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Tuesday, November 19, 2013

Deal increases solar's threat to generation

ANALYSIS The solar power industry has taken a first step in implementing a financing tool that could quicken the penetration of solar technology and further erode market fundamentals for both generators and load serving entities.

The first step was taken by SolarCity, which earlier this month floated $54 million of notes in the 144A private placement market that are secured by cash flows generated by a pool of photovoltaic systems and related leases and power purchase agreements.

For years a variety of stakeholders within the solar industry have been trying to securitize solar projects, particularly photovoltaic rooftop installations.

The solar power industry has already evolved a business model that moved the high initial cost of installing rooftop solar panels off of homeowners. Companies such as SolarCity bear those costs

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PJM, monitor differ over up-to-congestion deals

MARKETS PJM Interconnection staff and the independent market monitor continue to differ over the benefit or cost of "up-to-congestion" transactions to the market as a whole, the PJM Members Committee learned during Monday's informational webinar.

UTC bids allow market participants to say how much they are willing to pay for congestion between two nodes by specifying a spread limit between the locational marginal prices at both points.

In a presentation during the webinar, Joseph Bowring, president of Monitoring Analytics, which serves as PJM's independent market monitor, reiterated the conclusion he issued over the summer that UTC bidding contributes to underfunding of financial transmission rights and increases day-ahead congestion. He also maintains he

(continued on page 16)

TVA looks to keep nuclear unit as viable asset

GENERATION The Tennessee Valley Authority's objective at the partially completed Bellefonte-1 nuclear unit is to keep it as a viable asset until it becomes clear whether it is needed to meet demand or future environmental requirements.

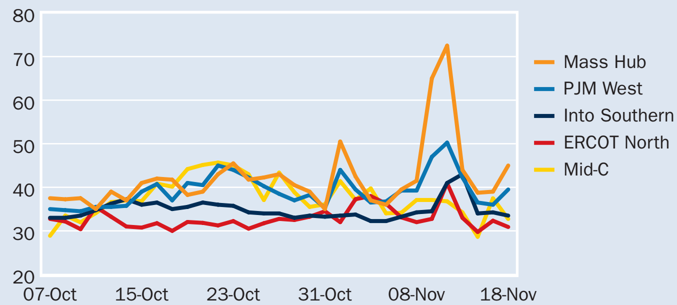
TVA is spending about $65 million a year to preserve the asset and do a little design work, CEO William Johnson said Monday during a conference call. TVA reduced the staffing at the project in June.

The current budget and staffing levels are sufficient to preserve the unit for potential future development, TVA said in its 10-K filed Monday with the Securities and Exchange Commission.

In 2011, the board of directors authorized TVA to complete the unit once the construction of Watts Bar-2 is complete. But there is no immediate need for Bellefonte, Duncan Mansfield, a

(continued on page 17)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Nov 19 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	43.89	44.78	30.54	32.31
NYISO	24.69	57.45	16.05	29.71
PJM	38.15	46.61	25.33	32.89
MISO	30.63	36.25	23.58	29.56
ERCOT	29.67	34.39	22.13	22.54
CAISO	37.55	40.38	30.86	32.92

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 Nov 19

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	45.00	8503	7.95	2.66	-7.93	-18.51	-34.39
N.Y. Zone-A	54.50	16116	30.83	27.45	20.68	13.92	3.78
PJM/MISO							
PJM West	39.50	11361	15.16	11.69	4.73	-2.22	-12.65
Indiana Hub	36.50	9772	10.36	6.62	-0.85	-8.32	-19.53
Southeast & Central							
Southern, Into	33.50	9141	7.85	4.18	-3.15	-10.48	-21.48
ERCOT, North	30.89	8726	6.11	2.57	-4.51	-11.59	-22.21
West							
Mid-C	32.72	8725	6.47	2.72	-4.78	-12.28	-23.53
SP15	42.75	11400	16.50	12.75	5.25	-2.25	-13.50

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 rise with demand

Northeast dailies firmed with stronger demand and jumps in spot gas markets. Forwards in the region were mixed. The NYMEX December natural gas futures contract settled 4.3 cents lower Monday at $3.617/MMBtu as selling emerged late in the session after the contract failed to hold above $3.70/MMBtu resistance.

High temperatures in Boston are expected in the upper 40s and lows in the mid-30s. ISO New England forecast peak load on Monday near 17,200 MW and 17,450 MW on Tuesday.

Algonquin city-gate spot natural gas soared about $1.83 to $5.35/MMBtu and Transco Zone 6 New York added 70 cents to about $3.80/MMBtu.

Mass Hub on-peak for Tuesday jumped about $6 to the mid-$40s/MWh and off-peak was up about $1 in the upper $20s/MWh.

The New York ISO forecast peak load on Monday near 20,750 MW and 20,184 MW for Tuesday. High temperatures in New York State are forecast in the 40s on Tuesday with lows in the 30s.

New York Zone G on-peak Tuesday added nearly $3 going to the low $40s/MWh.

Day-ahead auction prices in the ISO New England climbed Monday with load expected to creep up on Tuesday and a surge in spot gas prices.

Internal Hub on-peak gained $6.72 going to $44.42/MWh and Maine on-peak added $6.91 to $43.89/MWh. Connecticut on-peak rose $6.60 to $44.34/MWh. West-Central Mass on-peak gained $6.76 to $4.67/MWh.

Day-ahead auction prices in the New York ISO were mostly higher Monday with firm demand in the forecast and higher spot gas prices.

New York City on-peak climbed more than $2 to about $42.75/MWh, while Hudson Valley on-peak gained $3.14 to $42.92/MWh. Long Island on-peak climbed 72 cents to $48/MWh and West on-peak eased 27 cents to $57.45/MWh.

Northeast term power was mixed Monday with NYMEX gas futures moving down in the afternoon. In New England, Mass Hub on-peak December financial futures lost $2.50, with bids at $95/MWh and offers at $115/MWh at about 2:30 p.m. EST on the IntercontinentalExchange. Mass Hub on-peak January-February 2014 financial futures fell $2.50 going to about $127.50/MWh.

New York Zone A on-peak December financial futures jumped $4.50, with bids at $42/MWh and offers at $75/MWh on ICE. New York Zone G on-peak December financial futures climbed $2 to about $65.50/MWh on ICE.

Daily generation outage references

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

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

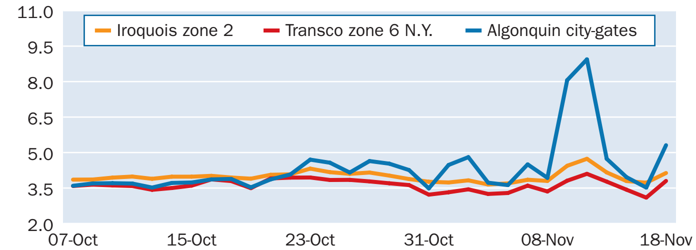
Sources: Generation owners, public information and other market sources.

Northeast day-ahead bilateral indexes for Nov 19 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	45.00	6.00	45.10	8503
N.Y. Zone-G	48.00	7.75	45.19	12098
N.Y. Zone-J	48.00	7.50	46.81	12098
N.Y. Zone-A	54.50	13.50	45.48	16116
Ontario*	32.00	4.00	32.42	8097
Off-Peak				
Mass Hub	29.00	2.00	33.02	5479
N.Y. Zone-G	26.50	-2.50	30.65	6679
N.Y. Zone-J	26.50	-2.75	31.23	6679
N.Y. Zone-A	21.50	0.50	26.35	6358
Ontario*	19.50	0.25	22.46	4934

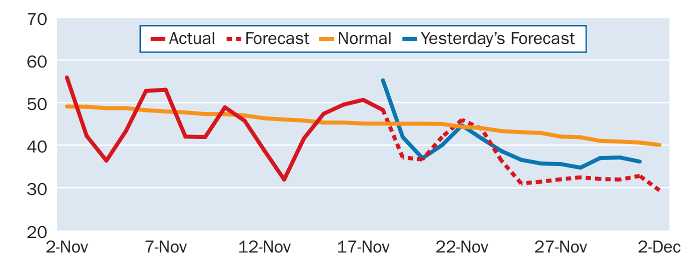
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO average temperature (°F)



Source: Custom Weather

Northeast load and generation mix forecast (GWh)

	Actual 17-Nov	%Chg	% Chg Year-ago	Forecast 18-Nov	19-Nov	20-Nov	21-Nov	22-Nov
ISONE								
Load	319	1	2	316	330	353	350	337
Generation								
Coal	12	2	80	9	16	23	21	16
Gas	122	3	-13	129	125	121	117	117
Nuclear	111	0	3	111	111	111	111	111
NYISO								
Load	382	-1	0	359	390	424	422	414
Generation								
Coal	10	-2	54	7	13	18	17	15
Gas	88	-2	-11	79	87	99	104	103
Nuclear	135	0	9	135	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Nov 19 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	44.42	0.00	0.09	6.72	40.07	8753
Connecticut	44.34	0.00	0.02	6.59	40.13	9696
NE Mass-Boston	44.15	0.00	-0.18	6.70	40.13	8700
SE Mass	44.35	0.00	0.02	6.53	40.55	8740
West-Central Mass	44.67	0.00	0.34	6.76	40.28	8803
Rhode Island	44.14	0.00	-0.19	6.64	40.03	8698
Maine	43.89	0.00	-0.44	6.91	39.36	10905
New Hampshire	44.78	0.00	0.46	6.87	40.13	11127
Vermont	43.94	0.00	-0.39	6.63	39.67	10917
Off-Peak						
Internal Hub	31.68	-0.08	0.13	8.10	30.36	8475
Connecticut	30.70	-0.62	-0.31	7.37	30.20	8177
NE Mass-Boston	32.04	0.34	0.08	8.46	30.39	8572
SE Mass	32.26	0.34	0.29	8.52	30.52	8629
West-Central Mass	31.82	-0.13	0.33	8.15	30.54	8513
Rhode Island	32.31	0.34	0.35	8.47	30.57	8645
Maine	31.34	0.34	-0.63	8.35	29.53	8414
New Hampshire	31.98	0.16	0.20	8.41	30.29	8585
Vermont	30.54	-0.63	-0.47	7.43	29.88	8197

NYISO day-ahead LMP for Nov 19 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	40.70	-0.49	2.47	2.92	39.68	10971
Central Zone	40.64	-2.18	0.71	2.24	36.59	12135
Dunwoodie Zone	42.44	-0.38	4.31	2.71	40.97	10881
Genesee Zone	39.15	-1.77	-0.37	2.29	35.06	11689
Hudson Valley Zone	42.92	-0.37	4.80	3.14	41.22	11005
Long Island Zone	48.00	-4.36	5.89	0.72	46.44	12307
Millwood Zone	42.52	-0.38	4.39	2.78	40.98	10903
Mohawk Valley Zone	39.50	-0.06	1.69	2.93	36.73	11217
N.Y.C. Zone	42.75	-0.38	4.62	2.06	41.62	10960
North Zone	24.69	11.14	-1.91	5.16	29.72	6134
West Zone	57.45	-20.46	-0.75	-0.27	42.04	17156
Off-Peak						
Capital Zone	23.78	-2.40	1.40	4.57	28.19	6970
Central Zone	20.81	-0.35	0.49	3.17	21.98	6622
Dunwoodie Zone	23.86	-1.87	2.01	4.23	27.43	6852
Genesee Zone	20.37	-0.26	0.13	2.98	21.35	6481
Hudson Valley Zone	24.06	-1.85	2.23	4.38	27.57	6909
Long Island Zone	29.71	-6.84	2.89	2.68	30.10	8531
Millwood Zone	23.89	-1.88	2.04	4.27	27.44	6862
Mohawk Valley Zone	20.97	-0.31	0.68	3.30	22.31	6494
N.Y.C. Zone	23.94	-1.87	2.09	4.24	27.59	6875
North Zone	16.05	2.73	-1.20	2.20	19.39	4309
West Zone	21.22	-0.91	0.33	3.49	21.74	6751

Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Next-week	11/18	71.50-72.50

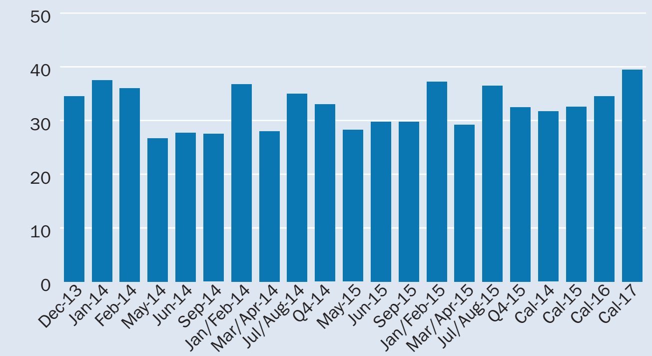
*Ontario prices are in Canadian dollars.

Northeast Platts-ICE Forward Curve, Nov 18 ($/MWh)

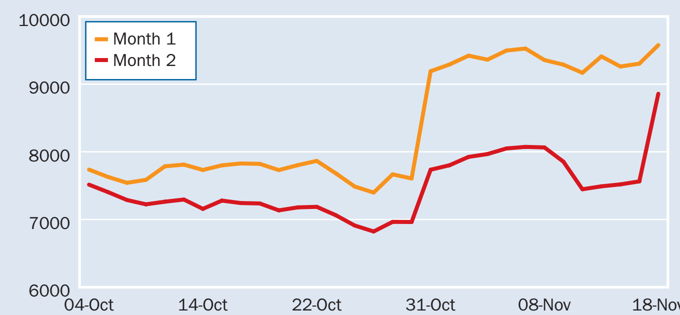
Prompt month: Dec 13	On-peak	Off-peak
Mass Hub	105.00	89.50
N.Y. Zone G	65.50	48.75
N.Y. Zone J	67.75	49.50
N.Y. Zone A	55.00	35.00
Ontario*	34.50	22.00

*Ontario prices are in Canadian dollars

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	200	c	Ont.	PMO	Unk	10/16/13
Darlington-2/OPG	868	n	Ont.	PMO	Unk	08/27/13
Fort Frances/Fort Frances	99	w	Ont.	MO	Unk	09/20/13
Goreway-11/Goreway	195	g	Ont.	MO	Unk	11/01/13
Goreway-12/Goreway	195	g	Ont.	MO	Unk	01/01/13
Goreway-13/Goreway	195	g	Ont.	MO	Unk	11/01/13
Goreway-15/Goreway	357	g	Ont.	MO	Unk	11/01/13
Greenfield-1/Calpine	212	g	Ont.	PMO	11/18/13	10/04/13
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
Lennox-4/OPG	525	bio	Ont.			
Littleong-2/OPG	70	h	Ont.	MO	Unk	11/06/13
Nanticoke-6/Brookfield	292	c	Ont.			
Nanticoke-7/Brookfield	90	c	Ont.	MO	Unk	10/25/13
Nanticoke-8/Brookfield	90	c	Ont	MO	Unk	10/31/13
Pickering-6/OPG	510	n	Ont.	MO	Unk	09/03/13
Portlands-1/Portlands	197	g	Ont.	MO	Unk	11/11/13
Portlands-2/Portlands	197	g	Ont.	MO	Unk	11/11/13
Portlands-3/Portlands	245	g	Ont.	MO	Unk	11/11/13
Taohsc/TransAlta	78	g	"Ont,"	MO	Unk	10/31/13
Thunderbay-2/OPG	150	c	Ont.	PMO	Unk	03/01/13
Thunderbay-3/OPG	153	c	Ont.	MO	Unk	10/11/13

SOUTHEAST MARKETS

ERCOT dailies weaker with load, weather

Electric Reliability Council of Texas dailies for Tuesday delivery were weaker on IntercontinentalExchange Monday morning with peak load and temperatures forecast to drop. Meanwhile, South Central and Southeast on-peak December terms rose. The NYMEX December natural gas futures contract settled 4.3 cents lower Monday at $3.617/MMBtu as selling emerged late in the session after the contract failed to hold above $3.70/MMBtu resistance.

Spot natural gas at Houston Ship Channel rose 10.1 cents to trade around $3.576/MMBtu.

ERCOT North Hub next-day on-peak physical power shed about $1.50 to trade around $30.75/MWh. Off-peak was bid at $21.50/MWh, $1.25 above Friday prices.

High temperatures across ERCOT's footprint were forecast in the upper 60s Tuesday, with lows expected in the low to mid-50s. The average November high temperature across the ERCOT region is in the upper 60s to low 70s, with the average low in the upper 40s to mid-50s.

System load in ERCOT was forecast to peak at 37,825 MW Monday and 35,675 MW Tuesday, compared with an actual peak of 40,248 MW Sunday.

Real-time prices averaged $23.75/MWh from 12:15 to 6 am CST Monday.

Wind generation was forecast to peak at 3,850 MW at 1 am CST Monday and 7,425 MW at midnight CST Tuesday.

North Hub balance-of-the-week was bid at $31.30 and offered at $32.75/MWh, Next-week on-peak was bid at $34.25 and offered at $34.70/MWh. Balance-of-the-month on-peak was bid at $31.50 and offered at $34.50. Houston Hub bal-week on-peak was bid at $31.50/MWh.

In the Southeast, dailies for Tuesday delivery were weaker Monday morning with temperatures forecast to decrease. Into Southern next-day on-peak power market was in the mid-$30s, down slightly from Friday prices. Off-peak lost $1.25 to trade around $25/MWh.

Spot natural gas at Transco Zone-3 added 16.5 cents to trade around $3.675/MMBtu.

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Southeast & Central day-ahead bilateral indexes for Nov 19 ($/MWh)

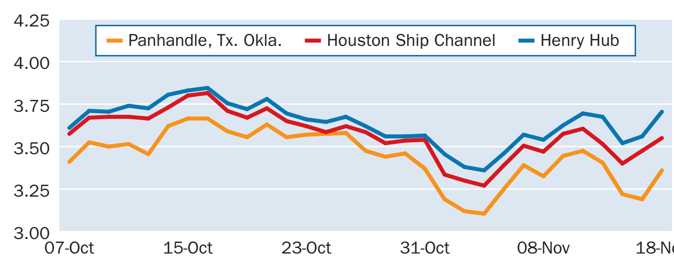
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	35.00	0.25	36.08	9211
Southern, Into	33.50	-0.75	34.83	9141
Florida	39.25	0.25	39.10	10724
TVA, Into	34.25	0.25	34.96	9320
Entergy, Into	33.50	-1.50	33.19	9331
Southeast Off-Peak				
VACAR	27.00	-1.00	27.86	7105
Southern, Into	25.50	-0.75	26.83	6958
Florida	28.25	0.25	28.74	7719
TVA, Into	25.75	-0.25	26.79	7007
Entergy, Into	23.50	-0.75	25.07	6546
ERCOT On-peak				
ERCOT, North	30.89	-1.44	34.06	8726
ERCOT, Houston	31.50	-0.75	34.42	8787
ERCOT, South	31.75	-0.75	34.48	8795
ERCOT, West	31.00	-1.00	34.04	8807
ERCOT Off-Peak				
ERCOT, North	21.75	1.50	22.63	6144
ERCOT, Houston	21.75	1.75	22.49	6067
ERCOT, South	21.75	1.50	22.51	6025
ERCOT, West	21.00	2.00	22.01	5966
SPP/MRO On-peak				
MAPP, South	34.00	1.00	33.79	9315
SPP, North	33.75	-0.25	33.81	10045
SPP/MRO Off-Peak				
MAPP, South	25.50	3.75	24.08	6986
SPP, North	24.75	1.50	24.59	7366

Southeast load and generation mix forecast (GWh)

	Actual 17-Nov	%Chg	% Chg Year-ago	Forecast 18-Nov	19-Nov	20-Nov	21-Nov	22-Nov
ERCOT								
Load	807	9	0	760	733	758	795	764
Generation								
Coal	312	6	8	319	321	320	326	322
Gas	365	15	-6	303	285	285	302	292
Nuclear	91	-26	2	91	92	97	106	115
SPP								
Load	514	-2	-4	533	543	565	573	573
Generation								
Coal	341	-2	2	358	388	389	377	379
Gas	106	-1	-20	106	112	116	116	119
Nuclear	49	0	-3	49	49	49	49	49

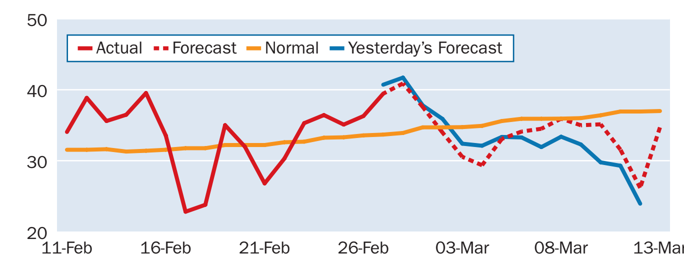
Source: Bentek

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



Source: Platts

ERCOT & SPP average temperature (°F)



Source: Custom Weather

ERCOT average day-ahead LMP for Nov 19 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	30.25	-0.70	33.41	8515
Hub Average	30.55	-0.64	33.44	8599
Houston Hub	30.88	-0.72	33.69	8640
North Hub	29.67	-0.83	33.33	8410
South Hub	31.43	-0.35	33.53	8750
West Hub	30.21	-0.69	33.23	8603
AEN Zone	34.39	0.24	34.27	9795
CPS Zone	32.80	-2.95	34.17	9140
LCRA Zone	31.93	-0.60	33.79	8899
Rayburn Zone	29.73	-0.83	33.44	8427
Houston Zone	30.94	-0.71	33.72	8654
North Zone	29.78	-0.79	33.41	8441
South Zone	32.16	-0.05	33.66	8952
West Zone	30.90	-0.39	34.12	8801
Off-Peak				
Bus Average	22.37	-0.60	22.56	6416
Hub Average	22.34	-0.63	22.49	6408
Houston Hub	22.40	-0.57	22.61	6379
North Hub	22.39	-0.56	22.64	6484
South Hub	22.46	-0.54	22.55	6387
West Hub	22.13	-0.83	22.16	6429
AEN Zone	22.42	-0.56	22.53	6512
CPS Zone	22.41	-0.56	22.50	6420
LCRA Zone	22.42	-0.55	22.52	6422
Rayburn Zone	22.39	-0.56	22.81	6484
Houston Zone	22.39	-0.59	22.61	6377
North Zone	22.39	-0.56	22.65	6484
South Zone	22.54	-0.52	22.61	6412
West Zone	22.13	-0.81	22.03	6428

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

Package	Trade date	Range
Southern, Into		
Bal-month	11/15	34.50-35.00
Bal-month	11/14	34.25-34.75
Next-week	11/15	35.00-35.50
Next-week	11/14	34.75-35.25
Entergy, Into		
Bal-week	11/13	34.00-34.50
Bal-week	11/12	33.25-33.75
Bal-month	11/15	33.75-34.25
Bal-month	11/13	34.00-34.50
Bal-month	11/12	33.25-33.75
Next-week	11/15	33.75-34.25
Next-week	11/13	33.50-34.00
Next-week	11/12	32.50-33.00
ERCOT, North		
Next-week	11/13	33.75-34.25

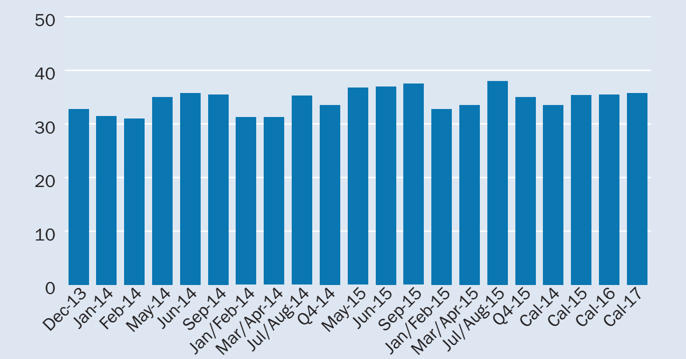
Market coverage

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

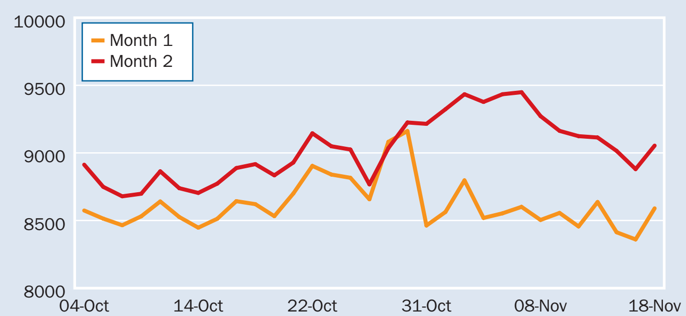
Southeast & Central Platts-ICE Forward Curve, Nov 18 ($/MWh)

Prompt month: Dec 13	On-peak	Off-peak
Southern Into	34.50	29.00
Entergy Into	32.75	26.25
ERCOT North	32.00	26.00
ERCOT Houston	32.25	25.50
ERCOT West	31.50	24.75
ERCOT South	32.25	25.75

Entergy Into: Forward curve on-peak ($/MWh)



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
Big Brown-2/Luminant	575	c	Texas	MO	Unk	10/01/13
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Deepwater/AES	138	c	Texas	PMO	Unk	10/01/13
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Harris/Duke Energy	900	n	N.C.	RF	12/03/13	11/09/13
Martin Lake-1/Luminant	750	c	Texas	PMO	Unk	09/25/13
Monticello-1/Luminant	565	c	Texas	PMO	Unk	09/08/13
Monticello-2/Luminant	565	c	Texas	PMO	Unk	08/25/13
Oconee-1/Duke	934	n	S.C.	MO	12/09/13	11/11/13
Oconee-2/Duke	934	n	S.C.	RF	12/09/13	10/11/13
Sequoyah-1/TVA	1186	n	Tenn.	RF	11/22/13	10/10/13
South Texas-1/STP	1413	n	Texas	MO	Unk	10/02/13
South Texas-2/STP Nuclear	1413	n	Texas	PMO	12/10/13	11/18/13
SR Berton/NRG	765	g	Texas	PMO	Unk	10/01/13
Surry-1/Dominion	861	n	Va.	RF	11/18/13	10/21/13
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13

WEST MARKETS

Most Western dailies decline; terms finish flat

Most Western dailies were down Monday as California expected relatively stable demand and with the move away from on-peak hours in the off-peak package. Terms finished flat, and the NYMEX December natural gas futures contract settled 4.3 cents lower at $3.617/MMBtu.

In the Northwest, Mid-Columbia day-ahead on-peak fell about $4.75 to trade between $32.25 and $33.75/MWh for delivery on Tuesday. Mid-C day-ahead off-peak was down around $3.50 to trade between $25 and $26.75/MWh. The Mid-C on-peak balance-of-the-month package traded between $36 and $37.50/MWh, up about $1.

Portland, Oregon's forecasts had highs in the low 50s and a low of 40 on Tuesday, down nearly 10 degrees from Monday's anticipated low.

The Bonneville Power Administration's wind output was 1,205 MW, and its hydro output was 8,838 MW at 7 am PDT on Monday.

In California, SP15 next-day on-peak lost more than 25 cents to trade between $42.75 and $43/MWh. SP15 day-ahead off-peak dropped $2.50 to around $34.75/MWh. SP15 bal-month was bid at $40.50 and offered at $42.50/MWh, up about 50 cents. NP15 day-ahead on-peak added more than 25 cents to trade between $42.25 and $42.50/MWh. NP15 day-ahead off-peak shed more than $2.75 to about $34.25/MWh.

Sacramento, California, expected highs in the upper 50s to low 60s and lows in the low 40s to near 50. Burbank's forecasts had highs from the upper 60s to around 70 and lows from the mid-40s to the mid-50s.

The California Independent System Operator projected peak demand to be 30,029 MW on Monday and 30,041 MW on Tuesday. Renewables were 1,826 MW, and wind was about 175 MW at 7 am PDT on Monday.

In the desert Southwest, Palo Verde next-day on-peak dropped about 50 cents to trade between $30.50 and $31.50/MWh. Palo Verde day-ahead off-peak gave up nearly $2.25 to trade between $26 and $26.50/MWh.

Phoenix expected highs in the upper 70s and lows in the high 60s.

Next-day natural gas prices in the Rockies and California were higher. Opal was up 17 cents to $3.625/MMBtu, Pacific Gas and Electric city-gate gained 5.4 cents to $3.879/MMBtu, and SoCal city-gate climbed 24.7 cents $3.922/MMBtu.

Day-ahead prices were down in the California Independent System Operator auction on Monday afternoon.

SP15 on-peak shed $5.05 to $39.09/MWh, as SP15 off-peak fell $4.42 to $31.84/MWh. NP15 on-peak gave up $4.47 to $40.38/MWh, and NP15 off-peak lost $3.14 to $32.92/MWh. ZP26 on-peak dropped $5.79 to $37.55/MWh, while ZP26 off-peak was declined $3.70 to $30.86/MWh.

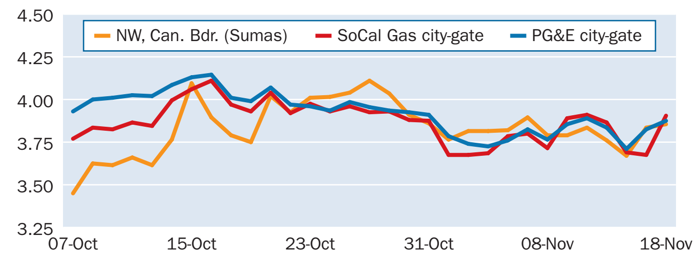
In the Northwest term markets, Mid-Columbia on-peak December fell 25 cents with bids at $38 and offers at $40/MWh

(continued on page 10)

Western day-ahead bilateral indexes for Nov 19 ($/MWh)

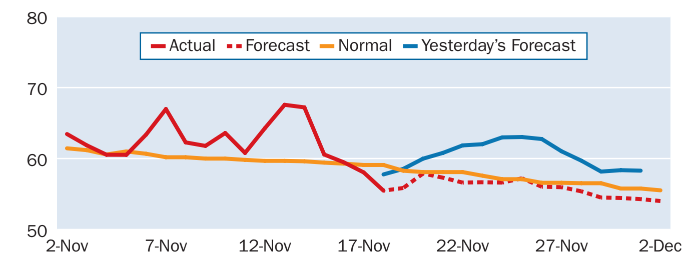
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	36.18	-4.70	38.91	9818
Mid-C	32.72	-4.75	35.33	8725
Palo Verde	30.85	-0.56	31.99	8475
Mead	32.75	-0.50	33.71	8733
Mona	32.00	-2.75	33.84	8815
Four Corners	32.00	-1.25	33.28	9065
NP15	42.25	0.25	42.47	10903
SP15	42.75	-0.50	44.08	11400
Off-Peak				
COB	28.64	-2.11	30.61	7772
Mid-C	25.98	-3.57	27.83	6928
Palo Verde	26.26	-2.24	27.33	7214
Mead	27.50	-2.75	28.29	7333
Mona	25.00	-3.00	25.38	6887
Four Corners	25.50	-2.00	25.80	7224
NP15	34.25	-2.75	35.20	8839
SP15	34.50	-2.75	35.55	9200

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO average temperature (°F)



Source: Custom Weather

Western load and generation mix forecast (GWh)

	Actual 17-Nov	%Chg	% Chg Year-ago	Forecast 18-Nov	19-Nov	20-Nov	21-Nov	22-Nov
CAISO								
Load	544	-3	-1	610	610	609	599	594
Generation								
Gas	229	-1	1	222	237	259	263	247
Nuclear	56	0	-5	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Nov 19 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	40.38	-0.24	-0.53	-4.47	42.91	10420
SP15 Gen Hub	39.09	0.15	-2.20	-5.05	43.04	10424
ZP26 Gen Hub	37.55	-0.24	-3.35	-5.79	41.30	10013
Off-Peak						
NP15 Gen Hub	32.92	0.00	-0.21	-3.14	35.43	8578
SP15 Gen Hub	31.84	0.00	-1.30	-4.42	35.43	8788
ZP26 Gen Hub	30.86	0.00	-2.27	-3.70	34.49	8519

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-week	11/18	38.75-39.25
Bal-month	11/18	36.00-37.50
Bal-month	11/15	35.50-36.50
Bal-month	11/12	37.50-38.50

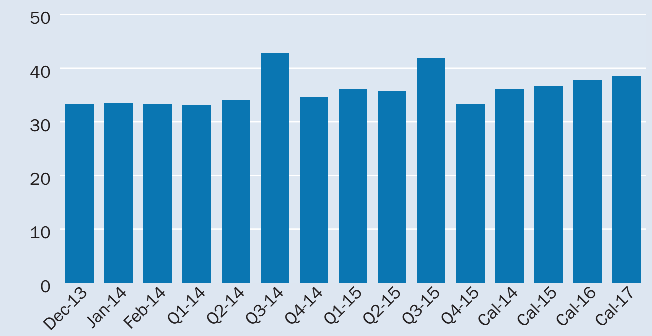
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
ACE Cogen/Constellation	118	g	Calif.	MO	Unk	09/29/13
Alamitos-2/AES	175	g	Calif.	MO	Unk	11/04/13
American Cogen/Calpine	135	g	Calif.	PMO	Unk	11/14/13
Belden/PG&E	119	h	Calif.	MO	Unk	11/07/13
Colgate-1/PCWA	177	h	Calif.	PMO	Unk	11/03/13
Colusa/PG&E	668	g	Calif.	PMO	Unk	11/10/13
Genesis/NextEra	250	s	Calif.	PMO	Unk	10/10/13
Haas-1&2/PG&E	144	h	Calif.	PMO	Unk	11/17/13
High Desert/Tenaska	830	g	Calif.	PMO	Unk	11/03/13
Inland Empire-1/GE	376	g	Calif.	PMO	Unk	11/14/13
Ivanpah-1/NRG	123	s	Calif.	PMO	Unk	10/10/13
Ivanpah-3/NRG	133	s	Calif.	PMO	Unk	10/10/13
Mountain View-3/Iberdrola	525	w	Calif.	PMO	Unk	10/01/13
Pine Flat/USACE	210	h	Calif.	PMO	Unk	10/02/13
Shiloh-I/Iberdrola	150	w	Calif.	MO	Unk	11/12/14
Solar Star-1/MidAmerican	310	s	Calif.	MO	Unk	10/01/13
Solar Star-2/MidAmerican	270	s	Calif.	MO	Unk	10/01/13
Sunrise/Edison	586	g	Calif.	PMO	Unk	11/17/13
Sutter/Calpine	525	g	Calif.	PMO	Unk	11/03/13

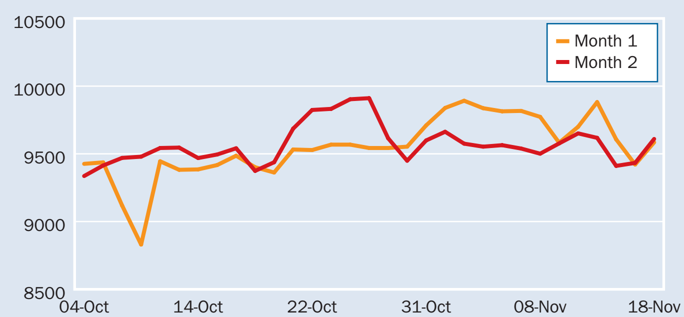
Western Platts-ICE Forward Curve, Nov 18 ($/MWh)

Prompt month: Dec 13	On-peak	Off-peak
Mid-C	38.50	31.50
Palo Verde	33.25	27.75
Mead	34.75	29.00
NP15	41.00	35.25
SP15	41.25	35.00

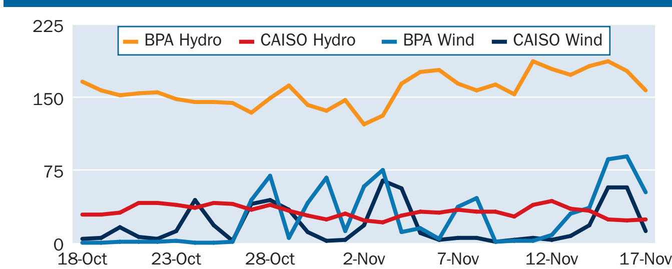
Palo Verde: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

Additional information on data and analysis:

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

PJM & MISO MARKETS

PJM & MISO dailies advance; terms flat

Mid-Atlantic day-ahead power moved up early Monday with demand forecast to move up and spot gas surging higher. Dailies in the Midwest also advanced. Terms in the two regions were flat. The NYMEX December natural gas futures contract settled 4.3 cents lower Monday at $3.617/MMBtu as selling emerged late in the session after the contract failed to hold above $3.70/MMBtu resistance.

The PJM Interconnection forecast peak demand on Monday near 97,169 MW and 101,230 MW for Tuesday. High temperatures in the PJM footprint are expected in the low 40s to mid-50s on Tuesday with lows in the upper 20s to around 40.

Spot gas prices in the region jumped with Texas Eastern M-3 spot natural gas up about 56 cents to about $3.67/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Tuesday gained about $3.50 going to the upper $30s/MWh and off-peak slipped about $1.50 to the low $30s/MWh.

Midwest dailies strengthened with nearby markets going higher and spot gas prices on the rise. High temperatures in the Midcontinent ISO region on Tuesday were forecat in the low 40s to mid-50s and lows in the upper 20s to mid-30s.

Chicago city gates spot gas moved up 10 cents to about $3.73/ MMBtu.

Indiana Hub on-peak for Tuesday gained about $3 going to the mid-$30s/MWh and off-peak added about $1.25 going to the mid-$20s/MWh. Minnesota Hub on-peak increased by about $2 going to the mid-$30s/MWh.

Dailies in the Midwestern portion of the PJM Interconnection were mostly higher with strong spot gas markets and higher demand in the forecast. AEP-Dayton Hub on-peak for Tuesday jumped about $3.75 to the mid-$30s/MWh and off-peak edged up 75 cent to the upper $20s/MWh.

Northern Illinois Hub on-peak for Tuesday was $2 higher in the mid-$30s/MWh and off-peak was nearly flat in the low $20s/ MWh.

Day-ahead auction prices in the PJM Interconnection were higher Monday with demand set to rise on Tuesday. Western Hub on-peak gained nearly $6 moving to $43.60/MWh and Eastern Hub on-peak added almost $7 going to just over $45/MWh.

JCPL on-peak was up $8.30 to $46.61/MWh and PSEG on-peak move up $5.26 to $46.26/MWh. BG&E on-peak gained $6.13 to $46.58/MWh and Pepco on-peak increased $6.17 to $46.36/MWh. Comed on-peak was up $5.17 to $38.68/MWh and Chicago Hub on-peak climbed $5.24 to $38.90/MWh.

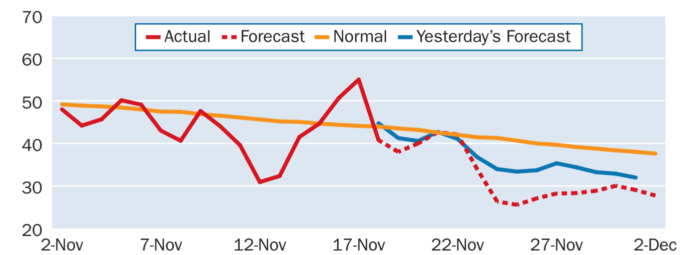
MISO day-ahead auction prices for Tuesday delivery cleared mostly firmer Monday afternoon. Indiana Hub remained the highest priced hub with on-peak clearing at $36.25/MWh, an increase of $1.71. Off-peak cleared at $29.56/MWh, up $7.60.

Michigan Hub on-peak cleared at $34.90/MWh, rising $1.22. Off-peak cleared at $25.71/MWh, adding $4.30. Illinois Hub

PJM & MISO day-ahead bilateral indexes for Nov 19 ($/MWh)

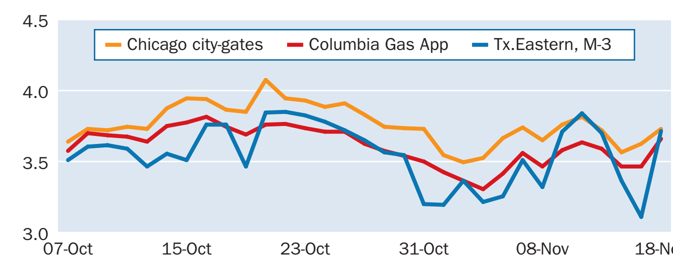
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	39.50	3.50	40.15	11361
Dominion Hub	38.75	1.50	40.94	10389
AD Hub	36.75	3.75	36.52	9800
NI Hub	34.50	2.00	34.44	9249
PJM Off-Peak				
PJM West	31.50	-1.50	32.63	9060
Dominion Hub	31.75	-3.00	33.96	8512
AD Hub	27.00	0.75	29.58	7200
NI Hub	21.00	-0.25	23.88	5630
MISO On-peak				
Indiana Hub	36.50	3.00	35.21	9772
Michigan Hub	35.75	3.75	34.60	9572
Minnesota Hub	38.00	4.00	37.40	10270
Illinois Hub	34.25	4.25	33.42	9182
MISO Off-Peak				
Indiana Hub	26.25	1.25	26.67	7028
Michigan Hub	25.75	1.25	26.60	6894
Minnesota Hub	25.00	5.00	22.02	6757
Illinois Hub	29.25	7.75	25.92	7842

PJM & MISO average temperature (°F)



Source: Custom Weather

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 17-Nov	%Chg	% Chg Year-ago	Forecast 18-Nov	19-Nov	20-Nov	21-Nov	22-Nov
PJM								
Load	1754	-6	1	1832	1972	2138	2109	2021
Generation								
Coal	776	-4	12	776	818	871	897	899
Gas	230	-2	-19	242	296	324	307	269
Nuclear	718	-1	1	723	723	723	723	723
MISO								
Load	1165	-6	-1	1303	1352	1392	1387	1372
Generation								
Coal	1032	-5	5	1142	1188	1182	1139	1123
Gas	13	-4	-37	34	84	111	113	94
Nuclear	200	-3	-9	206	206	206	206	206

Source: Bentek

MISO average day-ahead LMP for Nov 19 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	36.25	4.34	0.53	1.71	32.67	9775
Michigan Hub	34.90	2.53	0.99	1.22	32.13	9372
Minnesota Hub	30.63	0.31	-1.06	-6.96	33.27	8299
Illinois Hub	32.23	1.54	-0.69	0.25	30.97	8663
Off-Peak						
Indiana Hub	29.56	4.87	0.61	7.60	25.47	8335
Michigan Hub	25.71	0.70	0.93	4.30	24.92	7066
Minnesota Hub	25.03	1.87	-0.92	4.71	18.70	6884
Illinois Hub	23.58	-0.11	-0.40	-3.20	24.71	6487

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

Package	Trade date	Range
PJM West		
Bal-week	11/18	38.50-39.50
Bal-week	11/12	40.50-41.50
Next-week	11/18	39.50-40.50
Next-week	11/14	41.50-42.50
Next-week	11/13	41.00-42.00
Next-week	11/12	42.00-43.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Dresden-2/Exelon	926	n	Ill.	RF	11/30/13	11/10/13
Oyster Creek/Exelon	670	n	N.J.	MO	Unk	11/17/13
Prarie Island-2/Scel	585	n	Minn.	RF	12/13/13	09/21/13
Three Mile Island/Exelon	890	n	Penn.	RF	11/24/13	10/28/13

PJM average day-ahead LMP for Nov 19 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	39.71	-1.20	-1.82	5.73	33.23	10984
AEP-Dayton Hub	41.08	-1.01	-0.63	6.33	34.34	11363
ATSI Gen Hub	42.14	-1.03	0.45	6.32	36.10	11907
Chicago Gen Hub	38.15	-2.38	-2.19	5.20	31.64	10252
Chicago Hub	38.90	-2.17	-1.65	5.24	32.25	10455
Dominion Hub	42.75	0.42	-0.39	5.32	38.76	11533
Eastern Hub	45.02	0.91	1.38	6.92	40.02	12167
New Jersy Hub	46.18	1.95	1.51	6.44	39.16	12482
Northern Illinios Hub	38.40	-2.47	-1.85	4.92	31.98	10318
Ohio Hub	41.26	-0.95	-0.51	6.48	34.48	11173
West Internal Hub	41.74	-0.64	-0.34	5.77	36.30	12174
Western Hub	43.60	0.64	0.23	5.96	38.06	12715
AEP Zone	41.08	-1.04	-0.61	6.15	34.49	11362
Allegheny Power Zone	42.27	-0.22	-0.23	5.69	36.52	11801
Atlantic Elec Zone	45.06	1.10	1.24	6.74	38.29	12179
ATSI Zone	42.63	-1.02	0.92	6.52	36.59	12044
BG&E Zone	46.58	2.33	1.53	6.13	40.60	13135
ComEd Zone	38.68	-2.32	-1.72	5.17	32.14	10393
Dayton P&L Zone	42.32	-0.99	0.59	6.75	35.13	11525
Delmarva P&L Zone	44.90	1.01	1.17	6.58	39.77	12134
Dominion Zone	43.35	0.78	-0.15	5.42	39.00	11694
Duke Zone	39.96	-1.13	-1.63	5.90	33.32	10883
Duquesne Light Zone	40.56	-1.24	-0.92	5.75	34.81	11786
JCPL Zone	46.61	2.24	1.65	8.30	37.97	12598
MetEd Zone	44.56	1.26	0.58	6.92	37.86	12114
PECO Zone	43.95	0.84	0.40	6.73	37.78	11949
Pennsylvania Elec Zone	45.13	1.67	0.74	7.06	39.12	13566
PEPCO Zone	46.36	2.61	1.03	6.17	40.60	13074
PPL Zone	44.46	1.48	0.26	7.16	37.68	12086
PSEG Zone	46.26	2.03	1.51	5.26	40.12	12503
Rockland Elec Zone	46.52	2.21	1.59	5.13	40.05	12573
Off-Peak						
AEP Gen Hub	28.83	-0.28	-0.87	5.44	27.06	8509
AEP-Dayton Hub	29.51	-0.13	-0.33	5.62	27.95	8712
ATSI Gen Hub	30.01	-0.25	0.28	5.77	28.54	8915
Chicago Gen Hub	25.33	-2.96	-1.68	6.45	22.48	6962
Chicago Hub	26.30	-2.30	-1.38	6.72	23.17	7229
Dominion Hub	31.20	1.00	0.22	5.41	31.75	8743
Eastern Hub	31.14	0.59	0.58	5.50	30.56	9539
New Jersy Hub	31.12	0.50	0.64	5.39	29.89	9533
Northern Illinios Hub	25.41	-3.08	-1.48	5.86	22.91	6984
Ohio Hub	29.59	-0.08	-0.31	5.65	28.07	8310
West Internal Hub	30.21	0.19	0.05	5.59	29.27	9617
Western Hub	30.95	0.77	0.21	5.63	30.28	9854
AEP Zone	29.54	-0.16	-0.27	5.62	28.04	8719
Allegheny Power Zone	30.34	0.24	0.12	5.47	29.32	9094
Atlantic Elec Zone	31.02	0.59	0.46	5.58	29.78	9502
ATSI Zone	30.26	-0.27	0.55	5.90	28.75	8990
BG&E Zone	32.89	1.99	0.92	5.78	32.76	10077
ComEd Zone	25.80	-2.75	-1.42	6.50	23.00	7091
Dayton P&L Zone	30.26	-0.14	0.42	5.88	28.35	8601
Delmarva P&L Zone	31.17	0.65	0.54	5.45	30.51	9547
Dominion Zone	31.47	1.20	0.29	5.40	31.96	8820
Duke Zone	28.90	-0.28	-0.79	5.42	27.18	8215
Duquesne Light Zone	29.37	-0.39	-0.21	5.72	27.77	9106
JCPL Zone	31.18	0.50	0.71	6.04	29.53	9551
MetEd Zone	30.98	0.69	0.32	5.87	29.47	9278
PECO Zone	30.72	0.60	0.15	5.46	29.46	9198
Pennsylvania Elec Zone	30.44	-0.05	0.51	5.78	29.33	9784
PEPCO Zone	32.71	2.05	0.69	5.68	32.68	10022
PPL Zone	30.51	0.50	0.04	5.66	29.23	9135
PSEG Zone	31.12	0.48	0.66	4.97	30.15	9530
Rockland Elec Zone	30.99	0.39	0.62	4.88	30.02	9493

on-peak cleared at $32.23/MWh, a gain of 25 cents. Off-peak cleared at $23.58/MWh, a loss of $3.20.

Minnesota Hub became the lowest priced hub with on-peak clearing at $30.63/MWh, shedding $6.96. Off-peak cleared at $25.03/MWh, rising $4.71. Congestion costs at the hubs ranged from 31 cents to $4.34 for on-peak, and from negative 11 cents to $4.87 for off-peak.

Mid-Atlantic forwards hardly moved with weakness in NYMEX gas futures. PJM West on-peak December financial futures wre unchanged with bids at $41.50/MWh and offers at $41.75/MWh at about 2:30 p.m. EDT on the IntercontinentalExchange. PJM West on-peak January-February 2014 financial futures were down about 10 cents to about $42.65/MWh on ICE.

Midwest forwards were nearly unchanged with the downtick in NYMEX gas and steady nearby power markets. AD Hub on-peak December financial futures were flat with bids at $38/MWh and offers at $38.25/MWh on ICE. Indiana Hub on-peak December financial futures were steady around $36/MWh on ICE. NI Hub on-peak December financial futures edged down 25 cents to about $35.50/MWh.

Southeast markets *... from page 4*

High temperatures in Atlanta were forecast to drop to the upper 50s Tuesday, with lows expected in the low 40s. The average November high temperature in the city is 64; its average low is 45.

The ERCOT day-ahead auction for Tuesday delivery cleared weaker Monday afternoon with peak load forecast weaker. South Hub became the highest-priced hub position, as North Hub fell to the lowest-priced hub.

South Hub on-peak cleared at $31.43/MWh, falling 35 cents, while off-peak cleared at $22.46/MWh, dropping 54 cents. Houston Hub on-peak cleared in the auction at $30.88/MWh, losing 72 cents, while off-peak cleared at $22.40/MWh, shedding 57 cents.

West Hub on-peak cleared in the ERCOT auction at $30.21/MWh, a loss of 69 cents, while off-peak cleared at $22.13/MWh, a drop of 83 cents. North Hub on-peak cleared the auction at $29.67/MWh, down 83 cents from Sunday's clearing price, while off-peak cleared at $22.39/MWh, a decrease of 56 cents.

Austin Energy Zone on-peak led the load zones at $34.39/MWh, up 24 cents from Sunday. The highest hourly day-ahead price occurred at 6 pm CST in the South Hub at $36.64/MWh and in the Austin Energy Zone at $39.56/MWh.

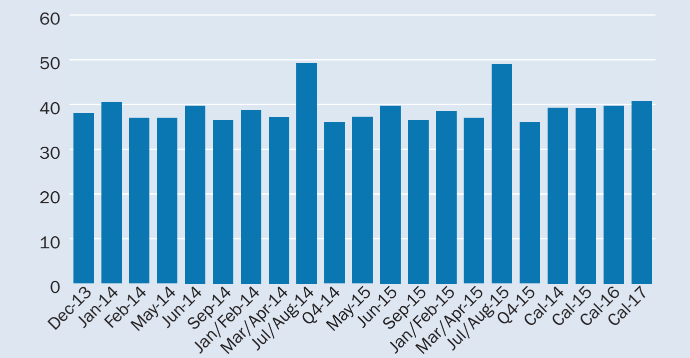
ERCOT system load was forecast to peak at 35,675 MW Tuesday, down 6% from Monday's expected peak of 37,825 MW.

South Central US on-peak December terms moved up Monday. ERCOT North on-peak December rose 25 cents to about $32.25/MWh, while January and February were each unchanged at about $34.75/MWh. Heat rates were up about 50 Btu/kWh on the IntercontinentalExchange at about 9:30 a.m. EST. Into Entergy

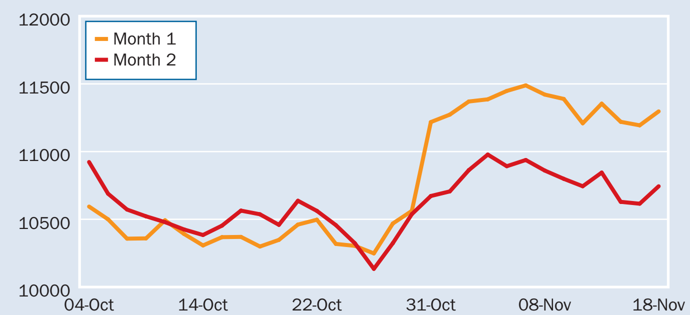
PJM & MISO Platts-ICE Forward Curve, Nov 18 ($/MWh)

Prompt month: Dec 13	On-peak	Off-peak
PJM West	41.75	34.25
AD Hub	38.00	31.75
NI Hub	35.50	27.00
Indiana Hub	36.00	28.25

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



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



on-peak December gained 50 cents to about $33/MWh, and January rose 50 cents to about $31.50/MWh.

Southeast US on-peak December rose Monday, as did December NYMEX gas futures. Into Southern December advanced 50 cents to about $34.75/MWh, January rose 25 cents to about $35.25/MWh, and February climbed 50 cents to about $34.75/MWh.

West markets *... from page 6*

on ICE around 9:30 am EST. On-peak January and the first quarter of 2014 had no bids or offers. In California, SP15 on-peak December financial terms were unmoved with bids at $40.75 and offers at $42.50/MWh. January stayed at about $41.50/MWh, and first quarter crept down 10 cents to about $42/MWh. NP15 on-peak December and January had no bids or offers, but first quarter was constant around $40.40/MWh. Palo Verde on-peak terms had no bids or offers in early trading.

NEWS

Exelon may push bill for long-term contracts

If power markets do not recover, Exelon may push legislation in Illinois under which the Illinois Power Agency would be forced to buy electricity under long-term contracts from the company's struggling in-state nuclear plants to supply non-shopping customers of Illinois electric utilities.

At least one energy analyst believes strong policy arguments could be made to support such a scenario, even though it would represent a departure from Exelon's long-held advocacy of energy markets and restructuring.

Exelon, the parent company of Chicago-based Commonwealth Edison, Constellation Energy and Peco Energy, has watched power prices plummet for its 19,000-MW nuclear fleet, the nation's largest, as it competes with burgeoning renewable energy and lower-cost natural gas generation.

Last week, Christopher Crane, Exelon CEO, told the Edison Electric Institute that if markets do not improve, the company could pursue "long-term contracts" or sell some of its nuclear units. For the first time, he mentioned the 1,824-MW Quad Cities nuclear plant near Cordova, Illinois, on the Mississippi River as a possible sale or shutdown candidate.

Exelon previously suggested some of its plants, including the 610-MW R.E. Ginna nuclear plant on Lake Ontario near Oswego, New York, and 1,078-MW Clinton nuclear plant in central Illinois, are potentially vulnerable to shutdown.

If Exelon wants a contract solution that involves the IPA, it would need legislation passed by the Illinois General Assembly. So far, that legislation is only being considered and is not in draft form, one state official said Monday.

The concept, however, is "percolating" among key company and political officials, he said.

Such a bill "would raise a whole number of issues that would have to be worked out," IPA acting director Anthony Star said in an interview. Under state law, his tiny agency purchases power on behalf of default customers of ComEd and Ameren Illinois, the state's two largest electric utilities with nearly 5 million combined customers.

"It's such an abstract idea," Star said. "I think it would be vigorously debated" in the Legislature.

David Kolata, executive director of the Citizens Utility Board consumer watchdog agency, agreed, adding consumers "have reason to be skeptical that such a deal could ultimately work out."

But that does not mean CUB, created during the mid-1980s with the support of then-legislator and current Democrat Governor Pat Quinn, would not consider the long-term contract idea, he said.

"If it was to work, it would have to be part of an overall, least-cost hedging strategy that also involved more energy efficiency procurement" by the IPA, Kolata said.

State Senator Mike Jacobs, a Democrat who chairs the Senate Energy Committee, said Monday that while he would need to see the precise wording of a bill to allow the contracts, he would be receptive to an Exelon request.

"We've asked the power companies to supplement everybody else," he said in an interview. "We asked them to buy the power from all the green companies. That's created some problems — overregulation."

Part of the problem is that no one knows for certain what will happen to gas prices in the future, he said, "and that is disconcerting" to Exelon, according to the lawmaker. "Clearly, something may have to happen."

Jacobs, in whose district the Quad Cities plant is located, said it is important that Illinois "guards one of its natural resources, nuclear energy."

Certainly, he said, the legislation "could be on the table" in the 2015 legislative session, if not in 2014.

Meanwhile, Paul Patterson, a Glenrock Associates analyst in New York, said an Exelon contract proposal could be defended on the basis of sound policy.

"It's important to remember," Patterson said, "that nuclear power provides carbon and air pollution-free electricity and is a source of fuel diversity, high quality employment as well as substantial local taxes. In addition, it's far more reliable than wind and solar, both of which get substantial subsidies."

He added: "So, from a policy perspective, does it make sense to shut these plants down, lose these benefits and put all of one's eggs in the natural gas basket?"

In a statement released by Exelon spokesman Paul Elsberg, the company said the combined effect of low wholesale power prices and the "unintended consequences of current energy policies" is challenging the economics of several of Exelon's nuclear units.

Exelon believes "power markets will recover," the company continued, "but if we do not see a long-term path to sustainable profitability for a particular unit, then we will consider all options, including unit shutdowns."

Any contract legislation sought by Exelon would mean a "fundamental shift" in the company's philosophy, Kolata pointed out, noting, "They've been a big proponent of energy markets and restructuring and that would almost go against" those positions.

Ultimately, though, Exelon is "trying to maximize their profits," Kolata said.

— Bob Matyi

FERC OKs ISO-NE mitigation rule change

Federal energy regulators accepted a proposal by ISO New England and the New England Power Pool Participants Committee that calls for modification of market power mitigation rules that apply to supply offers for resources that are committed out-of-merit to address a local reliability need.

The Federal Energy Regulatory Commission's Friday order responded to a mid-September filing made by ISO-NE and the NEPOOL committee.

In that filing, the committee and the ISO said that market participants owning resources that are committed out-of-merit to address a local reliability need are in a unique position to assert market power because such resources are committed based on the need to address local reliability concerns rather than their offer price.

They said that, under the existing tariff, the internal market monitor currently performs a reliability commitment mitigation conduct test to prevent such market participants from exercising this market power and earning excessive out-of-merit revenues through net commitment period compensation, or NCPC, payments.

Specifically, when a resource is committed by ISO-NE to address a local reliability need, the IMM evaluates the supply offer for that resource based on the minimum run time submitted in the supply offer, the FERC order explained.

If the financial parameters of the supply offer exceed 110% of the cost-based reference levels for that particular resource, the supply offer fails the conduct test, and the offer will then be mitigated to the reference level values for each parameter.

ISO New England and the New England Power Pool Participants Committee said that the effect of this mechanism is that the most a market participant can receive through NCPC payments for providing the local reliability service is 10% in excess of the resource's cost-based reference levels.

But the committee and the grid operator noted that the IMM has determined that the current conduct test is susceptible to manipulation when a resource is committed beyond its minimum run time. "Because the current conduct test evaluates a resource's performance only for the period of its minimum run time, a market participant that presumes or knows that its resource will be operated for reliability purposes beyond the resource's minimum run time can structure the parameters of its supply offer to receive out-of-market NCPC payments in excess of 10% above the applicable reference levels," the commission order explained.

Specifically, ISO-NE and the committee said that a market participant could lower the start-up fee component in the supply offer and raise either the no-load fee or energy offer price.

In an effort to block opportunities for market manipulation, the grid operator and the committee proposed to add an additional conduct test, the actual run time conduct test, for those resources that pass the current conduct test and which are dispatched for a local reliability need.

ISO-NE and the committee said that, unlike the current conduct test, the new test will be performed after the operation of the resource and will use the resource's actual run time, rather than its minimum run time. A resource will fail either the current conduct test or the actual run time conduct test if its financial parameters are in excess of 10% of the cost-based reference level for the resource, using the resource's minimum run time or actual run time, respectively. If the resource's supply offer fails the actual run time conduct test, the supply offer will be mitigated down to its reference level parameters, just as in the event of a failure of the current conduct test.

Therefore, according to ISO-NE and the committee, the new test will prevent a resource from passing the current conduct test and still earning in excess of the 10% adder by misrepresenting the parameters of its supply offer.

FERC also gave its blessing to the ISO-NE and participant committee's plan to remove from the current conduct test a second factor that is applied when evaluating a supply offer for mitigation.

Daily CSAPR allowance assessments, Nov 18

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, Nov 18

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

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

RGGI carbon allowance futures, Nov 15 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	2.95	0	Dec13	1.97	0
Dec13 V11	2.95	0	Dec14	1.97	0
Dec13 V12	2.95	0			
Dec13 V13	2.95	35			
Dec14 V10	3.05	0			
Dec14 V11	3.05	0			
Dec14 V12	3.05	0			
Dec14 V13	3.05	0			
Dec15 V10	3.15	0			
Dec15 V11	3.15	0			
Dec15 V12	3.15	0			
Dec15 V13	3.15	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.

The current conduct test evaluates the resource's operation to determine whether it violates either the 10% threshold or a potentially more restrictive threshold: the economic maximum limit (in megawatts) of the resource multiplied by $80/MW.

FERC said that it has no problem with the removal of the $80/MW factor prior to the upcoming winter, which ISO-NE and the participants committee note is a time of year when gas price volatility is likely to increase.

— Paul Ciampoli

Grid operators grapple with plant retirements

The pending retirement of coal-fired plants will present wholesale power markets with challenges that they have not previously faced, Steven Mitnick, senior energy advisor at Bates White Economic Consulting, said Friday.

"We are really challenged. What we are experiencing now is unprecedented," Mitnick said during a meeting of the Energy Bar Association Northeast Chapter to discuss grid operator responses to generation retirement.

"Historically we have not had that much exit and entry" into the market by generators, and that presents challenges because the exit and entry is not perfectly matched, Mitnick said. Unequal amounts of generation is retiring and being proposed, and it is coming and going at different locations and with varying time schedules, he explained.

Those challenges have been felt in the New York Independent System Operator region where stakeholders are hammering out issues related to unit retirements.

From the perspective of load, stakeholders would like more specificity on the definitions and distinctions between a retired and a mothballed unit, among other things, Richard Miller, director of Consolidated Edison's energy markets policy group said at the meeting. For instance, he said, if a unit is really mothballed as opposed to retired, it should have to specify a date at which it will return into service.

Another issue is the status of a retired unit's interconnection point with the grid. Usually the load serving entity takes control of those assets when a plant retires, but a "POI has value," Liam Baker with US Power Generating said, arguing that generators should be compensated for that value.

By way of contrast in the PJM Interconnection the capacity market is sending signals on when and where to enter the market, Paul Sotkiewicz, senior economist at PJM said. "The market is helping us manage deactivation, so we don't have reliability issues."

PJM is facing more than 22 GW of actual and announced retirements by 2016, but the ISO has time to come up with responses because its capacity market looks three years into the future, he said.

Sotkiewicz noted that of all the retirements in the region so far only two have given notice of less than 90 days while 58 have given more than three years notice. So even though those retirements could pose reliability issues, "we have time to put a response in place," he said.

ISO-NEW England also has a capacity market, but it handles unit retirements through a "de-listing" procedure whereby generators can use a variety of delisting techniques to exit the region's capacity market. Prior to the capacity auction generators can chose to permanently exit the market or to exit the market for one year through a static de-list. A generator can also use the dynamic de-list mechanism during the capacity auction to exit the market for one year.

If the market does not result in resources coming forward to meet reliability needs, the ISO has the option of moving ahead with a "backstop reliability solution" such as a transmission project, Kevin Flynn, ISO-NE's senior regulatory counsel, said.

— Peter Maloney

EPRI predicts efficiency impact on demand

Energy efficiency gains beyond what are currently predicted by the Energy Information Administration could reduce US consumption by between 8-11% from projected levels in 2035, according to a memo prepared by the Electric Power Research Institute.

"EPRI analysis indicates the energy efficiency programs — above and beyond those assumed in the [Annual Energy Outlook 2012] Reference Case — have the achievable potential to reduce the annual growth rate of electricity consumption between 2012 and 2035 from 0.72% to a range of 0.36% to 0.20%," the group said in a memo floated during the National Association of Regulatory Utility Commissioners' annual meeting in Orlando Monday.

According to the EIA's Annual Energy Outlook for 2012, energy consumption is expected to climb to 4,393 TWh in 2035, the memo said.

The memo previews a report slated to be released by the end of 2013 that finds that efficiency programs can find additional savings "by improving program delivery mechanisms through innovative market approaches (such as upstream programs targeted at equipment suppliers) and reducing market barriers through incentives and education."

Other groups have predicted the demand impact of efficiency gains in a similar range as EPRI's report, with Macquarie Equities Research pegging the annual impact at 0.5% and IEE, a collection of investor-owned utilities that focus on smart grid technologies and efficiency, putting the figure at 0.4% in its long-term demand forecast earlier this year.

EPRI said in the memo that commercial indoor lighting "continues to represent the greatest opportunity for achievable energy savings," estimating that it amounts to 38% of potential savings in 2035. Also helping the cause are efficiency gains in air conditioning, consumer electronics, office equipment and other areas.

— Bobby McMahon

Clean Line issues RFI for wind-farm developers

Wind-farm developers with projects under development in western Kansas have until January 13 to respond to a request for information issued on Monday by Clean Line Energy Partners, the developer of the planned 750-mile Grain Belt Express transmission line from western Kansas to Indiana.

The 600-kV, direct-current line, which Clean Line plans to design, build and energize by 2018, is expected cost about $2 billion to complete. It will have the capacity to transmit about 3,500 MW of low-cost wind power into the nation's industrial heartland with only minimal line losses.

Clean Line said in the RFI that the solicitation's intent "is to gather information about generators' demand for the Grain Belt Express [line's] transmission capacity and to collect data that will allow Clean Line to characterize the wind resource and production potential in western Kansas."

The RFI said that while it "is obvious to many in the wind industry that more transmission infrastructure is needed, the data collected through this RFI will be used to communicate this need to regulators and stakeholders. In addition, more detailed information about the wind resources in western Kansas will be helpful in discussions with utilities in the Midwest and Mid-Atlantic regions who may be interested in Clean Line's ability to transmit affordable, renewable energy to their markets."

The RFI that Clean Line issued in June regarding its proposed Plains & Eastern line from the Oklahoma Panhandle to near Memphis, Tennessee, showed that 15 wind farm developers are planning projects totaling more than 16,000 MW near the western terminus of that line. Clean Line said that, as in that earlier RFI, it will not provide regulators and potential wind power buyers with individual wind generator data gathered through the new Grain Belt Express RFI. Instead, "Clean Line will supply them with aggregate data" on the number of wind farms and the total MW of wind capacity under development in western Kansas, as well as general information about "indicative" wind power pricing.

Wind power generated in western Kansas will be delivered via alternating-current lines to the western terminus of the Grain Belt Express line in Ford County, near Dodge City, Clean Line said in the RFI. There, the energy will be converted to direct current for transmission to the east. Converter stations at the 345-kV Maywood substation in northeastern Missouri and at the 765-kV Sullivan substation in southwestern Indiana will convert the energy back to alternating current for delivery to buyers in the Midwest and Mid-Atlantic states.

Clean Line noted that the Midcontinent Independent System Operator has completed the feasibility study for the Maywood interconnection, and that Clean Line "expects to receive the results of the [PJM] system impact study early next year. After receiving the system impact study results, Clean Line will enter into the facilities study phase of the [PJM] interconnection process," the RFI said.

Clean Line said that on Friday it filed for negotiated rate authority with the Federal Energy Regulatory Commission; FERC already has granted Clean Line such authority for its Plains & Eastern project.

The Grain Belt Express RFI is available at the "Respond to RFI" section of www.grainbeltexpresscleanline.com. Clean Line will hold a respondents' webinar on December 16 to answer questions. Confidentiality agreements are due December 18, and the deadline for RFI responses is January 13.

— Housley Carr

Oklahoma co-op enters into wind PPAs

After assessing the wind power market in its multistate region, Western Farmers Electric Cooperative has entered into three power purchase agreements totaling 120 MW, the Anadarko, Oklahoma-based generation and transmission co-op said Monday.

Western Farmers, which helps secure power for 23 distribution co-ops in parts of Oklahoma, New Mexico, Texas and Kansas, said it has agreed to buy 100 MW from Apex Clean Energy's planned 300-MW Balko wind project in Beaver County, in Oklahoma's panhandle.

Richard Ross, manager of risk management at Western Farmers, declined to provide any pricing information, except to say that the G&T co-op is "comfortable" with the price it will be paying for the Balko wind power under the 20-year PPA.

Last month, Public Service Co. of Oklahoma concluded a request for proposals for 200 MW of wind power by entering into three 200-MW PPAs, including one with Apex for the output of the other two-thirds of the Balko project, which is expected to come online in 2015.

At the time, a PSO spokesman said that while he could not reveal the price the utility will be paying Apex for wind power from Balko, "What I can say ... is that these were some of the best prices we've ever seen for wind energy."

Recent wind-power RFPs by Austin Energy and Southwestern Public Service generated offers at low as $22/MWh, and—like PSO's solicitation—resulted in the Texas municipal utility and SPS entering into PPAs for far more wind power than they had planned.

Western Farmers' Ross said Monday that the co-op "became aware of" current wind power prices in its region and determined without benefit of a formal RFP that the price Apex offered was fair and competitive.

Western Farmers will purchase the output of two small wind projects totaling 20 MW in Curry County, New Mexico. The projects together will be known as Brahms Wind; the new wind farm will be owned by BayWa Renewable Energy, which recently purchased the projects from National Renewable Solutions. Again, the price Western Farmers will pay for the wind power was not disclosed.

The new wind PPAs bring to 486 MW the amount of wind power that Western Farmers is under contract to buy through long-term PPAs. The G&T co-op also owns 1,320 MW of fossil-fired capacity — 450 MW of it fired by coal and the rest by natural gas — and holds entitlements to 260 MW of hydroelectric power. It also buys a total of 366 MW from existing wind farms in Oklahoma.

Western Farmers "continues to support additional wind resources when they support stable, affordable electric rates for consumers," Gary Roulet, the G&T co-op's CEO, said in a statement. "Wind is an important part of [Western Farmers'] diverse mix of generation, and plays an integral part in our overall commitment to renewable energy, as well as enabling the ability to reduce fossil fuel emissions," he said.

In addition to 23 distribution co-ops, Western Farmers provides power to the Altus Air Force Base in southwestern Oklahoma.

— Housley Carr

Cal-ISO clears about $56.6 million of CRRs

The California Independent System Operator cleared about 286,924 MW of congestion revenue rights for 2014 for about $56.6 million total absolute dollars in its recent annual auction, according to data from the grid operator.

Of that total, about $12.8 million absolute dollars were for about 75,461 MW of CRRs for the first quarter of 2014 (January through March), about $14.2 million absolute dollars were for about 69,846 MW of CRRs for the second quarter (April through June), about $17.1 million absolute dollars were for about 72,203 MW of CRRs for the third quarter (July through September), and about $12.5 million absolute dollars were for about 69,413 MW of CRRs for the fourth quarter (October through December).

CRRs — also known as financial transmission rights in other markets — are financial instruments that allow market participants to hedge against congestion on the grid. An obligation CRR entitles its owner to be charged or receive compensation when Cal-ISO's transmission grid experiences congestion in the day-ahead market.

The positive dollars taken in by Cal-ISO in this auction totaled about $36 million for about 229,485 MW of positive CRRs. Of that total, about $7.8 million was for first quarter CRRs, $8.3 million for second quarter CRRs, about $11.5 million was for third quarter CRRs and about $8.3 million was for fourth quarter CRRs.

The auction cleared about 57,439 MW of negative CRRs for about negative $20.5 million. With negative CRRs, a participant is paid to take on the risk of congestion on a path in the direction opposite historical prevailing flow.

The overall net positive effect of the auction was about $15.5 million.

Vitol had the largest position by volume, with about 47,714 MW of CRRs and a net dollar position of about $7 million.

EDF Trading was second by volume, with about 42,719 MW of CRRs for about $1.7 million net dollars.

Edison Mission came in third, with about 30,128 MW of CRRs and a net dollar position of about $1.8 million.

Monolith Energy placed fourth with about 29,470 MW of CRRs and about $1.6 million net dollars.

Rounding out the top five by volume was Castleton Commodities with about 27,503 MW of CRRs and a net dollar position of about $1.4 million.

Powerex had the highest net positive dollar position, with about $8.9 million net dollars for about 6,474 MW of CRRs.

Noble Americas had the largest net negative dollar position, with about negative $6.1 million net dollars for about 3,271 MW of CRRs.

A total of 33 companies cleared CRRs in the annual auction.

— Juliana Brint

Cleco clears La. regulatory hurdles to join MISO

Louisiana regulators have cleared the way for Cleco Power to join the Midcontinent Independent System Operator December 19, the company announced Monday.

"We are pleased to complete the regulatory process to join MISO," said Darren Olagues, Cleco president. "We now have approval on how we account for MISO-related transmission and market changes that are part of being a member of a regional transmission organization."

The Louisiana Public Service Commission on Wednesday gave final approval for settlement of "certain implementation and integration issues" regarding Cleco joining MISO. The PSC had already approved in June the change of control of its high-voltage transmission system to MISO. That is when MISO became Cleco's reliability coordinator.

Headquartered in Pineville, Louisiana, Cleco owns or operates generation with a total nameplate capacity of about 3,300 MW and serves about 283,000 customers in Louisiana and Mississippi.

Of that total capacity, 600 MW is fueled by pet coke, 643 MW is fueled solely by natural gas, and the remainder is primarily fueled by natural gas but with the capability of also using either coal or oil.

— Mark Watson

Deal increases solar's threat

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and in return homeowners sign contracts under which the solar company owns the solar panels and sells the electrical output to the homeowner.

Such third-party arrangements facilitated the growth of residential solar rooftop installations by shifting the initial costs from homeowners and on to solar power companies, but eventually those same high capital costs can limit the potential growth of solar power companies.

If a solar company can find a way for its third-party business model to support financing needs, it also could improve its access to capital and ability to grow.

Securitization pools the cash flows from several individual projects, in this case a collection of contracts with homeowners for rooftop solar installations, and channels them through a single financial instrument.

The financial theory is that securitization spreads risks and builds up the size of the offering in order to make it economical for a financial institution to take on. Securitization is used in a variety of assets such as credit cards, car loans and, infamously, home mortgages.

Securitization has also been seen within the renewables industry as something of a "Holy Grail" that could serve to lower capital costs thereby lowering the overall costs of renewable technology in order to make it more competitive with conventional generation resources. That goal has taken on more urgency in recent years with the pending expiration of renewable energy subsidies. The production tax credit for wind power is set to expire at year end, and the investment tax credit for solar power steps down to 10% from 30% at year-end 2016.

A recent report by Michael Mendelsohn and David Feldman of the National Renewable Energy Laboratory estimated that the use of public capital could lower the levelized cost of energy for a wind or solar project by 8% to 16%.

In the wake of the SolarCity offering, Mendelsohn said his estimates could be "too conservative," given the pricing of the SolarCity city notes, which have an interest rate of 4.8%.

Mendelsohn said he has not done an analysis on how much lower capital costs could increase the penetration of distributed solar but it represents part of a "virtuous cycle" in which lower costs foster greater penetration which in turn aids in lower technology costs, providing the scope for solar DG to expand in all 50 states.

Currently the penetration of solar rooftop installations is low, less than 1%. NREL estimates there are only about 30,000 residential solar leases, but sees a "vast" potential among the 44 million rooftops in the US.

The SEIA says there are 200,000 distributed solar customers with an aggregate total of 2,300 MW installed as of 2011. That is a small number in the context of the 1,000,000-MW US power system, but rooftop solar is one of the fastest growing segments of the quickly growing renewables sector. Some analysts see 22% annual growth in PV installation, resulting in 30 GW by 2020 with 4.5 GW from distributed PV.

According to the Interstate Renewable Energy Council, annual installed grid-connected photovoltaic capacity grew by almost 300% from 2008 to 2010. About one-third of the total in 2010 came from utility-scale projects. The remaining capacity encompassed small installations at residential properties, government buildings, commercial entities, and military stations. And rooftop solar installations increased more than 200% between 2008 and 2010, hitting 600 MW.

And in 2012 grid-connected distributed photovoltaic capacity increased by 36% from 2011 to about 4,350 MW, according to the IREC. About two-thirds of the installations were added in California, Arizona, New Jersey and Nevada.

The growth of solar power is driven by several factors, chief among them though is the precipitous decline in PV costs, which have fallen from $3.80/watt in 2008 to 86 cents/watt in 2012.

Despite the low level of penetration, the threat is disproportionately large. In a January report, the Edison Electric Institute said that the less than 1% penetration of solar power represents "the largest near-term threat to the utility model."

Falling technology prices mean that rooftop, or distributed, solar is becoming more economical at a faster pace than either utility scale solar or wind power, Julien Dumoulin-Smith, an analyst at UBS, said in a November 15 report on the threat renewables pose to traditional generation. Distributed solar is also aided in those comparisons because it avoids transmission charges that can range from 5 cents/kWh to 15 cents/kWh.

In several markets, rooftop solar prices have already fallen enough to put them on par with other sources of power. Based on a threshold price of 13 cents/kWh, Dumoulin-Smith identifies nine states that are likely to see the greatest growth in distributed generation. They include all the New England states except Maine and Rhode Island, Alaska and Hawaii, as well as California, New Jersey and New York.

The UBS report calls the disruptive power of solar DG "massive." One of the near-term effects Dumoulin-Smith sees is for distributed solar "to further eat into the already depleted demand pie."

And as demand drops, utilities will be forced to raise rates to maintain their financial metrics, and rising rates could improve comparisons and make solar power look more attractive to potential customers.

More specifically Dumoulin-Smith says that because solar resources tend to peak at mid-day, they will tend to reduce the need for gas-fired combustion turbines that would normally be used for quick response during peak hours.

Combined, the penetration of wind and solar resources will reduce the ability of fossil-fueled baseload and peaking plants to recover the long-run marginal costs, he said.

— Peter Maloney

PJM, monitor differ

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found no evidence that UTC bidding enhances price convergence between day-ahead and real-time bidding.

Bowring said he bases these conclusions on analysis of trade data for May 2, 4, 22, 23 and 27, and said PJM staff agreed with the conclusions he reached based on this data.

A person speaking for PJM, who was not clearly identified to webinar listeners, said Bowring's conclusions are consistent with the data, but an error in the computer modeling for those days could have accounted for the significant differences Bowring found.

"The problem we have is that if there hadn't been a modeling error, there would not have been that effect from UTCs," the person said.

In other business, the committee learned that load-weighted average locational marginal wholesale power costs in the PJM Interconnection fell about 16.2% in October, in comparison with September.

And the October 2013 average LMP, at $34.60/MWh, was about 5.2% less than the October 2012 average LMP, which was $36.50/MWh. This September, the load-weighted average LMP was $41.30/MWh, according to a report by Paul Sotkiewicz, PJM chief economist.

In general, PJM's weather was somewhat milder this October than it was in October 2012. Pittsburgh, Pennsylvania, lies near the center of the PJM footprint. Pittsburgh's heating degree days this October, at 297, totaled almost 19% less than those of October 2012, which were 366, and its cooling degree days more than doubled, from 14 to 34.

A heating degree day is a measurement designed to reflect the demand for energy needed to heat a building, derived from comparing outside temperature to what would be considered comfortable temperature inside a building. A cooling degree day is similar, except it reflects demand needed to cool a building to a comfortable temperature, given outside temperatures.

— Mark Watson

TVA looks to keep unit as viable asset

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TVA spokesman, said Monday. Demand has fallen and it is not expected to reach 2007 levels for a decade, he said.

TVA is developing an estimate on the cost and schedule to complete the Bellefonte unit and the need for the unit will be considered in the integrated resource plan that has just gotten underway and will be completed in the spring of 2015, Mansfield said.

Johnson on Thursday gave a preliminary estimate of $7.4 billion to $8.9 billion to complete Bellefonte-1, up significantly from the $4.9 billion estimate in 2011. The new estimate was developed in response to a proposal by former TVA board chairman Dennis Bottorff, who said the unit could be completed in 2018, said.

TVA has not accepted Bottorff's proposal because the plan assumes a short-term need for the 1,260-MW nuclear unit, but the demand is not there, Johnson said Monday. "We will consider all options in the future," he said, noting that nothing is off the table but the proposal at this point does not match TVA's need.

TVA's demand has fallen as a result of the sluggish economy, and the slow growth in demand is being offset by energy efficiency measures implemented by customers, Johnson said.

Sales to industrial customers directly served by TVA were off 15% in 2013 primarily as a result of the closure of US Enrichment Corporation's uranium enrichment facility near Paducah, Kentucky. Lower sales were offset by higher off-system sales from excess generation, TVA said.

Power sales were down 2% in 2013, Johnson said. Sales for the year were 161,925 million kWh compared with 165,255 million kWh in 2012, TVA said in its 10-K.

TVA reduced the amount of power it purchased from the market by 25% during the year despite the additional planned nuclear unit outages, Johnson said.

TVA said last week that it would retire eight coal units totaling 3,067 MW and would build a natural gas-fired plant at the location of the Paradise coal-fired plant in Tennessee.

Johnson said Monday that the technology for the gas-fired plant has not yet been selected. It could be a single cycle or combined cycle plant, but TVA also is considering new gas-fired technologies, he said. The size and type of plant will be determined in the next two to three months, Johnson said.

The gas-fired plant is needed to balance the transmission grid, Johnson said. TVA had considered the option of adding transmission upgrades to stabilize the grid, but determined that transmission additions would not work, Johnson said. "It needs generation to prop it up," he said.

The two coal units at Paradise totaling 1,408 MW will not be retired until the new gas unit is completed, Johnson said.

Transmission upgrades are needed to accommodate the retiring coal-fired plants, Johnson said. Capital expenditures for transmission are about $200 million now and will increase by $100 million to $200 million a year as the coal units are closed, CFO John Thomas said. Expenditures will be about $300 million to $400 million during the next few years, he said.

TVA must retire units 1 through 5 at the Colbert plant in Alabama by June 30, 2016. It has not yet determined when it will retire the 457 MW Unit 8 at Widows Creek in Alabama.

During 2014 TVA will evaluate the rest of its coal fleet to determine whether to retire additional units or invest in emission controls, Johnson said.

In response to a question from an analyst, Johnson said TVA is in discussions with the Office of Management and Budget and the US Treasury department regarding the possibility of selling TVA.

The Obama administration in the budget released in April said it could sell TVA in part or as a whole as an option for addressing the federal power producer's financial situation. TVA has a congressionally mandated debt limit of $30 billion and as of September 30, it had $24.8 billion in bonds outstanding, the 10-K said.

"Reducing or eliminating the federal government's role in programs such as TVA, which have achieved their original objectives and no longer require federal participation, can help put the nation on a sustainable fiscal path," the budget said.

Johnson said TVA had hoped that the evaluation of the sale would be completed by the end of the year.

TVA's earnings for the year were $271 billion on revenue of $10,965 billion compared with $60 billion in earnings in 2012 on revenue of $11,220 billion.

— Mary Powers

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