Northern California Power Agency

February 2015 Finance Committee Materials

February 11, 2015

Municipal Market Update

Refunding Screens

Unsolicited Proposals

Rating Agency Reports

MARKET SNAPSHOT

- While interest rates remain at extremely low levels, the municipal market has been often marked by volatility
  - Economic data and central bank policy will remain a key driver of investor activity and volatility in the marketplace

February 10, 2015

Year	Maturity	MMD	UST	Year	Maturity	MMD	UST
1-Year	2016	0.14%	0.22%	16-Year	2031	2.50%	-
2-Year	2017	0.41%	0.66%	17-Year	2032	2.55%	-
3-Year	2018	0.63%	1.03%	18-Year	2033	2.59%	-
4-Year	2019	0.84%	-	19-Year	2034	2.63%	-
5-Year	2020	1.04%	1.51%	20-Year	2035	2.67%	2.43%
6-Year	2021	1.28%	-	21-Year	2036	2.70%	-
7-Year	2022	1.53%	-	22-Year	2037	2.72%	-
8-Year	2023	1.83%	-	23-Year	2038	2.74%	-
9-Year	2024	1.89%	-	24-Year	2039	2.76%	-
10-Year	2025	2.02%	1.99%	25-Year	2040	2.78%	-
11-Year	2026	2.13%	-	26-Year	2041	2.80%	-
12-Year	2027	2.24%	-	27-Year	2042	2.81%	-
13-Year	2028	2.33%	-	28-Year	2043	2.82%	-
14-Year	2029	2.40%	-	29-Year	2044	2.83%	-
15-Year	2030	2.45%	2.28%	30-Year	2045	2.84%	2.57%

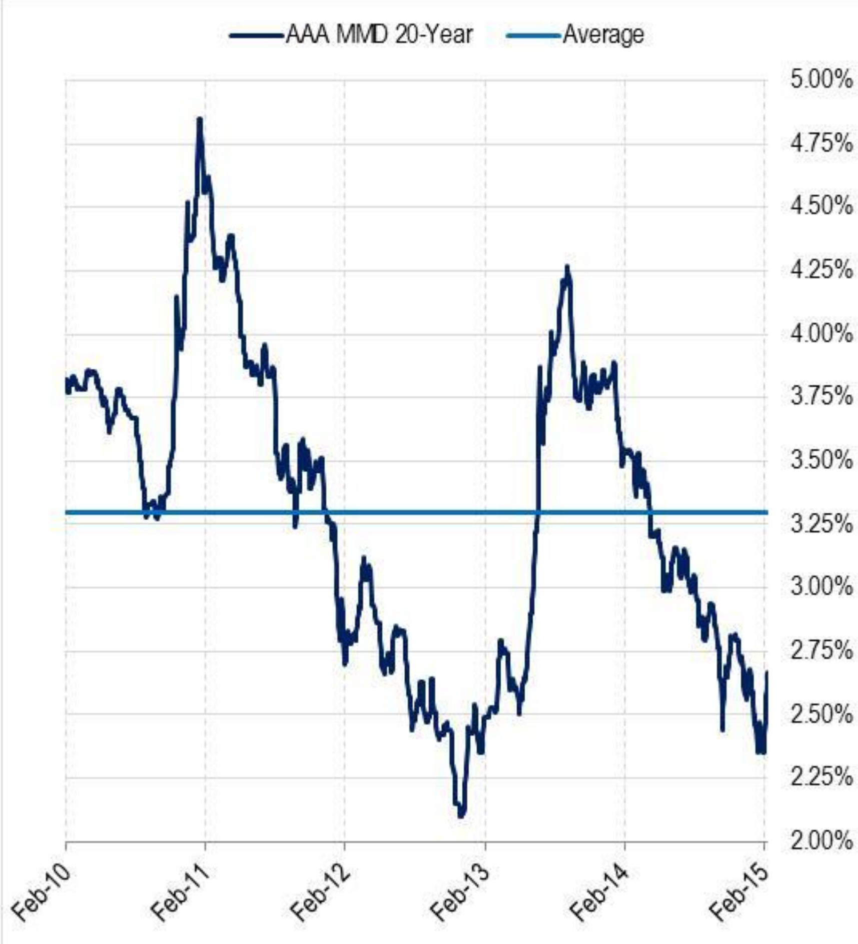
Source: Thomson Reuters

BENCHMARK TAX-EXEMPT INTEREST RATE PROGRESSION

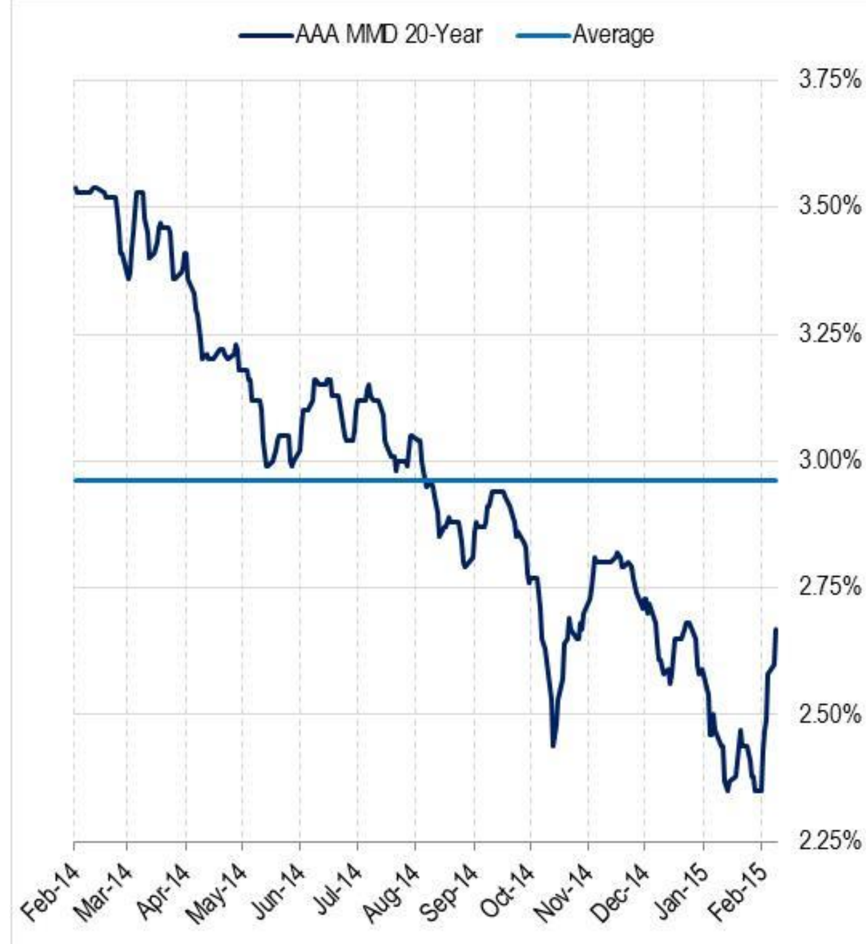
- Prior to backing up over the past of couple of weeks, interest rates had rallied back to levels near their all-time lows that were reached at the end of November 2012

20-Year AAA MMD Rates

Five Year History



One Year History

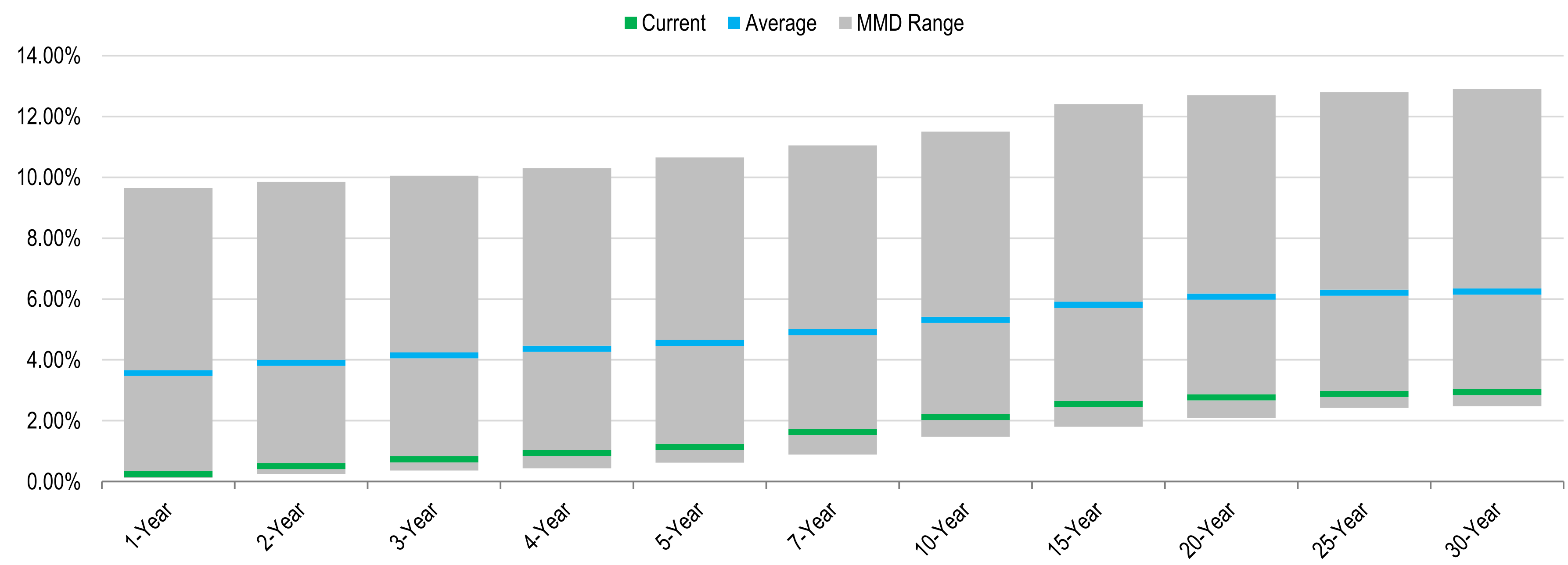


Source: Thomson Reuters

BENCHMARK TAX-EXEMPT INTEREST RATE POSITION

- Interest rates are within 65 bps of their all-time lows across the yield curve

AAA MMD Rate Position
(June 1, 1981 Inception to February 10, 2015)



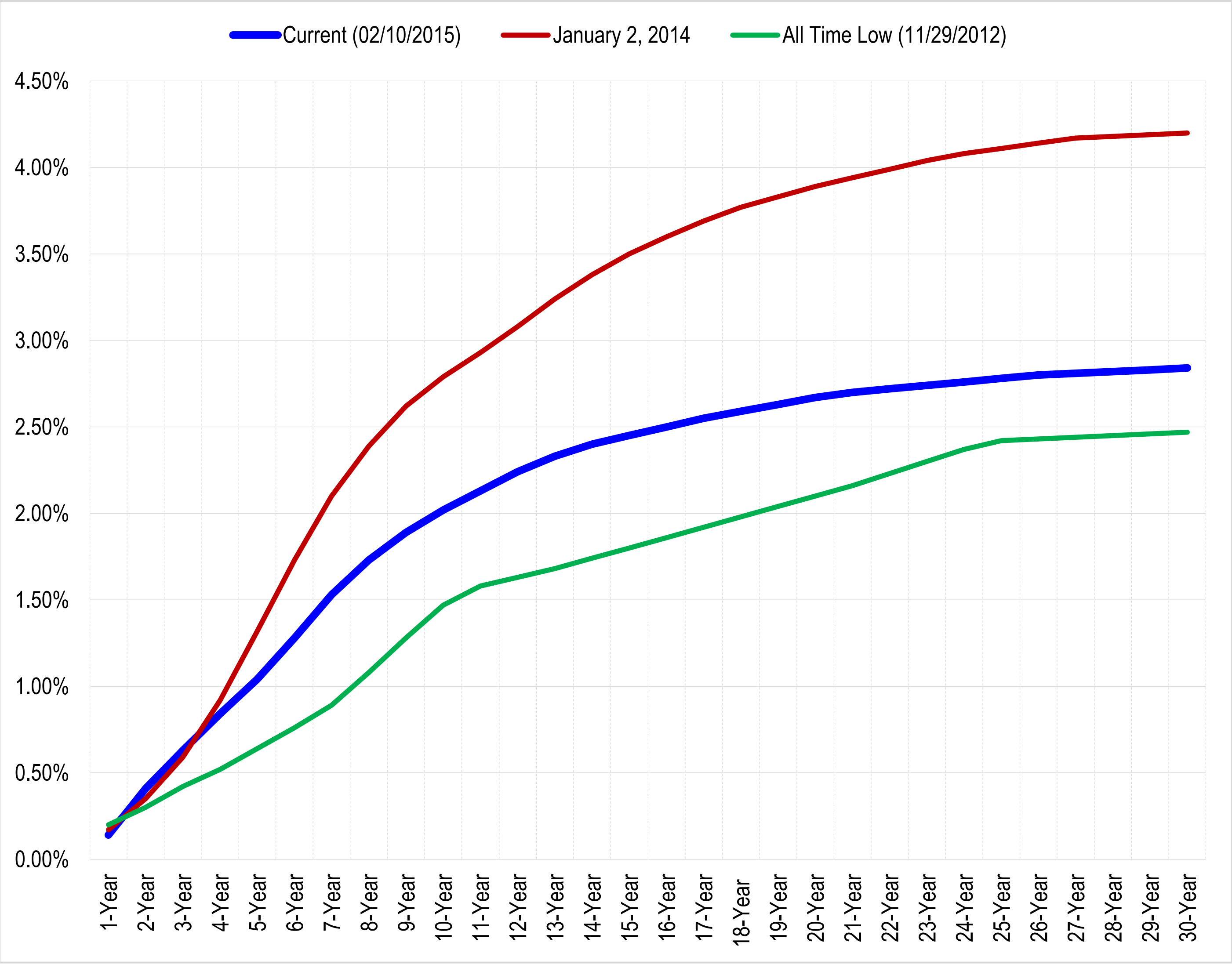
Summary of February 10, 2015 vs. Historical (since Inception) MMD Rates

Statistic	1-Year	2-Year	3-Year	4-Year	5-Year	7-Year	10-Year	15-Year	20-Year	25-Year	30-Year
February 10, 2015	0.14%	0.41%	0.63%	0.84%	1.04%	1.53%	2.02%	2.45%	2.67%	2.78%	2.84%
Average since Inception	3.27%	3.60%	3.85%	4.06%	4.26%	4.61%	5.01%	5.51%	5.78%	5.91%	5.94%
Spread to Average	-3.13%	-3.19%	-3.22%	-3.22%	-3.22%	-3.08%	-2.99%	-3.06%	-3.11%	-3.13%	-3.10%
Minimum	0.11%	0.25%	0.36%	0.44%	0.62%	0.89%	1.47%	1.80%	2.10%	2.42%	2.47%
Spread to Minimum	0.03%	0.16%	0.27%	0.40%	0.42%	0.64%	0.55%	0.65%	0.57%	0.36%	0.37%
Maximum	9.65%	9.85%	10.05%	10.30%	10.65%	11.05%	11.50%	12.40%	12.70%	12.80%	12.90%

Source: Thomson Reuters

AAA MMD Yield Curve Movement

AAA MMD Yield Curve Movement



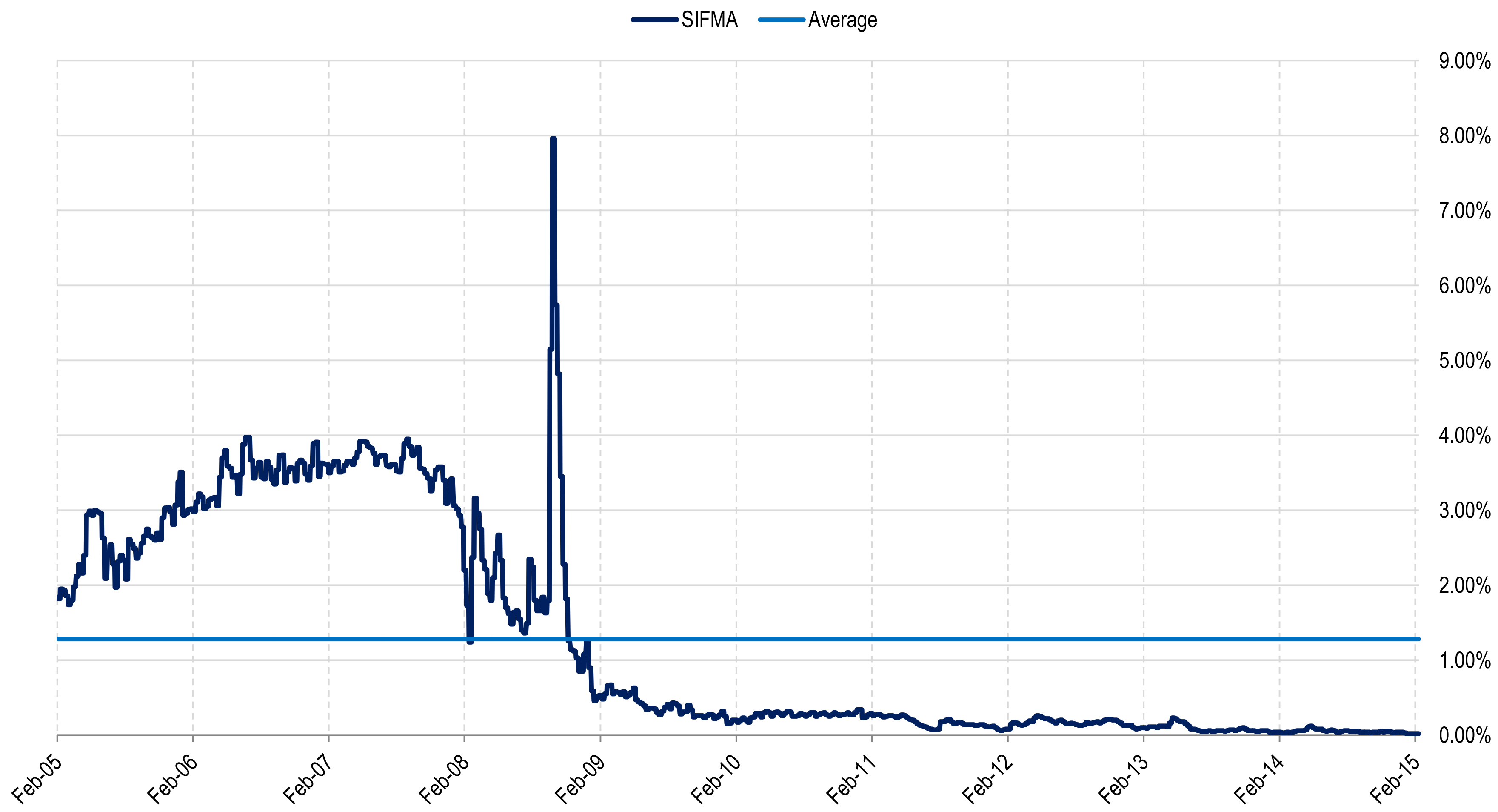
Maturity	∆ Since 01/02/14	∆ Since 11/29/12
1-Year	-0.03%	-0.06%
2-Year	0.06%	0.11%
3-Year	0.04%	0.21%
4-Year	-0.08%	0.32%
5-Year	-0.28%	0.40%
6-Year	-0.45%	0.52%
7-Year	-0.57%	0.64%
8-Year	-0.66%	0.65%
9-Year	-0.73%	0.61%
10-Year	-0.77%	0.55%
11-Year	-0.80%	0.55%
12-Year	-0.84%	0.61%
13-Year	-0.91%	0.65%
14-Year	-0.98%	0.66%
15-Year	-1.05%	0.65%
16-Year	-1.10%	0.64%
17-Year	-1.14%	0.63%
18-Year	-1.18%	0.61%
19-Year	-1.20%	0.59%
20-Year	-1.22%	0.57%
21-Year	-1.24%	0.54%
22-Year	-1.27%	0.49%
23-Year	-1.30%	0.44%
24-Year	-1.32%	0.39%
25-Year	-1.33%	0.36%
26-Year	-1.34%	0.37%
27-Year	-1.36%	0.37%
28-Year	-1.36%	0.37%
29-Year	-1.36%	0.37%
30-Year	-1.36%	0.37%

Source: Thomson Reuters

SHORT-TERM INTEREST RATE HISTORY

- Short-term rates remain at historically low levels

SIFMA Rate History and Position
(February 2005 to February 2015)



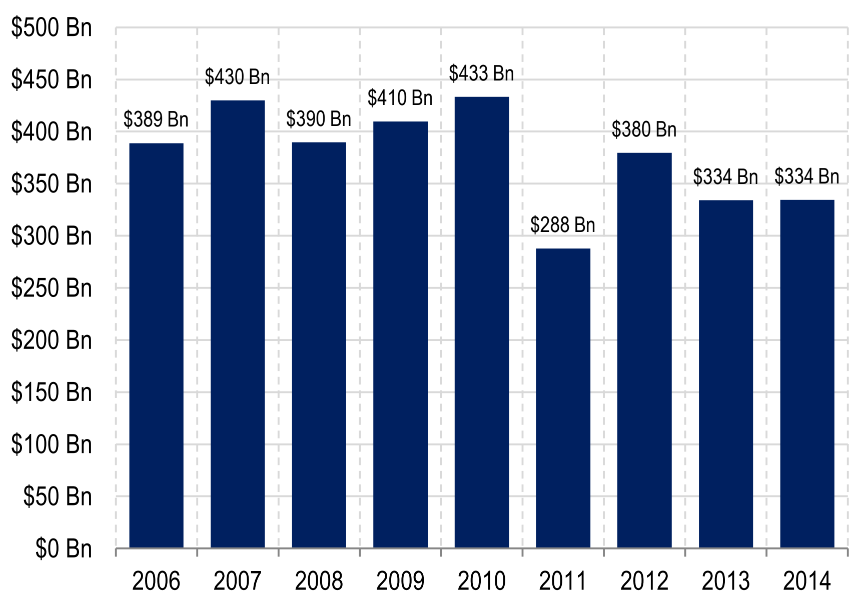
Source: Bloomberg

MUNICIPAL MARKET SUPPLY

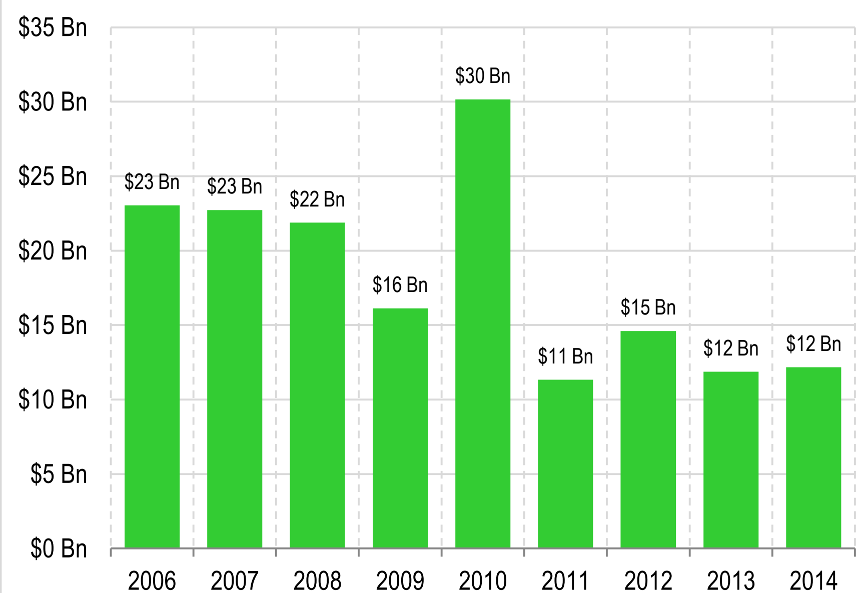
- Overall municipal market volume in 2014 started light, but picked up in the fourth quarter and ended up approximately flat versus 2013
- Public power volume was ~4% of total municipal issuance, in line with 2011- 2013, but down from 7% in 2010
  - Santee Cooper, LADWP, Energy Northwest, LIPA, OPPD, AMP, JEA, NPPD, GRDA, and WMMPA were the top issurs
- Approximately 57% of all transactions had a refunding component
- Issuance to start of 2015 has been strong, with supply in January almost 40% higher than last year
  - Almost 70% of the transactions in January 2015 have had a refunding component

Issuance Volume History
(2006 - 2014)

Overall Municipal Market Volume



Public Power Volume

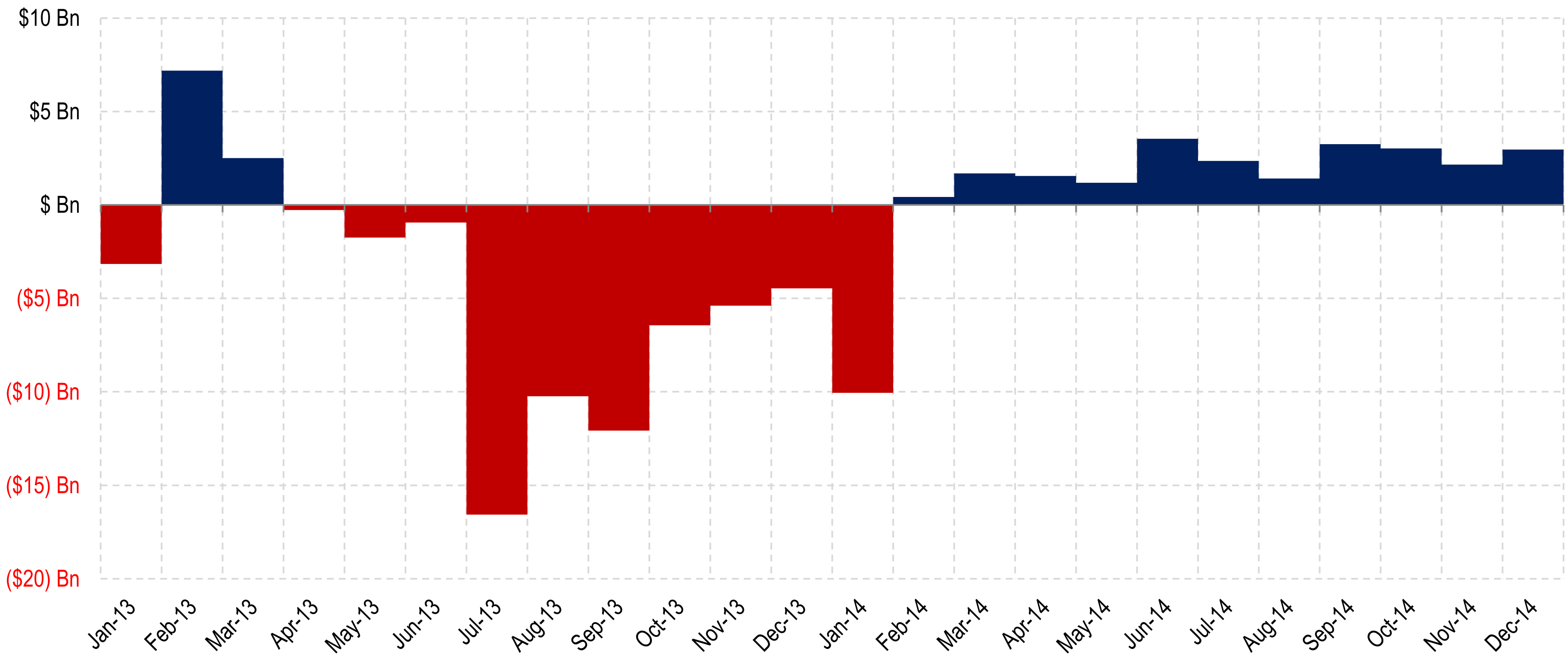


Source: Thomson Reuters

MUNICIPAL MARKET DEMAND

- The municipal market benefitted from an improved demand picture in 2014 compared to 2013
  - Inflows into muni bond funds have bolstered the demand side of the equation. There was approximately $28 billion of net inflows into municipal bond funds last year
- The demand for high-quality fixed income assets served to offset periods of heavy supply and mute volatility. The end of the year performance also benefited from an investor flight to safety, which continued to push yields lower
  - Positive net flows into muni bond funds have continued in January 2015

Net Long-Term Municipal Bond Mutual Fund Flows
(January 2013 to December 2014)



Source: Investment Company Institute

INTEREST RATE FORECAST

- The Federal Reserve ended its quantitative easing program and ceased security purchases in the fourth quarter of 2014. The focus of the discussion now is on when the Fed will increase short-term rates
- The FOMC suggested that the zero interest rate policy would continue for a considerable time after the asset purchase program ends; however, market participants are expecting that the rate hikes could begin in mid- 2015

The Street's Interest Rate Forecast (As of February 10, 2015)

Interest Rate	Current	Q1 15	Q2 15	Q3 15	Q4 15	Q1 16	Q2 16
30-Year UST	2.58%	2.63%	2.89%	3.10%	3.29%	3.44%	3.58%
10-Year UST	2.00%	2.06%	2.29%	2.49%	2.69%	2.89%	3.05%
2-Year UST	0.65%	0.65%	0.91%	1.17%	1.44%	1.67%	1.91%
3M LIBOR	0.26%	0.28%	0.44%	0.67%	0.96%	1.24%	1.60%
Fed Funds Target Rate (Upper Bound)	0.25%	0.25%	0.35%	0.60%	0.90%	1.15%	1.50%
Fed Funds Target Rate (Lower Bound)	0.00%	0.01%	0.15%	0.42%	0.69%	1.00%	1.35%

Source: Bloomberg

Monthly Market Review

January 2015

Economic Highlights

- As the U.S. economy continued to expand, slower growth in other parts of the world drove market reaction in January based on evidence that weakness around the globe would slow expansion in the U.S.
- The advance estimate reported that fourth-quarter U.S. gross domestic product (GDP) grew at an annual rate of 2.6% according to the Bureau of Economic Analysis. Weakness in exports and investment resulted in this being below economists' estimates of 3%.
- Following its January 27-28 meeting, the Federal Open Market Committee (FOMC) noted that economic activity was expanding at a "solid pace," yet warned that low energy prices would likely result in lower near-term inflation. The FOMC reiterated its intention to remain "patient" in normalizing the benchmark federal funds rate.
- Oil prices declined and the U.S. dollar strengthened in January in a continuation of trends that have dampened inflation, stressed emerging markets, and put disposable income in the pockets of energy consumers.
- U.S. economic data indicated a slowing trend at year end. Data released in January showed weaker results for retail sales, durable goods, factory orders, and the Institute for Supply Management (ISM) survey of manufacturing activity. Increased discretionary income created by lower gasoline prices failed to result in increased spending.

Bond Markets

- Similar to last year, yields fell sharply in January, defying forecasts that anticipated rising rates. Yields headed lower on disappointing economic data, persistently low inflation expectations, and a more accommodative FOMC statement indicating that the Federal Reserve (Fed) may move to raise rates later than expected.
- The yield curve flattened sharply, as long-term rates fell much more than short-term rates. The 30-year Treasury bond hit all-time low yields. The result was positive performance for most benchmarks, and those with longer durations saw the greatest benefit.
- Agencies underperformed comparable-maturity Treasuries for the month.
- Investment-grade corporate bonds outperformed government securities for the month as the higher income they generated offset the modest spread widening that resulted from a slow start to fourth-quarter earnings announcements.
- Sectors that contain structure risk—such as mortgage-backed securities (MBS), asset-backed securities (ABS), and callable Federal Agencies—underperformed significantly for the month. Downward pressure on yields increased prepayment and call risk, making these securities less attractive to investors.
- Money-market-related yields, especially those with maturities less than a year, continued to react to anticipated changes in monetary policy.

Equity Markets

- Similar to bond markets, U.S. equity markets reacted to discouraging economic data with a moderate correction in January; in general, large-cap indices fell around 3%.
- Global equity markets mostly rose in local-currency terms in response to optimism about the European Central Bank's (ECB's) announcement of a substantial new asset purchase program. The U.S. dollar strengthened further in January, which offset overseas gains when translated into U.S. dollars.

PFMAM Outlook

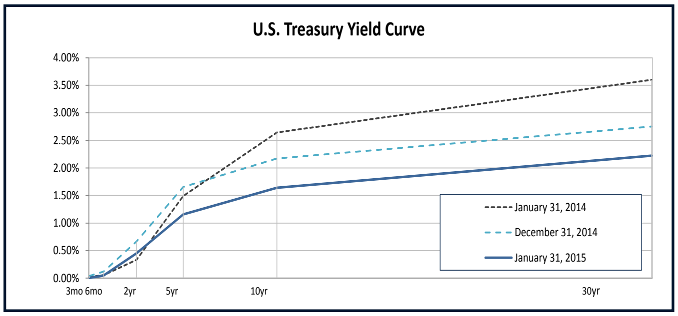
- The fixed-income markets often rally in January, and this month was no exception. Yields headed lower, driven by softening inflation trends and lower European sovereign debt yields. The underlying economic fundamentals in Europe and the ECB's quantitative easing program are consistent with this move. In the U.S., however, the January bond market rally could be short-lived as solid growth leaves room for the Fed to begin tightening monetary policy sometime later this year.
- We see a reversal of the January rally having the biggest effect on intermediate-maturity interest rates.
- We think that credit remains well-supported and the modest spreads available in intermediate-maturity investment-grade corporate bonds can offer an opportunity to add income to accounts with durations short of benchmarks.
- With the back-up in MBS spreads to Treasuries, there is also modest value in MBS with shorter weighted average lives and higher coupons to help cushion involuntary extensions that will occur if and when rates rise. Nonetheless, this sector is vulnerable to rising rates and an ultimate reduction in demand if/when the Fed exits the markets.
- The money market sector remains the most sensitive to Fed tightening. A modest decline in longer-maturity rates in January corresponded with the forbearing tone of the FOMC announcement; similarly, the six- to 12-month area will likely bear the brunt of any incipient move.

U.S. Treasury Yields	January 31, 2014	December 31, 2014	January 31, 2015	Monthly Change
3 Month	0.02%	0.04%	0.00%	(0.04%)
6 Month	0.05%	0.12%	0.05%	(0.07%)
2 Year	0.33%	0.67%	0.45%	(0.22%)
5 Year	1.49%	1.65%	1.16%	(0.49%)
10 Year	2.65%	2.17%	1.64%	(0.53%)
30 Year	3.60%	2.75%	2.22%	(0.53%)

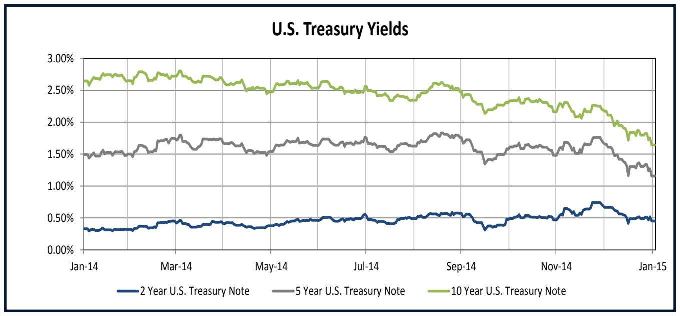
Yields by Sector and Maturity as of 1/31/15	U.S. Treasury	Federal Agency	Corporates (A Industrials)	Municipals
3 Month	0.00%	0.03%	0.38%	-
6 Month	0.05%	0.09%	0.45%	-
2 Year	0.45%	0.50%	0.88%	0.45%
5 Year	1.16%	1.28%	1.73%	1.12%
10 Year	1.64%	1.95%	2.59%	2.10%
30 Year	2.22%	-	3.47%	4.04%

Spot Prices and Benchmark Rates	January 31, 2014	December 31, 2014	January 31, 2015	Monthly Change
1 Month LIBOR	0.16%	0.17%	0.17%	0.00%
3 Month LIBOR	0.24%	0.26%	0.25%	(0.01%)
Effective Fed Funds Rate	0.07%	0.06%	0.06%	0.00%
Fed Funds Target Rate	0.25%	0.25%	0.25%	0.00%
Gold ($/oz)	$1,240.10	$1,184.10	$1,278.50	7.97%
Crude Oil $/Barrel	$97.49	$53.27	$48.24	(9.44%)
US Dollars per Euro	$1.35	$1.21	$1.13	(6.61%)

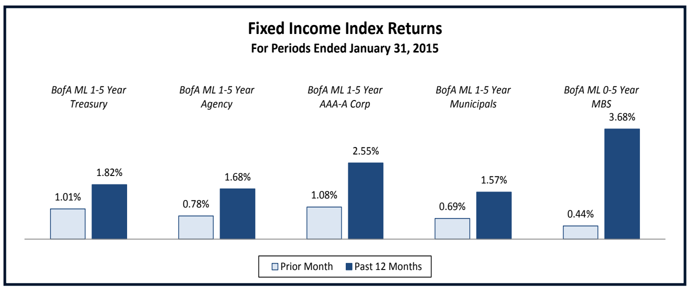
Upcoming Indicators to Watch Release Date		For	Consensus	Prior
Feb 6	Change in Nonfarm Payrolls	Jan	230K	252K
Feb 6	Unemployment Rate	Jan	5.60%	5.60%
Feb 6	Consumer Credit	Dec	$15.000B	$14.081B
Feb 12	Retail Sales Advance MoM	Jan	-0.30%	-0.90%
Feb 13	U. of Mich. Sentiment	Feb P	98.1	98.1
Feb 18	Housing Starts MoM	Jan	--	4.40%
Feb 19	Leading Index	Jan	--	0.50%



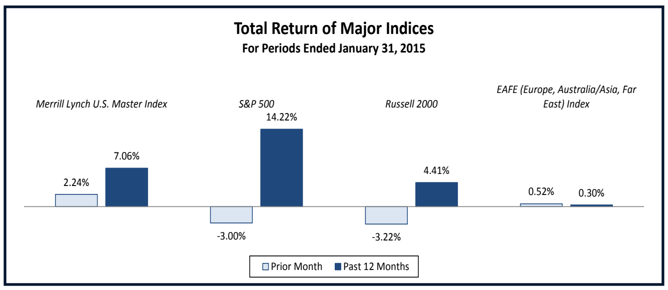
The yield curve flattened sharply for the month of January.



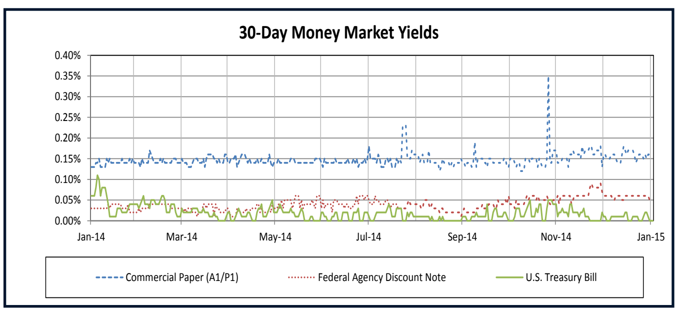
Treasury yields continued to fall for the month on a weaker global economic outlook and falling oil prices.



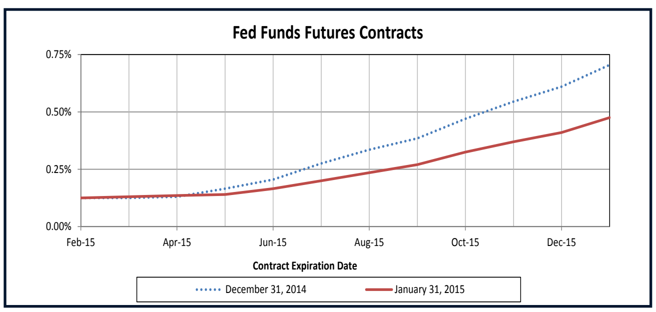
All sectors had positive returns for the month; high-quality corporates were the top performers.



Large-cap and small-cap U.S. equity had negative performance for the month, while domestic fixed income and developed-markets equity had positive performance.



For the most part, short-term Federal Agency and Treasury securities remained range-bound due to the low federal funds target rate.



The FOMC reiterated that it will be "patient" with regard to raising interest rates; it is anticipated that rates may rise at some point in 2015.

Source: Bloomberg. Data as of January 31, 2015.

Municipal Market Update

Refunding Screens

Unsolicited Proposals

Rating Agency Reports

REFUNDING SCREENS

- While there are certain refunding candidates in NCPA's debt portfolio that generate savings, currently none are very compelling
  - — Long escrow periods to call dates
  - — Relatively short amortization of the debt
- However, with rates having skirted all-time lows until recently, we will continue to monitor the NCPA debt portfolio

Geothermal Project | Refunding Screen | ($ in 000s)												
Candidate						New Yield	Individual PV Savings		Cumulative PV Savings		Negative	Escrow
Series	Component	Maturity	Par	Coupon	Call Date		$	%	$	%	Arbitrage	Efficiency
2009A	Serial	7/1/2020	$2,815	5.25%	7/1/2019	1.39%	$46	1.65%	$46	1.65%	$4	92.30%
2009A	Serial	7/1/2021	$2,970	5.50%	7/1/2019	1.63%	$121	4.07%	$167	2.89%	$36	77.20%
2009A	Serial	7/1/2022	$3,135	5.50%	7/1/2019	1.88%	$176	5.62%	$344	3.85%	$72	70.90%
2009A	Serial	7/1/2023	$3,305	5.00%	7/1/2019	2.08%	$176	5.34%	$520	4.25%	$104	63.00%
2009A	Serial	7/1/2024	$3,480	5.25%	7/1/2019	2.24%	$254	7.30%	$774	4.93%	$134	65.50%
			$15,705				$774	4.93%			$349	68.91%

Assumptions: Interest rates as of February 10, 2015; SLGS escrow; Delivery Date of 4/15/2015; COI of $15 per bond; UD of $3 per bond

Hydroelectric Project | Refunding Screen | ($ in 000s)												
Candidate						New Yield	Individual PV Savings		Cumulative PV Savings		Negative	Escrow
Series	Component	Maturity	Par	Coupon	Call Date		$	%	$	%	Arbitrage	Efficiency
2010A	Serial	7/1/2020	$9,150	5.00%	7/1/2019	1.34%	$226	2.47%	$226	2.47%	$0	100.00%
2010A	Serial	7/1/2021	$9,610	5.00%	7/1/2019	1.58%	$411	4.28%	$637	3.40%	$93	81.50%
2010A	Serial	7/1/2022	$10,145	5.00%	7/1/2019	1.83%	$553	5.45%	$1,190	4.12%	$209	72.60%
2010A	Serial	7/1/2023	$15,230	5.00%	7/1/2019	2.03%	$989	6.50%	$2,179	4.94%	$445	69.00%
			$44,135				$2,179	4.94%			$748	74.45%

Assumptions: Interest rates as of February 10, 2015; SLGS escrow; Delivery Date of 4/15/2015; COI of $7.5 per bond; UD of $3 per bond
Advance refundability status of series are subject to tax counsel review

- The Hydroelectric Project, Series 2008C transaction is callable 7/1/2018 and refunding it would generate higher savings (~7%), but our preliminary analysis suggests only a small portion of it is advance refundable
- The Lodi Energy Center, Series 2010A (Indenture Group A) transaction is callable 6/1/2020 and refunding it does not generate material savings in the current market (<4%)

Municipal Market Update

Refunding Screens

Unsolicited Proposals

Rating Agency Reports

Wells Fargo Securities
150 E 42nd Street, 25th Floor
New York, NY 10017

Memo

Date: January 16, 2015

To: **Northern California Power Agency**
Donna Stevener, Chief Financial Officer

From: **Wells Fargo Securities**
Brian Benson, Vice President
Adam Woodard, Managing Director

Subject: **Market and Refunding Update**

Market Update

As Municipal Bond market rates continue to decline, Wells Fargo Securities ("Wells Fargo") would like to present NCPA with analysis of potential refunding opportunities. Municipal market rates are near all-time lows, especially on the long-end of the yield curve. The table below summarizes this trend on various benchmark maturities:

"AAA" MMD Tracker

'AAA' MMD as of January 15, 2015	3-Year	5-Year	8-Year	10-Year	12-Year	15-Year	17-Year	20-Year	22-Year	25-Year	30-Year
Current MMD	0.65	1.05	1.55	1.75	1.93	2.12	2.22	2.35	2.40	2.46	2.52
10-Year Average	1.68	2.09	2.69	2.98	3.21	3.47	3.61	3.79	3.90	4.01	4.06
10-Year High Rate	3.88	3.97	4.43	4.86	5.20	5.52	5.64	5.76	5.85	5.92	5.99
High Rate Date	6/12/07	6/12/07	10/16/08	10/15/08	10/15/08	10/15/08	10/15/08	10/15/08	10/15/08	10/15/08	10/15/08
10-Year Low Rate	0.36	0.62	1.08	1.47	1.63	1.80	1.92	2.10	2.23	2.42	2.47
Low Rate Date	9/18/12	9/27/12	11/28/12	11/28/12	11/29/12	11/28/12	11/28/12	11/28/12	11/28/12	11/28/12	11/28/12
Spread from 10-Year Low	29 bps	43 bps	47 bps	28 bps	30 bps	32 bps	30 bps	25 bps	17 bps	4 bps	5 bps

Refunding Monitor

As the current interest rate environment borders historic lows, NCPA should constantly look at its outstanding debt to identify opportunities for savings. Wells Fargo has developed a specific model for NCPA designed to optimally evaluate refunding candidates based on both NPV savings and negative arbitrage. The model employs a proprietary in-house program called the Future Opportunity Cost Screening Monitor to help clients evaluate refunding opportunities and assess their value versus historical interest rate patterns. You will find this model attached to this memo, detailing all callable debt of NCPA.

Advance Refunding

Our analysis has identified the Hydroelectric 2010A Series as a potential advance refunding candidate (among others), with potential present value savings of $2.223 million or 5.04% of refunded par. However, verification is needed on the 2010A's advance refundability. It appears 2010A has one advance refunding left, per the IRS's guidelines that tracing back a bonds refunding precedents, if a new money bond issue was advance refunded and was issued pre-1986, it is allowed two advance refundings, as opposed to bonds issued post-1986 that are allowed only one. However, to verify this it would be helpful to have further documentation on 2010A's advance refunding history.

Wells Fargo Securities would like to further discuss this savings opportunity with NCPA. Please contact Brian Benson at (212) 214-6732 or Adam Woodard at (875) 314-3115 if you have any questions.

Sincerely,

Brian Benson	Adam Woodard
Vice President, Public Finance	Managing Direct, Public Finance
Energy & Corporate	Co-Head of Energy & Corporate
(212) 214-673	(875) 314-3115

Northern California Power Agency Refunding Candidates

Settlement: *4/1/2015*
COI: *0.75%*

							Current Market Rates as of 01/15/2015					Breakeven to Meet Savings Target			Negative Arbitrage		Breakeven Future Current Refunding							
Series	Scale	Maturity	Bond Type	Par Amount	Coupon	Next Call	Coupon	Yield to Call	Yield To Maturity	PV Savings ($)	PV Savings (%)	Yield to Call	Yield To Maturity	Change in Yield to Breakeven	Negative Arbitrage	Percentage of Savings	Breakeven YTC w/ 5% Coupon	Change in YTC to Breakeven	Breakeven AAA MMD	How Often Breakeven Last 30 yrs	Can Issue Refunding Bonds?	Cumulative Refunded Par of Targets	Cumulative PV Savings ($) of Targets	Cumulative PV Savings (%) of Targets
2010A	**CapFac**	**2024**	**SERIAL**	**5,390,000**	**5.250%**	**Feb-20**	5.000%	2.25%	2.25%	329,302	6.11%	2.58%	2.58%	33 bpts	249,552	76%	3.31%	106 bpts	2.81%	27%	Nov-19	5,390,000	329,302	6.11%
2010A	**CapFac**	**2025**	**SERIAL**	**1,010,000**	**5.250%**	**Feb-20**	5.000%	2.39%	2.57%	51,228	5.07%	2.61%	2.77%	22 bpts	53,685	105%	3.81%	142 bpts	3.26%	31%	Nov-19	6,400,000	380,530	5.95%
2010A	**CapFac**	**2023**	**SERIAL**	**5,150,000**	**5.250%**	**Feb-20**	5.000%	2.10%	2.10%	254,580	4.94%	2.33%	2.33%	23 bpts	200,367	79%	3.17%	107 bpts	2.72%	29%	Nov-19	11,550,000	635,110	5.50%
2010A	**CapFac**	**2022**	**SERIAL**	**4,860,000**	**5.250%**	**Feb-20**	5.000%	1.95%	1.95%	166,141	3.42%	2.00%	2.00%	5 bpts	152,876	92%	3.05%	110 bpts	2.65%	31%	Nov-19	16,410,000	801,251	4.88%
2010A	**CapFac**	**2021**	**SERIAL**	**4,550,000**	**5.000%**	**Feb-20**	5.000%	1.76%	1.76%	67,169	1.48%	1.53%	1.53%	-23 bpts	99,210	148%	2.81%	105 bpts	2.46%	32%	Nov-19	20,960,000	868,419	4.14%
2010A	**CapFac**	**2020**	**SERIAL**	**4,490,000**	**5.000%**	**Feb-20**	5.000%	1.54%	1.54%	(9,766)	-0.22%	0.98%	0.98%	-56 bpts	48,162	-493%	2.42%	88 bpts	2.12%	30%	Nov-19	-	-	-
2009A	**Geo**	**2024**	**SERIAL**	**3,480,000**	**5.250%**	**Jul-19**	5.000%	2.10%	2.10%	312,858	8.99%	2.74%	2.74%	64 bpts	135,820	43%	3.05%	95 bpts	2.60%	22%	today	3,480,000	312,858	8.99%
2009A	**Geo**	**2022**	**SERIAL**	**3,135,000**	**5.500%**	**Jul-19**	5.000%	1.76%	1.76%	217,378	6.93%	2.27%	2.27%	51 bpts	76,120	35%	2.71%	95 bpts	2.36%	25%	today	6,615,000	530,237	8.02%
2009A	**Geo**	**2023**	**SERIAL**	**3,305,000**	**5.000%**	**Jul-19**	5.000%	1.95%	1.95%	224,920	6.81%	2.40%	2.40%	45 bpts	106,813	47%	2.91%	96 bpts	2.51%	24%	today	9,920,000	755,156	7.61%
2009A	**Geo**	**2021**	**SERIAL**	**2,970,000**	**5.500%**	**Jul-19**	5.000%	1.54%	1.54%	151,027	5.09%	1.85%	1.85%	31 bpts	42,985	28%	2.38%	84 bpts	2.08%	25%	today	12,890,000	906,183	7.03%
2009A	**Geo**	**2020**	**SERIAL**	**2,815,000**	**5.250%**	**Jul-19**	4.000%	1.30%	1.30%	71,887	2.55%	1.22%	1.22%	-8 bpts	10,252	14%	1.79%	49 bpts	1.54%	25%	today	15,705,000	978,070	6.23%
2010A	**Hydro**	**2023**	**SERIAL**	**15,230,000**	**5.000%**	**Jul-19**	5.000%	1.95%	1.95%	1,036,468	6.81%	2.40%	2.40%	45 bpts	492,215	47%	2.91%	96 bpts	2.51%	24%	today	15,230,000	1,036,468	6.81%
2010A	**Hydro**	**2022**	**SERIAL**	**10,145,000**	**5.000%**	**Jul-19**	5.000%	1.76%	1.76%	570,461	5.62%	2.11%	2.11%	35 bpts	243,691	43%	2.69%	93 bpts	2.34%	25%	today	25,375,000	1,606,930	6.33%
2010A	**Hydro**	**2021**	**SERIAL**	**9,610,000**	**5.000%**	**Jul-19**	5.000%	1.54%	1.54%	403,157	4.20%	1.72%	1.72%	18 bpts	137,597	34%	2.36%	82 bpts	2.06%	25%	today	34,985,000	2,010,087	5.75%
2010A	**Hydro**	**2020**	**SERIAL**	**9,150,000**	**5.000%**	**Jul-19**	4.000%	1.30%	1.30%	213,068	2.33%	1.18%	1.18%	-12 bpts	33,146	16%	1.78%	48 bpts	1.53%	25%	today	44,135,000	2,223,155	5.04%
2008C	**Hydro**	**2024**	**SERIAL**	**15,550,000**	**5.000%**	**Jul-18**	5.000%	2.10%	2.10%	1,663,936	10.70%	2.94%	2.94%	84 bpts	591,242	36%	2.87%	77 bpts	2.42%	18%	Apr-18	15,550,000	1,663,936	10.70%
2008C	**Hydro**	**2023**	**SERIAL**	**13,095,000**	**5.000%**	**Jul-18**	5.000%	1.95%	1.95%	1,253,013	9.57%	2.74%	2.74%	79 bpts	433,038	35%	2.73%	78 bpts	2.33%	19%	Apr-18	28,645,000	2,916,949	10.18%
2008C	**Hydro**	**2022**	**SERIAL**	**13,035,000**	**5.000%**	**Jul-18**	5.000%	1.76%	1.76%	1,093,172	8.39%	2.48%	2.48%	72 bpts	348,757	32%	2.53%	77 bpts	2.18%	21%	Apr-18	41,680,000	4,010,122	9.62%
2008C	**Hydro**	**2021**	**SERIAL**	**12,435,000**	**5.000%**	**Jul-18**	5.000%	1.54%	1.54%	865,320	6.96%	2.15%	2.15%	61 bpts	241,079	28%	2.27%	73 bpts	1.97%	22%	Apr-18	54,115,000	4,875,442	9.01%
2008C	**Hydro**	**2020**	**SERIAL**	**11,805,000**	**5.000%**	**Jul-18**	4.000%	1.30%	1.30%	601,255	5.09%	1.68%	1.68%	38 bpts	133,188	22%	1.95%	65 bpts	1.70%	23%	Apr-18	65,920,000	5,476,698	8.31%
2008C	**Hydro**	**2019**	**SERIAL**	**11,210,000**	**5.000%**	**Jul-18**	4.000%	1.07%	1.07%	297,243	2.65%	0.99%	0.99%	-8 bpts	38,683	13%	1.50%	43 bpts	1.30%	23%	Apr-18	77,130,000	5,773,940	7.49%
2010A1	**Lodi**	**2025**	**TERM**	**7,925,000**	**5.000%**	**Jun-20**	5.000%	2.25%	2.25%	491,250	6.20%	2.56%	2.56%	31 bpts	364,528	74%	3.38%	113 bpts	2.88%	26%	today	7,925,000	491,250	6.20%
2010A1	**Lodi**	**2024**	**TERM**	**7,545,000**	**5.000%**	**Jun-20**	5.000%	2.10%	2.10%	407,024	5.39%	2.36%	2.36%	26 bpts	287,745	71%	3.24%	114 bpts	2.79%	27%	today	15,470,000	898,275	5.81%
2010A1	**Lodi**	**2023**	**TERM**	**7,185,000**	**5.000%**	**Jun-20**	5.000%	1.95%	1.95%	305,005	4.25%	2.10%	2.10%	15 bpts	217,077	71%	3.12%	117 bpts	2.72%	29%	today	22,655,000	1,203,280	5.31%
2010A1	**Lodi**	**2022**	**TERM**	**6,845,000**	**5.000%**	**Jun-20**	5.000%	1.76%	1.76%	208,173	3.04%	1.77%	1.77%	1 bpts	137,450	66%	2.89%	113 bpts	2.54%	30%	today	29,500,000	1,411,453	4.78%
2010A1	**Lodi**	**2021**	**TERM**	**6,520,000**	**5.000%**	**Jun-20**	5.000%	1.54%	1.54%	103,596	1.59%	1.33%	1.33%	-21 bpts	53,544	52%	2.44%	90 bpts	2.14%	30%	today	36,020,000	1,515,049	4.21%

Wells Fargo Securities
150 E 42nd Street, 25th Floor
New York, NY 10017

Important Disclosures

This document and any other materials accompanying this document (collectively, the “Materials”) are provided for general informational purposes only. By accepting any Materials, the recipient acknowledges and agrees to the matters set forth below.

Wells Fargo Securities (“WFS”) is providing these Materials to you for discussion purposes only in anticipation of serving as an underwriter or placement agent (collectively referred to herein as “underwriter”) to you. In our capacity as underwriter or placement agent, our primary role would be to purchase securities from you (or the issuer in the case of a conduit transaction) for resale to investors, or arrange for the placement of securities with investors on your behalf, in an arm’s length commercial transaction between you and WFS in which WFS would be acting solely as a principal or agent, as applicable. (Please be advised the term “placement agent” does not imply any agency or fiduciary relationship).

WFS is acting for its own interest and has financial and other interests that differ from yours. WFS is not acting as a municipal advisor or financial advisor, and has no fiduciary duty, to you or any other person pursuant to Section 15B of the Securities Exchange Act of 1934. The information in the Materials is not intended to be and should not be construed as “advice” within the meaning of Section 15B of the Securities Exchange Act of 1934. WFS is not expressing an opinion or providing any advice or recommendation about whether or not you should enter into any swap transaction in this presentation nor in any conversation between you and WFS with respect to the materials addressed in this presentation. WFS will not have any duties or liability to any person or entity in connection with the information being provided in the Materials. You should consult with your own financial and/or municipal, legal, accounting, tax, and other advisors, as applicable, to the extent you deem appropriate. If you would like a municipal advisor that has legal fiduciary duties to you, you are certainly free to engage a municipal advisor to serve in that capacity. Furthermore, please be advised that the information contained in the Materials does not constitute accounting or legal advice.

Transactions referenced in the Materials which are attributed to Wells Fargo or to WFS may include transactions executed by a Wachovia Corporation or Wells Fargo & Company (“WFC”) broker/dealer affiliate or by other municipal securities dealers and/or broker/dealers which were acquired by Wachovia Corporation or WFC.

Municipal underwriting and remarketing rankings referenced herein represent combined totals for Wells Fargo Bank, N.A. (“WFBNA”) and Wells Fargo Securities, LLC (“WFSLLC”). Municipal commercial paper rankings referenced herein represent totals for WFSLLC . Source information for any ranking information not otherwise provided herein is available on request.

WFS distributes municipal securities to institutional investors primarily through WFBNA and Wells Fargo Securities, LLC (“WFSLLC”). Distribution to middle market clients is provided primarily through WFSLLC and Wells Fargo Institutional Securities, LLC (“WFIS”). Retail distribution is primarily provided by Wells Fargo Advisors, which is the trade name used by Wells Fargo Advisors, LLC (“WFA”) and Wells Fargo Advisors Financial Network, LLC (“WFAFN”), two non-bank separate registered broker-dealers (members FINRA and SIPC). WFSLLC, WFIS, WFBNA, WFA, and WFAFN are affiliates and are each wholly owned subsidiaries of WFC.

In the event that the Materials include information related to a bank-purchased bond transaction (“Direct Purchase”), please be advised that Direct Purchase is a product offering of Wells Fargo Bank, N.A. or a subsidiary thereof (“Purchaser”) as purchaser / investor. WFS will not participate in any manner in any Direct Purchase transaction between you and Purchaser, and Wells Fargo employees involved with a Direct Purchase transaction are not acting on behalf of or as representatives of WFS. The information contained herein regarding Purchaser’s Direct Purchase is being provided to you by WFS only for purposes of providing you financing alternatives that may be available to you from Wells Fargo & Company and its affiliates. Information contained in this document regarding Direct Purchase is for discussion purposes only in anticipation of engaging in arm’s length commercial transactions with you in which Purchaser would be acting solely as a principal to purchase securities from you or a conduit issuer, and not as a municipal advisor, financial advisor or fiduciary to you or any other person or entity regardless of whether Purchaser, or an affiliate has or is currently acting as such on a separate transaction. Additionally, Purchaser has financial and other interests that differ from your interests. Purchaser’s sole role with respect to the Direct Purchase would be to purchase securities from you (or the issuer in the case of a conduit transaction). Any information relating to a Direct Purchase transaction is being provided to you pursuant to and in reliance on the “bank exemption” under the municipal advisor rules (“Muni Advisor Rules”) of the Securities and Exchange Commission (“SEC”) or the SEC’s guidance in its Registration of Municipal Advisors Frequently Asked Questions and Answers dated May 19, 2014 and the general information exclusion to advice under the Muni Advisor Rules.

Wells Fargo Securities is the trade name for certain securities-related capital markets and investment banking services of Wells Fargo & Company and its subsidiaries, including Wells Fargo Bank, National Association. Commercial banking products and services are provided by WFBNA. Investment banking and capital markets products and services are provided by WFS, and are not a condition to any banking product or service. Municipal derivatives services are provided by Wells Fargo Bank, N.A., a swap dealer registered with the CFTC and member of the NFA.

The information contained in the Materials and any subsequent discussions between us, including any and all information, advice, recommendations, opinions, indicative pricing, quotations and analysis with respect to any municipal financial product or issuance of municipal securities, are provided to you in reliance upon the IRMA exemption provided by the Rules.

The Materials do not constitute an offer to sell or a solicitation of an offer to buy, or a recommendation or commitment for any transaction involving the securities or financial products named or described herein, and are not intended as investment advice or as a confirmation of any transaction. Externally sourced information contained in the Materials has been obtained or derived from sources we reasonably believe to be reliable, but WFS makes no representation or warranty, express or implied, with respect thereto, and does not represent or guarantee that such information is accurate or complete. Such information is subject to change without notice and WFS accepts no responsibility to update or keep it current. WFS does not assume or accept any liability for any loss which may result from reliance thereon. WFS and/or one or more of its affiliates may provide advice to other persons or may from time to time have proprietary positions in, or trade as principal in, any securities or other financial products that may be mentioned in the Materials, or in derivatives related thereto.

Notwithstanding anything to the contrary contained in the Materials, all persons may disclose to any and all persons, without limitations of any kind, the U.S. federal, state or local tax treatment or tax structure of any transaction, any fact that may be relevant to understanding the U.S. federal, state or local tax treatment or tax structure of any transaction, and all materials of any kind (including opinions or other tax analyses) relating to such U.S. federal, state or local tax treatment or tax structure, other than the name of the parties or any other person named herein, or information that would permit identification of the parties or such other persons, and any pricing terms or nonpublic business or financial information that is unrelated to the U.S.

Wells Fargo Securities
150 E 42nd Street, 25th Floor
New York, NY 10017

federal, state or local tax treatment or tax structure of the transaction to the taxpayer and is not relevant to understanding the U.S. federal, state or local tax treatment or tax structure of the transaction to the taxpayer.

Any opinions or estimates contained in the Materials represent the judgment of WFS at this time, and are subject to change without notice. Interested parties are advised to contact WFS for more information.

IRS Circular 230 Disclosure:
To ensure compliance with requirements imposed by the IRS, we inform you that any statements or information regarding tax matters contained in the Materials does not constitute tax advice and shall not be used for the purpose of (i) avoiding tax penalties or (ii) promoting, marketing or recommending to another party any transaction or matter addressed herein.

If you have any questions or concerns about the disclosures presented herein, you should make those questions or concerns known immediately to WFS.

MUNICIPAL MARKET UPDATE

REFUNDING SCREENS

UNSOLICITED PROPOSALS

RATING AGENCY REPORTS

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

RatingsDirect®

U.S. Public Power 2015 Outlook: Despite Several Looming Issues, Credit Quality Should Remain Stable

Primary Credit Analyst:
Jeffrey M Panger, New York (1) 212-438-2076; jeff.panger@standardandpoors.com

Secondary Contacts:
Peter V Murphy, New York (1) 212-438-2065; peter.murphy@standardandpoors.com
Geoffrey E Buswick, Boston (1) 617-530-8311; geoffrey.buswick@standardandpoors.com

Table Of Contents

U.S. Public Power 2015 Outlook: Despite Several Looming Issues, Credit Quality Should Remain Stable

Although the U.S. public power sector is likely to hit some bumps in 2015, Standard & Poor's Ratings Services believes credit quality overall will remain solid and ratings will stay stable for the sector. Despite some exceptions -- such as the Puerto Rico Electric Power Authority in 2014 -- we believe public power's general rate-setting autonomy and a lack of competition for retail customers will underpin the sector's credit quality. Our outlook incorporates the following expectations:

- Fuel prices, particularly for natural gas, will remain at low levels.
- The economy will expand manageably, enabling utilities to absorb growth without creating undue capital and operational burdens.
- Public power utilities will continue to effectively respond to regulatory measures the U.S. Environmental Protection Agency (EPA) has imposed in the past five years.

Despite this stable outlook, challenges remain. Some of these are broad and more long-term, affecting many utilities. They include the following:

- New EPA regulations targeting carbon emissions at existing power plants will likely weigh more heavily on carbon-intensive utilities than previous measures, and they could affect grid reliability.
- We expect fuel diversification to continue declining, exposing the industry to fuel price volatility.
- Aggressive budgeting of revenue from surplus energy sales might return, weakening financial metrics stressing retail rates if margins fail to materialize.

(Watch the related CreditMatters TV segment titled, "Why U.S. Public Power Ratings Will Remain Stable This Year," dated Jan. 16, 2015.)

Outlook

- We believe that credit quality for the U.S. public power sector will largely be stable in 2015.
- We expect natural gas to continue being the predominant form of generation, with gas prices remaining low.
- We have not included proposed federal and state environmental regulations in our analysis, but we will as their impacts become clearer.

Our Economic Outlook And Its Effect On Utilities

Given how essential electric power is and the industry's general lack of competition for customers, economic trends tend to influence the public power sector only moderately. So although the U.S. economy appears to be poised for stronger growth, we do not expect this to translate into a significant increase in electricity demand in 2015.

Economic forecast

The robust economic expansion in both the second and third quarters of 2014 supports our view of solid growth heading into 2015. We expect U.S. GDP to expand 2.3% in 2014 and 3.1% in 2015 as private-sector strength offsets continued government austerity. We further expect the solid job gains to continue, with wage growth accelerating somewhat in 2015. We believe that the Federal Reserve will likely raise its policy rate in June, the first hike since 2006. Meanwhile, we project that the unemployment rate will continue to decline, averaging 5.8% in 2015 -- an improvement from the 6.2% estimate for 2014.

We base our industry and company-specific forecasts on our economic forecast, although we recognize performance in specific markets might be better or worse than the national averages. We believe credit market participants are also interested in our view of upside potential and downside risks, and we have provided two more scenarios (see table). Our economic forecast ("U.S. Economic Forecast: The Economy Spreads Some Holiday Cheer," published Dec. 22, 2014, on RatingsDirect) projects the chance of another U.S. recession in 2015 at 10%-15% (down from a 15%-20% chance the same time a year earlier).

Electric sales in 2014 generally were flat or increased slightly (after a prolonged period of flat-to-declining), suggesting the potential for modest load growth tied to an improving economy. Many utilities we rate project this trend to continue in 2015. Improving economic growth and lower unemployment generally bode well for electricity demand, particularly from industrial customers.

However, weather is a bigger factor for residential customers, and the Department of Energy's Energy Information Administration (EIA) expects weather patterns at near-normal levels in 2015, compared with 2014's frigid winter. Further restraining electricity demand are continued energy-efficiency measures being deployed to help meet emissions reduction targets and reduce capital needs. These factors contribute to the EIA's projection that electricity sales will increase only 0.7% in 2015, down slightly from 0.9% estimated for 2014, but higher than the 0.2% posted in 2013. The EIA estimates that, in 2014, residential ratepayers are paying about 3% more for electricity than in 2013, and it projects a 1.7% average rate increase for 2015.

Most public power utilities that we rate have some mechanism--formal or informal, automatic or discretionary--that enables them to pass through changes in fuel and purchased power costs to ratepayers. In our view, these mechanisms are crucial supports to credit quality. But we also note that not all such mechanisms are equal. From a credit perspective, the strongest mechanisms are triggered automatically and recover costs dynamically (or over short periods). In cases where the adjustment is at management's discretion (and not taken), or where recovery takes longer, coverage of fixed obligations and liquidity can be compromised. Given that political pressures can influence the willingness to adjust rates (both base and fuel), we believe the governing board's independence can influence credit quality.

Standard & Poor's Economic Outlook: Indicators From U.S. Public Power

	--Forecast/scenarios*--						
	--Downside case--		--S&P's economic outlook--		--Upside case--		--Actual--
	2014e	2015e	2014e	2015e	2014e	2015e	2013
Real GDP (% change)*	2.0	1.2	2.2	3.0	2.3	3.6	2.2

Standard & Poor's Economic Outlook: Indicators From U.S. Public Power (cont.)							
Economic growth is improving, but is not expected to translate into robust electricity demand							
Unemployment rate (%)*	6.2	6.4	6.2	5.8	6.2	5.7	7.4
Declining unemployment reflects a pick up in industrial production and provides modest rate raising headroom.							
Ten-Year Treasury note rate (%)*	2.6	2.8	2.6	3.0	2.6	3.3	2.4
We expect the Fed to hike interest rates in 2015, increasing utility borrowing costs.							
Natural gas prices, Henry Hub ($/mil. Btu)§	N.A.	6.38	4.44	3.83	N.A.	2.76	2.75
Natural gas prices are expected to decline in 2015 due high levels of production.							

*Standard & Poor's derives its forecast for GDP growth, unemployment rates, and treasury bill rates using the Global Insight model of the U.S. economy. Downside and upside cases are from the article, "U.S. Economic Forecast: The Economy Spreads Some Holiday Cheer," published Dec. 22, 2014, on RatingsDirect. Baseline forecast is from the U.S. Monthly Forecast Report. §The natural gas price baseline forecast and upcomes from the U.S. Department of Energy's Energy Information Adminsitration as published in its Short-Term Energy Outlook; upside and downside cases are lower and upper bounds to the 95% confidence level.. e--Estimate. N.A.--Not available.

Our Outlook For Generation And Fuels

The cost of fuel (both direct, and indirectly via purchased power) is the largest operating expense for most utilities that don't rely on nuclear or renewable resources.

Our outlook for commodity costs suggests falling gas and stable coal prices for 2015. If prices stay low, it would be a marked departure from historically volatile prices, and we believe that it will promote credit stability. However, while our outlook for fuel prices is generally favorable, we note that delivery systems -- rail for coal, and pipelines for natural gas -- were strained in 2014, presenting a possible greater near-term risk to electric utility operations and credit quality.

Natural gas

We believe natural gas prices are the most significant factor for fuel costs, not only for utilities that depend on gas to power their assets but for those that purchase power because gas-fired generation sets the marginal price of electricity in most markets. The low gas prices have given utilities room to absorb increased costs related to environmental regulations with minimal effects on rates. They've also offset the effect of lower electric sales resulting from a still-slowly recovering economy, conservation efforts, and fluctuating weather patterns.

Gas prices have historically been volatile, and relative to coal prices, they continue to be so. Since 2008, hydraulic fracturing and horizontal drilling have unlocked huge deposits of natural gas from shale formations. From 2008-2012, gas prices declined 69%, to $2.75 per million Btu (mmBtu) from an average of $8.86. With it came a shift in generation: In 2012, coal accounted for 37% of energy (compared with 48% in 2008), while gas accounted for 30% (up from 21%).

Although gas prices remain low relative to 2008 levels, they have increased a substantial 63% since 2012, to an average of $4.42 per mmBtu for the 12 months to October 2014. Reflecting a rise in natural gas prices (and in a departure from the long-term trend), coal-fired generation has ticked upward (to 40%), while gas now accounts for 27% of total generation.

The recent increase in the price of gas has made efficient coal units slightly more attractive for utilities that could switch. Nevertheless, we note that even at the somewhat elevated 2014 level, natural gas prices are less than half the average price for 2008. We project that the Henry Hub will average $3.75 per mmBtu in 2015, which should once again make natural gas the fuel of choice, and $4.00 through 2017. Meanwhile, the New York Mercantile Exchange forward price curve suggests natural gas prices will remain below $5 per mmBtu through 2022.

We see the 2014 increase in natural gas prices as a bit of an anomaly, because an unusually cold winter was behind it, offsetting strong natural gas production growth. As oil exploration companies have searched for higher-priced liquids, the discovery of natural gas has continued to abound. With natural gas production outstripping consumption (the EIA projects flat natural gas consumption in 2015), we project that the price of natural gas at the Henry Hub in Louisiana will average $3.75 per mmBtu in 2015. (For more information, see "Standard & Poor's Revises Its Crude Oil Price Assumptions; Natural Gas Assumptions Unchanged," published Dec. 16, 2014.)

Many utilities have used conservative hedging operations to manage gas price volatility in the past few years. This has increased budgetary certainty, mitigating the impact on financial metrics. However, we note that if gas prices do decline in 2015, the hedging activities could expose utilities to collateral posting requirements, placing additional importance on liquidity.

Anecdotally, it appears to us that much of the switching between gas and coal is occurring when gas prices hit the $3.50-$4 per mmBtu mark (although though this differs among utilities), so we might see some utilities use gas units more frequently in 2015. And given that the projections and forward price curves suggest natural gas prices will remain below $5 per mmBtu through 2022, we expect that this will have favorable implications for electric rates, competitive positioning, and financial metrics.

However, not all utilities are positioned to substitute natural gas for coal, given their significant investment in coal-fired generation assets. In addition, the interstate gas pipeline network is less extensive in some parts of the traditional coal-producing regions. Although gas commodity prices have been largely favorable, a constrained natural gas delivery system represents a growing credit concern. The nation's pipeline infrastructure is unable to accommodate spikes in natural gas demand. Unlike coal or oil, gas is not usually stored on-site, and utilities rely on timely deliveries.

According to the North American Electric Reliability Corp., about 19,000 megawatts (MW) of generating capacity went offline during the 2014 polar vortex, due to a combination of weather-related equipment failures and an inability to receive sufficient natural gas to meet increased demand. The drop in available capacity threatened grid reliability and forced deployment of high-cost and inefficient units powered by diesel and fuel oil, and this put upward pressure on electricity prices. During the polar vortex, wholesale electricity prices averaged $1,300 per MW-hour (MWh; 40x the average) in the region covered by the Electricity Reliability Council of Texas (ERCOT). In the PJM territory, the average cost of power was $150 per MWh in January 2014, about 3x the average price in 2013. However, this situation was somewhat short-lived, and for most utilities, it happened early in their fiscal years, giving them time to recover the increased operating costs.

Beyond pipeline constraints, another downside in the shift toward gas-fired generation is diminishing fuel diversity, which could result in greater exposure to higher operating costs. In addition, the length of power-supply contracts has shortened, with counterparties less willing to enter long-term contracts in part due to increasing demand and generally low gas prices. With long-term contracts harder to find, we believe supply portfolios incorporate relatively higher levels of spot purchases and short-term bilateral agreements. This, in turn, is increasing re-contracting risk and exposure to price spikes.

Although we expect that natural gas prices will remain low in the next five years, we believe that price volatility is inevitable. Coupled with environmental regulations targeting coal-fired generation, low gas prices are bringing a shift to gas-fired generation. This could increase gas prices while resulting in less fuel diversity, leaving utilities with relatively fewer tools to manage price volatility. Because utilities rely on gas-fired generation to a greater degree, hedging will take on a greater importance. We are concerned that this could result in contingent liabilities, creating implications for liquidity.

But we expect ratings will largely stay stable, with utilities passing compliance costs on to ratepayers while maintaining financial flexibility and relative competitive positioning. We believe higher gas prices might return if:

- Demand for natural gas increases, whether because of economic expansion, regulatory-prompted switching, or waning long-term interest in nuclear generation;
- Natural gas supply decreases due to increased opposition to hydraulic fracturing or other environmental challenges; or
- Volatility in world petroleum markets spills over into natural gas prices. (Historically linked, the prices of these commodities have become decoupled in recent years.)

Coal

Modestly higher electricity demand and higher natural gas prices contributed to electric utilities' increased coal consumption in 2013 and 2014. Nevertheless, there has been a clear shift toward natural gas-fired generation, and we expect this will continue.

We project total coal consumption will fall by 1.2% in 2015, due to a combination of coal unit retirements resulting from the Mercury and Air Toxics Standards (MATS), slower electricity sales growth (projected at 0.7%), and expected lower natural gas prices. The EIA projects that the annual average coal price to the electric power industry, which fell to $2.35 per mmBtu in 2013 from a historically high $2.39 in 2011, will have averaged $2.36 in 2014 and will remain at that level in 2015.

In 2014, the nation's rail lines shipped huge quantities of shale oil and corn, displacing coal shipments to utilities, primarily in the Midwest. Utility coal pile inventories, normally in the 45-day burn range, dwindled to about 10 days for some coal-fired utilities that had one shipper. In a few cases, utilities were forced to curtail dispatch of their most efficient baseload resources, and rely on higher-cost resources (either owned or purchased). After utilities complained to elected officials, the U.S. Surface Transportation Board, and the Federal Energy Regulatory Commission, shipments via Burlington Northern Santa Fe have picked up, and we believe inventories have rebounded somewhat, but we remain wary that the situation could return.

Our Outlook On Regulation

Ever since the Clean Air Act and related amendments passed, public power utilities have generally maintained credit quality by exercising their rate-setting autonomy and passing through increasing environmental compliance costs to ratepayers. And we believe that public power utilities will continue to effectively respond to regulatory measures adopted by the EPA over the past five years.

These regulations have placed what we view as largely manageable operational constraints and financial burdens on electric utilities. Although many electric service providers continue to deal with the new rules, particularly as relates to the Mercury and Air Toxics Standard (MATS), there has been little impact on credit quality. As some regulatory regimes have crystalized and deadlines approach, most utilities have reevaluated their power supply portfolios and have decided whether to retrofit or retire units -- with the current state of and outlook for energy demand, natural gas prices, and future regulatory measures influencing the decisions. These utilities have generally built these costs into financial and capital plans, which we review as part of our assessment of credit quality, so we expect little impact from these regulations.

However, the EPA's proposed carbon standards for existing power plants under Section 111(d) of the Clean Air Act, referred to as President Barack Obama's Clean Power Plan (CPP), could change this completely. We are concerned that the new EPA regulations targeting carbon emissions at existing power plants will weigh more heavily on carbon-intensive utilities than previous measures, and they could affect grid reliability.

The CPP

On June 2, 2014, the EPA released its proposed regulation of carbon emission from existing power plants. The proposal calls for a 30% cut in carbon dioxide emissions (although individual state targets vary) from existing power plants by 2030, with interim targets averaging 25% for 2020-2029. We believe that utilities with significant carbon footprints are most at risk, so any upward rating potential is very limited for them. The EPA is considering comments on the proposal, so it is possible that the regulation, which we expect the agency to finalize in June 2015, will change. Each state will then need to submit implementation plans by June 2016. These plans will provide a framework for utilities to formulate their individual response strategies; until we know these frameworks, compliance costs will not be measurable. The changed political landscape that has followed the 2014 midterm elections might bring about renewed challenges to the EPA's authority and attempts to delay the regulation's implementation, although the president could veto any challenges or use executive orders. We also believe lawsuits are a certainty. Given all this, we have not factored the plan's impact on our ratings, but will do so as plans become final.

The target reductions called for in the CPP were formulated using a combination of four methods, which the EPA refers to as "building blocks":

- Enhancing the efficiency of existing fossil fuel power plant equipment and processes for a 6% heat rate improvement;
- Shifting electric generation from carbon-intensive units to existing (and under construction) natural gas combined-cycle units that have lower emissions, with a goal of a 70% average capacity factor;
- Increasing energy production from zero- and low-emitting assets such as renewable and nuclear resources; and

- Reducing electricity demand 1.5% through retail customer efficiency programs.

Like the utilities we rate, we are beginning to formulate our views of the CPP. We believe the following:

- Given the shorter time frame (essentially four years from the filing of state implementation plans), complying with the interim goals will be more problematic than the complying with 2030 targets.
- Compliance will be far more complicated for utilities generating, buying, and selling power across state lines.
- Because of the regional nature of electric markets and because utilities in each state have their own paths to achieve emissions reductions, the CPP might spawn additional multistate carbon-trading networks, such as the Northeast already has under the Regional Greenhouse Gas Initiative.
- Natural gas prices and capital costs associated with zero- and low-emission generating assets will influence the plan's impact greatly.
- Infrastructure capacity issues related to the network of natural gas pipelines and the electricity transmission grid will constrain utilities' ability to achieve the targets. Additional shifts toward natural gas (as the CPP envisions) will depend on adding capacity to an already-strained pipeline system. Meanwhile, expected coal-unit retirements and the increasing use of renewable resources (often located far from load centers) place additional burdens on a transmission system that has suffered from underinvestment for many years. We expect that some states with constrained transmission, such as Florida, will face significant challenges in complying.
- Based on studies by regional transmission organizations, including ERCOT and the Southwest Power Pool (SPP), we are concerned that without significant investment in transmission, the CPP could result in a destabilized grid, causing cascading blackouts. ERCOT estimates retirements ranging from 3.3 gigawatts (GW) to 8.7 GW, which could represent about half of Texas' coal-fired capacity. The SPP projects 9 GW of coal-fired capacity (more than one-third of coal-fired capacity) will be retired.
- Based solely on the percentage reduction targets, it appears that Arizona, South Carolina, and Washington face significant issues. However, this can be somewhat misleading. For instance, Washington State expects to reduce carbon dioxide emissions by 74%. But as a hydropower-reliant state, Washington has a relatively small carbon footprint, so this target should be readily achievable. The already announced closure of one of the state's only coal plants should go a long way to enabling Washington to meet the compliance target. Less clear is how the EPA will treat nuclear projects under construction in its calculations of the emission reduction target. We note that this could have an effect in states with large-scale projects under construction, including Summer Nuclear Units 2 and 3 (South Carolina), Vogtle Units 3 and 4 (Georgia), and Watts Bar Unit 2 (Tennessee).
- Each state's reduction targets do not factor in the retirement of coal units that have only been announced. For example, in Ohio, a significant amount of coal-fired capacity is already slated for retirement for other reasons, such as complying with the EPA's MATS rule. As these units close over the next several years and depending on how the final regulations treat these retirements, Ohio's utilities might find they are well along their way, although this does not mean we don't expect Ohio's utilities to have a difficult time meeting the range of regulatory measures affecting coal-fired generation.
- As a matter of best practices, many utilities have long employed demand-side management programs. But with these programs well-established, it remains to be seen how much additional demand-side savings they can achieve, and we have concerns that hitting the remaining part of the target will be difficult.

In the wake of the 2014 midterm elections, the changed political landscape might bring about renewed challenges to the EPA's authority, but it might force the president's hand to use his veto power or executive orders to defend this and other regulatory measures. As well, lawsuits are almost guaranteed. Regardless of whether they succeed, legal tactics could delay the regulations' implementation. Given these uncertainties, we have not factored the plan's impact into our ratings so far, although we will as the issues become clearer.

Other regulatory measures

Since 2008, the EPA has promulgated more than a dozen initiatives, including:

- The MATS, which targets hazardous pollutants such as mercury, chromium, arsenic nickel, and acid gases. (On Nov. 25, 2014, the U.S. Supreme Court agreed to hear the electric utility industry's challenge to the law);
- The Cross State Air Pollution Rule, which targets criteria pollutants such as sulfur dioxide, nitrogen oxide, ozone, and particulate matter;
- The New Source Performance Standards (NSPS), which target greenhouse gases, including carbon dioxide, at new or substantially modified generating units;
- A proposal to govern the disposal of coal combustion residuals (ash from coal used to generate electricity); and
- A measure known as Rule 316-b of the Clean Water Act, which affects the design and construction of cooling water structures, with the aim of minimizing their impact on aquatic life.

We believe these regulations make the construction of additional coal-fired generation unlikely and will likely cause varying regional effects. The bulk of the announced retirements are units in the Midwest, Mid-Atlantic, and Southeast (outside of Florida), areas that are generally big users of carbon. Some utilities will be particularly vulnerable due to certain aspects of their operations, including the age, size, efficiency, and diversity of their generating units. Indeed, the bulk of the announced retirements are smaller, less-efficient coal-fired units with high heat rates and limited remaining useful lives -- in short, units that would have been retired anyway. For these utilities, retrofitting existing units is not cost-effective. In some cases, it would force them to pursue new generation, which might well introduce additional costs.

Although we expect substantial capital spending associated with both retrofits and retirements, we believe current low interest rates create favorable conditions and that, despite flat electric demand, public power's rate-setting autonomy will buoy credit quality by enabling utilities to recover these expenses through cost-adjustment mechanisms and base-rate increases. And because utilities generally finance these capital improvements with debt that amortizes across many years, we expect compliance costs will have only a modest impact on end-user electric rates. Standard & Poor's believes that the cost of complying with these regulations are by-and-large manageable -- anecdotally, it appears that compliance-driven rate increases have been 3%-5%.

State measures and the rise of renewables and distributed generation

Although legislation in terms of renewable energy at the federal level is dormant, some states have been active. Twenty-nine have adopted renewable portfolio standards, which mandate that a percentage of generation must come from renewable sources, such as wind or solar. An additional eight states have adopted renewable goals, while 23 have adopted energy-efficiency standards. Although public power utilities are exempt from the mandatory standards in 20 of the 29 states, many utilities nevertheless opt to comply for a variety of reasons, including environmental stewardship and political considerations.

Distributed generation (small-scale, decentralized, customer-level generation) has had no real effect on utilities that we rate, but as a growing trend, it is something we believe bears watching. Distributed generation enables retail customers to bypass their utility by installing their own generating resources (usually solar panels). This can result in lower electricity sales, leaving utilities the burden of shouldering the stranded fixed costs associated their large-scale power plants. Given the significant capital costs associated with installing distributed assets, we have found that such generation has made only modest inroads and generally only in communities that have high power costs, above-average incomes, and favorable weather profiles.

Ratings Distribution And Notable Rating Changes

Standard & Poor's has 302 senior-lien ratings in the public power sector, including wholesale, retail, and combined (multiple) systems. All but one of the ratings are investment-grade ('BBB-' or above). Although we do not rate any public power utilities 'AAA', we believe the rating distribution demonstrates overall credit strength, with about 33% in the 'AA' category and 62% in the 'A' category (see chart). Furthermore, 97% have stable outlooks. Traditional sector strengths that provide what we view as a solid credit foundation are rate-setting autonomy, a focus on the core mission of serving customers, and the lack of direct competition for retail customers.

In 2014, we raised the ratings on 12 public power utilities and lowered the rating on seven (including the PREPA, the rating on which we lowered four times). Notable rating actions in 2014 included the following:

PREPA. We lowered the rating ultimately to CCC/Watch Neg from BBB/Negative at the beginning of the year. We believe the authority's debt is vulnerable to nonpayment and depends on favorable business, financial, and economic conditions for the obligor to meet its commitment. PREPA has $8.3 billion of power revenue bonds.

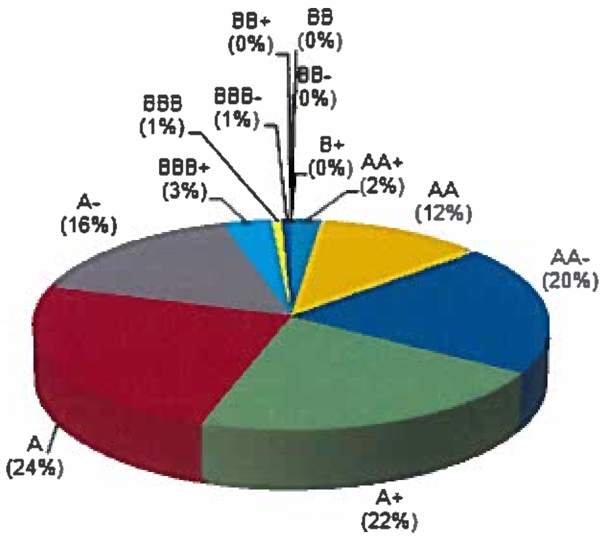
We believe the absence of an overarching solution to liquidity issues and the structural imbalance among its revenues, operating expenses, and debt service commitments suggests an increasing likelihood that the authority will not be able to satisfy debt service obligations on time and will avail itself of the Puerto Rico Public Corporation Debt Enforcement and Recovery Act to restructure its debt.

New York Power Authority (NYPA). We raised the rating on NYPA to AA from 'AA-' on Nov. 3. The upgrade reflected our view of the authority's track record of consistently strong fixed-charge coverage of at least 2.3x, a very favorable debt-to-capitalization ratio of 31% in 2013 (down from 42% in 2009), and the utility's forecast that it plans to use cash balances to fund portions of its capital program.

Illinois Municipal Electric Agency. We lowered our rating on IMEA's power supply system revenue bonds to 'A' from 'A+' on Nov. 19. The downgrade reflected our view of a trend of declining coverage of debt service and total fixed obligations, and a weaker credit profile of the joint-action agency's leading members.

Columbia, Mo., combined utility. On May 20, we raised our rating on Columbia's water and electric system revenue bonds to 'AA' from 'AA-'. The upgrade reflected our opinion that the system will be able to sustain solid debt service coverage and strong working capital because it has updated its power supply portfolio in recent years and fully integrated those resources into its rates.

U.S. Public Power Ratings Distribution As Of Jan. 1, 2015



MOODY'S
INVESTORS SERVICE

OUTLOOK
15 DECEMBER 2014

Rate this Research

ANALYST CONTACTS

Dan Aschenbach 212-553-0880
Senior Vice President
dan.aschenbach@moodys.com

Thomas Brigandi 212-553-2985
Associate Analyst
thomas.brigandi@moodys.com

John Medina 212-553-3604
AVP-Analyst
john.medina@moodys.com

Kevin G. Rose 212-553-0389
VP-Senior Analyst
kevin.rose@moodys.com

Chee Mee Hu 212-553-3665
MD-Project Finance
cheemee.hu@moodys.com

2015 Outlook – US Public Power Electric Utilities

Steady Financial Metrics Drive Stable Outlook

Our outlook for the US public power industry is stable. This outlook reflects our expectations for the fundamental business conditions in the industry over the next 12 to 18 months.

Our stable outlook is based on our expectation that debt-service coverage and liquidity of public power electric utilities will remain stable, supported by their ability to raise consumer rates when needed to recover the cost of generating and distributing energy.

» **The main reason for our stable outlook is public power electric utilities' unregulated ability to establish electricity rates.** For 2015, we expect that the median fixed-charge coverage ratio for rated US public power electricity generators will hold steady at about 1.6x and that median days cash on hand will remain at 174 days, roughly in line with 2014. Improvement in the US economy in 2015 will also help utilities maintain their credit metrics because any required rate increases should be more tolerable for consumers.

» **We do not expect utilities to take on significantly more debt in 2015.** Projected lower demand for electricity reduces the need for utilities to borrow in order to build new capacity, so leverage is unlikely to significantly increase in 2015. Environmental compliance and system reliability projects will remain a major focus of new capital improvement programs.

» **Uncertainty about the ability of public power electric utilities to comply with proposed federal carbon rules is an evolving long-term risk to our outlook.** Utilities are making plans to adapt to the proposed carbon emissions standards and to transition to cleaner power sources, but these strategies also come with risks.

» **What could change our outlook.** We would consider shifting to a negative outlook if the median fixed-charge coverage ratio for US public power electric generators falls below 1.5x or if we see signs that customers are shifting off the grid away from public power electric utilities. Neither of these scenarios is likely to play out over the next year. We are also unlikely to shift to a positive outlook in 2015.

Metrics will remain stable in 2015

Our stable outlook is based on our expectations that debt-service coverage and liquidity in the industry will remain stable, supported by the ability of public power electric utilities to raise consumer rates when needed to recover the costs of generating and distributing electricity.

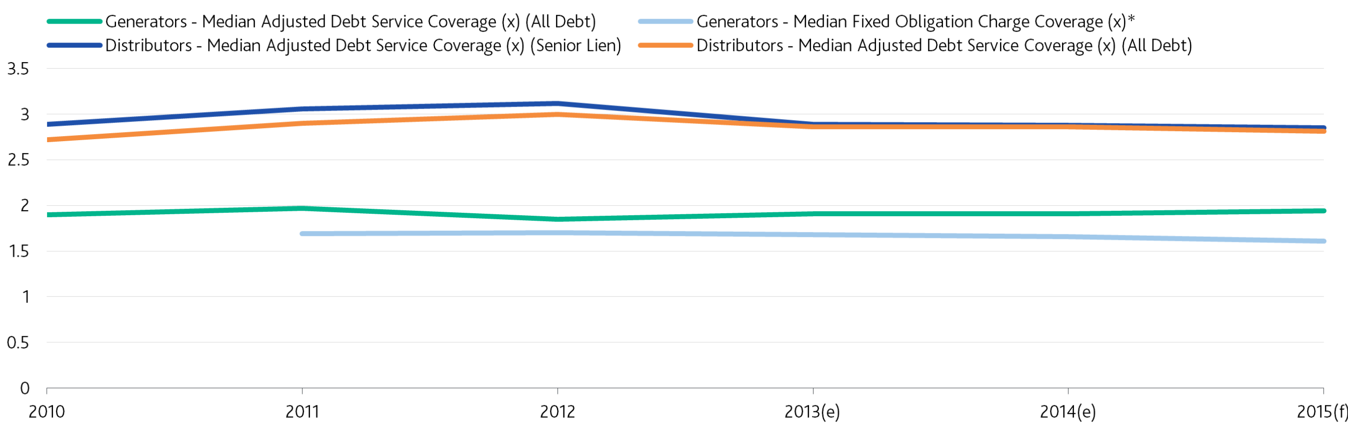
Slow growth in demand for electricity will put pressure on utilities to raise electric rates because their fixed costs will have to be spread out over the same or a lower volume of electricity. Still, the improving US economy and another year of low natural-gas prices will help keep electric rate increases moderate. If needed, however, public power electric utilities will use their unregulated ability to raise rates to keep their finances stable.

For rated US public power generators, we expect the median fixed-charge coverage ratio, which includes debt service plus debt payments to joint action agencies, will hold steady at about 1.6 times. Liquidity, measured by median days cash on hand, will remain 174 days. Exhibit 1 illustrates our expectations that the steady, multiyear trends in debt-service and fixed-charge coverage ratios for both generators and distributors will keep going.

Our rated universe of public power companies includes electricity generators, electricity distributors and joint action agencies, which are groups of municipal electric utilities that jointly finance electricity generation. Our outlook for the industry is mainly driven by our expectations for generators because they make up the bulk of the debt of the industry and because they support the debt of the joint action agencies.

Exhibit 1

The steady, multiyear trends in coverage ratios will continue next year



Notes: Data for 2013, 2014 and 2015 are our estimates. The adjusted debt-service coverage ratio includes the General Fund transfers as part of operations and maintenance expenses. The fixed-charge coverage ratio applies to utilities that participate in generation projects of joint action agencies (JAA) and includes the debt-service component of a take-or-pay obligation with a JAA as the debt service of the utility.

Source: Issuer financial statements and forecasts; Moody's Investors Service

As noted, the improving US economy and another year of low natural-gas prices will help keep electric rate increases moderate. Moody's expects the economy to expand about 3% next year, up from about 2% in 2014. Also, since natural gas represents an increasing share of the fuel used in electricity generation, low gas prices will ease the pressure on utilities to raise rates.

For generators, our estimate for fiscal 2014 adjusted debt-service coverage is 1.91x and for the fixed-charge coverage ratio it is 1.66x; our estimates for fiscal 2015 are 1.91x and 1.61x, respectively. For distributors, our estimate for the debt-service coverage ratio is 2.86x for 2014. Our estimate of days cash on hand for fiscal 2014 is 174 days for public power electric generators and 113 days cash for distributors.

For joint action agencies, we expect the median debt-service coverage ratio will also remain stable, at about 1x, given these agencies' take-or-pay and take-and-pay contract terms with generators. The stable fixed-charge coverage ratios of the public power electric utility generators provide an indication of the soundness of contract compliance on both sides.

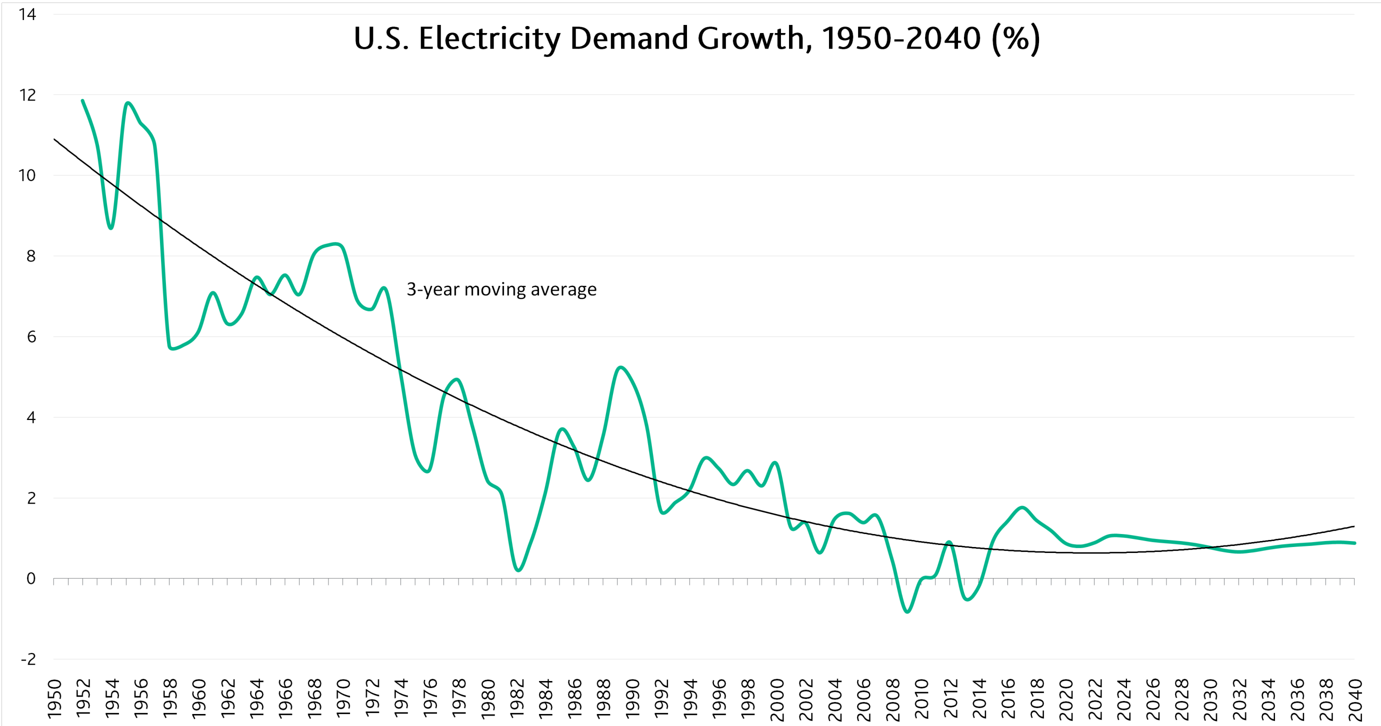
However, the phase-in of capital costs of several large, recently completed generation projects, including the Prairie State project, and the failure of participants to raise rates weakened the credit metrics of several electric utilities, including Paducah, Kentucky (A3 stable). Paducah's fixed-charge coverage ratio dropped to 1.11x in 2013 from 2.30x in 2010. We expect that Paducah's financial metrics will improve in 2015, however, as the costs of the project have now been more absorbed into financial results and the utility has developed financial improvement plans.

Debt levels should hold steady in 2015

Slower growth in demand for electricity will put pressure on utilities because their fixed costs will have to be spread out over the same or lower electricity usage volume. According to the US Energy Information Administration, flat to 2% demand growth will be the norm for the next two decades (see Exhibit 2). Much of the recent demand reduction is tied to the efficiency programs implemented by public power electric utilities.

But slower demand growth will also reduce the need for utilities to borrow in order to build new generation capacity. Against this backdrop, debt ratios for 18 of the largest 20 US public power electric utilities with generation ownership fell between 2010 and 2013, the latest data available. For example, New York State Power Authority's (Aa1 stable) debt ratio fell to 48% in 2013 from 51% in 2011. Seattle Light 's (Aa2 stable) ratio dropped from 67% to 62%. And JEA 's (Aa2 stable) ratio dropped to 76% from 84%. We expect debt ratios to continue to moderate into 2015.

Exhibit 2
US electricity demand growth is slowing



Source: US Energy Information Administration

Still, slower growth in electricity demand and the transition to cleaner energy are risks for public power companies. South Carolina Public Service Authority 's (Santee Cooper, A1 stable), a 45% owner in the Summer nuclear project, is a case in point.

Santee Cooper embarked on the new nuclear development project to initially add generation capacity to meet projected demand growth. But lower demand has reduced the utility's need for the total 45% share of the new nuclear capacity. Causes of lower demand include the impact of the national recession on South Carolina and an agreement with a co-operative to allow it to transition a portion of its power supply needs to another supplier over a six-year period. Santee Cooper is implementing strategies to mitigate the significant excess capacity when the units begin their commercial operation.

Transition to cleaner power is a long-term risk

Uncertainty about the ability of public power electric utilities to comply with proposed federal standards to reduce emissions of air pollutants and transition to cleaner power sources is a developing risk to our outlook.

Utilities are making plans to adapt to these changes, such as investing in renewable forms of energy or natural gas, but these strategies come with execution risks. Adopting new technology comes with the risk that it will not meet expectations and using new sources of power can cost more than existing power sources.

For example, California's municipal electric utilities are on track to supply 33% of retail power with renewable energy sources by 2020, thereby reducing the utilities' carbon exposure. Questions remain about whether the transmission grid can manage the intermittent energy supply of solar and wind power and whether costs are affordable. The Los Angeles Department of Water and Power (LADWP, Aa3 stable), for example, expects that retail rates will rise considerably. Consumer pushback on these rate increases could pressure the utility's credit metrics.

Another example of execution risk is that some utilities have made investments to meet federal and state environmental policies that are not yet final. Despite these investments, the utilities still might fall short of the final rules. The table below shows the new coal-fired units of select public power companies that have advanced environmental controls designed to meet current and expected standards.

Exhibit 3

Select New Coal-Fired Generating Plants and Efficiency Measures

Public Power Utility Owner	Credit Rating	Selected Plant Name	2013 Operating Capacity (MW)	2013 Plant Annual Net Generation (MWh)	2013 Plant Annual CO2 Equivalent Emmisions (tons)	2013 Plant Availability Factor (%)	2013 Plant Nominal Heat Rate (Btu/ kWh)	2013 Plant Capacity Factor (%)	Plant Nominal Heat Rate (Btu/kWh) [1/1/2014 - 8/31/2014]	Plant Capacity Factor (%) [1/1/2014 - 8/31/2014]
MJMEUC*	A3	Plum Point Energy Station	670	3,995,847	4,326,893	80.7	10,118	68.1	9,992.8	59.4
CPS Energy	Aa1	J K Spruce 2	785	3,807,137	4,046,382	62.2	9,546	55.4	9,489.9	87.5
Public Power Generating Agency1	A2	Whelan Energy Center 2	232	1,347,348	1,537,953	85.9	10,034	66.3	10,073.1	68.5
Illinois Municipal Electric Agency2	A1	Trimble County 2	760	4,187,355	4,086,667	71.8	9,369	62.9	10,889.2	56.6
Omaha Public Power District	Aa2	Nebraska City 2 (A1)	685	4,855,096	5,026,509	88.5	9,576	81.0	9,739.6	88.9
South Carolina Pub Serv Auth	A1	Cross 4	600	4,162,155	4,573,423	92.8	9,574	79.2	9,633.1	88.1
Salt River Project3	Aa1	Springerville 4	415	2,991,950	3,175,293	93.3	10,234	82.3	10,054.4	83.4
WPPI Energy4	A1	Elm Road Generating Station 2	634	2,448,397	2,576,383	65.0	9,476	44.1	9,298.3	71.4
American Mun Power Inc5	A1	Prairie State Energy Campus 1 2	1,629	8,350,518	8,997,555	68.3	9,819	58.5	9,657.3	62.1
Wyoming Municipal Power Agency6	A2	Dry Fork Station	405	3,066,625	3,588,151	91.6	10,444	86.4	10,431.9	94.8
		Capacity, Heat Rate Availability Medians				83.3	9,698	67.2	9,866	77.4

*MJMEUC (22.11%), Empire District Electric Co. (7.52%), Municipal Energy Agency of MS (6.0%)

[1] Hastings City of (36.86%). Heartland Consumers Power District (27.3%), Municipal Energy Agency of NE (27.3%), Grand Island City of (5.12%)

[1 cont] Nebraska City City of (3.42%)

[2] Louisville Gas & Electric Co. (38.67%), Kentucky Utilities Co. (36.33%), Indiana Municipal Power Agency (12.88%), Illinois Municipal Power Agency (12.12%)

[3] Tucson Electric Power Co. (48.29%), Tri-State G & T Assn Inc (25.92%), Salt River Project (25.79%)

[4] Wisconsin Electric Power Co. (83.34%), WPPI Energy (8.33%), Madison Gas and Electric Co. (8.33%)

[5] American Mun Power Inc (23.26%), IMEA (15.17%), IMPA (12.64%), MJMEUC (12.33%), Prairie Power Inc (8.22%), Southern Illinios Power Coop (7.90%)

[5 cont] Kentucky Muni Power Agency(7.82%), Northern Illinois Municipal (7.60%), Peabody Energy Corp. (5.06%)

[6] Basin Electric Power Coop (92.90%), Wyoming Municipal Power Agency (7.10%)

Sources: US Environmental Protection Agency, SNL, Moody's Investors Service

The Environmental Protection Agency's proposed rules to limit carbon emissions (see Appendix C) is credit negative for coal-dependent utilities because they will likely result in reduced power volumes and higher costs for generation. The Obama administration and the EPA have signaled to the industry that the focus will be on cutting coal-fired generation and have offered various ways to do so. The rule leaves much up to the states to devise their approach to regulate carbon emissions. In any case, we expect a highly contentious period of litigation and that the implementation of the rule would take years.

Appendix A

Broad Rating Factors Contained in Moody's Public Power Electric Utility Methodology: Credit Outlook Trends

BROAD CREDIT FACTOR	Jan-15	Dec-15	Comments
Cost Recovery Framework	S	S	*No change to public power business model including independent rate-setting; Economic recovery improving but slow
Willingness to Recover Costs	S	S	*Mostly stable; some downgrades are potential due to failing to maintain financial metrics
Management of Generation Risk	C	C	*Challenging as environmental regulations get implemented; renewable energy standards are met
Competitiveness	C	C	While competitive, prices are increasing relative to slower demand growth
Financial Strength	S	S	Financial metrics for most public power utilities should remain stable in 2015 .

F Favorable or Improving · S Stable Performance · C Challenges

Source: Moody's Investors Service

Appendix B

Ratings of Select Major Public Power Utilities

Large Muni Issuer	State	Senior Rating	Outlook	Debt ('000) Outstanding
Anaheim	CA	A1	Positive	678,680
Austin	TX	A1	Stable	1,399,079
Colorado Springs	CO	Aa2	Stable	2,329,807
Gainesville	FL	Aa2	Stable	974,795
Jacksonville Electric Authority (JEA)	FL	Aa2 (Sr.) Aa3 (Sub.)	Stable	2,837,815
Los Angeles Water and Power (Electric)	CA	Aa2	Stable	7,744,011
Memphis	TN	Aa2	Stable	562,995
Orlando Utilities Commision	FL	Aa2	Stable	1,563,270
San Antonio	TX	Aa1 (Sr.) Aa2 (Jr.)	Stable	5,131,925
Seattle	WA	Aa2	Stable	1,863,300
Springfield	IL	A3	Stable	585,335
Springfield	MO	Aa2	Stable	715,745
Tallahassee	FL	Aa3	Stable	594,510

Source: Moody's Investors Service

Ratings of Major State or District Public Power Utilities

Major State-District Issuer	State	Senior Rating	Outlook	Debt ('000) Outstanding
California Department of Water Resources-Power	CA	Aa2	Stable	6,554,000
Chelan Public Utility District	WA	Aa3	Stable	816,033
Grand River Dam Authority	OK	A1	Stable	814,371
Grant County Public Utility District	WA	Aa3	Stable	1,152,740
Guam Power Authority	Guam	Baa3 (Sr.) Baa2 (Sub.)	Positive	616,828
Long Island Power Authority	NY	Baa1 (Sr.) Baa2 (Sub.)	Stable	9,692,661
Lower Colorado River Authority	TX	A1	Negative	3,392,800
Lower Colorado River Authority -Transcorp Project	TX	A2	Stable	1,636,000
Nebraska Public Power District	NE	A1	Stable	2,072,129
New York State Power Authority	NY	Aa2	Stable	2,910,000
Omaha Public Power District	NE	Aa2	Stable	2,267,277
Puerto Rico Electric Power Authority	PR	Caa3	Negative	8,730,439
Sacramento Municipal Utility District	CA	A1 (Sr.) A2 (Sub.)	Stable	2,918,535
Salt River Project Agricultural Improvement and Power District	AZ	Aa1	Stable	3,888,260
Snohomish Public Utility District No.1	WA	Aa3	Stable	521,465
South Carolina Public Service Authority (Santee Cooper)	SC	A1	Stable	6,447,492

Source: Moody's Investors Service

Ratings of Joint Action Agencies

JAA Issuer	State	Senior Rating	Outlook	Debt ('000) Outstanding
American Municipal Power, Inc.	OH	A1 (issuer rating)	Stable	
Prairie State Project	OH	A1	Stable	1,676,920
Combined Hydroelectric Project	OH	A3	Stable	211,430
Meldahl Project	OH	A3	Stable	630,065

Fremont Energy Center	OH	A1	Stable	546,585
Energy Northwest	WA			
Project 1	WA	Aa1	Stable	1,321,060
Columbia Generating Station	WA	Aa1	Stable	3,224,040
Project 3	WA	Aa1	Stable	1,395,405
Indiana Municipal Power Agency	IN	A1	Stable	1,295,410
Intermountain Power Agency	UT	A1	Stable	1,615,001
Municipal Electric Authority of Georgia(Project One and General Resolution)	GA	A1 (Sr.) A2 (Sub.)	Stable	3,392,586
Series M-Vogtle Nuclear Project	GA	A2	Negative	904,410
Series J-JEA-Vogtle Nuclear Project	GA	A2	Negative	1,099,165
Series P-Power South-Vogtle Nuclear Project	GA	Baa2	Negative	664,301
North Carolina Eastern Municipal Power Agency	NC	Baa1	Positive	1,869,455
North Carolina Municipal Power Agency No. 1	NC	A2	Stable	1,433,090

Source: Moody's Investors Service

Appendix C

Summary of EPA's Proposed Best System of Emissions Reductions (BSER)

BSER Building Block	EPA Basis for BSER Determination	EPA Estimated Average Cost	% of BSER Co2 Reductions
1. Increase efficiency of fossil fuel power plants	EPA reviewed the opportunity for coal-fired plants to improve their heat rates through best practices and equipment upgrades, identified a possible range of 4-12% and chose 6% as a reasonable estimate. BSER assumes all coal plants increase their efficiency by 6%.	$6-12/ton	12%
2. Switch to lower-emitting power plants	EPA determined for re-dispatching gas for coal that the average availability of gas CC's exceeds 85% and that substatial number of CC units have operated above 70% for extended periods of time, modeled re-dispatch of gas CCs at 65-75%, and determined 70% to be technicially feasible. BSER assumes all gas CCs operate up to 70% capacity factor and displace higher-emitting generation (e.g., coal and gas steam units).	$30/ton	31%
3. Build more low/zero carbon generation	EPA indentified 5 nuclear units currently under construction and estimated that 5.8% of all existing nuclear capacity is "at-risk" based on EIA analysis. BSER assumes the new units and retaining 5.8% of at-risk nuclear capacity will reduce CO2 emmisions by operating at 90% capacity factor.	Under construction: $0/ton "At-Risk": $12-17/ton	7%
	EPA developed targets for existing and new renewable penetration in 6 regions based on its review of current RPS mandates, and calculated regional growth factors to achieve the target in 2030. BSER assumes that 2012 renewable generation grows in each state by its regional factor through 2030 (up to a maximum renewable target) to estimate future renewable generation.	$10-40/ton	33%
4. Use electricity more efficiently	EPA estimated energy efficiency deployment in the 12 leading states achieves annual incremental electricity savings of at least 1.5% each year. BSER assumes that all states increase their current annual savings rate by 0.2% starting in 2017 until reaching a maximum rate of 1.5%, which continues through 2030.	$16-24/ton	18%

Sources: Environmental Protection Agency and Moody's Investors Service

Moody's Related Research

Industry Outlooks:
2014 Outlook; US Public Power Electric Utilities: Certain Cost Recovery and Utilities' Ability to Adapt Drive Our Stable Outlook, December 2013 (160755)

US Public Power Electric Utilities: Limited Threats from Local Governance Underscore Credit Stability, June 2013 (153641)

US Regulated Utilities: Regulation Will Keep Cash Flow Stable as Major Tax Break Ends, February 2014 (164268)

US Merchant Power Outlook Changed to Stable, August 2014 (173800)

Special Comments:
Slow Economic Recovery Tests Willingness to Manage Rates and Costs, October 2012 (146421)

Regulatory framework holds key to risks and rewards associated with distributed generation, April 2014 (165944)

North American Natural Gas Pipelines: Retooling as Gas Flows Shift, New Demand Emerges from LNG and Power, May 2014 (169928)

Heat Rate Call Options: There Is No Heat When It Is Really Cold, April 2014 (166750)

Rooftop Solar, Distributed Generation Not Expected to Pose Threat to Utilities, November 2013 (160080)

The Prospect of US LNG Exports Influences Pricing and Gas Markets Worldwide, May 2013 (151819)

Methodology Update: Ratings Impact of Debt Service Reserve Funds That Rely on Financial Guarantor Surety Bonds, September 2009 (119665)

Rating Methodologies:
US Public Power Electric Utilities with Generator Ownership Exposure, December 2011 (135299)

US Municipal Joint Action Agencies, October 2012 (145899)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

ANALYST CONTACTS

NEW YORK

Dan Aschenbach 212.553.0880
Senior Vice President
dan.aschenbach

ASSOCIATE ANALYST
Thomas Brigandi

2015 Outlook: U.S. Public Power and Electric Cooperative Sector

Steady as She Goes

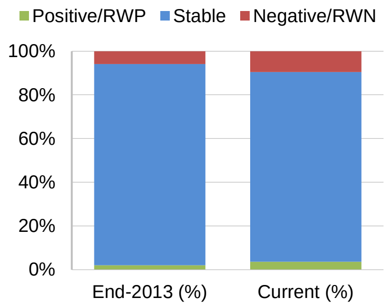
Outlook Report

Rating Outlook

STABLE

(2014: STABLE)

Rating Outlooks



RWP – Rating Watch Positive.
RWN – Rating Watch Negative.
Source: Fitch Ratings.

Sector Outlook

STABLE

(2014: STABLE)

- Environmental compliance manageable
- Rate pressures easing
- Improved local governments

Analysts

Dennis M. Pidherny
+1 212 908-0738
dennis.pidherny@fitchratings.com

Christopher Hessenthaler
+1 212 908-0773
christopher.hessenthaler@fitchratings.com

Kathy Masterson
+1 512 215-3730
kathryn.masterson@fitchratings.com

Alan Spen
+1 212 908-0594
alan.spen@fitchratings.com

Ryan Greene
+1 212 908-0593
Ryan.greene@fitchratings.com

Hugh Welton
+1 212 908-0742
hugh.welton@fitchratings.com

Stacey Mawson
+1 212 908-0678
stacey.mawson@fitchratings.com

Matt Reilly
+1 415 732-7572
matt.reillly@fitchratings.com

Lina Santoro
+1 212 908-0522
lina.santoro@fitchratings.com

Rating and Sector Outlooks Stable: Fitch Ratings' outlook for the public power and electric cooperative sector is stable through 2015. Strong sector characteristics, including autonomous rate-setting authority, the essentiality of electric service and reliable cash flow, should allow the sector to retain a solid fiscal foundation. The outlook for ratings is also stable.

Environmental Compliance Appears Manageable: Risks related to impending environmental regulations appear increasingly manageable for public power and cooperative utilities as compliance deadlines approach. New regulations proposed by the U.S. Environmental Protection Agency (EPA) to reduce the emission of greenhouse gases by power plants are expected to have a minimal near-term impact, but could limit resource options and increase operating costs over the long term.

Rate Pressures Ease: Public power and cooperative issuers have historically demonstrated both the ability and the willingness to increase electric rates to preserve financial margins. Although modest economic growth, declining real income and lower consumption have challenged margin growth in recent years, improved operating conditions appear to have reversed the downward trends in both affordability metrics and debt service coverage.

Low, Stable Costs Positive: Low natural gas prices and interest rates should support financial performance and moderate revenue requirements in 2015. Fitch's base case forecasts expect natural gas prices to remain stable in the intermediate term (approximately $4.00–$4.50 per thousand cubic feet [mcf]). Interest rates are expected to rise, but remain low by historical standards (2015 Fed funds target rate, 0.8%; 10-year U.S. Treasury bonds, 2%). Fuel and interest costs are among the largest expense items incurred by public power utilities.

Improved Environment for Local Governments: Fitch expects most local governments will benefit from a moderate revenue recovery and manageable spending pressures in 2015. Pressure on public power utilities to support local governments and other municipal enterprises through general fund transfers and other means is therefore likely to diminish.

Lower Consumption and Sales Growth: Efficiency gains, demand-side management (DSM) programs and distributed generation (DG) continue to reduce retail electricity consumption and sales growth, particularly for residential users — a mainstay of the sector. This trend will pressure unit costs and alter resource planning, but the sector's rate flexibility and conservative cost-of-service business model should limit any financial strain.

Outlook Sensitivities

Unwillingness to Support Metrics: A widely observed unwillingness of public power and cooperative issuers to raise rates to support current and projected financial metrics in response to economic weakness, increased cost pressures or declining consumption could change the rating outlook to negative.

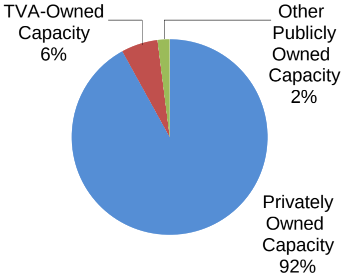
Key Issues for 2015

Strong Sector Fundamentals

Fitch believes strong sector characteristics and a conservative business model provide public power and electric cooperative issuers with stability and strength, even during periods of uncertainty, and will continue to do so in 2015. The fundamental strengths of the sector include: autonomous rate-making authority; the essentiality of electric service; mandates to serve well-defined areas with monopolistic characteristics; a relative cost-of-capital advantage over investor-owned utilities; and reliable cash flow. Sector stability is further evidenced by the current distribution of rating outlooks among Fitch-rated issuers. As of Dec. 3, 2014, 87% of the public power and cooperative ratings assigned by Fitch maintained a stable outlook.

Environmental Compliance Appears Manageable

Coal-Fired Capacity Retirement by Ownership



TVA – Tennessee Valley Authority.
Source: SNL.

The EPA's aggressive pursuit of regulations designed to reduce harmful emissions has had a pronounced effect on electric generators in recent years, particularly those with a high concentration of coal-fired capacity. The most significant rules have included the Mercury and Air Toxic Standards (MATS); Section 316(b) of the Clean Water Act, addressing the use of once-through cooling; and coal combustion residual disposal regulations. With compliance deadlines looming in 2015, these rules and their related compliance costs appear increasingly manageable for most public power and cooperative issuers as greater clarity with respect to both the rules and compliance strategies continues to emerge. Aided by the steadily improved economics of natural gas-fired generation and certain renewable resources, the transition cost for public power and cooperative utilities to lower emitting resources has generally proven to be less than initially anticipated.

The sector's exposure to generation at risk for retirement has also proven favorable. Of the 45.8 gigawatts (GW) of coal-fired capacity closed since 2010 or earmarked for closure by 2017, only 3.5 GW, or 7.9%, of the capacity is owned by public power entities, including 2.5 MW owned the Tennessee Valley Authority. Although public power's share of closures is higher than reported last year (2.1 GW; 6.9%), it remains disproportionately low vis-à-vis its share of the nation's nameplate generating capacity (22%).

Earlier this year, the EPA released the Clean Power Plan (CPP), its proposal to reduce carbon emissions from existing plants by establishing mandatory carbon dioxide reduction targets for each state that are collectively designed to reduce nationwide emissions from the power sector 30% by 2030. Despite the breadth and ambition of the CPP, Fitch believes the proposed rules are unlikely to have any near-term effect on public power and cooperative utilities, given the reduced reliance on coal-fired generation as a result of MATS, as well as the lead time for states and issuers to comply. However, over the longer term, compliance in states that continue to rely heavily on coal-fired generation and may be slow to adopt renewable portfolio standards and energy efficiency mandates could be more challenging and potentially costly.

Favorably, the proposed terms of the CPP alleviate earlier concerns about plant-specific emission standards for existing plants — similar to those proposed for new plants — which would have required extremely costly compliance strategies and resulted in additional premature retirements.

Related Research

Other Outlooks
www.fitchratings.com/outlooks

Other Research

Fitch Fundamentals Index – U.S. (3Q14) (October 2014)

U.S. Public Power Peer Study — June 2014 (June 2014)

Related Criteria

Criteria for Rating Prepaid Energy Transactions (July 2014)

Revenue-Supported Rating Criteria (June 2014)

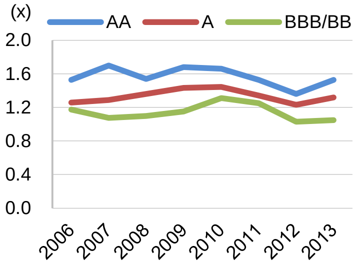
U.S. Public Power Rating Criteria (March 2014)

Rate Pressures Ease

Most public power and cooperative issuers have the authority to raise electric rates at their sole discretion, and have diligently exercised this authority to recover costs in a timely manner. This fundamental credit strength has helped ensure the timely recovery of costs and has ultimately contributed to the operating stability of the sector.

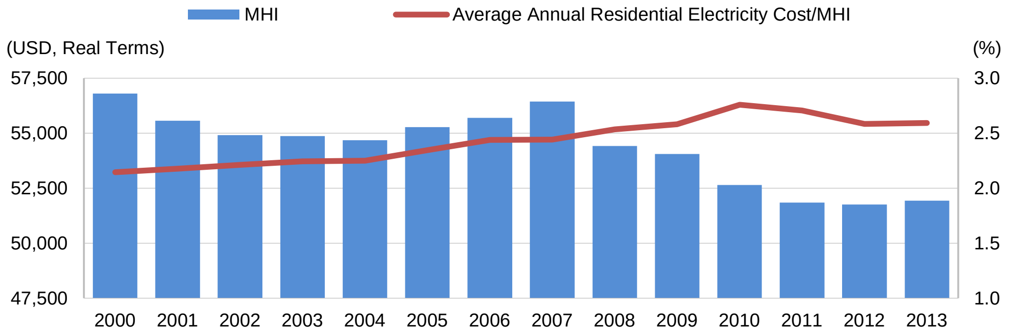
Rate pressures observed since the economic recession in 2008 appear to have eased somewhat as the retail cost of electricity, median household income and affordability metrics have all stabilized in recent years. Real household income rose for the first time in six years in 2013, while average residential electricity costs remained largely unchanged and roughly 7% below the peak observed in 2010. Average household usage was also largely unchanged in 2013. Although some issuers remain sensitive to imposing higher cost burdens on consumers recovering from financial strain, an improvement in debt service coverage medians in 2013 suggests stable, if not stronger operating margins.

Debt Service Coverage
Indicates the margin available to meet current debt service requirements.



Source: Fitch Ratings.

Residential Electric Cost to Median Household Income (MHI)



Source: U.S. Energy Information Administration, U.S. Census Bureau.

Fitch expects similar conditions for 2014 and 2015, reinforcing the sector's stable outlook.

Low Fuel Cost and Interest Rates Broadly Positive

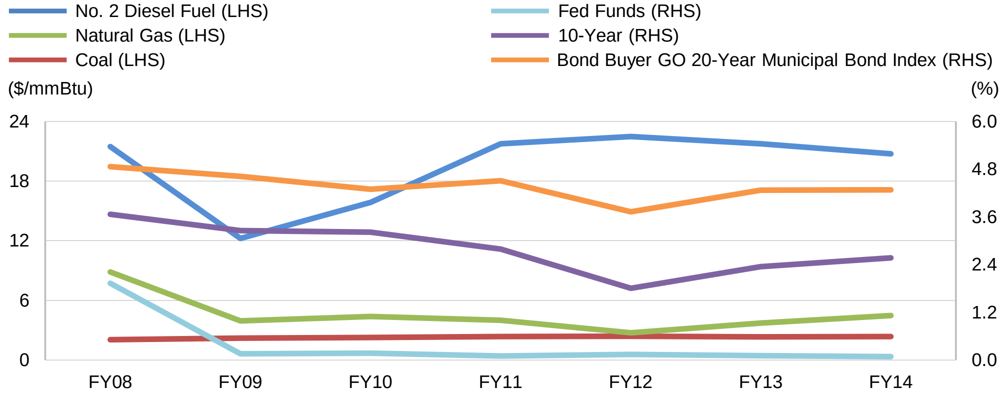
Low energy prices should remain broadly positive for most issuers through 2015. Favorable fuel and purchased power costs should continue to support stronger operating margins, provide headroom for rate increases necessary to mitigate other escalating costs, and in some cases, lower total charges to ratepayers. Prudent hedging strategies typically adopted by most public power issuers should further protect margins against any sudden upward price movement and stabilize costs through at least 2017.

Fitch's U.S. natural gas price deck 2015 base case and long-term natural gas prices remain unchanged at \$4.00/mcf and \$4.50/mcf, respectively, reflecting ongoing oversupply from shale gas production. Recent supply-driven declines in oil prices to levels approaching Fitch's long-term base case (\$75/barrel) should also support stronger operating performance. Although oil-fired generation accounts for less than 1% of total U.S. energy production, it remains the primary source for many of the sector's most troubled issuers.

Prevailing low interest rates and robust access to the capital markets are also positive for the capital-intensive public power sector, as the replacement and refunding of debt at lower rates has allowed issuers to reduce interest expense and lower revenue requirements. Nearly half of the municipal electric power debt issued for 2009–2013 was earmarked for the full or partial refunding of existing debt. Interest rates, including the benchmark 10-year Treasury and

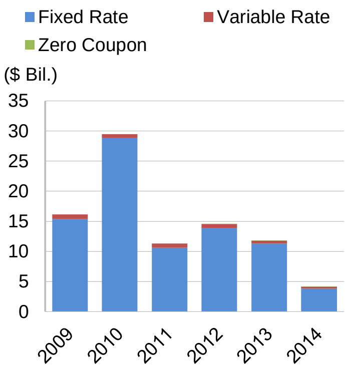
Bloomberg municipal index, remain above their record levels, but low by historical standards. Short-term interest rates remain near zero, consistent with Fed monetary policy.

U.S. Average Cost of Fuel and Interest Rates



MmBtu – Million British thermal units.
Source: U.S. Energy Information Administration, Fed.

Municipal Bond Issuance: Electric Power Sector



Source: The Bond Buyer.

Fitch expects the Fed to start raising interest rates in mid-2015. Yields on the 10-year Treasury are also expected to trend upward, but rates should remain low by historical terms. While Fitch's base case forecast for the normalization of U.S. monetary policy is relatively benign, the potential for a more stressful rate environment is also considered. In either case, the eventual rise in interest rates is not expected to have a material near-term effect on public power issuers, as most debt obligations are fixed rate and amortizing. Higher short-term rates would pose a more immediate risk. However, given the relatively low percentage of short-term debt and unhedged variable-rate debt outstanding, neither of the scenarios outlined above present a significant risk to the sector outlook.

U.S. Interest Rates: Base Case and Shock Scenario

(%)	Base Case			Shock Scenario		
Annual Averages	**2014**	**2015**	**2016**	**2014**	**2015**	**2016**
Real GDP Growth	2.0	3.1	3.0	2.0	3.0	0.0
CPI Inflation	1.8	2.0	2.0	2.5	3.5	4.5
Fed Funds Interest Rate	0.3	0.8	2.0	0.3	1.5	4.0
10-Year Treasury Yield	2.8	3.5	4.0	3.0	4.3	5.5

Source: Fitch Ratings.

Improved Environment for Local Governments

Fitch expects most local governments will benefit from a moderate revenue recovery and manageable spending pressures in 2015 following a period a heightened budgetary stress. Pressure on public power utilities to support local governments and other municipal enterprises is therefore likely to ease through the outlook period.

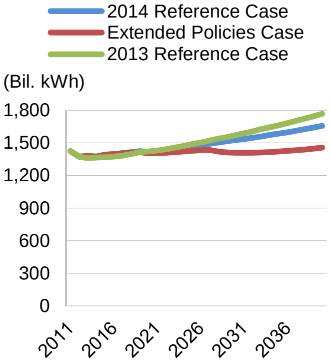
Public power utilities have managed the political pressure to meet general fund transfer requirements reasonably well in recent years, due in part to payment methodologies that are clearly defined and may include hard caps. Despite a gradual upward trend since 2006, median ratios for transfer payments as a percentage of operating revenues have remained between 4% and 6%. Transfer ratios in excess of 10% remain rare.

Less obvious forms of support, including interfund borrowing arrangements, overdue receivables, guarantee agreements or the commingling of cash, which could result in the credit quality of a utility being tied to or influenced by the credit quality of the corresponding local government, are expected to persist, but will be less of a concern as the outlook for local governments improves. Identifying these ties and evaluating their financial impact will remain a priority in cases where financial strain on a host local government is observed.

In cases of more severe stress or bankruptcy, Fitch believes most utility revenue bonds should be less vulnerable to nonpayment than certain other municipal debt given the special revenue treatment of pledged resources under the bankruptcy code, and the general strength of cash flows for most utilities to meet ongoing obligations. The recently approved plans for adjustment for Stockton, CA, and Detroit, MI, appear to support Fitch's view and the strength of municipal utility creditors in bankruptcy generally, as water and sewer utility creditors received 100% of their claims in both instances.

Lower Consumption and Sales Growth Anticipated

Residential Electricity Sales Forecast



Source: U.S. Energy Information Administration.

Efficiency gains and the expansion of DSM programs and DG are expected to lower future sales growth across the U.S. electric utility industry, particularly for residential users, which represent the largest customer segment for public power and cooperative issuers. EIA's 2014 Energy Outlook projects retail electricity demand to grow by 0.8% per year through 2040, down from its 2013 expectation of 0.9%, and well below the average of more than 2% over the previous 30 years. Expectations for residential electricity demand growth are even weaker at 0.7% (down from 0.9%) as average per-household consumption continues to decline as a result of federal efficiency standards. Assuming additional rounds of appliance standards and building codes (Extended Policies Case), the EIA predicts residential usage could grow as little as 0.2% through its 2040 forecast period.

Although this trend is expected to pressure unit costs and alter budgeting and resource planning, continued discipline in rate setting and improved rate design should limit near-term risk. The continued growth in DG, particularly rooftop solar installations that currently benefit from federal investment incentives and favorable net metering arrangements in some states, could present a more immediate challenge to electric sales. However risks should be limited barring a significant improvement in system economics or the development of an affordable stationary battery, neither of which is expected during the outlook period.

2014 Review

The public power and electric cooperative sector's performance exhibited high stability in 2014. Events unfolded generally as expected, as issuers continued to benefit from modest economic recovery, financial markets characterized by low interest rates and abundant liquidity, and relatively low fuel and energy prices.

Rating actions taken by Fitch throughout 2014 have been consistent with the stable outlook, as the vast majority represented rating affirmations (83%). Rating actions year to date also included four upgrades (2% of all rating actions) and six downgrades (2%), which were largely attributable to unique or isolated circumstances. Other actions included the placement or maintenance of issuers on Rating Watch (2%) and assigning new ratings (10%).

Notable rating actions during 2014 include those related to the Puerto Rico Electric Power Authority (PREPA), which was downgraded to 'CC' on June 26, 2014, and remains on Rating Watch Negative, reflecting Fitch's view that a financial restructuring or default by the PREPA is probable. Although the rating actions on PREPA do not portend a higher incidence of financial distress throughout the public power sector, PREPA's challenges illustrate the practical limitations of autonomous rate setting authority and the importance of robust liquidity.

The Carbon Effect

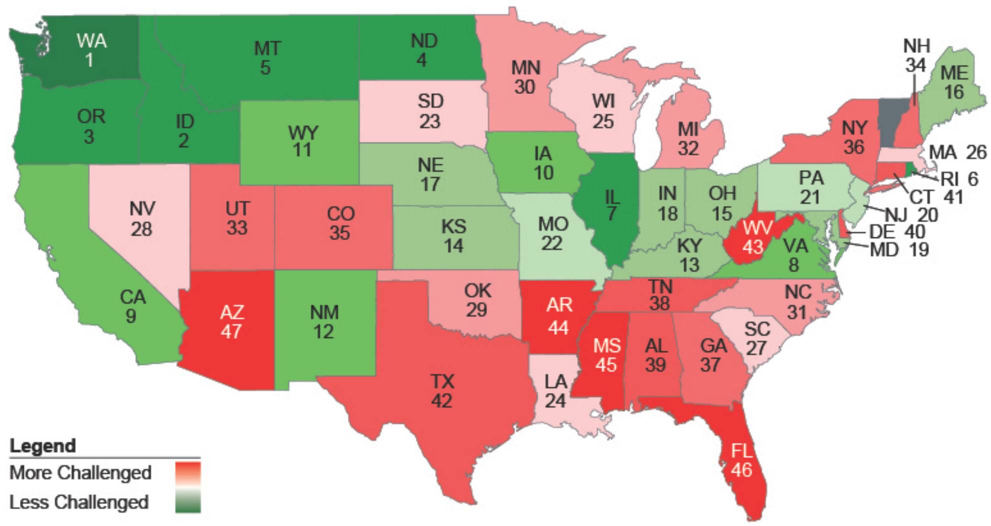
Assessing the Challenges for Public Power

Special Report

To view more videos from Fitch go to the Fitch Ratings home page and click on Multimedia.

Carbon Compliance Challenges: Fitch Ratings believes that preserving financial margins and credit quality, while complying with the EPA's proposed Clean Power Plan (CPP), will be most challenging for public power and cooperative utilities operating in states subject to sizable mandated carbon-reduction goals, high carbon-reduction costs and a relatively high cost of electricity. These states include Arkansas, Arizona, Florida, Mississippi and West Virginia based on the Fitch-calculated carbon cost recovery index (CCRI).

Carbon Cost Recovery Index
(Ranking the States)



Note: The labels reflect the rank of the index and state. Vermont has no sources of generation that are affected by the Clean Power Plan, therefore no goals have been established. Alaska and Hawaii have been excluded from Fitch's analysis.
Source: Fitch.

Effect on Credit Quality: Although the precise impact of emissions reduction on issuers is unclear and expected to vary, Fitch believes the effect on individual credit quality will hinge on each utility's ability and willingness to recover compliance costs from end users. The autonomous rate-setting authority enjoyed by the vast majority of public power and cooperative utilities should alleviate some concerns. However, the willingness of issuers to maintain robust financial metrics in the wake of higher operating costs is uncertain.

Mandated Carbon-Reduction Goals: The EPA released its CPP on June 2, 2014, which includes meaningful mandatory carbon dioxide (CO_2) reduction targets for each state. Although developed pursuant to uniform measures, state-specific emission-reduction goals vary widely. Each state will be required to develop and implement a compliance plan that achieves interim reduction goals beginning in 2020 and final compliance no later than 2030.

Initiatives Will Increase Costs: Political pressures and legal challenges could slow or prevent implementation of the CPP. However Fitch believes pressures to reduce carbon emission will persist. Be it as a result of legislation, regulation or a voluntary framework, emissions-reduction initiatives are expected to drive operating costs higher if reductions are achieved through the displacement of fossil-fired generation with higher cost carbon-free resources. Industry estimates of annual compliance costs are extremely broad, ranging from $5.5 billion to $73 billion.

Related Research

Fitch Fundamentals Index US (4Q14) (January 2015)

2015 Outlook: U.S. Public Power and Electric Cooperative Sector (Steady as She Goes) (December 2014)

U.S. Public Power Peer Study — June 2014 (June 2014)

U.S. Public Power Peer Study Addendum — June 2014 (June 2014)

Analysts

Dennis Pidherny
+1 212 908-0738
dennis.pidherny@fitchratings.com

Ryan Greene
+1 212 908-0593
ryan.greene@fitchratings.com

Olu Sonola
+1 212 908-0583
olu.sonola@fitchratings.com

Roshan Bains
+1 212 908-0211
roshan.bains@fitchratings.com

Introducing a Framework for Analysis

Prospective EPA rules to reduce carbon emissions are likely to have broad implications for public power and cooperative utilities. The purpose of this report is to introduce a framework for analyzing these implications on a state-by-state basis using the proposed terms of the CPP and other available data. This report does not intend to reach any conclusions about the effect of reduction initiatives on individual utilities, or to predict any rating actions.

High-Cost, High-Rate States Face Greatest Challenges

Fitch believes public power and cooperative utilities that operate in states subject to sizable mandated carbon-reduction goals, high carbon-reduction costs and high electric costs will be most challenged to maintain margins. For these utilities, meeting the goals and recovering related costs would require sizable rate increases on end users already burden by comparatively high electric costs or retail rates. Robust financial margins are a key determinant of credit quality for public power issuers.

For a more detailed description of Fitch's CCRI methodology see Page 8.

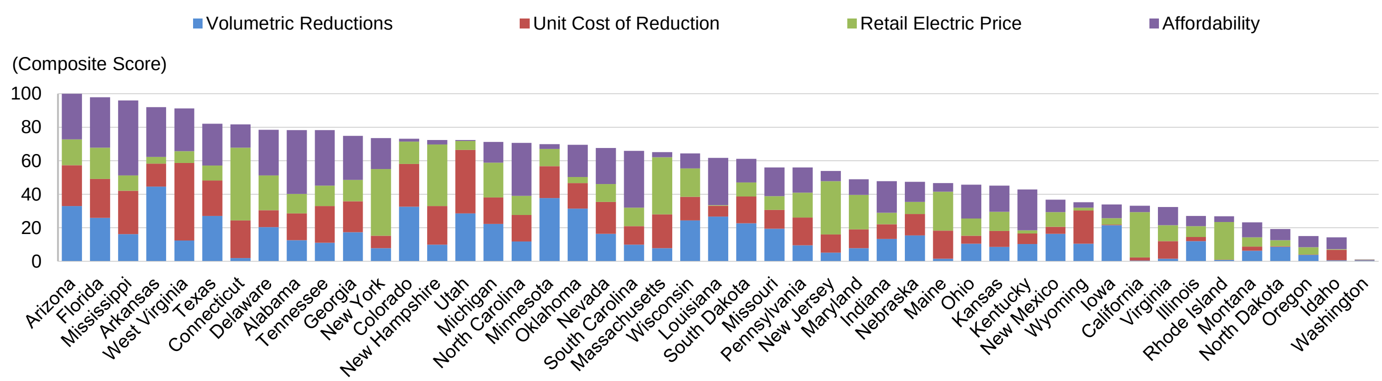
Fitch has calculated its CCRI, which considers the relative magnitude of mandated reduction goals, estimated cost of carbon-reduction alternatives, average retail rates and the cost of electricity as a percentage of median household income (MHI) for each state, to assess the combined influence of these variables, and effectively rank the states in terms of the challenge ahead. To determine composite scores, metrics for all four variables have been standardized against their respective means and weighted equally (25%) to provide balanced consideration.

Ranking each state using the CCRI methodology suggests Arkansas, Arizona, Florida, Mississippi and West Virginia will face the greatest challenges. Arkansas and Florida rank below the 30th percentile in all four factors examined. Moreover, Arkansas, Mississippi and West Virginia rank among the most challenged based on either the mandated reduction goals or unit reduction cost. All five states rank below the 28th percentile in affordability of electric costs.

Conversely, the states that appear best suited to comply with the proposed rules and maintain margins are Washington, Idaho and Oregon, largely due to relatively low mandated reduction costs, carbon-reduction measures that are available at little or no incremental cost according to EPA figures, and electric rates and costs that are lower than national averages.

The CCRI scores for each state, including the relative rankings of each component, are included in Appendix A. A graphical representation is provided below.

State Scores for Weighted Components of the CCRI



Note: Each component is normalized and scaled; with a total final score between 1 and 100.
Source: U.S. Census.

Assessing the Challenges

In assessing the challenges each utility faces, Fitch has focused on both the relative cost of complying with the CPP as proposed, and the likelihood of full cost recovery. Specifically, we have considered four variables in the analysis: the relative magnitude of mandated reduction goals, estimated cost of carbon-reduction alternatives, average retail rates, and cost of electricity as a percentage of MHI for each state.

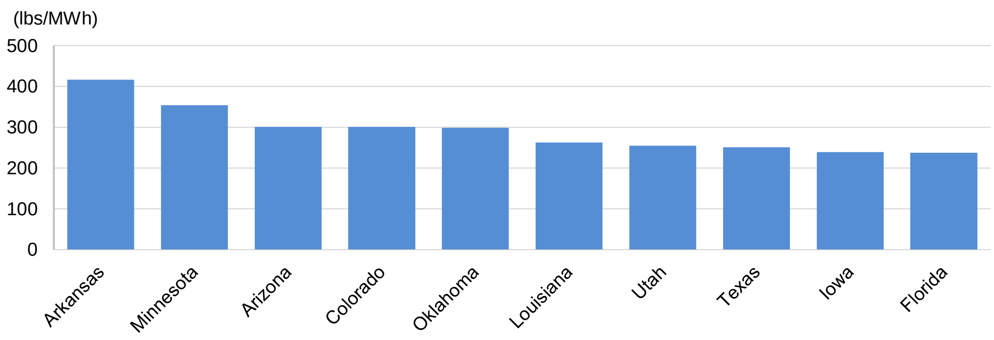
Framing the Cost of Compliance

The cost of compliance is likely to be shared by most, if not all states. However, precisely quantifying these costs is currently impossible and will ultimately depend on a variety of factors, including the final terms of reduction initiatives, the extent of regional cooperation, improvements in reduction technologies, relative fuel costs and the effectiveness of energy efficiency, demand-side management and distributed generation. Despite the uncertainty surrounding cost estimates and difficulties in calculating them, Fitch believes examining the relative magnitude of mandated reduction goals and estimated cost of carbon-reduction alternatives on a state-by-state basis provides some insight into the relative challenge each state faces.

Relative Carbon-Reduction Mandates

For the purpose of this analysis, Fitch has evaluated mandated reduction goals by calculating a carbon reduction ratio (CRR) for each state, defined as the ratio of the anticipated reduction in carbon emissions pursuant to the CPP (measured in pounds) to estimated 2030 net generation of electricity from all sources (measured in MWhs). Unlike the EPA's carbon intensity ratio, which only includes a portion of statewide generation in its calculation, Fitch believes measuring carbon reduction against total generation provides a broader indication of the relative burden. States with the highest CRRs ostensibly face the greatest required reduction measured against total electricity production from all sources. See Appendix B for additional details.

States with the Highest Carbon Reduction Ratios
(Final Goal CO_2 Emissions Reduction/Estimated 2030 Energy Output)



CO_2 – Carbon dioxide.
Source: EPA, EIA, Fitch.

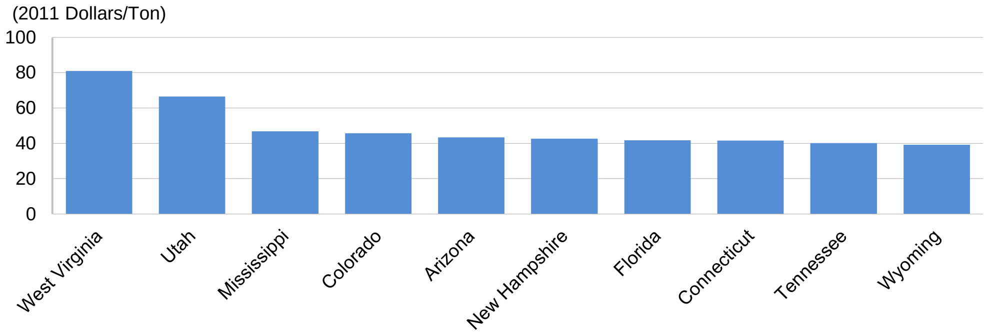
Cost of Carbon-Reduction Alternatives

In evaluating the cost of carbon-reduction alternatives, Fitch has focused on the EPA's state-by-state estimates for the constraint shadow price for CO_2, based on proposed emissions limits. These figures, measured in terms of 2011 dollars/ton and reported as part of its analysis of the proposed CPP (from the EPA's Integrated Planning Model Option 1 — State), provide an estimate of the marginal cost of carbon reduction for different time periods, and illustrate the variability in cost of reduction measures available to each state.

A higher carbon constraint shadow price indicates a higher marginal cost of carbon reduction, likely driven by fewer cost-effective opportunities for the redispatch of lower emitting generating units, demand-side energy efficiency and the development of renewable resources. Fitch uses the average of the three constraint shadow prices published by EPA as a proxy for the average cost of carbon reduction, which is not available.

States with the highest marginal cost of carbon reduction are summarized in the chart below and in detail in Appendix C.

States with the Highest Marginal Cost of Carbon Reduction



Source: EPA., Fitch.

Although the total cost of compliance with the CPP will be a factor of both the relative volumetric reduction — as measured by the CRR — and the unit cost of reduction alternatives, Fitch has chosen to examine these variables separately. The data available for analysis, all of which is preliminary and estimated, has not been compiled for the specific purpose of calculating compliance costs. Therefore, calculating a product of these two variables could distort results. For example, states for which the EPA models have produced shadow prices on the emissions rate constraint that are very low, or even $0, would appear to bear little or no additional costs regardless of the mandated reduction in carbon emissions. While this may ultimately prove true and favorable for utilities in these states, it would appear to underestimate the potential risk for states where mandated reduction is high and marginal cost estimates prove to be too low.

In general, states with the greatest mandated reductions and the highest cost carbon-reduction measures are expected to bear a disproportionately high share of nationwide costs.

Cost Recovery and Maintaining Margins Key to Credit Quality

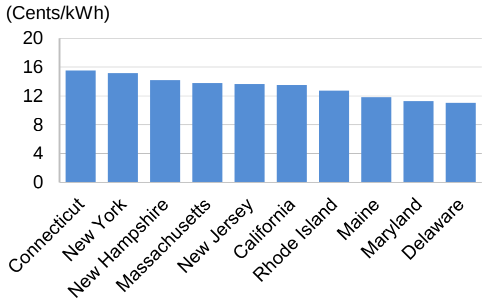
State-specific costs related to carbon-reduction initiatives are likely to be allocated to each utility system pursuant to the terms of the submitted compliance plan. Although the precise impact of each plan and related costs will vary, Fitch believes the effect on individual credit quality will hinge on each utility's ability and willingness to recover compliance costs from end users through higher rates or charges.

The autonomous rate-setting authority enjoyed by the vast majority of the public power and cooperative issuers rated by Fitch largely alleviates the concern that compliance costs will not be recovered. Electric rates for these issuers are determined by their respective governing boards and are not subject to external regulatory review or approval, which can introduce additional financial risk. However, an issuer's willingness to maintain and preserve robust margins in the wake of higher operating costs is uncertain. If the cost burden and related higher retail rates result in weaker financial metrics and reduced financial flexibility, downward rating pressure could materialize.

Electric Rates and Affordability

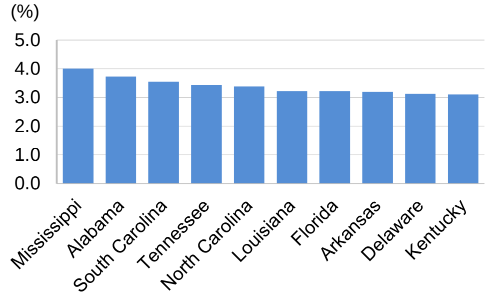
Although the willingness of public power and cooperative utilities to increase rates is difficult to measure or predict, Fitch believes utilities operating in states where the relative cost of electricity is highest generally face the greatest pressure to avoid rate increases. Two variables have been considered in this assessment: average retail rates and the cost of electricity as a percentage of MHI. In states where annual electric costs represent a high percentage of income, affordability is generally a concern for public power and cooperative utilities and may discourage full recovery.

Highest Average Retail Electric Rates



Source: EIA.

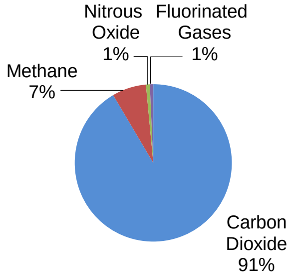
Highest Average Annual Cost of Electric/Median Household Income



Source: EIA, U.S. Census.

Alternatively, in states where retail rates are high in absolute terms, political pressure to limit rate increases may influence ratemaking decisions. In either case, a reluctance to increase rates could contribute to financial strain, even in states where compliance costs are relatively low. See Appendix D for additional details.

Direct Greenhouse Gas Emissions
(2013, by Gas)



Source: EPA.

Environmental Focus Shifts to Carbon

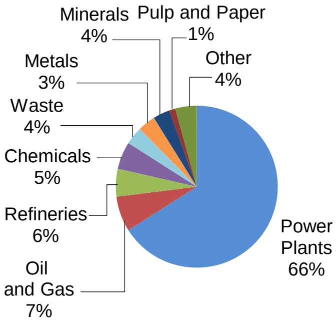
Rules Governing New Power Plants

The focus of environmental regulation began shifting toward greenhouse gas emissions, and more specifically CO2, in 2013, with the launch of the president's Climate Action Plan. The EPA announced its first steps to reduce carbon emissions from power plants on Sept. 20, 2013, by proposing carbon pollution standards — its New Source Performance Standards (NSPS) rules — for new power plants. The proposed NSPS rules would essentially require new coal-fired units to use expensive and largely untested carbon capture and storage technologies (CCS) to reduce emissions, significantly handicapping their cost competitiveness.

Fitch believes the proposed NSPS rules will have a limited effect on public power and cooperative utilities in the near term, as the historically low cost of natural gas-fired generation has reduced the demand for coal-fired generation. However, it could preclude utilities from pursuing new coal-fired units over the longer term, thereby limiting resource options and diminishing fuel diversity. Fitch views resource portfolios that are cost competitive and exhibit fuel diversity as the most supportive of long-term credit quality.

Rules Governing Existing Plants — The Clean Power Plan

Direct Greenhouse Gas Emissions
(By Sector, 2013)



Source: EPA.

On June 2, 2014, the EPA released the CPP, its proposal to reduce carbon emissions from existing power plants, which is expected to have much broader implications for electric generators than the NSPS rules. Issued pursuant to the EPA's authority under section 111(d) of the Clean Air Act, the CPP outlines state-specific emission rate-based CO2 goals, and guidelines for the development, submission and implementation of state plans to meet the mandated goals. The burning of fossil fuels to produce electricity generates the largest share of greenhouse gas emissions in the U.S.

Although developed using the same reduction measures or building blocks — increased efficiency at carbon-intensive power plants, increased generation from lower emitting resources, increased generation from non-emitting resources and improved energy efficiency — the state-specific reduction goals vary widely both in absolute and percentage terms. Targeted reductions in annual carbon emissions range from 54 million tons (Texas) to less than 1,000 tons (Rhode Island). Percentage reductions in carbon intensity range from 72% (Washington) to 11% (North Dakota).

The proposed rules provide states with broad flexibility to achieve their emission-reduction goal using any measures available, and are designed to allow states to build upon their progress made to date in reducing emissions. States may further participate in the development of a multistate compliance plan — in lieu of an individual plan — that reflects the regional structure of participating electric operating systems. In either case, states must begin achieving interim goals in 2020, and reach full compliance no later than 2030.

Compliance plans will be evaluated and approved based on four criteria: enforceable measures that reduce CO2 emissions; projected achievement of the goals set by the EPA; quantifiable and verifiable emission reductions; and the process for reporting plan implementation and progress toward goals. As currently proposed, each state is required to submit an initial plan that contains the relevant components by June 30, 2016, with further flexibility to provide complete plans by June 30, 2017 or 2018, as appropriate. The EPA expects to finalize the terms of the CPP by June 1, 2015.

Compliance Is an Ongoing Challenge

The proposed CPP rules appear to alleviate earlier concerns about plant-specific emission standards, similar to those adopted in the Mercury and Air Toxic Standards regulations and the NSPS rules. Although the EPA determined CCS represented a reasonable reduction measure for new plants, the technologies were not included among the best system measures for existing plants. This distinction allays Fitch's early concern that applying the NSPS standards retroactively to existing units could impair issuer credit quality by requiring extremely costly or infeasible compliance strategies, and potentially the premature retirement of productive generating units.

Some concern remains over the EPA's separate but related rules for limiting emissions from modified and reconstructed power plants, wherein certain upgrades and improvements to existing facilities could trigger a requirement to meet the more stringent NSPS limits. However, cases are expected to be limited, and additional flexibility in terms of compliance may be provided.

Despite the breadth and ambition of the CPP, Fitch believes the proposed rules are unlikely to have any near-term effects on public power and cooperative utilities. Many older, smaller coal-fired units that may have been affected by the rules have already been retired or are earmarked for closure as a result of low natural gas prices, competition from renewable energy and other stringent emission rules. However, over the longer term, compliance in states that rely heavily on coal-fired generation and have been slow to adopt renewable portfolio standards and energy-efficiency mandates could be more challenging and potentially costly.

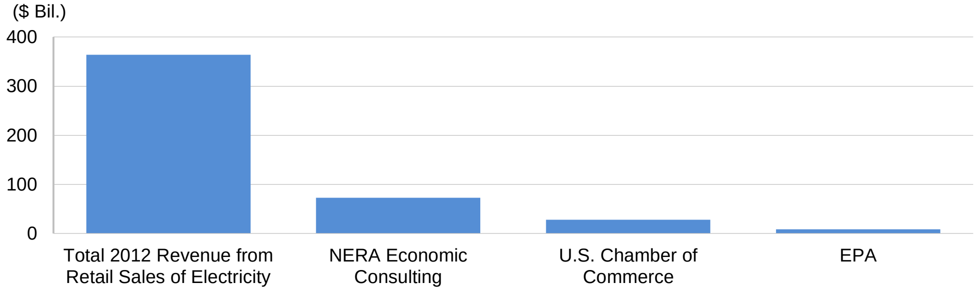
Carbon Reduction Certain, But the Costs Are Not

Legal challenges to the CPP that could defer adoption and implementation have already arisen, and more are anticipated. However, regardless of the final terms of the CPP or whether the plan is enacted, Fitch believes pressures to reduce carbon emissions will persist over the long term. Be it through the passage of legislation, regulatory rulemaking or a voluntary framework, carbon-reduction initiatives will remain part of the national and global energy landscape, and will be a challenge that public and cooperative utilities will have to address in years to come.

Enactment and implementation of the CPP as proposed would impose meaningful compliance costs on each of the states, and likely increase electric production costs, but estimates are widely diverse. Preliminary estimates by the EPA, including costs related to demand-side energy-efficiency programs, as well as monitoring, reporting and recordkeeping, range from $5.5 billion to $7.3 billion per annum in 2020, and $7.5 billion to $8.8 billion in 2030, depending on whether a regional or state-specific compliance approach is taken.

Electric costs are also expected to be driven higher if emission reductions are achieved through the displacement of fossil-fired generation with higher cost carbon-free resources. In its publication, *Assessing the Impact of Potential New Carbon Dioxide Regulations in the United States*, the U.S. Chamber of Commerce predicts annual compliance costs will average $28 billion, and total cumulative compliance costs through 2030 could reach nearly $480 billion, driven largely by the cost of new incremental power plant construction ($339 billion) and demand-side energy efficiency ($106 billion). Other estimates are even more onerous, including those reported by NERA Economic Consulting, which pegs average annual compliance costs of the CPP between $43 billion and $73 billion.

Industry Estimates of Annual Compliance Cost



Source: EPA, NERA Economic Consulting, U.S. Chamber of Commerce, EIA.

The variability in estimates varies widely in both dollar cost and in the context of potential cost increases. While EPA estimates represent only a nominal percentage (1.5%) on total revenue from retail sales of electricity in the U.S. ($364 billion in 2012), the more expensive NERA estimates represent over 20%.

Modifying the Analytical Framework

As noted earlier, the purpose of this report is to introduce a framework for analyzing the effect of proposed rules to reduce carbon emissions on public power and cooperative utilities, including the CCRI. Fitch recognizes the variables included in this analysis and the terms of any proposed rules are subject to change. The release of updated demographic, census and operating data will therefore provide opportunities to revise the analysis, recalculate the CCRI and publish the results periodically as appropriate.

Methodology for Calculating the CCRI

The CCRI score for each state is a composite measure of four components: The Carbon Reduction Ratio, Average Marginal CO2 Costs, Average Retail Price of Electricity and the Affordability Ratio as defined in Appendices B–D. The first step in the construction of the composite measure is a calculation of the mean and the standard deviation of each component, and the assignment of Z-scores to each metric.

The four corresponding Z-scores for each state are then equally weighted and summed to arrive at a composite Z-score, which reflects the relative influence of each component. Finally, the component Z-scores are re-scaled to produce final CCRI scores, where the minimum score is 1 and maximum score is 100.

Appendix A — Carbon Cost Reduction Index Calculations

State	Carbon/Volumetric Reductions (lbs/MWh)[a]	Rank	Marginal/ Unit Cost Of Carbon Reduction (2011, $/Ton)[b]	Rank	Average Retail Price of Electricity (Cents/kWh)[c]	Rank	Affordability Ratio[c] (%)	Rank	Carbon Cost Recovery Index	Rank
Arizona	301.1	45	43.3	43	9.8	33	3.1	36	100	47
Florida	237.4	38	41.8	41	10.4	36	3.2	41	98	46
Mississippi	144.5	28	46.8	45	8.6	20	4.0	47	96	45
Arkansas	416.5	47	24.4	23	7.6	7	3.2	40	92	44
West Virginia	104.8	21	81.0	47	8.1	11	2.9	34	91	43
Texas	251.2	40	38.2	37	8.6	19	3.0	35	82	42
Connecticut	10.3	6	41.5	40	15.5	47	2.4	24	82	41
Delaware	194.1	34	18.5	16	11.1	38	3.1	39	78	40
Alabama	114.5	25	29.7	29	9.2	28	3.7	46	78	39
Tennessee	98.9	18	40.1	39	9.3	29	3.4	44	78	38
Georgia	160.0	31	34.3	34	9.4	31	3.1	37	75	37
New York	71.0	11	13.9	13	15.2	46	2.7	30	74	36
Colorado	300.7	44	45.7	44	9.4	32	1.7	2	73	35
New Hampshire	88.0	15	42.6	42	14.2	45	1.7	4	72	34
Utah	254.7	41	66.6	46	7.8	10	1.6	1	72	33
Michigan	210.6	35	29.3	27	11.0	37	2.3	21	71	32
North Carolina	108.2	23	29.5	28	9.2	27	3.4	43	71	31
Minnesota	354.4	46	34.3	33	8.9	22	1.7	5	70	30
Oklahoma	298.9	43	27.7	26	7.5	6	2.7	29	69	29
Nevada	153.2	30	35.3	35	9.0	23	2.8	32	68	28
South Carolina	91.2	17	21.0	19	9.1	25	3.6	45	66	27
Massachusetts	69.8	10	37.7	36	13.8	44	1.8	6	65	26
Wisconsin	233.5	37	26.2	25	10.3	35	2.1	14	64	25
Louisiana	262.5	42	11.9	11	6.9	1	3.2	42	62	24
South Dakota	216.0	36	30.0	30	8.5	17	2.4	25	61	23
Missouri	188.8	33	21.4	20	8.5	18	2.6	28	56	22
Pennsylvania	88.0	16	31.5	31	9.9	34	2.5	26	56	21
New Jersey	45.6	7	20.9	18	13.7	43	2.0	11	54	20
Maryland	74.3	13	21.9	21	11.3	39	2.2	17	49	19
Indiana	133.4	26	17.1	15	8.3	14	2.7	31	48	18
Nebraska	151.8	29	24.6	24	8.4	15	2.3	23	47	17
Maine	7.7	4	33.1	32	11.8	40	1.9	10	47	16
Ohio	105.5	22	9.1	10	9.1	26	2.8	33	46	15
Kansas	82.7	14	19.1	17	9.3	30	2.5	27	45	14
Kentucky	104.5	20	12.2	12	7.3	5	3.1	38	43	13
New Mexico	174.1	32	8.5	9	8.8	21	2.1	13	37	12
Wyoming	101.9	19	39.2	38	7.2	4	1.8	7	35	11
Iowa	239.2	39	0.0	2	7.7	8	2.1	15	34	10
California	(3.8)	1	3.3	6	13.5	42	1.9	9	33	9
Virginia	8.9	5	22.1	22	9.1	24	2.3	22	32	8
Illinois	137.7	27	5.1	7	8.4	16	2.0	12	27	7
Rhode Island	0.2	2	0.0	1	12.7	41	1.8	8	27	6
Montana	71.8	12	5.5	8	8.3	13	2.3	20	23	5
North Dakota	110.1	24	0.0	3	7.8	9	2.1	16	19	4
Oregon	49.0	9	0.0	4	8.2	12	2.2	18	15	3
Idaho	0.2	3	16.9	14	6.9	2	2.2	19	14	2
Washington	48.7	8	2.7	5	6.9	3	1.7	3	1	1

[a]See Appendix B. [b]See Appendix C. [c]See Appendix D. Note: Affordability Ratio equals Average Yearly Residential Bill/Median Household Income.

Source: Fitch.

Appendix B — Carbon Reduction Ratio Calculations

State	2012 CO2 Emissions (Million Metric Tons)	2030 Final Goal CO2 Emissions per CPP (Million Metric Tons)	Final Goal CO2 Emissions Reduction (Million Metric Tons)	Final Goal CO2 Emissions Reduction (lbs)	2012 Energy Output (TWh)	Estimated 2030 Energy Output (TWh)	Carbon Reduction Ratio
Alabama	68.56	60.02	8.54	18,828,938,118	152.88	164.40	114.5
Arizona	36.71	21.29	15.42	33,983,977,736	110.90	112.87	301.1
Arkansas	36.23	23.37	12.86	28,347,133,230	65.01	68.06	416.5
California	43.73	44.11	(0.38)	(844,720,938)	199.52	219.67	(3.8)
Colorado	38.45	30.51	7.94	17,494,349,205	52.56	58.17	300.7
Connecticut	6.04	5.79	0.25	556,143,759	36.12	54.23	10.3
Delaware	4.36	3.52	0.84	1,852,360,014	8.63	9.55	194.1
Florida	107.60	81.29	26.31	57,994,005,422	221.10	244.27	237.4
Georgia	57.02	46.23	10.79	23,778,108,919	122.31	148.60	160.0
Idaho	0.64	0.64	0.00	3,909,230	15.50	16.19	0.2
Illinois	87.19	74.26	12.93	28,498,260,868	197.57	207.01	137.7
Indiana	91.78	84.60	7.18	15,837,171,333	114.70	118.70	133.4
Iowa	34.67	29.13	5.54	12,214,025,578	56.68	51.06	239.2
Kansas	31.16	29.36	1.80	3,975,987,555	44.42	48.05	82.7
Kentucky	82.89	78.41	4.48	9,869,335,642	89.95	94.42	104.5
Louisiana	44.52	31.68	12.84	28,313,875,601	103.41	107.86	262.5
Maine	1.63	1.58	0.05	107,822,164	14.43	13.94	7.7
Maryland	18.30	16.85	1.45	3,186,907,311	37.81	42.90	74.3
Massachusetts	11.91	10.55	1.36	3,000,320,236	36.20	42.96	69.8
Michigan	63.38	52.64	10.74	23,680,311,174	108.17	112.43	210.6
Minnesota	25.42	17.28	8.14	17,939,034,246	52.19	50.62	354.4
Mississippi	23.50	19.23	4.27	9,407,845,301	54.58	65.10	144.5
Missouri	70.93	62.94	7.99	17,609,117,553	91.80	93.27	188.8
Montana	16.26	15.31	0.95	2,100,621,974	27.80	29.26	71.8
Nebraska	24.64	22.11	2.53	5,568,524,232	34.22	36.69	151.8
Nevada	14.05	11.37	2.68	5,917,415,093	35.17	38.61	153.2
New Hampshire	4.21	3.30	0.91	1,996,751,965	19.26	22.70	88.0
New Jersey	11.83	10.30	1.53	3,381,382,026	65.26	74.13	45.6
New Mexico	15.73	12.67	3.06	6,752,117,881	36.64	38.78	174.1
New York	31.58	26.60	4.98	10,988,933,312	135.77	154.84	71.0
North Carolina	53.13	46.43	6.70	14,770,993,251	116.68	136.51	108.2
North Dakota	30.27	28.46	1.81	3,995,975,872	36.13	36.30	110.1
Ohio	92.86	85.94	6.92	15,245,857,121	129.75	144.47	105.5
Oklahoma	47.86	36.34	11.52	25,391,615,548	77.90	84.95	298.9
Oregon	6.96	5.49	1.47	3,248,626,648	60.93	66.29	49.0
Pennsylvania	105.83	95.68	10.15	22,370,211,775	223.42	254.29	88.0
Rhode Island	3.39	3.39	0.00	2,023,060	8.31	8.69	0.2
South Carolina	32.57	27.54	5.03	11,098,276,733	96.76	121.63	91.2
South Dakota	3.02	1.95	1.07	2,363,559,010	12.03	10.94	216.0
Tennessee	37.41	33.37	4.04	8,904,806,372	77.72	90.04	98.9
Texas	223.15	168.26	54.89	121,011,876,445	429.81	481.76	251.2
Utah	27.96	23.26	4.70	10,361,690,694	39.40	40.68	254.7
Virginia	24.83	24.47	0.36	792,932,298	70.74	88.89	8.9
Washington	6.68	3.89	2.79	6,148,026,487	116.84	126.35	48.7
West Virginia	65.61	61.69	3.92	8,634,534,027	73.41	82.39	104.8
Wisconsin	38.39	31.25	7.14	15,734,836,622	63.74	67.38	233.5
Wyoming	45.36	42.79	2.57	5,674,039,208	49.59	55.71	101.9

CPP – Clean Power Plan. TWh – Terawatt hours. Note: Carbon Reduction Ratio equals Final Goal CO2 Emissions Reduction/Estimated 2030 Energy Output (lbs/MWh).
Source: EPA, EIA, Fitch.

Appendix C — Marginal Cost of Carbon Reduction

(2011 $/Ton, Marginal CO2 Costs)

State	2020	2025	2030	Average 2020–2030
Alabama	23.33	28.74	37.10	29.73
Arizona	45.66	41.30	43.08	43.35
Arkansas	26.69	22.18	24.47	24.45
California	4.46	5.50	0.00	3.32
Colorado	44.19	46.37	46.64	45.73
Connecticut	34.98	43.11	46.53	41.54
Delaware	21.87	16.09	17.62	18.53
Florida	52.88	38.03	34.38	41.76
Georgia	34.48	34.91	33.49	34.29
Idaho	17.11	17.30	16.37	16.93
Illinois	3.99	4.91	6.34	5.08
Indiana	17.03	20.99	13.13	17.05
Iowa	0.00	0.00	0.00	0.00
Kansas	14.96	18.44	23.80	19.06
Kentucky	11.85	12.84	11.78	12.16
Louisiana	11.74	10.52	13.58	11.94
Maine	32.38	31.03	35.76	33.06
Maryland	17.17	21.16	27.31	21.88
Massachusetts	29.56	36.43	47.02	37.67
Michigan	23.78	28.02	36.17	29.32
Minnesota	39.55	31.23	31.99	34.26
Mississippi	67.02	48.74	24.71	46.82
Missouri	21.72	18.48	23.85	21.35
Montana	4.33	5.34	6.89	5.52
Nebraska	19.34	23.83	30.76	24.64
Nevada	37.58	33.28	34.96	35.28
New Hampshire	42.53	39.60	45.75	42.63
New Jersey	22.76	19.22	20.82	20.93
New Mexico	21.34	1.80	2.32	8.49
New York	12.35	12.78	16.50	13.88
North Carolina	36.46	25.71	26.34	29.50
North Dakota	0.00	0.00	0.00	0.00
Ohio	7.27	8.75	11.30	9.11
Oklahoma	27.73	28.00	27.41	27.72
Oregon	0.00	0.00	0.00	0.00
Pennsylvania	24.75	30.51	39.38	31.55
Rhode Island	0.00	0.00	0.00	0.00
South Carolina	22.59	21.57	18.93	21.03
South Dakota	28.78	29.24	32.13	30.05
Tennessee	39.01	39.78	41.57	40.12
Texas	36.59	37.54	40.50	38.21
Utah	75.84	61.32	62.50	66.55
Virginia	24.35	20.39	21.46	22.07
Washington	3.45	2.07	2.68	2.73
West Virginia	63.59	78.36	101.15	81.03
Wisconsin	20.54	25.31	32.67	26.17
Wyoming	30.79	37.94	48.97	39.23

CO2 – Carbon dioxide. Note: Marginal Costs are from EPA Integrated Planning Model results from Option 1: No Cooperation, reporting the shadow price on the lbs/MWh emissions rate constraint.
Source: EPA.

Appendix D — Electric Rates and Affordability Ratios

State	Average Monthly Residential Electric Bill ($)	Average Yearly Residential Electric Bill ($)	Median Household Income ($)	Affordability Ratio (%)	Retail Electric Rates (Cents/kWh)
Alabama	135.3	1,623	43,464	3.7	9.18
Arizona	119.8	1,438	47,044	3.1	9.81
Arkansas	104.1	1,250	39,018	3.2	7.62
California	87.9	1,055	57,020	1.9	13.53
Colorado	80.9	971	57,255	1.7	9.39
Connecticut	126.8	1,521	64,247	2.4	15.54
Delaware	127.9	1,535	48,972	3.1	11.06
Florida	123.4	1,481	46,071	3.2	10.44
Georgia	122.7	1,473	48,121	3.1	9.37
Idaho	87.5	1,050	47,922	2.2	6.92
Illinois	87.2	1,046	51,738	2.0	8.40
Indiana	104.9	1,259	46,158	2.7	8.29
Iowa	94.5	1,134	53,442	2.1	7.71
Kansas	106.2	1,274	50,003	2.5	9.33
Kentucky	106.5	1,279	41,086	3.1	7.26
Louisiana	105.0	1,260	39,085	3.2	6.90
Maine	77.8	933	49,158	1.9	11.81
Maryland	129.0	1,548	71,836	2.2	11.28
Massachusetts	93.5	1,122	63,656	1.8	13.79
Michigan	95.5	1,146	50,015	2.3	10.98
Minnesota	90.1	1,081	61,795	1.7	8.86
Mississippi	122.5	1,470	36,641	4.0	8.60
Missouri	107.8	1,294	49,764	2.6	8.53
Montana	84.9	1,019	45,088	2.3	8.25
Nebraska	100.5	1,206	52,196	2.3	8.37
Nevada	110.6	1,327	47,333	2.8	8.95
New Hampshire	98.8	1,186	67,819	1.7	14.19
New Jersey	109.1	1,309	66,692	2.0	13.68
New Mexico	74.6	895	43,424	2.1	8.83
New York	106.1	1,274	47,680	2.7	15.15
North Carolina	117.5	1,409	41,553	3.4	9.15
North Dakota	98.8	1,186	55,766	2.1	7.83
Ohio	105.2	1,263	44,375	2.8	9.12
Oklahoma	107.6	1,291	48,407	2.7	7.54
Oregon	93.8	1,126	51,775	2.2	8.21
Pennsylvania	106.8	1,281	51,904	2.5	9.91
Rhode Island	86.0	1,033	56,065	1.8	12.74
South Carolina	131.6	1,580	44,401	3.6	9.10
South Dakota	98.7	1,184	49,415	2.4	8.49
Tennessee	123.0	1,476	42,995	3.4	9.27
Texas	128.3	1,539	51,926	3.0	8.55
Utah	78.7	944	58,341	1.6	7.84
Virginia	123.7	1,485	64,632	2.3	9.07
Washington	88.5	1,062	62,187	1.7	6.94
West Virginia	106.1	1,274	43,553	2.9	8.14
Wisconsin	92.8	1,114	53,079	2.1	10.28
Wyoming	85.3	1,024	57,512	1.8	7.19

Note: Affordability Ratio equals Average Yearly Residential Bill/Median Household Income.
Source: EIA 2012 data, U.S. Census 2012 data.