



Comments on Holland Board of Public Works Power Supply Study

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Summary of Comments

Schlissel Technical Consulting, Inc., has completed a review of Holland Board of Public Works' ("HBPW") new Power Supply Study ("the Study").

The Study shows that HBPW's proposed resource plan is heavily focused on new coal-fired generation facilities with only relatively minor contributions from energy efficiency and renewable resources. However, coal-fired generation is subject to a host of uncertainties and risks for HBPW's customers, including:

- Uncertainty as to the availability of financing in capital markets and financing costs.
- Uncertainty as to the reductions in greenhouse gas emissions that ultimately will be required as a result of federal, regional or state action, and the cost of compliance with likely future regulations.
- Uncertainty whether post-combustion carbon capture and sequestration will prove to be technically viable as a retrofit for new coal plants like HBPW's proposed CFB coal plant.
- Uncertainty as to the costs and economic viability of post-combustion carbon capture and sequestration for coal plants, if it does prove technically viable.
- Uncertainty as to coal power plant construction costs and schedules.
- Uncertainty as to future coal prices and whether there will be supply disruptions that will affect plant performance and fuel prices.
- Uncertainty about the impact of more stringent regulations for current criteria pollutants (such as NO_x, SO₂ and mercury).
- Uncertainty about the impact of new rules regarding the storage and management of coal combustion wastes.

HBPW's supposed need for new generation is also premised on uncertainties. In these tenuous economic times, there is no guaranty that the projected new loads and energy sales HBPW is forecasting will materialize. In addition, state and/or federal government adoption of increased Renewable and Energy Efficiency Portfolio Standards could dramatically alter the amount of generation that HBPW needs and is required to build.

The confluence of factors – economic recession, construction cost trends, uncertainty about the details of federal greenhouse gas restrictions, impending costs associated with carbon emissions – means that this is a terrible time to make a significant investment in a long-lived carbon-intensive resource such as another new coal-fired power plant. Such an investment locks customers into paying for a course of action that could prove, and is indeed likely to prove, an ill-chosen option as greater certainty emerges over the next several years.

In light of these significant risks, it would be better to adopt a resource plan that allows for (1) the postponement of decisions concerning large capital expenditures for new coal-

fired power plants and (2) the flexibility to modify course as circumstances change. A resource plan that includes a near-term commitment to capital-intensive coal investments is the wrong choice in today's uncertain economic and financial conditions.

These comments provide a short summary of our findings followed by a more detailed explanation of each finding and a brief conclusion. We appreciate the Commission's consideration of these comments.

Summary of Findings

- Finding No. 1. HBPW provided only limited information and no workpapers or computer input and output files in support of the conclusions presented in the Study.
- Finding No. 2. It is clear that the Strategist modeling analyses presented in the Study do not adequately consider the significant risks and uncertainties that HBPW would face in building and operating the proposed CFB coal plant.
- Finding No. 3. HBPW's proposal to build yet another baseload coal plant will ensure coal will continue to dominate its resource mix for decades despite HBPW's plan to add some small amounts of renewable resources. HBPW will continue to be very heavily coal-dependent for decades unless it undertakes very aggressive efforts on energy efficiency and renewable resources.
- Finding No. 4. A comprehensive system for federal regulation of CO₂ and other greenhouse gas emissions is inevitable. It is generally expected that this federal regulation will require steep reductions in greenhouse gas emissions. However, the resource planning analyses in HBPW's Study show that its annual CO₂ emissions will increase, not decrease, if it self-builds or enters into joint ownership of a new coal-fired power plant. Thus, HBPW's projected future CO₂ emissions would be in conflict with evolving state, regional and national climate policies.
- Finding No. 5. Ratepayers will face significant financial risk associated with a decision to lock in increasing CO₂ emissions for the coming decades at a time when those emissions will be costly. Given the significant uncertainties regarding the stringency, design and timing of federal regulation of greenhouse emissions, a wide range of possible CO₂ costs should be used in resource planning analyses.
- Finding No. 6. The leveled cost analyses in the Study are misleading because they do not include CO₂ costs.
- Finding No. 7. The Study appears to overstate HBPW's need for new capacity.
- A. The Study projects high energy and peak load growth for HBPW through 2030.

- B. The Study assumes that HBPW will be able to achieve only extremely minor incremental energy efficiency savings after 2015.
 - C. The Study ignores the availability of a substantial amount of under-utilized gas-fired combined cycle and gas turbine capacity in and around the state of Michigan that could provide much, if not all, of the energy that would be generated at HBPW's proposed CFB coal plant.
- Finding No. 8. It is unclear what potential costs have been included in the analyses presented in the Study for complying with new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.
- Finding No. 9. HBPW understates the potential for future increases in coal prices.
- Finding No. 10. The biomass prices used in the Study appear low.
- Finding No. 11. It is unreasonable to expect that post combustion carbon capture and sequestration for a new CFB coal plant will be technically and economically available before the mid-to-late 2020s, if at all.

Findings

Finding No. 1. **HBPW provided only limited information and no workpapers or computer input and output files in support of the conclusions presented in the Study.**

HBPW provided only a very limited amount of information and no workpapers or computer input and output files as part of its Power Supply Study.

Without this information, it is impossible to verify the modeling results presented in Section 7 of the Study regarding the relative economics of the various coal plant options considered by Black & Veatch. It also is impossible to evaluate the validity of the key inputs for the Strategist modeling such as projected load growth, power plant emissions, power plant construction costs and assumed CO₂ prices.¹

The Strategist model contains many important internal settings and uses a large number of critical input assumptions. All of these can affect the modeling results. These settings and assumptions need to be fully reviewed in order to fully assess the reasonableness of the modeling results. Unfortunately, there has been no opportunity to make such a review here given the limited information provided by HBPW in its filing and the very short 29 day period which we have been provided for preparing these comments.

HBPW did provide answers to a set of questions submitted by the Sierra Club. While some of the responses have been helpful, other responses have raised additional

¹ HBPW did attach Black & Veatch's *Fall 2009 Energy Market Perspective: Midwest Baseline* to its Study. However, the information in this report did not represent the materials that are essential for properly and completely evaluating the results of Black & Veatch's Strategist modeling.

questions. Unfortunately, there is no time to submit a follow-up set of questions and no opportunity to meet with representatives of HBPW and Black & Veatch so that questions could be posed directly to them.

Finding No. 2. **It is clear that the Strategist modeling analyses presented in the Study do not adequately consider the significant risks and uncertainties that HBPW would face in building and operating the proposed CFB coal plant.**

A traditional methodology used in resource planning to evaluate risks and uncertainties is to conduct sensitivity analyses based on changes in key input assumptions. For example, sensitivities are modeled with base, low and high fuel prices, etc. Reasonable combinations of all technically and economically feasible alternatives also are considered. Ideally, the model is permitted to select resource plans based on lowest cost. These resource plans are later evaluated for their suitability on issues such as rate impacts, system reliability, environmental impacts, and ability to finance.

In fact, the Study claims that the economic analysis performed by Black & Veatch evaluated several different plans as well as sensitivities to determine the impact of various changes to the resource mix of these plans.² However, even without having a reasonable opportunity to review the workpapers and computer input and output files for the Study, it appears clear that the modeling analyses performed by Black & Veatch for HBPW were inadequate to evaluate the significant risks and uncertainties that the project faces.

1. No sensitivity analyses were performed that assumed higher construction costs for the proposed coal options. This is unrealistic and in conflict with the recent history of coal plant construction costs which have skyrocketed since the early years of this century.³

Indeed, even though the prices of key power plant construction commodities dropped between 2008 and late 2009, the estimated costs of new coal plants continued to rise. AMP-Ohio cancelled its proposed Meigs County coal plant in November 2009 after it had received a new, and 37 percent higher, estimated construction cost for the project. The estimated construction cost of the Eastern Kentucky Power Cooperative's Smith 1 CFB was increased by about 6 percent in January 2010.

Moreover, it appears that since the 3rd quarter of 2009 the prices of key power plant commodities have regained some of the ground they lost in the previous year. In addition, further increases can be expected in coming years as the world's economy recovers and energy and other infrastructure projects are pursued.

² Power Supply Study, at page 7-1.

³ See *Coal Plant Construction Costs*, a copy of which is included as Attachment No. 1 to these comments.

2. As will be explained in Finding No. 5, below, Black & Veatch did not consider a range of CO₂ costs, using, instead, a single CO₂ price trajectory. This was unreasonable and does not reflect the significant uncertainty associated with the design, timing and stringency of federal regulation of greenhouse gas emissions. It also means that the Study did not consider the economics of the proposed plant in a scenario with relatively high CO₂ prices.
3. Some of the scenarios presented in the Study were unrealistic. For example, in one scenario presented in Table 7-3 of the Study, Black & Veatch assumed that HBPW would be able to buy 5 MW shares of a number of coal plants and other generic baseload units that would be available in 2016. This is unrealistic. It does not appear that there are any other proposed plants that are expected to come on line in 2016 except perhaps for the Karn-Weadock unit whose viability and timing are very uncertain.
4. Black & Veatch did not examine any scenarios with higher or lower natural gas or coal prices.
5. It does not appear that any scenarios were modeled for the Study that included additional investments in energy efficiency as an option either on its own or as part of a portfolio with increased investments in renewable resources and/or a smaller natural gas-fired unit. This was unreasonable.
6. It appears that the Strategist model was not offered the option of choosing mid or long-term power purchases from existing and under-utilized gas-fired units in and around the state of Michigan either on their own or as part of portfolios with other resources such as energy efficiency and wind generation.

Finding No. 3. **HBPW's proposal to build yet another baseload coal plant will ensure coal will continue to dominate its resource mix for decades despite HBPW's plan to add some small amounts of renewable resources. HBPW will continue to be very heavily coal-dependent for decades unless it undertakes very aggressive efforts on energy efficiency and renewable resources.**

HBPW is very heavily dependent upon coal-fired generation. For example, in Fiscal Years 2007 and 2008 more than 97 percent of HBPW's internally generated energy (MWhs) came from coal-fired facilities. In Fiscal Year 2009, more than 99 percent of HBPW's internally generated energy came from its coal-fired facilities.

Moreover, it is reasonable to assume that significant portions of the MWhs that HBPW buys through the wholesale market also were generated at coal-fired facilities. Consequently, it can be expected that well over 75 percent of HBPW's total energy supply (including market purchases) comes from coal-fired units.

Figure 1-1 in the Study substantially understates HBPW's reliance on coal and severely overstates its dependence on natural gas because it presents a capacity breakdown by fuel

type instead of a breakdown of energy generation by fuel type.⁴ Examining a utility's generation by fuel type reveals much more about its dependence on a fuel than looking at a breakdown of capacity by fuel.

For example, the approximate 38 percent of HBPW's capacity that is coal-fired generates approximately 96 percent to 99 percent of its internally generated MWhs. Similarly, the approximate 53 percent of HBPW's capacity that is gas-fired generates only about 1 to 3 percent of its MWhs. The approximate 7 percent of HBPW's capacity that is oil-fired generates barely any of its energy.

Clearly then, HBPW will remain very heavily dependent on coal if it adds a new 70 MW CFB or a share of another coal plant such as Consumer Energy's proposed Karn-Weadock unit. This will be true even if HBPW co-fires 30 percent biomass at the CFB plant and/or adds the relatively small amounts of energy from renewable resources included in its Study.

Before 2000, a heavy reliance on coal may not have presented a financial problem other than constituting a highly undiversified resource base. However, at this time in the electric industry, HBPW's current and projected heavy dependence on coal-fired generation is risky for its retail customers for a number of reasons: the potential for higher fuel prices and coal supply disruptions; the potential for substantial carbon emission compliance costs; the potential for the federal government to mandate further reductions in other non-greenhouse gas coal plant emissions such as SO₂, NO_x, mercury and small particulates; and the other risks cited in these comments.

Finding No. 4. **A comprehensive system for federal regulation of CO₂ and other greenhouse gas emissions is inevitable. It is generally expected that this federal regulation will require steep reductions in greenhouse gas emissions. However, the resource planning analyses in HBPW's Study show that its annual CO₂ emissions will increase, not decrease, if it self-builds or enters into joint ownership of a new coal-fired power plant. Thus, HBPW's projected future CO₂ emissions would be in conflict with evolving state, regional and national climate policies.**

Corporate, government, and financial leaders increasingly anticipate imminent greenhouse gas regulation in the U.S., and that greenhouse gas emission restrictions will pose substantial challenges and create significant new costs for the owners of coal-fired power plants. For example, in its January 28, 2008 assessment of the *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*, Standard & Poor's noted that "the single biggest challenge regulated electric utilities will tackle is the discharge of carbon dioxide (CO₂) into the air."⁵

⁴ At page 1-2 of the Study.

⁵ *To 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*, Standard & Poor's, January 28, 2008, at page 2.

Standard & Poor's subsequently issued a report on *The Credit Cost of Going Green for U.S. Utilities*, in March 2008, in which it concluded that:

The debate is over. Not the one concerning climate change, but the one about whether the U.S. will act to limit greenhouse gas emissions to address the possibility that human activities are harming the planet. By now it's a foregone conclusion that the U.S. will pass laws that call for significant reductions in carbon dioxide (CO₂). The only uncertainty is the details of how much and by when....So for electric utilities, the credit question is not so much whether higher costs related to controlling emissions are coming, but rather when and how high they'll actually go.⁶

More recently, in its January 2009 Electric Industry Outlook, Moody's Investors Services also warned that:

The prospect for new environmental legislation—particularly concerning carbon dioxide—represents the biggest emerging issue for electric utilities, given the volume of carbon dioxide emissions and the unknown form and substance of potential CO₂ legislation.⁷

Moody's also emphasized that the credit risk for utilities arises from the uncertain costs and format of emissions regulation, acceleration of potential climate change legislation, as well as the possibility that rate regulators will balk at rising costs when consumers reach their tolerance level for cost increases, particularly in light of recessionary pressures.

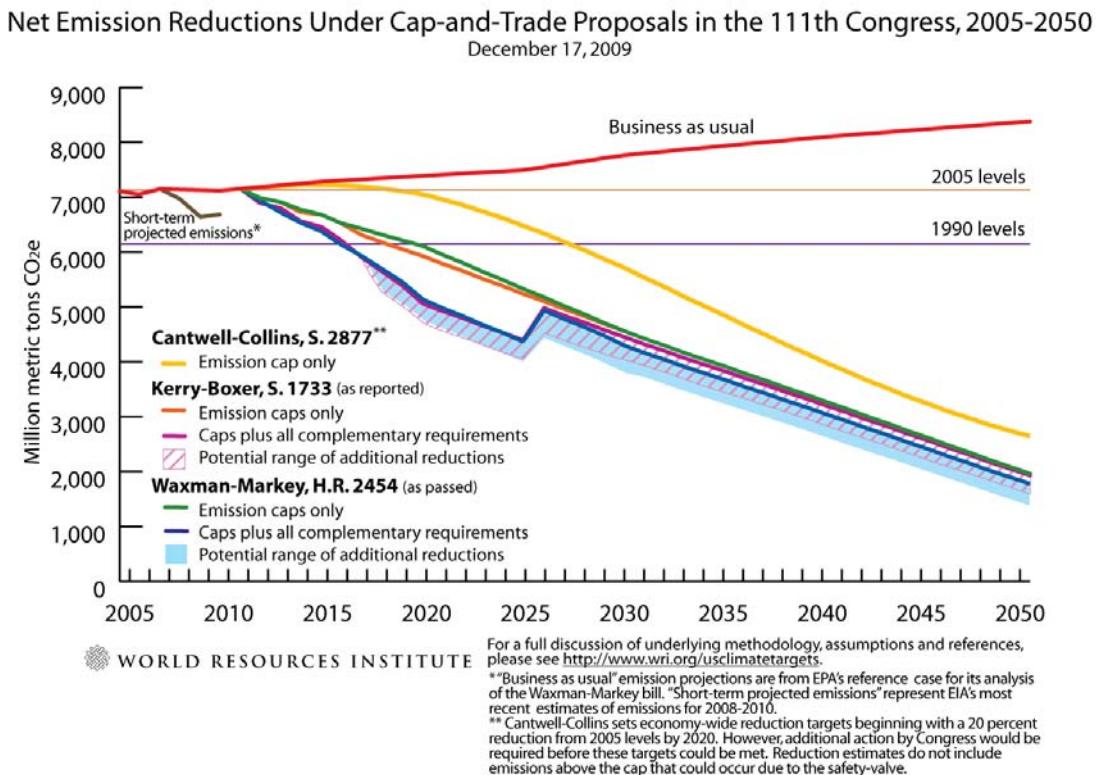
The general goal of most of the legislation and policies under consideration on the federal, state and regional levels would be to reduce annual domestic U.S. CO₂ emissions by 60 percent to 80 percent from current levels by the middle of this century. It is generally believed by climate scientists that reductions of this magnitude might enable the world to avoid the most harmful effects of global climate change.

The emissions levels that would be mandated by some of the bills that are currently being considered in the U.S. Congress are shown in Figure 1 below:

⁶ *The Credit Cost of Going Green*, Standard & Poor's, March 2008, at page 15.

⁷ *Moody's Global Infrastructure – Industry Outlook: "U.S. Investor-Owned Electric Utilities;"* Moody's Investors Services. January 2009.

Figure 1: Comparison of Legislative Climate Change Targets in the Current 111th U.S. Congress as of December 17, 2009



It is uncertain which, if any, of the specific climate change bills that have been introduced to date in the Congress will be adopted. Nevertheless, the general trend toward carbon regulation is clear; and it would be a mistake to ignore it in long-term decisions concerning electric resources. Over time the proposals are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows.

The March 2009 *Climate Action Plan* issued by the Michigan Climate Action Council recommended similar goals of reducing greenhouse gas emissions to 20 percent below 2005 by 2020 and to 80 percent below 2005 levels by 2050.⁸

In contrast to these evolving federal and state policies, the results of Black & Veatch's modeling reveal that adding either a 30 MW share of the proposed Karn-Weadock supercritical coal plant or building a 70 MW CFB would lead to significant *increases* in HBPW's annual CO₂ emissions between 2010 and 2030:

- In Case 2, in which HBPW would self-build a 70 MW CFB, its annual CO₂ emissions would increase by 32 percent between 2009 and 2030.

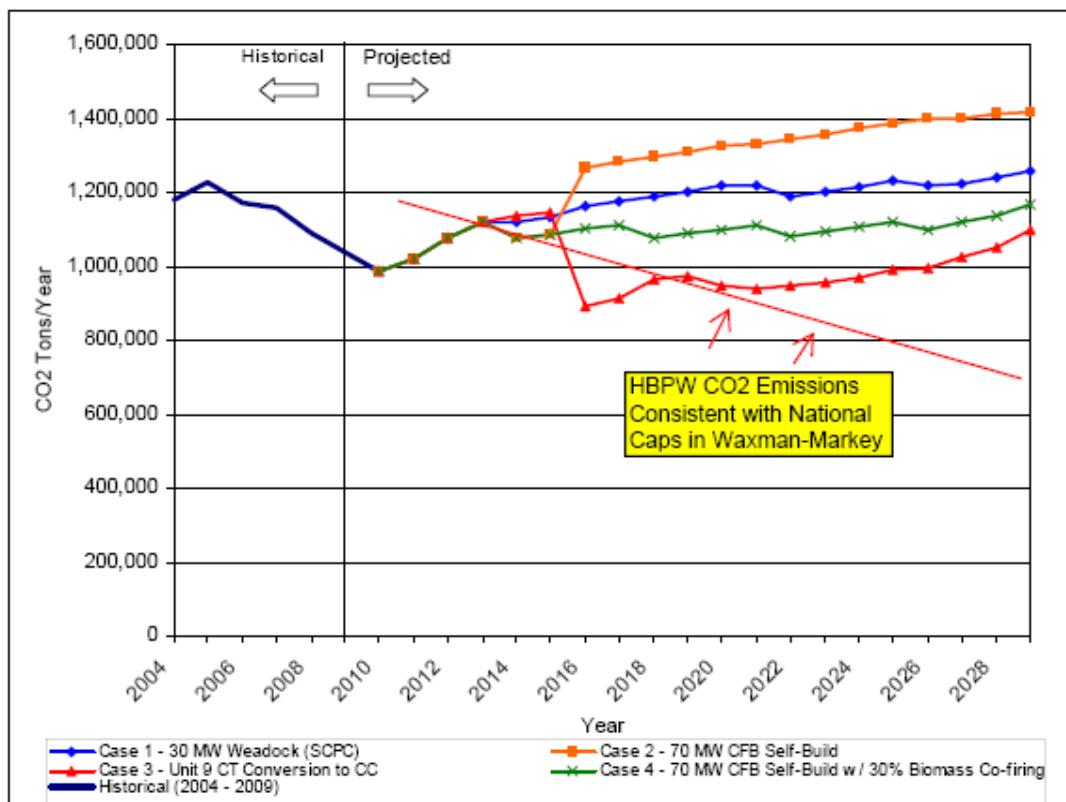
⁸ At page ExS-1.

- In Case 1, in which HBPW would purchase a 30 MW share of the supercritical pulverized Karn Weadock coal plant, its annual CO₂ emissions would increase by 17 percent between 2009 and 2030.

Even with 30 percent biomass co-firing at a new CFB coal plant, HBPW's annual CO₂ emissions would *increase* by 8 percent between 2010 and 2030. Of the four scenarios whose annual CO₂ emissions are presented in Figure 8-1 in the Study, Case 3, with the conversion of the Unit 9 CT to a combined cycle unit, would have the lowest annual CO₂ emissions – yet even the CO₂ emissions in this scenario would increase slightly between 2010 and 2030.

The CO₂ emissions profiles presented in Figure 8-1 from the Study are reproduced in Figure 2 below with a line added for the projected annual CO₂ emissions that HBPW might be limited to in order to be consistent with the national CO₂ caps in the Waxman-Markey legislation that was approved by the U.S. House of Representatives.

Figure 2: Modified Figure 8-1 from Study Including Projected CO₂ Emission Levels HBPW Would Need to Achieve to be Consistent with the National Caps in the Waxman-Markey Legislation



**Figure 8-1
Historical and Projected CO₂ Emissions**

As can be seen, HBPW's own projections show that its annual CO₂ emissions would increase, perhaps significantly, in each of the three scenarios in which it would self-build or participate in the ownership of a new coal plant. These increased CO₂ emissions would happen at the very time that legislation under consideration in Congress would be mandating reductions in emissions. In other words, HBPW's CO₂ emissions would be going in the wrong direction, i.e., up, at a time when the mandated levels of emissions were going down.

Finding No. 5.

Ratepayers will face significant financial risk associated with a decision to lock in increasing CO₂ emissions for the coming decades at a time when those emissions will be costly. Given the significant uncertainties regarding the stringency, design and timing of federal regulation of greenhouse emissions, a wide range of possible CO₂ costs should be used in resource planning analyses.

Black & Veatch conducted two sets of modeling analyses for the Study – one set had no CO₂ costs and a second set used a single CO₂ price trajectory. That single CO₂ price trajectory is shown in Figure 6-3 on page 6-2 of the Study.

It is completely unrealistic to assume that there will be no state, regional or federal regulation of greenhouse gas emissions at any time between 2010 and 2030. Indeed, as is explained in Finding No. 4, above, it is widely accepted that federal regulation of greenhouse gases is imminent and is a question of when and how, not if. For this reason, the modeling analyses in the Study that assume no CO₂ costs simply have no probative value and should be ignored. Such scenarios are biased in favor of the most carbon intensive alternatives, that is, those that include new coal plants.

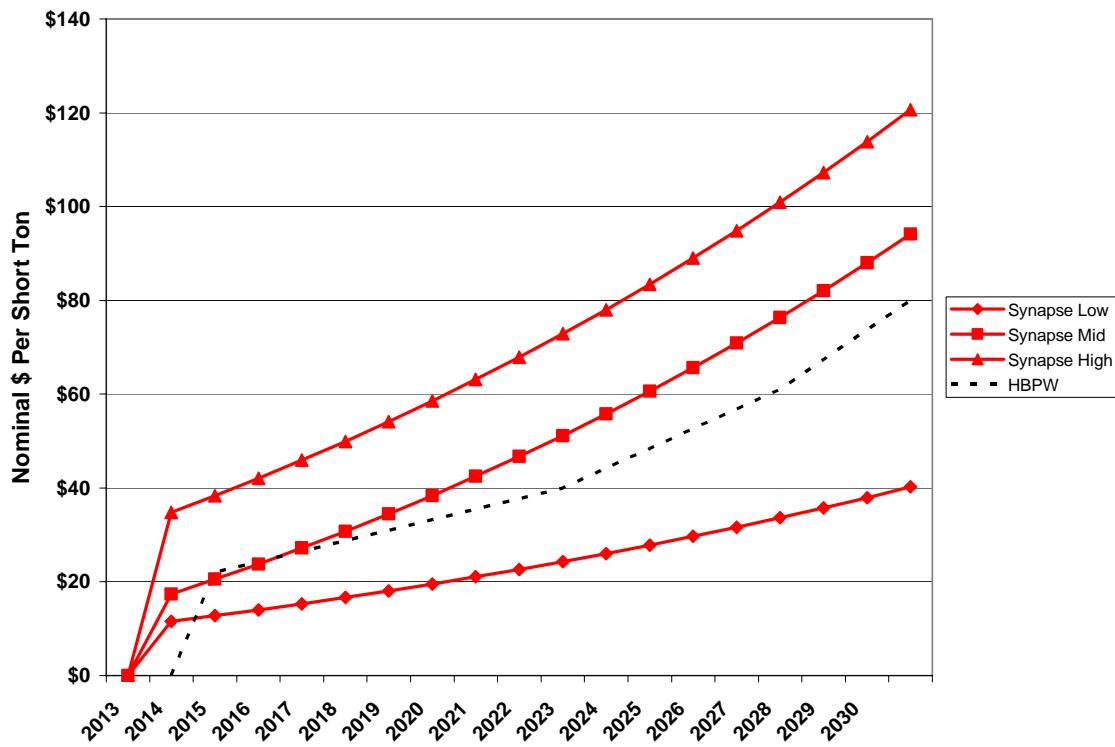
The single CO₂ price trajectory that Black & Veatch used in the modeling scenarios with CO₂ costs is a little low but would not be very unreasonable for use as a reference case scenario. However, Black & Veatch also should have examined a wide range of possible CO₂ prices in its modeling analyses given the uncertainties associated with the timing, stringency and design of federal or state regulation of greenhouse gas emissions.

Figure 3, below, compares the single CO₂ price trajectory used by Black & Veatch in its modeling analyses with the CO₂ price projections developed by Synapse Energy Economics.⁹

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The Synapse CO₂ price forecasts have been accepted by regulatory commissions in states such as California, Minnesota and New Mexico and are consistent with the prices used in resource planning by utilities around the U.S.

Figure 3: Black & Veatch vs. Synapse CO₂ Price Forecasts



As can be seen in Figure 3, the single Black & Veatch CO₂ and the Synapse Mid CO₂ price trajectories are not too different although the Black & Veatch CO₂ prices are below the prices in the Synapse Mid CO₂ trajectory in most years. However, the range of CO₂ prices encompassed by the Synapse Low and High CO₂ price trajectories allow for uncertainty whereas the single Black & Veatch CO₂ price trajectory does not.

Figure 4, below, then compares the single CO₂ allowance price trajectory that Black & Veatch used in the modeling analyses in the HBPW Study with the results of independent modeling of the legislation that has been introduced in the U.S. Congress in recent years. These modeling analyses include:

- The U.S. Department of Energy's Energy Information Administration's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007).¹⁰
- The EIA's October 2007 Supplement to the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*.¹¹
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008).¹²

¹⁰ Available at [http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf\(2007\)04.pdf](http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf).

¹¹ Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf

- The EIA’s assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008).¹³
- The EIA’s assessment of the *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009).¹⁴
- The U.S. Environmental Protection Agency’s (“EPA”)’ *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007).¹⁵
- The EPA’s *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008).¹⁶
- The EPA’s *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008).¹⁷
- The EPA’s *Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress* (June 2009)¹⁸
- *Assessment of U.S. Cap-and-Trade Proposals* by the Joint Program at the Massachusetts Institute of Technology (“MIT”) on the Science and Policy of Global Change (April 2007).¹⁹
- *Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191* by the Joint Program at MIT on the Science and Policy of Global Change (April 2008).²⁰
- *The Lieberman-Warner America’s Climate Security Act: A Preliminary Assessment of Potential Economic Impacts*, prepared by the Nicholas Institute for Environmental Policy Solutions, Duke University and RTI International (October 2007)²¹
- *U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways*, prepared by the

¹² Available at [http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf\(2007\)06.pdf](http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf)

¹³ Available at [http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf\(2008\)01.pdf](http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf).

¹⁴ Available at <http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html>.

¹⁵ Available at <http://www.epa.gov/climatechange/economics/economicanalyses.html>.

¹⁶ Available at <http://www.epa.gov/climatechange/economics/economicanalyses.html>.

¹⁷ Available at <http://www.epa.gov/climatechange/economics/economicanalyses.html>.

¹⁸ Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf.

¹⁹ Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf.

²⁰ Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.

²¹ Available at <http://www.nicholas.duke.edu/institute/econsummary.pdf>.

International Resources Group for the Natural Resources Defense Council (May 2008).²²

- *The Lieberman-Warner Climate Security Act – S. 2191, Modeling Results from the National Energy Modeling System – Preliminary Results*, Clean Air Task Force (January 2008).²³
- *Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model*, CRA International, April 2008.²⁴
- *Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM)*, a report by the American Council for Capital Formation and the National Association of Manufacturers, March 2008.²⁵

In total, these modeling analyses examined more than 85 different scenarios. These scenarios reflected a wide range of assumptions concerning important inputs such as: the “business-as-usual” emissions forecasts; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress and the cost of alternatives; and the presence or absence of a “safety valve” price.

In Figure 4:

- S.280 refers to the McCain-Lieberman bill introduced in 2007 in the 110th U.S. Congress
- S.1766 refers to the Bingaman-Specter bill introduced in 2007 in the 110th U.S. Congress
- S. 2191 refers to the Lieberman-Warner bill introduced in 2007 in the 110th U.S. Congress
- HR. 2454 refers to the Waxman-Markey bill introduced in 2009 in the current 111th U.S. Congress

²² Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf.

²³ Available at <http://lieberman.senate.gov/documents/catflwcsa.pdf>.

²⁴ Available at http://www.nma.org/pdf/040808_crai_presentation.pdf.

²⁵ Available at <http://www.accf.org/pdf/NAM/fullstudy031208.pdf>.

Figure 4: Levelized Black & Veatch and Synapse 2008 CO₂ Prices Compared to Results of Modeling of Proposed Federal Legislation

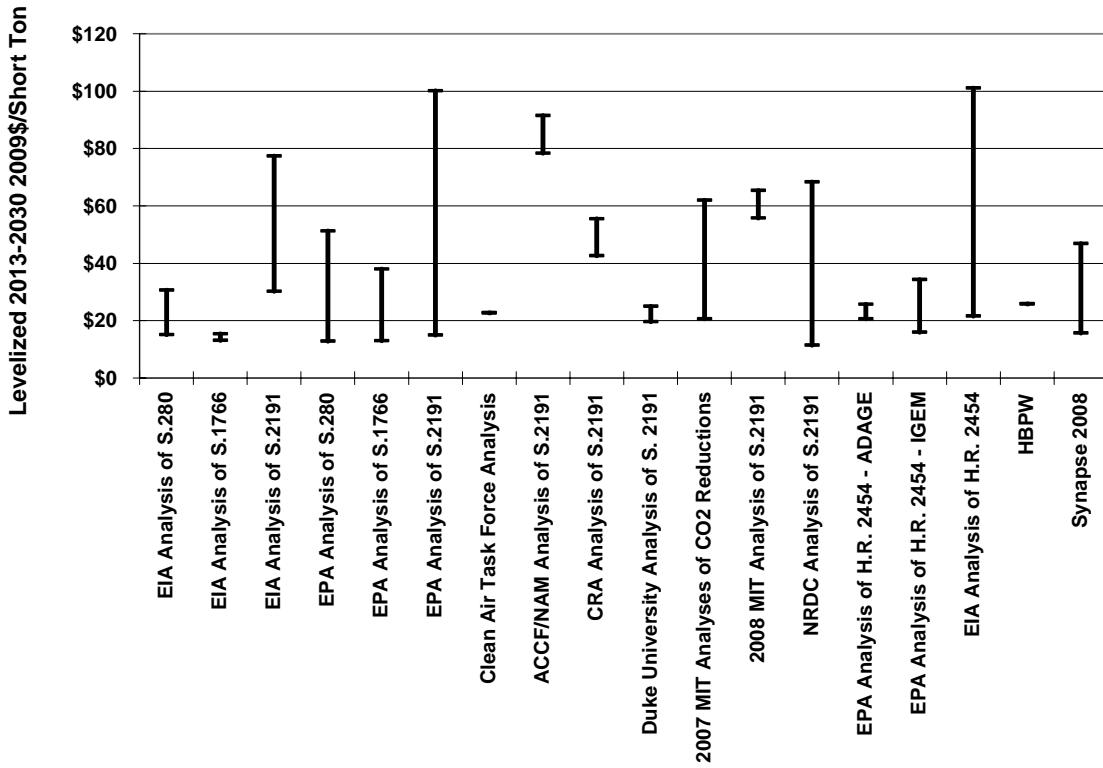


Figure 4 confirms that the single CO₂ price trajectory used by Black & Veatch did not adequately allow for the potential uncertainties associated with the design and stringency of future federal regulation of greenhouse gas emissions and for the possibility that CO₂ prices could be substantially higher than Black & Veatch now assumes.

It should be noted that the third through fifth bars from the right in Figure 4 show the ranges of leveled CO₂ prices from the modeling of the Waxman-Markey bill by the EIA and the EPA. However, it is not certain that whatever bill is ultimately passed by the U.S. Congress actually will reflect the terms of that legislation. This is the reason why the results of the modeling of the other legislation that has been introduced in previous U.S. Congresses remain relevant.

Finding No. 6. The leveled cost analyses in the Study are misleading because they do not include CO₂ costs.

HBPW says that Figures 5-3 and 5-4 of the Study show how renewable and conventional energy technologies compare on a leveled cost of energy basis. However, the cost comparisons do not include any CO₂ costs.²⁶ Thus, they underestimate what the total cost of power will be from the fossil fired technologies and make the coal-fired technologies

²⁶ See HBPW's response to Sierra Club Question No. 14.

appear more economic relative to the alternative, non-fossil and the gas-fired technologies than they actually will be when CO₂ costs are considered.

Finding No. 7. The Study appears to overstate HBPW's need for new capacity.

- A. **The Study projects high energy and peak load growth for HBPW through 2030.**
- B. **The Study assumes that HBPW will be able to achieve only extremely minor incremental energy efficiency savings after 2015.**
- C. **The Study ignores the availability of a substantial amount of under-utilized gas-fired combined cycle and gas turbine capacity in and around the state of Michigan that could provide much, if not all, of the energy that would be generated at HBPW's proposed CFB coal plant.**

A. The Study projects high energy and peak load growth for HBPW through 2030.

HBPW's energy sales were relatively stagnant for a period of about six or seven years even before major decreases were experienced in 2008 and 2009. However, HBPW now wants to implement a long-term resource plan based on very high energy sales and peak load growth in the short term and substantial growth in the long term.²⁷ Specifically, HBPW assumes a long term energy demand growth rate of approximately 2.3% between now and the year 2030.²⁸ This is nearly twice the level Black & Veatch assumes as the baseline long term energy demand growth in its most recent Energy Markets Perspective for the Midwest.²⁹ Unfortunately, apart from a brief explanation in a data response that HBPW may attract several new industrial customers in the short-term, no detailed evidence is provided as to where the long-term energy and demand growth will come from and why it is expected to be so much higher than the average Black & Veatch estimates for the region. This is a critical flaw and more information needs to be provided before the reasonableness of HBPW's energy and peak load forecasts can be evaluated. This is even more important given that HBPW apparently has not prepared another forecast since 2003 (far too long a period) and that its 2020 year forecast has been lowered by 31 percent from the forecast in the 2003 report.³⁰

Given such a divergence between recent history and its projected load growth, it is particularly critical for HBPW to pursue a flexible resource plan that can be changed as circumstances change. Committing to a long-term, expensive capital-intensive resource plan that depends very heavily on a new coal-fired power plant is the wrong decision at a

²⁷ See Table 3-1 and Figures 3-1 and 3-2 on pages 3-4 and 3-5 of the Power Supply Study.

²⁸ Power Supply Study, at page 3-3.

²⁹ Power Supply Study, Appendix A, at page 31.

³⁰ Power Supply Study, at page 3-6.

time like this. If HBPW pursues such a plan and its expected load growth does not materialize, its customers will be left paying the high costs of excess system capacity.

B. The Study assumes that HBPW will be able to achieve only relatively minor incremental energy efficiency savings after 2015.

HBPW increases its future need for new capacity by reducing its projected incremental annual energy efficiency savings from 1 percent in 2015 to an average of 0.2 percent between 2016 and 2030, the last year of its analysis. This is based on HBPW's assertion that a cumulative 8.2 percent of energy efficiency savings by 2030 is a reasonable level to assume for planning purposes.³¹ However, HBPW's assumed savings are overly conservative for a number of reasons:

- (1) HBPW provides no company- or even state-specific evidence to support its claim that it cannot achieve more than this amount of cost-effective energy efficiency each year after 2015. Unlike many other utilities, including investor-owned, public power, and electric membership cooperatives, HBPW has not prepared a specific energy efficiency potential study for its own service territory.³² Therefore, it has no evidentiary basis for concluding that higher energy efficiency savings cannot be achieved after 2015.
- (2) The available evidence suggests that the cost of achieving energy efficiency in Michigan is significantly less than the estimated leveled costs of HBPW's proposed CFB coal plant. For example, Consumers Energy's EGAA notes that energy efficiency has a leveled cost, on average, of only \$35 per MWh.³³ This average cost is substantially less than the leveled costs of the coal and natural gas supply side options presented in Tables 5-17, 5-20, 5-25 and 5-26 of the Study. Notably, the leveled costs in these Tables do not include CO₂ costs. Including CO₂ costs will make each of the fossil options (i.e., coal and gas) even more expensive compared to energy efficiency and, consequently, make energy efficiency measures an even better economic option.

Given a very low average cost such as this, it is reasonable to expect that there would be a substantial amount of untapped energy efficiency potential in HBPW's service territory that would cost less than even the \$79/MWh to \$91/MWh that HBPW claims for the leveled cost of power from the proposed CFB plant. HBPW should be required to include these lower cost energy efficiency savings before it is allowed to build the more expensive CFB plant.

³¹ Id., at page 3-8.

³² Id., at page 3-7.

³³ Consumers Energy's EGAA, Table 7, at pages 36 and 37.

- (3) The 0.2 percent annual energy efficiency savings that HBPW projects for the years 2016 to 2030 are substantially below the 2 percent annual savings that the Midwest Governors Association has set as its target.³⁴
- (4) As discussed in Attachment No. 2 to these Comments, the federal government has taken aggressive actions in recent years to fund energy efficiency programs and to stimulate the development and use of renewable resources. It appears from the Study that HBPW has not assumed energy efficiency savings that reflect these aggressive actions.
- (5) As discussed in Attachment No. 3 to these Comments, the EPRI study on which HBPW seeks to rely is flawed and, consequently, understates the potential for energy efficiency savings.
- (6) If HBPW had been sufficiently motivated to perform an analysis of the available cost effective potential for energy efficiency in its service territory, there is ample evidence to suggest that it would have found the potential to save considerably more than 0.2 percent per year in 2016 and beyond. In fact, some Midwest states' utilities are already achieving greater energy savings than 0.5 percent per year, including Iowa and Minnesota whose utilities saved 0.7 percent and 0.6 percent of load in 2006, respectively, and many states outside the Midwest are achieving much higher savings including Vermont and Connecticut, whose utilities cut demand by 1.8 percent and 1.3 percent in 2007 using energy efficiency. Recent energy efficiency potential studies have projected achievable cost-effective energy efficiency potential at levels more five to almost ten times higher than that projected by HBPW, including Kansas (1.1% achievable³⁵), Florida (1.3% achievable³⁶), Texas (1.2% achievable³⁷), and Vermont (1.9% achievable³⁸).

Thus, HBPW's assumption that it will be able to achieve only 0.2 percent incremental annual energy efficiency savings starting in 2016 is unsupported and should not be accepted. Instead, HBPW should be required to undertake and present the results of a utility-specific assessment of the potential for cost-effective energy efficiency and to update the Study to reflect these results accordingly before it is granted a permit for its proposed CFB coal plant.

³⁴ *Energy Security and Climate Stewardship Platform for the Midwest*, Midwestern Governor's Association, November 2007, at page 7. Available at <http://www.midwesternaccord.org/Platform.pdf>.

³⁵ Energy Efficiency Potential Study for the State of Kansas, Prepared by Summit Blue Consulting, August 11, 2008.

³⁶ Elliott et al., Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demand, June 2007, ACEEE Report No. EO72.

³⁷ Elliott et al, Potential for Energy Efficiency and Renewable Energy to Meet Texas's Growing Energy Demand, March 2007, ACEEE Report No. EO 73.

³⁸ Vermont Electric Energy Efficiency Potential Study, Prepared for the Vermont Department of Public Service by GDS Associates, Inc., January 2007.

- C. The Study ignores the availability of a substantial amount of under-utilized gas-fired combined cycle and gas turbine capacity that could provide much, if not all, of the energy that would be generated at HBPW's proposed CFB coal plant.

A review of the generation data in the U.S. EPA's Clean Air Markets Database shows that there is significant under-utilized natural gas-fired capacity in Michigan and the neighboring states of Ohio and Indiana. Given the very slow load and energy sales growth projected for this region, it is reasonable to expect that these gas-fired plants will continue to be under-utilized for years to come.

Table 1: Natural Gas-Fired Generating Units in Michigan, Ohio and Indiana – 2008 Capacity Factors.

State	Plant	Nameplate Capacity	2008 Capacity Factor
MI	Ada Cogeneration LP	33	71.2%
MI	Covert Generating Project	1,176	7.9%
MI	Dearborn Industrial Generation	760	17.2%
MI	Kinder Morgan Power Jackson Facility	570	9.2%
MI	Michigan Power LP	154	66.2%
MI	Midland Cogeneration Venture	1,849	33.8%
MI	University of Michigan	45	40.6%
MI	Zeeland Plant	591	9.4%
OH	Ashtabula	26	63.7%
OH	AEP Waterford Facility	922	3.3%
OH	Hanging Rock Energy Facility	1,322	6.7%
OH	Washington Energy Facility	600	6.1%
IN	Lawrenceburg Generating Station	1,232	4.6%
IN	Noblesville	328	14.2%
IN	Portside Energy	76	35.7%
IN	Sugar Creek Power Plant	555	5.2%
IN	Whiting Clean Energy	639	15.2%

Before its Study is accepted, HBPW should be required to demonstrate that entering into a mid-to-long-term power purchase agreement (PPA) for capacity and energy from existing gas-fired facilities is not a cost-effective alternative to building a new and expensive CFB coal plant.

A PPA with the Zeeland Plant should particularly be considered since it is located less than 10 miles from the City of Holland.

Finding No. 8. **It is unclear what potential costs have been included in the analyses presented in the Study for complying with new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.**

Prudent electric resource planning requires the consideration of costs for new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.

However, it is unclear from the Study what costs HBPW has assumed would be required to comply with air emission reduction requirements (other than CO₂) for the proposed

coal plant. HBPW has assumed the following emission reduction systems would be installed at its proposed coal plant: a limestone sorbent injection and polishing semi-dry spray dryer absorber (SDA) for SO₂ control, selective noncatalytic reduction (SNCR) for NOx control, ACI injection for mercury control, and a fabric filter for particulate control.³⁹ However, the costs HBPW assumed for this equipment is unknown. Like coal plant construction costs, the costs for emission control equipment have risen dramatically over the last several years. Understating the cost of this equipment renders the CPCW comparisons between projects unreliable.

Moreover, the type of equipment HBPW proposes to install is not the “top-of-the-line” equipment available to reduce the emissions identified. This year, the U.S. EPA already issued a new more demanding air quality standard for nitrogen oxides, and is scheduled to adjust standards relating to sulfur dioxide, particle pollution and ozone. EPA is also likely to issue regulations addressing interstate transport of air pollution. By 2011, EPA is scheduled to issue a federal implementation plan for regional haze, issue new source performance standards for key pollutants from electrical generating units and non-electrical generating unit boilers, and issue new standards for hazardous air pollutants, among other matters. It certainly is reasonable to expect that in most or all cases, EPA action will result in more stringent regulation of these pollutants. More stringent regulation would require more stringent controls that are likely to be more expensive. Increased costs will further widen the gap between HBPW’s proposed coal plant and other less environmentally destructive and less costly alternatives.

It is also unclear from the Study whether HBPW has appropriately considered the costs associated with disposing of coal combustion wastes, if at all.⁴⁰ Coal combustion wastes (“CCW”), also known as “coal ash” or “coal combustion products,” consist of fly ash, bottom ash, boiler slag and flue gas desulfurization sludge and are typically disposed of in landfills and surface impoundments. CCW can contain heavy metals such as arsenic, nickel, cadmium, chromium, lead, manganese, selenium and thallium, as well as sulfates, chlorides, boron, polycyclic aromatic hydrocarbons (“PAHs”), benzene, phenols, polychlorinated biphenyls (“PCBs”), cyanide, dioxins and furans. These substances can leach out of CCW and into water supplies when the waste comes into contact with water.

EPA has identified risks to human health and the environment from the disposal of CCW in landfills and surface impoundments. For example, EPA’s “Coal Combustion Waste Damage Case Assessment” dated July 9, 2007, recognized 24 proven cases of danger to human health or the environment and another 43 “potential” damage cases related to CCW. All but one of the 24 proven damage cases involved unlined disposal units.⁴¹

A series of spills in late 2008 and early 2009, including the major spill of approximately one billion gallons of CCW at Tennessee Valley Authority’s Kingston, TN coal plant in

³⁹ Power Plant Study, at page 5-40.

⁴⁰ HBPW’s response to Sierra Club Question No. 18 suggests that adequate consideration has not been given to the potential magnitude of CCW management and storage costs.

⁴¹ U.S. EPA, Notice of Data Availability on the Disposal of Coal Combustion Wastes in Landfills and Surface Impoundments, 72 Fed. Reg. 49714, 49718-19 (Aug. 29, 2007).

December 2008, drew the nation's attention to CCW storage. Based in part on these spills and an additional series of regulatory determinations regarding improper management and disposal of CCW from coal-fired power plants, EPA is currently considering regulations to address CCW under the federal Resource Conservation and Recovery Act ("RCRA").

Specifically, EPA is considering several options including 1) regulating CCW as hazardous waste under Subtitle C of RCRA, which would include a tracking system and federally enforceable permits; 2) regulating CCW as non-hazardous waste under Subtitle D of RCRA, which would include inducements for state solid waste programs and implementation of federal minimum regulations for landfills; 3) a hybrid approach, by which CCW would be considered a solid waste if certain conditions are met, but a hazardous waste if they are not; and 4) another hybrid approach whereby wet CCWs (in surface impoundments) would be regulated as hazardous wastes and dry CCWs (in landfills) would be regulated as non-hazardous wastes.

EPA also recently announced that it may develop regulations setting financial responsibility requirements for power plants under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA," better known as "Superfund"), citing, among other things, the "significant cleanup costs that can be generated by this industry sector."⁴²

EPA is expected to issue a draft of its proposed regulation on CCW in the very near future.

The costs associated with the EPA's anticipated regulation of coal combustion wastes are uncertain and will depend on how EPA classifies the wastes as well as plant specific factors (that is, wet versus dry storage, lined versus unlined, whether stored on the surface or not). One utility, Progress Energy Carolinas, stated the following in a December 1, 2009 Plan to Retire 550 MWs of Coal Units without SO₂ Controls:

EPA is currently considering re-characterizing the nature of and regulation of coal combustion products (bottom ash, fly ash and related materials, hereinafter CCPs) in response to TVA's Kingston Plant ash pond impoundment failure. Speculation is focusing on EPA's regulation of CCPs as a hazardous waste. A narrow usage exclusion may be possible where the finished product of CCP is fully encapsulated. Existing uses that involve land application or unconfined uses may be prohibited. If EPA characterizes CCPs as a hazardous waste or otherwise increases the regulatory requirements applicable to CCPs, the handling, storage and disposal of this material will result in significantly increased costs of operation, and more sophisticated handling equipment and disposal requirements. Classification of power plant CCP operations as activities that produce hazardous wastes as defined by the Resource Conservation and Recovery Act (RCRA) would trigger a number of additional regulatory requirements as well as potential liability associated with closure of

⁴²

75 Fed. Reg. 816, 822 (Jan. 6, 2010).

impoundments, leachate management and site remediation. Phase out of surface impoundments is under consideration by EPA.⁴³

Although the industry cost estimates may be exaggerated in order to dissuade the EPA from regulating CCW as hazardous waste, they do predict significant costs. For example, an October 30, 2009 letter to the Federal Office of Management and Budget from the Utility Solid Waste Activities Group⁴⁴ warned that:

If [coal combustion wastes] were regulated as hazardous wastes, the economic impact on the utility industry would be enormous, resulting in power plant closures, increased electricity rates for consumers, corresponding power reliability concerns, and virtually eliminating all [CCW] beneficial uses.⁴⁵

Testimony before Congress by a representative from EPRI similarly stated that:

A national coal combustion products regulation will alter the technology and economics of coal-fired power plants. Some owners would decide to prematurely shut down rather than incur the costs of compliance, while others would convert their ash handling and disposal systems and continue to operate in the post-regulation market.⁴⁶

The cost to clean up the damage from the December 2008 release from Tennessee's Kingston plant has been estimated to range from \$933 million to \$1.2 billion.⁴⁷

Despite the uncertainty associated with the EPA's possible regulation of coal combustion wastes, HBPW could reflect this issue in its resource planning analyses. The traditional way to address uncertainty in resource planning is to identify a wide range of the potential costs for key input assumptions.⁴⁸ Thus, HBPW could identify ranges of the possible costs for the different ways in which the EPA may regulate coal combustion wastes (that is, hazardous or not, etc.) and then apply those ranges of costs in sensitivities in its resource planning analyses.

⁴³ Power Plant Study, at pages 7 and 8.

⁴⁴ The Utility Solid Waste Activities Group is described as an informal consortium of 80 utility operating companies, the Edison Electric Institute and others.

⁴⁵ Power Plant Study, at page 2.

⁴⁶ Written Testimony of Ken Ladwig, Senior Research Manager at EPRI, before the Subcommittee on Energy and Environment of the United States House of Representatives, dated December 10, 2009.

⁴⁷ "TVA Reports 2009 Fiscal Year Third Quarter Results," available at www.tva.gov/news/release/julsep09/3rd_quarter.htm.

⁴⁸ For example, Duke considers ranges of potential CO₂, SO₂ and NOx allowance costs in its IRP analyses.

In sum, it is unclear whether HBPW has adequately factored into its analyses the economic risks of operating coal-fired power plants in the face of new or more stringent air emissions and coal combustion waste management requirements.

Finding No. 9. HBPW understates the potential for future increases in coal prices.

Figure 6-1, *Coal Prices*, in the Study presents the assumed “all-in delivered price [for coal] from a Powder River Basin (“PRB”) source.” This Figure shows coal prices rising at a rate slightly above inflation, 2.8 percent annually from 2010-2030, from \$2.15/MBtu to \$3.375/MBtu. This would translate to per ton costs for 8800 Btu PRB delivered coal increasing from \$38.00 to \$59.00 during the period covered by the forecast.⁴⁹

Such modest price growth may be consistent with the history of PRB coal. However, there is considerable evidence indicating that future coal markets will not be like past coal markets – most notably prices can be expected to be considerably higher.

The prices of PRB coal are currently increasing slowly after a decline from the historic highs experienced in mid 2008. In the short term (i.e., the next twelve months), gradual increases can be expected. However, for the medium and longer term, coal markets can no longer be relied upon to produce a reliable supply of low cost fuel. Instead of being an anomaly, the price run-ups that occurred in 2007 and 2008 are more likely harbingers of how markets will perform in the future. In fact, despite the current recession and relatively low coal prices across the country, between 2010 and 2012 industry analysts and market data tell us the price of PRB coal will rise by approximately 40 percent, and potentially higher.⁵⁰

After 2012, the prices for PRB coal are expected to rise significantly due to new cost pressures as mining becomes more complex and expensive and as large coal producers cultivate a worldwide base of users. Domestically, coal producers will try to use PRB coal’s relatively low prices to capture a larger portion of the energy market (new plants, retrofits and carbon capture projects). Further success with this strategy will place additional upward pressure on prices and hasten the depletion of PRB reserves.

These price pressures are structural in nature and will redefine the nation’s coal markets going forward. The new price environment will create a much higher floor for PRB coal, one that is less responsive to the normal patterns of domestic business cycles. This will

⁴⁹ All of these figures are estimates taken from a visual review of Figure 6-1 in the HBPW Study. There are no accompanying tables or charts that provide the background data upon which this chart is based. We are also assuming the use of 8800 Btu PRB coal. The reader of the Power Supply Study is referred generally to Appendix A, Energy Market Perspective. Only page 116 of that Appendix appears to address coal prices and it simply compares Powder River Basin, Central Appalachia and the Central Interior Basin Coal – and concludes PRB price rises will be slow and steady, outpacing the other regions through 2035.

⁵⁰ Peabody Energy, Forward Looking Statement, February 18, 2010 estimates PRB 8800 rising from \$10.00 per ton in 2009 to \$14.00 in 2012. NYMEX Futures (March 1, 2010) is reflecting a price movement of \$11.10 per ton in April 2010 to \$14.50 in December 2012. See also: Coal and Energy Price Report, *Powder River Basin prognostication has Arch seeing way to lucrative future*, Volume 12, No. 74, April 20, 2010. Arch’s view is more aggressive than NYMEX futures.

further erode coal's competitive edge with other power generation fuels in the United States.⁵¹

A recent report from the United States Geological Survey (USGS) and indications from industry leaders have raised red flag warnings about the long term supply sufficiency of economically recoverable coal in the Powder River Basin. The USGS report prompted press coverage in the Wall Street Journal that uncovered the fact that: a) the United States Energy Information Agency concurred with the findings of the USGS study and was revising the methodology by which the nation's coal reserve levels were being calculated; b) one of the nation's largest coal producers agreed with the findings of the study; and, c) another large power generator had purchased its own mine due to risks and uncertainties it perceived with the traditional mining industry.⁵²

A recent analysis of PRB coal offered by Arch Coal, a major mine owner in the PRB region, said that it expects intensified mining (beyond its current rate) and increased sales from the area.⁵³ The company pointed to shrinking stockpiles of PRB coal, diminished production of steam coal from Central Appalachia and historic price patterns in the PRB (which indicate a coming period of volatile upward price swings). The company is viewing a \$2 to \$5 per ton increase in the price of coal in the near to medium term as a realistic estimate of its potential.

Industry reporting and analysis places the current cost of PRB coal at \$11.10 per ton, with delivery costs at between \$30 and \$35 per ton – this means an “all-in” price above the prices suggested in the Study. Thus the assumed coal prices in the Study do not accurately represent the current market and expected future markets. It is quite possible that the price of PRB coal will rise during the forecast period more significantly to a level in the range of the low to mid \$70s per ton.⁵⁴

Finding No. 10. The biomass prices used in the Study appear low.

Black & Veatch assumes a \$3.00 per MBtu base delivered price for biomass fuel. Unfortunately, as with all of the other key assumptions, the Study provided no evidence supporting this price.⁵⁵ The use of a low biomass price biases the analysis in favor of the CFB option with 30 percent biomass.

⁵¹ United States Geological Survey, *Assessment of Coal Geology, Resources and Reserves in the Gillette Coalfield, Powder River Basin, Wyoming*, Open-File Report: 2008-102. <http://pubs.usgs.gov/of/2008/1202/>

⁵² Smith, Rebecca, *U.S. Foresees A Thinner Cushion of Coal*, Wall Street Journal, June 8, 2009.

⁵³ See Arch Coal, *Investor Presentation*, February 2010, at pages 11-14 and 27, 28.

⁵⁴ This assessment by TR Rose Associates suggests an increase in the underlying price of coal from its current level of \$12.00 by the end of 2011 to \$15.00 and then a price spike through 2011-12 upward of \$18.00; rising through 2017 into the lower \$20 per ton for a delivered price in the range of \$50-\$56 ton by 2017. A reasonable estimate suggests that the price of PRB coal by 2030 to HBPW's proposed coal plant will be more in the low to mid \$70 per ton range.

⁵⁵ HBPW's response to Sierra Club Question No. 6 suggests that the \$3.00 per MBtu price for biomass feedstock is just a general assumption and is not based on any site specific analysis.

The price HBPW used for biomass fuel used is 30% less than the price assumed by Wolverine Power Cooperative in its 2009 Electric Generating Alternatives Analysis (i.e., \$4.23 per MBtu.⁵⁶). Although there might be valid reasons to assume a lower biomass price for HBPW, there has been no evidence provided to support such a low value.

Finding No. 11. It is unreasonable to expect that post combustion carbon capture and sequestration for a new CFB coal plant will be technically and economically available before the mid-to-late 2020s, if at all.

Black & Veatch examined a scenario with carbon capture and sequestration (“CCS”) for the coal plant.⁵⁷ However, apparently at HBPW’s direction, Black & Veatch assumed that the U.S. DOE would pay for the entire cost of adding CCS to the proposed CFB plant. This is an extremely optimistic assumption that heavily biases the analysis in favor of the coal option. Unfortunately, the Study provided absolutely no evidence that it is reasonable to expect that the U.S. DOE would pay the entire cost of adding CCS to the proposed coal plant. If Black & Veatch wanted to test the economics of the proposed coal units assuming CCS is shown to be technologically and economically feasible, it should have looked at a range of scenarios in which the support provided by the federal government increased from a level of no economic support to the provision of a loan guarantee to, perhaps, a scenario in which there is some significant direct funding of the CCS equipment, but not 100 percent funding.

Without access to the modeling workpapers and files, it is not possible to determine in what year Black & Veatch assumed that CCS would be technologically feasible for a new CFB unit. It is generally accepted inside and outside the electric industry that there is currently no commercially viable technology for carbon capture and sequestration. For example, a witness for Dominion Virginia Power, which is currently building a CFB coal-fired power plant, presented the following testimony in July 2007:

[c]arbon capture technology is not commercially viable or available at the present time. Furthermore, the successful integration of all of the technologies needed for a commercial-scale carbon capture and sequestration system has yet even to be demonstrated. As a result, it is not currently feasible to construct a power plant with technology that can capture and store carbon emissions.⁵⁸

It also is expected that even if proven to be commercially and technically viable, post combustion CCS will not be available until the mid-2020s or later. For example, the 2007 Future of Coal study from the Massachusetts Institute of Technology (“MIT”) warned that:

⁵⁶ Wolverine EGAA, at page 55 of 114.

⁵⁷ See Table 7-3 on page 7-11 of the Power Supply Study,

⁵⁸ Direct Testimony of Dominion Virginia Power witness James K. Martin in Virginia State Corporation Commission Case No. PUE-2007-00066, dated July 13, 2007, at page 7, line 11. A copy of this testimony is available on the Virginia State Corporation Commission website at <http://docket.scc.virginia.gov/vaproduct/main.asp>

Many years of development and demonstration will be required to prepare for its successful, large scale adoption in the U.S. and elsewhere. A rushed attempt at CCS [carbon capture and sequestration] implementation in the face of urgent climate concerns could lead to excess cost and heightened local environmental concerns, potentially lead to long delays in implementation of this important option.⁵⁹

In addition, CCS is widely expected to increase the cost of generating power at new coal plants by perhaps 60 to 80 percent. For example, a very recent study by the National Energy Technology Laboratory (“NETL”) has projected that the cost of carbon capture and sequestration would be about \$75/tonne⁶⁰ of CO₂ avoided, in 2007 dollars, for pulverized coal plants.⁶¹

The 2007 Future of Coal Study from MIT estimated that the cost of carbon capture and sequestration would be about \$28/ton although it also acknowledged that there was uncertainty in that figure.⁶² The tables in that study also indicated significantly higher costs for carbon capture for new pulverized coal facilities, in the range of about \$37/ton and higher.⁶³ Transportation and sequestration of the captured CO₂ are expected to add another \$5/ton to \$10/ton to the cost.

Table 2, below, shows that a number of independent sources believe that adding and operating CCS equipment will raise the cost of generating electricity at new coal-fired power plants by perhaps as much as 60% to 80%.

⁵⁹ *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, 2007, at page 15.

⁶⁰ A tonne or metric ton is a measurement of mass equal to 1,000 kilograms or 1.1 tons.

⁶¹ *Cost and Performance Baseline for Fossil Energy Plants*, National Energy Technology Laboratory, Revised August 2007, at page 27.

⁶² *The Future of Coal, Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page xi.

⁶³ Id. at page 19.

Table 2: Projected Increase in the Cost of Generating Power Due to Carbon Capture and Sequestration

Source	Projected Increase in Cost of Electricity from Addition of CCS
Duke Energy Indiana ⁶⁴	68%
MIT Future of Coal Report ⁶⁵	61%
Edison Electric Institute ⁶⁶	75%
National Energy Technology Laboratory ⁶⁷	81%

Moreover, these cost estimates were for new plants that were designed and built to include carbon capture technology at the outset. The MIT Future of Coal Study concluded that it would be much more expensive to retrofit carbon capture technology onto existing coal-fired power plants.⁶⁸ That means that the cost of retrofitting carbon capture technology onto plants that were already built and in operation at the time that the technology becomes proven and commercially viable, like HBPW's proposed coal plant, could be significantly higher than the cost figures shown in the NETL and MIT studies for new coal plants.

Conclusion

Given the significant risks and uncertainties discussed above, the Commission should find that HBPW has not demonstrated a need for a new coal-fired power plant and that several less expensive and more environmentally beneficial alternatives exist to fill all or some of any new capacity need including: energy efficiency and load management; renewable resources; or a combination of a number of alternatives including purchased power.

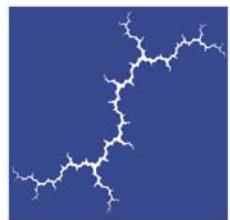
⁶⁴ Testimony of James E. Rogers in Indiana Utility Regulatory Commission Cause No. 43114, Joint Petitioners' Exhibit No. 1, at page 13, lines 6-11.

⁶⁵ *The Future of Coal, Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page 19.

⁶⁶ Letter to Hon. Edward J. Markey, Chairman, Select Committee on Energy Independence and Global Warming, from Thomas R. Kuhn, Edison Electric Institute, September 21, 2007, at page 4.

⁶⁷ *Cost and Performance Baseline for Fossil Energy Plants, Revised August 2007*, DOE/NETL – 2007/1281, at page 17.

⁶⁸ Id. at pages 28-29.



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Coal-Fired Power Plant Construction Costs

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Introduction

Construction cost estimates for new coal-fired power plants are very uncertain and have increased significantly in recent years. The industry is using terms like “soaring,” “skyrocketing,” and “staggering” to describe the cost increases being experienced by coal plant construction projects. In fact, the estimated costs of building new coal plants have reached \$3,500 per kW, without financing costs, and are still expected to increase further. This would mean a cost of well over \$2 billion for a new 600 MW coal plant when financing costs are included. These cost increases have been driven by a worldwide competition for power plant design and construction resources, commodities, equipment and manufacturing capacity. Moreover, there is little reason to expect that this worldwide competition will end anytime in the foreseeable future.

Cost Estimates for Proposed Coal-Fired Power Plants

As recently as 2005, companies were saying that proposed coal-fired power plants would cost as little as \$1,500/kW to \$1,800/kW. However, the estimated construction costs of new coal plants have risen significantly since then.

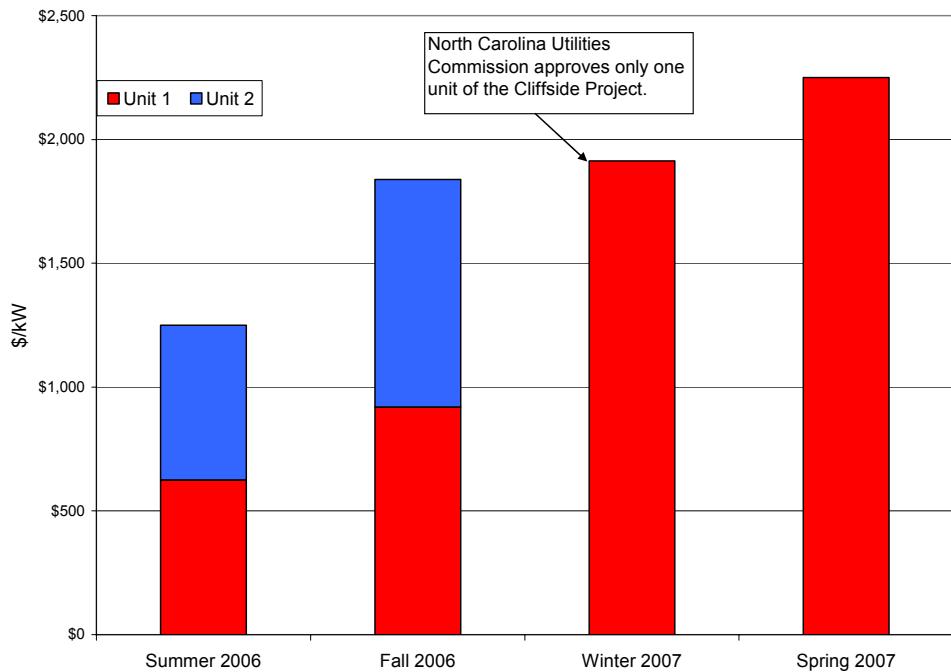
The following examples illustrate the cost increases that proposed projects experienced in the past two or three years:

- Duke Energy Carolinas' summer 2006 cost estimate for the two unit Cliffside Project was approximately \$2 billion. In the fall of 2006, Duke announced that the cost of the project had increased by approximately 47 percent (\$1 billion). After the project had been downsized because the North Carolina Utilities Commission refused to grant a permit for two units, Duke announced that the cost of the remaining single unit would be about \$1.53 billion, not including financing costs. In late May 2007, Duke announced that the cost of building the single Cliffside unit had increased by yet another 20 percent. As a result, the estimate cost of the one unit that Duke is building at Cliffside is now \$1.8 billion exclusive of financing costs. Thus, the single Cliffside unit is now expected to cost almost as much as Duke estimated for a two unit plant only two years ago in the summer of 2006.

The increases in the estimated cost of the Cliffside Project are presented in Figure 1 below.



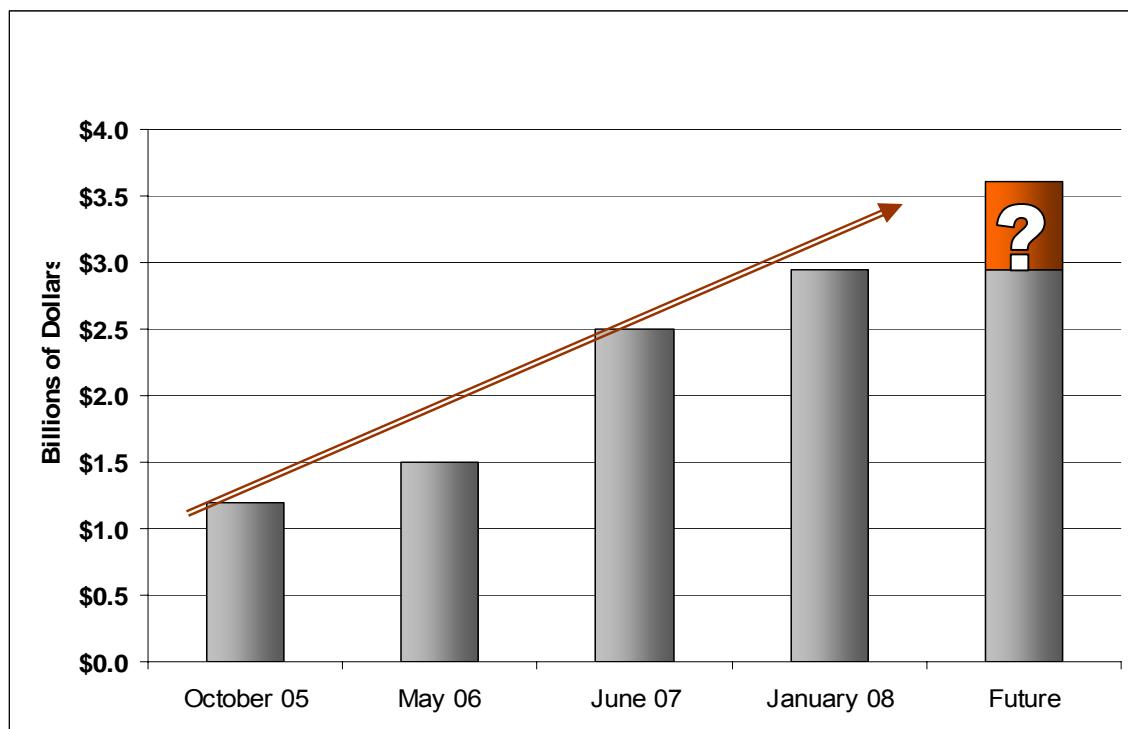
Figure 1: Duke Energy Carolinas Cliffside Project Cost Increases 2006-2007 (\$/kW)



- As shown in Figure 2 below, the estimated cost of AMP-Ohio's proposed 960 MW coal-fired power plant project nearly doubled between May 2006 and January 2008. The estimated cost increased by 15 percent in just the six months between June 2007 and January 2008. The estimated cost of the 960 MW plant is currently estimated at nearly \$3 billion, without any financing costs. This represents a construction cost of more than \$3,100 per kW. And the available evidence suggests that plant costs will continue to rise.



Figure 2: AMP-Ohio AMPGS Cost Increases 2005-2008 (\$)



- In mid-June 2008, Wisconsin Power & Light (“WPL”) announced a nearly 40 percent increase in the estimated cost of its proposed 300 MW Nelson Dewey 3 coal-fired power plant. The previous estimate had been prepared in late 2006. The estimated cost for this Circulating Fluid Bed plant is above \$3,500/kW, in early 2008 dollars. The company has similarly estimated that the cost of building a new supercritical coal plant also would exceed \$3,500/kW. In support of its new cost estimates, WPL presented testimony that noted that “EPC [Engineering, Procurement and Construction] pricing for other non-IGCC, primarily coal-fired generating projects under construction or in the planning stages have similarly increased with many projects falling in the \$2,500 to \$3,800/kW range, without AFUDC or uncommon owner’s costs (e.g., major railway additions.).”¹
- In April 2008, Duke Energy Indiana announced an 18 percent increase in the estimated cost of its proposed Edwardsport coal plant just since the spring of 2007. Duke said that “the increase in the cost estimate is driven by factors outside the Company’s control, including unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs.”² Duke noted in its Petition to the Indiana Utility Regulatory Commission that this

¹ Direct Testimony of Charles J. Hookham on behalf on Wisconsin Power & Light Company in Public Service Commission of Wisconsin Docket No. 6680-CE-170, June 2008, at page 21.

² Verified Petition in Indiana Utility Regulatory Commission Cause No. 43114 IGCC-1, filed on May 1, 2008, at pages 3-4

projected increase in cost "is consistent with other recent power plant project cost increases across the country."³

Nor are coal-fired power plants that are under construction immune to further cost increases. For example, Kansas City Power & Light just announced a 15 percent price increase for the Iatan 2 power plant that has been under construction for several years and is scheduled to be completed by 2010. This shows that one cannot assume that the cost of a plant will be fixed when construction begins.

Indeed, in the past utilities were able to secure fixed-price contracts for their power plant construction projects. However, it is not possible to obtain fixed-price contracts for new power plant projects in the present environment. The reasons for this change in circumstances has been explained as follows by a witness for the Appalachian Power Company, a subsidiary of American Electric Power in testimony before the West Virginia Public Service Commission:

Company witness Renchek discusses in his testimony the rapid escalation of key commodity prices in the [Engineering, Procurement and Construction] industry. **In such a situation, no contractor is willing to assume this risk for a multi-year project.** Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher.⁴ [Emphasis added.]

A fall 2007 assessment of AMP-Ohio's proposed coal-fired power plant similarly noted that the reviewing engineers from Burns and Roe Enterprises:

agree that the fixed price turnkey EPC contract is a reasonable approach to executing the project. However, the viability of obtaining a contract of this type is not certain. The high cost of the EPC contract, in excess of \$2 billion, significantly reduces the number of potential contractors even when teaming of engineers, constructors and equipment suppliers is taken into account. Recent experience on large U.S. coal projects indicates that the major EPC Contractors are not willing to fix price the entire project cost. This is the result of volatile costs for materials (alloy pipe, steel, copper, concrete) as well as a very tight construction labor market. When asked to fix the price, several EPC Contractors have commented that they are willing to do so, but the amount of money to be added to cover potential risks of a cost overrun would make the project uneconomical.⁵

³ *Id.* at page 7.

⁴ *Ibid.* at page 16, lines 16-20.

⁵ *Consulting Engineer's Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, for the Division of Cleveland Public Power, Burns and Roe Enterprises, Inc., October 16, 2007, at page 11-1.



In fact, rising commodity prices and increasing construction cost risks have been responsible, at least in part, for the cancellation or delay of more than fifty proposed coal-fired power plants since mid-2006. The following examples are illustrative of the factors and risks which have contributed to these cancellations and delays:

- Tenaska Energy cancelled plans to build a coal-fired power plant in Oklahoma 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.”⁶

- 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.”⁷ As a result, Westar Energy has suspended site selection for the coal-plant and is considering other options, including building a natural gas plant, to meet growing electricity demand. The company also explained that:

most major engineering firms and equipment manufacturers of coal-fueled power plant equipment are at full production capacity and yet are not indicating any plans to significantly increase their production capability. As a result, fewer manufacturers and suppliers are bidding on new projects and equipment prices have escalated and become unpredictable.⁸

⁶ Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

⁷ Available at

[http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/\\$file/122806%20coal%20plant%20final2.pdf](http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/$file/122806%20coal%20plant%20final2.pdf).

⁸ Id.

The increases in construction costs being experienced by proposed coal-fired power plants are due, in large part, to a significant increase in the worldwide demand for power plant design and construction resources, commodities and equipment. This worldwide competition is driven mainly by huge demands for power plants in China and India, by a rapidly increasing demand for power plants and power plant pollution control modifications in the United States required to meet SO₂ and NO_x emissions standards, and by the competition for resources from the petroleum refining industry.

The limited capacity of EPC firms and equipment manufacturers also has contributed to rising power plant construction costs. This has meant fewer bidders for work, higher prices, earlier payment schedules and longer delivery times. The demand for and cost of both on-site construction labor and skilled manufacturing labor also have escalated significantly in recent years.

In addition, the planned construction of new nuclear power plants is expected to compete for limited power plant design and construction resources, manufacturing capacity and commodities.

It is reasonable to expect that the factors that have led to skyrocketing power plant construction costs in recent years will lead to further increases in costs and construction delays in the five or more years before the projects are scheduled to be completed. For example, a May 15, 2008 story in the Wall Street Journal noted that “escalating steel prices are halting and slowing major construction projects worldwide and limiting shipbuilding and oil and gas exploration.” The same article noted that “Steel prices are up 40 percent to 50 percent since December, and industry executives say they have not reached a peak” and “raw materials prices have surged in the past year, fueled in part because of the rapid industrialization of China, India and other developing nations.”

Indeed, there is no reason to expect that the worldwide competition for resources or the existing supply constraints and bottlenecks affecting coal-fired plant construction costs will clear anytime in the foreseeable future.

The Virginia State Corporation Commission denied the request of Appalachian Power Company to build a coal-fired power plant in West Virginia. The Commission found that the proposal was neither “reasonable” nor “prudent.” In its order denying the request to build the new coal-fired power plant, the Virginia Commission also found that the Company’s cost estimate for the project was not credible and that the Company had not updated its cost estimate since November 2006. The Commission further noted that the Company (“APCo”) will not obtain actual or firm prices for components of the project until after receiving regulatory approval.⁹ The Virginia Commission Final Order included the following language concerning risk: “Indeed APCo has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in [Appalachian Power

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April 14, 2008 Final Order of the Virginia State Corporation Commission in Case No. PUE-2007-00068, at page 5.

Company's] service territory to assume." This is the very same "extraordinary" risk that the customers and ratepayers of investor-owned companies and publicly-owned utilities building new coal-fired power plants are being asked to assume because there are no fixed prices or contracts for the projects.

Finally, there is no currently commercially available technology for post-combustion capture of carbon dioxide from pulverized coal power plants. Moreover, it is estimated that such technology may not be commercially available until 2020 or 2030, if then. However, it is expected that the addition of carbon capture and sequestration technology will greatly increase the cost of generating power at coal-fired power. In fact, a number of independent sources agree, as illustrated in Table 1 below, that adding and operating CCS equipment will raise the cost of generating electricity at new coal-fired power plants by perhaps as much as 60% to 80%.

Table 1: Projected Increase in the Cost of Generating Power Due to Carbon Capture and Sequestration

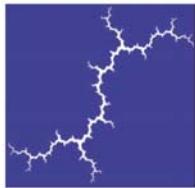
Source	Projected Increase in Cost of Electricity from Addition of CCS
Duke Energy Indiana ¹⁰	68%
MIT Future of Coal Report ¹¹	61%
Edison Electric Institute ¹²	75%
National Energy Technology Laboratory ¹³	81%

¹⁰ Testimony of James E. Rogers in Indiana Utility Regulatory Commission Cause No. 43114, Joint Petitioners' Exhibit No. 1, at page 13, lines 6-11.

¹¹ *The Future of Coal, Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page 19.

¹² Letter to Hon. Edward J. Markey, Chairman, Select Committee on Energy Independence and Global Warming, from Thomas R. Kuhn, Edison Electric Institute, September 21, 2007, at page 4.

¹³ *Cost and Performance Baseline for Fossil Energy Plants, Revised August 2007*, DOE/NETL – 2007/1281, at page 17.



Memorandum

To: NRDC and Sierra Club

From: Synapse Energy Economics

Date: June 26, 2009

Re: Sources of Funding relevant to Michigan within the American Recovery and Reinvestment Act (ARRA)

The American Recovery and Reinvestment Act (“ARRA” or “stimulus plan”) has numerous provisions designed to provide funding for renewable energy and energy efficiency projects in the United States. This memorandum summarizes the following relevant sources of funding allocated to the state of Michigan, including sources for which utilities and other organizations may apply: the Weatherization Assistance Program, the State Energy Program, the new Energy Efficiency and Conservation Block Grant Program, and various other sources of federal funds.

Weatherization Assistance Program

The Weatherization Assistance Program helps low-income households to permanently increase energy efficiency in their homes, thereby reducing their energy use, energy bills, and carbon emissions. Measures qualifying for support under the Weatherization Assistance Program include: insulation of attics, crawl spaces, walls and ducts; space-heating equipment; energy-efficient windows, refrigerators, water heaters, and air-conditioners; air sealing; repairs to roofs, doors, and windows, compact fluorescent light bulbs; low-flow showerheads; and client education. The DOE provides funding and technical guidance to states, but the states run their own programs, setting eligibility rules and selecting service providers. The ARRA amends the Weatherization Assistance Program such that families making less than 200% of the federal poverty level (approximately \$44,000/year for a family of four) are eligible to review up to \$6,500 per home in energy efficiency upgrades.¹ Approximately \$243 million is allocated to the Weatherization Program in Michigan under the ARRA.

State Energy Program

¹ United States Department of Energy. *Obama-Biden Administration Announces More Than \$122.3 Million in Weatherization Funding and Energy Efficiency Grants for Louisiana*. Press Release. March 12, 2009. Available at: <http://www.energy.gov/7012.htm>



More than \$82 million was allocated to the Michigan's State Energy Program through the ARRA. Funds provided through this Program are intended to support energy efficiency and renewable energy projects in individual states, and various states have proposed plans that prioritize energy savings, increase the use of renewable energy, and reduce greenhouse gas emissions, all while creating or retaining jobs.² Approximately 40% of the total allocation for Michigan (\$32 million) was released by the DOE in June 2009,³ and the state will focus this funding on the following three-year goals:

- Reducing energy consumption in public buildings by 20% by 2012;
- Establishing green communities;
- Creating markets for renewable energy systems; and
- Creating sustainable jobs in energy efficiency and renewable energy sectors.

In addition, the state will use a portion of these funds to conduct onsite energy audits in 500 homes and businesses through a partnership with two major Michigan utilities.⁴

Energy Efficiency and Conservation Block Grant Program

The Energy Efficiency and Conservation Block Grant Program (EECBG) was authorized under the Energy Independence and Security Act of 2007 (the EISA), but was funded for the first time under the ARRA.⁵ Funding is based partly around population and energy use, and the total amount available to Michigan under the EECBG is approximately \$76 million. These funds may be allotted to state, county, city, and tribal governments under grants issued by the DOE's Office of Weatherization and Intergovernmental Programs. Funds may be used for the following:

- Energy audits in residential and commercial buildings;
- Energy efficiency retrofits in residential and commercial buildings;
- Development and implementation of advanced building codes and inspections;
- Creation of financial incentive programs for energy efficiency improvements;
- Transportation programs that conserve energy;
- Projects to reduce and capture methane and other greenhouse gas emissions from landfills;
- Renewable energy installations on government buildings;
- Energy efficiency traffic signals and street lights; and

² United States Department of Energy. *Obama Administration Announces More Than \$32 Million for Energy Projects in Michigan*. Press Release. June 22, 2009. Available at: <http://www.energy.gov/7483.htm>

³ The initial 10% of funds was released for planning activities and the remaining 50% will be released when Michigan meets reporting, oversight, and accountability milestones required by the ARRA.

⁴ United States Department of Energy. *Obama Administration Announces More Than \$32 Million for Energy Projects in Michigan*. Press Release. June 22, 2009. Available at: <http://www.energy.gov/7483.htm>

⁵ Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5)*. Report for Congress. March 3, 2009. Page 6.



- Deployment of combined heat and power (CHP) and district heating and cooling systems.

The deadline for applications under the EECBG is June 25, 2009 at 8:00 PM EST for all applicants. A second funding allocation is expected to be made available at a later date.

Other Federal Funding Sources

Other sources of funding for renewable energy and energy efficiency programs include the following:

- *Extension of the Production Tax Credit:* A Production Tax Credit (PTC) provides a 2.1-cent per kilowatt-hour federal income tax credit for the first ten years of a renewable energy facility's operation based on the electrical output of the facility. The ARRA extends the PTC for three years for electricity generated from wind facilities placed into service by December 31, 2012. Other technologies eligible for a PTC include, geothermal, biomass, hydropower, landfill gas, waste-to-energy and marine facilities if they are placed in service by December 31, 2013.⁶
- *Expansion of the Investment Tax Credit:* An Investment Tax Credit (ITC) reduces federal income taxes based on capital investment in renewable energy projects. Under the ARRA, wind, geothermal, biomass and other technologies eligible for the PTC have the option of instead utilizing the 30% ITC (in lieu of the PTC). Expiration dates under the ITC are the same as under the PTC.⁷
- *Grant Program for Renewable Technologies in Lieu of Tax Credits:* Rather than utilize a Production Tax Credit or Investment Tax Credit for new renewable energy projects, project developers may apply for a cash grant from the Treasury Department equal to 30% of the cost of eligible projects. Eligible projects are those renewable energy projects that are placed in service in 2009-2010, or that begin construction during 2009-2010 and are placed in service by 2013 for wind, 2017 for solar, and 2014 for other technologies.⁸
- *Clean Renewable Energy Bonds:* The ARRA provides \$1.6 billion in new Clean Renewable Energy Bonds (CREBs) for eligible technologies owned by governmental or tribal entities, and municipal utilities and cooperatives. Eligible technologies include wind, closed-loop biomass, open-loop biomass, geothermal, small irrigation, hydropower, landfill gas, marine renewable, and trash combustion facilities. Qualifying projects of state, local, and tribal governments

⁶ Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5)*. Report for Congress. March 3, 2009. Page 18.

⁷ Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5)*. Report for Congress. March 3, 2009. Page 18.

⁸ Mark Bolinger, Ryan Wiser, Karlynn Cory, and Ted James. *PTC, ITC, or Cash Grant?: An Analysis of the Choice Facing Renewable Power Projects in the United States*. National Renewable Energy Laboratory. March 2009. Page 3. Available at: <http://eetd.lbl.gov/ea/emp/reports/lbnl-1642e.pdf>



will receive one-third of CREB funding, public power providers will receive one-third, and electric cooperatives will receive the final one-third.⁹

- *Energy Conservation Bonds:* Energy Conservation Bonds (ECBs) were established by the Emergency Economic Stabilization Act of 2008 with an initial funding allocation of \$800 million.¹⁰ The stimulus plan increased that allocation to \$2.4 billion. State and local governments will issue the bonds for projects such as:
 - Capital expenditures to reduce energy use in buildings by at least 20%, including publicly owned buildings;
 - The implementation of green community programs;
 - Development of electricity from renewables in rural areas;
 - Research and development of cellulosic ethanol or other non-fossil fuels;
 - Development of technologies that will capture and sequester CO₂;
 - Conversion of agricultural waste for fuel production;
 - Technologies to reduce peak electricity demand; and
 - Public education campaigns to promote energy efficiency.¹¹

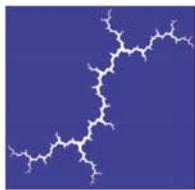
⁹ American Council on Renewable Energy. *Overview: Renewable Energy Provisions American Recovery and Reinvestment Act of 2009*. Page 3. Available at:

http://www.acore.org/files/images/email/acore_stimulus_overview.pdf

¹⁰ Tax credit bonds like CREBs and ECBs pay the bondholders by providing a credit against their federal income tax. While normal bonds pay interest to the holders, in the case of CREBs and ECBs, the federal government in effect pays the interest via tax credits. The purpose of CREBs and ECBs is to provide interest-free financing for clean energy projects.

¹¹ Congressional Research Service. *Energy Provisions in the American Recovery and Reinvestment Act of 2009* (P.L. 111-5). Report for Congress. March 3, 2009. Page 19.





Memorandum

To: NRDC and Sierra Club

From: Synapse

Date: June 26, 2009

Re: Critique of the EPRI Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: 2010 - 2030, dated January 2009

The Electric Power Institute (EPRI) published a technical report in January 2009 entitled *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.* The study purports to calculate the percentage of energy efficiency and demand response that can be achieved in the US by 2030. This summary memo provides a critique of this technical report. It should be noted that this critique references solely the Executive Summary of this report, as that is the only portion that has thus far been made available for our analysis. Based on that portion of the study, however, we believe that EPRI makes assumptions and uses methodologies that likely underestimate the achievable potential for energy efficiency programs over the next twenty years.

New codes, standards, and regulatory policies for energy efficiency are not considered in the EPRI assessment of achievable efficiency.

EPRI estimates of savings from energy efficiency are for codes, standards, and voluntary utility-operated programs that are currently in existence. They do not include new building codes, efficiency standards for equipment and/or appliances, new utility-sponsored programs, or programs administered by states or third parties. These new codes and standards will likely include measures that are not considered in this study, and may also increase the penetration rate of existing measures to a level that is much higher than that assumed by EPRI.

Estimates of energy efficiency savings are limited by the use of existing technologies only.

EPRI bases its estimates of energy efficiency savings on types of technology that are currently commercialized and cost-effective, e.g. lighting, appliances, etc. and it does not account for any innovations in these technologies over time or the addition of new technologies.

Existing equipment is assumed to be in use through the end of its useful life. However, energy-efficiency incentives can encourage early retirement in favor of more efficient equipment.



EPRI assumes that energy efficiency technologies will not “instantaneously or prematurely”¹ replace existing equipment, but rather will be phased-in as devices reach the ends of their useful lives. Utility or government incentives, however, may lead to the replace of these less efficient devices well before the end of their useful lives.

The useful life of energy efficiency devices is assumed by EPRI to be less than 15 years, while the period of this study is 20 years. Some efficient devices installed prior to the study period or at the beginning of the study period will reach the end of their useful lives well before 2030, but because EPRI allows for no new technologies as replacements, no new opportunities for energy efficiency can be created.

Estimates of savings include energy efficient technologies, but do not include as many energy efficient processes as may be practicable.

Energy efficient *technologies* are the drivers behind EPRI estimates of savings. These estimates include few energy efficient *practices* or *processes*. This criticism applies especially to estimates of industrial savings. EPRI’s estimates include only motor, lighting and heating improvements made by industrial customers. Including the wide variety of available industrial process improvements, as well as improved system designs for buildings, would increase estimates of energy efficiency potential.

The assumption that incremental costs for energy efficiency technologies will remain constant is flawed.

EPRI holds costs for energy efficiency technologies constant over the 20 year study period. This causes two errors in the estimates for economically achievable energy efficiency potential. The first errors occurs due to the fact that costs for technologies that are currently commercially available are likely to fall over time, and estimates of energy efficiency potential can therefore be achieved at a reduced cost. The second error occurs because certain efficiency technologies may fall into the efficiency category of “Technical Potential” which represents the amount of energy efficiency that could occur if all homes and business adopted the most efficient technologies available irrespective of cost. Technologies that are too expensive, while they may be available, are unlikely to be adopted by consumers. As the cost for these technologies falls, however, they are more likely to pass screens for economic cost-effectiveness and move into the efficiency category of “Economically Achievable Potential” and actually be put into service.

Use of the Participant Cost Test may not properly measure cost-effectiveness, and may therefore underestimate achievable potential.

The Participant Cost Test is one example of the cost-effectiveness screens mentioned above that measures cost of a program from the perspective of the customer. Most customers pay a flat rate per kWh of electricity, and so this test ignores savings that occur during peak hours of the day, e.g. those related to more efficient measures for space

¹ Electric Policy Research Institute. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: 2010 – 2030. Executive Summary*. January 2009. page 8.

cooling. The particular test also does not account for benefits that accrue due to avoided demand. Peak energy and avoided demand savings are much more valuable from a utility or total resource perspective, and efficiency measures that result in these types of savings would pass the corresponding screens for cost-effectiveness – the Utility Cost Test and the Total Resource Cost Test – that would not pass the Participant Cost Test.

EPRI assumes a relatively flat electricity price forecast in real dollars through 2030.

As electricity prices rise, customers are more likely to commit to energy efficiency measures, resulting in increased energy savings. Peak energy savings and avoided demand are also much more valuable as prices increase.

To summarize, EPRI makes many flawed assumptions in its report, holding technological progress, incremental cost of technologies, and national electricity prices flat over time. Maximum energy efficiency potential as estimated by EPRI reaches 8% energy savings by the year 2030, and the realistic savings estimate is only 5% in 2030. EPRI's estimate represents an incremental load savings of approximately 0.2% per year. While average energy efficiency savings was 0.24% in 2006, as reported by the American Council for an Energy-Efficient Economy (ACEEE) and cited by EPRI in its study,² it is critical to note that this is an average across the entire United States, and therefore includes states that are attempting absolutely no energy efficiency. This consequently brings down the national average by a significant margin. The most important critique of EPRI's estimate, therefore, is that *in practice*, many jurisdictions are *already* beating 0.2% savings per year by a wide margin, some by more than an order of magnitude. As reported by FERC in April 2009, the following states are leading the nation in their goals for energy efficiency:³

- Minnesota: 1.5% annual savings from prior year's sales to 2015;
- Ohio: reduce peak demand 8% by 2018 and achieve energy savings of 22% between 2009 and 2025;
- Maine: 10% energy efficiency by 2017;
- Massachusetts: 25% of electric load from demand response and energy efficiency by 2020;
- Maryland: 15% reduction in electricity use and peak from 2007 levels by 2015;
- New York: 15% reduction in electric use by 2015 from levels projected in 2008; and
- Vermont: 2% annual energy savings between 2009 and 2011.

² Electric Policy Research Institute. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: 2010 – 2030. Executive Summary*. January 2009. page 7.

³ Federal Energy Regulatory Commission. *Electric Market Overview: Energy Efficiency Resource Standards (EERS) and Goals*. Updated April 3, 2009.