PLATTS
McGRAW HILL FINANCIAL
www.platts.com
[ELECTRIC POWER]
MEGAWATT DAILY
www.twitter.com/plattspower
Friday, May 31, 2013

MidAmerican expansion has grid implications

ANALYSIS The purchase of NV Energy by MidAmerican Energy Holdings could spur MidAmerican to become a bigger player in renewable energy development and put the company in a position to be a transmission conduit in the West.

MidAmerican Energy, in a $5.6 billion cash deal, is expanding its footprint in the West by taking another publicly traded utility, NV Energy, private. The news was disclosed Wednesday.

MidAmerican, a subsidiary of Berkshire Hathaway, and NV Energy, announced a definitive agreement under which MidAmerican would acquire all NV Energy's outstanding shares for $23.75 each, a 23% premium to the closing price on the day of the announcement, May 29. The deal also includes the assumption of about $4.7 billion in debt. The companies put the enterprise value of the deal at about $10 billion. Included among

(continued on page 20)

PJM, monitor to refine MOPR review process

MARKETS The PJM Interconnection and its independent market monitor will spearhead a stakeholder initiative to make changes to the unit-specific review process used by some new generators seeking exemptions to the PJM capacity auction's minimum offer price rule.

"PJM and the IMM believe the current unit-specific review process is flawed, non-transparent and provides too much discretion to PJM and the IMM," PJM and Monitoring Analytics, its independent market monitor, said in the "problem statement" approved at a Thursday Markets and Reliability Committee meeting.

In December PJM proposed a number of changes to its MOPR, the buyer-side market power mitigation rule that determines the

(continued on page 21)

Generators cite PJM auction in Dominion case

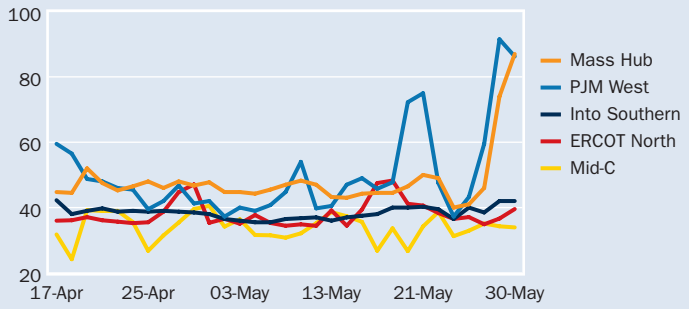
GENERATION Generators introduced the results of the most recent PJM Interconnection capacity auction as new evidence in Virgina that Dominion should be required to solicit alternatives to its plan to build a 1,300-MW natural gas-fired plant.

"The capacity resource clearing price for the RTO was $59.37/MW-day. This actual market price is significantly below the capacity price forecast filed in this case," PJM Power Producers said in a filing made Wednesday with the State Corporation Commission.

Dominion is seeking approval from the SCC to build the power station, but P3 and others have argued that the company should have issued a request for proposals to have actual market offers rather than modeled market offers to determine the best alternative for obtaining new power supplies.

(continued on page 21)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for May 31 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	65.40	73.86	37.58	41.03
NYISO	61.20	258.56	30.46	58.08
PJM	54.97	89.22	21.81	33.84
MISO	37.17	39.19	13.15	27.97
ERCOT	37.23	50.26	24.66	25.97
CAISO	49.90	57.02	35.49	36.61

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

Day-ahead bilateral indexes and spark spreads for May 31

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	87.00	13551	42.06	35.64	22.80	9.96	-9.30
N.Y. Zone-A	61.50	14397	31.60	27.33	18.78	10.24	-2.58
PJM/MISO							
PJM West	86.25	20766	57.18	53.02	44.72	36.41	23.95
Indiana Hub	47.75	11437	18.53	14.35	6.00	-2.35	-14.88
Southeast & Central							
Southern, Into	42.00	10139	13.00	8.86	0.58	-7.71	-20.14
ERCOT, North	39.55	9796	11.29	7.25	-0.83	-8.90	-21.01
West							
Mid-C	34.27	8832	7.11	3.23	-4.53	-12.29	-23.93
SP15	54.25	13248	25.59	21.49	13.30	5.11	-7.18

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 gain as forwards retreat

Daily power prices in the Northeast remained strong Thursday, with higher spot natural gas prices and increased electricity demand. Forward power prices were mostly down as the NYMEX July natural gas futures contract settled at $4.023/MMBtu, down 16.1 cents from Wednesday's close.

The NYMEX July gas contract was down due to bearish weather forecasts and a gas storage injection estimate from the Energy Information Administration that was on par with expectations, sources said.

ISO New England forecasted peak load on Thursday around 19,950 MW and 21,500 MW for Friday.

Algonquin city-gates spot natural gas gained about 80 cents to around $6.57/MMBtu, while Transco Zone 6 New York gained 36 cents to about $4.95/MMBtu.

Boston is expected to have high temperatures on Friday in the upper 80s.

Mass Hub on-peak for Friday moved up about $15 to the upper $80s/MWh. Mass Hub off-peak added about $10, going to mid-$40s/MWh.

The New York ISO forecasted demand on Thursday near 26,022 MW and 26,898 MW for Friday.

New York State is expected to have high temperatures stay in the upper 80s to low 90s.

New York Zone A on-peak for Friday traded in a wide range, from low $60s to around $115/MWh.

Day-ahead auction prices in ISONE remained strong as demand was expected to rise at the end of the week. Internal Hub peak moved up $6.14 to about $72.50/MWh and off-peak was up $8.62 to about $40.64/MWh.

Connecticut peak added $5.44, going to about $73.86/MWh and off-peak increased $8.59 to about $41.03/MWh.

Vermont peak gained $6.12 to about $73.79/MWh and off-peak was up $8.79 to about $40.87/MWh.

Day-ahead auction prices in NYISO were mixed, with heavy demand expected at the end of the week. NYISO also expected generation outages in the state to be about 4,462 MW on Friday, about 400 MW more than on Thursday.

Long Island peak added over $37, going to about $258.56/MWh and off-peak jumped $14.64 to about $58.08/MWh. West peak surged up $52.73 to about $115.18/MWh, while off-peak slipped $1.73 to about $33/MWh. New York City peeled back $7.42 to about $84.86/MWh and off-peak moved up $2.17 to about $43.69/MWh.

Hudson Valley peak gave up $6.90, going to about $84.55/MWh and off-peak was up $2.22 to about $43.38/MWh.

Capital region gained more than $20 to about $87/MWh and off-peak added $7.31 to about $45.73/MWh.

Consolidated Edison and Long Island Power Authority both declared Thursday a minimum oil burn day, which requires dual-fuel facilities to keep certain levels of oil in case of disruptions to

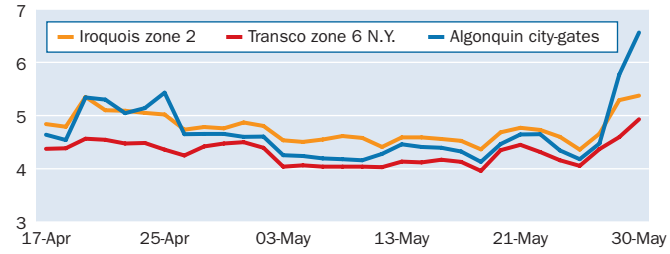
(continued on page 10)

Northeast day-ahead bilateral indexes for May 31 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	87.00	13.00	48.59	13551
N.Y. Zone-G	84.50	-7.00	51.93	16400
N.Y. Zone-J	84.75	-7.50	55.25	16448
N.Y. Zone-A	61.50	-1.00	44.52	14397
Ontario*	52.25	-1.00	34.14	11263
Off-Peak				
Mass Hub	44.00	10.00	33.16	6854
N.Y. Zone-G	43.50	2.25	34.20	8443
N.Y. Zone-J	43.75	2.25	34.68	8491
N.Y. Zone-A	33.00	-1.75	30.82	7725
Ontario*	25.00	-1.50	20.73	5389

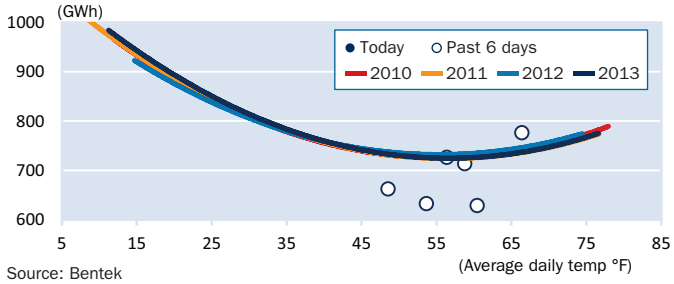
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO load per degree



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 29-May	%Chg	% Chg Year-ago	Forecast 30-May	31-May	01-Jun	02-Jun	03-Jun
ISONE								
Load	340	10	2	407	419	379	357	365
Generation								
Coal	6	40	37	16	21	18	13	7
Gas	161	26	-9	196	200	184	166	152
Nuclear	95	0	-10	98	98	98	98	98
NYISO								
Load	436	8	1	552	542	480	470	473
Generation								
Coal	11	4	85	27	28	24	20	15
Gas	182	41	-11	215	222	201	184	163
Nuclear	124	-8	9	128	128	128	128	128

Source: Bentek

ISONE day-ahead LMP for May 31 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	72.50	0.00	0.55	6.14	44.72	11576
Connecticut	73.86	0.00	1.91	5.44	45.39	12925
NE Mass-Boston	71.75	0.00	-0.21	5.88	44.72	11456
SE Mass	72.47	0.00	0.52	5.95	44.79	11572
West-Central Mass	72.84	0.00	0.89	5.83	45.05	11630
Rhode Island	71.34	0.00	-0.62	6.00	45.36	11390
Maine	65.40	-0.04	-6.51	5.36	43.44	12683
New Hampshire	70.74	0.00	-1.22	5.47	44.91	13717
Vermont	73.79	0.00	1.84	6.12	44.91	14309
Off-Peak						
Internal Hub	40.64	0.00	0.20	8.62	31.47	6951
Connecticut	41.03	0.00	0.59	8.59	31.71	7376
NE Mass-Boston	40.48	0.00	0.04	8.50	31.46	6924
SE Mass	40.67	0.00	0.23	8.51	31.50	6956
West-Central Mass	40.88	0.00	0.44	8.65	31.66	6992
Rhode Island	40.91	0.00	0.46	8.59	31.92	6996
Maine	37.58	0.00	-2.86	8.01	30.47	7189
New Hampshire	39.66	0.00	-0.78	8.23	31.36	7586
Vermont	40.87	0.00	0.43	8.79	31.42	7817

NYISO day-ahead LMP for May 31 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	86.90	-17.38	4.53	20.04	44.62	17773
Central Zone	71.22	-4.98	1.26	10.38	41.76	16658
Dunwoodie Zone	84.42	-12.54	6.90	-7.71	48.44	16467
Genesee Zone	69.08	-2.76	1.33	9.97	40.15	16156
Hudson Valley Zone	84.55	-12.44	7.12	-6.90	48.12	16492
Long Island Zone	258.56	-185.70	7.88	37.07	88.88	50436
Millwood Zone	84.74	-12.62	7.14	-7.43	48.41	16529
Mohawk Valley Zone	68.94	-1.51	2.45	4.59	42.43	14821
N.Y.C. Zone	84.86	-12.55	7.33	-7.42	51.10	16553
North Zone	61.20	0.36	-3.43	3.55	38.34	11867
West Zone	115.18	-49.32	0.87	52.73	43.24	26939
Off-Peak						
Capital Zone	45.73	-12.14	1.78	7.30	32.39	9341
Central Zone	33.32	-1.38	0.13	-2.79	30.65	7749
Dunwoodie Zone	43.32	-8.75	2.76	2.19	33.07	8714
Genesee Zone	32.71	-1.08	-0.18	-2.41	29.99	7608
Hudson Valley Zone	43.38	-8.68	2.89	2.22	33.26	8726
Long Island Zone	58.08	-22.73	3.54	14.64	40.16	11683
Millwood Zone	43.36	-8.80	2.75	2.24	33.07	8722
Mohawk Valley Zone	33.68	-1.09	0.79	-3.45	31.24	7177
N.Y.C. Zone	43.69	-8.75	3.13	2.17	33.55	8789
North Zone	30.46	0.25	-1.10	-3.90	29.47	5826
West Zone	32.97	-1.37	-0.21	-1.74	29.98	7669

Generation unit outage report

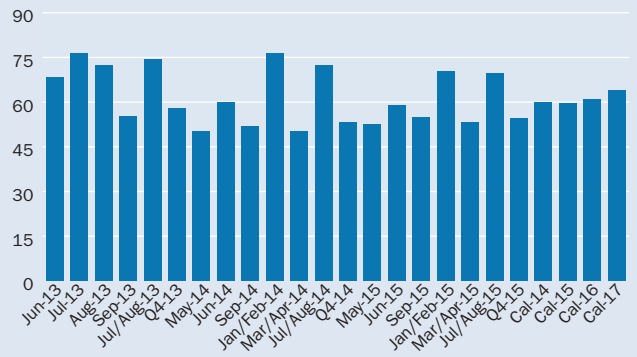
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-1/Bruce Power	750	n	Ont.	PMO	Unk	04/28/13
Bruce-3/Bruce Power	820	n	Ont.	MO	Unk	05/24/13
Pickering-4/OPG	500	n	Ont.	MO	Unk	05/24/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13

Northeast Platts-ICE Forward Curve, May 30 ($/MWh)

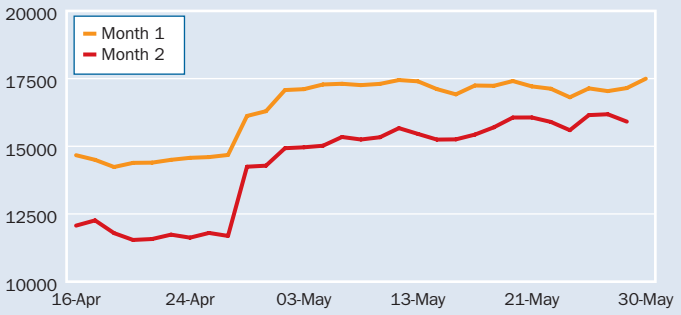
Prompt month: Jun 13	On-peak	Off-peak
Mass Hub	63.25	47.25
N.Y. Zone G	62.75	45.25
N.Y. Zone J	68.25	48.50
N.Y. Zone A	45.75	35.25
Ontario*	36.00	25.25

*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
N.Y. Zone-G		
Bal-month	05/24	76.00-77.00

*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 rise, countering spot gas drop

Daily power prices in the Electric Reliability Council of Texas climbed Thursday, despite weaker spot natural gas prices as demand forecasts remained at elevated levels. The NYMEX July natural gas futures contract settled at $4.023/MMBtu, down 16.1 cents from Wednesday's close.

The NYMEX July gas contract was down due to bearish weather forecasts and a gas storage injection estimate from the Energy Information Administration that was on par with expectations, sources said.

ERCOT North Hub next-day on-peak physical power rose about $2.86 to trade between $39.25 and $39.50/MWh for Friday delivery on IntercontinentalExchange.

Spot natural gas at Houston Ship Channel slipped about 3.4 cents to $4.095/MMBtu.

High temperatures across the ERCOT region were forecast to be steady this week, with Houston highs holding around 90 degrees and Dallas edging up to 90 degrees.

System load in ERCOT was forecast to peak at 52,217 MW Thursday and 55,833 MW Friday. The actual peak of 47,789 MW on Wednesday was about 4,000 MW under what was forecasted.

Real-time ERCOT North Hub prices averaged just under $22/MWh up until 9 a.m. CDT Thursday, with limited congestion seen across hubs and zones.

Wind generation was forecast to peak near 8,800 MW around 6 a.m. CDT Thursday and about 6,900 MW Friday morning. ERCOT expects wind generation to drop to about 3,300 MW Thursday evening and 3,900 MW Friday evening.

North Hub Next-week on-peak futures rose about $1, with bids at $39.50 and offers at $40.75/MWh.

In the Southeast, dailies moved little Thursday, with stable weather until the weekend. Into Southern next-day on-peak power markets were at about $42/MWh for Thursday delivery on ICE, mostly unchanged.

Spot natural gas at Transco Zone-3 dropped 4 cents to about $4.13/MMBtu.

High temperatures in Atlanta were forecast in the high-80s for

(continued on page 11)

Southeast & Central day-ahead bilateral indexes for May 31 ($/MWh)

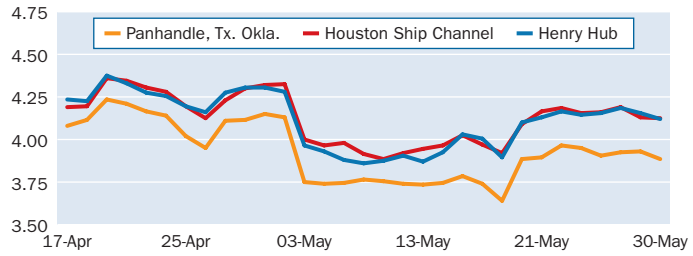
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	58.00	-7.50	42.58	13488
Southern, Into	42.00	0.00	38.07	10139
Florida	43.00	0.00	38.76	10214
TVA, Into	43.50	-1.00	39.42	10413
Entergy, Into	38.25	-0.75	35.99	9421
Southeast Off-Peak				
VACAR	30.00	0.50	27.47	6977
Southern, Into	29.00	0.00	26.70	7001
Florida	30.00	0.00	27.08	7126
TVA, Into	27.75	-0.50	26.62	6643
Entergy, Into	26.25	0.75	23.21	6466
ERCOT On-peak				
ERCOT, North	39.55	2.91	38.38	9796
ERCOT, Houston	43.25	2.75	39.92	10530
ERCOT, South	42.25	3.75	39.58	10322
ERCOT, West	39.00	4.00	37.58	9787
ERCOT Off-Peak				
ERCOT, North	24.96	0.86	25.28	6182
ERCOT, Houston	25.75	1.25	25.42	6269
ERCOT, South	25.75	1.50	25.40	6291
ERCOT, West	23.50	3.00	21.80	5897
SPP/MRO On-peak				
MAPP, Soth	44.00	-2.00	39.30	10811
SPP, North	43.00	-1.00	38.05	11068
SPP/MRO Off-Peak				
MAPP, Soth	25.50	-0.25	23.90	6265
SPP, North	26.00	0.50	23.48	6692

Southeast load and generation mix forecast (GWh)

	Actual 29-May	%Chg	% Chg Year-ago	Forecast 30-May	31-May	01-Jun	02-Jun	03-Jun
ERCOT								
Load	975	-1	-1	924	984	944	885	953
Generation								
Coal	420	0	21	386	408	416	409	405
Gas	359	-2	-16	364	400	406	389	380
Nuclear	123	0	-3	123	123	123	123	123
SPP								
Load	686	4	-4	690	700	675	635	646
Generation								
Coal	421	-2	17	422	421	417	412	410
Gas	169	24	-29	172	178	169	152	144
Nuclear	49	0	-5	49	49	49	49	49

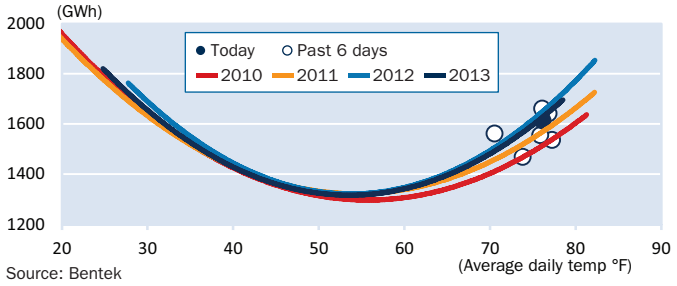
Source: Bentek

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



Source: Platts

ERCOT & SPP load per degree



Source: Bentek

ERCOT average day-ahead LMP for May 31 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	39.00	1.37	37.22	9598
Hub Average	39.46	1.42	37.39	9710
Houston Hub	41.73	1.11	38.47	10149
North Hub	38.23	1.37	36.94	9458
South Hub	40.63	2.74	37.78	9914
West Hub	37.23	0.51	36.37	9339
AEN Zone	45.16	3.74	37.92	11328
CPS Zone	44.44	3.47	40.20	10914
LCRA Zone	41.59	2.84	37.68	10215
Rayburn Zone	38.30	1.41	37.65	9476
Houston Zone	42.38	0.90	38.85	10308
North Zone	38.33	1.38	37.33	9484
South Zone	45.48	1.10	41.12	11098
West Zone	50.26	-1.70	63.09	12607
Off-Peak				
Bus Average	25.26	2.21	25.01	6194
Hub Average	25.30	2.28	24.77	6204
Houston Hub	25.87	2.10	25.55	6276
North Hub	25.17	2.14	25.27	6175
South Hub	25.49	2.27	25.18	6195
West Hub	24.66	2.58	23.06	6197
AEN Zone	25.37	1.93	25.20	6373
CPS Zone	25.94	2.25	25.54	6339
LCRA Zone	25.38	2.11	25.12	6203
Rayburn Zone	25.18	2.00	26.65	6178
Houston Zone	25.97	1.91	25.60	6302
North Zone	25.18	2.15	25.83	6176
South Zone	25.95	2.30	25.48	6307
West Zone	24.92	1.97	24.63	6261

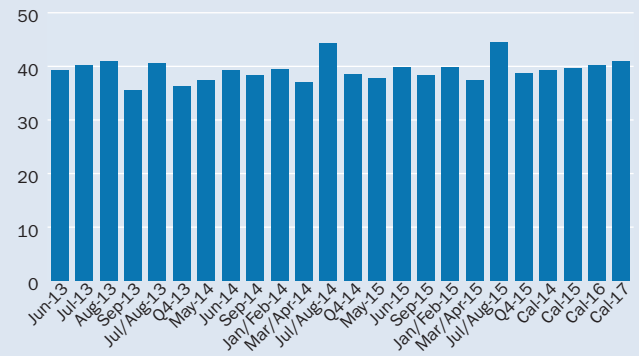
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	05/29	41.00-43.00
Bal-week (off-peak)	05/29	28.00-30.00
Next-week	05/30	38.00-39.00
Next-week	05/28	38.00-39.00
Entergy, Into		
Bal-week	05/29	36.00-39.00
Next-week	05/30	36.00-38.00
Next-week	05/28	36.00-38.00
ERCOT, North		
Bal-month	05/29	37.00-38.00
Next-week	05/29	38.00-39.00
Next-week	05/28	38.00-40.00
ERCOT, Houston		
Bal-month	05/28	39.25-41.25
ERCOT, West		
Bal-month (off-peak)	05/29	22.50-24.50

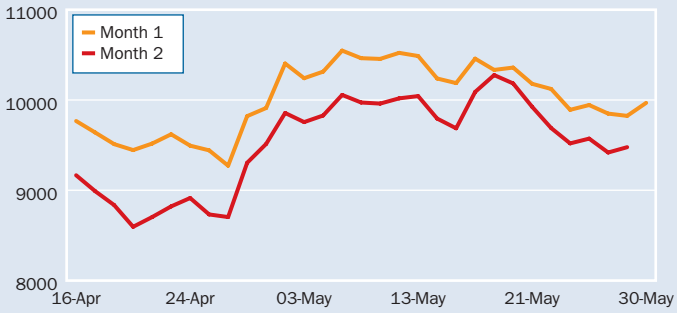
Southeast & Central Platts-ICE Forward Curve, May 30 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
Southern Into	39.25	29.50
Entergy Into	39.00	26.75
ERCOT North	46.00	32.00
ERCOT Houston	47.00	32.50
ERCOT West	46.75	31.25
ERCOT South	46.25	31.75

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.		Retired	09/26/09
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Harris/Duke	960	n	N.C.	MO	Unk	05/16/13

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

Dailies finish mixed; most terms retreat

Western dailies were mixed Thursday amid higher demand expected in California and lower spot natural gas prices. Most terms fell, and the NYMEX July natural gas futures contract posted a preliminary settlement of $4.023/MMBtu, down 16.1 cents from Wednesday's close.

In the Northwest, Mid-Columbia day-ahead on-peak was down about 25 cents to trade between $33 and $35/MWh for delivery on Saturday. Mid-C day-ahead off-peak was up more than $7.25 to trade between and $15 and 21.50/MWh.

Portland, Oregon, forecast highs were to climb to around 70 on Saturday, up more than 5 degrees from Thursday. Projected lows were for the high 40s to the low 50s.

The Bonneville Power Administration's wind at 7 a.m. PDT Thursday was 2,867 MW and its hydropower was 11,507 MW.

In California, SP15 next-day on-peak was up $1 to trade between $54.50 and $55.50/MWh. SP15 day-ahead off-peak lost 50 cents to about $36.50/MWh. NP15 day-ahead on-peak was up about nearly $2 to around $50/MWh. NP15 day-ahead off-peak fell 50 cents to trade between $32.50 and 33.50/MWh.

Sacramento, California, expected highs in the upper 90s on Saturday, an increase of more than 10 degrees from Thursday. Forecast lows were for the high 50s to the low 60s. Burbank, California, expected highs in the mid- to upper 80s with lows from around 60 to 65.

The California Independent System Operator projected peak demand to hit 31,946 MW on Thursday, 34,617 on Friday, and 34,582 MW on Saturday. Renewables were 4,395 MW and wind was about 2,400 MW at 7 a.m. PDT on Thursday.

In the desert Southwest, Palo Verde next-day on-peak was up almost $2.50 to trade between $41 and $41.75/MWh. Palo Verde day-ahead off-peak was down about 25 cents to trade between $25.25 and $27.50/MWh.

Phoenix highs were forecast to top 100 by Saturday, an increase from the upper 90s on Thursday. Expected lows were for the mid-70s to about 80.

On Thursday morning, Unit 1 at the Palo Verde nuclear plant was operating at 96% generating capacity, according to the Nuclear Regulatory Commission website.

Next-day natural gas retreated in the Rockies and California. Opal was down 2.1 cents to $3.944/MMBtu, Pacific Gas and Electric city-gate lost 2.5 cents to $4.230/MMBtu, and SoCal city-gate fell 5.4 cents to $4.246/MMBtu.

Day-ahead prices in the California ISO auction rose Thursday afternoon following the higher peak demand forecast. SP15 on-peak rose $8.91 cents to $57.02/MWh, while SP15 off-peak was up $1.73 to $36.61/MWh. NP15 on-peak gained $3.31 to $49.90/MWh, and NP15 off-peak added $1.46 to $36.18/MWh. ZP26 on-peak was up $5.19 to $50.03/MWh, and ZP26 off-peak increased $1.67 to $35.49/MWh.

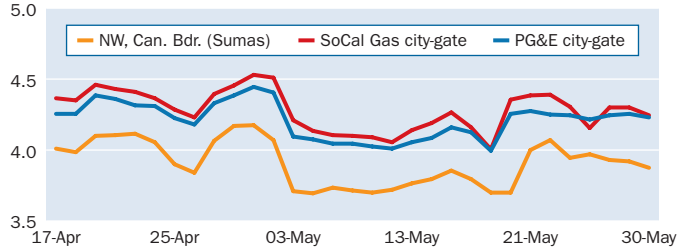
In the Northwest, Mid-Columbia on-peak June fell 75 cents

(continued on page 11)

Western day-ahead bilateral indexes for Jun 1 ($/MWh)

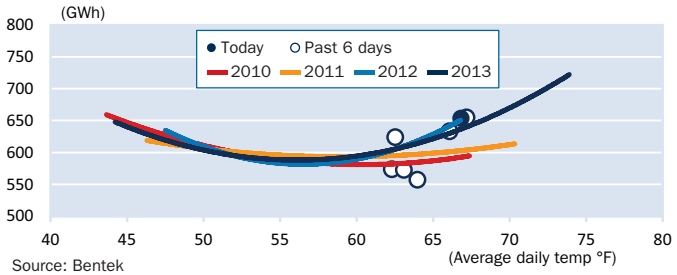
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	36.50	-0.58	36.50	9305
Mid-C	33.93	-0.34	33.93	8832
Palo Verde	41.34	2.27	41.34	9713
Mead	43.75	3.00	43.75	9951
Mona	35.75	1.00	35.75	8865
Four Corners	40.71	0.21	40.71	10253
NP15	49.00	1.25	49.00	11288
SP15	55.00	0.75	55.00	13248
Off-Peak				
COB	22.14	3.39	22.14	4705
Mid-C	19.40	7.56	19.40	3052
Palo Verde	26.56	-0.44	26.56	6712
Mead	26.50	-0.76	26.50	6657
Mona	20.25	-0.25	20.25	5230
Four Corners	26.25	0.25	26.25	6582
NP15	33.50	-0.25	33.50	7979
SP15	36.50	-0.50	36.50	9035

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO load per degree



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 29-May	%Chg	% Chg Year-ago	Forecast 30-May	31-May	01-Jun	02-Jun	03-Jun
CAISO								
Load	655	3	2	653	673	691	682	721
Generation								
Gas	158	21	3	170	201	265	289	272
Nuclear	56	0	-14	55	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for May 31 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	49.90	-3.13	-3.17	3.31	42.00	11796
SP15 Gen Hub	57.02	2.03	-1.21	8.91	49.05	13906
ZP26 Gen Hub	50.03	-2.76	-3.40	5.19	40.19	12203
Off-Peak						
NP15 Gen Hub	36.18	-0.04	-1.10	1.46	31.24	8516
SP15 Gen Hub	36.61	0.00	-0.71	1.73	32.97	8897
ZP26 Gen Hub	35.49	0.00	-1.83	1.67	28.64	8625

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	05/28	34.25-34.75
Bal-month (off-peak)	05/28	5.00-7.50

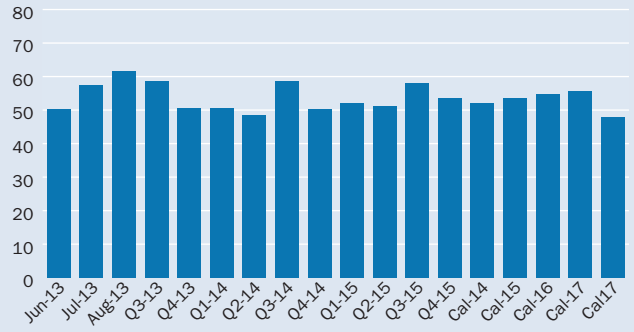
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Colgate-2/PCWA	176	h	Calif.	MO	Unk	05/29/13
Contra Costa-6/NRG	337	g	Calif.	MO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
Desert Star/SDG&E	495	g	Calif.	PMO	Unk	03/24/13
Empire-2/Inland Empire	366	g	Calif.	PMO	Unk	05/20/13
Encina-1/Cabrillo	106	g	Calif.	MO	Unk	05/27/13
Etiwanda-3/NRG	320	g	Calif.	MO	Unk	05/29/13
Huntington Beach-3/AES	225	g	Calif	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif	PMO	Unk	04/14/13
Kerkhoff-2/PG&E	154	h	Calif.	PMO	Unk	05/29/13
La Paloma-1/La Paloma	260	g	Calif.	PMO	Unk	05/27/13
Los Esteros/Calpine	188	g	Calif.	PMO	Unk	05/27/13
Morrow Bay-4/Dynegy	325	g	Calif.	MO	Unk	05/27/13
Moss Landing-2/Dynegy	510	g	Calif.	PMO	Unk	05/22/13
Ocotillo/Pattern	265	w	Calif.	MO	Unk	05/16/13
Otay Mesa/Otay Mesa	604	g	Calif.	MO	Unk	05/29/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12
Sunrise/Edison	586	g	Calif.	MO	Unk	05/16/13
Valley Solar/NRG	210	s	Calif.	PMO	Unk	05/12/13

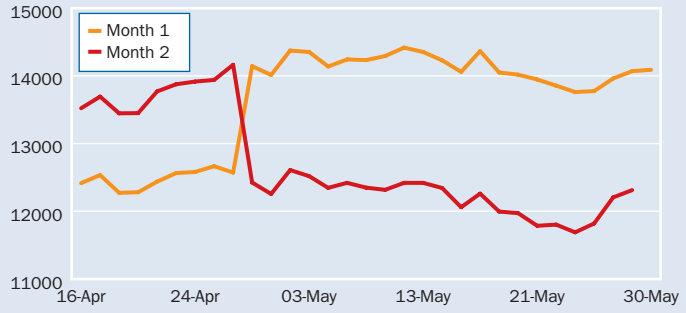
Western Platts-ICE Forward Curve, May 30 ($/MWh)

Prompt month: Jul 13	On-peak	Off-peak
Mid-C	34.00	19.50
Palo Verde	41.50	27.00
Mead	43.25	28.75
NP15	44.75	33.50
SP15	50.25	36.50

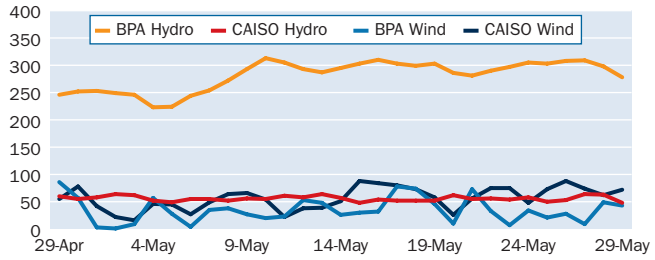
SP15: Forward curve on-peak ($/MWh)



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 soften, following spot gas

Daily power prices in the Mid-Atlantic and Midwest were mainly weaker Thursday, even as strong demand was expected to linger heading into the weekend. Forward power prices were down as the NYMEX July natural gas futures contract settled at $4.023/MMBtu, down 16.1 cents from Wednesday's close.

PJM Interconnection forecasted peak demand on Thursday around 133,851 MW and 130,040 MW on Friday.

Spot natural gas in the region peeled back, with Texas Eastern M-3 down 9 cents to $4.32/MMBtu on the IntercontinentalExchange.

High temperatures in the region were forecast to stay mostly in the low 90s.

PJM West Hub on-peak packages for Friday were flat to lower, with values in the low $80s to low $90s/MWh. PJM West Hub off-peak was holding in the low $30s/MWh.

Midcontinent Independent System Operator dailies moved down heading into the weekend amid steady spot gas prices. Chicago city gates spot gas was flat, around $4.20/MMBtu.

Indiana Hub peak peeled back about $5 to the upper $40s/MWh, and off-peak was flat to lower in the mid-$20s/MWh. Minnesota peak was down about $5 in the upper $30s/MWh.

Dailies in the Midwestern portion of PJM were heading lower Thursday, with weakness across nearby power markets. AEP-Dayton Hub peak was down in the upper $50s to upper $60/MWh and off-peak lost about $2, going to the upper $20s/MWh.

Northern Illinois Hub peak lost about $10, going to the mid-$50s/MWh and off-peak gave up about $3, going to the low $20s/MWh.

Day-ahead auction prices in PJM were mostly higher Thursday, with strong demand and a hot weather alert across the grid operator's territory.

PSEG Zone peak gained the most on the day, rising $15.68 to about $89.22/MWh, with off-peak moving up $2.35 to about $33.84/MWh. Rockland Electric Zone peak slipped more than $1 to about $71.51/MWh and off-peak was up nearly $2 to about $33.27/MWh.

Western Hub peak went up $3.13 to about $78.02/MWh and off-peak added $1.57 to about $31.75/MWh. PPL Zone peak jumped $15.68 to about $89.22/MWh and off-peak added $2.34 to about $33.26/MWh.

BG&E peak moved up $5.31 to about $87.85/MWh and off-peak was $1.53 higher to about $33.11/MWh.

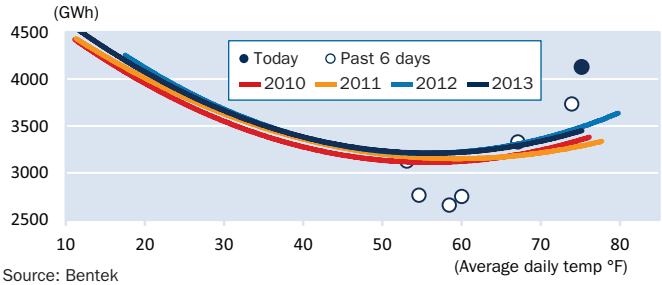
Chicago Hub peak was up 28 cents to about $56.59/MWh and off-peak shed $1.77, going down to $23.80/MWh.

MISO day-ahead auction clearing prices came down Thursday, with the greatest declines in the eastern portion of the MISO region. Illinois Hub on-peak average dropped $16.21 to $39.19/MWh for Friday delivery. Indiana Hub on-peak average fell $12.22 to $49.45/MWh, while the Michigan Hub on-peak average moved down $12.53 to $38.48/MWh.

PJM & MISO day-ahead bilateral indexes for May 31 ($/MWh)

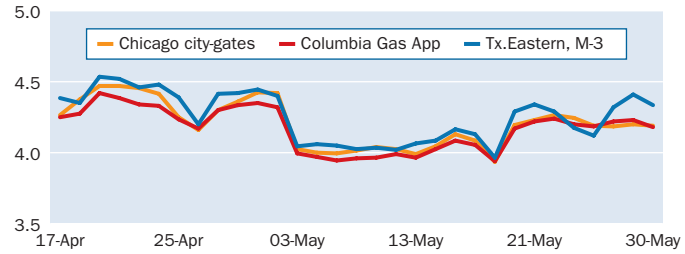
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	86.25	-5.25	50.97	20766
Dominion Hub	81.50	-5.00	51.07	19222
AD Hub	62.00	-9.00	45.34	15140
NI Hub	55.00	-11.00	42.65	13126
PJM Off-Peak				
PJM West	31.00	1.00	29.82	7464
Dominion Hub	32.00	2.00	29.93	7547
AD Hub	28.00	-2.00	28.67	6838
NI Hub	22.00	-3.00	22.39	5251
MISO On-peak				
Indiana Hub	47.75	-4.50	43.17	11437
Michigan Hub	49.25	-4.50	44.74	11174
Minnesota Hub	36.75	-5.75	38.90	8904
Illinois Hub	53.25	-2.25	42.72	12701
MISO Off-Peak				
Indiana Hub	24.25	-2.25	26.39	5808
Michigan Hub	29.50	-2.00	29.69	6693
Minnesota Hub	13.75	-8.75	20.77	3331
Illinois Hub	25.00	-1.25	24.76	5963

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 29-May	%Chg	% Chg Year-ago	Forecast 30-May	31-May	01-Jun	02-Jun	03-Jun
PJM								
Load	2295	14	3	2612	2540	2248	2040	2104
Generation								
Coal	997	7	13	1161	1117	1008	905	841
Gas	439	71	-21	512	467	390	330	296
Nuclear	647	-3	1	671	671	671	671	671
MISO								
Load	1437	9	2	1513	1491	1327	1198	1282
Generation								
Coal	1165	6	11	1235	1173	1096	1012	958
Gas	131	40	-41	115	110	98	65	50
Nuclear	172	2	-11	181	181	181	181	181

Source: Bentek

MISO average day-ahead LMP for May 31 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	37.23	-1.11	0.87	-12.22	39.14	8904
Michigan Hub	38.48	-0.34	1.36	-12.53	40.84	8712
Minnesota Hub	37.17	1.15	-1.44	-1.40	35.10	8985
Illinois Hub	39.19	2.44	-0.71	-16.21	38.99	9337
Off-Peak						
Indiana Hub	22.50	0.97	0.48	-4.31	26.38	5339
Michigan Hub	27.97	5.92	1.00	-3.78	29.62	6292
Minnesota Hub	13.15	-7.14	-0.76	-2.39	19.15	3137
Illinois Hub	25.67	4.95	-0.32	-1.15	24.57	6095

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

Package	Trade date	Range
PJM West		
Bal-month	05/28	87.00-104.00
Bal-month	05/24	72.00-77.00
Next-week	05/30	43.25-44.25
Next-week	05/29	45.50-46.50
Next-week	05/28	48.00-49.00
Next-week	05/24	57.50-61.50

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Beaver Valley-2/FE	901	n	Pa.	MO	Unk	05/29/13
Kewaunee/Dominion	581	n	Wis.		Retired	05/07/13
Monticello/Xcel	666	n	Minn.	PMO	05/31/13	03/02/13
North Anna-2/Dominion	903	n	Va.	MO	Unk	05/29/13
Palisades/Entergy	778	n	Mich.	MO	Unk	05/05/13
Susquehanna-1/PPL	1330	n	Pa.	PMO	05/31/13	05/09/13

PJM average day-ahead LMP for May 31 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	58.85	-9.34	-3.80	2.78	39.35	13908
AEP-Dayton Hub	62.34	-7.57	-2.08	3.20	41.05	14732
ATSI Gen Hub	72.31	-0.63	0.95	12.21	41.54	17012
Chicago Gen Hub	54.97	-11.84	-5.19	-0.12	37.61	13101
Chicago Hub	56.59	-11.43	-3.97	0.28	38.32	13488
Dominion Hub	73.32	2.41	-1.09	3.57	44.83	17261
Eastern Hub	76.25	1.17	3.09	9.44	44.14	17644
New Jersy Hub	83.75	9.18	2.57	13.40	45.47	19379
Northern Illinios Hub	55.89	-11.62	-4.48	0.11	38.07	13321
Ohio Hub	62.31	-7.71	-1.97	2.85	41.37	14653
West Internal Hub	76.88	5.01	-0.12	13.06	42.65	18474
Western Hub	78.02	6.52	-0.49	3.13	44.71	18747
AEP Zone	65.27	-4.91	-1.81	5.80	41.11	15426
Allegheny Power Zone	72.49	0.15	0.35	7.99	42.35	17411
Atlantic Elec Zone	76.18	1.66	2.53	9.90	43.59	17627
ATSI Zone	72.75	-0.97	1.73	10.54	42.03	17116
BG&E Zone	87.85	12.35	3.51	5.31	49.63	20817
ComEd Zone	56.25	-11.62	-4.11	0.16	38.19	13407
Dayton P&L Zone	65.15	-6.54	-0.30	5.10	41.68	15583
Delmarva P&L Zone	75.53	1.15	2.38	8.92	43.93	17476
Dominion Zone	73.88	1.99	-0.11	3.21	45.44	17393
Duke Zone	65.88	-2.48	-3.63	6.38	40.45	15759
Duquesne Light Zone	78.75	5.97	0.78	4.87	40.76	18836
JCPL Zone	77.36	2.87	2.50	10.53	43.50	17902
MetEd Zone	74.32	1.20	1.12	11.20	43.08	17378
PECO Zone	74.87	1.29	1.59	9.28	42.87	17508
Pennsylvania Elec Zone	75.22	2.61	0.62	7.10	43.51	18054
PEPCO Zone	85.25	11.30	1.96	4.10	48.83	20202
PPL Zone	77.91	4.82	1.10	13.77	43.36	18219
PSEG Zone	89.22	14.55	2.69	15.68	47.11	20646
Rockland Elec Zone	71.51	-3.19	2.70	-1.18	47.64	16547
Off-Peak						
AEP Gen Hub	27.31	-1.61	-1.36	-0.29	26.89	6396
AEP-Dayton Hub	28.32	-1.01	-0.95	0.17	27.92	6633
ATSI Gen Hub	30.93	0.62	0.03	1.61	28.17	7223
Chicago Gen Hub	22.86	-5.16	-2.27	-2.02	22.23	5443
Chicago Hub	23.80	-4.60	-1.88	-1.77	22.62	5668
Dominion Hub	32.82	2.85	-0.32	2.52	28.75	7645
Eastern Hub	33.19	1.41	1.50	1.96	29.62	7559
New Jersy Hub	33.60	1.65	1.67	2.24	29.73	7653
Northern Illinios Hub	21.81	-6.43	-2.04	-2.79	22.34	5194
Ohio Hub	28.34	-0.99	-0.95	0.20	28.14	6613
West Internal Hub	31.60	1.39	-0.08	1.97	28.23	7521
Western Hub	31.75	1.31	0.15	1.57	28.68	7556
AEP Zone	29.34	-0.17	-0.78	0.84	27.87	6870
Allegheny Power Zone	31.16	0.71	0.16	1.55	28.26	7410
Atlantic Elec Zone	32.97	1.29	1.40	1.79	29.44	7509
ATSI Zone	31.11	0.56	0.27	1.66	28.32	7265
BG&E Zone	33.11	1.65	1.18	1.53	29.72	7755
ComEd Zone	22.22	-6.12	-1.94	-2.55	22.37	5292
Dayton P&L Zone	28.57	-1.29	-0.43	-0.27	27.89	6778
Delmarva P&L Zone	33.01	1.39	1.34	1.90	29.56	7518
Dominion Zone	32.76	2.44	0.04	2.22	28.94	7631
Duke Zone	27.17	-1.56	-1.55	-0.33	27.02	6447
Duquesne Light Zone	30.22	0.12	-0.18	1.72	27.16	7172
JCPL Zone	33.53	1.53	1.72	2.24	29.51	7637
MetEd Zone	32.84	1.48	1.08	2.05	29.19	7576
PECO Zone	32.71	1.33	1.10	1.75	29.15	7546
Pennsylvania Elec Zone	32.03	0.97	0.78	1.69	29.05	7642
PEPCO Zone	32.89	1.80	0.80	1.59	29.45	7702
PPL Zone	33.26	1.81	1.17	2.34	29.27	7673
PSEG Zone	33.84	1.82	1.74	2.35	29.98	7707
Rockland Elec Zone	33.27	1.32	1.67	1.94	29.89	7578

The Minnesota Hub on-peak average, having stayed low under preasure from congestion, only slipped $1.40 to $37.17/MWh for Friday delivery. Minnesota Hub off-peak average was down $2.39 to $13.15/MWh.

The highest hourly day-ahead price was for the hour ending 3 p.m. EDT Friday for the Illinois Hub at $49.80/MWh, a decrease of about $20 from Thursday delivery. The lowest hourly day-ahead price was for the hour ending 4 a.m. CDT for the Minnesota Hub at $7.96/MWh, a decrease of about $8.80 from Thursday delivery.

Mid-Atlantic forward power prices fell Thursday as natural gas futures tumbled after the release of the Energy Information Administration's weekly gas storage estimate.

PJM West on-peak June financial futures were $1.50 weaker, with bids at $51.50/MWh and offers at $51.70/MWh on ICE at about 2:30 p.m. EDT. PJM West on-peak July-August lost $1.25 to about $60.75/MWh, while on-peak fourth quarter came down $1 to about $44.50/MWh. PJM West off-peak June shed 25 cents to about $34.50/MWh.

Midwest forwards were down Thursday with plummeting gas futures. AEP Dayton Hub on-peak June financial futures fell 75 cents to about $46.75/MWh. AD Hub on-peak July-August tumbled $1.25 to about $54.25/MWh.

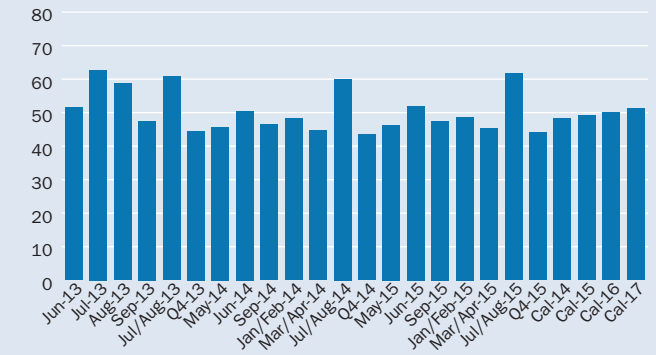
Indiana Hub on-peak June lost $1 to about $42/MWh, while Indiana Hub on-peak July-August came down $1.25 to about $49.75/MWh.

Northern Illinois Hub on-peak June dropped 75 cents to about $44.50/MWh. NI Hub on-peak July-August fell $1.25 to about $52/MWh.

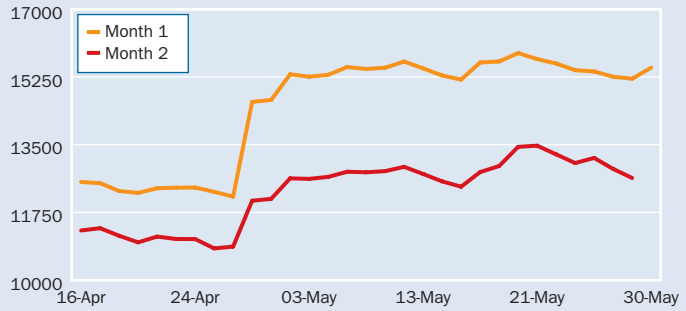
PJM & MISO Platts-ICE Forward Curve, May 30 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
PJM West	51.50	34.50
AD Hub	46.75	31.75
NI Hub	44.50	27.25
Indiana Hub	42.00	27.75

PJM West: Forward curve on-peak ($/MWh)



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



Northeast markets *... from page 2*

gas supplies. Real-time prices for Long Island Thursday afternoon were averaging near $300/MWh, while New York City averaged below $60/MWh.

Northeast term power prices were mostly down Thursday as July NYMEX gas futures plunged after the release of the EIA gas storage estimate.

In New England, Mass Hub on-peak June financial futures dropped $1, with bids at $62.50/MWh and offers at $64/MWh on ICE at about 2:30 p.m. EDT. Mass Hub on-peak July-August tumbled $1.25 to about $59.50/MWh, while on-peak fourth quarter fell 40 cents to about $59.10/MWh. Mass Hub off-peak June lost $1 to about $47.25/MWh.

New York Zone G on-peak June came down $1.25 to about $62.75/MWh. Zone G on-peak July-August dropped $1.50 to about $68/MWh.

New York Zone A on-peak June was unchanged at about $45.75/MWh, while Zone A on-peak July-August packages stood still at about $51.50/MWh.

Southeast markets ... *from page 4*

the rest of the week, just above the city's seasonal average. Lows are expected to range from about 65 to 70.

ERCOT day-ahead auction clearing prices climbed across most delivery locations Thursday afternoon, with peak load forecasted to increase.

The West Zone continued to see significant congestion for delivery between 4 to 6 p.m. CDT on Friday. West Zone clearing price for the hour-ending 5 p.m. CDT was $90.35/MWh, the highest price for the auction and $25.69 above the hub average. However, the average for the West Zone slipped $1.70 to $50.26/MWh for Friday delivery.

The AEN Zone also saw higher prices with congestion, but below the level at the West Zone.

The North Hub on-peak average climbed $1.37 to $38.23/MWh for Friday delivery, and the North Zone on-peak average was up $1.38 to $38.33/MWh. Houston Hub on-peak average rose $1.11 to $41.73/MWh, and the Houston Zone on-peak average was up 90 cents to $42.38/MWh.

The lowest hourly day-ahead price was for the hour ending 5 a.m. CDT for the West Hub at $18.62/MWh, an increase of about $1 from the same hour for Thursday delivery.

South Central US June terms tumbled Thursday. ERCOT Houston on-peak June dropped $1.50 to about $47/MWh, but July-August jumped $1.60 to about $91.25/MWh. Heat rates were up about 210 Btu/kWh on ICE around 2:30 p.m. EDT. ERCOT North June dived $1.50 to about $46/MWh, July-August advanced $1.60 to about $92/MWh, and September slid $1 to about $45.50/MWh.

Into Entergy June fell 25 cents to about $39/MWh, and July-August dipped $1 to about $39.40/MWh.

Southeast US on-peak June fell Thursday, as did July NYMEX gas futures. Into Southern June fell 25 cents to about $39.25/MWh, July-August skidded $1 to about $40.65/MWh, and September slipped down $1 to about $35.50/MWh.

West markets ... *from page 6*

with bids at $33.75 and offers at $34.25/MWh on ICE around 2:30 p.m. EDT. July dropped $1.50 to about $43.25/MWh, and the third quarter slid $1.15 to about $44.25/MWh. In California, SP15 on-peak June financial terms sank $1.50 with bids at $50 and offers at $50.25/MWh. July tanked $2 to about $57.50/MWh, and Q3 slipped down $1.75 to about $58.60/MWh. NP15 June stayed at about $44.75/MWh, and Q3 skidded $1.25 to about $52.25/MWh. Palo Verde June dipped $1 to about $41.50/MWh, July lost $1.25 to about $49.25/MWh, and Q3 dipped $1.15 to about $47.85/MWh.

EMISSIONS MARKETS

Calif. GHG allowances post moderate gain

California greenhouse gas allowance prices increased, while volume was down during the holiday-shortened week.

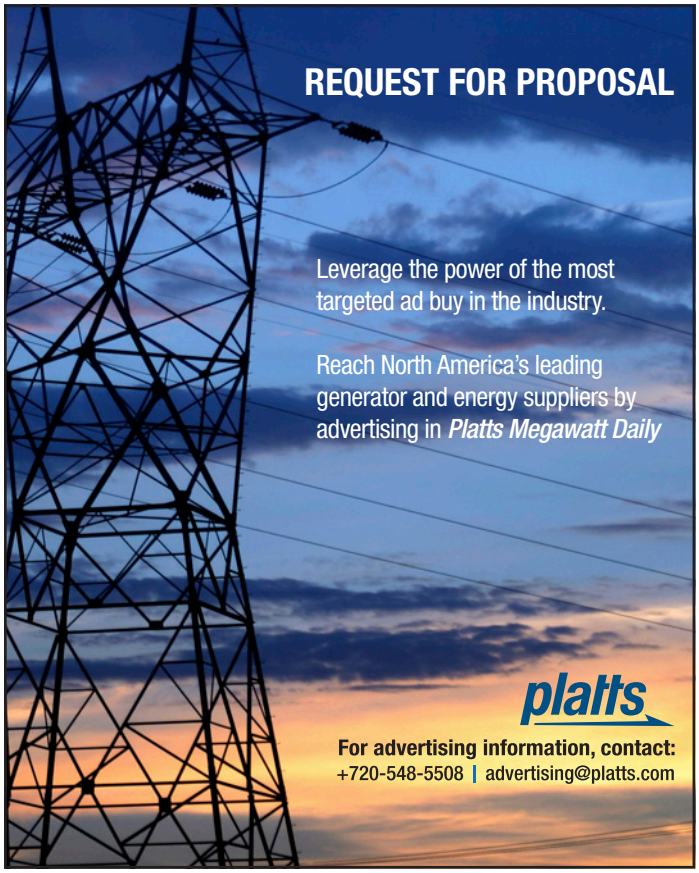
Contracts for end-of-the-year deliver on IntercontinentalExchange were 10-20 cents higher, compared with last week. The main futures contract traded on ICE – vintage 2013 for delivery in December 2013 – settled at $14.60/mt. The vintage 2015 contract for December 2015 delivery settled at $13.10/mt.

On ICE, there were 34 deals totaling 220 contracts, compared with 754 contracts a week earlier. One contract equals 1,000 mt. ICE also cleared six deals equaling 115 contracts, compared with 670 contracts a week earlier.

In over-the-counter markets, prices for California GHG allowances for December 2013 delivery were quoted at $14.50-$14.70/mt, up from $14.35-$14.50/mt a week earlier. 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 increased seven cents to settle at $3.51/st. There were three trades on ICE totaling 145. The exchange also cleared three deals representing 600 contracts.

— Geoffrey Craig



Daily CSAPR allowance assessments, May 30

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, May 30

	$/allowance	Change	$/st
SO2 2013	0.67	-0.02	1.34

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

RGGI carbon allowance futures, May 29 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.51	0	Dec13	1.97	0
Dec13 V11	3.51	0	Dec14	1.97	0
Dec13 V12	3.51	0			
Dec13 V13	3.51	0			
Dec14 V10	3.51	0			
Dec14 V11	3.51	0			
Dec14 V12	3.51	0			
Dec14 V13	3.51	0			
Dec15 V10	3.51	0			
Dec15 V11	3.51	0			
Dec15 V12	3.51	0			
Dec15 V13	3.51	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.

No trades heard in US CAIR emissions market

There were no trades in the Clean Air Interstate Rule's trading program on Thursday, according to brokers. This is in keeping with the quiet market seen in previous weeks.

There were also no transactions listed in the US Environmental Protection Agency's database. But the SO2 2013 allowance price did drop slightly.

Platts assessed SO2 2013 at 67 cents/allowance, down from the previous assessment of 69 cents/allowance on changing bids and offers. The 2014 SO2 allowance remained unchanged at 60 cents/allowance.

IntercontinentalExchange, the Atlanta-based exchange, began listing futures contracts for CAIR Annual NOx and CAIR Ozone Season NOx on May 20. During the week, a CAIR NOx Annual contract for December 2013 was listed on ICE with a bid of $38 and an offer of $55. A CAIR NOx Ozone contract for October 2013 was listed with a bid of $12.50 and an offer of $35.

Brokers maintained that there is no interest in the market. They also said no one is trading the products, which is why there is such a wide spread between the bids and offers.

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.

— Beth Ward

REC MARKETS

Connecticut RPS revision bill advances

A controversial bill in Connecticut that would make sweeping changes to the rules governing the state's Class I standard took a step closer to being signed into law this week.

On Tuesday, the House of Representatives passed the bill (S.B. 1138), which now must go back to the Senate in order to reconcile some minor differences.

The bill would fundamentally alter the types of resources supplying Class I renewable energy certificates. At present, Connecticut relies overwhelmingly on out-of-state biomass and landfill gas facilities to meet its Class I requirements.

The proposed legislation would reduce the value of Class I RECs generated by biomass and landfill gas facilities starting 2015. Other types of renewable facilities in New England could technically fill the void resulting from the departure of biomass and landfill gas.

However, as the Department of Energy and Environmental Protection has noted, the dynamics of the New England Class I REC market are such that cross-qualified renewable facilities migrate first to other states, like Massachusetts, where prices tend to be higher.

Consequently, the bill seeks to boost Class I supply in two ways. First, it expands the list of eligible resources. The maximum capacity of hydropower would be increased from 5 MW to 30 MW. And anaerobic digesters would be allowed to generate Class I RECs for the first time.

Second, the bill authorizes new long-term procurements. DEEP would run the solicitations, and require the utilities to sign power purchase agreements.

One plan involves 20-year contracts for Class I resources built in 2013 or later. The other solicitation entails 15-year contracts signed with large Canadian hydropower suppliers, a provision that has drawn significant criticism from a range of stakeholders.

The bill caps the amount that large-scale hydro can count toward the Class I requirements at 5%, and says solicitations will occur only in the event the market faces a Class I REC shortage.

The last day of Connecticut's legislative session is June 5. Governor Dannel Malloy supports the bill.

In New Jersey, the Board of Public Utilities approved on Wednesday a pair of programs involving Public Service Electric and Gas that would add 142.5 MW of new solar capacity.

The Solar Loan III program includes 97.5 MW of utility-financed solar, and the Solar 4 All Extension program amounts to 45 MW of utility-owned generation.

Solar development in New Jersey has slowed significantly since 2012 in response to relatively low solar REC prices. SREC revenue is a major component of a project's feasibility.

The two programs approved by the BPU mean solar projects will get built despite soft SREC prices. The Solar Energy Industries Association said in a statement that it backed Wednesday's decisions.

One consequence, however, could be even lower SREC prices. That is because PSE&G will presumably sell the SRECs into the spot market in order to earn money and soften the impact on ratepayers.

Jeanne Fox, a BPU commissioner, voted against the Solar 4 All program, on the grounds that it would push down SREC prices further, according to a media report.

In Ohio, the Power Siting Board gave approval to the 140-MW Buckeye II wind farm being developed by Everpower Wind.

There are currently 403 MW of utility-sized wind farms in Ohio. Iberdrola owns the 304-MW Blue Creek wind farm and EDP Renewables owns the 99-MW Timber Road wind farm.

According to a staff report on the project dated October 2012, Buckeye II wind farm would likely qualify as an in-state renewable facility, though Everpower had yet to sign a power purchase agreement for the electricity and/or RECs.

Without a PPA, Everpower would need to sell the electricity and RECs in the wholesale market. Construction of the wind farm is expected to be complete by the end of 2013.

— Geoffrey Craig

Renewable Energy Certificate Markets May 30 ($/MWh)

	Low	High	Mid
Class I/Tier I RECs*			
Connecticut	54.00	55.00	54.500
Maryland	6.80	6.90	6.850
Massachusetts	62.50	63.50	63.000
New Jersey	6.80	6.90	6.850
Ohio In-State	3.75	6.25	5.000
Pennsylvania	6.80	6.90	6.850
Texas	2.40	2.45	2.425
Solar RECs*			
Maryland	115.00	125.00	120.000
Massachusetts	200.00	220.00	210.000
New Jersey	130.00	140.00	135.000
Ohio In-State	45.00	55.00	50.000
Pennsylvania	15.00	20.00	17.500
California RPS*			
California Bundled REC (Bucket 1)	34.00	38.00	36.000
California Bundled REC (Bucket 2)	4.00	9.00	6.500
California Tradable REC (Bucket 3)	0.75	1.25	1.000
Voluntary RECs*			
National voluntary, any technology	0.75	0.85	0.800
National voluntary, wind	0.85	0.95	0.900

*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

Meetings focus on Entergy move to MISO

Entergy stakeholders and regulators conducted lengthy meetings with Midcontinent Independent System Operator staffers in New Orleans this week to facilitate moving the Entergy footprint into MISO.

On Wednesday, the Entergy Regional State Committee, which encompasses regulators in the states where Entergy has operating companies — Arkansas, Louisiana, Mississippi and Texas — learned that MISO will take over reliability coordination operations for the Entergy footprint Saturday.

On Thursday, Entergy-area stakeholders met with MISO staffers regarding the development of various possible future scenarios to be used in planning transmission and generation projects.

Entergy, Cleco, Lafayette (Louisiana) Utilities, Louisiana Generation, Louisiana Energy and Power Authority, South Mississippi Electric and municipal utilities in Conway, North Little Rock and West Memphis, Arkansas, have been participating in parallel reliability coordination operations since early May.

Reliability coordination involves keeping track of current transmission system conditions – such as scheduled and unscheduled outages — that could impair overall grid reliability. In the past, Southwest Power Pool has been performing this service.

The news about reliability coordination came as part of a report concerning the effort to integrate the Entergy region of Arkansas, Louisiana, Mississippi and Texas into MISO, which is scheduled to take place December 19, pending federal and state regulatory approval.

John Lawhorn, MISO senior director of regulatory and economic studies, said integration of the Entergy footprint into MISO is "on track" and that no major issues have been identified.

On Thursday, Lawhorn led a stakeholder workshop regarding MISO's seven-step planning process, designed to provide "the best-fit" transmission grid so that it can meet demand in the more likely scenarios.

The scenarios presented include "business as usual" with little change in economic growth rates and environmental policy; "limited growth" with slower-than-usual economic and energy demand growth partly because of increased environmental restrictions; "robust economy" with significant economic development in southern Louisiana and East Texas because of cheap natural gas; and a "South to Midwest transfer" scenario which models limited ability to expand the Midwest natural gas pipeline infrastructure, causing increased reliance upon the southern region's gas-fired generation fleet.

Because the Entergy footprint has substantial excess generation capacity, less than 100 MW of additional resource capacity would be needed from 2013 to 2032 in each of these scenarios, except under the robust economy scenario, in which an additional 7,200 MW of gas-fired generation would likely be needed, according to a presentation by a MISO staffer.

Each case showed that gas-fired generation would experience a substantial increase in energy supplied to the Entergy footprint, from 72,502 MWh in 2013 to 88,582 MWh in the limited-growth scenario, to about 104,400 MWh in the business-as-usual and South-to-Midwest transfer scenarios, and to 141,914 MWh in the robust economy scenario.

MISO has set 14.2% as a planning reserve target, and the Entergy footprint's current planning reserve is almost 40%. The robust economy scenario would result in the Entergy footprint's planning reserve falling near the target around 2012 and remain relatively flat thereafter. In the other three scenarios, the planning reserve margin would not fall below 20% before 2030.

On Wednesday, state regulators in the area served by Entergy utilities approved a resolution to enhance their input into MISO operations if Entergy is allowed to join MISO as proposed this December.

The resolution calls for the addition of one representative of the regulators in the area served by Entergy to MISO's Advisory Committee.

This option was one of three included in a May 1 letter to the ERSC from John Bear, MISO president and CEO, concerning how MISO's governance structure should be adjusted to "meet the needs of jurisdictional commissions in the Entergy region as well as commissions from" the existing MISO states.

Other options that Bear said could also be implemented include updating the MISO transmission owners agreement to add a regulatory committee reporting directly to the board of directors and considering the development of a "regional state compact … [with] legal authority to conclude, on a footprint wide basis, that a proposed portfolio or project that was going to be cost-shared broadly was in the public interest."

In other business on Wednesday, Robert Sinclair, a vice president at Potomac Economics, which serves as independent market monitor for MISO itself and for MISO in its role as Entergy's independent coordinator of transmission, reported on an extensive examination of transmission scheduling and congestion events to determine whether Entergy may have engaged in anticompetitive behavior.

Ultimately, Sinclair said his organization found "no potential anticompetitive conduct from operation of Entergy's transmission system or generation during the study period" of December through April.

— Mark Watson

CEC links climate change, power use increase

Climate change will increase electricity use in California by up to 1,800 GWh and peak demand by up to 1,745 MW by 2024, according to preliminary analysis by the California Energy Commission.

Average temperatures in California have climbed 1.7 degrees since the 1890s, and further increases will boost electricity use and reduce efficiency of the power system, CEC Chair Robert Weisenmiller said Thursday during a workshop on the commission's draft demand forecast for the state.

The CEC preliminary forecast is divided into high- mid- and low-demand scenarios. The middle scenario assumes average

temperatures increase by 1 degree by 2024, driving up electric use by 1,240 GWh and peak demand by about 1,060 MW, said Chris Kavalec, CEC's chief forecaster.

Under the mid-demand scenario, demand would grow by almost 1% a year through 2024, according to the draft assessment. Peak demand would grow by 1.25% a year through 2024 in that scenario.

The low-demand scenario assumes that climate change has no effect on electricity use.

Temperature increases would reduce natural gas demand by between roughly 240 million therms and 630 million therms by 2024, according to Kavalec.

Kavalec cautioned that the preliminary forecast likely will be changed during the summer. For example, CEC and Navigant, a consulting firm, intend to include energy efficiency savings that are not included in the draft forecast, he said. Also, updated electric vehicle estimates will be included, along with revised rate hike estimates.

Estimated rate increases have a major effect on the forecast, according to Kavalec. The rate increases have a significant impact on the adoption of photovoltaic panels and commercial combined heat and power facilities, he said.

Under the mid-demand scenario, the CEC estimates that electric rates will increase 14.4% through 2015, 33.7% through 2020 and 39.2% by 2025, driven by costs related to PV incentives, the state's greenhouse gas cap and trade program, rising natural gas prices and other issues, he said. However, electric utilities doubt that their rates will increase as much as the CEC is assuming, he said.

About half of the electricity savings in the forecast come from the effect of higher prices, Kavalec said.

The California Public Utilities Commission is informally investigating ways to confirm the effects of energy efficiency programs, said Brian Stevens, an advisor to PUC President Michael Peavey. Getting "confident" estimates for achievable energy efficiency savings is a priority for the California Independent System Operator, added Keith Casey, ISO vice president for markets and infrastructure development.

Once the demand forecast is finalized, it will be used by the PUC in its 2014 long-term procurement plan and resource adequacy deliberations. The ISO will use the information when it prepares various studies.

The CEC plans to develop additional energy efficiency scenarios over the next two months and issue a revised forecast in August, Kavalec said. The CEC expects to adopt a final forecast in the fall, he said.

— Ethan Howland

Calpine stands out among peers: Fitch Ratings

Calpine's narrow focus on natural gas-fired generation, strong presence in the Electric Reliability Council of Texas, and aggressive but prudent capacity-expansion plans make the independent power company stand out among its peers, Fitch Ratings said Thursday.

"Most of the other large merchant generators have coal and nuclear in [their generation] mix, and because of that their sensitivity to changes in natural gas prices is often much higher than Calpine's," Fitch Senior Director Shalini Mahajan, the rating agency's primary analyst for Calpine, said in an interview.

Calpine's 27,321-MW fleet, all but 729 MW of which is gas-fired, fares well in dispatch stacks when gas prices are high because of its higher-than-average efficiency, and it routinely displaces coal-fired generation when gas prices are low, said Mahajan.

ERCOT, where Calpine owns 8,014 MW of gas-fired capacity and is planning more, is "a very attractive market to be in—in our view it's the most attractive market in the country," she said. Calpine has "good exposure" in ERCOT, where gas-fired generation drives the market and which faces a tight supply situation for the foreseeable future.

Mahajan said Calpine has been expanding its presence in ERCOT. In November it acquired an 800-MW combined-cycle plant in Bosque County, and it is building 390 MW of cogeneration capacity at existing Calpine sites: 200 MW at its Channel facility in Houston and 190 MW at its Deer Park facility.

"They are also looking at further expansion opportunities" in ERCOT, she said, noting that the significant free cash flow provided by Calpine's profitable, low-maintenance fleet allows the company to take advantage of both new-build and acquisition opportunities.

In addition to the ERCOT cogeneration projects under construction, Calpine is building a 309-MW combined-cycle facility in Delaware that has cleared the PJM capacity auction and two combined-cycle projects totaling 773 MW in California that hold long-term power purchase agreements.

Calpine also is considering the possibility of building 650 MW of additional merchant capacity and 345 MW of contracted capacity that would come online in 2016-17.

In a statement, Fitch said it expects Calpine to generate "more than $800 million of free cash flow in 2014; annual free cash flow is expected to climb upwards of $1 billion 2015 onwards."

Fitch said that because of Calpine's gas-fired focus, ERCOT exposure and ability to generate profits under any likely gas-price scenario it has upgraded the company's "issuer default rating" to B+ from B, and its credit rating to BB+/RR1 from BB/RR1.

"Capital deployment in the already announced new generation projects, which comprises projects under long-term contracts as well as merchant generation in ERCOT and PJM, is expected to drive [earnings] growth in the near term," Fitch said.

"Longer term, Calpine remains positively leveraged to scarcity pricing reflecting demand supply imbalances in its markets as well as to a recovery in natural gas prices given its highly efficient fleet and natural gas being on the margin for power prices in most of the markets it operates in."

Fitch added, "The level of generation [earnings] stability demonstrated by Calpine over the last four years is quite unique among the merchant power generation companies."

Mahajan said Calpine has benefited from the geographic diversity of its gas-fired assets: it owns 7,316 MW in the swath of states from Wisconsin to Maine; 6,026 MW in California and

Arizona; and 5,236 MW in the region from Oklahoma to Florida.

Calpine is fortunate to have relatively limited exposure in PJM, given the unexpectedly low, $59.37/MW/day capacity auction price for June 2016 through May 2017 just realized there, Mahajan said.

She added that several other generators have a far greater share of their capacity in PJM, and unlike Calpine are saddled with coal-fired and nuclear assets that need higher capacity prices to justify their operation.

Asked if Calpine's clear lack of fuel diversity poses any risk, Mahajan said that in Fitch's view it does not. She acknowledged that natural gas prices spiked several years ago, challenging the finances —and even the futures — of companies like Calpine.

But shale gas discoveries and development have changed the market for the foreseeable future, the Fitch executive said. "We now expect gas prices to remain within a narrow range —between $3.50 and $4.50[/MMBtu]—for a reasonable period of time … And we think that's favorable from Calpine's point of view."

Mahajan said several factors other than availability and price are working in favor of gas, including environmental regulations requiring coal-unit owners to invest in emission control equipment and the increasing likelihood of greenhouse gas rules that again favor gas over coal.

— Housley Carr

Lawmaker seeks DOJ probe of JP Morgan

A Democrat on the House Financial Services Committee on Wednesday asked the Department of Justice to investigate JP Morgan's bidding practices in organized power markets, urging officials to send "a strong signal to the markets that all bad actors are held accountable for their irresponsible actions."

In his May 29 letter to Attorney General Eric Holder, Representative Dan Kildee of Michigan noted that the Federal Energy Regulatory Commission is investigating the alleged manipulation, but that DOJ should also investigate.

JP Morgan earlier this month confirmed in a 10-Q filing that FERC is actively "investigating the firm's bidding practices in certain organized markets," following reports that FERC is looking to hold energy traders and a top executive at JP Morgan Ventures Energy liable for alleged power market manipulation in California and Michigan.

According to FERC documents, the California Independent System Operator and Midcontinent Independent System Operator alerted FERC on four separate occasions between March 2011 and June 2011 to bidding strategies they viewed as "abusive."

Kildee in the letter pointed to reports of JP Morgan's alleged malfeasance, including that Michigan and California received roughly $83 million in allegedly fraudulent charges from JP Morgan. He also noted that FERC has suspended JP Morgan Ventures Energy's authority to sell power at market-based rates for six months.

Said Kildee, "These allegations are serious charges, including traders devising deliberate schemes to manipulate energy prices and top bank executives lying under oath. . . . The people of Michigan, and the American public generally, deserve a marketplace where all participants play by the same rules. I urge the Justice Department to resolve this matter by investigating these potentially illegal practices."

A DOJ spokeswoman said that the department has received the letter "and will review it and respond accordingly."

— Bobby McMahon

ERCOT congestion rights value climbs 12.5%

Electric Reliability Council of Texas congestion revenue rights for the first half of 2014 cost about 12.5% more than CRRs recently auctioned for the last six months of 2013, data released Thursday show.

Market participants acquired 386,766 MW of CRR capacity for the first six months of 2014 at a value of about $65.8 million, compared with about 225,607 MW of capacity for the last six months of 2013 at a value of $58.5 million.

ERCOT is in the process of auctioning CRRs for rolling six-month periods stretching two years into the future, offering 60%, 45%, 30% and 15% of available capacity for the first, second, third and fourth six-month periods, respectively.

In the results posted Thursday, market participants acquired about $31.5 million for positive and negative obligation CRRs – paying ERCOT $28 million for 172,401 MW of positive obligation CRRs and receiving $3.5 million for 44,437 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 $34.3 million for 169,928 MW of option CRR capacity in auction results posted Thursday.

The net effect of all this trading – positive obligation and option CRRs minus negative obligation CRRs – was $58.8 million received by ERCOT.

In terms of capacity for both obligation and option CRRs for the first six months of 2014, Luminant Energy acquired the most, at 95,508 MW valued at $8.2 million, which was enough to rank Luminant third in the dollar-total rankings of 61 winning bidders.

In terms of dollars, Shell Energy led the pack with $10.1 million, followed by Monolith Energy at $8.4 million, Luminant at $8.2 million, BP Energy at $6.4 million, and NRG Power at $5.4 million.

In terms of capacity, rounding out the top five after Luminant were NRG at 58,665 MW, BP at 40,066 MW, Shell at 36,920 MW and Merrill Lynch at 15,728 MW.

The largest total spent on CRRs for a single path for the first half of 2014 was about $18 million spent for 11,655 MW from the

West Hub to the West Load Zone.

The largest number of CRRs for a single path for the first half of 2014 was 66,732 MW from the North Hub to the North Load Zone, at a value of $4.3 million.

The next six-month segment of CRR capacity – for the last half of 2014 — is be auctioned between June 11 and June 14 with the results posted on the ERCOT website by June 27.

— *Mark Watson*

88-Bcf storage build is below five-year average

An 88-Bcf storage injection for the week ending May 24 was within market expectations and boosted nationwide inventories to 2.141 Tcf, the Energy Information Administration said Thursday.

The build was within consensus analyst predictions between 87 Bcf and 91 Bcf. It was slightly below the five-year average build of 92 Bcf but well above last year's 72-Bcf injection.

As a result, the 680-Bcf deficit to the year-ago level shrank to 664 Bcf, while the 84-Bcf deficit to the five-year average of 2.229 Tcf rose to 88 Bcf.

Tim Evans, an analyst at Citi Futures Perspective, called the EIA report "neutral" to the market, although the NYMEX gas futures contract tumbled after the data's release *(see story, page 1)*.

Other analysts said the continued shift by electricity generators away from gas may mean bigger storage additions in the weeks ahead.

"Injections this May are 20 Bcf more than last year thanks to power providers switching back to coal from natural gas," said Gelber & Associates analyst Kent Bayazitoglu. "More recent injections have been solid enough where some of these prices above $4.20/MMBtu might be too high, with power demand going back to coal."

Despite the slight expansion last week of the surplus to the long-term average, analyst Stephen Smith of Stephen Smith Energy Associates noted that the surplus has declined by 334 Bcf over the past 10 weeks even with gas prices of $4/MMBtu or higher.

One key reason is that demand during the 2006-2010 period was reacting to prices of more than $6/MMBtu, making today's $4 gas a "relative bargain for power generation," Smith said. Indeed, gas-fired power production has been steadily increasing since the midpoint of the 2006-2010 reference period Smith uses in his model.

Meanwhile, some demand projections also indicate the possibility of larger storage builds heading into summer.

Gas-fired generation demand is likely to fall in the Northeast as some 1.2 GW of nuclear capacity was set to come back online Thursday, noted Platts unit Bentek Energy. Total US power burn was about 7.5 Bcf/d higher this week than the prior six-day average, but was forecast to taper off going forward as temperatures revert to normal in most regions, Bentek added.

According to EIA, storage inventories now are 110 Bcf below the five-year average of 1.020 Tcf in the East, 47 Bcf above the five-year average of 333 Bcf in the West and 25 Bcf below the five-year average of 876 Bcf in the producing region.

— *Stephanie Seay*

Stakeholders ask court to undo FERC Order 1000

A cavalcade of state commissions, utilities, grid operators and others on Tuesday filed opening briefs asking the DC Circuit Court of Appeals to overturn key aspects of the Federal Energy Regulatory Commission's Order No. 1000 regional transmission planning and cost allocation rule, if not the entire rule.

FERC faces a torrent of litigation over Order No. 1000 at the DC Circuit (South Carolina Public Service Authority, et al. v FERC, 12-1232, et al.), where petitioners are asking the court to review and undo several fundamental underpinnings of the rule, including FERC-mandated transmission planning and cost allocation as well as the elimination of the right of incumbent utilities to build regional lines without competing with other developers, also called their right of first refusal. The briefs filed Tuesday were divided by subject matter.

For instance, parties including Southern Company, the Alabama Public Service Commission, the Midcontinent Independent System Operator and more than 20 others in a joint May 28 brief on threshold issues argued that FERC lacks authority under the Federal Power Act to mandate transmission planning, saying that FERC's Order No. 1000 and its modifications upon rehearing "are neither based on substantial evidence nor constitute reasoned decisionmaking."

Noting that FERC referred to ROFRs in federal tariffs and a lack of mandated planning and cost allocation as a "theoretical threat," the parties in the brief argued that "rates are not unjust and unreasonable just because there might be a better approach or they might be capable of improvement." The parties added that FERC's theory "is entirely speculative" and does not "satisfy FERC's burden under section [FPA] 206 to demonstrate that existing tariffs and contracts are operating in an unjust or unreasonable manner."

In challenging the order's cost allocation provisions, Southern Company, the National Rural Electric Cooperative Association, the South Carolina Public Service Authority and others in a separate brief argued that FERC exceeded its FPA authority and Supreme Court precedent "by providing transmission developers with a mechanism to secure funding for their projects on a socialized basis, from entities with whom they have no business relationship and to whom they do not provide service."

The parties in the cost allocation filing said that the order "is contradicted by the plain language" of the FPA "and by foundational precedent holding that a utility's right to cost recovery — i.e., to charge rates — in connection with the provision of transmission service in interstate commerce is established by contracts and voluntary commercial arrangements, not by FERC acting ostensibly under the FPA."

The parties added that the FPA "does not authorize FERC to mandate a broad assessment of charges by a transmission provider – in essence a tax – to entities that are not in a contractual or customer relationship with, or taking transmission service from, that provider."

Arguing that FERC erred in its decision to largely mandate the elimination of federal ROFRs, the Edison Electric Institute, MISO,

the Southwest Power Pool and FirstEnergy argued that "The determination of who constructs and owns regionally-planned transmission facilities is beyond FERC's jurisdiction under section 206 because that determination neither directly affects transmission rates nor is closely related to transmission rates."

Additionally, the parties in the ROFR brief argued that FERC cannot support its finding that ROFRs are discriminatory and that FERC "wrongly asserts jurisdiction under section 206 to override established state jurisdiction over the construction and siting of electric transmission facilities absent clear expression of congressional intent to do so."

And on the state front, state commissions in Florida, Connecticut and elsewhere broadly challenged Order No. 1000 as impinging on state authority, saying that "despite FERC's disclaimers that Order No. 1000 does not exercise authority over matters reserved to the States, the rule does just that, through regulatory fiats that render transmission planning processes and their outcomes Federal a fait accompli."

Said the states, "By then controlling which projects receive wholesale cost allocation, FERC, and not the States, decides whether a project should be built and who can build it. The FPA does not empower FERC in this regard, but rather reflects a policy of reserving regulation to the States."

Elsewhere in briefs, EEI and NRECA separately challenged aspects of how Order No. 1000 pertained to non-jurisdictional utilities. And transmission developer ITC Transmission in its brief faulted FERC's decision to prohibit allocating costs of transmission lines greater than 345 kV to a region where the line is not located, even if the region is benefited by the line.

Said ITC, "FERC provides no logical explanation" for doing so, and said that FERC's concern that "the allocation of costs to regions in which lines are not located would impose an unacceptable burden on regions to monitor transmission planning processes in other regions" is misplaced.

— Bobby McMahon

FERC rejects PJM bid to "notice" sellers

The Federal Energy Regulatory Commission on Wednesday rejected a proposal by the PJM Interconnection to add language to its tariff putting sellers "on notice" that it may reduce their payments if they operate out of line with ISO rules, saying that PJM did not provide enough detail on the mechanics of such reductions.

FERC made this finding in response to PJM's March proposal (Docket No. ER13-1200) to add language to its tariff making it clear "to all market sellers that if they operate their generating units in contravention of the requirements of the tariff, operating agreement and PJM manuals, particularly with respect to reliability limits and dispatch instructions, then they may not receive the full amount of revenue for their output or reduction of energy."

PJM said the language, which stated that resources must follow PJM rules "to be eligible to receive the full entitlement of all potential sources of revenue for their output of energy or the reduction thereof," was necessary "to eliminate an incentive for a market seller to operate a generating unit in a manner that is incompatible with reliability and stability of the PJM bulk power system."

But FERC in the May 29 order found that PJM failed "to provide any detail or tariff language describing the specific circumstances under which compensation would be reduced or how the compensation would be reduced." The commission also said that PJM failed to show that it was just and reasonable "to have the discretion to reset compensation levels retroactively when neither the particular circumstances that would trigger PJM's actions nor the financial consequences are specified in the tariff."

In the same order, FERC approved PJM's proposal to stipulate that "lost opportunity cost compensation shall be limited to the lesser of the unit's highest incremental megawatt output level that it can achieve following economic dispatch, i.e. economic maximum or its maximum facility output."

According to FERC's order, PJM aimed in the action to clarify the lost opportunity costs that sellers would receive upon reducing their energy, saying that doing so would deter sellers from operating units "at an inappropriately high megawatt output level that might have a negative impact on system reliability." FERC agreed.

— Bobby McMahon

Kentucky Power sees value in biomass deal

Kentucky Power conceded this week a proposed long-term power purchase agreement for 58 MW of biomass power from an eastern Kentucky plant that has not been built would be more expensive than other options, but argued the deal with ecoPower Generation-Hazard LLC is a "unique opportunity" to diversify its fuel mix.

The utility, an American Electric Power subsidiary, has been peppered with questions from the Public Service Commission staff, state attorney general and an industrial energy group since Kentucky Power filed its application with the PSC on April 10.

The Kentucky Industrial Utility Customers, in particular, has claimed the 20-year PPA is extraordinarily expensive and could cost the utility's 175,000 customers hundreds of millions of dollars over its lifetime.

Columbus, Ohio-based AEP, one of the largest electric utilities in the US, does not buy any biomass power in its 11-state system, Kentucky Power said in its response.

The ecoPower Generation accord would increase electric rates by about 13% over two decades, Kentucky Power said.

Replying to a question from the attorney general's office, Kentucky Power defended the higher cost of the renewable power. Entering into an agreement with ecoPower Generation "is a unique opportunity for the company to increase its fuel diversity and promote economic growth, all within the commonwealth of Kentucky," it said.

Moreover, it is unlikely that renewable resources in Kentucky would be the least-cost option under any power purchase scenario, it added. "However, to move forward with fuel diversity, the commission must decide when and if it is the proper time to approve a facility that is not the least-cost option.

The company believes that the ecoPower biomass facility is the appropriate facility to do so."

Traditionally, the PSC has used least-cost criteria to base its decisions on whether to approve PPAs.

In March, Governor Steve Beshear, a two-term Democrat, signed S.B. 46, which authorizes the PSC to allow utilities to recover costs not collected in existing utility rates for the purchase of power from a biomass energy facility.

Several years ago, Beshear unveiled a state energy plan that called for the increased development of biomass power, viewed by the governor as the state's most abundant and accessible renewable energy resource.

Kentucky gets more than 90% of its power from coal.

Kentucky Power said it would use the biomass power to serve all loads — peak, baseload and intermediate. Any excess power would be sold off-system, it said.

According to a Kentucky Power assessment, its internal energy requirements are forecasted to increase from 7.3 million MWh in 2013 to nearly 8 million MWh in 2032. The utility is a winter-peaking system whose demand typically spikes during cold months.

Renewable energy credits received from the ecoPower Generation transaction could have a value of $2-$6 per REC. Kentucky Power said it anticipates selling the RECs and flowing the proceeds back to customers. It is proposing to credit these proceeds through an ecoPower Generation rider or surcharge if approved by the commission.

Under terms of the PPA, any costs for locational marginal pricing associated with PJM Interconnection costs up to the point of delivery would be borne by ecoPower Generation.

EcoPower Generation, a privately owned company, plans to locate the plant about 10 miles northwest of Hazard on 125 acres of a reclaimed coal mine in the Coal Fields Industrial Park. The facility would generate electricity using biomass materials including sawdust, wood chips, tip wood and low-quality logs.

The plant would employ about 30 full-time workers and provide hundreds of ancillary jobs in the construction, timber and trucking industries. It would be ecoPower Generation's first such facility. Although the cost of the project has not been publicly disclosed, it is believed to be less than $200 million.

The plant would go into commercial operation in the first half of 2017.

— Bob Matyi

Total value falls in Cal-ISO CRR auction

The total dollar value for the financial transmission rights in the California Independent System Operator's auction for June was down almost $2 million from May, while the total volume was up, according to auction results from the ISO.

The total dollar value for the CRRs, known in other markets as as congestion revenue rights, was around $14.5 million, down from about $16.4 million for May.

Total megawatt volume in the June auction increased to about 44,515 MW, up from around 35,516 MW last month.

The auction included 568 deals for a total of 6,907 MW at $0/MWh. That's compared to 259 deals for a total of 3,035 MW at $0/MWh for May.

Staying in first place by volume was Monolith Energy with roughly 7,723 MW for a net dollar position of about $176,568. That's down from 8,256 MW for a net dollar position of about $196,956 for May.

Mercuria remained in second place with roughly 5,319 MW for a net dollar position of -$107,634. That's compared with about 3,558 MW and a net dollar position of roughly -$171,906 in May.

Vitol climbed back into to the top five by taking the third ranking from Edison Mission with about 3,868 MW for a net dollar position of around $424,146.

Similarly, EDF was back, finishing fourth with around 3,373 MW for a net dollar position of about $278,024.

Castleton Commodities dropped one slot to fifth with about 3,365 MW for a net dollar position of around $248,561. That's compared to roughly 3,061 MW for a net dollar position of about -$112,649 for May.

California's monthly CRR auction offers on- and off-peak FTRs that entitle the holder to revenue when congestion occurs in the direction of the CRR. If the congestion occurs in the opposite direction, the CRR holder must make a payment to the grid operator.

A positively priced CRR indicates that an entity needs the transmission capacity and therefore pays the ISO for the ability to flow power on a particular source-sink path, while a negative priced CRR indicates a counterflow congestion contract in which the grid operator pays the market participant after the settlement process.

— Martin Coyne

Meeting scheduled on Calif. reliability mechanism

The Federal Energy Regulatory Commission on Tuesday scheduled a technical conference bringing California stakeholders together to identify market-based incentives for ensuring reliability, following its decision in March to reject a California Independent System Operator plan to compensate flexible resources that are uneconomic to run because of new cooling water requirements.

FERC said the staff-led conference (Docket No. AD13-5), scheduled for July 31 and August 1 in Sacramento, California, "is intended to facilitate a structured dialogue on flexible and local resources at risk of retirement" between Cal-ISO and its stakeholders toward creating "a market-based mechanism to provide incentives to ensure that the reliability needs are met," according to a May 28 notice from the commission.

The commission March 29 rejected Cal-ISO's plan (Docket No. ER13-550) to use a flexible capacity and local reliability resource (FLRR) retention mechanism to address an anticipated influx of renewables and other variable energy resources, combined with a capacity shortage of 4,600 MW by 2020 due to California's ban of once-through cooling at coastal power plants.

Cal-ISO proposed to designate resources that are at risk of retirement and compensate them to remain online if they are necessary for flexible capacity or local reliability needs over the

next two to five years. If such resources benefit the whole system, the costs of compensating them would be borne by all market participants.

But FERC rejected the proposal, saying the FLRR was not an "appropriate tool to address the stated needs of maintaining a reliable grid." Rather, FERC directed staff to convene a technical conference, saying that "we believe that the most effective course of action would be for CAISO and its stakeholders to focus on the development of a durable, market-based mechanism" to meet the grid's reliability needs.

"The purpose of such a conference would be to coordinate FERC staff with [the California Public Utilities Commission], CAISO and industry participants on resolving the reliability issues presented here," FERC said in the March 29 order.

— Bobby McMahon

Utility weekly output drops 4% from 2012: EEI

US utilities generated 74,913 GWh in the week that ended Saturday, down 4% from the 77,998 GWh generated in the corresponding week of 2012, the Edison Electric Institute said Thursday.

The weekly total was 3,789 GWh above the 71,124 GWh produced in the week that ended May 18, EEI said.

Output fell in eight of the nine regions EEI tracks, with the largest percentage decrease in the West Central region, where output fell 7.1% to 5,960 GWh.

The next largest slide was in the Rocky Mountain region, where production fell 6.4% to 4,620 GWh.

The only increase was in the Pacific Northwest, where output rose 0.7% to 2,654 GWh.

Year-to-date utility generation was just over 1.543 million GWh, up 1.2% from nearly 1.525 million GWh in the comparable period of 2012, EEI said.

— Keiron Greenhalgh

MidAmerican deal has grid implications ...from page 1

MidAmerican's existing subsidiaries is PacifiCorp.

PacifiCorp now has 10,579 MW of capacity, just over 16,000 miles of transmission lines, and 1.8 million customers in Wyoming, Utah, Idaho, Washington, Oregon and California.

While PacifiCorp's presence in some of those states, California and Idaho in particular, is minimal, the NV Energy acquisition would fill a gap in MidAmerican's utility footprint. Like a missing puzzle piece, the Nevada acquisition links PacifiCorp assets in Wyoming, Idaho and Utah with its assets in California and Oregon.

That, some analysts say, could be the biggest benefit MidAmerican could reap from the acquisition. Within MidAmerican, Nevada could become a transmission conduit from the Pacific Northwest and from the windy upper Plains states to Las Vegas and, from there, to load centers in California and Arizona.

MidAmerican Energy Holdings owns and/or operates more than 18,000 miles of transmission lines in the US, and its MidAmerican Transmission subsidiary has assets or projects in Canada, California, Arizona, Texas and Nebraska. NV Energy has 3,800 miles of transmission lines.

Furthermore, the acquisition of NV Energy may help PacifiCorp's planned participation in an energy imbalance market being developed by it and the California Independent System Operator.

Cal-ISO had urged NV Energy to participate in the EIM, targeted for an October 2014 launch.

Taking over NV Energy's footprint could provide PacifiCorp more direct access to the California grid, thereby significantly expanding the potential size of the EIM.

Meanwhile, one analyst, who requested anonymity, suggested that Buffett's next target should be Avista, which serves northern Idaho and eastern Washington, or Puget Sound Energy, which serves a swath of territory around Washington's Puget Sound, or Portland General Electric, which serves an area around Portland, Oregon, that is between PacifiCorp territories in Oregon and Washington.

Deal breaks mold of typical transaction

The acquisition does not fit the mold of a typical utility acquisition. It is a cash deal, not a stock swap, which is the norm, and it is not predicated on cost savings. And because NV Energy would become a subsidiary of MidAmerican Energy Holdings, which itself is a subsidiary of Berkshire Hathaway, the Nevada utility would no longer be publicly traded and subject to shareholder overview or the same level of financial regulatory oversight. Analysts say that could allow MidAmerican to improve NV Energy's returns by leveraging up its balance sheet.

In an interview, Greg Abel, chairman, president and CEO of MidAmerican Energy Holdings, touted the benefits a utility can enjoy under private ownership. "We make decisions for the long term," he said. And not having the pressure of meeting quarterly or annual earnings expectations, allows MidAmerican to do what is best for customers and all stakeholders. "Rather than having multiple shareholders [NV Energy] will have one shareholder, Berkshire Hathaway," Abel said.

In terms of cost savings, Abel said there would be none. "We are looking at sharing expertise. We let the acquired utilities operate as autonomous business units."

Abel identified three main factors that were pivotal in the decision to acquire NV Energy: the quality of the company's management, its regulated assets and economic conditions in Nevada.

"We like states that define their energy policies," he said, noting that Nevada has a "significant" renewable portfolio standard that would allow MidAmerican to lend its renewable expertise in building new renewable projects in Nevada.

Over the past several years, MidAmerican has bulked up on renewable energy projects. Earlier this month, the company announced plans to invest $1.9 billion to bring a 1,050-MW wind farm in Iowa online by year-end 2015.

Nevada's RPS goes from 6% of electrical output coming from

renewable sources to 15% in 2015. And NV Energy has said it plans to spend $2 billion to purchase or invest in new renewable energy by 2015.

The planned acquisition is also seen as a bet on Nevada's economy. In a prepared statement, Warren Buffett, chairman of Berkshire Hathaway, said "We are pleased to make a long-term investment in Nevada's economy."

That could be a savvy bet if Nevada's economy, one of the hardest hit in the mortgage crisis, rebounds with a housing recovery, especially if the price MidAmerican is paying for NV Energy proves to be low.

Buffett has a reputation as a bottom feeder. Time will tell if Berkshire picked up NV Energy for a good price. Meanwhile, analysts say the acquisition is slightly positive for the utility sector. It values NV Energy at 16.5 times 2015 earnings estimates, 14% higher that the regulated utility average of 14.4 times. And, if it does not provide an incentive to buy utility stocks, it at least provides a reason to hold on to them.

While Abel said MidAmerican's acquisition in NV Energy was not driven by geographic considerations, analysts have pointed out that NV Energy will fit nicely into MidAmerican's utility portfolio.

For years, Buffett has targeted the acquisition of utilities with stable, regulated returns. In 2000, Berkshire bought its first utility, paying $2 billion to acquire MidAmerican Energy, Iowa's largest utility.

MidAmerican today serves nearly 734,000 electric retail customers in Iowa and South Dakota with 8,087 MW of owned and contracted capacity, and 712,000 retail gas customers in Iowa, South Dakota, Illinois and Nebraska.

MidAmerican then became Berkshire's vehicle for Berkshire's utility acquisitions and in 2006 acquired PacifiCorp from ScottishPower for $5 billion, adding the largest utility in the Northwest to its portfolio.

Abel said that MidAmerican is "absolutely committed to closing this deal, and we have a full plate with a large number of renewable projects under way." And while the company is always driven to maintain its existing assets, "the great thing about being part of Berkshire Hathaway is that we will continue to look, and if any opportunities present themselves, we are open for business."

— *Peter Maloney*

PJM, monitor to refine MOPR review ...from page 1

threshold price for new units offering into PJM's annual capacity auction. One of the main proposals was to replace the unit-specific review for those seeking a MOPR waiver with two categorical exemptions. One exemption covers 'competitive entry' units that receive no funding outside the market while the other covers new units used for self-supply by municipal power, cooperatives and other load-serving entities.

The Federal Energy Regulatory Commission approved PJM's proposed categorical exemptions in early May, but ruled that PJM also had to retain the unit-specific review process.

"There may be resources ineligible for any [categorical] MOPR exemptions that have lower competitive costs than the default offer floor, and these resources should have the opportunity to demonstrate their competitive entry costs," FERC said.

In light of that ruling, PJM and its market monitor want to make changes to the unit-specific review process. Andy Ott, PJM's senior vice president for markets, said that the grid operator hopes to have these changes in place for next year's capacity auction, which will be held in May.

The problem statement approved by the MRC listed several modeling assumptions used in the unit-specific review process that will be reconsidered, including use of nominal levelized gross cost of new entry, use of residual value, the exclusion of sunk costs, the calculation of net revenues, the calculation of the average cost of capital and asset life.

Joseph Bowring, president of Monitoring Analytics, highlighted forward-looking net revenues and cost of capital as areas that will require "special attention."

While the problem statement was approved at Thursday's meeting, a representative from a state public utility commission expressed concern that the changes should not be overly restrictive for new plants seeking MOPR exemptions under the unit-specific review process.

"We're concerned that whatever is developed not be a straitjacket," the representative said. "It's important that we allow these projects to develop and present their own cost structures."

Ott said that PJM and Monitoring Analytics will put forward a "very specific" joint proposal for changes to the unit-specific review process. That proposal and any stakeholder-supported alternatives will be discussed at PJM's Capacity Senior Task Force.

— *Juliana Brint*

P3 cites PJM auction in Dominion case ...from page 1

"The market appears to have a very different view of market prices than relied on by the company. It is particularly striking that such a significant gap exists in the near-term market prices given Dominion's claim that it knows the market so well," P3 said. The market forecast price used by Dominion was redacted from the document.

P3 also noted that enough generation cleared the auction to give PJM a 21.1% reserve margin. "These commitments are firm and binding on bidders in the market, suggesting that PJM will have sufficient capacity to meet its needs through May 2017 regardless of whether the Brunswick project is approved," the generators said.

Assuming that Brunswick capacity was removed from the total cleared capacity, the forecasted reserve margins would be well above PJM's 15% to 16% target, P3 said. "It is clear that the Brunswick plant is not needed through at least 2017," the group said.

Dominion would not comment on whether it bid the plant into the auction. "Unfortunately, we are not disclosing any information about our power stations and the PJM auction," Dan Genest, a company spokesman, said.

P3 said it is widely believed based on publicly available

documents from PJM that the Brunswick plant was bid into the auction and cleared. P3 urged the commission to ask Dominion whether it was. "The ratepayers deserve to know the extent of Dominion's commitment of resources that have not yet been approved by the commission," the group said.

The consumer counsel in the office of the attorney general asked the SCC to deny Dominion's application and direct the company to conduct and evaluate the results of a broad-based market solicitation.

"Delaying construction by five years would allow Dominion to take advantage of current historically low PJM capacity prices," the consumer counsel said in a post-hearing brief submitted to the SCC.

Dominion could reduce capacity costs by $454 million over five years by replacing Brunswick with short-term PJM market capacity purchases, the consumer counsel said.

The SCC staff in its post hearing brief said it has concerns about the limited scope of Dominion's solicitation of third party suppliers and whether that solicitation resulted in meaningful alternatives to the construction of Brunswick. The company informally discussed contract extension with three non-utility generators, the staff said.

Staff expressed concern that Dominion chose the site for Brunswick and signed agreements for major components before talking with the NUGs. "These two actions seem particularly incompatible with the idea that Dominion was objectively looking for 'bilateral opportunities' as alternatives to building the Brunswick plant," the staff said.

Dominion in its brief said Brunswick would be a "work horse" and will meet 9% of the company's energy requirements. Dominion's capacity gap will increase from 582 MW to 4,056 MW in 2027 if the plant is not built, Dominion said.

— Mary Powers

PLATTS
McGRAW HILL FINANCIAL

MEGAWATT DAILY

Volume 18 / Issue 104 / Friday, May 31, 2013

ISSN # 1088-4319

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

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

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

Manager, Advertisement Sales
Kacey Comstock

Advertising
Tel : +1-720-548-5508

UDI WORLD ELECTRIC POWER PLANTS DATABASE

NEW 2013 EDITION

UDI World Electric Power Plants Database (WEPP) is a global inventory of electric power generating units. It contains design data for plants of all sizes and technologies operated by regulated utilities, private power companies, and industrial autoproducers (captive power).

UNIQUE DATABASE IS THE LARGEST INFORMATION RESOURCE AVAILABLE

- Design information for more than 167,000 units at nearly 75,000 plant sites in 230+ countries — every country is represented
- Coverage of installed and projected steam and gas turbines, combined-cycle plants, IC engines, hydro units, wind turbines, and renewable energy units
- Details on plant operators, geographic location, capacity (MW), age, technology, fuels, and boiler, turbine, and generator manufacturers, emissions control equipment, and more

PURCHASE OPTIONS

All files can be opened directly in Excel or imported into Access or other database management software. Purchase the entire **World Electric Power Plants Database** or just select regions.

- All Units (CD-ROM)
- Asia (CD-ROM) — 44,000+ units
- Europe (CD-ROM) — 48,000+ units
- North America (CD-ROM) — 38,000+ units
- All Other (CD-ROM) —34,000+ units
- New Global Units (CD-ROM)
  - **new data subset** — this file pulls together all new and planned units of all technologies and fuels with in-service dates of 2010 and later at more than 4,000 plants worldwide

FOR MORE INFORMATION OR TO ORDER, VISIT WWW.UDIDATA.COM OR CALL YOUR NEAREST PLATTS OFFICE:

North America
1-800-PLATTS8 (toll-free)

Europe/Middle East/Africa
+44-20-7176-6111

Latin America
+54-11-4804-1890

Asia-Pacific
+65-6530-6430

For more information on Platts UDI databases and directories visit

WWW.UDIDATA.COM

PLATTS
McGRAW HILL FINANCIAL