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Settlement illustrates New England challenges

ANALYSIS The first and only gas-fired power plant ever to clear New England's capacity auction is headed to the finish line, but the path the developers had to navigate raises questions about the environment for projects that might follow.

Footprint Power's 674-MW Salem Harbor plant in Salem, Massachusetts, is expected to come online in June 2016 after reaching a settlement agreement with the Conservation Law Foundation, its last major opponent, that calls for the plant to ratchet down its carbon dioxide emissions and to close the plant by 2050.

The settlement has "the real potential to put a chill on the investment market to build combined-cycle projects" in New England, Dan Dolan, president of the New England Power Generators Association, said.

Under the settlement with CLF, Footprint has agreed to

(continued on page 16)

Cold-weather testing effort backed by PJM panel

MARKETS Rules for verifying or testing cold-weather availability for resources in the PJM Interconnection may be implemented by October 1 under a proposal endorsed Tuesday by the PJM Operating Committee.

In approving an issue charge and problem statement entitled "Cold Weather Resource Performance Improvement," the committee agreed to review grid, resource and market data from this past winter's "polar vortex" event to find ways to mitigate the risk from future cold weather events. The documents noted that as much as 22% of PJM's generation capacity went into forced outage over the January 6-8 operating data, which is more than double previous estimates of potential generation outages.

The committee also will seek to educate stakeholders about

(continued on page 17)

NW utilities face widening winter peak shortfall

GENERATION Northwest utilities face a winter peak shortfall that grows to 3,350 MW in the next five years, according to the Pacific Northwest Utilities Conference Committee.

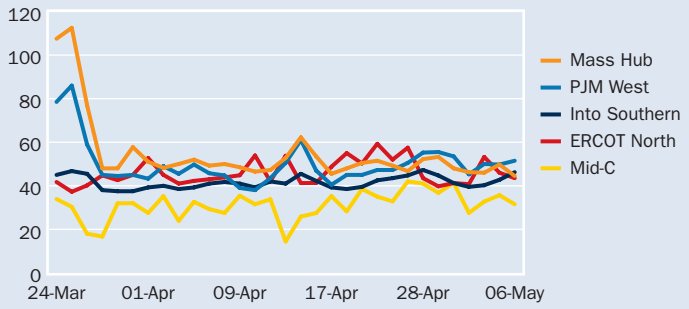
The winter shortfall expands to 6,700 MW in 2024, according to an annual report from PNUCC. Next year, the region's utilities expect a 1,190 MW summer-time shortfall, which grows to 6,670 MW in 2023.

Utilities are beginning to address the shortfall by developing plans to add about 1,790 MW, Shauna McReynolds, PNUCC deputy director, told a Northwest Power and Conservation Council committee Tuesday. Natural gas-fired plants and wind farms make up most of the planned generation, she said.

"Utilities are seeing the need to add resources to serve peak demand and introduce additional flexibility to meet fluctuations

(continued on page 17)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for May 7 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	42.08	43.32	32.99	35.36
NYISO	37.83	52.66	26.83	32.65
PJM	44.33	51.88	26.85	33.96
MISO	40.43	76.62	18.03	44.51
ERCOT	44.25	57.57	29.03	29.82
SPP	49.19	55.83	19.54	26.21
CAISO	48.90	53.02	35.48	38.18

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 May 7

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	44.50	10006	13.37	8.92	0.03	-8.87	-22.21
N.Y. Zone-A	41.00	9820	11.78	7.60	-0.75	-9.10	-21.63
PJM/MISO							
PJM West	51.50	12370	22.36	18.19	9.87	1.54	-10.95
Indiana Hub	51.25	10789	18.00	13.25	3.75	-5.75	-20.00
Southeast & Central							
Southern, Into	46.25	9701	12.88	8.11	-1.43	-10.96	-25.26
ERCOT, North	43.50	9310	10.79	6.12	-3.23	-12.57	-26.59
West							
Mid-C	31.52	6947	-0.24	-4.78	-13.86	-22.93	-36.54
SP15	51.50	10640	17.62	12.78	3.10	-6.58	-21.10

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 follow spot gas lower; terms mixed

New England dailies fell Tuesday as lower spot natural gas prices outweighed a slightly higher peak load forecast for Wednesday. Northeast forward prices were mixed amid a rise in gas futures.

Mass Hub day-ahead on-peak futures dropped $5 to about $44.75/MWh for Wednesday delivery on the IntercontinentalExchange. Boston's temperature forecasts show highs in the low 60s Tuesday and Wednesday. Mass Hub balance-of-the-week on-peak futures climbed $1.25 to about $45.50/MWh, with expectations of temperatures in line with or above seasonal norms.

Algonquin city-gates natural gas lost 60.6 cents to about $4.379/MMBtu on ICE.

ISO New England forecast peak load for Tuesday at 14,840 MW. The forecast for Wednesday is 14,910 MW, for Thursday 14,900 MW and for Friday 14,680 MW.

In New York state, Zone G bal-week on-peak fell $5.75 to about $45/MWh on ICE, with normal to above-normal temperatures forecast. Zone A bal-week on-peak dropped $3 to about $40/MWh.

New York ISO forecast peak load for Tuesday at 18,300 MW, or 207 MW higher than the actual peak Monday. The forecast for Wednesday is 17,611 MW, for Thursday 17,771 MW and for Friday 18,092 MW. New York City's temperature forecasts show highs in the upper 70s Tuesday and Wednesday.

Transco Zone 6 New York natural gas lost less than one cent to about $4.121/MMBtu on ICE.

Day-ahead auction on-peak clearing prices in ISO-NE fell slightly Tuesday. Internal Hub on-peak dropped 69 cents to $42.98/MWh for Wednesday delivery. Connecticut Zone on-peak lost 53 cents to $43.32/MWh. NE Mass Boston Zone on-peak fell 85 cents to $43.26/MWh. Maine Zone on-peak dropped $1.34 to $42.08/MWh.

Day-ahead auction clearing prices in NYISO were mixed Tuesday. The average price at Hudson Valley Zone fell $2.16 to $46.26/MWh. New York City Zone off-peak climbed $1.82 to $30.75/MWh. Capital Zone on-peak dropped $1.11 to $42.97/MWh. West Zone off-peak dropped $1.45 to $28.27/MWh.

Northeast term power was mixed Tuesday with higher natural gas futures and mixed basis. June NYMEX gas gained 11.1 cents to about $4.799/MMBtu. Algonquin city-gates June financial futures fell 14.5 cents to $1.375/MMBtu. Transco Zone 6-NY June climbed 1.4 cents to minus 76.1 cents/MMBtu.

Mass Hub June on-peak financial futures dropped $1 to about $64.50/MWh on ICE. Mass Hub July-August on-peak also lost $1 to about $66.50/MWh.

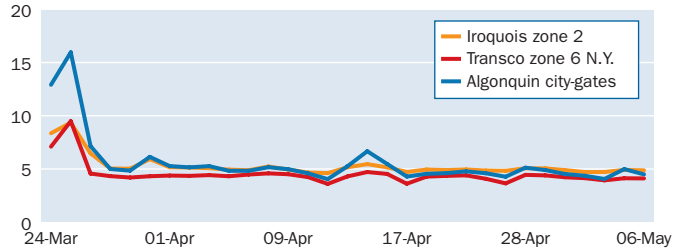
In New York, Zone G July-August on-peak rose 10 cents to about $68.25/MWh. Zone A June on-peak fell 30 cents to about $49.95/MWh. Zone A July-August was about flat at about $60/MMBtu.

Northeast day-ahead bilateral indexes for May 7 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	44.50	-5.25	46.90	10006
N.Y. Zone-G	48.25	-0.75	48.20	10746
N.Y. Zone-J	49.00	-0.75	48.95	10913
N.Y. Zone-A	41.00	-0.75	41.25	9820
Ontario*	32.75	-3.50	36.10	6100
Off-Peak				
Mass Hub	32.00	-6.25	33.20	7195
N.Y. Zone-G	30.75	0.25	29.05	6849
N.Y. Zone-J	31.25	0.25	29.55	6960
N.Y. Zone-A	26.50	0.25	25.50	6347
Ontario*	20.00	0.25	20.00	3725

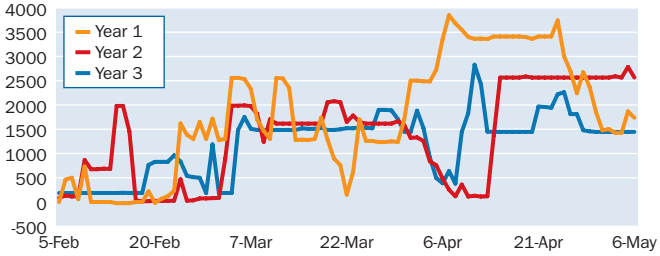
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO nuclear generation outages (GW)



Source: NRC

Northeast load and generation mix forecast (GWh)

	Actual 05-May	%Chg	% Chg Year-ago	Forecast 06-May	07-May	08-May	09-May	10-May
ISONE								
Load	315	13	3	309	318	323	319	295
Generation								
Coal	5	873	3	0	0	1	1	1
Gas	126	9	-1	172	171	158	144	134
Nuclear	89	0	2	89	89	89	89	89
NYISO								
Load	393	12	2	387	396	399	402	383
Generation								
Coal	10	207	31	10	8	6	5	4
Gas	90	3	-20	86	91	102	111	119
Nuclear	112	-9	-7	115	115	115	115	115

Source: Bentek

ISONE day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	42.98	-0.02	-0.06	-0.69	43.90	9488
Connecticut	43.32	-0.02	0.27	-0.53	44.14	9284
NE Mass-Boston	43.26	-0.02	0.22	-0.85	44.25	9550
SE Mass	42.92	0.02	-0.17	-0.76	43.81	9474
West-Central Mass	43.18	-0.02	0.13	-0.65	44.12	9530
Rhode Island	43.10	0.19	-0.16	-0.74	44.15	9514
Maine	42.08	-0.02	-0.97	-1.34	42.94	8660
New Hampshire	42.90	-0.02	-0.15	-0.83	43.92	8829
Vermont	42.33	-0.02	-0.72	-0.41	43.08	8712
Off-Peak						
Internal Hub	33.93	-0.12	0.02	0.10	31.07	7000
Connecticut	34.08	-0.12	0.17	0.30	31.03	7050
NE Mass-Boston	34.03	-0.12	0.12	0.02	31.23	7020
SE Mass	34.10	0.12	-0.06	0.31	31.08	7034
West-Central Mass	34.07	-0.12	0.16	0.11	31.18	7028
Rhode Island	35.36	1.12	0.20	1.33	31.44	7294
Maine	32.99	-0.12	-0.93	-0.19	30.37	6716
New Hampshire	33.69	-0.15	-0.20	0.05	30.96	6859
Vermont	33.65	-0.12	-0.27	0.17	30.85	6851

NYISO day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	42.97	0.07	2.23	-1.11	42.84	9583
Central Zone	41.72	-0.07	0.83	-0.93	40.92	9963
Dunwoodie Zone	46.89	-0.83	5.25	-2.15	46.32	10435
Genesee Zone	41.21	-0.05	0.34	-1.17	40.42	9841
Hudson Valley Zone	46.26	-0.67	4.77	-2.16	45.81	10293
Long Island Zone	52.66	-4.93	6.92	-4.32	53.44	11718
Millwood Zone	46.78	-0.81	5.15	-2.22	46.26	10411
Mohawk Valley Zone	41.79	-0.10	0.88	-1.15	41.09	9745
N.Y.C. Zone	47.24	-0.84	5.59	-2.22	46.86	10512
North Zone	37.83	0.00	-2.98	-1.06	36.84	7787
West Zone	40.41	-0.07	-0.47	-1.22	39.39	9649
Off-Peak						
Capital Zone	29.61	0.00	1.29	1.74	26.81	6481
Central Zone	28.74	0.00	0.42	1.56	25.98	6758
Dunwoodie Zone	30.57	0.00	2.25	1.77	27.79	6770
Genesee Zone	28.72	0.00	0.39	1.51	25.97	6754
Hudson Valley Zone	30.51	0.00	2.18	1.72	27.71	6754
Long Island Zone	32.65	-1.03	3.30	-1.86	32.06	7230
Millwood Zone	30.55	0.00	2.23	1.77	27.77	6765
Mohawk Valley Zone	28.66	0.00	0.34	1.49	25.91	6512
N.Y.C. Zone	30.75	0.00	2.42	1.82	27.96	6808
North Zone	26.83	0.00	-1.50	1.42	24.07	5463
West Zone	28.27	0.00	-0.06	1.45	25.50	6648

Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Next-week	05/01	48.00-48.50
N.Y. Zone-A		
Next-week	05/01	43.00-43.50

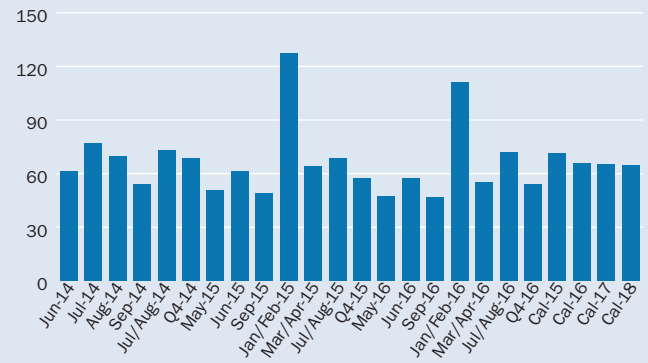
*Ontario prices are in Canadian dollars.

Northeast Platts M2MS Forward Curve, May 6 ($/MWh)

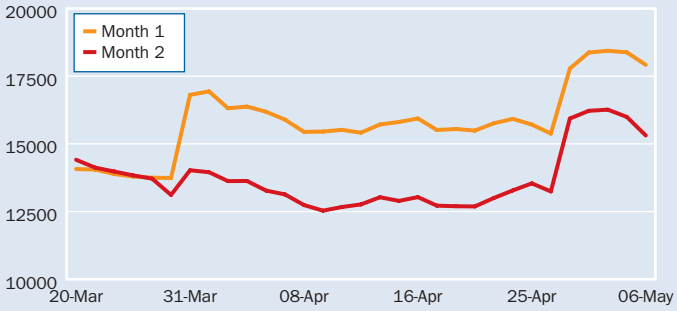
Prompt month: Jun 14	On-peak	Off-peak
Mass Hub	64.60	46.25
N.Y. Zone G	61.30	40.75
N.Y. Zone J	66.05	42.30
N.Y. Zone A	49.95	33.75
Ontario*	34.10	20.30

*Ontario prices are in Canadian dollars

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	205	bio	Ont.	PMO	Unk	04/16/14
Brighton Beach/ATCO/OPG	580	g	Ont.	MO	Unk	05/05/14
Bruce-2/Bruce Power	750	n	Ont.	MO	Unk	04/15/14
Bruce-3/Bruce Power	750	n	Ont.	MO	Unk	04/08/14
Darlington-1/OPG	876	n	Ont.	MO	Unk	04/07/14
Greenfield-2/Calpine	212	g	Ont.	MO	Unk	04/23/14
HaltonHills-1/TransCanada	226	g	Ont.	MO	Unk	04/04/14
HaltonHills-2/TransCanada	226	g	Ont.	MO	Unk	04/04/14
HaltonHills-3/TransCanada	305	g	Ont.	MO	Unk	04/04/14
Lennox-2/OPG	525	bio	Ont.	MO	Unk	03/06/14
Millstone-2/Dominion	879	n	Conn.	MO	05/16/14	04/07/14
Pickering-8/OPG	500	n	Ont.	MO	Unk	02/18/14
Thunderbay-2/OPG	153	bio	Ont.	MO	Unk	05/06/14
Thunderbay-3/OPG	153	bio	Ont.	MO	Unk	05/06/14
West Windsor/TransAlta	128	g	Ont.	MO	Unk	04/07/14

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 drop in ERCOT, rise in Southeast

Electric Reliability Council of Texas dailies were weaker Tuesday, with temperatures and demand expected to decline Wednesday. Dailies in the Southeast followed spot gas higher, while ERCOT forward prices also climbed as gas futures prices increased.

ERCOT North Hub day-ahead on-peak physical power shed $2.50 to about $43.50/MWh for Wednesday delivery on the IntercontinentalExchange.

Spot natural gas at Houston Ship Channel added 4 cents to about $4.635/MMBtu.

System load in ERCOT was forecast to peak at 47,150 MW Tuesday and 46,745 MW Wednesday, compared with an actual peak of 49,194 MW Monday. The high temperature in Dallas was forecast at 87 Wednesday, 5 degrees above normal. In Houston, the high temperature was expected at 83 Wednesday, 3 degrees below normal.

Real-time prices across all hubs averaged $27/MWh from 12:15-6 am CDT Tuesday. Wind generation was forecast to 8,275 MW at midnight CDT Wednesday. North Hub balance-of-the-week on-peak lost 25 cents to about $42.75/MWh, with temperatures as much as 7 degrees above normal. Next-week on-peak dropped 75 cents to about $43.25/MWh, with temperatures as much as 8 degrees above normal, while balance-of-the-month added $1.50 to about $47/MWh.

Southeast dailies were stronger Tuesday with temperatures forecast to be steady. Into Southern day-ahead on-peak physical power added $5 to the mid-$40s/MWh. Spot natural gas at Transco Zone-3 gained 4.8 cents to around $4.758/MMBtu. The high temperature in Atlanta was forecast at 86 Wednesday, 7 degrees above normal, with the low expected at 62, which would be 3 degrees above normal.

The ERCOT day-ahead auction cleared weaker Tuesday. Houston Hub remained the highest-priced hub with on-peak down $3.96 to clear the auction at $47.46/MWh. West Hub on-peak lost $1.75 to clear at $45.36/MWh. North Hub on-peak eased $1.66 to $44.47/MWh. South Hub became the lowest-priced

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for May 7 ($/MWh)

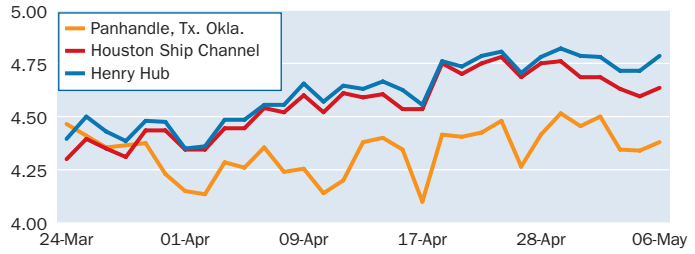
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	47.50	3.25	43.70	9804
Southern, Into	46.25	3.50	42.00	9701
Florida	45.75	3.50	43.10	9150
TVA, Into	47.50	2.75	43.65	9901
Entergy, Into	62.25	-1.25	52.90	13380
Southeast Off-Peak				
VACAR	32.75	3.25	30.43	6760
Southern, Into	33.00	4.50	30.29	6922
Florida	34.75	4.50	32.04	6950
TVA, Into	32.25	3.25	30.46	6722
Entergy, Into	37.00	-0.25	36.57	7953
ERCOT On-peak				
ERCOT, North	43.50	-2.50	44.95	9310
ERCOT, Houston	47.25	-3.75	49.80	10139
ERCOT, South	44.50	-2.50	46.35	9451
ERCOT, West	44.25	-2.50	45.70	9552
ERCOT Off-Peak				
ERCOT, North	28.50	2.75	28.29	6100
ERCOT, Houston	28.50	2.75	28.32	6116
ERCOT, South	28.25	2.75	28.21	6000
ERCOT, West	28.50	2.75	28.29	6152
SPP/MRO On-peak				
MAPP, South	54.25	-6.50	49.35	11543
SPP, North	53.50	-4.25	48.00	12215
SPP/MRO Off-Peak				
MAPP, South	29.25	1.75	30.46	6223
SPP, North	24.00	-0.75	29.64	5479

Southeast load and generation mix forecast (GWh)

	Actual 05-May	%Chg	% Chg Year-ago	Forecast 06-May	07-May	08-May	09-May	10-May
ERCOT								
Load	784	-5	9	789	887	907	942	933
Generation								
Coal	289	-7	14	291	312	326	346	363
Gas	335	-2	2	337	338	337	356	368
Nuclear	91	0	13	91	91	91	91	91
SPP								
Load	559	-1	2	560	644	641	606	571
Generation								
Coal	290	-7	-9	311	320	318	314	312
Gas	221	24	-2	186	184	164	144	139
Nuclear	31	0	47	31	31	31	31	31

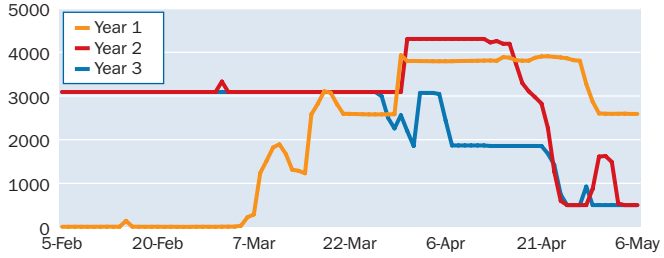
Source: Bentek

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



Source: Platts

ERCOT & SPP nuclear generation outages (GW)



Source: NRC

ERCOT average day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	44.93	-2.26	42.71	9620
Hub Average	45.39	-2.57	43.45	9718
Houston Hub	47.46	-3.96	46.75	10189
North Hub	44.47	-1.66	41.59	9524
South Hub	44.25	-2.98	43.09	9411
West Hub	45.36	-1.75	42.41	9783
AEN Zone	44.86	-2.32	42.79	9675
CPS Zone	45.53	-2.71	43.83	9776
LCRA Zone	45.70	-2.09	43.57	9814
Rayburn Zone	44.68	-1.91	41.85	9570
Houston Zone	49.12	-3.85	48.02	10543
North Zone	45.26	-2.36	42.11	9694
South Zone	47.98	0.25	44.36	10203
West Zone	57.57	-1.28	57.21	12418
Off-Peak				
Bus Average	29.35	1.01	27.18	6314
Hub Average	29.34	1.01	27.18	6313
Houston Hub	29.46	1.02	27.28	6352
North Hub	29.42	1.02	27.21	6342
South Hub	29.03	0.93	27.02	6216
West Hub	29.44	1.04	27.23	6359
AEN Zone	29.41	1.03	27.20	6351
CPS Zone	29.29	0.98	27.11	6329
LCRA Zone	29.50	1.07	27.26	6372
Rayburn Zone	29.43	1.03	27.21	6343
Houston Zone	29.48	1.03	27.30	6355
North Zone	29.43	1.03	27.21	6343
South Zone	29.12	0.97	27.10	6235
West Zone	29.82	1.42	28.04	6440

MISO South average day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Arkansas Hub	54.51	4.90	-1.68	2.11	48.77	11855
Louisiana Hub	53.82	3.46	-0.92	-42.62	55.10	11578
Texas Hub	76.62	25.98	-0.64	-3.05	70.45	16448
Off-Peak						
Arkansas Hub	27.33	-1.92	-0.68	-5.95	31.14	5962
Louisiana Hub	37.37	7.33	0.10	4.01	32.12	8078
Texas Hub	44.51	14.32	0.24	1.28	43.44	9604

SPP average day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
SPP North Hub	49.19	-4.19	-0.39	-8.21	48.05	10468
SPP South Hub	55.83	2.90	-0.84	-2.24	51.33	12413
Off-Peak						
SPP North Hub	19.54	-6.02	-0.99	-2.89	21.66	4163
SPP South Hub	26.21	-0.15	-0.19	0.30	25.60	5846

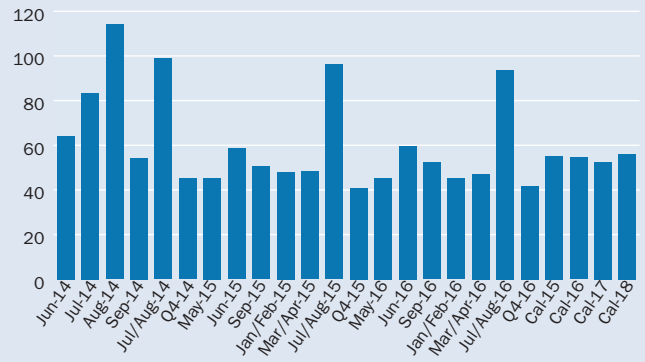
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Next-week	05/05	42.50-43.50
Next-week	05/01	44.00-45.00

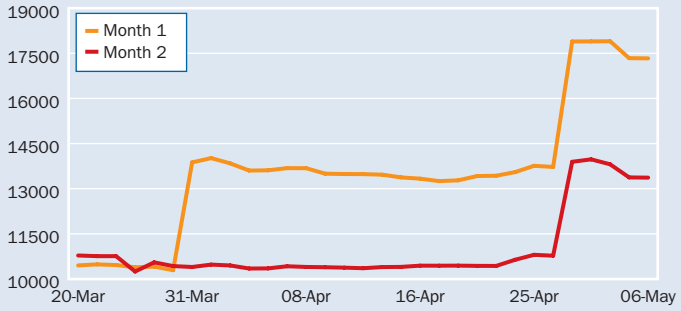
Southeast & Central Platts M2MS Forward Curve, May 6 ($/MWh)

Prompt month: Jun 14	On-peak	Off-peak
Southern Into	43.30	31.05
Entergy Into	39.05	27.45
ERCOT North	61.30	38.40
ERCOT Houston	64.15	39.70
ERCOT West	62.15	29.10
ERCOT South	62.15	37.70

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						
Ark. Nuclear-2/Entergy	1065	n	Ark.	MO	Unk	04/28/14
Big Brown-2/Luminant	575	c	Texas	MO	Unk	02/18/14
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Catawba-1/Duke	1163	n	S.C.	RF	Unk	05/06/14
Deepwater/AES	138	c	Texas	PMO	06/01/14	10/01/13
Martin Lake-1/Luminant	750	c	Texas	PMO	Unk	09/25/13
Martin Lake-2/Luminant	750	c	Texas	MO	Unk	12/16/13
Oconee-3/Duke	865	n	N.C.	RF	Unk	04/15/14
Seymour-2/LCRA	590	c	Texas	PMO	Unk	04/02/14
South Texas-1/STP	1280	n	Texas	MO	05/10/14	03/14/14
SR Berton/NRG	765	g	Texas	PMO	Unk	10/01/13
Summer-1/SCE&G	1008	n	S.C.	MO	Unk	04/07/14
Waterford-3/	1222	n	La.	MO	05/23/14	04/14/14
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13
Wolf Creek/Wolf Creek	1184	n	Kan.	PMO	05/15/14	03/08/14

WEST MARKETS

West dailies mixed; terms up

West dailies were mixed Tuesday amid steady demand and slightly higher spot natural gas prices. Terms rose.

In California, SP15 day-ahead on-peak futures jumped $4.50 to about $52/MWh for Wednesday delivery on the IntercontinentalExchange. SP15 day-ahead off-peak added 25 cents to about $39.25/MWh. SP15 on-peak balance-of-the-month moved up $3 to about $54.25/MWh. NP15 day-ahead on-peak futures were up $3 to about $52.50/MWh on ICE. NP15 day-ahead off-peak futures added 50 cents to about $39.50/MWh. NP15 balance-of-the-month on-peak climbed $3.50 to about $56.50/MWh. Spot gas in the region was slightly higher, with PG&E city-gate adding 1 cent to about $5.24/MMBtu and SoCal city-gate up 3 cents to about $5.05/MMBtu.

High temperatures on Wednesday in California are expected in the mid-60s to upper 70s, with lows in the upper 40s to upper 50s. The California Independent System Operator forecast peak demand on Tuesday at about 27,864 MW; 28,179 MW for Wednesday; 28,447 MW for Thursday; and 28,538 MW for Friday. In the Southwest, Palo Verde day-ahead on-peak eased 25 cents to about $40.25/MWh and Palo Verde day-ahead off-peak rose $1.75 to about $34.50/MWh. High temperatures in Phoenix midweek are forecast in the upper 70s, with lows in the upper 50s.

In the Northwest, Mid-Columbia day-ahead on-peak fell $4.25 to about $31.50/MWh. Mid-C day-ahead off-peak added 75 cents to about $2.25/MWh. Mid-C balance-of-the-month on-peak was up nearly $5 to about $35.50/MWh, while bal-month off-peak was up $2.75 to about $7.25/MWh. High temperatures in the Northwest Wednesday are predicted in the mid-60s, with lows in the low 40s.

California ISO day-ahead auction prices firmed for the midweek. NP15 on-peak gained $1.68 clearing at $51.22/MWh, while SP15 on-peak added $6.61 going to $53.02/MWh. ZP26 on-peak was up $4.37 to $48.90/MWh.

Western US forwards gained Tuesday with strong NYMEX natural gas futures. June NYMEX gas futures rose 11.1 cents to $4.799/MMBtu. In the Northwest, Mid-Columbia on-peak June added 50 cents to about $30/MWh on the InterContinentalExchange at about 2:30 p.m. EDT. Mid-C off-peak June was up 50 cents to about $7/MWh. Mid-C on-peak July advanced 50 to about $44.25/MWh. Mid-C on-peak third quarter lost 65 cents to about $47.25/MWh. In California, SP15 on-peak June financial terms increased $1.25 to about $51.25/MWh. SP15 on-peak July gained $1.50 to about $59/MWh and on-peak Q3 was up $1.20 to about $60/MWh. NP15 on-peak June was up 50 cents to about $51/MWh. In the Southwest, Palo Verde on-peak June advanced $1.75 to about $47.25/MWh.

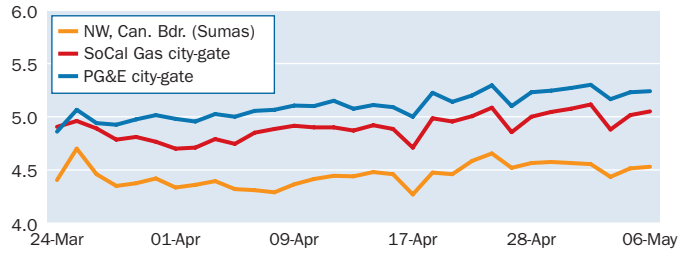
Market coverage

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.

Western day-ahead bilateral indexes for May 7 ($/MWh)

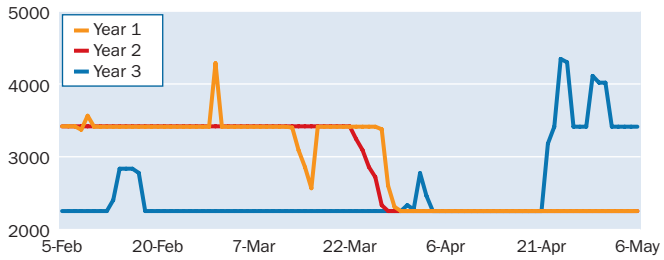
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	37.60	-5.02	41.31	8077
Mid-C	31.52	-4.17	32.74	6947
Palo Verde	39.89	-0.70	41.45	8398
Mead	44.75	3.75	42.63	9246
Mona	37.00	-0.50	38.04	8195
Four Corners	39.50	1.00	37.50	8476
NP15	52.00	2.50	53.42	9924
SP15	51.50	4.00	51.38	10640
Off-Peak				
COB	15.27	3.09	13.97	3280
Mid-C	2.17	0.68	7.25	478
Palo Verde	34.75	2.06	32.03	7316
Mead	36.50	1.25	34.04	7541
Mona	22.00	-2.00	25.11	4873
Four Corners	27.25	0.25	27.11	5848
NP15	40.50	1.50	39.54	7729
SP15	39.50	0.50	38.14	8161

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO nuclear generation outages (GW)



Source: NRC

Western load and generation mix forecast (GWh)

	Actual 05-May	%Chg	% Chg Year-ago	Forecast 06-May	07-May	08-May	09-May	10-May
CAISO								
Load	521	-8	-4	528	582	607	592	547
Generation								
Gas	223	11	15	198	212	229	239	241
Nuclear	56	0	-2	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	51.22	-1.21	-1.90	1.68	52.62	9775
SP15 Gen Hub	53.02	-0.08	-1.23	6.61	51.71	10954
ZP26 Gen Hub	48.90	-1.69	-3.74	4.37	48.32	10103
Off-Peak						
NP15 Gen Hub	38.18	0.60	-0.24	-1.84	40.69	7296
SP15 Gen Hub	36.03	-0.43	-1.37	-2.62	39.14	7462
ZP26 Gen Hub	35.48	-0.42	-1.93	-2.87	38.49	7347

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
COB		
Bal-month (off-peak)	05/01	10.50-11.50
Mid-C		
Bal-month	05/05	31.25-32.25
Bal-month	05/02	30.25-31.25
Bal-month	05/01	30.25-31.25
Bal-month	04/30	29.75-30.75
Bal-month (off-peak)	05/05	4.25-5.25
SP15		
Bal-month	05/05	51.00-52.00

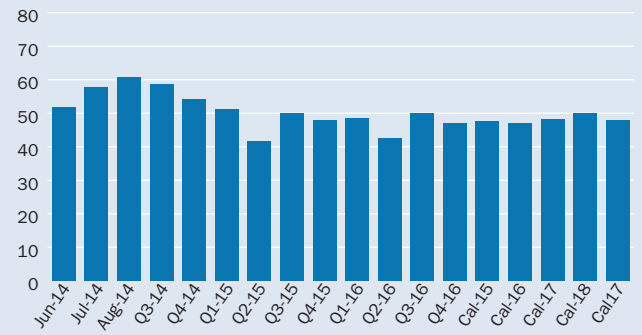
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Ace/Constellation	118	c	Calif.	PMO	Unk	05/04/14
Belden/PG&E	119	h	Calif.	PMO	Unk	01/27/14
Colgate-2/YCWA	176	h	Calif.	PMO	Unk	01/13/14
Crockett/Crockett	240	g	Calif.	MO	Unk	05/05/14
Encina-5/NRG	330	g	Calif.	PMO	Unk	04/20/14
Helms-3/PG&E	404	h	Calif.	PMO	Unk	02/09/14
High Desert/Inland Energy	830	g	Calif.	PMO	Unk	05/04/14
Inland Empire-1/GE	376	g	Calif.	PMO	Unk	05/04/14
Inland Empire-2/GE	366	g	Calif.	PMO	Unk	05/01/14
LaPaloma-1/LaPaGenco	260	g	Calif.	PMO	Unk	05/04/14
Mecalf/Calpine	593	g	Calif.	MO	Unk	05/04/14
Morro Bay-4/Dynegy	325	g	Calif.	MO	Unk	03/03/14
Richmond Refinery/Chevron	114	g	Calif.	PMO	Unk	04/14/14

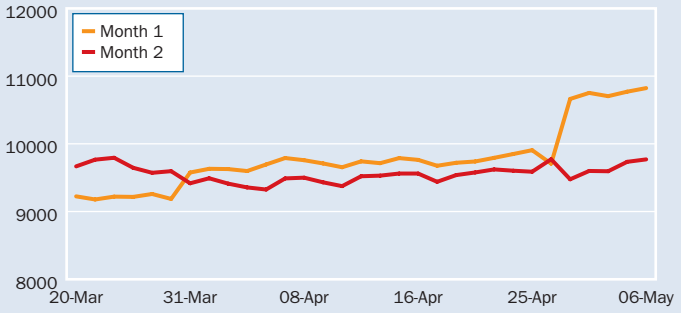
Western Platts M2MS Forward Curve, May 6 ($/MWh)

Prompt month: Jun 14	On-peak	Off-peak
Mid-C	30.00	7.00
Palo Verde	46.75	30.80
Mead	50.35	32.25
NP15	51.75	37.25
SP15	51.25	37.25

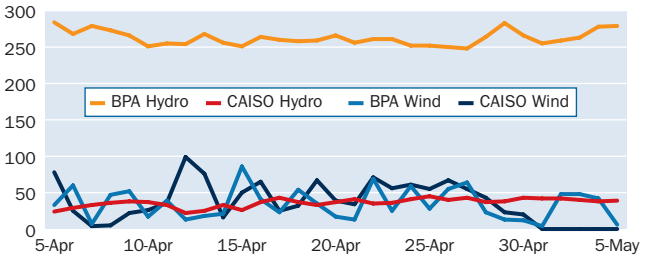
NP15: Forward curve on-peak ($/MWh)



NP15: 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

Demand drives dailies up as terms gain too

Dailies prices in the Mid-Atlantic and in the Midcontinent ISO region increased Tuesday as higher demand expected Wednesday outweighed lower spot natural gas prices. Most forward prices also climbed with an increase in gas futures.

PJM Interconnection West Hub day-ahead on-peak futures rose 25 cents to about $50/MWh for Wednesday delivery on the IntercontinentalExchange.

Texas Eastern M-3 natural gas fell 3.9 cents to about $4.05/MMBtu on ICE.

PJM West on-peak balance-of-week futures gained $2.75 to about $61/MWh on ICE, and on-peak next-week futures advanced $1.50 to about $52.50/MWh on ICE.

PJM forecast peak load for Tuesday at 88,260 MW, an increase of about 300 MW from the actual peak Monday. The forecast is 90,996 MW for Wednesday, 96,060 MW Thursday and 93,077 MW Friday. Temperatures in most of the eastern portion of PJM are forecast to range from the 40s to 60s Wednesday, and from the 50s to 80s Friday through Saturday.

MISO dailies rose Tuesday with strengthening demand. Indiana Hub day-ahead on-peak futures added $1.25, going to about $51.50/MWh on ICE. Indiana Hub on-peak balance-of-week dived $1.25 to about $53/MWh on ICE, but on-peak balance-of-month climbed $1 to about $48.50/MWh.

MISO forecast peak load at 79,876 MW for Tuesday, an increase of about 1,800 MW from the actual peak Monday. The forecast is 83,749 MW for Wednesday, 85,804 MW for Thursday and 81,373 MW for Friday.

Dailies in the Midwestern portion of PJM were mixed Tuesday. AD Hub day-ahead on-peak futures surged $1.75 to about $50.50/MWh, but NI Hub Chicago day-ahead on-peak dipped $1.25 to about $49/MWh.

PJM day-ahead auction prices fell Tuesday. The average PJM Western Hub on-peak price fell $4.12 to $47.18/MWh for Wednesday delivery. The largest decrease was at the Delmarva Power & Light zone, with the on-peak average dropping $9.29 to $48.46/MWh. The Metropolitan Edison zone in eastern Pennsylvania was the lowest priced hub or zone, sliding $4.97 to $44.33/MWh. The Pennsylvania Electric zone was the highest-priced hub or zone, with on-peak falling the least, down $2.13 to $51.88/MWh.

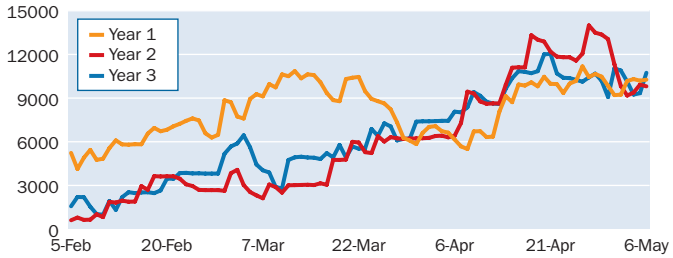
MISO North/Central region day-ahead auction prices cleared higher Tuesday. Illinois was the highest-priced hub with on-peak edging up the smallest amount, just 37 cents, to $58.61/MWh. Indiana on-peak rose $4.95 to clear the auction at $50.51/MWh. Michigan on-peak rose $5.38 to $53.32/MWh. Minnesota was the lowest-priced hub with on-peak surging the most, up $7.07 to $40.43/MWh.

Mid-Atlantic June forwards rose Tuesday as June NYMEX natural gas prices gained 11.1 cents to about $4.799/MMBtu. PJM West on-peak June financial futures rose 25 cents to about $54.50/

PJM & MISO day-ahead bilateral indexes for May 7 ($/MWh)

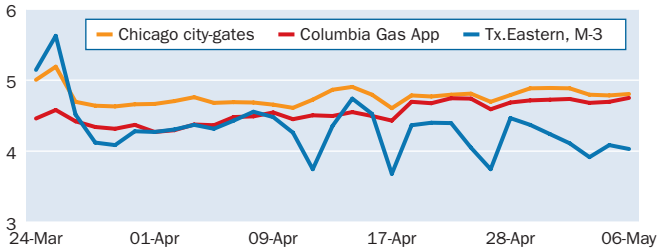
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	51.50	1.75	50.00	12370
Dominion Hub	52.00	2.25	50.40	10839
AD Hub	50.50	1.75	48.50	10434
NI Hub	50.25	0.00	47.80	10458
PJM Off-Peak				
PJM West	31.75	-0.75	31.95	7626
Dominion Hub	31.75	-1.25	32.25	6618
AD Hub	31.75	-0.75	32.75	6560
NI Hub	30.75	3.00	27.00	6400
MISO On-peak				
Indiana Hub	51.25	1.00	48.35	10789
Michigan Hub	54.00	1.25	50.90	10948
Minnesota Hub	41.00	4.25	37.10	8742
Illinois Hub	59.50	3.25	51.00	12364
MISO Off-Peak				
Indiana Hub	30.00	-0.50	30.35	6316
Michigan Hub	32.25	-5.75	33.30	6538
Minnesota Hub	17.25	1.00	18.85	3678
Illinois Hub	38.75	6.00	32.45	8052

PJM & MISO nuclear generation outages (GW)



Source: NRC

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 05-May	%Chg	% Chg Year-ago	Forecast 06-May	07-May	08-May	09-May	10-May
PJM								
Load	1886	15	4	1852	1935	2078	2107	1948
Generation								
Coal	755	19	14	734	723	717	722	694
Gas	259	4	-7	270	271	302	325	320
Nuclear	605	0	-4	608	609	614	621	629
MISO								
Load	1656	10	36	1635	1739	1828	1826	1695
Generation								
Coal	1013	12	0	873	968	1048	1054	1027
Gas	284	57	161	83	100	190	228	217
Nuclear	185	0	-18	180	180	180	180	180

Source: Bentek

MISO average day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	50.51	-1.46	0.68	4.95	45.71	10638
Michigan Hub	53.32	-0.58	2.61	5.38	47.80	10816
Minnesota Hub	40.43	-9.55	-1.31	7.07	37.36	8624
Illinois Hub	58.61	8.85	-1.53	0.37	48.91	12179
Off-Peak						
Indiana Hub	31.23	1.01	0.28	-1.07	31.94	6600
Michigan Hub	33.64	2.40	1.30	-6.54	34.69	6871
Minnesota Hub	18.03	-11.05	-0.86	0.80	21.11	3855
Illinois Hub	40.40	11.40	-0.94	5.71	33.19	8420

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

Package	Trade date	Range
PJM West		
Bal-week	05/06	61.00-62.00
Bal-week	04/30	46.50-48.50
Bal-month	05/01	50.00-52.00
Next-week	05/06	48.75-52.85
Next-week	05/05	50.75-52.00
Next-week	05/01	48.50-49.50
Next-week	04/30	51.00-52.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Beaver Valley-2/FE	901	n	Penn.	PMO	06/04/14	04/21/14
Braidwood-2/Exelon	1210	n	Ill.	RF	05/25/14	05/05/14
Davis Besse/FE	913	n	Ohio	PMO	Unk	02/01/14
Ginna/Constellation	597	n	N.Y.	MO	05/15/14	04/28/14
Quad Cities-2/Exelon	867	n	Ill.	MO	Unk	03/31/14
Salem-2/PSEG	1156	n	N.J.	MO	Unk	04/13/14
Surry-2/Dominion	813	n	Va.	RF	Unk	04/21/14
Susquehanna-1/PPL	1282	n	Penn.	RF	05/11/14	04/12/14
Thorold/Northland Power	287	g	Ont.	MO	Unk	05/05/14

PJM average day-ahead LMP for May 7 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	45.62	-0.57	-1.30	-5.04	46.11	10124
AEP-Dayton Hub	47.65	-0.38	0.54	-5.15	47.83	10575
ATSI Gen Hub	49.78	0.55	1.73	-5.09	49.35	10987
Chicago Gen Hub	45.94	-1.39	-0.16	-5.29	46.36	9557
Chicago Hub	47.02	-0.89	0.42	-5.26	47.17	9782
Dominion Hub	47.62	0.86	-0.73	-4.59	48.69	9938
Eastern Hub	47.99	1.08	-0.58	-8.20	48.99	11636
New Jersy Hub	46.09	-1.00	-0.41	-4.66	47.92	11174
Northern Illinios Hub	46.63	-1.05	0.19	-5.25	46.87	9701
Ohio Hub	48.06	-0.36	0.92	-5.16	48.12	9998
West Internal Hub	48.54	1.20	-0.16	-4.71	48.48	11646
Western Hub	47.18	1.21	-1.52	-4.12	47.96	11321
AEP Zone	47.62	-0.26	0.38	-5.12	47.80	10568
Allegheny Power Zone	47.50	0.83	-0.82	-4.61	47.89	10689
Atlantic Elec Zone	45.03	-1.33	-1.14	-5.03	47.37	10918
ATSI Zone	50.79	1.34	1.96	-4.21	49.88	11212
BG&E Zone	50.01	3.00	-0.48	-3.68	50.46	11654
ComEd Zone	46.81	-1.04	0.36	-5.26	47.02	9739
Dayton P&L Zone	48.44	-1.24	2.19	-5.92	49.04	10209
Delmarva P&L Zone	48.46	1.68	-0.71	-9.29	49.26	11750
Dominion Zone	47.89	1.06	-0.67	-4.54	48.90	9993
Duke Zone	47.16	-0.83	0.50	-5.36	47.52	9939
Duquesne Light Zone	47.31	0.51	-0.70	-4.61	47.07	10923
EKPC Zone	46.12	-1.31	-0.07	-5.44	46.73	10739
JCPL Zone	45.93	-1.45	-0.12	-4.77	47.44	11135
MetEd Zone	44.33	-1.64	-1.53	-4.97	46.16	10237
PECO Zone	44.67	-1.45	-1.38	-4.87	46.61	10314
Pennsylvania Elec Zone	51.88	4.32	0.06	-2.13	49.51	12262
PEPCO Zone	48.52	1.81	-0.78	-4.38	49.48	11306
PPL Zone	44.59	-1.44	-1.47	-4.83	46.26	10297
PSEG Zone	46.88	-0.37	-0.25	-4.54	48.74	11367
Rockland Elec Zone	46.44	-0.92	-0.14	-4.39	48.21	11260
Off-Peak						
AEP Gen Hub	28.66	-0.23	-0.80	-2.75	31.02	6367
AEP-Dayton Hub	29.60	-0.13	0.03	-2.76	31.92	6575
ATSI Gen Hub	30.35	0.02	0.63	-3.02	32.57	6710
Chicago Gen Hub	26.85	-2.27	-0.59	-3.90	29.81	5607
Chicago Hub	27.77	-1.66	-0.27	-3.72	30.47	5800
Dominion Hub	30.13	0.62	-0.20	-2.82	32.58	6329
Eastern Hub	30.44	0.78	-0.04	-3.21	32.47	7307
New Jersy Hub	29.82	-0.02	0.14	-2.66	32.35	7158
Northern Illinios Hub	27.47	-1.83	-0.40	-3.79	30.18	5738
Ohio Hub	29.76	-0.12	0.18	-2.78	32.05	6229
West Internal Hub	29.91	0.30	-0.09	-2.70	32.15	7148
Western Hub	30.13	0.79	-0.37	-2.20	32.25	7200
AEP Zone	29.69	-0.04	0.03	-2.77	31.97	6595
Allegheny Power Zone	29.90	0.41	-0.21	-2.62	32.08	6738
Atlantic Elec Zone	29.24	-0.11	-0.36	-2.70	32.01	7018
ATSI Zone	30.66	0.16	0.80	-2.90	32.77	6779
BG&E Zone	31.12	1.27	0.15	-2.15	33.37	7223
ComEd Zone	27.51	-1.87	-0.32	-3.80	30.24	5746
Dayton P&L Zone	30.19	-0.33	0.83	-3.04	32.63	6401
Delmarva P&L Zone	30.61	1.01	-0.09	-3.38	32.51	7349
Dominion Zone	30.28	0.70	-0.12	-2.79	32.71	6361
Duke Zone	29.42	-0.21	-0.06	-2.88	31.74	6237
Duquesne Light Zone	29.15	0.03	-0.58	-2.71	31.25	6723
EKPC Zone	28.81	-0.53	-0.36	-3.06	31.37	6691
JCPL Zone	29.81	-0.15	0.26	-2.63	32.11	7155
MetEd Zone	28.95	-0.19	-0.56	-2.68	31.36	6663
PECO Zone	29.03	-0.15	-0.52	-2.70	31.62	6683
Pennsylvania Elec Zone	33.96	3.75	0.50	-0.30	33.47	7903
PEPCO Zone	30.64	0.96	-0.02	-2.54	33.02	7111
PPL Zone	29.03	-0.15	-0.52	-2.60	31.40	6682

MWh on ICE. PJM West on-peak July-August fell 25 cents to about $67.50/MWh, while on-peak September rose 50 cents to about $48.50/MWh.

Most Midwest June forward prices rose Tuesday. AD Hub on-peak June financial futures rose 65 cents to about $48.75/MWh, and on-peak July-August edged down 15 cents to about $57.50/MWh. Indiana Hub on-peak June moved up 90 cents to about $48/MWh, while on-peak July-August inched up 20 cents to about $55.25/MWh. Northern Illinois Hub on-peak July-August slid 65 cents to about $54.50/MWh.

Southeast markets ... *from page 4*

hub as on-peak shed $2.98 to clear at $44.25/MWh.

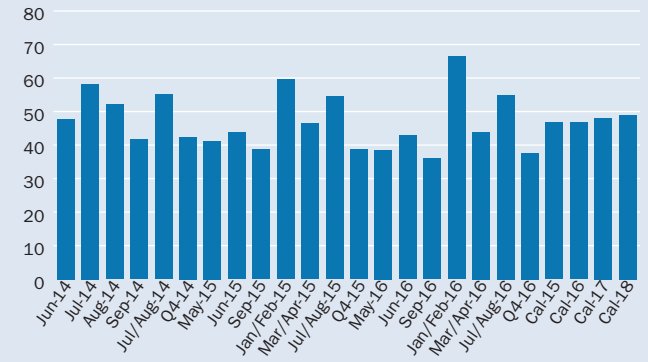
For the MISO South region, most day-ahead auction prices tumbled Tuesday. Texas was the highest-priced hub with on-peak dropping $3.05 to $76.62/MWh. Arkansas on-peak rose $2.11 to $54.51/MWh. Louisiana was the lowest-priced hub and fell the most, with on-peak sinking $42.62 to $53.82/MWh.

ERCOT June forwards were stronger Tuesday along with gas prices. June NYMEX gas futures added 11.1 cents to about $4.799/MMBtu. ERCOT North June rose $1.75 to about $61.50/MWh. June on-peak heat rates were up 50 Btu/kWh on ICE. ERCOT North on-peak July-August gained $2.75 to about $99/MWh.

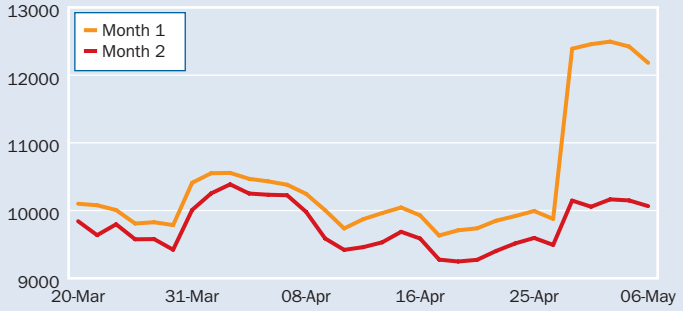
PJM & MISO Platts M2MS Forward Curve, May 6 ($/MWh)

Prompt month: Jun 14	On-peak	Off-peak
PJM West	54.60	34.00
AD Hub	48.65	31.15
NI Hub	45.20	26.90
Indiana Hub	47.80	29.55

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



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



NEWS

NRG bullish on Texas for demand, prices

NRG Energy is most bullish on the Texas market when it comes to basic fundamentals driving an increase in power prices, David Crane, president and CEO of NRG, said during an earnings call with analysts Tuesday.

There have been improving maket signs in the Commonwealth Edison market in Illinois and the East has been a pleasant surprise, Crane said.

"But for basic fundamentals, we remain bullish on Texas. Demand growth there was enormous," he said. The state had 11% demand growth when not adjusted for weather, and a 3% growth in demand when adjusted for weather, Crane said.

"ComEd has growing opportunities for us," Mauricio Gutierrez, CFO, said, noting there had been a nice rally in NI Hub prices that signals a change in market fundamentals. The significant rally in natural gas prices and low gas storage levels have helped the dark spread of NRG's fleet of baseload generation, Gutierrez said.

An expansion of heat rates after the Environmental Protection Agency's cross-state air pollution rule was upheld by the Supreme Court also was a driver in forward prices because there may be more coal plant retirements, Gutierrez said.

The market prices for the balance of 2014 reflect decent volumes, but beyond this year prices may not hold because of liquidity and volumes affecting prices in later years, Gutierrez warned.

NRG is hoping to see better prices in PJM Interconnection, said Chris Moser, senior vice president for commercial operations. The company is expecting a 1 GW reduction in imports from MISO in the upcoming capacity auction and a 2 GW to 4 GW reduction in demand response offers.

New generation being developed in PJM will face challenging economics in spite of the improvement in energy margins, the company said. In all markets, even Texas, existing assets are being acquired at a deep discount of replacement costs, Crane said. "We're not seeing pricing approaching new entry pricing, so how people are doing greenfield construction in the merchant market is baffling to us," he said.

In the Midwest, given the challenges of additional wind power and negative pricing, the region is entering into a transition period that will see more generation retirements, especially coal and nuclear baseload generation that has little flexibility and high fixed costs, Gutierrez said. "We can see that in the heat rate expansion," he said.

NRG is at the point where it has acquired all the generating capacity and retail customers it needs to fulfill its growth plan, but the company it is open to opportunistic purchases, Crane said.

The best way to outperform during times of extreme weather, as seen this winter, is with a generation fleet using multiple fuels that gives it the flexibility to navigate through the volatility, Crane said. "We've made a virtue of multi-fuel when the trend is toward all-gas, all-the-time," he said.

NRG on Monday entered into a definitive agreement for the first drop-down of assets to NRG Yield for $349 million in cash and the assumption of $657 million in debt.

The projects moved into NRG Yield were the TA High Desert 20-MW solar farm in Los Angeles County, California; the RE Kansas South, a 20 MW solar farm in Kings County, California and the El Segundo Energy Center, a 550-MW fast-start gas-fired plant in Los Angeles County.

In other actions during the quarter, NRG closed three acquisitions, the purchase of Edison Mission Energy, which brings the company generation fleet to 53,000 MW, the acquisition of Dominion Resources' competitive retail electricity business and the acquisition of Roof Diagnostics Solar.

NRG expects the rooftop solar business to move from a local business to a big, fast-growing business and the company's goal is to seamlessly offer solar to three million customers, Crane said.

— Mary Powers

Duke goes to FERC for help on gas purchases

The gas and power market fallout from the harsh weather of January has pushed into May with the filing of a complaint at the Federal Energy Regulatory Commission by Duke Energy against PJM Interconnection for being told to buy gas for a power plant in late January — only to see that facility not be used as PJM expected.

Duke is seeking reimbursement from PJM for about $9.8 million for buying the gas at PJM's direction, asserting that the compensation is allowed under the PJM tariff.

The complaint stems from recorded conversations between the PJM dispatch office and Duke's manager of generation dispatch and logistics for Duke's Midwest Commercial Generation business about buying gas for Duke's Lee generation facility near Chicago. PJM had issued a maximum emergency generation alert on January 27, giving details that PJM expected demand to reach 141,000 MW for the next day, with minimal generation reserves available.

Duke's gas traders informed the company's generation dispatch official that gas prices were at $37/MMBtu, and based on the experiences of a similar cold weather event a week earlier when the Lee combustion turbine facility was not called upon, Duke decided not to buy gas for the Lee facility to be available on January 28. "The economics of buying the gas without running the plant simply made no sense — it would be a money-losing proposition," Duke said.

A PJM dispatch official then called Duke later in the day, emphasizing that "this is not an economic decision" and "this is a reliability issue, so all units must be available. With the imperative manner of the call and emergency circumstances it reflected, Duke reversed course and secured gas for the Lee facility to be available, at a cost of about $12 million, according to the complaint.

It turned out that the Lee generation units were not needed in the PJM real-time market on January 28.

Through various mitigation efforts, Duke has been able to recover more than $2 million, seeking unrecovered costs of about $9.8 million in the complaint.

In a presentation to the PJM members committee last month, PJM mentioned the demand forecasting volatility in late January,

when the grid operator projected that demand would be 141,000 MW on January 28, yet actual load was at about 138,000 MW. A few days before and after that day, actual load was about 4,000 MW higher than what was forecast for January 24 and January 30, along with plenty of generation facilities being unavailable.

Duke told FERC that PJM's tariff provides for compensation for the gas purchases, but PJM has declined the company's request for reimbursement. "It is difficult to imagine a provision that could more plainly require that Duke be compensated for its actions – taken in good faith and against its own judgment and interest at the command of its Reliability Coordinator," Duke said in reference to PJM.

"Duke's understanding is that PJM does not dispute that Duke 'acted in good faith to implement or comply with' PJM's directive, but nonetheless PJM has rejected Duke's claims" for compensation, the company told FERC.

PJM's position is that it does have authority to compensate companies for gas losses in some circumstances, but it is unable to compensate Duke based on the circumstances involved — the facility in question did not clear the day-ahead market and did not run for PJM, said PJM spokeswoman Paula DuPont-Kidd.

"If a market seller believes it should be compensated for its loses, it should file a request at the FERC for a waiver to recover the costs," DuPont-Kidd said Tuesday, adding that PJM is still reviewing the Duke complaint.

Duke related that the operating conditions on Kinder Morgan's Natural Gas Pipeline Co. influenced Duke's decision not to buy gas on January 27, along with its need to buy gas for 48 hours for the Lee units in order to comply with the PJM directive. NGPL had an hourly takes restriction, operational flow orders and suspended a balancing service that Duke often used to secure gas for the Lee facility. "Because the Electric Day includes parts of two Gas Days, under the hourly takes restriction and the OFO, a unit needing to be available in all hours of an Electric Day would need to buy two full Gas Days' worth of gas," and the lack of a balancing service meant that Duke had to use or re-sell gas volumes on the same Gas Day, according to the complaint

A TransCanada pipeline explosion on January 25 also constricted supply to the Chicago area at the time of the event, which contributed to significantly higher prices on other pipelines such as NGPL, Duke added.

It asked the commission for action within 60 days. If compensation to Duke through the PJM tariff is not deemed appropriate, Duke sought a one-time waiver of the limited parts of the tariff that prohibit make-whole payments to Duke.

— Tom Tiernan

Daily CSAPR allowance assessments, May 6

CSAPR ($/st)	2012 Range	Mid	2013 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, May 6

	$/allowance	Change	$/st
SO2 2014	0.77	0.00	1.54

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, May 5 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec14 V11	4.45	0	Dec14	1.97	0
Dec14 V12	4.45	0			
Dec14 V13	4.45	0			
Dec14 V14	4.45	0			
Dec15 V11	4.55	0			
Dec15 V12	4.55	0			
Dec15 V13	4.55	0			
Dec15 V14	4.55	0			
Dec16 V11	4.65	0			
Dec16 V12	4.65	0			
Dec16 V13	4.65	0			
Dec16 V14	4.65	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.

FirstEnergy reviews retail marketing strategy

Adopting a "far more conservative approach" to competitive power markets buffeted by extreme volatility in recent months, FirstEnergy is reviewing its retail marketing strategy while keeping an open sales position of about 20 million MWh annually to give it more flexibility, company officials said Tuesday.

The Akron, Ohio-based company's electric deliveries increased by about 6% in the first quarter, to 40.4 million MWh, largely, though not entirely, as a result of the extremely cold winter, Anthony Alexander, FirstEnergy president and CEO, told analysts during a conference call to discuss quarterly earnings.

The company earned $208 million, or 49 cents/share, in the first three months of 2014 compared with $196 million, or 46 cents/share, a year ago. Revenue rose to $4.2 billion, a 14% gain.

While quarterly sales were strong, the first three months of 2014 "illuminated the fact that current energy priorities are putting reliability of our energy sector in jeopardy," Alexander warned. "This is of particular importance in competitive states where customer service and pricing are very much dependent on stable and predictable wholesale markets."

Those markets have been anything but stable and predictable in recent months, he suggested, forcing FirstEnergy to rethink its entire competitive sales strategy as embodied by FirstEnergy Solutions, its competitive arm that serves about 2.7 million customers in several states.

FirstEnergy currently has committed sales of 56 million MWh in 2015 and only 32 million MWh in 2016, intentionally leaving an open position of about 20 million MWh. The company expects to generate 75 million to 80 million MWh annually during the two years.

The open sales position "gives us substantial flexibility as we consider how to tailor our competitive business going forward," Alexander said.

In response to a question from Dan Eggers of Credit Suisse, Alexander declined to say where FirstEnergy might look to reduce the exposure of its retail sales business.

Although markets have been "fairly stable" of late, Alexander said, "what we're seeing today, however, is perhaps a precursor of what we might be looking at down the road as more generation is taken off line," and more stringent government environmental rules result in thousands of megawatts of coal plant retirements.

"I think all of those are leading us to refine our strategy to see exactly where these targets ought to be, given what we're seeing now of something that may be more of a long-term event in the energy markets," Alexander added.

FirstEnergy, he said, needs to determine "what level of retail sales can be supported by our level of generation. What is the appropriate level of retail sales to source in the market, if any, and where that mix is depends on what happens to risk premiums that need to be reflected as wholesale markets have far more energy prices in them."

Both Leila Vespoli, FirstEnergy executive vice president for markets and chief legal officer, and FES president Donald Schneider described as modest rule changes in PJM Interconnection's upcoming auction as they relate to imports and demand response.

The changes "may move the market a little bit," Vespoli said, quickly adding they will not affect the market substantially.

"It's possible to see this needle move a little bit in the favorable direction," said Schneider, "but not nearly enough to sustain what PJM needs from a reliability perspective moving forward."

Vespoli told Julien Dumoulin-Smith of UBS that FirstEnergy continues to have conversations with Ohio officials about the possibility of reserving some of its generation to serve default customers to reduce the supply uncertainty that occurred during the so-called "polar vortex" last winter.

"We are talking with folks in Ohio to see what we might do in Ohio to mitigate some of the reliability issues with respect to that and ensure stable pricing in Ohio," Vespoli said.

FirstEnergy has not disclosed any specific proposals it is pursuing.

— Bob Matyi

AEP grid project aimed at overload threat

American Electric Power's transmission arm in Ohio told state regulators Tuesday it needs to rebuild an approximately 50-mile, 345-kV transmission line to remove the threat of transmission system overloads in southeastern Ohio because of impending coal plant retirements.

If endorsed by the Public Utilities Commission, construction on the the Sporn-Muskingum River 345-kV transmission line reconductor project would begin in January, with the work completed sometime next summer, according to a filing by AEP Ohio Transco.

Columbus, Ohio-based AEP, one of the largest electric utility companies in the US, plans to retire more than 6,000 MW of older coal-fired generation, mostly in Ohio, in the next couple of years to comply with new Environmental Protection Agency rules.

"Environmental regulations are forcing the retirement of coal-fired generating units in Ohio and surrounding states by 2015," the transco said. "AEP and FirstEnergy generation retirements will cause transmission system overloads in the southeastern Ohio area."

FirstEnergy, a rival Ohio utility based in Akron, is shutting several thousand megawatts of coal generation in Ohio and surrounding states.

The proposed system improvements needed to alleviate the potential overload conditions include reconducting the Sporn-Muskingum 345-kV line, the transco said.

The project would consist of "un-wiring the existing six wired single-circuit line and reconducting the line as a double-circuit line and re-conducting the south circuit of the Waterford Extension 345-kV transmission line," according to the filing.

Three lattice frame structures would be replaced with two-pole tubular self-supporting dead-end structures on concrete foundations and five existing lattice frame structures would be reinforced as part of the nearly $50 million project.

No relocation of transmission lines is required, the transco added, nor is additional right of way necessary.

AEP spokeswoman Tammy Ridout said that as a result of an analysis performed by PJM Interconnection, a Pennsylvania-based independent system operator, "we determined that there is the potential for system overloads in 2015 following a significant number of generation retirements."

The transmission line in question runs between AEP's 1,050-MW Philip Sporn baseload coal plant on the Ohio River near New Haven, West Virginia, and its 1,425-MW Muskingum River baseload coal plant near Beverly, Ohio. Both plants are being shut down.

The project "is an effort to stay ahead of overloads and rework the system to account for the power flow changes that will occur as generation is required," Ridout noted.

AEP CEO Nicholas Akins has been stressing the continued importance of much of the approximately 6,000 MW of coal-fired generation AEP has targeted for closing in the next year or so.

During the first quarter, the roughly 2,500 MW of older coal generation in Ohio that will be shut down next year achieved a 46% capacity factor, he said during AEP's first-quarter earnings call on April 27. And those plants, Akins added, operated 89% of the time during the so-called "polar vortex" in early January when extremely cold weather caused load to balloon, leading PJM's reserve margin to drop to as low as 1% at one point.

— Bob Matyi

EIA jacks up summer, fall gas price forecasts

Citing a sluggish start to the storage refill season and continuing cold weather through early spring, the Energy Information Administration on Tuesday hiked its Henry Hub spot price forecast for the third quarter by 43 cents, or more than 10%, to $4.60/MMBtu.

In its May Short-Term Energy Outlook, EIA also raised its fourth-quarter price forecast from a month ago by 39 cents, or about 9%, to $4.56/MMBtu.

The agency also increased its annual forecasts from April's

outlook, with the 2014 target climbing 30 cents to $4.74/MMBtu and 2015 jumping 22 cents to $4.33/MMBtu. Henry Hub prices averaged $3.73/MMBtu in 2013.

Gas in storage as of April 25 totaled just 981 Bcf, 45% below last year and 50% shy of the five-year average, EIA noted. "Very cold weather and low inventories contributed to volatile Henry Hub natural gas spot prices over the past few months, increasing from $3.95/MMBtu on January 10 to a high of $8.15/MMBtu on February 10, before falling back to $4.61/MMBtu on February 27, then bouncing back up to $7.98/MMBtu on March 4," the report said.

The storage injection season "has started somewhat slowly, but EIA expects injections will pick up over the summer to end October at just over 3.4 Tcf," based on expected average weekly injections of 90 Bcf — which would be 20 Bcf/week above the five-year average.

On the demand side, EIA said it now expects consumption to average 72.3 Bcf/d this year, 1.3% above 2013's level, "led by the industrial sector." Next year, demand should weaken by 100,000 Mcf/d "as a return to near-normal winter weather contributes to lower residential and commercial consumption."

Power-sector demand figures to take a roller-coaster ride, EIA said, estimating that higher gas prices this year will help push consumption in that sector down 0.4% to 22.2 Bcf/d. But next year, the agency said it that to increase to 23.1 Bcf/d "with the retirement of some coal plants."

Marketed gas production will jump this year and next by 3% and 1.8% respectively, said EIA, adding that regional pricing dynamics will drive production activities.

"Rapid natural gas production growth in the Marcellus Shale formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months," the report said. "Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, which prices are closer to the Henry Hub spot price."

— *Chris Newkumet*

Prices unlikely to give ground anytime soon: Analysts

Tight supplies and hot weather could easily push US gas prices past the $5/MMBtu mark at times this summer, some analysts say in new reports, while citing the uncertainty over longer-term supply dynamics.

"Following a spike and pullback during the winter months, prompt NYMEX natural gas prices have rallied pretty meaningfully in recent weeks to allow for more gas to move into storage during the spring and summer," with prices currently near $4.80/MMBtu, said analysts at Bank of America Merrill Lynch.

Near-term prices are rallying "to force a demand reduction and thus allow for more natural gas to move into storage at a faster rate," the analysts said in a new report. While utility coal stockpiles are generally low, that seems to be mostly affecting generators who burn Powder River Basin coal, while generators that burn Appalachian coal report normal stocks, they added.

Meanwhile, gas storage inventories currently sit 981 Bcf, a nearly 1-Tcf deficit to the five-year average.

"There is a lot of natural gas demand in the US that can move into coal relatively quickly, so natural gas prices have risen to the $4.70-$5 level where gas to Appalachian coal-switching is very significant. As a result, we expect gas consumed in power generation to fall year-over-year," BofA said.

In the long run, however, "it may prove challenging to rebuild inventories of natural gas above 3.5 Tcf by the end of the injection season given the ongoing supply dynamics. And having drawn almost 3 Tcf in the past winter, a stock level meaningfully below this number would likely make market participants rather anxious."

Independent analyst Stephen Smith said in a new report that this fall's deficit is likely to narrow to about 250 Bcf, with a risk that the autumn storage peak could come in even lower than his prediction of 3.4 Tcf.

Assuming normal weather, Smith raised his second-quarter Henry Hub price estimate by 10 cents to $4.65/MMBtu, while raising his third-quarter price by 15 cents to $4.85/MMBtu and his fourth-quarter price by 10 cents to $4.70/MMBtu. He pushed his 2014 average price by 10 cents to $4.80/MMBtu.

But "all else equal, a 10% hotter-than-normal summer, for example, could easily push fall deficit projections higher and the current strip higher," Smith said. "The July-October strip, now near $4.70/MMBtu, could easily exceed $5/MMBtu for this 'hot summer' scenario."

Those higher prices would likely result in gas' share of the power generation market vs. coal falling by 2.2% from May through October 2014 compared with last year, Smith said.

The BofA analysts noted that while near-term futures prices are surging, calendar year 2015 and 2016 prices have risen only modestly. "As a result, prices are now encouraging coal burn near-term, but are not yet incentivizing a big ramp-up in drilling activity across the country."

On the demand side, BofA said US gas demand is likely to rise by 13 Bcf/d, or 18%, into 2018. "Most of the demand growth is concentrated in 2017-18 on the back of a ramp up in LNG export projects, coal plant retirements, exports to Mexico, and strong growth in gas intensive manufacturing capacity such as fertilizer and ethylene plants," BofA added.

"Can supply step up to the challenge?" the analysts asked. "Productivity in many mature shale gas plays is no longer improving at the staggering rates of 2009-12. Output is falling fast in areas like the Fayetteville or the Haynesville."

Even if associated gas production in oil fields grows further, "it will likely fall far short of meeting the large pent-up incremental demand over the next five years," the BofA analysts said. "To encourage producers to move back into high-cost gas plays, we see long-dated (calendar-year 2017 and beyond) US nat gas rising to $5.50/MMBtu."

— *Stephanie Seay*

Forecast flows at The Dalles slip to 108% of normal

The Pacific Northwest water supply outlook edged down this week, which caused some mixed movements in forward power markets.

Columbia River flows from April through September 2014 at The Dalles Dam on the Washington-Oregon border likely will be

108% of normal, the US Northwest River Forecast Center said in its most recent Ensemble Streamflow Prediction report.

The Dalles projection is 1 percentage point lower compared with the NWRFC's projection issued last week. The NWRFC is a unit of the National Oceanic and Atmospheric Administration.

Flows at Grand Coulee Dam during the same period are predicted to be 110% of normal, also 1 percentage point lower than the prior week's outlook, the NWRFC said.

ESP forecasts compare historical and current data and run the information through model scenarios to project what water supplies could look like.

Power and natural gas market participants closely watch the reports as an indication of upcoming water supplies for Pacific Northwest hydro generation.

Forward power markets reacted to the small downtick with mixed movements. Mid-Columbia on-peak June was up about 15 cents to about $29.50/MWh, and off-peak June was off 40 cents at about $6.50/MWh.

Mid-Columbia on-peak third quarter was off 35 cents to about $47.90/MWh, and off-peak Q3 was down 50 cents to about $30.40/MWh.

The full-value June forward natural gas price at the Northwest Pipeline, Sumas, was down about 8 cents over the past week to about $4.40/MMBtu, while the full-value summer package was down about 7 cents to about $4.52/MMBtu.

— *Eric Wieser*

Black Hills Energy issues RFP for Colo. supplies

Black Hills Energy–Colorado Electric has issued an all-source request for proposals to meet its power supply needs for southern Colorado.

Black Hills Energy is seeking summer firm peaking capacity of 42 MW in 2017, 29 MW in 2018 and 33 MW in 2019, and up to 60 MW of renewable energy resources, according to the solicitation.

Black Hills Energy will consider market purchases and offers from independent power producers. The company will take bids for both dispatchable and intermittent, energy-only resources.

The firm supply needs were identified in Black Hills Energy's last integrated resource plan while the renewables are needed to meet Colorado's renewable portfolio standard, which climbs to 30% by 2020.

Black Hills Energy has hired Accion Group to oversee the bidding process.

Black Hills Energy will host a pre-bid conference on May 22. Bids are due July 31. The company expects the Colorado Public Utilities Commission to make a decision on the company's proposed portfolio by the end of February.

The bid package is online at https://bhe2014rfp.accionpower.com.

Black Hills Energy, a Black Hills Corp. subsidiary, has 94,000 electric customers in southeastern Colorado.

— *Ethan Howland*

Georgia Power solar effort gains big response

More than 50 solar power developers submitted proposals in response to Georgia Power's early April solicitation for 495 MW of utility-scale solar power, the leading solar advocate on the Georgia Public Service Commission said Tuesday, adding that he expects the price of winning proposals to come in "south of 8 cents" per kWh.

Commissioner Bubba McDonald, who has successfully pressed Georgia Power to add a total of more than 700 MW of solar power by the end of 2016, said in an interview that PSC staffers told him that 55 developers proposed solar projects in response to the request for proposals Georgia Power issued April 2.

McDonald said he has not been told the total number of proposals submitted by the 55 bidders, or the total capacity of the projects proposed. He added, however, that the RFP spurred competition "as strong as potash," and he is optimistic the bid prices for power will be among the lowest offered to date.

"Georgia right now is the leading state in the nation for solar development," McDonald said, noting that—in keeping with the state's conservative tradition—"we're doing it without subsidies and without any affect on ratepayers."

John Kraft, spokesman for Georgia Power, could not confirm what McDonald said regarding the number of respondents to the RFP. Kraft did say, however, that the response to the solicitation "was robust and exceeded the amount of the total need." He said the utility is evaluating and expects to notify the shortlist bidders in August. "The winners will be announced in our public filing at the commission in early October."

In the RFP, Georgia Power sought 495 MW of utility-scale solar capacity, 280 MW of it deliverable starting in 2015 and 215 MW deliverable starting in 2016. The 495 MW includes 70 MW of solar capacity remaining in Georgia Power's original Advanced Solar Initiative and 425 MW of additional utility-scale solar approved by the PSC last June.

The 70-MW tranche, known as ASI 2015, involves solar projects of between 1 MW and 20 MW each that would come online by the end of 2015. The price Georgia Power will pay for that power is capped at $120/MWh—or 12 cents/kWh—though competitive bidding is expected to drive the actual price to a considerably lower level. The term of power purchase agreements for this tranche will be 20 years, as it was in the draft.

The 425-MW tranche is divided into two parts: a 210-MW element known as ASI-Prime 2015 for projects that would come online by the end of 2015, and a 215-MW element known as ASI-Prime 2016 for projects that would come online by the end of 2016.

Unlike the ASI portion of the solicitation, in ASI-Prime 2015 and 2016 there is no MW cap on the capacity of each solar project; that is, projects of more than 20 MW are welcomed. Bidders could proposed PPA terms of 15, 20, 25 or 30 years.

The solar power prices Georgia Power will be willing to pay to the winners of the ASI-Prime 2015 and 2016 is capped at the utility's levelized avoided cost for the term of the PPA. In the RFP, Georgia Power provided guidance on what it expects those levelized avoided costs to be.

For example, for ASI-Prime projects that would come online in 2015, Georgia Power said its estimated or "indicative" levelized avoided costs would be $85/MWh for a project with a 15-year PPA, $90/MWh for a project with a 20-year PPA, $95/MWh for a project with a 25-year PPA, and $100/MWh for a project with a 30-year PPA.

For ASI-Prime projects that would come online in 2016, Georgia Power said its estimated or "indicative" levelized avoided costs would be $90/MWh for a project with a 15-year PPA, $95/MWh for a project with a 20-year PPA, $100/MWh for a project with a 25-year PPA, and $105/MWh for a project with a 30-year PPA.

Georgia Power expressed optimism before the RFP was issued that the actual bid prices will be considerably lower than those estimated price caps, and had noted that while the price cap in its 2013 RFP for utility-scale solar was $120/MWh, the average winning bid for the 50 MW in selected projects was $85/MWh.

In a related development, Commissioner McDonald said Tuesday that the US Army plans to build a total of 90 MW of solar facilities at three Army bases in Georgia. The projects—30 MW at each base—are separate from Georgia Power's RFP, McDonald said. The bases where the solar facilities are to be sited will be identified later.

— Housley Carr

Settlement illustrates NE challenges ...from page 1

systematically reduce carbon dioxide emissions from its Salem Harbor plant, which would make it the first plant in the nation to operate under such a regime.

The CO2 emissions from Salem start at 2,279,530 tons of CO2/year and stay there until 2025, but then have to decline by about 3% a year, reaching 528,874 tons of CO2/year by year-end 2049, a roughly 80% reduction over the life of the plant.

The settlement also includes "level playing field" provisions that stipulate that if Footprint Power, after five years of operation, believes another power plant has been granted siting and air permits in Massachusetts under less stringent requirements than specified in the CLF settlement, Footprint can reopen the terms of its settlement with CLF.

The settlement reflects Footprint's desire not to be competitively disadvantaged by its agreement with CLF; it also reflects CLF's confidence that the emissions levels it set with Footprint will become widely accepted, either that or CLF believes it will be able to reach similar agreements for new plants being built by other developers.

Massachusetts' Global Warming Solutions Act of 2008 requires the state to set economy wide greenhouse gas emission reduction goals to achieve reductions of as much as 25% below 1990 statewide levels by 2020, and 80% below those levels by 2050. But while the state has finalized the regulations for some sectors it has yet to finalize regulations pertaining to power plants.

The regulations for new sources should be finalized in the next year or so, while the regulations for existing plants are likely to be done this fall, David Cash, commissioner of the Massachusetts Department of Environmental Protection, said.

In fact the settlement with CLF grew out of the frustration within the environmental community over the lack of a plan for reducing CO2, Peter Furniss, Footprint's CEO said.

So even though Footprint's Salem project would remove 500,000 tons of CO2 a year by shutting down a coal plant and the new gas plant is designed with fast start capability to facilitate the integration of wind power into the grid, it was still targeted by environmentalists.

That was frustrating, Furniss said, but he eventually came around to CLF's point of view and in the end was willing to put a CO2 reduction plan on paper.

How emissions are handled at the Salem plant will depend on what happens system wide, Furniss said. Salem's emissions reductions are not going to come from equipment upgrades that can capture ever greater amounts of emissions. There is no commercially viable technology to capture CO2. Instead, the reductions will come from a variety of renewable energy credits. Footprint can buy RECs, make investments that generate RECs, and can use fractional credits from the Regional Greenhouse Gas Initiative to meet its emissions targets.

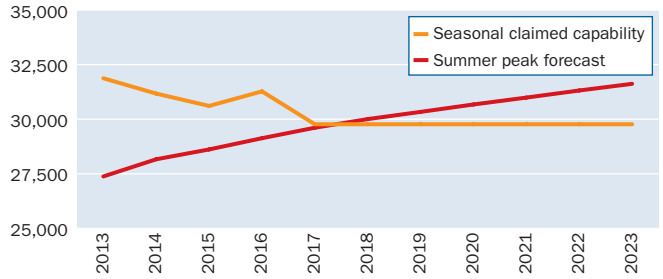
Footprint will also be able to bank credits from its own operations. It could, for instance, bank unused credits in the early years of operation when it will have higher emissions levels and would not likely be running enough hours to use all of its allotted credits. Then in later years, it could adjust its operations to meet the tighter standards with a combination of banked RECs reduced operating hours.

And, because of the level playing field provisions, Furniss said he sees no real risk to Footprint from competitors that might follow the Salem project.

It remains to be seen, of course, if any new build projects will follow Footprint's lead and if they will face the same hurdles. New England has attracted very little investment in new generation over nearly the past decade for two, related reasons. The area has had a surplus of capacity and capacity prices have been very low. But that appears to be changing.

ISO-New England's capacity market has cleared at the administratively set floor price for the first seven of its forward capacity markets. This year, for FCA#8, ISO-NE removed the floor price, but then the announcement by EquiPower Resources that it intended to shut its 1,528-MW Brayton Point plant Massachusetts swung the outlook to a deficit, triggering rules that called for the

ISO New England: capacity vs. forecast peak



Source: ISO New England

implementation of a price ceiling.

FCA#8, for delivery years 2017-18, cleared at $15/kW-month for the 1,370 MW of new resources that bid in while the remaining 24,885 MW of existing resources will be paid the administratively triggered price of $7.025/kW-month.

The ceiling price was a one-time fix, but for FCA#9 ISO-NE is moving toward adopting a sloped, instead of vertical, demand curve that would result in less volatile price swings in capacity prices and allow for the market to send a price signal in advance of needs rather than close to when they occur.

Given the likelihood of further capacity shortages ISO-NE could be short going into FCA#9, which could result in clearing prices even higher than in the recent auction.

UBS analyst Julien Dumoulin-Smith forecasts that FCA#9 will clear at $11.08/kW-month, compared with $7.02/kW-month in FCA#8. His forecast is based, in part, on the limited ability developers to move new plants forward without sufficient gas pipeline capacity in place.

A total of 3,357 MW of plants have already told ISO-NE that they intend to close, including the Brayton plant, the 604-MW Vermont Yankee nuclear plant, the 342-MW Norwalk Harbor plant in Connecticut, and the 749-MW coal plant at Salem Harbor. (Footprint's gas plant is replacing those coal units.)

In addition, ISO-NE has a list of list of plants totaling 8,272 MW, that it considers "potentially at risk" for retirement by 2020. If the four plants that have already announced their retirement plans are removed from that list, there are still 6,300 MW of plants that are at risk of retirement.

To fill that gap, as of April there were 56 proposed projects totaling 6,900 MW in ISO-NE's interconnection queue. The queue includes 27 wind projects representing about 2,100 MW and 17 natural gas or dual-fuel (natural gas and oil) projects representing about 4,300 MW.

Of course, not all of those projects will see the light of day, but a clearer picture will begin to emerge in June when developers can begin filing expressions of interest for bidding new projects into the FCA.

Meanwhile the capacity and peak forecasts that ISO-NE used in FCA#8 —- comparable figures for FCA#9 are not yet available – indicate a need for new capacity. Forecast capacity begins to come close to summer peak demand in 2017, erasing any probably reserve margin. Then in 2018 peak demand, at 30,005 MW, begins to push through forecast capacity of 29,768 MW.

It remains to be seen how those forecasts will carry into FCA#9, but the current outlook could bodes well for higher prices in the next capacity auction, and that price signal could draw new investment to the market. Then, as new supply enters the market, Dumoulin-Smith expects capacity prices to decline in FCA#10.

NEPGA's Dolan remains optimistic about the outlook for new generation in New England. "Given what happened in the last capacity market, there is going to be a need for new capacity," he said.

But the hurdles developers of thermal plants will have to cross will be challenging. Not only will they be working in a heavily populated region where any infrastructure project draws opposition, they will be working under the first law in the country to mandate declining levels of GHG emissions.

Faced with those challenges it is likely that renewables will begin to make inroads in New England's generation mix.

But, like thermal plants, renewables also face challenges in New England. Even though there are renewable portfolio standards in all six New England states – Vermont's is voluntary – it has been tough to finance a renewable project on a merchant basis, Francis Pullaro, executive director of Renewable Energy New England, said.

In the last couple of years, however, the region's two biggest load states, Connecticut and Massachusetts, passed laws calling for utilities to sign power purchase agreements with renewable energy projects. Those laws have already resulted in contracts for about 800 MW of renewable energy.

In CLF's view, renewables will continue to play a larger and larger role in New England's generation mix as costs continue to decline and come closer to the levelized cost of generation.

But some fossil plants will also have a role, particularly plants with fast start capability that can firm and support intermittent renewable resources. "Our hope is that the market design evolves to value that role," Jonathan Peress, vice president and director of CLF's clean energy and climate program, said.

Peress also noted that CLF is one of the stakeholders involved in shaping the market design of ISO-NE.

— Peter Maloney

Cold-weather testing effort backed by PJM ...from page 1

best practices for cold weather preparation and resource testing, based on information from other areas such as ISO New England, the New York Independent System Operator, the upper Midwest and the February 2011 cold snap in the Southwest, which resulted in rolling blackouts.

The committee also will investigate the need for verification to ensure nontraditional resources such as variable resources, demand response and dual-fuel generators can operate in extreme cold.

— Mark Watson

NW utilities face winter peak shortfall ...from page 1

in load and to balance variable generation going forward," the PNUCC report said.

Each year the PNUCC drafts a region-wide assessment of utility plans for Oregon, Washington and Idaho as well as parts of Montana, Nevada, Utah and Wyoming. The report is based on utility forecasts and resource plans.

As utilities are planning for their power supply needs, the Northwest's hydroelectric system is becoming more constrained by environmental and other requirements, the PNUCC report said. Over the last 15 years, the hydropower system's peaking capacity has dropped by about 5,400 MW, the report said.

"Utilities are seeing the need to add resources to serve peak demand and introduce additional flexibility to meet fluctuations

in load and to balance variable generation going forward," the report said.

Annual summer exports out of the Northwest are forecast to fall from 2,176 MW this year to 1,517 MW by 2023. Meanwhile, winter imports are expected to slip from 1,546 MW to 1,453 MW over the same period, according to the report.

Demand response will likely play a growing role in curbing peak load in the Northwest, Dick Adams, PNUCC executive director, said. PNUCC expects summer demand response capacity to grow from 366 MW this year to 567 MW in 2023, according to the report.

"Demand response is becoming more of a player in what utilities are doing," Adams said. Utilities will likely launch more demand response programs to deal with the looming winter supply shortfall, he said.

Expected load is lower than in last year's forecast, partly because of the economy and energy efficiency measures. Overall, utility load is expected to grow by 0.9% a year over the next decade, Adams said. Regional load is expected to grow to 22,754 MW in 2023, up from 20,536 MW this year, according to the report.

However, utilities may not be including pending federal energy efficiency standards into their load forecasts, according to Tom Eckman, NPCC manager of conservation resources. Econometric forecasts use historical data, he said.

The NPCC estimates that federal energy standards adopted since 2010 will cut the Northwest's electric use by 6.83 million MWh through 2029, Eckman said. The savings represent about 13% of NPCC's long-term conservation goal.

The new federal efficiency standards will drive down NPCC's load forecast that will be included in its upcoming power plan compared with its last power plan issued in 2010, Eckman said.

The standards will require conservation programs to shift their focus to other areas, Eckman said.

— Ethan Howland

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