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Top 10 Investor Questions For U.S. Merchant Power Companies

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Standard & Poor's Ratings Services categorizes the U.S. power sector into three segments. "Regulated utilities" are companies that are wholly rate-regulated or have limited unregulated operations (e.g., American Electric Power Co. Inc., Southern Co.). "Diversified utilities" are companies that are mostly unregulated, but own regulated utility operations (e.g., Public Service Enterprise Group Inc., Exelon Corp.). Finally, independent power producers (IPP) are pure merchant generation companies with no utility operations (e.g., NRG Energy Inc., Calpine Corp.). For the purpose of this commentary, we consider "merchant power" to consist of integrated merchants and IPPs.

Below, we present our views regarding issues that investors frequently raise about issuer and industry credit quality.

Credit Concerns

What are the challenges confronting the merchant sector in 2012?

The merchant sector will confront yet another year of declining electricity demand, in our opinion. In conjunction with low natural gas prices, which have kept downward pressure on gross margins, we see significant headwinds for merchant power generation in 2012. The IPPs will continue to struggle this year as natural gas prices hover near 10-year lows, pulling down power prices by 50% compared with 2008 levels. Typically, these companies hedge their production less than diversified utilities. Many of these companies are leveraged to higher natural gas price expectations. For these reasons, among others, Standard & Poor's 2012 outlook for the U.S. merchant power and the IPP sector is negative. Indeed, we've taken several negative rating actions over the past six months (see charts 1 and 2).

Chart 1

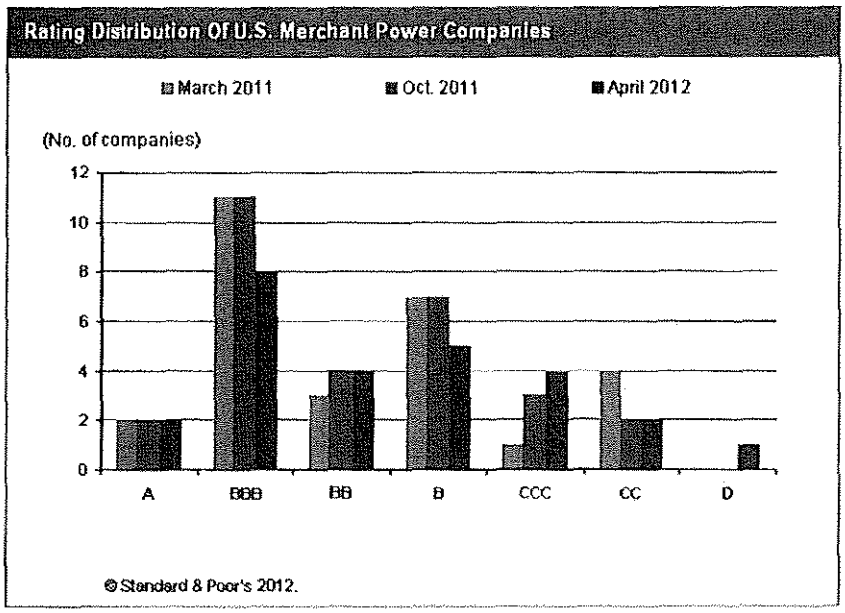
Rating Distribution Of U.S. Merchant Power Companies
March 2011
Oct. 2011
April 2012
(No. of companies)
12
10
8
6
4
2
0
A
BBB
BB
B
CCC
CC
D
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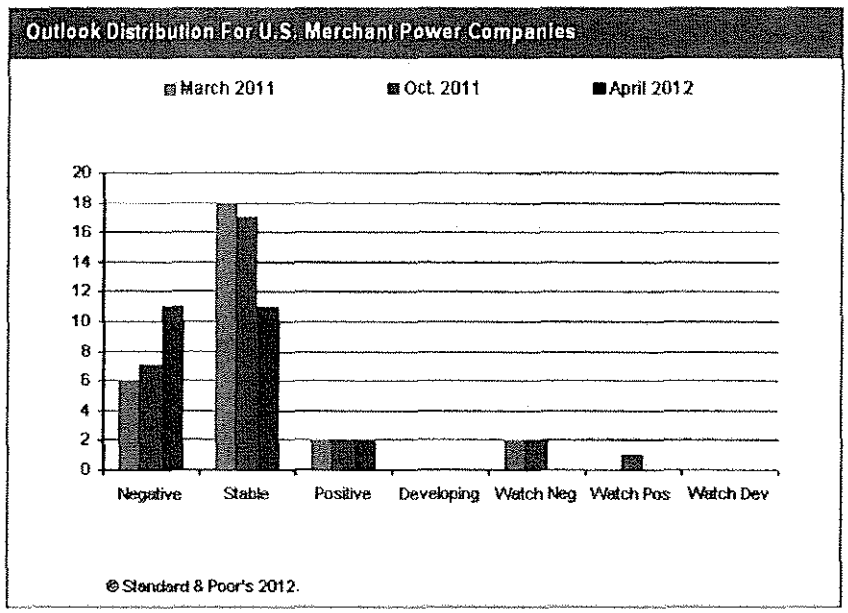
Chart 2



The two significant rating changes in 2012 were the three-notch downgrade of AmerenEnergy Generating Co. to 'BB-' from 'BBB-' and the one-notch downgrade of Edison Mission Energy (EME) and subsidiary Midwest Generation LLC to 'CCC+' from 'B-'. We based Ameren Corp.'s downgrade on the decline in forward power prices and their impact on "dark" spreads (the difference between the price of coal and the electricity sold). Similarly, EME's rating cut stemmed from near-term refinancing risks, also due to expectations of reduced future cash flow and liquidity from low natural gas prices.

Other significant rating changes over the course of 2011 included the downgrade of Energy Future Holdings Corp. (and affiliates) to 'CCC' from 'CCC+'. We consider the company's multiple distressed exchanges and credit facility extensions as tantamount to default. Similarly, despite a restructuring attempt, Dynegy Holdings LLC announced an exchange offer and subsequently filed for bankruptcy protection in November 2011.

Why are IPPs suffering dramatic credit quality declines? Are ratings of investment-grade diversified utilities under threat?

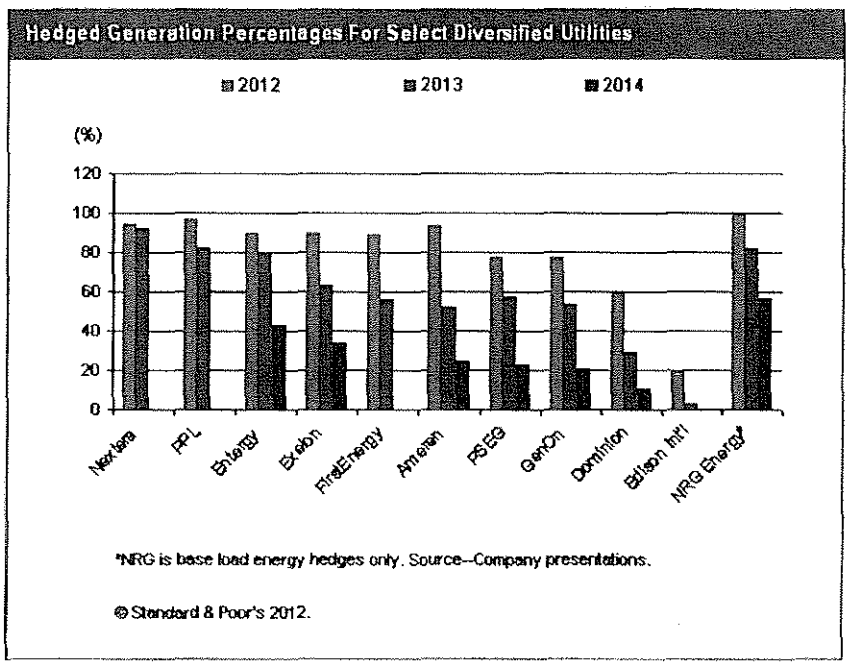
The IPP sector is overleveraged, the result of aligning capital structures with expectations of $6 to $8 per million Btu (mmbtu) gas prices over the long term. Companies such as NRG Energy and GenOn Energy Holdings Inc., which have significant high-priced hedges still outstanding, are currently relatively insulated from the market, but in reality can only postpone a reckoning with the consequences to their capital structures of dramatically lower gas prices when those hedges roll off. The expected bottoming of the merchant cycle in 2012 coincides with significant debt and revolving credit maturities. As a result, the IPP sector could be headed for a spate of bankruptcies similar to the one merchant power went through from 2001 to 2004 due to an overbuild of gas-fired capacity.

Diversified utilities have higher credit quality than independent power producers for many reasons:

- Their more efficient generating plants are capable of dispatching along the supply curve;
- Their plants usually serve better markets because they were built originally as the production assets of a regulated utility; and
- A meaningful proportion of their cash flow is regulated, or they transferred generation assets from utility operations at book value. Dominion Resources Inc. and PPL Corp., for instance, have significantly more regulated cash flows than many of their peers, such as PSEG and Exelon, and have less exposure to merchant markets.

Diversified utilities also hedge more of their expected production than do IPPs, which somewhat insulates them from market forces (see chart 3). The front end of the forward pricing curve is not that meaningful because these companies are usually highly hedged for the near to medium term. These companies focus more on the back end of the forward natural gas curve because they typically do not enter hedges of more than three years. Further out on the price curve, hedging becomes progressively expensive because of thinner power-trading volumes and higher liquidity needs due to margining requirements associated with mark-to-market provisioning. Thus, depressed natural gas prices in the front end do not trouble diversified utilities as long as the structural, long-term forward gas prices remain intact.

Chart 3



However, claims that supply from the various shale natural gas-gathering areas can support U.S. gas needs for the

next 75 to 90 years have depressed natural gas prices for the long term and can derail long-term gas price fundamentals. Today's low prompt (near-term) gas price is merely the start of a price curve that has sagged appreciably over the past two years. The natural gas market appears to be communicating, via the pricing in the outer years of the curve, that the future does not warrant higher prices. We believe this is the dominant risk that diversified utilities currently must deal with, despite their hedging activities.

While we expect additional announcements of coal plant retirements over the next 12 months, particularly given the lower capacity prices set for June 2012 in the PJM Interconnection electricity pricing auction. Such announcements may result in higher gas prices as demand for the fuel rises to meet higher demand from higher utilization of existing and new gas-fired facilities. Still, the impressive amount of shale gas production tempers that upside.

Over the past six months, 2013 and 2014 forward prices in most unregulated markets have fallen about 15% to 20%. Diversified utilities undertake ratable hedging largely to bring predictability to future cash flows, which otherwise would be extremely volatile. Because of the rolling hedging strategy, these utilities are hedging their 2014 forward generation and facing sharply lower forward prices. (For instance, the PJM Interconnection 2014 forward prices have sunk to about $40 per megawatt-hour (MWh) from about $50 per MWh as recently as September 2011). Leaving the generation unhedged in expectation of higher price discovery will represent a directional bet.)

Yet, an effective hedging strategy does provide time to adjust. Should forward power prices remain depressed for a long time, or even decline further, current hedges provide diversified utilities time to strengthen capital structures against deteriorating fundamentals. Some have responded by exiting unregulated businesses (PEPCO Holdings Inc.'s sale of subsidiary Conectiv's 4,500 MW), while others have rebalanced their regulated/unregulated generation mix (PPL's purchase of Louisville Gas & Electric Co., Kentucky Utilities Co., and Central Networks from E.ON AG).

We generally expect stand-alone unregulated subsidiaries of diversified utilities to achieve adjusted funds from operations (FFO) to debt ratios of about 25% to maintain ratings in the 'BBB' category. This requirement could be higher or lower depending on a company's unregulated to regulated business mix and whether the unregulated business continues to generate free operating cash flow. Diversified utilities would also weather the storm if the U.S. Environmental Protection Agency implements the Mercury and Air Toxics Standards (MATS) as drafted and if we see higher power prices in 2015. However, if the prevailing commodity price situation persists, we expect that some companies may have to address their backwardated earnings profiles by reducing capital spending, cutting dividends, or issuing equity. Failing this, negative outlooks and lower ratings are likely to occur as early as the second half of 2012.

What are the main hurdles Dynegy Holdings must pass if it is to emerge from bankruptcy, and how will it affect Dynegy Inc.?

The complexity of this bankruptcy is evident in the many credit issues that Dynegy's numerous subsidiaries must face, as well as in the various levels of debt in Dynegy's corporate structure. The track record of similar merchant companies is mixed. Mirant Corp., now GenOn, had an intricate capital structure with various types of debt at assorted subsidiaries, a level of complexity that contributed to its long 36-month bankruptcy from July 2003 to January 2006. Calpine, also harboring a complex capital structure, although with more debt than others at the holding company level, also spent 36 months in bankruptcy, from December 2005 to January 2008. In contrast, NRG Energy emerged from its May 2003 bankruptcy filing--a mere seven months later because of the prepackaged nature of its bankruptcy. One favorable attribute of the Dynegy bankruptcy is the company's negotiation of preliminary terms with key creditors soon after the U.S. Bankruptcy Court's determination that Dynegy Holdings

and Dynegy Inc. had fraudulently transferred certain assets in 2011. Dynegy's initial response to the court's findings was strong, giving the impression of a long road ahead. The numerous lawsuits surrounding this bankruptcy would seem to indicate that the issues will not be resolved expeditiously. The 'CC' rating on Dynegy Inc. reflects the possibility that it could ultimately be involved in Dynegy's Holdings' bankruptcy proceeds and reorganization.

What are the baseline economic assumptions behind your rating outlooks?

U.S. GDP accelerated to an annualized 3% pace in fourth-quarter 2001--four times stronger than the 0.7% reported in the first half of 2011.Our economists now expect real GDP to rise 2.1% in 2012, a bit stronger than in 2011, although much weaker than the 3% rate in 2010. For 2013, we expect just 2.3% growth.

We expect the U.S. economy to continue to improve, albeit slowly (see table 1). While GDP eventually ended up 1.7% higher year-over-year in 2011, most indicators of aggregate demand did not keep up with job gains. Recession fears are alive and kicking in 2012. The eurozone crisis is far from over and the risk of near-term U.S. austerity is very real. Regulatory uncertainties going into 2013, the large overhang of excess housing supply, and struggling consumers also point to murky prospects. Higher oil prices from increased Middle East unrest are now the largest near-term threat to the U.S. recovery. Our economists believe the U.S. could slip into another recession if the West Texas Intermediate benchmark price reaches around $150 per barrel (about $170 for the Brent benchmark). We expect that each $10 rise would take about 20 basis points (bps) off GDP growth in each of the first two years of the price hike. This is a bit less than in the past because cheap natural gas and coal prices now are good substitutes for pricy oil products. Natural gas pricing, in particular, no longer reacts significantly to oil prices. In this environment, a cautious outlook, especially for the most cyclically sensitive sectors, seems warranted still.

Table 1

S&P Economic Outlook (as of April 12, 2012)

			2012					
	2011	Q4 2011	Q1e	Q2e	Q3e	Q4e	2012e	2013e
(% change)								
Real GDP	1.7	3.0	2.1	2.0	1.8	2.3	2.1	2.5
Consumer spending	2.2	2.1	2.1	2.6	2.0	2.2	2.0	2.2
Equipment investment	10.4	7.5	8.0	8.1	5.7	8.4	8.5	7.5
Nonresidential construction	4.6	(0.9)	(0.8)	(0.9)	(0.6)	(1.3)	2.2	2.2
Residential construction	(1.5)	11.8	20.1	4.2	7.2	10.3	9.8	16.4
Federal government	(1.9)	(7.0)	3.6	(5.3)	(3.7)	(3.7)	(1.8)	(3.6)
State and local government	(2.2)	(2.2)	(0.6)	(1.4)	(1.4)	(0.9)	(1.4)	(0.7)
Exports	6.7	2.7	3.8	4.3	6.4	7.0	4.2	7.1
Imports	4.9	3.7	7.1	3.0	4.8	4.0	4.1	3.7
CPI	3.1	1.3	2.4	2.0	1.9	1.5	2.7	1.7
Core CPI	1.7	1.9	2.0	2.2	1.9	1.8	2.1	1.9
Nonfarm unit labor costs	1.9	2.8	1.8	1.9	2.7	2.4	2.3	2.0
Nonfarm productivity	0.6	0.9	(1.0)	0.6	0.1	0.6	0.3	1.0
(Levels)								
Unemployment rate (%)	8.9	8.7	8.3	8.3	8.2	8.1	8.2	7.9
Payroll employment (mil.)	131.4	132.0	132.7	133.2	133.7	134.3	133.5	135.7

Table 1

S&P Economic Outlook (as of April 12, 2012) (cont.)								
Federal funds rate (%)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
10-year Treasury note yield (%)	2.6	2.0	2.0	2.2	2.4	2.3	2.2	2.7
'AAA' corporate bond yield (%)	4.6	3.9	3.9	4.0	4.2	4.2	4.1	4.4
Mortgage rate (30-year conventional) (%)	4.5	4.0	3.9	4.0	4.1	4.0	4.0	4.2
Three-month T-Bill rate (%)	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1
S&P 500 index	1,269	1,226	1,355	1,364	1,395	1,387	1,380	1,439
S&P operating earnings ($/share)	96.44	23.73	23.95	25.5	26.48	26.62	102.54	113.94
Current account ($ bil.)	(473)	(496)	(548)	(574)	(566)	(543)	(557)	(508)
Exchange rate (major trade partners)	84.6	86.3	86.9	86.8	87.0	87.1	87.0	87.7
Crude oil ($/barrel, West Texas Intermediate	95.07	94.04	102.92	102.67	103.17	107.0	103.94	114.74
Saving rate (%)	4.7	4.5	3.9	3.8	3.8	3.8	3.8	3.4
Housing starts (mil.)	0.61	0.67	0.7	0.71	0.75	0.8	0.74	1.0
Unit sales of light vehicles (mil.)	12.7	13.4	14.5	14.2	14.1	14.1	14.2	14.9
Federal surplus (fiscal year unified, bil. $)	(1,297)	(322)	(413)	(98)	(242)	(272)	(1,075)	(781)

e--Estimate.

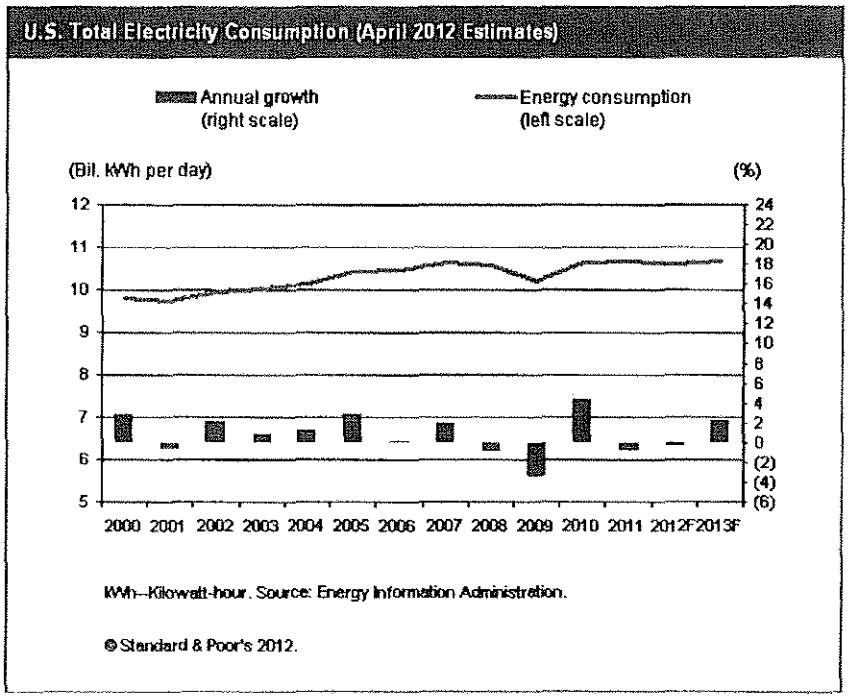
How have economic indicators affected power consumption?

Historically, a weakness in overall economic activity has hurt demand in the power sector. Although the sector continues to benefit from low natural gas prices, an additional concern is that demand may continue to decline.

After remaining flat in 2011, weather-normalized power output has declined about 0.8% year-to-date compared with the same period last year due to slowing industrial production. However, absolute power generation has collapsed across all regions as heating-degree days declined an average 22% compared with last year. The National Oceanic and Atmospheric Administration is forecasting heating degree-days to total 4,020 for 2012, about 11% below the 30-year normal level. Similarly, the projected 17% year-over-year decline in U.S. cooling degree days during the second and third quarters this year could reduce residential electricity use by 5% this summer.

As a result of the projected lower level of economic activity in the U.S., the U.S. Energy Information Administration (EIA), in its April 10, 2012 estimate, expects growth in total electricity consumption to be down 0.4% in 2012. The EIA's demand growth expectation for 2012 is a meaningful downward revision from the 2.4% growth it expected as recently as May 2011 (see chart 4).

Chart 4



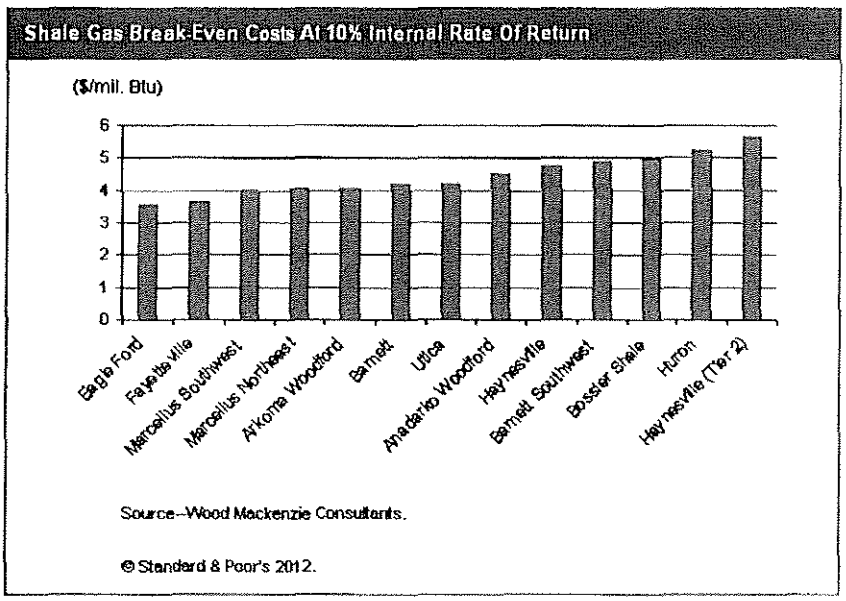
Lower demand for power increases reserve margins and lowers market heat rates, and hurts energy and capacity prices in the power markets.

What are your assumptions for natural gas prices and how does commodity price risk affect your credit opinion on this sector?

We published our latest price assumptions on RatingsDirect on April 18, 2012 in an article titled "Standard & Poor's Lowers Its U.S. Natural Gas Price Assumptions; Oil Price Assumptions Are Unchanged."

On April 10, 2012, natural gas prices fell to below $2.0 per million British thermal units (mmBtu)--their lowest level in a decade. The falling prices stem largely from oversupply. Shale gas is the lowest-cost resource in the U.S. (see chart 5). Development costs for shale gas plays have become much more competitive than those for conventional assets, and continuing advances in technology are making it even cheaper. After a decade of flat production through year-end 2006, gas production has surged 12.5 billion cubic feet per day (bcf) over the past five years, increasing by nearly 4.5 bcf per day just in 2011. Industry consultant Wood Mackenzie estimates that, after excluding the cost of leasing acreage, the largest shale plays have development break-even costs (including a 10% internal rate of return) at less than $5 per mmBtu after factoring in drilling, completion, and overhead. Given that many wells have a mix of natural gas liquids and natural gas, the effective break-even price for natural gas is even lower.

Chart 5



The biggest surprise has been the mild weather. The very warm winter spurred working natural gas inventories to new records. As of March 30, 2012, working inventories totaled 2,479 bcf, 934 bcf above the five-year average, dragging down spot prices dramatically.

We have long argued that merchant power can be divided into two different markets. It's critical for a merchant generator to separate the cyclical, short-term power market fundamentals from the structural, long-term factors. Energy demand and natural gas inventory largely dictate power prices in the short term, while reserve margins and the cost structure of the highest-cost power producer drive structural power prices. In other words, electricity demand usually dictates prompt (near-term) power prices, while supply--the marginal cost of natural gas production and delivery--decides long-term power prices. Shale gas development has been weighing on short-term power prices since late 2008, but only started bringing down long-term power prices from February 2010. That influence on the forward curve accelerated in the last quarter of 2011. The back end of the forward curve has flattened considerably since 2009. The 2013 strip in the current forward curve declined to about $3.50 per million cubic feet (mcf) by March 2012, compared with about $7.50 per mcf in June 2009.

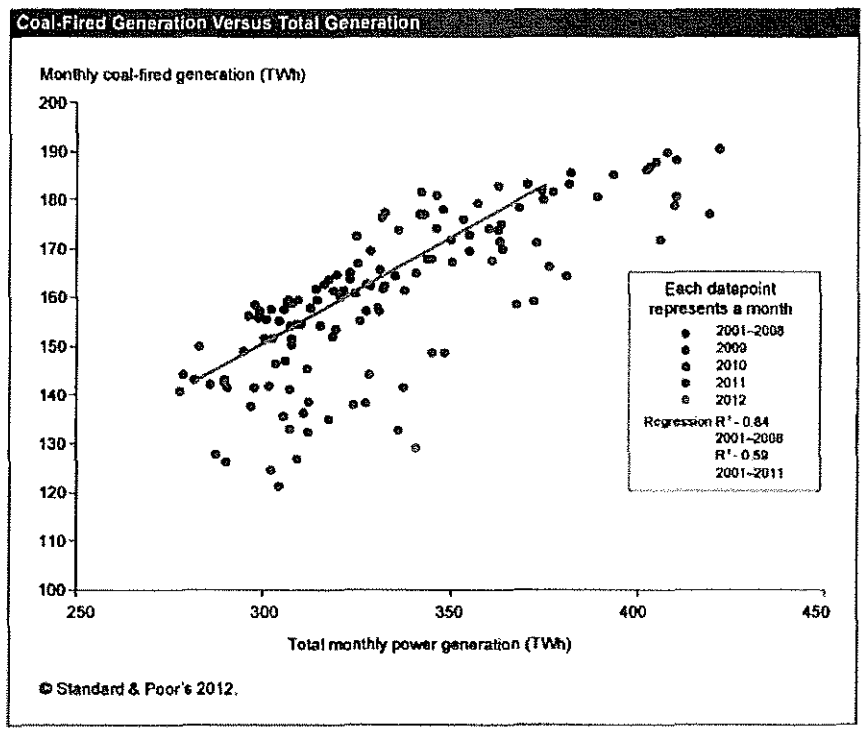
While inefficient coal units are the first to get displaced from the supply stack as gas prices decline (and IPPs have historically owned more of these inefficient units), diversified utilities' generation mix skews more toward base load nuclear and coal generation than for IPPs. Therefore, diversified utilities' cash flow is often more leveraged to shifts in natural gas prices. For instance, falling gas prices harm Exelon Generation Co. LLC more than its peers because 95% of its generation comes from base load nuclear plants, all of which declining natural gas prices affect. However, falling gas prices are not bad news for all generators. A prolonged lower gas price is favorable for

predominantly natural gas-fired operators such as Calpine. Even if gross margins per MWh sold decline, Calpine's plants have greater utilization and volumes sold, and this largely offsets any potential margin decline.

What are your views on coal-fired generation and credit implications for coal plant operators?

The power sector started 2012 dramatically, with a significant slide in power and natural gas prices following the D.C. Circuit Court's decision in December 2011 to stay implementation of the EPA's Cross-State Air Pollution Rule (Casper). A mild winter added to the decline. Through 2011 and into 2012, increasing levels of coal-to-gas displacement (see chart 6) has occurred, initially in the Southeast and Mid-Atlantic before spreading to other regions.

Chart 6



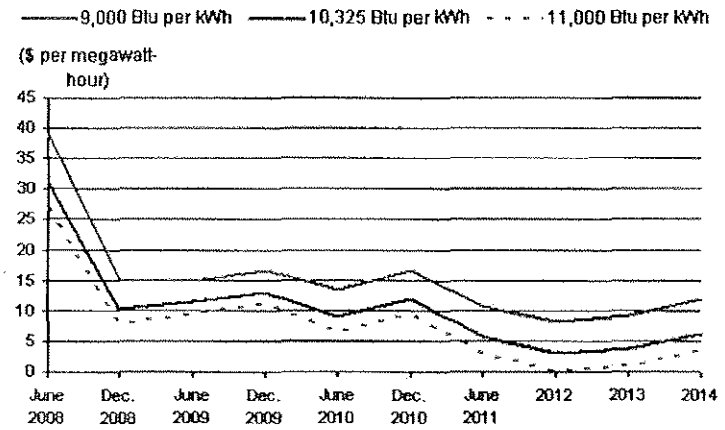
In January 2012, coal-fired production dropped to a low of just 38% of total production, compared with the historic average of about 45%, caused largely by mid-merit gas-fired generation displacing inefficient coal-fired units. The EIA projects power sector coal consumption to decline by nearly 5% in 2012, and for coal consumption to drop below 900 million short tons for the first time since 1996 as generation from natural gas and wind increases.

As prices continue to decline, coal is increasingly setting the marginal cost of power and power prices in the near term will mainly reflect shifts in coal prices rather than gas prices. We believe pricing of power has likely found

some stability with limited downside to eastern Appalachian coal prices, which at $57.00 per ton in the spot market in April 2012 are about the same as the cash cost for many suppliers (cash cost is the price at which coal producers would remove production from the market, providing a floor to prices). Despite the recent lower coal prices, spot dark spreads in the Northeast became negative for sub-critical coal units by March 2012 (see chart 7), from $5 to $6 per MWh as recently as June 2011 and from about $30 per MWh in first-quarter 2008.

Chart 7

Dark Spreads For A Generic Coal-Fired Unit In The PJM West Region*



*The three lines represent gross margins for an efficient, average, and inefficient heat rate coal unit. We've assumed $1.50 per megawatt-hour of variable operating and maintenance costs. KWh--Kilowatt-hour. Source: Standard & Poor's estimates.

Ominously, with a drag on spot gas prices on the forward curve, even forward dark spreads have turned negative for coal-fired generation (see table 2). Responding to the economics, generators announced a wave of coal-plant retirements over the past six months. At this point, retirement decisions appear due more to economic considerations than to environmental compliance.

Table 2

2013 Forward Central Appalachian Coal- And Natural Gas-Fired Marginal Costs*

Coal		Natural gas	
Price ($ per ton)	68	Price ($ per mil. cubic feet)	3.44
Transportation cost ($ per ton)	20	Price ($ per mil. Btu)	3.28
Total cost ($ per ton)	88	Basis differential ($ per mil. Btu)	0.2
Total cost ($ per mil. Btu)	3.52	Delivered cost of gas ($ per mil. Btu)	3.48

Table 2

2013 Forward Central Appalachian Coal- And Natural Gas-Fired Marginal Costs* (cont.)

Inefficient coal plant heat rate (mil. Btu per MWh)	11,000	Switching combined cycle gas turbine heat rate (mil. Btu per MWh)	9,500
Coal marginal fuel cost ($ per MWh)	41.72	Gas marginal fuel cost ($ per MWh)	35.02

*We compare an 11,000 heat rate coal unit with a 9,000 heat rate gas unit. Switching competition is not between the most efficient gas unit and the least efficient coal unit, but between units in the middle of the dispatch curve for each fuel type. Other variable costs are coa at $3 per MWh and gas at $2 per MWh. MWH--Megawatt-hour

Almost all of AmerenEnergy Generating's generation comes from burning coal. Our February 2012 downgrade of the company directly related to the significant reduction in cash flows from eroding dark spreads. GenOn, EME, and FirstEnergy Corp. are also seeing lower dark spreads. EME, in particular, will be the most affected due to its fairly low price hedge levels.

What impact will the EPA rules--Casper and Mercury and Air Toxics Standards (MATS)--have on merchants' credit quality?

The implementation date of Casper is being litigated. A number of States, utilities and trade groups are appealing the EPA's approach to the definition of "significant contribution" of particulates and So2. Petitioners are also asking if whether the EPA can proceed directly to a federal implementation plan instead of allowing states to craft their own strategies within a federal target. A ruling is expected by July 2012. We currently believe that a start date is unlikely before 2013. Comments have also been filed against the MATS with the U.S. Court of Appeal for the D.C. Circuit. The EPA's comments to the initial motions of the petitioners are not due before mid-May 2012.

To comply with both new rules, coal-fired generators have announced about 32 gigawatts (GW) of retirements through 2021 (although about 5 GW of retirement decisions are in abeyance following a stay on Casper). While a regulated utility can operate a plant out-of-dispatch for some time, a merchant generator has to respond relatively quickly. Perversely though, regulated utilities announced the first wave of coal-plant retirements. As Casper has been in the works for many years, and has had two predecessor rules, companies have grown accustomed to repeated delays. Merchant operators that have deferred environmental upgrade decisions have generally been rewarded with postponed regulations. Eventually though, unregulated generators will generally close unscrubbed smaller and older coal-fired plants. Among the merchant companies, FirstEnergy and GenOn have announced significant near-term closures of about 3,350 MW and 2,850 MW, respectively.

Generators will also continue to install pollution-control equipment to reduce emissions from existing coal-fired power plants when it is cost effective. Credit quality could come under pressure for companies such as Ameren, Dominion Resources, FirstEnergy, and PPL, which have both regulated and merchant generation businesses because these companies will have to rely on market pricing to recover merchant environmental capital spending. If current energy prices don't improve, we would expect some weaker consolidated financial measures. On the flip side, expectations of retirements are influencing capacity pricing to the upside in recent auctions.

What are your expectations for capacity prices and how do they affect credit?

Offsetting a bearish nearer term view, we believe several incremental plant retirements are likely. About 32 GW of retirements have already been announced through 2021. These retirements will influence capacity markets.

In New England, the very large oversupply has kept capacity prices near floor level. It is likely that the New England Independent System Operator will contemplate a market redesign and consider zonal modeling along with separate products for peaking power.

We're most focused on PJM because a large number of merchant plants operate in the region. Specifically, we look for operators of unregulated capacity in PJM's regional transmission organization (RTO) to potentially announce additional asset retirements given the substantial decline in capacity prices in June to $16 per MW-day from $110 per MW-day (see table 3). In addition to Casper and MATS, New Jersey's high energy demand day environmental regulations, effective in 2015, would likely see retirements of about 14 GW in PJM alone through 2021 of older coal units that are unscrubbed, are under 500 MW, and have capacity factors of about 30%.

Table 3

Historic Capacity Prices In PJM Zones

($/megawatt-day)

PJM zones	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015
Auction year	2006	2007	2008	2009	2010	2011
Eastern Mid-Atlantic Area Council	191.32	174.29	110.00	139.73	245.00	136.50
Mid-Atlantic Area Council	191.32	174.29	110.00	133.37	226.15	136.50
Southwest Mid-Atlantic Area Council	237.33	174.29	110.00	133.37	226.15	136.50
Rest of pool	102.04	174.29	110.00	16.46	27.73	126.00
Delmarva Power & Light South	N/A	186.12	110.00	222.30	245.00	136.50
Public Service Electric & Gas	N/A	N/A	N/A	139.73	245.00	136.50
Public Service Electric & Gas North Zone	N/A	N/A	N/A	185.00	245.00	225.00
Potomac Electric Power	N/A	N/A	N/A	N/A	247.14	136.50

N/A- Not applicable. Source: PJM Interconnect Website.

While we still expect price convergence for all capacity zones in the PJM, the incremental 13 GW of deactivation requests could result in a structural shift in RTO capacity prices because it decreases the amount of installed capacity and may also decrease capacity transfers into zones (as is evident in American Transmission Systems Inc. (ATSI) zone. The PJM's latest capacity auction parameter filings suggest transmission constraints are developing across ATSI's region likely due to recent plant retirements. Based on the capacity emergency transfer limit to capacity emergency transfer objective calculations the ATSI zone will likely price high in the 2015/2016 auction.

However, the most significant factor in these auctions is the degree to which EPA-driven retirements or environmental cost amortizations will change the supply curve. Also, a complicating issue is that a generator's deactivation request is reversible. If a generator submits a deactivation request, it does not have to withdraw from the capacity auction; the generator can still submit a sell offer if it decides not to retire. Consequently, there is some uncertainty surrounding eventual retirements. Notwithstanding these shorter-term developments, we believe that prices of all zones will likely converge, after EPA-driven retirements phase concludes, due primarily to transmission upgrades

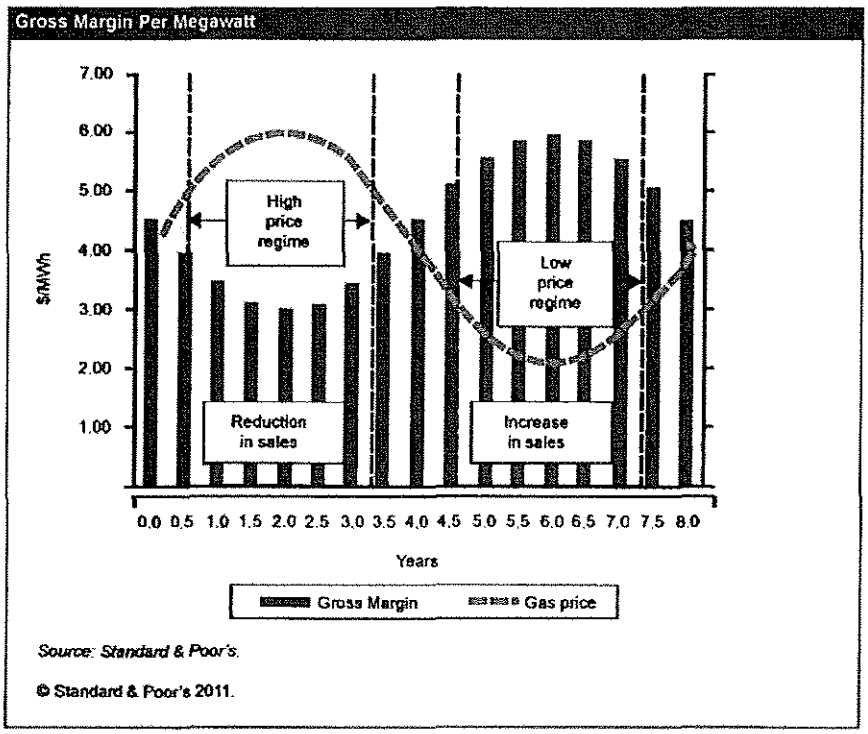
From a credit perspective, capacity prices have been priced in through our outlook period in the PJM. We assume floor pricing in New England.

Do you view retail power business as supporting credit?

From a credit standpoint, we view an "asset-lite" retail power business as risky. We view load-following retail power contracts as risky because such contracts can result in large liquidity requirements should prices move adversely from the prices contracted. Furthermore, these contracts expose margins to market risks, including load-shaping, fuel, and volume risks.

However, for merchant generators, retail generally provides some offset to wholesale prices, and merchant generators have increasingly mitigated the impact of declining wholesale prices by expanding their retail business. From a credit perspective, capital charges--including the cost of working capital, credit facilities, contingent collateral, as well as the cost of equity required to cover risk capital requirements--increase roughly in proportion to commodity prices. At high power price levels, capital charges are also high and cut into gross margins. Yet customers are less inclined to lock in prices at these levels. As a result, at elevated prices we expect fixed-price sales to fall, reducing total capital requirements and lifting average margins on existing retail volumes. At low power prices, capital charges decline. While customer migration ensues, gross margins for retail volumes rise due to increasing headroom between locked-in retail prices and wholesale prices. Thus, although the generation business's profitability declines when prices are low, the retail business's profitability improves, and vice versa (see chart 8).

Chart 8



Given the significant volatility of capacity markets, retail operations can mitigate wholesale power risk by blending capacity prices in retail products that bring forward the capacity price uplift in later years. For instance, in the Duke Energy auction in Ohio, FirstEnergy Solutions bid largely into the three-year contracts that cleared substantially higher prices than one-year contracts (see table 4).

Table 4

FirstEnergy's Retail Prices In Duke Auction

	2011/2012	2012/2013	2013/2014	2014/2015
Auction year	2008	2009	2010	2011
Regional transmission organization capacity price ($ per MW-day)	110.00	16.46	27.73	126.00
One-year contract ($ per MWh)		49.72		
Two-year contract ($ per MWh)		51.10		
Three-year contract ($ per MWh)			57.08	

MW--Megawatt. MWh--Megawatt-hour.

Related Criteria And Research

- What's Driving The U.S. Merchant Power Sector's Credit Outlook For 2012?, Jan. 11, 2012
- U.S. Merchant Power Sector's Near-Term Economic Prospects Overshadow Longer-Term Environmental Upside, Oct. 12, 2011
- Changes Are Coming For U.S. Coal Markets And Coal-Burning Power Generators As New Environmental Rules Loom, Sept. 20, 2011
- Why Casper, The EPA's Cross-State Air Pollution Rule, Is Spooking the Electricity Sector, Sept. 12, 2011

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Summary:

Exelon Corp.

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Summary:

Exelon Corp.

Credit Rating: BBB/Stable/A-2

Rationale

Standard & Poor's Ratings Services' 'BBB' corporate credit ratings on diversified energy company, Exelon Corp, reflects its consolidated business risk profile, which we view as "strong." Exelon's business risk profile reflects the higher-risk operations of unregulated supply affiliate Exelon Generation Co. LLC (ExGen), which has increased in size to subsume Constellation's unregulated business. Exelon's business risk also reflects the excellent business risk profiles of regulated delivery businesses, Commonwealth Edison (ComEd), PECO Energy (PECO), and Baltimore Gas & Electric Co. (BGE), which have generally predictable transmission and distribution cash flows. Because of ring-fencing, we will continue to deconsolidate BGE and analyze it as an equity investment, counting only distributions to the parent as primary contributions to the parent's credit quality and financial profile.

As of June 30, 2012, Exelon had about $18.4 billion of on-balance-sheet debt. We also impute about $4.6 billion of off-balance-sheet debt on the books for computing financial ratios, pertaining mostly to unfunded pension and other postemployment benefit obligations and power-purchase agreements.

Postmerger, Exelon is now the nation's second-largest regulated distributor of electricity and gas, with 5.4 million customers in Illinois and Pennsylvania and 1.2 million customers in Maryland. Exelon also distributes natural gas to 490,000 customers in the Philadelphia metropolitan area through PECO and 650,000 customers in Maryland. ExGen engages in unregulated energy generation, wholesale power marketing, and energy delivery. The company has long-term exposure to market risk and meaningful exposure to nuclear assets (17,000 megawatts [MW] across 19 units). The company now has about 35,000 MW and 450 billion cubic feet (bcf) (2012 estimates) of natural gas business. The company has recently divested about 2,648 MW of generation to address market power concerns.

Exelon derives a larger proportion of earnings from its regulated and retail operations. Through retail and wholesale channels, ExGen now provides about 170 terawatt-hours (TWhrs), or approximately 5%, of total U.S. power demand. We expect the switched markets in Pennsylvania, Ohio, Michigan, and Arizona to grow at about 10% in the commercial and industrial class and at about 15% in the residential class between 2011 and 2014. The fleet is well positioned to grow where capacity available for competitive supply has room to grow. We expect these incremental revenue streams to make the consolidated Exelon somewhat more resilient to commodity prices. The combination provides ExGen regional diversification of the generation fleet and a customer-facing load business, as generation and load positions are now better balanced across multiple regions. In most locations, ExGen will have adequate intermediate and peaking capacity within the portfolio for managing load shaping (matching resources with energy needs) risks. However, the company will still need to buy and sell length in the market to manage portfolio needs, in our opinion. Moreover, ExGen has a significant open position in the mid-west (exposed to merchant market), and a somewhat tight position in ERCOT and New England, where it has some risk of finding itself short when loads are

high, in our opinion.

Supply subsidiary, ExGen's cash flow is sensitive to commodity prices as almost 95% of its premerger generation is nuclear, all of which sliding gas prices are impairing. ExGen's unregulated operations accounted for about 65% of the consolidated enterprise by cash flow and capital spending in 2011. Given that base-load generation is price-taking--it doesn't affect the market price--we expect ExGen's adjusted funds from operations (FFO) to debt to remain volatile--relative to its peers--and we expect it to swing in a band of over 40% in 2011 to about 27% by 2014. For instance, all else remaining equal, we estimate gross margins in 2014 will be lower by about $500 million for every $5 per MW-hour (round-the-clock) decline in power prices, about $215 million for every $0.5 per million cubic feet (Mcf) decline in gas prices, and about $110 million for every $1 per MWh decline in retail margins.

As a result, ExGen's contribution to the overall Exelon cash flow declines to about 55% under our base case, because of the decline in unregulated cash flow when commodity prices fall. However, despite the lower power prices, we view the business risk profile of parent Exelon as strong. We expect financial measures to decline over the next 2-years and the corporate credit ratings reflect our expectation that 2014 will be the trough year. Based on the present forward curve, cash flow measures are still adequate for the rated level in that year. However, as a result of the declining gross margin in forward years, we view Exelon's cash flow adequacy ratio as more akin to the "significant" financial risk profile than the erstwhile "intermediate" one.

We view ExGen's ratable hedging strategy favorably, as it ensures that a high percentage of the company's near-term generation is locked in. Hedging not only protects unregulated generation cash flows from steep price declines, it also provides the company time to adjust its cost structure or its capital structure, should prices remain depressed. However, hedging activities insulate, but do not isolate, power merchants from commodity price effects. Current hedges show the significant value of Exelon's hedging program. Even though these hedges insulate ExGen, perversely, they also show the sensitivity of ExGen's margins to the prospect of a continued shale production onslaught. The decline in mark-to-market value through 2014 shows the limit to which Exelon can hedge--a price-taking fleet can hedge, but only at the prices the market will bear. Also, the gross margin contribution at ExGen will face a decline as higher-priced hedges expire, evident in the drop in wholesale hedged gross margins. Still, the forwards show a contango as reflected in the increase in ExGen's open EBITDA from higher natural gas forwards. Additionally, we believe retail contributions will increase, given the potential for cost savings, volumes gained from the constellation merger, and recent acquisitions (StarTex and MX Energy Holdings).

We view parent Exelon's financial policy and internal funding as "aggressive." The current level of dividends, at about $1.8 billion, results in a dividend payout of about 80%, according to our estimates--meaningfully higher than the 50% to 65% range for peers. Moreover, Exelon's capital spending requirements are significant between 2012 and 2014, at about $18.5 billion. Although utility capital spending tends to be funded in regulated rates (i.e under yjr rate base),unregulated generation will have to fund its own capital requirements and recover them in market prices. However, cash flow from operations will be insufficient for capital spending and dividends, resulting in external needs of financing. We estimate that the funding gap would be greatest in 2014 because of a trough in earnings even as ExGen's requirement to contribute towards Exelon's dividend commitments are the highest internal financing needs of the utilities. This funding gap could widen if the company fails to achieve merger driven O&M savings in its forecast.

We estimate Exelon's incremental long-term financing needs at an average of about $1.4 billion to $1.5 billion in 2014 and 2015. Still, incrementally lower gas prices, combined with higher than anticipated O&M costs, would hurt ExGen's debt protection measures more than the level of new debt financing in ExGen's forecast through 2015.

Under our consolidated base case (we assume lower gas prices and market heat rates that result in power prices roughly 10% lower than the current forward contracts), we expect FFO to total debt of the pro forma company (i.e., Exelon and Constellation combined) to decline to about 25% in 2012 and then to hover at 22% to 23.5% through 2015. We expect free operating cash flow to debt to remain marginally positive even in 2013 and 2014 when we expect financial measures to trough. However, we expect discretionary cash flow (after dividends) to turn significantly negative--in a range between $1.1 and $1.7 billion through the period--mostly because of high capital spending. Similarly, we expect total debt to total capital to be about 57% and debt to EBITDA to hover at about 4.0x. These ratios are still consistent with Standard & Poor's 'BBB' rating guideposts for a financial risk profile we assess as "significant," especially since a meaningful amount of capital expenditure is discretionary. The company's recent decision to defer the LaSalle extended power uprate (EPU) by two years demonstrates flexibility to adjust the program as needed based on market conditions. We estimate that deferring the project by two years will free-up about $400 million through 2014.

Liquidity

The short-term rating on Exelon and affiliates is 'A-2'. Standard & Poor's views the liquidity across the Exelon group of companies as "strong," in light of the debt maturities we expect and available credit facilities. We estimate that sources of cash will exceed the companies' uses by about 2x during the next 12 to 24 months. We expect sources over uses for Exelon and ExGen to remain positive even if EBITDA declines by 50%. In addition, because of Exelon's solid relationships with banks and high conversion of FFO to discretionary cash flow, we believe the company can absorb low-probability, high-impact shocks.

Exelon has sufficient alternative sources of liquidity to cover current liquidity needs, including ongoing capital requirements, moderate capital spending, and upcoming debt maturities. Ironically, a declining power price environment is favorable from a liquidity perspective as cash is being posted to ExGen on its forward hedges. The next large maturities are in 2015 for Exelon and 2014 for ExGen.

In March 2010, ComEd replaced its $952 million credit facility with a three-year, $1 billion unsecured revolving credit facility that expires March 25, 2013. On March 10, 2012, the capacity under Constellation's revolving facility fell to $1.5 billion from $2.5 billion, reducing aggregate bank commitments to $3.2 billion. All facilities reside at the parent level. In addition, Exelon is working through the migration of letters of credit and has a liquidity reduction plan in place that it will finalize toward the end of 2012.

As of July 27, 2012, Exelon, ExGen, ComEd, PECO, and BGE had credit facilities of $2.84 billion, $5.6 billion, $1.0 billion, $0.6 billion, and $0.6 billion, respectively. These facilities expire between September 2013 and March 2017. Availability under these facilities was $2,319 million and $3,807 million respectively for Exelon and ExGen, respectively, and $999 million, $599 million and $564 million for ComEd, PECO, and BGE, respectively. Excluding commercial paper outstanding, the aggregate availability was $7.86 billion.

Outlook

The outlook on the ratings is stable. That said, we believe that higher natural gas production from shale plays and a delay in environment rules related to plant retirements can significantly hurt the company's financial performance. We believe these headwinds have increased and Exelon faces a potential earnings decline in 2014. Should the prevailing commodity environment persist, the company may have to address its declining earnings profile by reducing capital spending. We expect Exelon and ExGen to maintain consolidated FFO to debt in the 22% to 23% and 25% to 27% ranges, respectively, in 2014 to maintain current ratings. We will specifically monitor the expected negative discretionary cash position that results from Exelon's large dividend commitment. A positive outlook--currently not under consideration--can result if natural gas prices stabilize and power prices respond favorably to coal-plant retirements, resulting in an improvement in consolidated FFO to debt levels of over 27%.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

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Summary:

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Summary:

Commonwealth Edison Co.

Credit Rating: BBB/Stable/A-2

Rationale

Standard & Poor's Ratings Services' ratings on Commonwealth Edison Co. (ComEd) reflect the consolidated credit profile of Chicago-based parent Exelon Corp. Exelon's other considerable subsidiaries include regulated PECO Energy Co., unregulated Exelon Generation Co. LLC, and the recently merged assets of the former Constellation Energy Group Inc., including rate-regulated Baltimore Gas & Electric Co. In general, our ratings on ComEd are limited to the lower of our consolidated rating on Exelon or ComEd's stand-alone credit quality. The ratings also reflect ComEd's "excellent" business risk profile and Exelon's "significant" financial risk profile under our criteria.

ComEd's excellent business risk profile reflects its monopolistic, rate-regulated utility transmission and distribution businesses that provide an essential service. ComEd serves about 3.8 million electricity customers in the City of Chicago and the surrounding area. The company's distribution rates are regulated by the Illinois Commerce Commission and the transmission rates, which make up about 23% of the company's rate base, are regulated by the Federal Energy Regulatory Commission. Additionally, we view the distribution and transmission businesses as lower risk than the generation businesses that often included in many fully integrated electric utilities.

ComEd took the initiative in engaging state legislators and regulators to effect reform in the utility regulatory process. As a result, at year-end 2011, the Illinois governor signed into law House Bill 3036 that will allow for a formula process for determining rates, including the recovery of actual costs and a formula for calculating return on equity (ROE). While we initially viewed these developments as potentially enhancing ComEd's credit quality, we think the outcome of ComEd's first rate filing under the new law suggests that the company's management of regulatory risk could remain challenging. In that case, the commission ordered that ComEd reduce rates by more than $165 million, which is more than $100 million lower than ComEd's initial rate case filing. The company requested a rehearing on certain issues of the order and expects a rehearing order by November 2012. ComEd has since filed a second rate case under the new law, requesting a $106 million rate increase and the staff has recommended a $37 million rate increase. We expect that the company will continue to file annual distribution formula rate cases through this streamlined process.

Our corporate credit rating on ComEd incorporates its affiliation with Exelon's competitive energy businesses. The competitive energy businesses' strong business risk profile reflects their ultimate dependence on the market price for electricity, which has recently sharply declined. Although management continues to proactively manage those areas that it can directly influence--including capital spending, operations and maintenance (O&M) costs, and maintaining its hedging strategy--sustained weak power prices will hurt the competitive businesses' cash flow over the intermediate term. Furthermore, prolonged weakness of the power markets, particularly the flattening of the forward curve, could potentially reduce the value of the company's hedging strategy to protect it from weak power prices. Although the company's hedging strategy provides a degree of price insulation over the short term, sustained depressed power

prices could eventually undermine this credit enhancement.

The significant financial risk profile reflects Exelon's consolidated financial measures under our base-case scenario that for 2013-2015 funds from operations (FFO) to debt will approximate 22% to 24%. Key assumptions under our base case include lower gas prices and market heat rates that result in power prices that are about 10% lower than the current forward contracts. For the 12 months ended June 2012, adjusted FFO to debt decreased to 28.9% from 34.25% at year-end 2011, and adjusted debt to EBITDA and adjusted debt to total capital weakened to 4.5x and 52.7%, respectively, compared with 2.9x and 55.7% at year-end 2011.

We expect that Exelon's historically positive discretionary cash flow will turn negative, primarily reflecting high capital spending of about $18.5 billion for 2012-2014 and annual dividends about $18.5 billion. We expect that Exelon will meet these cash shortfalls in a manner that is at least credit-neutral. As such under our base-case scenario we expect total debt to total capital to be about 57% and debt to EBITDA to approximate 4.0x.

Liquidity

Our short-term rating on Exelon and ComEd is 'A-2'. We view Exelon's consolidated liquidity as strong and Exelon can more than cover its cash needs for the next two years, even if FFO declines.

Our liquidity assessment is based on the following factors and assumptions:

- We expect Exelon's consolidated liquidity sources (including cash, FFO, and credit facility availability) to exceed its uses by about 1.8x over the next 12 months.
- Debt maturities are material with about $1 billion maturing in 2013 and approximately $1.5 billion maturing in 2014.
- Even if EBITDA declines by 30%, we believe net sources will be well in excess of liquidity requirements.
- The company can absorb high-impact, low-probability events with limited need for refinancing, has the flexibility to lower capital spending, has sound bank relationships and solid standing in the credit markets, and has generally prudent risk management.

In our analysis, we assumed liquidity sources of about $12.5 billion over the next 12 months. We estimate the company will use about $7 billion over the same period for capital spending, debt maturities, working capital needs, and shareholder dividends.

As of July 27, 2012, Exelon, ExGen, ComEd, PECO, and BGE had credit facilities of $2.84 billion, $5.6 billion, $1.0 billion, $0.6 billion, and $0.6 billion, respectively. Availability under these facilities was $2,319 million and $3,807 million for Exelon and ExGen, respectively, and $999 million, $599 million, and $564 million for ComEd, PECO, and BGE, respectively. Excluding commercial paper outstanding, the aggregate availability was $7.86 billion.

ComEd's $1 billion revolving credit facility that expires in March 2017 has a financial covenant requiring that ComEd must maintain cash from operations to interest expense of at least 2x. As of June 30, 2012, ComEd had adequate cushion with respect to this financial covenant.

Recovery analysis

We assign recovery ratings to first-mortgage bonds (FMBs) issued by investment-grade U.S. utilities, which can result in the notching of issue ratings above a corporate credit rating on a utility, depending on the category and the extent of the collateral coverage. We base the investment-grade FMB recovery methodology on the ample historical record of

nearly 100% recovery for secured bondholders in utility bankruptcies, and on our view that the factors that supported those recoveries (limited size of the creditor class, and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist. Under our notching criteria, when assigning issue ratings to utility FMBs, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, as well as the regulatory limitations on bond issuance. FMB ratings can exceed a corporate credit rating on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories.

ComEd's FMBs benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of 1.5x supports a recovery rating of '1+' and an issue rating two notches above the corporate credit rating.

Outlook

The stable outlook reflects Standard & Poor's baseline forecast that parent Exelon's consolidated FFO to debt will approximate 22% to 24% over the next three years. We could lower our rating on ComEd if Exelon's consolidated financial measures weaken so that FFO to debt is consistently below 22%. This could occur if electricity prices remain weak and economic growth is minimal. Because our corporate credit rating on ComEd is limited to the lower of its stand-alone credit quality or our corporate credit rating on its parent, for us to raise our rating on ComEd, we would first have to upgrade Exelon, and ComEd's stand-alone credit quality would have to reflect the higher rating. Although we view a ratings upgrade as less likely, this could occur if Exelon's consolidated FFO to debt is consistently greater than 27%.

Related Criteria And Research

- Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Analytical Methodology, April 15, 2008
- Changes To Collateral Coverage Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds, Sept. 6, 2007

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Exelon Corp.

Major Rating Factors

Strengths:

- Low-cost base-load generation,
- Strong operating track record, and
- Ample available liquidity.

Weaknesses:

- Exposure to market prices of a price-taking fleet,
- Backdated EBITDA profile and potential for a significant decline in cash flow, and
- Aggressive financial policies.

Corporate Credit Rating
BBB/Stable/A-2

Rationale

Standard & Poor's Ratings Services' 'BBB' corporate credit ratings on diversified energy company, Exelon Corp, reflects its consolidated business risk profile, which we view as "strong." Exelon's business risk profile reflects the higher-risk operations of unregulated supply affiliate Exelon Generation Co. LLC (ExGen), which has increased in size to subsume Constellation's unregulated business. Exelon's business risk also reflects the excellent business risk profiles of regulated delivery businesses, Commonwealth Edison (ComEd), PECO Energy (PECO), and Baltimore Gas & Electric Co. (BGE), which have generally predictable transmission and distribution cash flows. Because of ring-fencing, we will continue to deconsolidate BGE and analyze it as an equity investment, counting only distributions to the parent as primary contributions to the parent's credit quality and financial profile.

As of June 30, 2012, Exelon had about $18.4 billion of on-balance-sheet debt. We also impute about $4.4 billion of off-balance-sheet debt on the books for computing financial ratios, pertaining mostly to unfunded pension and other postemployment benefit obligations and power-purchase agreements.

Postmerger, Exelon is now the nation's second-largest regulated distributor of electricity and gas, with 5.4 million customers in Illinois and Pennsylvania and 1.2 million customers in Maryland. Exelon also distributes natural gas to 490,000 customers in the Philadelphia metropolitan area through PECO and 650,000 customers in Maryland. ExGen engages in unregulated energy generation, wholesale power marketing, and energy delivery. The company has long-term exposure to market risk and meaningful exposure to nuclear assets (19,000 megawatts [MW] across 23 units). The company now has about 35,000 MW and 465 billion cubic feet (bcf) (2012 estimates) of natural gas business. The company has recently divested about 2,648 MW of generation to address market power concerns.

Exelon derives a larger proportion of earnings from its regulated and retail operations. Through retail and wholesale channels, ExGen now provides about 170 terawatt-hours, or approximately 5%, of total U.S. power demand. We expect the switched markets in Pennsylvania, Ohio, Michigan, and Arizona to grow at about 10% in the commercial and industrial class and at about 15% in the residential class between 2011 and 2014. The fleet is well positioned to grow where capacity available for competitive supply has room to grow. We expect these incremental revenue

streams to make the consolidated Exelon somewhat more resilient to commodity prices. The combination provides ExGen regional diversification of the generation fleet and a customer-facing load business, as generation and load positions are now better balanced across multiple regions. In most locations, ExGen will have adequate intermediate and peaking capacity within the portfolio for managing load shaping (matching resources with energy needs) risks. However, the company will still need to buy and sell length in the market to manage portfolio needs, in our opinion. Moreover, ExGen has a significant open position in the mid-west (exposed to merchant market), and a somewhat tight position in ERCOT and New England, where it has some risk of finding itself short when loads are high, in our opinion.

Supply subsidiary, ExGen's cash flow is sensitive to commodity prices as almost 95% of its premerger generation is nuclear, all of which sliding gas prices are impairing. ExGen's unregulated operations accounted for about 65% of the consolidated enterprise by cash flow and capital spending in 2011. Given that base-load generation is price-taking--it doesn't affect the market price--we expect ExGen's adjusted funds from operations (FFO) to debt to remain volatile--relative to its peers--and we expect it to swing in a band of over 40% in 2011 to about 27% by 2014. For instance, all else remaining equal, we estimate gross margins in 2014 will be lower by about $500 million for every $5 per MW-hour (round-the-clock) decline in power prices, about $215 million for every $0.5 per million cubic feet (mcf) decline in gas prices, and about $110 million for every $1 per MWh decline in retail margins.

As a result, ExGen's contribution to the overall Exelon cash flow declines to about 55% under our base case, because of the decline in unregulated cash flow when commodity prices fall. However, despite the lower power prices, we view the business risk profile of parent Exelon as strong. We expect financial measures to decline over the next two years and the corporate credit ratings reflect our expectation that 2014 will be the trough year. Based on the present forward curve, cash flow measures are still adequate for the rated level in that year. However, as a result of the declining gross margin in forward years, we view Exelon's cash flow adequacy ratio as more akin to the "significant" financial risk profile than the erstwhile "intermediate" one.

We view ExGen's ratable hedging strategy favorably, as it ensures that a high percentage of the company's near-term generation is locked in. Hedging not only protects unregulated generation cash flows from steep price declines, it also provides the company time to adjust its cost structure or its capital structure, should prices remain depressed. However, hedging activities insulate, but do not isolate, power merchants from commodity price effects. Current hedges show the significant value of Exelon's hedging program. Even though these hedges insulate ExGen, perversely, they also show the sensitivity of ExGen's margins to the prospect of a continued shale production onslaught. The decline in mark-to-market value through 2014 shows the limit to which Exelon can hedge--a price-taking fleet can hedge, but only at the prices the market will bear. Also, the gross margin contribution at ExGen will face a decline as higher-priced hedges expire, evident in the drop in wholesale hedged gross margins. Still, the forwards show a contango as reflected in the increase in ExGen's open EBITDA from higher natural gas forwards. Additionally, we believe retail contributions will increase, given the potential for cost savings, volumes gained from the constellation merger, and recent acquisitions (StarTex and MX Energy Holdings).

We view parent Exelon's financial policy and internal funding as "aggressive." The current level of dividends, at about $1.8 billion, results in a dividend payout of about 80%, according to our estimates--meaningfully higher than the 50% to 65% range for peers. Moreover, Exelon's capital spending requirements are significant between 2012 and 2014, at

about $18.5 billion. Although utility capital spending tends to be funded in regulated rates (i.e., under rate base), unregulated generation will have to fund its own capital requirements and recover them in market prices. However, cash flow from operations will be insufficient for capital spending and dividends, resulting in external needs of financing. We estimate that the funding gap would be greatest in 2014 because of a trough in earnings even as ExGen's requirements to contribute toward Exelon's dividend commitments are the highest internal financing needs of the utilities. This funding gap could widen if the company fails to achieve merger driven O&M savings in its forecast. We estimate Exelon's incremental long-term financing needs at an average of about $1.4 billion to $1.5 billion in 2014 and 2015. Still, incrementally lower gas prices, combined with higher than anticipated O&M costs, would hurt ExGen's debt protection measures more than the level of new debt financing in ExGen's forecast through 2015.

Under our consolidated base case (we assume lower gas prices and market heat rates that result in power prices roughly 10% lower than the current forward contracts), we expect FFO to total debt of the pro forma company (i.e., Exelon and Constellation combined) to decline to about 25% in 2012 and then to hover at 22% to 23.5% through 2015. We expect free operating cash flow to debt to remain marginally positive even in 2013 and 2014 when we expect financial measures to trough. However, we expect discretionary cash flow (after dividends) to turn significantly negative--in a range between $1.1 and $1.7 billion through the period--mostly because of high capital spending. Similarly, we expect total debt to total capital to be about 57% and debt to EBITDA to hover at about 4.0x. These ratios are still consistent with Standard & Poor's 'BBB' rating guideposts for a financial risk profile we assess as "significant," especially since a meaningful amount of capital expenditure is discretionary. The company's recent decision to defer the LaSalle extended power uprate (EPU) by two years demonstrates flexibility to adjust the program as needed based on market conditions. We estimate that deferring the project by two years will free-up about $400 million through 2014.

Liquidity

The short-term rating on Exelon and affiliates is 'A-2'. Standard & Poor's views the liquidity across the Exelon group of companies as "strong," in light of the debt maturities we expect and available credit facilities. We estimate that sources of cash will exceed the companies' uses by about 2x during the next 12 to 24 months. We expect sources over uses for Exelon and ExGen to remain positive even if EBITDA declines by 50%. In addition, because of Exelon's solid relationships with banks and high conversion of FFO to discretionary cash flow, we believe the company can absorb low-probability, high-impact shocks.

Exelon has sufficient alternative sources of liquidity to cover current liquidity needs, including ongoing capital requirements, moderate capital spending, and upcoming debt maturities. Ironically, a declining power price environment is favorable from a liquidity perspective as cash is being posted to ExGen on its forward hedges. The next large maturities are in 2015 for Exelon and 2014 for ExGen.

In March 2010, ComEd replaced its $952 million credit facility with a three-year, $1 billion unsecured revolving credit facility that expires March 25, 2013. On March 10, 2012, the capacity under Constellation's revolving facility fell to $1.5 billion from $2.5 billion, reducing aggregate bank commitments to $3.2 billion. All facilities reside at the parent level. In addition, Exelon is working through the migration of letters of credit and has a liquidity reduction plan in place that it will finalize toward the end of 2012.

As of July 27, 2012, Exelon, ExGen, ComEd, PECO, and BGE had credit facilities of $2.84 billion, $5.6 billion, $1.0 billion, $0.6 billion, and $0.6 billion, respectively. These facilities expire between September 2013 and March 2017. Availability under these facilities was $2,319 million and $3,807 million respectively for Exelon and ExGen, respectively, and $999 million, $599 million and $564 million for ComEd, PECO, and BGE, respectively. Excluding commercial paper outstanding, the aggregate availability was $7.86 billion.

Outlook

The outlook on the ratings is stable. That said, we believe that higher natural gas production from shale plays and a delay in environment rules related to plant retirements can significantly hurt the company's financial performance. We believe these headwinds have increased and Exelon faces a potential earnings decline in 2014. Should the prevailing commodity environment persist, the company may have to address its declining earnings profile by reducing capital spending. We expect Exelon and ExGen to maintain consolidated FFO to debt in the 21% to 23% and 25% to 27% ranges, respectively, in 2014 to maintain current ratings. We will specifically monitor the expected negative discretionary cash position that results from Exelon's large dividend commitment. A positive outlook--currently not under consideration--can result if natural gas prices stabilize and power prices respond favorably to coal-plant retirements, resulting in an improvement in consolidated FFO to debt levels of over 27%.

Business Description

Chicago-based diversified energy company Exelon operates in 47 states, the District of Columbia, and Canada. Supply subsidiary Exelon Generation Co. (ExGen) is the largest competitive U.S. power generator, with about 35,000 MW of owned capacity. It provides energy products and services to about 100,000 business and public sector customers and about 1 million residential customers. Exelon's utilities deliver electricity and natural gas to more than 6.6 million customers in central Maryland, northern Illinois, and southeastern Pennsylvania.

On March 12, 2012, Exelon completed the merger with Constellation Energy Group Inc. (CEG), with CEG becoming a wholly owned subsidiary of Exelon. CEG's interest in RF Holdco LLC, which held CEG's interest in Baltimore Gas & Electric Co. (BGE), was transferred to Exelon Energy Delivery Co. LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interest in Commonwealth Edison Co. (ComEd) and PECO Energy Co. (PECO). CEG's generation and customer supply businesses were transferred to ExGen. CEG's shareholders received 0.930 shares of Exelon common stock in exchange for each share of CEG.

Business segments

Exelon operates through its four principal subsidiaries: ExGen, ComEd, PECO, and BGE. Subsequent to the merger with CEG in March 2012, ExGen now also includes CEG's customer supply and generation businesses.

ExGen consists of owned, contracted, and investments in electric generating facilities and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services, and natural gas exploration and production activities. ExGen's generation assets are mostly nuclear (55%) and gas (28%). Geographically, the assets are in the Mid-Atlantic (38%) and Mid-West (34%) regions

with most of the assets in Illinois (33%) and Pennsylvania (26%).

On April 5, 2012, ExGen's solar investment, the Antelope Valley Solar Ranch One project, received first advance of a loan guaranteed by the U.S. Dept. of Energy's (DOE) Loan Programs Office, finalizing Exelon's ownership of the project. First Solar is building the 230 MW photovoltaic power project in northern Los Angeles and will also operate and maintain the project. The projected commercial operations date for the first portion of the project is in late 2012, with full operation planned for late 2013. However, the project is somewhat delayed because Los Angeles County sought information regarding electrical certifications. In June 2012, the project received approval to restart construction from Los Angeles' public works department. The project has a 25-year power purchase agreement (PPA), approved by the California Public Utilities commission (PUC), with Pacific Gas and Electric Co. for the full output of the plant.

The regulated businesses include:

- ComEd, which serves 3.8 million electric customers (as of June 30, 2012) in northern Illinois, including Chicago.
- PECO, which serves 1.6 million electric customers (as of June 30, 2012) in southeastern Pennsylvania, including Philadelphia, and gas customers (0.5 million as of June 30, 2012) in surrounding Pennsylvania counties.
- BGE, which serves electric and gas customers (1.2 million and 0.7 million respectively as of June 30, 2012) in central Maryland, including Baltimore.

Rating Methodologies/Key Criteria Considerations

- We consider the ratings of Exelon and ExGen to be inextricably linked because we consider ExGen a core and primary subsidiary of Exelon.
- We consolidate the utility subsidiaries when assessing credit quality, given the absence of any meaningful structural (ring-fencing) or regulatory insulation. A measure of this is an assessment of the likelihood of Exelon providing financial support to affiliate utilities in Illinois and Pennsylvania if any adverse regulatory/legislative developments occur. We may rate the subsidiaries more on a stand-alone basis if we determine that Exelon may not support an affiliate under a stress scenario, or that the subsidiary is no longer a core holding.
- BGE is ring-fenced from the parent's operations. The ring-fenced structure insulates BGE's credit from that of Exelon, allowing up to a three-notch separation in ratings. Because BGE's credit profile is insulated, but not isolated, from the effects of the larger, unregulated operations, if the parent's credit profile deteriorates then we would expect BGE's credit ratings to weaken, as well. Although BGE is ring-fenced from the parent, we incorporate its distributions to the parent into the parent's business risk assessment.

We rate the parent holding company's senior unsecured debt 'BBB-', one notch below Exelon's corporate credit rating because of the 20% priority debt test (i.e., the holding company debt is structurally subordinate to debt at the operating companies). All of CEG's debt (excluding BGE) now resides at Exelon Corp. even as all assets were combined at the ExGen level.

Of the total $17.8 billion of on-balance-sheet debt, $15.2 billion is at the operating companies (these numbers exclude hybrid securities). After including account payables, income taxes, etc., senior claims are above 30% of total fixed assets of $76 billion as of June 30, 2012. The notching is effected once senior claims exceed 20% of total assets (minus certain intangible assets). As a result, we consider the holding company debt as disadvantaged.

Business Risk Profile: Strong

Exelon's "strong" business profile is predicated on its competitive cost structure. ExGen has among the most competitive merchant power plants because of its nuclear assets. As long as the economy grows modestly, ExGen's assets in regions such as the Mid-Atlantic will likely benefit from improving structural fundamentals for its fleet of plants such as environmental legislation. We also believe that the competitive position of ExGen's nuclear fleet will remain strong in the medium term as these assets are best positioned to serve the wholesale needs of regional transmission and distribution companies. However, ExGen's cash flows are also among the most sensitive to natural gas prices declines because almost 95% of its pre-merger generation was nuclear, all of which is affected by declining gas prices. Given that base-load generation is price-taking, we expect ExGen's adjusted FFO to debt to remain volatile relative to its peers--and we expect it to swing in a band of more than 40% in 2011 to about 26% by 2014 and 2015. Still, the low cost structure of nuclear generation requires gas prices to fall and remain below $2.75 per thousand cubic feet (mcf) levels over a sustained period before ExGen's funds from operations (FFO) to debt declines below 20%Also, following the merger, Exelon gets a larger proportion of earnings from its regulated and retail operations. We expect these incremental revenue streams to make the consolidated Exelon somewhat more resilient to commodity prices.

Regulated businesses

For a comprehensive assessment of the credit quality of the utilities, please see their respective reports on RatingsDirect.

We categorize regulation in Maryland and Illinois (where BGE and ComEd operate, respectively) as "less credit supportive," while we view Pennsylvania, where PECO operates, as "credit supportive."

- Pennsylvania permits competition for the supply of retail electricity while transmission and distribution service remains regulated under the Competition Act.
- Illinois has also initiated competition for retail electricity. ComEd's operations suffer from the economic downturn because sales depend on industrial and wholesale customers.
- Maryland has implemented electric customer choice and competition among electric suppliers, so customers can choose their electric energy supplier. However, BGE remains the sole distributor of electricity to these customers.

Market position

We view the business risk profiles of ComEd, PECO, and BGE as "excellent" and we view the long-term prospects for the supply business as strong. We believe Exelon's base load nuclear assets have a competitive cost structure, which is the primary reason for its strong business risk profile. However, we note that Exelon's cash flows vary significantly with changes in electricity and natural gas commodity prices. Specifically, we note that Exelon is more exposed to drops in commodity price than its peers. Falling natural gas prices harm ExGen more than its peers because almost 90% of its generation (excluding power purchased through contracts) is from base load nuclear generation, all of which declining natural gas prices affect. However, we recognize that the company's cost structure is among the most competitive in the industry.

Commonwealth Edison Co.

ComEd is a regulated transmission and distribution company that serves 3.8 million customers in Chicago and surrounding areas. About 77% of revenues pertain to distribution and are regulated by the Illinois Commerce

Commission (ICC). The remaining 23% relate to transmission and are regulated by the Federal Energy Regulatory Commission (FERC). In 2010, the company filed for a $396 million rate increase, which it later adjusted to $343 million based on an 11.5% return on equity (ROE). The staff recommended a rate increase of $113 million based on a return on equity (ROE) of 10%. Eventually, the ICC approved a $143 million increase based on a 10.5% ROE and a $6.549 billion rate base. Exelon estimates the increase will raise residential rates by 4%. The new rates went into effect in June 2011. Subsequently, under the formula rate process, ComEd filed a $59 million revenue decrease based on a 10.05% ROE. In May 2012, the ICC ordered a $168 million decrease. On the transmission side, the FERC updated the annual formula rate in May 2012, approving an 11.5% ROE. The rates went into effect June 2012.

On May 30, 2012, the ICC issued its final order for ComEd's 2011 formula rate proceeding. The order reduced the annual revenue requirement by $168 million, or about $110 million more than the reduction that ComEd proposed. Of this, about $50 million will be reflected in the annual reconciliation, thereby delaying the timing of cash flows. In second-quarter 2012, ComEd recorded a reduction of revenue of about $100 million pre-tax to decrease the regulatory asset for 2011 and 2012. (Please see the summary analysis on ComEd published Sept. 27, 2012.)

PECO Energy Co.

PECO is a regulated electric and gas transmission and distribution company that serves 1.6 million electric customers and 490,000 gas customers in Philadelphia and surrounding areas. About 90% of revenues come from distribution, which the Pennsylvania Utility Commission (PUC) regulates, and 10% comes from transmission, which the FERC regulates. PECO successfully transitioned to full-competitive rates by effectively managing its regulatory risk and benefiting from low market power prices. PECO proactively conducted five competitive wholesale power auctions for 2011 that locked in lower power costs for its customers. The PUC-approved default service plan (DSP) has a 29-month term that ends May 2013. PECO has filed a second DSP outlining a plan from June 2013 through May 2015. In addition, PECO has been able to settle its electric and gas rate cases for $245 million, or about 68% of the amount requested ($225 million for electricity and $20 million for gas; the approved increases were 71% and 46%, respectively, of the amounts requested). Because of the settlement and the wholesale power auctions, customers' total electric bills increased by only 5%. We believe this level of rate increase will not attract any regulatory risk.

In January and April 2012, PECO entered into contracts with PUC-approved bidders, including ExGen, for electric supply for default electric service that began in June 2012 and block contracts beginning December 2012. A PUC order on the filing is expected in mid-October 2012. PECO has one competitive procurement remaining over the term of the DSP program. (See the summary analysis on PECO published Sept. 21, 2012, for further details.)

BGE

BGE is a regulated transmission and distribution company that serves 1.2 million customers in a 2,300 square mile area around Baltimore in Maryland. The latest electric and gas rates went into effect in December 2010 based on 9.86% and 9.56% ROEs, respectively. In July 2012, BGE filed for increases of $151 million and $53 million to its electric and gas base rates, respectively with the Maryland Public Service Commission. The requested ROE in the application is 10.5%. The commission will determine any increase in rates after a seven-month proceeding with input from all interested parties. The new electric and gas distribution base rates are expected to take effect in late February 2013. The latest transmission rates are based on an 11.3% ROE and were effective June 2012. (Please see the summary analysis on BGE published May 22, 2012, for further details.)

Credit Issues And Considerations

The portfolio has geographic, and fuel diversity. Still, economically, Exelon's cash flow are highly susceptible to price movements of natural gas, which is the marginal fuel in most regions. While the company also has a long position on market heat rates and carbon and other emissions, the price taking nature of its large base-load fleet makes it more vulnerable to downward movements in gas prices compared with its peers.

We consider about 65% of Exelon's operations as unregulated in our business risk profile assessment. It incorporates contributions from BGE on a limited basis as we view BGE as ring-fenced from Exelon resulting in restricted contributions. As per one condition to the merger approval, BGE is anyway not making any distributions to Exelon through 2014. We note though that about 45% of aggregate Exelon debt is at utilities serviced from lower-risk regulated cash flow. This analysis imputes all Exelon Corp. parent level debt to the unregulated businesses.

The merger provides greater scope and scale benefits

From a credit perspective, we view the merger favorably. While the combination has diversification benefits, it largely centers around expanding the retail power business that matches load to generation. The combination provides Exelon regional diversification of the generation fleet and a customer-facing load business as generation and load positions are now better balanced across multiple regions. In almost all locations, Exelon will have adequate intermediate and peaking capacity in the portfolio for managing load-shaping risks. For instance, Exelon has generation in the Midwest Independent System Operator, PJM Interconnection, and Electric Reliability Council of Texas (ERCOT) regions, while CEG has significant retail load in these locations but is short on generation. However, the company will still need to buy and sell long in the market to manage portfolio needs, in our opinion.

Through retail and wholesale channels, Exelon now provides about 170 terawatt-hours, or about 5%, of total U.S. power demand. The company expects the switched markets in Pennsylvania, Ohio, Michigan, and Arizona to grow at about 10% in the commercial and industrial class and at about 15% in the residential class between 2011 and 2014. The fleet is well positioned to grow where capacity available for competitive supply has room to grow. That said, Exelon has a significant open position in the Midwest (exposed to merchant market), and a somewhat tight position in ERCOT and New England where it is at some risk to be caught short under strong load assumptions, in our opinion.

The combination can reasonably extract merger synergies

Merger synergies accrue from a combination of labor and information technology savings from corporate and commercial consolidations, reduced collateral requirements, supply chain savings, among others. Exelon expects to maintain an O&M compound annual growth rate of about 1%--lower than inflation. Although Exelon expects to hit a run-rate of $500 million by 2014, our assumptions are relatively more conservative at about $300 million to $350 million in synergies in 2015-2016. We have assumed this level because Exelon has experienced reasonable success in past cost reduction initiatives and in assimilating past mergers.

Despite the merger, current forward natural gas prices still imply downside risks mitigated to some extent by retail upside, which offers a countercyclical offset

Longer-term electricity demand has shrunk with the decline in GDP growth expectations. The North American Electric Reliability Corp. estimated 2011 nationwide reserve margins near 27%, well above the nationwide average target levels

of about 15%. Power markets will likely remain oversupplied (with exceptions, like the Texas market) given tepid load growth at least until 2015 when coal-plant retirements will take inefficient units off the aggregate generation (the supply "stack") and cause reserve margins to tighten.

Capacity prices appear to suggest an improvement in outlook in the 2015 time-frame. The 2015/2016 PJM reliability pricing model auction prices cleared at $136/MW-day for regional transmission organizations (RTO), an increase of about 8% from 2014/2015 prices. The increase mainly stemmed from significant planned generation retirements (about 14 gigawatts) over the next three years, driven largely by environmental regulations. The increase in prices was more significant for MAAC/EMAAC/SWMAAC prices in the region, which increased about 23% from 2014/2015 results. ExGen's fleet has significant capacity in the PJM region (RTO--about 11,500 MW; EMAAC/MAAC/SWMAAC--about 13,800 MW) which is where the capacity prices have jumped most. We expect the overall impact of recent auction results to be modestly favorable for Exelon's credit quality given that our expectation was about $125 per MW-day.

Weather dominates near-term fundamentals. The mild 2011-2012 winter resulted in dramatic storage surplus. The supply overhang, a relatively slow economic recovery, and a steady supply side growth will likely keep prices ranging around $3.50 to$4.00 per million Btu through 2014, in our opinion. This downturn has also affected forward prices through 2016 due to ongoing spot market weakness and concerns around a sluggish economic recovery. However, a contango (i.e., when the futures curve is upward sloping) has developed in the one- to two-year natural gas forward prices. Industry experts expect higher natural gas prices in 2013 and 2014 as a natural consequence of the sharp decline in drilling brought about by the $2.00 gas price observed in 2012 (natural gas rigs are down to 518 compared with 886--a 71% drop from just one year ago). Still, a lingering concern is that shale gas production could continue to impress as increasing amounts of production in the Marcellus Shale region is brought to market. On the flip side, while PJM and other eastern independent system operators remain well supplied through 2014, the market is heavily discounting (not reflecting any uplift in power prices) forthcoming power plant retirements or higher costs to meet new emissions rules.

However, power prices across the Mid-Atlantic and Midwest have retracted their gains in the year. The decline in power prices is not only driven by natural gas prices. Contrary to expectations, implied market heat rates declined. Prompt and forward power prices in the PJM declined in the last quarter despite a modest rally in gas prices in July. We ascribe the unexpected decline in heat rates to declining coal prices. As coal is increasingly setting the marginal cost of supply, heat rates and power prices have increasingly started tracking coal prices instead of gas prices. Nuclear plant operators like Exelon are confronted with lower power prices without the benefit of lower fuel prices. We note though that the declining heat rates also appear to suggest a more fundamental shift due to lower-than-expected demand growth.

Current hedges show the significant value of Exelon's hedging program. While these hedges insulate ExGen, they also show the sensitivity of ExGen's margins to the prospect of a continued shale gas production onslaught. The decline in mark-to-market value through 2014 shows the limitation of a price-taking fleet--a company can hedge, but only at the prices the market will bear. Still, the forwards do show a contango as reflected in the increase in open EBITDA due to higher natural gas forward prices.

The merchant generation contribution at ExGen will face a decline as above-market hedges expire, evident in the drop in wholesale hedged gross margins. However, we expect retail contributions to increase given potential for cost savings, volumes gained from the CEG merger, and recent acquisitions (StarTex and MX Energy Holdings). Separately, we have noted that retail business offers an offset to wholesale operations. In a declining wholesale power environment, retail margins increase because retail contracts are locked in when prices were higher. The declining wholesale prices also reduce capital and collateral needs, further boosting $ per megawatt-hour (MWh) margins on the existing retail business (even as new and returning retail business contracts). That said, maintaining retail margins around $4 per MWh in an increasingly competitive market may prove challenging, in our opinion.

Under the forward commodity environment, Exelon's dividend payout ratio will likely climb to about 80% to 85% and the funding gap for Exelon's capital spending also widens

The current level of dividend payment requires about $1.8 billion of cash, which is significant relative to Exelon's 2014 net income. Under the S&P pricing deck, projections for 2014 remain sensitive to natural gas and power price assumptions. All else equal, we estimate gross margins in 2014 will be lower by about $500 million for a $5 per mcf (round-the-clock) decline in power, about $215 million for a $0.5 per million cubic feet (mmcf) decline in natural gas prices and about $110 million for a $1 per MWh decline in retail margins.

Moreover, under Exelon's current capital program, spending requirements are significant between 2012 and 2014 at about $18.5 billion. While utility capital spending tends to be funded in rate base, unregulated generation will have to fund its own capital requirements and recover them in market prices. In the current commodity environment, we expect ExGen to generate about $3.2 billion to $3.8 billion of cash flow from operations between 2012 and 2015. These are not sufficient for capital spending and dividend payments so ExGen will need external financing.

We estimate that the capital spending funding gap would be greatest in 2014 because of a trough in earnings even as ExGen's requirement to contribute toward Exelon's dividend commitments is the highest because the utilities will have internal financing needs of their own. Given the current investment plan we estimate a shortfall of about $2.5-$3.0 billion over the three-year period 2013-2015, with relatively larger gaps in 2014 and 2015. Should Exelon maintain its current capital spending plans, these investments will likely need external financing (incremental debt or new equity funding). Still, incrementally lower gas prices would have a much greater impact on ExGen's debt protection measures than the level of new debt financing in ExGen's forecast through 2015.

Exelon has a few discretionary levers it can pull in the event of a further fall in commodity prices.

Flexibility on timing of generation growth projects. On the nuclear front, about 250 MW have been added to date with total spending expected to be $3.8 billion from 2008 to 2019. The company's recent decision to defer the LaSalle extended power uprate by two years demonstrates flexibility to adjust the program as needed based on market conditions and free cash flow availability. We estimate that deferring the project by two years will free-up about $400 million through 2014.

Project financing. Although Exelon's wind and solar development pipelines provide investments with long-term, contracted cash flows, these projects are noncore to Exelon. The company has indicated that it will likely project finance these investments. Taken together, we estimate that deferrals, cancellations, and off-balance-sheet financing can reduce debt financing by about $1 billion through 2016. The overall impact would be to bolster FFO to debt ratios by 120 to 250 basis points, all else remaining equal.

Regulated cash flow. Rate base will grow at the utilities, especially in Illinois, due to legislation passed in 2011 that increases spending and reduces regulatory lag. We estimate that PECO and ComEd will contribute about $400 million to $500 million toward Exelon's consolidated dividend commitments of about $1.8 billion per year between 2012 and 2014.

Equity issuance and dividend cuts are not currently in the plans as the company expects prices to recover, but we believe the company is committed to maintaining investment-grade ratings and will consider these avenues should the need arise..

Management

We view Exelon's business strategy as an important determinant of the company's credit profile. In recent years, Exelon has implemented a strategy of internal growth through reinvesting in existing businesses and investing in new technologies. There is also a bias toward longer term contracted businesses.

Management's business strategy appears to be three-pronged: expanding the company's clean generation portfolio through the nuclear uprate program, enlarging alternative energy investments through wind development projects (and solar projects), and in the medium term investing in new technologies such as the smart grid.

While the utilities primarily focus on growing rate base and earning a reasonable return, they are also playing a role in competitive markets by investing in transmission. Yet, Exelon has indicated that--longer-term--its core power strategy does not preclude the potential for acquisitions, especially in assets that can potentially offset the business risk profile of its wholesale generation business and reduce the company's exposure to natural gas. Management considers renewable assets a good hedge for its existing business, as they help diversify away from natural gas exposure, and also because states such as Pennsylvania and Illinois also have a renewable portfolio standard mandate. However, renewable energy is not core to the company's strategy.

Profitability/Peer comparisons

Exelon compares well with peers like FirstEnergy Corp., having stronger financial measures. While PPL Corp. has weaker financials, its business risk profile is stronger given its significantly larger dependence on regulated cash flow. Similarly, compared with Public Service Electric & Gas Co. (PSEG), Exelon is somewhat less regulated. PSEG is also expanding its regulated business and therefore we view it as having stronger credit.

Financial Profile: Significant

Accounting

Exelon's accounting policies conform to industry standards. We impute a significant amount of debt to Exelon, as much as $4.4 billion which consists mostly of about $2.9 billion related to Pension/OPEB, about $500 million related to operating leases and about $1.0 billion related to their power purchases.

Financial governance and policies/risk tolerance

Hedging strategy.

- ExGen procures coal and natural gas through long-term and short-term contracts, and spot-market purchases.
- It obtains nuclear fuel mostly through long-term contracts.

- ExGen receives about 55% of its uranium concentrate requirements from 2012 through 2016 from three producers.
- ComEd, PECO, and BGE mitigate exposure as a result of regulatory mechanisms that allow them to recover procurement costs from retail customers.
- Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility.
- Although ExGen enters into derivative contracts to hedge this anticipated exposure, it is exposed to relatively greater commodity price risk in subsequent years because a larger portion of its electricity portfolio is currently unhedged.
- As of June 30, 2012, the proportion of hedged generation was 99%-102% for 2012, 79%-82% for 2013, and 46%-49% for 2014.

Although the bulk of total projected margin is under contract for the next two years, this percentage rolls off in the outer years, pointing to the need for ExGen to constantly enter into new contracts and exposing it to wholesale market price volatility. The price-taking nature of the fleet results in margin erosion when wholesale power prices begin to decline and the company renews contracts at lower levels. Credit concerns stem from ExGen's relatively larger exposure to merchant margin volatility due to its base-load nuclear generation. Furthermore, these contracts expose ExGen's margins to market risks, including load-shaping, fuel, and volume risks. Although margins are highly hedged, they are hedged based on expected volumes.

As nuclear assets are essentially price-takers, hedged gross margins depend on power prices set by longer-term marginal fuel prices (natural gas in most instances). While the backwardated EBITDA still supports current rating levels, deterioration in merchant market fundamentals has the most potential to affect Exelon's credit quality.

Projected cash flow adequacy and capital structure/asset protection:

Cash flow adequacy. We assess the cash flow adequacy of Exelon and also that of ExGen because ExGen provides the most cash flow. We do so because we view the ability of the utilities' to upstream dividends consistently as somewhat uncertain because of their capital spending requirements based on their changing smart grid/renewable energy plans.

Although Exelon hedges ratably, cash flow from the unregulated generation business has declined about $1 billion over 2010 and 2011 levels. We expect Exelon's adjusted FFO to debt ratio to decline to about 27% by year-end 2012 as the high-priced hedges fall away. Consolidated cash flow measures should remain stable at about 23.5% to 24% through 2013 because the company has hedged a significant proportion of generation. However, we expect ratios to trough by 2015 to about 22% as the full impact of the commodity cycle takes effect. Exelon will need consolidated debt protection measures of at least 21% for the current rating level.

Subsequently, we expect a modest recovery driven by coal-plant retirements. Risks to our analyses exist in the form of incremental headwinds from shale gas production and a delay in price recovery. Fundamental shifts in power consumption, brought about by energy efficiency, could also lower market heat rates and affect power prices.

ExGen's cash flow protection, as reflected by the ratio of adjusted FFO to debt, was about 43.4% in 2010 (after incorporating $1.3 billion of Exelon debt). However, we expect 2012 and 2013 adjusted FFO to debt to decline to around 30% due to lower power prices, when generation will be hedged, and lower in 2014 to trough at about 25% to 26%. We consider adjusted FFO to debt measures at about 26% for ExGen as required for the rating.

We would continue to characterize ExGen's and Exelon's cash flows as satisfactory for the current rating. Still, while

we expect Exelon to generate strong operating cash flow, its internal funding will remain weak due to a significant capital spending program for reliability enhancements, smart grid programs, renewable energy at the utilities, and a large nuclear uprate program.

Capital structure/Asset protection

Exelon has significant off-balance-sheet obligations that represent about one-fourth of total adjusted debt. After adjusting for ExGen's tolling contracts and the consolidated entity's unfunded pension and postretirement benefit obligations, we consider Exelon's capital structure risk as significant. However, about 45% of total adjusted debt is at utility operating companies:

As of June 30, 2012, Exelon's adjusted debt to total capital was about 55.5%. Given the current business mix, which depends considerably on the volatile generation business, we consider leverage to be high. Still, because the book value of ExGen's nuclear assets is undervalued, we would characterize book value debt to capital as a somewhat weak indicator of financial risk. Nonetheless, we give relatively less importance to the debt to capital ratio because Exelon's ability to service its debt is not affected directly by this ratio.

Debt per kilowatt (kW), a more relevant leverage statistic, remains modest. Excluding debt at the utilities and after imputing all debt relating to PPAs and unfunded pensions and post-retirement obligations, Exelon's stand-alone merchant business of adjusted owned and contracted kWs remains modest at about $275 per kW and under $500 per kW when we include only base-load kW. We believe this is well below the replacement value of base load nuclear units.

Liquidity

We estimate that Exelon and ExGen's sources of cash during the next 12 to 24 months to exceed uses by about 1.8x and 2.0x, respectively. We expect sources over uses for both companies to remain positive even if EBITDA declines by 50%.Exelon has sufficient alternative sources of liquidity to cover current liquidity needs including ongoing capital requirements and margin requirements at ExGen, moderate capital spending, and upcoming debt maturities.

Of the original $10.3 billion in combined credit facilities and bilaterals, $1 billion was reduced when the merger closed. The balance of $1.5 billion (of the erstwhile $2.5 billion CEG facility) will be terminated by year-end. A $300 million bilateral line of credit at ExGen will remain to help fill the $6.1 billion in ExGen combined company estimated liquidity needs ($5.3 billion revolving credit facility, $300 million bilateral credit line, and the $500 million revolving credit facility at Exelon). The $900 million in remaining bilaterals at Exelon (formally CEG bilaterals) will be terminated by year-end 2012.

As of July 27, 2012, credit facilities consisted of:

- Exelon, $2.84 billion;
- ExGen, $5.6 billion;
- ComEd, $1 billion;
- PECO, $600 million; and
- BGE, $600 million.

These facilities expire between September 2013 and March 2017. Availability under these facilities was $2,319 million

and $3,807 million respectively for Exelon and ExGen, and $999 million, $599 million, and $564 million for ComEd, PECO, and BGE, respectively. Excluding commercial paper outstanding, the aggregate availability was $7.86 billion.

Debt maturity profile

Except for 2015 and 2016, the annual maturities for the next several years are about $1 billion, which is about 20% of Exelon's annual FFO, and hence, in our view, manageable. Furthermore, between 2012 and 2016, about 66% of the maturities consist of regulated utility debt. Exelon and ExGen do not have any significant maturities till 2015 and 2014, respectively.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings Detail (As Of September 28, 2012)	
Exelon Corp.	
Corporate Credit Rating	BBB/Stable/A-2
Junior Subordinated	BB+
Senior Unsecured	BBB-
Corporate Credit Ratings History	
22-Jul-2009	BBB/Stable/A-2
21-Oct-2008	BBB/Watch Neg/A-2
29-Aug-2007	BBB+/Stable/A-2
Business Risk Profile	Strong
Financial Risk Profile	Significant
Related Entities	
Baltimore Gas & Electric Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preference Stock	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB+
Commonwealth Edison Co.	
Issuer Credit Rating	BBB/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	BB+
Senior Secured	A-
Senior Unsecured	BBB
Exelon Generation Co. LLC	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured	BBB

Ratings Detail (As Of September 28, 2012) (cont.)	
Senior Unsecured	BBB-
Senior Unsecured	BBB/A-2
PECO Energy Co.	
Issuer Credit Rating	BBB/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	BB+
Senior Secured	A-
Senior Secured	AA-/Stable
Philadelphia Electric Co.	
Senior Secured	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.