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Friday, July 12, 2013

Maryland REC market may lure MISO wind

ANALYSIS The Maryland Tier I renewable energy certificate market presents an attractive destination for wind farms located in Midcontinent Independent System Operator's footprint.

It is a new scenario that capitalizes on the growing premium for Maryland Tier I RECs compared with the alternatives available to MISO-based wind farms.

Apart from long-term power purchase agreements, these wind farms can sell their RECs on the spot market in states like Michigan, Minnesota, Illinois and Wisconsin, or in the voluntary market. But prices are low, hovering around one dollar or below.

Maryland, New Jersey and Pennsylvania, on the other hand, have seen RECs increase in value over the last 12 months, with quotes now in the $7-$8 range.

It is common for REC prices to differ across products due to

(continued on page 19)

Gas demand up as nuclear outages, heat coincide

GENERATION An unplanned outage that began Wednesday at Pacific Gas and Electric's Diablo Canyon nuclear plant in California is one of several nuclear maintenance issues nationwide that have boosted natural gas demand in markets already tight due to summer heat.

The 1,197-MW Diablo Canyon unit 2 outage brings with it associated gas demand that Platts unit Bentek Energy currently pegs at 284,000 Mcf/d.

Before the outage, Diablo Canyon's unit 1 had output at or near zero from June 27 to July 2 and operated at varying levels of capacity on surrounding days, according to Nuclear Regulatory Commission status reports. That came as the mercury touched above the 100-degree mark for several

(continued on page 20)

PJM panel rejects plan to cut long-term FTRs

MARKETS The PJM Interconnection's Market Implementation Committee on Thursday rejected a proposal to reduce the risk of financial transmission rights underfunding by cutting in half the amount of capability offered in long-term FTR auctions.

Under PJM's current rules, all capability available after auction revenue rights are reserved is offered in long-term FTR auctions, which cover planning periods three years in the future. But under a proposal developed through PJM's FTR Task Force, PJM would only offer 50% of that capability in the long-term auctions.

Tim Horger, manager of market simulation at PJM, said that while the change would reduce the amount of revenue generated in long-term FTR auctions, PJM hopes it would also reduce the risk of underfunding. Horger said that because the long-term auction deals with FTRs three years in the future, PJM does not

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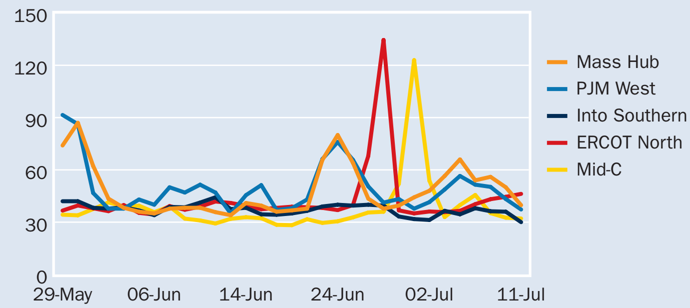
Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Jul 12 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	38.82	40.81	27.53	28.57
NYISO	35.88	54.00	25.41	34.43
PJM	36.05	43.84	22.14	28.44
MISO	32.77	35.95	15.47	23.95
ERCOT	50.03	71.84	25.76	26.06
CAISO	44.34	46.41	35.44	37.11

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

Day-ahead bilateral indexes and spark spreads for Jul 12

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	39.75	10643	13.61	9.87	2.40	-5.07	-16.28
N.Y. Zone-A	36.25	10313	11.65	8.13	1.10	-5.93	-16.48
PJM/MISO							
PJM West	37.25	10855	13.23	9.80	2.93	-3.93	-14.23
Indiana Hub	32.00	8755	6.42	2.76	-4.55	-11.86	-22.83
Southeast & Central							
Southern, Into	30.00	8310	4.73	1.12	-6.10	-13.32	-24.15
ERCOT, North	46.23	12913	21.17	17.59	10.43	3.27	-7.47
West							
Mid-C	32.10	9318	7.99	4.54	-2.35	-9.24	-19.58
SP15	48.25	12901	22.07	18.33	10.85	3.37	-7.85

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 drop, following spot gas

Daily power prices in the Northeast moved down Thursday, with demand falling and lower spot natural gas prices. Forward prices dipped as the NYMEX August natural gas futures contract settled at $3.613/MMBtu Thursday, down 6.7 cents.

ISO New England forecasted peak load on Thursday near 22,860 MW and 19,380 MW for Friday. High temperatures for Boston are expected in the low 70s on Friday.

Algonquin city-gates spot natural gas tumbled about 42 cents to $3.78/MMBtu and Transco Zone 6 New York was down 35 cents to $3.70/MMBtu.

Mass Hub on-peak for Friday lost more than $10 dropping to around $40/MWh and off-peak moved down about $5.50 to the upper $20s/MWh.

The New York ISO forecasted peak load for Thursday around 27,704 MW and 25,041 MW on Friday. High temperatures in New York state are forecast to be in the 70s Friday.

New York Zone A peak for Friday fell about $4 to mid-$30s/MWh and New York Zone G peak gave up about $10 going to mid-$40s/MWh.

Day-ahead auction prices in ISO-NE tumbled Thursday with demand expected to move further down heading into the end of the week. Internal Hub peak lost $11.49 dropping to $39.94/MWh and Connecticut peak was down $11.91 to $40.81/MWh. Vermont peak moved down $11.44 clearing at about $40.19/MWh and Maine peak was off $10.59 to $38.82/MWh. NE-Mass Boston peak came down $11.43 to $40.07/MWh.

Day-ahead auction prices in NYISO fell further Thursday with demand set to take its typical dip on Friday. Long Island peak tumbled $29.18 to $53.44/MWh and New York City peak fell over $11 clearing at $54/MWh. Hudson Valley peak moved down $9.25 to about $45.53/MWh and West zone peak was off $4.18 to $35.88/MWh.

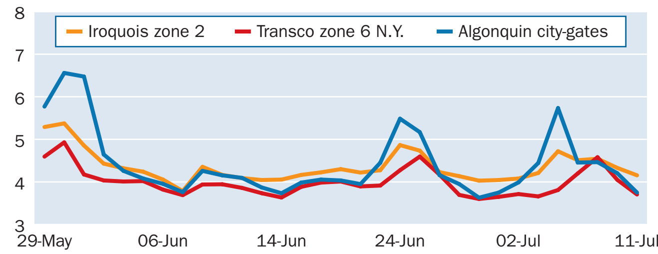
Northeast term power prices crept down Thursday with weaker natural gas futures. Mass Hub on-peak August financial futures fell 25 cents, with bids at $52/MWh and offers at $53.50/MWh on the IntercontinentalExchange. New York Zone A on-peak August financial futures dropped 25 cents to $45.50/MWh. New York Zone G on-peak August financial futures fell 25 cents to $61/MWh.

Northeast day-ahead bilateral indexes for Jul 12 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	39.75	-10.25	50.44	10643
N.Y. Zone-G	46.00	-10.00	56.39	11705
N.Y. Zone-J	54.25	-10.75	62.03	13804
N.Y. Zone-A	36.25	-3.75	41.06	10313
Ontario*	24.00	-2.00	28.78	5676
Off-Peak				
Mass Hub	28.00	-5.25	32.19	7497
N.Y. Zone-G	29.25	-4.25	34.31	7443
N.Y. Zone-J	34.50	-5.25	37.44	8779
N.Y. Zone-A	26.50	-3.25	29.36	7539
Ontario*	18.25	-2.00	21.14	4316

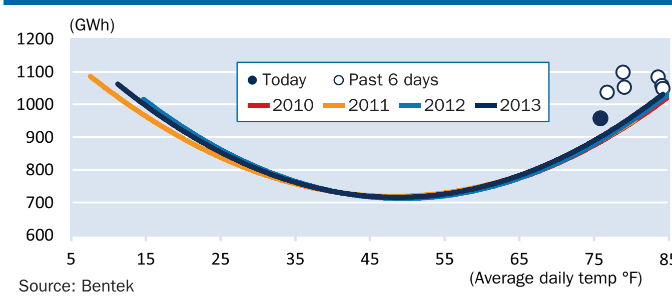
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO load per degree



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 10-Jul	%Chg	% Chg Year-ago	Forecast 11-Jul	12-Jul	13-Jul	14-Jul	15-Jul
ISONE								
Load	449	3	4	398	390	362	372	423
Generation								
Coal	30	15	125	23	21	21	22	24
Gas	190	7	-12	178	165	163	171	180
Nuclear	111	0	-6	111	111	111	111	111
NYISO								
Load	603	0	1	560	508	460	463	532
Generation								
Coal	44	2	113	33	28	27	29	33
Gas	235	-1	-3	236	205	188	196	210
Nuclear	119	24	8	122	125	125	125	125

Source: Bentek

ISONE day-ahead LMP for Jul 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	39.94	0.00	-0.20	-11.49	56.12	10526
Connecticut	40.81	0.00	0.67	-11.90	57.16	10261
NE Mass-Boston	40.07	0.00	-0.06	-11.43	56.27	10561
SE Mass	39.98	0.00	-0.15	-11.44	55.99	10539
West-Central Mass	40.21	0.00	0.08	-11.62	56.48	10598
Rhode Island	39.59	0.00	-0.54	-11.30	55.28	10434
Maine	38.82	0.00	-1.31	-10.60	52.49	9437
New Hampshire	39.89	0.00	-0.24	-11.15	55.58	9697
Vermont	40.19	0.00	0.06	-11.44	56.39	9770
Off-Peak						
Internal Hub	28.36	0.00	0.01	-3.36	33.12	6836
Connecticut	28.56	0.00	0.21	-3.39	33.37	6756
NE Mass-Boston	28.32	0.00	-0.03	-3.20	33.08	6828
SE Mass	28.37	0.00	0.02	-3.23	33.02	6839
West-Central Mass	28.47	0.00	0.12	-3.37	33.33	6863
Rhode Island	28.57	0.00	0.22	-3.26	33.09	6887
Maine	27.53	0.00	-0.82	-2.52	31.43	6562
New Hampshire	28.09	0.00	-0.26	-3.01	32.77	6694
Vermont	28.32	0.00	-0.03	-3.22	33.16	6748

NYISO day-ahead LMP for Jul 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	40.75	-0.22	1.95	-5.80	47.49	10629
Central Zone	38.80	0.00	0.22	-4.78	43.97	10997
Dunwoodie Zone	46.54	-3.59	4.38	-10.13	56.45	11718
Genesee Zone	37.46	0.00	-1.12	-4.52	42.41	10617
Hudson Valley Zone	45.53	-2.72	4.24	-9.25	54.92	11464
Long Island Zone	53.44	-9.27	5.59	-29.17	83.83	13454
Millwood Zone	46.46	-3.52	4.37	-10.09	56.39	11698
Mohawk Valley Zone	40.17	-0.22	1.37	-5.38	45.70	10965
N.Y.C. Zone	54.00	-10.69	4.73	-11.02	60.89	13596
North Zone	36.83	0.00	-1.75	-4.27	41.12	8952
West Zone	35.88	0.00	-2.70	-4.18	40.89	10169
Off-Peak						
Capital Zone	28.04	0.00	1.44	-3.85	32.08	7143
Central Zone	26.87	0.00	0.26	-3.66	29.86	7463
Dunwoodie Zone	29.23	0.00	2.62	-4.26	33.29	7020
Genesee Zone	26.49	0.00	-0.11	-3.61	29.38	7359
Hudson Valley Zone	29.12	0.00	2.52	-4.29	33.21	6995
Long Island Zone	32.89	-2.76	3.53	-6.89	40.09	7900
Millwood Zone	29.18	0.00	2.58	-4.30	33.28	7010
Mohawk Valley Zone	27.32	0.00	0.72	-3.75	30.48	7322
N.Y.C. Zone	34.43	-4.95	2.88	-5.26	37.05	8271
North Zone	25.41	0.00	-1.19	-2.98	28.16	6056
West Zone	26.30	0.00	-0.30	-3.52	29.10	7306

Generation unit outage report

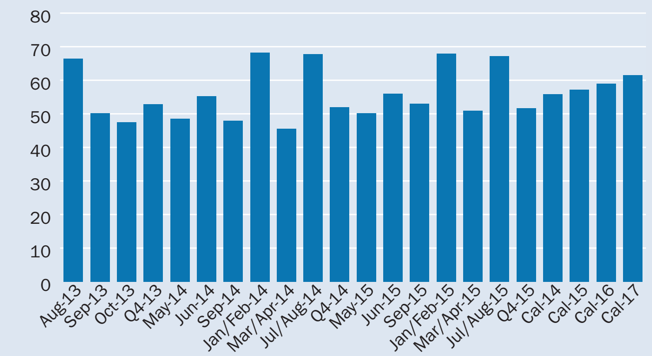
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Pickering-1/OPG	500	n	Ont	MO	Unk	06/07/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13

Northeast Platts-ICE Forward Curve, Jul 11 ($/MWh)

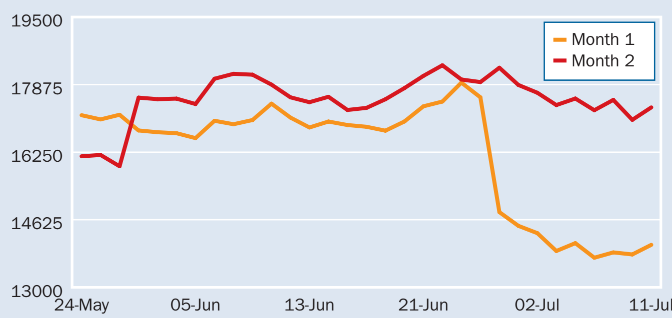
Prompt month: Aug 13	On-peak	Off-peak
Mass Hub	52.75	36.00
N.Y. Zone G	61.00	40.00
N.Y. Zone J	66.50	42.75
N.Y. Zone A	45.50	33.50
Ontario*	34.25	23.75

*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		
Bal-week	07/08	52.00-54.00
Next-week	07/11	70.00-71.00

*Ontario prices are in Canadian dollars.

Daily generation outage references

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

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

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

SOUTHEAST MARKETS

ERCOT dailies increase on rising demand

Daily power prices in the Electric Reliability Council of Texas increased Thursday, with higher demand despite mainly steady temperatures. Forward prices in ERCOT and the Southeast dipped as the NYMEX August natural gas futures contract settled at $3.613/MMBtu Thursday, down 6.7 cents.

ERCOT North Hub next-day on-peak physical power rose about $1.70 to trade between $46 and $46.25 /MWh for Friday delivery on IntercontinentalExchange.

Spot natural gas at Houston Ship Channel moved down about 3.3 cents to $3.637/MMBtu on ICE.

High temperatures in ERCOT North were forecast to remain near 100 degrees until the weekend. Houston's temperatures were expected to stay in the mid-to-high 90s through Friday.

System load in ERCOT was forecast to peak at 64,031 MW Thursday, up from an actual load of 63,620 MW Wednesday. Friday ERCOT load is forecast to reach a peak of 65,060 MW.

North Hub next-week on-peak futures were bid at $39.25 and offered at $40/MWh on ICE, a discount to dailies. North Hub balance-of-the-month on-peak futures were bid at $50.50 and offered at $54/MWh.

In the Southeast, dailies dropped with lower spot gas prices. Into Southern next-day on-peak power markets dropped $6 to about $30/MWh for Friday delivery on ICE.

Spot natural gas at Transco Zone-3 fell 7.9 cents to about $3.611/MMBtu on ICE.

High temperatures in Atlanta were forecast to hold steady in the mid-80s through Friday, about 6 degrees below the seasonal average.

The ERCOT day-ahead auction for Friday delivery cleared stronger Thursday, with peak load forecast to rise. West Hub remained in the highest-priced hub position, and North Hub the lowest-priced hub. West Hub on-peak cleared in the ERCOT auction at $53.72/MWh, a jump of $8.75, while off-peak cleared at $25.83/MWh, up around 25 cents.

Houston Hub on-peak cleared in the auction at $52.42/MWh, a gain of more than $9, while off-peak cleared at $25.80/MWh, gaining almost 25 cents. South Hub on-peak cleared at $51.58/

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for Jul 12 ($/MWh)

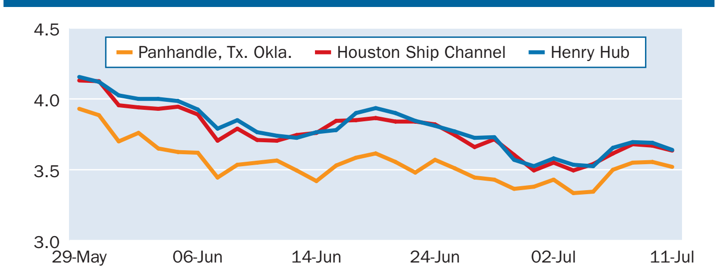
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	31.75	-6.00	37.00	8535
Southern, Into	30.00	-6.00	34.17	8310
Florida	35.50	-2.00	35.86	9010
TVA, Into	30.50	-5.00	35.11	8356
Entergy, Into	34.00	-2.25	35.19	9464
Southeast Off-Peak				
VACAR	25.75	-0.75	24.00	6922
Southern, Into	25.75	-0.25	23.21	7133
Florida	26.50	-1.50	27.17	6726
TVA, Into	24.75	-0.50	23.06	6781
Entergy, Into	23.50	-0.25	21.08	6541
ERCOT On-peak				
ERCOT, North	46.23	1.69	39.38	12913
ERCOT, Houston	47.25	1.75	41.56	13025
ERCOT, South	47.50	1.75	41.36	13194
ERCOT, West	48.75	2.50	40.53	13752
ERCOT Off-Peak				
ERCOT, North	25.26	1.06	23.65	7056
ERCOT, Houston	25.50	1.00	23.94	7030
ERCOT, South	25.50	1.00	23.94	7083
ERCOT, West	25.25	1.00	23.77	7123
SPP/MRO On-peak				
MAPP, South	34.25	-2.50	36.81	9409
SPP, North	33.75	-2.75	36.17	9588
SPP/MRO Off-Peak				
MAPP, South	23.25	-0.25	21.69	6387
SPP, North	23.00	-0.25	21.48	6534

Southeast load and generation mix forecast (GWh)

	Actual 10-Jul	%Chg	% Chg Year-ago	Forecast 11-Jul	12-Jul	13-Jul	14-Jul	15-Jul
ERCOT								
Load	1205	4	-1	1190	1201	1127	1056	1123
Generation								
Coal	468	5	16	450	454	455	448	448
Gas	558	2	-13	573	559	520	481	480
Nuclear	123	0	-3	123	123	123	123	123
SPP								
Load	868	-1	-2	735	740	726	716	776
Generation								
Coal	496	-3	8	422	417	433	443	457
Gas	255	-1	-25	232	218	216	213	217
Nuclear	48	0	-3	48	49	49	49	49

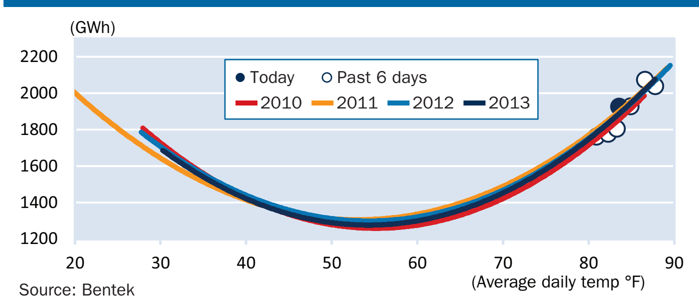
Source: Bentek

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



Source: Platts

ERCOT & SPP load per degree



Source: Bentek

ERCOT average day-ahead LMP for Jul 12 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	51.31	7.97	38.87	14261
Hub Average	52.03	8.37	39.24	14462
Houston Hub	52.42	9.05	39.99	14464
North Hub	50.41	7.41	38.33	14027
South Hub	51.58	8.29	39.21	14280
West Hub	53.72	8.77	39.45	15111
AEN Zone	52.86	7.36	40.43	14868
CPS Zone	52.75	8.11	39.97	14719
LCRA Zone	52.07	7.91	39.67	14531
Rayburn Zone	50.03	7.80	38.25	13924
Houston Zone	52.69	8.81	40.18	14538
North Zone	50.65	7.43	38.50	14095
South Zone	53.53	7.63	40.41	14821
West Zone	71.84	11.89	49.00	20209
Off-Peak				
Bus Average	25.80	0.22	24.21	7090
Hub Average	25.80	0.22	24.22	7089
Houston Hub	25.80	0.23	24.24	7055
North Hub	25.82	0.23	24.20	7101
South Hub	25.76	0.22	24.22	7034
West Hub	25.83	0.21	24.23	7190
AEN Zone	25.98	0.22	24.41	7233
CPS Zone	26.06	0.27	24.33	7160
LCRA Zone	25.87	0.22	24.26	7108
Rayburn Zone	25.82	0.23	24.20	7102
Houston Zone	25.80	0.23	24.24	7055
North Zone	25.82	0.23	24.20	7102
South Zone	25.82	0.23	24.25	7050
West Zone	25.91	0.16	24.55	7211

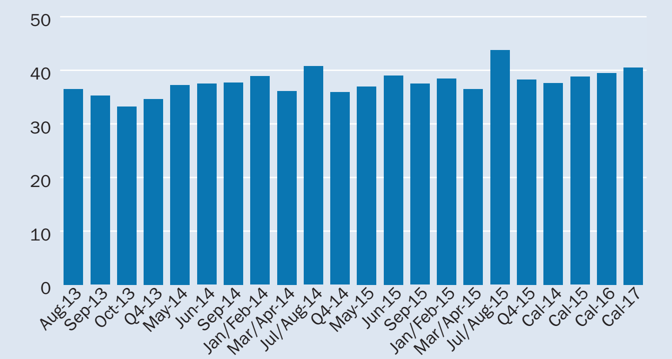
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	07/08	34.75-35.25
Entergy, Into		
Bal-month	07/11	34.50-35.00
Next-week	07/11	36.50-37.00
ERCOT, North		
Bal-week	07/10	48.00-48.50
Bal-month	07/08	23.75-24.25
Next-week	07/11	39.50-40.00
Next-week	07/10	42.75-43.25
Next-week	07/08	46.25-47.00
ERCOT, South		
Bal-week	07/10	49.00-49.50

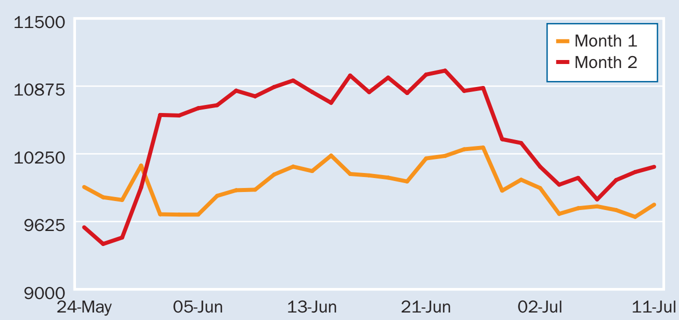
Southeast & Central Platts-ICE Forward Curve, Jul 11 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
Southern Into	36.50	29.00
Entergy Into	35.75	26.75
ERCOT North	82.25	31.75
ERCOT Houston	83.75	31.75
ERCOT West	84.75	31.75
ERCOT South	82.00	32.75

Southern Into: Forward curve on-peak ($/MWh)



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



Generation unit outage report

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

Market coverage

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

WEST MARKETS

Western dailies finish mixed; most terms slip

Western dailies were mixed Thursday with less demand expected in California and lower spot natural gas prices in the region. Most terms dropped back, and the NYMEX August natural gas futures contract posted a preliminary settlement of $3.613/MMBtu, down 6.7 cents compared with Wednesday's close.

In the Northwest, Mid-Columbia day-ahead on-peak was down about 50 cents to trade between $29.75 and $33.50/MWh for delivery on Friday and Saturday. Mid-C day-ahead off-peak prices fell around 25 cents to trade between $16.75 and $20.50/MWh. The Mid C on-peak balance-of-the month package was bid at $41 and offered at $42/MWh, up about $1.75.

Portland, Oregon's forecast highs were for the low to mid-70s through Saturday, about five degrees below normal, while expected lows were in the low 50s.

The Bonneville Power Administration's wind at 7 a.m. PDT Thursday was 2,489 MW, and its hydropower was 9,766 MW.

In California, SP15 next-day on-peak added more than $1 to about $48.50/MWh. SP15 day-ahead off-peak was up more than $1.25 to around $34.25/MWh. SP15 bal-month was bid at $49 and offered at $51, down roughly 50 cents. NP15 day-ahead on-peak was down $1.50 to about $44.50/MWh. NP15 day-ahead off-peak was flat at around $33/MWh. NP15 bal-month was bid at $45.50 and offered at $49.50/MWh, up around 25 cents.

Sacramento, California, expected normal highs in the low 90s through Saturday with lows in high 50s. Forecast highs for Burbank were for the mid-80s with projected lows from the mid- to high 60s.

Cal-ISO projected peak demand to hit 38,343 MW on Thursday, 38,132 MW on Friday, and 34,920 MW on Saturday. Renewables were at 3,749 MW and wind was about 1,900 MW at 7 a.m. PDT on Thursday.

The day-ahead market in California seemed to easily absorb the indefinite loss of the 1,197-MW nuclear reactor at Diablo Canyon-2. The unit shut down automatically Wednesday when equipment was damaged by pressure washing.

In the desert Southwest, Palo Verde next-day on-peak dropped almost $2.75 to trade between $37 and $39.50/MWh. Palo Verde day-ahead off-peak was up more than $1.75 to trade between $26 and $27/MWh. Palo Verde bal-month was bid at $41.50 and offered at $45.75/MWh, up slightly.

Phoenix expected highs between 100 and 111 thorough Saturday with lows in the high 80s.

Next-day natural gas prices retreated in the Rockies and California. Opal was down 6.8 cents to $3.482/MMBtu, PG&E city-gate fell 5.2 cents to $3.833/MMBtu, and SoCal city-gate dropped 9.8 cents to $3.837/MMBtu.

Most day-ahead prices were down in the California Independent System Operator auction Thursday afternoon after the lower demand forecasts.

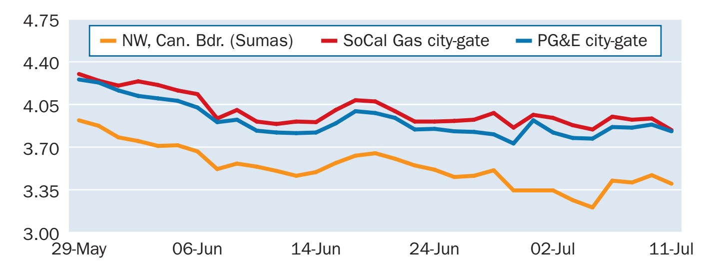
SP15 on-peak fell $3.80 to $46.41/MWh, as SP15 off-peak gained 22 cents to $37.11/MWh. NP15 on-peak was down $1.42

(continued on page 10)

Western day-ahead bilateral indexes for Jul 12-13 ($/MWh)

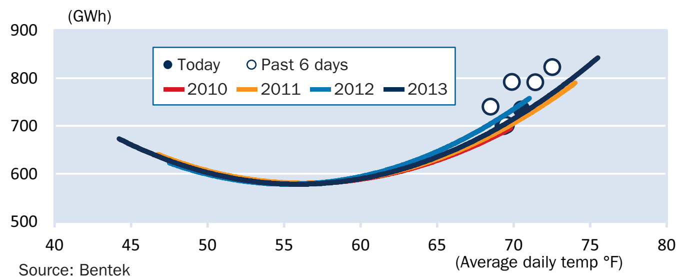
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	36.30	-0.58	54.38	10126
Mid-C	32.10	-0.45	47.16	9318
Palo Verde	39.01	-2.54	56.46	10717
Mead	42.74	-4.51	64.04	11428
Mona	44.00	0.25	59.36	12828
Four Corners	43.00	-2.25	58.54	12147
NP15	44.50	-1.50	56.45	11619
SP15	48.25	1.00	56.61	12901
Off-Peak				
COB	22.10	1.10	16.92	6165
Mid-C	18.89	-0.07	13.94	5483
Palo Verde	26.50	2.00	26.96	7280
Mead	28.00	3.00	29.10	7487
Mona	22.00	0.25	23.94	6414
Four Corners	25.11	1.61	26.84	7093
NP15	33.00	0.00	34.94	8616
SP15	34.25	1.50	35.87	9158

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO load per degree



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 10-Jul	%Chg	% Chg Year-ago	Forecast 11-Jul	12-Jul	13-Jul	14-Jul	15-Jul
CAISO								
Load	791	-4	2	735	735	702	703	773
Generation								
Gas	288	1	1	296	283	277	290	298
Nuclear	56	0	-9	28	29	33	41	48

Source: Bentek

CAISO average day-ahead LMP for Jul 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	44.91	-0.37	-2.25	-1.42	54.59	11727
SP15 Gen Hub	46.41	-0.24	-0.89	-3.80	53.24	12409
ZP26 Gen Hub	44.34	-0.81	-2.39	-2.01	49.83	11855
Off-Peak						
NP15 Gen Hub	35.44	-0.63	-1.34	-1.11	35.90	9156
SP15 Gen Hub	37.11	0.24	-0.54	0.22	32.96	9738
ZP26 Gen Hub	35.82	-0.22	-1.37	0.53	31.71	9398

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	07/11	40.00-41.00
Bal-month	07/10	39.25-40.25
Bal-month	07/09	41.50-42.00
Bal-month	07/08	42.00-44.00
Bal-month (off-peak)	07/11	24.00-25.50
Bal-month (off-peak)	07/10	23.00-23.50
Bal-month (off-peak)	07/08	21.25-23.50
Next-week	07/11	43.75-44.25
Palo Verde		
Bal-month	07/11	43.75-44.25
NP15		
Bal-month	07/10	47.00-47.50
SP15		
Bal-month	07/10	49.50-50.00

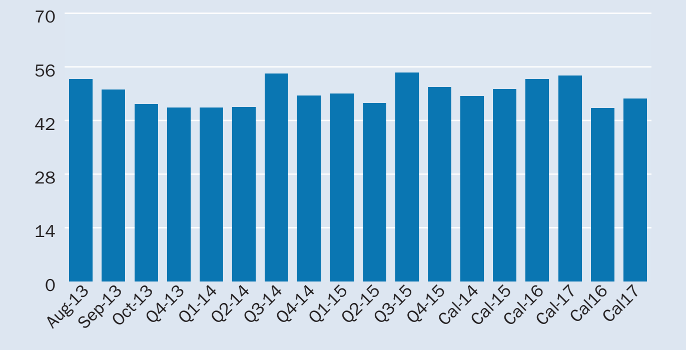
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Contra Costa-6/NRG	337	g	Calif.	MO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
Diablo Canyon-2/PG&E	1150	n	Calif.	MP	Unk	07/10/13
Huntington Beach-3/AES	225	g	Calif	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif	PMO	Unk	04/14/13
Inland Empire-2/GE	366	g	Calif.	MO	Unk	07/10/13
Los Esteros/Calpine	188	g	Calif.	PMO	Unk	05/27/13
Mexcali/Sempra	180	g	Calif.	MO	Unk	05/02/13
Ocotillo/Pattern	265	w	Calif.	MO	Unk	05/16/13
Redondo-7/AES	506	g	Calif.	MO	Unk	07/08/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12

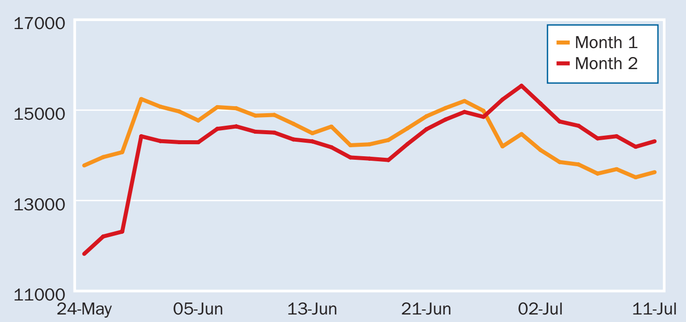
Western Platts-ICE Forward Curve, Jul 11 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
Mid-C	43.50	30.25
Palo Verde	44.50	29.00
Mead	46.00	30.75
NP15	48.75	37.50
SP15	52.75	38.00

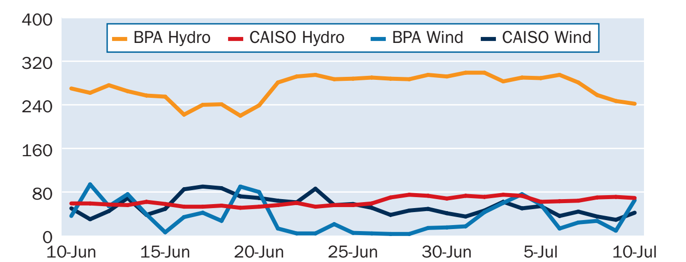
SP15: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

Additional information on data and analysis:

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

PJM & MISO MARKETS

PJM dailies down, along with forwards

Daily power prices in the Mid-Atlantic and Midwest were down Thursday, with temperatures and demand set to drop at the end of the week. Forward prices in both regions dipped as the NYMEX August natural gas futures contract settled at $3.613/MMBtu Thursday, down 6.7 cents.

PJM Interconnection forecasted peak demand for Thursday at 126,011 MW and 115,066 MW for Friday. High temperatures across the PJM footprint are forecast in the mid-70s to low 80s on Friday.

Spot natural gas in the region moved down again with Texas Eastern M-3 moving down 19 cents to about $3.57/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Friday gave up about $5.75 to upper $30s/MWh. PJM West Hub off-peak gave up about $2 going to mid-$20s/MWh.

Midcontinent ISO dailies moved down with lower spot gas and weaker nearby power prices. Chicago city-gates spot gas lost about 6 cents, going to $3.71/MMBtu.

Indiana Hub peak for Friday fell about $2 going to low $30s/MWh and off-peak fell about $1 going to low $20s/MWh. Minnesota peak for Friday was steady around the mid-$30s/MWh.

Dailies in the Midwestern portion of PJM fell with lower expected demand and temperatures. AEP-Dayton Hub peak for Friday decreased about $4.50 to the mid-$30s/MWh and off-peak gave up about $1.50 to about the mid-$20s/MWh. Northern Illinois Hub peak lost about $3.25 going to low $30s/MWh, and off-peak was down about $2 to the low $20s/MWh.

Day-ahead auction prices in PJM moved down again with lower expected demand and temperatures for Friday. Eastern Hub peak fell $4.16, clearing at $42.88/MWh, while Western Hub peak lost $3.80, clearing near $39.46/MWh. JCPL peak lost $6.67, clearing at $43.40/MWh, as New Jersey Hub peak lost $5.65 to reach $43.31/MWh. BG&E peak was off $4.29, clearing at $41.44/MWh, while Pepco peak was down $4.32 to $40.61/MWh.

Chicago Hub peak lost 82 cents to clear at $37.39/MWh and ComEd peak fell 78 cents to $37.20/MWh.

MISO day-ahead auction prices cleared mostly weaker Thursday. Michigan Hub on-peak remained the highest-priced hub at $35.95/MWh, down $2.22. Off-peak cleared at $23.95/MWh, a decrease of $1.41.

Minnesota Hub on-peak cleared at $33.93/MWh, falling $2.12, while off-peak cleared at $15.47/MWh, losing $5.56. Illinois Hub on-peak cleared at $32.81/MWh, up 6 cents. Off-peak cleared at $21.70/MWh, a gain of 97 cents. Indiana Hub fell to the lowest-priced hub with on-peak clearing at $32.77/MWh, a loss of $1.36. Off-peak cleared at $20.82/MWh, easing $2.32.

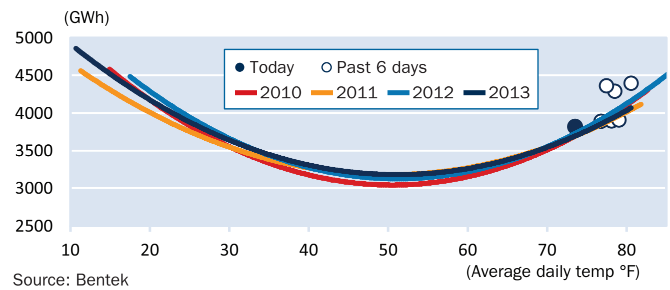
Congestion costs at the hubs ranged from 6 cents to $2.24 for on-peak, and from negative $3.64 to $3.24 cents for off-peak.

Mid-Atlantic forwards slipped Thursday as gas futures came down. PJM West on-peak August financial futures fell 50 cents

PJM & MISO day-ahead bilateral indexes for Jul 12 ($/MWh)

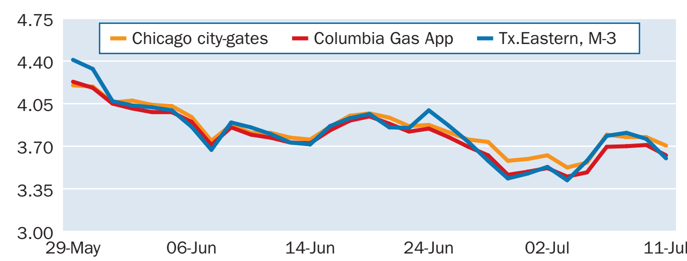
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	37.25	-6.00	45.56	10855
Dominion Hub	36.25	-6.50	45.19	9871
AD Hub	35.25	-4.25	40.56	9425
NI Hub	32.25	-3.25	37.44	8704
PJM Off-Peak				
PJM West	26.00	-2.25	26.67	7576
Dominion Hub	26.00	-1.25	26.39	7080
AD Hub	24.00	-1.50	25.14	6417
NI Hub	20.50	-2.00	20.92	5533
MISO On-peak				
Indiana Hub	32.00	-2.00	37.97	8755
Michigan Hub	36.00	-2.00	39.31	9332
Minnesota Hub	34.50	-0.50	38.92	9256
Illinois Hub	31.00	-1.50	36.47	8384
MISO Off-Peak				
Indiana Hub	22.00	-1.00	22.61	6019
Michigan Hub	24.00	-1.50	23.86	6222
Minnesota Hub	20.00	0.00	20.56	5366
Illinois Hub	21.50	-0.50	21.78	5815

PJM & MISO load per degree



Source: Bentek

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 10-Jul	%Chg	% Chg Year-ago	Forecast 11-Jul	12-Jul	13-Jul	14-Jul	15-Jul
PJM								
Load	2692	1	2	2327	2234	2147	2176	2489
Generation								
Coal	1252	1	14	1085	1072	1107	1136	1164
Gas	500	0	-20	398	329	334	384	435
Nuclear	778	0	1	777	777	777	777	777
MISO								
Load	1667	-4	-1	1488	1437	1364	1382	1615
Generation								
Coal	1361	-4	8	1257	1191	1185	1215	1270
Gas	170	-15	-45	99	75	98	145	196
Nuclear	193	0	-11	193	193	193	193	193

Source: Bentek

MISO average day-ahead LMP for Jul 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	32.77	0.06	0.03	-1.36	34.42	8928
Michigan Hub	35.95	2.24	1.03	-2.22	36.40	9292
Minnesota Hub	33.93	1.42	-0.18	-2.12	36.32	9075
Illinois Hub	32.81	0.81	-0.69	0.06	33.41	8845
Off-Peak						
Indiana Hub	20.82	0.74	0.40	-2.32	21.85	5576
Michigan Hub	23.95	3.24	1.04	-1.41	23.12	6082
Minnesota Hub	15.47	-3.64	-0.58	-5.56	18.85	4064
Illinois Hub	21.70	2.26	-0.24	0.97	20.74	5762

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

Package	Trade date	Range
PJM West		
Bal-week	07/09	41.25-42.00
Bal-week	07/08	46.25-49.00
Bal-month	07/11	55.75-56.75
Bal-month	07/10	55.25-56.25
Next-week	07/11	60.50-67.00
Next-week	07/10	58.50-59.50
Next-week	07/09	55.00-56.50
Next-week	07/08	54.75-56.75
AD Hub		
Next-week	07/11	54.75-55.75

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Davis-Besse/FirstEnergy	971	n	Ohio	MO	Unk	06/29/13
Kewaunee/Dominion	581	n	Wis.	NA	Retired	05/07/13
Monticello/Xcel	666	n	Minn.	PMO	07/14/13	03/02/13

PJM average day-ahead LMP for Jul 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	36.28	-0.69	-2.64	-1.85	36.88	9949
AEP-Dayton Hub	38.10	-0.11	-1.40	-2.50	39.09	10448
ATSI Gen Hub	39.60	0.07	-0.08	-3.68	41.35	11026
Chicago Gen Hub	36.05	-1.23	-2.33	-0.76	35.63	9707
Chicago Hub	37.39	-0.50	-1.72	-0.82	36.76	10067
Dominion Hub	38.41	0.13	-1.33	-4.47	43.89	10411
Eastern Hub	42.88	-0.09	3.37	-4.16	50.91	11692
New Jersy Hub	43.31	0.81	2.89	-5.65	50.96	11808
Northern Illinios Hub	36.91	-0.73	-1.96	-0.72	36.32	9939
Ohio Hub	38.29	-0.11	-1.21	-2.54	39.27	10295
West Internal Hub	38.88	0.10	-0.82	-3.74	41.95	11271
Western Hub	39.46	0.12	-0.27	-3.80	44.17	11439
AEP Zone	38.10	-0.10	-1.41	-2.68	39.28	10445
Allegheny Power Zone	38.92	-0.20	-0.48	-3.17	41.22	10880
Atlantic Elec Zone	42.70	0.04	3.06	-4.61	49.19	11642
ATSI Zone	39.92	0.14	0.18	-3.61	41.70	11116
BG&E Zone	41.44	0.41	1.42	-4.29	49.88	11681
ComEd Zone	37.20	-0.65	-1.75	-0.78	36.61	10018
Dayton P&L Zone	38.35	-0.54	-0.72	-2.45	39.35	10447
Delmarva P&L Zone	42.45	-0.10	2.94	-4.09	50.26	11574
Dominion Zone	39.05	0.17	-0.72	-4.59	44.67	10586
Duke Zone	37.03	-0.15	-2.43	-2.27	38.22	10089
Duquesne Light Zone	38.09	-0.28	-1.23	-2.71	38.85	10998
JCPL Zone	43.40	1.00	2.79	-6.67	52.57	11832
MetEd Zone	41.17	0.28	1.28	-4.98	47.77	11253
PECO Zone	41.38	-0.14	1.91	-4.13	47.43	11309
Pennsylvania Elec Zone	40.16	-0.05	0.60	-4.11	43.54	11719
PEPCO Zone	40.61	0.48	0.52	-4.32	48.20	11447
PPL Zone	40.96	0.37	0.99	-4.86	47.14	11197
PSEG Zone	43.54	0.93	3.00	-5.23	50.55	11870
Rockland Elec Zone	43.84	1.37	2.87	-5.54	50.74	11953
Off-Peak						
AEP Gen Hub	25.06	-0.17	-1.24	-1.87	25.01	6700
AEP-Dayton Hub	25.88	0.07	-0.66	-2.05	25.92	6920
ATSI Gen Hub	26.93	0.45	0.01	-2.70	26.74	7333
Chicago Gen Hub	22.14	-2.91	-1.41	-1.75	21.70	5880
Chicago Hub	22.85	-2.52	-1.10	-1.72	22.30	6067
Dominion Hub	26.92	0.62	-0.17	-1.79	26.64	7162
Eastern Hub	28.26	0.49	1.30	-2.36	28.32	7457
New Jersy Hub	28.27	0.55	1.26	-2.73	28.51	7460
Northern Illinios Hub	22.66	-2.59	-1.21	-1.67	22.09	6016
Ohio Hub	26.01	0.13	-0.59	-2.06	26.08	6868
West Internal Hub	26.77	0.49	-0.19	-2.18	26.46	7543
Western Hub	26.99	0.48	0.04	-2.20	26.91	7605
AEP Zone	25.97	0.12	-0.61	-2.10	25.94	6945
Allegheny Power Zone	26.82	0.46	-0.10	-1.95	26.50	7321
Atlantic Elec Zone	28.17	0.47	1.24	-2.44	28.23	7434
ATSI Zone	27.03	0.44	0.13	-2.68	26.82	7363
BG&E Zone	27.89	0.50	0.93	-2.20	27.85	7657
ComEd Zone	22.80	-2.55	-1.11	-1.69	22.22	6054
Dayton P&L Zone	25.98	-0.09	-0.39	-2.01	25.94	6956
Delmarva P&L Zone	28.11	0.49	1.16	-2.33	28.16	7418
Dominion Zone	27.13	0.57	0.10	-1.84	26.85	7219
Duke Zone	25.00	-0.13	-1.34	-1.92	25.10	6694
Duquesne Light Zone	26.03	0.32	-0.76	-2.21	25.79	7344
JCPL Zone	28.13	0.44	1.23	-2.47	28.43	7424
MetEd Zone	27.42	0.47	0.49	-2.34	27.53	7293
PECO Zone	27.71	0.48	0.77	-2.39	27.77	7370
Pennsylvania Elec Zone	27.41	0.48	0.47	-2.66	27.41	7870
PEPCO Zone	27.56	0.51	0.59	-2.09	27.43	7566
PPL Zone	27.20	0.43	0.31	-2.24	27.21	7235
PSEG Zone	28.42	0.62	1.33	-2.99	28.68	7499
Rockland Elec Zone	28.44	0.66	1.31	-3.49	28.77	7505

with bids at $52.50 and offers at $52.75/MWh on ICE. PJM West on-peak fourth-quarter moved down 5 cents to about $41.60/MWh. PJM West on-peak January-February 2014 financial futures dropped 25 cents to about $45.25/MWh on ICE.

Midwest forwards were down Thursday with gas futures and weaker power markets to the east. AD Hub on-peak August financial futures fell 50 cents with bids at $47.25 and offers at $48.10/MWh on ICE. Indiana Hub on-peak August financial futures were down 50 cents with bids at $43.25 and offers at $45/MWh on ICE. NI hub on-peak August financial futures slipped 25 cents to about $46/MWh.

Southeast markets ... from page 4

MWh, adding about $8.25, while off-peak cleared at $25.76/MWh, rising about 25 cents. North Hub on-peak cleared the auction at $50.41/MWh, up almost $7.50 from Wednesday's clearing price, while off-peak cleared at $25.82/MWh, up around 25 cents.

West Zone on-peak led the load zones at $71.84/MWh, a gain of almost $12 from Wednesday.

The highest hourly day-ahead price occurred at 5 p.m. CDT in the Houston Hub at $155.31/MWh and in the West Zone at $194.01/MWh.

South Central on-peak August terms fell Thursday, as August NYMEX gas futures dropped. ERCOT North on-peak August tumbled $2.75 to about $82.25/MWh, September dropped $1 to about $40.50/MWh, and the fourth quarter fell 55 cents to about $33.10/MWh. Heat rates were steady on ICE.

Into Entergy on-peak August shed 75 cents to about $35.75/MWh, September fell 25 cents to about $34/MWh, and Q4 crept down 10 cents to about $32.90/MWh.

Southeast on-peak August fell Thursday, as did August NYMEX gas futures. Into Southern August slid 50 cents to about $36.50/MWh, September fell 25 cents to about $35.25/MWh, and Q4 crept down 10 cents to about $34.65/MWh.

West markets ... from page 6

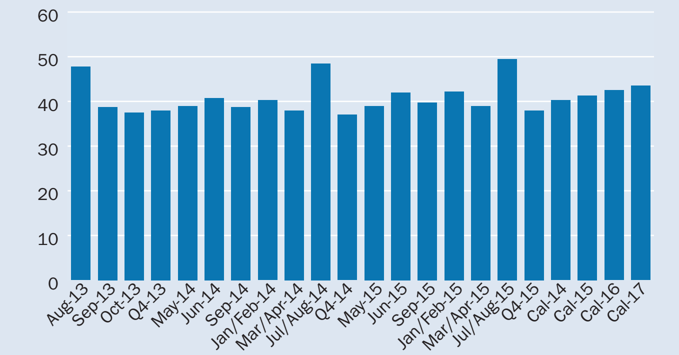
to $44.91/MWh, and NP15 dropped $1.11 to $35.44/MWh. ZP26 on-peak shed $2.01 to $44.34/MWh, while ZP26 off-peak added 53 cents to $35.82/MWh.

In the Northwest term markets, Mid-Columbia on-peak August rose 25 cents with bids at $43.25 and offers at $44/MWh on ICE around 2:30 p.m. EDT. September rose 25 cents to about $38.50/MWh, and the fourth quarter crept up 10 cents to about $35.50/MWh. In California, SP15 on-peak August financial terms lost 50 cents with bids at $52.60 and offers at $52.90/MWh. September fell 50 cents to about $50/MWh, and Q4 fell 45 cents to about $45.40/MWh. NP15 August slid 50 cents to about $48.75/MWh, September dropped $1 to about $45.25/MWh, and Q4 fell 25 cents to about $42.90/MWh. Palo Verde August had no bid and an offer of $45.90/MWh in late trading, September had a bid of $37.75/MWh and no offer, and Q4 fell 25 cents to about $34.75/MWh.

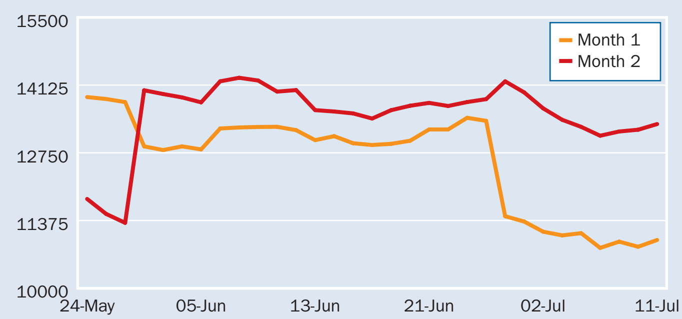
PJM & MISO Platts-ICE Forward Curve, Jul 11 ($/MWh)

Prompt month: Aug 13	On-peak	Off-peak
PJM West	52.75	32.50
AD Hub	47.75	29.75
NI Hub	46.00	26.50
Indiana Hub	44.50	27.25

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



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



EMISSIONS MARKETS

Calif. GHG allowance market sees quiet week

California greenhouse gas allowances were range-bound, while trading volume fell sharply during the holiday-abbreviated week.

Contracts for end-of-the-year delivery on IntercontinentalExchange ranged from flat to 15 cents lower this week. The main futures contract traded on ICE – vintage 2013 for delivery in December 2013 – settled at $14.35/mt. The vintage 2015 contract for December 2015 delivery settled at $13.35/mt.

On ICE, there were only 13 deals, compared with 26 deals a week earlier. Total volume was 103 contracts. One contract equals 1,000 mt. ICE cleared 5 deals equal to 125 contracts, compared with 1,086 contracts a week earlier.

In over-the-counter markets, prices for California GHG allowances for December 2013 delivery fell to $14.25-$14.50/mt, down from $14.5-$14.6/mt. California-compliant offsets were quoted at $10-$11.50.

In the East, the Regional Greenhouse Gas Initiative's vintage 2012 contract for December 2013 delivery decreased 13 cents to $3.40/st. There no deals seen on ICE during the week.

— Geoffrey Craig

Daily CSAPR allowance assessments, Jul 11

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

All prices in $/st

Daily CAIR allowance assessments, Jul 11

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

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

RGGI carbon allowance futures, Jul 10 ($/allowance)

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

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

'Dead calm' marks weekly emissions market

Prices in the US Clean Air Interstate Rule trading program remained unchanged for the week, with one trader Thursday describing the market as "dead calm."

Platts assessed vintage 2013 SO2 at 64 cents/allowance. Vintage 2014 SO2 was assessed at 58 cents/allowance.

Both remained unchanged from previous assessments.

The bid/offer spread for vintage 2013 CAIR seasonal NOx allowances remained unchanged for the week, holding at $18/$25.

Bids and offers for vintage 2013 CAIR NOx Annual and NOx Ozone allowances continue to appear on the IntercontinentalExchange screen but are not trading.

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

REC MARKETS

Conn. issues RFP for Class I resources

Connecticut began implementing a sweeping piece of legislation this week overhauling the state's renewable portfolio standard, issuing a long-term solicitation immediately after the bill was signed into law.

The legislation was motivated by a desire to steer Connecticut away from relying mostly on out-of-state biomass and landfill gas resources, and move toward "cleaner," newer technologies, like wind, to meet Class I requirements.

Though, controversially, the bill also allows large-scale hydroelectric facilities to contribute toward meeting Class I demand for the first time. That amount, however, is capped.

As part of the law, The Department of Energy and Environmental Protection was directed to oversee a long-term solicitation. DEEP requested supplies of Class I-eligible electricity and renewable energy certificates. Utilities will act as counterparties under 20-year contracts with developers.

Eligible facilities must have an online date of no earlier than January 1. The size of the procurement is 174 MW, an amount increased to 525 MW for wind farms due to their lower capacity factor.

The turnaround is expected to be fast. The whole process, culminating in the contracts being voted on by the Public Utilities Regulatory Commission, should be done by October 9.

The timetable allows wind farms to be able to qualify for federal production tax credits set to expire at the end of the year. It also ensures new Class I supply comes onto the market.

One of the central questions emerging from the legislative debate was whether Connecticut would have enough Class I supply to meet demand if biomass and landfill gas facilities were phased out.

Traders responded with skepticism that supply would prove adequate, a market source said, pointing to the sudden increase in forward prices for Connecticut Class I RECs to levels still seen today, a market source said.

Judging the fundamentals of the Connecticut Class I market can be tricky. The amount of capacity available to supply the Connecticut Class I market appears robust, but a significant portion is qualified in multiple states.

Connecticut has had difficulty attracting multi-qualified RECs because prices tend to be higher in other New England states, like Massachusetts.

Instead, supply has mostly come from old biomass power plants and other resources not certified anywhere else.

The DEEP solicitation is intended to help fill the hole left by the departure of these suppliers. It also guarantees that RECs will actually flow to Connecticut. The capacity sought equals about 4% of load, DEEP said.

In New Jersey, the Board of Public Utilities' Office of Clean Energy posted a list of grid-tied solar projects applying to become qualified under the state's solar carve-out.

The Solar Act of 2012 requires grid-tied facilities in the development phase to get BPU approval before they can generate solar RECs. Net-metered projects do not fall in this category.

The provision was meant to stem a growing tide in New Jersey of developers moving away from residential, behind-the-meter projects in favor of large-sized facilities, especially those located on farmland.

The Solar Act allows 80-MW of grid-tied projects to come online each year through 2016. The application window for developers lasted from May 15 to May 30.

According to the list published this week, there were 27 applications received representing 136.4 MW. The 80-MW limit was not reached in any of the three compliance years.

The BPU is expected to vote on whether to approve these projects at its August 21 meeting. The outcome will impact the New Jersey SREC market as a whole due to the potential impact on supply.

— Geoffrey Craig

Renewable Energy Certificate Markets Jul 11 ($/MWh)

	Low	High	Mid
Class I/Tier I RECs*			
Connecticut	53.00	55.00	54.000
Maryland	7.90	8.00	7.950
Massachusetts	62.50	64.00	63.250
New Jersey	8.10	8.20	8.150
Ohio In-State	5.00	7.00	6.000
Pennsylvania	7.95	8.05	8.000
Texas	2.30	2.35	2.325
Solar RECs*			
Maryland	120.00	130.00	125.000
Massachusetts	205.00	225.00	215.000
New Jersey	125.00	130.00	127.500
Ohio In-State	40.00	52.00	46.000
Pennsylvania	12.00	18.00	15.000
California RPS*			
California Bundled REC (Bucket 1)	28.00	34.00	31.000
California Bundled REC (Bucket 2)	3.00	8.00	5.500
California Tradable REC (Bucket 3)	0.70	0.90	0.800
Voluntary RECs*			
National voluntary, any technology	1.10	1.20	1.150
National voluntary, wind	1.15	1.25	1.200

*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

MISO acts on multi-period FTR auctions

The Midcontinent Independent System Operator is moving forward with preparations to implement multi-period monthly auctions for financial transmission rights in October, MISO representatives said at a Wednesday FTR working group meeting.

MISO currently holds monthly and annual FTRs auctions, but for several years market participants have encouraged the grid operator to develop multi-period monthly auctions. This new type of FTR product will allow market participants to hedge day-ahead transmission congestion risk for the balance of the current planning period.

After the multi-period monthly auction proposal was approved by stakeholders in August, MISO filed the proposed changes with the Federal Energy Regulatory Commission on December 7 (Docket No. ER13-536). MISO asked FERC to approve the changes effective October 1 but has not yet received a response from the commission.

In its filing, MISO argued that the introduction of multi-period monthly auctions will increase overall FTR market participation, leading to increased competition and improved price signals. MISO also said the change would give market participants more opportunities to hedge their risks by adjusting their FTR portfolios.

MISO representatives said Wednesday that they are moving ahead with system testing with the goal of implementing multi-period monthly auctions in October. Barring a rejection from FERC, the first multi-period monthly auction will be held in October and will include FTR periods covering November, December, January and February.

But for the southern region that is in the process of integrating into MISO, multi-period monthly auctions will only be available after the November partial year FTR allocation, according to MISO's presentation.

During Wednesday's meeting, some market participants worried that the introduction of multi-period monthly auctions could exacerbate FTR underfunding issues. Madison Gas and Electric and Wisconsin Public Power Inc. raised similar concerns in comments filed with FERC, saying that MISO's proposal does not include adequate safeguards "to assure full funding of FTRs without excessive uplift charges."

In a January response filed with FERC, MISO argued that such concerns are "purely speculative" and insisted the utilities did not "demonstrate any current significant underfunding" of FTRs. In its initial filing MISO also promised to conduct an overall evaluation of the multi-period monthly auctions one year after implementation.

MISO representatives said they plan to hold market participant workshops in early September and a mock FTR bidding window in mid-September. MISO representatives said they are also working on improving the FTR portal submission process and working on changes to FTR funding reports in advance of the introduction of multi-period monthly auctions.

— Juliana Brint

Climate change impacting energy markets: DOE

Large portions of the US power sector — including hundreds of generating plants, much of the electrical grid and scores of waterways that the industry uses to transport coal and other fuels — are becoming increasingly vulnerable to disruption by climate change and extreme weather events, the Obama administration warned Thursday.

The Department of Energy, in an 83-page report, said rising temperatures, declining water availability and other climate-related phenomena will "affect the ability of the United States to produce and transmit electricity from fossil, nuclear, and existing and emerging renewable energy sources."

Droughts associated with climate change could also increasingly hamper barge shipments of coal to power plants, the report says, as well as the US' newfound oil and gas natural shale-drilling boom, since that sector is largely dependent on hydraulic fracturing operations that use huge amounts of water.

"Oil and gas production, including unconventional oil and gas production … is vulnerable to decreasing water availability, given the volumes of water required for enhanced oil recovery, hydraulic fracturing, and refining," the report says.

The report comes as DOE and other federal agencies are gearing up to implement President Barack Obama's recently announced plan to combat climate change. The centerpiece of Obama's plan calls for the Environmental Protection Agency to issue the first-ever federal limits on heat-trapping greenhouse-gas emissions from electricity generators — new plants as well as existing facilities.

DOE cites a number of examples in the report that it says illustrate how climate change and extreme weather events have already impacted the US energy markets and commodity prices in recent years. In 2010, for example, when water levels in Nevada's Lake Mead dropped to levels not seen since 1956, federal officials were forced to reduce the generating capacity of the Hoover Dam by a full 23%, DOE noted. And as water levels in the lake continued to drop, dam operators were concerned that reductions in generating capacity would destabilize energy markets in the Southwestern US, DOE said.

DOE also noted that a number of nuclear and coal-fired power plants had to either reduce their generating capacity or shut down entirely in recent years due to climate-related reasons. Just last year, for example, Dominion Resources was forced to shut down one reactor at its Millstone Nuclear Power Station in Connecticut because the temperature of the plant's cooling water — which Dominion drew from Long Island Sound — was too high, DOE said.

"The two-week shutdown resulted in the loss of 255,000 megawatt-hours of power, worth several million dollars," DOE said.

Similarly, DOE noted that the Tennessee Valley Authority had to reduce the power output of its Browns Ferry Nuclear Plant in Athens, Alabama, three times in recent years because the Tennessee River, where the plant discharges its (heated) cooling water, grew too warm to receive any more of the facility's releases.

"TVA was forced to curtail the power production of its nuclear reactors, in some cases for nearly two months," DOE said. "While no power outages were reported, the cost of replacement power was estimated at $50 million."

The report also argues that higher temperatures associated with climate change will increase electricity demand for cooling, while decreasing fuel oil and natural gas demand for heating. DOE offers several real-life examples in the report that it says illustrate those supply and demand forces, including one that links a spike in wholesale electricity prices to an "extreme weather event."

"A sustained period of high temperatures across Texas in 2011 created sharp increases in wholesale electricity prices," DOE noted in the report. "In one instance, the 15-minute real-time price averaged $45/MWh in the morning but increased to $1,937/MWh in the afternoon during peak demand."

DOE said that many coal-fired power plants as well as nuclear facilities are especially vulnerable to climate-related droughts because they require so much water for cooling purposes. DOE noted that the Electric Power Research Institute, an industry think tank, found that approximately 25% of all US electric generators are located in counties projected to be at high or moderate water supply sustainability risk in 2030.

Much of the nation's 300,000-mile-long transmission grid is also vulnerable to higher temperatures associated with climate change, DOE said. Citing several different studies, DOE said higher temperatures have been proven to reduce the carrying capacity of high-voltage transmission lines. For example, one study of the California power grid projected that a 9°F increase in air temperature could decrease transmission line capacity by as much as 8%, and substation capacity by upwards of 4%, DOE said.

The report offers a host of recommendations on the how the power sector could stave off the worst impacts of climate change. For example, it said the industry could retrofit or shutter older power plants that use so-called "once-through" cooling-water systems, which require tremendous amounts of water. Plants that use more modern closed-cycle systems — or better yet, air cooling — are far less vulnerable to climate-related droughts, DOE said.

EPA, on that front, is slated to issue a rule by November 4 that is aimed at reducing the billions of fish and other aquatic organisms that are killed every year by power plant cooling water intake structures. Environmental groups want EPA to require closed-cycle cooling for all power plants, which would significantly reduce fish mortality as well as the power sector's use of water.

But the power sector is vigorously fighting that approach, saying it would no longer be economical to operate many once-through generating stations if the facilities were required to install cooling towers. Indeed, in a study last year, EPRI found that the costs of installing closed-cycle cooling systems at 428 large generating plants that currently lack that technology would exceed $100 billion. EPRI said that if EPA did decide to mandate closed-cycle cooling, upwards of 26,000 MW of fossil generation would be "potentially at risk of premature retirement for economic reasons."

— Brian Hansen

AEP to retire, rather than convert, 585-MW unit

Bowing to market and environmental realities after weighing its options for several months, American Electric Power said Thursday it will retire, rather than convert to natural gas, a 585-MW unit at its Muskingum River coal-fired plant near Beverly, Ohio.

The Columbus, Ohio-based company decided long ago it would cease burning coal in the 1,425-MW baseload plant in 2015 to comply with new Environmental Protection Agency rules.

The only question is what would happen to Unit 5, which went into commercial operation in 1968 and is the plant's largest unit.

Under a deal reached between AEP and other parties in February to modify the company's 2007 new source review consent agreement, AEP had the choice of retiring Muskingum River Unit 5 or refueling it with gas.

"We considered the refueling, but with the way the market is and the environmental investment that would need to be made, the numbers just didn't make sense" to convert the unit to gas, said AEP spokeswoman Tammy Rideout.

To switch the unit to gas and have it comply with new water quality rules proposed by the EPA would cost the company an estimated $61 million, she said.

And so, Unit 5 now is expected to join the plant's four smaller units in retirement in 2015. "We don't have an exact retirement date yet," she said, "but it looks like it will be in 2015."

Several factors were considered before the company reached the final decision on Unit 5, including environmental compliance costs, fuel prices and AEP Ohio's planned move to competition in 2015. AEP Ohio, an AEP subsidiary, includes Ohio Power and Columbus Southern Power, which together serve almost 1.5 million customers.

AEP Ohio has formed an independent generation company, and its generation assets are expected to be moved into the genco sometime after 2014.

"Ohio is in kind of a short-term situation because we won't have an obligation long term for that capacity" to serve native load, she noted. "So, it becomes a different type of decision due to the Ohio market as well."

Rideout hastened to add: "It's really more the market price of electricity — current market conditions are a factor as well."

Muskingum River burns Central Appalachian coal. Historically, Unit 5 has consumed 1 million to 1.5 million short tons of coal annually, although Rideout said it has been less in recent years.

AEP plans to retire about 6,600 MW of older coal-fired generating capacity mainly to comply with EPA regulations. Some of the retirements already have occurred. They include 450-MW Unit 5 in February 2012 at the 1,105-MW Philip Sporn plant near New Haven, West Virginia, and 165-MW Unit 3 last December at the 1,891-MW Conesville plant near Conesville, Ohio.

Rideout said her company also plans to invest $4-5 billion to install pollution controls at some of its other coal plants. They include the 2,600-MW Rockport plant in Spencer County, Indiana, one of the largest baseload plants in that state.

Once all the retirements and retrofits are said and done, AEP will continue to be a major coal-fired generator, albeit not as much as before.

"We're at about 60% coal capacity now," Rideout noted, "and that will go to 46% by 2020. And natural gas will go from 23% now to about 33% by 2020."

Coal currently accounts for roughly 23,000 MW of AEP's total generating capacity of about 38,000 MW.

AEP's decision to retire Muskingum River Unit 5 comes in the wake of Ohio utility FirstEnergy's anouncement earlier this week it expects to close the Hatfield's Ferry and Mitchell coal plants in Pennsylvania, representing 2,080 MW of capacity, later this year.

— Bob Matyi

Gas storage inventories rise to 2.687 Tcf

A higher-than-average build of 82 Bcf boosted US gas storage inventories to 2.687 Tcf last week, squarely meeting expectations and again narrowing the deficit to previous years, the Energy Information Administration reported Thursday.

The injection was much bigger than the 41 Bcf reported in the same week of 2012 and topped the five-year average of 74 Bcf. As a result, the 491-Bcf deficit to the year-ago level dropped to 443 Bcf, while the 30-Bcf deficit to the five-year average of 2.709 Tcf narrowed to 22 Bcf.

A strong storage build was made possible by lower gas demand during the July 4th holiday weekend as well as milder weather in every region except the sweltering West, where injections slowed, analysts said.

The EIA report "did not indicate that utilities are switching to natural gas *en masse*," said Aaron Calder of Gelber & Associates. Rather, it stemmed from "mild temperatures last week as well as the holiday-shortened work week."

Calder also noted that most forecasters are predicting mild weather for the rest of the summer and, with that outlook, "a change in fuel preferences is the key to any potential rally" for gas prices.

The impact of the Independence Day holiday will also be reflected in next week's EIA release, as more days associated with the long weekend will be reflected, said Logan Reese, an analyst with Platts unit Bentek Energy.

Bentek expects injection rates to remain at or above normal for the rest of July, which could lift total inventories above the five-year average for the first time since late March.

EIA reported a 53-Bcf injection in the East to 1.244 Tcf, compared with 1.529 Tcf a year ago; a 2-Bcf injection in the West to 445 Bcf, compared with 482 Bcf a year ago; and a 27-Bcf injection in the producing region to 998 Bcf, compared with 1.119 Tcf a year ago.

Inventories now are 89 Bcf below the five-year average of 1.333 Tcf in the East, 34 Bcf above the five-year average of 411 Bcf in the West and 33 Bcf above the five-year average of 965 Bcf in the producing region.

— Stephanie Seay

Gas, wind seen competing, cooperating in Texas

Natural gas will continue to be the leading fuel for power generation in Texas, but its growth will be dependent on a complex relationship with renewable energy resources, particularly wind, according to industry officials and analysts.

“It’s not legitimate to say up front that more renewables will crowd out gas, or vice versa,” Jurgen Weiss, co-author of a recent Brattle Group report on the subject, said in an interview Thursday. “There are elements that have the two types of resources competing, but there are other elements that make them complementary resources.”

According to the Electric Reliability Council of Texas — which represents 85% of the state's electric load — in 2012 gas accounted for almost 45% of power generation in ERCOT, with coal at 34% and wind at 12%. Texas has by far more wind power capacity than any other state at roughly 12,000 MW.

And wind is expected to play an even bigger role in Texas' power generation, especially with the completion of the ERCOT-managed Competitive Renewable Energy Zones project later this year.

CREZ, a $6.9 billion transmission project, is designed to bring wind-generated power from remote regions of the state such as West Texas — which has lots of wind but relatively few people — to population centers in the eastern half of the state.

Some experts predict that wind will compete head-to-head with low-priced gas produced from Texas shale plays, while others contend that the relationship between the two generation sources will be more nuanced.

“As a fast-ramping resource that is relatively easily turned on and off, natural gas-fired power plants (in particular combustion turbines) are well-suited for backing up and smoothing out intermittent renewables and providing capacity,” The Brattle Group's report said.

One of the challenges is that wind does not always blow at the right times. That means another form of power generation is needed to back up wind power, and in Texas that is most likely a combined-cycle, gas-fired plant, Weiss said.

“If you had more renewable generation from wind resources, then it’s likely you would have to deal with the intermittency of the generation,” he said. Having a gas-fired plant on standby would give the system the flexibility to respond to a loss of wind power quickly.

Weiss predicted that the build-out of the CREZ system will boost wind's share of the Texas power-generation market.

“Clearly the increases in wind were being hampered because it was getting increasingly difficult to sell the wind output where the wind was being produced,” he said. “There is not a lot of local demand that can absorb the wind [power]. Therefore you were seeing negative prices in those areas.”

Weiss said that even with current gas prices, wind generation in Texas will be cost-competitive with gas, while coal is likely to be the biggest loser in the competition because of increasing environmental regulation at the state or federal level.

“It’s quite possible to imagine a future where you will see an expansion of both wind and gas, and you will see coal facing more challenges than those two technologies," he said.

But Katharine Lusk, principal in AKL Wind Energy, a privately held wind development company based in Big Spring, Texas, rejected the notion that gas and wind generation would develop a synergistic role.

"I think they're competitive," she said. "I don't see them working side by side."

Lusk said that in theory a complementary relationship is possible, "but economically the providers of electricity are going to take whatever is the least expensive method of producing electricity that they can provide to the consumer. And that right now is going to be natural gas because of all the shale plays and the abundance of natural gas."

Norm Berthusen, vice president of trading and consulting firm Energy Unlimited, said federal regulations would play a big role in what forms of energy are used to generate power in Texas going forward. "I think this is going to be an issue of where our government determines what's going to happen in terms of greenhouse gas," he said.

If the federal government places tough restrictions on GHGs, gas-fired generation will become "the best alternative short-term choice we've got," he said.

"Nuclear, on a long-term basis, might be the better choice, but nuclear has a tremendous amount of other challenges to get past," Berthusen said. "There's not an easy answer to this."

David Pursell, an analyst with Tudor Pickering Holt, said wind and other renewables would not be economic without large government subsidies because low gas prices are keeping power prices down — and consumers want to see that continue.

"The amount of coal generation pushed off by gas last year is a clear indication that the power market cares about low-cost generation," he said.

— Jim Magill

Report offers details on grid constraints, prices

Metropolitan Edison had the highest 2012 average energy price of FirstEnergy's four utilities in Pennsylvania primarily caused by transmission congestion, a report by the Brattle Group filed with the Public Utility Commission said.

The report, made public by the PUC on Thursday, said lower capacity costs at the PJM Interconnection drove down total wholesale costs for all four utilities' load zones although other components also affected prices, the report said.

Met-Ed is in PJM's Met-Ed zone, Pennsylvania Electric is in the Penelec zone, West Penn Power is in the APS zone and Penn Power is part of the ATSI zone.

Met-Ed's wholesale costs fell 14%, Pennsylvania Electric's fell 10%, West Penn Power fell 28% and Penn Power's fell by 24%, the report said.

PJM's capacity auction is locational and can result in different capacity prices between zones depending on transmission costs, the report said.

The average zonal peak hour locational marginal prices in the Met-Ed zone decreased by 24% and off peak LMPs decreased by 22%, the report said.

"The Met-Ed zone continues to show the largest positive transmission congestion cost component for both peak and off-peak hours," the report said.

Total PJM net transmission congestion costs, including transmission congestion charges to loads, credits to generators and charges for point-to-point transactions, decreased, the report said.

In 2012, the wholesale cost of electricity for Penelec was \$53.54/MWh, \$54.99/MWh for Met-Ed, \$43.71/MWh for West Penn Power and \$41.63/MWh for Penn Power. The average PJM wholesale cost was \$48.54/MWh.

The wholesale cost per megawatt hour includes 17 separate elements.

The marginal congestion cost for Met-Ed in 2012 was 67 cents/MWh compared with the PJM average of 4 cents/MWh, the report said. Penelec and Penn Power are in less congested areas and their marginal congestion costs were lower than PJM's average. West Penn Power's marginal congestion cost was the same as the PJM average.

The capacity portion of the wholesale cost of electricity was \$6.05/MWh for PJM, but it was \$13.62/MWh for Penelec and Met-Ed. West Penn Power and Penn Power both had capacity prices of \$3.69/MWh.

Between 2011 and 2012, the total cost of wholesale power fell by about 22%, primarily caused by a decline in energy and capacity prices, the report said. Changes in demand and supply and the continuing decline in natural gas prices caused the decline in energy prices. Larger reductions were found in the APS zone at 28% and the Penn Power zone with 26%, the report said.

The locational marginal price like the overall wholesale cost of power fell from 2010 to 2012 for three of the FirstEnergy utilities. The only outlier was Penn Power with an 11% increase in day-ahead prices from 2010 to 2011, the report said. The other FirstEnergy Pennsylvania utilities had a 3% to 6% decrease in day-ahead prices and a 0.3% to 7% decrease in real-time prices during the time period, the report said.

From 2011 to 2012, the utilities saw an average decrease of 18% to 26% in both day-ahead and real-time energy prices, the report said.

In 2012, all the of FirstEnergy's Pennsylvania companies had a net zonal transmission congestion cost, which can be attributed to individual transmission facilities that constrain the most economic dispatch, the report said. The APS interface, for example, has the highest transmission congestion impact in PJM and contributed 16.1% to the total PJM transmission congestion costs, or about \$68 million.

"The AP South interface is usually responsible for price separation between the eastern and western parts of PJM," the report said.

The top constraint in the Met-Ed zone is the Hunterstown transformer and the West interface is the top constraint for the Penelec Zones. "These constraints are typically among the top three constraints in PJM in terms of their impact on transmission congestion costs," the report said.

Market dynamics were driven in 2012 by declining gas and coal prices and resulted in the lowest average annual energy prices since 2002, the report said.

The report also noted the competition found in the Pennsylvania retail market. As of April 1, the percentage of residential customers served by an alternative supplier ranged from 28.5% in Met-Ed's service territory to 31.4% in Penn Power's service territory. The percentage of commercial load served by alternative suppliers ranged from 67.4% in Met-Ed's territory to 67.9% in Penn Power's territory. The share of industrial load served by competitive retail suppliers ranged from 88.9% in West Penn Power's territory to 98.4% in Penn Power's territory, the report said.

— Mary Powers

PSC directs Georgia Power solar purchase

A divided Georgia Public Service Commission on Thursday voted to direct Georgia Power to buy an additional 525 MW of solar power, but Stan Wise, the PSC's longest-serving member, called the solar plan "social engineering" and "feel-good energy policy" that will raise retail rates.

The proposal by Commissioner Bubba McDonald to direct Georgia Power to buy 260 MW of solar power that will begin commercial operation in 2015 and 265 MW that will come online in 2016 came as a motion to amend the utility's proposed integrated resource plan.

After voting 3-2 to approve McDonald's solar amendment, the PSC voted 4-1 to approve the amended IRP plan as a whole; Wise and Commissioner Chuck Eaton voted against the solar motion, and Wise alone voted against the amended IRP.

McDonald, the leading advocate for solar power on the commission, said in arguing for his motion that solar power costs are declining, that Georgia Power should further diversify its generation portfolio, and that by buying solar power at no more than the utility's avoided costs the plan would not result in higher rates.

He said that the plan will build on the Advanced Solar Initiative approved by the PSC in November. The ASI calls for Georgia Power to contract for 105 MW of solar power this year and 105 MW more in 2014.

In April, the utility used a lottery system to select 45 MW of distribution-scale solar projects of less than 1 MW each, and in June Georgia Power received 90 bids in response to a solicitation for 60 MW of utility-scale projects of 1 to 20 MW each. The winners of the utility-scale solar request for proposals will be announced this year. The lottery and RFP processes will be repeated in the spring.

McDonald's motion to direct Georgia Power to purchase an additional 525 MW of solar power mid-decade specifies that 100 MW of that will be in the form of distribution-scale projects and the remaining 425 MW be utility-scale. This time, there will be no upper cap on the size of individual solar proposals, and Southern Company and its subsidiaries — apparently including Southern Power and Georgia Power itself — will be permitted to submit proposals.

In response to questions by commissioners before the vote on McDonald's motion, Georgia Power representatives said that it was the PSC's prerogative to direct the utility to buy more solar power, and that, as proposed, the expanded solar plan would not put upward pressure on rates.

That did not appease Wise, who said that the expanded solar plan is "a mandate being force-fed to a utility that is long on power." He noted that Georgia Power has said that, even with the more than 2,000 MW of older coal-fired capacity it plans to retire under its IRP, the utility's reserve margin will remain above 25% for the foreseeable future.

Wise said that the expanded solar plan is "worse than [a renewable portfolio standard] because you're mandating a specific renewable. You're predetermining the winner." He added, "No matter what the next fad is, the primary driver in our decisions needs to be economics."

As noted, Georgia Power's newly approved IRP calls for retiring most of its older, smaller coal units, including Plant Branch units 3 and 4; Plant Yates units 1 through 5; and Plant Kraft units 1 through 3. It also calls for the utility to switch its coal-fired Plant Yates units 6 and 7 and Plant Gaston units 1 through 4 to gas firing — the Yates units by April 2015 and the Gaston units by April 2016.

Further, the IRP calls for the utility to start buying a total of 998 MW of gas-fired power from sister company Southern Power starting in 2015, and for the utility to continue building two 1,100-MW nuclear units at its Plant Vogtle that are scheduled to come online in the fourth quarter of 2017 and the fourth quarter of 2018, respectively. Georgia Power holds a 45.7% ownership interest in both of the units.

The PSC's vote for expanded solar won praise from environmental and consumer groups, including Georgia Watch. "We fully support the commission's [solar] decision," said Elena Parent, the group's executive director.

Parent added that the PSC should have heeded the request by Georgia Watch and other to retire the four Plant Gaston coal units rather than repower them with gas. Retiring the units, she said, would have reduced the utility's "extremely high reserve margin."

The Sierra Club said in a statement that the expanded solar plan "provides another opportunity for Georgia Power to completely phase out its expensive and unnecessary coal-burning units at Plant McIntosh."

— Housley Carr

EKPC aims to keep Cooper coal unit open

East Kentucky Power Cooperative will seek Kentucky Public Service Commission approval in August for an environmental upgrade at 116-MW Unit 1 at its Cooper coal-fired power plant.

The move aims to prevent the unit's retirement and enable the baseload facility to meet federal air quality rules, the co-op said Thursday.

A scrubber installed last year on Cooper's other coal unit, 225-MW Unit 2, to reduce sulfur-dioxide emissions has sufficient capacity to accommodate flue gases from Unit 1, the Winchester-based entity, one of the nation's largest generation and transmission co-ops, has concluded.

"At this time, East Kentucky is seeking regulatory approvals for a proposal to construct ductwork to route Cooper Unit 1's flue gas through Cooper 2's dry circulating scrubber," Nick Comer, an East Kentucky spokesman, said.

If regulatory approvals are forthcoming, "Cooper Unit 1 would stay in operation," as would Unit 2, he said. Cooper's two units went into commercial operation in 1965 and 1969, respectively. The plant burns Central Appalachian coal.

For more than a year, East Kentucky has been evaluating the future of its Cooper and 216-MW Dale coal plants. Cooper is located in Pulaski County, Dale in Clark County.

In June 2012, the co-op released a formal request for proposals for up to 300 MW of long-term power, with possible implications for both Cooper and Dale.

The decision to pursue the estimated $15 million ductwork project at Cooper 1 was a result of the formal solicitation that attracted more than 100 proposals from 65 bidders. East Kentucky, Comer said, is "still going through the RFP process for the balance of that 300-MW request," and other decisions are possible this year.

According to Comer, the co-op has submitted a "notice of intent" to the PSC about the proposed Cooper 1 project.

Routing Cooper 1's flue gases through Unit 2's scrubber would allow Unit 1 to comply with the Environmental Protection Agency's Mercury and Air Toxics Standards, he said. "We believe that would bring Cooper Unit 1 into compliance and it would comply once MATS goes into effect. Therefore, we would continue to run the Cooper plant."

He added: "What we're proposing is a very reasonable investment to extend the life of a very reliable generating unit" the co-op contends is needed to serve its mostly rural load.

As it stands, he said, "We believe Cooper 1 would not comply with tighter regulations going into effect in 2015. Therefore, as it's currently configured, we would not be able to run Cooper 1."

Although it is yet unclear when construction would start on the project, Comer said the work would be completed by 2015, in time to meet the EPA requirement.

In the past decade, East Kentucky has spent hundreds of millions of dollars to construct a pair of 278-MW coal units at its roughly 1,300-MW Spurlock baseload generating station near Maysville, the co-op's largest power plant.

Three years ago, it canceled plans to build another 278-MW coal unit, Smith 1, in Clark County, citing rising project costs.

East Kentucky's total generating capacity is about 3,000 MW, including about 2,000 MW of coal and 1,000 MW of natural gas.

The co-op supplies 16 distribution co-ops that serve more than 520,000 customers in more than 80 of Kentucky's 120 counties.

— Bob Matyi

PTC drives SPP, ERCOT wind farm developments

Wind farm development activity is “robust” in the Southwest Power Pool and Electric Reliability Council of Texas regions as utilities and wind developers alike seek to take advantage of the extended federal production tax credit, the executive director of The Wind Coalition said Wednesday.

Jeff Clark said in an interview that several utilities in the SPP and ERCOT regions have issued—and in some cases concluded — quick-turnaround solicitations for wind power aimed specifically at wind projects on which construction could begin by year’s end, a requirement for PTC qualification.

Austin Energy, for example, last month concluded a wind RFP by entering into three power purchase agreements for a total of 570 MW of wind power — from $23 to $33/MWh.

Thanks to the PPAs, Duke Energy Renewables will build a total of 400 MW of wind capacity in South Texas’s Starr County, while E.On Climate & Renewables will build a 170-MW wind farm in Nueces County, Texas, also in South Texas.

Southwestern Public Service, meanwhile, said Wednesday that it has entered into three wind PPAs totaling 698 MW, and Public Service Co. of Oklahoma is reviewing nearly two dozen bids it received July 5 in response its June RFP, again for up to 200 MW of wind power.

Some wind projects are advancing to construction without benefit of a PPA. Invenergy Wind said last week that it has closed on construction financing for a 149-MW wind farm it is building near Goldthwaite in Texas’ Mills County, north of Austin. The project will be completed this year and will sell its output into ERCOT’s competitive wholesale market.

“This year there’s a big push to get projects under construction” to qualify for the PTC, “and next year we’ll see" work on those projects continue, said Clark. “The big question is, what’s the nation’s long-term energy policy going to be” and what will Congress and state legislatures do to encourage development and use of clear, renewable energy sources like wind and solar.

Clark declined to provide specific recommendations on what Congress should do, but agreed with a suggestion that a continued federal PTC—even one that declined gradually over a few years before being phased out—and a national renewable portfolio standard would be positive elements of a US energy policy.

The Wind Coalition executive director said that a combination of wind-turbine technological advances and excellent wind resources is making wind power in the SPP and ERCOT regions very cost competitive with traditional sources of power.

Clark noted that Georgia Power recently contracted to buy 250 MW of wind project from an Oklahoma project despite the lack of a Georgia RPS—and because the cost of the wind power is less than the utility’s avoided cost.

Alabama Power, which like Georgia Power is a subsidiary of Southern Company, did the same thing a few months ago, entering into two PPAs totaling 404 MW for wind from Kansas and Oklahoma wind farms.

Clark called the Southern Company utilities’ wind PPAs “a prime example of what [the SPP and ERCOT regions] can do”—namely, serve as a source for significantly increasing amounts of wind power for utilities hundreds of miles away with no wind resources closer at hand.

He added that new transmission capacity will need to be built to enable the output of thousands of MW of new wind farms to buyers in the Southeast, Midwest and other regions. The more than 2,000 miles of new 345-kV lines that are part of the Public Utility Commission of Texas’ multibillion-dollar “competitive renewable energy zones" transmission project are under construction or already in operation, Clark said, adding that the CREZ lines will open up for wind farm development parts of West Texas and the Texas Panhandle that have some of the nation's best wind resources.

The Wind Coalition continues to press for the continued development of wind-related transmission lines in the SPP, and to support efforts by merchant transmission developers like Clean Line Energy Partners and Pattern Energy to advance long-distance, direct-current lines that would help export large amounts of wind power to other parts of the US.

Clark noted, finally, that state legislators in the SPP and ERCOT region in 2013 did not back away from commitments to support renewables. He said there was a major push by renewables opponents in Kansas to undo the state's RPS in the Legislature this year; the effort was defeated, Clark said, "but it will continue next year." A similar effort to repeal Texas' RPS "didn't gain traction," he said.

In Oklahoma, legislators extended the state's own PTC, which provides a $5/MWh credit on wind power production for a wind farm's first 10 years of operation.

— Housley Carr

ERCOT CRR value down for early 2015

Electric Reliability Council of Texas congestion revenue rights for the first half of 2015 cost about 32% less than CRRs for the first half of 2014, data released Thursday show.

Market participants acquired 210,946 MW of CRR capacity for the first half of 2015 at a value of $44.6 million, compared with about 386,766 MW of CRR capacity for the first six months of 2014 at a value of about $65.8 million.

The auction results posted on the ERCOT website Thursday were the last of four six-month CRR auction strips stretching from July 1, 2013, through June 30, 2015. The auction was for 60%, 45%, 30% and 15% of available capacity for the first, second, third and fourth six-month periods. Thus, this most recent auction was for 15% of available capacity.

In the results posted Thursday, market participants acquired $19.7 million worth of positive and negative obligation CRRs – paying ERCOT $16.8 million for 74,988 MW of positive obligation CRRs and receiving $2.9 million for 13,024 MW of negative obligation CRRs.

An obligation CRR is a financial instrument that entitles a CRR owner to be charged or receive compensation when ERCOT's transmission grid experiences congestion in the day-ahead or real-time markets. With negative obligation CRRs, market participants are paid to assume the risk of congestion impeding transmission in a direction opposite from expected power flow.

With an option CRR, a purchaser is entitled to revenue if congestion occurs from a particular electricity source to a particular destination, but the buyer is not obligated to pay if congestion occurs in the opposite direction.

Market participants spent about $24.8 million for 122,934 MW of option CRR capacity for the first half of 2015.

The net effect of all this trading – positive obligation and option CRRs minus negative obligation CRRs – was $38.8 million received by ERCOT.

In terms of capacity of both obligation and option CRRs for the first half of 2015, Shell Energy acquired the most, at 35,987 MW, valued at $4.3 million, of which $792,665 was for negative obligation CRRs. Shell's dollar total ranked third out of the 51 winning bidders.

In terms of dollars, BP Energy's total was largest, with $6.5 million for 30,528 MW of obligation and option CRRs, of which $6,188 was for negative obligation CRRs. Rounding out the top five, in terms of dollar totals, were Monolith Energy at $4.6 million, Shell at $4.3 million, Exelon Generation at $4 million and Luminant Energy at $3.5 million.

In terms of capacity, rounding out the top five after Shell were BP with 30,528 MW, NRG Power with 25,968 MW, Luminant with 21,631 MW and CPS Energy with 12,152 MW.

The largest number of CRRs for a single path for the first half of 2015 was 35,107 MW from the North Hub to the North Load Zone at a cost of $2.7 million.

The most spent on CRRs for a single path for the first half of 2016 was almost $10 million for 6,670 MW from the West Hub to the West Load Zone.

The next round of multimonth CRRs, for the first half of 2014, will begin in October, covering the first six months of 2014, with the results posted no later than November 14.

— Mark Watson

Maryland REC market may lure MISO wind

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the balkanized nature of the market. But sellers cannot always take advantage of the opportunity this provides.

A wind farm owner in Montana, for example, might spot high REC prices in Massachusetts, but would be deemed ineligible to sell there because the facility is located outside New England or an adjacent control area.

What is interesting about the current situation is that MISO-located wind farms do qualify for Maryland Tier I status.

Unlike other states, Maryland allows renewables outside PJM to count as long as the electricity is delivered into the region.

That provision was of little relevance when Maryland Tier I REC prices were not worth enough to justify the additional wheeling expense.

But the rise in Maryland Tier I REC prices has Midwest wind farm owners taking a closer look at the situation, and considering a switch from MISO to PJM, market sources say.

Such a move entails some paperwork. A renewable facility must apply for Maryland Tier I status with the Public Service Commission. Once approved, it would need to delist from MISO's renewable tracking system, and enter PJM's.

How long this opportunity lasts will depend on the number of wind farms actually making the move, according to Ryan Cook, vice president of Clear Energy Brokerage & Consulting.

A flood of new supply would depress Maryland Tier I RECs possibly to the point where the transaction no longer makes sense. And if that sequence occurs, there could be a spillover effect, he said.

Many of the facilities selling Maryland Tier I RECs qualify in other PJM states. A drop in Maryland REC prices would cause sellers to look elsewhere, like New Jersey, diverting supply and ultimately pushing down these prices as well, Cook said.

While wind capacity in MISO is large, in all likelihood, the universe of generators that might switch to PJM is much smaller.

Some portion of the RECs generated by Midwestern wind farms must stay in the region to help utilities meet state-mandated renewable portfolio standards.

Minnesota, Michigan, Illinois, Wisconsin and Iowa, for example, all have mandatory renewable requirements.

Utilities built wind farms or signed long-term power purchase agreements with developers to comply with RPS obligations. It seems unlikely facilities falling under either set-up would delist from MISO.

The more probable candidates are wind farms without obligations to sell their electricity and RECs to utilities. These facilities should, in theory, seek out the highest-valued REC product possible.

Identifying which of the 256 wind farms totaling 11,443 MW currently registered in MISO's tracking system falls into the latter category is a difficult task.

One method involves excluding those wind farms selling 100% of their electricity to utilities and cooperatives based on sales data reported to the Federal Energy Regulatory Commission.

During the first quarter of 2013, there were 18 MISO-based wind farms that were selling their output to customers other than utilities and co-ops. The customers were MISO, the generator's marketing arm, such as NextEra Energy Power Marketing or Macquarie Energy, an unaffiliated marketer.

The combined generation totaled 1.267 million MWh, which represents an identical number of RECs. One REC equals 1 MWh.

Put into perspective, Maryland's Tier I demand equals approximately five million RECs in 2013. That means the MISO wind farms identified here would be on pace to supply enough RECs to cover annual demand.

— Geoffrey Craig

Gas demand up

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consecutive days in Sacramento.

Also helping to bump up gas demand recently were the brief outage at Arizona Public Service's Palo Verde nuclear generation unit 1 in Arizona and the absence of generation from Southern California Edison's permanently closed San Onofre Nuclear Generation Station in Southern California.

Bentek estimates that gas needed to replace nuclear generation outages at 477,000 Mcf/d month-to-date in the Western Electricity Coordinating Council footprint, up slightly from 463,000 Mcf/d in the same period last year.

Another individual region that has seen its gas replacement grow this year as a result of nuclear outages is the Northeast Power Coordinating Council. So far this month, gas replacement has averaged 194,000 Mcf/d, up from 111,000 Mcf/d in the same period of 2012, Bentek data shows.

That has come from recent outages at Entergy's Indian Point unit 2 and Nine Mile Point unit 1 in New York, as well as a brief outage at Vermont Yankee in New England.

Constellation Energy Nuclear Group's 640-MW gross capacity Nine Mile Point unit 1 was operating at 21% capacity Thursday, according to the NRC, after being at zero Tuesday and Wednesday and 22% Monday. A plant spokeswoman said the capacity limitations were needed "to perform a valve repair and implement additional component improvements."

Indian Point's 1,067-MW gross capacity unit 2 in Buchanan, New York, was back up to 100% by Wednesday after operating at 2% capacity last Thursday and 25% capacity Monday and Tuesday.

The lower nuclear output helped give Transcontinental Gas Pipe Line zone 6 New York cash prices a lift to begin this week. The point jumped 39 cents/MMBtu Monday and another 38 cents/MMBtu on Tuesday, Platts data shows.

Looking ahead, Transco zone 6 New York August basis jumped 7 cents to plus 24 cents Wednesday, and Algonquin city-gates August basis rose 4.5 cents to plus 52 cents, according to Platts forward curve assessments.

The most recent Diablo Canyon outage comes after an electrical disturbance occurred in equipment that supports moving power to the California electricity grid, PG&E said in a statement issued Wednesday afternoon.

PG&E spokesman Blair Jones said the incident is under investigation and PG&E had not determined how long the unit might be down.

The outage gave the PG&E city-gate spot price some support Thursday. Though it slipped 6 cents, it was roughly even with Southern California Gas' city-gate, which has been the higher of the two points for most of the last several months.

Meanwhile, PG&E city-gate's prompt-month and bal-summer basis moved up a half-cent Thursday, bringing basis to plus 17 cents for August and 19.5 cents for bal-summer.

Also contributing to price strength last week was Palo Verde unit 1 operating at 58% capacity for a few days after a small "explosion" in an electrical arc in an electrical cabinet in the turbine building.

An event report from operator Arizona Public Service said the incident "did not result in any challenges to the fission product barrier or result in any releases of radioactive material."

Elsewhere, FirstEnergy's Davis-Besse nuclear unit in Ohio has been shut since the end of June, when it automatically tripped offline, according to the NRC status report.

PSEG Nuclear's 1,240-MW Hope Creek nuclear unit in New Jersey was operating at 98% of capacity Thursday, according to the NRC.

Company spokesman Joseph Delmar said Wednesday that "when it is humid, we have challenges to maintain condenser vacuum."

Delmar said operators at the 1,240-MW unit will reduce its power output as needed during the summer to maintain the vacuum. He said the plant's return to full power would "depend on the weather conditions."

Even with this recent spate of short-term outages, Ron Norman, an energy capital markets expert with PA Consulting Group, said nuclear generation outages this year have not had major market impacts.

"There have not been a lot of unexpected outages that have been particularly material," Norman said. "In general, these are relatively minor operational issues that occur from time to time."

— Patrick Badgley

PJM panel rejects plan

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have good transparency on what transmission outages or new market-to-market flowgates will be in place during the planning period, increasing the risk of modeling discrepancies that could lead to underfunding.

In recent years, PJM has repeatedly come up short on funding for FTRs, which has triggered a series of complaints to the Federal Energy Regulatory Commission and a number of PJM stakeholder proceedings. According to a recent complaint by FirstEnergy, FTR payout was 76% during the first seven months of the 2012/2013 planning period, resulting in $109 million of underfunding.

Horger said that the change would only improve FTR underfunding by 5% at most.

"As far as revenue inadequacy impact, we don't have real good numbers on what would be the impact," Horger said. "It depends on which paths clear. Most paths causing revenue inadequacy are already limited [in the long-term auctions]. ... I guarantee you it'll be less than 5%."

Horger estimated that the change would reduce by half the revenues collected from long-term FTR auctions, which he said currently stand at about $15 million to $30 million per year. But Horger said that even under the status quo the revenue from long-term auctions is dwarfed by revenue from annual auctions, which he estimated to be about $500 million per year.

But some market participants argued that the decrease in auction revenues and liquidity would outweigh the benefits of reduced underfunding risks. The MIC voted against the proposal, with 58 PJM members voting in favor, 105 voting against and 14 abstentions.

The change would have "a significant detrimental effect on market efficiency," one market participant said. "There will be a lot less liquidity, a lot less price discovery. ... The idea was to create liquidity and a forward curve for FTRs. This significantly harms that effort while at the same time having a theoretical and minimal impact on underfunding."

— Juliana Brint

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