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American Municipal Power Generating Station

Initial Project Feasibility Study Update

AMP OHIO

American Municipal Power - Ohio, Inc.

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R·W·BECK

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Introduction

American Municipal Power-Ohio, Inc. ("AMP-Ohio") is planning to construct a 960 net megawatt (MW)[1] coal-fired generating station consisting of two 480 MW units which will be located in Meigs County, Ohio, in the township of Letart. The station is titled the American Municipal Power Generating Station ("AMPGS"), which together with other facilities and arrangements comprises the AMPGS Project, also referred to herein as the Project.

AMP-Ohio has engaged R.W. Beck, Inc. ("R. W. Beck") to provide Owner Engineer ("OE") services for the AMPGS Project which include, among other things, the preparation of a Project Feasibility Study. An Initial Project Feasibility Study was prepared and delivered to AMP-Ohio in June 2007 (referred to herein as the "Initial Feasibility Study"). A Final Project Feasibility Study will be prepared in 2009 based on updated information available prior to full notice to proceed with construction. Also, R. W. Beck will prepare summary reports for Project financing updated to reflect the most recent information available as of the date of the associated Official Statement.

Since the preparation of the Initial Feasibility Study, AMP-Ohio has received proposals from three Engineer-Procure-Construct ("EPC") contractors with indicative pricing information and proposed terms and conditions for an EPC contract. Also, other information has become available and certain assumptions have been updated. The purpose of this report is to provide an update to reflect such changes to the (i) description of the AMPGS Project, (ii) EPC contract, technical specifications and plans for constructing the plant, (iii) estimated capital costs and financing requirements, (iii) projected operating costs (including fuel costs), (iv) projected annual power costs of the Project and a comparison to projected power market prices and (v) risk analysis. This report constitutes the Initial Project Feasibility Study Update (the "Report") and summarizes our work up to the date of this Report.

As used in this Report, the capitalization of any word not normally capitalized indicates that such word is defined in the particular agreement or other document discussed. References to and descriptions of such agreements or documents in this Report represent our understanding of certain general principles thereof, but do not purport to be complete and are qualified in their entirety by reference to such agreements or documents.

[1] The 960 MW rating reflects the projected summer capacity rating of the Project. The annual average rating is projected to be 987 MW.

Project Arrangement

Approximately 97.5 percent of the AMPGS Project is planned to be owned by AMP-Ohio and AMP-Ohio will enter into take-or-pay power sales contracts with each of the participating AMP-Ohio Members. The remaining 2.5 percent of the AMPGS Project will be owned by the Central Virginia Electric Cooperative ("CVEC"). Initial drafts of the contractual arrangements between CVEC and AMP-Ohio with respect to joint ownership and the operation of the AMPGS Project have been developed. This arrangement provides for each of the two owners to be responsible for the financing of the respective ownership interest.

There are 87 Members of AMP-Ohio that are participating in the development of the AMPGS Project that have or may execute Power Sales Contracts with AMP-Ohio (the "Participants"). The Power Sales Contracts authorize AMP-Ohio to finance, construct and operate the AMPGS Project and specify the Member's obligations to take or pay for the power and transmission service from the AMPGS Project under the terms of the contract. Each participating Member will be entitled to receive a fixed entitlement share of the output of the AMPGS Project at a "postage stamp rate" that will be designed to recover the fixed and variable costs of the AMPGS Project and certain related transmission services.

Section 31 of the Power Sales Contract includes a provision allowing Participants that executed the Power Sales Contract prior to November 1, 2007, a one-time option to reduce the requested Power Sales Contract Resource Share ("PSCR Share") or repudiate the Contract upon certain notice received by AMP-Ohio prior to March 1, 2008.

AMP-Ohio intends to finance the cost of acquisition and construction of the Project with revenue bonds authorized under a Master Trust Indenture and secured by the Power Sales Contracts with the Members.

Project Timeline

The overall Project development timeline has not changed with a target commercial operation date of April 2013 for Unit 1 and October 2013 for Unit 2. However, some of the EPC proposals showed completion dates that were later than the target dates by up to four months. As shown in the timeline below (Figure 1), the remaining major milestones that are on the critical path of the Project schedule include:

- Out-of-State (outside of Ohio) Power Sales Contracts signed by March 2008
- Exercise land options in July 2008
- Complete EPC open book preliminary design and EPC Contract negotiations by March 2009
- All construction permits approved by March 2009
- EPC Contract final Notice to Proceed ("NTP") for construction by April 2009

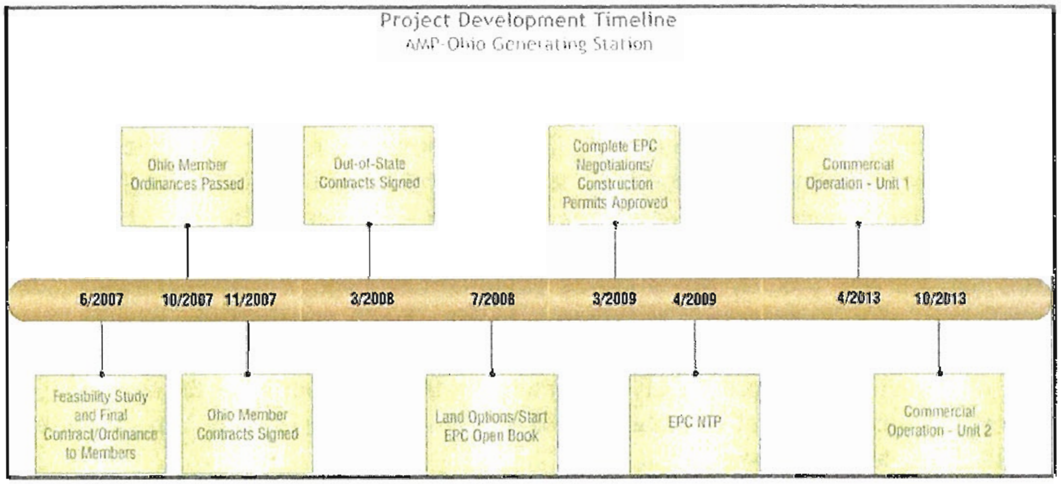

Figure 1 - Project Development Timeline

Project Description

The proposed AMPGS Project is a 960 MW coal-fired generating station which is to be located in Meigs County, Ohio, in the township of Letart. The AMPGS Project will be operated as a base load plant comprised of two nominal 480 net MW generating units.

The AMPGS will be required to comply with federal New Source Performance Standards ("NSPS") and will be permitted as a major new air emission source in a location designated as an "attainment" area for all criteria pollutants. AMP-Ohio submitted an application for a Permit to Install ("PTI") to the Ohio Environmental Protection Agency ("Ohio EPA") in May 2006. A draft PTI was issued by the Ohio EPA on September 13, 2007. A final PTI is anticipated to be issued prior to the end of the first quarter in 2008. The application for the PTI specifies that the Project will install Best Available Control Technology ("BACT") for control of emissions from AMPGS, including the use of low NO_x burners, over-fire air, a selective catalytic reduction ("SCR") unit for NO_x reduction, fabric filter bag house to capture and reduce particulate emissions, the Powerspan Corporation's ("Powerspan") multi-pollutant control technology ("ECO-SO_2) ammonia-based flue gas desulfurization ("FGD") technology or a limestone FGD to capture and reduce SO_2 emissions and Hg, and a wet electrostatic precipitator ("ESP") to capture and reduce condensable emissions and fine particulates.

The Powerspan technology is discussed in further detail in Section 3 and Appendix D of the Initial Feasibility Study. This newer technology is a wet flue gas desulfurization ("Wet FGD") system that uses urea, which will be processed to produce ammonia, which will then be used as a reagent in the wet FGD process to reduce SO_2 emissions from the plant's flue gas. The product from the reaction of SO_2 and ammonia is a liquid ammonium sulfate, which will be processed through a crystallizing process to produce solid ammonium sulfate, a fertilizer, which can be sold in the fertilizer market.

AMP-Ohio is pursuing the Powerspan ammonia-based FGD technology, because it would achieve outlet emissions at best available control technology levels, produce a valuable co-product that reduces landfill use (compared to the synthetic gypsum produced by traditional limestone FGD technologies), provide co-benefits of mercury and particulate matter control, and may also allow for potential future CO_2 capture. Powerspan has reported that the application of the Powerspan CO_2 process on plants utilizing their SO_2 process would reduce potential CO_2 capture costs as compared to installation of a Powerspan CO_2 capture process on a conventional power plant equipped with a limestone FGD emission controls.[2] In the event that the Powerspan technology cannot be appropriately guaranteed by the EPC contractor for the AMPGS Project, a limestone wet scrubber could be developed to satisfy air permitting requirements for the Project.

The proposed two generating units will be capable of burning a blend of coals. Coal will be delivered by barge to the generating station and will be moved to the site using a conveyor system.

At the time of preparing the Initial Feasibility Report, the steam generators for each unit were proposed to be subcritical pulverized coal ("PC") boilers that use natural gas as the startup fuel. The request for proposals that were issued by AMP-Ohio after the issuance of the Initial Feasibility Report provided for either a subcritical or supercritical boiler. All EPC proposals received specified that each contractor would supply supercritical boilers. Evaluation of the EPC proposals is in progress and will include evaluation of the supercritical boilers.

The AMPGS Project also includes: (i) the construction of an on-site switchyard and a double-circuit 345 kV transmission line from the AMPGS to an interconnection point at an existing transmission line; (ii) a tie point for the natural gas supply pipeline to the generating station; and (iii) an on-site solid waste landfill.

[2] In May 2004, Powerspan and the Department of Energy's ("DOE") National Energy Technology Laboratory announced a cooperative research and development agreement (CRADA") to develop a cost effective CO_2 removal process for coal-based power plants. The regenerative process uses an ammonia-based solution to capture CO_2 in the flue gas and prepare it for subsequent sequestration. The ammonia solution is recycled after regeneration. In September 2005, Powerspan announced plans to begin a pilot test of its CO_2 capture process, with testing scheduled to begin in late 2007. AMP-Ohio is a partner in this pilot CO_2 capture testing process. Initial cost estimates developed by DOE indicate that the ammonia-based process can capture CO_2 in a manner that could provide savings compared to available amine based CO_2 capture technologies. Powerspan has entered into an agreement with NRG to install and test an 125 MW demonstration unit for their CO_2 capture technology at the WA Parish Plant site in Texas. In addition Powerspan and BP Alternate Energy have entered into a collaborative agreement to develop and commercialize the Powerspan CO_2 capture process.

Estimated Capital Costs and Financing Requirements

The estimated capital costs for construction of the AMPGS Project as of January 2008 which reflect the most recent information available are summarized in Table 1 below. The total construction costs include EPC costs, transmission facilities (including an on-site 345 kV substation), land and infrastructure upgrades and owner's costs. The estimated value for the EPC contract is approximately $[redacted] for the two units and includes all costs associated with the engineering, design, equipment, material, construction and start-up of the Project facilities, and a provision for contractor escalation and contingency. This amount includes a [redacted] percent contingency for the EPC contract estimate. A summary of the updated EPC cost estimate is shown in Attachment 1.

The current estimated EPC Costs shown in Table 1 are higher than the estimated costs provided in the Initial Feasibility Report issued in June 2007. The main drivers for the cost change are due to [redacted]

Other Project costs that will be contracted, constructed and paid separate from the EPC contract by AMP-Ohio include interconnecting 345 kV transmission line (double circuit), interconnection 345 kV switchyard, various electric system upgrades and land and infrastructure upgrades. Total estimated costs for these Other Project costs are $[redacted] million.

Owner's costs are estimated to be $[redacted] (other than financing costs). Such costs include owner's engineer, environmental consultants, financial and legal consultants and AMP-Ohio staff expenses, initial inventories, spare parts, initial working capital and $[redacted] for owner's contingency. As of the date of this Report, our best estimate of the total cost of construction is estimated to be approximately $2.95 billion which is summarized in Table 1 below. Attachment 1 provides an estimate of the range for the total cost of construction which is based on EPC bid pricing and our projections of the lower and higher ranges of construction related costs.

Table 1
Estimated Costs of Construction

Description	Dollars in Thousands
Capital Costs	
EPC Costs [1] [2]	[redacted]
Other Costs:	
Transmission Line and Interconnection Switchyard	[redacted]
Transmission System Upgrades [3]	[redacted]
Land and Infrastructure Upgrades [4]	[redacted]
Total Capital Costs	[redacted]
Owner's Costs	
AMP-Ohio Staff, Legal, Engineers and Consulting Costs [5]	[redacted]
Taxes and Insurance	[redacted]
Initial Inventories and Spare Parts [6]	[redacted]
Start-up and Commissioning Expenses	[redacted]
Working Capital [7]	[redacted]
Owner's Cost Escalation	[redacted]
Owner's Contingency	[redacted]
Total Owner's Costs (w/o Financing Costs)	[redacted]
Total Estimated Costs of Construction	$2,949,600

[1] The development of the estimated costs of construction of the AMPGS Project, which now reflects supercritical design, is set forth in Attachment 1.

[2] Amount includes allowance for cost escalation, EPC profit and [redacted] percent contingency for the EPC contract estimate.

[3] Estimated costs associated with transmission system upgrades related to interconnecting the Plant to the PJM system, estimated at [redacted] Also includes upgrade costs associated with transmission services required to deliver capacity to the MISO Participants, estimated at [redacted]

[4] Includes estimated costs of a gas line, land costs, rights of way, landfill development and infrastructure costs.

[5] Includes initial developmental costs to date, the estimated costs of AMP-Ohio staff costs related to management of permitting, licensing and the EPC open book process, legal, engineers and other consulting fees.

[6] Includes an allowance of [redacted] for initial fuel and other commodity inventories and [redacted] for initial spare parts inventory.

[7] Based on one month of fixed and variable operation and maintenance costs (excluding fuel and other commodities).

As shown in Table 2 below, the total estimated amount of bonds to fund the total cost of the Project including construction costs, interest during construction, deposit to a Reserve Account (as required by the Master Trust Indenture) and bond issuance expenses is estimated to be approximately $3.391 billion, of which $3.307 billion is estimated for AMP-Ohio's 97.5 percent ownership share. AMP-Ohio's financing plan reflects issuance of variable-rate debt on an interim basis during the construction period to fund construction costs and interest during construction. Following the construction period, AMP-Ohio would then undertake permanent financing of the Project through issuance of fixed-rate long-term bonds that would refund the previously issued interim variable-rate debt. The estimated bond financing requirements are shown below in Table 2.

Table 2
Total Estimated Bond Amount

Description	Dollars In Thousands
Estimated Bond Amount	
Construction Costs [1]	$2,949,600
Net Interest During Construction [2]	315,275
Deposit to Reserve Account [3]	83,075
Issuance Expenses [4]	43,442
Total Estimated Bond Amount [5]	$3,391,392

[1] Per Table 1.
[2] Estimated amount to be deposited in the Interest Account to pay interest on bonds outstanding to July 1, 2013. Net of estimated interest earnings at an assumed rate of 3.75 percent on unexpended balances in the Construction Fund, Interest Account and Reserve Account during the construction period through 2013.
[3] Estimated amount required to be deposited into the Reserve Account based on one-half of the estimated maximum debt service on all Project permanent debt.
[4] Estimated expenses associated with bond underwriter's fees, legal fees, and other expenses incurred in connection with the bond financings. Such amounts were based on 0.5 percent of the principal amount of Bonds issued prior to permanent financing and 1 percent of the principal amount of Bonds issued in 2013 for permanent financing
[5] This amount reflects 100 percent of the AMPGS Project. AMP-Ohio's ownership share at 97.5 percent would be $3,306,607.

Plans for Constructing and Operating the Plant

Schedule and Plan for Construction

The proposed project development and commercial operation schedule is shown in Figure 2 and has not changed from the schedule shown in the Initial Feasibility Study.

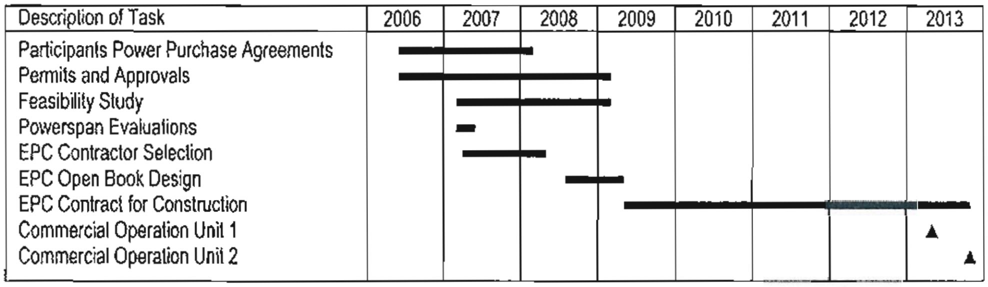

Figure 2 - Project Development and Commercial Operation Schedule

Activities that are ongoing as of the date of this Report generally include permitting, Participant approvals, and the evaluation of EPC contractor proposals. EPC proposal evaluations and recommendations for contract award are anticipated to be completed by April 2008. EPC Contract negotiations and award would then follow allowing initiation of the preliminary design by the EPC Contractor in July 2008. The EPC contract is scheduled to be finalized by March 2009, followed by an EPC contract final NTP in April 2009. Permits required for construction are anticipated to be received by March 2009. The estimated EPC schedule for engineering, procurement and construction of Unit 1 is a 48-month schedule beginning in April 2009 and ending with substantial completion in April 2013. The Unit 2 commissioning and substantial completion is assumed to occur approximately 6 months later than Unit 1, or October 2013. However, the schedule could change as design and construction details are developed leading up to the final NTP.

AMP-Ohio plans to contract with a single firm to engineer (and design), procure the equipment, and construct the plant. This method reduces the number of contracts executed which makes contract administration by AMP-Ohio less labor intensive than having to negotiate several large contracts to accomplish the same tasks. It also minimizes many of the risks associated with interfacing and coordinating between different contractors.

The EPC-RFP issued by AMP-Ohio requested a fixed price for the open book-preliminary design phase portion of the project and an indicative price for the final design, construction, and commissioning of the AMPGS. At the conclusion of the open book preliminary design phase, a target/fixed price would be established for the remainder of the EPC contract ("final EPC Contract"). Some of the EPC proposals received included a fixed price for the engineering effort during the open book preliminary design phase with estimated pricing for early equipment procurements during this phase. The proposals also discussed target pricing for the final EPC

Contract with some proposals allowing for fixing the price of equipment when early orders are made for major equipment suppliers.

The target price approach is the current contracting approach being used for the Prairie State Project[3] of which AMP-Ohio has a 23.26% ownership share. Considering the range of contract structures offered by the EPC Contractors, it is unlikely that a full fixed-price contract can be cost effectively negotiated with an EPC Contractor. In order to minimize the EPC risk cost premium, AMP-Ohio will likely be required to assume some of the construction cost risk and possibly some schedule risk for the Project. The keys to successfully minimizing these risks will be the planned open book preliminary design phase to be conducted as the initial step of the EPC Contract. This step will provide details (i.e. scope of work, scope of supply, plant performance, price, and schedule guarantees) required to finalize the EPC contract between AMP-Ohio and the EPC Contractor.

The EPC contract will cover the majority of Project facilities to be constructed, except for the natural gas supply to the plant, the construction of the on-site switchyard and transmission line from the plant site to the tie-in point with the existing transmission grid, construction of transmission upgrades, the on-site landfill and communication ties to AMP-Ohio's communication system. Design, procurement and construction for these other facilities would be performed under separate contracts.

Plant Operation and Maintenance

As of the date of this Report, AMP-Ohio intends to assume the responsibilities of operating and maintaining the Project. This includes fuel procurement, fuel and ash handling, general materials procurement, environmental reporting and the overall operation and maintenance of the plant. AMP-Ohio and The Andersons (a national agriculture company) have executed a Memorandum of Understanding concerning a potential contract for an initial 5-year period to operate and maintain the fertilizer plant, including procurement and supply of urea and marketing of the ammonium sulfate fertilizer produced from the Powerspan emission control system. A projection of the performance, commodity prices, and operating expenses of the AMPGS Project for the period 2013 – 2032 is set forth in Attachment 2.

The estimated operation and maintenance expenses for the Project are summarized in Table 3 below. These costs have been slightly increased from the estimates in the Initial Feasibility Study. Variable O&M costs and major maintenance costs were increased to account for the change from subcritical boilers to supercritical boilers.

[3] Nine participating entities, including AMP-Ohio, have established a company, the Prairie State Generating Company, LLC, ("PSGC"), which has developed and is constructing a "mine mouth," pulverized coal-fueled power generating facility with a 1,582 MW nominal rating on a site in Washington and St. Clair Counties, Illinois and adjacent coal mines capable of supplying the generating facility with coal from certain coal reserves (the "Prairie State Project").

Table 3
Estimated Production Related O&M Expenses [1]

Category	2013$
Total Fixed O&M, $/kW-year	38.38
Variable O&M, $/MWh	9.80
Fuel, $/MWh	21.08
Total Annual Operating Costs, $/MWh	36.04

[1] Includes total fixed O&M, variable O&M, and fuel, including allowance costs (NO_x, SO_2, Hg and CO_2).

Fuel and Transportation

Blending different coals provides the AMPGS with the flexibility to use cost competitive coals while meeting the sulfur air emission requirements of the Permit to Install. The eastern blend was used for this Initial Feasibility Study Update, due to the higher delivered cost for a western blend using Powder River Basin ("PRB") coal. The coal handling equipment will include the capability to process both bituminous and PRB coal.

Table 4 below summarizes the expected fuel supply characteristics and the estimated delivered blended fuel price for the year 2013.

Table 4
Fuel Supply Characteristics and Costs for Eastern Blend

Annual Tons for Blend [1]	2,731,300
Heating Value for Fuel Blend (Btu/lb)	12,096
Sulfur Content for Fuel Blend (%)	2.12
Ash Content for Fuel Blend (%)	10.52
Delivered Fuel Price for Blend ($/MMBtu) [2]	2.35

[1] Fuel consumption values are based on average annual plant output of 987 MW (net); design heat rates of 8,990, Btu/kWh
[2] Fuel prices are escalated values for delivery in 2013.

Environmental Considerations and Requirements

The Project is being planned to include air emission control systems to comply with the expected regulatory requirements, based on information in the air permit application for the Project. The following emission limitations are expected:

Table 5
Proposed Air Emission Limits and Controls

Pollutant	Control Systems	Emission Limit (lbs/MMBtu)
SO_2	Powerspan Wet Scrubber	0.15
NO_x	Low NO_x Burners and SCR	0.07
PM/PM10	Baghouse/Wet ESP	0.025
Hg [1]	Baghouse/Powerspan Wet Scrubber	1.9×10^{-6}

The Project will be subject to certain environmental requirements that include, but are not limited to: (i) NO_X and SO_2 allowance obligations, including those required under the Clean Air Interstate Rule ("CAIR"); (iii) mercury emissions allowances obligations under the Clean Air Mercury Rule ("CAMR") which includes the establishment of a cap and trade program. In addition , the project may be subject to, potential carbon dioxide ("CO_2") emission allowances obligations in the form of either a carbon tax imposed on emissions of CO_2 or some form of a cap and trade system comparable to what presently exists for SO_2 and NO_X emissions. The impact of complying with these rules has been estimated in the projected operating results by assuming that the Project will purchase allowances from the market.

Clean Air Act and Carbon Dioxide Emissions

On April 2, 2007, the U.S. Supreme Court ("Court") in Massachusetts v. EPA, concluded that the Clean Air Act ("CAA") authorizes the United States Environmental Protection Agency ("EPA") to regulate green house gases ("GHG") from new motor vehicles if that agency makes an endangerment finding. If the EPA makes such a finding, The EPA must decide what to do from a regulatory perspective. The Court did not set a timetable for action by the EPA and there are no such deadlines established in the CAA.

Control of greenhouse gases such as CO_2 is receiving a great deal of attention within the United States Congress and many state legislatures. The predominant sentiment is that regulation is inevitable and only the timing and method of regulation is not presently known. The two primary methods of regulation are either a carbon tax imposed on emissions of CO_2 or some form of a cap and trade system with CO_2 emission allowances comparable to what presently exists for SO_2 and NO_X emissions.

Since the preparation of the Initial Feasibility Study, there has been additional new proposed legislation introduced in the Senate to limit CO_2 emissions. The proposed bills apply to a broad spectrum of industry sectors, including the electric utility industry. In addition to new proposed legislation that would address CO_2 emissions, there have been numerous recent reports prepared by academic, research, and industry organizations that have investigated technologies, incentives and costs to address reductions in GHG emissions, including CO_2, and carbon capture and storage capabilities at coal-fired electric generation plants and other industrial facilities.

At this time, there does not appear to be a consensus as to what the level of future regulation of emissions will be, or the costs associated with that regulation, but any such costs would impact the Project and the electric market.

Emissions Allowance Price Projections

In the Initial Feasibility Study, a carbon tax ranging between \$5/ton to \$15/ton (in 2006 dollars) was assumed to be in place beginning between 2012 and 2018. Higher CO_2 emissions cost levels will impact the AMPGS Project as well as the entire electric utility market. To demonstrate the potential impact of higher CO_2 emissions cost levels, a sensitivity case was prepared and is presented herein. This higher CO_2 emissions cost sensitivity case was based on projections presented in testimony by R. W. Beck during the Ohio Power Siting Board ("OPSB") hearing on January 4, 2008 associated with AMP-Ohio's application for Certificate of Environmental Compatibility and Need for AMPGS. The range of CO_2 emission values used in the sensitivity case was based on those prepared by Synapse Energy Economics and presented by David Schlissel in his testimony at the OPSB hearing on December 18, 2007. While we have used these CO_2 values for this sensitivity case, R. W. Beck and AMP-Ohio are not endorsing these values since there is considerable uncertainty with respect to the future regulation of CO_2 emissions and the emission allowance values that may result from such regulations.

Projections of allowance costs for SO_2 and NO_X are based on EPA estimates and R. W. Beck's proprietary model that projects the marginal cost of pollutant reductions to comply with the Acid Rain and CAIR regulations. Projections of allowance costs for Hg are based on EPA estimates and R. W. Beck's data base of mercury control costs for compliance with CAMR. The actual price of allowances in the future will be market dependent and could be lower or higher than the cost estimates herein.

Two sets of projected operating results have been prepared for the AMPGS Project to reflect the CO_2 emissions cost levels used for the Initial Feasibility Study, referred to as the Base Case, and to reflect the higher CO_2 costs in the Sensitivity Case, as discussed above. The NO_X, SO_2 and Hg emission allowance values, which were used in both cases, and the Base Case and Sensitivity Case values for CO_2 emissions costs are set forth below in Table 6. As used in this Report, carbon tax refers generally to CO_2 emission costs or prices, and not a specific CO_2 tax (versus cap and trade) mechanism.

Table 6
Emissions Allowance Prices ($/ton)

Year	NO_X Ozone	NO_X Annual	SO_2	Hg[1]	Base Case CO_2[2]	Sensitivity Case CO_2 [3]
2013	2,101	1,283	1,255	38.7	3.38	13.19
2014	2,250	1,368	1,284	41.7	5.19	15 95
2015	2,409	1,459	1,328	44.7	7.08	18.83
2016	2,581	1,555	1,404	48.5	9.06	21.83
2017	2,765	1,657	1,503	52.5	11.14	24.96
2018	2,962	1,766	1,547	56.7	13.29	28.22
2019	3,172	1,883	1,586	61.0	13.61	31.62
2020	3,397	2,007	1,635	65.4	13.94	35.16
2021	3,638	2,140	1,677	68.4	14.27	37.41
2022	3,897	2,281	1,734	71.5	14.62	39.74
2023	4,174	2,431	1,803	74.6	14.97	42.16
2024	4,470	2,592	1,876	77.9	15.32	44.67
2025	4,788	2,763	1,969	81.4	15.69	47 28
2026	5,129	2,945	2,029	85.0	16.07	49.97
2027	5,299	3,043	2,096	88 8	16.46	52.77
2028	5,475	3,144	2,166	92.7	16.85	53.99
2029	5,657	3,249	2,238	96.9	17.25	55.23
2030	5,845	3,357	2,312	101.2	17.67	56 50
2031	6,039	3,468	2,389	105.7	18.09	57.80
2032	6,240	3,583	2,468	110.4	18.53	59.13

[1] Cost expressed in million $/ton.

[2] The CO_2 expected values reflect the probability that CO_2 will be in place that year with assumed probabilities of 14.3% in 2012, 28.6% in 2013, 42.9% in 2014, 57.1% in 2015, 71.4% in 2016, 85.7% in 2017, and 100% in 2018 and thereafter.

[3] Based on projections prepared by Synapse Energy Economics and presented by David Schlissel in his testimony before the Ohio Power Siting Board on December 18, 2007 associated with AMP-Ohio's application for Certificate of Environmental Compatibility and Need for AMPGS.

A projection of the emissions allowance costs under the Base Case associated with the AMPGS Project is shown in Attachment 2.

Status of Permits and Licenses Required

The Project must be constructed and operated in accordance with applicable environmental laws, regulations, policies, guidelines, codes and standards. Table 7 identifies the key permits and approvals required for the construction and operation of the Project. Based on our review, we are of the opinion that AMP-Ohio has identified the major permits and approvals necessary for the construction and operation of the Project. AMP-Ohio has applied for the key permits and approvals required to construct and operate the Project.

Table 7
Status of Key Permits and Approvals for Construction and Operation of the Project

	Responsible Agency	Status	Comments
Federal			
Spill Prevention Control and Countermeasure ("SPCC") Plan	United States Environmental Agency ("USEPA")	To be prepared prior to start up	Required as per 40 CFR 112, Oil Pollution Prevention regulations, if the Project stores more than 1320 gallons of oil at the site (including electrical transformer oil)
Hazardous Waste Identification Number	USEPA/Ohio Environmental Protection Agency ("OEPA")	To be obtained prior to start up	Required for handling, management and disposal of hazardous wastes
Rivers and Harbors Act Section 10 and Clean Water Act Section 404 Permit	United States Corps of Engineers ("COE")	Application submitted May 2007	Required for dredge and fill activities in waters of the United States. A Section 7 Biological Opinion will be required from the United States Fish and Wildlife Service
Notice of Construction or Alteration	Federal Aviation Administration	FAA Study Request submitted September 2007; FAA approval received pending public comments to be final, March 2008	Required for tall structures (i.e., stacks and cranes)
State			
Certificate of Environmental Compatibility and Public Need for Plant	Ohio Power Siting Board ("OPSB")	Application submitted May 2007. OPSB hearings completed January 2008	Required for site approval under state law
Certificate of Environmental Compatibility and Public Need for Transmission	OPSB	Application submitted October 2007. Application deemed complete by OPSB in December 2007	Required for transmission line approval under State law.

	Responsible Agency	Status	Comments
Permit to Install ("PTI")/ Prevention Of Significant Deterioration ("PSD")	OEPA	Application submitted May 2006. Draft Permit noticed September 2007.	Required for an air emission source. Sets forth air emission limits, monitoring, testing, reporting and record-keeping requirements
Permit			
Title V Permit to Operate	OEPA	Application shall be submitted within one year after start of operation	Will consolidate all air permit requirements
Title IV Acid Rain Permit	OEPA	Must be applied for 24 months prior to start of operation	Required for compliance with Acid Rain Provisions of the Clean Air Act Amendments of 1990. Requires the Project to hold SO_2 allowances to cover its annual SO_2 emissions. NO_X emission limitations are also set forth in the permit
National Pollutant Discharge Elimination System ("NPDES") Permit	OEPA	Application submitted May 2007	Required for wastewater discharges, including stormwater, from the Project. Sets forth wastewater effluent limitations, monitoring, testing, reporting, and record-keeping requirements
Section 401 Water Quality Certificate	OEPA	Application submitted May 2007	Required to demonstrate no long-term and short-term impacts on water quality. Also, compliance is required with the Antidegradation Rule revised October 1997 and May 1998
General NPDES for Construction Activities	OEPA	To be obtained prior to initiation of construction	Required for stormwater management during construction activities
Landfill PTI	OEPA	Application submitted May 2007	Required for the development of landfill used to dispose of solid waste (fly ash and bottom ash)
Local			
Local Permits and Approvals	Meigs County	Approvals to be secured by EPC contractor	

Required Transmission Services

To deliver the output of the AMPGS Project, AMP-Ohio must: (i) interconnect with PJM[4] through PJM's generator interconnection process as a Capacity Resource; (ii) obtain firm point-to-point transmission service under the PJM Open Access Transmission Tariff ("PJM OATT") to deliver the Project output (or a portion thereof) to the MISO[5] border for those Participants that are located within MISO; and (iii) obtain transmission in MISO from the PJM border for those participants that are located within MISO. As of the date of this Report, AMP-Ohio is in the process of taking the necessary steps to obtain these services.

Studies conducted as of the date of this Report by PJM indicate that the direct interconnection facilities for the Project totaling approximately $[redacted] include the construction of a double-circuit 345 kV transmission line from the Project site to an interconnection point at an existing transmission line located approximately five (5) miles from the Project site. In addition, interconnection service requires the construction of approximately [redacted] in transmission upgrades to the existing transmission system. These costs have been included in the capital costs of the Project. There is a schedule risk related to the time it will take to go through the interconnection process and construct the necessary transmission upgrades. Most of the required upgrades are estimated to take 12 months; however, some projects could take longer due to equipment lead times.

The System Impact Study conducted by PJM also identified certain conditions under which the plant output could be curtailed to 0 MW. One of these conditions is the outage of a transformer, and a failure of the transformer could mean a long outage (multiple months) for both the transformer and AMPGS. We assumed a [redacted] cost to purchase a backup transformer to mitigate this risk and have included this cost in the capital cost of the Project.

Point-to-point transmission service to MISO and for transmission service within MISO may require transmission upgrades. Transmission studies by MISO and PJM will determine any necessary transmission upgrade costs to provide the requested service. AMP-Ohio will need to submit the transmission requests to MISO and PJM. At AMP-Ohio's request, R. W. Beck has performed load flow studies to estimate the potential transmission upgrade costs to provide point-to-point transmission service from the Project to the participants in MISO. The results of the study indicated a

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[4] PJM Interconnection (PJM) is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity over thirteen states in the northeastern United States. PJM provides open access to transmission markets, long-term transmission planning and reliability, and operates a wholesale energy market. PJM's energy markets operations include Day-Ahead, Real-Time and Financial Transmission Rights markets. PJM also operates capacity markets.

[5] The Midwest Independent Transmission System Operator, Inc. (MISO) is a non-profit, member-based organization that provides open access to transmission markets, long-term transmission planning, and transparent prices and manages the security-constrained economic dispatch of generation over its fifteen state territory. MISO's energy markets operations include Day-Ahead, Real-Time and Financial Transmission Rights markets.

range of [redacted] to [redacted] for upgrade costs. For the purpose of this Report, [redacted] has been included in the capital costs of the Project for estimated upgrades associated with the point-to-point transmission requests in MISO. As with the interconnection upgrades, there is also a schedule risk related to the time it will take to go through the transmission service request process and construct the necessary transmission upgrades. If any required upgrades are not completed on time. the Participants in MISO would still be able to make use of the AMPGS by selling capacity and energy into PJM and using the revenue to offset their MISO charges.

Another risk that all power supply alternatives face is pricing differentials between the point of delivery and the point of receipt. In a Locational Marginal Pricing ("LMP") market such as PJM and MISO, this "basis differential" risk consists of three parts: (i) energy market basis differentials caused by congestion and marginal losses; (ii) capacity market basis differentials due to implementation of a location based capacity market which PJM implemented June 1, 2007; and (iii) potential pancaked charges (the Project will bear charges in the form of RTO administration fees and ancillary services charges for the point-to-point service to the PJM/MISO border based on the existing PJM and MISO rate design). Additionally the Project could bear wheeling charges based on any FERC approved transmission cost allocation methodology for new transmission facilities. While these risks are not expected to be as significant as the risks of new transmission upgrades, conditions can change over time.

Projected Operating Results of the AMPGS Project

R. W. Beck has prepared projections of the net power costs that will be the basis of the charges to the Participants for the AMPGS Project ("Projected Operating Results") for the period 2013 through 2032. These Projected Operating Results reflect 100 percent of the costs of the AMPGS Project[6] and are consistent with our understanding of the terms and conditions of the Power Sales Contract and Master Trust Indenture, both dated as of November 2007. The Projected Operating Results set forth the costs that comprise the Postage Stamp Rate ("PSR") as defined in the Power Sales Contract. The PSR is a uniform rate that will apply to all of the Participants. The Projected Operating Results also include a projection of the activities in the funds that are defined in the Master Trust Indenture and Power Sales Contracts.

In preparing the Projected Operating Results and other economic analysis included in this Report, we have assumed that there will be a carbon tax imposed on emissions of CO_2 or some form of a cap and trade system with CO_2 emission allowances comparable to what presently exists for SO_2 and NO_X emissions.

To demonstrate the potential impact of higher CO_2 emissions cost levels, we have prepared a Base Case and Sensitivity Case under the two assumed levels of CO_2 emission costs shown in Table 6 herein.

[6] Because CVEC will own approximately 2.5 percent of the AMPGS Project, the AMP-Ohio ownership share will be approximately 97.5 percent which is less than 100 percent. However, we for purposes of the projections set forth here we have reflected 100 percent of the costs and output of the AMPGS Project.

Base Case Results

Projected Operating Results under the Base Case are set forth in Attachment 3 and are based on the principal considerations and assumptions that are discussed in a following section of this Report. Table 8 below provides a summary of the Base Case Projected Operating Results for the selected years shown.

Table 8
Summary of AMPGS Projected Operating Results (Base Case)

	Description		2015	2020	2025	2030	2032
	Revenues:						
1	Participant Revenues [1]	$000	$491,328	$579,175	$637,767	$704,061	$733,525
2	Other Revenues [2]	$000	46,284	50,786	53,235	55,863	57,279
3	*Total Revenues*	$000	$537,611	$629,960	$691,002	$759,924	$790,804
	Operating Expenses:						
4	Fixed Operating Costs [3]	$000	$44,376	$48,933	$54,039	$59,760	$62,237
	Variable Operating Costs:						
5	Fuel Costs	$000	164,431	190,794	221,388	256,894	272,644
6	Non-Fuel Variable Operating Costs [4]	$000	87,620	144,062	165,242	188,002	197,822
7	*Variable Operating Costs*	$000	252,051	334,856	386,630	444,896	470,466
8	Replacement Power [5]	$000	23,077	27,681	31,590	36,239	38,446
9	*Total Operating Expenses*	$000	319,505	411,471	472,259	540,895	571,149
10	Net Revenues [6]	$000	$218,107	$218,490	$218,743	$219,029	$219,655
11	Deposit to Working Capital Reserve Account [7]	$000	1,331	1,714	1,968	2,254	2,380
12	Debt Service [8]	$000	197,068	197,068	197,068	197,068	197,068
13	Deposit to Reserve & Contingency Fund [9]	$000	19,707	19,707	19,707	19,707	20,207
14	Total Revenue Requirements	$000	$537,611	$629,960	$691,002	$759,924	$790,804
	Unit Operation:						
15	Net Capacity	MW	960.0	960.0	960.0	960.0	960 0
16	Gross Energy	GWh	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2
17	Plus. Replacement Energy Purchases	GWh	303.0	303.0	303.0	303.0	303.0
18	Less: Surplus Energy Sales [10]	GWh	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)
19	Net Energy	GWh	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2
20	Capacity Factor	%	85.0%	85.0%	85.0%	85.0%	85.0%
	Average Project Costs (with CO2):						
21	*Net Fixed Costs*	*$/KW-mo*	20.77	21.21	21.80	22.50	22.83
22	*Net Non-Fuel Variable Costs*	*$/MWh*	12.26	20.15	23.12	26.30	27.67
23	*Net Fuel Costs*	*$/MWh*	22.37	25.96	30 12	34.96	37.10
24	*Average Costs to Participants [11]*	*$/MWh*	68.73	81.02	89.22	98.50	102.62
	Average Project Costs (w/o CO2):						
25	*Average Costs to Participants [12]*	*$/MWh*	61 70	67.17	73.63	80.94	84.21

[1] Participant Revenues are equal to Total Revenue Requirements (line 14) less other revenues (line 2).
[2] Includes interest earnings, short-term market sales, transfers from R&C Fund and other Project revenues (if any).
[3] Includes fixed O&M, transmission costs, insurance, property taxes, AMP-Ohio A&G costs and bank and trustee fees.
[4] Includes environmental costs (including estimated CO_2 and mercury emissions costs), variable O&M, Powerspan costs and credits for fertilizer sales.
[5] Estimated cost of replacement power purchased from the short-term energy market to replace AMPGS during scheduled and forced outages.
[6] Equal to Total Revenues (line 3) less Total Operating Expenses (line 29).
[7] Deposit to Working Capital Reserve Account equal to 5% of the total monthly Operating Expenses.
[8] Estimated debt service on Bonds projected to be issued to finance the total cost of construction of the AMPGS Project
[9] Deposit to Renewal & Replacement Account equal to the greater of 10% of Debt Service or the estimated renewals & replacements for such year.
[10] The quantity of short-term market energy sales that are expected to be in excess of the energy required under the Power Sales Contracts with the Participants.
[11] Net Project costs with CO_2 emissions costs
[12] Net Project costs without CO_2 emissions costs

Lines 1 through 7 of Attachment 3 present the projected revenues from the Project. Participant revenues, shown on Line 1, represent the annual cost of the Project to the Participants, net of other revenues available to reduce the Participant payments. The Participant revenues were developed by subtracting the other revenues (shown on lines 2-6 of Attachment 3) from the Total Revenue Requirements (shown on line 45 of Attachment 3).

Lines 8 through 28 of Attachment 3 present the projected operating costs of the Project. Lines 8 through 14 contain the fixed operating costs, Lines 15 through 23 contain the variable operating costs, and Lines 24 through 27 contain the cost of purchasing replacement power.

Lines 31 through 35 of Attachment 3 present the projected debt service associated with the Project. For the Projected Operating Results, we assumed that AMP-Ohio would finance the total cost of construction of the Project by issuing bonds. We assumed that 20 percent of the bonds would be issued as variable rate debt and 80 percent would be issued as fixed rate debt. Additionally, we assumed level debt service payments on the bonds for a 40 year period from 2014 through 2053.

Total revenue requirements shown on line 45 of Attachment 3 were computed by summing total operating expenses, the annual deposit to the Working Capital Reserve Account, the total debt service requirement, and the total annual deposit to the Reserve and Contingency Fund.

The development of the average AMPGS Project costs in $/MWh is shown on lines 45 through 59 of Attachment 3. The major components of the average annual Project costs are shown below in Figure 3. Net debt service, which represents approximately 32 percent of the total costs, equals the total debt service payments less interest earnings. Fuel cost represents approximately 34 percent of the total costs and includes the cost of coal purchases and coal transportation costs. Assuming the Base Case CO_2 values, CO_2 costs make up approximately 16 percent of the total costs and assume that a CO_2 tax or allowance program would be put in place sometime during the period 2012-2018. Other environmental costs represent approximately 4 percent of the total costs and include emission costs and/or allowance costs related to SO_2, NO_x, and Hg. Other net operating costs include all other operating costs (net of other revenues) and represent approximately 14 percent of the total costs.

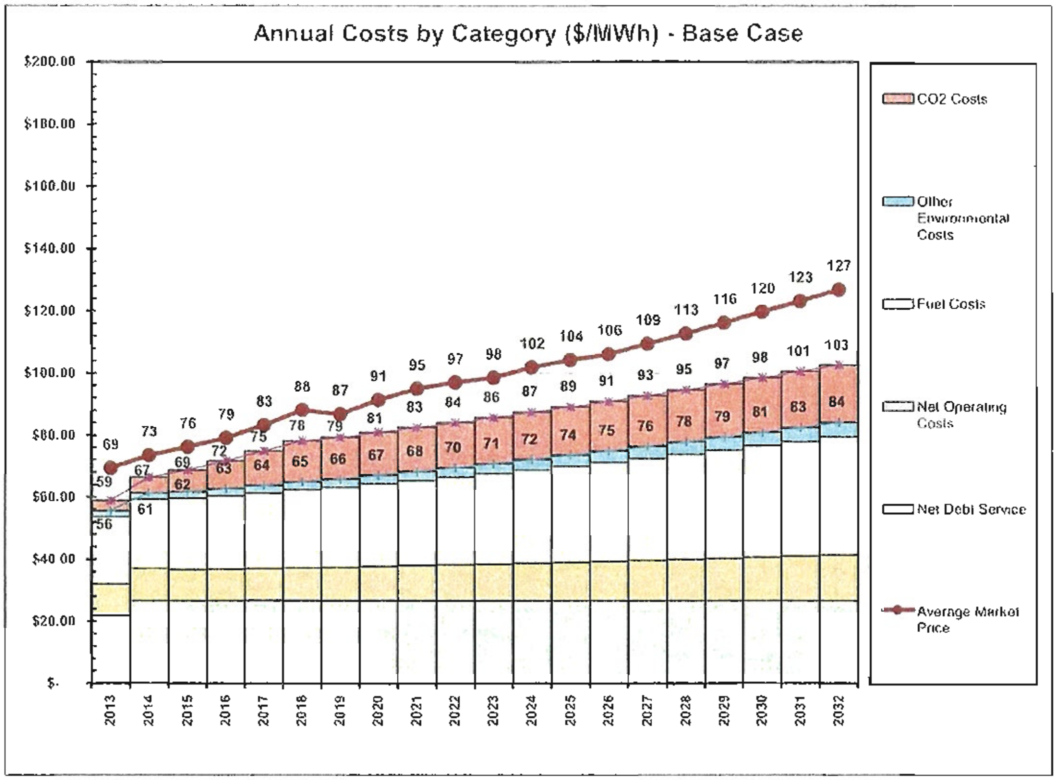

Figure 3 – Base Case - Projected Annual Power Costs by Category ($/MWh)

We have prepared updated projections of market prices for each of the regions in which the Participants are located over the period 2008 through 2027. The projected market prices were based on, among other things, the estimated cost of future generic coal plants, combined cycle plants and combustion turbine plants that are assumed to be installed in the future to supply projected power requirements. The estimated capital costs and operating costs of the generic power plants are based on our database of costs for similar type power plants across the country adjusted for market and economic environment conditions in the region where the AMPGS will be located.

As shown in Figure 3 above, the projected average annual costs of the AMPGS Project under the Base Case are estimated to be lower than the projected market prices in the region where AMPGS will be located.

High CO_2 Sensitivity Case Results

To demonstrate the potential impact of higher CO_2 emissions cost levels, a sensitivity case of the projected average annual cost of the AMPGS Project and the projected market prices was prepared based on the assumed higher CO_2 emissions cost levels shown in Table 6. The range of CO_2 emission values used in the Sensitivity Case was based on those prepared by Synapse Energy Economics and presented by David Schlissel in his testimony at the OPSB hearing on December 18, 2007. While we have used these CO_2 values for this sensitivity case, R. W. Beck and AMP-Ohio are not endorsing these values since there is considerable uncertainty with respect to the future regulation of CO_2 emissions and the emission allowance values that may result from such regulations. The summary of the results of the Sensitivity Case is shown in Figure 4 below.

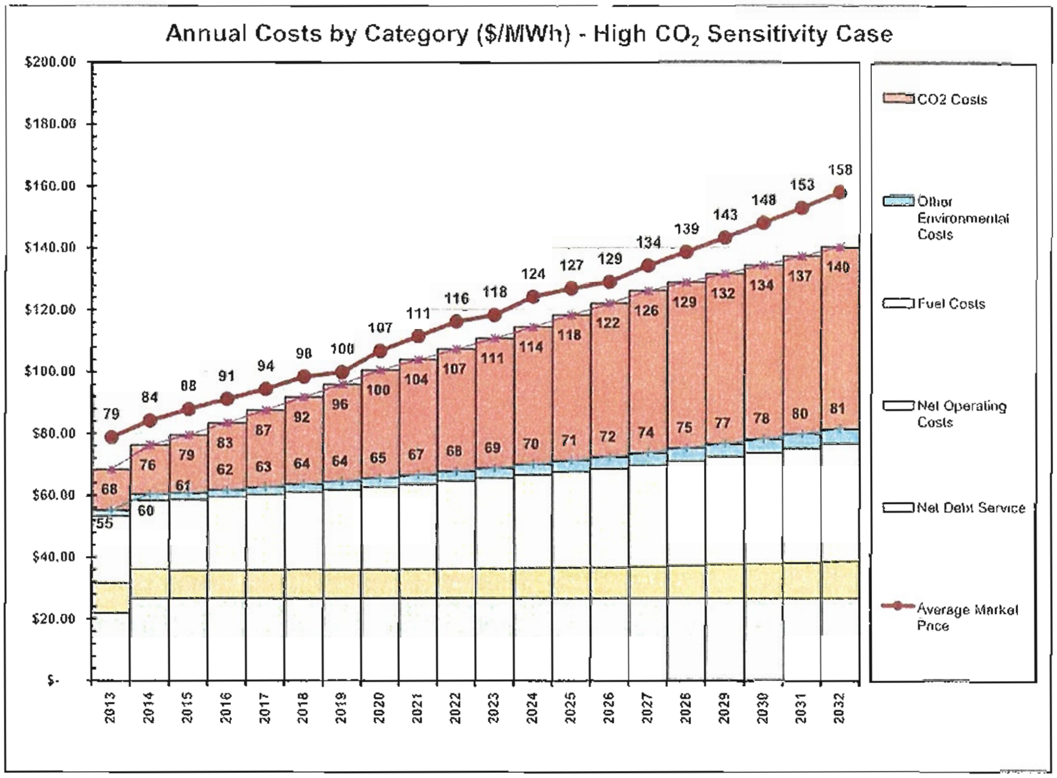

Figure 4 – High CO_2 Sensitivity Case - Projected Annual Power Costs by Category ($/MWh)

As shown in Figure 4 above, the projected average annual costs of the AMPGS Project under the Sensitivity Case are estimated to be lower than the projected market prices in the region where AMPGS will be located.

Analysis of Potential Project Risks

To address the potential risks of the AMPGS Project, as part of the Initial Feasibility Study, a qualitative risk assessment and a quantitative risk assessment were prepared.

The risks identified during the qualitative risk assessment and considered to be moderate to high risks included (i) developmental and construction cost risks related to potential delays, cost overruns and availability of human craft resources; (ii) price risks related to volatility in coal prices, fertilizer prices and SO_2, NO_X allowance prices and (iii) regulatory risks related to more stringent environmental laws associated with CO_2. All other risks were considered to be low to moderate.

The quantitative risk analysis took into consideration the risks that were identified under qualitative risk analysis that could have a substantial impact on future power costs. These risk variables include the following:

- price risks including: coal price volatility, market price volatility (effects surplus energy sales), load forecast (effects surplus energy sales) and fertilizer price volatility (revenues from Powerspan scrubber);
- construction cost risks including: potential increases in construction costs and potential delays in on-line date;
- interest rate risks including: short-term variable rate volatility and long-term fixed rates fluctuations; and
- environmental cost risks including: SO_2 and NOx allowance costs and potential CO_2 and Mercury emission costs.

A description of the assumptions and the development of the risk variables used in the risk analysis are set forth in Appendix A. Based on the volatility defined for each risk variable, stochastic modeling and statistical analysis techniques were used to analyze how in aggregate these risks could impact AMP-Ohio's projected net Participant power costs. The results of the risk analysis include a projection of the potential range (with a certain confidence level) and expected value of the annual net cost to the Participants for the AMPGS Project.

Figure 5, below, provides a graphical representation of the results of the probabilistic analysis, in terms of the average annual AMPGS Project costs (in \$/MWh), for an expected value and a 90% confidence interval (area between the 5% and 95% confidence estimate) under the Base Case assumptions. From a risk perspective, the level of uncertainty or volatility in each case is proportional to the size of the range between the 5% and 95% estimates. The band between the 5% and 95% estimates represents the 90% confidence interval; in other words, the average annual AMPGS Project costs would be expected to be within this band 90% of the time.

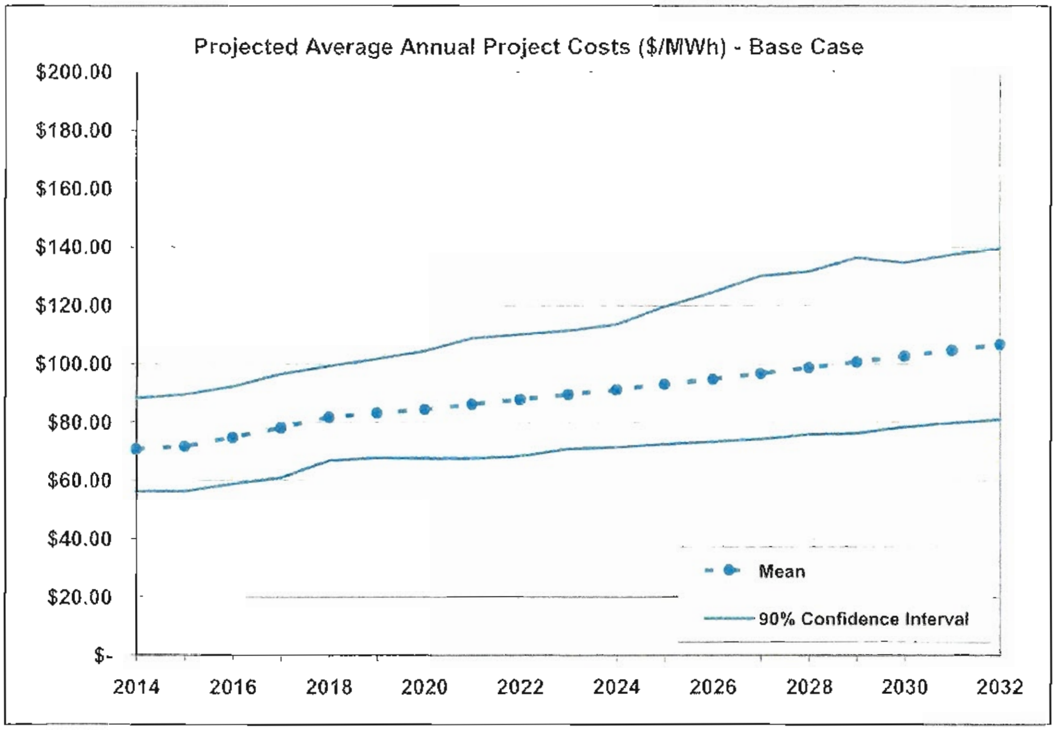

Figure 5 – Base Case Average Annual AMPGS Project Costs at 90% Confidence Interval ($/MWh)

The projected average annual AMPGS Project costs under the Base Case assumptions are projected to be approximately $85.72 / MWh on an average annual levelized[7] basis over the period 2013 through 2032. The projected uncertainty in future power costs as measured by the standard deviation ("STD") in the projected average annual levelized power costs is estimated to be approximately $10.74 / MWh (or 12.5%).

The major risk factors that cause the uncertainty in power costs and their contribution to the STD under the Base Case are shown in Table 9 below.

[7] The average annual levelized AMPGS Project costs where developed by computing the net present value of the net costs divided by the net present value of the net energy over the period 2013 through 2032.

Table 9
Base Case - Risk Factors Contribution to STD

Description	Contribution to STD	
	$/MWh	% of Total
Coal Prices	3.48	32%
Urea and Ammonium Sulfate Prices	1.91	18%
CO_2 Costs	2.43	23%
Construction Cost, Schedule, and Interest Rates	2.44	23%
Surplus & Replacement Energy Costs	0.36	3%
SO_2, NO_x, and Mercury Costs	0.12	1%
Total	10.74	100%

As shown above, the uncertainty in the projected average annual AMPGS Project costs is most influenced by coal prices, and also by CO_2 costs, urea and ammonium sulfate prices, and construction and financing cost uncertainty.

As previously discussed, there is considerable uncertainty with respect to the future regulation of CO_2 emissions and the emission allowance values that may result from such regulations. The range of CO_2 costs could be greater than the $5 to $15/ton range (expressed in 2006 dollars) assumed for the Base Case, and to the extent that CO_2 costs are higher, the relative contribution to STD would be greater, assuming all else is unchanged.

Obligations and Risks of Ownership

The ownership of the AMPGS Project will carry with it the obligations and attendant risks in such ownership. An important goal of AMP-Ohio in developing the contractual arrangements related to the AMPGS Project has been and will be to mitigate, to the extent possible, the risks of developing, constructing and owning a 960 MW coal plant. However, inherent in any ownership are risks that require recognition by AMP-Ohio and the potential Participants, and these risks could be substantial. The potential impact of risks have been discussed and analyzed herein. These analyses and discussions may not be all-inclusive. However, it should be pointed out that the impact of many of the risks which are now the responsibilities of investor-owned utilities or other wholesale providers supplying wholesale power to the Participants are or would be reflected in the rates charged to the Participants for power and energy, but usually at a higher cost of money than AMP-Ohio.

Principal Considerations and Assumptions

In the preparation of the studies and analyses set forth in this Report, we have made certain assumptions with respect to conditions that may occur in the future. While we believe these assumptions are reasonable for the purpose of this Report, they are dependent upon future events and actual conditions may differ from those assumed. In addition, we have used and relied upon certain information and assumptions provided to us by AMP-Ohio and others, including but not limited to information on fuel costs for the Project, interest rate assumptions, Participant information, preliminary Project design information prepared by other engineers, permit applications and supporting studies, and Project site information. While we believe the sources to be reliable, we have not independently verified the information and offer no assurances with respect thereto. To the extent that actual future conditions differ from those assumed herein, the actual results will vary from those forecast.

Section 9.2 of the Initial Feasibility Study lists the principal considerations and assumptions made by R. W. Beck in preparing the studies and analyses set forth in Initial Feasibility Study and rendering the initial findings and conclusions set forth in Section 9.3 of the Initial Feasibility Study.

The following principal considerations and assumptions have been restated and/or updated from those contained in the Initial Feasibility Study and have been relied on in rendering the conclusions set forth below.

1. General inflation was assumed to be 2.3 percent per year based on the consensus projections prepared by Blue Chip Economic Indicators for 4th quarter 2007.
2. Operating characteristics of the AMPGS Project were assumed to be as follows:
   a) The AMPGS Project would consist of two, coal-fired generating units with a net dependable capability of 480 MW for each unit, totaling 960 MW for the plant. The 960 MW rating reflects the projected summer capacity rating of the Project. The annual average capacity rating was projected to be 987 MW.
   b) The AMPGS Project would continue to be capable of a net demonstrated capability of 960 MW during the course of our analysis.
   c) The commercial operation date for AMPGS Project Unit 1 would occur in April 2013, and the commercial operation date for AMPGS Project Unit 2 would occur in October 2013. Such dates are based on the current Project schedule.
   d) The net plant heat rate estimates were provided by EPC Contractors in their proposals for a supercritical boiler design. Those estimates ranged from 8,900 Btu/KWh to 9,090 Btu/KWh. For purposes of long range performance assumptions, including an allowance for degradation over time of one percent, a generating unit heat rate of 8,990 Btu/KWh was assumed.

e) A four percent forced outage rate was assumed for the plant, and one month of scheduled maintenance for each unit was assumed for each year, which results in an overall average annual availability factor for the AMPGS Project of 88 percent.

f) The projected output of the AMPGS Project was based on a computer simulation of the future operations of generating units as they would operate in PJM. It was assumed that AMP-Ohio will fully dispatch and utilize the AMPGS Project in the PJM market and would purchase from the power market to provide replacement power when AMPGS is not available. The average annual capacity factor resulting from such simulations was approximately 85 percent. The estimated annual energy output was projected to average approximately 7,349,200 MWh per year.

3. The projected total construction cost of the AMPGS Project was estimated to be approximately $2.9 billion, as prepared by R. W. Beck in January 2008 and as discussed herein.

4. It was assumed that all costs associated with the AMPGS Project prior to the commercial operation dates of the two units would be funded through revenue bonds issued by AMP-Ohio beginning in 2008 and that AMP-Ohio would capitalize interest on such revenue bonds through July 1, 2013.

5. The projections of various elements of the Projected Operating Results set forth herein were based on the following interest earnings and interest rate assumptions:

a) Interest earnings rates on monies in the Revenue Fund, General Fund, the Reserve and Contingency Fund and Debt Service Account at an average rate of 3.75 percent.

b) Interest earnings rates on monies in the Reserve Fund at an average rate of 5.25 percent.

c) An average interest rate of 5.25 percent on fixed-rate bonds assumed to be issued in 2013.

d) An average interest rate of 3.75 percent on variable-rate bonds assumed to be issued during the construction period 2008-2012.

6. The principal installments and debt service schedules for each series of projected bonds were based upon the assumptions that:

a) Eighty percent of the future estimated debt to be issued from 2008 to 2013 to fund the total estimated cost of construction of the AMPGS Project would be issued as fixed-rate bonds, and the remaining twenty percent would be issued as variable-rate bonds.

b) A total of approximately $3.391 billion of future estimated debt would be required and issued from time to time over the period 2008 through 2013 to fund the total estimated cost of construction of the

AMPGS Project including the amounts required to fund interest during construction, reserves and issuance expenses.

c) Principal installments would begin in 2014 and debt service payments (principal and interest) would be based on level debt service over the 40 year period 2014 through 2053.

7. The projections of fuel costs were based on information provided by AMP-Ohio and assume that AMP-Ohio would purchase coal for the AMPGS Project from mines in Ohio and the Central Appalachian region, as described in the section entitled "Fuel and Transportation".

8. Non-fuel operation and maintenance costs for the AMPGS Project were estimated by R. W. Beck to reflect the normal range of costs for similar coal-fired plants as set forth in Attachment 2. The assumptions relating to other direct and indirect costs of the AMPGS Project are set forth in Attachment 2.

9. Environmental assumptions for the AMPGS Project, including emission rates, emission allowance costs, and carbon tax assumptions, were developed by R. W. Beck consistent with the Project permit applications and operating assumptions for the Project, as described in the section entitled "Environmental Considerations and Requirements".

10. Under the Base Case, a carbon tax of \$5/ton to \$15/ton (in 2006\$) is assumed to be in place beginning between 2012 and 2018. Under the Sensitivity Case, CO_2 emissions costs were based on projections presented in testimony by R. W. Beck during the OPSB hearing on January 4, 2008 associated with AMP-Ohio's application for Certificate of Environmental Compatibility and Need for AMPGS. The range of CO_2 emission values used in the sensitivity case was based on those prepared by Synapse Energy Economics and presented by David Schlissel in his testimony at the OPSB hearing on December 18, 2007. While we have used these CO_2 values for this sensitivity case, R. W. Beck and AMP-Ohio are not endorsing these values since there is considerable uncertainty with respect to the future regulation of CO_2 emissions and the emission allowance values that may result from such regulations.

11. The assumptions with respect to the Powerspan process were as follows:

a) Powerspan variable costs include the cost of urea, fly ash and bottom ash waste disposal, adjustments in auxiliary power consumption and steam consumption, adjustments in makeup water, cooling water, equipment air, natural gas, maintenance, labor and other fertilizer plant operating costs from typical limestone scrubbing costs included in variable O&M costs, mercury disposal, ammonium sulfate transportation and fertilizer revenues associated with the operation of Powerspan. These costs were assumed to escalate at the general rate of inflation except as noted in Attachment 2.

b) Urea costs were based on an assumed urea price in 2007 of \$269 per ton, escalating at the general rate of inflation thereafter.

c) Fertilizer revenues were based on an assumed price in 2007 of $173 per ton for solid fertilizer and $60 per ton for liquid fertilizer, escalating at the general rate of inflation thereafter.

12. It was assumed that all licenses, permits and approvals necessary to construct and operate the AMPGS Project would be issued on timely basis and any conditions set forth therein would not require reduced operation of, or increased costs to the AMPGS Project.

13. It was assumed that AMP-Ohio and the Participants would take the necessary actions to interconnect AMPGS with PJM and to obtain firm point-to-point transmission service under the PJM OATT to deliver the output of AMPGS to the MISO boarder for those Participants that are located within MISO.

14. It was assumed that AMP-Ohio, on behalf of the Participants, would take the necessary actions to modify the Participants' transmission service to designate AMPGS as a new Network Resource either in PJM or in MISO, depending on their location.

15. It was assumed that AMP-Ohio would successfully secure all contracts, permits, agreements, or other arrangements necessary to develop, construct, finance, and operate the AMPGS Project.

16. In our role as Owner's Engineer for the AMPGS Project, we have not determined the validity and enforceability of any contract, agreement, rule, or regulation applicable to the Project and its operations. However, for purposes of this Report, we have assumed that all contracts, agreements, rules, or regulations applicable to the AMPGS Project will be fully enforceable in accordance with their terms and that all parties will comply with the provisions of their respective agreements.

The power cost projections herein have been prepared based on the assumption that all contracts, agreements, statutes, rules and regulations (hereinafter described as "contractual and legal requirements") that have been relied upon by R. W. Beck in preparing these projections will be fully enforceable in accordance with their terms and conditions. We make no representations or warranties, and provide no opinion concerning the enforceability or legal interpretation of such contractual and legal requirements.

Initial Findings and Conclusions

For purposes of this Report, we have conducted an update to our initial engineering studies and reviews to consider the technical feasibility of the AMPGS Project and we have prepared an updated economic analysis for the Project over the forecast period 2013-2032.

Based upon such considerations and assumptions and upon the updated analyses and studies as summarized in this Report, which Report should be read in its entirety in conjunction with the following, we are of the opinion that:

1. Provided that on-going site investigations do no reveal anything that would prohibit construction, the site is suitable for the construction and operation of the AMPGS Project.

2. The proposed pulverized coal-fired steam electric plant technology to be incorporated in the AMPGS Project is a sound and proven method of electricity production.

3. The scale up of the Powerspan ECO-SO_2 process from the commercial demonstration unit to the size of the AMPGS Project is within technical feasibility given the types of equipment involved and the vendors' demonstrated experience with the equipment. However, it is not unreasonable to expect that issues not presently contemplated could arise as the full scale installation is designed, constructed and tested. We expect that such issues can be accommodated by adjustments in the field and/or modifications to the equipment. Provided true and meaningful "wrap" guarantees are obtained from the EPC/Process Contractor(s), such modifications and the associated financial responsibilities would be the responsibility of the EPC/Process Contractor(s).

4. Provided that the facility is designed, constructed and maintained as proposed, and the required renewals and replacements are made on a timely basis, the AMPGS Project should have a useful life of at least 40 years.

5. Proposed plans for design, construction and operation of the AMPGS Project are being developed in accordance with good engineering practices and generally-accepted industry practices.

6. Based on our review of the expected fuel quality and conceptual design information developed by S&L, an availability factor of 88 percent, an annual average capacity of 987 MW and a net heat rate of 8,990 Btu/kWh, assuming utilization of an eastern coal fuel blend with a supercritical boiler, are achievable.

7. The planned construction schedule with a duration of 48 months, preceded by an 8 to 9 month open book preliminary design phase, is reasonable for the AMPGS Project.

8. AMP-Ohio has identified the key permits and approvals required for construction and operation of the AMPGS Project, and has submitted permit applications to the appropriate regulatory agencies for such key permits and approvals.

9. The preliminary estimated total construction cost for the AMPGS Project of $2.9 billion was prepared in accordance with generally-accepted practices and methods and reflects equipment, material and labor market conditions in the region of the AMPGS Project as of the date of this Report. The cost is comparable to similar projects with which we are familiar.

10. The methodology for preparing the initial O&M cost estimate for the AMPGS Project and the estimated O&M costs that are reflected in the projected power costs of the AMPGS Project are reasonable for the proposed plant configuration and are comparable with similar projects with which we are familiar, after adjustment for incorporation of the Powerspan technology

11. It is presently estimated that an aggregate principal amount of bonds totaling approximately $3.391 billion will be required to be issued over the period 2008 through 2013 to pay for the cost of construction of the AMPGS Project, based on AMP-Ohio's proposed financing plan and the assumed bond interest rates and financing requirements. The approximate bond amount for an AMP-Ohio ownership share of 97.5 percent would be $3.306 billion.

12. The AMPGS Project can be interconnected to the PJM system at the interconnection location selected by AMP-Ohio, and the proposed contracted capacity can be delivered to the PJM Participants. In order for AMPGS Project capacity to be delivered to the MISO Participants, further transmission system upgrades may be required for firm transmission service. Based on a power flow studies prepared by R. W. Beck costs for potential transmission system upgrades have been included in the estimated interconnection costs to provide firm transmission service from the Project to the MISO Participants.

13. The AMPGS Project represents a reasonable cost long-term base-load power supply option for the AMPGS Project Participants.

14. AMP-Ohio recognizes that there are internal, market, and external risk events that could occur in the future and adversely impact the AMPGS Project. AMP-Ohio should be able to manage certain of those risks through prudent utility practices and implementation of the risk mitigation strategies that have been identified in the Initial Feasibility Study.

Attachment 1

Updated EPC Cost Estimate

R·W·BECK

Attachment 1

American Municipal Power Generating Station
Updated EPC Cost Estimate - Dollars in Millions

Line No.	Description	January 2008	Range (January 2008) Low	High
1	EPC Cost w/o Escalation, Contingency and Powerspan	[redacted] [1]	[redacted]	[redacted]
2	Powerspan	[redacted] [2]	[redacted]	[redacted]
3	Adjustments	[redacted] [3]	[redacted]	[redacted]
4	Subtotal	[redacted]	[redacted]	[redacted]
5	Contingency	[redacted] [4]	[redacted]	[redacted]
6	Escalation	[redacted] 5]	[redacted]	[redacted]
7	Total EPC Costs	[redacted]	[redacted]	[redacted]

Footnotes:

[1] Based on EPC proposal prices excluding air quality control system costs

[2] Estimate of Powerspan costs plus installed cost of bag house, ID fans and ductwork
Erection costs are assumed to be by EPC contractor for the bag house and Powerspan ECO-SO_2 process.

[3] Adjustments include additional costs for craft labor incentives

[4] Contingency allowance of approximatel[redacted]percent for EPC contract

[5] Adjusted escalation based on EPC proposal pricing

Attachment 2

Projected Operating Costs of AMPGS Plant – Base Case

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

Line No.	Description	2013 (1)	2014	2015	2016	2017	2018	2019	2020	2021	2022
	PERFORMANCE										
1	Capacity (MW) [2]	987	987	987	987	987	987	987	987	987	987
2	Capacity Factor (%)	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
3	Availability (%) [3]	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%
4	Energy Generation (GWh) [4]	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349
6	Net Plant Heat Rate (Btu/kWh) [5]	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990
7	Total Coal Consumption (BBtu) [6]	66,069	66,069	66,069	66,069	66,069	66,069	66,069	66,069	66,069	66,069
8	Heating Value of Coal (Btu/lb)	12,096	12,096	12,096	12,096	12,096	12,096	12,096	12,096	12,096	12,096
9	Coal Consumption (Tons x 10^3) [6]	2,731	2,731	2,731	2,731	2,731	2,731	2,731	2,731	2,731	2,731
10	Total NO_x Allowances Purchased (Tons) [7]	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276
11	Mercury Allowances Purchased (Tons) [8]	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628
12	SO_2 Allowances Purchased (Tons) [9]	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955
13	CO_2 Allowances Purchased (Tons x 10^3) [10]	7,102	7,102	7,102	7,102	7,102	7,102	7,102	7,102	7,102	7,102
14	Urea - SCR Consumption Rate (Tons) [11]	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386
15	Urea Consumption (Tons x 10^3) [12]	110	110	110	110	110	110	110	110	110	110
16	Ash Production (Tons x 10^3) [13]	332	332	332	332	332	332	332	332	332	332
	COMMODITY PRICES										
17	General Inflation (%) [14]	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
18	Coal Commodity Price ($/Ton) [15]	$54.65	56.29	57.98	59.72	61.51	63.35	65.25	67.21	69.23	71.30
19	Coal Transportation Price (Blended) ($/Ton) [16]	$2.08	2.16	2.23	2.31	2.39	2.48	2.56	2.65	2.74	2.84
20	All-In Average Coal Price Delivered ($/MMBtu)	$2.35	2.42	2.49	2.56	2.64	2.72	2.80	2.89	2.97	3.06
21	Urea Price ($/Ton) [17]	$308	315	323	330	338	345	353	362	370	378
22	SO_2 Allowances ($/Ton) [18]	$1,255	1,283	1,328	1,403	1,503	1,548	1,586	1,635	1,677	1,734
23	Mercury Allowances ($/Oz) [19]	$1,209	1,303	1,397	1,516	1,641	1,772	1,906	2,044	2,138	2,234
24	NO_x Allowances - Annual ($/Ton) [20]	$1,283	1,367	1,459	1,555	1,657	1,766	1,883	2,007	2,141	2,281
25	NO_x Allowances - Ozone ($/Ton) [21]	$2,101	2,250	2,409	2,581	2,765	2,962	3,172	3,397	3,639	3,895
26	CO_2 Allowances ($/Ton) [22]	$3.38	5.19	7.08	9.06	11.14	13.29	13.61	13.94	14.27	14.62
27	Activated Carbon Costs ($/Ton) [23]	$0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	OPERATING EXPENSES ($000) [24]										
28	Coal Commodity	$149,244	153,722	158,334	163,084	167,976	173,015	178,206	183,552	189,058	194,730
29	Coal Transportation	$5,692	$5,891	6,097	6,311	6,532	6,761	6,997	7,242	7,496	7,758
30	Auxiliary Fuel	$0	0	0	0	0	0	0	0	0	0
31	Start-Up Fuel	$0	0	0	0	0	0	0	0	0	0
	Fixed O&M										
32	Labor	$15,244	15,595	15,954	16,320	16,696	17,080	17,473	17,875	18,286	18,706
33	Operator G&A	$573	586	600	614	628	642	657	672	687	703
34	Other Fixed [25]	$16,047	16,416	16,793	17,179	17,575	17,979	18,392	18,815	19,248	19,691
35	Fixed O&M	$31,864	32,597	33,347	34,113	34,899	35,701	36,522	37,362	38,221	39,100
	Variable O&M										
36	Major Maintenance/Capital Expenses [26]	$13,118	13,420	13,728	14,044	14,367	14,698	15,036	15,382	15,735	16,097
37	Other Variable [27]	$9,198	9,410	9,626	9,847	10,074	10,306	10,543	10,785	11,033	11,287
38	Variable O&M	$22,316	22,830	23,354	23,891	24,441	25,004	25,579	26,167	26,768	27,384
	Emissions Allowances										
39	SO_2 Emissions Allowances	$6,217	6,360	6,579	6,954	7,445	7,669	7,858	8,100	8,308	8,591
40	Mercury Emissions Allowances	$2,429	2,617	2,806	3,044	3,295	3,559	3,829	4,105	4,293	4,488
41	NO_x Emissions Allowances - Annual	$2,966	3,162	3,374	3,597	3,831	4,083	4,354	4,642	4,950	5,274
42	NO_x Emissions Allowances - Ozone	$2,025	2,168	2,321	2,487	2,664	2,854	3,056	3,273	3,506	3,754
43	CO_2 Emissions Allowances	$24,006	36,868	50,288	64,359	79,138	94,356	96,686	98,991	101,351	103,853
44	Emissions Allowances	$37,643	51,175	65,368	80,441	96,373	112,521	115,783	119,111	122,408	125,960
45	Activated Carbon	$0	0	0	0	0	0	0	0	0	0
46	Urea - SCR	$1,661	1,699	1,738	1,778	1,819	1,861	1,903	1,947	1,992	2,038
	Powerspan										
47	Urea Cost ($/Yr)	$33,901	34,680	35,478	36,294	37,129	37,983	38,856	39,750	40,664	41,600
48	Waste Disposal Cost ($/Yr)	$3,809	3,896	3,986	4,078	4,171	4,267	4,366	4,466	4,569	4,674
49	Auxiliary Power ($/Yr)	($1,011)	(1,034)	(1,058)	(1,082)	(1,107)	(1,133)	(1,159)	(1,185)	(1,212)	(1,240)
50	Renewals, Replacements & Maintenance	($70)	(72)	(73)	(75)	(77)	(79)	(80)	(82)	(84)	(86)
51	Other Operating Costs	$12,665	12,957	13,255	13,559	13,871	14,190	14,517	14,851	15,192	15,541
52	Labor	$653	668	684	699	716	732	749	766	784	802
53	Transportation	$3,940	4,031	4,123	4,218	4,315	4,414	4,516	4,620	4,726	4,835
54	Solid Fertilizer Credit	($42,441)	(43,417)	(44,416)	(45,437)	(46,482)	(47,552)	(48,645)	(49,764)	(50,909)	(52,080)
55	Liquid Fertilizer Credit	($1,040)	(1,064)	(1,089)	(1,114)	(1,139)	(1,165)	(1,192)	(1,220)	(1,248)	(1,276)
56	Powerspan [28]	$10,406	10,645	10,890	11,140	11,397	11,659	11,927	12,201	12,482	12,769
57	Maintenance Parts and Services	$0	0	0	0	0	0	0	0	0	0
58	Water Treatment Chemicals	$0	0	0	0	0	0	0	0	0	0
59	Sales Tax on Commodities [29]	$0	0	0	0	0	0	0	0	0	0
60	Insurance and Property Tax [30]	$5,520	5,520	5,520	5,520	5,520	5,520	5,520	5,520	5,520	5,520
61	Corporate G&A [31]	$497	509	520	532	544	557	570	583	596	610
62	Total Operating Expenses	$264,842	284,588	305,167	326,810	349,501	372,598	383,007	393,685	404,541	415,868
	AVERAGE BUSBAR COST [32]										
63	Total Annual Costs	$264,842	284,588	305,167	326,810	349,501	372,598	383,007	393,685	404,541	415,868
64	Fixed Operating Cost ($000)	$37,881	38,626	39,387	40,165	40,963	41,778	42,612	43,465	44,337	45,230
65	Fixed Operating Cost ($/kW-yr) [33]	$38.38	39.13	39.91	40.69	41.50	42.33	43.17	44.04	44.92	45.83
66	Fixed Operating Cost ($/MWh)	$5.15	5.26	5.36	5.47	5.57	5.68	5.80	5.91	6.03	6.15
67	Total Variable Operating Cost ($000)	$226,961	245,962	265,780	286,645	308,538	330,820	340,395	350,220	360,204	370,638
68	Total Variable Operating Costs ($/MWh) [34]	$30.88	33.47	36.16	39.00	41.98	45.01	46.32	47.65	49.01	50.43
69	Fuel Cost ($/MWh)	$21.08	21.72	22.37	23.05	23.75	24.46	25.20	25.96	26.74	27.55
70	Non-Fuel Variable Operating Costs ($/MWh)	$9.80	11.75	13.79	15.95	18.24	20.55	21.12	21.69	22.27	22.88
74	AVG. OPERATING COST (with CO2) ($/MWh)	$36.04	38.72	41.52	44.47	47.56	50.70	52.12	53.57	55.05	56.59
75	AVG. OPERATING COST (without CO2) ($/MWh)	$32.77	33.71	34.68	35.71	36.79	37.86	38.95	40.10	41.25	42.46

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

Line No.	Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	PERFORMANCE										
1	Capacity (MW) [2]	987	987	987	987	987	987	987	987	987	987
2	Capacity Factor (%)	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
3	Availability (%) [3]	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%
4	Energy Generation (GWh) [4]	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349
6	Net Plant Heat Rate (Btu/kWh) [5]	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990
7	Total Coal Consumption (BBtu) [6]	66,069	66,069	66,069	66,069	66,069	66,069	66,069	66,069	66,069	66,069
8	Heating Value of Coal (Btu/lb)	12,096	12,096	12,096	12,096	12,096	12,096	12,096	12,096	12,096	12,096
9	Coal Consumption (Tons x 10^3) [6]	2,731	2,731	2,731	2,731	2,731	2,731	2,731	2,731	2,731	2,731
10	Total NO_x Allowances Purchased (Tons) [7]	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276
11	Mercury Allowances Purchased (Tons) [8]	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628	0.0628
12	SO_2 Allowances Purchased (Tons) [9]	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955
13	CO_2 Allowances Purchased (Tons x 10^3) [10]	7,102	7,102	7,102	7,102	7,102	7,102	7,102	7,102	7,102	7,102
14	Urea - SCR Consumption Rate (Tons) [11]	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386
15	Urea Consumption (Tons x 10^3) [12]	110	110	110	110	110	110	110	110	110	110
16	Ash Production (Tons x 10^3) [13]	332	332	332	332	332	332	332	332	332	332
	COMMODITY PRICES										
17	General Inflation (%) [14]	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
18	Coal Commodity Price ($/Ton) [15]	$73.44	75.65	77.91	80.25	82.66	85.14	87.69	90.32	93.03	95.82
19	Coal Transportation Price (Blended) ($/Ton) [16]	$2.94	3.04	3.15	3.26	3.37	3.49	3.61	3.74	3.87	4.01
20	All-In Average Coal Price Delivered ($/MMBtu)	$3.16	3.25	3.35	3.45	3.56	3.66	3.77	3.89	4.01	4.13
21	Urea Price ($/Ton) [17]	$387	396	405	414	424	434	444	454	464	475
22	SO_2 Allowances ($/Ton) [18]	$1,803	1,876	1,969	2,030	2,096	2,165	2,237	2,313	2,389	2,469
23	Mercury Allowances ($/Oz) [19]	$2,331	2,434	2,544	2,656	2,775	2,897	3,028	3,162	3,303	3,450
24	NO_x Allowances - Annual ($/Ton) [20]	$2,432	2,591	2,764	2,945	3,044	3,143	3,249	3,357	3,468	3,584
25	NO_x Allowances - Ozone ($/Ton) [21]	$4,174	4,471	4,788	5,129	5,299	5,475	5,657	5,846	6,040	6,240
26	CO_2 Allowances ($/Ton) [22]	$14.97	15.31	15.69	16.07	16.46	16.86	17.24	17.67	18.09	18.54
27	Activated Carbon Costs ($/Ton) [23]	$0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	OPERATING EXPENSES ($000) [24]										
28	Coal Commodity	$200,572	206,590	212,787	219,171	225,746	232,519	239,494	246,679	254,079	261,701
29	Coal Transportation	$8,030	8,310	8,601	8,902	9,213	9,536	9,870	10,215	10,573	10,943
30	Auxiliary Fuel	$0	0	0	0	0	0	0	0	0	0
31	Start-Up Fuel	$0	0	0	0	0	0	0	0	0	0
	Fixed O&M										
32	Labor	$19,136	19,577	20,027	20,487	20,959	21,441	21,934	22,438	22,954	23,482
33	Operator G&A	$719	736	753	770	788	806	825	844	863	883
34	Other Fixed [25]	$20,144	20,607	21,081	21,566	22,062	22,569	23,088	23,619	24,163	24,718
35	Fixed O&M	$39,999	40,920	41,861	42,823	43,809	44,816	45,847	46,901	47,980	49,083
	Variable O&M										
36	Major Maintenance/Capital Expenses [26]	$16,467	16,846	17,234	17,630	18,036	18,450	18,875	19,309	19,753	20,207
37	Other Variable [27]	$11,547	11,812	12,084	12,362	12,646	12,937	13,235	13,539	13,850	14,169
38	Variable O&M	$28,014	28,658	29,318	29,992	30,682	31,387	32,110	32,848	33,603	34,376
	Emissions Allowances										
39	SO_2 Emissions Allowances	$8,935	9,297	9,755	10,057	10,385	10,730	11,085	11,460	11,837	12,235
40	Mercury Emissions Allowances	$4,682	4,889	5,109	5,335	5,574	5,818	6,082	6,352	6,634	6,929
41	NO_X Emissions Allowances - Annual	$5,623	5,993	6,390	6,811	7,038	7,269	7,514	7,763	8,019	8,287
42	NO_X Emissions Allowances - Ozone	$4,022	4,308	4,613	4,942	5,106	5,275	5,450	5,632	5,820	6,013
43	CO_2 Emissions Allowances	$106,328	108,774	111,458	114,115	116,930	119,718	122,471	125,492	128,483	131,652
44	Emissions Allowances	$129,590	133,261	137,325	141,260	145,033	148,810	152,602	156,699	160,793	165,116
45	Activated Carbon	$0	0	0	0	0	0	0	0	0	0
46	Urea - SCR	$2,085	2,133	2,182	2,232	2,283	2,336	2,389	2,444	2,501	2,558
	Powerspan										
47	Urea Cost ($/Yr)	$42,556	43,535	44,537	45,561	46,609	47,681	48,777	49,899	51,047	52,221
48	Waste Disposal Cost ($/Yr)	$4,781	4,891	5,004	5,119	5,236	5,357	5,480	5,606	5,735	5,867
49	Auxiliary Power ($/Yr)	($1,269)	(1,298)	(1,328)	(1,358)	(1,390)	(1,422)	(1,454)	(1,488)	(1,522)	(1,557)
50	Renewals, Replacements & Maintenance	($88)	(90)	(92)	(94)	(96)	(99)	(101)	(103)	(106)	(108)
51	Other Operating Costs	$15,899	16,265	16,639	17,021	17,413	17,813	18,223	18,642	19,071	19,510
52	Labor	$820	839	858	878	898	919	940	962	984	1,006
53	Transportation	$4,946	5,060	5,176	5,295	5,417	5,541	5,669	5,799	5,933	6,069
54	Solid Fertilizer Credit	($53,277)	(54,503)	(55,756)	(57,039)	(58,351)	(59,693)	(61,066)	(62,470)	(63,907)	(65,377)
55	Liquid Fertilizer Credit	($1,306)	(1,336)	(1,366)	(1,398)	(1,430)	(1,463)	(1,497)	(1,531)	(1,566)	(1,602)
56	Powerspan [28]	$13,063	13,363	13,670	13,985	14,306	14,635	14,972	15,316	15,669	16,029
57	Maintenance Parts and Services	$0	0	0	0	0	0	0	0	0	0
58	Water Treatment Chemicals	$0	0	0	0	0	0	0	0	0	0
59	Sales Tax on Commodities [29]	$0	0	0	0	0	0	0	0	0	0
60	Insurance and Property Tax [30]	$5,520	5,520	5,520	5,520	5,520	5,520	5,520	5,520	5,520	5,520
61	Corporate G&A [31]	$624	638	653	668	683	699	715	732	748	766
62	Total Operating Expenses	$427,497	439,393	451,917	464,553	477,275	490,259	503,519	517,355	531,466	546,093
	AVERAGE BUSBAR COST [32]										
63	Total Annual Costs	$427,497	439,393	451,917	464,553	477,275	490,259	503,519	517,355	531,466	546,093
64	Fixed Operating Cost ($000)	$46,143	47,078	48,034	49,011	50,012	51,035	52,082	53,153	54,248	55,369
65	Fixed Operating Cost ($/kW-yr) [33]	$46.75	47.70	48.67	49.66	50.67	51.71	52.77	53.85	54.96	56.10
66	Fixed Operating Cost ($/MWh)	$6.28	6.41	6.54	6.67	6.81	6.94	7.09	7.23	7.38	7.53
67	Total Variable Operating Cost ($000)	$381,354	392,315	403,883	415,542	427,263	439,224	451,437	464,202	477,218	490,724
68	Total Variable Operating Costs ($/MWh) [34]	$51.89	53.38	54.96	56.54	58.14	59.76	61.43	63.16	64.93	66.77
69	Fuel Cost ($/MWh)	$28.38	29.24	30.12	31.03	31.97	32.94	33.93	34.96	36.01	37.10
70	Non-Fuel Variable Operating Costs ($/MWh)	$23.51	24.14	24.83	25.51	26.17	26.83	27.50	28.21	28.92	29.67
74	AVG. OPERATING COST (with CO2) ($/MWh)	$58.17	59.79	61.49	63.21	64.94	66.71	68.51	70.40	72.32	74.31
75	AVG. OPERATING COST (without CO2) ($/MWh)	$43.70	44.99	46.33	47.68	49.03	50.42	51.85	53.32	54.83	56.39

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

NOTES:

[1] Assumed commercial operation date of January 1, 2013.

[2] Assumed net dependable capacity under normal operating conditions, including allowance for long-term degradation.

[3] Based on estimates provided by R. W. Beck for expected average annual maximum availability level. Includes provision for both forced and scheduled outages.

[4] Assumes Project is base-loaded and operated at full load whenever the plant is available.

[5] Net plant heat rate assumed to average 8,990 Btu/kWh, based on the estimates provided by the EPC Contractors in their proposals for a supercritical boiler design, including an annual allowance for plant degradation.

[6] Annual fuel consumption at the projected annual capacity factors and heat rates, assuming a higher heating value of the coal of 12,096 Btu/lb

[7] NO_x allowances that the Project is projected to purchase based on an assumed emissions rate of 0.07 lbs/MMBtu.

[8] Mercury allowances that the Project is projected to purchase based on an assumed emissions rate of $1.90x10^{-6}$ lbs/MMBtu.

[9] SO_2 allowances that the Project is projected to purchase based on an assumed emissions rate of 0.15 lbs/MMBtu.

[10] CO_2 allowances that the Project is projected to purchase based on an assumed emissions rate of 215 lbs/MMBtu.

[11] Annual quantity of urea required for operation of the SCR at the indicated capacity factors assuming an uncontrolled emission rate of 0.25 lbs/MMBtu and a controlled rate of 0.07 lbs/MMBtu and 2.12 percent sulfur in the fuel blend.

[12] Annual quantity of urea required for operation of the Powerspan Scrubber at the indicated capacity factors assuming 2.12 percent sulfur in the fuel blend.

[13] Annual quantity of bottom ash and fly ash produced, based on an ash content of the coal of 10.52 percent.

[14] Based on projections prepared by Blue Chip Economic Indicators.

[15] FOB price of coal as projected by AMP-Ohio's fuel consultant for the design coal blend for the AMPGS.

[16] Based on estimates provided by AMP-Ohio's fuel consultant and the design coal bend for the AMPGS

[17] Based on an assumed urea price in 2007 of $270 per ton, escalated at the general rate of inflation thereafter.

[18] SO_2 allowance costs assumed to be $1,094 per ton in 2006. Projections of allowance costs are based on EPA estimates and R W. Beck's proprietary model.

[19] Based on the mercury allowance costs reflected in Table 6 of this Report..

[20] Based on the NO_x annual allowance costs reflected in Table 6 of this Report.

[21] Based on the NO_x ozone season allowance costs reflected in Table 6 of this Report.

[22] A carbon tax is assumed to begin during the period 2012 to 2018 with a 28.6 percent probability of occurrence in 2012, increasing to 100 percent by 2018. Costs shown are based on the CO_2 annual allowance costs reflected in Table 6 of this Report.

[23] No carbon injection assumed for mercury control.

[24] O&M expenses estimated by R.W Beck to reflect the normal range of costs for similar coal-fired plants, equipped with conventional limestone scrubber systems, with which R.W. Beck is familiar These costs are assumed to escalate at the general rate of inflation except as noted.

[25] Additional fixed operations and maintenance expenses estimated by R.W. Beck. Includes projected costs for routine preventative maintenance performed during outages, plant support equipment and temporary labor, vehicle maintenance, structure and grounds maintenance and demand-related backfeed electric charges.

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

[26] Maintenance expenditures as estimated by R.W. Beck. Includes projected costs and capitalized expenditures for scheduled major overhauls that require an extended outage.

[27] Additional variable operations and maintenance expenses, estimated by R.W. Beck. Includes projected costs for routine scheduled maintenance performed during outages, raw and process water, sewage expenses, waste disposal, chemicals and gases, consumable materials and supplies and energy-related backfeed electric charges.

[28] Powerspan variable costs include urea, ash disposal, adjustments for auxiliary power consumption and steam consumption, adjustments for makeup water, cooling water, equipment air, natural gas, maintenance, labor and other fertilizer plant operating costs. Also included are costs for mercury disposal, ammonium sulfate transportation and fertilizer revenues associated with the operation of Powerspan. These costs are assumed to escalate at the general rate of inflation except as noted.

[29] Based on a sales rate of 0.0 percent applied to all Project equipment and materials which are tax exempt, coal commodity, auxiliary fuel, urea, ammonia, carbon and water treatment chemical costs.

[30] Based on $0.10 per $100 of the estimated gross plant value to be insured. Property taxes are currently estimated to be the same as insurance costs per year. Property taxes are estimated based on 0.10 percent of gross plant investment.

[31] Based on estimate provided by AMP Ohio, escalated thereafter by the general rate of inflation.

[32] Excludes costs associated with debt service.

[33] Fixed Operating Costs include labor, other fixed expenses, insurance, property taxes and general and administrative costs.

[34] Variable Operating Costs include coal, coal transportation, auxiliary fuel, emissions allowances, activated carbon, ash disposal, Powerspan, ammonia, water treatment chemicals, and other variable expenses.

Attachment 3

Projected Operating Results - Base Case

AMP-Ohio Generating Station
Projected Operating Results - Base Case

	Description		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	REVENUES:											
1	Participant Revenues [1]	$000	$210,683	$475 426	$491 328	$512,466	$535 145	$558,451	$567 787	$579,175	$590 361	$601 597
2	Interest Earnings [2]	$000	6 111	7,220	6,916	6,856	6,830	6,807	6,787	6,812	6,835	6,862
3	Short-term (Market) Sales [3]	$000	5,010	31,835	33,080	34,695	36,154	37,680	38 488	39,303	40 172	40,986
4	Other Project Revenues	$000	0	0	0	0	0	0	0	0	0	0
5	Transfers from R&C Fund [4]	$000	0	1,867	6,287	5,979	5,663	5,340	5,009	4,671	4 325	3,972
6	Other Receipts	$000	0	0	0	0	0	0	0	0	0	0
7	*Total Revenues [5]*	$000	$221,803	$516,348	$537,011	$559,995	$583,792	$608,277	$618,071	$629,960	$641,693	$653,417
	OPERATING EXPENSES [6]:											
	Fixed Operating Costs:											
8	Fixed O&M	$000	$15 932	$32,597	$33,347	$34,114	$34 898	$35 701	$36,622	$37,362	$38,221	$39,100
9	Insurance & Property Taxes [7]	$000	3,265	6,530	6,530	6,530	6,530	6,530	6,530	6,530	6 530	6,530
10	Transmission Costs [8]	$000	1,837	3,759	3,846	3,934	4,025	4,117	4,212	4,309	4 408	4,509
11	AMP-Ohio A&G Costs [7]	$000	500	512	523	535	548	560	573	586	600	614
12	Bank and Trustee Fees [7]	$000	125	128	131	134	137	140	143	147	150	153
13	Other Direct Project Costs	$000	0	0	0	0	0	0	0	0	0	0
14	*Fixed Operating Costs*	$000	$21,659	$43,525	$44,376	$45,246	$46,137	$47,048	$47 980	$48,933	$49,908	$50,906
	Variable Operating Costs:											
15	Fuel Costs	$000	$77,468	$159,613	$164,431	$169,395	$174,508	$179,776	$185,203	$190,794	$196,554	$202,488
16	SO_2 Emissions Costs	$000	3,109	6,362	6,581	6,957	7,448	7,666	7,859	8,102	8,310	8,592
17	NO_x Emissions Costs	$000	2,496	5,331	5,695	6,083	6,496	6,938	7 411	7,914	8,454	9,029
18	Hg Emissions Costs	$000	1,215	2,617	2,806	3,044	3,295	3,559	3,829	4 105	4,293	4,488
19	CO_2 Emissions Costs	$000	12,003	36,862	50,285	64,348	79,121	94,392	96,664	99,008	101,352	103,638
20	Variable O&M	$000	4,599	9,410	9,626	9,847	10,074	10,306	10,543	10,785	11,033	11,287
21	Gross Urea and Powerspan Costs	$000	27,774	56,825	58,132	59 469	60,837	62,236	63,668	65,132	66,630	68,163
22	Fertilizer Credits [9]	$000	(21,741)	(44,481)	(45,504)	(46,551)	(47,622)	(48,717)	(49,837)	(50,984)	(52,156)	(53,356)
23	*Variable Operating Costs*	$000	$106,923	$232,539	$252,051	$272,593	$294,157	$316,155	$325,338	$334,856	$344,470	$354,529
	Replacement Power [10]:											
24	Capacity Purchases	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Energy Purchases	$000	0	22,266	23,077	23,957	25,200	26,675	26,313	27,681	28,776	29,395
26	Transmission Costs	$000	0	0	0	0	0	0	0	0	0	0
27	*Total Replacement Power Purchases*	$000	$0	$22,266	$23,077	$23,957	$25,200	$26,675	$26,313	$27,681	$28,776	$29 395
28	*Total Operating Expenses*	$000	$128,582	$298,330	$319,505	$341,796	$365,494	$389,878	$399,631	$411,471	$423,154	$434,830
29	Net Revenues [11]	$000	$93,221	$218,018	$218 107	$218,199	$218,298	$218,400	$218,440	$218,490	$218,538	$218,587
30	Deposit to Working Capital Reserve Account [12	$000	$536	$1 243	$1 331	$1,424	$1,523	$1,624	$1,665	$1,714	$1,763	$1 812
	DEBT SERVICE:											
31	Principal	$000	$0	$28,549	$29,942	$31,404	$32,938	$34,548	$36,238	$38 014	$39,877	$41,833
32	Interest	$000	84,259	168,519	167 126	165,665	164,131	162,520	160,830	159,055	157,192	155,236
33	*Total Debt Service [13]*	$000	$84,259	$197 068	$197 068	$197,068	$197,068	$197,068	$197,068	$197 068	$197,068	$197,068
34	Other Debt Payments	$000	0	0	0	0	0	0	0	0	0	0
35	*Total Debt Service Requirement*	$000	$84,259	$197,068	$197 068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068
	RESERVE AND CONTINGENCY FUND (Deposits to R&C Sub Accounts):											
36	Overhaul Account	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Renewal and Replacement Account [14]	$000	8,426	19,707	19 707	19,707	19,707	19,707	19 707	19,707	19,707	19,707
38	Capital Improvements Account	$000	0	0	0	0	0	0	0	0	0	0
39	Rate Stabilization Account	$000	0	0	0	0	0	0	0	0	0	0
40	Environmental Improvement Account	$000	0	0	0	0	0	0	0	0	0	0
41	Other	$000	0	0	0	0	0	0	0	0	0	0
42	*Total R&C Fund*	$000	$8,426	$19,707	$19,707	$19,707	$19,707	$19,707	$19,707	$19,707	$19,707	$19,707
	Available for Transfer to General Account											
43	Net Revenues Available for Transfer to General Account [15]	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	Amounts Available from R&C Fund to Transfer to General Account [16]	$000	$1,867	$6,287	$5,979	$5,663	$5,340	$5,009	$4,671	$4,325	$3,972	$3,610
45	**Total Revenue Requirements [17]**	$000	$221,803	$516,348	$537,611	$559,995	$583,792	$608,277	$618,071	$629,960	$641,693	$653,417

	Description		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	AVERAGE PROJECT COSTS (with CO_2):											
46	Net Costs to Participants [18]	$000	$210,683	$475,426	$491,328	$512,466	$535,145	$558,451	$567,787	$579,175	$590,361	$601,597
47	- Net Fixed Costs	$000	$103,760	$242,887	$239 276	$239 873	$240,988	$242,296	$242 449	$244,319	$245,891	$247,068
48	- Net Non-Fuel Variable Costs	$000	$29,455	$72,926	$87,620	$103 198	$119,649	$136,379	$140,135	$144,062	$147,916	$152,041
49	Fuel Costs	$000	$77,468	$159,613	$164,431	$169 395	$174,508	$179,776	$185,203	$190,794	$196,554	$202,488
50	Net Capacity	MW	480.0	960 0	960.0	960 0	960.0	960.0	960.0	960.0	960.0	960.0
51	Gross Energy	GWh	3,674.6	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2
52	Plus. Replacement Energy Purchases [19]	GWh	0.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303 0	303 0
53	Less. Surplus Energy Sales [20]	GWh	(100.5)	(504.0)	(504.0)	(504 0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)
54	Net Energy	GWh	3,574 1	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7 148.2
55	Capacity Factor	%	85.0%	85.0%	85.0%	85 0%	85.0%	85 0%	85.0%	85.0%	85.0%	85.0%
56	*Net Fixed Costs*	*$/KW-mo*	18.01	21.08	20 77	20 82	20.92	21 03	21 05	21 21	21.34	21.45
57	*Net Non-Fuel Variable Costs*	*$/MWh*	8.24	10.20	12.26	14 44	16.74	19.08	19 60	20.15	20.69	21.27
58	*Net Fuel Costs*	*$/MWh*	21 08	21 72	22.37	23.05	23.75	24.46	25 20	25.96	26 74	27.55
59	*Average Costs to Participants [21]*	*$/MWh*	58.95	66 51	68 73	71.69	74.86	78 13	79 43	81 02	82.59	84.16
	AVERAGE PROJECT COSTS (w/o CO_2):											
60	*Average Costs to Participants [22]*	*$/MWh*	55.59	61 35	61 70	62 69	63.80	64 92	65.91	67 17	68.41	69.63
61	Average Postage Stamp Rate [23]	$000	$210,683	$475,426	$491,328	$512,466	$535,145	$558,451	$567,787	$579,175	$590,361	$601,597
62		GWh	3,574 1	7,148.2	7 148.2	7,148.2	7,148.2	7,148.2	7,148.2	7 148.2	7,148.2	7,148.2
63		*$/MWh*	58.95	66.51	68 73	71 69	74.86	78 13	79 43	81 02	82 59	84 16

AMP-Ohio Generating Station
Projected Operating Results - Base Case

	Description		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	REVENUES:											
1	Participant Revenues [1]	$000	$612,985	$625,333	$637,767	$650,190	$663,207	$676,498	$690,052	$704,061	$718,415	$733,525
2	Interest Earnings [2]	$000	6,891	6,921	6,951	6,984	7,018	7,054	7,092	7,132	7,174	7,227
3	Short-term (Market) Sales [3]	$000	41,789	42,547	43,422	44,356	45,168	45,974	46,924	47,899	48,926	50,052
4	Other Project Revenues	$000	0	0	0	0	0	0	0	0	0	0
5	Transfers from R&C Fund [4]	$000	3,610	3,240	2,861	2,473	2,077	1,671	1,257	832	398	0
6	Other Receipts	$000	0	0	0	0	0	0	0	0	0	0
7	*Total Revenues [5]*	$000	$665,275	$678,041	$691,002	$704,002	$717,470	$731,197	$745,325	$759,924	$774,912	$790,804
	OPERATING EXPENSES [6]:											
	Fixed Operating Costs:											
8	Fixed O&M	$000	$40,000	$40,920	$41,861	$42,824	$43,809	$44,816	$45,847	$46,901	$47,980	$49,084
9	Insurance & Property Taxes [7]	$000	6,530	6,530	6,530	6,530	6,530	6,530	6,530	6,530	6,530	6,530
10	Transmission Costs [8]	$000	4,613	4,719	4,827	4,938	5,052	5,168	5,287	5,409	5,533	5,660
11	AMP Ohio A&G Costs [7]	$000	628	642	657	672	687	703	719	736	753	770
12	Bank and Trustee Fees [7]	$000	157	161	164	168	172	176	180	184	188	193
13	Other Direct Project Costs	$000	0	0	0	0	0	0	0	0	0	0
14	*Fixed Operating Costs*	$000	$51,927	$52,971	$54,039	$55,132	$56,250	$57,393	$58,563	$59,760	$60,984	$62,237
	Variable Operating Costs:											
15	Fuel Costs	$000	$208,602	$214,900	$221,388	$228,073	$234,959	$242,055	$249,364	$256,894	$264,652	$272,644
16	SO_2 Emissions Costs	$000	8,934	9,296	9,757	10,054	10,386	10,731	11,088	11,456	11,837	12,230
17	NO_x Emissions Costs	$000	9,643	10,301	11,003	11,752	12,142	12,546	12,963	13,393	13,839	14,298
18	Hg Emissions Costs	$000	4,682	4,889	5,109	5,335	5,574	5,818	6,082	6,352	6,634	6,929
19	CO_2 Emissions Costs	$000	106,324	108,810	111,437	114,136	116,906	119,676	122,517	125,500	128,483	131,608
20	Variable O&M	$000	11,546	11,812	12,084	12,362	12,646	12,937	13,234	13,539	13,850	14,169
21	Gross Urea and Powerspan Costs	$000	69,730	71,334	72,975	74,653	76,370	78,127	79,924	81,762	83,642	85,566
22	Fertilizer Credits [9]	$000	(54,583)	(55,838)	(57,123)	(58,437)	(59,781)	(61,156)	(62,562)	(64,001)	(65,473)	(66,979)
23	*Variable Operating Costs*	$000	$364,879	$375,503	$386,630	$397,929	$409,203	$420,735	$432,610	$444,896	$457,465	$470,466
	Replacement Power [10]:											
24	Capacity Purchases	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Energy Purchases	$000	29,833	30,878	31,590	32,145	33,164	34,159	35,184	36,239	37,326	38,446
26	Transmission Costs	$000	0	0	0	0	0	0	0	0	0	0
27	*Total Replacement Power Purchases*	$000	$29,833	$30,878	$31,590	$32,145	$33,164	$34,159	$35,184	$36,239	$37,326	$38,446
28	*Total Operating Expenses*	$000	$446,639	$459,352	$472,259	$485,205	$498,617	$512,287	$526,357	$540,895	$555,775	$571,149
29	Net Revenues [11]	$000	$218,636	$218,689	$218,743	$218,797	$218,853	$218,910	$218,968	$219,029	$219,137	$219,655
30	Deposit to Working Capital Reserve Account [12]	$000	$1,861	$1,914	$1,968	$2,022	$2,078	$2,135	$2,193	$2,254	$2,316	$2,380
	DEBT SERVICE:											
31	Principal	$000	$43,886	$46,042	$48,306	$50,682	$53,178	$55,798	$58,549	$61,438	$64,472	$67,658
32	Interest	$000	153,182	151,026	148,763	146,386	143,891	141,271	138,519	135,630	132,596	129,410
33	*Total Debt Service [13]*	$000	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068
34	Other Debt Payments	$000	0	0	0	0	0	0	0	0	0	0
35	*Total Debt Service Requirement*	$000	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068	$197,068
	RESERVE AND CONTINGENCY FUND (Deposits to R&C Sub Accounts):											
36	Overhaul Account	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Renewal and Replacement Account [14]	$000	19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,753	20,207
38	Capital Improvements Account	$000	0	0	0	0	0	0	0	0	0	0
39	Rate Stabilization Account	$000	0	0	0	0	0	0	0	0	0	0
40	Environmental Improvement Account	$000	0	0	0	0	0	0	0	0	0	0
41	Other	$000	0	0	0	0	0	0	0	0	0	0
42	*Total R&C Fund*	$000	$19,707	$19,707	$19,707	$19,707	$19,707	$19,707	$19,707	$19,707	$19,753	$20,207
	Available for Transfer to General Account											
43	Net Revenues Available for Transfer to General Account [15]	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	Amounts Available from R&C Fund to Transfer to General Account [16]	$000	$3,240	$2,861	$2,473	$2,077	$1,671	$1,257	$832	$398	$0	($0)
45	**Total Revenue Requirements [17]**	$000	$665,275	$678,041	$691,002	$704,002	$717,470	$731,197	$745,325	$759,924	$774,912	$790,804

	Description		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	AVERAGE PROJECT COSTS (with CO_2):											
46	Net Costs to Participants [18]	$000	$612,985	$625,333	$637,767	$650,190	$663,207	$676,498	$690,052	$704 061	$718,415	$733,525
47	- Net Fixed Costs	$000	$248,106	$249,830	$251,138	$252,261	$254,004	$255,763	$257,442	$259,165	$260,951	$263,059
48	Net Non-Fuel Variable Costs	$000	$156,277	$160,603	$165,242	$169,856	$174,244	$178,680	$183,246	$188,002	$192,813	$197,822
49	- Fuel Costs	$000	$208,602	$214,900	$221,388	$228 073	$234,959	$242,055	$249,364	$256,894	$264,652	$272,644
50	Net Capacity	MW	960 0	960.0	960.0	960.0	960.0	960 0	960.0	960.0	960.0	960.0
51	Gross Energy	GWh	7,349.2	7,349.2	7,349.2	7,349.2	7 349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2
52	Plus: Replacement Energy Purchases [19]	GWh	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303 0	303.0	303.0
53	Less Surplus Energy Sales [20]	GWh	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504 0)	(504.0)	(504.0)	(504.0)	(504.0)
54	Net Energy	GWh	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2
55	Capacity Factor	%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
56	*Net Fixed Costs*	*$/KW-mo*	21 54	21.69	21.80	21.90	22.05	22.20	22.35	22.50	22.65	22.83
57	*Net Non-Fuel Variable Costs*	*$/MWh*	21.86	22 47	23.12	23.76	24.38	25.00	25.64	26.30	26.97	27 67
58	*Net Fuel Costs*	*$/MWh*	28.38	29.24	30.12	31.03	31 97	32.94	33 93	34.96	36.01	37 10
59	*Average Costs to Participants [21]*	*$/MWh*	85 75	87 48	89.22	90 96	92.78	94.64	96.54	98.50	100.50	102.62
	AVERAGE PROJECT COSTS (w/o CO_2):											
60	*Average Costs to Participants [22]*	*$/MWh*	70.08	72.26	73.63	74 99	76.43	77.90	79.40	80.94	82.53	84.21
61	Average Postage Stamp Rate [23]	$000	$612,985	$625,333	$637,767	$650,190	$663,207	$676,498	$690,052	$704,061	$718,415	$733,525
62		GWh	7,148.2	7,148.2	7 148.2	7,148.2	7,148 2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2
63		*$/MWh*	85.75	87.48	89.22	90 96	92 78	94.64	96.54	98.50	100.50	102.62

Footnotes:

[1] Participant Revenues are equal to Total Revenue Requirements (line 7) less other revenues (lines 2 - 6).

[2] Projected interest earnings on unexpended amounts in (i) the General Fund, R&C Fund and Debt Service Fund based on interest earnings rate of 3.75%, (ii) the Reserve Fund based on interest earnings rate of 5.25%.

[3] Estimated short-term market sales of energy from AMPGS which is expected to be in excess to the energy required under the Power Sales Contracts with the Participants.

[4] Estimated amounts available in the R&C Fund remaining from the prior year after expenditures for renewals and replacements to AMPGS

[5] Equal to Total Revenue Requirements (Line 45).

[6] Unless otherwise noted, based on projections as set forth in the Operating Cost projections for the Base Case (See Attachment 2).

[7] Estimate based on information provided by AMP-Ohio.

[8] Transmission costs include the projected cost of PJM congestion costs and marginal losses costs incurred to deliver AMPGS power to the delivery point (PJM/MISO border) Estimated at $0.50/MWh in 2013 and escalated by inflation thereafter.

[9] Estimated credits from sales of ferterlizer produced by the Powerspan scrubber

[10] Estimated cost of replacement power purchased from the short-term energy market to replace AMPGS during scheduled and forced outages

[11] Equal to Total Revenues (line 7) less Total Operating Expenses (line 28)

[12] Deposit to Working Capital Reserve Account equal to 5% of the total monthly Operating Expenses.

[13] Estimated debt service on Bonds projected to be issued to finance the total cost of construction of the AMPGS Project. Assumes interest rates of 3.75% on variable-rate bonds and 5.25% on fixed-rate bonds and that 20% of the bonds would be variable-rate bonds and 80% would be fixed-rate bonds Assumes level debt service payments over the 40-year period 2014 - 2053.

[14] Deposit to Renewal & Replacement Account equal to the greater of 10% of Debt Service or the estimated renewals & replacements for such year.

[15] Equal to Line 29 minus Line 30 minus Line 35 minus Line 42.

[16] Amount available in the R&C Fund estimated to be remaining at the end of the year after expenditures for renewals and replacments to AMPGS.

[17] Equal to the sum of Line 28, Line 30, Line 35, and Line 42.

[18] From Line 1.

[19] The quantity of replacement power purchased from the short-term energy market to replace AMPGS during scheduled and forced outages

[20] The quantity of short-term market energy sales that are expected to be in excess of the energy required under the Power Sales Contracts with the Participants

[21] Average Costs to Participants equal Line 1 / Line 54

[22] Average Costs to Participants without CO_2 equal (Line 1 - Line 19) / Line 54.

[23] Based on net Project Cost including CO_2 from above.

[24] Estimated Participant sales of energy from their share of AMPGS Project which is in excess of their load requirements and assumed to be sold into the market.

[25] Estimated average net cost to the Participants after surplus energy sales.

Attachment 4

Risk Analysis Assumptions

ATTACHMENT 4
RISK ANALYSIS ASSUMPTIONS

Risk Analysis Process

The quantitative risk analysis process consists of three basic steps:

(1) identifying the risk variables to be analyzed (based on results from the qualitative risk assessment);

(2) developing data necessary to represent the volatility, probability and range of values for each key risk variable; and

(3) executing a custom risk analysis model to identify the range and probabilities of the outcomes (results) for the average annual AMPGS Project power costs (in $/MWH).

The process uses R. W. Beck's SERF model of MISO and PJM regions to forecast 50 scenarios of hourly power prices and associated monthly fuel prices.

A custom risk analysis model ("AMP-Ohio Risk Model") was developed to project average annual AMPGS Project power costs. The AMP-Ohio Risk Model uses the results of 50 scenarios of power prices and fuel costs produced by the SERF model and probability distribution functions ("PDFs") for selected risk variables to project the estimated net cost of the AMPGS Project for each year in the study period (2013-2032).

The AMP-Ohio Risk Model develops 1,000 simulations of the AMPGS Project power costs based on the defined PDFs, fixed costs inputs and results from the fuel and market price scenarios (i.e., application of Monte Carlo sampling technique). Resulting PDFs and confidence intervals of AMPGS Project power costs were developed from the 1,000 simulations.

Assumptions and Development of Risk Variables

The assumptions with regard to the risk variables are discussed below.

One of the first steps in the quantitative analysis includes (i) preparing market data inputs (such as gas prices and coal prices), environmental cost inputs and inputs on future generation costs by type of plant (including capital costs, operating costs, etc.); (ii) selecting the variables that could impact power supply decisions ("risk" variables); and (iii) preparing probability distribution functions (PDFs) that describe the uncertainty of each risk variable.

The quantitative risk analysis should take into consideration the risks that have been identified under qualitative risk analysis that could have a substantial impact on future power costs for each alternative. These risk variables include the following:

- Price Risks
  - Coal price volatility
  - Market price volatility (effects surplus energy sales)
  - Fertilizer price volatility (revenues from Powerspan scrubber)
- Construction Cost Risks
  - Increases in costs
  - Delays in on-line date
- Interest Rate Risks
  - Short-term variable rate volatility
  - Long-term fixed rates fluctuations
- Environmental Cost Risks
  - SO_2 and NO_x allowance costs
  - CO_2 and Mercury emission costs

Risk Variables Developed from Regional Market Model

The volatility in coal prices and market prices are captured by the 50 scenarios produced by the R. W. Beck SERF model. Figure 4-1 shows the results of the 50 scenarios for the projected AMPGS coal prices. Figure 4-2 shows the 50 scenarios for the projected market prices which were used in developing the replacement power costs under the Base Case. The bold lines in graphs included in Figures 4-1 and 4-2 represent the expected value (or mean value) and the 5 percent and 95 percent confidence estimates.

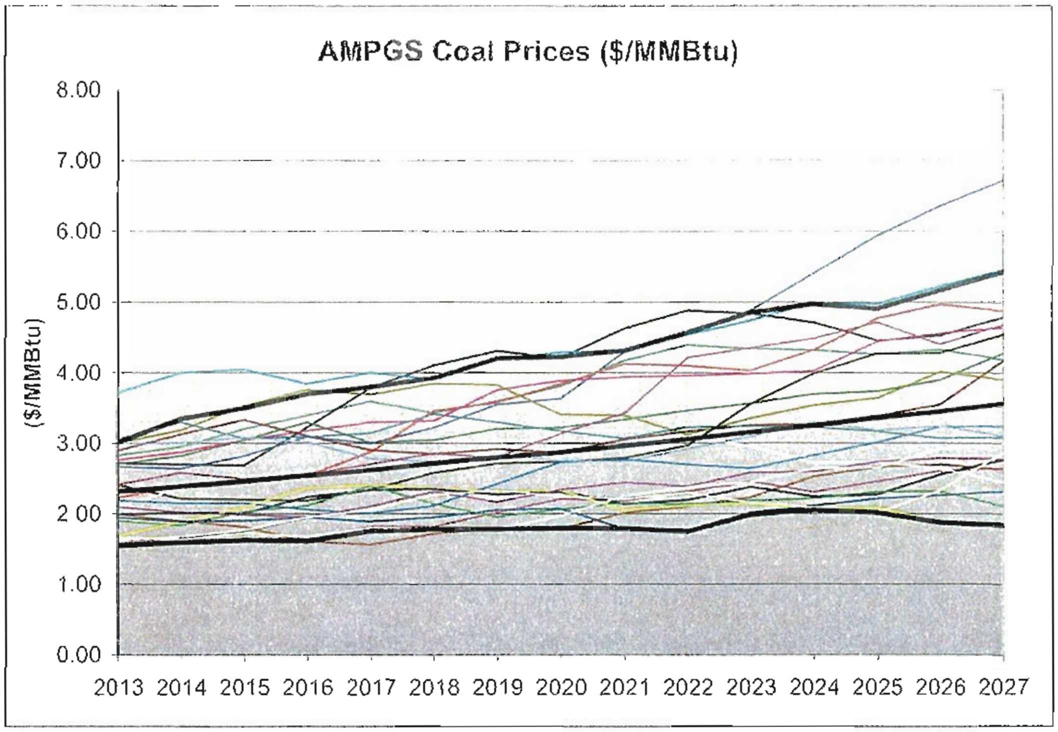

Figure 4-1 - Range of Projected Coal Prices ($/MMBtu)

[redacted]

The projected CO_2 allowance prices ($/ton) were developed by the SERF Model. Under the Base Case, a carbon tax of $5/ton to $15/ton (in 2006$) was assumed to be in place beginning between 2012 and 2018. The discrete probabilities for the CO_2 costs under the Base Case are shown in Table 4-1 below.

Table 4-1
Base Case – CO_2 Cost Probabilities

Probability	$/Ton (2006)
0%	$0.00
20%	$5.00
20%	$7.50
20%	$10.00
20%	$12.50
20%	$15.00
Expected	$10.00

The CO_2 expected values for each year reflected the probability that CO_2 would be in place that year with assumed probabilities of 14.3 percent in 2012, 28.6 percent in 2013, 42.9 percent in 2014, 57.1 percent in 2015, 71.4 percent in 2016, 85.7 percent in 2017, and 100 percent in 2018 and thereafter. The results of the 50 scenarios under the Base Case are shown in Figure 4-3.

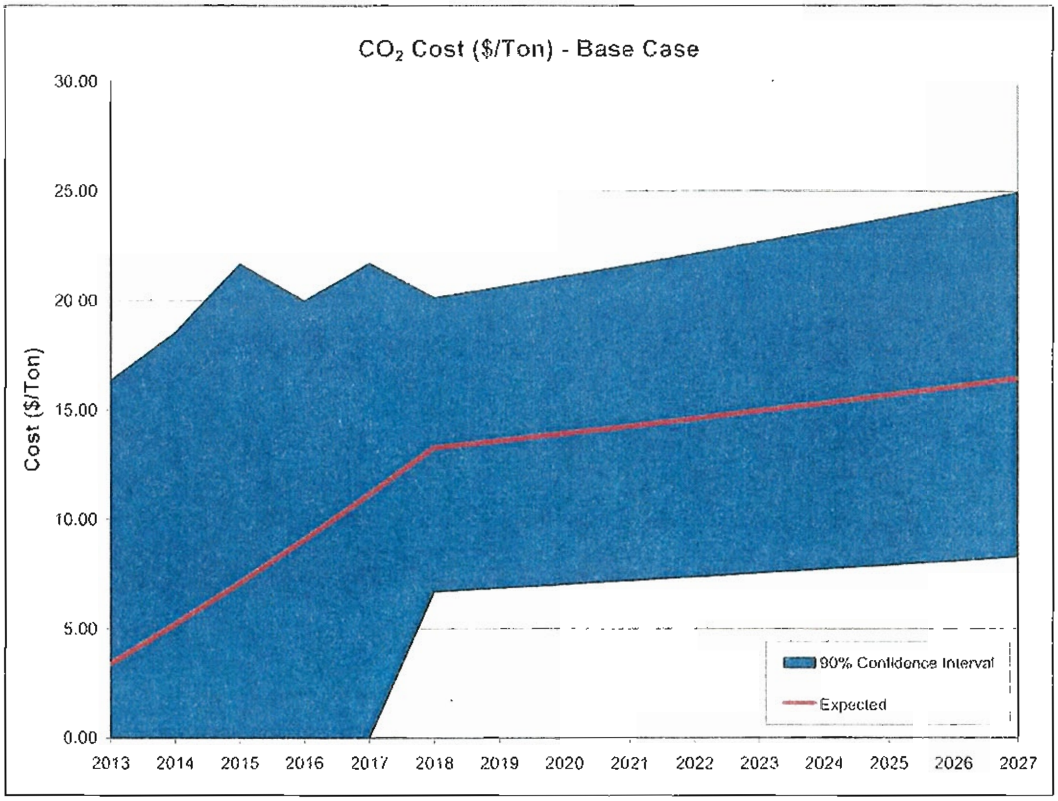

Figure 4-3 - Base Case Projected Range of CO_2 Emissions Costs ($/MWh)

Risk Variables from Powerspan Report

As discussed in Appendix D of the Initial Feasibility Study – "Powerspan Process Technical Assessment and Feasibility Study", the Powerspan process will utilize urea as a reagent and produce ammonium sulfate from the process. Urea (46 percent nitrogen by weight) and ammonium sulfate (21 percent nitrogen by weight) are two types of fertilizers used in the United States and worldwide. The difference in prices for these two commodities is an important factor in the economic viability of the ECO-SO_2 process given the high cost of urea reagent and the need to recover such costs by the sale of the ammonium sulfate.

A probabilistic analysis was developed and discussed in the Powerspan report. These results used in the quantitative analysis of the AMPGS Project costs. Figure 4-4 shows the results of 50 scenarios for projected urea prices in $/ton. Figure 4-5 shows the 50 scenarios for the projected ammonium sulfate in $/ton.

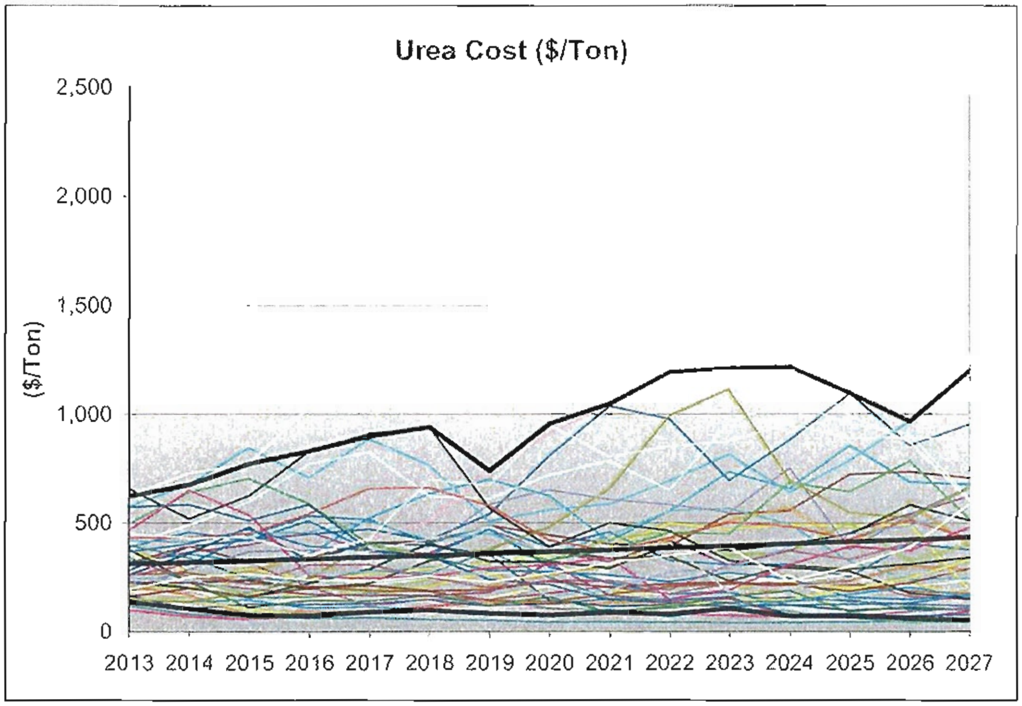

Figure 4-4 - Range of Projected Urea Prices ($/ton)

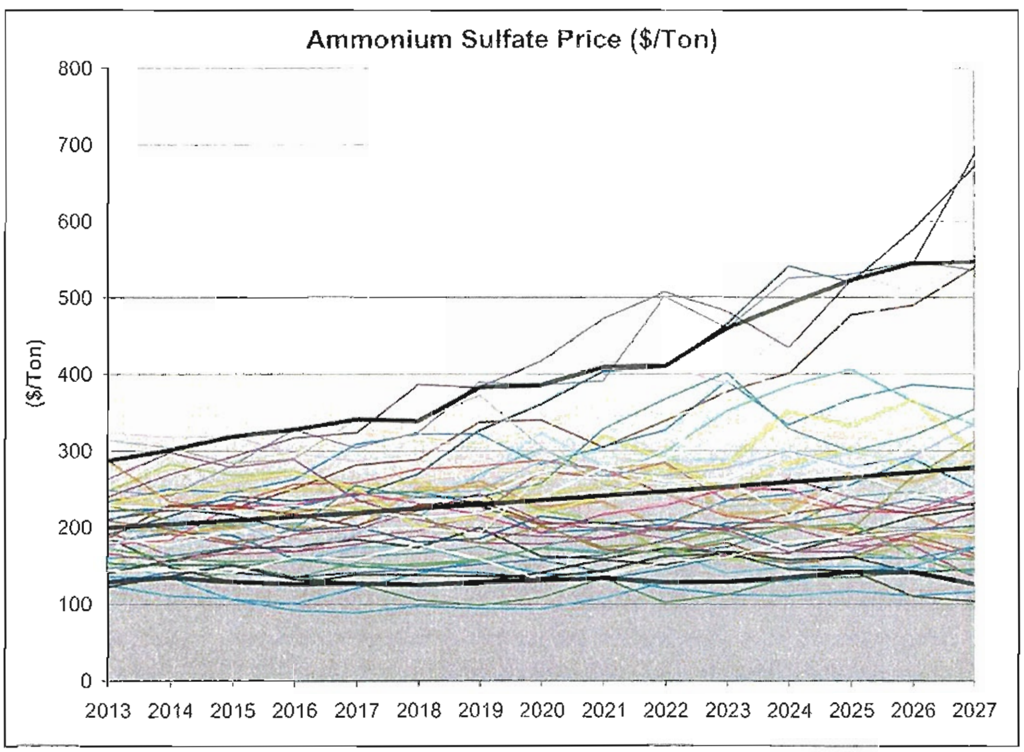

Figure 4-5 - Range of Projected Ammonium Sulfate Prices ($/ton)

Development of Other Risk Variables

The construction cost risks were quantified by taking into account the estimated potential range in projected construction costs and potential changes in the construction schedule of AMPGS. Based on our experience related to the construction and construction costs for coal plants similar to AMPGS, we have assumed that the total estimated construction costs reflected in the Base Case could vary by +18 percent or -5 percent. We have assumed that the construction schedule could be early by 3 months are delayed by as much as 12 months. The resulting triangular probability distributions are shown in Figure 4-6 and 4-7.

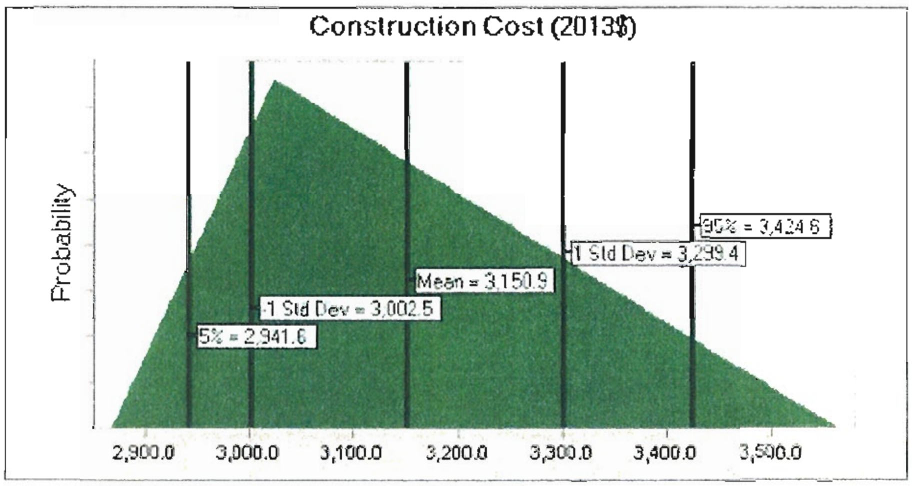

Figure 4-6 - PDF Assumed for Construction Costs (2013$) ($/kW) [1]

[1] Reflects costs from October 2008 through September 2013 and excludes developmental costs.

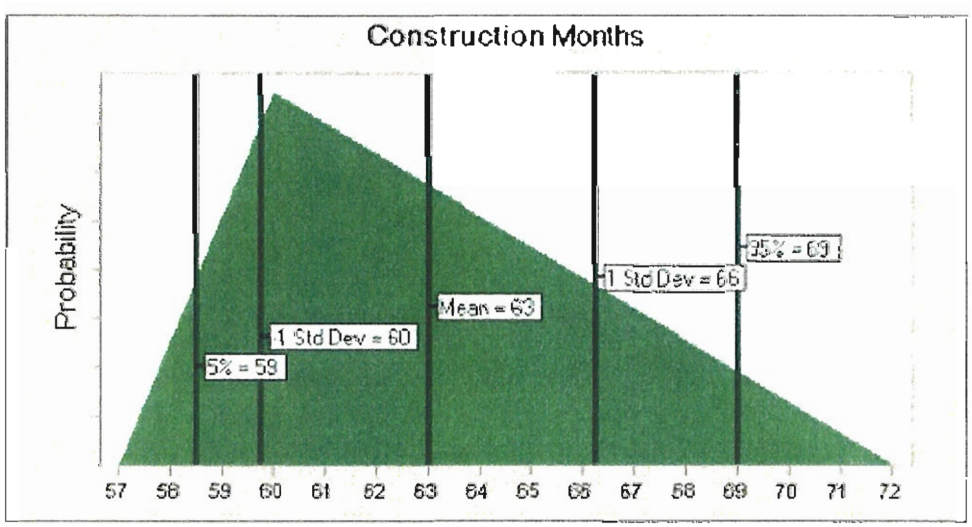

Figure 4-7 - PDF Assumed for Construction Schedule (months)

As illustrated in Figures 4-8 and 4-9 below, interest rate volatility was modeled based on lognormal probability distributions with an assumed standard deviation of 20 percent of the mean value (based on volatility in historical interest rates).

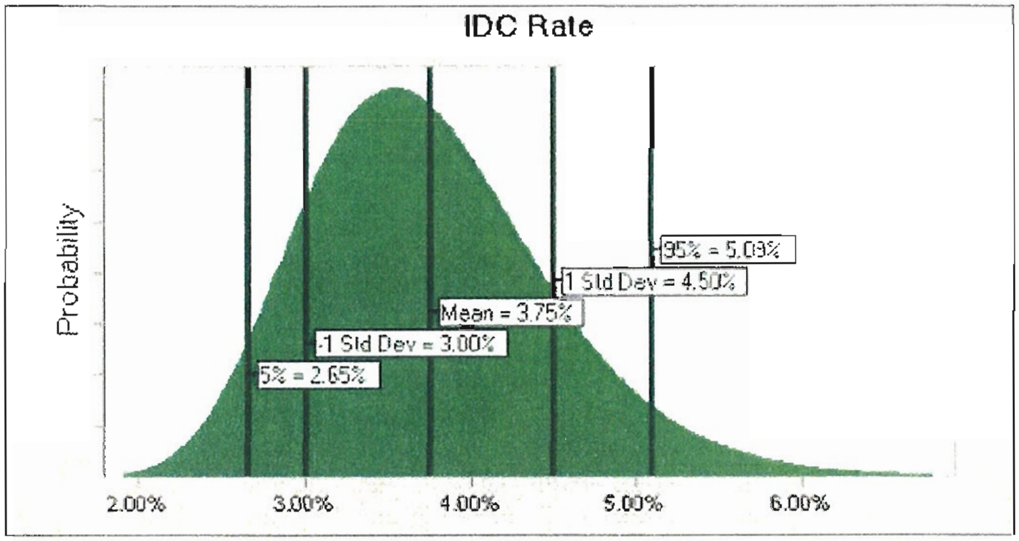

Figure 4-8 - PDF Assumed for Interest on Variable Rate Debt (%)

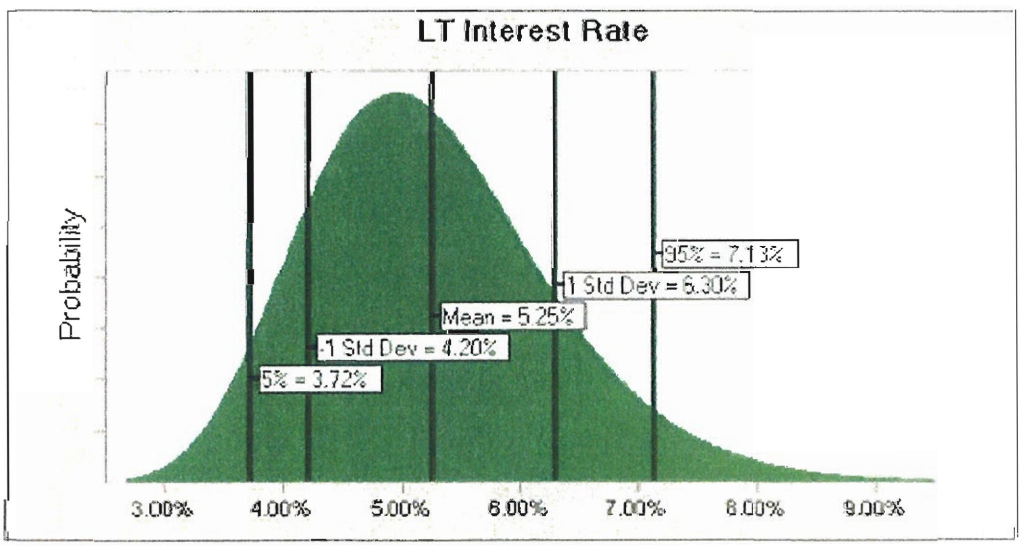

Figure 4-9 - PDF Assumed for Interest on Fixed Rate Debt (%)

As illustrated in Figures 4-10 and 4-11, volatility in allowance prices for SO_2 and NO_X was modeled based on lognormal probability distributions with an assumed standard deviation of 33 percent of the mean value (based on historical volatility in allowance prices).

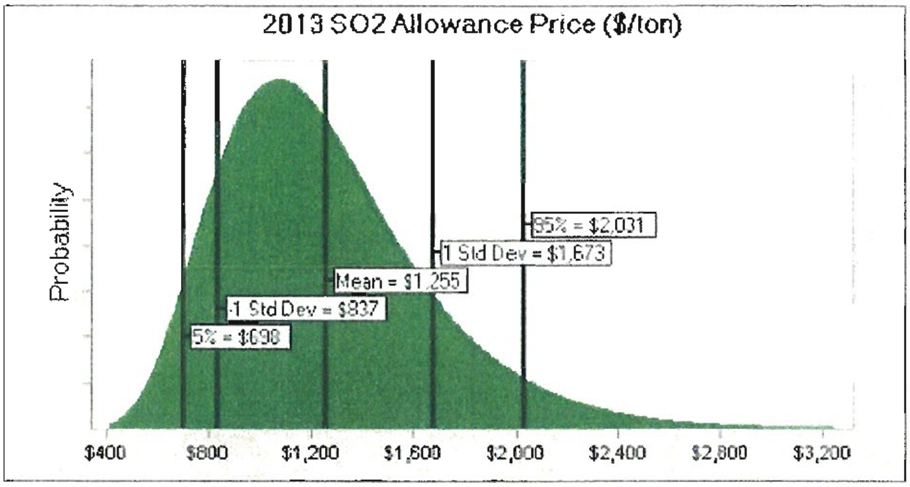

Figure 4-10 PDF Assumed for SO_2 Allowance Price ($2013/ton)

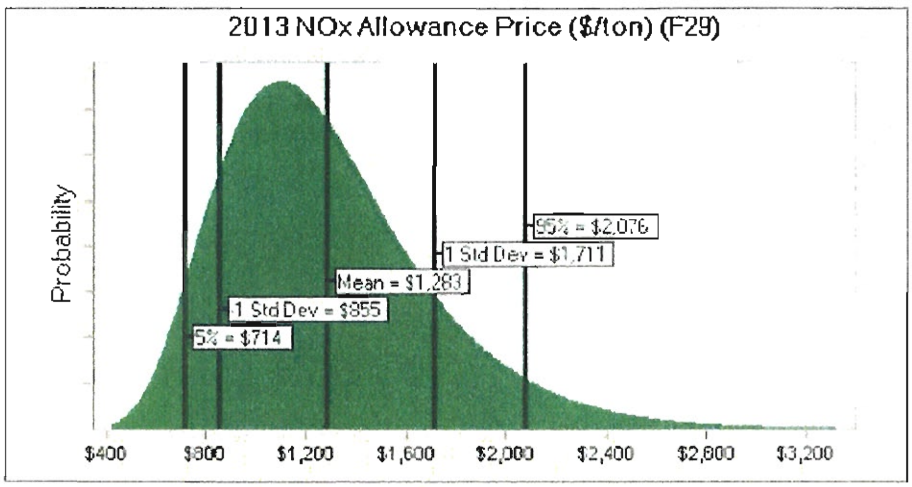

Figure 4-11 - PDF Assumed for NO_X Allowance Price ($2013/ton)

As illustrated in Figure 4-12 below, mercury emissions cost volatility was modeled based on a lognormal probability distribution with standard deviation of 33 percent (assumes the same STD as other allowance prices).

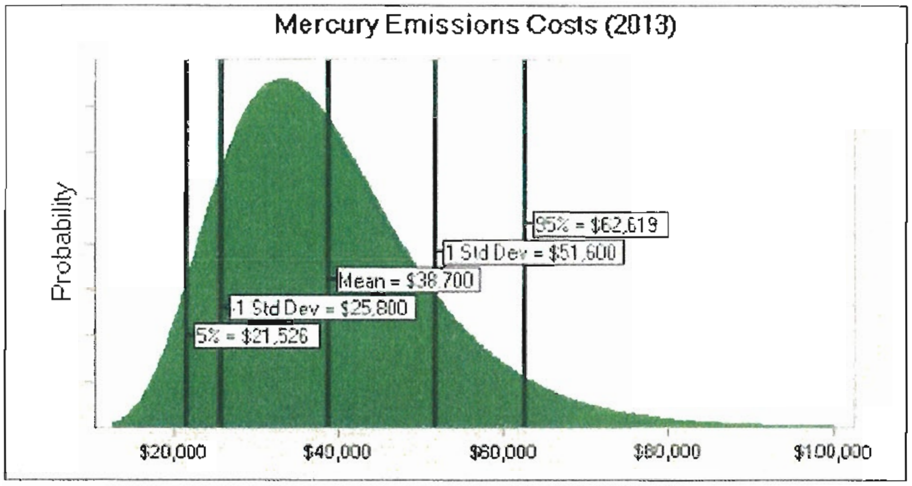

Figure 4-12 - PDF Assumed for Mercury Emissions Costs ($000/ton in 2013 Dollars)

Based on the PDFs and/or volatility defined for each risk variable, we have used stochastic modeling and statistical analysis techniques to analyze how in aggregate these risks could impact AMP-Ohio's projected Project power costs. The results of the risk analysis include a projection of the potential range (with a certain confidence level) and expected value of the average annual power cost for the AMPGS Project. The results of these analyses are in the Report to which this is attached.