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Thursday, October 3, 2013

Dynegy's plans could increase PJM imports

ANALYSIS Efforts now under way by Dynegy in Illinois could enable more exports into PJM Interconnection's next capacity auction even after a record level of imports cleared in the most recent auction.

Dynegy, one of the larger merchant generators in the Midcontinent Independent System Operator region, hopes to bid capacity from its nearly 3 GW of coal-fired capacity into PJM's next capacity auction, for the 2017-18 delivery year.

Dynegy has embarked on two transmission studies. The first is looking to find capacity on existing transmission lines and on pathways that are expected back in service that could enable as much as 3 GW of capacity to move through the Ameren Illinois territory into Indiana and then into PJM.

Dynegy expects to hear back from MISO by year end on what

(continued on page 18)

Developers respond to N.Y. line competition

TRANSMISSION Several utility and private developers submitted projects to New York regulators this week in the first formal step in a competition to fill a 1,000 MW transmission need.

Boundless Energy, NextEra Transmission New York, North American Transmission, NY Transco and Poseidon Transmission applied for certificates of environmental compatibility and public need, according to filings posted by late-day Wednesday before the state Public Service Commission.

Several developers have been contemplating participation. This week's filings marked the first opportunity to see which are serious about undergoing New York's siting review process, known as Article 7.

(continued on page 19)

Calif. needs changes to hit emission goals: plan

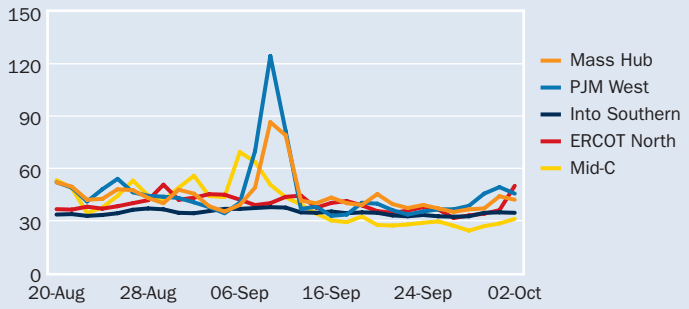
MARKETS California must make wholesale changes to its electric system to meet the state's goal of cutting greenhouse gas emissions by 80% from 1990 levels by 2050, according to a draft scoping plan issued by the state's Air Resources Board.

Some of the recommended changes in the draft plan include expanded energy efficiency, demand response and renewable programs. Also, the plan released Tuesday for public comment envisions most of the state's cars and trucks running on electricity, which would be a major source of new demand for utilities, but would require major infrastructure investments.

California is on track to meeting its statutory goal of cutting GHG emissions to 1990 levels by 2020, the draft plan said. However, without further action, emissions will begin climbing around 2030, according to the draft plan.

(continued on page 20)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Oct 3 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	39.32	45.32	22.64	27.09
NYISO	40.52	63.85	21.79	36.70
PJM	38.39	47.59	22.56	27.65
MISO	33.95	40.79	22.01	27.50
ERCOT	54.20	88.43	21.52	28.39
CAISO	38.13	41.33	30.56	31.71

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 Oct 3

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	42.00	11413	16.24	12.56	5.20	-2.16	-13.20
N.Y. Zone-A	45.50	12727	20.48	16.90	9.75	2.60	-8.13
PJM/MISO							
PJM West	45.50	13025	21.05	17.55	10.57	3.58	-6.90
Indiana Hub	38.50	10434	12.67	8.98	1.60	-5.78	-16.85
Southeast & Central							
Southern, Into	34.50	9491	9.06	5.42	-1.85	-9.12	-20.03
ERCOT, North	50.00	14015	25.03	21.46	14.33	7.19	-3.51
West							
Mid-C	31.00	8683	6.01	2.44	-4.70	-11.84	-22.55
SP15	41.75	11392	16.10	12.43	5.10	-2.23	-13.23

Note: All indexes are on-peak. Spark spreads are reported in ($) and Marginal heat rates in (Btu/kWh). A full listing of bilateral indexes and marginal heat rates are inside this issue.

Inside this Issue

NORTHEAST MARKETS

Northeast dailies and terms move lower

Northeast dailies peeled back with demand forecast to move lower. Forwards in the region also fell as the NYMEX November gas futures settled 6.7 cents lower Wednesday at $3.542/MMBtu as traders priced in large storage injection estimates while awaiting an Energy Information Administration storage report to be released on Thursday.

ISO New England forecast peak load on Wednesday near 16,800 MW and 16,600 MW for Thursday.

High temperatures in Boston are forecast in the mid-70s on Thursday. Algonquin city-gate spot natural gas gained about 8 cents to about $3.72/MMBtu and Transco Zone 6 New York moved up 2 cents to about $3.74/MMBtu.

Mass Hub on-peak for Thursday lost about $2 to the low $40s/MWh and off-peak lost about $2.50 to the low to mid-$20s/MWh.

The New York ISO forecast peak demand on Wednesday near 21,650 MW and 20,235 MW on Thursday. High temperatures in New York State are forecast in the low to upper 70s.

New York Zone A on-peak for Thursday firmed by about $1 in the mid- to upper $40s/MWh. NY Zone G on-peak peeled back about $1 in the upper $40s/MWh.

Day-ahead auction prices in the ISO New England moved up even as demand is forecast to ease slightly on Thursday. Internal hub on-peak gained $2.57 moving to $44.58/MWh, while Connecticut on-peak added $3.27 to $45.32/MWh. Maine on-peak jumped $6.13 to $39.32/MWh. West-Central Mass moved up $2.74 to $45.01/MWh.

Day-ahead auction prices in the New York ISO were mixed with demand forecast to move down on Thursday. New York City on-peak moved down more than $1 to about $49.10/MWh and Long Island on-peak fell $7.26 to $63.85/MWh. Hudson Valley on-peak fell 70 cents to $48.61/MWh. On the other hand, West on-peak gained nearly $3 moving to $44.75/MWh and North on-peak jumped $10.58 to $40.52/MWh.

Northeast term power prices edged down with a late slide in NYMEX gas futures. In New England, Mass Hub on-peak November financial futures were down 50 cents, with bids at $49/MWh and offers at $51/MWh at about 2:30 p.m. EDT on the IntercontinentalExchange. Mass Hub on-peak December eased 25 cents to $77.25/MWh. Mass Hub on-peak January-February 2014 crept down to about $99.50/MWh.

New York Zone A on-peak November financial futures stayed strong edging up 75 cents, with bids at $37.45/MWh and offers at $39.50/MWh on ICE. New York Zone G on-peak November financial futures were steady around $47.50/MWh.

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

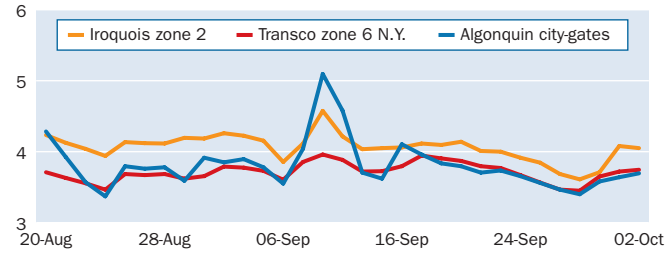
Sources: Generation owners, public information and other market sources.

Northeast day-ahead bilateral indexes for Oct 3 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	42.00	-2.00	41.00	11413
N.Y. Zone-G	48.50	-1.25	46.08	12444
N.Y. Zone-J	49.00	-1.00	47.00	12572
N.Y. Zone-A	45.50	1.00	41.42	12727
Ontario*	37.50	0.50	34.00	9120
Off-Peak				
Mass Hub	24.00	-2.50	25.33	6522
N.Y. Zone-G	24.75	-2.00	25.67	6350
N.Y. Zone-J	25.00	-1.75	25.83	6414
N.Y. Zone-A	23.00	-0.75	23.33	6434
Ontario*	19.50	-0.50	19.67	4742

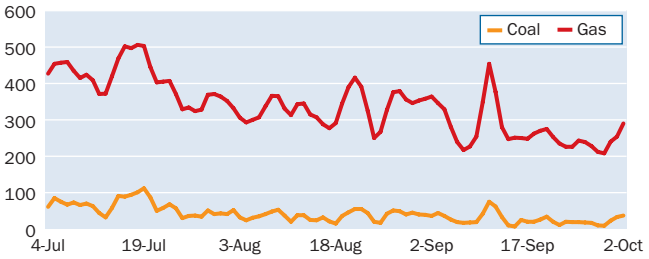
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO gas and coal generation (GWh)



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 01-Oct	%Chg	% Chg Year-ago	Forecast 02-Oct	03-Oct	04-Oct	05-Oct	06-Oct
ISONE								
Load	335	3	2	349	346	343	311	306
Generation								
Coal	16	30	80	16	11	9	8	8
Gas	122	0	-13	144	141	132	122	117
Nuclear	111	0	-2	111	111	111	111	111
NYISO								
Load	427	8	-1	457	448	447	425	425
Generation								
Coal	17	55	65	22	17	13	13	13
Gas	131	11	-7	146	132	131	134	136
Nuclear	135	0	7	135	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Oct 3 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	44.58	0.10	0.25	2.57	41.92	12233
Connecticut	45.32	0.13	0.95	3.27	42.13	11840
NE Mass-Boston	44.47	0.10	0.13	2.63	41.85	12202
SE Mass	43.88	0.19	-0.55	2.53	41.21	12040
West-Central Mass	45.01	0.13	0.64	2.74	42.19	12349
Rhode Island	44.02	0.56	-0.78	2.24	41.32	12077
Maine	39.32	-1.78	-3.14	6.13	36.56	9889
New Hampshire	44.36	0.11	0.01	2.63	41.54	11155
Vermont	44.99	0.14	0.62	2.71	42.04	11315
Off-Peak						
Internal Hub	23.74	-0.32	0.11	-2.28	25.31	6570
Connecticut	23.74	-0.32	0.12	-2.12	25.22	6202
NE Mass-Boston	23.63	-0.32	0.01	-2.23	25.22	6542
SE Mass	24.34	0.33	0.07	-1.76	25.58	6736
West-Central Mass	23.87	-0.32	0.25	-2.26	25.42	6607
Rhode Island	27.09	3.02	0.13	-0.33	27.42	7497
Maine	22.64	-0.32	-0.98	-1.74	23.98	5683
New Hampshire	23.55	-0.32	-0.08	-2.27	25.04	5910
Vermont	23.63	-0.32	0.01	-2.28	25.12	5932

NYISO day-ahead LMP for Oct 3 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	46.99	-0.04	2.75	-1.30	45.02	12380
Central Zone	44.91	0.00	0.70	0.76	41.93	12557
Dunwoodie Zone	48.54	0.00	4.34	-0.76	46.41	12454
Genesee Zone	44.73	-0.01	0.52	0.99	41.60	12507
Hudson Valley Zone	48.61	0.00	4.41	-0.70	46.35	12472
Long Island Zone	63.85	-13.88	5.77	-7.26	60.90	16380
Millwood Zone	48.66	0.00	4.45	-0.73	46.48	12483
Mohawk Valley Zone	45.71	0.13	1.64	1.19	42.82	12464
N.Y.C. Zone	49.10	-0.14	4.76	-1.09	47.35	12597
North Zone	40.52	1.18	-2.50	10.58	35.12	10191
West Zone	44.74	-1.04	-0.50	2.99	40.29	12509
Off-Peak						
Capital Zone	24.20	0.00	1.46	-2.12	25.21	6332
Central Zone	22.97	0.00	0.23	-1.01	23.49	6427
Dunwoodie Zone	24.69	0.00	1.94	-2.05	25.69	6330
Genesee Zone	22.98	0.00	0.24	-0.90	23.41	6431
Hudson Valley Zone	24.69	0.00	1.95	-2.05	25.66	6332
Long Island Zone	36.70	-11.29	2.67	3.71	32.93	9411
Millwood Zone	24.69	0.00	1.95	-2.05	25.69	6331
Mohawk Valley Zone	23.44	0.00	0.70	-1.07	24.02	6344
N.Y.C. Zone	24.92	0.00	2.18	-2.03	25.93	6391
North Zone	21.79	0.00	-0.95	-0.53	22.17	5470
West Zone	22.87	0.00	0.13	-0.90	23.26	6400

Generation unit outage report

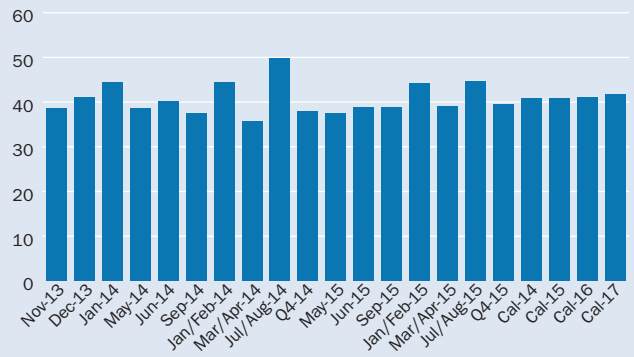
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Arnprior/OPG	92	h	Ont.	MO	Unk	10/02/13
Atikokan/OPG	205	c	Ont.	PMO	Unk	09/11/12
Auguasabon/OPG	51	h	Ont.	MO	Unk	09/27/13
Darlington-2/OPG	868	n	Ont.	PMO	Unk	08/27/13
Darlington-4/OPG	869	n	Ont.	MO	Unk	10/02/13
East Windsor-2/EWC	50	g	Ont.	MO	Unk	10/02/13
Fort Frances/Fort Frances	99	w	Ont.	MO	Unk	09/20/13
GTAA-3/GTAA	34	g	Ont.	MO	Unk	10/01/13
Lambton-3/OPG	326	c	Ont.	MO	Unk	09/06/13
Lambton-4/OPG	320	c	Ont.	MO	Unk	09/27/13
Lennox-3/OPG	525	bio	Ont.	MO	Unk	09/05/13
Little Long-2/OPG	133	h	Ont.	Mo	Unk	09/27/13
Nanticoke-6/Brookfield	292	c	Ont.	MO	Unk	09/05/13
Nanticoke-7/Brookfield	90	c	Ont.	MO	Unk	09/17/13
Peach Bottom-3/Exelon	1182	n	Pa.	PMO	Unk	09/09/13
Pickering-1/OPG	500	n	Ont.	MO	Unk	09/30/13
Pickering-6/OPG	510	n	Ont.	MO	Unk	09/03/13
Taohsc/TransAlta	78	g	Ont.	MO	Unk	09/03/13
Thunderbay-2/OPG	150	c	Ont.	PMO	Unk	03/01/13

Northeast Platts-ICE Forward Curve, Oct 2 ($/MWh)

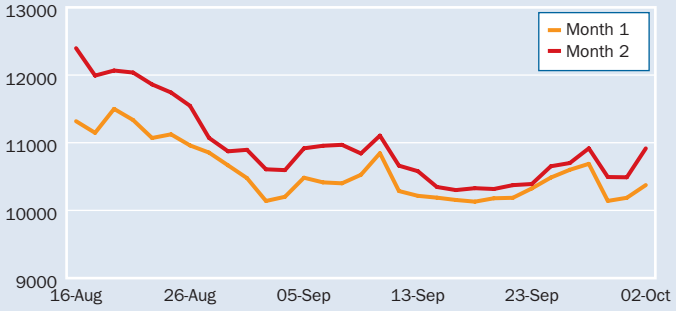
Prompt month: Nov 13	On-peak	Off-peak
Mass Hub	50.00	38.50
N.Y. Zone G	47.50	39.25
N.Y. Zone J	50.50	40.00
N.Y. Zone A	38.50	31.75
Ontario*	29.75	21.00

*Ontario prices are in Canadian dollars

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



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



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Next-week	09/30	40.75-41.75

*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 as terms retreat

Daily power prices in the Electric Reliability Council of Texas increased on the IntercontinentalExchange Wednesday amid higher spot natural gas prices. Forward prices mostly dropped while the NYMEX November gas futures settled at $3.542/MMBtu, 6.7 cents lower than Tuesday's closing price.

Spot natural gas at Houston Ship Channel added 3.3 cents to trade around $3.638/MMBtu.

ERCOT North Hub next-day on-peak physical power jumped up about $13.75 to trade around $49.75/MWh. Off-peak gained about 25 cents to trade around $23.75/MWh.

High temperatures across ERCOT's footprint were forecast in the mid-80s to low 90s Thursday, with lows expected in the low 70s. The average October high temperature across ERCOT is in the upper 70s to low 80s, with the average low in the upper 50s to mid-60s.

System load in ERCOT was forecast to peak at 54,475 MW Wednesday and 53,525 MW Thursday, compared with an actual peak of 52,661 MW Tuesday.

Real-time prices averaged $22.50/MWh from 12:15 to 6 am CDT Wednesday. Wind generation was forecast to peak at 6,250MW at 1 am CDT Wednesday and 7,050 MW at midnight CDT Wednesday.

North Hub balance-of-the-week was bid at $48 and offered at $50/MWh. Next-week on-peak was bid at $33.25 and offered at $34/MWh.

Balance-of-the-month on-peak was bid at $32.50 and offered at $35/MWh. Houston Hub bal-week was bid at $60 and offered at $80/MWh. Next-week on-peak was bid at $38.25 and offered at $43.50/MWh.

In the Southeast, power for Thursday delivery was priced weaker Wednesday as temperatures were forecast to be steady. Into Southern next-day on-peak power was bid at $33.25 and offered at $35.75/MWh, down about 25 cents from Tuesday.

Spot natural gas at Transco Zone-3 added 7.9 cents to trade around $3.649/MMBtu. High temperatures in Atlanta were forecast in the low 80s Tuesday, with lows expected in the mid-

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for Oct 3 ($/MWh)

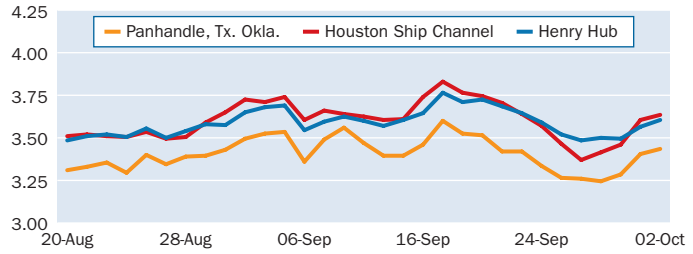
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	37.25	-1.25	37.67	9894
Southern, Into	34.50	-0.25	34.58	9491
Florida	36.25	-0.25	36.33	9824
TVA, Into	35.50	-1.25	36.08	9680
Entergy, Into	33.25	-0.50	33.67	9268
Southeast Off-Peak				
VACAR	25.25	-0.75	25.58	6707
Southern, Into	25.00	-0.25	24.92	6878
Florida	24.50	-0.50	24.58	6640
TVA, Into	24.50	-0.50	24.58	6680
Entergy, Into	23.00	-0.25	22.92	6411
ERCOT On-peak				
ERCOT, North	50.00	14.00	40.00	14015
ERCOT, Houston	71.00	17.75	58.08	19600
ERCOT, South	60.25	14.75	49.25	16771
ERCOT, West	51.25	14.00	41.25	14406
ERCOT Off-Peak				
ERCOT, North	23.75	0.25	23.25	6657
ERCOT, Houston	25.50	0.25	24.92	7039
ERCOT, South	25.50	0.25	24.92	7098
ERCOT, West	22.00	-1.00	22.50	6184
SPP/MRO On-peak				
MAPP, South	33.75	-2.00	35.08	9184
SPP, North	33.50	-1.50	34.58	9753
SPP/MRO Off-Peak				
MAPP, South	22.50	-0.25	22.50	6122
SPP, North	22.50	0.00	22.25	6550

Southeast load and generation mix forecast (GWh)

	Actual 01-Oct	%Chg	% Chg Year-ago	Forecast 02-Oct	03-Oct	04-Oct	05-Oct	06-Oct
ERCOT								
Load	991	6	0	980	1008	1004	870	782
Generation								
Coal	393	-1	12	371	395	411	397	384
Gas	433	21	-8	462	438	416	348	308
Nuclear	96	-19	-2	91	92	96	104	111
SPP								
Load	627	8	-4	637	657	655	555	507
Generation								
Coal	388	8	3	393	400	401	367	341
Gas	153	4	-22	162	171	167	131	110
Nuclear	33	57	-7	49	49	49	49	49

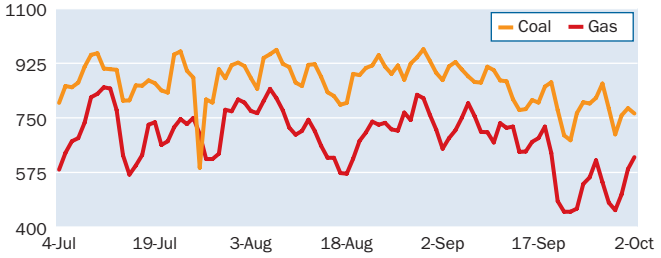
Source: Bentek

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



Source: Platts

ERCOT & SPP gas and coal generation (GWh)



Source: Bentek

ERCOT average day-ahead LMP for Oct 3 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	59.11	17.31	46.40	16519
Hub Average	62.95	17.81	49.80	17590
Houston Hub	76.86	18.87	62.76	21235
North Hub	54.20	17.20	41.54	15233
South Hub	65.24	17.87	52.02	18189
West Hub	55.49	17.28	42.88	15631
AEN Zone	62.49	18.26	49.19	17604
CPS Zone	66.16	19.36	52.18	18446
LCRA Zone	63.85	18.25	50.49	17802
Rayburn Zone	54.27	17.39	41.33	15252
Houston Zone	77.59	18.83	63.54	21436
North Zone	54.66	17.50	41.82	15361
South Zone	66.32	16.61	53.51	18492
West Zone	88.43	32.71	64.50	24910
Off-Peak				
Bus Average	24.57	0.71	24.04	6928
Hub Average	24.59	0.46	24.22	6933
Houston Hub	26.25	0.81	25.50	7281
North Hub	24.40	1.02	23.66	6949
South Hub	26.18	0.80	25.36	7359
West Hub	21.52	-0.80	22.36	6127
AEN Zone	24.53	0.96	23.79	6983
CPS Zone	28.39	0.99	27.27	7981
LCRA Zone	25.43	1.03	24.65	7148
Rayburn Zone	25.78	1.96	24.26	7342
Houston Zone	26.30	0.81	25.55	7295
North Zone	24.67	1.22	23.77	7025
South Zone	26.59	0.77	25.81	7475
West Zone	22.17	-0.42	22.78	6310

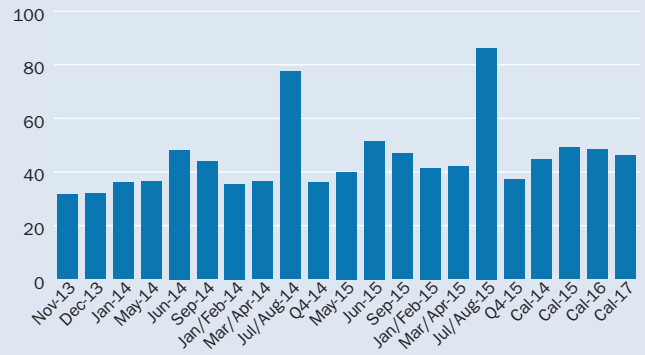
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	10/02	34.00-34.50
Bal-week	09/30	33.50-34.00
Bal-month	10/02	33.50-34.00
Bal-month	09/30	33.00-33.50
Bal-month	09/26	31.50-32.00
Next-week	10/02	32.75-33.25
Next-week	09/30	32.25-32.75
Next-week	09/27	33.75-34.25
Next-week	09/26	32.50-33.00
Entergy, Into		
Bal-week	10/02	32.00-32.50
Bal-month	10/02	32.00-32.50
Bal-month	09/26	32.75-33.25
Next-week	10/02	32.00-32.50
Next-week	09/27	32.00-32.50
Next-week	09/26	33.25-33.75
ERCOT, North		
Bal-week	09/30	34.25-35.00

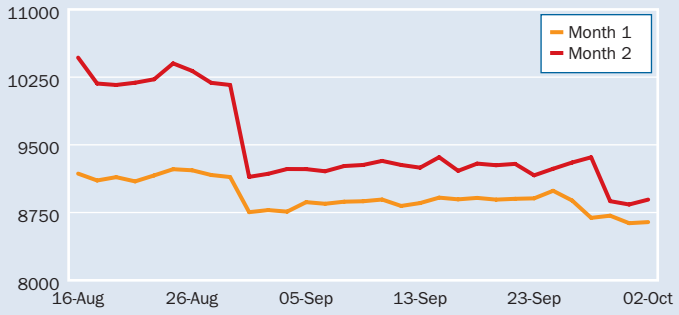
Southeast & Central Platts-ICE Forward Curve, Oct 2 ($/MWh)

Prompt month: Nov 13	On-peak	Off-peak
Southern Into	33.25	28.00
Entergy Into	31.50	25.25
ERCOT North	31.50	25.25
ERCOT Houston	34.25	26.00
ERCOT West	30.50	24.25
ERCOT South	32.25	25.25

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						
Big Brown-2/Luminant	575	c	Texas	MO	Unk	10/01/13
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
Deepwater/AES	138	c	Texas	MO	Unk	10/01/13
Farley-1/Southern	918	n	Ala.	MO	Unk	09/30/13
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Martin Lake-1/Luminant	750	c	Texas	Mo	Unk	09/25/13
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
South Texas-1/STP	1413	n	Texas	MO	Unk	10/02/13
SR Berton/NRG	765	g	Texas	MO	Unk	10/01/13
St.Lucie-1/FPL	872	n	Fla.	RF	Unk	09/30/13
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13

WEST MARKETS

Most Western dailies move back; terms stumble

Most western dailies were down Wednesday morning with slightly lower demand expected in the California on Thursday. Terms also fell, and the NYMEX November gas futures posted a preliminary settlement of $3.542/MMBtu, 6.7 cents lower than Tuesday's close.

In the Northwest, Mid-Columbia day-ahead on-peak was up almost $2.75 to trade between $30.25 and $32/MWh for delivery on Thursday. Mid-C day-ahead off-peak was up more than $1.25 to trade between $27.50 and $28.25/MWh. The Mid-C on-peak balance-of-the-month package traded between $33 and $33.25/MWh, up more than $1.25.

Portland, Oregon's forecasts had highs in the upper 50s through Thursday. Expected lows were from the mid- to high 40s.

The Bonneville Power Administration's wind output was 182 MW, and its hydro output was 8,307 MW at 7 am PDT on Wednesday.

In California, SP15 next-day on-peak fell about 75 cents to trade between $41 and $41.75/MWh. SP15 day-ahead off-peak dropped more than $1 to trade between $31.50 and $32/MWh. SP15 bal-month was bid at $41.85 and offered at $42.50/MWh on IntercontinentalExchange, down more than 25 cents. NP15 day-ahead on-peak was down about $1.25 to trade between $39.50 and $40/MWh. NP15 day-ahead off-peak declined $1 to about $31.75/MWh. NP15 bal-month was bid at $39.85 and offered at $41.50 on the ICE, up slightly.

Sacramento, California, expected highs from the mid- to upper 70s and lows in the low 50s. Forecast highs for Burbank were in the mid-70s with anticipated lows in the mid- to upper 50s. The California Independent System Operator projected peak demand to be 30,923 MW on Wednesday and 30,840 MW on Thursday.

California renewables were 3,427 MW, and wind was more than 1,700 MW at 7 am PDT on Wednesday.

In the desert Southwest, Palo Verde next-day on-peak was down around $1.25 to trade between $32.50 and $34/MWh. Palo Verde day-ahead off-peak shed climbed nearly 25 cents to trade between $25.75 and $26/MWh. Palo Verde bal-month was bid at $34 and offered at $35.50/MWh, about flat.

Phoenix expected highs in the low 90s and lows near 70.

Next-day natural gas prices rose in the Rockies and California. Opal was up 8.2 cents to $3.557/MMBtu, Pacific Gas and Electric city-gate added 4.2 cents to $3.957/MMBtu, and SoCal city-gate gained 4.7 cents to $3.772/MMBtu.

Most day-ahead prices were down in the Californian Independent System Operator auction Wednesday afternoon following the lower demand forecast. SP15 on-peak fell 41 cents to $40.38/MWh, as SP15 off-peak slipped 63 cents to $31.33/MWh. NP15 on-peak was up $1.51 to $41.33/MWh, and NP15 off-peak lost 40 cents to $31.71/MWh. ZP26 on-peak dropped 87 cents to $38.13/MWh, while ZP26 off-peak shed 67 cents to $30.56/MWh.

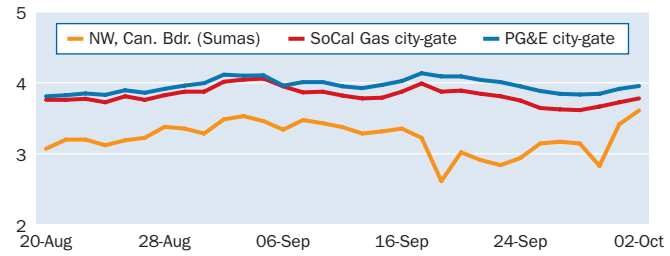
In the Northwest, Mid-Columbia on-peak November was

(continued on page 10)

Western day-ahead bilateral indexes for Oct 3 ($/MWh)

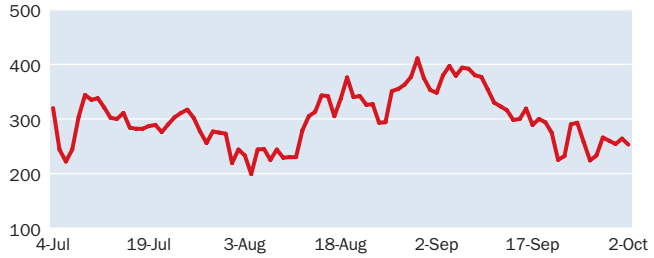
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	34.19	1.11	32.80	9445
Mid-C	31.00	2.63	28.74	8683
Palo Verde	33.40	-1.35	34.01	9304
Mead	35.00	-0.25	35.00	9550
Mona	32.00	-1.75	32.17	9078
Four Corners	35.00	-0.25	35.08	9957
NP15	39.75	-1.25	40.33	10051
SP15	41.75	-0.50	41.75	11392
Off-Peak				
COB	28.29	0.51	27.57	7815
Mid-C	27.99	1.36	26.23	7840
Palo Verde	25.75	0.00	25.25	7173
Mead	26.50	0.50	25.92	7231
Mona	20.75	-0.25	21.25	5887
Four Corners	25.00	-0.25	24.39	7112
NP15	31.75	-1.00	32.00	8028
SP15	31.75	-1.00	31.83	8663

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO gas generation (GWh)



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 01-Oct	%Chg	% Chg Year-ago	Forecast 02-Oct	03-Oct	04-Oct	05-Oct	06-Oct
CAISO								
Load	655	0	0	661	655	654	619	612
Generation								
Gas	264	4	1	253	236	239	261	273
Nuclear	56	0	-6	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Oct 3 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	41.33	1.21	-2.09	1.51	40.78	10451
SP15 Gen Hub	40.38	-0.89	-0.94	-0.41	41.51	11004
ZP26 Gen Hub	38.13	-1.06	-3.02	-0.87	38.94	10391
Off-Peak						
NP15 Gen Hub	31.71	0.00	-0.55	-0.40	32.38	8071
SP15 Gen Hub	31.33	0.00	-0.94	-0.63	32.27	8642
ZP26 Gen Hub	30.56	0.00	-1.70	-0.67	31.41	8431

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	10/02	33.00-33.50
Bal-month	10/01	31.50-32.00
Bal-month (off-peak)	10/02	28.75-30.00
SP15		
Bal-week	10/02	43.25-43.75
Bal-month	10/02	41.75-42.25

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
ACE Cogen/Constellation	118	g	Calif.	MO	Unk	09/29/13
Alta-7/TerraGen	168	w	Calif.	PMO	Unk	10/01/13
Des Sunlight/NextEra	250	s	Calif.	MO	Unk	09/08/13
Haas1-2/PG&E	144	h	Calif.	PMO	Unk	10/01/13
Hatchet Ridge/Pattern	102	w	Calif.	MO	Unk	10/01/13
Helms-3/PG&E	404	h	Calif.	MO	Unk	09/22/13
Inland Empire/GE	366	g	Calif.	MO	Unk	10/01/13
Kerckhoff-1/PG&E	154	h	Calif.	PMO	Unk	09/29/13
Lodi Energy Center/NCPA	303	g	Calif.	PMO	Unk	10/01/13
Mariposa/Diamond	196	g	Calif.	PMO	Unk	10/01/13
Mexicali-1/Sempra	625	g	Calif.	MO	Unk	09/26/13
Middle Fork/PCWA	218	h	Calif.	PMO	Unk	10/01/13
Morro Bay-4/Dynegy	325	g	Calif.	MO	Unk	10/01/13
Mountain View-3/Iberdrola	525	w	Calif.	PMO	Unk	10/01/13
Solar Star-1/MidAmerican	310	s	Calif.	MO	Unk	10/01/13
Solar Star-2/MidAmerican	270	s	Calif.	MO	Unk	10/01/13

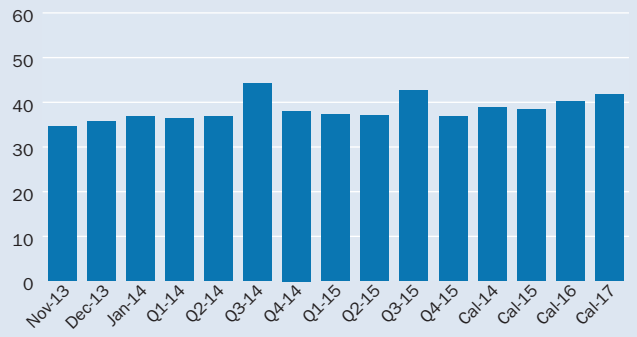
Additional information on data and analysis:

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

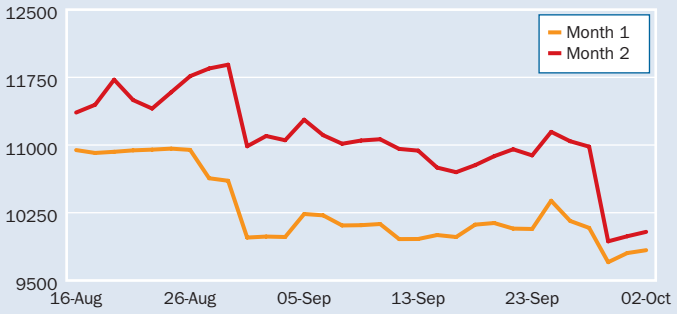
Western Platts-ICE Forward Curve, Oct 2 ($/MWh)

Prompt month: Nov 13	On-peak	Off-peak
Mid-C	36.75	31.00
Palo Verde	32.50	26.25
Mead	34.50	28.00
NP15	41.50	35.00
SP15	42.50	35.00

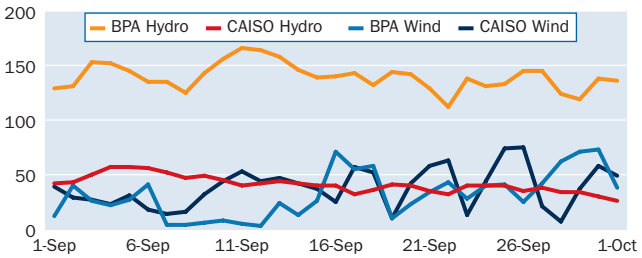
Mead: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

PJM & MISO dailies and forwards lower

Mid-Atlantic dailies peeled back early Wednesday even with demand forecast to rise and firm spot gas markets. Dailies in the Midwest also turned lower. Forwards in the two regions fell as the NYMEX November gas futures posted a preliminary settlement of $3.542/MMBtu, 6.7 cents lower than Tuesday's close.

The PJM Interconnection forecast peak demand on Wednesday at 104,143 MW and 107,018 MW for Thursday. High temperatures in the PJM footprint are forecast in the mid-70s to mid-80s on Thursday.

Spot gas in the region moved up with Texas Eastern M-3 spot natural gas gaining 7 cents to around $3.65/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Thursday fell about $3 to the mid-$40s/MWh and off-peak was off about $2.50 to the mid-$20s/MWh.

Midwest dailies peeled back with nearby weakness. Chicago city gates spot gas edged up 2 cents to about $3.72/MMBtu. Indiana Hub on-peak for Thursday lost most of the previous day's gains falling about $4.50 to the upper $30s/MWh and off-peak shed about 50 cents to about the low to mid-$20s/MWh.

Minnesota Hub on-peak for Thursday lost about $3 going to the low $40s/MWh.

Dailies in the Midwestern portion of the PJM Interconnection were down. AEP-Dayton Hub on-peak for Thursday lost about $4 going to the low $40s/MWh and off-peak shed about $1 in the mid-$20s/MWh.

Northern Illinois Hub on-peak for Thursday lost about $5 going to the upper $30s/MWh and off-peak was off about $3 going to the low $20s/MWh.

Day-ahead auction prices in the PJM Interconnection were mixed even with overall RTO demand expected to rise. Eastern Hub on-peak fell more than $4 to about $43.67/MWh and Western Hub on-peak easing 67 cents to $43.99/MWh.

PSEG on-peak dropped $8.51 to $44.08/MWh and JCPL on-peak lost $9.43 to $45.76/MWh. BG&E on-peak fell about $2.07 to $47.59/MWh and Pepco on-peak was off $1.21 to $46.24/MWh. Comed on-peak gained $3.62 to $39.41/MWh and Chicago Hub on-peak fell $3.51 to $39.43/MWh.

MISO day-ahead auction prices cleared weaker Wednesday afternoon. Minnesota Hub remained the highest-priced hub with on-peak clearing at $40.79/MWh, a loss of $1.27. Off-peak cleared at $22.01/MWh, a drop of 83 cents.

Michigan Hub on-peak cleared at $36.84/MWh, falling $2.69. Off-peak cleared at $27.50/MWh, adding $2.96. Indiana Hub on-peak cleared at $36.45/MWh, down $4.27. Off-peak cleared at $24.04/MWh, a decrease of 3 cents.

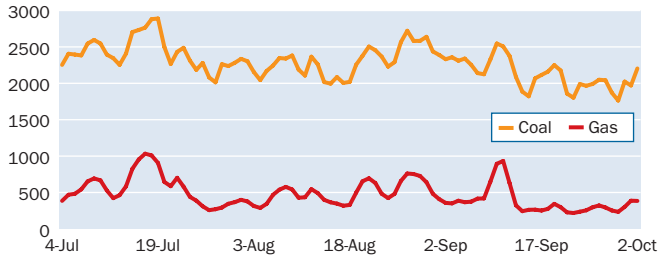
Illinois Hub remained the lowest priced hub with on-peak clearing at $33.95/MWh, a loss of $2.81. Off-peak cleared at $22.53/MWh, a gain of 48 cents.

Congestion costs at the hubs ranged from negative $1.75 to

PJM & MISO day-ahead bilateral indexes for Oct 3 ($/MWh)

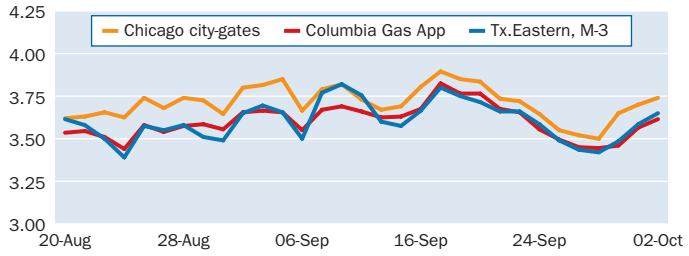
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	45.50	-3.75	46.75	13025
Dominion Hub	46.25	-2.50	46.58	12534
AD Hub	40.50	-4.25	42.75	11050
NI Hub	37.75	-5.25	40.75	10094
PJM Off-Peak				
PJM West	26.00	-2.50	27.50	7443
Dominion Hub	25.50	-2.75	27.17	6911
AD Hub	26.00	-1.00	26.67	7094
NI Hub	21.00	-3.00	22.67	5615
MISO On-peak				
Indiana Hub	38.50	-4.50	40.50	10434
Michigan Hub	37.25	-4.75	40.25	9841
Minnesota Hub	41.00	-3.00	42.83	11179
Illinois Hub	34.50	-3.50	36.75	9194
MISO Off-Peak				
Indiana Hub	23.50	-0.50	23.50	6369
Michigan Hub	23.00	-2.00	23.58	6077
Minnesota Hub	22.00	11.25	14.67	5999
Illinois Hub	21.75	1.25	20.83	5796

PJM & MISO gas and coal generation (GWh)



Source: Bentek

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 01-Oct	%Chg	% Chg Year-ago	Forecast 02-Oct	03-Oct	04-Oct	05-Oct	06-Oct
PJM								
Load	1832	-5	0	2128	2189	2227	2079	1918
Generation								
Coal	803	-10	13	996	1018	991	943	887
Gas	316	26	-20	331	327	337	341	311
Nuclear	679	0	1	681	681	684	688	692
MISO								
Load	1369	4	-1	1407	1456	1461	1272	1138
Generation								
Coal	1167	3	6	1208	1167	1151	1091	1033
Gas	71	41	-40	52	68	89	67	20
Nuclear	206	5	-11	203	203	203	203	203

Source: Bentek

MISO average day-ahead LMP for Oct 3 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	36.45	-0.46	-0.04	-4.27	40.39	9875
Michigan Hub	36.84	-0.74	0.63	-2.69	39.01	9733
Minnesota Hub	40.79	3.62	0.23	-1.27	41.94	11144
Illinois Hub	33.95	-1.75	-1.25	-2.81	35.70	9044
Off-Peak						
Indiana Hub	24.04	0.29	0.21	-0.03	24.45	6561
Michigan Hub	27.50	3.26	0.71	2.96	26.03	7324
Minnesota Hub	22.01	-1.50	-0.04	-0.83	19.18	6060
Illinois Hub	22.53	-0.21	-0.81	0.48	21.75	6041

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

Package	Trade date	Range
PJM West		
Bal-week	10/01	49.00-51.25
Bal-week	09/30	50.50-52.00
Bal-week	09/27	45.00-47.50
Bal-month	09/26	38.00-39.00
Next-week	10/02	39.50-40.50
Next-week	10/01	40.50-41.50
Next-week	09/27	39.75-41.25
Next-week	09/26	41.00-42.75
AD Hub		
Bal-week	10/01	43.50-44.50

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Beaver Valley/FirstEnergy	959	n	Penn.	RF	Unk	09/30/13
DC Cook-2/IMP	1151	n	Mich.	RF	Unk	10/02/13
Kewaunee/Dominion	581	n	Wis.	NA	Retired	05/07/13
Oyster Creek/Exelon	670	n	N.J.	PMO	Unk	09/30/13
Prarie Island-2/Xcel	585	n	Minn.	RF	Unk	09/21/13

PJM average day-ahead LMP for Oct 3 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	38.39	-2.05	-2.43	1.05	38.53	10540
AEP-Dayton Hub	40.30	-1.63	-0.95	0.60	40.51	11063
ATSI Gen Hub	45.57	1.48	1.21	-3.47	45.97	12687
Chicago Gen Hub	38.40	-2.35	-2.13	3.34	37.68	10270
Chicago Hub	39.43	-1.92	-1.52	3.51	38.74	10546
Dominion Hub	44.85	2.98	-1.01	0.68	44.36	12176
Eastern Hub	43.67	-0.88	1.67	-4.08	44.54	11848
New Jersy Hub	44.51	-0.05	1.68	-8.21	46.70	12076
Northern Illinios Hub	38.92	-2.18	-1.78	3.35	38.19	10409
Ohio Hub	40.73	-1.52	-0.63	0.56	40.91	11033
West Internal Hub	44.51	1.90	-0.27	1.01	43.81	12764
Western Hub	43.99	0.92	0.19	-0.67	44.44	12613
AEP Zone	40.41	-1.51	-0.95	0.67	40.54	11095
Allegheny Power Zone	42.04	-0.26	-0.57	0.84	41.95	11720
Atlantic Elec Zone	43.25	-1.16	1.54	0.82	42.39	11736
ATSI Zone	46.85	2.43	1.55	-2.32	47.17	13044
BG&E Zone	47.59	3.09	1.62	-2.07	49.18	13312
ComEd Zone	39.41	-1.90	-1.57	3.62	38.69	10539
Dayton P&L Zone	41.18	-2.10	0.40	0.71	41.45	11282
Delmarva P&L Zone	43.44	-0.67	1.24	-1.47	43.35	11787
Dominion Zone	44.99	2.66	-0.55	0.46	44.66	12214
Duke Zone	39.50	-1.99	-1.39	0.77	39.83	10822
Duquesne Light Zone	41.55	-1.01	-0.32	1.94	40.95	11869
JCPL Zone	45.76	1.02	1.87	-9.43	48.04	12416
MetEd Zone	42.03	-1.03	0.18	-3.58	42.95	11484
PECO Zone	42.05	-1.48	0.65	-2.33	42.44	11488
Pennsylvania Elec Zone	44.20	0.30	1.02	-1.51	44.66	12688
PEPCO Zone	46.24	2.60	0.76	-1.21	47.23	12933
PPL Zone	43.68	0.62	0.19	-3.09	43.80	11934
PSEG Zone	44.08	-0.43	1.64	-8.51	46.52	11961
Rockland Elec Zone	44.49	-0.06	1.68	-5.40	45.68	12071
Off-Peak						
AEP Gen Hub	25.24	0.11	-0.98	-0.11	25.37	6994
AEP-Dayton Hub	26.17	0.39	-0.34	-0.15	26.31	7252
ATSI Gen Hub	26.95	0.37	0.47	0.28	26.81	7562
Chicago Gen Hub	22.56	-2.57	-0.98	1.08	22.31	6087
Chicago Hub	23.14	-2.29	-0.69	0.90	23.02	6245
Dominion Hub	26.17	0.42	-0.37	-0.21	26.35	7186
Eastern Hub	27.11	0.39	0.61	0.17	26.88	7440
New Jersy Hub	27.41	0.57	0.72	0.47	27.01	7520
Northern Illinios Hub	22.98	-2.34	-0.80	0.85	22.89	6201
Ohio Hub	26.39	0.48	-0.21	-0.15	26.54	7206
West Internal Hub	26.52	0.48	-0.08	0.15	26.47	7681
Western Hub	26.63	0.37	0.15	0.14	26.56	7714
AEP Zone	26.06	0.27	-0.33	-0.11	26.17	7220
Allegheny Power Zone	26.24	0.30	-0.17	0.07	26.21	7393
Atlantic Elec Zone	27.10	0.40	0.59	0.40	26.77	7437
ATSI Zone	27.30	0.55	0.63	0.39	27.07	7659
BG&E Zone	27.13	0.33	0.69	0.11	27.10	7654
ComEd Zone	23.11	-2.29	-0.71	1.02	22.94	6237
Dayton P&L Zone	26.44	0.13	0.20	-0.04	26.51	7309
Delmarva P&L Zone	27.02	0.40	0.50	0.11	26.82	7414
Dominion Zone	26.32	0.38	-0.17	-0.15	26.47	7228
Duke Zone	25.56	0.05	-0.61	-0.21	25.75	7065
Duquesne Light Zone	26.14	0.25	-0.22	0.07	26.09	7529
JCPL Zone	27.65	0.76	0.78	0.49	27.15	7588
MetEd Zone	26.53	0.38	0.03	0.28	26.32	7328
PECO Zone	26.71	0.36	0.24	0.33	26.46	7379
Pennsylvania Elec Zone	27.23	0.47	0.64	0.43	26.95	7805
PEPCO Zone	26.83	0.33	0.39	0.06	26.84	7570
PPL Zone	26.50	0.39	-0.01	0.31	26.25	7320
PSEG Zone	27.34	0.50	0.73	0.46	26.98	7503
Rockland Elec Zone	27.45	0.59	0.75	0.50	27.06	7533

$3.62 for on-peak, and from negative $1.50 to $3.26 for off-peak.

Mid-Atlantic forward prices eased Wednesday as NYMEX gas reversed course and headed down later in the day. PJM West on-peak November financial futures eased about 50 cents, with bids at $40.70/MWh and offers at $40.80/MWh at about 2:30 p.m. EDT on the IntercontinentalExchange. PJM West on-peak December was down about 25 cents to $42/MWh. PJM West on-peak January-February 2014 financial futures gave up 40 cents dropping down about $44.50/MWh.

Midwest forwards were down with weakness in NYMEX gas futures. AD Hub on-peak November financial futures softned by about 25 cents, with bids at $37.70/MWh and offers at $38.20/MWh on ICE. Indiana Hub on-peak November financial futures were down 25 cents, with bids at $34.40/MWh and offers at $34.70/MWh on ICE. NI Hub on-peak November financial futures dropped about 75 cents to with bids at $33.50/MWh and offers at $35.25/MWh on ICE.

Southeast markets ... *from page 4*

60s. The average October high temperature in the city is 73, while the average low is 54.

The ERCOT day-ahead auction cleared much stronger Wednesday afternoon even with peak load projected to fall slightly. Houston Hub remained the highest-priced hub and North Hub the lowest-priced. Houston Hub on-peak cleared in the auction at $76.86/MWh, rising about $18.75, while off-peak cleared at $26.25/MWh, adding around 75 cents.

South Hub on-peak cleared at $65.24/MWh, adding around $14.75, while off-peak cleared at $26.18/MWh, moving up about 75 cents. West Hub on-peak cleared in the ERCOT auction at $55.49/MWh, a jump of around $17.25, while off-peak cleared at $21.52/MWh, a loss of around 75 cents. North Hub on-peak cleared the auction at $54.20/MWh, up almost $17.25 from Tuesday's clearing price, while off-peak cleared at $24.40/MWh, an increase of about $1.

West Zone on-peak led the load zones at $88.43/MWh, gaining around $32.75 from Tuesday.

The highest hourly day-ahead price occurred at 5 pm CDT in the Houston Hub at $198.68/MWh, and in the West Zone at $227.31/MWh.

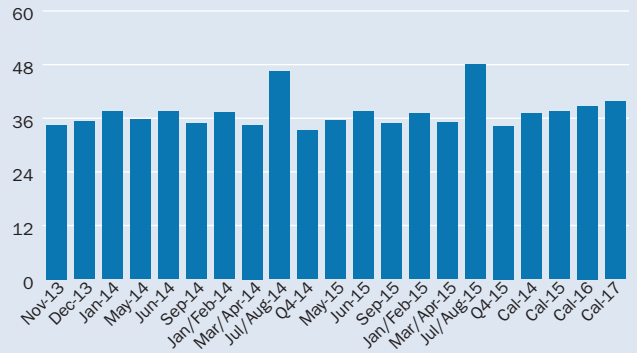
Most South Central on-peak term prices fell at the front of the curve Wednesday, as November NYMEX gas futures declined. ERCOT North on-peak November lost 40 cents to about $31.50/MWh, December fell 25 cents to about $32.25/MWh, and January-February edged down 10 cents to about $35.65/MWh. Heat rates were up about 30 Btu/kWh on ICE around 2:30 p.m. EDT. Into Entergy on-peak November stayed around $31.50/MWh, but December fell 25 cents to about $31.75/MWh.

Southeast on-peak November was unmoved Wednesday, even as November NYMEX gas futures moved down. Into Southern

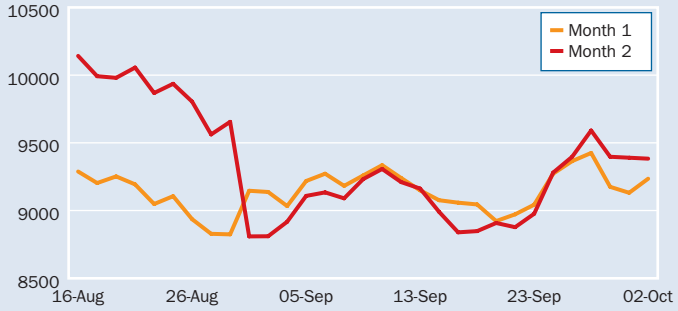
PJM & MISO Platts-ICE Forward Curve, Oct 2 ($/MWh)

Prompt month: Nov 13	On-peak	Off-peak
PJM West	40.75	32.25
AD Hub	38.00	30.50
NI Hub	34.50	23.75
Indiana Hub	34.50	27.00

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



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



November stayed at about $33.25/MWh, December fell 25 cents to about $33.50/MWh, and Jan-Feb 2014 dipped 35 cents to about $36.50/MWh.

West markets ... *from page 6*

unmoved with bids at $36.50 and offers at $37/MWh on ICE around 2:30 pm EDT. December rose 25 cents to about $40.50/MWh, and the first quarter dipped 35 cents to about $35.25/MWh. In California, SP15 on-peak November financial terms fell 50 cents with bids at $42.50 and offers at $42.75/MWh. December fell 50 cents to about $42/MWh, and first quarter shed 75 cents to about $42.65/MWh. NP15 November fell 50 cents to about $41.50/MWh, and December fell 50 cents to about $41.75/MWh. Palo Verde November had no bid and an offer of $33.25/MWh, December had no bid and an offer of $34.75/MWh, and first quarter fell 25 cents to about $35/MWh.

NEWS

IETA sets standard contract for GHG instruments

A new standardized contract for trading instruments used to comply with California's greenhouse gas cap-and-trade program was unveiled Wednesday by the International Emissions Trading Association.

The document aims to boost liquidity in the secondary market for GHG allowances and offset credits, according to Richard Saines, an attorney with Baker & McKenzie who heads the firm's North American environmental markets practice.

Baker & McKenzie led an IETA committee tasked with writing the contract, called the California Emissions Trading Master Agreement.

This is the not the first effort of its kind. In 2012, the Edison Electric Institute published a standardized contract related to California cap-and-trade compliance instruments.

Saines says he hopes the IETA document can gain traction with a broader community than the electricity-dominated audience most familiar with EEI.

The California cap-and-trade program was launched in 2013. It requires companies, including power plant owners, electricity importers and large industrial customers to hold enough compliance instruments to cover their emissions. The compliance list expands in 2015 to include fuel distributors.

Compliance entities can use offset credits for as much as 8% of their needs. The remainder must come from GHG allowances.

The IETA contract entails the physical trade of cap-and-trade instruments. The volume of trading for physical GHG allowances and offset credits in the secondary market has been limited to date.

The first batch of offset credits was issued in September by the California Air Resources Board. Eligible offset projects must undergo a lengthy verification process before CARB will generate the credits that owners can sell into the market.

As for GHG allowances, trading has concentrated around the futures market. The IntercontinentalExchange lists a California GHG allowance contract that transacts on a regular basis.

One of the main challenges behind writing the standardized contract dealt with the possibility that CARB would later invalidate an offset project, Saines said.

CARB placed liability on the shoulders of buyers. But that increased risks beyond most buyers' appetites, considering they would be without any recourse if the credits purchased are ultimately deemed worthless, he said.

Instead, the standardized contract holds sellers responsible. In the event a project generating the credits is invalidated, the seller would have to make the buyer whole, Saines said.

The situation is therefore more akin to counterparty risk, something the two sides are probably more familiar with analyzing and understanding. Such an approach should lead to more trading volume, he said.

— *Geoffrey Craig*

FERC to hold conference on PJM DR proposal

The Federal Energy Regulatory Commission wants to look further into PJM Interconnection's proposal to require more information from demand response providers bidding into its capacity auction in the face of competing calls that the proposal goes too far or not far enough.

FERC in the order Tuesday announced it would schedule a technical conference in the next sixty days to discuss the proposal, saying that a number of issues raised in comments "warrant further discussion, including but not limited to whether the proposed requirements for demand resources are reasonable, given the resource development cycle used by curtailment service providers to provide demand response inside PJM and given the overall reliability objectives of the [Reliability Pricing Model, PJM's capacity auction]."

At the same time, Commissioners Tony Clark and Philip Moeller in a concurring statement questioned whether "additional mechanisms are needed to ensure the reliability of PJM's system and its capacity products."

The proposal in part stems from a FERC order (EL13-57) in April requiring PJM to submit for commission review proposed changes that required additional supporting information from DR providers. PJM had made those changes via its manual and had not submitted them for FERC review, but DR providers in a complaint to FERC argued that those changes would "significantly affect jurisdictional rates, terms and conditions of service, and accordingly must be submitted" to FERC as required under the Federal Power Act.

PJM submitted its proposal in June (ER13-2108), requiring that DR providers seeking to bid into PJM's capacity auction submit a host of details about their DR assets to the grid operator before the auction commences. Those details include those DR sites the bidder currently has and "reasonably expects to have under contract" during the delivery year and how the bidder plans to achieve those demand reductions.

DR providers are also required to have an officer of the company "certify that the information supplied is true and correct, and that the DR Provider is submitting the plan 'with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the [reliability pricing model] Auction through demand resource registrations by the specified Delivery Year."

PJM said the changes are necessary on account of the significant growth in DR and the growth in demand offer levels, which it attributes in part to "overly optimistic assumptions about the demand resource providers' . . . ability to develop entirely new demand response" and "an assumption that resources need not offer in the base residual auction the demand response levels that they actually expect to provide, on the theory that they could buy out of their capacity commitments in the bilateral market or incremental auctions."

And while merchant generators in comments supported PJM's actions, FirstEnergy and Duke protested the proposal, saying that the information that DR providers must submit "is much more

limited than information required for generation capacity resources." The utilities also said that PJM should require DR providers to "supply schedules that reflect an increasing percentage of customers-under-contract in the incremental auctions, instead of the proposed open-ended schedule requirement, because this would provide a better guideline to DR providers and better information to PJM as to whether the demand response will actually be deliverable."

And while utilities are seeking additional requirements on such sources, DR company Comverge in its protest argues that the proposed changes are unjust and unreasonable and would "damage the ability of demand response providers to participate in RPM," according to the order.

Among several complaints, Comverge argues that the certificating requirement restricts "only the rights of demand resources to make purchases in the incremental auctions as needed if the predicted level of demand resource does not come to fruition, and are therefore unduly discriminatory." The company also said that DR resources should be treated differently that generation resources, including because "the majority of planned demand response retail customers who will register in the delivery year are not under contract at the time of the base residual auction."

FERC in the order said little with respect to the arguments surrounding PJM's proposal, announcing that a technical conference will be held and suspending PJM's filing for five months.

But Moeller and Clark in their concurrence appear skeptical of complaints over the proposal, saying that "our initial assessment is that PJM's filing represents a balanced approach for resolving its reliability concerns."

"However, we are also interested in a technical conference as a means of discovering whether additional mechanisms are needed to ensure the reliability of PJM's system and its capacity products," the commissioners said.

The pair noted that it had in its concurrence with the commission's April order expressed support for PJM being able to ensure that resources bidding into the capacity auction would actually be able to help ensure reliability. In that concurrence, they said "PJM has a legitimate need to require that demand resources provide certain information to substantiate offers to supply capacity."

— Bobby McMahon

Daily CSAPR allowance assessments, Oct 2

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, Oct 2

	$/allowance	Change	$/st
SO2 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, Oct 1 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	2.73	0	Dec13	1.97	0
Dec13 V11	2.73	0	Dec14	1.97	0
Dec13 V12	2.73	0			
Dec13 V13	2.72	0			
Dec14 V10	2.79	0			
Dec14 V11	2.79	0			
Dec14 V12	2.79	0			
Dec14 V13	2.78	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.

Md. advocate wants PJM review of need for line

Maryland regulators should order Delmarva Power & Light to ask the PJM Interconnection to re-evaluate the need for a 25-mile 138-kV transmission line based on current load forecasts, the Office of the People's Counsel, the state's consumer advocate, said Tuesday.

The line would run 25.9 miles between the Church and Wye Mills substations in Queen Anne's County and would avoid the possibility of severe reliability problems that could lead to cascading outages, Delmarva Power said in its December application for a certificate of public convenience and necessity. The $31.3 million project would resolve near-term and intermediate-term reliability concerns, the company said.

The project was included in PJM's 2009 regional transmission expansion plan that said it is needed by June 1, 2015.

The only proof Delmarva Power offered to support the need for the project was the fact that it was included in the RTEP, people's counsel said in a brief filed Tuesday with the PSC.

But evidence at the September 10 hearing on the proposal showed that PJM's RTEP analysis was based on significantly outdated load data, the consumer advocate said.

PJM uses load data to determine if reliability problems are likely and whether new transmission lines are needed to serve the growing demand so reliability violations can be avoided.

"A determination of a forecasted contingency violation depends highly on the accuracy of the load forecast for the following three- to five-year period upon which the RTEP is based," the people's counsel said.

There is a reasonable likelihood that reliability violations no longer exist considering the radical disparity between present actual loads and the much higher loads incorrectly projected that PJM used as the basis for its analysis, the people's counsel said.

Delmarva Power load forecasts have been decreasing over the

past several years, but the transmission project was never re-evaluated to consider the effect the 2008 recession had on the projected load growth in the region, the people's counsel said.

The dramatically reduced load forecasts in later RETS have caused many other transmission projects originally included in the 2009 RTEP to be cancelled, the people's counsel said.

The PSC staff testified at the hearing that the peninsula area in which the project would be located is not a robust system and a stronger backbone transmission system is needed to accommodate growth south of Wilmington, Delaware, and the 138-kV project would help accomplish that, the consumer advocate said. But staff agreed that PJM does not order a transmission owner to undertake a project unless PJM has found a violation of NERC standards or its own standards, the people's counsel said.

The people's counsel did not ask the PSC to dismiss Delmarva Power's application to build the new line, but asked that PJM analyze the need based on current load forecasts that also include demand reduction and changes in generation.

"If the N-1-1 contingency violation remains, then OPC would withdraw its opposition and Delmarva Power's application," the people's counsel said.

PJM's load forecasts are done on a macro level and Delmarva Power and its wholesale customers conduct their own forecasts at the distribution level, Delmarva Power said in a brief filed Tuesday with the PSC.

Although PJM calculated a 1.3% load growth, the growth rate for DPL's wholesale customers in specific areas of the system is 3.5%, the utility said. While PJM has not reevaluated the need for the new line, Delmarva Power has and it has determined the project is still necessary, the utility said.

— *Mary Powers*

Utilities hope states address DG cost shifting

Investor-owned utilities want state regulators to address the cost shifting that they say takes place as distributed generation gains popularity, asserting in a new paper that DG customers are not paying their fair share of costs associated with having on-site generation resources.

The growth of DG, often rooftop photovoltaic systems, is presenting challenges for utilities and regulators in several states, with solar power advocates and utilities facing off in the debate about the costs and benefits of DG additions.

In many states with net metering rules and increasing levels of renewable resources at customer facilities, more customers are adding DG resources, with utilities protesting that those customers pay less to the utility for the use of the grid, leaving a greater cost burden on customers without solar panels or DG systems. When the DG market was nascent, the dollars involved were not great, but its growth is presenting a troubling future for some utilities, with California seeing possible cost shifts of $1 billion by 2020 due to net metering, a consultant told the Public Utilities Commission in a recent report.

DG advocates claim that their additions lessen the burden on utilities to add generation, transmission and distribution infrastructure. Net metering advocates say that by having on-site generation where power is being used, and occasionally supplying power when DG output is more than a customer's usage, DG provides a benefit to utilities that may not be fully reflected in net metering rules.

Against this backdrop comes a report this week from IEE, a collection of IOUs focusing on innovation and efficiency in the utility sector. The point of the report is to inform regulators that instead of being "independent," DG customers make use of the power grid to balance their on-site generation output, both when they need more power beyond the DG resource and when they provide power in excess over their usage, the report said.

Most utility rate designs do not account for the grid balancing services to be included in costs paid by DG customers, and those costs are left to be picked up by other customers, which is "fundamentally unfair," said Lisa Wood, executive director of IEE. Because residential rates are almost always designed to recover most of the utility system's fixed costs through a volumetric kWh charge, a DG customer will avoid paying some or all of its share of the fixed costs, Wood said.

An average residential customer bill, based on usage of 1,000 kWh per month, has about 55% of the charges in fixed costs for generation, transmission, distribution and ancillary or balancing services, some of which can be avoided by DG customers, the report said. And the more customers that move to DG options, the greater the cost burden on remaining customers in a utility territory.

"In light of the rapid growth in net-metered DG, it is critical that these customers pay their fair share of the cost of grid services provided to them – and sooner rather than later. Updating net metering policies to put an end to the cost shifting that is occurring today should be done now," IEE said in the report.

Pointing to some mainstream media stories on DG growth and claims of DG advocates, Wood said in an interview that "there is a lot of hype" about DG customers being freed from relying on the power grid, but that is not true.

Most of the state net metering rules "ignore the value of grid services provided to DG customers. In fact, a draft study released last week projects about $1 billion in cost shifting per year in 2020 due to net metering in California. Now that we've jump-started DG in the US, it is time to move to net metering 2.0 and end this cost shifting," Wood said in a statement.

The IEE paper outlines three tariff or cost recovery options that are being tested in a few jurisdictions, each of which strives to have DG customers compensate utilities for their share of fixed costs. One is to impose "standby" charges on DG customers, which is in place at Dominion Virginia Power, for the use of grid services. Dominion requires a residential net-metered DG customer with a peak load between 10 kW and 20 kW to pay a monthly transmission standby charge of $1.40/kW and a monthly distribution standby charge of $2.79/kW.

Another option, which is in place at Austin Energy in Texas, is to treat on-site generation and consumption separately, instead of netting them over a billing period, IEE said. This approach requires a separate meter for on-site generation, but it allows

utilities to charge DG customers for gross consumption, while also compensating those customers for any generation at the utility's avoided cost of procuring power, as called for under the Public Utility Regulatory Policies Act.

The third option is to design a demand charge that would cover a reasonable portion of the grid services costs to be paid by DG customers. That is one of the options proposed by Arizona Public Service, which has drawn protests from solar advocates as regulators examine the utility proposal, IEE noted.

An Arizona Corporation Commission staff report found that the costs and benefits of net metering are essentially a matter of rate design, and the Solar Energy Industries Association is looking forward to a decision in the case, SEIA said this week. "SEIA agrees with the staff report that any changes to [net metering] in the future should only be addressed as part of a general rate case, in which the commission has the appropriate tools at its disposal to make necessary adjustments," said Carrie Cullen Hitt, senior vice president for state affairs at SEIA.

IEE does not believe the three options listed in the report are the only paths for regulators to pursue as they see more DG additions, Wood said. "Every state is going to figure out what works with their utilities," but the report highlights three possibilities as the issue becomes more prominent, she said.

— *Tom Tiernan*

NGSA anticipates little price volatility this winter

Natural gas supply and demand are largely in balance, and the US will likely see very little price volatility this winter, the Natural Gas Supply Association said Wednesday in its winter outlook.

"When NGSA weighed all the different pressure points, the picture that emerged for the upcoming winter is one of quiet growth in supply as well as in demand for natural gas," said Greg Vesey, chairman of NGSA and vice president of Gas Supply and Trading for Chevron.

In a press conference in Washington, D.C., Vesey said demand from the industrial sector could grow 3.5% this winter, while demand from the electric sector is expected to decrease "very slightly" because of a decrease in fuel-switching this year.

Coal-to-gas switching is expected to continue for a sixth straight winter, but switching is forecast to average 4.2 Bcf/d rather than last winter's 5.1 Bcf/d, Vesey said.

Residential and commercial demand this winter is expected to be similar to last winter's demand, he added.

Vesey also projected another winter of strong gas production and storage levels.

"This winter's supply is expected to be even more robust than last year, but characterized by subtle changes that are indicative of the ability of the competitive gas market to adjust to customers' needs," he said.

He explained that 8% of this winter's production is expected to come from "associated gas" — produced by drillers seeking natural gas liquids and petroleum.

The growth of associated gas explains how natural gas production continues at strong levels despite a 28% drop in the number of natural gas-only well completions, Vesey said. Last winter, 8,900 natural gas wells were completed, but this winter the NGSA expects 6,400 natural gas wells to be completed.

There was 5.2 Bcf/d of associated gas produced in 2012, NGSA said, adding that it expects associated gas production to climb to 5.4 Bcf/d in 2013 and 5.5 Bcf/d in 2014.

At least 44% of lower 48-state gas production this winter will come from shale, NGSA said. Tight sands will account for 19%, coalbed methane 6%, offshore 6% and other conventional sources will account for 17%.

"We expect associated gas to continue to be a key component of winter supply as oil drilling in the Bakken and Eagle Ford shales continue and new gas infrastructure is put in place to reduce gas flaring," he said.

The abundant supplies of shale gas have affected storage patterns, he noted. "Since 2009, we've seen the peak date for storage inventories become a moving target, shifting by a week or more on average to a later peak in mid-November," he said.

"The proximity of Marcellus shale gas to consuming regions in the East has changed the way the market uses storage," he said.

Weather is expected to be similar to last winter's more normal pattern, which "portends level demand for natural gas heating," he said.

In taking a long view of the natural gas industry's future, Vesey said the association expects to see sustained growth in industrial demand over the remainder of this decade, as the petrochemical, fertilizer, steel and gas-to-liquids industries begin construction on major natural gas-intensive projects.

The group said gas is spurring 77 major industrial projects between 2012 and 2019. He said 45 are new, 23 are expansions and nine are restarts.

"These are projects that people really intend to do," he said. "Who ever thought we would talk about growth in the steel industry in the United States. It is very real."

Industrial demand will grow faster than other economic segments through 2020, the NGSA said. Industrial use will expand from 25 Bcf/d in 2012 to 30 Bcf/d by 2020. The demand from the residential and commercial segment is expected to grow from 20 Bcf/d in 2012 to 22 Bcf/d in 2020, and electric demand will expand from 25 Bcf/d in 2012 to 28 Bcf/d in 2020.

Imports of LNG are expected to be 0.4 Bcf/d in 2013, the same as last year. Imports of gas from Canada are predicted to decline to 4.2 Bcf/d in 2013 from 4.7 Bcf/d in 2012. But exports to Mexico are expected to rise to 2.1 Bcf/d in 2013 from 1.7 Bcf/d in 2012.

While gas production technology has been leap-frogging itself, gas wells can't be turned on and off in the same way a water faucet is, Vesey said. "You are always hesitant to turn off a well because you don't know what will come back on. The industry can respond very quickly with drilling. Within 12 to 18 months it can bring additional production on line."

While wind-generated electric power has been competing with natural gas in some sections of the country, it isn't considered a threat to natural gas's future. "It is actually good for natural gas because wind needs back up. Wind is not reliable. When they are looking for back up power, [generators] look to the quick start up

ability of natural gas powered power plants," Vesey said.

Efforts to make it easier for foreign companies to invest in Mexico's shale gas plays seems remote now, but Mexico "remains another opportunity" for US producers, he said. "There are attractive areas in Mexico that folks would want to participate in. Our exports to Mexico are increasing. It has a very vibrant economy and there is a need for the gas."

The use of natural gas in high horsepower engines, such as railroad locomotives, will likely remain small in the near future, noted NGSA President R. Skip Horvath, adding "the market is so responsive."

The market will grow "if we can figure out a way to use the energy in natural gas to do these heavy-lifting chores," he said. "Who would have thought even 10 years ago we could be powering (railroad locomotives) with natural gas? Those engines are being designed and built now."

"These things take time to ramp up," he said. "You can't expect a large ballooning of a market like that because it takes so long to turn over equipment."

— *Rodney White*

Md. plant developer hopes to bid into auction

Massachusetts-based Genesis Power hopes to bid its proposed 735-MW Keys Energy Center in Maryland into the PJM Interconnection's May 2014 capacity auction, the company's president said.

"We've asked the [public service commission's] technical staff to review proposed changes on an expedited basis so we can participate in the auction," Bob Place, president said Wednesday in an interview.

The project proposed in 2012 for Prince George's County, Maryland was delayed by issues with its cooling water and natural gas delivery systems, but those problems have been resolved, the company said in a letter to Judge Terry Romine, the Public Service Commission's chief public utility law judge.

Romine earlier asked for an update on the project or the company's application for a certificate of public convenience and necessity would be dismissed.

The problems facing the project kept the company from bidding the natural-gas fired generating station into the May auction, but it will be bid into the next auction assuming that the CPCN has proceeded to a certain point, the letter said. The May auction is for delivery in 2017/2018.

The company was having right-of-way problems with its plan to use cooling water from the Washington Suburban Sanitary Commission, but to resolve the issue it has decided to replace the plant's wet-cooled condenser with an air-cooled condenser.

"This change simultaneously solves several problems without requiring material changes to the basic plant design," the company said.

The change eliminates the 100-foot right-of-way corridor needed from 90 landowners and it eliminates 17 miles of cooling water piping, the letter said.

The company also decided to build, own and operate the gas lateral needed to deliver fuel to the project. It has filed for certification at the Federal Energy Regulatory Commission, the letter said.

Plans call for the interconnection with an interstate gas pipeline owned by Dominion Transmission located about seven and a half miles away, John Sherwell, project manager at the power plant research program, a division of the Maryland Department of the Environment, said earlier in an interview.

"The end result is a much-improved project that will require only modest changes to the information submitted to date and modest incremental new topics," the company said.

Project managers met with state agencies on the proposed changes and will file a revised environmental review document on December 1 along with documents detailing the project's updates, the letter said.

The news that the problems have been resolved and the project plans to go forward comes just a day after the US District Court for the District of Maryland ruled that the PSC's order requiring three state utilities to sign long-term contracts to support the construction of a new gas-fired power plant is unconstitutional.

The state-sponsored support for a gas-fired plant proposed by Competitive Power Ventures was meant to help address the PSC's concerns over the lack of new generation in Maryland. The state imports about 30% of the power it needs to serve its load, the PSC said.

A second project without a subsidy also has been proposed in the region. A Panda Energy subsidiary has asked for approval for the proposed 859-MW Mattawoman natural gas-fired project in Prince George's County near the Keys Energy project.

Panda has asked for approval by March 1 so it can commit the capacity to the PJM capacity auction in May.

— *Mary Powers*

AEP can keep largest Ohio customer, PUC says

American Electric Power can keep its largest single-site customer in Ohio after state regulators Wednesday denied Ormet.'s request to shop for an alternative power supplier, though the Public Utilities Commission said AEP must reduce the aluminum company's rates.

AEP fought to retain the approximately 500-MW load of Ormet's Hannibal aluminum smelter in the economically distressed southeast part of the state. AEP Ohio has served the smelter for years.

Ormet filed for bankruptcy on February 25 and told the PUC it would be forced to liquidate without significant rate relief demanded by Wayzata Investment Partners, which won bankruptcy court approval in June to acquire Ormet for $282 million.

Whether the relief granted by the PUC is sufficient to keep Ormet afloat remains to be seen. The Hannibal-based company had no immediate comment on the commission's rate relief decision.

The PUC said Ormet must continue buying power under a

modified "unique arrangement" with AEP Ohio through December 31, 2018. Ormet agreed to the 10-year deal four years ago, the PUC said, and must keep its commitment.

The commission modified the arrangement to provide some rate relief for Ormet, albeit not as much as the company sought. Ormet's fixed generation and fuel costs will be capped at $50/MWh for the company's smelter. Ormet had asked the PUC to reduce the $57.99/MWh it was charged by AEP in the first quarter to $45.99/MWh for the remainder of 2013.

Electricity accounts for about one-third of a smelter's operating costs. US smelters, on average, pay about $37/MWh.

Although AEP opposed Ormet's rate relief request, it said it was willing to let Ormet shop if the aluminum maker paid a $60 million termination fee. Ormet refused, saying it had used up the $30 million advanced to it by Wayzata after Ormet filed for bankruptcy.

PUC Chairman Todd Snitchler recounted Ormet's long history with AEP. In the 1990s, Ormet successfully petitioned the PUC to leave the AEP system so it could buy less expensive power on the market. Then, a few years later, Ormet returned to the utility.

"It is important to note," Snitchler said, "that many voices have offered support for Ormet and the significance of Ormet's operations in southeast Ohio. The commission recognizes the importance of Ormet and in arriving at its decision today considered the need to balance that importance with what is fair to all of AEP Ohio's other ratepayers."

Snitchler, as did commissioner Steven Lesser, said they were troubled by the fact that no other states, such as neighboring West Virginia where some Ormet employees live, have been asked to provide subsidies to keep the Hannibal smelter open. "Ohio has taken the lead in helping Ormet out," Snitchler said. "It is my hope that, at some point, there is a recognition from other states of the extraordinary support that Ohio and Ohio ratepayers have provided to these other states' citizens and that that recognition results in appropriate action."

Ormet had no immediate reaction to the PUC order. Brenda Miracle, spokeswoman for Ormet CEO Michael Tanchuk, said the company plans to issue a statement Thursday.

Lesser expressed "disappointment that Ormet has failed to meet its corporate responsibility as promised and testified to in prior proceedings before this commission." Over the past four years, he noted, Ormet has been granted "unprecedented aid in excess of $346 million" from the commission. "The source of this aid has been AEP and to the greater extent, other Ohio ratepayers."

Ormet says it wants to construct a 550-MW natural gas-fired plant by late 2015 to supply power to the smelter. In its order, the PUC said the project "is already at risk and behind schedule, and that many of the details, such as the permitting and financing for the project, remain to be decided."

If and when the plant is built, the commission said it would revisit Ormet's request to sever its ties with AEP.

Terri Flora, an AEP spokeswoman, said the company was pleased the PUC order "will not really impact customers any differently." AEP and Ormet "have a long history," she added. "We continue to support them in their endeavors. They're operating in a very challenging aluminum market, and the commission provides them with a path to move forward."

— Bob Matyi

93 Bcf-97 Bcf storage injection expected

A consensus of analysts expects the Energy Information Administration on Thursday to estimate a natural gas storage injection of 93 Bcf-97 Bcf for the reporting week ended Friday.

An addition to stocks within those expectations would be larger than the 77-Bcf build for the year-ago week and the five-year-average addition of 82 Bcf, according to EIA data. As a result, the 179-Bcf deficit to last year should shrink while the 30-Bcf surplus to the five-year average should expand.

The wider range of analysts' expectations spanned from an injection of 88 Bcf-100 Bcf.

For the week that ended September 20, EIA reported a build of 87 Bcf, lifting overall inventories to 3.386 Tcf.

Bentek Energy's supply/demand model predicts an injection of 96 Bcf for the week that ended Friday, while its pipeline flow model anticipates an addition to stocks of 94 Bcf.

Bentek, a unit of Platts, said total US demand declined 2.7 Bcf/d compared with the previous week and was running 4.1 Bcf/d below the previous three-week average.

Citi Futures Perspective analyst Tim Evans said the market could see above-average injections over the next three weeks,

given shoulder-season weather likely on tap. Evans predicted the surplus to the five-year average could expand to 130 Bcf as of the week ending October 18.

"We think nearby futures could fall to $3.25/MMBtu or less under the weight of this pressure, with storage operators wanting to see a clear margin on any late volumes added to inventory," Evans said.

— *Jessica Marron*

Wind groups back bid to revise PJM-MISO pact

The wind power industry is backing calls to remedy alleged flaws in the PJM Interconnection and Midcontinent Independent System Operator's process for building cross-border projects, arguing that such projects are necessary to address wind curtailment near the seam.

The American Wind Energy Association, the Mid-Atlantic Renewable Energy Coalition and others said in their October 1 filing (EL13-88) that they generally support Northern Indiana Public Service Company's complaint asking FERC to revise the Joint Operating Agreement between the two ISOs.

NIPSCO last month argued that PJM and MISO have accomplished very little "with respect to joint planning to address seams and through flow issues in adjacent planning footprints," noting that "to date, not one single interregional transmission upgrade project has been approved under the JOA transmission planning provisions."

The utility urged FERC to enact a number of reforms in order to support transmission capacity along the seam, including realigning the cross-border planning process to run concurrently with PJM and MISO's individual planning processes and requiring the two ISOs to use a single set of criteria to evaluate cross-border market efficiency projects. The utility also asked FERC to require the ISOs to expand the benefits they consider in evaluating cross-border projects.

Wind groups backed NIPSCO's concerns in their filing, saying that the JOA's failure to look at all the benefits of a particular project "essentially eliminates the potential of utilizing the most cost-effective transmission additions that could adequately meet each region's key requirements." The groups also said that the existing JOA and its related processes are not sufficient to address seams issues, and that this failure is affecting wind generators in Illinois.

Wind generators operating in the northern part of the state, the filing said, "are being curtailed at an increasing rate and improvements to the transmission system at the seam between MISO and PJM are the only solutions for minimizing these occurrences of lost production. However, potential transmission projects that could alleviate this congestion do not meet the intra-regional planning criteria that are required in the JOA for the approval of cross-border transmission," wind groups said.

They went on to say that "the lack of this transmission is driving up the costs of wholesale power due to the lack of access to the lowest cost resources."

— *Bobby McMahon*

Several factors seen driving N.C. solar boom

Falling solar photovoltaic panel prices, state and federal investment tax credits, state renewable portfolio requirements and other factors are driving an unprecedented boom in utility-scale solar development in North Carolina, a leading solar developer and others said this week.

"We're working on at least 200 MW" of solar projects in North Carolina that already hold power purchase agreements with the local utility or electric cooperative, Jay Sistrunk, manager of business development at SunEnergy1, said in a Wednesday interview. "And that's a modest estimate," he said. Most of SunEnergy1's projects are in the 5-to-20-MW range.

Sistrunk said that while North Carolina's "renewable energy and energy efficiency portfolio standard," or REPS—the state's version of a renewable portfolio standard—is enabling investor-owned utilities, municipal utilities and electric cooperatives to meet a rising portion of their renewables requirements through low-cost solar, the utility-scale solar market in the state is being driven most by state and federal ITCs.

The state ITC runs through the end of 2015 and the federal ITC runs through 2016, he said, adding that while falling solar panel prices are making solar power more cost-competitive, the tax credits are critically important to the economic modeling that helps determine if a project gets financed and built.

Sistrunk said that solar advocates hope that the state and federal ITCs will be extended, but that many solar developers and investors are racing to develop projects now in case the tax credits are allowed to expire.

Other major solar developers in North Carolina include SunPower, Strata Solar, o2 Energies, and Community Energy.

"We think there's an opportunity for continued growth" in the utility-scale solar sector in North Carolina, particularly if tax incentives remain in place, solar panel prices keep falling, and utilities like Duke Energy Carolinas, Duke Energy Progress and Dominion North Carolina continue to see solar power as one of the most cost-effective ways to meet their REPS requirements.

Under the REPS, which was enacted in 2007, IOUs, munis and co-ops currently need to 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 after 2021.

According to a September report by the Solar Energy Industries Association and GTM Research, North Carolina ranked fourth among the states in the amount of solar capacity installed in the second quarter of this year; only California, Arizona and New Jersey installed more.

The installed cost of solar capacity also continues to decline, the SEIA/GTM report said. Utility-scale solar projects cost an average of $2,100/kW in the second quarter, compared with $2,600/kW a year earlier.

In a separate report updated on October 1, SEIA said that 254

MW of utility-scale solar capacity is in operation in North Carolina, 53 MW is under construction, and at least 162 MW is under development.

"In 2008, less than 10 MW of solar capacity was interconnected to our system [in North Carolina], and now we have more than 200 MW," said Jeff Brooks, spokesman for DEC and DEP, two Duke Energy subsidiaries that each serve parts of North Carolina and South Carolina.

"A lot that increase was driven by the REPS," said Brooks, noting that the Duke units turned to solar power for a substantial portion of its 3%/2012 renewables requirement and expects to continue doing so for its increasing mandates in 2015, 2018 and 2021. Asked how close DEC and DEP are to meeting their 2015 requirements, he said, "We don't give out the details" for competitive reasons.

SunEnergy1's Sistrunk said that while the current market for utility-scale solar in North Carolina is strong, it could be negatively affected if the North Carolina Utilities Commission decides later this year to reduce the avoided cost-based rates that DEC and DEP are required to pay solar developers for their power.

DEC and DEP currently pay "just under 7 cents/kWh" for that power, he said, and solar developers have argued that—if avoided costs are properly calculated—that price should rise to "the upper sevens or even higher." The Duke units, in contrast, have asked the NCUC to reduce the solar power price. A decision by NCUC is expected by the end of this year.

— Housley Carr

AES files to mothball, retire Deepwater units

AES has filed suspension of operations notices with the Electric Reliability Council of Texas for two units at its 140-MW, coal-fired Deepwater plant in Pasadena, Texas.

The filings seek to mothball indefinitely a 139-MW unit, and decommission and retire a 1-MW unit at the plant, according to the two separate Monday filings.

AES did not respond to requests for comment by press time.

On July 3, AES filed with ERCOT to seasonally mothball the 138-MW unit starting October 1. ERCOT accepted the suspension August 2, saying the unit was "not needed to support ERCOT transmission system reliability during the defined suspension period. The resource may be mothballed."

ERCOT is conducting another Reliability Must Run review because the terms of the request filed Monday are different, ERCOT spokeswoman Robbie Searcy said.

The July 3 filing proposed to "suspend operation on a year-round basis and begin operation on a seasonal basis with a Seasonal Operation Period that begins on June 1 and ends on September 30." The new filing indicated the unit will be mothballed indefinitely.

"Also, since both units feed the same bus, they will both be included in the study," Searcy said about the 138-MW and 1-MW units named in the recent filings.

The standard process is to perform a reliability must run review to ensure there are no transmission-related reliability concerns associated with taking the units off-line, Searcy previously said.

The 138-MW unit was mothballed last winter season.

ERCOT has already accepted notices to seasonally mothball NRG's 765-MW natural gas-fired SR Berton plant in Deer Park, Texas; and two units at Luminant's 1,880-MW, coal-fired Monticello plant in Mount Pleasant, Texas.

— Kassia Micek

FirstEnergy issues RFP for SRECs in Pennsylvania

FirstEnergy on Wednesday issued a request for proposals for 13,500 solar photovoltaic alternative energy certificates per year over 10 years for its Pennsylvania utilities.

Bids will be due by November 14, the company said. The Brattle Group will conduct the solicitation.

Bidders can offer to sell tranches of 500 certificates and will be responsible for providing the 500 certificates every year for 10 years for each tranche it wins. Delivery begins June 1, 2014.

The certificates are being solicited on behalf of Metropolitan Edison, Pennsylvania Electric and Pennsylvania Power.

The certificates are used by utilities to satisfy mandates under state renewable-energy portfolio standards, rather than building new renewable energy generation to meet their entire requirement.

In Pennsylvania, they are referred to as "alternative" energy certificates because Pennsylvania allows other fuels to meet the requirements, such as waste coal.

Information is available at www.firstenergycorp.com/PA2013SPAECRFP.

— Mary Powers

Utility output down 2.3% on year in week: EEI

Utilities generated 71,574 GWh in the week that ended Saturday, down 2.3% from the 73,293 GWh generated in the corresponding week of 2012, the Edison Electric Institute said Wednesday.

The weekly total was 3,650 GWh below the 75,224 GWh produced in the week that ended September 21, EEI said.

Output fell in six of the nine regions EEI tracks. The Rocky Mountain saw the steepest decline, 13% to 4,772 GWh. The next largest decrease was the Pacific Southwest's 9.9% to 5,425 GWh. Smaller decreases were seen in New England, the Mid-Atlantic, the Southeast and South Central.

Year-to-date utility generation was 3.034 million GWh, 0.7% below the 3.055 million GWh for the same period of 2012, EEI said.

— Paul Ciampoli

Dynegy's plans could increase imports ...from page 1

portion of that generation capacity can be shipped to PJM. It would be "rather remarkable and unexpected" if MISO found paths available for all 3 GW, Dynegy spokeswoman Katy Sullivan said.

The second study is examining the possibility of a direct link between Dynegy's 1,800-MW coal plant in Baldwin, Illinois, into PJM. Even though the Baldwin study is separate, the Baldwin capacity is included in the 3 GW covered by the first study.

The Baldwin interconnection study is a much more recent request that will take more time to evaluate. Dynegy could not

give a clear time frame for a response from MISO, except to say that the study would not likely be finished this year.

Dynegy is also working on two transmission projects. One is expected to be complete by 2015 and involves transformer and line upgrades near the Baldwin plant. The other, expected in service by 2017, would increase the capacity of an existing line to relieve constraints that are expected to be created near the Indiana border by the Illinois Rivers transmission project.

The 380-mile Illinois Rivers project is being developed by Ameren Transmission Company of Illinois to move renewable energy from west to east. The 345-kV line is planned to run from Palmyra, Missouri, across the Mississippi River at Quincy, Illinois, and across central Illinois into Indiana at Sugar Creek.

The costs of the transmission projects are still being estimated, but they are in the millions of dollars, said Sullivan.

Both of Dynegy's transmission projects would help move more capacity from the company's coal plants into PJM. Dynegy has four coal plants on the western side of Illinois. In addition to the Baldwin plant, they are the 441-MW unit 6 of the Havana plant in Havana, the 293-MW Hennepin plant in Hennepin, and the 446-MW Wood River plant in Alton.

Dynegy did not bid its Illinois coal plants into the last PJM capacity auction. But Dynegy, as well as other generators such as Ameren, are eager to be able to bid their capacity into PJM because of the wide differences between MISO and PJM capacity prices.

Dynegy has submitted three system impact studies with PJM. Two of the studies are for plans that would move power from Ameren Illinois territory into PJM. One is for 3,081 MW of capacity from June 1, 2016 to June 1, 2022, the other for 260 MW from June 1, 2017 to June 1, 2022. The third study is for 1,000 MW that would come from the Tennessee Valley Authority area.

Sullivan said the model Dynegy is using for its transmission studies are the requests that Ameren did about a year ago that allowed its Ameren Generating unit to bid about 900 MW into the 2016-17 capacity auction.

Dynegy is in the process of acquiring Ameren Energy Resources, Ameren's merchant generation unit. The acquisition would double Dynegy's coal-fired capacity in Illinois to about 8,000 MW.

AER's Illinois coal plants are the 895-MW Coffeen station in Montgomery County, a 949-MW plant in Joppa, the 1,215-MW Newton plant in Jasper County, the 410-MW Duck Creek plant in Canton, and the 650-MW E.D. Edwards plant in Bartonville.

In the wake of the acquisition announcement, Dynegy said being able to sell more capacity into PJM was one of the reasons it was acquiring the assets. At the time, Dynegy president and CEO Robert Flexon said Ameren planned to sell 900 MW into PJM. In the past, Ameren has only sold 150 MW from its Edwards plant into the PJM capacity auction.

Ameren did bid and clear into the PJM auction. The RTO clearing price in PJM's 2016-17 capacity auction, which closed in May, was $59.37/MW-day. MISO's capacity auction closed in April and cleared at $1.05/MW-day.

"That is the signal the market is giving, and we are responding," Sullivan said.

That spread was enough to drive a 90% surge in imports in PJM's 2016-17 capacity auction. A total of 7,483 MW of imports cleared the auction, up from 3,935 MW in the previous auction. Of the totals 7,070 MW of the cleared bids came from west of PJM compared with 3,621 MW in the previous auction.

The rise in imports is one of the reasons cited for the clearing prices, which undercut the reduced expectations of many analysts.

To participate in PJM's capacity auction, an external resource must demonstrate deliverability with a study and show that it has requested firm transmission service into PJM.

Of the 7,483 MW of cleared import bids, about 4,788 MW, or 64%, had confirmed firm transmission service. The rest had requested such requests on paths that are under study.

That situation has raised flags at PJM. On September 12, PJM's Planning Committee approved a problem statement on the issue. In the document, PJM said it is concerned that the amount of imports that cleared its last auction may have approached or even exceeded its import capability.

In addition to concerns that some of the promised capacity might not be available because the exporter could not secure transmission rights, PJM is concerned that it might be double counting transmission capacity into the PJM territory.

PJM relies on neighboring control areas for backup power during an emergency. PJM is now concerned that some of the capacity imports could be booked on lines needed for emergency supplies.

Planning for emergency supplies, known as the capacity benefit margin, is included in the calculation of the RTO's installed reserve margin. If the amount of transmission capability dedicated to capacity imports continues to grow without analyzing the limitations of the transmission system to handle imports in actual operations, reliability could be adversely affected.

One of the solutions PJM is exploring to address the problem is the imposition of a cap on imports.

PJM's Planning Committee aims to have a solution drafted in time to submit it to the Federal Energy Regulatory Commission for approval so that it could be posted in PJM's pre-auction parameters by February 1, 2014, so that it would be in place for the May 2014 capacity auction.

It remains to be seen how PJM's schedule to address the import issue will intersect with Dynegy's push to increase its MISO exports. But the imposition of an import cap in PJM could turn the rest of the RTO into a "quasi-constrained LDA" and put upward pressure on capacity prices, further widening spreads between PJM and MISO capacity auctions, said Julien Dumoulin-Smith, analyst with UBS.

— Peter Maloney

Developers respond to line competition ...from page 1

State regulators sought the projects as part of Governor Andrew Cuomo's Energy Highway Blueprint. Issued a year ago, the blueprint calls for up to 3,200 MW of additional generation and transmission capacity.

The state says it needs the new transmission to ease congestion problems caused by two-thirds of the state's load being downstate, around New York City, while one-half of its generation is upstate.

Boundless Energy offered more than 1,000 MW of capacity in a project called Leeds Path West. The project includes new 345-kV overhead and underground transmission, as well as existing lines that the company would reconductor. Boundless Energy served as the technical partner in New York's 65-mile underground and underwater Neptune Regional Transmission, which has been in operation since 2007.

NextEra Transmission New York, whose parent NextEra Transmission owns and operates utilities in New Hampshire and Texas, proposed two overhead, 345-kV lines. The 57-mile Oakdale to Fraser would parallel an existing transmission line between the Broome County and the Fraser Substation in Delaware County. The project has an expected in-service date of August 2018.

NextEra's other proposal, Marcy to Pleasant Valley, is a 148-mile line that parallels existing lines between the Marcy Substation in Oneida County and the Pleasant Valley Substation in Dutchess County. The company said that Marcy to Pleasant Valley would increase transfer capability and reduce demand congestion costs by nearly $2.3 billion, production costs by $350 million, transmission system losses by $349 million, and capacity payments by up to $803 million over 10 years. Its in-service date is September 2017.

North American Transmission also proposed two 345-kV overhead projects: the 80-mile Edic to Fraser and 65-mile New Scotland to Leeds to Pleasant Valley. The company offered a preliminary cost estimate of Edic to Fraser of $217.4 million, and said that its affiliate, LS Power, would arrange debt and equity financing. Since 2005, LS Power has raised over $22 billion of debt and equity for its projects, according to the filing.

NY Transco is a public/private partnership that includes the Long Island Power Authority and the New York Power Authority, along with the state's investor-owned utilities: Central Hudson Gas and Electric, Consolidated Edison Company of New York, Orange and Rockland Utilities, National Grid, New York State Electric & Gas, Rochester Gas and Electric.

The NY Transco project has three parts. The Second Ramapo to Rock Tavern is a 345-kV line, sponsored by Con Edison. The Marcy South Series Compensation, sponsored by NYPA and NYSEG, includes reconductoring of the existing Fraser to Coopers Corners Line. The final part of the utility project is Edic to Pleasant Valley and Second Oakdale to Fraser 345 kV Lines, sponsored by National Grid and NYSEG.

NY Transco says that its projects, which span several counties, will reduce annual installed capacity costs by $50 million to $200 million, varying from year to year.

Most of NY Transco projects involve upgrades or additions to existing transmission. In all, the projects require only about two square miles of land that is not already used for transmission. Portions of the projects could begin operating as early as 2016, according to the filing.

Poseidon Transmission, a subsidiary of Anbaric Transmission offered an underground and submarine HVDC line to import up to 500 MW of power from the PJM Interconnection into Long Island. The Poseidon cable would be buried along existing rights-of-way or underwater, according to the developer.

Parent Anbaric Transmission participated in development of two similar projects in New York over the past six years: the 660-MW Neptune Regional Transmission System and the 660-MW Hudson Line that links the PJM grid with a Con Ed Substation in Manhattan.

The filing deadline for the siting review was October 1. The commission has yet to set a date when it will select winners. – Lisa Wood

— Lisa Wood

Calif. needs changes: plan ...from page 1

More GHG reductions will require even greater effort and at a quicker pace, according to the draft plan. Meeting the 2020 target requires about 1% annual emissions reductions. Meeting the 2050 goal set by an executive order will require 5.2% yearly emissions cuts, the draft report said.

"Reducing energy sector emissions will require wholesale changes to the state's current electricity and natural gas systems," the draft report said. "The purpose and functions of utilities may also need to evolve as California increasingly shifts toward more renewable and distributed energy integration. A new utility business model may need to be developed to ensure that utilities remain financially viable under a transitioning energy system."

In 2006, the California Legislature passed Assembly Bill 32, which set the state's 2020 GHG goal and directed the ARB to develop a plan to meet the target. The bill requires the ARB to

update its GHG reduction plan every five years and the current draft marks the first time the ARB, with major input from other agencies and stakeholders, has revised its GHG strategy.

Rather than providing specific details, the scoping plan serves as a roadmap to be implemented by various agencies like the California Public Utilities Commission the the California Independent System Operator. The energy sector accounts for about 40% of California's GHG emissions.

The draft plan calls for more energy efficiency, demand response and combined heat-and-power capacity. It recommends a possible expansion of California's renewable portfolio standard, which climbs to 33% by 2020. It also calls for increased focus on the state's distribution and transmission system while "decarbonizing" the state's natural gas-fired fleet.

"Developing a near zero emission strategy for the energy sector will require efficient next-generation technology; vast new low carbon generation resources; a robust transmission and distribution infrastructure; and carbon capture, utilization, and sequestration for the remaining fossil generation," the draft plan said.

California will need to work with other states to reach its goals, according to the draft plan. "[A statewide energy] plan should recommend policies and strategies for continuing California's collaboration with the Western Electricity Coordinating Council toward developing multi-state GHG reduction strategies within the western electricity system," the draft plan said, noting that a regional energy imbalance market could help reduce GHG emissions by fostering more efficient power plant operations and reducing renewable forecasting errors.

ARB is considering several changes to California's GHG cap-and-trade program this year, according to the draft plan. "ARB is proposing mechanisms to keep allowance prices within an acceptable range by allowing a limited amount of future allowances to be used for compliance should prices get too high," the draft plan said. "The continuation of the cap-and-trade program post-2020 will enhance the effectiveness of the new cost containment mechanism proposal."

The ARB will hold a workshop on October 15 to take public comment on the draft plan. At the end of the month, the ARB board will hear public comment and provide direction to staff of possible revisions to the draft plan. The board is expected to consider approving the plan in the spring.

— Ethan Howland

PLATTS
McGRAW HILL FINANCIAL

MEGAWATT DAILY

Volume 18 / Issue 191 / Thursday, October 3, 2013

ISSN # 1088-4319

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

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

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