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Thursday, September 5, 2013

Dynegy alters hedging to fix price 'disconnect'

ANALYSIS Dynegy is adjusting its hedging strategy in response to what it says is a disconnect between the locational marginal price at its power plant busbar and the price at the Midcontinent Independent System Operator's Indiana Hub where the company hedges its sales.

Dynegy reduced its balance of year hedge levels for its coal segment, which operates five power plants totaling 4,180 MW in Illinois, to 57%, from 68% in April, leaving the company open to busbar pricing in 2013.

Companies often have front year hedges in the 90% range. At the same time, Dynegy said it is protecting a portion of the remaining hedges with financial transmission rights.

Dynegy explained its actions, saying that correlation between busbar prices from the Midcontinent Independent System Operator

(continued on page 18)

Calif. players were overcharged for congestion

MARKETS Power market participants would receive $6.6 million in payments from the California Independent System Operator to compensate them for invalid congestion charges in January, ISO officials said Wednesday.

The ISO discussed its plan to correct prices for January 9, 13, 14, and 26 created by a software glitch related to transmission constraints.

The constraints happened in the Birds Landing area of Northern California, a key area for wind deviations on the grid. "Initially, the ISO deemed the congestion it observed as valid given the system conditions and outages it observed in those areas at the time," according to a technical bulletin issued by the grid operator.

When the ISO examined the congestion again in February, it determined it to be false. "There were approximately 60 pricing

(continued on page 18)

Draft plan details Calif. procurement targets

POWER SUPPLIES Utilities in Southern California would procure about 3,250 MW of renewable and energy efficiency resources as well as 3,000 MW of conventional generation under a draft plan developed by key state agencies and grid operator.

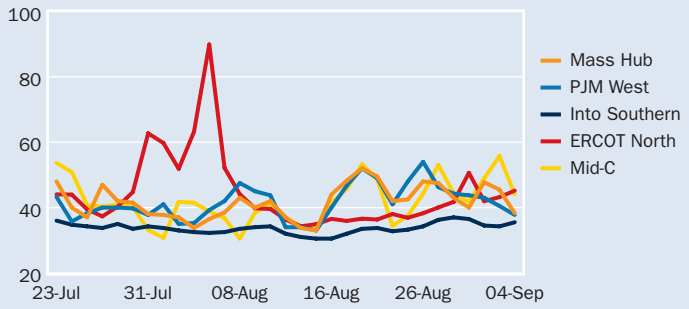
The reliability plan for the Los Angeles basin and San Diego is designed to address Southern California Edison's decision to retire the 2,150-MW San Onofre nuclear plant, the potential shutdown of 5,068 MW of coastal power plants that use ocean water for cooling and 400 MW in annual load growth.

San Onofre supplied about 16% of the region's power and provided critical voltage support for the area.

The plan was written by staff of the California Energy Commission, the Public Utilities Commission and the California Independent System Operator, while consulting with other state

(continued on page 19)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Sep 5 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	34.85	38.64	24.84	27.10
NYISO	32.78	57.31	23.68	35.01
PJM	30.27	42.92	20.20	28.23
MISO	29.90	37.35	20.29	22.73
ERCOT	46.19	67.71	25.77	27.08
CAISO	50.93	68.96	34.88	39.45

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

Day-ahead bilateral indexes and spark spreads for Sep 5

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	38.25	9935	11.30	7.45	-0.25	-7.95	-19.50
N.Y. Zone-A	36.00	9704	10.03	6.32	-1.10	-8.52	-19.65
PJM/MISO							
PJM West	37.75	10634	12.90	9.35	2.25	-4.85	-15.50
Indiana Hub	33.00	8696	6.44	2.64	-4.95	-12.54	-23.93
Southeast & Central							
Southern, Into	35.50	9588	9.58	5.88	-1.53	-8.93	-20.04
ERCOT, North	45.18	12421	19.72	16.08	8.81	1.53	-9.38
West							
Mid-C	44.11	12460	19.33	15.79	8.71	1.63	-8.99
SP15	63.50	16056	35.82	31.86	23.95	16.04	4.18

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

Northeast dailies retreat; forwards flat

Northeast dailies tumbled with loads expected to decrease with lower temperatures. Forwards in the region were flat. The NYMEX October natural gas futures contract picked up steam late in the session Wednesday and posted a preliminary settlement of $3.683/MMBtu, up 1.7 cents, after a day of sideways trading activity.

ISO New England forecast peak load on Wednesday at 18,870 MW and 16,510 MW for Thursday. High temperatures in Boston are expected to be in the upper 60s on Thursday.

Algonquin city-gate spot natural gas gained about 7 cents going to around $3.92/MMBtu and Transco Zone 6 New York eased about 2 cents to about $3.77/MMBtu.

Mass Hub on-peak for Thursday dropped more than $7 going to the upper $30s/MWh and off-peak gave up about $4 moving to the mid-$20s/MWh.

The New York ISO forecast peak load for Wednesday at about 24,300 MW and 21,495 MW for Thursday. High temperatures in New York state are projected to be in the mid-60s to mid-70s on Thursday.

New York Zone A on-peak prices for Thursday were valued in the mid-$30s/MWh, a decrease of about $2. NY Zone G on-peak prices fell more than $6 valued in the low $40s/MWh.

Day-ahead auction prices in the ISO New England tumbled Wednesday with load expected to fall on Thursday. Internal Hub on-peak gave up $13.80 moving down to $42.05/MWh and Conneciticut on-peak was off $13.59 moving to $42.59/MWh. Maine on-peak was off $13.94 going to $40.33/MWh, while Rhode Island on-peak lost $9.82 dropping to $44.51/MWh. NE-Mass Boston lost $14.84 to $42.07/MWh.

Day-ahead auction prices in the New York ISO were lower with demand forecast to ease. New York City on-peak fell $4.08 going to $43.69/MWh and Hudson Valley on-peak lost $5.45 moving to $41.44/MWh. West on-peak fell $5.73 moving to $36.05/MWh while Long Island on-peak gave up 36 cents dropping to $57.31/MWh.

Northeast term power was flat for the prompt month Wednesday. In New England, Mass Hub on-peak October financial futures were unchanged, with bids at $39.90/MWh and offers at $40.20/MWh on the IntercontinentalExchange at about 2:30 p.m. EDT. Beyond the prompt month New England saw dcelines. Mass Hub on-peak fourth quarter was down 55 cents to about $54.60/MWh, with a $1.25 drop for December alone. Mass Hub on-peak January-February 2014 came off $2.25 to about $96.75/MWh.

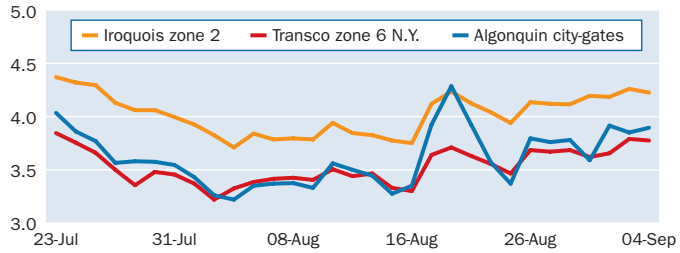
New York Zone A on-peak October financial futures held steady, with bids at $36.95/MWh and offers at $38.50/MWh on ICE. Zone A on-peak fourth quarter was unchanges at about $39/MWh on ICE.

Northeast day-ahead bilateral indexes for Sep 5 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	38.25	-7.25	43.83	9935
N.Y. Zone-G	41.25	-6.00	45.42	10313
N.Y. Zone-J	43.75	-4.00	46.75	10938
N.Y. Zone-A	36.00	-2.00	37.67	9704
Ontario*	32.25	-2.00	34.25	7378
Off-Peak				
Mass Hub	26.00	-3.50	27.50	6753
N.Y. Zone-G	27.25	-2.75	28.58	6813
N.Y. Zone-J	27.50	-2.75	29.08	6875
N.Y. Zone-A	25.50	-1.75	25.83	6873
Ontario*	20.00	-1.25	20.17	4576

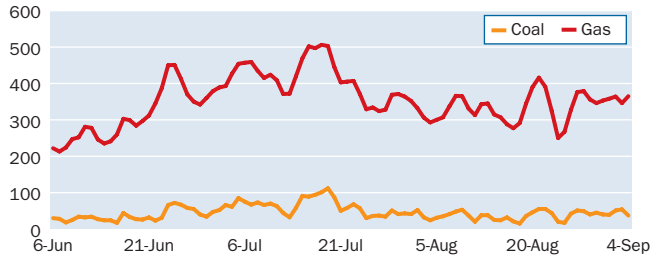
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO gas and coal generation (GWh)



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 03-Sep	%Chg	% Chg Year-ago	Forecast 04-Sep	05-Sep	06-Sep	07-Sep	08-Sep
ISONE								
Load	412	4	3	388	358	339	321	336
Generation								
Coal	24	8	75	14	11	11	12	15
Gas	170	2	-12	187	160	138	140	154
Nuclear	107	0	-4	107	107	107	107	107
NYISO								
Load	513	1	0	485	448	413	394	409
Generation								
Coal	29	4	67	23	14	12	12	14
Gas	176	-11	-6	178	153	133	140	157
Nuclear	133	0	6	133	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Sep 5 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	36.69	-0.20	0.01	-5.36	45.89	9531
Connecticut	37.30	-0.20	0.61	-5.29	46.34	9277
NE Mass-Boston	36.45	-0.20	-0.24	-5.62	46.14	9466
SE Mass	37.12	0.22	0.02	-5.68	46.00	9642
West-Central Mass	36.98	-0.20	0.29	-5.33	46.16	9605
Rhode Island	38.64	2.01	-0.26	-5.87	46.36	10035
Maine	34.85	-0.20	-1.83	-5.48	44.17	8285
New Hampshire	36.63	-0.20	-0.05	-5.66	46.08	8707
Vermont	37.20	-0.20	0.52	-5.54	46.45	8843
Off-Peak						
Internal Hub	26.06	-0.09	0.07	-2.54	29.47	6796
Connecticut	26.17	-0.09	0.17	-2.59	29.58	6486
NE Mass-Boston	26.01	-0.09	0.01	-2.57	29.43	6782
SE Mass	26.27	0.09	0.09	-2.40	29.47	6849
West-Central Mass	26.19	-0.09	0.19	-2.55	29.62	6829
Rhode Island	27.10	0.87	0.14	-2.08	30.00	7067
Maine	24.84	-0.09	-1.16	-2.52	28.00	5889
New Hampshire	25.85	-0.09	-0.15	-2.51	29.20	6128
Vermont	25.97	-0.09	-0.03	-2.62	29.48	6156

NYISO day-ahead LMP for Sep 5 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	38.93	-0.01	1.98	-5.65	44.09	9805
Central Zone	37.34	0.04	0.45	-4.79	41.81	10074
Dunwoodie Zone	41.77	-0.80	4.04	-5.31	47.62	10434
Genesee Zone	36.61	0.03	-0.29	-3.94	40.42	9879
Hudson Valley Zone	41.44	-0.61	3.89	-5.45	47.21	10351
Long Island Zone	57.31	-14.99	5.38	-0.36	55.91	14316
Millwood Zone	41.69	-0.80	3.96	-5.39	47.64	10414
Mohawk Valley Zone	37.58	0.25	0.90	-4.60	42.19	9785
N.Y.C. Zone	43.69	-2.33	4.42	-4.08	48.80	10913
North Zone	32.78	2.06	-2.09	-0.18	34.54	7793
West Zone	36.05	0.03	-0.85	-5.73	39.93	9727
Off-Peak						
Capital Zone	26.50	0.00	1.48	-2.77	30.98	6690
Central Zone	25.42	0.00	0.39	-2.05	29.14	6919
Dunwoodie Zone	27.23	0.00	2.20	-2.64	31.84	6770
Genesee Zone	25.15	0.00	0.13	-1.97	28.62	6847
Hudson Valley Zone	27.22	0.00	2.19	-2.69	31.84	6768
Long Island Zone	35.01	-6.95	3.03	2.17	36.00	8704
Millwood Zone	27.18	0.00	2.15	-2.64	31.82	6759
Mohawk Valley Zone	25.60	0.00	0.58	-2.20	29.53	6711
N.Y.C. Zone	27.43	0.00	2.40	-2.62	32.43	6821
North Zone	23.68	0.03	-1.32	-1.82	27.18	5613
West Zone	25.37	0.00	0.34	-1.92	28.63	6904

Generation unit outage report

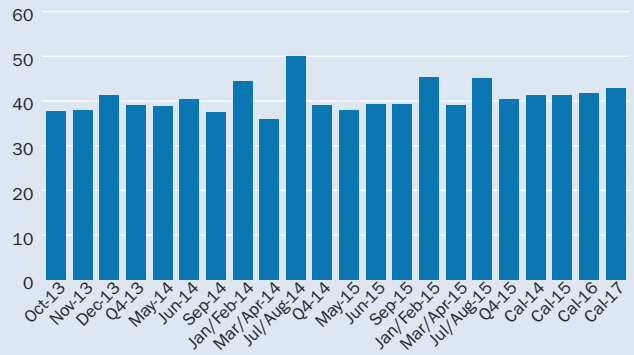
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	200	c	Ont.	PMO	Unk	09/11/12
Darlington-2/OPG	868	n	Ont.	PMO	Unk	08/27/13
Darlington-4/OPG	869	n	Ont.	PMO	Unk	08/28/13
DeCew Falls/OPG	167	h	Ont.	Unk	Unk	08/22/13
Fort Frances/H2O Power	10	h	Ont.	Unk	Unk	09/04/13
Goreway-15/Sithe	357	g	Ont.	Unk	Unk	08/19/13
Greenfield-1/Greenfield	212	g	Ont.	Unk	Unk	09/03/13
Greenfield-2/Greenfield	212	g	Ont.	Unk	Unk	09/03/13
Greenfield-3/Greenfield	212	g	Ont.	Unk	Unk	09/03/13
Greenfield-4/Greenfield	517	g	Ont.	Unk	Unk	09/03/13
Little Long-3/OPG	66.5	h	Ont.	Unk	Unk	08/22/13
Pickering-6/OPG	510	n	Ont.	Unk	Unk	09/03/13
Pickering-8/OPG	500	n	Ont.	PMO	Unk	08/27/13
Taohsc/TransAlta	78	g	Ont.	Unk	Unk	09/03/13
Thunderbay-2/OPG	150	c	Ont.	PMO	Unk	03/01/13
White Dog/OPG	68	h	Ont.	Unk	Unk	09/04/13

Northeast Platts-ICE Forward Curve, Sep 4 ($/MWh)

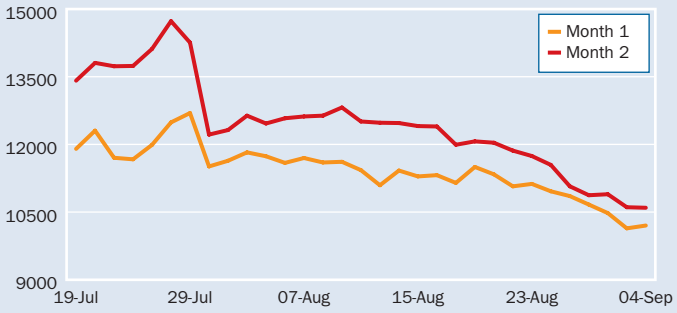
Prompt month: Oct 13	On-peak	Off-peak
Mass Hub	40.00	30.75
N.Y. Zone G	44.00	34.00
N.Y. Zone J	48.00	35.50
N.Y. Zone A	37.75	31.25
Ontario*	29.25	20.00

*Ontario prices are in Canadian dollars

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



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



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Next-week	09/03	45.25-46.25

*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

Dailies climb, despite lower demand, temperatures

Daily power prices in the Electric Reliability Council of Texas were stronger on IntercontinentalExchange Wednesday, even with peak demand expected to drop as temperatures are forecast to decline. Southeast forward prices were down Wednesday, while South Central forwards were mixed as the NYMEX October natural gas futures contract settled at $3.683/MMBtu, up 1.7 cents.

Spot natural gas at Houston Ship Channel was steady, around $3.709/MMBtu.

ERCOT North Hub next-day on-peak physical power rose about $2 to trade around $45.25/MWh. Off-peak added nearly $1.50 to trade around $25.50/MWh.

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

System load in ERCOT was forecast to peak at 63,950 MW Wednesday and 62,425 MW Thursday, compared with an actual peak of 63,411 MW Tuesday.

With the exception of the west, teal-time prices averaged $24.50/MWh, while West Hub averaged $25.75/MWh from 12:15 to 6 am CDT Wednesday. Wind generation was forecast to peak at 2,525 MW at midnight CDT Wednesday and 3,025 MW at midnight CDT Thursday.

North Hub balance-of-the-week on-peak packages were bid at $43 and offered at $43.75/MWh. Next-week on-peak was bid at $38.50 and offered at $39.50/MWh.

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

Spot natural gas at Transco Zone-3 was steady around $3.676/MMBtu. High temperatures in Atlanta were forecast in the mid-80s Wednesday, with lows expected in the upper 60s. The average September high temperature in the city is 82; its average low is 65.

The ERCOT day-ahead auction cleared stronger Wednesday afternoon. West Hub remained the highest-priced hub, as South

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for Sep 5 ($/MWh)

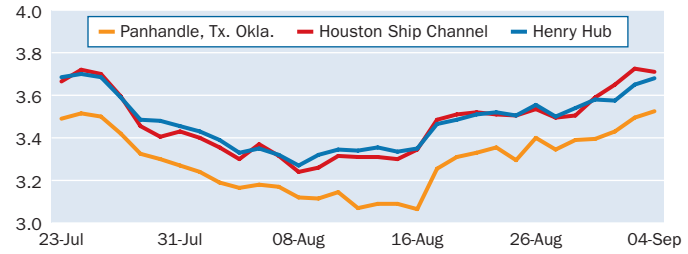
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	36.00	0.25	36.17	9549
Southern, Into	35.50	1.25	34.75	9588
Florida	38.00	1.50	36.92	9113
TVA, Into	35.00	0.75	34.58	9428
Entergy, Into	34.50	1.00	33.92	9426
Southeast Off-Peak				
VACAR	22.50	-1.50	20.70	5968
Southern, Into	21.75	-1.25	19.75	5874
Florida	25.00	-0.50	25.25	5995
TVA, Into	21.50	-1.50	20.00	5791
Entergy, Into	19.75	-1.25	17.30	5396
ERCOT On-peak				
ERCOT, North	45.18	1.98	43.44	12421
ERCOT, Houston	46.00	1.50	44.58	12391
ERCOT, South	45.50	2.25	43.50	12506
ERCOT, West	46.50	2.00	44.75	12593
ERCOT Off-Peak				
ERCOT, North	25.50	1.38	23.87	7010
ERCOT, Houston	25.50	1.50	23.85	6869
ERCOT, South	25.50	1.50	23.85	7009
ERCOT, West	25.50	1.25	23.90	6906
SPP/MRO On-peak				
MAPP, South	36.50	0.00	36.17	9759
SPP, North	38.25	2.00	36.58	10851
SPP/MRO Off-Peak				
MAPP, South	21.50	-1.50	20.30	5749
SPP, North	21.50	-1.00	20.05	6099

Southeast load and generation mix forecast (GWh)

	Actual 03-Sep	%Chg	% Chg Year-ago	Forecast 04-Sep	05-Sep	06-Sep	07-Sep	08-Sep
ERCOT								
Load	1171	6	-1	1054	1104	1092	1060	1054
Generation								
Coal	494	7	12	421	427	431	435	439
Gas	460	2	-10	459	486	474	476	485
Nuclear	119	0	-2	119	123	123	123	123
SPP								
Load	745	6	-5	683	711	737	723	736
Generation								
Coal	437	5	4	401	418	434	447	456
Gas	195	1	-25	201	205	210	219	228
Nuclear	49	0	-2	49	49	49	49	49

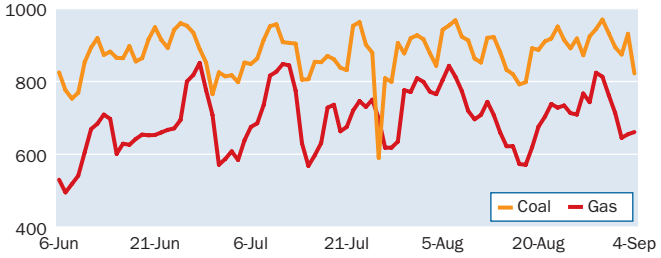
Source: Bentek

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



Source: Platts

ERCOT & SPP gas and coal generation (GWh)



Source: Bentek

ERCOT average day-ahead LMP for Sep 5 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	46.63	1.81	42.44	12722
Hub Average	46.88	1.79	42.61	12789
Houston Hub	47.27	1.69	42.89	12728
North Hub	46.35	1.95	42.22	12753
South Hub	46.19	1.38	42.28	12698
West Hub	47.70	2.12	43.04	12925
AEN Zone	46.38	1.93	42.35	12567
CPS Zone	46.61	0.80	42.78	12835
LCRA Zone	47.47	1.48	43.03	13073
Rayburn Zone	46.45	1.87	42.27	12781
Houston Zone	47.77	1.88	43.24	12863
North Zone	46.82	2.00	42.56	12883
South Zone	47.24	0.47	43.42	12987
West Zone	67.71	3.13	60.64	18345
Off-Peak				
Bus Average	25.85	0.50	24.77	7063
Hub Average	25.84	0.48	24.77	7059
Houston Hub	25.86	0.52	24.77	6948
North Hub	25.86	0.51	24.77	7147
South Hub	25.85	0.52	24.76	7118
West Hub	25.77	0.36	24.76	7000
AEN Zone	25.87	0.51	24.87	7026
CPS Zone	25.92	0.47	24.87	7147
LCRA Zone	25.87	0.51	24.79	7134
Rayburn Zone	25.87	0.52	24.77	7147
Houston Zone	25.87	0.52	24.78	6949
North Zone	25.87	0.52	24.78	7147
South Zone	25.87	0.51	24.78	7124
West Zone	27.08	0.64	25.31	7356

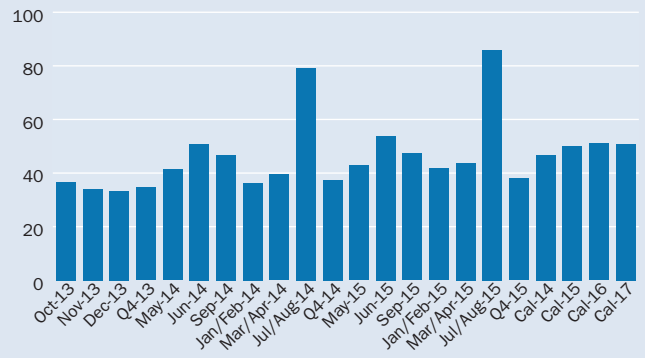
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Next-week	08/29	35.50-36.00
Entergy, Into		
Bal-week	09/03	34.00-34.50
Bal-month	09/03	31.00-31.50
Next-week	09/03	32.50-33.00
ERCOT, North		
Bal-week	09/04	43.25-43.75
Bal-week	09/03	41.75-42.25
ERCOT, Houston		
Bal-week	09/04	43.25-43.75
Next-week	08/29	43.50-44.00
ERCOT, South		
Bal-week	09/04	43.25-43.75

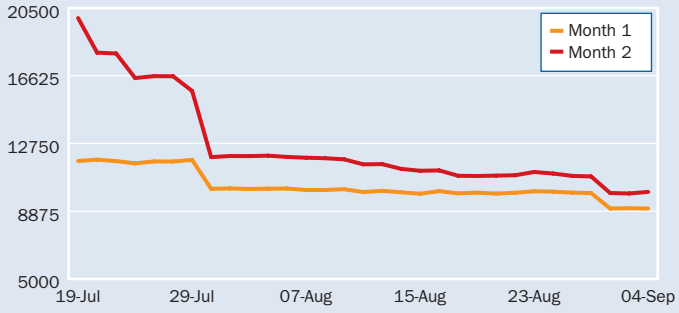
Southeast & Central Platts-ICE Forward Curve, Sep 4 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
Southern Into	33.00	28.50
Entergy Into	31.25	25.75
ERCOT North	34.00	25.75
ERCOT Houston	36.75	26.75
ERCOT West	32.75	24.50
ERCOT South	35.00	25.50

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Crystal River-3/Progress	838	n	Fla.	NA	Retired	09/26/09
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Monticello-2/Luminant	565	c	Texas	MO	Unk	08/25/13
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13

Market coverage

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

WEST MARKETS

Most Western dailies decline, and terms finish flat

Most Western power dailies were down Wednesday with lower Northwest temperatures and despite higher demand expected in California. Terms closed flat, and the NYMEX October natural gas futures contract posted a preliminary settlement of $3.683/MMBtu, up 1.7 cents from Tuesday's close.

In the Northwest, Mid-Columbia day-ahead on-peak fell around $11.50 to trade between $43 and $45.50/MWh for delivery on Thursday. Mid-C day-ahead off-peak prices lost about $1.25 to trade between $27.75 and $29/MWh. The Mid-C on-peak balance-of-the-month package traded between $45 and $46/MWh, up about $1.25.

Portland, Oregon's forecast highs were near 70 on Thursday, about a 10-degree drop. Expected lows were in the low 60s.

The Bonneville Power Administration's wind at 7 am PDT Wednesday was 415 MW and its hydropower was 5,958 MW.

In California, SP15 next-day on-peak was down slightly, trading between $62 and $64/MWh. SP15 day-ahead off-peak dropped about $1 to trade between $38.75 and $39.25/MWh. SP15 bal-month was bid at $51.75 and offered at $55.25/MWh, down about 75 cents. NP15 day-ahead on-peak climbed 50 cents to around $52.75/MWh. NP15 day-ahead off-peak was slightly lower to trade between $35.25 and $36.25/MWh. NP15 bal-month was bid at $44.50 and offered at $51.50/MWh, down about 50 cents.

Sacramento, California, expected highs in the upper 80s and lows in the low 60s. Forecast highs for Burbank were around 100, while anticipated lows were near the mid-70s.

The California Independent System Operator projected peak demand to hit 43,142 MW on Wednesday and 44,657 MW on Thursday. Renewables were 2,424 MW, and wind was about 750 MW at 7 am PDT on Wednesday.

In the desert Southwest, Palo Verde next-day on-peak was up about $2.75 to trade between $46 and $55/MWh. Palo Verde day-ahead off-peak rose around 75 cents to trade between $28.50 and $28.75/MWh. Palo Verde bal-month was offered at $39/MWh.

Phoenix expected highs near 107 and lows in the high 80s.

Next-day natural gas prices were mixed in the Rockies and California. Opal was up 6.1 cents to $3.636/MMBtu, Pacific Gas and Electric city-gate lost 1 cent to $4.105/MMBtu, and SoCal city-gate climbed 3.2 cents to $4.047/MMBtu.

Most day-ahead prices were down slightly in the California Independent System Operator auction. NP15 on-peak fell 41 cents to $51.83/MWh, and NP15 off-peak lost 33 cents to $35.68/MWh. ZP26 on-peak dropped 99 cents to $50.93, while ZP26 off-peak shed 70 cents to $34.88/MWh. SP15 on-peak climbed $10.45 to $68.96/MWh, as SP15 off-peak added 36 cents to $39.45/MWh.

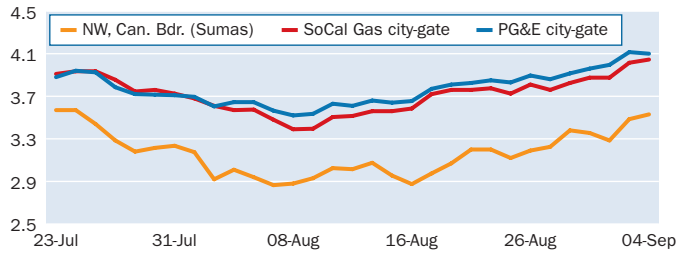
In the Northwest, Mid-Columbia on-peak October fell 25 cents with bids at $37.25 and offers at $37.50/MWh on ICE around 2:30 p.m. EDT. The fourth quarter crept down 15 cents to about $39.50/MWh, and the first quarter of 2014 lost 35 cents to about

(continued on page 10)

Western day-ahead bilateral indexes for Sep 5 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	50.70	-12.45	55.89	13703
Mid-C	44.11	-11.67	49.60	12460
Palo Verde	47.06	2.83	43.57	12247
Mead	53.00	1.75	49.25	13401
Mona	57.25	-3.75	54.75	15992
Four Corners	48.25	3.75	45.92	12936
NP15	52.75	0.50	51.33	12866
SP15	63.50	0.50	59.58	16056
Off-Peak				
COB	32.25	-1.33	36.27	8716
Mid-C	28.11	-1.48	33.39	7941
Palo Verde	28.52	0.59	30.72	7422
Mead	30.50	0.75	32.30	7712
Mona	28.00	-0.50	31.10	7821
Four Corners	28.75	1.00	30.63	7708
NP15	36.00	0.25	38.35	8780
SP15	39.00	-1.00	41.15	9861

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO gas generation (GWh)

Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 03-Sep	%Chg	% Chg Year-ago	Forecast 04-Sep	05-Sep	06-Sep	07-Sep	08-Sep
CAISO								
Load	815	10	1	777	798	825	790	773
Generation								
Gas	366	5	1	352	351	365	376	377
Nuclear	56	0	-7	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Sep 5 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	51.83	-8.13	-4.07	-0.41	48.22	12641
SP15 Gen Hub	68.96	5.48	-0.54	10.45	59.23	17436
ZP26 Gen Hub	50.93	-8.45	-4.64	-0.99	48.40	12876
Off-Peak						
NP15 Gen Hub	35.68	-1.06	-1.66	-0.33	35.59	8677
SP15 Gen Hub	39.45	1.21	-0.15	0.36	38.39	10061
ZP26 Gen Hub	34.88	-1.39	-2.12	-0.70	35.09	8894

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	09/04	44.50-46.00
Bal-month	09/03	44.50-45.00
Bal-month	08/30	41.50-42.00
Bal-month (off-peak)	09/03	30.75-31.25
SP15		
Bal-month	09/04	53.50-54.00
Bal-month	09/03	53.75-54.75

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Contra Costa-6/NRG	337	g	Calif.	PMO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
Desert Sunlight/NextEra	300	s	Calif.	MO	Unk	08/15/13
El Segundo-3/NRG	335	g	Calif.	MO	Unk	07/23/13
Huntington Beach-3/AES	225	g	Calif.	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif.	PMO	Unk	04/14/13
Mexicali/Sempra	180	g	Calif.	PMO	Unk	07/22/13
Pine Flat/USACE	210	h	Calif.	PMO	Unk	08/11/13
Silver Ridge/AES	200	g	Calif.	PMO	Unk	09/02/13

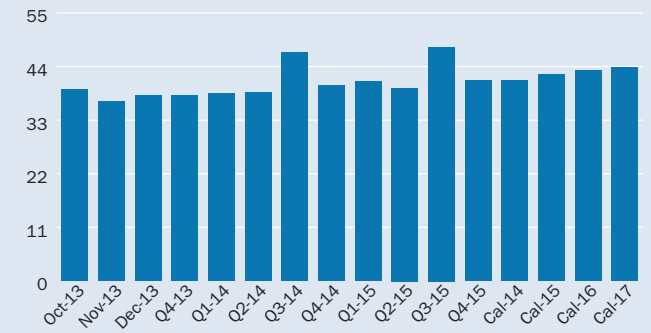
Additional information on data and analysis:

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.

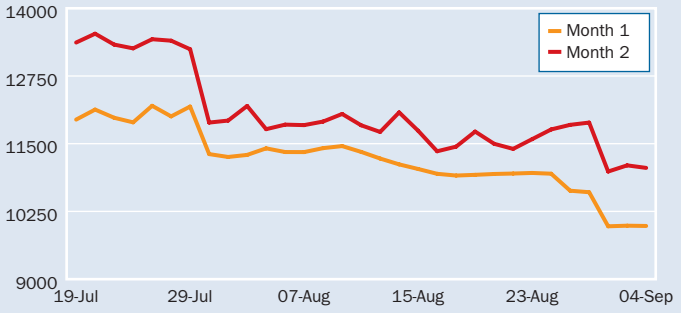
Western Platts-ICE Forward Curve, Sep 4 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
Mid-C	37.50	31.00
Palo Verde	37.00	27.75
Mead	39.25	29.75
NP15	44.00	36.25
SP15	48.50	37.75

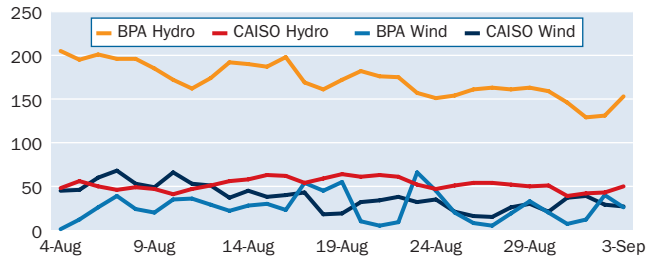
Mead: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

PJM dailies drop; forwards steady

Daily power prices in the Mid-Atlantic fell Wednesday, as demand is expected to decline with lower temperatures in the forecast. Forward prices in the Mid-Atlantic and Midwest were mostly unchanged, as the NYMEX October natural gas futures contract settled at $3.683/MMBtu, up 1.7 cents.

PJM Interconnection forecasted peak demand on Wednesday at 113,826 MW and 110,724 MW for Thursday. High temperatures across the PJM footprint are expected in the low 70s to mid-80s.

Spot natural gas in the region edged up, with Texas Eastern M-3 gaining about 4 cents to $3.69/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Thursday delivery lost about $3, going to the upper $30s/MWh and off-peak packages fell about $2.75 in the mid-$20s/MWh.

Midcontinent ISO dailies were mostly weaker, with mild weather and weak nearby power prices. Chicago city-gates spot gas added about 2 cents to reach $3.82/MMBtu.

Indiana Hub on-peak for Thursday delivery slipped 75 cents in the low $30s/MWh, as off-peak lost about $2 in the low $20s/MWh. Minnesota Hub on-peak for Thursday delivery edged up about $1 in the mid-$30s/MWh. Michigan Hub on-peak was holding steady in the mid-$30s/MWh.

Dailies in the Midwestern portion of PJM eased with mild weather. AEP-Dayton Hub on-peak lost more than $3, going to the low $30s/MWh and off-peak fell about $2 going to the low $20s/MWh. Northern Illinois Hub on-peak for Thursday gave up nearly $3, moving down to the low $30s/MWh. NI Hub off-peak lost about $4, going to around $20/MWh.

Day-ahead auction prices in PJM mostly eased Wednesday, with lower demand expected. Western Hub on-peak fell $1.66, going to $36.99/MWh while Eastern Hub on-peak lost $3.57, going to $37.51/MWh. BG&E on-peak edged up 31 cents to $42.92/MWh and Pepco on-peak fell 56 cents to $41.77/MWh. JCPL on-peak was down $1.28 to $36.86/MWh and PSEG on-peak was down $1.98 to $37.01/MWh. ComEd on-peak lost $1.34, moving to $31.63/MWh and Chicago Hub on-peak decreased $1.34, going to $31.66/MWh.

MISO day-ahead auction prices cleared stronger Wednesday afternoon. Minnesota Hub became the highest-priced hub, with on-peak clearing at $37.35/MWh, up $4.89. Off-peak cleared at $20.29/MWh, a gain of $1.83. Michigan Hub became the highest-priced hub with on-peak clearing at $34.99/MWh, rising 33 cents. Off-peak cleared at $22.73/MWh, adding $1.61. Indiana Hub on-peak cleared at $33.98/MWh, moving up 32 cents. Off-peak cleared at $22.23/MWh, jumping $1.59.

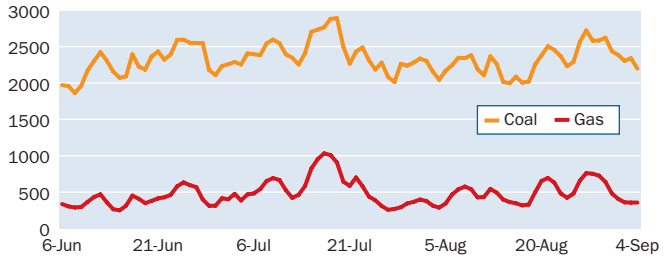
Illinois Hub remained the lowest-priced hub, with on-peak clearing at $29.90/MWh, climbing 95 cents. Off-peak cleared at $20.97/MWh, an increase of 82 cents.

Congestion costs at the hubs ranged from negative $4.11 to $1.61 for on-peak, and from negative 21 cents to 28 cents for off-peak.

PJM & MISO day-ahead bilateral indexes for Sep 5 ($/MWh)

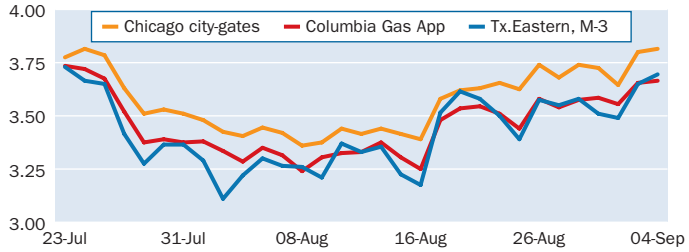
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	37.75	-2.75	40.42	10634
Dominion Hub	43.25	-2.50	44.42	11634
AD Hub	31.75	-2.75	34.50	8028
NI Hub	31.75	-3.00	34.00	8322
PJM Off-Peak				
PJM West	24.25	-2.75	24.42	6831
Dominion Hub	27.25	-4.00	27.17	7330
AD Hub	23.00	-2.00	23.00	5815
NI Hub	21.00	-3.00	21.67	5505
MISO On-peak				
Indiana Hub	33.00	-0.75	33.75	8696
Michigan Hub	34.50	-0.75	34.92	8784
Minnesota Hub	33.50	0.50	35.50	8827
Illinois Hub	28.75	-3.25	32.33	7571
MISO Off-Peak				
Indiana Hub	21.00	-2.00	21.33	5534
Michigan Hub	21.50	-2.00	22.17	5474
Minnesota Hub	19.00	-1.00	19.42	5007
Illinois Hub	19.75	-0.50	18.67	5201

PJM & MISO gas and coal generation (GWh)



Source: Bentek

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 03-Sep	%Chg	% Chg Year-ago	Forecast 04-Sep	05-Sep	06-Sep	07-Sep	08-Sep
PJM								
Load	2305	1	0	2020	2094	2012	1895	2033
Generation								
Coal	1148	-1	11	966	973	1031	1075	1103
Gas	296	-7	-19	287	288	262	265	326
Nuclear	794	1	2	798	798	798	798	798
MISO								
Load	1398	7	-2	1441	1435	1435	1436	1426
Generation								
Coal	1193	4	6	1230	1182	1174	1254	1278
Gas	60	50	-42	71	80	93	138	150
Nuclear	207	0	-11	207	207	207	207	207

Source: Bentek

MISO average day-ahead LMP for Sep 5 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	33.98	-0.67	-0.58	0.32	32.60	8967
Michigan Hub	34.99	-0.48	0.23	0.33	33.71	8902
Minnesota Hub	37.35	1.61	0.51	4.89	31.20	9836
Illinois Hub	29.90	-4.11	-1.23	0.95	30.97	7873
Off-Peak						
Indiana Hub	22.23	0.28	0.41	1.59	21.37	5912
Michigan Hub	22.73	0.21	0.98	1.61	21.92	5755
Minnesota Hub	20.29	-0.21	-1.04	1.83	18.19	5322
Illinois Hub	20.97	-0.20	-0.37	0.82	20.11	5538

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

Package	Trade date	Range
PJM West		
Bal-week	09/04	32.75-33.75
Bal-week	08/30	37.75-39.00
Bal-month	09/04	43.50-44.50
Next-week	09/04	46.25-47.25
Next-week	09/03	47.25-48.75
Next-week	08/30	41.25-42.25
Next-week	08/29	37.50-38.50
AD Hub		
Next-week	09/04	41.75-42.75

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Kewaunee/Dominion	581	n	Wis.	NA	Retired	05/07/13

PJM average day-ahead LMP for Sep 5 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	30.27	-2.99	-2.11	-1.08	30.35	8108
AEP-Dayton Hub	31.65	-2.81	-0.91	-1.06	31.80	8478
ATSI Gen Hub	32.81	-2.81	0.25	-1.38	33.52	8914
Chicago Gen Hub	31.02	-2.90	-1.45	-1.37	30.31	8126
Chicago Hub	31.66	-2.78	-0.94	-1.34	31.03	8292
Dominion Hub	42.45	7.39	-0.32	-1.54	45.55	11410
Eastern Hub	37.51	0.07	2.06	-3.57	45.30	10047
New Jersy Hub	36.93	0.11	1.44	-1.70	42.50	9891
Northern Illinios Hub	31.44	-2.78	-1.16	-1.32	30.77	8235
Ohio Hub	31.89	-2.81	-0.67	-1.07	32.09	8422
West Internal Hub	34.97	0.27	-0.67	-0.78	35.79	9861
Western Hub	36.99	1.49	0.13	-1.66	40.38	10430
AEP Zone	31.78	-2.67	-0.92	-0.98	31.74	8514
Allegheny Power Zone	33.96	-0.65	-0.76	-1.67	35.85	9297
Atlantic Elec Zone	37.23	0.08	1.78	-1.59	43.27	9972
ATSI Zone	32.90	-2.82	0.35	-1.52	33.73	8938
BG&E Zone	42.92	5.96	1.59	0.31	47.25	11799
ComEd Zone	31.63	-2.76	-0.99	-1.34	30.98	8285
Dayton P&L Zone	32.13	-2.86	-0.38	-0.94	32.35	8477
Delmarva P&L Zone	37.44	0.16	1.91	-3.18	44.91	10029
Dominion Zone	42.47	7.14	-0.04	-0.80	44.79	11416
Duke Zone	30.95	-2.75	-1.66	-0.94	31.03	8167
Duquesne Light Zone	30.72	-3.01	-1.65	-1.87	31.86	8609
JCPL Zone	36.86	0.20	1.29	-1.28	42.21	9873
MetEd Zone	35.91	0.14	0.40	-5.37	43.68	9679
PECO Zone	36.19	-0.03	0.85	-1.60	42.22	9754
Pennsylvania Elec Zone	34.53	-1.47	0.63	-2.57	37.88	9674
PEPCO Zone	41.77	5.44	0.95	-0.56	45.85	11482
PPL Zone	35.26	-0.31	0.20	-2.77	41.77	9503
PSEG Zone	37.01	0.14	1.50	-1.98	42.72	9914
Rockland Elec Zone	36.40	-0.44	1.46	-1.71	41.35	9749
Off-Peak						
AEP Gen Hub	22.72	-0.57	-0.99	0.14	23.26	6106
AEP-Dayton Hub	23.38	-0.44	-0.46	0.15	24.06	6283
ATSI Gen Hub	23.84	-0.55	0.12	0.04	24.54	6503
Chicago Gen Hub	20.20	-2.95	-1.12	1.31	18.68	5312
Chicago Hub	20.51	-2.92	-0.85	1.27	19.11	5394
Dominion Hub	28.23	3.71	0.25	-1.42	29.10	7590
Eastern Hub	25.88	0.68	0.94	-0.40	26.65	6954
New Jersy Hub	25.47	0.58	0.63	-0.51	26.39	6845
Northern Illinios Hub	20.46	-2.86	-0.96	1.23	19.06	5380
Ohio Hub	23.50	-0.41	-0.37	0.13	24.25	6219
West Internal Hub	24.70	0.54	-0.12	0.36	24.99	7009
Western Hub	25.17	0.71	0.19	-0.23	25.79	7143
AEP Zone	23.38	-0.46	-0.43	0.31	23.84	6283
Allegheny Power Zone	24.27	0.07	-0.07	-0.01	24.93	6674
Atlantic Elec Zone	25.65	0.63	0.74	-0.39	26.48	6891
ATSI Zone	23.91	-0.56	0.20	0.00	24.63	6523
BG&E Zone	26.61	1.49	0.84	0.04	26.98	7342
ComEd Zone	20.49	-2.90	-0.88	1.27	19.08	5389
Dayton P&L Zone	23.53	-0.52	-0.23	0.23	24.08	6257
Delmarva P&L Zone	25.88	0.71	0.90	-0.34	26.59	6954
Dominion Zone	27.80	3.19	0.34	-0.64	28.28	7473
Duke Zone	22.87	-0.48	-0.93	0.28	23.32	6082
Duquesne Light Zone	22.99	-0.66	-0.63	-0.02	23.76	6490
JCPL Zone	25.30	0.50	0.53	-0.59	26.29	6798
MetEd Zone	25.18	0.70	0.21	-0.22	25.81	6803
PECO Zone	25.36	0.65	0.43	-0.35	26.14	6850
Pennsylvania Elec Zone	24.68	-0.08	0.49	-0.57	25.64	6979
PEPCO Zone	26.69	1.79	0.62	0.21	26.86	7363
PPL Zone	24.76	0.54	-0.04	-0.45	25.58	6690
PSEG Zone	25.59	0.64	0.68	-0.46	26.46	6876
Rockland Elec Zone	25.25	0.34	0.63	-0.66	26.26	6783

Mid-Atlantic forwards were mostly unchanged Wednesday as October NYMEX gas futures rose slightly. PJM West on-peak October financial futures held steady, with bids at $41.20/MWh and offers at $41.30/MWh on ICE. PJM West on-peak fourth-quarter was unchanged at about $41.85/MWh. PJM West on-peak January-February 2014 financial futures was unchanged at about $45.25/MWh on ICE.

Midwest forwards were unchanged Wednesday. AD Hub on-peak October financial futures were steady, with bids at $37.50/MWh and offers at $38.15/MWh on ICE. Indiana Hub on-peak September financial futures were unchanged, with bids at $34.50/MWh and offers at $34.85/MWh on ICE.

Southeast markets ... *from page 4*

Hub became the lowest-priced hub. West Hub on-peak cleared in the ERCOT auction at $47.70/MWh, a gain of more than $2, while off-peak cleared at $25.77/MWh, a jump of more than 25 cents. Houston Hub on-peak cleared in the auction at $47.27/MWh, rising almost $1.75, while off-peak cleared at $25.86/MWh, adding around 50 cents. North Hub on-peak cleared the auction at $46.35/MWh up around $2 from Tuesday's clearing price, while off-peak cleared at $25.86/MWh, moving up about 50 cents. South Hub on-peak cleared at $46.19/MWh, an increase of nearly $1.50, while off-peak cleared at $25.85/MWh, rising about 50 cents.

West Zone on-peak led the load zones at $67.71/MWh, adding about $3.25 from Tuesday. The highest hourly day-ahead price occurred at 5 pm CDT in the West Hub at $97.56/MWh and in the West Zone at $136.80/MWh.

ERCOT system load was forecast to peak at 62,425 MW Thursday, down 2% from Wednesday's expected peak of 63,950 MW.

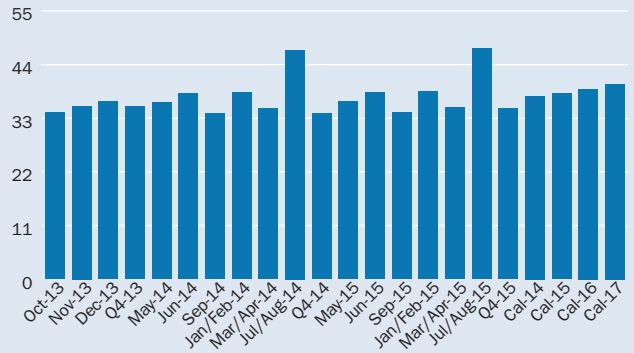
South Central on-peak terms were mixed Wednesday, as October NYMEX gas futures edged up in late trading. ERCOT North on-peak October inched up 10 cents to about $33.75/MWh, the fourth quarter crept up 10 cents to about $33.45/MWh, and the first quarter rose 10 cents to about $36.50/MWh. Heat rates were up about 40 Btu/kWh on ICE. Into Entergy on-peak October skidded 50 cents to about $31.25/MWh, and Q4 fell 30 cents to about $31.35/MWh.

Southeast on-peak October went down Wednesday, even as October NYMEX gas futures went up. Into Southern October slid 50 cents to about $33/MWh, Q4 fell 25 cents to about $33.15/MWh, and first quarter stayed around $36.40/MWh.

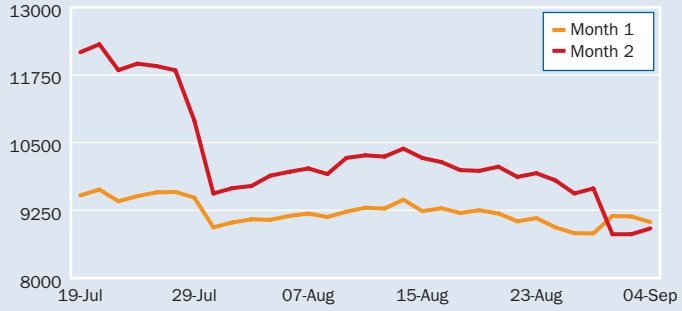
PJM & MISO Platts-ICE Forward Curve, Sep 4 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
PJM West	41.25	30.75
AD Hub	37.75	29.50
NI Hub	34.25	23.00
Indiana Hub	34.75	27.00

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



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



West markets ... *from page 6*

$36.40/MWh. In California, SP15 on-peak October financial terms were unchanged with bids at $48.25 and offers at $48.50/MWh. Fourth quarter inched down 20 cents to about $47.15/MWh, and first quarter fell 25 cents to about $46/MWh. NP15 October stayed at about $44/MWh, and fourth quarter fell 25 cents to about $43.90/MWh. Palo Verde on-peak October stayed at about $37/MWh, Q4 stayed at about $35.85/MWh, and first quarter stayed at about $36.50/MWh.

NEWS

JP Morgan faces obstruction inquiry: reports

JP Morgan Chase is under investigation for obstruction of justice in connection with the firm's alleged power market manipulation, reports said Wednesday.

The US Attorney for the Southern District of New York, Preet Bharara, is pursuing the investigation along with the Federal Bureau of Investigation, according to news first reported by Reuters. It was also reported Wednesday that the investigation is looking at what information JP Morgan employees gave to federal regulators during a recently resolved probe of power market practices.

Platts and other media outlets had reported that Bharara's office was investigating JP Morgan, although allegations of obstruction of justice had not emerged.

FBI spokesman Peter Donald declined to comment Wednesday. Jennifer Quielz, spokeswoman for the US Attorney's office, neither confirmed nor denied the investigation.

Representatives for JP Morgan did not respond to a request for comment.

Word of the DOJ investigation emerges as JP Morgan faces mounting scrutiny for its power market practices from Congress and others following the Federal Energy Regulatory Commission's $410 million settlement in July with the bank over alleged market manipulation of power markets in California and Michigan.

JP Morgan neither admitted nor denied FERC's allegations contained in the settlement.

During the investigation, FERC suspended JP Morgan's market-based rate authority for six months as a result of allegations that the company "made factual misrepresentations and omitted material information" to both California Independent System Operator and FERC in connection with its actions in California, according to the commission.

As part of the settlement, FERC stressed generally to those under investigation "the importance of candor and accuracy during all stages of market monitor inquiries and commission investigations."

FERC and JP Morgan as part of the deal agreed to ask the US Court of Appeals for the District of Columbia Circuit to vacate a US District Court for the District of Columbia ruling regarding emails between JP Morgan and its attorneys related to the investigation.

In that case, Judge Deborah Robinson found that the emails were protected under attorney-client privilege.

FERC appealed the lower court decision to the DC Circuit, asking that it be vacated. Oral arguments were held in the matter in May, but the DC Circuit on July 19 put the case in abeyance following a sealed letter from FERC filed earlier that month.

In an August 2 letter, the Senate Homeland Security and Governmental Affairs Committee's permanent subcommittee on investigations asked FERC to provide more details on its investigation into JP Morgan.

In that letter, Senators Carl Levin, Democrat-Michigan, and John McCain, Republican-Arizona, requested the documents because the committee "is currently reviewing matters relating to the physical commodity interests held by financial holding companies."

— Bobby McMahon

CARB staff offers cap-and-trade amendments

California Air Resources Board staff proposed a number of amendments to the state's greenhouse gas cap-and-trade program on Wednesday, including revisions to the rules related to "resource shuffling."

CARB is supposed to vote on the amendments at a hearing scheduled for October 24 in Sacramento. The proposed amendments are now subject to a public comment period.

In 2012, the board directed its staff to review and clarify a handful of issues surrounding the cap-and-trade program, which went into effect January 1. In July, CARB staff released draft amendments.

One of the more controversial areas of the cap-and-trade program has revolved around the ban on so-called "resource shuffling," which impacts electricity imports.

Western power traders have argued that the regulations covering resources shuffling were too vague, and asked CARB to provide more guidance.

Wednesday's amendments clarify the term's meaning and list 13 examples of trading activities that CARB will not consider to be resource shuffling.

Stakeholders asked CARB to articulate these "safe harbors" in order to better understand how the board interprets resource shuffling. The original regulations did not include any examples of permissible behavior.

Safe harbors include a situation in which an importer must accept a delivery of electricity, or when an importer decreases delivery from a high emission source because it already has more than enough electricity to meet demand. Another example is certain short-term transactions in electricity markets.

CARB staff also proposed eliminating a requirement that parties must sign a letter attesting under the penalty of perjury that they have not committed resource shuffling.

Western power traders told CARB that the attestation requirement would drive down trading at key hubs.

CARB suspended the attestation requirement for 18 months back in August 2012, heeding a request made by Philip Moeller of the Federal Energy Regulatory Commission.

Moeller said in a letter to California Governor Jerry Brown he was concerned about the disruptions the resource shuffling ban might have on the electricity market.

Resource shuffling is a practice in which parties could swap electricity from high emissions with low emissions sources in an attempt to minimize a compliance obligation.

Under California's cap-and-trade program, the entity holding title to electricity as it crosses the border must acquire enough GHG allowances to cover the related emissions.

Shuffling resources would give the appearance of a GHG reduction that is simply offset by an increase outside California, according to CARB.

The cap-and-trade program covers generators, electricity importers and industrial facilities. The cap expands in 2015 to include distributors of transportation fuels.

Another change proposed by CARB staff is approving a new category of projects eligible to generate offset credits. The cap-and-trade program allows compliance entities to use offset credits to satisfy as much as 8% of emissions.

CARB has approved four offset protocols to date. Offset supply should be enough to meet the 8% limit during the first compliance period, but would fall short when the cap expands starting in 2015, CARB staff says.

As such, CARB staff is proposing that the board include a fifth category, allowing mine methane capture projects to count.

The proposed amendments would also expand the transitional assistance for the industrial sector.

The industrial sector receives the bulk of its GHG allowances for free during the first compliance period through 2014. Current rules state that industrial facilities must buy an increasing share of their GHG allowances starting in the second compliance period (2015-17).

CARB staff is proposing to continue the same allocation method through the second compliance period, and start the reduction in 2018 instead.

Natural gas distributors would see their transitional assistance include 75% free GHG allowances when they enter the program in 2015. This amount would decrease to 50% by 2020.

The original regulations did not specify how GHG allowances will be distributed to natural gas utilities.

— Geoffrey Craig

Daily CSAPR allowance assessments, Sep 4

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

All prices in $/st

Daily CAIR allowance assessments, Sep 4

	$/allowance	Change	$/st
SO2 2013	0.68	0.00	1.36

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

RGGI carbon allowance futures, Sep 3 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	2.90	0	Dec13	1.97	0
Dec13 V11	2.90	0	Dec14	1.97	0
Dec13 V12	2.90	0			
Dec13 V13	2.90	50			
Dec14 V10	2.90	0			
Dec14 V11	2.90	0			
Dec14 V12	2.90	0			
Dec14 V13	2.90	0			
Dec15 V10	2.90	0			
Dec15 V11	2.90	0			
Dec15 V12	2.90	0			
Dec15 V13	2.90	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.

Closures do not signal nuclear fleet problems: S&P

The permanent closure of five US nuclear power reactors so far in 2013 does "not have widespread implications for the US nuclear fleet, nor do they signal problems endemic to the sector," a Standard & Poor's analyst said in a report released Wednesday.

"In our view, the circumstances [leading to the plants' closures] are unique to each affected facility," David Boden, a credit analyst with S&P, said in the report. S&P, like Platts, is a McGraw Hill Financial company.

This year, Duke Energy has announced the closure of Crystal River-3 in Florida, Dominion Power has shut Kewaunee in Wisconsin, Southern California Edison's San Onofre -1 and -2 in California will not reopen; and Entergy Nuclear will start shutting Vermont Yankee in Vermont. The operators have given a variety of reasons for closing the reactors.

Noting that those five reactors are owned by investor-owned utilities, Boden said in the report that, by contrast, "public power and cooperative utilities rarely exclusively own their nuclear capacity; typically, but not universally, they co-own it with others, most often seasoned nuclear operators. We believe shared ownership and partnering with an accomplished operator mitigates risk."

However, he said, "although we do not believe the cited plant retirements indicate greater credit risk for public power and cooperative utilities with nuclear assets, we believe that certain risks are inherent to nuclear development and ownership. The construction delays that each of the five new plants in development are experiencing, and the operating problems at the Omaha Public Power District's Fort Calhoun Station, bear this out."

Four new power reactors are under construction in Georgia and South Carolina at Vogtle and Summer, respectively, and the Tennessee Valley Authority is completing construction of Watts Bar-2 in Tennessee.

"The output of the nuclear units under construction is either captive or under contract; these will not be merchant plants. Therefore, we do not believe the economic problems that scuttled the Vermont Yankee and Kewaunee nuclear plants are relevant for the new crop of plants," Boden said.

"However, low natural gas prices have stifled interest in developing additional nuclear capacity beyond the plants already in development, at least for now," he said.

"Standard & Poor's believes that limited interest in additional nuclear plants, or even some additional retirements of merchant capacity will not hurt the credit quality of not-for-profit utilities

that can recover their nuclear investments' cost from their consumers," he said.

Low power prices and natural gas prices were cited as among the reasons for the decisions to close Kewaunee and Vermont Yankee. The San Onofre units had been shut since January 2012 due to excessive wear on replacement steam generators.

Crystal River-3 had been offline since September 2009 as a result of damage to the containment during steam generator replacement work. Efforts to repair the containment failed, causing more widespread damage, and Duke concluded the financial risks of a more extensive repair outweighed the potential benefits.

— Steven Dolley

53 Bcf-57 Bcf storage estimate expected

Analysts expect the Energy Information Administration Thursday will estimate a natural gas storage injection of between 53 Bcf and 57 Bcf for the reporting week that ended Friday.

An addition to stocks within those expectations would be larger than the 33-Bcf build last year but below the five-year-average injection of 60 Bcf, according to EIA data.

As a result, the 235-Bcf deficit to last year and the 45-Bcf surplus to the five-year average each should shrink.

The wider range of analysts' expectations spanned from an injection of 48 Bcf to 65 Bcf.

For the week ended that August 23, EIA reported a build of 67 Bcf, lifting overall inventories to 3.13 Tcf.

Platts unit Bentek Energy's supply/demand model predicts an injection of 59 Bcf for the week that ended Friday, while its pipeline flow model anticipates an addition to stocks of 54 Bcf.

Citi Futures Perspective analyst Tim Evans said the surplus to the five-year-average should shrink to about 26 Bcf by September 13, as warmer-than-normal weather limits the pace of storage injections in the coming weeks.

In addition, "we're continuing to see an impact on injections because of coal-to-gas switching," said TFS Energy Futures analyst Gene McGillian.

But with the NYMEX gas futures contract trading above $3.60/MMBtu, McGillian expects this trend will reverse, leading to "a healthier injection pace" over the balance of September and October.

— Jessica Marron

Dominion wins offshore wind auction

Dominion Virginia Power on Wednesday won the Department of the Interior's second-ever competitive auction for offshore wind development in federal waters with a $1.6 million bid.

The offshore area, roughly 23.5 nautical miles from the Virginia Beach coastline, has the potential to support more than 2,000 MW of wind generation, according to Interior's Bureau of Ocean Energy Management.

Dominion, also known as Virginia Electric and Power, was one of only two companies to participate in the auction to lease the 112,800 acres offshore Virginia. The auction lasted six rounds and Apex Virginia Offshore Wind was the only other company to bid.

Six other companies, including EDF Renewable Development and Iberdrola Renewables, were deemed eligible by Interior to take part in the auction but did not place bids.

BOEM Director Tommy Beaudreau told reporters Wednesday that he was pleased at what he saw as "robust" interest in developing offshore wind.

"I'm extremely pleased in the level of competition and the interest that we've seen for these auctions," Beaudreau said. "It's very healthy."

On July 31, Rhode Island-based Deepwater Wind won the first-ever competitive auction for offshore wind development in federal waters when it won the rights to develop an area of nearly 165,000 acres about nine nautical miles off Rhode Island. Deepwater beat two other companies in that 11-round auction with a $3.8 million winning bid.

Auctions for offshore wind development in federal waters off Maryland, Massachusetts and New Jersey are planned over the next year, Beaudreau said.

The Dominion project off the coast of Virginia is still subject to additional approvals, including site assessment plans and construction operations plans, which are expected to take about five years. It could be more than a decade before operations begin in the lease area. The lease is for 33 years, BOEM said.

"Offshore wind has the potential to provide the largest, scalable renewable resource for Virginia if it can be achieved at reasonable cost to customers," said Mary Doswell, Dominion's senior vice president for alternative energy solutions, in a statement. "We will now proceed with the BOEM timetable for development of the commercial wind energy area while advancing our research proposal and looking for ways to lower the cost of bringing offshore wind generation to customers."

— Brian Scheid

DP&L to hold auctions under approved plan

Dayton Power & Light will hold a series of competitive power auctions to support its move to full market rates for generation starting in 2017 under an electric security plan approved Wednesday by the Ohio Public Utilities Commission.

DP&L, an AES subsidiary and the smallest of Ohio's four major investor-owned electric utilities, is the last to have an ESP endorsed by state regulators.

The commission rejected arguments by some intervenors that DP&L should pursue a market-rate offer instead of an ESP. Both rate plans are allowed under S.B. 221, the state's 2008 electric restructuring law. The PUC has not authorized any MROs thus far, opting to approve ESPs for FirstEnergy, Duke Energy Ohio and AEP Ohio, an American Electric Power subsidiary that includes Ohio Power and Columbus Southern Power.

In the DP&L order, the commission said it was not convinced by intervenors "that we should compare the ESP to an expected MRO that goes immediately to 100 percent market rates because, as we have indicated previously, we are not convinced that DP&L could immediately divest its generation assets and still provide

stable, safe and reliable retail electric service."

The commission added: "We believe that an MRO that goes immediately to 100 percent market rates would create substantial quantifiable and non-quantifiable costs to DP&L and its customers, and we do not expect that such an MRO would be proposed by DP&L or authorized by the commission."

FirstEnergy, Duke and AEP Ohio have spun off their generation assets or are doing so. DP&L has said it does not anticipate divesting its generation holdings until late in the decade.

The PUC order outlined its intent for DP&L to conduct an energy-only auction for 10% of its standard service offer load for the period of January 1, 2014, to December 31, 2014; 40% for the period of January 1, 2015, to December 31, 2015; and 70% for the period of January 1, 2016, to December 31, 2016.

The three-year ESP is set to end on December 31, 2016. At that time, the company is expected to have divested all of its generation assets.

DP&L has about 3,800 MW of generation resources, of which about 2,800 MW is coal-fired.

DP&L had proposed a five-year transition to market rates, but the PUC staff recommended a three-year plan. A three-year plan is more beneficial, staff said, because market rates are volatile, projections of capital expenditures and shopping are unreliable and the future financial integrity of the company is unpredictable.

The commission said its schedule "will move DP&L rates to market while granting DP&L sufficient time to refinance its long-term debt to facilitate the divestment of the company's generation assets."

PUC chairman Todd Snitchler said the DP&L order "moves Ohio closer to all of its electric distribution utilities moving to market-based rates. The terms of this order provide rate stability for customers and financial stability for DP&L along with provisions to facilitate growth in the state's retail electric market and encourage economic development for the purposes of attracting new investment and improved job growth."

By approving the order Wednesday, "DP&L will move to market-based rates in the quickest period possible," he said.

DP&L agreed to contribute $2 million annually from 2014 to 2016 to support economic development in its service territory.

DP&L officials could not be immediately reached for comment. The utility serves about 500,000 customers in west-central Ohio.

— Bob Matyi

FirstEnergy seeks OK to sell hydro plants

FirstEnergy is seeking approval to sell 11 hydroelectric power stations with a total capacity of 527 MW in Pennsylvania, Virginia and West Virginia to an LS Power subsidiary.

A sales agreement was reached August 23 and FirstEnergy has applied to the Federal Energy Regulatory Commission for approval of the sale. If approved, the sale is expected to close in the fourth quarter. The Virginia State Corporation Commission also must approve the sale.

"This proposed transaction is consistent with FirstEnergy's financial plan to divest non-strategic unregulated generation assets and use the proceeds to improve credit metrics at our competitive business," Stephanie Thornton, a company spokeswoman, said.

Harbor Hydro Holdings, a subsidiary of LS Power Equity Partners II, is the buyer. The company did not return a request for comment by press time.

The sale still has many conditions to resolve before it closes, Thornton said. Resolution of a potential competing license application and other claims related to the Seneca plant also is a condition to closing the transaction, the company said.

The hydroelectric stations include the 451-MW Seneca Pumped Storage the 6-MW Allegheny Lock & Dam 5 the 7-MW Allegheny Lock & Dam 6 and the 52-MW Lake Lynn plant, all in Pennsylvania.

West Virginia units include the 3-MW Millville plant, the 2-MW Dam 4 in Shepherdstown, and the 1.2 MW Dam 5 in Falling Waters.

Projects in Virginia include the 750-kW Warren plant in Front Royal, the 1.6-MW plant in Luray and the 860-kW Shenandoah and 1.4-MW Newport plant in Shenandoah.

FirstEnergy subsidiary Allegheny Generating will continue to own 1,200 MW of the 3,000-MW Bath County pumped storage hydro plant in Warm Springs, Virginia, the company said.

Jersey Central Power & Light will continue to own 200 MW of the 400 MW Yards Creek pumped storage plant in Blairstown, New Jersey.

— Mary Powers

AEP unit moving to diversify generation mix

The addition of non-traditional resources such as demand side management, distributed generation and utility scale renewables could allow Appalachian Power to defer the addition of new fossil capacity beyond 2027, the company said in its integrated resource plan.

"APCo is proposing a resource portfolio that diversifies its generating mix, mitigating potentially deleterious impacts of uncertain environmental legislation or regulations as well as volatile natural gas prices," the plan said. APCo is a unit of American Electric Power.

The plan assumed, however, that regulators would approve the company's proposal to purchase half of the 1,633-MW Mitchell generating station near Moundsville, West Virginia. Much of the IRP will not be affected by the Virginia State Corporation Commission's decision to deny the purchase, Appalachian Power said in a letter dated Friday that accompanied the IRP. The company acknowledged that the decision would affect the IRP somewhat and plans to submit an update.

Appalachian Power filed its 2013 plan with the Virginia State Corporation Commission. It is not required to file an IRP with the West Virginia Public Service Commission, Jeri Matheney, a company spokeswoman, said.

The IRP also assumes that regulators will approve the merger of Wheeling Power with Appalachian Power. The Virginia SCC has

approved the merger, but West Virginia regulators have not yet made a decision.

Appalachian Power's peak summer growth rates would increase load about 450 MW by 2027, the IRP said. The merger with Wheeling initially would add 480 MW of summer peak demand, the plan said.

The company expects its existing capacity resources to cover its load requirements for several years beyond the PJM Interconnection's planning year of 2016/2017. But after the proposed merger, scheduled to be completed by the end of the year, Appalachian Power's energy position would be short, the company said. "As a result of APCo's unique position as a winter peaking utility, merely satisfying the PJM capacity requirements, designed around a summer peak, will still leave APCo short of generating capacity in the winter and thus exposing APCo to market pricing during these periods," the company said.

In its IRP, APCo considered two plans, one that added additional demand-side management, distributed solar generation and utility scale wind and solar generation and another that simply added new fossil generation.

Adding 92 MW of savings through demand side management programs beyond the 47 MW from existing programs and adding 400 MW of utility-scale solar generation would reduce the need for new fossil generation in 2027 by 143 MW, the company said.

The plan ramps up energy efficiency to 2.1% by 2027 and renewable resources will make up 6.2% of the 2027 energy requirement, the plan said.

The addition of the conservation measures and renewable generation would cost $668 million more than adding fossil generation but it would reduce the company's reliance on coal-fired capacity generation to 70% from 77% through 2027, the IRP said. Its energy mix attributable to coal-fired generation would decrease to 60% from 64% through 2027, the plan said.

Appalachian Power expects load growth of 0.5% with the addition of Wheeling Power, the plan said. Winter peak is expected to grow 0.4% and summer peak is expected to grow 0.6%, the company said.

Winter peak is estimated to be 7,419 MW this year, rising to 7,812 MW in 2027 without factoring in demand side management programs. The internal energy requirement for the two utilities is estimated to be 36,491 GWh this year and rising to 41,736 GWh in 2027 without demand side management, the IRP said.

APCo considered a number of supply-side options to meet energy requirements as well as demand-side options.

Market purchases could be used to hedge capacity planning exposures, the IRP said.

The company always is considering the possibility of purchasing existing merchant power plants or utility owned plants, the IRP said. Analysis is used to compare the price of such an option to new plant construction, the plan said.

Coal and nuclear baseload options were not included in the IRP. Environmental Protection Agency rules make the construction of new coal plants impractical and the cost makes nuclear construction impractical, the IRP said.

— Mary Powers

ERCOT works toward ERS protocol by end of year

The Electric Reliability Council of Texas is working to move a proposed protocol on Emergency Response Service through the approval process before the end of the year since the pilot is ending soon.

Since the 30-Minute ERS pilot ends at the end of January, there is urgency to get the protocol approved before the end of the year, said one participant in Wednesday's ERS workshop. The workshop was scheduled to solve any issues before the next Wholesale marker Subcommittee meeting on September 11, said Mark Patterson, ERCOT manager of demand integration.

The plan is for Nodal Protocol Revision Request 564 to be taken up at the next WMS meeting, then at the September 19 Protocol Revision Subcommittee meeting, before the October 3 or November 7 Technical Revision Committee meeting, and finally the November 19 ERCOT Board of Director meeting, Patterson said.

ERCOT is proposing an ERS product with a 30-minute ramp rate in order to secure additional demand response capability and further strengthen reliability in the ERCOT region, according to the NPRR.

The pilot began in July 2012 to assess the operational benefits of an ERS-30 product. The pilot takes large power users who agree to the program offline when the ERS is dispatched due to large discrepancies in power. This provides more tools to address capacity shortages.

Based on the results of the pilot observed to date, ERCOT has concluded that such a product would bring additional participation from loads that cannot meet a 10-minute ramp requirement, thereby providing additional reliability benefits, according to the NPRR.

The final report on the pilot will be presented at the November ERCOT board meeting, Patterson said.

While a longer ramp means the product is less responsive than the existing 10-minute ERS product, being able to deploy it earlier during an Energy Emergency Alert gives ERCOT an additional reliability tool that should be especially valuable during foreseeable peak conditions, such as summer afternoons, according to the NPRR.

"ERS generators are evaluated on how much they export to the grid," a workshop participant said.

Some stakeholders wanted NPRR 505 on ERS weather-sensitive load to be included in NPRR 564. ERCOT does not support including NPRR 505 in NPRR 564 due to a potential impact on the schedule, Patterson said when presenting ERCOT's response. NPRR 505 is still being tested in a pilot with a final report due at the end of the year, Patterson added.

— Kassia Micek

Texas PUC takes 'huge step forward': GDF official

The Public Utility Commission of Texas last week took "a huge step forward" toward implementing scarcity pricing-related changes to the Electric Reliability Council of Texas market that would value reliable capacity and provide needed incentives for encouraging development of new capacity, Stefaan Sercu, president and CEO at

GDF SUEZ Energy Marketing North America, said Tuesday.

Sercu, whose company owns and operates about 4,000 MW of fossil-fired generating capacity in ERCOT, said in an interview that he is optimistic the PUC will approve proposed changes—including a form of operating reserve demand curve, or ORDC, known as "interim solution B+"—as soon as early October.

Sercu said an early October decision to direct ERCOT to implement interim solution B+ would provide sufficient time for the ORDC to be in place by the summer of 2014. That, he said, would "make a serious statement to the market" and likely encourage the development of additional natural gas-fired capacity that would come online by 2017-18.

At the PUC's August 29 meeting, the commission directed ERCOT to move forward with a protocol on interim solution B+, which stems from a proposal Harvard University professor William W. Hogan, research director of the Harvard Electricity Policy Group, recommended in November 2012.

In a memorandum issued the day before the PUC meeting, Commissioner Kenneth Anderson said the interim solution B+ ORCD could be implemented in six to eight months, and would not preclude the commission from implementing additional resource adequacy mechanisms if that proved necessary. Most important, said Anderson, the ORDC approach the PUC is considering "incents actual reliability year-round because it places an explicit and transparent value on operating reserves."

GDF Suez's Sercu said the company is "very happy to see the commission moving in this direction." He said the ERCOT market's existing pricing curve is "flat until near the very end," when it rises sharply, while the pricing curve in the ORDC envisioned by the PUC would rise earlier and more gradually. That way, he said, "as supplies get tighter prices would rise to reflect that." The planned approach also "would value capacity that is there when it's needed."

Sercu said that in the past couple of years GDF Suez has expanded the capacity of its existing ERCOT fleet by a total of about 200 MW through relatively low-cost projects he described as "low-hanging fruit," including a 100-MW expansion of the company's natural gas-fired Midlothian combined-cycle facility, whose summertime capacity is now about 1,300 MW.

He added, however, that while GDF Suez has been exploring the possibility of undertaking higher-cost "enhancement" projects that would add still more capacity to its existing units, it has held back from doing so until ERCOT's market rules are changed to make such projects economically justifiable.

Further, Sercu said, several of the company's Texas plant sites have room to add entirely new units, but again GDF Suez plans to see how the revised ERCOT market works "for a year or two" before making any commitment to build new capacity there.

GDF Suez owns 100% of five natural gas-fired facilities in ERCOT—Wise, Midlothian, Ennis, Hays, and Wharton—as well as 50% of the gas-fired Oyster Creek plant and all of the coal-fired, 632-MW Coleto Creek plant.

Sercu noted that he has been "extremely impressed" with PUC Chairman Donna Nelson and Commissioner Anderson for "getting into the weeds"—or exploring in real depth—the complex issues involved in market design and resource adequacy over the past several months. He added that he sees the new addition of Commissioner Brandy Marty as "a good thing," in part because as the third member of the PUC she will be in a position to break any deadlock.

— Housley Carr

ISO-NE must clarify CFTC exemption, FERC says

ISO New England must further clarify whether market participants have to own physical electricity transmission assets before it receives Federal Energy Regulatory Commission approval for tariff changes as part of federal exemptive relief compliance, according to the agency.

FERC called for the clarification in a conditional approval order issued August 30.

On March 28, the Commodity Futures Trading Commission issued exemptive relief for regional transmission organizations and independent system operators from certain rules under the Dodd-Frank Wall Street Reform and Consumer Protection Act and provisions under the Commodity Exchange Act. However, ultimately the order required RTOs and ISOs to make slight changes in their tariffs to be eligible for the exemption.

In order to receive the CFTC exemption, those entering market transactions must be "appropriate persons" or "eligible contract participants" as defined by the Commodity Exchange Act, or "persons who are in the business of either generating, transmitting, or distributing electric energy, or providing electric energy services that are necessary to support the reliable operation of the transmission system."

However, ISO-NE's interpretation of CFTC market participants in their tariff revision came under fire from smaller load-serving entities who believe the exemptive categories are unduly discriminatory. In its conditional approval, FERC agreed, and furthermore found the the ISO-NE interpretation contradicted other documents it had previously submitted.

Freedom Logistics and Easy Energy, two small-load serving entities, argued that they could be forced out of the market if ISO-NE requires market participants to own physical assets and comply with more stringent net worth and letters of credit requirements, it could force them out of the market altogether. FERC said it is unclear if ISO-NE requires market participants to own physical assets.

Currently, Freedom Logistics and Easy Energy do not own physical assets and could be ineligible for participating in ISO-NE with the approved changes.

Specifically, Freedom Logistics also said that requiring competitive energy providers to own physical assets in order to make use of the exemption may deny retail customers the ability to access a sizeable fraction of currently available competitive electric service providers.

FERC, in trying to weigh the concerns of smaller market players, ultimately said ISO-NE must clarify that it intended for the tariff language to impose a physical-asset-ownership requirement, and agreed the language may discriminate against

small load-serving entities.

"ISO-NE must either explain why distinguishing among load-serving entities is justified, or clarify its proposed tariff revisions," FERC said in the order.

Additionally, Freedom Logistics and Easy Energy also argued that new tariff requirements, which require participants to maintain a net worth exceeding $1 million or total assets exceeding $5 million, or have a letter of credit to make up the difference, were prohibitively costly for small participants.

FERC, however, did not see a problem with those requirements, and said that while the changes do "constitute a tightening of the current minimum criteria for market participation" they would minimize the impact on ISO-NE's market in the event of an individual customer's default, and help ensure participants do not have to pay for losses associated with default.

While the concerns of Freedom and Easy Energy were taken into account, FERC ultimately approved the tariff changes subject to ISO-NE submitting a compliance filing within 30 days from August 30.

On Tuesday, the FERC also approved tariff revisions for the Midcontinent Independent System Operator with little fanfare as no market participants filed comments opposing the changes.

MISO's tariff revisions, which are similar to ISO-NE's as part of the CFTC exemption, include the requirement that tariffs authorize the sharing of confidential market data and information with the CFTC without notice to market participants.

Requests by both PJM Interconnection and New York Independent System Operator to changes in their tariffs to comply with the CFTC exemption were approved by the FERC in early August.

The tariff revisions will be effective August 12 for PJM, and September 15 for NYISO, which specifically asked for more time "so that market participants will have sufficient time to comply prior to the expiration of the NYISO's no-action relief letter from the CFTC on September 30."

MISO's tariff revisions are currently effective as of September 2.

— Christopher Tremulis

SNC-Lavalin selling portion of stake in N.Y. facility

SNC-Lavalin said Wednesday it has reached an agreement to sell 66% of its minority stake in the 575-MW Astoria Energy II natural gas-fired facility located in Astoria, Queens, New York.

The Montreal, Canada-based firm was construction manager and lead designer of the roughly $1.3 billion facility that became operational in July 2011 and supplies power to the New York Power Authority under a 20-year tolling agreement.

A spokeswoman for SNC-Lavalin, Leslie Quinton, would not comment on how large a minority equity stake the construction firm has had in the facility, or to whom the 66% was sold.

The facility is owned by Astoria Energy Project Partners II LLC. In addition to SNC-Lavalin, equity investors in the facility are GDF Suez Energy North America, with an estimated 30% stake, Energy Investors Group, and JEMB Realty, a privately-held real estate and energy investment firm.

GDF Suez also has a large equity stake in the 575-MW Astoria Energy I facility that is located next to Astoria Energy II that supplies power to Con Edison of New York.

SNC-Lavalin said in a statement on Wednesday that its agreement to sell a portion of its minority interest in Astoria II "is in line with the company's strategic plan to monetize a portion of its mature infrastructure concession investments."

It said it is "targeting growth in key markets with a focus on the resources sector, including oil and gas, mining and metallurgy, and environment and water."

The construction firm said it hopes to see "sustained growth" in its clean power and Infrastructure business, "while continuing to move forward with its fully integrated services strategy, including project financing, engineering, construction and operations and maintenance."

— Jeffrey Ryser

Unitil seeks supplies for Mass., N.H. customers

New Hampshire-based Unitil is seeking firm, load-following power for its Massachusetts and New Hampshire customers in two separate solicitations issued Wednesday.

In New Hampshire, the utility's subsidiary Unitil Energy Systems seeks supply for its small, medium and large customers that are on default service.

The request for proposals seeks prices that are fixed monthly for all of the utility's small and medium customers under a six-month term from December 1, 2013 to May 31, 2014. For large customers the utility seeks variable-priced bids for the same six-month period.

Bidders must specify the prices monthly in $/MWh for small and medium customers. Bids may vary by calendar month, but must be uniform for the entire month and must cover the entire period. The RFP does not specify a maximum price.

The variable pricing bids for large customers must reflect real-time locational marginal prices for the New Hampshire load zone. Bidders can include variable, monthly fixed adders to the LMP that cover other costs, such as capacity, ancillary services, and administration charges. The monthly fixed adders, in $/MWh, must be uniform for the calendar month, and must cover the entire six months.

UES will select winners based on, among other things, bid price and the bidder's financial and operational viability.

The UES contracts are conditioned upon approval by the New Hampshire Public Utilities Commission. The utility anticipates PUC approval by October 4.

Default service is the only form of supply offered by the utility, whose service territory is open to competitive retail competition. Therefore, the RFP seeks load-following service, rather than a specific megawatt block of power.

Winning bidders must supply whatever amount of load the utility requires, which could change over the course of the contract if customers switch back and forth between utility service and competitive supply. As part of the RFP packet, UES is making information available to bidders, such as historical load and sales data, to help them gauge the likely supply need.

The utility seeks wholesale supply; winners will have no retail relationship with UES customers. The utility will continue to provide billing and customer service to those on default service and it assumes responsibility for the collection of money owed by customers.

The RFP does not include any renewable portfolio standard requirements.

In Massachusetts, Unitil subsidiary Fitchburg Gas & Electric seeks power for 50% of its small and medium load from December 1, 2013 to November 30, 2014. The FG&E terms, requirements and evaluation criteria largely mirror those of the UES solicitation for small and medium customers.

In both states, due dates are Tuesday, September 17 for forms, including contract comments and indicative pricing and Tuesday, September 24 for final pricing. Unitil plans to execute contracts for both states on Wednesday, September 25.

The RFPs are available at www.unitil.com/rfp under "Current Procurement" for UES. The contact is Todd Bohan at (603) 773-6473 or bohan@unitil.com.

— Lisa Wood

Dynegy alters hedging to fix 'disconnect'

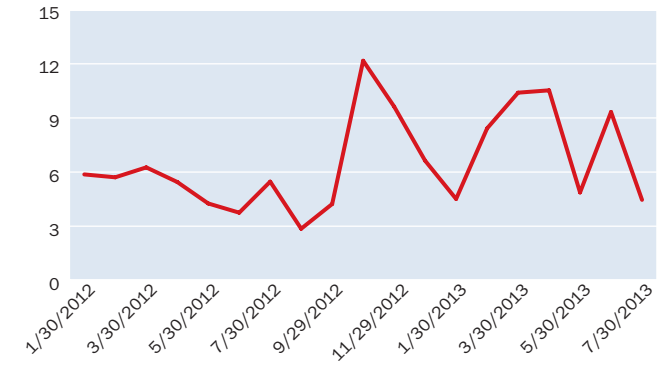
...from page 1

and the hedged price at MISO's Indiana Hub have "eroded significantly" in the past year and particularly over the past six months. In its second quarter earnings call, the company attributed the breakdown to scheduled transmission line outages close to its 1,800-MW coal-fired plant in Baldwin, Illinois, as well as unplanned transmission and generation outages in Indiana in June.

MISO data compiled by Platts shows that the spreads between real time around-the-clock Baldwin and Indiana Hub prices have spiked on several occasions over the past year. After staying below $6.30 in 2012, and even dipping as low as $2.86 in August, they jumped to $12.17 at the end of October and then popped up to the $10 level in March and April of this year.

Similarly an analysis of Baldwin and Indiana Hub prices shows a tight correlation for 2012 – mostly in the 0.7 to 0.9 range – that blows out in October when it dropped to 0.4. The correlation rose again over the next several months, rising to 0.7 in January and February before dropping to 0.5 in March and April. The correlation has since risen to 0.9 in July.

Indiana Hub-Baldwin around-the-clock real-time LMP spread ($/MWh)



Source: MISO

Dynegy said the breakdown of the Baldwin-Indiana Hub correlation led to a decline in its coal segment's earnings before interest, taxes, depreciation and amortization, or EBITDA, as its Indiana Hub hedges for the first half of 2013 ended up, on average, 98 cents/MWh below market prices, resulting in payments of $4 million. For the same period last year, Dynegy said its hedges were $3.51/MWh above market prices, resulting in net receipts in excess of $28 million.

The problem Dynegy is facing is known as "dirty" or "imperfect" hedging. That occurs when there is not an exact match between the risk someone wants to hedge and the available hedging instruments, particularly exchange traded futures.

Traditionally, instead of using such a "generic" hedge, such as one available on an exchange, the company can go to a financial institution, which can custom design a hedge at a cost using over-the-counter swaps.

However, uncertainty around regulations that are being drawn up by the Commodity Futures Trading Commission to implement the Dodd-Frank Wall Street Reform and Consumer Protection Act have had many market players shying away from swaps.

In Dynegy's case, it has taken several steps to shift in hedging strategy. During the earnings call, Chief Commercial Officer Henry Jones said the company has participated more aggressively in annual and monthly financial transmission rights auctions. FTRs hedge the congestion costs between two points on the grid. Congestion costs usually account for the bulk of the difference between LMPs.

Also, FTR auctions which are run by regional transmission organizations are generally regulated by the Federal Energy Regulatory Commission and are not affected by the same uncertain that currently face OTC swaps.

In the annual MISO FTR auction conducted in May 2013 for the 2013-14 planning year, Jones said Dynegy secured FTR volumes equal to approximately 17% of the around-the-clock output of the company's coal facilities on an annualized basis.

He also said the company has executed a total of 500 MW of around-the-clock busbar basis swaps for 2014 to "perfect" hedges put on the Indiana Hub for that period. And, thirdly, he said Dynegy bought back a portion of "unperfected" hedges at the Indiana Hub that are not supported by busbar sales or FTR positions.

Jones said those actions leave the company with a larger open position, exposing it to market risks at the busbar, but reducing exposure to the risk of a price increase on its hedges at the Indiana Hub without a corresponding price increase for its generation's locational marginal pricing.

— Peter Maloney

Calif. players overcharged for congestion

...from page 1

locations" reflecting the congestion, which "in turn may have impacted, to some level, the congestion at ... trading hub NP15," the ISO said.

"Wind locations that are electrically close to these constraints saw a compounded congestion component ... reaching in certain instances prices in the range of negative $3,000 in the five-minute real-time market," the ISO bulletin said.

The ISO expects that most of the prices will be corrected to negative $30/MWh.

Still, the software glitch did not harm ISO markets overall, said Guillermo Alderete, the ISO's manager of market validation and quality, in a conference call on Wednesday with California market participants.

"It didn't affect the day-ahead market, hour-ahead market or real-time market," he said.

Asked by a Northern California Power Agency official why the ISO didn't see the root cause of the problem earlier, Alderete said the grid operator usually does.

"There are obviously software challenges that occur. Each software component goes through testing and validation before it is used. Unfortunately, this one got through because of the nature and complexity of it," he said.

The refunds by trade date would be $673,787 for January 9, $5.7 million for January 13, $82,315 for January 14 and $236,205 for January 26.

Because the price correction would occur outside the time frame allowed by the Federal Energy Regulatory Commission, the ISO expects to seek FERC's permission this month to make the changes, Aderete said.

The grid operator is taking comments from market participants on the issue until September 11.

Concerns about electricity price corrections in California is a long-standing issue.

Market participants, including Calpine and Constellation Energy Commodities Group, have flagged what they see as excessive price corrections for the ISO's Market Surveillance Committee.

— Martin Coyne

Calif. plan details procurement targets ...from page 1

agencies and affected utilities.

The plan, released late Tuesday, calls for adding about 3,250 MW of "preferred resources" — local energy efficiency, demand response, renewable generation, combined heat and power, and storage, to meet about half of the region's needs. Meeting the target would require an additional 1,000 MW on top of what is already expected for the region.

The plan calls for new transmission, including infrastructure that provides voltage support or increases resource sharing between Orange County and San Diego, plus about 3,000 MW of fossil-fueled generation, or about twice as much as already authorized for the area.

Finally, the state should establish backstop permits so that once through cooling requirements can be quickly deferred and power plants can be quickly deployed if planned resources are not developed rapidly enough to meet reliability needs, according to the plan.

"In order to realize the following plan, a variety of decisions must be approved by key state agencies, elevating the importance of beginning planning now to make sure regulatory actions are

made in time to meet future electricity needs in the region," the draft plan said.

"Prompt action is required to address both near term and long term needs given that major grid infrastructure investments take considerable time to implement," the plan said.

In the near term, the PUC plans to speed up the process next year to procure additional preferred resources in Southern California, according to the plan. "Further, the ISO is examining the feasibility of implementing a pilot multi year auction for energy efficiency and demand response programs targeted in the LA Basin and San Diego areas," the plan said.

Also, because it can take more than seven years to develop and build infrastructure projects in Southern California, SoCal Ed and SDG&E are considering licensing sites that would be made available to independent power producers in future solicitations, according to the plan.

"This proposal will require flexibility within the various state rules on licensing and development time frame, but could facilitate the addition of new generation in significantly shorter times if and once the need is authorized by the CPUC," the plan said.

Several longer term contingency options include extending once-through cooling compliance deadlines, according to the plan. Also, SDG&E is studying the possibility of permitting an energy park that could host 1,000 MW of IPP generation to be built as needed. Further, SoCal Ed is preparing sites for peaking generation in case there is a shortfall from preferred resources.

To deal with growing natural gas supply constraints, Southern California Gas and SDG&E are expected to file an application to upgrade the natural gas system serving San Diego, according to the plan. Natural gas-fired power plants in the area are the first customers to be curtailed, the plan said.

In a move that would improve voltage support, the plan calls for possibly converting one of San Onofre's generators into a synchronous condenser. SoCal Ed intends to finish a feasibility assessment this year.

SDG&E has taken action to delay retiring the 188-MW Cabrillo II peaking unit in San Diego by two years until 2015, according to the plan. SDG&E is expected to ask the PUC this year to approve a land lease and power purchase agreement that could extend the unit's shutdown date.

The CEC and PUC will hold a meeting Monday to discuss the draft plan.

— Ethan Howland

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