Exelon move highlights softness: analyst

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The derate cancellations come in the wake of Dominion's shutdown in May of the 556-MW Kewaunee nuclear plant in Wisconsin.

"Everyone is well aware of the market conditions and the challenge they present, and that's what drove our decision to remove those projects from our plan," Exelon spokesman Paul Elsberg said Wednesday. Continued low power prices played a key role in Exelon's calculations.

That is hardly a surprise, Paul Patterson, a Glenrock Associates analyst in New York who tracks Exelon, said in an interview. "It's another dreary data point for merchant nuclear, at least currently," he said.

Given the weak power prices, Exelon "does not want to make that investment" in uprates at the 2,313-MW LaSalle plant in northern Illinois and the 2,400-MW Limerick plant northwest of Philadelphia, he said.

Sluggish investments in US merchant plants could change "if gas prices shoot up or something," he added.

But Exelon has "no plans to revisit those projects," Elsberg said about LaSalle and Limerick.

For now, the company will continue to pursue planned uprates at three other nuclear plants: 2,396-MW Byron and 2,354-MW Braidwood in Illinois and 2,296-MW Peach Bottom in Pennsylvania, according to Elsberg.

Byron and Braidwood will be completed later this year while Peach Bottom is targeted for completion in 2015 and 2016. In all, Exelon is adding nearly 200 MW — 34 MW each at Byron and Braidwood and 130 MW at Peach Bottom.

Exelon co-owns Peach Bottom with Public Service and Gas of New Jersey and is the plant's operator.

Even though the two planned uprates have been scrapped, Elsberg pointed out that Exelon has added about 1,400 MW "of clean nuclear energy" over the past 15 years through uprates at its nuclear facilities.

Exelon controls about 19,000 MW of nuclear generating capacity that will increase to about 19,200 MW once the uprate projects under way are finished. Altogether, the company owns nearly 35,000 MW of generation capacity.

In the first quarter, Exelon's nuclear plants produced about 36 million MWh, a slight increase from 35.2 million MWh a year earlier. The plants achieved a 96.4% capacity factor in the first three months of this year, up from 93.6% in the comparable period of 2012. The production data excluded units owned by Constellation Energy Nuclear Group.

Although the two nuclear uprates have been shelved, Elsberg said Exelon "will be looking to invest in our existing businesses in other ways in future years."

— Bob Matyi

NYISO changes approved

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transactions are more variable than power purchases by an LSE to support its load obligations because the bidding activity is often dependent on the price differentials between control areas and the availability of transmission lines," FERC said in its order. "NYISO argues that, due to this variability, using historical purchases to calculate the credit requirements for external transactions, instead of real-time bidding activity, can leave NYISO with undue credit exposure on a day when a market participant's activity increases, and can require a market participant to unnecessarily post collateral when no bids have been entered."

The NYISO said the current credit requirements do not account for the risk posed by external transactions that are scheduled in the day-ahead market but do not flow in real-time.

For example, FERC said, NYISO analysis found that "import suppliers that have historically settled a high proportion of day-ahead transactions financially at a loss are essentially virtual suppliers because they do not supply the physical power in real-time. NYISO's existing credit methodology is not designed to account for this risk."

To address these shortcomings, NYISO has proposed using the automated credit management system it implemented between 2008 and 2010 to monitor bids for external transactions in real-time and set distinct credit requirements for such transactions. FERC approved the proposal in a Tuesday order (Docket No. ER13-1199).

Under the new system, a market participant's credit requirements for external transactions will be the sum of the import, export and wheel through credit requirements and the net amount owed to the ISO for settled external transactions. By monitoring the external transaction bids in real-time NYISO will be able to reject any bids that are not supported by sufficient credit from the market participant.

NYISO requested that the changes become effective Wednesday, the date it planned to install software that will allow it to monitor external transactions bids in real-time. FERC accepted that proposed start date, but noted that NYISO could have up to 45 days if needed to make the necessary changes.

— Juliana Brint

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