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Tuesday, February 18, 2014

Generation additions in 2013 dropped 52%

ANALYSIS The amount of generation capacity that entered service in 2013 dropped by more than 50% compared with 2012, with gas-fired generation accounting for the lion's share of the additions, a trend that is likely to continue for the foreseeable future, according to an analysis of Platts data.

A total of 15,078 MW entered service in 2013, compared with 31,652 MW in 2012. Much of the difference came from a precipitous decline in the amount of wind power added to the grid in 2013 after a record year in 2012 that saw 13,903 MW of wind turbines enter service.

If wind capacity additions had stayed at their 2012 level, there would have been a 3,400-MW gap between 2012 and 2013, instead of the 16,575-MW gap. As it is, only 789 MW of wind power entered service in 2013. Uncertainty about the expiring production

(continued on page 13)

CFTC aggregation plan needs tweaks: groups

MARKETS Energy industry groups and futures exchanges believe plans by the US Commodity Futures Trading Commission to aggregate trading activity for the purpose of position limits compliance is largely tenable — although they believe the proposal still needs some crucial fixes.

The aggregation rule which works in conjunction with the proposed position limits rule is "to ensure that there is no concerted effort by an affiliated group to defeat the limits and engage in collective excessive speculation," according to the CFTC.

In comment letters filed recently, energy groups such as the American Gas Association, the Commercial Energy Working Group and the Coalition of Physical Energy Companies all called

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Duke RFP seeks utility-scale solar capacity

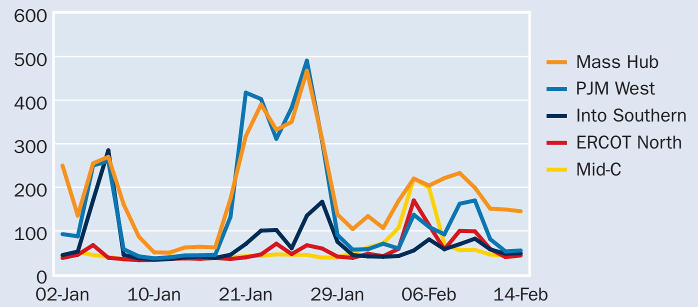
GENERATION Solar developers in North Carolina and South Carolina have until March 28 to respond to a joint solicitation by Duke Energy Carolinas and Duke Energy Progress for 300 MW of utility-scale solar capacity that can begin commercial operation by the end of 2015, the Duke Energy subsidiaries said Friday.

DEC and DEP said in a joint statement that their newly issued request for proposals "is targeting solar facilities greater than 5 MW ... [and] is limited to projects that are in the company's current transmission and distribution queue." Prospective bidders must have filed interconnection requests for projects of more than 5 MW with DEC or DEP by February 13—the day before the RFP was issued—to be eligible.

Rob Caldwell, Duke Energy's vice president for renewable

(continued on page 16)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Feb 15 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	178.02	183.93	109.87	114.10
NYISO	53.59	146.85	33.13	89.20
PJM	47.43	80.21	37.18	63.84
MISO	38.62	68.78	24.97	50.91
ERCOT	38.03	39.14	27.06	28.00
CAISO	53.43	54.70	46.55	47.58

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 Feb 18

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	145.00	6493	-11.33	-33.66	-78.33	-122.99	-189.99
N.Y. Zone-A	68.00	8873	14.36	6.69	-8.63	-23.96	-46.95
PJM/MISO							
PJM West	55.00	9913	16.16	10.61	-0.48	-11.58	-28.23
Indiana Hub	44.50	7581	3.41	-2.46	-14.20	-25.94	-43.55
Southeast & Central							
Southern, Into	48.50	8735	9.63	4.08	-7.03	-18.13	-34.79
ERCOT, North	43.50	7974	5.32	-0.14	-11.05	-21.96	-38.33
West							
Mid-C	46.86	8858	9.83	4.54	-6.04	-16.62	-32.49
SP15	58.75	10624	20.04	14.51	3.45	-7.61	-24.20

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 rise amid higher gas, with terms mixed

Northeast daily prices were higher Friday, amid rising spot natural gas prices and mixed peak load projections. Forward prices were mixed, with little movement in the NYMEX March natural gas futures contract.

Mass Hub on-peak day-ahead futures gained $61 to about $183.50/MWh for Tuesday delivery on the IntercontinentalExchange. Mass Hub balance-of-the-week futures were around $210/MWh, despite high temperatures forecast from the low 40s to the near 55 in Boston next week.

Algonquin city-gates spot gas rose $4.975 to $23.210/MMBtu on ICE.

ISO New England forecast peak load for Friday at 18,000 MW, 1,245 MW below the actual peak Thursday. The forecast for Saturday is 17,100 MW, with Sunday at 17,900 MW, Monday at 18,810 MW and Tuesday at 18,350 MW.

High temperatures for Boston are forecast in the low 40s on Tuesday, up from near 25 Monday.

In New York, on-peak day-ahead at Zone G, the Hudson Valley, was up $73.50 to $183.50/MWh. Zone G next-week was at about $200/MWh. In western New York, Zone A on-peak day-ahead added $64.50 to about $128/MWh. Zone A next-week futures were about $128/MWh.

Transco Zone 6 New York spot gas added $2.637 to reach $8.867/MMBtu on ICE.

New York ISO forecast peak load for Friday at 22,450 MW, 528 MW less than the actual peak Thursday. The forecast for Saturday is 20,299 MW, with Sunday at 20,669 MW, Monday at 21,810 MW and Tuesday at 21,596 MW.

High temperatures in New York state were forecast from the high 30s to the low 40s on Tuesday, with a warming trend expected to see central and the southern regions hitting the mid-50s and mid-60s later in the week.

Day-ahead auction clearing prices in ISO-NE were up Friday. Internal Hub on-peak for Saturday delivery rose $18.53 to clear at $182.60/MWh and off-peak increased $2.58 to $113.92/MWh.

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Northeast day-ahead bilateral indexes for Feb 17 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	215.00	66.00	181.93	9627
N.Y. Zone-G	108.00	-2.00	152.00	8594
N.Y. Zone-J	109.00	-1.75	154.32	8673
N.Y. Zone-A	84.25	20.75	92.61	10994
Ontario*	70.25	19.50	77.07	5174
Off-Peak				
Mass Hub	159.00	53.50	134.66	7120
N.Y. Zone-G	93.25	26.00	94.43	7420
N.Y. Zone-J	93.75	25.75	95.80	7460
N.Y. Zone-A	71.50	30.50	67.02	9330
Ontario*	56.25	23.50	46.93	4143

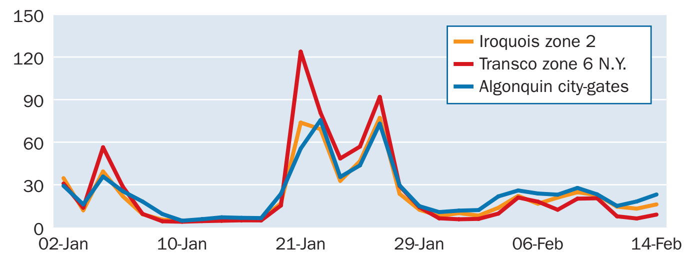
*Ontario prices are in Canadian dollars

Northeast day-ahead bilateral indexes for Feb 18 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	145.00	-70.00	178.85	6493
N.Y. Zone-G	85.75	-22.25	146.48	6823
N.Y. Zone-J	86.25	-22.75	148.65	6863
N.Y. Zone-A	68.00	-16.25	90.56	8873
Ontario*	56.50	-13.75	75.35	4161
Off-Peak				
Mass Hub	115.00	-44.00	133.02	5149
N.Y. Zone-G	70.00	-23.25	92.40	5570
N.Y. Zone-J	70.25	-23.50	93.67	5590
N.Y. Zone-A	55.75	-15.75	66.08	7275
Ontario*	42.50	-13.75	46.56	3130

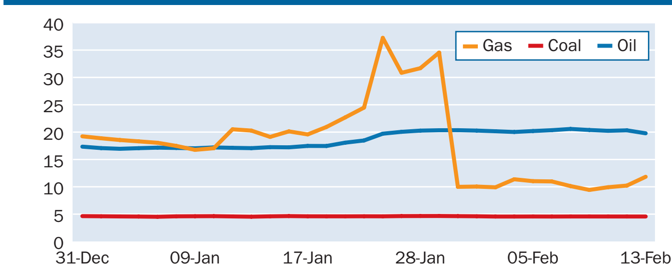
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE fuel cost comparision ($/MMBtu)



Source: Platts

Northeast load and generation mix forecast (GWh)

	Actual 13-Feb	%Chg	% Chg Year-ago	Forecast 14-Feb	15-Feb	16-Feb	17-Feb	18-Feb
ISONE								
Load	383	-7	3	387	366	368	408	392
Generation								
Coal	40	-34	13	36	38	45	51	43
Gas	119	-9	-4	110	104	107	114	110
Nuclear	111	0	4	111	111	111	111	111
NYISO								
Load	473	-5	4	476	443	451	493	472
Generation								
Coal	26	-34	45	27	29	38	42	26
Gas	137	10	-18	115	107	110	117	112
Nuclear	135	0	-2	135	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Feb 15 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	182.60	0.00	1.37	18.52	163.20	8384
Connecticut	178.02	0.00	-3.21	15.89	160.99	9674
NE Mass-Boston	183.93	0.00	2.70	20.00	163.42	8527
SE Mass	181.74	0.00	0.51	18.11	163.07	8345
West-Central Mass	182.20	0.00	0.97	18.12	163.31	8366
Rhode Island	182.24	0.00	1.01	18.51	163.00	8368
Maine	179.20	0.00	-2.03	21.44	156.23	9627
New Hampshire	182.51	0.00	1.28	19.83	162.26	9805
Vermont	180.20	0.00	-1.03	17.07	163.09	11212
Off-Peak						
Internal Hub	113.92	0.00	0.90	2.58	121.33	6177
Connecticut	112.03	0.00	-0.99	1.24	120.14	7096
NE Mass-Boston	114.10	0.00	1.08	3.26	121.13	6283
SE Mass	113.74	0.00	0.72	2.88	121.29	6168
West-Central Mass	113.97	0.00	0.95	2.37	121.64	6180
Rhode Island	114.02	0.00	1.00	2.65	121.52	6183
Maine	109.87	0.00	-3.15	3.44	116.19	6854
New Hampshire	112.84	0.00	-0.18	2.94	119.56	7039
Vermont	112.68	0.00	-0.34	2.10	120.68	7788

NYISO day-ahead LMP for Feb 15 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	102.21	-43.41	4.36	-11.62	142.76	8296
Central Zone	59.19	-5.23	-0.48	3.08	91.58	7786
Dunwoodie Zone	92.16	-32.94	4.79	-8.25	132.06	7548
Genesee Zone	56.66	-4.09	-1.87	3.79	87.92	7454
Hudson Valley Zone	91.94	-32.63	4.88	-7.89	131.56	7530
Long Island Zone	146.85	-85.55	6.86	45.01	157.51	12027
Millwood Zone	92.59	-33.17	4.98	-8.27	132.55	7583
Mohawk Valley Zone	61.72	-5.44	1.85	4.13	95.30	5830
N.Y.C. Zone	91.44	-32.10	4.90	-7.78	132.59	7489
North Zone	53.59	0.00	-0.85	6.47	84.96	3334
West Zone	56.51	-5.32	-3.24	2.90	78.15	7434
Off-Peak						
Capital Zone	88.05	-51.23	2.82	14.13	108.23	8044
Central Zone	40.26	-6.22	0.04	-5.06	63.36	5568
Dunwoodie Zone	75.56	-38.89	2.66	8.22	97.23	7508
Genesee Zone	38.31	-4.82	-0.52	-5.34	60.83	5299
Hudson Valley Zone	75.27	-38.51	2.75	8.15	96.92	7480
Long Island Zone	89.20	-51.22	3.96	21.07	108.45	8864
Millwood Zone	75.94	-39.15	2.78	8.27	97.66	7546
Mohawk Valley Zone	41.67	-6.80	0.86	-4.96	65.78	4320
N.Y.C. Zone	75.01	-38.27	2.73	7.93	97.12	7454
North Zone	33.13	0.00	-0.87	-7.59	56.98	2290
West Zone	39.95	-6.27	-0.32	-4.55	60.36	5526

Generation unit outage report

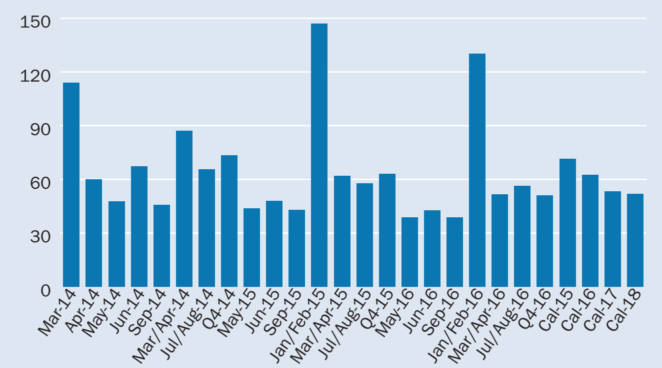
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	200	c	Ont.	PMO	Unk	10/16/13
Bruce-2/Bruce Power	682	n	Ont.	MO	Unk	02/10/14
Fort Frances/Fort Frances	10	w	Ont.	MO	Unk	02/03/14
Lennox-4/OPG	525	bio	Ont.	MO	Unkl	02/03/14
Littlelong/OPG	133	h	Ont.	MO	Unk	02/13/14
Pickering-4/OPG	515	n	Ont.	MO	Unk	01/06/14
Pickering-7/OPG	485	n	Ont.	MO	Unk	02/03/14
Thunderbay-3/OPG	153	c	Ont.	MO	Unk	01/16/14

Northeast Platts M2MS Forward Curve, Feb 14 ($/MWh)

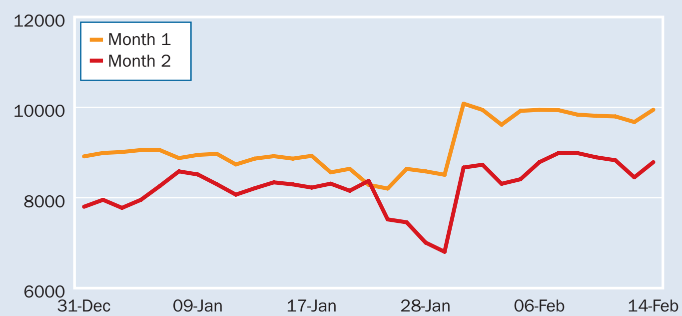
Prompt month: Mar 14	On-peak	Off-peak
Mass Hub	114.00	80.25
N.Y. Zone G	92.00	66.25
N.Y. Zone J	96.00	68.25
N.Y. Zone A	64.00	44.50
Ontario*	46.00	28.25

*Ontario prices are in Canadian dollars

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



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



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Bal-week	02/12	105.00-125.00
N.Y. Zone-A		
Next-week	02/12	65.00-69.00

*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

Dailies climb, along with temperatures

Electric Reliability Council of Texas daily prices were higher Friday, despite peak load projected to drop as temperatures climb. Term prices fell as the March NYMEX gas futures contract showed little movement.

ERCOT North Hub day-ahead on-peak physical power rose $4.75 to about $44.50/MWh for Monday-Tuesday delivery on the IntercontinentalExchange. Weekend was at about $39.50/MWh.

Spot natural gas at Houston Ship Channel added 38 cents to reach $5.465/MMBtu.

High temperatures across ERCOT are forecast to rise to the upper 60s Saturday, low to mid-70s Sunday, low 70s to low 80s Monday and mid-70s Monday, with lows ranging from the mid-30s to the mid-60s. The average February high temperature across ERCOT is in the low to mid-60s, with the average low in the 40s.

System load in ERCOT is forecast to peak at 40,325 MW Friday and 34,950 MW Saturday, compared with an actual peak of 49,525 MW Thursday. Monday is expected to peak at 35,450 MW, while Tuesday is expected to reach 36,200 MW.

Real-time prices averaged $22.50/MWh from 12:15 am to 6 am CST Friday. Wind generation was forecast to peak at 6,800 MW at 6 am CST Saturday.

North Hub balance-of-the-week on-peak lost $5.50 to about $43/MWh on ICE, with the 6-10 day forecast showing temperatures 10 to 19 degrees above seasonal norms. Next-week on-peak gained $17 to about $57.50/MWh on ICE. Houston Hub next-week on-peak was at about $57.50/MWh.

Southeast dailies were stronger Friday, with temperatures forecast at or above seasonal norms. Into Southern day-ahead on-peak physical power gained $1.50 to the upper $40s/MWh for Monday delivery on ICE.

Spot natural gas at Transco Zone-3 added 25.7 cents to about $5.567/MMBtu.

High temperatures in Atlanta are forecast at 49 Saturday, 58 Sunday, 69 Monday and 71 Tuesday, with lows expected to range from the low 30s to mid-50s. The average February high temperature in Atlanta is 57, with the average low at 38.

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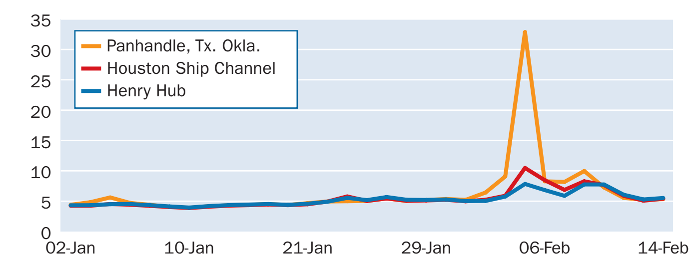
Southeast & Central spot natural gas prices ($/MMBtu)



Source: Platts

Southeast & Central day-ahead bilateral indexes for Feb 17-18 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	50.25	1.25	63.96	7384
Southern, Into	48.50	1.00	55.94	8735
Florida	47.75	1.00	50.90	8385
TVA, Into	47.50	-0.50	61.04	8471
Entergy, Into	51.50	1.00	61.60	9432
Southeast Off-Peak*				
VACAR	42.00	-4.25	47.89	6172
Southern, Into	41.50	-4.50	44.07	7474
Florida	40.75	-4.50	39.97	7155
TVA, Into	40.75	-4.75	45.01	7267
Entergy, Into	47.50	-4.50	50.53	8700
ERCOT On-peak				
ERCOT, North	43.50	3.75	72.74	7974
ERCOT, Houston	43.00	3.75	70.15	7919
ERCOT, South	41.75	3.75	69.63	7658
ERCOT, West	43.75	3.75	73.38	8274
ERCOT Off-Peak*				
ERCOT, North	27.50	-1.50	42.29	5041
ERCOT, Houston	27.50	-1.50	41.65	5064
ERCOT, South	27.25	-1.50	41.81	4998
ERCOT, West	27.75	-1.50	42.58	5248
SPP/MRO On-peak				
MAPP, South	49.25	-0.50	67.38	8312
SPP, North	49.50	0.50	65.63	9278
SPP/MRO Off-Peak*				
MAPP, South	31.00	0.25	41.93	5232
SPP, North	32.75	-0.50	43.31	6139

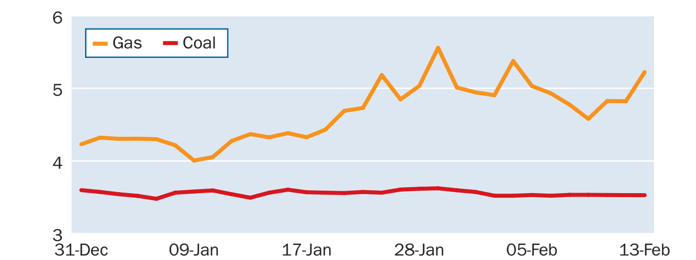
*Off-peak is for Saturday-Tuesday delivery.

Southeast load and generation mix forecast (GWh)

	Actual 13-Feb	%Chg	% Chg Year-ago	Forecast 14-Feb	15-Feb	16-Feb	17-Feb	18-Feb
ERCOT								
Load	1028	-1	17	1029	849	746	799	809
Generation								
Coal	485	8	22	522	429	377	363	360
Gas	330	-23	15	245	235	227	236	238
Nuclear	123	0	28	123	123	123	123	123
SPP								
Load	724	3	12	721	620	576	600	586
Generation								
Coal	455	-2	-2	474	421	392	372	360
Gas	156	-23	29	117	100	87	93	92
Nuclear	61	244	38	61	61	61	61	61

Source: Bentek

Southeast fuel cost comparision ($/MMBtu)



Source: Platts

ERCOT average day-ahead LMP for Feb 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	38.25	0.90	70.11	7114
Hub Average	38.43	0.87	69.81	7146
Houston Hub	38.92	0.60	68.39	7213
North Hub	38.04	0.94	70.86	7013
South Hub	38.50	1.02	68.12	7112
West Hub	38.24	0.88	71.82	7273
AEN Zone	38.42	0.85	76.91	7306
CPS Zone	38.52	0.96	70.91	7171
LCRA Zone	38.45	0.91	85.25	7159
Rayburn Zone	38.03	-0.82	71.29	7011
Houston Zone	38.90	-0.08	68.50	7210
North Zone	38.04	0.48	71.30	7014
South Zone	38.60	1.00	76.59	7129
West Zone	39.14	-3.77	74.95	7443
Off-Peak				
Bus Average	27.10	-1.02	45.51	5211
Hub Average	27.13	-1.14	45.46	5216
Houston Hub	27.13	-1.65	45.17	5216
North Hub	27.07	-0.87	45.63	5137
South Hub	27.13	-1.14	45.17	5192
West Hub	27.19	-0.89	45.86	5328
AEN Zone	27.16	-1.19	48.84	5323
CPS Zone	27.21	-1.22	45.92	5219
LCRA Zone	27.18	-1.17	47.63	5214
Rayburn Zone	27.06	-0.89	45.65	5136
Houston Zone	27.13	-1.68	45.19	5217
North Zone	27.07	-0.89	45.67	5137
South Zone	27.17	-1.28	48.34	5200
West Zone	28.00	-2.43	47.62	5488

MISO South average day-ahead LMP for Feb 15 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Arkansas Hub	42.85	-5.32	-2.10	-2.44	52.99	7910
Louisiana Hub	51.37	1.81	-0.70	-1.67	59.64	9455
Texas Hub	48.92	-1.82	0.48	0.44	61.21	9066
Off-Peak						
Arkansas Hub	41.89	3.32	-1.31	-6.69	47.14	7937
Louisiana Hub	44.31	4.94	-0.51	-6.82	49.70	8401
Texas Hub	46.41	5.89	0.64	-3.31	54.94	8992

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

Package	Trade date	Range
ERCOT, North		
Next-week	02/11	43.00-44.00

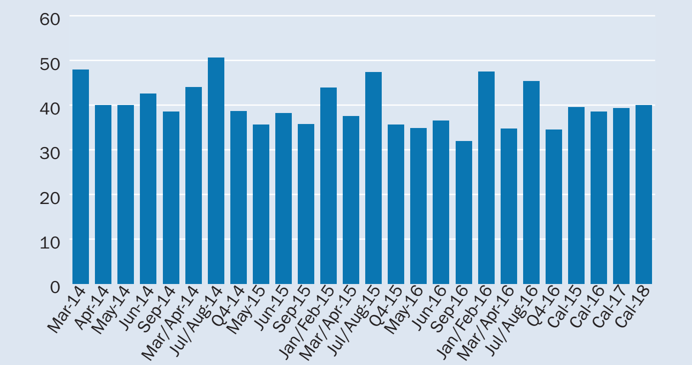
Market coverage

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.

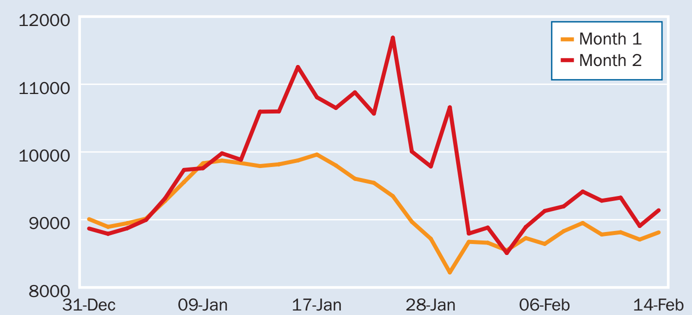
Southeast & Central Platts M2MS Forward Curve, Feb 14 ($/MWh)

Prompt month: Mar 14	On-peak	Off-peak
Southern Into	47.95	38.55
Entergy Into	42.45	34.10
ERCOT North	47.55	36.75
ERCOT Houston	49.35	40.00
ERCOT West	46.95	36.35
ERCOT South	48.60	38.20

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						
Big Brown-2/Luminant	575	c	Texas	MO	Unk	10/01/13
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Deepwater/AES	138	c	Texas	PMO	06/01/14	10/01/13
Grand Gulf-1/Entergy	1498	n	Miss.	PMO	03/07/14	02/07/14
Hatch-1/SOCO	911	n	Ga.	PMO	03/16/14	02/03/14
Martin Lake-1/Luminant	750	c	Texas	PMO	Unk	09/25/13
Martin Lake-2/Luminant	750	c	Texas	MO	Unk	12/16/13
Martin Lake-3/Luminant	750	c	Texas	PMO	06/01/14	12/14/13
Monticello-1/Luminant	565	c	Texas	PMO	05/15/14	10/01/13
Monticello-2/Luminant	565	c	Texas	PMO	05/15/14	10/01/13
SR Berton/NRG	765	g	Texas	PMO	05/01/14	10/01/13
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13

WEST MARKETS

West dailies up; terms mixed

West dailies were higher Friday with the for-Monday-Tuesday premium and strong spot gas prices. Terms were mixed.

In California, SP15 day-ahead on-peak futures gained $6 to about $58/MWh for Monday-Tuesday delivery on the InterContinentalExchange. SP15 day-ahead off-peak fell $2.25 to about $45.75/MWh for Monday-Tuesday delivery. NP15 day-ahead on-peak futures gained $6 to about $58/MWh on ICE. NP15 day-ahead off-peak futures decreased $1.75 to about $45.75/MWh for Monday-Tuesday delivery. Spot gas in the region moved up with PG&E Citygate adding about 11 cents to about $5.60/MMBtu and SoCal Citygate was up 23 cents to about $5.66/MMBtu.

High temperatures on Tuesday in California are predicted to be in the upper 50s to low 60s with lows in the upper 40s to low 50s. The California Independent System Operator forecast peak demand for Friday at 28,482 MW; 27,038 MW for Saturday; 26,432 MW for Sunday; and 27,533 MW for Monday. In the Southwest, Palo Verde day-ahead on-peak moved up $3.50 to about $49/MWh for Monday-Tuesday delivery and PV day-ahead off-peak slipped 50 cents to about $37.50/MWh for Monday-Tuesday delivery. Spot gas in the Southwest gained with Opal up 21 cents to about $5.35/MMBtu. High temperatures in Phoenix on Tuesday are forecast in the low 80s with lows in the mid-50s.

In the Northwest, Mid-Columbia day-ahead on-peak increased $3 to about $46.75/MWh for Monday-Tuesday delivery on ICE and Mid-C day-ahead off-peak edged down $1.25 to about $38.75/MWh for Monday-Tuesday delivery. High temperatures in the Northwest on Tuesday are predicted to be in the low to mid-40s with lows in the upper 20s to low 40s.

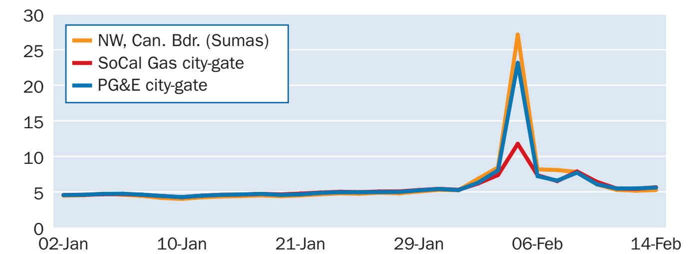
California ISO day-ahead auction prices fell with lower forecast demand on Saturday. NP15 on-peak fell $2.30 to $54.70/MWh and SP15 on-peak lost $3.67 clearing at $54.35/MWh. ZP26 on-peak gave up $3.04 to $53.43/MWh.

Western US on-peak forwards were mixed at the front of the curve Friday, as natural gas futures wavered between positive and negative territory. March NYMEX gas futures inched down 0.9 cent to $5.214/MMBtu, after being up 2.9 cents early in the day. In the Northwest, Mid-Columbia on-peak March was unmoved at about $48.50/MWh on the InterContinentalExchange around 2:30 pm EDT. The second quarter fell 40 cents to $34.65/MWh, as the third quarter crept up 10 cents to about $52/MWh. In California, SP15 on-peak March financial terms fell 30 cents to $59.30/MWh. Q2 fell 25 cents to $51.25/MWh and Q3 edged down 20 cents to $59.25/MWh. NP15 March moved down 55 cents to $57.65/MWh and Q2 rose 40 cents to about $49.90/MWh. Palo Verde on-peak March edged up 10 cents to about $47.25/MWh.

Western day-ahead bilateral indexes for Feb 17-18 ($/MWh)

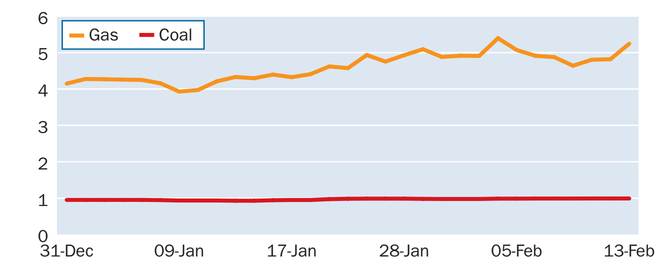
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	49.50	3.95	85.48	9192
Mid-C	46.86	3.25	87.92	8858
Palo Verde	48.86	3.33	69.34	9027
Mead	52.75	4.41	77.11	9539
Mona	45.00	5.50	73.80	8563
Four Corners	48.00	5.75	73.57	9065
NP15	58.00	6.00	78.12	10348
SP15	58.75	5.75	78.30	10624
Off-Peak*				
COB	41.25	-0.35	70.12	7660
Mid-C	38.55	-1.51	73.53	7287
Palo Verde	37.75	-0.25	53.15	6975
Mead	41.00	-1.25	55.50	7414
Mona	34.00	-1.00	55.03	6470
Four Corners	33.25	0.25	52.94	6280
NP15	46.00	-1.50	61.58	8207
SP15	46.00	-2.00	60.42	8318

Western spot natural gas prices ($/MMBtu)



Source: Platts

Western fuel cost comparision ($/MMBtu)



Source: Platts

Western load and generation mix forecast (GWh)

	Actual 13-Feb	%Chg	% Chg Year-ago	Forecast 14-Feb	15-Feb	16-Feb	17-Feb	18-Feb
CAISO								
Load	574	-4	-4	577	539	530	590	600
Generation								
Gas	256	3	24	277	276	271	273	275
Nuclear	28	0	-3	28	29	33	41	48

Source: Bentek

CAISO average day-ahead LMP for Feb 15 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	54.70	0.00	-1.23	-2.30	70.54	9760
SP15 Gen Hub	54.35	0.00	-1.59	-3.67	69.68	9828
ZP26 Gen Hub	53.43	0.00	-2.51	-3.04	69.06	9661
Off-Peak						
NP15 Gen Hub	47.58	0.00	-0.63	1.72	58.74	8621
SP15 Gen Hub	46.77	0.00	-1.44	0.74	57.95	8731
ZP26 Gen Hub	46.55	0.00	-1.66	0.95	57.85	8689

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-week	02/14	72.00-73.25
Bal-month	02/14	58.00-59.50
Bal-month	02/13	48.50-49.50
Bal-month	02/12	47.00-48.00
Bal-month	02/11	46.50-47.50
Bal-month (off-peak)	02/13	47.00-48.00
Bal-month (off-peak)	02/12	40.75-42.00
Bal-month (off-peak)	02/11	39.00-40.00

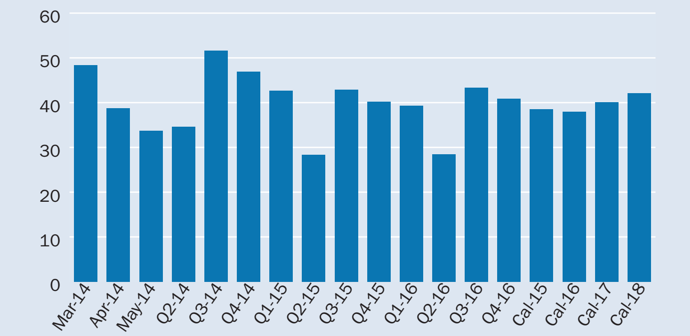
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Alamitos-4/AES	336	g	Calif.	PMO	Unk	02/10/14
Belden/PG&E	119	h	Calif.	PMO	Unk	01/27/14
Big Creek/SCE	820	h	Calif.	PMO	Unk	01/26/14
Colgate-2/YCWA	176	h	Calif.	PMO	Unk	01/13/14
Coolwater-3/NRG	245	g	Calif.	PMO	Unk	01/05/14
Diablo-1/PG&E	1150	n	Calif.	PMO	Unk	02/10/14
Eastwood/SCE	200	h	Calif.	PMO	Unk	02/03/14
Etiwanda-4/NRG	320	g	Calif.	PMO	Unk	02/10/14
Helms-3/PG&E	404	h	Calif.	PMO	Unk	02/09/14
Ivanpah-1/BrightSource	123	s	Calif.	MO	Unk	02/09/14
Metcalf/Calpine	593	g	Calif.	PMO	Unk	01/13/14
Morro Bay-3/Dynegy	325	g	Calif.	MO	Unk	02/06/14
Morro Bay-4/Dynegy	325	g	Calif.	MO	Unk	01/12/14
Mountainview/SCE	525	g	Calif.	MO	Unk	12/17/13
OrmondBch-2/NRG	775	g	Calif.	PMO	Unk	02/02/14
Palomar/SDG&E	575	g	Calif.	PMO	Unk	02/03/14
Pine Flat/USACE	210	h	Calif.	PMO	Unk	10/02/13
Solar Star-1/MidAmerican	310	s	Calif.	MO	Unk	10/01/13
Solar Star-2/MidAmerican	270	s	Calif.	MO	Unk	10/01/13
Sunrise/Edison	586	g	Calif.	PMO	Unk	02/06/14

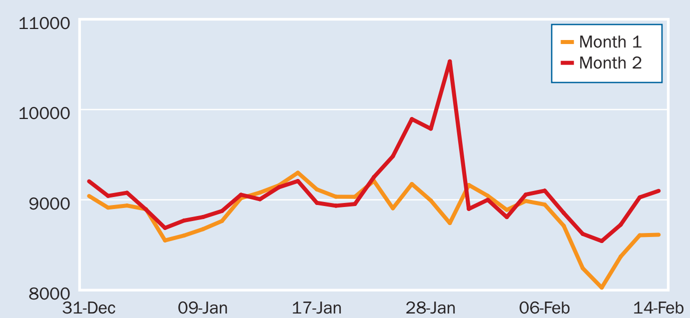
Western Platts M2MS Forward Curve, Feb 14 ($/MWh)

Prompt month: Mar 14	On-peak	Off-peak
Mid-C	48.40	41.85
Palo Verde	47.10	37.65
Mead	50.70	39.25
NP15	58.10	46.90
SP15	59.50	49.40

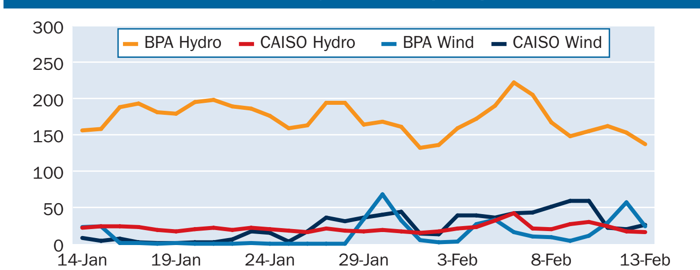
Mid-C: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

Dailies jump on strong demand, spot gas

Mid-Atlantic dailies climbed Friday, with stronger spot natural gas prices and load forecasts, with daily prices rising in the Midwest as well.

PJM Interconnection West Hub day-ahead on-peak futures jumped $25 to about $75/MWh for Monday delivery on the IntercontinentalExchange. PJM West Hub Tuesday on-peak futures retreated from that level to about $55/MWh. PJM West on-peak balance-of-the-week futures were $10 lower than Tuesday deliveries, at about $45/MWh on ICE.

Texas Eastern M-3 climbed 96 cents $6.838/MMBtu for Saturday-Tuesday delivery on ICE.

PJM forecasted peak load for Friday at 109,927 MW, an increase of about 6,000 MW from Thursday's peak. The forecast for Saturday is 108,129 MW, with Sunday at 107,464 MW, Monday at 115,879 MW and Tuesday at 108,475 MW.

Temperatures in the eastern part of PJM are forecast to be near freezing Monday, but risingrough the rest of the week.

Midcontinent ISO dailies rose Friday. Indiana Hub day-ahead on-peak futures climbed $2 to about $54/MWh for Monday delivery on ICE. Indiana Hub Tuesday on-peak futures retreated from that level to about $50/MWh. Indiana Hub on-peak balance-of-the-week futures were $10 lower than Tuesday deliveries, at about $40/MWh on ICE.

MISO forecasted peak load for Friday at 90,640 MW, a decrease of about 6,000 MW from the actual peak Thursday. The forecast for Saturday is 82,130 MW, with Sunday at 79,880 MW, Monday at 84,770 MW and Tuesday at 84,190 MW. Loads and load forecasts include MISO South.

Dailies in the Midwestern portion of PJM were also rising Friday. AD Hub day-ahead on-peak futures climbed $2 to about

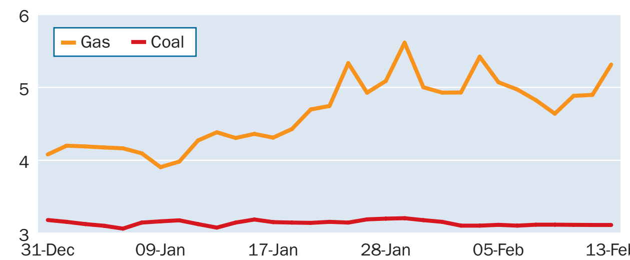
PJM & MISO day-ahead bilateral indexes for Feb 17 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	76.75	23.75	97.16	13833
Dominion Hub	77.25	21.25	98.64	12440
AD Hub	53.50	2.75	82.91	9675
NI Hub	51.00	2.75	80.55	7932
PJM Off-Peak				
PJM West	52.00	4.75	69.95	9372
Dominion Hub	53.00	3.00	71.55	8535
AD Hub	46.50	1.50	59.59	8409
NI Hub	40.50	1.50	52.64	6299
MISO On-peak				
Indiana Hub	53.00	3.25	81.02	9029
Michigan Hub	57.25	3.25	84.00	6923
Minnesota Hub	40.25	3.50	62.34	4460
Illinois Hub	51.25	0.75	73.27	7118
MISO Off-Peak				
Indiana Hub	41.50	-2.75	55.45	7070
Michigan Hub	45.00	-2.75	57.70	5441
Minnesota Hub	32.25	6.00	34.66	3573
Illinois Hub	33.25	-1.75	45.07	4618

PJM & MISO day-ahead bilateral indexes for Feb 18 ($/MWh)

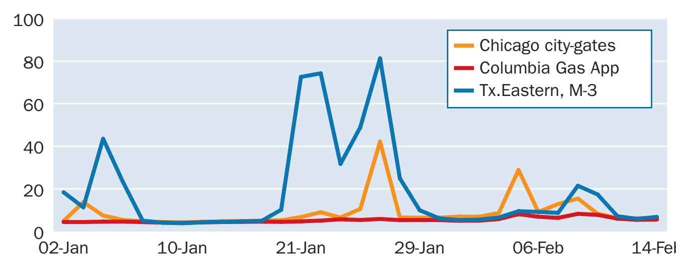
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	55.00	-21.75	93.65	9913
Dominion Hub	55.00	-22.25	95.00	8857
AD Hub	47.00	-6.50	79.92	8499
NI Hub	42.75	-8.25	77.40	6649
PJM Off-Peak				
PJM West	43.00	-9.00	67.71	7750
Dominion Hub	43.50	-9.50	69.21	7005
AD Hub	38.50	-8.00	57.83	6962
NI Hub	35.25	-5.25	51.19	5482
MISO On-peak				
Indiana Hub	44.50	-8.50	77.98	7581
Michigan Hub	48.75	-8.50	81.06	5895
Minnesota Hub	31.50	-8.75	59.77	3490
Illinois Hub	43.25	-8.00	70.77	6007
MISO Off-Peak				
Indiana Hub	38.25	-3.25	54.02	6516
Michigan Hub	41.50	-3.50	56.35	5018
Minnesota Hub	27.75	-4.50	34.08	3075
Illinois Hub	28.75	-4.50	43.71	3993

PJM fuel cost comparision ($/MMBtu)



Source: Platts

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 13-Feb	%Chg	% Chg Year-ago	Forecast 14-Feb	15-Feb	16-Feb	17-Feb	18-Feb
PJM								
Load	2542	-8	9	2574	2453	2365	2516	2379
Generation								
Coal	1171	-11	22	1194	1183	1161	1152	1158
Gas	318	-14	-2	303	311	318	319	279
Nuclear	750	1	-4	754	758	758	758	758
MISO								
Load	2112	-5	42	2126	1914	1784	1851	1840
Generation								
Coal	1333	-8	7	1276	1297	1288	1275	1288
Gas	279	-25	195	79	129	200	235	233
Nuclear	145	-1	-24	132	133	136	142	147

Source: Bentek

MISO average day-ahead LMP for Feb 15 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	52.68	1.81	0.61	-4.51	70.30	8914
Michigan Hub	68.78	16.68	1.84	6.66	83.85	8309
Minnesota Hub	38.62	-11.08	-0.56	-4.04	54.03	4270
Illinois Hub	46.04	-2.45	-1.78	-12.56	68.78	6376
Off-Peak						
Indiana Hub	37.43	-2.67	0.23	-3.07	50.85	6366
Michigan Hub	50.91	9.98	1.05	-3.41	68.43	6114
Minnesota Hub	30.57	-9.33	0.02	3.50	33.50	3338
Illinois Hub	24.97	-13.25	-1.67	-6.65	42.56	3373

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

Package	Trade date	Range
PJM West		
Bal-week	02/12	56.00-59.00
Bal-week	02/11	75.00-80.00
Bal-week	02/10	99.00-101.00
Bal-month	02/10	65.00-67.25
Next-week	02/12	52.00-55.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Davis Besse/FirstEnergy	971	n	Ohio	PMO	04/19/14	02/01/14
Fermi-2/DTE Energy	1555	n	Mich.	RF	03/16/14	02/10/14
La Salle-1/Exelon	1207	n	Ill.	MO	03/01/14	02/10/14
Palisades/Entergy	845	n	Mich.	PMO	02/22/14	01/19/14

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 average day-ahead LMP for Feb 15 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	49.76	-3.09	-3.69	3.30	73.07	7512
AEP-Dayton Hub	53.16	-2.11	-1.28	3.29	77.60	8025
ATSI Gen Hub	55.65	-1.16	0.27	4.03	80.17	8575
Chicago Gen Hub	49.73	-4.80	-2.02	2.79	74.96	7748
Chicago Hub	51.33	-4.05	-1.16	3.29	76.53	7998
Dominion Hub	58.65	2.95	-0.85	4.77	83.25	9526
Eastern Hub	69.63	9.59	3.50	8.63	92.33	10226
New Jersy Hub	65.30	6.55	2.21	5.15	96.92	9590
Northern Illinios Hub	50.89	-4.12	-1.53	3.29	75.88	7929
Ohio Hub	53.58	-2.08	-0.88	3.34	78.20	8069
West Internal Hub	55.59	-0.04	-0.91	3.96	80.26	10041
Western Hub	58.07	1.61	-0.08	3.48	83.94	10488
AEP Zone	53.59	-1.63	-1.34	3.25	77.87	8089
Allegheny Power Zone	57.59	1.45	-0.41	3.08	81.32	10127
Atlantic Elec Zone	57.92	-0.29	1.67	2.96	87.76	8506
ATSI Zone	55.72	-1.42	0.59	3.74	80.73	8585
BG&E Zone	59.65	1.19	1.92	3.98	88.47	9953
ComEd Zone	51.23	-4.07	-1.25	3.20	76.40	7981
Dayton P&L Zone	54.23	-2.07	-0.25	3.60	79.13	9423
Delmarva P&L Zone	74.91	14.67	3.69	11.42	94.17	11000
Dominion Zone	59.41	2.99	-0.12	4.67	84.54	9650
Duke Zone	51.90	-1.93	-2.71	3.54	75.67	9018
Duquesne Light Zone	47.43	-6.39	-2.73	2.96	73.05	8578
EKPC Zone	52.12	-1.94	-2.49	3.90	75.56	9094
JCPL Zone	57.48	-1.38	2.31	2.85	90.91	8441
MetEd Zone	56.41	-0.91	0.77	2.86	85.17	8805
PECO Zone	55.73	-2.02	1.20	2.23	86.20	8699
Pennsylvania Elec Zone	59.93	2.28	1.10	3.22	85.63	11197
PEPCO Zone	59.90	2.12	1.23	4.22	87.93	9994
PPL Zone	56.95	-0.06	0.47	3.39	85.40	8890
PSEG Zone	72.24	13.37	2.32	7.37	102.84	10609
Rockland Elec Zone	80.21	20.81	2.85	9.56	109.84	11779
Off-Peak						
AEP Gen Hub	41.55	-3.07	-2.49	6.30	52.80	6313
AEP-Dayton Hub	43.70	-2.65	-0.76	5.48	55.49	6641
ATSI Gen Hub	49.28	2.54	-0.37	6.81	61.24	7702
Chicago Gen Hub	37.18	-8.47	-1.46	5.42	48.46	5859
Chicago Hub	38.02	-8.28	-0.80	5.16	49.60	5991
Dominion Hub	48.08	1.01	-0.04	1.07	62.69	8302
Eastern Hub	58.19	8.61	2.47	6.68	70.27	9630
New Jersy Hub	55.46	7.04	1.31	4.98	72.16	9178
Northern Illinios Hub	37.70	-8.32	-1.10	5.17	49.18	5939
Ohio Hub	43.77	-2.84	-0.50	5.39	55.61	6658
West Internal Hub	47.38	1.03	-0.76	4.58	60.33	8700
Western Hub	49.19	2.05	0.03	3.08	62.74	9031
AEP Zone	44.63	-1.76	-0.72	4.91	56.46	6782
Allegheny Power Zone	49.11	2.37	-0.37	3.54	61.11	8735
Atlantic Elec Zone	50.75	2.80	0.84	4.10	67.11	8398
ATSI Zone	48.88	1.87	-0.10	6.65	60.97	7639
BG&E Zone	50.31	1.70	1.49	1.64	66.60	8914
ComEd Zone	37.92	-8.30	-0.89	5.15	49.46	5975
Dayton P&L Zone	44.97	-1.96	-0.19	5.93	57.18	7914
Delmarva P&L Zone	61.29	11.43	2.76	7.78	71.38	10143
Dominion Zone	48.82	1.28	0.43	0.98	63.75	8431
Duke Zone	42.18	-3.04	-1.90	5.82	54.00	7423
Duquesne Light Zone	40.24	-4.36	-2.51	7.76	53.82	7426
EKPC Zone	42.17	-3.49	-1.45	6.17	54.03	7409
JCPL Zone	51.50	2.98	1.41	5.61	68.61	8522
MetEd Zone	49.44	2.06	0.28	4.26	65.27	8442
PECO Zone	49.98	2.13	0.74	3.92	66.55	8534
Pennsylvania Elec Zone	51.10	3.49	0.50	4.35	63.89	9916
PEPCO Zone	50.05	1.78	1.16	1.04	66.12	8868
PPL Zone	49.35	2.23	0.01	4.43	65.30	8426
PSEG Zone	59.21	10.69	1.41	4.92	75.81	9798
Rockland Elec Zone	63.84	15.03	1.70	5.94	78.61	10565

$52.50/MWh for Monday delivery on ICE. AD Hub Tuesday on-peak futures retreated from that level to about $48/MWh.

PJM day-ahead auction prices cleared higher Friday, despite lower demand on the weekend. The average PJM Western Hub on-peak price rsoe $3.48 to $58.07/MWh for Saturday delivery. The largest increase was in Maryland, with Delmarva Power & Light Zone on-peak average rising $11.42 to $74.91/MWh. Rockland Electric Zone in New Jersy remains the highest-priced hub or zone, climbing $9.56 to $80.21/MWh. Duquesne Zone was lowest-priced zone, with on-peak moving up $2.96 to$47.43/MWh. In the west, ComEd Zone on-peak rose $3.20 to $51.23/MWh.

MISO day-ahead auction prices cleared mostly weaker Friday. Michigan Hub remained the highest-priced hub with on-peak rising $6.66 to clear at $68.78/MWh. Indiana Hub on-peak dropped $4.51 to clear at $52.68/MWh. Illinois Hub on-peak lost $12.56 to clear at $46.04/MWh. Minnesota Hub remained the lowest-priced hub, with on-peak down $4.04 to $38.62/MWh.

Mid-Atlantic March forwards jumped Friday, while March NYMEX natural gas prices inched down 0.9 cent to $5.214/MMBtu. PJM West on-peak March financial futures surged $3 to about $62/MWh on ICE. PJM West off-peak March moved up $3.10 to $45.25/MWh, while on-peak July-August rose 35 cents to $65.15/MWh.

Midwest March forward prices moved up sharply Friday. AD Hub on-peak March financial futures gained $2.05 to about $52.60/MWh, while AD Hub on-peak July-August was unchanged at about $56.40/MWh. Indiana Hub on-peak March moved up $1.10 to $51.25/MWh, while on-peak July-August jumped $1.45 to about $55.65/MWh. Northern Illinois Hub on-peak March jumped $1.20 to about $49.20/MWh.

Northeast markets ... from page 2

Connecticut on-peak added $15.89 to $178.02/MWh as off-peak inched up $1.24 to $112.03/MWh. NE-Mass Boston on-peak was up $20 to $189.63/MWh and off-peak gained $3.26 to $114.10/MWh. Maine on-peak rose $21.43 to $179.20/MWh and off-peak increased $3.44 to $109.87/MWh.

Day-ahead auction clearing prices in NYISO were mixed Friday. The average Hudson Valley Zone on-peak price fell $7.83 to $91.94/MWh and the off-peak average added $8.15 to $75.27/MWh. Capital Zone on-peak dropped $11.62 to $102.21/MWh and off-peak climbed $14.13 to $88.05/MWh. New York City Zone J on-peak was down $7.78 to $91.44/MWh and off-peak increased $7.93 to $75.01/MWh. West Zone on-peak gained $2.91 to $56.51/MWh and off-peak declined $4.55 to $39.95/MWh.

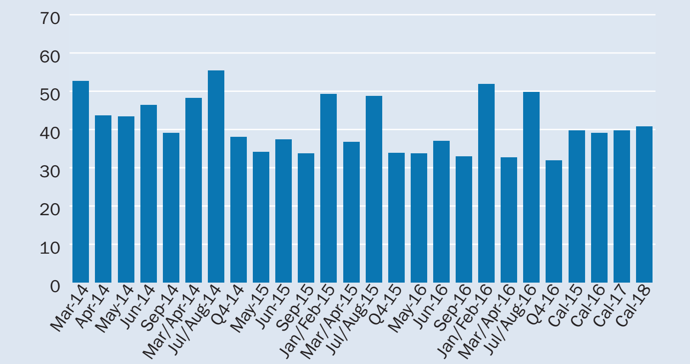
Northeast term prices were mixed Friday despite relatively steady gas futures and the Algonquin city-gates financial basis rising 83.5 cents to about $7.610/MMBtu. Mass Hub on-peak March financial futures rose $20 to about $101/MWh. Mass Hub on-peak July-August financial futures fell $1.40 to $64.50/MWh.

New York Zone G on-peak March financial futures fell $2 to about $83/MWh. New York Zone A on-peak March financial futures lost more than $2 to about $61/MWh.

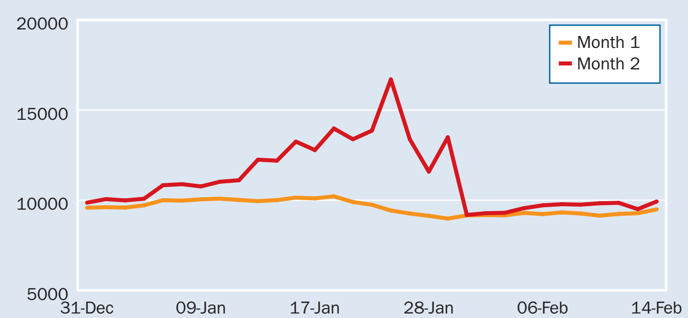
PJM & MISO Platts M2MS Forward Curve, Feb 14 ($/MWh)

Prompt month: Mar 14	On-peak	Off-peak
PJM West	61.95	44.45
AD Hub	52.70	39.75
NI Hub	50.30	36.10
Indiana Hub	51.80	37.65

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



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



Southeast markets ... from page 4

he ERCOT day-ahead auction cleared firmer Friday. Houston Hub remained the highest-priced hub as on-peak added 60 cents to clear at $38.92/MWh for Saturday delivery. South Hub on-peak gained $1.02 to clear at $38.50/MWh. West Hub on-peak rose 88 cents to clear at $38.24/MWh. North Hub remained the lowest-priced hub as on-peak moved up 94 cents to clear at $38.04/MWh.

For the MISO South Region, day-ahead auction prices cleared mostly weaker Friday. Louisiana Hub remained the highest-priced hub with on-peak losing $1.67 to clear at $51.37/MWh for Friday delivery. Texas Hub on-peak added 44 cents to clear the auction at $48.92/MWh. Arkansas Hub remained the lowest-priced hub with on-peak shedding $2.44 to clear at $42.85/MWh, with off-peak dropping $6.69 to $41.89.

ERCOT March term prices fell Friday, as March NYMEX gas futures inched down 0.9 cent to $5.214/MMBtu. ERCOT North March fell 35 cents to $47.45/MWh, as July-August dropped $1.05 to $93.30/MWh. Heat rates were down about 60 Btu/kWh on ICE at about 2:30 pm EDT.

NEWS

AEP can keep $368 million in power charges

American Electric Power will be allowed by the Ohio Supreme Court to keep $368 million in disputed electric charges arising from the company's provider of last resort obligations in a split Thursday ruling that featured a scathing dissent by Justice Paul Pfeiffer.

The charges were collected from customers by Columbus, Ohio-based AEP from April 2009 to May 2011, a period when the company set aside generation for potential use by its roughly 1.4 million Ohio customers, even though some had switched to competitive suppliers.

AEP Ohio, an AEP subsidiary, is in the process of transitioning to full competition in 2015. As such, "None of that generation will be available in 2015," AEP spokeswoman Terri Flora said Friday. "Once we transition to a fully competitive market in 2015, that won't be there."

Two groups, the Ohio Office of Consumers' Counsel and Industrial Energy Users of Ohio, have fought the POLR charges for several years on regulatory and legal fronts. They argued AEP was not entitled to recover the charges from customers.

The Public Utilities Commission previously found the charges to be "unjustified."

In a 5-2 decision, the Supreme Court disagreed. The court relied on a 1957 case it said established a precedent in favor of utilities in similar disputes.

Writing for the majority, Justice Judith Ann Lanzinger said the relevant statute does not require AEP to prove the investment charges actually were "necessary" as IEU-Ohio had asserted. Lanzinger said testimony given during the PUC case demonstrated that recovering the investment was permissible because the costs compensated AEP to upkeep its generation plants, which resulted in lower-cost power and cheaper prices for customers.

AEP was pleased with the ruling. "Bottom line: We still think what we put in there justified the need for a POLR charge," Flora said. "The Supreme Court followed the law."

But that old law should be overturned, Pfeiffer said in a strongly-worded dissenting opinion joined by Justice William O'Neill.

"It is unconscionable that a public utility should be able to retain $368 million that it collected from consumers based on assumptions that are unjustified," Pfeiffer wrote. "In this case, we are talking about $368 million in unjustified charges that, instead of redounding to the people who paid them, reside in the coffers of a public utility without the justification of actual costs. This illusory charge will become pure unwarranted profit based on this court's decision today. And it does not have to be this way."

The OCC, the state's residential utility consumer watchdog, was equally outraged.

The decision "means that 1.4 million residential and business customers will not get a refund of $368 million from AEP," said OCC spokesman Marty Berkowitz.

He added: "We had hoped that these appeals would provide some relief from AEP's electric rates that are the highest in the state for residential consumers." Citing federal data, Berkowitz said Ohioans are paying higher residential electric rates, on average, than consumers in 32 other states.

Glenrock Associates analyst Paul Patterson said he was not surprised by the ruling, given that "so much of the economics of the power sector are determined by such legal interpretation."

AEP Ohio intends to conduct four power auctions this year, the first on February 25, as part of its plan to move to market-based rates in 2015.

In early January, the company transferred more than 11,000 MW of mostly coal-fired, utility-owned generation into a separate generation company, AEP Genco.

— Bob Matyi

Mich. renewable costs continue to fall: report

Renewable energy development costs, especially for wind, continue to decline in Michigan, the Public Service Commission said in a Friday report that appears certain to further fan a simmering debate over the state's soon-to-expire 10% by 2015 renewable portfolio standard.

Since the RPS was enacted by the Legislature in 2008 as part of P.A. 295, a comprehensive energy law, renewable energy projects totaling 1,182 MW have been developed in Michigan, according to the report.

The weighted average cost of all renewable energy technologies put in place in Michigan now is $78.39/MWh, much lower than in recent years, and well below the $133/MWh levelized cost of new conventional coal-fired generation, the PSC said.

PSC chairman John Quackenbush noted that 2012 marked the first time Michigan utilities were required to meet an interim compliance target under the RPS, "and all of them succeeded." Renewables accounted for almost 7% of generation portfolios by the end of 2013, and the state's largest electric utilities, Consumers Energy and DTE Energy, are well on their way to reaching the 10% threshold next year.

Efforts to meet the 2015 mandate are "going smoothly," he added.

The most recent renewable energy contracts approved by the PSC for new wind capacity boast levelized costs in the range of $50-$59/MWh, the report said, half of comparable costs for the first few renewable energy contracts endorsed by the commission in 2009 and 2010.

"Statewide, there has been significant investment in the renewable energy sector since the passage of P.A. 295 in 2008," the report said. "Conservatively, assuming an installed cost of $2,000 per kW for new renewable energy projects, over $2.2 billion has been invested" to bring new renewable energy projects on line through 2013 in Michigan. "The $2.2 billion includes both incremental cost of compliance and the portion of costs recovered as energy costs."

Accelerating renewable energy development also is aiding Michigan's economy as it rebounds from double-digit unemployment rates during the depths of the 2008 recession.

Last year, the PSC said, renewable generation facilities were built using Michigan equipment and labor. Contracts for utility-scale projects, which also will employ Michigan residents, were approved by the commission and solar energy pilot programs that use Michigan labor for installation continued and expanded.

During 2014, the 100-MW Tuscola Bay Wind II farm in Tuscola and Bay counties and the 74.8-MW Pheasant Run project in Huron County, both built by a subsidiary of NextEra Energy Resources, began commercial operation. Four wind farms totaling 312.2 MW of capacity are expected to go into operation in 2014.

In September, the commission approved DTE's long-term power purchase agreement with Heritage Wind Energy's 20-MW Big Turtle wind farm in Huron County. At least half of the project's total cost, including materials, components, logistics and labor, will be sourced in Michigan, the PSC said.

The timing of the PSC report virtually ensures it will be part of the Legislature's debate this year over major energy issues, including whether to extend and increase the RPS requirement or allow it to expire at the end of next year.

Jim Byrum, president of the Michigan Agri-Business Association, said in a Friday interview the report "will absolutely have a bearing on the debate and, more importantly, on peoples' attitudes toward renewable and sustainable energy."

The association's approximately 500 members scattered across Michigan look to additional renewable energy development to meet some of their demand, he said.

Samantha Harkins, director of state affairs for the Michigan Municipal League, said the report "shows that the cost of renewable energy continues to decline dramatically, and our lawmakers should see this as an opportunity to reduce electricity bills for families, businesses and communities."

Michigan Governor Rick Snyder, a Republican seeking re-election this year, has voiced support for renewable energy. However, he has not yet submitted a specific proposal to the Legislature on whether he wants to see the RPS merely extended or enhanced.

— Bob Matyi

Smelter seeks rate cut from Ameren

If the rates Ameren Missouri charges Noranda Aluminum, its largest customer, are not reduced to $30/MWh, the aluminum maker will shut its operations and the utility likely would be forced to sell the 485 MW now consumed by Noranda in the wholesale market at an even lower price, Noranda said in a filing with regulators.

The $41.44/MWh price that Ameren Missouri now charges Noranda for power consumed at its New Madrid aluminum smelter is "unreasonable," and puts Noranda at a major competitive disadvantage to other US aluminum makers, Noranda said in a February 13 filing at the Missouri Public Service Commission.

Noranda said its smelter's annual electric bill is now $160 million, up $44 million since 2008. Kip Smith, Noranda's president and CEO, said in pre-filed testimony that Ameren Missouri should sell power to the smelter under a 10-year contract at $30/MWh, with any rate increases during the contract's term capped at 2% per approved base-rate increase.

Noranda asked that the $30/MWh price become effective August 1. It said that the rate reduction would require an increase of up to 1.8% in the rates paid by other customers of Ameren Missouri, but the trade-off is justified because of Noranda's positive economic impact and the consequences for Ameren Missouri if the New Madrid smelter were to close.

The New Madrid smelter, in the southeast corner of the state, employs nearly 900, produces 260,000 metric tons of aluminum products annually and consumes about 10% of the electricity Ameren Missouri generates, Noranda said, or "485 MW of power, 24 hours a day, seven days a week, 52 weeks per year, with a 98% load factor."

The proposed contract "will keep Noranda viable and sustainable for the future," the company said. "Since that rate is higher than the variable cost incurred to serve Noranda and also higher than what American Missouri can sell the power to others in the event that Noranda was subject to closure, Ameren Missouri's other customers will benefit from the relief requested."

Daily CSAPR allowance assessments, Feb 14

CSAPR ($/st)	2012 Range	Mid	2013 Range	Mid
SO_2 Group 1	5.00-35.00	20.00	5.00-25.00	15.00
SO_2 Group 2	25.00-75.00	50.00	25.00-65.00	45.00
NOx Annual	40.00-70.00	55.00	30.00-70.00	50.00
NOx Seasonal	20.00-90.00	55.00	20.00-80.00	50.00

All prices in $/st

Daily CAIR allowance assessments, Feb 14

	$/allowance	Change	$/st
S02 2013	0.77	0.06	1.54

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

RGGI carbon allowance futures, Feb 13 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec14 V11	3.68	0	Dec14	1.97	0
Dec14 V12	3.68	0			
Dec14 V13	3.68	50			
Dec14 V14	3.68	375			
Dec15 V11	3.77	0			
Dec15 V12	3.77	0			
Dec15 V13	3.77	0			
Dec15 V14	3.77	0			
Dec16 V11	3.86	0			
Dec16 V12	3.86	0			
Dec16 V13	3.86	0			
Dec16 V14	3.86	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.

Correction

An article Wednesday misstated the Federal Energy Regulatory Commission's authority under the Public Utility Regulatory Policies Act. FERC under the statute has the authority to pursue litigation against state commissions, not generators, to enforce the requirements of the law.

Looking at day-ahead prices for the Illinois Hub in the Midcontinent Independent System Operator over the past year, the average price was $34.84/MWh, based on Platts price data.

The aluminum maker said the 1.8% rate increase that other customers would need to incur to make Ameren Missouri whole is "less than the increase that would be required to make up for the loss of sales to Noranda should the New Madrid smelter close."

Noranda noted in a statement that its rate-reduction request is supported by the Missouri Retailers Association, which includes large commercial consumers, and the Missouri Industrial Energy Consumers, which represents large industrial consumers.

Noranda alleged in a separate but related filing that Ameren Missouri currently is earning more than its authorized 9.8% rate of return on equity, and that the PSC should reduce the utility's authorized ROE to 9.4%.

"We strongly disagree with the earnings complaint case and rate design allegations, and we intend to vigorously argue our position" before the PSC, Warren Wood, Ameren Missouri's vice president of regulatory and legislative affairs, said in a statement. "In fact, in November 2013, we announced plans [to] file a rate case during the second half of 2014 to recover operating costs and investments for environmental initiatives and energy infrastructure necessary for providing safe and reliable service to our customers."

Wood called the aluminum company's filings "attempts by Noranda to lower their costs by shifting them to residential customers, small business owners and other businesses as quickly as possible. This action is simply inappropriate. Noranda's rate is the lowest in the state, which already is more than 60% below our residential customer rate. In addition, they are seeking a rate below the rate set in their original contract in 2005."

Noranda is one of several smelter owners seeking to reduce their power costs. In Kentucky, Century Aluminum earlier this month won state support for its plan to purchase the 350 MW its Sebree smelter needs from the wholesale market rather than from Big Rivers Electric, the regional generation and transmission cooperative. Century's Hawesville smelter last August started buying the 500 MW it needs from the wholesale market, again switching from Big Rivers, and in October, American Electric Power lost its largest customer, Ormet's smelter, with a demand of 500 MW, when the plant closed after state regulators refused Ormet's request for rate relief.

— Housley Carr

TVA fuel cost to increase 23.25% for March

The Tennessee Valley Authority will increase its wholesale fuel cost by 23.25% in March, according to a TVA spokesman.

For the billing period beginning March 1, the total monthly fuel cost will be 2.688 cents/kWh compared with 2.181 cents/kWh in February, TVA spokesman Scott Brooks said Friday.

"The increase from February is due mainly to higher demand from a record cold January," Brooks said.

TVA reached a new record winter demand of 33,353 MW on the morning of January 24 with temperatures averaging about 7 degrees across the region, according to a TVA news release. The previous record was 32,572 MW set on January 16, 2009 when temperatures averaged 12 degrees.

This year's rate is more than 31.25% higher than the March 2013 monthly fuel cost of 2.047 cents/kWh.

The total monthly fuel cost is what TVA uses to recover the costs of the fuel it utilizes to generate electricity — such as coal and natural gas. It is variable and calculated monthly as generation fuel costs and purchased power costs from other suppliers rise and fall. The fuel cost makes up one-third of the overall wholesale rate.

TVA charges wholesale prices to the 155 local power companies that, in turn, provide power to 9 million people in parts of seven southeastern US states.

— Kassia Micek

Generation additions in 2013 dropped 52%

...from page 1

tax credit put the brakes on wind power development last year.

Gas-fired plants also declined in 2013 compared with 2012, but gas' 31% decline was not as steep as wind's 94% drop. A total of 7,086 MW of gas plants came online in 2013, compared with 10,211 MW in 2012.

A majority, 58%, of the new gas plants came online in the Western Electricity Coordinating Council. The Southeast accounted for more than 25% of the action. Specifically Florida and SERC gained 18% and 10%, respectively, of gas plants that entered service last year.

It is hardly surprising that fewer coal plants came online in 2013 compared with 2012 – 1,567 MW compared with 3,570 MW – given the low price of natural gas stemming from rising production in shale formations and tighter power plant emission regulations.

The installation of fossil or conventional fuel plants declined across the board in 2013. Most renewable resources showed gains, though the reduced wind power was the exception. Solar power led the way with a 142% gain in installations last year, 3,983 MW compared with 1,649 MW in 2012.

Power plants fired by wood or biomass also showed gains, though the scale is smaller. A total of 484 MW of wood-burning plants came online in 2013, compared with 330 MW in 2012, and 162 MW of biomass plants entered service in 2013, compared with 50 MW the previous year.

Another trend in the market can be summed up in the way coal and solar power swapped places over the past two years, marking an inflection point in the development of those resources. The size of the coal fleet is slowly shrinking because of retirements and a near standstill in the construction of new coal plants. Solar power, on the other hand, is burgeoning, driven by favorable state policies and declining equipment costs.

In 2012, 3,570 MW of coal plants came online and 1,649 MW of solar plants entered service. In 2013, 3,983 MW of solar plants entered service and 1,567 MW of coal plants came online.

Currently there are only three coal plants under construction: Power4Georgians' 850-MW Plant Washington, due online in 2019; Mississippi Power's 582-MW integrated gasification combined-cycle Kemper project that would turn lignite into gas and is slated to enter service later this year, and Two Elk Power is building a 250-MW coal plant in Wyoming that is due online in 2016.

Beyond that, there are only a handful of coal projects that have been proposed. If technologies that convert coal to a gas or that burn coalbed methane are included, 10 projects totaling 3,776 MW have been proposed, but only one, Sunflower Electric Power's 895-MW Holcomb expansion project, is a straightforward coal project, and it is working its way through permitting challenges.

Extrapolating from Platts data, there likely will be a decline in the amount of generation that comes online in 2014 and 2015 compared with 2013. The data show 12,795 MW of generation under construction that is due online this year, and 5,456 MW under construction and due online in 2015. More capacity is likely to enter construction throughout 2014, boosting the potential for more plants to enter service, particularly in 2015, but right now the trend appears to be headed down.

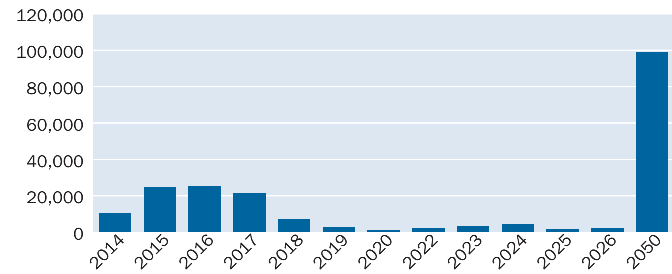
Overall, there are 26,676 MW of generation under construction and slated for service between 2014 and 2019. A good portion of the capacity that is under construction is comprised of nuclear plants, 5,742 MW or 22% of the total, which bump wind power into the third-largest type of plants under construction. Gas still accounts for the majority of plants under construction, with 10,906 MW, comprising 41% of the total.

Most of those gas plants, 43%, are being built in PJM Interconnection, with the Electric Reliability Council of Texas and Western Electricity Coordinating Council areas as the next-most active, accounting for 25% and 15% of the new builds, respectively.

In terms of timing, the last of the gas projects now under construction come online in 2016, the largest among them being Competitive Power Venture's 700-MW Woodbridge project in New Jersey and Panda Power's 829-MW Liberty project in Pennsylvania.

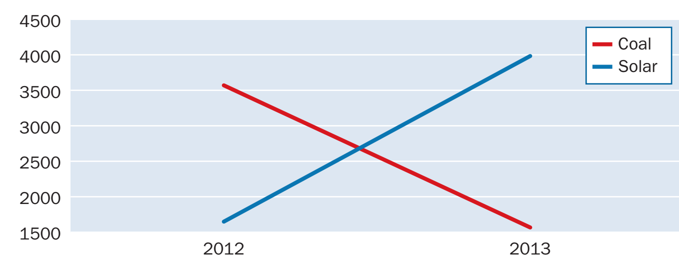
A timeline of projects now under construction shows that wind and solar power installations fall off steeply from 2016 to 2017, which matches the expiration of tax credits. The 30% investment tax credit for solar power expires at year-end 2016 and the PTC for wind power expired at the end of December. But when Congress extended the PTC, it also changed the eligibility criteria, which provide a new definition of "in construction" that, in effect, extends the PTC deadline to April 15, 2014.

Online dates of projects under development (MW)



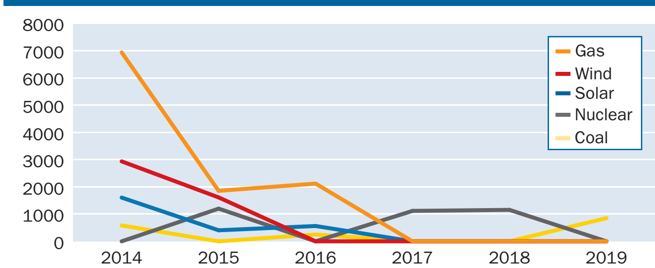
Source: Platts

Trading places:
Aggregate capacity of coal and solar plants entering service (MW)



Source: Platts

Online dates of projects under construction (MW)



Source: Platts

Starting in 2015, nuclear power should have a strong showing in capacity additions. Those come from just three projects: Southern Company's 2,308-MW Vogtle plant, due online in 2018, the 2,234-MW Summer project being built by South Carolina Electric & Gas and Santee Cooper, and the addition of a 1,200-MW reactor at the Watts Bar station by the Tennessee Valley Authority, due online in 2015.

Likewise, coal jumps up in 2019, the result of a single project, the 850-MW Plant Washington. Late last year, a spokesman for the project said it had begun construction, but the project is still facing stiff opposition from the Sierra Club.

Looking further out than 2020, the outlook for new generation is less clear. Historically, far more projects are proposed than ever come online. The same is likely true of the 205,644 MW of projects that Platts data show in various stages of development, from advanced, to early, to proposed.

By target online dates, those projects show a curve similar to projects under construction, peaking at 25,287 MW in 2016 and falling to 1,120 MW by 2020. Nearly half of the projects, 98,927 MW, are not firm enough to have a target online date.

Gas and wind resources continue to dominate development projects, with wind having a slight edge over gas, 75,112 MW, or 37% of the total, compared with 71,864 MW of gas projects, representing 35% of the total.

Given the expiration of the PTC and the uncertain prospects of its extension, it is unlikely that most of those wind projects will ever spin. Just over half of the development wind projects have indefinite online dates. About 40% of those projects are listed as "proposed," 31% are listed as in "early" development, and 28% are listed as in "advanced" development.

There are also 14,338 MW of proposed nuclear projects at 10 sites, but it is unlikely that all of them will be built given the high cost and opposition to new nuclear plants.

There are also nearly 20,000 MW of hydroelectric projects under development, nearly 60 times as many as came online in 2013. About 70% of that total is comprised of 13,838 MW of pumped storage projects, which tend to be large, and can be hard to permit. The smallest of the pumped storage projects under development is 150 MW. The largest is just over 2,000 MW. Another 1,300 MW of the hydro projects are being developed by a single company, Free Flow Power.

Developers can propose projects for a variety of reasons, but the circumstances that make a project viable can change quickly. In broad terms, the forces that have been shaping the market are likely to continue to drive the pace and composition of new generating resources. One of the most important changes in the generation market is the pending retirement of coal plants, which is being driven by two main forces, the low cost of natural gas and tighter emissions regulations.

While the price of natural gas is expected to remain relatively low for the foreseeable future, gas prices are notoriously volatile and often do not conform to predictions. Environmental regulations, on the other hand, tend to move in one direction.

Black & Veatch forecasts that 48 GW of coal plants will retire by 2015, when the Mercury and Air Toxic Standards rule begins to take effect. B&V sees another 12 GW of coal-fired generation retiring by 2020, and between 2020 and 2038, B&V forecasts that another 86 GW of coal plants will retire. In all, about 146 GW of coal plants, about half the US fleet, will retire over the next 25 years, B&V forecasts.

That creates opportunities for gas-fired and renewable generation, as the Platts data show, and as B&V forecasts, with estimates of 100 GW of renewables and 348 GW of gas-fired generation coming online over the next 25 years. B&V estimates that those new gas plants will drive a 3.11% annual average growth rate in gas demand.

The growth in gas and renewables is not likely to trace a smooth curve. It is more likely to be lumpy or spikey, particularly in the near term.

Over the next several years, the gap left by retiring coal plants might not be filled by new gas plants as much as by better utilized plants. "A lot of combined-cycle gas plants are only operating at about a 30% capacity factor. They will be picking up some of that baseload capacity that is going to retire," according to Rob Patrylak, managing director in B&V's management consulting division.

— Peter Maloney

CFTC aggregation plan needs tweaks ...from page 1

on the CFTC to focus on actual control and decision-making of trading in futures and swaps when grouping positions, as opposed to overall corporate ownership structures.

Importantly, concerns stem from the CFTC proposal to aggregate futures positions based on ownership thresholds of 20%, 50%, or greater, which depending on where a subsidiary fell within those ranges, would determine how the CFTC would apply the rule or consequently grant an exemption.

Many commenters including CME Group and IntercontinentalExchange, who would ultimately enforce the rule on the ground level, said the percentages were arbitrary and "randomly selected."

Companies which operate in the energy business are often of considerable size with multiple subsidiaries operating in markets globally, but more importantly operate separately from one another with little interaction.

Companies are concerned that the trading activity of these separate affiliates would be added together by the CFTC for compliance under position limits, which restrict the ownership of futures contracts in 28 different commodities including crude oil and natural gas.

For example, MidAmerican Energy Holdings Company operates a multitude of electricity and natural gas subsidiaries such as Rocky Mountain Power, Northern Natural Gas, CalEnergy and others. MidAmerican's controlling shareholder is Berkshire Hathaway, which then on a greater scale operates in a multitude of venues where they could be entering into similar futures contracts.

MidAmerican is concerned primarily that the CFTC would aggregate the positions of all their subsidiaries due to common ownership by Berkshire, as opposed to the more tenable aggregation of trading within each subsidiary based on the day-to-day control and coordination of trading decisions.

"In short, Berkshire and its operating businesses that enter into futures, options or swaps subject to the commission's proposed position limits operate independently and do not coordinate their trading," MidAmerican said.

The group went on to say that "unless relief is made available to majority-owned affiliates that are consolidated for accounting purposes, companies like MidAmerican will be subjected to potentially serious regulatory costs and consequences."

While exemptions are allowed under the current proposal, groups have said applying and being in a position to receive approval for an exemption could be untenable depending on how the final rule is written.

"Because actual day-to-day control over, or coordination of, trading activity should be the commission's regulatory concern, majority-owned entities should have a fair opportunity to demonstrate to the commission that in spite of GAAP-required financial statement consolidation, an absence of actual trading control or coordination, together with other restrictions on information-sharing, justify disaggregation relief," said AGA.

Furthermore, the natural gas group said "the true implications of disaggregation relief will not be readily apparent to physical commodity market participants until the commission finalizes its rules regarding the scope of swaps, futures and referenced commodity contracts included in positions limits."

AGA indicated that the inclusion of trade options in any aggregation toward position limits could have a material impact on whether or not the groups believe the aggregation proposal is workable.

"The commission should also not focus on the character of the trading engaged in by the entities requesting relief," said the Commercial Energy Working Group. "Requiring that all of the owned entities positions qualify as bona fide hedging transactions or do not exceed 20% of a position limit does not address the question of whether coordination or control exists."

While the CFTC is not under any direct timetable to propose a final rule on the issue, it is likely a decision on the aggregation proposal or position limits would not come until a full complement of commissioners is in place at the CFTC.

Currently, the commission is working with only three commissioners as those appointed to fill the remaining slots and replace outgoing Commissioner Bart Chilton have yet to be considered or confirmed by the US Senate.

— Christopher Tremulis

Duke RFP seeks solar capacity ...from page 1

generation development, said there are many eligible projects, with more than 2,500 MW of capacity having already been proposed in the state by solar developers.

Caldwell said DEC and DEP are open to the possibilities of either buying the output of developer-built and –owned solar facilities or buying the facilities themselves once their construction is complete. Duke Energy Renewables, an independent power affiliate of the two utilities, will not be permitted to respond to the RFP.

The Duke executive said, "For bidders who wish for Duke … to assume ownership, it will allow us to better locate and integrate the new capacity into our energy mix. We are in the best position to manage the unique characteristics of intermittent solar generation into our existing system."

According to the RFP, DEC and DEP's "strong preference" is that "turnkey" solar projects the utilities might acquire have capacities of at least 20 MW each. "Respondents that submit a turnkey construction proposal must provide an all-in engineering, procurement and construction price for the sale of a fully constructed project," the solicitation said. "Pricing must represent the price of the project at the time of ownership transfer, which will occur immediately preceding the project's in-service date."

Regarding projects offering PPAs, the RFP said the utilities will consider agreements with terms of up to 15 years. Pricing for PPA proposals "must be bundled for the entire output of the facility (energy, capacity, [renewable energy credits], ancillaries) and stated in dollars per MWh per year," the solicitation said. Bidders may propose either fixed pricing or pricing with a fixed escalation rate, such as 2%/year. "Escalation rates may not be tied to any indices," the RFP said.

"Our mission is to bring more renewable generation onto the Duke Energy system in the most cost-effective manner possible," Caldwell said, adding that the RFP "allows the company to take advantage of projects already in the planning stages."

Caldwell said the solar projects selected as the winners of the solicitation this summer or early fall "will practically double our current solar capacity" in North Carolina, which in 2007 implemented a "renewable energy and energy efficiency portfolio standard," or REPS, with increasing requirements regarding the contribution of solar and other renewable capacity.

Under the REPS, investor-owned utilities, municipal utilities and electric cooperatives currently must secure at least 3% of their electricity from a combination of renewable energy and expanded energy efficiency. That mandate rises to 6% in 2015, 10% in 2018 and—-for IOUs, but not munis or co-ops—to 12.5% in 2021.

Utilities can meet up to one-quarter of the requirements through 2021 through energy efficiency-related load reductions, and up to four-tenths of the requirement through energy efficiency after 2021.

Duke noted Friday that North Carolina's REPS allows for renewable energy facilities connected to DEC and DEP's Carolinas system to meet North Carolina's compliance obligations. As a result, facilities in DEC- and DEP-served portions of South Carolina "will be eligible to submit proposals for the power and associated renewable energy certificates, if they meet other criteria in the RFP," the company statement said.

Duke said that focusing on solar projects that can be completed and brought online by the end of 2015 will allow for "for full utilization of the North Carolina state energy tax credit and the federal Investment Tax Credit," both of which significantly reduce the ultimate capital cost of the projects.

PowerAdvocate, a "web-based platform" for managing RFPs, will administer this solicitation for DEC and DEP. "You must be registered as a supplier in PowerAdvocate to gain access to the RFP and response packages," Duke told potential bidders in a second statement. "Once registration has been accepted by PowerAdvocate, please share your interest in reviewing the RFP via an email to DECRenewableRFP@duke-energy.com."

DEC and DEP said in the solicitation that they expect to select a short list of finalists by April 30; to complete negotiations with turnkey-contract and PPA winners by August 1; and submit turnkey proposals to the North Carolina Utilities Commission for regulatory review by October 1.

— *Housley Carr*

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McGRAW HILL FINANCIAL

MEGAWATT DAILY

Volume 19 / Issue 32 / Tuesday, February 18, 2014

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

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Weekly bilateral indexes for week ending Feb 15 ($/MWh)

	Index	Change	Low	High
Northeast On-peak				
Mass Hub	190.55	23.85	149.00	232.75
N.Y. Zone-G	190.40	68.00	110.00	221.50
N.Y. Zone-J	192.30	66.90	110.75	223.75
N.Y. Zone-A	108.80	30.70	63.50	141.00
Ontario*	90.70	25.90	50.75	120.25
PJM On-peak				
PJM West	111.60	24.80	53.00	169.75
Dominion Hub	114.00	26.45	56.00	171.25
AD Hub	91.50	11.30	50.75	130.25
NI Hub	88.45	9.90	48.25	129.00
MISO On-peak				
Indiana Hub	86.15	4.65	49.75	129.00
Michigan Hub	90.10	6.85	54.00	131.50
Minnesota Hub	65.80	2.50	36.75	98.25
Illinois Hub	78.40	5.85	50.50	111.00
Southeast On-peak				
VACAR	74.10	14.80	49.00	104.00
Southern, Into	62.90	10.95	47.50	82.00
Florida	57.20	11.35	46.75	67.25
TVA, Into	68.10	8.70	48.00	89.00
Entergy, Into	66.30	5.35	50.50	82.25
ERCOT On-peak				
ERCOT, North	70.94	-15.30	39.75	100.00
ERCOT, Houston	68.60	-13.95	39.25	97.00
ERCOT, South	67.00	-16.40	38.00	93.50
ERCOT, West	70.85	-16.90	40.00	100.00
SPP/MRO On-peak				
MAPP, South	74.35	6.70	49.75	98.50
SPP, North	71.80	5.90	49.00	92.50
Western On-peak				
COB	55.32	-77.68	49.50	70.25
Mid-C	52.72	-90.41	44.50	78.00
Palo Verde	54.00	-41.15	49.25	62.00
Mead	56.84	-53.18	51.25	64.00
Mona	54.83	-51.84	49.00	67.00
Four Corners	53.29	-53.09	42.25	63.00
NP15	63.17	-40.54	52.00	73.00
SP15	63.33	-40.46	53.00	73.25

	Index	Change	Low	High
Northeast Off-Peak				
Mass Hub	150.00	35.55	105.50	184.00
N.Y. Zone-G	114.50	39.90	67.25	133.00
N.Y. Zone-J	115.60	39.20	68.00	134.25
N.Y. Zone-A	77.35	21.55	41.00	101.50
Ontario*	53.45	14.90	32.75	64.75
PJM Off-Peak				
PJM West	88.05	32.60	47.25	154.00
Dominion Hub	90.50	34.20	50.00	158.00
AD Hub	71.20	20.60	45.00	121.00
NI Hub	63.50	19.30	39.00	110.00
MISO Off-Peak				
Indiana Hub	65.80	17.90	44.25	91.00
Michigan Hub	68.55	19.15	47.75	93.00
Minnesota Hub	40.25	10.70	26.25	56.00
Illinois Hub	53.20	13.90	35.00	74.50
Southeast Off-Peak				
VACAR	56.92	11.71	45.00	85.00
Southern, Into	49.63	7.30	42.00	61.00
Florida	46.42	12.17	44.50	51.00
TVA, Into	51.42	7.96	43.00	68.50
Entergy, Into	60.29	14.91	52.00	73.25
ERCOT Off-Peak				
ERCOT, North	47.88	-1.29	29.00	69.50
ERCOT, Houston	46.96	-1.42	29.00	68.00
ERCOT, South	47.33	-1.21	28.75	69.25
ERCOT, West	48.29	-1.09	29.25	70.00
SPP/MRO Off-Peak				
MAPP, South	50.96	11.42	30.75	61.00
SPP, North	52.83	12.00	33.25	61.50
Western Off-Peak				
COB	51.84	-52.10	40.00	67.25
Mid-C	50.14	-65.16	37.00	75.00
Palo Verde	45.64	-23.25	38.00	52.00
Mead	49.36	-20.10	42.00	57.00
Mona	46.50	-27.71	35.00	59.00
Four Corners	40.86	-34.25	33.00	50.50
NP15	53.79	-24.10	47.50	61.00
SP15	54.14	-20.36	47.50	62.00

*Ontario prices are in Canadian dollars

Weekend bilateral indexes for Feb 15-16 ($/MWh)

	Saturday Index	Sunday Index
Northeast On-peak		
Mass Hub	172.50	172.50
N.Y. Zone-G	101.25	101.25
N.Y. Zone-J	102.25	102.25
N.Y. Zone-A	73.00	73.00
Ontario*	60.50	60.50
PJM On-peak		
PJM West	61.50	61.50
Dominion Hub	62.00	62.00
AD Hub	51.50	51.50
NI Hub	46.00	46.00
MISO On-peak		
Indiana Hub	49.25	49.25
Michigan Hub	53.50	53.50
Minnesota Hub	36.75	36.75
Illinois Hub	47.50	47.50
Southeast On-peak		
VACAR	50.00	50.00
Southern, Into	46.00	46.00
Florida	45.25	45.25
TVA, Into	46.75	46.75
Entergy, Into	48.50	48.50

	Saturday Index	Sunday Index
Northeast Off-Peak		
Mass Hub	122.25	122.25
N.Y. Zone-G	78.25	78.25
N.Y. Zone-J	78.75	78.75
N.Y. Zone-A	60.25	60.25
Ontario*	48.50	48.50
PJM Off-Peak		
PJM West	46.00	46.00
Dominion Hub	46.50	46.50
AD Hub	43.00	43.00
NI Hub	38.00	38.00
MISO Off-Peak		
Indiana Hub	38.50	38.50
Michigan Hub	42.00	42.00
Minnesota Hub	28.25	28.25
Illinois Hub	29.25	29.25
Southeast Off-Peak		
VACAR	42.00	42.00
Southern, Into	41.50	41.50
Florida	40.75	40.75
TVA, Into	40.75	40.75
Entergy, Into	47.50	47.50

	Saturday Index	Sunday Index
ERCOT On-peak		
ERCOT, North	40.75	40.75
ERCOT, Houston	41.00	41.00
ERCOT, South	40.00	40.00
ERCOT, West	41.00	41.00
SPP/MRO On-peak		
MAPP, South	44.00	44.00
SPP, North	40.00	40.00
Western On-peak		
COB	45.55	N.A.
Mid-C	43.61	N.A.
Palo Verde	45.53	N.A.
Mead	48.34	N.A.
Mona	39.50	N.A.
Four Corners	42.25	N.A.
NP15	52.00	N.A.
SP15	53.00	N.A.

*Ontario prices are in Canadian dollars

	Saturday Index	Sunday Index
ERCOT Off-Peak		
ERCOT, North	27.50	27.50
ERCOT, Houston	27.50	27.50
ERCOT, South	27.25	27.25
ERCOT, West	27.75	27.75
SPP/MRO Off-Peak		
MAPP, South	31.00	31.00
SPP, North	32.75	32.75
Western Off-Peak		
COB	41.60	41.60
Mid-C	40.06	40.06
Palo Verde	38.00	38.00
Mead	42.25	42.25
Mona	35.00	35.00
Four Corners	33.00	33.00
NP15	47.50	47.50
SP15	48.00	48.00

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