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Tuesday, September 17, 2013

Better residential load control can aid peak savings

ANALYSIS The peak demand savings available from the residential market seem small when viewed on a per-customer basis, but the large scale of some load-control programs and the size of residential load during peak demand periods can produce sizeable demand reductions.

The number of customers enrolled in these programs can vary dramatically, based on the incentives or rewards for doing so — usually some type of monthly or annual credit — but peak demand savings of more than 100 MW are routine for the largest programs in the country. A few programs with more than 300,000 customers enrolled, at Southern California Edison, Florida Power & Light and Progress Energy Florida, are capable of reducing peak demand by 500 MW or more, though savings below 100 MW are more common for typical utility programs.

(continued on page 16)

Xcel Energy unit 'cautiously optimistic' about EIM

MARKETS Public Service Co. of Colorado, an Xcel Energy utility, is "cautiously optimistic" about the energy imbalance market proposed by the California Independent System Operator and PacifiCorp, a utility official said Monday.

However, PSCo will wait until the ISO and PacifiCorp settle on a final market design before deciding if the utility will participate in the EIM, David Lemmons, PSCo senior manager for market operations, said during a meeting held by the PUC EIM Group, which is made up of state utility commissioners from the West. The group has been studying a possible EIM in the West.

There are still issues to be worked out, such as how market congestion will be handled in an EIM, Lemmons said. But the process is "moving in the right direction," he said.

(continued on page 17)

Third party clearing of FTRs eyed in ISO-NE

FINANCIAL TRANSMISSION RIGHTS After more than a year of subcommittee discussions, ISO New England is moving forward with a proposal to implement third-party clearing of financial transmission rights, a change that it says would enable it to begin offering long-term and balance of planning period FTRs.

FTRs are financial settled instruments used by market participants to hedge the costs of transmission between two points on the grid. FTRs are awarded by independent system operators through auctions, but since May 2012 ISO-NE and Nodal Exchange have been exploring the benefits of using an independent third party for clearing.

ISO-NE's proposal to implement third-party clearing of FTRs was recommended by the New England Power Pool's Budget and

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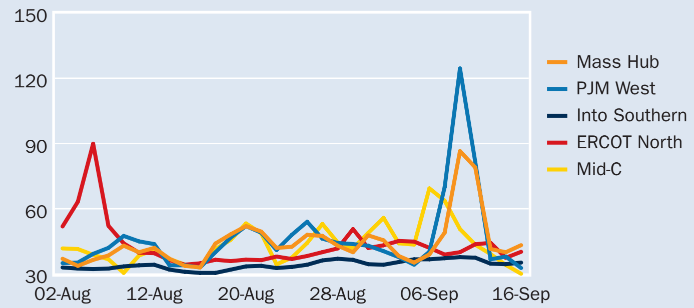
Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Sep 17 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	32.97	44.66	19.21	34.43
NYISO	29.08	50.17	21.26	34.45
PJM	28.09	55.19	18.66	26.92
MISO	28.23	30.86	13.52	23.69
ERCOT	41.35	76.35	27.73	28.24
CAISO	40.99	44.97	31.95	33.65

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 17

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	43.25	10908	15.50	11.53	3.60	-4.33	-16.23
N.Y. Zone-A	30.50	8433	5.18	1.57	-5.67	-12.90	-23.75
PJM/MISO							
PJM West	32.75	9273	8.03	4.50	-2.57	-9.63	-20.23
Indiana Hub	31.00	8278	4.79	1.04	-6.45	-13.94	-25.18
Southeast & Central							
Southern, Into	35.25	9592	9.53	5.85	-1.50	-8.85	-19.88
ERCOT, North	40.20	11097	14.84	11.22	3.98	-3.27	-14.14
West							
Mid-C	30.11	8830	6.24	2.83	-3.99	-10.81	-21.04
SP15	44.25	11769	17.93	14.17	6.65	-0.87	-12.15

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

- New lines, substations needed in west Texas: study 11
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NORTHEAST MARKETS

Dailies strengthen on spot gas gains

Daily power prices in the Northeast strengthened Monday, with increasing spot natural gas prices pushing power prices higher. Forward prices were higher as the NYMEX October natural gas contract settled at $3.738/MMBtu, up 6.1 cents.

ISO New England forecasted peak load on Monday at 16,060 MW and 15,730 MW for Tuesday. High temperatures in Boston are expected in the upper 50s on Tuesday.

Algonquin city-gates spot natural gas jumped about 51 cents to around $4.13/MMBtu and Transco Zone 6 New York gained about 7 cents to about $3.80/MMBtu.

Mass Hub on-peak for Tuesday delivery rose about $3 to the low $40s/MWh and off-peak held steady in the mid-$20s/MWh.

The New York ISO forecasted peak load for Monday around 20,200 MW and 18,867 MW on Tuesday. High temperatures in New York state are forecast in the low to mid-60s on Tuesday.

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

Day-ahead auction prices in ISO-NE were down Monday, with lower load projected for Tuesday. Internal Hub on-peak lost $4.49 going to $41.18/MWh and Mained on-peak tumbled $9.23 to $32.97/MWh. Vermont on-peak gave up $4.35 to $40.49/MWh. Connecticut on-peak was down $4.22 to $41.09/MWh and NE-Mass Boston lost $4.57 to $41.65/MWh. Rhode Island on-peak slipped 54 cents to $44.66/MWh.

Day-ahead auction prices in NYISO moved down Monday with lower loads expected with the mild weather. New York City on-peak lost about $2.92 going to $41.30/MWh and Long Island on-peak eased $2.28 moving to $50.17/MWh. West zone on-peak was down $4.51 to $30.20/MWh and Hudson Valley on-peak gave up $3.77 moving to $39.62/MWh. North zone on-peak fell $5.02 to $29.08/MWh.

Northeast term power prices moved up Monday with natural gas futures. Mass Hub on-peak October financial futures rose 75 cents, with bids at $41/MWh and offers at $41.75/MWh at about 2:30 p.m. EDT on the IntercontinentalExchange. Mass Hub on-peak fourth-quarter rose 35 cents to about $55.35/MWh. PJM West on-peak January-February 2014 financial futures were unchanged at about $97/MWh on ICE.

New York Zone A on-peak October financial futures were unchanged, with bids at $37/MWh and offers at $38.50/MWh on ICE. New York Zone A on-peak October financial futures rose 25 cents, with bids at $43/MWh and offers at $47/MWh on ICE.

Daily generation outage references

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

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

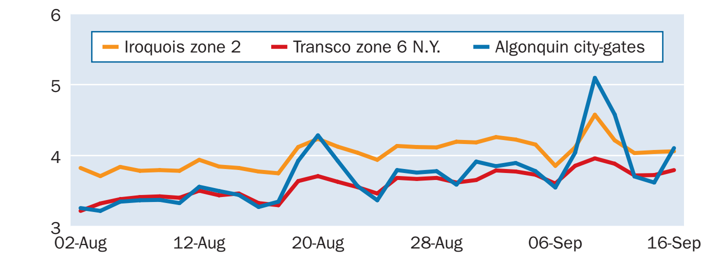
Sources: Generation owners, public information and other market sources.

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

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	43.25	3.25	49.55	10908
N.Y. Zone-G	39.75	-3.75	52.45	10121
N.Y. Zone-J	41.50	-4.00	54.05	10567
N.Y. Zone-A	30.50	-5.50	42.20	8433
Ontario*	25.00	-5.50	36.64	6006
Off-Peak				
Mass Hub	26.50	0.00	29.52	6683
N.Y. Zone-G	24.75	-6.75	30.59	6302
N.Y. Zone-J	25.00	-7.00	30.59	6365
N.Y. Zone-A	23.00	-3.00	27.48	6359
Ontario*	18.50	-2.50	21.98	4445

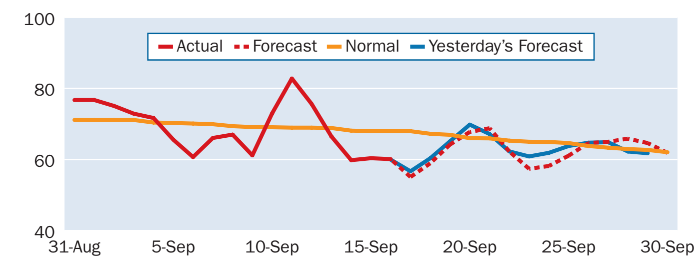
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO average temperature (°F)



Source: Custom Weather

Northeast load and generation mix forecast (GWh)

	Actual 15-Sep	%Chg	% Chg Year-ago	Forecast 16-Sep	17-Sep	18-Sep	19-Sep	20-Sep
ISONE								
Load	297	-6	2	326	330	341	352	354
Generation								
Coal	5	-44	77	9	9	12	13	13
Gas	132	2	-13	136	141	151	154	148
Nuclear	95	0	-4	102	107	107	107	107
NYISO								
Load	374	-2	-1	430	408	400	421	432
Generation								
Coal	5	-23	63	13	16	17	15	13
Gas	131	1	-6	146	141	141	143	147
Nuclear	135	1	6	135	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Sep 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	41.18	0.19	0.24	-4.48	53.95	10683
Connecticut	41.09	0.19	0.16	-4.23	47.43	10642
NE Mass-Boston	41.65	0.19	0.72	-4.57	47.63	10806
SE Mass	41.39	0.95	-0.30	-4.32	47.85	10739
West-Central Mass	41.23	0.19	0.30	-4.47	49.01	10697
Rhode Island	44.66	4.17	-0.25	-0.54	46.95	11588
Maine	32.97	-5.85	-1.93	-9.24	44.40	8135
New Hampshire	40.37	0.04	-0.41	-4.40	47.40	9960
Vermont	40.49	0.08	-0.33	-4.36	47.98	9990
Off-Peak						
Internal Hub	33.52	0.98	0.22	7.01	29.74	9481
Connecticut	33.06	0.63	0.11	8.69	29.51	8885
NE Mass-Boston	33.99	1.26	0.41	5.63	29.91	9614
SE Mass	33.92	1.42	0.19	4.37	30.19	9594
West-Central Mass	33.49	0.94	0.23	7.20	29.81	9473
Rhode Island	34.43	2.08	0.03	-0.10	31.31	9739
Maine	19.21	-11.35	-1.76	-6.23	26.62	4787
New Hampshire	32.96	1.11	-0.47	6.38	29.24	8216
Vermont	32.56	0.63	-0.38	8.48	29.21	8117

NYISO day-ahead LMP for Sep 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	40.46	-7.99	2.03	-3.18	45.18	10570
Central Zone	31.14	-0.45	0.24	-5.06	41.60	8636
Dunwoodie Zone	40.07	-6.13	3.50	-3.77	48.99	10214
Genesee Zone	30.40	-0.35	-0.40	-5.05	40.10	8429
Hudson Valley Zone	39.62	-6.00	3.18	-3.77	48.42	10101
Long Island Zone	50.17	-15.75	3.98	-2.28	57.80	12791
Millwood Zone	39.99	-6.19	3.36	-3.75	49.00	10195
Mohawk Valley Zone	31.96	-0.51	1.01	-5.21	41.92	8610
N.Y.C. Zone	41.30	-7.00	3.85	-2.92	49.99	10528
North Zone	29.08	0.00	-1.37	-5.01	33.42	7174
West Zone	30.20	-0.47	-0.71	-4.51	39.68	8376
Off-Peak						
Capital Zone	24.01	-0.30	1.42	-2.82	29.24	6360
Central Zone	22.66	-0.02	0.35	-0.15	27.28	6414
Dunwoodie Zone	24.49	-0.23	1.97	-2.30	29.82	6292
Genesee Zone	22.47	-0.01	0.17	-0.04	26.87	6361
Hudson Valley Zone	24.42	-0.22	1.91	-2.20	29.83	6274
Long Island Zone	34.45	-9.84	2.32	4.78	34.00	8850
Millwood Zone	24.40	-0.23	1.89	-2.33	29.79	6269
Mohawk Valley Zone	22.86	-0.02	0.55	-0.25	27.50	6285
N.Y.C. Zone	24.72	-0.23	2.20	-2.33	30.22	6350
North Zone	21.26	0.00	-1.03	-0.39	24.65	5299
West Zone	22.82	-0.02	0.52	0.23	26.96	6461

Generation unit outage report

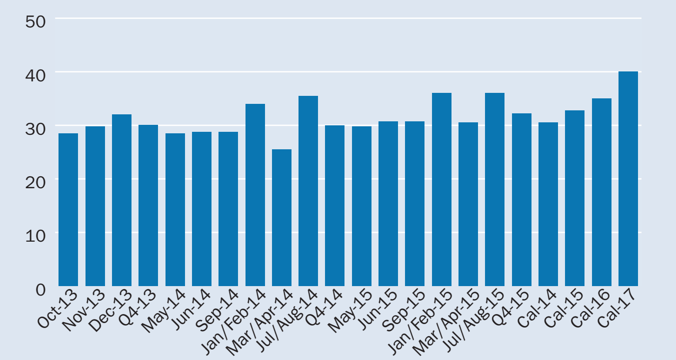
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	200	c	Ont.	PMO	Unk	09/11/12
Bruce-3/Bruce Power	750	n	Ont.	Unk	Unk	09/13/13
Darlington-2/OPG	868	n	Ont.	PMO	Unk	08/27/13
DeCew Falls/OPG	167	h	Ont.	Unk	Unk	08/22/13
Greenwich/Enbridge	99	w	Ont.	Unk	Unk	09/13/13
Lambton-3/OPG	326	c	Ont.	Unk	Unk	09/06/13
Lennox-3/OPG	525	bio	Ont.	Unk	Unk	09/05/13
Nanticoke-6/Brookfield	292	c	Ont.	Unk	Unk	09/05/13
Peach Bottom-3/Exelon	1182	n	Pa.	PMO	Unk	09/09/13
Pickering-6/OPG	510	n	Ont.	Unk	Unk	09/03/13
Portlands-1/PEC	197	g	Ont.	Unk	Unk	09/08/13
Portlands-2/PEC	197	g	Ont.	Unk	Unk	09/08/13
Portlands-3/PEC	245	g	Ont.	Unk	Unk	09/08/13
Susquehanna-2/PPL	1330	n	Penn.	MO	Unk	09/14/13
Taohsc/TransAlta	78	g	Ont.	Unk	Unk	09/03/13
Thunderbay-2/OPG	150	c	Ont.	PMO	Unk	03/01/13

Northeast Platts-ICE Forward Curve, Sep 16 ($/MWh)

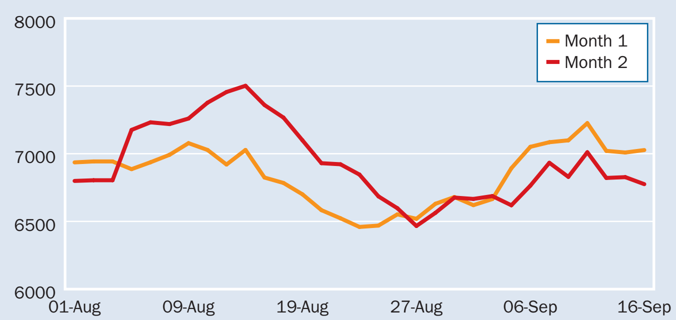
Prompt month: Oct 13	On-peak	Off-peak
Mass Hub	41.50	32.00
N.Y. Zone G	45.00	35.00
N.Y. Zone J	47.25	36.50
N.Y. Zone A	38.00	31.75
Ontario*	28.50	18.75

*Ontario prices are in Canadian dollars

Ontario*: Forward curve on-peak ($/MWh)



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



Northeast near-term bilateral markets ($/MWh)

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

*Ontario prices are in Canadian dollars.

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 MARKETS

ERCOT dailies rise, along with most term prices

Power for Tuesday delivery in the Electric Reliability Council of Texas was priced higher on the IntercontinentalExchange Monday, with peak load expected to be steady and spot natural gas prices higher. Forward prices in the South and Southeast were flat to a bit higher as the NYMEX October natural gas contract settled at $3.738/MMBtu, up 6.1 cents.

Electric Reliability Council of Texas dailies for Tuesday delivery were firmer on the IntercontinentalExchange Monday morning with peak load forecast steady.

Spot natural gas at Houston Ship Channel added 9 cents to trade around $3.700/MMBtu.

ERCOT North Hub next-day on-peak physical power rose about $2.75 to trade around $40.25/MWh. Off-peak gained about $1.25 to trade around $26/MWh.

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

System load in ERCOT was forecast to peak at 59,775 MW Monday and 59,650 MW Tuesday, compared with an actual peak of 54,025 MW Sunday.

Real-time prices averaged $25.25/MWh and were flat from 12:15 a.m. to 6 a.m. CDT Friday. Wind generation was forecast to peak at 3,875 MW at 1 a.m. CDT Monday and 3,875 MW at midnight CDT Tuesday.

North Hub balance-of-the-week packages were bid at $37.50 and offered at $38.50/MWh. Next-week on-peak packages were bid at $36.25 and offered at $37/MWh.

In the Southeast, dailies for Tuesday delivery were stronger Monday morning with temperatures forecast decreasing. Into Southern next-day on-peak power was bid at $35 and offered at $36/MWh, a gain of $1 from Friday prices.

Spot natural gas at Transco Zone-3 added 5.9 cents to trade around $3.665/MMBtu. High temperatures in Atlanta were forecast in the los 80s Tuesday, with lows expected in the upper 60s. The average September high temperature in Atlanta is 82; the

(continued on page 10)

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

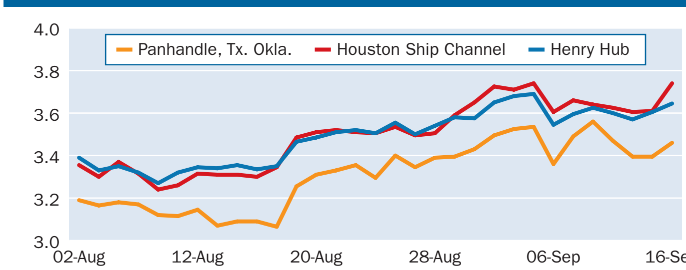
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	34.75	-0.75	39.82	9169
Southern, Into	35.25	0.75	35.89	9592
Florida	38.00	0.75	38.11	10270
TVA, Into	34.25	0.25	36.89	9182
Entergy, Into	36.00	0.50	35.02	9952
Southeast Off-Peak				
VACAR	24.00	1.50	23.32	6332
Southern, Into	24.75	2.75	22.74	6735
Florida	27.25	1.50	26.46	7365
TVA, Into	24.00	2.50	22.62	6434
Entergy, Into	22.75	2.75	20.60	6289
ERCOT On-peak				
ERCOT, North	40.20	2.75	41.99	11097
ERCOT, Houston	41.00	2.25	42.55	10977
ERCOT, South	40.25	3.00	41.95	11111
ERCOT, West	40.75	1.75	43.61	11265
ERCOT Off-Peak				
ERCOT, North	25.83	1.08	24.76	7130
ERCOT, Houston	26.25	0.75	25.06	7028
ERCOT, South	25.75	1.25	24.69	7108
ERCOT, West	25.75	1.00	24.76	7118
SPP/MRO On-peak				
MAPP, South	36.75	2.75	38.34	9866
SPP, North	35.00	1.75	37.64	10116
SPP/MRO Off-Peak				
MAPP, South	24.25	2.25	22.18	6510
SPP, North	23.00	2.00	21.72	6647

Southeast load and generation mix forecast (GWh)

	Actual 15-Sep	%Chg	% Chg Year-ago	Forecast 16-Sep	17-Sep	18-Sep	19-Sep	20-Sep
ERCOT								
Load	1029	-2	0	1025	1062	1111	1116	1070
Generation								
Coal	404	-3	12	402	424	437	439	433
Gas	462	-1	-9	460	461	474	476	461
Nuclear	119	0	-2	119	119	119	119	119
SPP								
Load	617	3	-5	629	665	737	775	718
Generation								
Coal	377	4	4	378	398	425	442	418
Gas	176	3	-23	171	179	202	217	199
Nuclear	19	0	-3	19	20	25	33	41

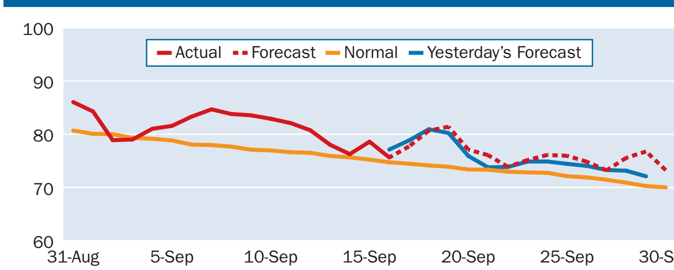
Source: Bentek

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



Source: Platts

ERCOT & SPP average temperature (°F)



Source: Custom Weather

ERCOT average day-ahead LMP for Sep 17 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	41.55	3.89	41.17	11424
Hub Average	41.60	3.84	41.44	11438
Houston Hub	41.91	3.96	41.28	11271
North Hub	41.43	3.94	40.90	11468
South Hub	41.71	3.88	40.92	11537
West Hub	41.35	3.57	42.69	11481
AEN Zone	42.19	3.78	41.76	11715
CPS Zone	43.04	4.12	41.42	11910
LCRA Zone	42.22	3.88	41.57	11685
Rayburn Zone	41.35	3.97	40.97	11446
Houston Zone	42.08	3.97	41.53	11317
North Zone	41.71	4.01	41.15	11546
South Zone	42.37	4.18	41.63	11721
West Zone	76.35	13.57	60.76	21200
Off-Peak				
Bus Average	27.76	2.28	25.42	7779
Hub Average	27.77	2.28	25.42	7783
Houston Hub	27.77	2.28	25.42	7641
North Hub	27.74	2.27	25.42	7783
South Hub	27.75	2.26	25.42	7788
West Hub	27.81	2.32	25.43	7925
AEN Zone	27.73	2.24	25.44	7901
CPS Zone	27.92	2.32	25.48	7853
LCRA Zone	27.77	2.26	25.43	7811
Rayburn Zone	27.74	2.27	25.42	7783
Houston Zone	27.77	2.28	25.42	7641
North Zone	27.74	2.27	25.42	7783
South Zone	27.78	2.28	25.43	7795
West Zone	28.24	2.66	26.02	8047

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

Package	Trade date	Range
Southern, Into		
Bal-week	09/16	35.50-36.00
Bal-week	09/11	36.00-36.50
Bal-week	09/10	37.50-38.00
Bal-month	09/16	34.50-35.00
Bal-month	09/11	35.50-36.00
Bal-month	09/10	36.00-36.50
Next-week	09/16	34.50-35.00
Next-week	09/11	34.50-35.00
Next-week	09/10	38.00-38.50
ERCOT, North		
Next-week	09/11	36.25-36.75

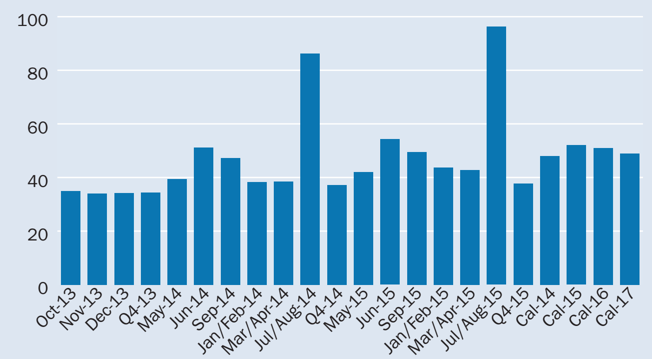
Additional information on data and analysis:

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.

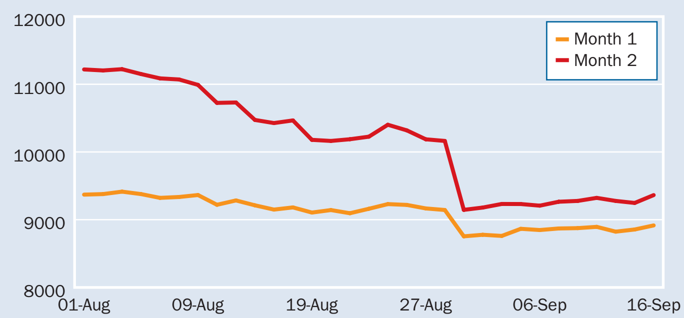
Southeast & Central Platts-ICE Forward Curve, Sep 16 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
Southern Into	33.00	28.50
Entergy Into	31.50	26.00
ERCOT North	35.00	26.00
ERCOT Houston	37.50	27.00
ERCOT West	34.75	25.00
ERCOT South	36.00	25.75

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



ERCOT North: 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
Catawba-2/Duke	1305	n	S.C.	PMO	Unk	09/16/13
Crystal River-3/Progress	838	n	Fla.	NA	Retired	09/26/09
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Hatch-2/Southern Nuclear	921	n	Ga.	MO	Unk	09/15/13
Monticello-1/Luminant	565	c	Texas	MO	Unk	09/08/13
Monticello-2/Luminant	565	c	Texas	MO	Unk	08/25/13
North Anna-1/Dominion	990	n	Va.	PMO	Unk	09/08/13
Robinson-2/Duke	805	n	S.C.	RF	Unk	09/14/13
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13
Wolf Creek/Wolf Creek	1235	n	Kan.	MO	Unk	09/12/13

WEST MARKETS

West dailies down; terms steady to lower

Most western dailies were down Monday morning with lower demand expected in California on Tuesday and the move back to off-peak prices without on-peak hours. Forwards were steady to lower. The NYMEX October natural gas contract posted a preliminary settlement Monday of $3.738/MMBtu, up 6.1 cents, on supportive weather forecasts and the potential for a smaller-than-average storage injection to be reported on Thursday.

In the Northwest, Mid-Columbia day-ahead on-peak lost more than $4 to trade between $29 and $31.25/MWh for delivery on Tuesday. Mid-C day-ahead off-peak fell more than $1.75 to trade between $25.50 and $28.25/MW. The Mid-C on-peak balance-of-the-month package was bid at $30.25 and offered at $33.50/MWh, down more than $2.50.

Portland, Oregon's forecasts had highs from in the upper 60s through Wedenesday. Expected lows were from high 50s to 60.

The Bonneville Power Administration's wind output was 3,467 MW and its hydro output was 5,525 MW at 7 a.m. PDT on Monday.

In California, SP15 next-day on-peak was down more than $4.75 to trade between $43.75 and $44.25/MWh. SP15 day-ahead off-peak shed $6.50 to about $32.75/MWh. SP15 bal-month was bid at $44 and offered at $48/MWh, down around $1.50.

NP15 day-ahead on-peak declined $3.50 to about $41.75/MWh. NP15 day-ahead off-peak slipped $3.75 to about $33.25/MWh. NP15 bal-month was bid at $44 and offered at $48/MWh, down around $1.50.

Sacramento, California, expected highs from 80 to 85 and lows in the high 60s. Forecast highs for Burbank were in the upper 80s on Tuesday, down about 10 degrees, with anticipated lows in the low 60s.

The California Independent System Operator projected peak demand to be 39,058 MW on Monday, and 34,120 MW on Tuesday. Renewables were 2,379 MW and wind was less than 700 MW at 7 a.m. PDT on Monday.

In the desert Southwest, Palo Verde next-day on-peak was up slightly, trading between $33.75 and $37/MWh. Palo Verde day-ahead off-peak dropped more than $5.25 to trade between $25.35 and $24.75/MWh on the IntercontinentalExchange.

Phoenix expected highs from 101 to 103, up a few degrees, and lows in the low 80s. Next-day natural gas prices rose in the Rockies and California. Opal climbed 12.5 cents to $3.555/MMBtu, PG&E city-gate added 4.4 cents to $4.014/MMBtu, and SoCal city-gate was up 7.3 cents to $3.863/MMBtu.

Most day-ahead prices were down in the California ISO auction Monday afternoon following the lower peak demand forecast. SP15 on-peak fell $2.30 to $44.97/MWh as SP15 off-peak dropped 23 cents to $32.81/MWh. NP15 on-peak lost $1.73 to $42.70/MWh and NP15 off-peak was up 4 cents to $33.65/MWh. ZP26 on-peak slid 24 cents to $40.99 while ZP26 off-peak shed 4 cents to $31.95/MWh.

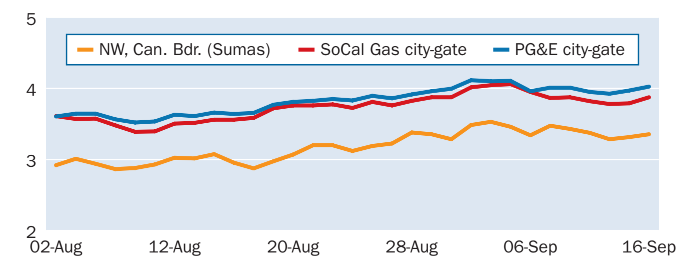
Western US on-peak October terms were steady to down Monday, even as October natural gas futures rose in late trading. In the Northwest, Mid-Columbia on-peak October subtracted 50

(continued on page 10)

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

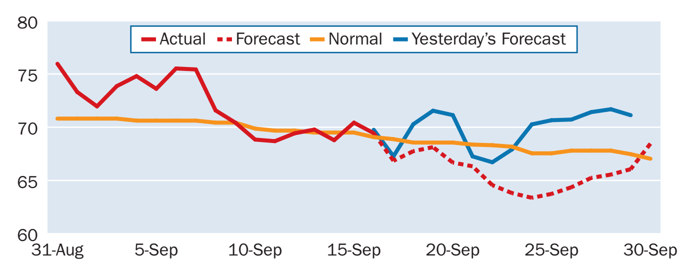
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	34.67	-1.71	50.40	9604
Mid-C	30.11	-4.05	46.59	8830
Palo Verde	35.04	-2.20	39.24	9528
Mead	36.25	-2.50	43.64	9641
Mona	30.50	-2.75	45.63	8777
Four Corners	34.50	-6.25	42.04	9597
NP15	42.00	-3.25	49.06	10435
SP15	44.25	-4.50	54.08	11769
Off-Peak				
COB	27.63	-2.37	33.58	7654
Mid-C	26.88	-2.00	32.08	7883
Palo Verde	25.25	-5.25	28.71	6866
Mead	25.50	-5.50	30.10	6782
Mona	19.97	-6.03	27.17	5747
Four Corners	25.25	-4.75	28.51	7024
NP15	33.50	-3.50	36.65	8323
SP15	32.75	-6.50	38.76	8710

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO average temperature (°F)



Source: Custom Weather

Western load and generation mix forecast (GWh)

	Actual 15-Sep	%Chg	% Chg Year-ago	Forecast 16-Sep	17-Sep	18-Sep	19-Sep	20-Sep
CAISO								
Load	674	-3	1	727	725	720	718	713
Generation								
Gas	318	3	2	314	301	294	292	285
Nuclear	56	0	-7	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Sep 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	42.70	-0.06	-2.19	-1.73	46.92	10609
SP15 Gen Hub	44.97	0.48	-0.46	-2.30	52.01	11945
ZP26 Gen Hub	40.99	-0.92	-3.05	-0.24	46.03	10887
Off-Peak						
NP15 Gen Hub	33.65	0.37	-0.44	0.04	35.05	8448
SP15 Gen Hub	32.81	-0.18	-0.73	-0.23	35.65	8928
ZP26 Gen Hub	31.95	-0.19	-1.58	-0.05	33.64	8695

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	09/13	34.00-35.00
Bal-month	09/11	37.50-39.00
Bal-month	09/10	40.75-41.25
SP15		
Bal-month	09/16	44.75-45.25
Bal-month	09/12	48.00-49.00
Bal-month	09/11	48.75-49.25

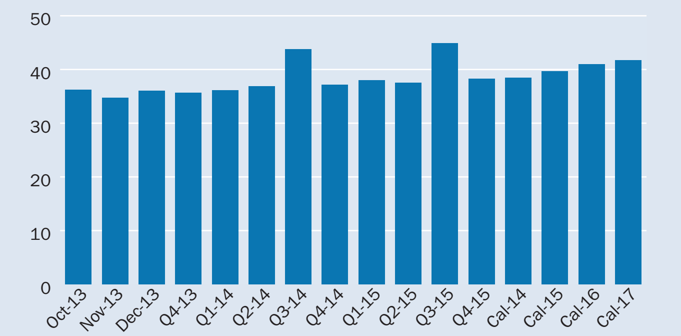
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Contra Costa-6/NRG	337	g	Calif.	PMO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
Des Sunlight/NextEra	250	s	Calif.	MO	Unk	09/08/13
El Segundo-3/NRG	335	g	Calif.	MO	Unk	07/23/13
Huntington Beach-3/AES	225	g	Calif.	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif.	PMO	Unk	04/14/13
Mexicali/Sempra	180	g	Calif.	PMO	Unk	07/22/13
Moss Landing-2/Dynegy	510	g	Calif.	PMO	Unk	09/15/13
Pine Flat/USACE	210	h	Calif.	PMO	Unk	08/11/13

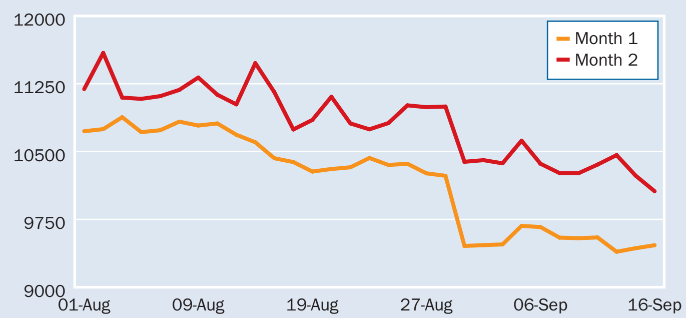
Western Platts-ICE Forward Curve, Sep 16 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
Mid-C	34.00	28.75
Palo Verde	36.25	27.25
Mead	38.25	29.25
NP15	43.00	37.25
SP15	46.25	37.25

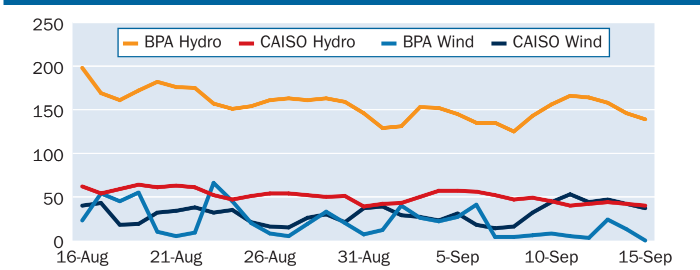
Palo Verde: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

PJM dailies drop on lower expected demand

Daily prices in PJM Interconnection and the Midwest were down Monday, with weaker demand expected on Tuesday. Forward prices were flat to lower as the NYMEX October natural gas contract settled at $3.738/MMBtu, up 6.1 cents.

PJM Interconnection forecasted peak demand on Monday at 95,312 MW and 92,293 MW for Tuesday. High temperatures in the PJM footprint are predicted in the mid-60s to low 70s on Tuesday.

Spot natural gas in the region edged up with Texas Eastern M-3 gaining about 9 cents going to around $3.66/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Tuesday fell about $2.75 to the low $30s/MWh and off-peak dipped about $2 going to the low $20s/MWh.

Midcontinent ISO dailies were mostly weaker with mild weather in the outlook. Chicago city-gates spot gas gained about 11 cents to about $3.80/MMBtu.

Indiana Hub on-peak for Tuesday shed about $1 in the low $30s/MWh and off-peak gained about $2 in the low $20s/MWh. Minnesota Hub on-peak dropped about $5 going to the upper $20s/MWh.

Dailies in the Midwestern portion of PJM moved down with nearby power markets weakness. AEP-Dayton Hub on-peak for Tuesday lost about $2.75 going to the low $30s/MWh and off-peak gave up about $1 going to the low $20s/MWh. Northern Illinois Hub on-peak for Tuesday fell about $4 going to the upper $20s/MWh and off-peak was down about $2 to around $19/MWh.

Day-ahead auction prices in PJM Interconnection were mostly lower with weak demand and mild weather in the outlooks. Eastern Hub on-peak bucked the losing trend and moved up $3.18 to $55.19/MWh, while Western Hub on-peak fell 71 cents to $34.25/MWh. BG&E on-peak fell $2.17 to $35.92/MWh and Pepco on-peak lost $1.90 going to $36.10/MWh. JCPL on-peak gave up $2.01 to $35.57/MWh and PSEG on-peak decreased $3.21 to $36.34/MWh. Chicago Hub and ComEd on-peak both slipped 4 cents to $29.03/MWh and $28.99/MWh, respectively.

MISO day-ahead auction prices cleared weaker Monday. Illinois Hub moved into the highest-priced hub with on-peak clearing at $30.86/MWh, down $4.38. Off-peak cleared at $20.36/MWh, down 55 cents. Minnesota Hub on-peak cleared at $29.83/MWh, down $4.11. Off-peak cleared at $13.52/MWh, down $6.72. Michigan Hub on-peak cleared at $28.41/MWh, a drop of $4.97. Off-peak cleared at $23.69/MWh, an increase of 93 cents. Indiana Hub fell to the lowest priced hub with on-peak clearing at $28.23/MWh, losing $4.34. Off-peak cleared at $22.69/MWh, rising 25 cents.

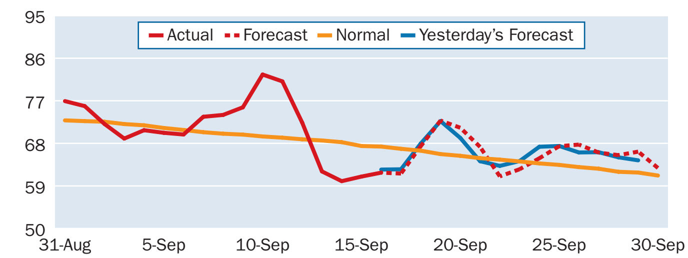
Congestion costs at the hubs ranged from 11 cents to $3.69 for on-peak, and from negative $4.30 to $4.85 for off-peak.

Mid-Atlantic forwards moved little Monday as October NYMEX natural gas futures rose. PJM West on-peak October financial futures were unchanged, with bids at $41.30/MWh and offers at $41.50/MWh at about 2:30 p.m. EDT on the IntercontinentalExchange. PJM West on-peak fourth-quarter

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

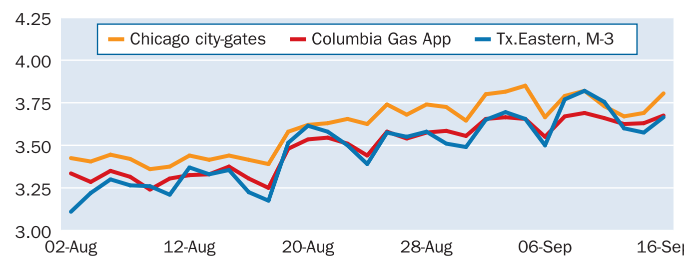
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	32.75	-5.25	52.66	9273
Dominion Hub	34.00	-7.25	59.39	9109
AD Hub	30.50	-2.75	42.80	8112
NI Hub	29.00	-3.25	43.45	7622
PJM Off-Peak				
PJM West	22.00	-2.25	26.14	6229
Dominion Hub	22.75	-2.75	29.07	6095
AD Hub	21.75	-1.00	24.39	5785
NI Hub	18.50	-2.75	22.41	4862
MISO On-peak				
Indiana Hub	31.00	-1.00	39.61	8278
Michigan Hub	31.75	-1.25	40.68	8120
Minnesota Hub	32.00	-2.50	39.68	8382
Illinois Hub	33.25	5.25	36.77	8733
MISO Off-Peak				
Indiana Hub	21.75	1.50	22.86	5808
Michigan Hub	22.00	1.25	23.59	5627
Minnesota Hub	19.25	1.75	20.91	5043
Illinois Hub	20.75	3.00	20.43	5450

PJM & MISO average temperature (°F)



Source: Custom Weather

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 15-Sep	%Chg	% Chg Year-ago	Forecast 16-Sep	17-Sep	18-Sep	19-Sep	20-Sep
PJM								
Load	1692	-2	0	1840	1925	1981	2105	2193
Generation								
Coal	753	-4	12	865	1010	1102	1128	1097
Gas	231	3	-19	233	237	253	289	326
Nuclear	686	0	2	687	691	706	731	757
MISO								
Load	1144	-2	-1	1319	1335	1417	1579	1508
Generation								
Coal	1010	-2	6	1135	1145	1167	1235	1195
Gas	41	33	-40	35	41	84	144	124
Nuclear	183	2	-11	187	188	190	194	198

Source: Bentek

MISO average day-ahead LMP for Sep 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	28.23	0.23	0.45	-4.34	36.09	7564
Michigan Hub	28.41	0.11	0.75	-4.97	36.80	7280
Minnesota Hub	29.83	3.52	-1.23	-4.11	37.72	7838
Illinois Hub	30.86	3.69	-0.37	-4.38	33.73	8138
Off-Peak						
Indiana Hub	22.69	4.13	0.28	0.25	22.29	6220
Michigan Hub	23.69	4.85	0.55	0.93	22.98	6141
Minnesota Hub	13.52	-4.30	-0.47	-6.72	19.16	3617
Illinois Hub	20.36	2.49	-0.42	-0.55	19.97	5501

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

Package	Trade date	Range
PJM West		
Bal-week	09/16	38.25-39.25
Bal-week	09/13	42.50-44.00
Bal-week	09/11	39.00-40.00
Bal-week	09/10	62.50-63.50
Next-week	09/16	39.50-40.50
Next-week	09/12	43.25-44.50
Next-week	09/11	43.50-44.50
Next-week	09/10	44.00-45.25

Generation unit outage report

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

PJM average day-ahead LMP for Sep 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	29.43	-1.46	-1.63	-0.64	36.34	7962
AEP-Dayton Hub	30.40	-1.35	-0.78	-0.54	38.12	8224
ATSI Gen Hub	31.80	-0.83	0.11	-0.26	40.26	8706
Chicago Gen Hub	28.09	-2.92	-1.52	-0.30	37.50	7410
Chicago Hub	29.03	-2.40	-1.11	-0.04	38.55	7657
Dominion Hub	35.50	2.80	0.18	-3.79	52.45	9527
Eastern Hub	55.19	21.22	1.44	3.18	53.12	14810
New Jersy Hub	35.96	2.15	1.29	-2.47	47.42	9651
Northern Illinios Hub	28.80	-2.44	-1.28	-0.07	38.17	7599
Ohio Hub	30.59	-1.33	-0.60	-0.53	38.48	8138
West Internal Hub	32.05	0.06	-0.53	-0.69	42.85	9105
Western Hub	34.25	1.39	0.34	-0.71	46.25	9729
AEP Zone	30.49	-1.30	-0.74	-0.50	38.15	8249
Allegheny Power Zone	32.11	0.13	-0.54	-0.97	42.13	8854
Atlantic Elec Zone	34.69	1.07	1.09	-1.36	46.13	9308
ATSI Zone	31.96	-0.84	0.28	-0.22	40.66	8749
BG&E Zone	35.92	2.08	1.31	-2.17	52.93	9903
ComEd Zone	28.99	-2.39	-1.14	-0.04	38.50	7648
Dayton P&L Zone	31.08	-1.20	-0.25	-0.49	38.81	8329
Delmarva P&L Zone	50.98	17.35	1.10	1.39	51.73	13679
Dominion Zone	35.23	2.35	0.35	-3.46	51.68	9453
Duke Zone	29.99	-1.27	-1.27	-0.59	37.60	8039
Duquesne Light Zone	30.25	-1.07	-1.21	-0.74	38.18	8545
JCPL Zone	35.57	1.74	1.30	-2.02	48.26	9546
MetEd Zone	34.04	1.31	0.20	-1.50	47.02	9182
PECO Zone	34.04	1.03	0.48	-1.33	45.01	9181
Pennsylvania Elec Zone	33.71	0.43	0.76	0.01	43.14	9575
PEPCO Zone	36.10	2.62	0.96	-1.90	52.52	9954
PPL Zone	34.08	1.15	0.40	-1.57	44.93	9191
PSEG Zone	36.34	2.45	1.36	-3.21	47.35	9753
Rockland Elec Zone	32.22	-1.77	1.46	-0.53	44.96	8646
Off-Peak						
AEP Gen Hub	23.10	0.16	-0.95	0.01	23.84	6369
AEP-Dayton Hub	23.69	0.33	-0.53	0.15	24.55	6532
ATSI Gen Hub	24.54	0.63	0.03	0.51	25.17	6817
Chicago Gen Hub	18.66	-3.98	-1.25	-0.29	20.81	5038
Chicago Hub	19.34	-3.54	-1.00	-0.28	21.38	5221
Dominion Hub	25.58	1.41	0.28	-0.13	28.75	6959
Eastern Hub	26.92	2.32	0.71	1.19	28.27	7353
New Jersy Hub	25.85	1.14	0.82	-0.15	27.26	7061
Northern Illinios Hub	19.16	-3.63	-1.10	-0.29	21.26	5174
Ohio Hub	23.82	0.40	-0.47	0.16	24.72	6424
West Internal Hub	24.30	0.54	-0.13	0.16	25.50	7037
Western Hub	24.82	0.53	0.40	0.24	26.18	7187
AEP Zone	23.69	0.27	-0.47	0.23	24.43	6531
Allegheny Power Zone	24.31	0.46	-0.03	0.08	25.38	6830
Atlantic Elec Zone	25.23	0.71	0.64	0.20	26.74	6893
ATSI Zone	24.64	0.60	0.15	0.52	25.28	6842
BG&E Zone	25.38	0.55	0.95	0.14	27.45	7116
ComEd Zone	19.20	-3.66	-1.03	-0.28	21.31	5184
Dayton P&L Zone	23.79	0.23	-0.32	0.08	24.73	6521
Delmarva P&L Zone	26.51	2.00	0.63	0.91	27.96	7241
Dominion Zone	25.30	1.02	0.39	-0.08	28.22	6883
Duke Zone	23.14	0.14	-0.89	-0.02	24.00	6341
Duquesne Light Zone	23.80	0.43	-0.52	0.29	24.31	6834
JCPL Zone	25.61	0.90	0.82	0.18	27.64	6995
MetEd Zone	24.88	0.68	0.31	0.24	26.19	6810
PECO Zone	25.01	0.70	0.42	0.15	26.30	6849
Pennsylvania Elec Zone	25.02	0.60	0.53	0.34	26.02	7253
PEPCO Zone	25.17	0.53	0.76	0.12	27.38	7056
PPL Zone	24.82	0.68	0.25	0.29	25.89	6794
PSEG Zone	26.08	1.30	0.89	-0.53	27.22	7123
Rockland Elec Zone	24.46	-0.33	0.90	0.20	26.86	6680

increased 20 cents to about $42.10/MWh. PJM West on-peak January-February 2014 financial futures were unchanged at about $45.25/MWh on ICE.

Midwest forwards were flat to lower Monday even as gas futures rose. AEP-Dayton Hub on-peak October financial futures fell 25 cents, with bids at $37.50/MWh and offers at $38.10/MWh on ICE. Indiana Hub on-peak October financial futures were unchanged, with bids at $34.50/MWh and offers at $35/MWh on ICE.

Southeast markets ... *from page 4*

average low is 65.

The ERCOT day-ahead auction for Tuesday delivery cleared stronger Monday afternoon with peak load forecast steady. Houston Hub became the highest-priced hub as West Hub fell to the lowest-priced position. Houston Hub on-peak cleared in the auction at $41.91/MWh, rising around $4, while off-peak cleared at $27.77/MWh, adding about $2.25.

South Hub on-peak cleared at $41.71/MWh, growing almost $4, while off-peak cleared at $27.75/MWh, gaining around $2.25. North Hub on-peak cleared the auction at $41.43/MWh, down almost $4 from Sunday's clearing price, while off-peak cleared at $27.74/MWh, up around $2.25. West Hub on-peak cleared in the ERCOT auction at $41.35/MWh, a gain of about $4, while off-peak cleared at $27.81/MWh, a gain of more than $2.25

West Zone on-peak led the load zones at $76.35/MWh, adding more than $13.50 from Sunday.

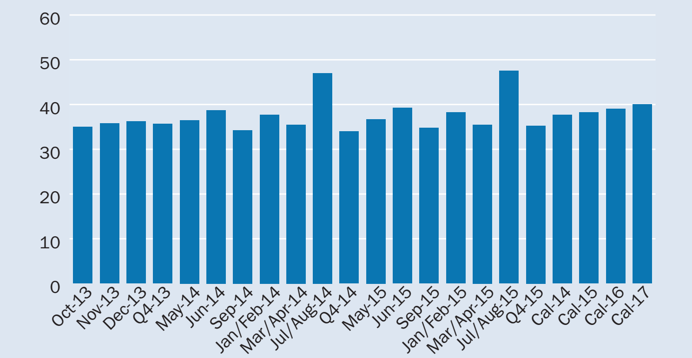
The highest hourly day-ahead price occurred at 5 p.m. CDT in the Houston Hub at $56.15/MWh and in the West Zone at $129.40/MWh.

Most South Centralon-peak October terms moved up Monday, as October NYMEX gas futures increased on the day. ERCOT North on-peak October advanced 75 cents to about $34.75/MWh, the fourth quarter surged 60 cents to about $34.35/MWh, and the first quarter of 2014 rose 50 cents to about $38/MWh. Heat rates were up about 10 Btu/kWh on ICE at about 2:30 p.m. EDT. Into

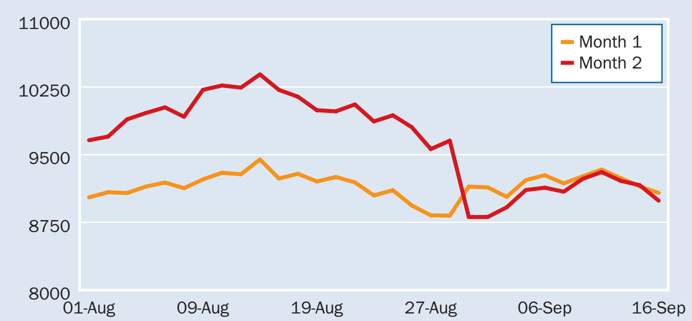
PJM & MISO Platts-ICE Forward Curve, Sep 16 ($/MWh)

Prompt month: Oct 13	On-peak	Off-peak
PJM West	41.50	31.00
AD Hub	37.75	29.50
NI Hub	35.00	22.75
Indiana Hub	34.75	27.00

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



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



Entergy on-peak October rose 25 cents to about $31.50/MWh, and Q4 crept up 10 cents to about $31.50/MWh.

Southeast US on-peak October was unmoved Monday, even as Octobor NYMEX gas futures rose. Into Southern October stayed at about $33/MWh, Q4 stayed at cents to about $33.15/MWh, and Q1 2014 inched up 10 cents to about $36.85/MWh.

West markets ... *from page 6*

cents with bids at $33.75 and offers at $34.25/MWh on the IntercontinentalExchange around 2:30 p.m. EDT.

The fourth quarter crept up 15 cents to about $37.90/MWh, and the first quarter of 2014 inched up 15 cents to about $35.90/MWh. In California, SP15 on-peak October financial terms fell 25 cents with bids at $46 and offers at $46.50/MWh. Q4 edged up 10 cents to about $46.10/MWh, and Q1 2014 was up 15 cents to about $45.90/MWh. NP15 October stayed at about $43/MWh, and Q4 stayed at about $43.40/MWh.

Palo Verde October stayed at about $36.25/MWh, Q4 climbed 40 cents to about $35.65/MWh, and Q1 2014 stayed at about $36.15/MWh.

NEWS

Lines, substations needed in west Texas: study

An Electric Reliability Council of Texas study on west Texas identifies the need for new substations, lines and autotransformers, as well as numerous upgrades, to handle load growth brought on by the booming oil and natural gas industry in that region.

The final 2012 West Texas Sensitivity Study Report was filed with the ERCOT Regional Planning Group Monday. The study is an extensive review that addresses the reliability and economic transmission needs to meet the growing electric demand driven by the oil and natural gas industry in west Texas. The study is an addendum to the 2012 Five-Year Transmission Plan.

The Five-Year Transmission Plan had forecast 2015 load in west Texas at 4,352 MW. The new study bumps that forecast up to 5,661 MW based on increased demand from the oil and natural gas industry. ERCOT also requested a high load forecast be included, which the study reported as 6,167 MW.

For 2017, the study has forecast load in west Texas at 6,154 MW, up from the 4,554 MW in the Five-Year Transmission Plan. A high load forecast was reported as 6,640 MW.

For the Midland, Ector and Andrews County Reliability Project nearly 670 MW of additional load is modeled in these counties for 2017, according to the study.

"Primarily driven by the oil and gas business development and supporting commercial, industrial and residential development in the region, the significant load increase will cause wide spread overloads and low voltages under system intact and contingency conditions," according to the study. "The study result of the 2017 normal load case indicates the overload of roughly 83 miles of 138 kV lines, 11 miles of 69 kV lines and two existing 345/138 kV transformers at Moss and Midland East.

"These unacceptable system issues in the region precipitate the need for transmission reinforcement."

The solution, according to the study, is to construct two new 345/138 KV substations, install two new 500 MVA 345/138 kV autotransformers, construct a new 138 kV line, loop lines into the new substations, and disconnect the existing 230 kV line now connected to the Southwest Power Pool and connect it to the ERCOT system at 345 kV operation.

The Reagan and Crocket County Reliability Project would expand the existing Humble Tap 69 kV substation to accommodate new 138/69 kV facilities, install a new 138/69 kV transformer, upgrade three lines, loop an existing line into the expanded substation, and close two 69 kV lines. There is nearly 200 MW of additional load modeled in these counties, according to the study.

The Reeves, Winkler and Ward County Reliability Project would construct a new 138 kV substation, loop an existing line into the new substation, expand the existing Flat Top 69 kV substation to accommodate new 138/69 kV facilities, install a new 138/69 kV transformer at Flat Top, create a new 138 KV line from the new substation to Flat Top, and upgrade an existing line. Approximately 41 MW of additional load is expected in the counties by 2017, according to the study.

The Crane County Reliability Project includes upgrading a transformer and upgrading a bus tie. Approximately 40 MW of additional load is expected in Crane County by 2017, according to the study.

The Tom Green and Irion County Reliability Project would upgrade a transformer, install two 345/138 kV transformers, construct two new 138 kV lines, upgrade an existing 138 kV line, upgrade two existing 138/69 kV transformers, and convert an existing 69 kV line to 138 kV. Approximately, 132 MW of additional load is modeled in Tom Green and Irion Counties for 2017.

The Menard and Mason County Reliability Project would expand an existing 69 kV substation and construct a new 69 kV line. This area is expected to have 18 MW of additional load by 2017.

The Mitchell County Reliability Project seeks to upgrade two existing 138 kV lines and a 138/69 kV transformer. The area is expected to see an additional 117 MW of load by 2017.

The Uvalde and Bandera County Reliability Project would upgrade two existing 69 kV lines to accommodate an additional 7 MW of load.

The Llano County Reliability Project proposes to upgrade a 138 kV line. No additional load was models in Llano County. However, results indicate the overload of the line under various contingency conditions, according to the study.

Coke County Reliability Project would upgrade a 138/69 kV transformer, install capacitor banks at two 69 kV buses, and add a capacitor bank to an existing 69 kV substation. Roughly 42 MW of additional load is modeled for the area.

The Taylor County Reliability Project includes an upgrade to a 69 kV line. The region will see approximately 111 MW of additional load.

The reliability project for Borden, Howard and Mitchell counties includes expanding an existing 138 kV substation to accommodate 345/138 kV facilities, installing a new 345/138 kV transformer, and connecting a 345 kV line.

A reliability project for Reagan, Upton, Irion and Tom Green Counties could construct a new 345/138 kV substation, loop lines into the new substation, install a new 345/138 kV transformer to the new substation, and upgrade an existing 138 kV line.

The Economic Case Assumption proposed one project, the upgrade of a 138/69 kV autotransformer in 2017.

The study analyzed the reliability and efficiency of the transmission system for the years 2015 and 2017 according to the North American Electric Reliability Corporation reliability standards and the ERCOT Planning Criteria, according to the study. Identified upgrades need to be further reviewed by the appropriate transmission planners to determine the need for an earlier in-service year — 2014 or 2016, respectively.

The next ERCOT Regional Planning Group meeting is September 24.

— Kassia Micek

Groups ask NY to slow down on transmission

Entergy and large energy consumers are urging New York regulators to slow down on plans for 1,000 MW of new transmission, saying the projects may no longer be needed.

The call for a stay comes as an October 1 deadline looms for projects to apply to the Public Service Commission for approval in the competitive process. Six utility and independent developers have proposed 16 projects, as part of Governor Andrew Cuomo's energy highway blueprint. The state plans to offer cost recovery through utility rates.

The projects are meant to ease congestion between upstate and downstate points. But some stakeholders say the state can no longer justify the cost of the undertaking.

"The PSC is contemplating moving forward with projects in this proceeding that have estimated costs that may exceed $1 billion but, due to changed facts and circumstances, these projects are neither necessary nor justifiable economically for customers," Entergy said in a filing Friday.

Transmission congestion, especially around New York City, has been a topic of discussion for years in the state. But Entergy, Nucor Steel Auburn, and Multiple Interveners, which represents 55 commercial, industrial and institutional energy users, said conditions have changed in recent years. The transmission projects are no longer needed because of falling natural gas prices and the construction of more than 1 GW of new gas-fired generation in the New Yory City area, the commenters said.

In its petition for a stay, Mutiple Intervenors said that from 2008 to 2012, annual congestion-related costs declined significantly – by about 79% – in the interfaces the transmission projects are meant to improve: Central-East and UPNY-SENY.

Those calling for a stay also said the state is overstepping its bounds and wading into the Federal Energy Regulatory Commission's turf by regulating cost recovery for transmission projects.

NuCor added that the state has failed to fully investigate the benefits from the congestion relief projects and who will receive those benefits – both are requirements under FERC's Order No. 1000. "FERC made it abundantly clear that transmission benefits and beneficiaries must be demonstrated, they cannot simply be alleged," NuCor said.

NextEra Energy Transmission, however, disagreed with the call to delay the transmission projects. The developer urged the PSC to move forward with the next step, which is a siting review and comparison of the projects.

The state has not yet fully examined the need for the projects because that happens in the next stage of review under New York's "Article VII", according to NextEra, which has proposed two of the sixteen projects.

NexEra also argued that the commission is acting within its legal authority — that it can require utilities to make transmission improvements when congestion threatens overall system reliability, flexibility, and efficiency.

The PSC schedule calls for developers to submit their initial applications October 1. The PSC will then evaluate them on their own merits and compare them against each other. The PSC has yet to set a date for selecting winners among the applicants.

The state plans to choose projects that reduce congestion and meet other public policy goals at the lowest cost. The projects are expected to create "significant economic and environmental benefits by permitting excess power from upstate sources, including renewable energy facilities, to reach the downstate areas," according to the PSC.

The developers who proposed the 16 projects are Boundless Energy, Cricket Valley Energy Center, New York Transmission Company, a joint venture of the investor-owned utilities in New York, North America Transmission and West Point Partners. All of the projects are AC transmission lines.

— Lisa Wood

Daily CSAPR allowance assessments, Sep 16

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 16

	$/allowance	Change	$/st
S02 2013	0.67	0.00	1.34

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

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

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	2.70	0	Dec13	1.97	0
Dec13 V11	2.70	0	Dec14	1.97	0
Dec13 V12	2.70	0			
Dec13 V13	2.70	50			
Dec14 V10	2.70	0			
Dec14 V11	2.70	0			
Dec14 V12	2.70	0			
Dec14 V13	2.75	0			
Dec15 V10	2.70	0			
Dec15 V11	2.70	0			
Dec15 V12	2.70	0			
Dec15 V13	2.75	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.

Alberta monitor weighs in on possible coal sale

The Alberta Market Surveillance Administrator has offered guidance to Alberta's Balancing Pool on whether the possible sale of an 800 MW power purchase arrangement tied to the Genessee coal plant would be challenged on competition grounds.

The Balancing Pool was created in 1999 by the Alberta government to help manage the transition from a system of traditionally regulated electricity assets to wholesale power market competition under the province's Electric Utilities Act. Under the law, the pool transfers the output of power plants into the competitive market by selling or auctioning off power purchase arrangements.

Genesee is a three-unit, 1,250-MW coal plant owned by Capital Power Corporation and located about 40 miles southwest of Edmonton. While the generation from units 1 and 2 is still managed by the pool, the 425-MW unit 3 is a join venture of Capital Power and TransAlta. The companies independently dispatch and market their share of the unit 3 output.

In what would be a third phase of transferring, the pool is mulling the sale of the PPA for Genesee units 1 and 2.

"The Balancing Pool is considering the sale of the PPA for Genesee units 1 and 2 as the next step for a competitive electricity market in Alberta," said Eagle Kwok, the pool's director of planning and development. "That PPA could be sold in a single 800-MW transaction or a number of smaller strips. While we are contemplating the sale of the PPA, no decision has been made yet."

As part of its decision-making process, the pool sought an opinion from the province's Market Surveillance Administrator.

Responding in a website update last Wednesday, the MSA said it was "asked by the Balancing Pool whether the sale of the Genesee PPA, in whole as an 800-MW generation asset or as several strip contracts, would be challenged on competition grounds."

MSA said the "short answer we gave the Balancing Pool is that it depends on the detail of the transaction(s) in question, the competitive circumstances in the Alberta market at the time and for the forseeable future, and the degree to which the parties have market power in the Alberta wholesale market."

Each proposed PPA sale "would be reviewed on a case by case basis although those involving entities new to Alberta or without significant existing market power would not likely raise a competition issue," the MSA said.

If the MSA feels that a Balancing Pool proposal to sell the Genesee PPA would threaten electricity market competition in the province, it "could lead to an application to the Alberta Utilties Commission seeking to block or modify the transaction," MSA said.

Alternatively, the market monitor could refer the proposed transaction or transactions to the provincial Competition Bureau, the MSA noted.

If the Balancing Pool decides to sell the Genesee PPA in its entirety or in strips, it would do so through a document known as a "Request for Expressions of Interest."

The Balancing Pool began considering the sale of the Genesee PPA because the timing seemed right following three similar transactions between 2000 and 2009, Kwok said.

The process of selling PPA takes place under a Market Achievement Plan. The first MAP occurred in 2000 and resulted in the auction of more than 2,800 MW. MAPs representing smaller amounts of generation were concluded in 2003 and 2006.

"The $2.2 billion in revenue generated" from the auctions "was redistributed to Alberta consumers via the electricity rebate program," said Amy Sopinka, a post-doctoral research fellow at the University of Victoria in British Columbia, who has studied the Alberta market in depth.

— Martin Coyne

Louisiana munis to build gas-fired unit

The Louisiana Energy & Power Authority, a municipal utility group, will build a 64-MW, natural gas-fired combined-cycle unit in Morgan City by September 2015 to meet a portion of the power needs of six of its 17 muni members, LEPA said Monday.

Tim Matte, a member of LEPA's board of directors and a former mayor of Morgan City, said the munis in Houma, Morgan City, Plaquemine, Rayne, Vidalia, and Jonesville, Louisiana, have entered into take-or-pay contracts for different and specific shares of the output of the $153 million unit, which will be called LEPA Unit 1.

Houma's muni, known formally as Terrebonne Parish Utilities Department, will take 40.9% of the output, while the munis in Morgan City and Plaquemine will take a combined 33.3%.

Matte said that a total of 10 LEPA munis initially contributed toward the development of LEPA Unit 1, but ultimately only six munis decided to enter into contracts for portions of the unit's output. He said that each of the six has the distinction of owning and operating their own generation, and that the planned unit, with its high efficiency and low heat rate, will enable the participating munis to ramp down the use of their older, less efficient units.

One of the primary drivers that led to the development of the combined-cycle project, said Matte, was the fact that transmission constraints in parts of Louisiana undermined what otherwise would have been economic purchases of low-cost power by the munis.

Siting a new, highly efficient source of power near Houma and Morgan City's load fully mitigates those transmission constraints, he said, and will actually enable participating munis to export excess power from their once-constrained region.

Matte noted that the combined-cycle project was developed "pre-MISO"—that is, before Entergy Corp.'s utility subsidiaries secured federal and state regulatory approval to join the Midcontinent Independent System Operator. Entergy plans to turn over operational control of its transmission system to MISO in December.

Matte said that after Entergy announced its intention to join MISO the munis developing the combined-cycle project studied whether the project still made sense, given that MISO will employ economic dispatch to determine which units run—or do not run.

"We determined that [the planned unit] not only would make sense, it would be advantageous" and is likely to be dispatched regularly by MISO to provide baseload power.

Fitch Ratings said in a statement that the power sales contracts the six participating munis signed "include standard step-up provisions that require each participant to purchase up to 125% of its original allocation of the project output in the event that another participant defaults." Fitch gave the project's bonds a favorable A- rating.

"The project is expected to supply the participants with competitively priced natural gas-fired capacity and energy which upon completion should enable the participants to reduce reliance on older, less efficient generation," Fitch said.

The rating agency said LEPA Unit 1's proximity to several Gulf Coast interstate gas pipeline systems "and access to ample capacity and gas supplies will mitigate the risks associated with volatile fuel costs, which will represent about 75% of ongoing operating costs."

— Housley Carr

Indiana lawmakers to eye retail choice

An Indiana legislative panel soon will formally discuss the possibility of enacting retail electric choice in the state, giving fresh hope to competition advocates that the General Assembly next year finally may be ready to allow business and residential customers to buy power from alternative suppliers in the regulated state.

Members of the Regulatory Flexibility Committee have agreed to talk about "customer choice, deregulation and competitive procurement in the energy industry" at their next meeting later this month, Molly Johnson, press secretary to Republican State Senator Jim Merritt, confirmed Monday. Merritt co-chairs the Reg Flex committee.

In anticipation of that session, the Retail Energy Supply Association and COMPETE Coalition sent letters to the committee on Monday, urging members to support a transition to electric competition in Indiana.

Most of Indiana's neighbors, including Illinois, Ohio and Michigan, have deregulated all or portions of their electric industries. Bills aimed at ushering in competition in Indiana have been floated in the Legislature in recent years, only to collapse.

COMPETE said competitive power markets keep downward pressure on prices, drive innovation and provide more options to consumers while ensuring a reliable supply of electricity.

According to the group, Indiana businesses have seen their electricity rates soar by more than 60% over the past 10 years. During that time, Illinois customers have watched their electricity rates "steadily fall after adopting a competitive electricity market."

Rates in Illinois, once well above the national average, "are now well below the national average and the lowest in the Midwest, recently falling below even Indiana," the group added.

Joel Malina, COMPETE's executive director, said in an interview the Reg Flex committee meeting "opens a starting gate" for a renewed push to pass competition legislation in Indiana next year.

"Electricity prices are high, so we think this might be the opening for the Legislature," he said.

Dozens of businesses that spend almost $100 million a year on electricity and employ nearly 55,000 Indiana residents signed the COMPETE letter. Major signees include Wal-Mart, Staples, Macy's, Rite-Aid and Owens-Corning.

The group said that contributing to the success of Illinois' competitive market is shifting the costs risk of owning and operating generation plants from utility customers to private investors, "where they belong."

This is particularly relevant for Indiana, they said, considering the $1.5 billion cost-overrun for Duke Energy Indiana's 618-MW Edwardsport integrated gasification combined cycle plant in rural Knox County. The baseload plant's original $1.95 billion price tag in late 2007 has almost doubled to $3.5 billion.

In a competitive market, the group said, such project or environmental costs are borne by investors "who are better able to adapt quickly to changing market conditions and manage the risks than customers."

RESA, a national trade group, encouraged the Reg Flex committee to carefully consider and engage in further examination to see how electric industry restructuring and the introduction of competition will help the state to meet its future energy needs.

"Customers should be afforded the ability and information to make their own decisions and choices regarding their electric choice needs, just as they do with telecommunications, natural gas and airlines, all of which were previously regulated under a protected monopoly system of price regulation," RESA told the committee.

Melissa Laudersale, RESA president, said the group has customers in neighboring states with competition "who are asking for customer choice for their facilities in Indiana, and we are as eager to serve them as they are to have a choice in energy supply."

The General Assembly is scheduled to convene in Indianapolis in early January for the start of its 2014 session.

— Bob Matyi

CFTC names new chief of market oversight unit

The Commodity Futures Trading Commission decided to stay in house to select their next director of the Division of Market Oversight Monday as Chairman Gary Gensler named Vincent McGonagle to lead the group responsible for market surveillance.

In his new role, which will start October 7, McGonagle will head the division that oversees trade execution facilities and swap data repositories, market surveillance and examines existing exchanges to ensure compliance, according to the agency.

The CFTC said that McGonagle recently supervised CFTC's cases against Barclays PLC, UBS and RBS related to manipulative conduct and false reporting concerning LIBOR and other global benchmark interest rates.

"I thank the chairman for giving me the opportunity to lead the talented staff in the Division of Market Oversight," McGonagle said in a statement. "Liquid, fair and financially secure US derivatives markets are at the core of our mission, and I look forward to being more directly involved in the regulatory oversight of these markets."

CFTC Chairman Gary Gensler said McGonagle "has a wealth of experience from his 16 years in the Division of Enforcement, ... has excellent judgment and foresight as evidenced by his opening the commission's review of possible LIBOR abuses."

McGonagle joined the CFTC as a staff attorney in 1997, holds a BA in economics from LaSalle University and his JD from Pepperdine University School of Law.

— Christopher Tremulis

Power system changes are urged in report

Federal and state energy officials should make major policy changes, including a move away from rate-of-return regulation, an expansion of incentives for renewables and an inclusion of demand and supply-side options in all markets, to improve the US electricity system as it is modernized, a clean-energy advocacy group urged in a report Monday.

The report, put out by the California-based Energy Foundation, includes a series of policy and power market design recommendations aimed at making the US electricity system more environmentally-friendly and flexible.

"Managed badly, we will spend too much time, money and pollution on obsolete power plants, leave our country increasingly exposed to system failure and let our energy technology businesses slip to the back of the pack," the report states.

Officials with the Energy Foundation planned to unveil the report, America's Power Plan, at the National Association of State Energy Officials' annual meeting in Denver.

The policy recommendations outlined in the report are needed amidst the "radical makeover" the US electricity system is undergoing. This makeover is being driven by technological breakthroughs, including cheaper solar and wind energy systems and natural gas and oil fracking; an increase in competition that has followed the move away from vertically integrated utility monopolies over the past 20 years; and a promotion of renewable energy through energy efficiency, demand-response and other efforts, the report says.

"These trends will change the power system and utility businesses at their core," the report states. "We must re-think power system incentives and regulation as well as the relationship of American citizens and their government with the power system."

The recommendations include the use of performance-based regulation which could give utilities "the freedom to innovate," expanding renewable electricity standards to provide a long-term market signal for investors and financing, and making all demand and supply-side options available in all markets.

"All options — central and distributed generation, transmission, efficiency, and demand-response — should compete with one another to provide electricity services," the report states.

— Brian Scheid

SoCal Ed issues solicitation for CHP contracts

Southern California Edison is looking to sign power purchase agreements with combined heat and power facilities in California.

The Rosemead, California-based utility did not set a target for how much capacity it intended to contract for, but proposals must be for at least 5 MW, according to the request for offers released Thursday.

The RFO is part of a settlement agreement approved by the California Public Utilities Commission in 2010. Under the settlement, the state's investor-owned utilities must contract for at least 3,000 MW of CHP capacity by 2021.

Through three solicitations, SoCal Ed must acquire 1,402 MW. This is SoCal Ed's second RFO under the program. Following it first solicitation, SoCal Ed proposed five contracts totaling 838 MW. The PUC rejected an 80-MW PPA, has approved a 39-MW contract, is preparing to vote on a 318-MW contract, and required that two contracts totaling 400 MW be changed so that at most they come in at 200 MW.

Merrimack Energy is acting as the independent evaluator for the solicitation.

Indicative bids are due November 7.

The RFO is online at www.sce.com/CHPRFO.

For more information about the RFO, email CHPRFO@sce.com with a copy to the independent evaluator at waynejoliver@aol.com or call Benny Wu at 626-302-3230 or David Lewry at 626-302-3222.

— Ethan Howland

Westar gets 35 proposals from wind RFP

Westar Energy received a total of 35 proposals from 22 companies in response to the utility's August 22 solicitation for "at least 80 MW" of wind power deliverable starting no later than late 2016, Westar said Monday.

Westar spokeswoman Gina Penzig said that while the utility has just begun to analyze the bids it received in response to the quick-turnaround request for proposals, which were due September 13, an initial review suggests the prices offered are low and highly competitive. "It looks very positive; it looks very good," she said, adding that it was too soon to provide price-range specifics.

Recent wind-power RFPs by Austin Energy and Southwestern Public Service generated offers at low as $22 or $23/MWh, and resulted in the Texas muni and SPS entering into power purchase agreements for far more wind power than they had planned. Austin Energy, which had planned to contract for up to 200 MW of wind, entered into PPAs for 570 MW; SPS, a subsidiary of Xcel Energy, did not specify how much it was seeking, and contracted for 698 MW.

Westar's Penzig said the utility needs to add about 80 MW of additional wind power to its system to comply the next stage of Kansas's renewable portfolio standard, which calls for wind farms and other renewable sources to account for at least 15% of a utility's generating capacity by 2016.

She added, however, that Westar believes that, with wind power prices low due to heightened competition and the federal production tax credit, contracting now for even more wind power "could provide a good hedge" against the likelihood of federal carbon regulation. In 2012, Westar secured about 73% of its electricity needs from coal-fired units.

Westar said in the RFP that the utility's preference is for PPAs with 20-year terms and the right—but not the obligation—for the utility to extend the PPAs by another five years. Westar also said it would prefer the right to purchase the wind farm or other renewable asset for fair market value at either 10 or 15 years after it starts commercial operation, at the end of the PPA's initial term, or after the five-year PPA extension.

Westar currently owns a total of 149 MW of wind capacity at two wind farms, and holds wind PPAs for a total of 515 MW; it also buys 6 MW from a landfill gas-fired unit.

Penzig said Westar plans to select the winning wind proposal or proposals in October. That, she said, would give the developer or developers time to take needed steps by the end of 2013 to qualify for the PTC.

— *Housley Carr*

Residential load control can aid savings

...from page 1

When peak demand is at its highest for many utilities, they call on load-control devices to cycle central air conditioners, pool pumps and sometimes other equipment to bring down residential demand. The programs do not turn the appliances off. They sequence when compressors run so that all are not running at the same time. The value of these programs are that peak demand periods carry some of the most expensive prices for power throughout a given year, so even though they may only be called upon a few times, they help utilities avoid buying higher-cost power from peaking generation units.

Perhaps more importantly, the residential customer segment accounts for a much greater percentage of peak load than the commercial or industrial segments, said Ahmad Faruqui of The Brattle Group, and others. Although the nationwide average power usage is almost evenly divided among residential, commercial and industrial sectors over a given year, AC usage can drive the residential sector above 60% of peak demand in some regions, said Blake Young, CEO of demand response firm Comverge.

That is why “we believe that the residential sector should not only be a larger focus for utilities, but should in fact be an element of every DR program,” Young said in a blog posted earlier this month on the Comverge website.

Compared with the large commercial and industrial customers that do not alter their usage much based on the weather, residential customers, driven largely by AC load, can account for more than 50% of the peak demand in the Electric Reliability Council of Texas during summer peak hours, Faruqui said in a presentation to the Texas Public Utility Commission last year.

The average savings can be 0.8 kw to 1.5 kw per customer enrolled in residential load control programs, Faruqui said. In ERCOT alone, there is a potential to reduce peak demand anywhere from 500 MW to almost 3,000 MW through enhanced load control programs, Faruqui said. That is based on customer participation levels of between 10% and 30% for utilities in ERCOT, he said.

“We have found that direct load control devices can make a significant contribution” toward reducing peak demand, with contributions of about 1 kw per AC unit, 1kw per hot water heater and 0.5 kw per pool pump, said Simon Jones, spokesman for Comverge.

Most direct load control programs involve central air conditioners that can be timed to cycle on or off by utilities through a device on the compressor or a smart thermostat, with participants told that the cycling would not affect home comfort that much and that the cycling events are limited to a certain number and duration. Customers often have a limited number of opportunities to override utility signals as part of such programs.

The Federal Energy Regulatory Commission, in its assessment of demand response and advanced meters in the US, identified more than 300 residential direct load control programs around the country. The largest programs have several hundred thousand customers enrolled. But even at smaller utilities, a high percentage of customer enrollment can produce peak demand savings that prevent utilities from buying expensive power during high load days.

At Alliant Energy in Iowa, Alliant has about 50,000 residential customers enrolled in its load control program, which pays customers $8/month to be available for an AC cycling program, and $2/month to be available for an electric hot water heater cycling program, said Justin Foss, spokesman for the utility. When all customers are called upon for cycling their units, which has happened a few times this year during high temperatures, Alliant trims about 38 MW of demand, Foss said.

The demand reduction is in comparison with an average utility load of about 3,500 MW in Iowa, with an all-time peak record of 3,724 MW. The demand reduction may seem small, but “we are short on power” at Alliant, and when it calls cycling events “we have to buy less of the expensive energy” on peak demand days, Foss said.

Alliant’s savings per customer are quite good, with plenty of utilities garnering savings below that level, said Joel Gilbert, chief software architect and co-founder of Apogee Interactive, a software firm used by many utilities in the efficiency/DR markets.

The market value for demand reductions can vary across the US, as load control programs have different costs and incentives tied to them, but they tend to be cost effective given the peak power prices seen in some regions, Gilbert said in an email.

At FirstEnergy, which has 10 utilities spread over six states, two utilities have residential AC cycling programs, said FirstEnergy spokesman Mark Durbin. FirstEnergy has 17,000 customers participating in Ohio, with the potential to shave peak load by about 13 MW, and 14,000 customers participating in New Jersey with the potential to shave peak load by 20 MW, Durbin said.

At FP&L, customers can earn up to $137/year for participating in the utility’s load-control program, depending on the number of devices they are willing to have cycled and the time of year they are available, explained Florencia Contesse, spokeswoman for the utility. The program allows FP&L to control as much as 1,027 MW of residential demand, Contesse said.

The FERC report identified FP&L as having the largest load control program in the US, with more than 700,000 customers enrolled.

The larger load control programs at a few utilities may be considered anomalies because many utilities do not want to interrupt residential customer usage for fear of customers not liking the programs, Faruqui said in response to questions. Other utilities have plenty of generation capacity and do not see a need for load control programs, while others only focus on supply-side solutions and do not pay much attention to demand-side management, Faruqui said.

Even with the sizable savings available through load control programs, Opower is pushing to take them further with enhanced usage data and broader enrollment for utilities with advanced meters installed for all of their customers. Opower last week touted its "behavioral demand response" effort that has been in place at Baltimore Gas & Electric, taking its consumer behavior analytics capability and applying it to load control programs by reaching customers through their preferred communication channel (email, text messaging or phone calls) and motivating them to reduce usages during peak demand periods.

"We look forward to assisting utility partners around the world" by taking advanced meter data and showing utilities the savings potential of expanding their load control programs, said Roderick Morris, senior vice president of marketing and operations at Opower. Unlike traditional load control programs that are voluntary, Opower's effort would have all customers with advanced meters automatically enrolled in a program, with the ability to opt out, Morris said in an interview.

Morris said the behavioral demand response effort could enhance time-of-use rate plans and other measures to control peak demand at the residential level, which has been a challenge for some utilities.

— Tom Tiernan

Xcel Energy unit 'cautiously optimistic' ...from page 1

Ideally, PSCo would like to participate as an EIM entity along with the ISO and PacifiCorp, even though it is not interconnected to the California or PacifiCorp systems, Lemmons said. Short of direct participation, PSCo could operate as an EIM within its balancing authority area, he said.

The proposed EIM would use an automated five-minute dispatch to supply balancing energy across a broad footprint. Market supporters contend that it would improve reliability while helping to integrate intermittent renewable generation into the system.

There is little doubt that an EIM will be formed, according to Travis Kavulla, a Montana Public Service Commission commissioner and chair of the PUC EIM Group. "It's obvious something will be implemented," Kavulla said in an interview. An EIM "is a much more manageable process than a full-blown [regional transmission organization]," he said.

Currently, many of the balancing authorities across the West operate using manual dispatch with an hourly schedule, Kavulla said, noting that complicated bilateral transactions are often made over the phone. Further, the West's many balancing authorities are carrying greater reserves than required if they pooled their resources, he said. "It's a case study of inefficiency," he said of the current structure.

Some regulators and public utilities in the West are concerned that an EIM could lead to greater federal control over their operations or oversight authority, but Kavulla believes an EIM can be developed that protects local control. "Sure, self governance and self control is worth something ... but does it exceed the benefits of operating in a regional market?" Kavulla said. "I don't see this as an insurmountable problem."

While Montana and many Western states and market participants will not be directly affected by the proposed EIM, there are "plenty of" transmission owners, generators and balancing authorities that want to be involved in the market or just want to understand it, Kavulla said.

Utilities like Avista, NorthWestern Energy and Portland General Electric have been following the issue closely through the Northwest Power Pool, which has also been studying the possibility of forming an EIM, Kavulla said. Some of them may want to see how the ISO/PacifiCorp market shapes up before deciding what to do, he said.

The Cal-ISO intends to issue a final market implementation draft proposal next week, Mark Rothleder, ISO vice president for market quality and renewable integration, told the PUC EIM Group. The proposal, which will include 15-minute unit commitment for quick-start resources and 5-minute dispatch, will go to the ISO board in November for a vote, he said. ISO staff expects the board to vote on a proposal for how the EIM will be governed in December, said Don Fuller, ISO director of strategic alliances.

The Bonneville Power Administration is concerned about the "aggressive timeline" for implementing the proposed EIM, according to Cathy Ehli, BPA vice president for transmission marketing and sales. "It's a fairly quick target we're going after," she said, noting that the federal power marketer is still assessing the possible effects from the proposal.

Southern California Edison strongly supports an EIM, but would like to see it developed in two phases, according to Jeff Nelson, SoCal Ed manager of market design and analysis. In an initial phase outlined by SoCal Ed, the ISO and PacifiCorp's EIM entity would operate separately. After any startup issues have been ironed out, the ISO and PacifiCorp would operate jointly, he said.

Currently, PacifiCorp can export 525 MW to California and import about 400 MW, according to Stefan Bird, PacifiCorp senior vice president.

SoCal Ed is "optimistic" that the issues can be worked out, Nelson said.

— Ethan Howland

Third party clearing of FTRs eyed ...from page 1

Finance Subcommittee earlier this year. On Wednesday, it came up for discussion for the first time at the NEPOOL Markets Committee meeting.

The main benefits of moving to third-party clearing would be protecting market participants from having to cover another FTR holder's losses in the event of a default, allowing ISO-NE to implement long-term and balance of planning period FTRs and facilitating secondary market trading of FTRs, according to ISO-NE's Wednesday presentation.

"Having that credit and default risk responsibility for these new products not be with the ISO but to rather be with [Nodal Exchange], essentially moves the risk off [market participants]," said Paul Cusenza, chairman and CEO of Nodal Exchange.

ISO-NE has been working to implement long-term FTRs for several years, but the grid operator and market participants could not agree on workable credit requirements. Joel Gordon, director of Market Policy for PSEG Power and chair of the Budget and Finance Subcommittee, said third-party clearing was seen as a way to enable the implementation of long-term FTRs.

"We weren't able to implement [long-term FTRs] because we weren't able to figure out financial assurance" policy, Gordon said. "Third-party clearing was the mechanism to get to a financial assurance arrangement that worked for participants and the ISO."

Although the ISO and Nodal Exchange had floated the idea of limiting how many nodes are offered in FTR auctions as part of the shift to third-party clearing, the current plan is to retain all points currently available in the monthly and annual FTR auctions. But for long-term auctions, ISO-NE plans to offer a more limited set of nodes.

ISO-NE's Wednesday presentation notes that while the design for third-party clearing of FTRs was developed with Nodal Exchange, "the design is not exclusive and another or additional exchange/clearing partner(s) are possible."

ISO-NE has not heard from any other clearing houses interested in third-party clearing of FTRs, according to ISO-NE spokeswoman Lacey Ryan.

Nodal Exchange, founded in 2007, operates a commodity exchange that offers nodal, cash-settled futures contracts for power that are cleared through LCH.Clearnet, an independent clearing house. Nodal Exchange floated the idea of clearing FTRs outside of ISO markets as early as 2010, but ISO-NE would be the first to adopt this approach.

Cusenza said Nodal Exchange's granular offerings make it well-positioned to conduct third-party clearing of FTRs.

For FTRs, the ISO needs "an entity that's able to handle all of their micro granular locations," Cusenza said. "We're capable and willing to do that for the market. We want to be able to provide this service."

Cusenza said Nodal Exchange will charge a small fee to market participants based on the volume of FTRs that they purchase in the auction and clear through Nodal Exchange.

Nodal Exchange's shareholders include Macquarie Energy, NextEra Energy Resources, and LEX Energy, according to Nodal Exchange's website. LEX Energy is a private equity firm with a number of investors who are also investors in DC Energy, according to Nodal Exchange's website. Macquarie, NextEra and DC Energy are all participants in ISO-NE's FTR market.

Bruce Bleiweis, director of market affairs at DC Energy, says his company supports the third-party clearing proposal.

"This has been an ongoing initiative of ISO-NE management and the benefits to participants include the removal of default allocation risk for NEPOOL members," Bleiweis said in an email. "DC Energy understands that this development will also enable the implementation of long-term and balancing auctions for ISO-NE, initiatives that received broad based support and have been approved by FERC. DC Energy considers these steps to be important and appropriate market developments."

In its Wednesday presentation, ISO-NE said that one of the rules under the new set-up would be that "the third-party administrator or its affiliate will not have a proprietary interest in market trades." ISO-NE's Ryan said this provision will not preclude the participation of Nodal Exchange shareholders.

"They are not classified as affiliates, so we do not believe that their participation would be limited," Ryan said in an email.

The ISO is hoping to receive approval from the markets committee by the end of the year, according to the Wednesday proposal. The ISO hopes to secure approval from the Participants Committee in January 2014 and file the proposal with FERC in February 2014, with the goal of implementing third-party clearing in the fourth-quarter of 2014.

— Juliana Brint

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