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The Prairie State Coal Plant:
The Reality vs. the Promise

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Executive Summary

The 217 municipalities and 17 electric membership cooperatives in the Midwest that buy power from the Prairie State coal plant, a project developed by Peabody Energy, were promised a low cost, stable source of electricity. However, the 2.5 million ratepayers in these municipalities and cooperatives ("the communities") are now learning that the reality of the plant is turning out to be very different than the promise. Instead of being a source of low cost electricity, the first year cost of power from Prairie State is 40 to 100 percent higher than the current cost of power in the Midwest wholesale markets and is expected to remain higher than market prices for the next ten to thirteen years, if not longer.

Consequently, as this report shows, Prairie State will almost certainly not provide an economic benefit for ratepayers of these communities (on a cumulative annual basis) until the late 2030s or the 2040s, if then. In other words, the higher near-term costs of power from the project are certain while the benefits that these communities were promised are extremely speculative. As a result, participation in the Prairie State project has created and will continue for the long term to create significant fiscal problems and stresses for the participating communities.

Purpose of Report

The purpose of this report is:

(1) To investigate why the actual cost of power from the Prairie State Energy Campus is more than 40 percent higher than the "low costs" that communities were promised when buying power from the project was marketed to them;

(2) To analyze the relative cost of power from Prairie State compared to buying power from the regional PJM[1] and MISO[2] wholesale markets;

(3) To examine whether there are any factors that have the potential to increase the future financial risks and/or costs for communities in the Midwest of buying power from Prairie State; and

[1] PJM is the regional transmission organization (RTO) that manages the high-voltage electric grid and the wholesale electricity market that serves 13 states in the Mid-Atlantic and Midwest Regions of the U.S. and the District of Columbia.

[2] MISO (the Midwest Independent Transmission System Operator) is the RTO that manages the high-voltage electric grid and the wholesale electricity market that serves 11 states in the Midwest and the Upper Mid-West Regions of the U.S. and one Canadian Province.

(4) To provide questions that participating communities and their ratepayers can ask Peabody and the other Prairie State owners concerning the financial risks to which the communities and ratepayers are exposed due to their involvement in the Prairie State project.

Summary of Findings

1. Peabody Energy Corporation ("Peabody") was the initial developer of the 1600 MW Prairie State Energy Campus ("Prairie State" or "PSEC") coal-fired power plant. Beginning as early as 2001 Peabody began an aggressive campaign to induce joint municipal power agencies in states throughout the Midwest to participate in the project with promises of long-term low-cost power. By 2007, Peabody succeeded in selling approximately 95 percent of the ownership interests in the project to joint public power agencies in eight states. These power agencies, in turn, entered into long-term 'take-or-pay' or 'take-and-pay' power purchase agreements with 217 communities and 17 rural electric coops in Virginia, Ohio, Kentucky, Indiana, Illinois, Michigan, Missouri and West Virginia.

2. All of the communities that signed agreements to buy power from Prairie State are exposed to the significant financial risk that the actual cost of power from the project will be higher than they were promised. However, the approximately 82 communities that signed 'take-or-pay' contracts with American Municipal Power ("AMP"), Kentucky Municipal Power Agency, Northern Illinois Municipal Power Agency and the Missouri Joint Municipal Electric Utility Commission are particularly at risk because they are obligated to pay for their proportionate shares of Prairie State's fixed costs whether or not the plant generates any power.

3. In addition to the actual generating facilities, an ownership interest in PSEC includes an interest in the Lively Grove Mine and the Jordan Grove ashfill sites that are located near the generating facility. As a result of its sale transactions, Peabody, through its subsidiary, Lively Grove Energy, now retains only a 5.06 percent interest in the Prairie State project. However, Peabody has the option to sell even that very limited ownership share after the fifth anniversary of Prairie State's substantial completion date. It would not have to wait even the five years to sell its interest in Prairie State if its minimum ownership interest requirement is waived by a majority of the non-Peabody owners or if other conditions related to mine operations are met.

4. Although communities in the Midwest were originally promised that entering into long-term power purchase agreements to buy power from Prairie State would provide long-term, stable low cost energy, the actual first year cost of power from Prairie State is significantly higher than communities were promised as recently as 2007. For example, the actual first year cost of power for the 68 communities in Ohio, Virginia and West Virginia that are buying Prairie State power from AMP is in the range of 40 percent to 100 percent higher than the $41 per megawatt hour that they were promised.

5. The first year cost of power from Prairie State also is significantly higher than the price of purchasing power (including both capacity and energy) from the wholesale PJM and MISO markets and can be expected to remain higher for at least another decade, if not longer. As a result, participants in Prairie State will pay millions of dollars each in higher power costs through 2025, if not longer. The figures in the following table are illustrative of the excess power costs that communities in Ohio and Missouri will have to pay for power from Prairie State through 2025. Unfortunately, the costs that communities in other Midwest states are being billed for power from the plant were not available during the preparation of this report.

Table S-1: Illustrative Excess Power Costs through 2025 Due to Participation in Prairie State.

Community	MW Share of PSEC (MW)	Excess Power Costs Through 2025 Due to Participation in PSEC
Bowling Green OH	35.000	$27 million
Celina OH	14.928	$12 million
Cleveland OH	24.880	$19 million
Galion OH	9.952	$8 million
Hamilton OH	35.000	$27 million
Hudson OH	9.952	$8 million
Napoleon OH	4.976	$4 million
New Bremen OH	5.971	$5 million
Piqua OH	19.904	$15 million
Shelby OH	3.981	$3 million
Tipp City OH	9.952	$8 million
Versailles OH	3.981	$3 million
Columbia MO	50.000	$56 million

6. The figures in this table assume that Prairie State actually achieves the high level of operating performance (that is, average 85 percent annual capacity

factors) that Peabody, AMP and the other owners claim. The excess power costs paid by these communities (and all of the other communities that have long-term contracts to purchase power from the plant) will be even higher if Prairie State fails to achieve this level of performance. These figures show that Prairie State will almost certainly not provide an economic benefit for communities (on a cumulative annual basis) until the late 2030s or the 2040s, if then. In other words, the costs from the project are certain while the benefits are extremely speculative.

7. The significantly higher current and projected future cost of power from Prairie State (over what the participating communities were promised when the project was marketed to them) is the direct result of a substantial increase in the cost of construction from $4.0 billion to $4.9 billion.[3] This increase should have been anticipated by Peabody, AMP and the other owners of Prairie State when they marketed power purchase agreements to potential participating communities as the construction cost of almost every coal project had skyrocketed since 2000.

8. Bechtel designed, engineered and constructed the Prairie State project. Peabody did not have a fixed price for the project until 2010. Prior to that time, there was only a target price contract for Prairie State that provided incentives for completing the project at less than the specified target price – there were no construction cost guarantees.

9. Many participating communities were billed for Prairie State construction costs even before the plant began commercial operations on June 12, 2012. For example, the 68 communities in Ohio, Virginia, West Virginia, and Michigan that have contracts with AMP to buy power from PSEC paid over $11 million during the months of March, April and May 2012 even though the plant was not yet in commercial operations and, consequently, was not generating any power for them.

10. There is no guarantee that Prairie State will operate at the 85 percent annual capacity factors that Peabody, AMP and the other owners claim. In fact, the units already have experienced significant pre-operational problems that have delayed the start of commercial operations.

11. Contrary to what communities were promised, the Lively Grove mine may not have enough capacity to produce coal for Prairie State for 30 years. If it does not, additional sources will have to be developed or obtained and the

[3] The total costs, including debt service costs for the project, are $11.7 billion.

cost of power from Prairie State will likely be higher in future years than Peabody and the other project owners have acknowledged.

10. Additional capacity for the storage of the coal ash wastes produced by Prairie State will be required. The cost of acquiring this additional ashfill capacity will be passed on to the participating communities and their ratepayers and will mean further increases in the cost of power from Prairie State.

11. As a result, participation in the Prairie State project has created and will continue for the long term to create significant fiscal problems and stresses for the participating communities.

The following information supports these findings.

Background

The Prairie State Energy Campus ("PSEC") is a 1600 Megawatt ("MW") mine-mouth pulverized coal power plant in Southern Illinois.

Peabody began developing the PSEC project in 2001 to maximize the use of its high-sulfur Illinois Basin coal reserves. By 2007, Peabody's subsidiary Prairie State Generating Company ("PSGC") had acquired the necessary environmental and other relevant permits, had already awarded a number of contracts with various equipment vendors, and had issued purchase orders to major equipment. PSGC also had contracted with Bechtel to be the Engineering, Purchasing and Construction ("EPC) contractor for the project.

Between 2002 and 2007, Peabody, through PSGC, aggressively marketed ownership interests and sold all but 5 percent of its ownership interest in PSEC. As shown in Table 1, below, Prairie State's ultimate owners now include five joint municipal power agencies and two generation and transmission cooperatives.

Table 1: PSEC's Current Owners.

Owner	Ownership Share
American Municipal Power (AMP)	23.26%
Illinois Municipal Electric Agency (IMEA)	15.17%
Indiana Municipal Power Agency (IMPA)	12.64%
Missouri Jount Municipal Electric Utility Commission (MJMEUC)	12.33%
Prairie Power Inc (PPI)	8.22%
Southern Illinois Power Cooperative (SIPC)	7.90%
Kentucky Muni Power Agency (KMPA)	7.82%
Northern Illinois Municipal Power Agency (NIMPA)	7.60%
Peabody Energy subsidiary Lively Grove Energy	5.06%

Two hundred and thirty four (234) communities (that is, municipalities and electric membership cooperatives in the Midwest have purchase power agreements to buy power from PSEC. These communities serve approximately 2.5 million customers.

Each of the joint municipal power agencies convinced many of the communities they serve to enter into long term purchase power agreements ("PPA") to buy a contractually determined share of power from Prairie State for periods of thirty to forty years. In some instances, the communities signed take-and-pay contracts whereby they would make payments for all energy and capacity needs from their respective municipal power agencies. Other communities are obligated under 'take-or-pay' contracts where each community is obligated to pay its pro-rata share of Prairie State's large fixed costs whether or not it receives any power from the plant. For example, a number of communities served by AMP face heightened financial risk given the relatively large commitments to buy power from Prairie State when the cost of power on the wholesale market is projected to cost significantly less.

In several instances, participating communities committed to buying tens of thousands of megawatt hours generated at Prairie State for the purpose of selling excess power at a profit. However, because the cost of power from Prairie State is so much higher than the price of power purchased from the PJM and MISO markets, as will be discussed below, communities will not be able to sell any of their excess PSEC power at a profit. At best, such sales will only mitigate the economic burden that Prairie State places on participating communities and their ratepayers.

Table 2, below, shows the megawatts of Prairie State capacity for which some illustrative communities in Ohio and Virginia have contracted and compares the size of this commitment to the communities' projected peak demands and estimated average demands in 2015 and 2025.

The information on each community's peak demand was taken from a September 23, 2010 report prepared for AMP by R.W. Beck. However, it is more appropriate to compare the MW commitment of each community to its average demand rather than its peak demand because Prairie State is projected to be a baseload facility that will operate for more than the hours of peak demand. [4] As can be seen from Table 2, some communities will be extremely dependent on Prairie State for their capacity and energy. This means that these communities (as well as the other participating communities around the Midwest) will be severely impacted by PSEC's climbing construction costs and could be hit even harder if the plant does not perform as promised by Peabody, AMP or their joint municipal power agency or Generation and Transmission co-op.

Table 2: Illustrative PSEC Commitments by Communities in Ohio and Virginia Relative to Projected Peak and Average 2015 and 2025 Demands.

Community	(MW)	(As % of 2015 Peak Demand)	(As % of 2015 Average Demand)	(As % of 2025 Peak Demand)	(As % of 2025 Average Demand)
Bowling Green	35	33.7%	51.8%	25.9%	39.9%
Celina	14.928	33.0%	50.8%	31.3%	48.2%
Danville VA	49.76	21.1%	32.5%	18.6%	28.7%
Galion	9.952	43.0%	66.2%	41.5%	63.8%
Jackson Center	1.393	36.0%	55.3%	34.7%	53.3%
Milan	0.995	40.2%	61.9%	38.4%	59.1%
Minster	6.966	30.2%	46.5%	24.2%	37.3%
New Bremen	5.971	50.1%	77.0%	48.6%	74.7%
Piqua	19.904	30.1%	46.3%	26.8%	41.2%
Tipp City	9.952	33.2%	51.0%	29.0%	44.7%
Wellington	3.981	27.6%	42.5%	22.5%	34.6%

Utilities that Decided Not to Participate in Prairie State

At the same time that new owners were purchasing shares of PSEC and were marketing power purchase agreements to communities around the Midwest, other utilities decided against participating.

Wisconsin Public Power Inc, ("WPPI") a power supplier to 40 Wisconsin municipalities had signed a letter of intent in 2005 to purchase a six percent share of PSEC, representing 99 MW of capacity. This agreement, which had a fixed price for the power from PSEC, was subsequently revised so that WPPI could purchase power from Prairie State even if Wisconsin regulators barred it from taking an ownership stake. But after regulators approved WPPI's participation as an owner, Peabody sued WPPI. The suit claimed that the fixed price purchase power agreement had

[4] Based on our experience, we have assumed a 65 percent load factor for this analysis. This means that the average load for each community is assumed to be 65 percent of the peak demand.

been voided because regulators had approved WPPI's participation in the project and because the agreed-to fixed price was no longer valid due to the rising project costs.[5] News reports said that Peabody argued in the suit that the $45 per megawatt hour ("MWh") fixed price purchase power agreement would result in a "windfall" for WPPI and would be a "financial burden" for the Prairie State project.[6] WPPI withdrew from the Prairie State project and the proposed purchase power agreement was voided as part of the negotiated settlement to Peabody's law suit.

CMS Energy, a privately owned utility in Michigan, signed an agreement with Peabody in October 2006 to co-develop PSEC. Under the agreement, CMS and Peabody would each own 15 percent shares of the project with the remaining 70 percent being sold to Midwest municipal utilities and electric cooperatives. CMS would be lead project developer and operator.

However, CMS Energy withdrew from Prairie State just seven months later, announcing that the project no longer met the company's investment criteria.[7] However, a news report also said that CMS withdrew because it was unable to get its wholesale customers to agree to long-term power contracts and therefore saw the project as too risky.[8] As will be discussed in this report, the project's estimated construction cost had risen to about $4 billion at about the time that CMS Energy withdrew from Prairie State.

2012 Power Costs

When AMP was soliciting communities to participate in the Prairie State project, it promised that PSEC would provide long-term stable and low-cost power that would cost $41 per MWh in the plant's first year of operations and that, over the long-term, would remain significantly below future wholesale power market prices. Both of these promises were wrong as both the first year and the long-term costs of power from Prairie State have increased significantly.

Figure 1, below, compares the $41 per MWh first year power price that AMP promised communities back in 2007 with AMP's currently claimed average power cost for 2012 (its first year of operation) and with the current PJM average "All-in" cost of power. The average "All-in" PJM cost includes capacity, energy, and other wholesale load costs.

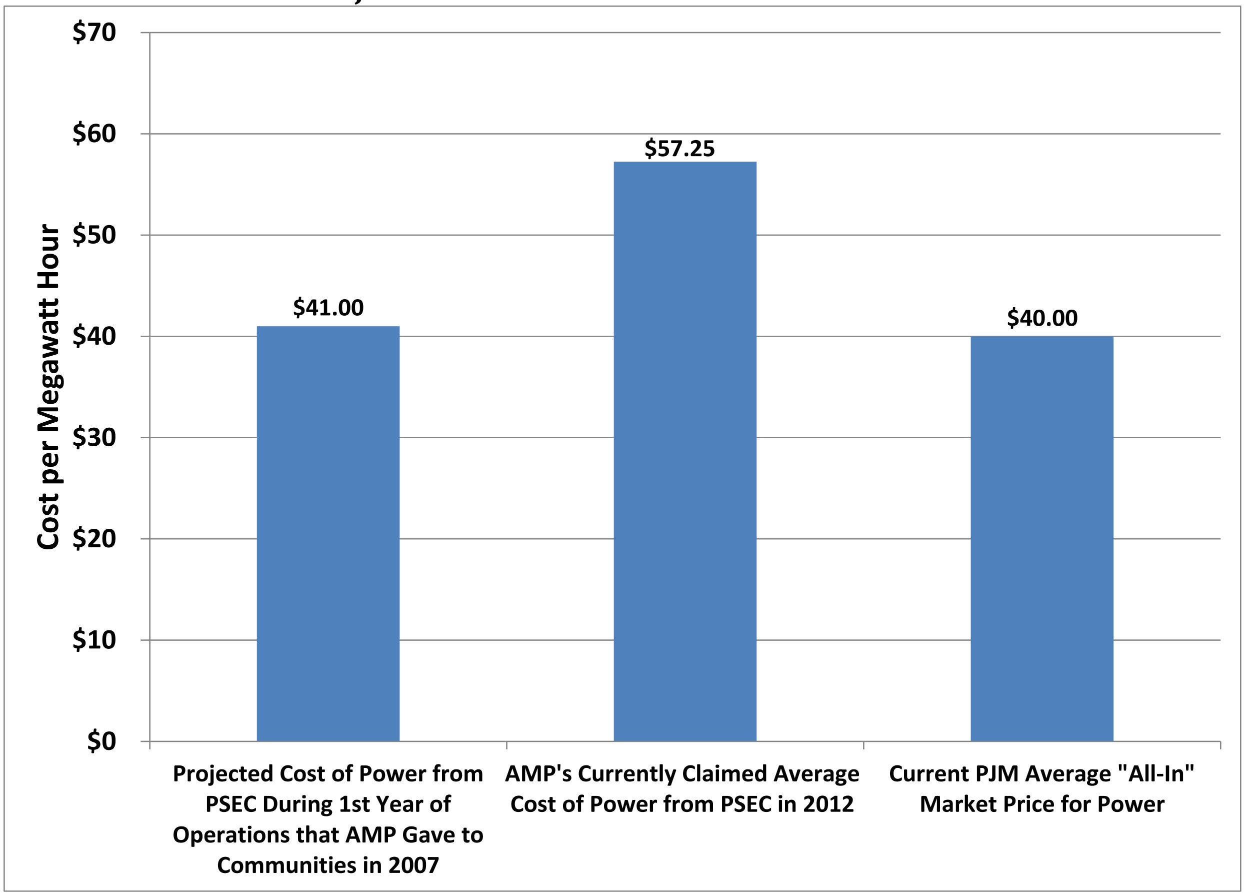
5 *Peabody Sues Wis. Utility over Plant*, St. Louis Post-Dispatch, November 16, 2006.

6 Delays, Cost Overruns Blemish Illinois Coal Project, St. Louis Post-Dispatch, June 17, 2012.

7 *CMS Withdraws from Peabody Project*, St. Louis Business Journal, May 7, 2007.

8 St. Louis Post-Dispatch, May 5, 2007, available at http://business.highbeam.com/435553/article-1G1-163022190/peabody-partner-prairie-state-project-backs-out-michigan.

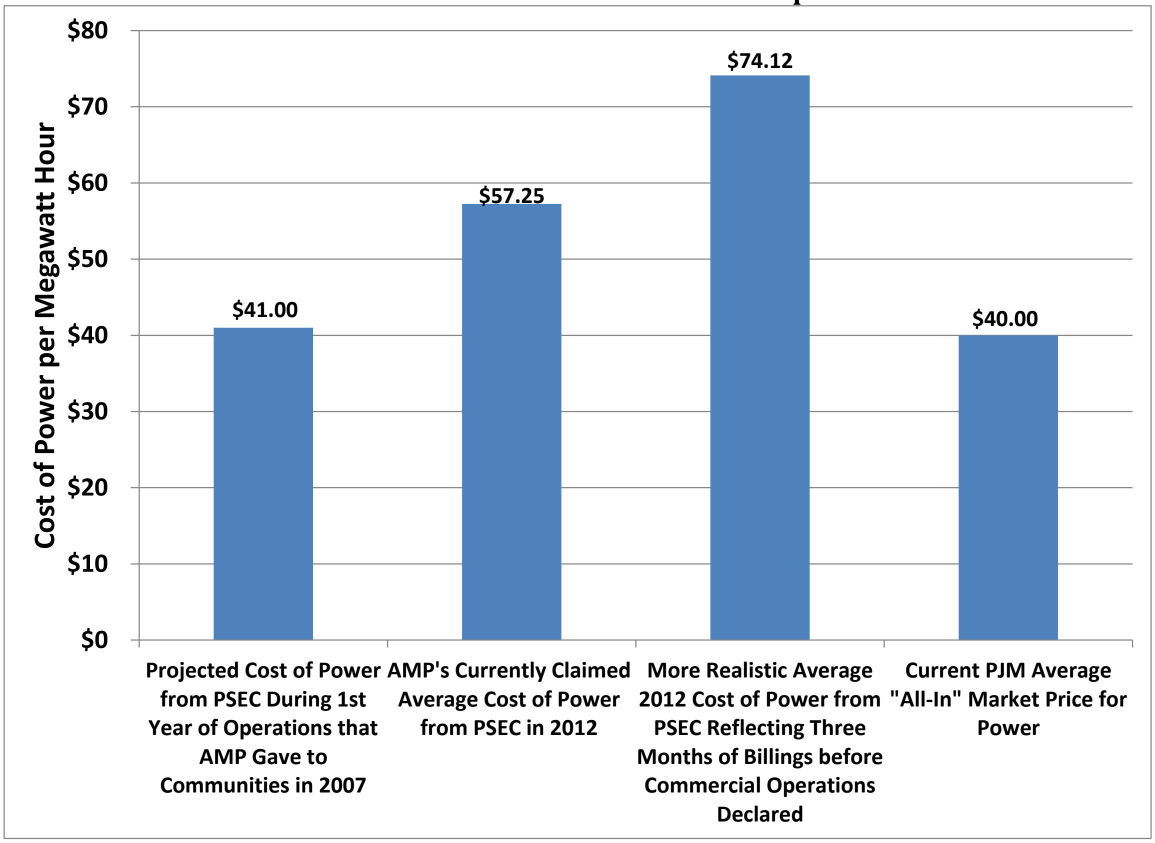
Figure 1: **Prairie State First Year Power Costs – AMP 2007 Promise vs. 2012 Claim and PJM 2012 "All-in" Market Cost**



Thus, even AMP now admits that the average cost of power from Prairie State for a participating community will be some 40 percent higher than the cost that AMP promised back in late 2007, and that the first year cost of power also will be about $17.25 per MWh, or 40 percent, higher than the average cost of the power (including capacity, energy and other wholesale load costs) that a participating community could otherwise purchase from the PJM market.

However, the $57.25 per MWh first year cost of power that AMP claims will be paid by the 68 communities in Ohio, Virginia and West Virginia participating in Prairie State is misleading because it does not reflect the approximate $11 million that these communities paid to AMP for the three months of March, April and May 2012 during which Prairie State was not yet in commercial operations and, consequently, during which they were not receiving any power from the plant. Each community was billed for these costs under the 'take-or-pay' contracts it signed with AMP. These contracts obligate communities to pay for the Prairie State-related fixed costs (e.g., the annual interest on the funds that AMP borrowed to pay for its share of construction costs) whether or not the plant generates any power. If these three months of billings are included, the average first year cost of power from PSEC increases to $74.12 per MWh, as shown in Figure 2, below.

Figure 2: Prairie State First Year Power Costs Including Three Months of Billings before Unit 1 Was Declared in Commercial Operations



Even this average first year power cost of $74.12 per MWh probably is too low, however, because it reflects AMP's assumption that Prairie State will operate at an 85 percent capacity factor in 2012. A plant's capacity factor is a measure of how much it actually generates during a month or a year as compared to what it would generate if it operated at 100 percent power for all of the hours of the month or the year. The higher the capacity factor, the more MWh the plant generates.

The number of MWh a plant produces is important in calculating average power costs because the more the plant generates, the larger number of MWh over which its fixed costs will be spread. This means that a plant with an 85 percent average annual capacity factor during the year will have a lower average power cost than if the plant only operated at a 65 percent or a 75 percent capacity factor.

AMP assumes that Prairie State will operate at an average 85 percent annual capacity factor from the moment that it began commercial operations. This is an extremely optimistic (even pollyannish) assumption. New power plants traditionally have break-in periods during which they experience poorer performance. Consequently, many plants that eventually have excellent operating performance over extended periods often have fairly low (30 percent to 40 percent to 50 percent) capacity factors during their first months or even years of commercial operations. It is unreasonably optimistic to assume that Prairie State will avoid such shakedown problems.

If the very conservative assumption that Prairie State will operate at an average 75 percent capacity factor is used, instead of the 85 percent capacity factor assumed by AMP, the plant's average first year power cost would be $80.67 per MWh. A 75 percent average capacity factor for its first year of operations would still be very good compared to the actual experience of other new power plants.

The likelihood of Prairie State achieving 85 percent capacity factors either in its initial year of operations or over the longer term is further diminished by the increased market competition from natural gas fired power plants and wind generation and by the reduced demands for power due to the economic downturn and increased investments in energy efficiency in many states in both PJM and MISO.

Natural gas prices collapsed in late 2008 due to increased production of natural gas from shale formations. The resulting lower natural gas prices have led to the displacement of a significant portion of coal-fired generation in the Midwest by natural gas-fired units. Even though some increases in natural gas prices are anticipated in the next decade, due in part to increased regulation of fracking, prices are nevertheless expected to remain low for a significant number of years, not reaching $5 per million BTU until 2020 or later. This will mean continuing competition for coal-fired generation (and displacement of coal by gas) and that market prices will remain low for the long-term.

For example, the director of North American power forecasting for IHS Cambridge Energy Research Associates has been quoted as concluding that things have changed with regard to natural gas prices:

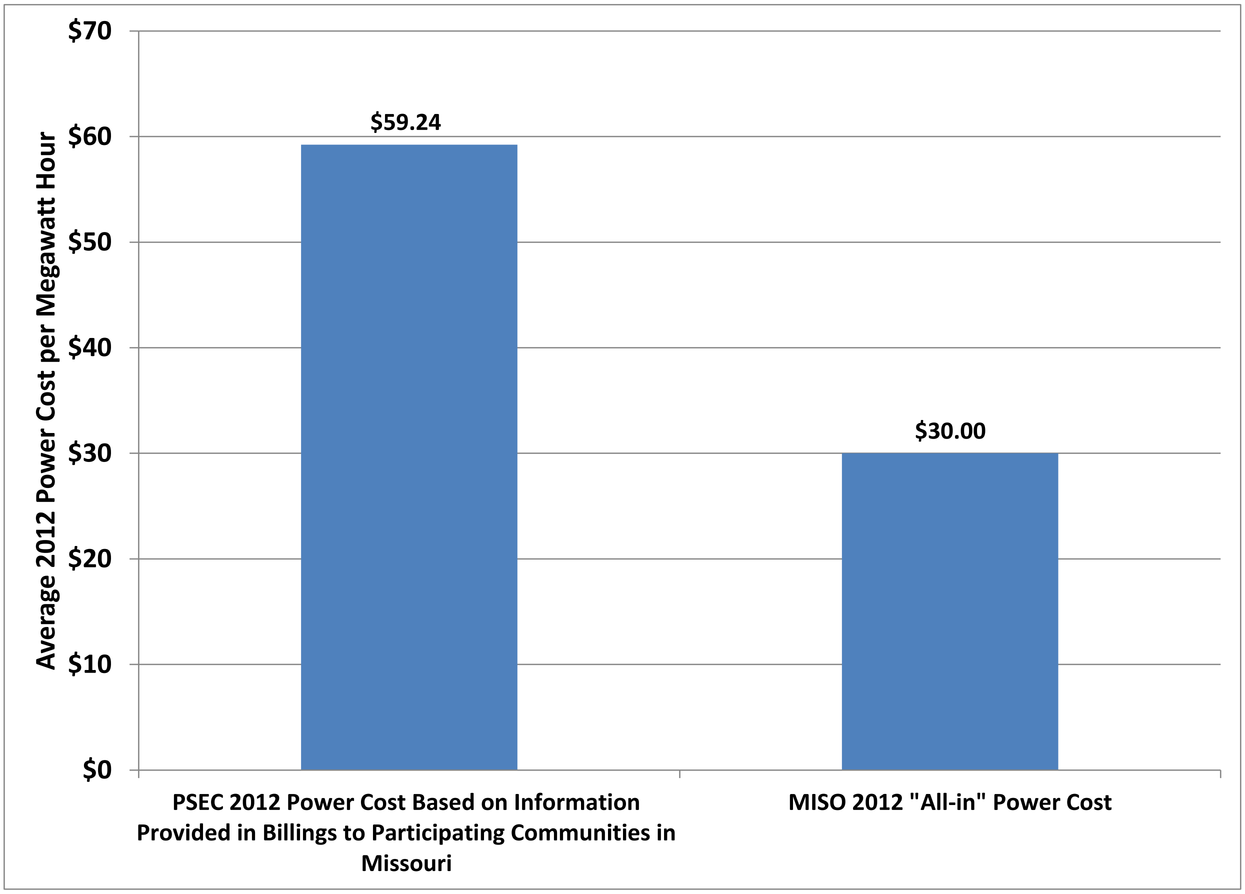
> His long-term projection of natural-gas prices is much lower than a few years ago, a shift that is tied to the development of natural gas from shale deposits. Even if natural-gas prices make a leap from current lows, he doesn't see wholesale electricity prices averaging higher than $50 per megawatt-hour for at least the rest of this decade, and potentially longer.

> If forecasts like this hold true, Prairie State's owners will need to wait a long time to see their investment produce power that costs about the same as the market.[9]

Although we have seen much less information on the projected costs of operating Prairie State from the non-AMP owners, the data we have seen suggests that their first year costs of power from PSEC also are significantly higher than current market prices in MISO, where most non-AMP communities are located. Figure 3, below, shows that the average cost of power from Prairie State during 2012 will be approximately double the estimated $25 to $30 per MWh "All-in" price of power in the MISO wholesale market.

9 The Columbus Dispatch Sunday April 29, 2012.

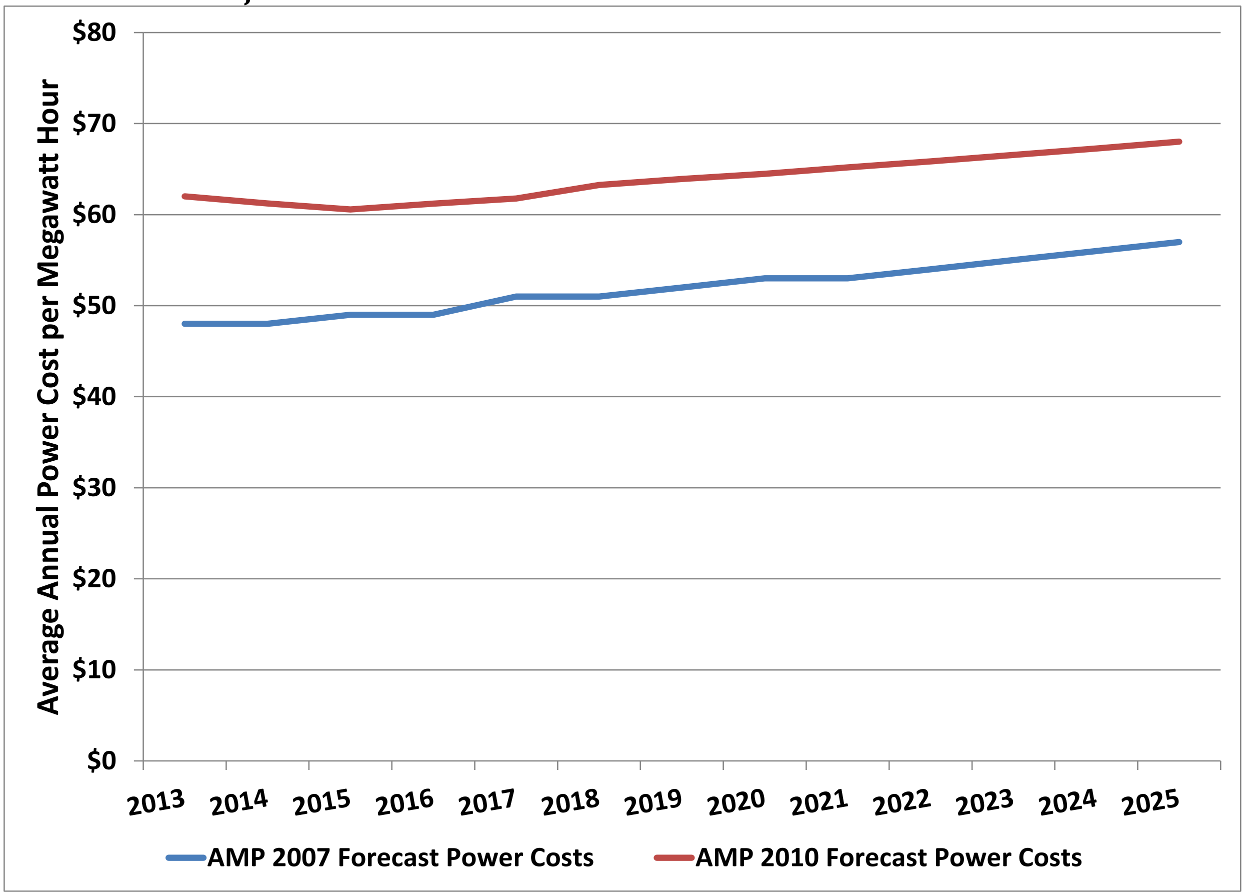
Figure 3: PSEC 2012 Power Price for Communities in Missouri vs. Average MISO "All-in" Price



Long-Term Power Costs

At the same time that PSEC's projected first year power costs have increased significantly in recent years, the plant's long-term power costs also have risen dramatically, as is shown in Figure 4, below, which compares the average annual power costs that AMP used in 2007 to entice communities to participate in the Prairie State project with AMP's revised projections from the summer of 2010.

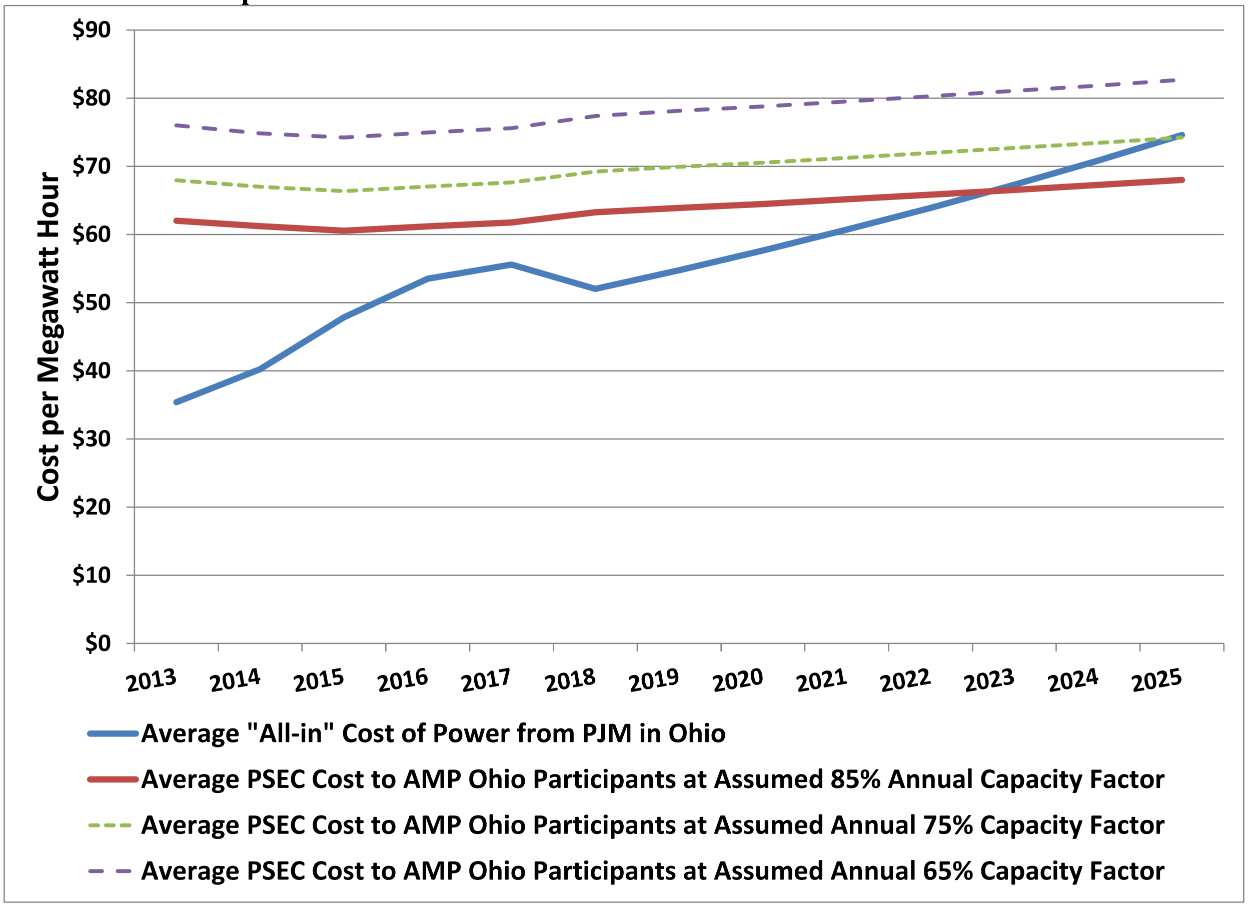
Figure 4: **AMP 2007 Projection of Prairie State Power Costs vs. AMP 2010 Projection.**



This Figure shows that even AMP does not expect the cost of power from Prairie State to go down over the long term.

Figure 5, below, then shows that AMP's projected power costs will remain significantly above "All-in" PJM market prices for Ohio through at least 2023 even if the plant operates at the 85 percent average annual capacity factor that AMP optimistically assumes. If Prairie State operates at only a 75 percent average annual capacity factor, its average power cost will remain above the average PJM "All-in" price until 2025. Finally Prairie State's average power cost will remain above the average PJM "All-in" price for Ohio for several years beyond 2025, at least, if the plant only achieves a 65 percent average annual capacity factor.

Figure 5: AMP Projected PSEC Annual Power Costs vs. Forecast PJM Average "All-in" prices.

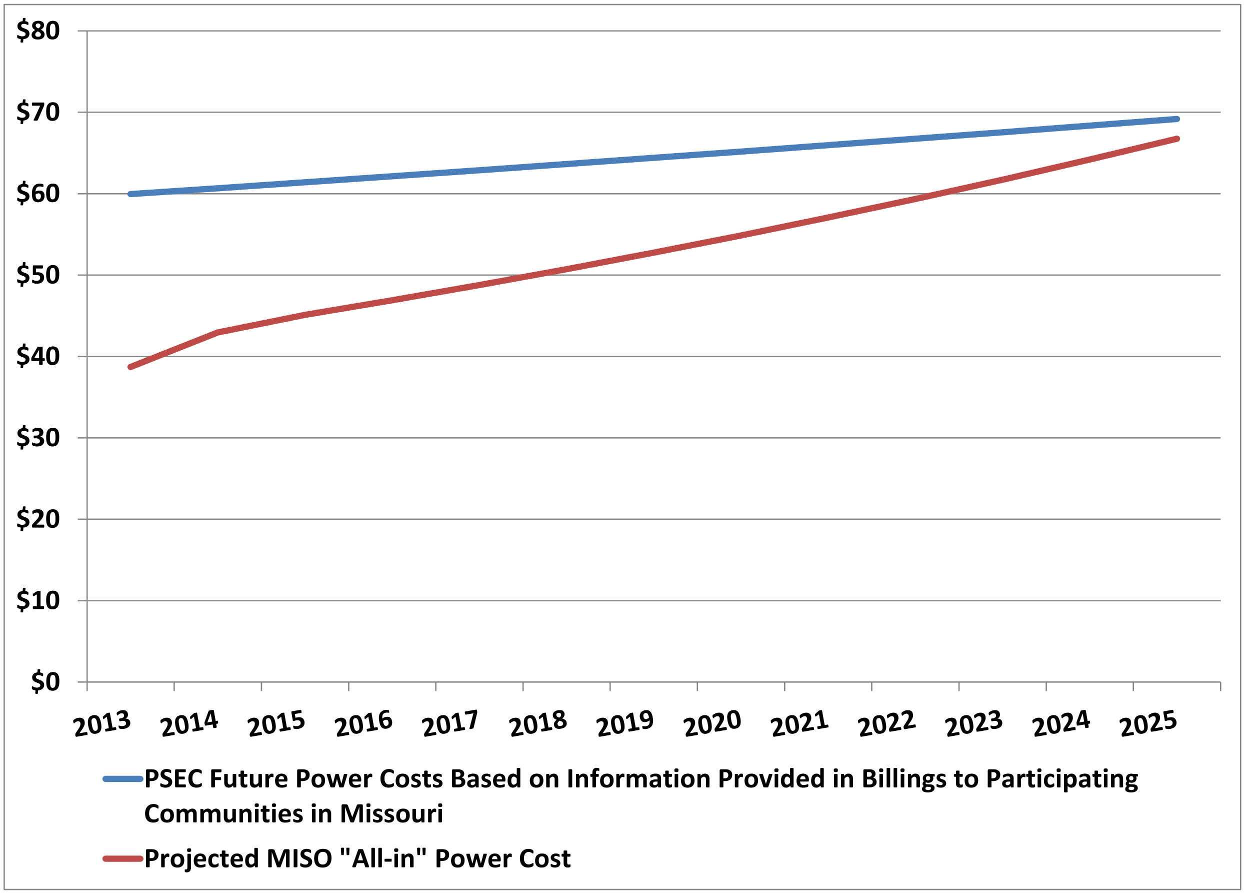


The projected average "All-in" costs of power from PJM are based on (1) published futures energy prices, (2) published capacity prices and (3) an adder for other wholesale load costs based on a review of PJM "All-in" prices for 2010 and 2011.

Figure 6, below, then compares the estimated long-term cost of power from Prairie State for participating communities in Missouri with our estimated long-term MISO "All-in" power costs.[10] Unfortunately, for the purposes of this report, we have not had access to the billing data for communities in other MISO states that would allow us to present a similar comparison for those participants.

[10] The projected long-term MISO "All-in" cost of power is estimated based on the 2012 $30 per MWh average price, increased from 2012 through 2023 at the current annual escalation rates for natural gas futures and at 4 percent per year from 2023 through 2025.

Figure 6: Comparative Cost of Power from PSEC for Participating Communities in Missouri.



Figures 5 and 6 show that communities in Ohio and Missouri will be paying substantially more for power from Prairie State for the foreseeable future in the hope that at some point in the distant future, the price of the power from PSEC will be competitive with market prices and, consequently, that they will receive economic benefits from their large investments in the project. However, the further in the future that these economic benefits are expected to materialize, the more speculative and, therefore, unlikely, they must be considered. Consequently, it is entirely possible that participating in Prairie State will never be an economical investment for these communities especially if the time value of money is considered (as it should be in these types of economic and financial analyses). This means that the near higher costs of power from Prairie State should be weighed far more heavily than the speculative benefits that might be obtained a decade or two in the future.

Moreover, buying power from the market on a long-term basis is not necessarily the lowest cost, low risk alternative to participating in Prairie State. Instead, communities might be able to buy capacity and energy from currently underutilized natural gas-fired capacity in or near where they are located. Unfortunately, it does not appear that AMP ever presented this alternative to its participating communities.

At the same time, these power cost comparisons do not reflect the likelihood that new and more stringent environmental regulations will be adopted in future decades that will increase the cost of power from Prairie State beyond what AMP currently believes. Nor do these power cost comparisons reflect the likelihood that at some point in the not-too-distant future a regulatory mechanism for reducing global warming gases will be adopted that will further increase the cost of power from Prairie State. Because coal is the most carbon-intensive fuel, the cost of power from Prairie State is more likely to be affected than market prices (which reflect a blend of power from coal, natural gas, and wind, in particular) or the price of power from gas-fired plants.

Finally, these high Prairie State power costs, as compared to market prices, mean that communities will not be able to sell any excess power at a profit. At best, such sales would only mitigate the economic burden that Prairie State places on participating communities and their ratepayers.

Figures 1 through 6 compare power prices on a dollar per MWh basis. However, participating communities have committed to buying tens to thousands of megawatt hours that will be generated at Prairie State. This means that their total bills for the foreseeable future will be dramatically higher than they would be if they merely relied on the market for their capacity and energy. Table 3, below, shows the differences in their bills that an illustrative group of cities in Ohio and Missouri could be expected to pay for power from Prairie State through 2025 as compared to what they would pay for power from the PJM and the MISO markets.

Table 3: Illustrative Excess Power Costs through 2025 Due to Participation in Prairie State.

Community	MW Share of PSEC (MW)	Excess Power Costs Through 2025 Due to Participation in PSEC
Bowling Green OH	35.000	$27 million
Celina OH	14.928	$12 million
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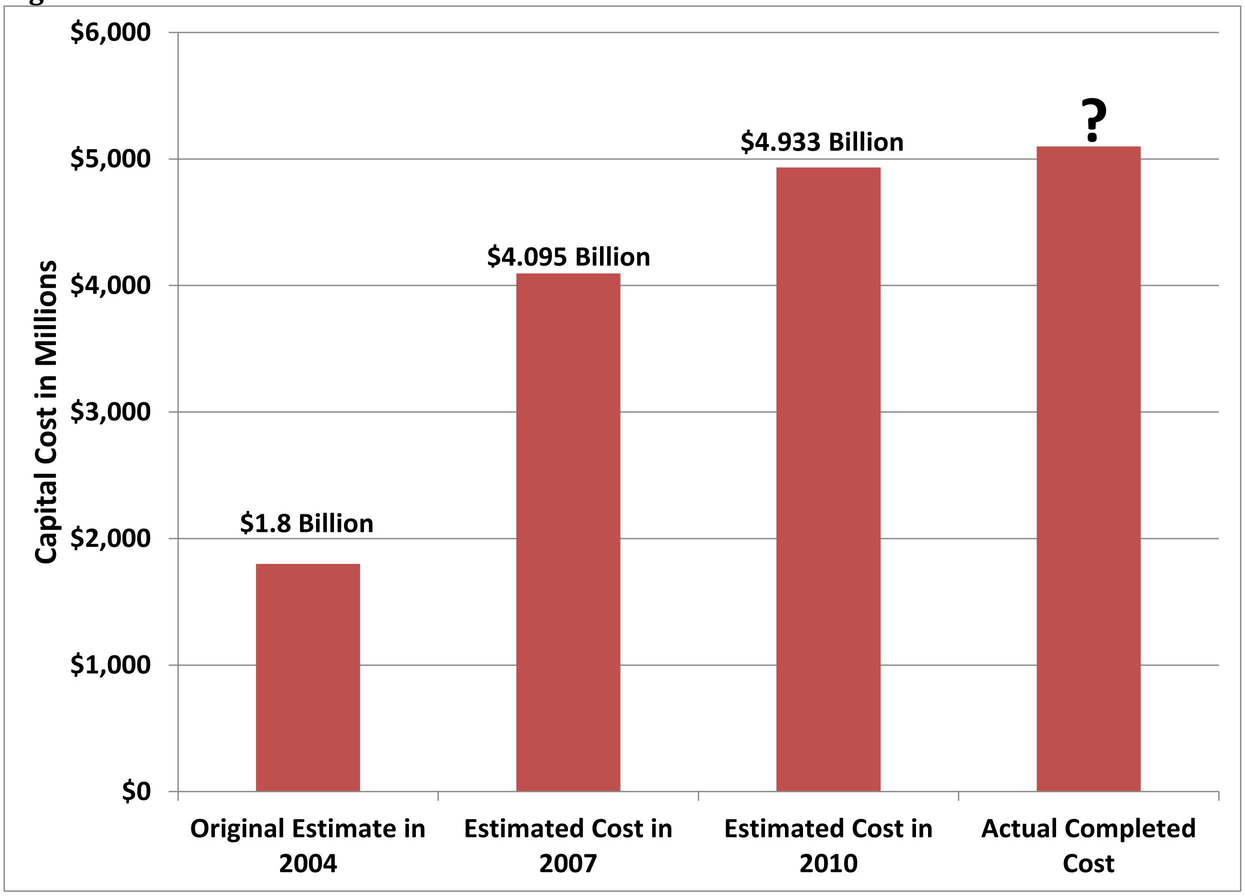
Columbia MO	50.000	$56 million

The figures in this Table assume that Prairie State actually achieves the 85 percent average annual capacity factor that Peabody, AMP and the other owners claim that it will operate at. The excess power costs paid by these communities (and all of the other communities that have long-term contracts to purchase power from the plant) will be even higher if Prairie State fails to achieve this level of performance. These figures show that Prairie State will almost certainly not provide an economic benefit for communities (on a cumulative annual basis) until the late 2030s or the 2040s, if then. In other words, the costs from the project are certain while the benefits are extremely speculative.

Rising Coal Plant Construction Costs

The substantial increase in Prairie State's power costs since 2007 was the direct result of a foreseeable increase in the project's construction cost. This increase is shown in Figure 7, below, along with Peabody's initial $1.8 billion cost estimate.

Figure 7: Prairie State Construction Cost Estimates.



By as early as the years 2004-2007, the actual experience of soaring construction costs at nearly every other domestic U.S. coal construction project should have warned Peabody, AMP and the other joint municipal power agencies and co-ops that there was a significant risk, if not a certainty, that the cost of building Prairie State would continue to skyrocket due to the worldwide competition for power plant design and construction resources, equipment and commodities. Although Peabody discussed the fact that the EPC ("Engineering, Procurement and Construction") costs for new coal plants were rising in a January 2007 marketing presentation to the Illinois Municipal Electric Agency ("IMEA"), it assured the power agency that it had investigated an alternative contracting strategy with Bechtel to "minimize" the effect of coal plant EPC cost increases. Peabody also said that the contract with Bechtel would have a "price capped at value determined at execution of EPC contract." In fact, the contract that Peabody signed with Bechtel in June 2007 did not have a capped price. Instead, the project would not have a fixed price contract until 2010 and that fixed price would be approximately $1 billion higher than the "target" price in the 2007 contract.

It is unclear, however, whether Peabody fully and accurately revealed the risk of rising plant construction costs (or any other risk) when it was aggressively marketing ownership shares in PSEC to other potential owners and/or that AMP and the other joint municipal power agencies fully revealed this risk (and the other risks of participating in the Prairie State project) when they were enticing local communities to enter into long-term purchase power agreements.

The following examples of rising coal plant construction costs should have been known to Peabody, AMP and the other joint municipal power agencies:

- By June 2007, the estimated construction cost of AMP's proposed Meigs County coal plant had more than doubled from $1.2 billion in October 2005 to $1.5 billion in May 2006 to $2.5 billion in June 2007.

- Duke Energy Carolinas had originally estimated the cost of building its proposed two-unit coal-fired Cliffside Project would be approximately $2 billion. However, in the fall of 2006, the Company announced that the cost of the project had increased by approximately 47 percent ($1 billion). After the project had been downsized to one unit (because the North Carolina Utilities Commission refused to grant a permit for two units) Duke announced in late May 2007 that the cost of the single unit it was building was approximately $1.8 billion, exclusive of financing costs. In other words, the single Cliffside coal-fired unit that Duke was building was now expected to cost almost as much as Duke originally had estimated for a two unit plant.

- Tenaska Energy cancelled plans to build a coal-fired power plant in Nebraska in 2007 because of rising steel and construction prices. According to the Company's general manager of business development:

> "… coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.
>
> And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot…. At one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.
>
> We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and

equipment and it just wouldn't be a prudent business decision to build it."[11]

- Westar Energy announced in December 2006 that it was deferring site selection for a new 600 MW coal-fired power plant due to significant increases in the facility's estimated capital cost of 20 to 40 percent, over just 18 months. This prompted Westar's Chief Executive to warn: "When equipment and construction cost estimates grow by $200 million to $400 million in 18 months, it's necessary to proceed with caution."[12]

Unfortunately, there is no evidence that Peabody, AMP or any of the other joint municipal power agencies proceeded with caution with regard to the Prairie State project.

Another significant factor that should have caused great concern and worry was that in 2007 there was no fixed price contract for designing, engineering and building Prairie State nor was there any prospect for such a fixed price contract at that time. Instead, after June 2007 there was merely a contract with Bechtel with a $2.9 billion target price. There was no guarantee or protection that this price would be met, as indeed it was not.

Moreover, coal plant construction costs continued to skyrocket after 2007 so Peabody, AMP and the other joint municipal power agencies could not have any assurance or confidence that Prairie State would avoid the dramatic cost increases experienced by other projects. For example:

- The estimated cost of AMP's Meigs County coal plant was increased from $2.5 billion to $2.949 billion in early 2008. The project was eventually cancelled after it was subsequently announced in November 2009 that the estimated cost had risen by another 37 percent.

- The estimated cost of Duke Energy Indiana's Edwardsport coal plant increased from $1.985 billion in 2007 to $2.35 billion in 2008 to $2.88 billion in 2010, a 45 percent increase, and has continued to rise after 2010.

- The announced cost of the proposed Karn-Weadock coal plant in Michigan was increased by 32 percent (from $2,765 per kW to $3,589 per kW] in January 2009.

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11 Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

12 Available at www.westarenergy.com

- The estimated construction cost of Kansas City Power & Light's Iatan 2 coal plant was increased by 15 percent in the spring of 2008 even though the unit already was nearly three years into construction. This showed that even plants that were under construction were not immune to significant cost increases.
- The estimated cost of Wisconsin Power & Light's Nelson Dewey 3 coal plant was increased by 47 percent between February 2006 and September 2008.

More than 75 planned coal plants were cancelled by 2010 due to the soaring coal plant construction cost and/or other serious risks such as (1) the possibility that projected system demands would not materialize, (2) the collapse of natural gas prices in late 2008 that made generation from existing or new gas-fired units much more competitive and (3) the possibility that state or federal governments would adopt regulatory regimes that placed a price on the emission of global warming gases. Among the cancelled projects were Peabody's proposed Kentucky-based Thoroughbred Energy Campus and AMP's Meigs County coal plants. Both Peabody and AMP opted to natural gas projects instead of new coal plants.[13]

Unfortunately, there is no evidence that Peabody, AMP or any of the other joint municipal power agencies initially evaluated or subsequently reconsidered their participation in PSEC in light of these serious risks.

Additional Risks

Mine-Related Risks and Coal Prices Charged to Participants

Reports prepared for AMP by the engineering firm R.W. Beck reveal that there are safety and financial risks associated with the Lively Grove Mine and its operations that could lead to higher costs for power from Prairie State. Lively Grove Mine is located next to the Prairie State generating units and was sold by Peabody to the other owners with a permit for anticipated production of 6 million tons of Illinois Basin coal per year, sufficient to supply all of the plant's fuel for 30 years of operations. Each of the PSEC owners purchased a proportionate share of the mine and assumed the costs of development, acquisition and construction charges for Mine Operation. Peabody assumed the role of consultant, supervising mine operations for a fee and, in addition to securing permits for the Mine from the State of Illinois, designed and secured approvals for the Mine Plan from federal regulators. According to a Peabody 2007 SEC filing, the company received $84.2 million in cash for the mine and recognized a total gain of $17.8 million for the 172

[13] For example, see https://amppartners.org/newsroom/amp-signs-mou-firstenergy-fremont-energy-center/.

million coal ton reserve.[14] However, Peabody has not publicly disclosed the fees the company received for its consulting services.

As early as 2009, PSGC (the company that now owns Prairie State) was cited by federal regulators for operating the Lively Grove Mine with an unapproved ventilation plan and an unapproved roof control plan in violation of federal regulations. [15] These issues are critical to the safety of the mine and mine workers as well as the capacity of the Lively Grove Mine to provide the promised 30 year supply of coal to the project.[16] In May 2010 the United States Department of Mine Safety and Health Administration affirmed the citations. Although PSGC has appealed this decision, the ruling has not been overturned nor any compromise been announced.

According to a 2010 report prepared for AMP by R.W. Beck:

> "If PSGC is unsuccessful in returning to the original Mine Plan, or at a minimum, a compromise plan which contains reasonable and supportable requirements that would allow efficient operations without compromising safety, PSGC reports that the projected capital costs of the mine development and the annual per ton operating costs of the Mine would be higher than those assumed. Further, the amount of recoverable coal reserves available to the Project would be lower than originally expected and may not be sufficient to provide fuel for baseload operations for the full 30 year economic life of the PSEC."[17]

These issues present a number of potentially adverse financial risks for the communities that purchase power from Prairie State. First, if, and when, PSGC acknowledges that the Mine will not provide coal for 30 years of plant operations, it is likely that a more expensive source will be needed to supply the remaining eight years of coal (approximately 48 million tons of coal). However, Prairie State's owners borrowed for thirty years against a purported 30 year coal supply. If there is

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14 Peabody Energy, Form 10Q, September, 30, 2007.

15 These citations are in addition to 94 mining violations from 2011 through the first quarter of 2012 issued by MSHA. Mine Safety and Health Administration, *Mine Overview: Lively Grove,* Mine ID # 1103193, April 13, 2011 (with data updated through the first quarter of 2012).

16 At issue in these citations are whether the use of 40-foot cuts and extra wide entries without previous testing or evaluation are a suitable part of the ventilation and roof control plans given the conditions at the mine. Of concern is the likelihood of roof falls, the control of methane and respirable dust given the prevailing geological conditions of mines in Southern Illinois.

17 AMP's 2010 Official Statement, at page 19.

not enough coal for the full 30 years, then participant communities may have to pay the continued debt service on the coal reserves for eight years after the coal mine is closed.[18] At the same time, another source for the coal will have to be added with the additional costs ultimately being passed along to the communities purchasing power from Prairie State project and their ratepayers. The 2010 R.W. Beck report noted that there are additional coal reserves in close proximity to the plant and that, if needed, those reserves, currently owned by Peabody Energy, would be sold to PSGC.[19] These developments could significant erode the alleged fuel cost savings envisioned by the mine mouth concept and Peabody's original plan for Prairie State.

Second, the 2010 ruling of the United States Department of Mine Health and Safety Administration could lead to increased spending for the Lively Grove Mine and, consequently, higher coal prices if the ruling is not overturned on appeal. Such a capital cost increase could to additional borrowing by the plant owners and an increase in the cost of power from Prairie State.

Third, even under a compromise agreement with the Mine Health and Safety Administration, proceeding with Peabody Energy's original Mine Plan leaves Prairie State's owners exposed to the damages created by future adverse incidents at the mine. The ruling is a red-flag warning that the original Mine Plan constitutes a safety risk.[20] This risk going forward will be borne by the owners of the mine. The owner is PSGC. Future financial and political liability rests with PSGC, the state public power agencies and participating localities, not Peabody Energy.

Long Term Storage of Coal Combustion Wastes

Prairie State's owners are also expected to incur significant costs associated with the acquisition of additional storage capacity for the coal combustion waste produced by the generation facility. Peabody permitted and then sold to the new Prairie State owners in 2007 two sites and associated railway infrastructure and permits for transportation of the coal combustion waste away from the facility and outside of Washington County, with the promise of providing 1700 acres of coal ash storage with combined capacity of 36 years.[21] By 2010, the capacity of these sites had been re-assessed and according to the 2010 RW Beck report for AMP, these

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18 See Appendix I, most bonds are being repaid over thirty years.

19 The September 22, 2010 R.W. Beck *Consulting Engineer's Report,* that is included as Appendix G to AMP's 2010 Official Statement, at page G-9.

20 Roof cave-ins at Illinois Basin mines are a well documented phenomenon related to the specific mine geology of the region. G.M. Molinda, C. Mark, D.M. Pappas and T.M. Kiemetti, *Overview of Coal Mine and Ground Control Issues in the Illinois Basin,* www.cdc.gov/niosh/mining/pubs/pdfs/oocmg.pdf

21 See Kentucky Municipal Power Agency Official Statement, 2007 available at http://emma.msrb.org/MS263585-MS238893-MD466220.pdf

sites were found to have substantially less capacity than what Peabody's permit had indicated.

The Jordan Grove ashfill was permitted by the State of Illinois for 23 years but after the property was re-assessed it was determined to have only 12-14 years of coal combustion waste capacity.

In December 2011, PSGC and Peabody submitted requests to the Illinois EPA and Washington County Board for the permitting for additional coal combustion waste storage. On June 26, 2012, the Washington County Board approved modified zoning ordinances that would allow 740 acres of farmland near the Prairie State site to be used for additional ashfill storage. The Washington County Board approved an ashfill storage site within the County despite the fact that Prairie State executives had assured them in 2005 that "All waste products will be disposed of outside of Washington County in disposal sites properly permitted by the State of Illinois."[22]

Under the terms PSGC's agreement with Washington County, project owners will pay $30 million dollars to Washington County for the 740 acres of additional ashfill capacity in addition to tipping fees of 30 cents per ton of coal ash dumped and 10 cents per ton trucked out of the area on country roads.[23] The plant is currently projected to produce approximately 3 to 4 million tons of coal ash per year which would mean an estimated $1 million in fees for the county annually. It is expected that these costs will be passed along to the communities through their respective municipal agencies and added into the cost of purchasing power from Prairie State. To date, project officials have been silent on what, if any, additional costs will be incurred by the project's owners and who will ultimately pay.

CONCLUSION

The current and projected costs of power from Prairie State are significantly higher than both (1) participating communities were promised and (2) than the cost of purchasing the same power (including both capacity and energy) from the PJM and MISO wholesale markets. The promise of the plant, a guarantee of low cost electricity through the control of the ownership of the power generation resource has materialized into something quite different. In fact, the power from Prairie State will be neither low cost nor affordable. Moreover, there are real risks that the cost of

[22] See Transcript from the February 10, 2005 Public Hearing before the Washington County Zoning Board of Appeals, Washington County, Illinois.

[23] S See "Prairie State Reverses Course on Illinois Coal Ash Site," Dan Ferber, Midwest Energy News, July 25, 2012 available at http://www.midwestenergynews.com/2012/07/25/prairie-state-reverses-course-on-washington-county-illinois-coal-ash-site/

power from Prairie State could be higher than we have calculated due to further increased construction prices, higher coal costs and poor combustion waste and water resource planning.[24] For the participant communities, many questions remain concerning how they will manage this financial liability.

Questions concerning Construction Costs and the Price of Power

1. Does Prairie State Generating Center have a comprehensive audited financial statement for the construction project? Is it available to the participating communities?
2. What will Prairie State's final construction cost be?
3. What will the final total project development costs for the Prairie State project including all mining and ashfill costs be?
4. When will the final cost information be made available to participating community members?
5. How will "final price information" carry outstanding financial risks? How will the accounting present the cost of future ashfill resources? How will these calculations account for the mine reserve risks? What are the protections that participating communities have regarding the design and construction of the project given the type and level of problems experienced thus far?

Questions on the "Liquidated Damages" Provision of the Contract with Bechtel

1. How much of the additional project costs can be recovered from Bechtel in liquidated damages claims?
2. How much of this has already been received by Prairie State from Bechtel for liquidated damages?
3. If there are liquidated damages paid by and owed by Bechtel for failure to meet the commercial operating date, why have participants been asked to pay now for electricity not being received?

[24] The financial and environmental risks associated with Prairie State's water withdrawal plan from the Kaskaskia River and waste management plan from the Lively Grove Mine present a number of potential liabilities to the project participants for the duration of the project's operations. At this time, there has been limited public disclosure concerning the terms of the water purchase agreement with the Illinois Department of Natural Resources ("IDNR") or the likelihood that the water withdrawal restriction within that permit would halt operations of the Prairie State facility during drought conditions. Additionally, Prairie State participants are expected to incur capital expenditures to modify the Lively Grove Mine's wastewater management plan to provide infrastructure to maintain the facility's structural integrity. At the time of this report, there have been no public statements made from the PSEC Owners concerning estimates for these capital expenditures or how these added costs will be apportioned among the project participants over time.

4. Why did Prairie State not devise a plan to use the liquidated damages cash flow as part of a plan to mitigate costs to participant communities?
5. What costs to participants are covered under the liquidated damages provision and what costs incurred by participants are not?
6. When were the liquidated damages provisions agreed to in the contract?
7. Did Peabody Energy negotiate these provisions as part of the package prior to the sale of ownership interests to the other project Participants?
8. Were the liquidated damages contract provisions strengthened at the time the "fixed price" agreement was made in July 2010?
9. How much will the cash from Bechtel to Prairie State Generating Center for liquidated damages save participants on their monthly bills?
10. How will costs for operational problems at Unit 1, occurring since the official date of Commercial Operation (June 12, 2012), affect the power prices charged to communities?

Mine-Related Questions

1. What is the current status of the MSHA administrative proceeding and underlying violation described in this report? What is the time certain deadline for settling the safety and financial issues involved in this matter?
2. Are there any other MSHA violations that are of a similar level of seriousness that have not been disclosed to the Participants?
3. Why did Peabody Energy declare in 2006 that the mine had a 22 year supply of coal for the Prairie State project, and then subsequently increase the supply to 30 years?
4. Did the defective Mine Plan change the capacity measure to give the impression that the mine had an actual life of 30 years?
5. How much was paid for the mine by Prairie State to Peabody Energy?
6. How much has Peabody Energy been paid for technical services or construction oversight related to the Lively Grove mine?
7. Would the price of the mine have been different if it was known that there was only a 22 year coal supply?
8. Is the mining currently being performed at Lively Grove consistent with the Mine Plan or the federal administrative ruling?
9. Will there be a formal public decision made on whether additional coal resources will be necessary?
10. When will this decision be made? How will it be communicated?

11. What are the estimated cost impacts of any new mine reserves?

12. How will those costs be allocated to project participants?

13. Has Prairie State Generating Center taken any actions to recover any or all of the payments made by it to Peabody Energy for the sale of the mine or technical services provided related to the Lively Grove mine?

14. Has there been any investigation by Prairie State to determine how Peabody Energy, the nation's largest private mining company, could have made such an error?

15. Did Prairie State officials take any action to heighten its scrutiny of representations made by Peabody Energy to it regarding the mine in the wake of the administrative decision?

Coal Waste Storage-related Questions

1. How many ashfills have been or will be bought to serve the needs of the Prairie State plant?

2. What are the ashfills?

3. How much will these ashfills cost?

4. What is the reason for the need for so many ashfills for the project? Will the Prairie State plant create more ash than originally projected, or are the available facilities too small to meet the needs of the plant?

5. How will these costs be added to the debt service payment requirements of project participants?

6. How will these costs be added to the operating budget of Prairie State and the cost of electricity to participants?

7. How much will ashfill capacity for the Prairie State plant ultimately cost, and how much would it have cost if only one ashfill was purchased that truly met the capacity needs of the Prairie State site?

8. How much did Prairie State Energy pay to Peabody Energy for the Jordan Grove ashfill? When were the payments made?

9. How much has Prairie State paid to any other owner or group of owners for future ashfill resources for Prairie State?

10. What would have been the value of the Jordan Grove ashfill if it were known that the capacity was actually 12-14 years and not the 23 years promised as part of the Illinois State permit?

11. Has Prairie State Generating Center attempted to recover any funds expended for the Jordan Grove site from Peabody Energy based upon the

failure of the site to meet the actual capacity targets apparently approved in the permit process?

Appendix I: 2007-2010 Prairie State Bond Issuances by Issuer, Amount, Interest Payment and How Much of a Federal Subsidy was Involved

Date	Issuer	Amount of Bond	Total Interest (Life of Bond)	Maturity	Build America Bond?	Federal Interest Subsidy (Life of Bond)
		Dollars	Dollars			Dollars
8/29/07	Kentucky Municipal Power Agency (KMPA07)[i]	307,710,000	381,674,713[ii]	2042[iii]	No	
5/5/10	Kentucky Municipal Power Agency (KMPA07)[iv]	183,730,000	190,843,752	2037	Yes	58,808,003
8/5/09	Electric Board of City of Princeton, Kentucky[v]	20,285,000[vi]	26,371,516	2042	Yes	6,689,225
8/15/07	Northern Illinois Municipal Power Agency[vii]	318,750,000	296,455,000	2041	No	
8/5/09	Northern Illinois Municipal Power Agency[viii]	141,950,000	151,847,000	2041	Yes	44,000,000
11/30/10	Northern Illinois Municipal Power Agency[ix]	72,310,000	115,419,000	2041	Yes	40,396,650
7/15/09	Illinois Municipal Power Agency[x]	321,790,000	349,498,535	2035	Yes	120,156,761
11/18/10	Illinois Municipal Power Agency[xi]	140,290,000	142,989,231	2042	Yes	50,046,256[xii]
9/27/07	Indiana Municipal Electric Agency[xiii]	423,700,000	619,029,000	2042	No	
4/18/09	Indiana Municipal Electric Agency[xiv]	210,435,000	280,274,000	2042	No	
9/29/10	Indiana Municipal Electric Agency[xv]	143,875,000	205,722,000	2042	Yes	68,070,800[xvi]
9/12/07	Missouri Joint Municipal Electric Utility[xvii]	549,805,000	494,407,104	2041	No	
12/10/09	Missouri Joint Municipal Electric Utility[xviii]	207,920,000	260,379,928	2042	Yes	98,187,664
12/7/10	Missouri Joint Municipal Electric Utility[xix]	78,005,000	113,769,000	2041	Yes	41,860,948
6/20/08	American Public Power-Ohio, Inc. (AMP08B)[xx]	760,665,000	676,450,729	2043	No	
3/24/09	American Public Power-Ohio, Inc. (AMP09A)[xxi]	166,565,000	149,829,010	2043	No	
10/7/09	American Public Power-Ohio, Inc. (AMP09B)[xxii]	469,580.000.00	757,799,119	2043	Yes	251,854,220[xxiii]
9/27/10	American Public Power-Ohio, Inc.[xxiv]	300,000,000	616,065,140	2047	Yes	215,622,799
	Sub Total	4,817,365,000	5,828,823,777			995,693,326
	Prairie Power Inc - 8.27%	410,170,000	Not Available			
	Southern Illinois Power Cooperative - 7.90%	394,210,000	Not Available			
	Peabody Energy - 5.07%	250,000,000	Not Available			
	Total	5,871,745,000	5,828,823,777			

[i] Kentucky Municipal Power Agency, Official Statement: $291,065,000 Power System Revenue Bonds and $16,645,000 Taxable Power Systems Revenue Bonds, Appendix B, August 29, 2007. (KMPA07)

[ii] KMPA07, Annual Long-Term Debt Service Requirements, Appendix B.

[iii] KMPA07, Maturity Schedule

[iv] KMPA10, Semi Annual Long-Term Debt Service Requirements, Appendix B.

[v] Electric Board of City Of Princeton, Kentucky, Official Statement: $7,964,000 City of Princeton Kentucky Electric Plan Board and $12,320,000 City of Princeton Kentucky Electric Plan Board (Build America Bonds), August 5, 2009 (EBCP09)

[vi] EBCP09, Annual Long-Term Debt Service Requirements, Appendix, August 5, 2009

[vii] Northern Illinois Municipal Power Agency, (NIMPA), Official Statement: $1318,750,000 Northern Municipal Agency, Debt Service Requirements, 2007, p. 16.

[viii] Northern Illinois Municipal Power Agency, (NIMPA), Official Statement: $141,950,000 Northern Municipal Agency, August 5, 2009, p.15.

NIMPA are estimated based on Debt Service Requirement figures supplied in the OS. The Debt Service Requirements provide Total Debt Service payments for issuances with no break out of interest and subsidy.

[x] Illinois Municipal Electric Agency, Official Statement: $321,790,000.00 Illinois Municipal Electric Agency Power Supply Revenue Bonds, July 15, 2009, p.16.

[xi] Illinois Municipal Electric Agency, Official Statement: $140,290,000.00 Illinois Municipal Electric Agency Power Supply Revenue Bonds, Taxable Series 2010A), (Build America Bonds – Direct Payment), November 18, 2010.

[xii] This is an estimate of the BAB subsidy as the OS does not break out the full subsidy amount independently from the overall interest charge. On page S-2 of the OS the issuer describes the BAB subsidy and states it is equal to 35% of the interest paid for the bond.

[xiii] Indiana Municipal Power Agency, $423,700,000.00 Power System Revenue Bonds: $403,575,000.00 Power system Revenue Bonds, 2007 Series A and $20,125,000 Taxable Bonds, Series B, September 21, 2007, p. 16.

[xiv] Indiana Municipal Power Agency, $210,435,000.00 Power System Revenue Bonds: $194,000,000.00 Power system Revenue Bonds, 2009 Series A and $16,035,000.00 Taxable Bonds, Series B, April8, 2009.

[xv] Indiana Municipal Power Agency, $123,640,000 Power System Revenue Bonds, 2010 Series A (Build America Bonds – Direct Payment-Federally Taxable); $20, 235,000 Power System Refunding Revenue Bonds, 2010 Series B, September 29, 2010.

[xvi] Represents 35% of interest payment on the $123,640,000.00 Build America Bond portion of the offering.

[xvii] Missouri Joint Municipal Electric Utility, $549,805,000.00 Official Statement: Missouri Joint Municipal Electric Utility Commission, Power Project Bonds (Prairie State Project), September 12, 2007, p. 35.

[xviii] Missouri Joint Municipal Electric Utility, $207,920,000.00 Official Statement: Missouri Joint Municipal Electric Utility Commission, December 10, 2009, p. 37.

[xix] Missouri Joint Municipal Electric Utility, $78,005,000.00 Official Statement: Missouri Joint Municipal Electric Utility Commission, December 1, 2010.

[xx] American Public Power-Ohio, Inc., $ 760,655.000 American Public Power-Ohio, Inc., Prairie State Campus Project Revenue Bonds, Debt Service Requirements, (AMP08), p. 16. A bond issuance for $120,000,000.00 undertaken in April 2, 2008 is refunded under this Bond issuance.

[xxi] American Public Power-Ohio, Inc., $166,650,000.00 American Public Power-Ohio, Inc. Prairie State Campus Project Revenue Bonds, Debt Service Requirements, p. 16.

[xxii] American Public Power-Ohio, Inc., 469,580,000 American Public Power-Ohio, Inc. Prairie State Campus Project Revenue Bonds, Debt Service Requirements, p. 15.

[xxiii] AMP09B, P. 16.

[xxiv] American Public Power-Ohio, Inc., $300,000,000 American Public Power-Ohio, Inc. Prairie State Campus Project Revenue Bonds, Debt Service Requirements, September 29, 2010, p.15, (AMP10)