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Friday, September 13, 2013

Nuclear retirement not likely to lift generators

ANALYSIS

Entergy's planned closure of its 605-MW Vermont Yankee nuclear plant at the end of 2014 could provide incremental income for some generators in the region, but it is not likely to lift the prospects of all generators or result in incentives for new generation in the region over the near term.

Entergy announced its plans to shut the beleaguered nuclear plant on August 27, citing low natural gas and wholesale electric prices, high plant costs and market design flaws that continue to result in "artificially low energy and capacity prices."

The announcement prompted an $8/MWh jump on August 28 in forward wholesale power prices at the Mass Hub for the January-February 2015 package to $98/MWh. On the same day, forwards for the January-February 2014 package jumped by $2.50/

(continued on page 19)

MISO, SPP clash on seams issues at meeting

MARKETS

The Midcontinent Independent System Operator and the Southwest Power Pool clashed on several seams issues at a Thursday joint stakeholder meeting.

The grid operators had conflicting opinions about MISO's methodology for calculating power flow within its market footprint, whether SPP should be compensated for certain flows between the traditional MISO region and the integrating MISO South region, and the implementation of market-to-market flowgates between MISO and SPP.

MISO and SPP have been at odds over MISO's methodology for calculating flows within its footprint since August 2011, when SPP initiated dispute proceedings under the grid operators' joint operating agreement.

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PUCT directs ERCOT to study pricing details

MARKETS

The Public Utility Commission of Texas is directing the Electric Reliability Council of Texas to further look into a scarcity pricing proposal.

The commission is working towards making a decision on a scarcity pricing proposal known as "interim solution B+," which stems from a proposal Harvard University professor William W. Hogan, research director of the Harvard Electricity Policy Group, recommended in November 2012 and which emphasized the importance of an operating reserve demand curve in improving real-time scarcity pricing in the ERCOT market. Hogan's proposal involves real-time co-optimization of energy and ancillary services.

At Thursday's PUC meeting, commissioners approved a

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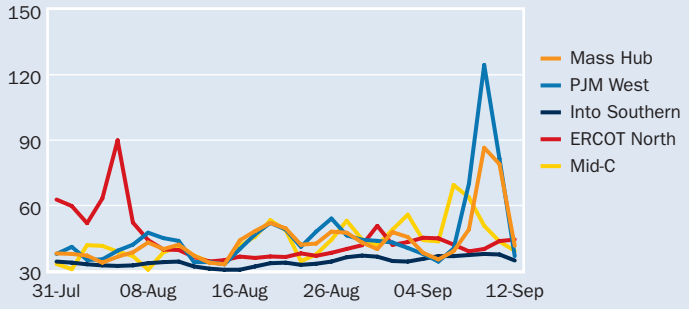
Price trends at key trading points ($/MWh)



Source: Platts

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

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	36.39	38.73	28.30	30.22
NYISO	33.85	45.28	26.75	35.37
PJM	27.86	48.92	20.17	43.11
MISO	26.69	33.28	19.32	23.04
ERCOT	42.23	64.18	25.09	25.68
CAISO	42.87	46.45	32.10	33.72

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

Day-ahead bilateral indexes and spark spreads for Sep 13

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	41.50	11544	16.34	12.74	5.55	-1.64	-12.43
N.Y. Zone-A	34.50	9760	9.76	6.22	-0.85	-7.92	-18.53
PJM/MISO							
PJM West	36.75	10586	12.45	8.98	2.03	-4.91	-15.33
Indiana Hub	32.25	8824	6.67	3.01	-4.30	-11.61	-22.58
Southeast & Central							
Southern, Into	34.75	9666	9.59	5.99	-1.20	-8.39	-19.18
ERCOT, North	44.34	12543	19.60	16.06	8.99	1.92	-8.69
West							
Mid-C	39.18	11846	16.03	12.72	6.11	-0.51	-10.43
SP15	46.75	12721	21.03	17.35	10.00	2.65	-8.38

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 decline on lower demand, spot gas

Daily power prices in the Northeast dropped Thursday as demand is expected to decline Friday and spot natural gas prices were lower. Forward prices were mixed as the NYMEX October natural gas futures contract settled at $3.638/MMBtu, rising 7.1 cents from Wednesday's close.

ISO New England forecasted peak load on Thursday at 22,350 MW, dropping to 17,860 MW for Friday. High temperatures in Boston are expected to be in the low 70s on Friday.

Algonquin city-gates spot natural gas dropped 92 cents to $3.66/MMBtu, while Transco Zone 6 New York dipped about 16 to $3.72/MMBtu.

Mass Hub on-peak for Friday delivery fell about $38, to the low $40s/MWh, as off-peak gave up about $10, going to the low $30s/MWh.

The New York ISO forecasted peak load for Thursday near 27,300 MW and 22,020 MW on Friday. High temperatures in New York state are predicted to be in the upper 50s to mid-70s on Friday.

New York day-ahead packages were absent from early trading on IntercontinentalExchange.

Day-ahead auction prices in ISO-NE tumbled Thursday with demand expected to fall at the end of the week. Internal Hub on-peak dropped $51.27 going to $37.83 and Maine on-peak was off $27.37 to $36.39/MWh. Connecticut on-peak was down $30.87 moving to $38.26/MWh and Vermont on-peak fell $31.53 to $38.10/MWh. West-Central Mass came off nearly $37 going to $38.03/MWh.

Day-ahead auction prices in NYISO were mostly down, with lower demand forecast for Friday. Long Island on-peak dropped $55.43 to $45.28/MWh and New York City on-peak gave up $42.64 to $44.99/MWh. West on-peak was down $15.46 to $34.25/MWh and Hudson Valley on-peak shed $40.32 to $42.17/MWh. North on-peak bucked the losing trend and gained more than $1 going to $33.85/MWh.

Northeast term power was mixed Thursday as gas futures climbed after the release of weekly gas storage data. Mass Hub on-peak October financial futures rose 25 cents, with bids at $40/MWh and offered $40.50/MWh on ICE. Mass Hub fourth quarter on-peak increased 45 cents to about $54.35/MWh.

New York Zone A on-peak October financial futures dropped 75 cents, with bids at $36.85/MWh and offers at $38.50/MWh on ICE.

Daily generation outage references

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

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

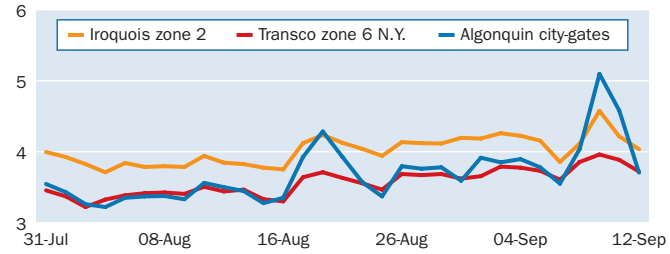
Sources: Generation owners, public information and other market sources.

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

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	41.50	-37.50	51.31	11544
N.Y. Zone-G	42.25	-42.75	54.86	10896
N.Y. Zone-J	45.00	-43.50	56.39	11605
N.Y. Zone-A	34.50	-16.00	44.19	9760
Ontario*	29.00	-7.00	38.61	7150
Off-Peak				
Mass Hub	29.50	-11.00	30.19	8206
N.Y. Zone-G	32.25	-8.25	31.14	8317
N.Y. Zone-J	28.50	-12.25	31.06	7350
N.Y. Zone-A	28.50	-6.75	28.14	8062
Ontario*	22.50	-6.75	22.47	5548

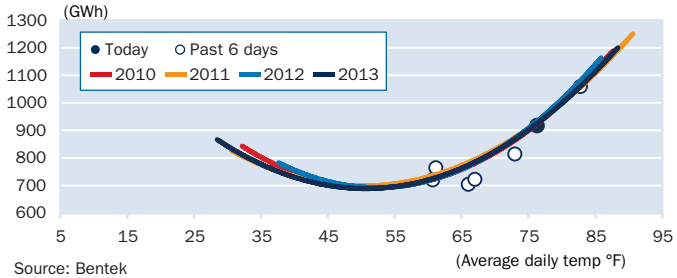
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO load per degree



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 11-Sep	%Chg	% Chg Year-ago	Forecast 12-Sep	13-Sep	14-Sep	15-Sep	16-Sep
ISONE								
Load	457	27	2	409	363	306	296	332
Generation								
Coal	30	193	76	24	11	6	7	8
Gas	217	25	-13	186	133	105	110	128
Nuclear	95	0	-4	95	96	98	101	104
NYISO								
Load	602	33	-1	509	425	376	370	410
Generation								
Coal	46	115	63	30	12	6	6	7
Gas	236	35	-6	180	119	93	99	114
Nuclear	125	0	6	125	125	127	129	131

Source: Bentek

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	37.83	-0.06	0.02	-51.27	56.91	10320
Connecticut	38.26	-0.14	0.52	-30.86	49.21	10097
NE Mass-Boston	37.63	-0.14	-0.10	-30.04	47.94	10266
SE Mass	38.00	0.14	-0.01	-29.52	48.23	10368
West-Central Mass	38.03	-0.12	0.28	-36.94	50.53	10375
Rhode Island	38.73	1.32	-0.46	-27.48	47.16	10566
Maine	36.39	-0.14	-1.34	-27.37	45.38	9116
New Hampshire	37.66	-0.14	-0.08	-30.32	48.35	9433
Vermont	38.10	-0.14	0.36	-31.53	50.04	9543
Off-Peak						
Internal Hub	29.30	-0.08	0.09	-5.49	30.04	6939
Connecticut	29.25	-0.08	0.05	-5.60	30.13	7163
NE Mass-Boston	29.19	-0.08	-0.02	-5.44	29.94	6913
SE Mass	29.61	0.09	0.24	-4.89	30.08	7012
West-Central Mass	29.41	-0.08	0.21	-5.60	30.18	6965
Rhode Island	30.22	0.79	0.15	-4.42	30.69	7158
Maine	28.30	-0.08	-0.90	-4.14	27.76	6914
New Hampshire	29.15	-0.08	-0.06	-5.34	29.80	7121
Vermont	29.57	-0.08	0.36	-5.42	30.07	7223

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	41.25	-3.21	2.38	-23.75	47.05	10874
Central Zone	35.92	-0.12	0.13	-22.64	44.06	10125
Dunwoodie Zone	42.47	-2.62	4.18	-44.47	51.94	10885
Genesee Zone	34.94	-0.09	-0.82	-15.18	42.32	9850
Hudson Valley Zone	42.17	-2.56	3.94	-40.31	51.30	10808
Long Island Zone	45.28	-4.34	5.27	-55.43	60.93	11606
Millwood Zone	42.42	-2.63	4.12	-44.64	51.97	10873
Mohawk Valley Zone	36.83	-0.17	1.00	-21.80	44.24	10066
N.Y.C. Zone	44.99	-4.75	4.57	-42.63	53.01	11531
North Zone	33.85	0.16	-1.65	1.02	33.90	8481
West Zone	34.52	-0.12	-1.28	-15.45	41.92	9730
Off-Peak						
Capital Zone	31.64	-0.75	2.09	-7.89	30.41	8127
Central Zone	29.02	-0.04	0.19	-6.94	28.61	8037
Dunwoodie Zone	32.29	-0.59	2.90	-7.97	31.10	8016
Genesee Zone	28.55	-0.03	-0.28	-6.70	28.16	7906
Hudson Valley Zone	32.35	-0.57	2.98	-8.26	31.16	8031
Long Island Zone	35.37	-2.73	3.85	-10.27	34.30	8780
Millwood Zone	32.27	-0.59	2.88	-7.99	31.08	8009
Mohawk Valley Zone	29.46	0.01	0.68	-6.69	28.82	7870
N.Y.C. Zone	32.95	-0.97	3.19	-7.93	31.57	8178
North Zone	26.75	0.40	-1.65	-0.98	25.54	6535
West Zone	28.51	-0.04	-0.32	-6.59	28.23	7896

Market coverage

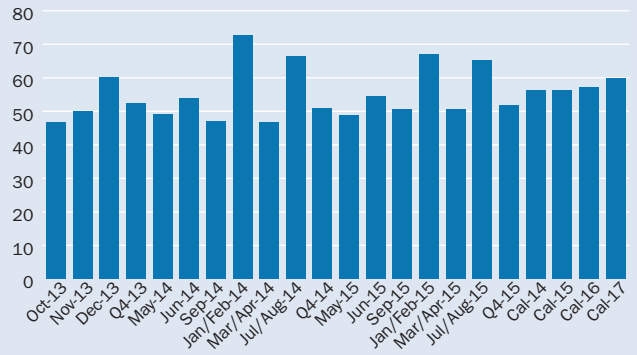
Platts provides a detailed methodology related to its coverage of North American electricity markets at: http://platts.com/MethodologyAndSpecifications/ElectricPower. Questions can be directed to Mike Wilczek, Market Editor, (202) 383-2246, Mike_Wilczek@platts.com.

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

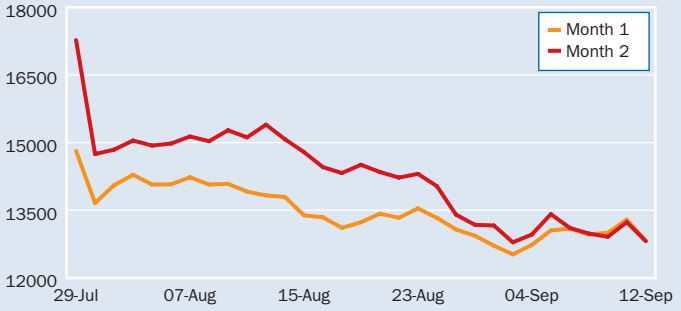
Prompt month: Oct 13	On-peak	Off-peak
Mass Hub	40.25	31.00
N.Y. Zone G	44.50	33.75
N.Y. Zone J	46.75	35.25
N.Y. Zone A	37.75	30.25
Ontario*	28.25	18.50

*Ontario prices are in Canadian dollars

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



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



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Next-week	09/10	40.50-41.50

*Ontario prices are in Canadian dollars.

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	200	c	Ont.	PMO	Unk	09/11/12
Darlington-2/OPG	868	n	Ont.	PMO	Unk	08/27/13
DeCew Falls/OPG	167	h	Ont.	Unk	Unk	08/22/13
Lambton-3/OPG	326	c	Ont.	Unk	Unk	09/06/13
Lennox-3/OPG	525	bio	Ont.	Unk	Unk	09/05/13
Nanticoke-6/Brookfield	292	c	Ont.	Unk	Unk	09/05/13
Peach Bottom-3/Exelon	1182	n	Pa.	PMO	Unk	09/09/13
Pickering-6/OPG	510	n	Ont.	Unk	Unk	09/03/13
Pilgrim-1/Entergy	728	n	Mass.	MO	Unk	09/08/13
Portlands-1/PEC	197	g	Ont.	Unk	Unk	09/08/13
Portlands-2/PEC	197	g	Ont.	Unk	Unk	09/08/13
Portlands-3/PEC	245	g	Ont.	Unk	Unk	09/08/13
Taohsc/TransAlta	78	g	Ont.	Unk	Unk	09/03/13
Thunderbay-2/OPG	150	c	Ont.	PMO	Unk	03/01/13

SOUTHEAST MARKETS

Dailies up, despite lower demand, spot gas

Daily power prices in the Electric Reliability Council of Texas were higher on the IntercontinentalExchange Thursday, even as demand was projected to move down and spot natural gas prices declined. Forward prices in the South and Southeast were steady or higher as the NYMEX October natural gas futures contract settled at $3.638/MMBtu, rising 7.1 cents from Wednesday's close.

Spot natural gas at Houston Ship Channel shed 2.1 cents to trade around $3.604/MMBtu.

ERCOT North Hub next-day on-peak physical power rose about $4.25 to trade around $44.25/MWh. Off-peak added nearly $1 to trade around $25.75/MWh.

High temperatures across ERCOT's footprint were forecast in the mid-90s Friday, with lows expected in the mid-70s. The average September high temperature across ERCOT is in the upper 80s to low 90s, with the average upper 60s to low 70s.

System load in ERCOT was forecast to peak at 61,475 MW Thursday and 58,875 MW Friday, compared with an actual peak of 58,154 MW Wednesday.

Real-time prices averaged $23.75/MWh and were flat from 12:15 a.m. to 6 a.m. CDT Thursday. Wind generation was forecast to peak at 3,200 MW at 1 a.m. CDT Thursday and 2,625 MW at 1 a.m. CDT Friday.

North Hub next-week on-peak was bid at $36 and offered at $36.50/MWh.

In the Southeast, dailies for Friday delivery were steady Thursday, with temperatures forecast steady. Into Southern next-day on-peak power market was in the mid-$30s/MWh, fairly steady with Wednesday prices.

Spot natural gas at Transco Zone-3 shed 4.1 cents to trade around $3.584/MMBtu. High temperatures in Atlanta were forecast in the mid-80s Thursday, with lows expected in the low 70s. The average September high temperature in Atlanta is 82; the average low is 65.

The ERCOT day-ahead auction cleared weaker Thursday afternoon with peak load forecast to decline. West Hub remained the highest-priced hub and South Hub the lowest-priced. West Hub on-peak cleared in the ERCOT auction at $44.18/MWh, a loss

(continued on page 10)

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

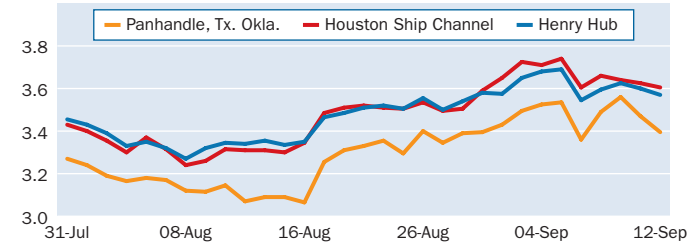
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	35.25	-13.25	40.86	9463
Southern, Into	34.75	-2.75	36.11	9666
Florida	37.50	-2.00	38.22	9566
TVA, Into	34.25	-5.00	37.50	9435
Entergy, Into	35.50	-1.25	34.86	10014
Southeast Off-Peak				
VACAR	25.00	-2.25	23.46	6711
Southern, Into	24.50	-0.75	22.75	6815
Florida	28.00	-0.75	26.56	7143
TVA, Into	23.75	-1.50	22.77	6543
Entergy, Into	22.50	-0.75	20.58	6347
ERCOT On-peak				
ERCOT, North	44.34	0.68	42.69	12543
ERCOT, Houston	44.50	0.75	43.14	12318
ERCOT, South	44.25	0.75	42.67	12412
ERCOT, West	46.00	1.25	44.44	13199
ERCOT Off-Peak				
ERCOT, North	25.89	0.11	24.68	7324
ERCOT, Houston	26.00	0.25	24.87	7197
ERCOT, South	25.75	0.00	24.65	7223
ERCOT, West	26.00	0.25	24.69	7461
SPP/MRO On-peak				
MAPP, South	33.50	-3.50	39.00	9267
SPP, North	33.00	-3.50	38.42	9720
SPP/MRO Off-Peak				
MAPP, South	22.00	-1.50	22.06	6086
SPP, North	21.75	-1.25	21.79	6406

Southeast load and generation mix forecast (GWh)

	Actual 11-Sep	%Chg	% Chg Year-ago	Forecast 12-Sep	13-Sep	14-Sep	15-Sep	16-Sep
ERCOT								
Load	1088	2	-1	1044	1059	1029	998	1064
Generation								
Coal	427	-3	12	405	422	431	431	431
Gas	488	11	-10	476	468	457	442	448
Nuclear	119	0	-2	119	123	123	123	123
SPP								
Load	750	-5	-5	694	669	624	636	696
Generation								
Coal	434	-6	4	409	398	394	404	411
Gas	235	3	-24	204	179	164	169	173
Nuclear	49	0	-2	19	20	25	33	41

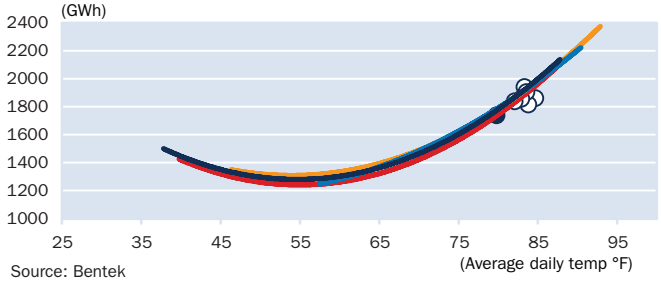
Source: Bentek

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



Source: Platts

ERCOT & SPP load per degree



Source: Bentek

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

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	42.53	-1.65	42.13	11960
Hub Average	42.81	-1.50	42.46	12038
Houston Hub	42.52	-1.57	42.19	11759
North Hub	42.29	-1.80	41.84	11941
South Hub	42.23	-1.74	41.78	11846
West Hub	44.18	-0.91	44.03	12641
AEN Zone	42.58	-1.73	42.73	12183
CPS Zone	42.57	-1.56	42.20	12040
LCRA Zone	42.48	-1.78	42.50	12015
Rayburn Zone	42.43	-2.06	41.93	11978
Houston Zone	42.72	-1.63	42.48	11814
North Zone	42.38	-2.01	42.12	11966
South Zone	42.65	-1.92	42.59	11964
West Zone	64.18	9.86	61.50	18363
Off-Peak				
Bus Average	25.13	-0.95	25.31	7036
Hub Average	25.14	-0.95	25.31	7039
Houston Hub	25.14	-0.94	25.31	6947
North Hub	25.12	-0.96	25.31	7048
South Hub	25.11	-0.97	25.30	7052
West Hub	25.18	-0.95	25.31	7128
AEN Zone	25.10	-0.98	25.34	7106
CPS Zone	25.14	-0.95	25.36	7077
LCRA Zone	25.09	-0.99	25.31	7061
Rayburn Zone	25.12	-0.96	25.31	7049
Houston Zone	25.14	-0.94	25.31	6946
North Zone	25.12	-0.96	25.31	7048
South Zone	25.14	-0.95	25.32	7059
West Zone	25.68	-0.71	26.01	7268

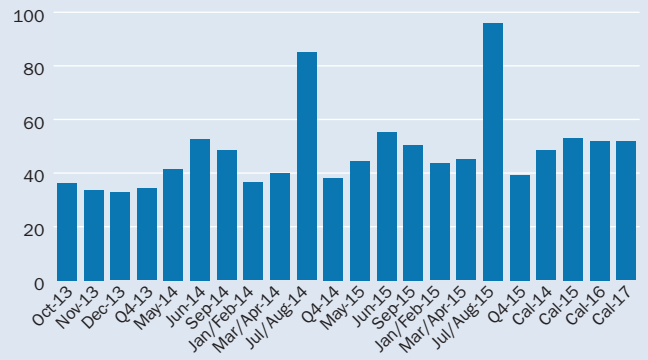
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	09/11	36.00-36.50
Bal-week	09/10	37.50-38.00
Bal-week	09/09	38.00-38.50
Bal-month	09/11	35.50-36.00
Bal-month	09/10	36.00-36.50
Bal-month	09/09	36.00-36.50
Next-week	09/11	34.50-35.00
Next-week	09/10	38.00-38.50
Next-week	09/09	37.00-37.50
Entergy, Into		
Bal-week	09/09	35.75-36.25
Bal-week	09/06	35.00-35.50
Bal-month	09/09	33.25-33.75
Bal-month	09/06	36.00-36.50
Next-week	09/09	34.75-35.25
Next-week	09/06	37.00-37.50
ERCOT, North		
Next-week	09/11	36.25-36.75

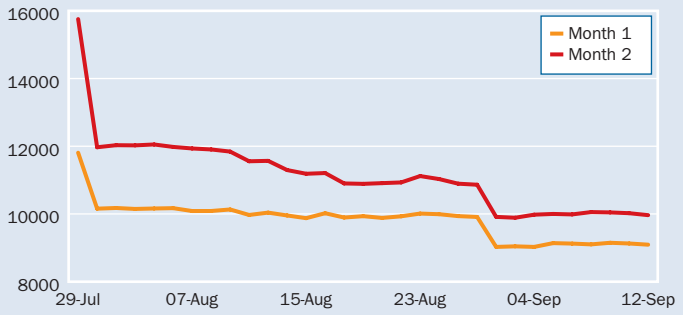
Southeast & Central Platts-ICE Forward Curve, Sep 12 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
Southern Into	33.00	28.25
Entergy Into	31.25	25.75
ERCOT North	33.75	25.50
ERCOT Houston	36.25	26.50
ERCOT West	32.25	24.25
ERCOT South	34.75	25.25

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						
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Crystal River-3/Progress	838	n	Fla.	NA	Retired	09/26/09
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Monticello-1/Luminant	565	c	Texas	MO	Unk	09/08/13
Monticello-2/Luminant	565	c	Texas	MO	Unk	08/25/13
North Anna-1/Dominion	990	n	Va.	PMO	Unk	09/08/13
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13
Wolf Creek/	1235	n	Kan.	MO	Unk	09/12/13

WEST MARKETS

Dailies lower; terms steady to up

Most western dailies were down slightly Thursday morning amid lower demand expected in California on Saturday and lower spot natural gas prices in the region. Forwards were steady to higher. The NYMEX October natural gas futures contract posted a preliminary settlement Thursday of $3.638/MMBtu, rising 7.1 cents in spite of a storage injection that was in line with expectations.

In the Northwest, Mid-Columbia day-ahead on-peak lost more than $4.25 to trade between $38 and $40/MWh for delivery on Friday and Saturday. Mid-C day-ahead off-peak fell more than $1 to trade between $28.25 and $30/MWh. The Mid-C on-peak balance-of-the-month package was bid at $36.25 and offered at $37.50/MWh, down more than $1.25.

Portland, Oregon's forecasts had in the mid- to highs 80s through Saturday. Expected lows were from low to mid-60s.

The Bonneville Power Administration's wind output was 137 MW and its hydro output was 6,536 MW at 7 a.m. PDT on Thursday.

In California, SP15 next-day on-peak was down about 75 cents to trade between $46.75 and $47.50/MWh. SP15 day-ahead off-peak also dropped 50 cents to about $33/MWh. SP15 bal-month was bid at $47.80 and offered at $48.50 on the IntercontinentalExchange, down more than 75 cents.

NP15 day-ahead on-peak lost more than $1.75 to around $44.25/MWh. NP15 day-ahead off-peak dropped 50 cents to about $33.50/MWh. NP15 bal-month was bid at $43.30 and offered at $46.50/MWh, down more than $3.25, on the ICE.

Sacramento, California, expected highs from the upper 80s to the low 90s and lows in the low 60s. Forecast highs for Burbank were in the low to mid-90s with anticipated low to high 60s.

The California Independent System Operator projected peak demand to be 35,627 MW on Thursday, 38,571 MW on Friday and 37,356 MW on Saturday.

California renewables were 3,062 MW and wind was about 1,350 MW at 7 a.m. PDT on Thursday. In the desert Southwest, Palo Verde next-day on-peak was up about $1 to trade between $35 and $36.25/MWh. Palo Verde day-ahead off-peak was down nearly 50 cents, trading between $25 and $25.25/MWh. Palo Verde bal-month was bid at $35.50 and offered at $38/MWh, down about $1.25. Phoenix expected highs to reach 101 Saturday, up a few degrees, and lows from the mid-70s to 80.

Next-day natural gas prices retreated in the Rockies and California. Opal was down 2.3 cents to $3.445/MMBtu, PG&E city-gate lost less than 2.7 cents to $3.950/MMBtu, and SoCal city-gate fell 5.1 cents to $3.820/MMBtu.

Most day-ahead prices were up in the California ISO auction Thursday as higher demand was expected in most of California on Friday.

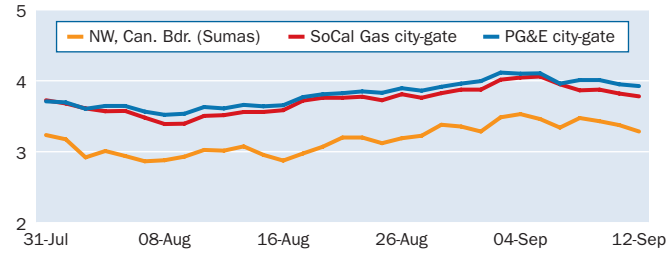
SP15 on-peak rose $1.67 to $46.45/MWh, while SP15 off-peak

(continued on page 10)

Western day-ahead bilateral indexes for Sep 13-14 ($/MWh)

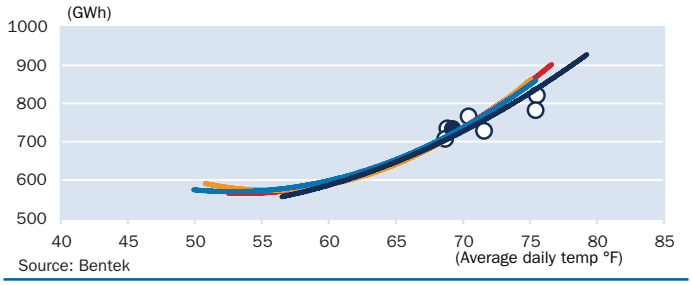
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	41.25	-2.69	53.11	11853
Mid-C	39.18	-4.29	49.22	11846
Palo Verde	35.56	0.88	39.81	9933
Mead	39.38	-0.35	44.75	10716
Mona	36.75	-0.75	48.14	10793
Four Corners	36.00	0.75	42.84	10330
NP15	44.50	-1.50	50.05	11338
SP15	46.75	-0.75	55.45	12721
Off-Peak				
COB	28.60	-1.33	34.51	8218
Mid-C	28.57	-1.13	32.91	8638
Palo Verde	25.25	-0.38	28.70	7053
Mead	26.50	-1.00	30.30	7211
Mona	21.47	-1.28	27.85	6305
Four Corners	25.25	0.50	28.53	7245
NP15	33.50	-0.50	36.82	8535
SP15	33.00	-0.50	39.13	8980

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO load per degree



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 11-Sep	% Chg %Chg	% Chg Year-ago	Forecast 12-Sep	13-Sep	14-Sep	15-Sep	16-Sep
CAISO								
Load	708	-4	1	734	756	722	707	757
Generation								
Gas	345	-3	2	344	346	351	349	335
Nuclear	56	0	-7	56	56	56	56	56

Source: Bentek

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	43.75	-0.73	-2.30	-0.64	48.15	11146
SP15 Gen Hub	46.45	0.24	-0.57	1.67	53.93	12639
ZP26 Gen Hub	42.87	-0.70	-3.21	2.40	47.31	11665
Off-Peak						
NP15 Gen Hub	33.72	0.33	-0.50	-0.57	35.38	8551
SP15 Gen Hub	33.05	-0.06	-0.78	0.29	36.30	8839
ZP26 Gen Hub	32.10	-0.18	-1.61	0.29	34.14	8586

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-week	09/09	54.00-55.00
Bal-week	09/06	64.50-65.50
Bal-month	09/11	37.50-39.00
Bal-month	09/10	40.75-41.25
SP15		
Bal-month	09/12	48.00-49.00
Bal-month	09/11	48.75-49.25

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Contra Costa-6/NRG	337	g	Calif.	PMO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
Des Sunlight/NextEra	300	s	Calif.	MO	Unk	08/15/13
Des Sunlight/NextEra	250	s	Calif.	MO	Unk	09/08/13
El Segundo-3/NRG	335	g	Calif.	MO	Unk	07/23/13
Huntington Beach-3/AES	225	g	Calif.	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif.	PMO	Unk	04/14/13
Mexicali/Sempra	180	g	Calif.	PMO	Unk	07/22/13
Pine Flat/USACE	210	h	Calif.	PMO	Unk	08/11/13

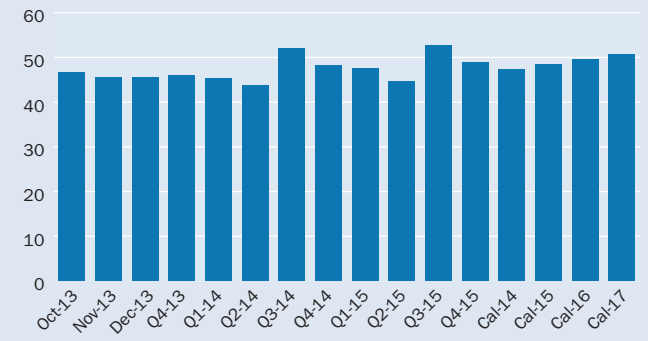
Additional information on data and analysis:

For more information on data and analysis from Bentek, 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.

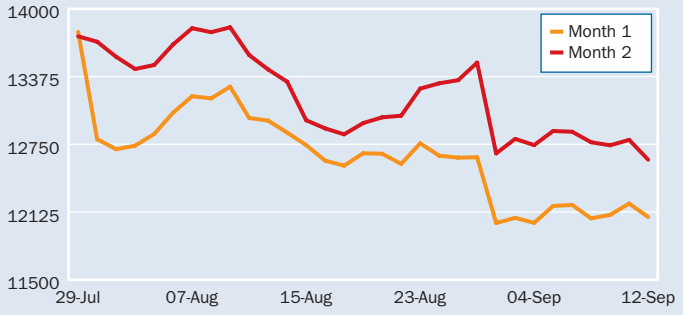
Western Platts-ICE Forward Curve, Sep 12 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
Mid-C	36.00	30.50
Palo Verde	36.75	26.75
Mead	38.00	28.75
NP15	43.25	35.75
SP15	46.75	37.00

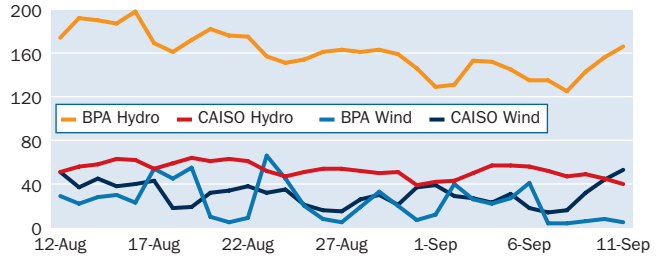
SP15: Forward curve on-peak ($/MWh)



SP15: Marginal heat rate on-peak (Btu/kWh)



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

Dailies drop while forwards climb

Daily power prices in the Mid-Atlantic and Midwest declined Thursday as demand is expected to plummet on milder weather. Mid-Atlantic forward prices were higher, while forwards in the Midwest were mixed as the NYMEX October natural gas futures contract settled at $3.638/MMBtu, rising 7.1 cents from Wednesday's close.

PJM Interconnection forecasted peak demand on Thursday at 130,074 MW and 100,846 MW for Friday. High temperatures in the PJM footprint are forecast in the low 60s to upper 70s on Friday.

Spot gas in the region also remained weak, with Texas Eastern M-3 dropping about 15 cents to around $3.60/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Friday tumbled about $43.50 going to the upper $30s/MWh. PJM West Hub off-peak gave up about $6.75 moving to mid-$20s/MWh.

Daily prices in the Midcontinent ISO were also lower with lower temperatures in the mix and weaker spot gas prices. Chicago city-gates spot gas lost about 6 cents to reach $3.67/MMBtu. Indiana Hub on-peak for Friday fell about $12 going to the low $30s/MWh and off-peak gave up about $4 moving down to the low $20s/MWh.

Dailies in the Midwestern portion of the PJM dropped further with weakness in nearby markets and lower expected demand. AEP-Dayton Hub on-peak for Friday delivery dropped about $21 to the low $30s/MWh and off-peak gave up about $5 to the mid-$20s/MWh. Northern Illinois Hub on-peak for Friday tumbled about $21 to the low $30s/MWh and off-peak gave up about $6 to the low $20s/MWh.

Day-ahead auction prices in PJM fell with demand set to move lower on Friday. Eastern Hub on-peak dropped more than $30, going to about $38/MWh, while Western Hub on-peak dropped about $23.49 to $36.47/MWh. JCPL on-peak was off $26.16 to $48.92/MWh and PSEG on-peak gave up $28.92 to $40.71/MWh. BG&E on-peak gave up $29.50, moving to $42.91/MWh and Pepco on-peak dropped $31.44 to $43.03/MWh. ComEd on-peak fell $5.94 to $29.04/MWh and Chicago Hub on-peak lost $5.92 to $29.06/MWh.

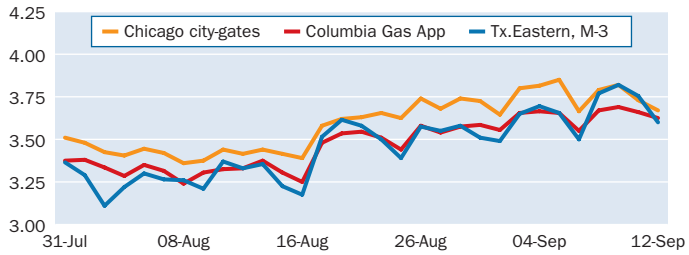
MISO day-ahead auction prices cleared weaker Thursday. Minnesota Hub remained the highest-priced hub, with on-peak clearing at $33.28/MWh, down $14.01. Off-peak cleared at $19.32/MWh, down $7.06. Michigan Hub on-peak cleared at $31.59/MWh, a drop of $7.79. Off-peak cleared at $23.04/MWh, a decrease of $3.80. Indiana Hub on-peak cleared at $30.52/MWh, losing $7.82. Off-peak cleared at $22.38/MWh, falling $3.07. Illinois Hub fell to the lowest-priced hub, with on-peak clearing at $26.69/MWh, shedding $7.83. Off-peak cleared at $19.76/MWh, a loss of 48 cents.

Congestion costs at the hubs ranged from negative $3.88 to $1.66 for on-peak, and from negative $1.10 to 90 cents for off-peak.

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

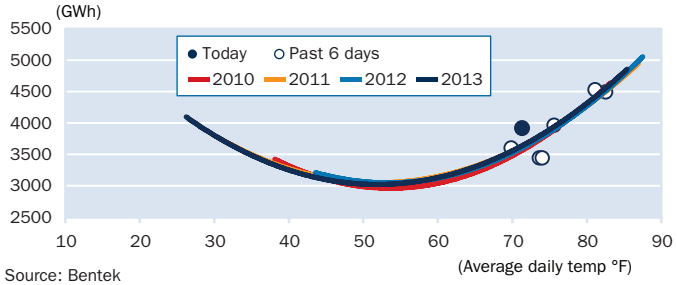
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	36.75	-44.75	56.50	10586
Dominion Hub	40.00	-52.50	64.22	10884
AD Hub	31.50	-20.50	45.22	8571
NI Hub	31.00	-21.00	46.31	8447
PJM Off-Peak				
PJM West	26.75	-6.50	26.81	7705
Dominion Hub	30.50	-9.75	30.17	8299
AD Hub	23.75	-5.25	24.86	6463
NI Hub	21.75	-5.25	22.97	5926
MISO On-peak				
Indiana Hub	32.25	-11.75	41.42	8824
Michigan Hub	33.50	-12.75	42.53	8775
Minnesota Hub	35.00	-1.00	41.11	9537
Illinois Hub	27.75	-6.00	38.14	7566
MISO Off-Peak				
Indiana Hub	21.50	-4.00	23.28	5882
Michigan Hub	22.75	-4.50	24.08	5959
Minnesota Hub	21.25	-0.50	21.47	5790
Illinois Hub	17.75	-1.25	20.69	4840

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



Source: Platts

PJM & MISO load per degree



Source: Bentek

PJM & MISO load and generation mix forecast (GWh)

	Actual 11-Sep	%Chg	% Chg Year-ago	Forecast 12-Sep	13-Sep	14-Sep	15-Sep	16-Sep
PJM								
Load	2789	4	0	2436	2018	1725	1683	1988
Generation								
Coal	1221	3	12	1095	1048	1031	1036	1050
Gas	623	6	-19	452	215	118	155	238
Nuclear	715	4	2	706	710	723	747	771
MISO								
Load	1737	-4	-1	1479	1291	1140	1146	1327
Generation								
Coal	1363	-5	6	1208	1050	1012	1049	1087
Gas	302	2	-40	149	0	0	0	44
Nuclear	187	0	-11	187	188	190	194	198

Source: Bentek

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	30.52	-0.69	-0.32	-7.82	38.61	8338
Michigan Hub	31.59	-0.46	0.52	-7.79	39.39	8260
Minnesota Hub	33.28	1.66	0.08	-14.01	40.04	9050
Illinois Hub	26.69	-3.88	-0.96	-7.83	35.49	7250
Off-Peak						
Indiana Hub	22.38	0.82	0.32	-3.07	22.81	6057
Michigan Hub	23.04	0.90	0.91	-3.80	23.57	5988
Minnesota Hub	19.32	-0.85	-1.07	-7.06	20.48	5218
Illinois Hub	19.76	-1.10	-0.38	-0.48	20.54	5287

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

Package	Trade date	Range
PJM West		
Bal-week	09/11	39.00-40.00
Bal-week	09/10	62.50-63.50
Bal-week	09/09	65.00-75.00
Bal-week	09/06	52.00-54.00
Next-week	09/12	43.25-44.50
Next-week	09/11	43.50-44.50
Next-week	09/10	44.00-45.25
Next-week	09/09	46.00-47.00
Next-week	09/06	47.00-48.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Braidwood-1/Exelon	1242	n	Ill.	PMO	Unk	09/09/13
Fermi-2/Detroit Edison	1155	n	Mich.	PMO	Unk	09/09/13
Kewaunee/Dominion	581	n	Wis.	NA	Retired	05/07/13

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	27.86	-4.22	-2.12	-4.66	38.83	7663
AEP-Dayton Hub	29.11	-4.17	-0.92	-5.73	40.85	8008
ATSI Gen Hub	30.58	-3.54	-0.07	-8.46	43.32	8490
Chicago Gen Hub	28.39	-4.28	-1.53	-5.26	40.76	7710
Chicago Hub	29.06	-4.15	-0.98	-5.92	41.95	7894
Dominion Hub	39.62	5.88	-0.46	-31.38	57.47	10753
Eastern Hub	37.98	1.76	2.02	-30.09	55.47	10319
New Jersy Hub	42.98	7.32	1.47	-27.76	51.21	11676
Northern Illinios Hub	28.82	-4.18	-1.20	-5.71	41.50	7827
Ohio Hub	29.44	-4.07	-0.68	-5.86	41.24	7963
West Internal Hub	31.39	-1.99	-0.82	-14.83	46.52	9006
Western Hub	36.47	2.31	-0.03	-23.49	50.43	10463
AEP Zone	28.88	-4.38	-0.93	-6.12	40.89	7946
Allegheny Power Zone	31.70	-1.82	-0.68	-15.92	45.60	8852
Atlantic Elec Zone	38.92	3.31	1.42	-26.58	50.04	10573
ATSI Zone	30.87	-3.53	0.21	-8.92	43.81	8570
BG&E Zone	42.91	7.52	1.20	-29.50	58.44	11974
ComEd Zone	29.04	-4.12	-1.04	-5.94	41.89	7888
Dayton P&L Zone	30.16	-4.07	0.04	-7.17	41.61	8240
Delmarva P&L Zone	38.02	2.08	1.75	-29.20	54.35	10330
Dominion Zone	38.32	4.28	-0.16	-30.35	56.62	10399
Duke Zone	28.86	-4.09	-1.24	-7.21	40.33	7885
Duquesne Light Zone	28.92	-3.80	-1.48	-6.71	41.01	8252
JCPL Zone	48.92	13.35	1.37	-26.16	52.29	13290
MetEd Zone	37.60	2.96	0.44	-28.53	51.32	10258
PECO Zone	36.39	1.30	0.90	-27.40	48.78	9928
Pennsylvania Elec Zone	33.69	-1.16	0.66	-19.84	46.63	9681
PEPCO Zone	43.03	8.14	0.70	-31.44	57.91	12006
PPL Zone	36.52	1.91	0.42	-25.89	48.61	9964
PSEG Zone	40.71	4.95	1.57	-28.92	51.01	11060
Rockland Elec Zone	41.70	5.92	1.59	-28.09	49.02	11329
Off-Peak						
AEP Gen Hub	24.24	-1.21	-1.19	-1.31	24.13	6576
AEP-Dayton Hub	24.93	-1.17	-0.53	-1.46	24.89	6763
ATSI Gen Hub	26.12	-0.61	0.09	-1.53	25.52	7163
Chicago Gen Hub	20.17	-5.11	-1.36	-3.49	21.59	5418
Chicago Hub	20.79	-4.82	-1.03	-3.74	22.15	5585
Dominion Hub	30.65	3.90	0.11	-6.34	29.77	8217
Eastern Hub	27.59	-0.08	1.03	-4.02	29.04	7276
New Jersy Hub	35.51	7.92	0.95	3.73	27.77	9366
Northern Illinios Hub	20.69	-4.80	-1.16	-3.59	22.04	5557
Ohio Hub	25.13	-1.08	-0.43	-1.50	25.07	6754
West Internal Hub	26.16	-0.27	-0.21	-2.71	25.99	7348
Western Hub	27.03	0.22	0.17	-2.89	26.73	7595
AEP Zone	24.70	-1.42	-0.52	-1.48	24.76	6700
Allegheny Power Zone	25.93	-0.51	-0.20	-2.38	25.80	7134
Atlantic Elec Zone	29.37	1.89	0.83	-1.84	27.28	7746
ATSI Zone	26.29	-0.63	0.28	-1.49	25.64	7211
BG&E Zone	28.25	0.77	0.84	-4.12	28.18	7727
ComEd Zone	20.62	-4.96	-1.06	-3.81	22.11	5538
Dayton P&L Zone	25.55	-1.15	0.06	-1.56	25.11	6915
Delmarva P&L Zone	27.61	0.10	0.88	-3.84	28.69	7283
Dominion Zone	29.54	2.68	0.23	-5.95	29.16	7921
Duke Zone	24.60	-1.22	-0.82	-1.39	24.33	6660
Duquesne Light Zone	25.06	-0.76	-0.82	-1.50	24.60	7033
JCPL Zone	43.11	15.56	0.91	10.93	28.32	11370
MetEd Zone	28.58	1.64	0.31	-2.09	26.69	7629
PECO Zone	26.75	-0.48	0.59	-4.07	26.79	7139
Pennsylvania Elec Zone	27.65	0.42	0.59	-1.42	26.46	7844
PEPCO Zone	27.96	0.80	0.52	-4.46	28.16	7647
PPL Zone	27.90	1.07	0.19	-2.26	26.36	7447
PSEG Zone	32.88	5.20	1.03	1.15	27.63	8671
Rockland Elec Zone	34.94	7.26	1.03	3.30	27.63	9215

Mid-Atlantic forwards rose Thursday as gas futures climbed after the release of weekly gas storage data. PJM West on-peak October financial futures were up 25 cents, with bids at $41.35/MWh and offers at $41.60/MWh on ICE. PJM West on-peak fourth-quarter rose 25 cents to about $41.90/MWh. PJM West on-peak January-February 2014 financial futures rose 25 cents to about $45/MWh on ICE.

Midwest forwards were mixed Thursday despite the rise in gas futures. AD Hub on-peak October financial futures rose 25 cents, with bids at $37.65/MWh and offers at $37.20/MWh on ICE. Indiana Hub on-peak October financial futures were down 25 cents, with bids at $34.35/MWh and offers at $34.90/MWh on ICE.

Southeast markets ... *from page 4*

of about $1, while off-peak cleared at $25.18/MWh, a drop of about $1.

Houston Hub on-peak cleared in the auction at $42.52/MWh, falling around $1.50, while off-peak cleared at $25.14/MWh, shedding almost $1. North Hub on-peak cleared the auction at $42.29/MWh, down about $1.75 from Wednesday's clearing price, while off-peak cleared at $25.12/MWh, a decrease of almost $1. South Hub on-peak cleared at $42.23/MWh, falling about $1.75, while off-peak cleared at $25.11/MWh, losing almost $1. West Zone on-peak led the load zones at $64.18/MWh, adding about $9.75 from Wednesday.

The highest hourly day-ahead price occurred at 5 p.m. CDT in the West Hub at $67.55/MWh and in the West Zone at $102.89/MWh. ERCOT system load was forecast to peak at 58,875 MW Friday, down 4% from Thursday's expected peak of 61,475 MW.

South Central on-peak October terms were steady to higher Thursday, as October NYMEX natural gas futures increased. ERCOT North on-peak October advanced 50 cents to $33.75/MWh, the fourth quarter rose 35 cents to $33.25/MWh, and January-February 2014 surged 50 cents to $36.75/MWh. Heat rates were down about 50 Btu/kWh on ICE at about 2:30 p.m. EDT. Into Entergy on-peak October stayed at about $31.25/MWh, and Q4 also stayed at about $31.25/MWh.

Southeast US on-peak October was unmoved Thursday, even as October NYMEX gas futures moved up. Into Southern October stayed at about $33/MWh, Q4 stayed at about $33.10/MWh and January-February 2014 rose 25 cents to $36.60/MWh.

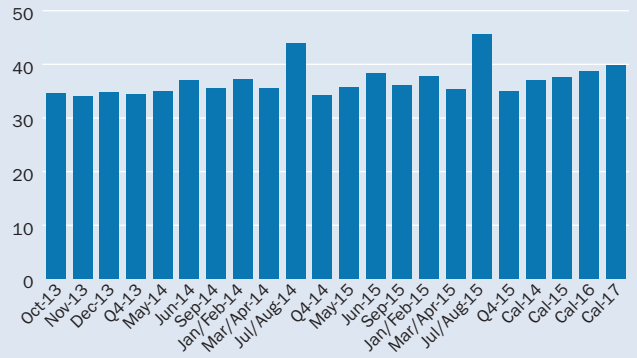
West markets ... *from page 6*

added 29 cents to $33.05/MWh. ZP26 on-peak added $2.40 to $42.87, while ZP26 off-peak gained 29 cents to $33.72/MWh. NP15 on-peak fell 64 cents to $43.75/MWh and NP15 off-peak dropped 57 cents to $33.72/MWh. Peak demand in the Pacific Gas and Electric area was forecast to drop from 17,144 MW on Thursday to 15,986 on Friday.

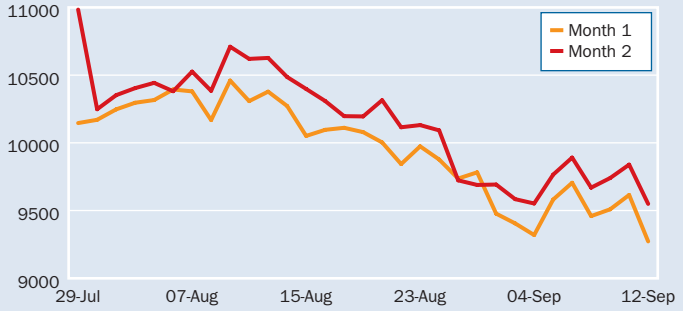
PJM & MISO Platts-ICE Forward Curve, Sep 12 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
PJM West	41.50	31.00
AD Hub	38.00	29.25
NI Hub	34.75	22.75
Indiana Hub	34.50	26.25

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



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



Western US on-peak October terms were steady to higher Thursday, as October natural gas futures rose in late trading.

In the Northwest, Mid-Columbia on-peak October was unchanged with bids at $35.75 and offers at $36/MWh on the IntercontinentalExchange around 2:30 p.m. EDT. The fourth quarter stayed at about $38.50/MWh, and the first quarter of 2014 rose 25 cents to about $35.75/MWh.

In California, SP15 on-peak October financial terms were unmoved with bids at $46.50 and offers at $46.85/MWh. Q4 crept up 15 cents to about $45.90/MWh, and Q1 2014 rose 25 cents to about $45.25/MWh. NP15 October rose 25 cents to about $43.25/MWh, and Q4 climbed 40 cents to about $43.25/MWh.

Palo Verde October advanced $1 to about $36.75/MWh, Q4 rose 50 cents to about $35.15/MWh, and Q1 2014 had no bids and an offer of $36.25/MWh. Mead on-peak October rose 25 cents to about $38/MWh.

EMISSIONS MARKETS

Calif. GHG allowances inch down

Values and trading volume for California greenhouse gas allowances fell this week.

Contracts for vintage 2013 GHG allowances delivered at the end of 2013, 2014 and 2015 on IntercontinentalExchange decreased 60-67 cents. The main futures contract traded on ICE – vintage 2013 for delivery in December 2013 – settled at $12.35/metric ton. The vintage 2015 contract for December 2015 delivery settled at $12.95/mt, down 40 cents.

Trading volume on ICE was about the same as the previous week. There were 15 deals done on ICE representing 115 contracts. The number of bilateral deals cleared by ICE saw a sharp decrease. There were 22 ICE-cleared deals, representing 684 contracts, down from 40 deals and 2,615 contracts a week earlier. One contract equals 1,000 mt.

In over-the-counter markets, prices for California GHG allowances for December 2013 delivery decreased from $12.75-$13/mt to $12.35-$12.45/mt this week. California-compliant offsets were quoted at $8.75-$9.25/mt.

In the East, the Regional Greenhouse Gas Initiative's vintage 2013 contract for December 2013 delivery decreased 20 cents cents to settle at $2.70/short ton. There were 13 deals on ICE totaling 525 contracts. ICE also cleared 11 deals worth 1,900 contracts. One contract equals 1,000 st.

— Geoffrey Craig

Vintage 2013 SO2 allowances assessed down

No trades were heard in the Clean Air Interstate trading program for the week ending September 13, according to a survey of emissions traders.

Trading continues to be depressed due to weak demand, as declining US emissions and a glut of allowances has sapped interest from buyers.

Platts assessed vintage 2013 SO2 at 67 cents/allowance Thursday, down 1 cent from the prior week on lower broker marks. Vintage 2014 SO2 was assessed at 58 cents/allowance, which remained unchanged.

Bids for vintage 2013 CAIR Seasonal NOx allowances provided by brokers ranged between $19 and $20, while offers ranged between $21 and $22.

On Thursday, a $12 bid was posted on ICE but the best offer was $28.

Platts assessed all CSAPR 2012 allowances unchanged, with Group 1 SO2 at $20/st, Group 2 SO2 at $50/st, and both annual and seasonal NOx allowances at $55/st.

— Andrew Moore

Daily CSAPR allowance assessments, Sep 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, Sep 12

	$/allowance	Change	$/st
SO2 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, Sep 11 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	2.70	0	Dec13	1.97	0
Dec13 V11	2.70	0	Dec14	1.97	0
Dec13 V12	2.70	0			
Dec13 V13	2.70	75			
Dec14 V10	2.70	0			
Dec14 V11	2.70	0			
Dec14 V12	2.70	0			
Dec14 V13	2.77	0			
Dec15 V10	2.70	0			
Dec15 V11	2.70	0			
Dec15 V12	2.70	0			
Dec15 V13	2.77	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.

REC MARKETS

New Jersey SREC prices rise on supply news

New Jersey solar renewable energy certificate prices increased this week from $125-$131 to $135-$138.

The jump followed the release of monthly solar installation figures by the Board of Public Utilities, which showed a significant drop in August.

There were 8.4 MW installed in August, down from 11.5 MW in July and well-below historical averages. In August 2012, for example, New Jersey saw 23.3 MW installed.

The August installation figures are in line with estimates of how much solar can be added each month and for the market to still return to undersupply in the foreseeable future.

Even though near-term SREC requirements will be easily met, slower installation rates make it possible for demand to eventually catch up. The BPU forecasts compliance year 2015-16 as balanced under a low-growth scenario. That marks a stark turnaround. In 2012-13, supply is estimated to be 2.3 times greater than demand.

Elsewhere, New England Class I renewable energy certificates are trading close to their respective alternative compliance payments, continuing a persistent trend.

As is the case in New England, markets in which supply falls far short of demand see REC prices increase until just below the ACP. Compliance entities will presumably be willing to pay as much as the penalty fee to obtain a REC.

Massachusetts Class I RECs have been flush against the ACP since September 2012. The ACP was $64.02 in 2012 and is $65.27 in 2013. Connecticut Class I RECs hit the ACP of $55 in January 2013, and have remained there ever since. These are the two most liquid REC products in the region.

Without room to grow, Class I REC prices will eventually go down. It is unknown when this might happen; the timing depends upon renewable developers being able to bring new projects online.

Certainty over price direction sparks the question whether traders can take advantage. Is this scenario ripe for someone to "short" the market?

To short the market, a trader would first agree to sell RECs to be delivered at a later date. The seller is considered short because he does not own the RECs and must acquire them to cover his position.

For the strategy to succeed, spot prices must fall, allowing the trader to purchase RECs for less than the amount he will receive through the forward contract. The difference equals profit.

At first glance, the situation in New England appears ideal for short selling to occur. The spot market is bound to see REC prices decline.

But in practice, the strategy is more difficult because it depends upon sufficient liquidity. The short seller must find a buyer on both legs of the transaction.

With respect to the forward contract, the buyer and short seller need to agree to acceptable terms, including price. Striking a deal is made easier if the buyer feels as motivated as the short seller to strike a deal.

For buyers, a forward contract minimizes the risk of spot prices increasing. That benefit is weighed against lost opportunities were spot prices to decrease instead.

The structure of the REC market factors into this calculus, lessening the appeal for buyers to enter into forward contracts.

For one, the maximum amount REC prices cost is finite. The worst case scenario is for a buyer to pay the equivalent of the ACP. In that sense, the ACP is a de facto price ceiling and serves the same role as a cost-free call option.

Another characteristic to consider is the REC market's binary nature. When the market is undersupplied, prices are close to the ACP. When the market is oversupplied, prices are very low.

Buyers anticipate prices will swing from one extreme to another. In New England, there is an incentive for buyers to continue buying through the spot market and wait until prices fall hard.

Liquidity is also a challenge with respect to the second leg of the transaction. The short seller must fulfill a delivery obligation by acquiring RECs through the spot market. But finding enough RECs could be problematic.

The REC market sees bouts of illiquidity due to a lack of bids and offers, or a wide gap separating the two.

To minimize this risk, short sellers periodically enter the market and buy some RECs rather than leave a position totally uncovered until just before the delivery deadline.

The rules specific to New England prevent a short seller from hedging across multiple compliance periods. A REC must be retired the same year as generation, or else these RECs will be wiped from the system.

For example, a non-compliance entity cannot purchase a vintage 2013 REC and store it beyond the 2013 compliance year. That means vintage 2013 RECs cannot be used to cover a short position in 2014.

The banking rules increase the risks associated with short selling across years, perhaps by enough to narrow the time frame speculators will consider to the present compliance period.

— Geoffrey Craig

Renewable Energy Certificate Markets Sep 12 ($/MWh)

	Low	High	Mid
Class I/Tier I RECs*			
Connecticut	54.00	55.00	54.500
Maryland	13.40	13.60	13.500
Massachusetts	64.00	65.00	64.500
New Jersey	13.40	13.60	13.500
Ohio In-State	7.00	10.00	8.500
Pennsylvania	13.40	13.60	13.500
Texas	1.90	2.00	1.950
Solar RECs*			
Maryland	120.00	130.00	125.000
Massachusetts	240.00	260.00	250.000
New Jersey	135.00	138.00	136.500
Ohio In-State	40.00	50.00	45.000
Pennsylvania	15.00	20.00	17.500
California RPS*			
California Bundled REC (Bucket 1)	26.00	32.00	29.000
California Bundled REC (Bucket 2)	3.00	6.00	4.500
California Tradable REC (Bucket 3)	0.70	0.90	0.800
Voluntary RECs*			
National voluntary, any technology	1.00	1.10	1.050
National voluntary, wind	1.05	1.15	1.100

*Prices are for the value of the environment attribute of the renewable energy certificate only and do not include energy. Bundled transactions are normalized by subtracting the market price of electricity.

NEWS

O'Malia seeks to ease concerns over swap rules

A Commodity Futures Trading Commission member on Thursday sought to alleviate energy industry concerns that the agency would change swap-transaction reporting rules without public comment or a formal rulemaking.

Scott O'Malia, who held a Technology Advisory Committee meeting in Washington, said he wants an open and public discussion before any changes are made to CFTC rules governing swap-deal reporting for energy end-users.

He also said any changes to the reporting requirements would be made through a formal CFTC rulemaking process that requires a public comment period.

Energy groups had expressed concern that the commission could be changing reporting requirements without their participation. They outlined these concerns in a July letter after hearing about the CFTC's work with swap-data repositories to revamp the way data is submitted to the agency.

SDRs are currently operated by IntercontinentalExchange, CME Group and The Depository Trust & Clearing Corporation. They were set up to report swap transaction data to the public after the passage of the 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, in an effort to shed light on the over-the-counter swaps market.

O'Malia said the work being done to standardize data between SDRs and the commission would not affect end-user reporting requirements for swap transactions.

To further ease concerns, O'Malia pointed to the CFTC's Technology Committee website, where he said additional information regarding the process would be available to the public and end-users.

The CFTC, which is hoping to use swaps transaction data more effectively, has primarily been working with SDRs to standardize data fields and improve data quality. But it invited the energy industry groups to participate in the discussion after they raised concerns about the process.

With limited time, O'Malia only addressed the issues of concern in passing Thursday, but a source at the commission said the CFTC's Division of Market Oversight would coordinate with the energy trade groups to clear up any doubts they have about the standardization process.

In the meeting, O'Malia acknowledged that the letter submitted by energy groups "forced him to rethink" the process and said he wanted further participation from end-users to make standardization as transparent as possible.

"If we were going to make a requirement to change data fields we would have to do that through a rule change, which would require notice and comment," he said.

The letter was signed by the Natural Gas Supply Association, the American Public Power Association, the Edison Electric Institute, the Electric Power Supply Association and the National Rural Electric Cooperative Association.

The groups welcomed O'Malia's comments Thursday.

"We are pleased the CFTC is recognizing end-users as stakeholders in data collection and that they recognize the need for a transparent and orderly process when considering changes," said Jenny Fordham, NGSA's vice president for energy markets.

"We're looking forward to helping ensure processes that help the commission achieve its objective of well-functioning markets, and that are workable and well-understood by market participants," she said.

— Christopher Tremulis

65-Bcf storage build seen reflecting soft demand

Gas storage inventories rose by 65 Bcf last week, the Energy Information Administration said Thursday, an above-average build that several analysts attributed to a sharp drop in power-generation demand over the Labor Day weekend.

The injection, which lifted stocks to 3.253 Tcf for the week ending September 6, was in line with most analysts' expectations but was well above the 27 Bcf reported a year earlier and slightly higher than the five-year average of 62 Bcf.

The deficit to the year-ago inventory of 3.425 Tcf narrowed to 172 Bcf, or 5%, while the surplus to the five-year average of 3.207 Tcf inched up to 46 Bcf.

The injection was "more than temperature data alone implied, suggesting a significant drop in demand over the Labor Day holiday and possibly some loss of market share to cheaper coal in the competitive power utility sector," said analyst Tim Evans at Citi Futures Perspective.

Total US power demand dropped by about 1.1 Bcf/d last week from the prior week on a combination of mild weather and the holiday weekend, said Jeff Moore, an analyst at Platts' unit Bentek Energy. But he suggested that Northeast power demand might have been underestimated.

The East region's storage injection "came in lower than our estimates, even though sample injections increased along with a drop in power burn estimates. The sample injection increases mostly occurred in the Midwest, while Northeast facilities were pretty flat week-over-week," Moore said. "I think there is some level of underestimation in the Northeast power burn demand estimates, because you would expect injections to increase in line with the Midwest, but that wasn't the case."

Nationwide, the weather last week was 9% cooler than the same week of 2012 but 32% warmer than the five-year average, said analyst William Featherston at UBS. About 15% of cooling degree days remain in the injection season that ends October 31, noted Featherston, who predicted a 55-65 Bcf injection next week, compared with 2012's 67-Bcf build and the five-year average of 78 Bcf.

Analyst Teri Viswanath at BNP Paribas agreed, saying that "by next week, the population-weighted cooling degree days should realign with the 10-year normal, allowing injections to rise."

EIA reported a 49-Bcf injection in the East to 1.647 Tcf, compared with 1.826 Tcf a year ago; a 2-Bcf injection in the West to 507 Bcf, compared with 494 Bcf a year ago; and a 14-Bcf

injection in the producing region to 1.099 Tcf; compared with 1.106 Tcf a year ago.

Inventories now are 114 Bcf below the five-year average of 1.761 Tcf in the East, 54 Bcf above the five-year average of 453 Bcf in the West and 106 Bcf above the five-year average of 993 Bcf in the producing region.

— *Stephanie Seay*

Arizona scraps move to competitive market

The Arizona Corporation Commission unexpectedly halted its investigation into restructuring the state's retail market, partly over legal concerns.

Arizonans for Electric Choice & Competition said the group intends to continue pressing for retail competition in the state. "We regret the lack of openness in the ACC process that led to this decision," Stan Barnes, AECC president, said Thursday. "This discussion is not over, and we look forward to continuing to pursue a path that will lead to the opening of Arizona's electricity market to retail competition."

Besides leaving Arizona's wholesale and retail markets unchanged, the decision clears the way for retiring three units at a coal-fired plant in northwestern New Mexico.

"The commission's action is a positive development for the future of the Four Corners power plant," said Damon Gross, Arizona Public Service spokesman. "This clarity will allow APS and the other owners to move forward with the next steps."

After the ACC in May decided to consider restructuring the state's power market, APS put on hold its plans buy Southern California Edison's 739-MW stake in the 2,040 MW, coal-fired Four Corners plant.

Only one major issue – landing a new coal supply contract for the plant – remains to be tackled before the $294 million deal can close, Gross said. APS expects to complete the deal by the end of the year, he said.

Several New Mexico state representatives and senators from the Four Corners area had urged the ACC to end its investigation of competition because it was holding up action on the Four Corners plant. In an August 20 letter to the ACC, the San Juan County Commission said the investigation was the only issue holding up the deal and that a coal supply contract had been negotiated and was ready to be completed.

The other owners of Four Corners include Public Service Co. of New Mexico, Salt River Project, El Paso Electric and Tucson Electric Power.

During an early August conference call to discuss quarterly earning, Pinnacle West CFO James Hatfield said the transaction could close within a month of the ACC making a decision on restructuring.

Once the deal is completed, APS plans to retire its other wholly owned units 1, 2 and 3, which have 560 MW of capacity, and install about $315 million in selective catalytic reduction equipment on the plant's two remaining units by 2018. The plan has been approved by the Environmental Protection Agency as a way to bring the Four Corners plant in compliance with regional haze rules.

Meanwhile, Arizona's on-again, off-again flirtation with competition has ended in defeat for independent power suppliers. In 2002, a few months before APS and Tucson Electric Power were set to divest their generating assets as part of a move to a competitive market, the ACC halted the effort because of the Western energy crisis.

However, the ACC in May voted to re-examine the possibility, partly because of their support for competition. The ACC took comments in the case and was expected to hold hearings on the issue later this month and in October. During a Wednesday open meeting, however, with nothing on the agenda about the investigation into retail competition, the ACC went into executive session. When the commissioners emerged from the closed-door session, they decided to halt the investigation.

ACC Chairman Bob Stump said he supported competition, but that restructuring faced too many legal hurdles, according to a report in the *Arizona Republic*. An ACC spokeswoman was unable to comment on the decision by presstime.

Groups and businesses like Ambit Holdings, Noble Energy Solutions, NRG Energy, the National Energy Marketers Association, the Retail Energy Supply Association and Wal-Mart were urging the ACC to move the state toward retail competition.

In contrast, utilities, AARP, scores of individuals and many businesses opposed deregulation, arguing that it was risky and potentially expensive.

A competitive market faced key legal issues, partly because the ACC's responsibilities are outlined in the state Constitution, according to a Wednesday filing with the commission by a lawyer representing the Arizona Investment Council.. The attorney argued that the ACC must set utility rates, not competitive markets.

— *Ethan Howland*

California utilities seeking supplies

Southern California Edison Thursday issued a solicitation to begin the process of replacing coastal power plants that are set to be retired because they use ocean water for cooling.

SoCal Ed will consider a mix of resources, including natural gas-fired generation, renewables, energy efficiency and energy storage. "This is the first time that SCE will launch a solicitation of this type," said Steven Eisenberg, vice president of energy contracts for the utility. "It's meaningful because it compares all resources at the same time in an 'apples to apples' situation."

SoCal Ed is seeking 1,400 MW to 1,800 MW of capacity in the West Los Angeles section of the Los Angeles basin local reliability area to meet long-term local capacity requirements by 2021. SoCal Ed also intends to procure 215 MW to 290 MW in the Moorpark section of the Big Creek/Ventura local reliability area.

The California Public Utilities Commission approved the procurement targets in February. For the Los Angeles basin, the PUC directed SoCal Ed to acquire at least 1000 MW, but no more than 1,200 MW, of natural gas-fired resources. At least 50 MW must be from energy storage and at least 150 MW must be

so-called preferred resources like renewables, energy efficiency and storage. The PUC said SoCal Ed could buy up to an additional 600 MW of preferred resources.

The utility will also continue its effort to negotiate cost-of-service bilateral contracts with the current owners of once-through cooling units that are slated to be retired under state law.

In a solicitation plan filed with the PUC, SoCal Ed notes that there are various challenges to building gas-fired power plants around Los Angeles, including a lack of air emission reduction credits and siting issues.

SoCal Ed will consider power purchase agreements of up to 20 years. The utility intends to be flexible with online dates to accommodate staggered delivery periods and the possible need to secure new resources as soon as 2015 because of the decision to retire the 2,150-MW San Onofre nuclear plant, according to the plan filed with the PUC.

Bidders must submit notices that they intend to make offers by December 2 and indicative offers are due December 16. SoCal Ed intends to complete contract negotiations by May 29 before submitting the PPAs to the PUC for approval.

The solicitation is online at: https://www.sce.com/wps/portal/home/procurement. For more information, email LCR.RFO@sce.com or contact Gene Lee at (626) 302-3081 or Jesse Bryson at (626) 302-3297.

The utility hired Sedway Consulting to act as the independent evaluator for the solicitation process.

Farther north in California, the Palo Alto municipal utility issued a request for proposals for renewable generation to help the city meet its 33%-by-2015 renewable energy goal. The city plans to sign at least one power purchase agreement ranging in length from five to 30 years, according to the RFP issued Tuesday.

Proposed projects must supply from 20,000 MWh/year to no more than 60,000 MWh/year. The city did not put a limit on how much power it would contract for.

Palo Alto prefers projects in California, but will consider resources with a delivery point inside the Western Electricity Coordinating Council footprint. Projects must be in operation between January 1 and December 31, 2016.

The city will hold a pre-bid conference call September 25. Bids are due October 9. The utility expects to name the final bidders a month later.

Palo Alto has a peak demand of 180 MW and an annual energy demand of 1 million MWh.

The RFP is online at: http://www.cityofpaloalto.org/gov/depts/asd/solicitations.asp. For more information, contact: carolynn.bissett@cityofpaloalto.org, contract administrator, or james.stack@cityofpaloalto.org, project manager.

In mid-June, the Palo Alto City Council approved three solar photovoltaic PPAs related to projects totaling 80 MW. Under the contracts, Silverado Power will sell the output from its planned 40-MW Elevation and 20-MW Western Antelope Blue Sky projects over 30 years for $68.77/MWh, according to the city. Atlantic Power's Ridgeline Energy will sell electricity from its proposed 20-MW Frontier project over 30 years for $69/MWh. Palo Alto expects the projects to be operating in 2016.

Palo Alto expects the projects to produce about 182,500 MWh/year, providing about 18% of the city's electric needs. Once operating, almost half of Palo Alto's electricity will come from renewable sources.

The contracts grew out of a solicitation for renewable energy issued in the fall last year. Palo Alto received 92 offers.

— Ethan Howland

Gas-fired generation to grow 1/3 by 2035: ICF

Gas demand for power generation will grow by about one-third by 2035, with much of that increase driven by the need to use gas as a backstop to renewables, an analyst with ICF International said Wednesday.

"The percentage of power generation being met by natural gas is growing over time. A part of that demand is for the firming up of variable generation, which is to say wind and solar," ICF Vice President Harry Vidas said in an interview.

Vidas, who spoke earlier this week at a meeting of the Wyoming Infrastructure Authority in Jackson, said power generated by renewable sources can "have the characteristics of being needed sometimes very unexpectedly, with very sharp increases or decreases in demand for throughout the day."

He predicted that the percentage of total US electricity fueled by gas would increase to 40% in 2035 from about 30% in 2012, despite a short-term decline as gas prices begin to recover from historic lows. The Energy Information Administration this week predicted that gas used for electric generation will go from 25 Bcf/d in 2012 to 22.1 Bcf/d in 2013 and 21.6 Bcf/d in 2014.

But Vidas said several factors, including the early retirement of coal-fired plants and the planned retirements of nuclear capacity after 2030, would lead to increased use of gas for power generation starting later this decade.

Currently, gas-fired plants produce about 1,000 terawatt hours per year, and he said that is expected to double by 2035.

Vidas said that as gas use as a backup to renewable generation increases, the gas and electric industries will have to work together more closely to ensure that gas is available when and where it is needed to keep the lights on.

"You have the power-generation sector requiring more gas and requiring it on a more difficult-to-serve basis, which is to say requiring it with more ups and downs in demand," he explained.

In absolute terms, coal will remain the dominant fuel for power over the next 20 years even though its share of the total generation pie will shrink, Vidas said.

"It won't be a substantial amount, but it'll be some decline, mostly due to the pricing of natural gas versus coal; it's less expensive to build a new gas-fired power plant. The environmental regulations just build on top of that," he said.

"We're anticipating very few new coal plants and we're expecting the retirements of some existing coal plants, but the bulk of that generation will stay online," Vidas added.

As renewable sources continue to play a bigger part of the generation mix, "the renewables are going to take a certain market share for power generation, and that's going to decrease the

generation from coal or gas," he said.

However, as a result of the growing use of renewables, the way gas is dispatched to power plants is bound to undergo a fundamental change.

"Because of the role of gas is going to play in firming intermittent generation, it's going to mean that the gas that's demanded for that service is going to vary hour by hour and even minute to minute. The ability of the gas industry to meet those swings in demand requires additional infrastructure, and that's part of the challenge," Vidas said.

And that challenge is not simply a technical one that could be met with just the construction of more pipeline or storage capacity or the onsite storage of an alternative fuel such as oil. "All of those technologies can be used. It's just a question of: when and where will they be needed and can they be built in time?"

Power generators, independent system operators and regional transmission organizations have been working with gas pipeline companies to address these questions, Vidas noted.

Independent system operators and regional transmission organizations "have been commissioning different studies to look at this question, with the idea of trying to determine how adequate the current infrastructure is to meet the demand, and what additional infrastructure would be needed over time to provide the gas service," he said.

In addition, several studies have been launched to determine what needs to done to reorganize the electric markets to ensure they can take advantage of increased gas infrastructure, Vidas said.

— Jim Magill

Study looks at water use by power plants

Coal, nuclear and natural gas power plants account for 41% of freshwater withdrawals in the US, roughly 137.4 billion gallons of water per day, figures that are only expected to increase in coming years, according to a report released Thursday.

The report conducted by Synapse Energy Economics and funded by the Civil Society Institute, a Massachusetts-based think tank, claims that the power sector's water needs could be constrained by a variety of factors, including climate change, population growth and increased demand, particularly water needed for oil and gas fracking operations.

Melissa Whited, a Synapse associate and one of the study's authors, said the water requirements of coal, nuclear and gas power plants "are enormous and leave it vulnerable to droughts and heat waves."

"Going forward, our water resources will be further squeezed by population growth coupled with the impacts of climate change," Whited said. "The massive water use of coal, nuclear, and natural gas generators will be increasingly challenged, particularly when alternatives that require little water, such as wind and solar, are readily available."

Power plants withdraw water from lakes, rivers and estuaries for once-through or recirculating cooling systems.

Coal plants withdraw more than 85 billion gallons of freshwater per day for their cooling systems, by far the most of any plant type, according to the report. Nuclear power plants withdraw nearly 45 billion gallons, while natural gas plants withdraw about 7.4 billion gallons, the report shows.

But water use by coal and natural gas plants will dramatically increase if plants install carbon capture and sequestration systems, technologies which are currently seen as cost prohibitive. CCS conversions would increase water consumption rates by 83% for existing coal plants due to increased fuel consumption needed and the increased water intensity of the process, according to Whited. CCS conversions would increase consumption by natural gas plants by 91%, according to the report.

"As water resources become scarcer in many parts of the country, this may limit the ability of plants with CCS to operate, particularly during heat waves or droughts," the report said.

Fracking operations use about 2 million to 6 million gallons of water per well, a small amount compared with the daily withdrawals of thermoelectric plants, but the use poses a high risk of pollution, the report notes.

Water consumption for natural gas from fracking ranges from 0.6 to 1.8 gallons of water per MMBtu of gas and as much as 2 gallons of water per MMBtu may be needed for processing and transport, the report claims.

The report makes a series of recommendations including more long-term planning for water risks and a push for more renewable energy sources, particularly solar and wind.

"They solve pollution problems and water problems at once," said Frank Ackerman, an environmental economist with Synapse and a co-author of the report.

Grant Smith, a senior energy analyst with CSI, said that the report showed a clear need for "less thirsty" sources of power.

"There are energy sources available to us that are not water intensive," he said. "It is time for America to be decisive, to choose an energy path that is sustainable and that protects public health."

— Brian Scheid

FERC chief weighs in on threats to grid

The chairman of the Federal Energy Regulatory Commission on Thursday raised the possibility of isolating regions of the electric grid in the event of a serious cybersecurity event or natural disaster, calling attacks on key transmission substations one of the biggest risks the grid faces.

"[W]e do need to start thinking about having regional disconnects where we can isolate regions of the country" ... in the event of outages, Jon Wellinghoff said at an Environmental and Energy Study Institute forum in Washington.

He said that, in the event of a natural disaster or a physical attack against grid infrastructure, "we need to ensure that the grid can be stabilized."

Wellinghoff in particular noted that each of the three US interconnections — Eastern, Western and Texas — are vulnerable because their operations hinge on a number of high-voltage transmission substations.

"So we need to do what we can to minimize those vulnerabilities by ensuring that we can isolate portions of each one of those interconnects," he said, adding that "there are physical security issues that certainly have to be dealt with. I think the biggest risk is potentially attacks on the system at those critical nodes."

— *Bobby McMahon*

Dominion to spend $4.6 bil on generation

Dominion will spend $4.6 billion on generation through 2018 and immediately begin the conversion of the 200 MW Bremo coal-fired plant to burn natural gas after receiving approval this week from Virginia regulators, Tom Farrell, chairman, president and CEO, sand during Barclays CEO Power-Energy conference.

The conversion of three coal-fired plants to burn biomass will be completed this year and work on the 1,300-MW Warren County gas-fired plant is on schedule, Farrell said.

Dominion is the fastest growing service territory of any size in the PJM Interconnection's footprint and it is facing a 3,800 MW generation gap over the next 12 years, Farrell said. The company has a future combined cycle plant planned to help make up the difference.

There could be capital expenditures in addition to the $4.6 billion that would be used to develop offshore wind generation, Farrell said. The company last week won a lease from the Department of Interior for 115,000 acres off the coast of Virginia to develop offshore wind. "But we'll see how this goes," Farrell said. Dominion has been working with the Department of Energy to install test turbines and its looking for grant money to help pay for the investment, he said.

"We've said all along with this project we are very interested in it, but it's going to have to get approved by our regulators so it's going to be part of our rate base. It will be a utility asset or it has less likelihood of being built," Farrell said.

Dominion also is pursuing a 1,300-MW gas-fired plant in Brunswick County near the North Carolina line. "It is going to replace capacity that's going to be lost when we close down coal plants in the far eastern part of the state because of the mercury rule," Farrell said.

Dominion expects to spend $3.2 billion on transmission through 2018. The company has eight transmission projects underway or under development.

"But there still is much more to be done. The difference between what we're working on now and what else needs to be done are very large projects that are going to take many years to complete," Farrell said.

Dominion submitted three proposals in response to PJM's competition for the Artificial Island project in New Jersey. It is one of 24 projects meant to address congestion in highly constrained locations within PJM's territory, Farrell said.

PJM is running a series of competitions for reliability, market efficiency, or public policy-related constraint areas, Farrell said.

"I don't know if we'll bid on all 24 of these projects. We will bid on many of these projects and we'll see how that goes, but none of that is in our capital expenditure plans, the $3.2 billion program. That would be additive growth capital," Farrell said.

The winner for the Artificial Island project will be announced in the first quarter of 2014, Farrell said.

Dominion's planned capital growth through 2018 is an average of $2.6 billion a year, which includes spending on transmission, generation and its gas businesses.

— *Mary Powers*

AEP to transfer Ohio generation by January 1

American Electric Power is on track to transfer some 7,800 MW of utility-owned generation assets in Ohio to an independent generation company by January 1, the company said Thursday.

There currently are no plans to sell the Ohio plants, despite a recent report to the contrary by Julien Dumoulin-Smith of UBS Investment Research, an AEP spokeswoman said.

"The Ohio generation fleet will be positioned for success," said Brian Tierney, executive vice president and CFO of AEP, at the Barclay's CEO Energy-Power conference in New York.

Tierney said his company is "focused on the corporate separation of our Ohio genertion assets," adding that company officials are trying to assign costs to AEP's competitive business "like an IPP [independent power producer] would be cost."

The corporate separation plan for the AEP Ohio business was approved last year by the Ohio Public Utilities Commission. AEP Ohio includes Ohio Power and Columbus Southern Power, which serve nearly 1.5 million customers. The plan is part of AEP Ohio's transition to full competition by 2015.

Tierney noted the Federal Energy Regulatory Commission approved the Ohio corporate separation plan on April 29.

AEP spokeswoman Melissa McHenry, meanwhile, denied a UBS report from late August that AEP may be preparing to divest its Ohio generation holdings. Demoulin-Smith estimated that the Ohio assets are worth $2.1 billion after $1.2 billion in debt and suggested the most likely purchaser would be Dynegy.

"Our goal is to transfer the assets by the end of the year" to a genco, she said. "We continue to stay focused on working on the transfer of those assets."

Included in the Ohio assets are about 5,300 MW of coal-fired generation and 2,500 MW of natural gas-fired capacity, according to McHenry.

She said the company still is awaiting three orders from FERC related to AEP's applications to terminate the interconnection agreement that exists among AEP's utilities in the Midwest; approval of a new power coordination agreement among Appalachian Power, Kentucky Power and Indiana Michigan Power; and other tariff filings related to corporate separation. Those orders are expected by year's end, she said.

Tierney also said AEP expects a final order by the Kentucky Public Service Commission within two months on Kentucky Power's request to purchase 50%, about 780 MW, of the 1,560-MW Mitchell baseload coal plant along the Ohio River near Moundsville, West Virginia, from Ohio Power. "We have a non-unanimous settlement" filed with the PSC in support of the

Mitchell plant transfer, he said.

On July 30, however, the Virginia Corporation Commission rejected APCo's plan to buy the other 50% interest in Mitchell. APCo also is an AEP subsidiary. The commission did endorse APCo's application to acquire a portion of the Amos baseload coal plant near Winfield, West Virginia, from Ohio Power. "We think there's very strong support for the transfer of Amos into APCo," Tierney said.

On another issue, Tierney said AEP continues to place a high priority on its transmission business. The company has formed independent transmission companies, or transcos, in most of the 11 states where it operates.

Tierney said AEP invested just $50 million in transcos in 2010. Between 2010 and 2015, it anticipates investing $2.8 billion in that business.

— Bob Matyi

Duke units to boost wholesale sales: CEO

Duke Energy's utility subsidiaries in North Carolina, South Carolina and Florida will increase their wholesale power sales over the next few years as the needs of existing and new wholesale customers grow, Duke President and CEO Lynn Good said Thursday.

"We have signed contracts with wholesale customers that have step-increases in the number of megawatts sold," Good said during a presentation at the 2013 Barclays Capital CEO Energy-Power Conference in New York City.

She did not provide specifics, but Duke Energy Progress has said that its 20-year contract with North Carolina Electric Membership Corp., the electric cooperative group, is expected to grow from about 1,000 MW in 2013 to about 2,000 MW by 2032. Also, Duke Energy Carolinas' 18-year contract with Central Electric Membership Corp., NCEMC's counterpart in South Carolina, is expected to grow from 115 MW this year to 1,000 MW by 2019.

Good also said that Duke Energy Florida plans to decide in early 2014 whether to "self-build" 1,150 MW of mostly peaking capacity, buy existing peaking units and/or enter into long-term power purchase agreements for peaking power it expects to need starting in the 2015-17 period.

RFP will soon be issued

Within the next 30 days, DEF plans to issue a request for proposals for possible alternatives to self-building 1,800-MW of natural gas-fired combined-cycle the utility expects to need starting in 2018. The winner of the RFP will be selected by late 2014, Good said, Notably, Good did not commit DEF to issuing an RFP for the utility's incremental needs in the 2015-17 period. Last month, Florida Public Counsel J.R. Kelly said he believes the utility should be required to issue an RFP to prove to state regulators' satisfaction that it fully vetted its power-supply options and chose the best and least-cost alternative.

Under a far-reaching settlement agreement DEF, the Office of Public Counsel and other parties unveiled on August 1, the utility agreed to cancel the engineering-procurement-construction contract for its 2,200-MW Levy County nuclear project and retire its two Crystal River coal units, and won Office of Public Counsel backing for DEF's plan to add 1,150 MW of peaking capacity in the 2015-17 period and 1,800 MW of baseload/intermediate capacity in 2018.

Good also said during her presentation that Duke believes it has "a very strong case" regarding Duke Energy Ohio's September 2012 request to receive a cost-based capacity charge similar to what the commission already has approved for American Electric Power's Ohio Power and Columbus Southern Power subsidiaries.

DEO and the AEP subsidiaries are fixed resource requirement utilities under PJM's reliability pricing model capacity market, a designation that enables state regulators to set their capacity charges.

Good said Duke expects the PUC to rule on DEO's request in the fourth quarter. Asked by an energy analyst whether Duke expects to be able to maintain its projected 4-to-6%/year earnings growth rate if the PUC rejects DEO's request, Good said, "We believe we can achieve [that growth rate] with Ohio or without Ohio"—a reference to Duke's suggestion it may seek to divest its DEO-related fleet if it cannot receive capacity charges to help cover their costs.

On still other matters, Good said DEC "remains in talks" with Santee Cooper about the possibility of acquiring a 10% ownership interest in the two-unit, 2,200-MW expansion of the V.C. Summer nuclear station in Fairfield County, South Carolina. Santee Cooper holds a 45% stake in the expansion project, but has said it hopes to roughly halve that stake.

— Housley Carr

FirstEnergy solicits Ohio RECs, SRECs

FirstEnergy wants to buy renewable energy certificates and solar renewable energy certificates on behalf of its Ohio utilities, the company said Thursday.

The utilities are Ohio Edison, Cleveland Electric Illuminating and Toledo Edison. The RECs and SRECs must be generated between January 1, 2011 and December 31, 2013. FirstEnergy is seeking "in-state" and "all-state" RECs and SRECs.

Ohio's alternative energy law requires one-half of the mandate be met through eligible facilities located inside the state. The remainder can come from eligible facilities in Ohio or an adjacent state. The rules have given rise to two categories of RECs and SRECs: in-state and all-state.

Specifically, FirstEnergy wants 100 in-state SRECs, 6,500 all-state SRECs, 120,000 in-state RECs and 145,000 all-state RECs.

Navigant Consultant is running the procurement. The RFP manager is Dan Bradley. His contact information is 516-876-4036 or rfp@navigant.com. The RFP has its own website: www.firstenergycorp.com/OH2013RECRFP.

A webinar discussing the RFP will be held September 19. Proposals are due October 14.

— Geoffrey Craig

Retirement not likely to lift ...from page 1

MWh to $97/MWh.

Prices for both packages have traded around those levels since August 28, moving up to $101.25/MWh for the 2015 package and settling back to $98.25/MWh on September 9. Pricing on the 2014 package was still at its recent high of $97.50/MWh on September 9.

The forward prices suggest that some generators, particularly combined-cycle gas turbines, may be able to step in to replace some of the baseload power that goes away after Vermont Yankee is retired, but analysts say that the environment for generators in New England is likely to get worse before it gets better.

"The market will be tighter, but not for good reasons," analyst Paul Patterson at Glenrock Associates said, referring to the declining energy and capacity prices in ISO-New England. "There might be more food to eat because someone starved, but that doesn't mean there is a banquet out there."

Vermont Yankee would be in the starved category. It had $39 million of EBITDA and $19 million of free cash flow in 2012, but analyst Julien Dumoulin-Smith at UBS forecasts that the plant is looking at $20 million of EBITDA in 2013 and $4 million in 2014, then growing losses of $12 million, $24 million and $35 million in the next three years. He estimates that Vermont Yankee's free cash flow would turns negative even sooner, sinking to $31 million in 2013, dropping to $50 million in 2015 and a $63 million loss in 2017.

Nonetheless, Entergy could be one of the near-term beneficiaries of Vermont Yankee's closure. Entergy owns two other power plants in ISO-NE: the 688-MW Pilgrim nuclear plant in Plymouth, Massachusetts, and a 583-MW combined-cycle gas turbine in Johnston, Rhode Island.

Vermont Yankee's capacity factor so far this year is about 88% and Pilgrim's is about 71%. The Rhode Island plant's capacity factor was about 57% through the end of July.

Vermont Yankee's absence could leave room for both plants to run at higher capacity factors, particularly Pilgrim, which has been offline in both August and September to address a steam leak and an electrical fault, along with a 45-day refueling outage earlier in the year.

But although the closure of Vermont Yankee could move the dispatch of other plants up a little, Vermont Yankee is just not big enough to have a large effect on the economics in ISO-NE. The 605-MW plant represents 25% of New England's nuclear plants, but only about 13% of the region's nuclear capacity and 1.7% of the total capacity of 34,473 MW.

Furthermore, as many analysts are quick to point out, ISO-NE has as much as 5 GW or 6 GW of excess capacity, and that is reflected in the low capacity prices, which are supposed to provide an incentive for developers to build new power plants.

ISO-NE's seventh forward capacity auction, which closed in February for the 2016-17 delivery year, cleared at the floor price of $3.15/kW-month and resulted in a prorated price of $2.74/kW-month.

ISO-NE's forward capacity auction closes when bidding hits the FCA's floor price. All remaining capacity in the auction clears at that price, even the excess capacity. So rather than paying for capacity it does not need, ISO-NE offers bidders the option of taking the clearing price for fewer megawatts or supplying their full bid of megawatts for the prorated price.

In its FCA #7, ISO-NE required 32,968 MW and 36,220 MW cleared, resulting in an excess of 3,252 MW. The acquired capacity included 31,641 MW of generation, 2,748 MW of demand response resources, and 1,830 MW of imports.

The results of the previous FCA provide a telling sign of the possible effect of Vermont Yankee on the New England market. Vermont Yankee bid and cleared the most recent auction, but did not clear the previous auction. Nonetheless, FCA #6 resulted in a prorated price of $3.13/kW-month and 2,853 MW of excess capacity. The prorated price for FCA #6 is still below the floor price of FCA #7, and the difference in excess capacity of the two auctions, 399 MW, is less than Vermont Yankee's capacity of 605 MW.

The small effect of Vermont Yankee's absence from FCA #6 is also reflected in ISO-NE's reaction to Entergy's announcement of the nuclear plant's closure. The ISO said its most recent studies show that the regional grid could be operated reliably without Vermont Yankee because of new resources acquired through the FCA, completion of transmission upgrades, and the demand-reducing effects of energy efficiency measures.

ISO-NE declined to discuss the specific transmission projects referenced in its statement, but did say the ISO worked with transmission owners in Massachusetts, New Hampshire and Vermont to identify reliability needs.

In terms of new resources, FCA #7 was the first auction to clear a significant amount of new capacity. The biggest part of that increase came from Footprint Power's gas-fired 674-MW Salem Harbor project in Massachusetts.

That region of the ISO, NEMA/Boston, was the only one where prices separated from the rest of the ISO.

The auction closed in the first round when the new resource submitted a bid to "delist" or withdraw from the auction. That bid was not accepted because the region needed the capacity, and the auction closed at $14.99/kW-month. Existing resources in NEMA/Boston will be paid $6.66/kW-month.

In addition to the mitigating effects of transmission upgrades and new generation resources, ISO-NE in a December 2012 report estimated that energy efficiency measures in the region would result in a 1,343-GWh reduction in electrical

output per year, resulting in 0% growth in average electricity consumption and an average reduction of 206 MW from peak demand each year.

ISO-NE expects to update its analysis of the effect of Vermont Yankee's closure in a report scheduled for release 90 days from Entergy's announcement.

Not only are capacity prices in ISO-NE low, they could decline even further. Under an order from the Federal Energy Regulatory Commission, in the next capacity auction, FCA #8, the floor price will go away. Analysts generally expect that to result in lower clearing prices.

UBS' Dumoulin-Smith estimates a price of 99 cents/kW-month in the next auction, or possibly even lower. Pricing could recover in the subsequent auction, for 2018-19, with some assets leaving the market at $1.67/kW-month, he said.

With the elimination of the floor price in the next auction, the cratering of prices could result in a wave of retirements, particularly oil-fired capacity. He has estimated that as much as 6 GW could be at risk of retirement.

Dumoulin-Smith also thinks Entergy's Pilgrim plant, as a single unit, higher-cost nuclear plant, is vulnerable, though not in the time frame of the next FCA but in subsequent auctions.

Entergy spokesman Terry Young disagreed with that assessment, saying Pilgrim's larger size makes its economics very different than Vermont Yankee's. In addition, Pilgrim is in a higher-priced zone in ISO-NE, Young said.

George Katsigiannakis, a principal with ICF International, also sees the market going lower in ISO-NE's next capacity auction, but not as low as Dumoulin-Smith estimates. Capacity prices will be depressed for the next three or four auctions, but will start to rise around 2020 as a variety of factors converge, creating the need for new capacity, Katsigiannakis said.

In addition to eliminating the floor price, ISO-NE is also reforming the FCA by instituting a pay for performance measure meant to ensure generators fulfill their capacity obligations. In addition, as the market in New York tightens the level of imports, which have been running at about 2,000 MW a year, they will likely decline.

The key will be how much capacity is going to retire and how fast that will happen, Katsigiannakis said. The delisting of retiring units will set the price in the next auction, but overall, he said, prices are not high enough to encourage new generation.

In the PJM Interconnection region, Panda Energy is building the 829-MW Liberty project in Pennsylvania, despite low capacity pricing.

Panda says low local gas prices, substantially lower than Henry Hub prices, justify the investment. "But in New England, gas basis differential does not exist," Katsigiannakis said.

Even though gas prices have been declining because of the flood of production from the Marcellus shale region, New England has seen less effect than other areas in the Northeast because of limited gas pipeline capacity to the region.

The full-year 2015 package for Algonquin City-gates was $6.04/MMBtu on September 11, while the same package for Henry Hub was $4.08/MMBtu. At the Tetco-M3 hub in eastern Pennsylvania gas forwards were at $3.89/MMBtu on September 11.

Unlike forward power prices, natural gas forward prices did not bump up as much as power prices on Entergy's announcement, despite the fact that any new thermal generation that is going to be built in New England will very likely be gas-fired.

Forward prices for the full-year Algonquin City-gates 2015 package moved up to $6.12/MBtu on August 28, from $6.03/MMBtu on the previous day, a 1.5% move. Forward power prices for a comparable package moved up about 9%.

In the short term, some incumbent generators in New England, particularly peaking plants, could be the beneficiaries of the region's pipeline constraints.

In the longer term, however, the supply of gas into New England, which heavily relies on the fuel for winter heating, has been a hotly debatedtopic. Generators generally rely on interruptible supplies and are reluctant to enter into firm contracts without offsetting electricity offtake contracts. But those issues, as well as the physical constraints, may ease over the next three or four years because of new planned gas pipelines.

Spectra Energy's Algonquin Incremental Market project would add 433,000 dekatherms/day to an existing pipeline that runs from New York to Massachusetts. Spectra says it already has agreements in place for anchor shippers and expects the line to enter service in 2016.

Kinder Morgan's Northeast Expansion project would link Marcellus supplies with the Iroquois Gas Transmission system for deliveries into New England by 2017 or 2018.

Kinder Morgan's Tennessee Gas Pipeline is also working on a Connecticut expansion project that would add 72,100 Dt/d into the Iroquois line and has an in-service date of November 2016.

Williams and Cabot Oil & Gas also have proposed a pipeline, called Constitution, that would bring an additional 650,000 Dt/day from the Marcellus to the Iroquois pipeline by 2015.

And Portland Natural Gas Transmission System's proposed Continent to Coast Expansion project would access supplies from TransCanada and connect with other New England systems to bring 130,000 to 180,000 Dt/day into the region.

"Everybody is seeing an end game" for constraint problems that have dogged the New England gas market, Maureen Smith, a member of Orr & Reno's energy and environmental practice, said. Permits are still needed for the projects, but it looks like regulators in the region see the need, she said.

While bringing more gas into New England could benefit retail customers – a recent report from Black & Veatch pegged the benefits for electric customers at as much as $281 million – it might not be such good news for generators.The expansions could lower gas prices in the region and further erode regional power prices and spark spreads, warned Dumoulin-Smith. That could be negative for generators in general and disproportionately negative for nuclear generators, he said.

— Peter Maloney

MISO, SPP clash on seams issues *...from page 1*

SPP officials said that they have concerns about how MISO handles calculations for imports and exports, the high level of unreported flows on MISO-SPP interfaces and how significant amounts of MISO market flows are designated as non-curtailable under the North American Electric Reliability Corporation's Interchange Dispatch Calculator. SPP has said in earlier presentations that it loses about 35% of its curtailment management capability due to unreported or unaccounted for flows and that its analysis has shown a strong correlation between unreported flows and MISO market flows.

"There's flow out there that MISO is putting on the system that we're not allowed to capture," an SPP official said at Thursday's meeting.

SPP has proposed changes to MISO's calculation methodology. But MISO officials said they do not believe the proposed changes would resolve the issue of unaccounted flows on SPP interfaces.

MISO officials said they are open to further discussion of the issue, but also said that they are not convinced that their current methodology is causing problems.

There is "no proof that unaccounted flows are MISO flows," MISO said in its presentation. "[We] have not identified the key drivers behind unaccounted flows. [We] have not identified any solutions to mitigate these unaccounted flows."

Another point of contention at Thursday's meeting was how to treat flows between the traditional MISO footprint and the integrating MISO South region. This topic is at issue in an ongoing dispute before the U.S. Court of Appeals for the District of Columbia Circuit (Southwest Power Pool, Inc. v. Federal Energy Regulatory Commission, 12-1158).

SPP officials said Thursday that they believe that MISO should compensate SPP for "all intentional, unscheduled flows imposed on SPP's system" when MISO exceeds its 1,000 MW contract path for capacity to the Entergy system.

"After December 19, 2013 up to 2,000 MW is expected to be transferred between MISO Midwest and MISO South that will no longer require a study of the impact to neighboring systems. Without [the Operations Reliability Coordination Agreement limits], MISO's studies indicate as much as 5,000 MW could be transferred between MISO Midwest and MISO South. If there are reliability or congestion impacts from these flows, SPP is expected to pay for them," SPP said in its presentation.

MISO officials noted that FERC has ruled that in addition to its contract path for 1,000 MW of capacity between its traditional footprint and the Entergy system, MISO should also be able to share SPP's 1,000 MW contract path to Entergy. Additionally, MISO said in its presentation that it does not believe that these flows will impose costs on SPP or require transmission investment.

The grid operators also sparred over the implementation of market-to-market coordination.

As part of its approval of SPP's proposal to implement a day-ahead market, FERC instructed SPP to work with MISO to develop market-to-market procedures to efficiently manage congestion across the seams. SPP filed a proposal for market-to-market coordination with FERC in June (Docket No. ER13-1864).

SPP's proposal included a provision that both ISOs must agree before a new flowgate can be added. These flowgates represent interface boundaries that may experience significant congestion and are managed through market-to-market coordination.

"Without this requirement that both parties coordinate in advance of the addition of [market-to-market] flowgates, operating practices by one party, such as outage scheduling, can have a substantial detrimental impact to the other party by creating revenue adequacy shortfalls in the impact party's [financial transmission rights market," SPP said in its June filing.

This issue has been a point of contention recently between MISO and the PJM Interconnection, with PJM arguing that MISO's short outage scheduling deadlines are leading to revenue adequacy problems in PJM's FTR market.

But at Thursday's meeting MISO objected to SPP's proposal, arguing that it gives the ISOs unilateral authority to reject potential flowgates that otherwise meet the criteria for creation.

"MISO believes that [market-to-market] results in the use of the most efficient and least cost generation to manage congestion and should be used whenever possible," MISO said in a presentation. "[Market-to-market] is always the correct answer for customers in the combined footprint and its use should not be limited as a way to improve FTR funding."

— Juliana Brint

PUCT directs ERCOT to study pricing *...from page 1*

directive for ERCOT to look into bigger issues related to "interim solution B+," which include the operating reserve demand curve used, the minimum contingency level and value of lost load. The commission asked ERCOT to use the information to run scenarios.

VOLL is the value that represents a customer's willingness to pay for reliable electricity service, according to the report. It is generally measured in dollars per MWh.

The process could be done in three to four weeks, an ERCOT staff member said.

The PUC also asked ERCOT to provide update at each commission meeting throughout the process.

"We understand it may not be perfect. You're just starting out," PUC Chairwoman Donna Nelson said. "It'll give us additional information."

ERCOT is currently drafting a Nodal Protocol Revision Request on "interim solution B+" on PUC directive.

While ERCOT still has a lot of work to do on it, the protocol should be out late next week, an ERCOT staff member said, adding the timing is in line with the three weeks ERCOT original said the document could take.

Separately, the PUC asked its staff to open a new docket on co-optimization in general and its likely costs and benefit to see if the method is a "go or no go," Nelson said.

"There's a lot more improvement that can be made," PUC Commission Kenneth Anderson said.

The commission also requested The Brattle Group move forward on analysis with the ERCOT and the PUC staffs.

Market participants have a deadline of Sept. 23 to file comments on the additional data to be filed to the PUC. The reports and comments will be discussed during an October 8 PUC workshop dedicated to resource adequacy.

— Kassia Micek

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