Synapse
Energy Economics, Inc.

The Risks of Participating in the AMPGS Coal Plant

February 13, 2008

Prepared for the Natural Resources Defense Council

AUTHOR
David Schlissel

22 Pearl Street
Cambridge, MA 02139
www.synapse-energy.com
617.661.3248

Table of Contents

1. Introduction and Conclusions

Synapse Energy Economics was retained by the Natural Resources Defense Council to assess the risks associated with American Municipal Power Ohio's ("AMP-Ohio") proposed 960 MW coal-fired power plant in Meigs County, Ohio ("AMPGS Project") and to evaluate, in particular, construction costs, costs of CO_2 regulations, and alternatives to the proposed plant.

Our conclusions are as follows:

1. The most significant uncertainties and risks associated with the proposed AMPGS Project are the potential for future federal restrictions on greenhouse gas emissions, state actions that can affect the need for and the relative economics of a new coal-fired power plant, uncertainties related to carbon capture and sequestration, and further increases in the project's capital cost.
2. Increasing numbers of proposed coal-fired power plants have been cancelled, delayed and rejected by state regulatory commissions in large part due to the uncertainties regarding regulation of future greenhouse gas emissions and construction costs.
3. Coal is the most carbon intensive fuel. Federal regulation of greenhouse gas emissions is a matter of when, not if. The costs of this regulation will have a significant impact on the relative economics of the proposed AMPGS Project. However, AMP-Ohio has only used a single and very low set of projected CO_2 emissions costs in its analyses of the proposed plant. It would be imprudent for AMP-Ohio and its member communities to continue their participation in the AMPGS Project without fully considering the risk of significantly higher CO_2 prices in their resource planning studies.
4. Soaring power plant construction costs also will have a significant impact on the results of properly performed resource planning. Actual and estimated power plant capital costs have been increased by the domestic and international competition for design and construction resources, manufacturing capacity and commodities. Indeed, the AMPGS construction cost estimate already has increased significantly from $1.2 billion in October 2005 to $1.5 billion in May 2006 to $2.5 billion in June 2007 and, very recently, to the current $2.949 billion figure --and the detailed design of the Project and procurement of major plant equipment have not been completed. Construction has not even been started.

   It would be imprudent not to allow for the possibility that the same domestic and international competition that has led to the recent skyrocketing of power plant construction costs will continue to push project costs upward during the design and construction of the proposed AMPGS Project.
5. Cleveland Public Power already is exposed to these risks through its commitment to purchase 25 MW of the Prairie State coal-fired power

plant. Participation in the AMPGS Project will significantly increase this risk exposure.

6. The February 2007 Power Supply Plans prepared for AMP-Ohio's member communities which conclude that participation in the AMPGS Project is part of an optimal supply plan are seriously flawed. In particular, these Power Supply Plans relied upon out-of-date and very low cost estimates for the AMPGS Project and did not include as options additional energy efficiency or the potential for purchasing or contracting for capacity and energy from existing natural gas-fired power plants. These Power Supply Plans also assumed very low CO_2 prices. Consequently, the results of these studies were biased in favor of the coal-fired AMPGS.

7. There are a number of alternatives to the proposed AMPGS Project that should be investigated before a community makes a 50 year "take-or-pay" contractual commitment to purchase energy and capacity from the plant. These alternatives include energy efficiency and demand-side management programs, renewable resources, purchasing or contracting for energy and capacity from underused natural gas-fired power plants in the region, and, if necessary, building new gas-fired capacity. A portfolio of these alternatives would offer more flexibility and would limit Cleveland's exposure to the coming federal regulation of greenhouse gas emissions.

2. The Risks of Participating in the AMPGS Project

Risk and uncertainty are inherent in all enterprises. But the risks associated with any options or plans need to be balanced against the expected benefits from each such option or plan. In particular, parties seeking to build new generating facilities and the associated transmission face a host of major uncertainties. The most significant uncertainties and risks associated with building and operating new coal-fired generating plants like the proposed the AMPGS Project are the potential for future restrictions on CO_2 emissions and the potential for significant increases in the project's capital cost. However, there also are other potential uncertainties and risks for new coal plants including the potential for higher fuel prices, fuel supply disruptions that could affect plant operating performance and fuel prices, and the potential for increasing stringency of regulations of current criteria pollutants.

Unfortunately, the Power Supply Plans prepared by R.W. Beck and AMP-Ohio in February 2007 were significantly flawed and biased in a number of ways that favored the AMPGS Project. In particular, R.W. Beck and AMP-Ohio used a low CO_2 price forecast and what was then a year old construction cost estimate for the AMPGS in developing the Power Supply Plans. Then R.W. Beck and AMP-Ohio failed to conduct any sensitivity analyses to evaluate how the capital additions in the plans would change along with changes in these critical assumptions. R.W. Beck and AMP-Ohio failed to prepare such sensitivities for higher CO_2 prices and increased construction costs even though they had prepared similar sensitivities to see how capacity additions in the plans would change with changes in estimated loads, gas prices and what R.W. Beck called the implied heat rate (power costs divided by gas prices). The failure to conduct sensitivities for higher CO_2 prices was especially significant because of the low CO_2 price forecast that R.W. Beck used in the base case analyses in developing the Power Supply Plans.

Moreover, the analyses in the June 2007 Initial Project Feasibility Study that R.W. Beck prepared for AMP-Ohio did not remedy or correct for these failures in large part, because that Feasibility Study did not present resource planning studies which examined whether the proposed AMPGS Project should be part of a least-cost, least-risk capacity expansion plan by looking at the costs and benefits of a range of supply-side and demand-side options. Instead, the Initial Project Feasibility Study only compares what it projects will be the cost of power from the AMPGS Project against the AMP-Ohio members' current costs of power and the alternative of buying power from the market. This is a far different analysis than should have been performed during the resource planning process for determining which supply-side and demand-side alternatives will provide power for the participating AMP-Ohio member communities at the least cost and with the least risk.

3. Uncertainty over Future Carbon Regulations and Constructions Costs has Led to Coal Power Plant Cancellations, Delays, and Rejections by State Regulatory Commissions

Since late 2006, more than twenty proposed coal-fired power plants have been cancelled. More than three dozen others have been delayed. State regulatory commissions in Oregon, Florida, North Carolina, Oklahoma and Washington State have rejected proposed power plants. The Secretary of Health and Environment of the State of Kansas has rejected permits for two 700 MW coal-fired power plants.

The decision of the Florida Public Service Commission in denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties over plant costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.[1] On October 18, 2007, the Kansas Department of Health and Environment rejected an application to build two 700 MW coal-fired units at an existing power plant site. In a prepared statement explaining the basis for this decision, Rod Bremby, Kansas's secretary of health and environment noted that "I believe it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing."[2]

A number of companies have announced that they will not pursue new coal-fired generating facilities. For example, in its recently-filed Resource Plan in Colorado, Xcel Energy announced that:

1 Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.
2 See www.kansascity.com/105/story/323833.html.

> In sum, in light of the now likely regulation of CO_2 emissions in the future due to a broader interest in climate change issues, the increased costs of constructing new coal facilities, and the increased risk of timely permitting to meet planned in-service dates, Public Service does not believe it would be prudent to consider at this time any proposals for new coal plants that do not include CO_2 capture and sequestration.[3]

Idaho Power Company similarly has concluded that:

> Due to escalating construction costs, the transmission cost associated with a remotely located resource, potential permitting issues, and continued uncertainty surrounding GHG laws and regulations, IPC [Idaho Power Company] has determined that coal-fired generation is not the best technology to meet its resource needs in 2013. IPC has shifted its focus to the development of a natural gas-fired combined cycle combustion turbine located closer to its load center in southern Idaho.[4]

Minnesota Power Company also has announced that it was considering only carbon minimizing resources and would not consider a new coal resource without a carbon solution.[5] The Company also announced that in the long-term it would consider pulverized coal and IGGC plants with proven carbon capture and CO2 sequestration technologies.[6]

4. AMP-Ohio Has Not Adequately Considered the Likely Costs of Federal Regulation of Greenhouse Gas Emissions in its Analyses of the AMPGS Plant

There is widespread agreement that federal regulation of greenhouse gases is a matter of when, not if. The question is not whether the United States will develop a national policy addressing climate change, but when and how. Furthermore, it is clear that the electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of regulating large point sources. There are, of course, important uncertainties with regard to the timing, the emission limits, and many other details of what a carbon policy in the United States will look like.

Moreover, if the AMPGS Project were to be built, carbon regulation is not an issue that definitely could be addressed in the future, and at a reasonable cost, once the timing and stringency of federal regulations are known. This is because unlike for other power

---

3 Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-34.

4 U.S. Securities and Exchange Commission Form 10-Q, Third Quarter of 2007, Idaho Power Company, at pages 49-50.

5 *Petition for Approval, Minnesota Power's 2008 Resource Plan*, Minnesota Public Utilities Commission Docket No. E015/RP-07-1357, dated October 31, 2007, at page 5.

6 Id, at page 6.

plant air emissions like sulfur dioxide and oxides of nitrogen, there currently is no commercially demonstrated or economically viable method for post-combustion removal of carbon dioxide from pulverized coal plants at full scale. Some technologies, such as the Powerspan technology discussed by AMP-Ohio are starting to be tested with plans for scale up. However, it might be years, if not decades, before there will be commercially available post-combustion technology for the capture and sequestration of greenhouse gas emissions from pulverized coal-fired power plants.

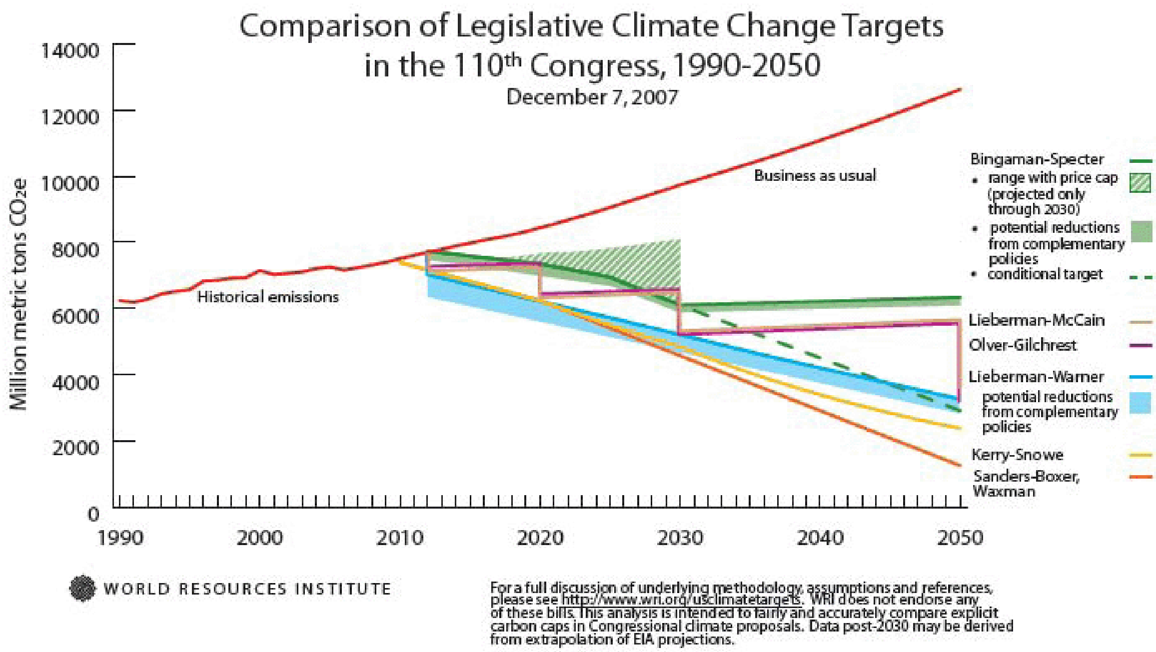
To date, the U.S. government has not required greenhouse gas emission reductions. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. The federal proposals that would require greenhouse gas emission reductions that had been submitted in the current U.S. Congress are summarized in Table 1 below.

Table 1: Summary of Mandatory Emissions Targets in Proposals Discussed in current U.S. Congress

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
Feinstein-Carper S.317	Electric Utility Cap & Trade Act	2007	▪ 2006 level by 2011 ▪ 2001 level by 2015 ▪ 1%/year reduction from 2016-2019 ▪ 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe S.485	Global Warming Reduction Act	2007	▪ 2010 level from 2010-2019 ▪ 1990 level from 2020-2029 ▪ 2.5%/year reductions from 2020-2029 ▪ 3.5%/year reduction from 2030-2050 ▪ 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	▪ 2004 level in 2012 ▪ 1990 level in 2020 ▪ 20% below 1990 level in 2030 ▪ 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	▪ 2%/year reduction from 2010 to 2020 ▪ 1990 level in 2020 ▪ 27% below 1990 level in 2030 ▪ 53% below 1990 level in 2040 ▪ 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	▪ Cap at 2006 level by 2012 ▪ 1%/year reduction from 2013-2020 ▪ 3%/year reduction from 2021-2030 ▪ 5%/year reduction from 2031-2050 ▪ equivalent to 70% below 1990 level by 2050	US national
Bingaman–Specter S.1766	Low Carbon Economy Act	2007	▪ 2012 levels in 2012 ▪ 2006 levels in 2020 ▪ 1990 levels by 2030 ▪ President may set further goals $\geq$60% below 2006 levels by 2050 contingent upon international effort	Economy-wide
Lieberman-Warner S. 2191	America's Climate Security Act	2007	▪ 2005 level in 2012 ▪ 1990 level in 2020 ▪ 65% below 1990 level in 2050	U.S. electric power, transportation, and manufacturing sources.

The emissions levels that would be mandated by the bills that have been introduced in the current Congress are shown in Figure 1 below:

Figure 1: Emissions Reductions Required under Climate Change Bills in Current US Congress



These bills increasingly aim for emissions reductions of 60% to 80% from current levels by 2050 based on the scientific conclusion that these levels of reductions will be necessary to stabilize atmospheric CO_2 concentrations at levels likely to avoid the most dangerous impacts of climate change.

An increasing number of states also are taking significant actions to reduce greenhouse gas emissions both individually and as part of regional efforts.

Table 2: Announced State and Regional Greenhouse Gas Emission Reduction Goals

State	GHG Reduction Goal	Western Climate Initiative member (15% below 2005 levels by 2020)	Regional Greenhouse Gas Initiative member (Cap at current levels 2009-2015, reduce this by 10% by 2019)
Arizona	• 2000 levels by 2020 • 50% below 2000 levels by 2040	yes	
California	• 2000 levels by 2010 • 1990 levels by 2020 • 80% below 1990 levels by 2050	yes	
Connecticut	• 1990 levels by 2010 • 10% below 1990 levels by 2020 • 75-85% below 2001 levels in the long		yes
Delaware			yes
Florida	• 2000 levels by 2017 • 1990 levels by 2025 • 80% below 1990 levels by 2050		
Hawaii	• 1990 levels by 2020		
Illinois	• 1990 levels by 2020 • 60% below 1990 levels by 2050		
Maine	• 1990 levels by 2010 • 10% below 1990 levels by 2020 • 75-80% below 2003 levels in the long		yes
Maryland			yes
Massachusetts	• 1990 levels by 2010 • 10% below 1990 levels by 2020 • 75-85% below 1990 levels in the long		yes
Minnesota	• 15% by 2015, 30% by 2025 • 80% by 2050		
New Hampshire	• 1990 levels by 2010 • 10% below 1990 levels by 2020 • 75-85% below 2001 levels in the long		yes
New Jersey	• 1990 levels by 2020 • 80% below 2006 levels by 2050		yes
New Mexico	• 2000 levels by 2012 • 10% below 2000 levels by 2020 • 75% below 2000 levels by 2050	yes	
New York	• 5% below 1990 levels by 2010 • 10% below 1990 levels by 2020		yes
Oregon	• Stabilize by 2010 • 10% below 1990 levels by 2020 • 75% below 1990 levels by 2050	yes	
Rhode Island	• 1990 levels by 2010 • 10% below 1990 levels by 2020 • 75-80% below 2001 levels in the long		yes
Utah		yes	
Vermont	• 1990 levels by 2010 • 10% below 1990 levels by 2020 • 75-85% below 2001 levels in the long term		yes
Washington	• 1990 levels by 2020 • 25% below 1990 levels by 2035 • 50% below 1990 levels by 2050	yes	

Indeed, ten states already have adopted climate change plans. Plans are currently under development in another 18 states.

An increasing number of states also have adopted policies to promote the increased use of energy efficiency and renewable resources. For example, as of December 2007, twenty-five states have adopted Renewable Portfolio Standards that require certain percentages of renewable resources in the future. Another four states have adopted goals, rather than formal standards, for the use of renewable resources.

States also are moving aggressively to save energy and reduce their power consumption through energy efficiency and demand side measures. For example, the State of New York has adopted and is now starting to implement a "15 by 15" program through which it intends to reduce energy consumption by 15 percent by 2015.[7] The State of New Jersey has set a goal of reducing energy consumption by 20 percent by 2020.[8]

In addition, regional efforts to reduce greenhouse gas emissions have been undertaken by states in the Northeastern, upper Midwest and Western areas of the nation.[9] For example, in November 2007, the Governors of six Midwestern states, including Minnesota, Illinois, Iowa, Kansas, Michigan and Wisconsin, and the Premier of Manitoba signed the Midwestern Greenhouse Gas Accord. This agreement committed the states to establishing greenhouse gas emissions targets and timetables, to developing a market based and multi-sector cap-and-trade mechanism to achieve those reduction targets, to developing a regional registry and tracking mechanism, and to developing and implementing additional steps as needed to achieve the reduction targets.[10] The Governors of Indiana, Ohio and South Dakota also signed the agreement as observers to participate in the formation of a regional cap-and-trade system.

At the same time, nine states working together through the Midwest Governors Association have adopted the goal of meeting at least 2 percent of regional annual retail sales of electricity through energy efficiency improvements by 2015, with additional savings in subsequent years, and adopted regional renewable energy goals of 10% by 2015, 20% by 2020, 25% by 2025, and 30% by 2030.[11] These policies will affect how much new capacity will be needed and what capacity will be the most economic to add.

The Expected CO_2 Emissions from the AMPGS Plant

Coal is the most carbon intensive fuel. AMP-Ohio has estimated that the AMPGS plant will emit 7,367,000 tons of CO_2 each year for a projected 60 year operating life.

---

7 Remarks by Governor Eliot Spitzer. "15 by 15": A Clean Energy Strategy for New York. 19 Apr 2007. Found at: http://www.state.ny.us/governor/keydocs/0419071_speech.html.

8 Governor's *Economic Growth Strategy* 2007.

9 "Five Western Governors Announce Regional Greenhouse Gas Reduction Agreement," press release dated February 26, 2007.

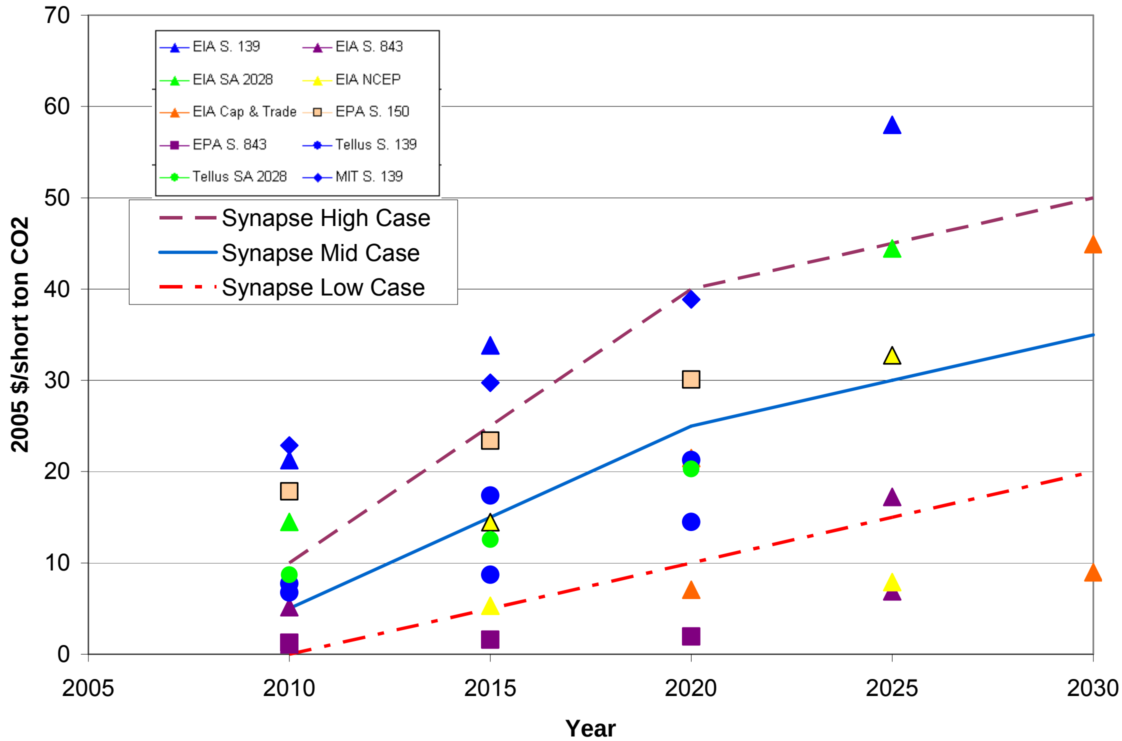
10 http://www.midwesterngovernors.org/resolutions/GHGAccord.pdf.

11 Midwest Governors Association, "Energy Security and Climate Stewardship Platform for the Midwest, 2007," Nov. 15, 2007. The Platform was agreed to by Indiana, Illinois, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota, Wisconsin and the province of Manitoba.

CO_2 Price Forecasts

Synapse has developed a set of CO_2 price forecasts that we believe should be used in resource planning and to evaluate proposed power plant projects. These forecasts are presented in Figure 2 below:

Figure 2: Synapse CO_2 Prices Forecasts



These forecasts were developed in the spring of 2006. However, they continue to be reasonable under the more stringent emissions reductions that would be required by the legislative proposals that have been introduced in the current Congress. In general, these CO_2 price forecasts were based, in part, on the results of economic analyses of individual bills that had been submitted in the 108th and 109th Congresses. We also considered the likely impacts of state, regional and international actions, the potential for offsets and credits, and the likely future trajectories of both emissions constraints and technological program. Carbon capture and sequestration could be a technological innovation that might temper or even put a ceiling on CO_2 emissions allowance prices.

R.W. Beck also has developed a CO_2 price forecast that it has used to evaluate the proposed AMPGS Project and to develop the February 2007 Power Supply Plans for the City of Cleveland and other potential project participants. However, R.W. Beck price forecast contains only a single set of projected prices, and not a range of prices as in the Synapse CO_2 price forecasts. And that single set of projected prices was very low compared to both the Synapse forecasts and the expected prices of CO_2 emissions allowances under the legislation that has been introduced in the U.S. Congress. Figure 3, below, compares the AMP-Ohio and Synapse CO_2 price forecasts.

Figure 3: Synapse and AMP-Ohio CO2 Price Forecasts

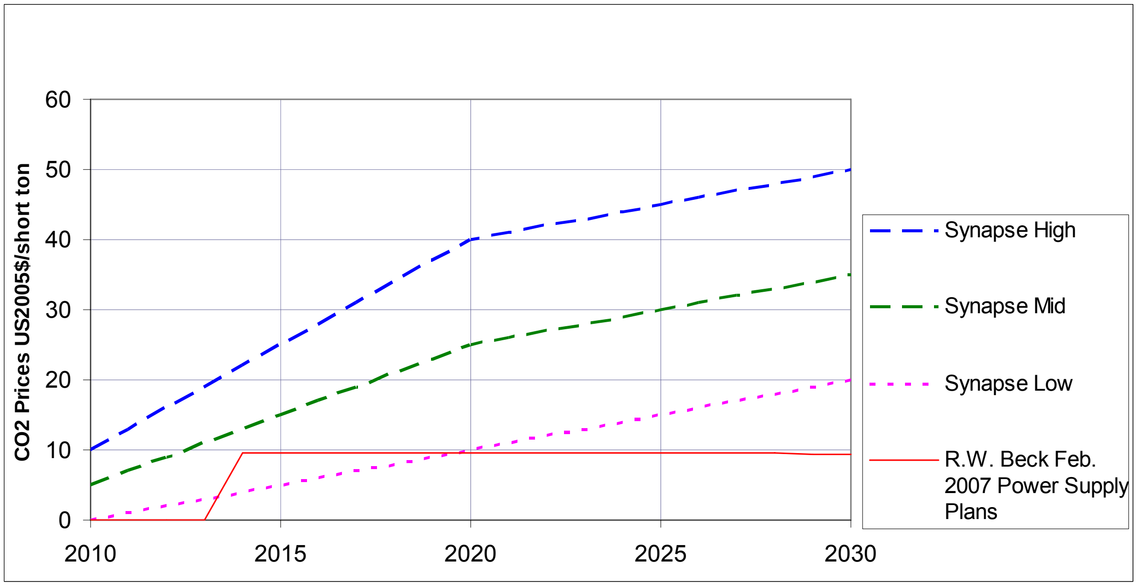


Figure 4, below, then compares both the Synapse CO_2 price forecasts and the AMP-Ohio forecast to the projected prices of CO_2 emissions allowances developed in recent studies of the prices that would be needed to achieve the emissions reduction targets in global warming legislation that has been introduced in the current Congress. These studies include:

- Analyses of Senate Bill S.280, the current McCain-Lieberman proposal, by the U.S. Environmental Protection Agency ("EPA") and the Energy Information Administration of the U.S. Department of Energy ("EIA").[12] The EPA examined seven different scenarios reflecting a range of assumptions concerning such important factors as the levels of offsets that would be allowed and the assumed levels of nuclear generation. The EIA examined eight different scenarios. . Figure 5 shows the range of levelized costs in the scenarios studied by the EPA and the EIA.

- An Assessment of U.S. Cap-and-Trade Proposals was recently issued by the MIT Joint Program on the Science and Policy of Global Change. This Assessment evaluated the impact of the greenhouse gas regulation bills that are being considered in the current Congress.[13] The range of CO_2 costs for the

---

12 *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* Energy Information Administration, July 2007, Supplement to the Energy and Markets Impacts of S. 280, Energy Information Administration, October 2007, and *EPA Analysis of the Climate Stewardship and Innovation Act of 2007, S. 280 in 110th Congress*, July 16, 2007.

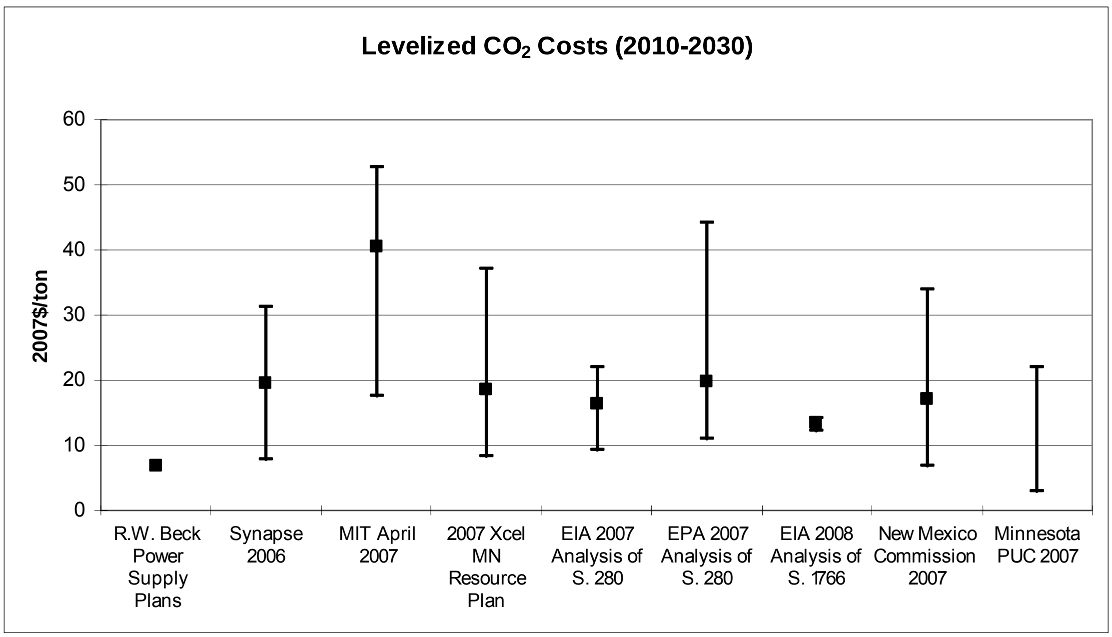
13 Twenty nine scenarios were modeled in the April 2007 MIT *Assessment of U.S. Cap-and-Trade Proposals*. These scenarios reflected differences in such factors as emission reduction targets (that is, reduce CO_2 emissions 80% from 1990 levels by 2050, reduce CO_2 emissions 50% from 1990 levels by 2050, or stabilize CO_2 emissions at 2008 levels), whether banking of allowances would be allowed, whether international trading of allowances would be allowed, whether only developed countries or the U.S. would pursue greenhouse gas reductions, whether there would be safety valve prices adopted as part of greenhouse gas regulations, and other factors.
In general, the ranges of the projected CO_2 prices in these scenarios were higher than the range of CO_2 prices in the Synapse forecast. For example, twelve of the 29 scenarios modeled by MIT projected higher CO_2 prices in 2020 than the high Synapse forecast. Fourteen of the 29 scenarios

three core scenarios studied by MIT are shown in Figure 5. These three scenarios analyzed (1) a reduction of greenhouse gas emissions of 80 percent from current levels by 2050; (2) a reduction of greenhouse gas emissions of 50 percent from current levels by 2050; and (3) stabilization of CO_2 emissions at year 2008 levels.

- The EIA's analysis of Senate Bill S. 1766, the Low Carbon Economy Act introduced in July 2007 by Senators Bingaman and Specter.[14]

Figure 4 also includes the range of CO_2 prices that Xcel Energy, a large Midwestern utility, has announced that it will use for resource planning[15] and the ranges of CO_2 prices that the New Mexico Public Regulation Commission[16] and the Minnesota Public Utilities Commission[17] have ordered that utilities use in their electric resource planning. Finally, Figure 4 includes, on a levelized basis, the Synapse forecasts of CO_2 prices that were presented in Figures 2 and 3 above.

Figure 4: Synapse and R.W. Beck CO2 Price Forecasts Used to Develop Power Supply Plans Compared to Other Recent Forecasts



(almost half) projected higher CO_2 prices in 2030 than the high Synapse forecast. The study is available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf.

14 *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007*, Energy Information Administration of the U.S. Department of Energy, January 2008, available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/index.html.

15 Northern States Power Company, *2007 Resource Plan*, Minnesota Public Utilities Commission Docket No. E002/RP-07__, December 14, 2007, at page 4-4.

16 *Order Approving Recommended Decision and Adopting Standardized Carbon Emissions Costs for Integrated Resource Plans,* New Mexico Public Regulation Commission, Case No. 06-00448-UT, dated May 16, 2007.

17 *Order Establishing Estimate of Future Carbon Dioxide Regulation Costs*, Minnesota Public Utilities Commission, Docket No. E-999/CI-07-1199, dated December 21, 2007.

Thus, on a levelized basis, the CO_2 price forecast that R.W. Beck used to develop the February 2007 Power Supply Plans for the AMP-Ohio member communities is significantly lower than the CO_2 prices forecast by the EPA, EIA and researchers at the Massachusetts Institute of Technology based on the legislative proposals in the current U.S. Congress. The R.W. Beck CO_2 price forecast also is low compared to the range of prices that the New Mexico and Minnesota regulatory commissions have directed that utilities use in their resource planning and that Xcel Energy has adopted. In contrast, the Synapse CO_2 price forecasts are consistent with the results of these studies, analyses and regulatory orders.

Figure 5 and Table 3, below, compare the projected total cost of power from the AMPGS Project for the years 2013-2032 on a dollar per megawatt hour ($/MWh) basis with the R.W. Beck and the Synapse Low, Mid and High CO_2 price forecasts. The AMPGS Project annual costs on a $/MWh basis, without CO_2 costs, that were used to calculate the numbers in Figure 5 and Table 3 were taken from the June 2007 *Initial Project Feasibility Study* for the AMPGS Project that was prepared for AMP-Ohio by R.W. Beck. For this reason, they reflect the older $2.5 billion construction cost for the Project, not the recently announced, and higher, $2.949 billion estimated construction cost.

Figure 5: The Projected Annual Cost of Power ($/MWh) from the AMPGS Project under the Synapse and R.W. Beck CO_2 Price Forecasts (in nominal dollars)

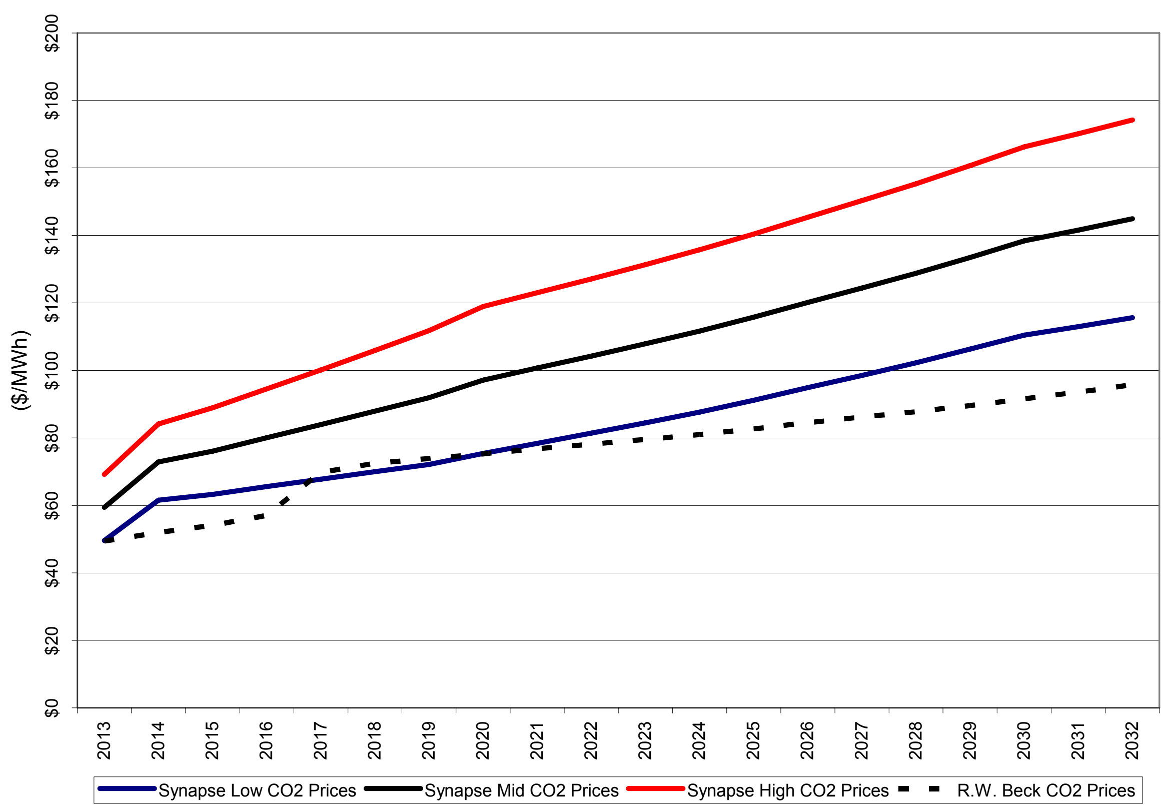


Table 3 presents the annual costs of power that are shown graphically in Figure 5.

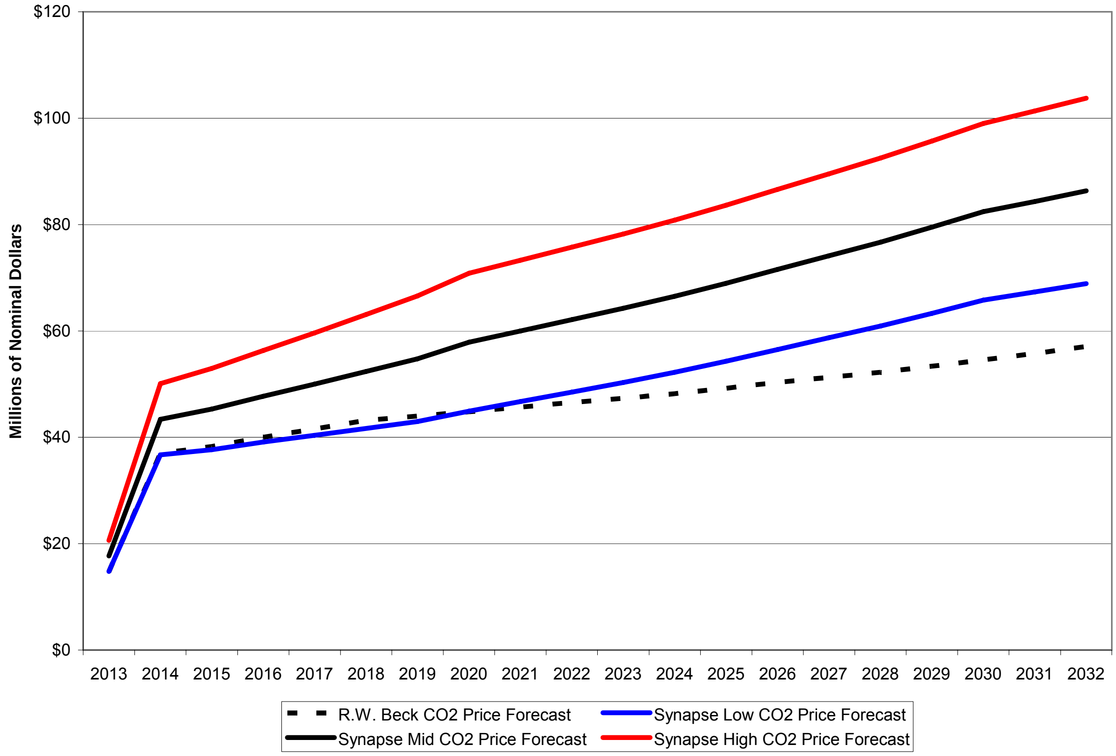
Table 3: The Projected Annual Cost of Power ($/MWh) from the AMPGS Project under the Synapse and R.W. Beck CO2 Price Forecasts (in nominal dollars)

	AMPGS Cost of Power with R.W. Beck CO_2 Price Forecast	AMPGS Cost of Power with Synapse Low CO_2 Price Forecast	AMPGS Cost of Power with Synapse Mid CO_2 Price Forecast	AMPGS Cost of Power with Synapse High CO_2 Price Forecast
2013	$49.44	$49.62	$59.40	$69.17
2014	$62.03	$61.58	$72.84	$84.11
2015	$64.23	$63.23	$76.06	$88.89
2016	$67.15	$65.59	$80.06	$94.53
2017	$69.78	$67.76	$83.94	$100.11
2018	$72.52	$69.96	$87.92	$105.88
2019	$73.84	$72.10	$91.93	$111.76
2020	$75.16	$75.39	$97.17	$118.94
2021	$76.72	$78.41	$100.73	$123.05
2022	$78.11	$81.39	$104.27	$127.15
2023	$79.45	$84.42	$107.87	$131.32
2024	$80.94	$87.66	$111.69	$135.73
2025	$82.60	$91.14	$115.78	$140.42
2026	$84.45	$94.88	$120.13	$145.39
2027	$86.06	$98.55	$124.44	$150.32
2028	$87.68	$102.23	$128.76	$155.30
2029	$89.58	$106.29	$133.49	$160.68
2030	$91.52	$110.49	$138.37	$166.24
2031	$93.58	$113.01	$141.58	$170.16
2032	$95.84	$115.62	$144.91	$174.20

Thus, R.W. Beck's estimated cost of power from the AMPGS Project is lower than the projected cost of power under even the Synapse Low CO_2 price forecast. R.W. Beck's estimated cost of power from the AMPGS Project is much lower than the projected cost of power under the Synapse Mid and High CO_2 price forecasts.

Figure 6, below, then presents the annual costs that the City of Cleveland would have to pay for power from the AMPGS plant under the R.W. Beck and the Synapse Low, Mid and High CO_2 price forecasts.

Figure 6: The Projected Annual Cost of Power, in nominal dollars, for the City of Cleveland's share of the AMPGS Project under the Synapse and R.W. Beck CO_2 Price Forecasts



Thus, the City of Cleveland could eventually be paying more than $80 to $100 million each year for the power from its 80 MW share of the AMPGS Project. By as early as 2018, the City of Cleveland could be paying $50 million or more for its share of the power from the AMPGS Project.

There is great interest in carbon capture and sequestration for power generation. However, that solution is not yet both technically and economically viable for pulverized coal plants, and might not be commercially available for pulverized coal plants for years or decades. Carbon capture also is currently expected to come with a rather steep cost. For example, Table 4, below, presents the results of recent assessments by utilities and researchers at the Massachusetts Institute of Technology and the National Energy Technology Laboratory which conclude that adding carbon capture technology will increase the price of generating power at a pulverized coal-fired power plant by somewhere between 61 percent and 81 percent.

Table 4: 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[18]	68%
MIT Future of Coal Report[19]	61%
Edison Electric Institute[20]	75%
National Energy Technology Laboratory[21]	81%

These cost increases translate into prices for carbon capture of approximately $30 to $70 per ton of CO_2. AMP-Ohio has claimed that the AMPGS plant could be retrofitted in the future with a new carbon dioxide capture technology at an estimated cost of approximately $20 per ton.[22] However, this Powerspan ECO2 carbon dioxide capture technology has not been tested on any scale beyond the laboratory and, pilot scale testing is only now beginning. Therefore, both its CO_2 capture ability and the $20 per ton cost estimate remain to be demonstrated. A one MW test of the technology at an operating power plant, producing a mere 20 tons of CO_2 per day, will be started in 2008 and a 125 MW demonstration is not scheduled to start until at least 2012. Therefore, it will be years before it is known for certain whether the Powerspan ECO2 carbon dioxide technology will even be technically and commercially viable. The $20/ton cost figure cited by AMP-Ohio appears to be based solely on unproven extrapolations from laboratory tests and not actual operational experience. AMP-Ohio does not even cite in what year's dollars this $20/ton figure is supposed to be. If the $20/ton figure only reflects the cost of capturing CO_2 at the plant even this low cost should be increased by perhaps another $5-$10/ton to reflect the estimated costs of transportation and sequestration.

5. AMP-Ohio Has Not Adequately Considered the Risk of Further Increases in the Cost of the AMPGS Plant in its Analyses

The currently estimated cost of the AMPGS Project, without interest and other financing-related costs, is $2.949 billion.[23] The currently estimated total cost of the Project, with interest and other financing-related costs, is $3.391 billion.[24]

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

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

20 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.

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

22 AMP-Ohio's Response to Request No. 9 in Exhibit DAS-2.

23 Updated *AMPGS Project Feasibility Study,* January 2008.

24 Updated *AMPGS Project Feasibility Study*, January 2008.

However, in its Application to the Power Siting Board, AMP-Ohio noted that the price increases currently being experienced in the expected construction costs of coal based electric generation "are staggering."[25] AMP-Ohio also noted that "Price increases of 10% in a single six month period are being reported. Using this data and similar data on other projects as an estimate, a one month delay in a $2 billion project is over $33 million."[26] Indeed, the AMPGS construction cost estimate already has increased significantly from $1.2 billion in October 2005 to $1.5 billion in May 2006 to $2.5 billion in June 2007 and, very recently, to the current $2.949 billion figure.

Moreover, there remains substantial design and cost uncertainty because the AMPGS Project is still is at very early conceptual stage, as was explained in Burns and Roe's review for the Division of Cleveland Public Power:

> In performing our due diligence review of a conceptual cost estimate, BREI relied on current in-house cost data for plants of a similar size. A more detailed review could not take place at this time since engineering has not begun and bulk quantities for items such as concrete, structural steel, building sizing, piping, electrical cable, conduit and tray, etc., have not been developed. Budget quotations for most major equipment have not been obtained, which further restricted our review to the use of current in-house data.[27]

In fact, it is not even certain that the plant will be a subcritical pulverized coal plant as AMP-Ohio has left the door open for modifying the design to a supercritical plant.

Although AMP-Ohio now estimates that the AMPGS Project will cost $2.5 billion without financing costs, it is reasonable to expect that the actual cost of the project will be much higher than AMP-Ohio estimates. The costs of building power plants have soared in recent years as a result of the worldwide demand for power plant design and construction resources and commodities. There is no reason to expect that plant costs will not continue to rise during the years when the detailed engineering, procurement and construction of the AMPGS will be underway. This is especially true given the extremely early stage of the engineering and procurement for the project.

For example, Duke Energy Carolinas' originally estimated cost for the two unit coal-fired 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 that single unit would be about $1.53 billion, not including financing costs. In late May 2007, Duke announced that the cost of building that single unit had increased by about another 20 percent. As a result, the estimated 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 originally estimated for a two unit plant.

25 AMP-Ohio Application, Section OAC 4906-13-05, at page 4.
26 Id.
27 Id.

Other coal-fired power plants have experienced similar cost increases. For example:

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

  > ".. coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.
  >
  > And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot… At one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.
  >
  > We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it."[28]

- 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."[29] 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.[30]

The worldwide competition for power plant design and construction resources, commodities and equipment 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 SO_2 and NO_x

---

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

29 Available at http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/$file/122806%20coal%20plant%20final2.pdf.

30 Id.

emissions standards, and by the competition for resources from the petroleum refining industry. The demand for labor and resource to rebuild the Gulf Coast area after Hurricanes Katrina and Rita hit in 2005 also has contributed to rising costs for construction labor and materials. The expected construction of new nuclear power plants also is expected to compete for limited power plant design and construction resources, manufacturing capacity and commodities.

For example, a June 2007 report by Standard & Poor's, Increasing Construction Costs Could Hamper U.S. Utilities' Plan to Build New Power Generation, has noted that:

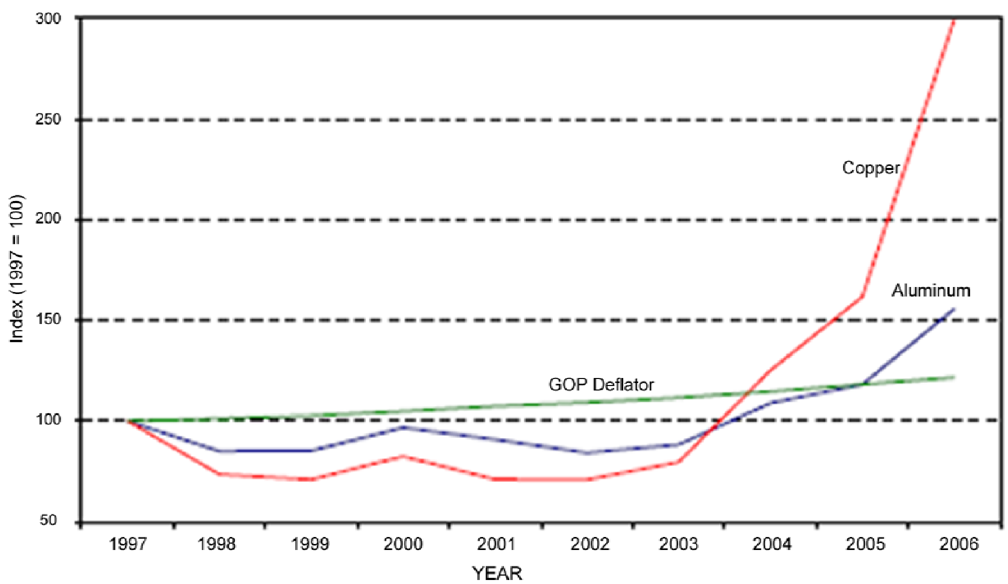
> As a result of declining reserve margins in some U.S. regions … brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation. While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poors' Rating Services broadly classifies under the following categories
>
> - Global demand for commodities
> - Material and equipment supply
> - Relative inexperience of new labor force, and
> - Contractor availability
>
> The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement and construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels. As a result, it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT). In a separate yet key point, as capital costs rise, energy efficiency and demand side management already important from a climate

change perspective, become even more crucial as any reduction in demand will mean lower requirements for new capacity.[31]

More recently, the president of the Siemens Power Generation Group told the New York Times that "There's real sticker shock out there."[32] He also estimated that in the last 18 months, the price of a coal-fired power plant has risen 25 to 30 percent.

The following figures from a September 2007 report on *Rising Utility Construction Costs* prepared by the Brattle Group for the Edison Foundation of the Edison Electric Institute illustrate the magnitude of the cost increases that have been experienced in recent years for some of the key commodities used in building new power plants. Although there appears to have been some moderation in price increases for some commodities during 2007, it is unclear whether this is a short-term blip or a long-term trend. Given the strong competition for resources and commodities from proposed construction projects in China and India, it is more likely the former than the latter.

Figure 7: Aluminum and Copper Price Increases



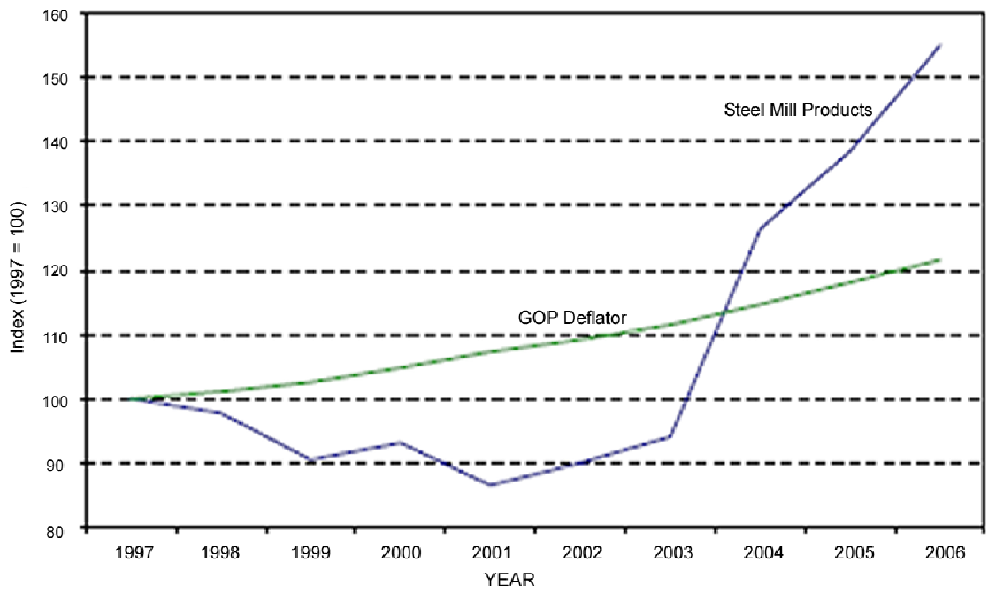
Source: The U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis

---

31 *Increasing Construction Costs Could Hamper U.S. Utilities' Plans to Build New Power Generation*, Standard & Poor's Rating Services, June 12, 2007, at page 1. A copy of this report is included in Exhibit DAS-7.

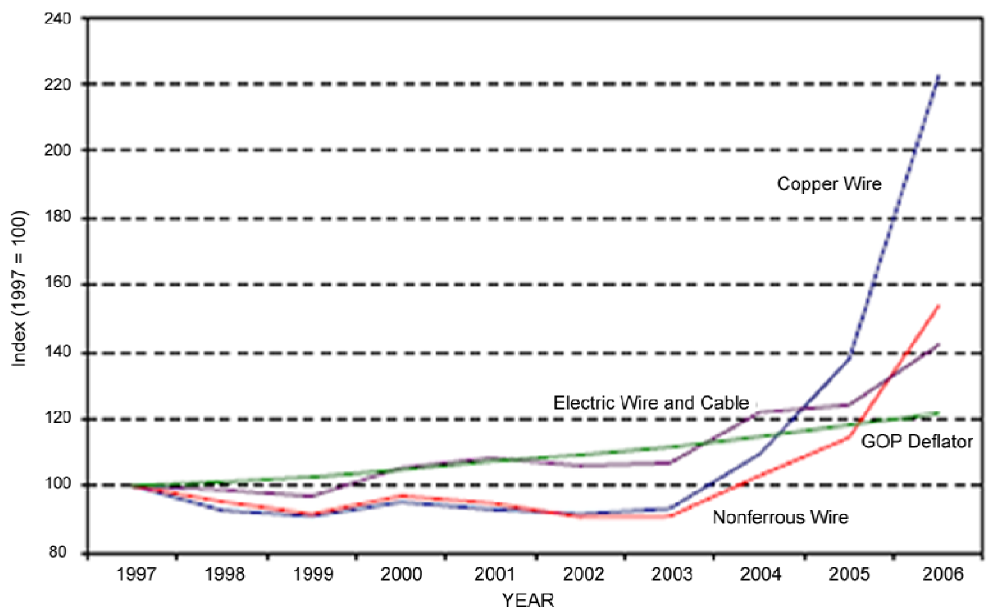
32 "Costs Surge for Building Power Plants," *New York Times*, July 10, 2007.

Figure 8: Steel Mill Product Price Increase



Source: The U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis

Figure 9: Electric Wire and Cable Price Increases



Source: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis

A 10 percent to 40 percent increase in the cost of building the AMPGS Project would increase the price of power from the plant by about $2/MWh to $8/MWh.

In addition, the same factors that have led to construction cost increases also can be expected to result in construction schedule delays. Consequently, it is reasonable to expect that the AMPGS Project will not be in-service by 2013 as AMP-Ohio now claims.

6. Participants in the AMPGS Project Would Bear the Risk of Further Construction Cost Increases

AMP-Ohio has said that it can mitigate the risk of further future cost increases by entering into a fixed price EPC contract for the AMPGS project.[33] However, the recent evidence that we have seen suggests that it will be extremely unlikely, or indeed impossible, for AMP-Ohio to find a firm willing to enter into such a fixed price contract for the proposed plant.

For example, in its recent report for the Division of Cleveland Public Power, Burns and noted that it:

> agrees 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.[34]

This conclusion is consistent with testimony presented last fall by a witness for the Appalachian Power Company, a subsidiary of American Electric Power:

> 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.[35] [Emphasis added.]

The unwillingness of power plant engineers and constructors to commit to fixed-price contracts means that the risks of increasing costs have been transferred to the participants in new coal-fired plant construction projects like AMPGS.

---

33 For example, see page 4-2 of the *Initial Project Feasibility Study*.

34 *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.

35 Ibid, at page 16, lines 16-20.

7. The Power Supply Plans Prepared for the City of Cleveland and Other Potential AMPGS Participants are Flawed

Synapse has reviewed several of the Power Supply Plans that were prepared for potential participants in the AMPGS Project by R.W. Beck. We have identified a number of serious flaws in these Power Supply Plans that favor the proposed AMPGS Project. The most significant of these flaws include:

- Additional cost-effective energy efficiency was not considered as a resource option.
- R.W. Beck used only a single forecast low forecast of CO_2 prices and did not examine any sensitivities studies reflecting higher CO_2 prices.
- A low construction cost estimate that was prepared in February 2006 was used for the AMPGS Project and other coal plants. This construction cost estimate was substantially lower than the current $2.5 billion construction cost estimate. No sensitivity analyses were prepared to examine how the preferred capacity additions would change in response to higher AMPGS Project construction costs.
- There is no evidence that R.W. Beck prepared any sensitivities reflecting the potential for any schedule delays.
- It appears that a high capital cost for wind resources was used.
- It appears that an unreasonably low capacity factor was used for new wind resources. New wind turbines are achieving higher than 25 percent annual capacity factors.
- It is unclear whether they assumed a continuation of the wind production tax credit. A continuation of the wind production tax credit would reduce the cost of power from independent wind projects.
- Wind was not included as an option in the base case analyses and it is unclear how much wind was modeled in alternate studies that determined how much wind would be needed to meet an assumed 10 percent Renewable Portfolio Standard energy requirement.
- R.W. Beck did not include the option of purchasing or entering into a long-term supply contract with an existing natural gas-fired power plant in its analyses.

Also, when preparing the Power Supply Plans, R.W. Beck predetermined the "specified combinations of the alternatives to be analyzed (i.e., portfolios)."[36] The outcome of the resource planning process can be influenced by the nature of the portfolios predetermined by R.W. Beck. A superior approach is to allow the resource planning or capacity expansion model to select adding supply-side and demand-side resources and, thereby, build the portfolios based upon the criterion of minimizing the net or cumulative present value of the optimal or preferred plans.

---

[36] February 16, 2007 *Power Supply Plan for the City of Cleveland*, at page 2.

AMP-Ohio has not compared the cost of the proposed AMPGS Project to demand-side resources.[37] Indeed, AMP-Ohio is only now undertaking a study of the potential for demand-side management and energy efficiency and the results of that study will not be available until after communities have had to commit to the AMPGS Project. AMP-Ohio has not provided any analyses of the potential for wind and/or other renewable resources within Ohio or the communities it serves and it is unclear whether it has even investigated this potential.[38]

For all of these reasons, the February 2007 Power Supply Plans provided to the City of Cleveland and the other communities served by AMP-Ohio should not be relied upon as showing that the AMPGS Project is part of a least cost, low risk resource plan.

8. Alternatives to Participation in the AMPGS Project

Before committing to purchase 80 MW of the capacity and associated energy from the AMPGS Project, the City of Cleveland and all other communities considering whether to participate in the project should independently evaluate in resource planning studies the relative economics of the plant as compared to other technically and economically feasible alternatives. These alternatives include: energy efficiency, renewable energy, combined heat and power, and short-term and long-term contracts from regional gas-fired power plants. These resource planning studies should be based on the most up-to-date information about the estimated costs of all demand-side and supply-side options.

Combined Heat and Power

Combined heat and power (CHP), also known as cogeneration, is the simultaneous production of electricity and heat from a single fuel source, such as: natural gas, biomass, biogas, coal, waste heat, or oil.

CHP is not a single technology, but an integrated energy system that can be modified depending upon the needs of the energy end user.

CHP provides:

- Onsite generation of electrical and/or mechanical power.
- Waste-heat recovery for heating, cooling, dehumidification, or process applications.
- Seamless system integration for a variety of technologies, thermal applications, and fuel types into existing building infrastructure.

The two most common CHP system configurations are:

- Gas turbine or engine with heat recovery unit
- Steam boiler with steam turbine

By installing a CHP system designed to meet the thermal and electrical base loads of a facility, CHP can greatly increase the facility's operational efficiency and decrease

---

37 AMP-Ohio's Response to Request No. 30 in Exhibit DAS-2 in Ohio Power Siting Board Case No. 06-1358-EL-BGN.

38 Id, Response to Request No. 9.

energy costs. At the same time, CHP reduces the emission of greenhouse gases, which contribute to global climate change.[39]

There already are 43 CHP sites in Ohio with a total of 658.5 MW of capacity.[40] A study conducted by ONSITE SYCOM Energy Corporation for the US DOE/EIA identified a market potential of 3,075 MW in the commercial/institutional sectors in Ohio.[41] The data in Table 5 below is taken from the ONSITE report, and shows the breakdown of market potential across sectors:

Table 5: Combined Heat and Power Technical Potential in the Commercial/Institutional Sectors in Ohio

Business Sector	Potential Capacity (MW)	% of Total
Hotels/Motels	115.7	3.8%
Nursing homes	439.4	14.3%
Hospitals	376.8	12.3%
Schools	567.8	18.5%
Colleges & Universities	195.8	6.4%
Commercial laundries	24.5	0.8%
Car washes	9.7	0.3%
Health clubs	114.6	3.7%
Golf clubs	67.1	2.2%
Museums	13.6	0.4%
Correctional facilities	80.2	2.6%
Water treatment/Sanitary	45.5	1.5%
Extended service restaurants	138.9	4.5%
Supermarkets	47.7	1.6%
Refrigerated warehouse	15.8	0.5%
Office buildings	821.9	26.7%
Total	3,075	**100.0%**

It also can be expected that there is a very substantial potential for CHP in the industrial sector, as well.

A number of studies suggest that the economic potential for combined heat and power is approximately 25 percent to 40 percent of this technical potential. This would suggest that there is approximately 750 MW to 1,200 MW of economic combined heat and power capacity in the commercial and industrial sectors in Ohio plus significant additional capacity in the industrial sector throughout the state. The economics of pursuing potential CHP resources should be investigated before a long-term commitment is made to an expensive resource like the AMPGS Project.

Energy Efficiency

At the Midwestern Governors meeting in November 2007, the State of Ohio agreed with other Midwestern states to work to achieve 2 percent of annual sales of electricity and natural gas through efficiency improvements by 2015 and to continue to achieve an

39 For a more detailed explanation of the benefits of CHP, see http://www.chpcentermw.org/pdfs/AMP_Ohio_Presentation.pdf

40 http://www.eea-inc.com/chpdata/States/OH.html

41 *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, Prepared for the US Dept. of Energy, Energy Information Administration by ONSITE SYCOM Energy Corporation, January 2000 (Revision 1), Table B-1, pages 57-58.

additional 2 percent in efficiency improvements each year thereafter.[42] Other states and municipal utilities have adopted even more aggressive goals for energy savings through demand-side management, as shown in Table 6 below.

Table 6: Plans for Cumulative Energy Reductions Through DSM

Jurisdiction or Entity	Savings Target	Source
New Jersey	20% by 2020	Governor's Economic Growth Strategy 2007
California	16% by 2013	CPUC 2004 Goals Order (calculated)
New York	15% by 2015	Governor's Clean Energy Plan 2007
Sacramento Municipal Utility District (CA)	15% by 2017	Data provided by SMUD
Austin Energy City Owned Utility (TX)	15% by 2020	2003 Strategic Plan
SDG&E (CA)	13% by 2013	2004 Long-Term Resource Plan
Puget Sound Energy (WA)	12% by 2013	2005 Least Cost Plan
Pacific Gas & Electric Co. (CA)	12% by 2013	2004 Long Term Procurement Plan

Studies by the Midwest Energy Efficiency Alliance (2006) and the American Council for an Energy-Efficiency Economy (2006) and information recently submitted to the Public Utility Commission of Ohio by Duke Energy Ohio (2006) show that there is a substantial potential for cost-effective energy efficiency in the residential and commercial electric and natural gas sectors.[43] These savings through energy efficiency would cost substantially less than the City of Cleveland can expect to pay for power from the AMPGS Project.

Cleveland Public Power's October 24, 2007 presentation to the City Council shows its baseload demands growing to 163 MW in 2013, 173 MW in 2023, and 198 MW in 2033. This is approximately 1 MW, or less than 1 percent, per year, through 2023 and 2.5 MW, or less than 2 percent, per year between 2023 and 2033. A number of states and utilities have reported annual savings from energy efficiency of more than 1 percent. For example:

---

42 *Energy Security and Climate Stewardship Platform for the Midwest,* 2007, at page 6.

43 *Midwest Residential Market Assessment and DSM Potential Study*, Midwest Energy Efficiency Alliance, Sponsored by Xcel Energy, March 2006; *Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest,* American Council for Energy-Efficient Economy (ACEEE), January 2005; 2006 Amended Application of Duke Energy Ohio, Inc. to Establish Demand-Side Management Programs for Residential and Non-Residential Customers, Public Utility Commission of Ohio Case No. 06-91-EL-UNC, 06-92-EL-UNC, 06-93-GA-UNC.

- San Diego Gas & Electric (CA) – 2.0% in 2005
- Southern California Edison (CA) – 1.7% in 2005
- Massachusetts Electric Company (MA) – 1.3% in 2005
- Sacramento Municipal Utility District (CA) – 1.2% for each of the years 1991 through 1996
- State of Connecticut – 1.1% in 2005
- State of Vermont – 1.0% in 2005

Achieving these levels of energy efficiency savings would essentially eliminate Cleveland Public Power's projected baseload demand growth through 2023 and significantly reduce its forecast baseload demand growth between 2023 and 2033.

AMP-Ohio has retained a firm to conduct a study of the potential for energy efficiency. However, this is backwards. Rather than looking at the potential for energy efficiency after making a commitment to an expensive new generating plant, AMP-Ohio, the City of Cleveland and other communities should be using assessments of the potential for cost-effective energy efficiency as an input to its resource planning analyses.

Renewable Resources

The state of Ohio has the potential for renewable wind and biomass resources. The Governor of Ohio has committed the state to the goals of producing 10 percent of its energy from renewable resources by 2015, 20 percent by 2020, 25 percent by 2025, and 30 percent by 2030.[44] These goals should be incorporated into resource planning by the City of Cleveland and other communities before a commitment is made to a major non-renewable resource like the AMPGS Project. One way to do so would be to issue a Request for Proposal from renewable resources to identify the potential supply and cost.

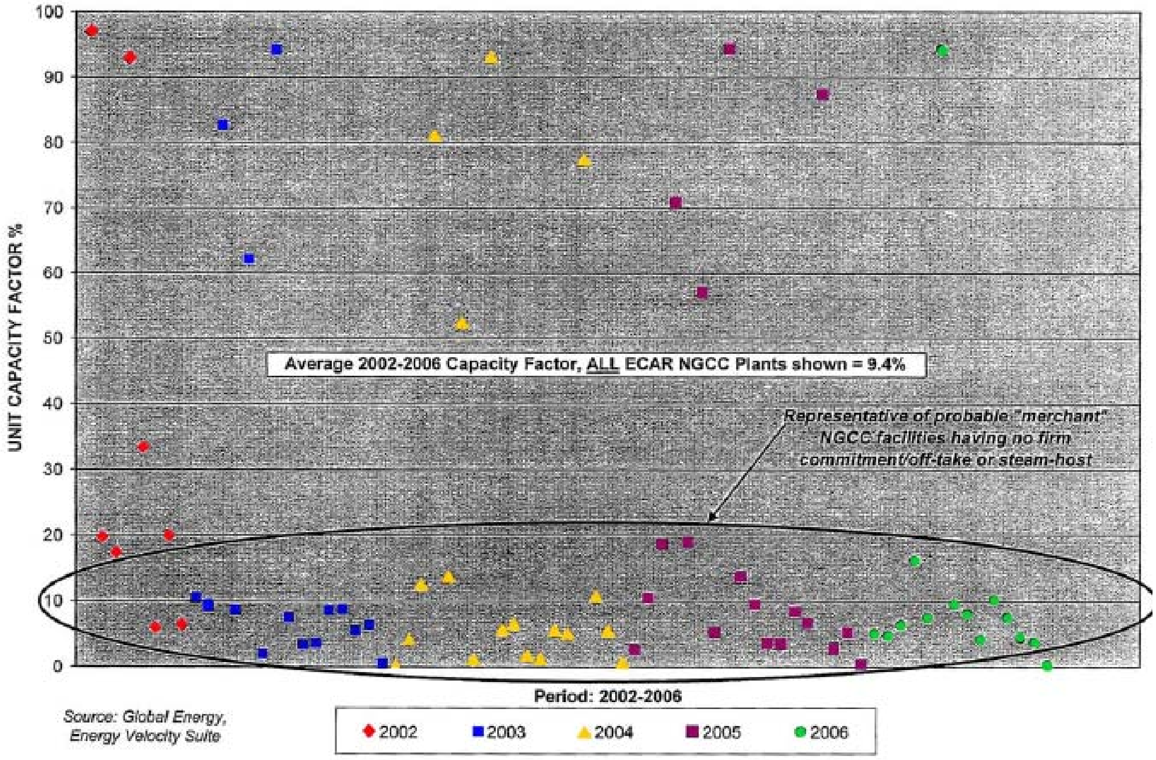
There is a good potential for offshore wind resources in Cleveland and along the coast of Lake Erie.[45] The Cuyahoga Regional Energy Development Task Force has recommended the development of a 5 MW to 20 MW demonstration wind energy project offshore downtown Cleveland in Lake Erie.[46] The Cleveland Foundation has suggested that Cleveland Public Power consider owning this project.[47]

Short-Term or Long-Term Capacity and Energy Purchases from Existing Gas-Fired Power Plants

Evidence submitted to the West Virginia Public Service Commission by the Appalachian Power Company in mid-2007 showed that existing gas-fired combined cycle power plants in the old ECAR region (that is, Ohio, Indiana, Michigan, western Pennsylvania, West Virginia, and Kentucky) operated at very low capacity factors during the years 2002-2006. In fact, according to Appalachian Power Company, natural gas-fired combined cycle plants in ECAR averaged only a 9.4 percent capacity factor during this five year period.

44 *Energy Security and Climate Stewardship Platform for the Midwest,* 2007, at page 6.
45 See http://www.eere.energy.gov/windandhydro/windpoweringamerica/where_is_wind_ohio.asp
46 http://www.cuyahogacounty.us/pdf/RegEnergyTF.pdf.
47 www.**clevelandcitycouncil**.org/LinkClick.aspx?fileticket=OQNLeIA/5eI=&tabid=208

Figure 10: Natural Gas Combined Cycle Capacity Factors in ECAR during 2002-2006[48]



While, as the Company notes, it is reasonable to assume that the merchantability of natural gas combined cycle plants will improve over time, this historical data suggests that the City of Cleveland may be able to enter into short-term or long-term purchases of capacity and energy from existing combined cycle facilities at favorable terms. This alternative should be investigated through the issuance of a competitive request for proposals ("RFP") before the City or any other community commits to being a participant in the AMPGS Project.

48 Source: Appalachian Power Company SCW Exhibit No. 12-A, page 2 of 2, in West Virginia Public Service Commission Case No. 06-0033-E-CN.