LARGE FILING SEPERATOR SHEET

CASE NUMBER: 06-1358-EL-BGN

FILE DATE: 1/03/2008

SECTION: Part 2 of 5

NUMBER OF PAGES: 187

DESCRIPTION OF DOCUMENT: Transcript Volume IV and Exhibits

(OPEN RECORD.)

EXAMINER BOJKO: Can we go off the record for a second.

(Discussion held off the record.)

EXAMINER BOJKO: Okay, we can go back on.

Q. (By Ms. Jaiswal) Mr. Schlissel, do you have Exhibit AMP-Ohio 13 in front of you or can you please find it?

A. Fifteen?

Q. I'm sorry, 13.

A. Thirteen?

Q. The Burns & Roe.

A. Yes, I do.

Q. Do you recall today, I think it was just before lunch Mr. Bentine asked you a series of questions about this document?

A. Yes, I do.

Q. This morning he asked you. Did Mr. Bentine ask you about page 1-2?

A. Yes.

Q. And did he ask you about paragraph 3?

A. Yes, he did.

Q. He asked you to read the first line in paragraph 3, correct?

A. That's correct.

Q. Would you please read the paragraph and in the interest of time begin with "However," which is line 3? Have you found that?

A. Yes.

Q. What does that say?

A. "However, there are a number of significant risks associated with use of the Powerspan ECO-SO2 process. The scale-up of the ECO-SO2 process and its operation is a major unknown risk factor. The design proposed for AMPGS differs in some key areas from the pilot plant being tested

at the Burger" -- B-u-r-g-e-r -- "Station," and then it goes on from there.

Q. Thank you.

If you could turn to page 1-3.

A. Yes.

Q. And if you could go to what's numbered paragraph 9.

A. Okay.

Q. If you could please read the sentence five lines down beginning with "It."

A. Well, the previous sentence Mr. Bentine asked me to read was "BREI finds the cost estimate to be in the range of the expected cost for a two-unit subcritical coal-fired power plant of this size and design." And then Sargent & Lundy -- I'm sorry, I apologize, Burns & Roe goes on to say, "It is noted that the escalation estimate may not be conservative as seen by significant increases in construction material costs in recent years."

Q. If you go to 2-8, and if you could go down to paragraph 4.

A. Paragraph 4?

Q. Yes.

A. Okay.

Q. Second sentence, could you please read that second sentence?

A. "In their ECO process evaluation, R.W. Beck made various assumptions with respect to the conditions that may exist or events which may occur in the future. R.W. Beck did not offer any justifications or provide assurances for the validity of the assumptions used in the report, and stated that some assumptions may vary significantly due to unanticipated events and circumstances."

Q. And the last one on this, if you could go back to 1-4.

A. 1-4.

Q. If you could go to what's numbered as 1.5 at the bottom there.

A. Yes.

Q. And if you could please read that.

A. Well, there's a listing of -- "The key potential risks identified as a result of our review of the AMPGS project are: The selection of a subcritical PC technology given the industry trend to choose supercritical PC technology for units in the 500-megawatt size range;

"2. Risks associated with use of the

Powerspan ECO-SO2 process including scale-up concerns and the need for a full wrap performance guarantee;

"3. The difficulty of obtaining a fixed price EPC contract and its impact on the project cost;"

And "4. The potential for higher escalation than assumed in the project construction cost."

Q. Let's move on.

Do you recall Mr. Bentine asking you about construction costs for power plants?

A. Yes.

Q. What is the current estimated cost for the proposed plant, construction cost?

A. Roughly 2.5 billion including owner's costs.

Q. And with interest and other financing?

A. Roughly 2.9 billion.

Q. And do you recall Mr. Bentine asking you about increases in construction costs?

A. Yes.

Q. Why have construction costs increased for power plants?

A. Well, as I discussed at some length in my

testimony, because of the competition for design, for commodities, the metals, the copper, the wire, the alloy piping, the commodities that -- concrete and steel that are used in power plants and other construction, refinery, chemical industry, and other sources, competition for construction and design labor, construction and spots with the EPC contractors as Mr. Bentine and I discussed this morning, manufacturing capacity in terms of fabricating the major equipment components, the boilers, the steam generators, other components of a coal-fired power plant.

Q. And within the past two years have other power plants changed their estimated project costs due to construction cost increases?

A. Yes, a number have, as I present in my testimony.

Q. And what are those plants?

A. It's in my testimony. I list some of them.

Q. Which ones do you list?

A. Actually, I don't list ones that have increased. I list a number that have been cancelled, a number that have been rejected, and a number of

companies that have announced that they will not consider coal plants in the near future.

Q. Has AMP-Ohio commented on construction cost increases?

A. Yes. In their application they used the term "staggering," and I would agree.

Q. Are you familiar with the factors that AMP considered in determining construction costs?

A. I don't know -- I'm sorry, I know this is not a good comment for redirect, but I don't understand the question.

Q. Were AMP's construction costs -- strike that.

On page 61 of your testimony, if you could turn to 61.

A. Page 51 or 61?

Q. Sixty-one, please.

A. Yes.

Q. Do you know based on that what R.W. Beck believed the cost of the project could increase before it's completed?

MR. BENTINE: What's the reference here, please?

MS. MALONE: Which question?

MS. JAISWAL: Sorry, line 11.

MR. BENTINE: Thank you.

A. As I cite in the initial project feasibility study and in the risk assessment, Beck indicates that they believe the project cost could increase by as much as 15 percent over the current estimate or decrease by 5 percent.

Q. And what is your view on that number?

A. I certainly think it could increase by 15 percent. It could decrease by 5 percent, but I don't think that's very likely. It could increase by 15 percent in a few months; that's the experience of some power plants. I think once -- it will be telling once they actually decide whether they're going to build a supercritical plant or not, have an EPC contract, and more design work to see what the cost actually is.

Q. And if you could turn to page 62.

A. Yes.

Q. Question 1. So if you can read that to yourself and answer why you believe that the February 2006 numbers -- what you think of the February 2006 numbers used by R.W. Beck.

MR. BENTINE: Objection.

EXAMINER PRICE: Grounds?

MR. BENTINE: Outside the scope of cross. I didn't ask a question about this, I didn't ask a question about from February of 2006 and the sensitivities that Beck did or didn't do.

MS. JAISWAL: Mr. Bentine asked about construction costs, and he also brought to issue what the plant's construction costs are, and these go to construction costs.

EXAMINER PRICE: Sustained.

THE WITNESS: Your Honor, could we have a recess so I can tell my sister-in-law not to give my bed away?

EXAMINER PRICE: Let's go off the record for five or ten minutes.

(Discussion held off the record.)

MS. MALONE: I need to indicate on the record that the witness is conversing with counsel --

THE WITNESS: I thought we asked for a break.

MS. MALONE: It doesn't matter.

EXAMINER PRICE: Yeah; you're to make your phone call.

Thank you.

(Recess taken.)

EXAMINER PRICE: Let's go back on the record.

Please proceed.

Q. (By Ms. Jaiswal) Let's move on. Mr. Schlissel, do you recall AMP's counsel asking you about your expertise?

A. Yes.

Q. Do you have expertise in resource planning?

A. Yes.

Q. What is your experience in resource planning?

A. I've reviewed and helped prepare resource plans for roughly 25 years, maybe longer.

Q. What is resource planning?

A. Resource planning is determining what's an appropriate capacity, it's generally considered capacity expansion, but integrated resource planning looks at both demand side and supply side, what's the lowest-cost, lowest-risk plan to adopt for any party.

Q. Have other utilities, boards, commissions accepted your recommendations?

A. Yes.

Q. When?

A. On resource planning issues the Indiana Utility Regulatory Commission adopted my findings back in '86; the Texas Public Utilities Commission, '89; more recently the New Mexico Public Regulation Commission adopted a range of CO2 costs that they're requiring utilities to use in resource planning based on my presentation. The Florida Glades project decision that Mr. Bentine and I discussed, the Commission's order takes -- doesn't cite my name, but it takes my testimony and cites and pastes it into their order, my positions. Those are some examples.

I could give you many more. I've been accepted by a number of commissions, I've not been accepted by some commissions; that happens.

Q. And who are your other clients?

A. Mr. Bentine asked me a number of who are my clients in some recent cases. Other recent clients of mine within the last year have included the U.S. Department of Justice and working for them in a lawsuit; the attorney general of the state of New York; the governor of the state of New York; the New Mexico commission I just mentioned adopted my range of CO2 costs, they actually hired me to do a

different case. I have worked for some environmental groups. I've worked for other consumer advocates. I've worked for other state attorneys general.

Another project of mine which is a little more than a year old, a year and a half old, I worked for General Electric Company. I've worked over the years for publicly owned utilities in New York, North Carolina, Massachusetts, Texas.

Q. What did you do for GE? You mentioned General Electric.

A. They were sued by the owner of a merchant power plant in Wyoming and I was retained to do a quantification of the cost of the outage.

Q. And the attorney generals of New York and did you mention another state?

A. Well, no, the governor of New York and the attorney general of New York, I recently prepared a resource study of alternatives to retiring -- I'm sorry, to relicensing of the Indian Point nuclear power plant. That's a big issue in New York. The plants are up to the end of their initially licensed 40-year operating lives and the owner wants to relicense them.

Q. Do you recall Mr. Bentine asking you

about a proposal from Synapse to the city of Oberlin?

A. Yes.

Q. And under what circumstances was Synapse brought to make this proposal?

A. In mid-November we, and I mean another colleague of mine at Synapse and myself, received a request for qualifications from the city of Oberlin, they were seeking to have a noncoal resource plan developed and they were seeking firms who would be willing to look at the issue.

I initially expressed concern to my colleagues at Synapse because of the work I'm doing for NRDC in this proceeding, so I asked Mr. Fisk whether NRDC would object and then my colleagues spoke to the city of Oberlin to ask if they would be concerned if there was any real or apparent conflict of interest. I wanted them to be clear of what we were doing in this case.

We were asked to submit a proposal. I forget what number is it. AMP-Ohio 10 is the proposal that Synapse submitted to the city of Oberlin to do that study.

Q. And in that proposal what is the charge for Synapse's service there? Is it 4,800?

A. Well, the total bill is $49,500. The total proposed budget. Mr. Bentine specifically asked me about a $4,800 item entitled "Review AMPGS project analysis data."

Q. And what is the basis for that charge?

A. I put it into the proposal anticipating that I would have the opportunity to see the underlying R.W. Beck work papers and modeling analyses that went into the power supply plant for the city of Oberlin that I've not had a chance to review in this case.

Q. Moving on, do you recall AMP's counsel asking about whether certain companies are vertically integrated?

A. Yes.

Q. Do you recall him asking you about companies that have significant generating resources?

A. Yes.

Q. Do you recall him asking you about companies that have certain loads to meet?

A. Yes.

Q. Do the carbon cost and the construction cost risks apply equally to AMP as they do these other companies?

A. Yes.

Q. Why?

A. Because any, I mean, the construction cost risk is blind in terms of it doesn't just go after integrated companies, it doesn't just go after merchant companies, it will affect any company seeking or organization seeking to build a coal-fired power plant.

The same with CO2 costs. I have seen no proposal that says CO2 costs will only apply to vertically integrated companies or to merchant generators. There's no -- there's absolutely no language consideration of any proposal like that.

MS. JAISWAL: I have a confidential exhibit that's already been introduced.

EXAMINER PRICE: Thank you. Let's go on the confidential portion of the transcript.

(CONFIDENTIAL PORTION EXCERPTED.)

(OPEN RECORD.)

EXAMINER PRICE: Please proceed.

Q. (By Ms. Jaiswal) Mr. Schlissel, do you

recall AMP's counsel asking you about reliance and overreliance on natural gas?

A. Yes.

Q. What is your view on reliance and overreliance on natural gas?

A. I think it's a risk to overrely on natural gas, a company and area should have a balanced generation mix.

Q. Are you concerned about overreliance on natural gas in this region?

A. No. I mean, theoretically I would be, but I don't think as a practical matter that there's a major reliance on gas in this region so I think we're a long way from overreliance.

Q. Do you recall Mr. Bentine asking you --

EXAMINER PRICE: I'd like to follow up with that.

Are you saying that there is not a, I mean, there's an economic risk and then there's the actual physical use. So you're saying that there's no economic risks posed by this region to natural gas prices?

THE WITNESS: No. No, I'm not saying there's no risk. What I'm saying is that the region

is very heavily dependent on coal so that if you increase the amount of gas, gas is a risk of gas price volatility or increases, but that in the overall balance you're spreading out your --

EXAMINER PRICE: Weren't Mr. Bentine's questions directed at the economic risk?

THE WITNESS: I'm talking about economic risk. I'm not talking about supply risks. I have not seen any analyses that show over the long-term there will not be gas. The analyses I've seen are the price of gas. So it's an economic issue. There will be liquid natural gas imports into the United States, there will be terminals, the question is what will the price be. So that's an uncertainty, and as AMP-Ohio did, they should study that when we look at a resource plan.

What I'm talking about is this region is very heavily dependent on coal and that to balance that, maybe reduce the dependence on coal and increase the dependence on gas and renewables and et cetera is a good thing. To diversify your supplies in terms of the fuel diversity is a good thing.

EXAMINER PRICE: Thank you.

MS. JAISWAL: I'm sorry, your Honor. Did you have any further questions?

EXAMINER PRICE: Please proceed.

Q. (By Ms. Jaiswal) Do you recall AMP's counsel, Mr. Bentine, asking you about the 2,000-megawatt gap that AMP has assessed?

A. Yes.

Q. Alternative energy sources couldn't fill that entire gap; is that correct?

A. That's correct.

Q. What role could alternative energy sources play in filling that gap?

A. They could play a role in terms of providing some capacity, again, I've not done a study so I can't say how much, but some capacity. They also could provide cheap energy rather than capacity, so that they certainly have a role and a plan and I think, as Mr. Bentine pointed out, they already are making -- AMP is making some efforts in those areas as well.

Q. And are they doing that as part of their planning process for this project?

A. They're doing it -- the evidence I've seen as part of the planning process --

MR. BENTINE: I'm going to object. There is no legal basis for requiring that we're doing this planning the way that these folks think we ought to do it for this project, so I think it's irrelevant.

EXAMINER PRICE: Response?

MS. JAISWAL: It is Mr. Schlissel's opinion as an expert on how costs should be considered and how costs were considered here and how alternatives were considered here. He was asked those questions on direct.

EXAMINER PRICE: May I have the question back again?

(Question read.)

EXAMINER PRICE: This has been troubling me for some time and so I'm going to open Pandora's box here and probably live to regret this.
Mr. Schlissel, earlier you testified that you, you talked in your direct testimony about resource planning and earlier you said that resource planning is the equivalent of integrated resource planning.

THE WITNESS: Yes, sir.

EXAMINER PRICE: Is that not generally done in states that require a showing of need for a particular power plant?

THE WITNESS: No; lots of companies are doing resource planning now as a matter of prudent management.

EXAMINER PRICE: Okay. So you're saying -- Mr. Bentine's making a legal argument, I'm asking the witness a question, it's not a good position to be in.

THE WITNESS: If I might explain a little further.

EXAMINER PRICE: No. No.

THE WITNESS: Okay. All right.

EXAMINER PRICE: That's all right. We're going to sustain Mr. Bentine's objection. I'll ask Miss Jaiswal to rephrase the question.

Q. (By Ms. Jaiswal) In your experience are you aware of other companies that use integrated resource planning?

A. Yes. On an increasing basis companies are turning back to integrated resource planning for looking at supply and demand-side alternatives.

Q. Moving on; when was the initial project feasibility study conducted?

A. June of 2007.

Q. And when was the application submitted

for this plant?

A. Sometime in the spring, I believe. I don't recall the exact date.

Q. What is your view on the timing of the considerations that are in the initial feasibility study with respect to the application?

A. I think it's appropriate as part of the application.

Q. And the dates of the initial project feasibility study.

A. I'm sorry?

Q. The dates of the initial project feasibility study in those considerations.

A. Yes.

MR. BENTINE: I don't know what we're talking about here. I'm going to object. I don't understand the question or the answer and what the context is.

EXAMINER PRICE: Ms. Jaiswal.

Q. Let's turn to --

EXAMINER PRICE: I'm asking for a response.

MS. JAISWAL: Oh, I will rephrase.

EXAMINER PRICE: Okay.

Q. Let's turn to AMP's Exhibit 11, the initial project feasibility study. Do you have that? The executive summary portion, not the entire one.

EXAMINER BOJKO: I'm sorry, which number is this?

EXAMINER PRICE: AMP 11.

MS. JAISWAL: It's 11.

Q. If you could go to ES-2.

MR. BENTINE: If you could hold on one moment.

Thank you.

A. Yes.

Q. And if you could go to paragraph 2. Do you recall Mr. Bentine asking you about this yesterday?

A. Yes.

Q. Do you recall Mr. Bentine asking you if alternatives were considered in the Sargent & Lundy studies on technology analysis and fuel availability and delivery costs discussed in paragraph 2?

A. Yes.

Q. According to the project feasibility study, when were those analyses conducted?

MR. BENTINE: Objection.

EXAMINER PRICE: Grounds?

MR. BENTINE: Irrelevant when those were -- I'll withdraw that. Just go right ahead.

MS. JAISWAL: Could you please read back the question?

(Question read.)

A. 2003 or 2004.

Q. Have circumstances changed since those studies were done and that would alter their analysis?

MR. BENTINE: I'm going to object. There is no foundation that this gentleman has done the work necessary to come to that conclusion, and until that foundation is made, I object.

EXAMINER PRICE: Sustained.

Q. Are you familiar with these studies?

A. I've looked at them, yes.

Q. When did you look at them?

A. They were provided -- I believe I saw them before I filed my testimony, so it would have been sometime in November.

Q. And what is your view on AMP's reliance of these analyses with respect to the proposed plant?

MR. BENTINE: Objection.

EXAMINER PRICE: Grounds?

MR. BENTINE: Looking at them does not qualify him to do that. These are big studies, they're complicated, they were studies that have been reviewed by R.W. Beck, they're studies that have been reviewed by Burns & Roe in some detail, and all of this culminated over a very long period of time on our application which does not contain the Sargent & Lundy studies.

In fact, I was happy to hear somebody say "application," that's one of the few times in this whole proceeding that we've talked about the application in this which, I might add, was found complete by the board.

So until we lay a foundation about him looking at this, perhaps in as deep a detail as he looked at CO2 or construction costs, I didn't object to him opining on those because he had done a bit of work on that, and certainly enough to be here and to opine, we don't agree necessarily with how he's opining but we don't object to his ability to do it. I do object to this because unless there's a foundation as to what he has looked at and how much time he spent on that in order to come to conclusions

about it, I think it's inappropriate.

MS. JAISWAL: Mr. Bentine asked Mr. Schlissel about these exact documents. He asked him about this paragraph in this document. Based on his objection, I had to go to this document so that I could ask about these questions. He asked about this document yesterday, he asked about alternatives, when alternatives were considered, and he raised these Sargent & Lundy studies himself.

Mr. Schlissel is permitted to express his opinion on these studies.

EXAMINER PRICE: I think Mr. Bentine's looking for a greater foundation than you've laid thus far, so why don't you ask some foundational questions and then we'll see if this all sorts itself out.

Q. (By Ms. Jaiswal) Did you review these studies?

A. Yes.

Q. Please tell us how you did your review.

A. I looked through the studies, read through the studies, looked at the discussion of the alternatives in the studies and the assumptions of costs in the studies. I then considered whether

those assumptions of costs were reasonable in terms of 2003 -- late-2003 and 2004 when they were prepared, and I concluded they were.

I then looked at the costs in those studies and thought about the cost estimates for the various alternatives in those studies compared to what the same alternatives are now being estimated at, and I determined that those cost estimates are significantly below the costs being considered today by a range of people, not just Synapse, but by a range of people for the various alternatives being considered that were considered by Sargent & Lundy. And I thought that Sargent & Lundy had done an okay job at the time, but that the numbers were old and out of date.

MS. JAISWAL: Just a few more questions.

Q. Do you recall AMP's counsel posing a hypothetical to you today about the Gorsuch plant?

A. Yes.

Q. And do you recall him talking about -- asking you about shutting down the Gorsuch plant?

A. Yes.

Q. Do you know --

MS. MALONE: Are you saying "Gorsuch"?

MS. JAISWAL: Gorsuch. Sorry. Excuse me, the Gorsuch plant.

Q. Do you know of a reason why a company may not want to shut down a plant?

A. Well, the answer is yes, I think that when there is carbon regulation, existing coal plants will probably have allowances attributed to them which will make generating power at those plants very, very economic, will generate revenues for the owners whether they're public or private, and that when that happens, I think that any entity will think long and hard before they shut down an existing coal plant.

As I say, it will generate revenues, and if it's municipalities that are starving for revenues, they may not be so eager to shut the plants down then as they may indicate today.

EXAMINER BOJKO: I have a follow-up question. Were you talking in general about your opinions about why somebody would or wouldn't shut down a coal plant or are you talking specifically about the plant that was asked of you?

THE WITNESS: I'm talking in general because I've seen no evidence regarding the plant

that's specifically in front of me beyond that they're considering either retiring or repowering.

EXAMINER BOJKO: So you don't know -- you don't have any independent knowledge of why they would or wouldn't shut that particular plant down or keep it going.

THE WITNESS: Well, I do have independent knowledge in terms of comparing what's likely to be the cost of generating --

EXAMINER BOJKO: No. No. No. No. I'm asking about that specific plant, if you have knowledge of what the municipality may or may not be considering in their decision to keep it running or to close it down.

THE WITNESS: That's correct.

EXAMINER BOJKO: Thank you.

You may proceed.

Q. (By Ms. Jaiswal) The Gorsuch plant, the questions regarding the Gorsuch plant were posed to you as a hypothetical; is that correct?

A. Yes.

Q. I think this is my last question. This is my last question. Mr. Schlissel, based on your expertise, what is your recommendation to this board

in evaluating the proposed project's CO2 cost, construction cost, and cost of alternatives?

A. Before the board makes an ultimate decision, require AMP-Ohio to go back and do further studies. I don't know the legality of whether that can be done before denying it or as an interim step.

The world has changed, is in the process of changing, and the risks of the changes need to be studied before a commitment is made to built such a large coal plant. It may be that it turns out that the plant is the most economic option, lowest-risk option when you consider those; that is certainly a possibility. But that the study, a fair study needs to be done and that's my recommendation, that it be done before there be a decision approving the plant.

MS. JAISWAL: No further questions, your Honor.

EXAMINER PRICE: Staff?

MR. WRIGHT: No.

MS. MALONE: No questions.

EXAMINER PRICE: Mr. Bentine.

MR. BENTINE: I have a few, your Honor.

- - -

RECROSS-EXAMINATION

By Mr. Bentine:

Q. If you know, Mr. Schlissel, it is the objective of your clients to stop this plant from being built; isn't it?

MS. JAISWAL: Objection, your Honor, on multiple grounds: Objective, lack of foundation, Mr. Schlissel is not a representative for NRDC, he has -- there's no basis for him --

EXAMINER PRICE: He's your witness. He's NRDC's witness, and he can answer the question if he knows the answer.

A. I'm generally aware that that is their objective, yes.

Q. And you indicated early on in the redirect by your counsel that you weren't recommending cancelling the plant, you were simply recommending that more studies have to be done before it would be approved.

A. That's what my testimony says, yes.

Q. And I believe you indicated in earlier testimony, perhaps with a question from the Bench, that you thought all those studies could be done in four to six months?

A. Three to six months.

Q. Three to six months; close enough. So let's say we stopped today and we did those studies in three to six months.

A. Okay.

Q. And we came back to the Commission with those studies and filed a supplement to our application and that gets set for hearing, and then we have discovery and we have more filed testimony and we get it set for hearing and we're back here, oh, how long, 90 days after the six months is over?

A. Okay.

Q. So that's nine months.

A. Okay.

Q. What do you think is going to be -- do you think those EPC contractors that are going to give us bids in February are going to say "Fine, guys, why don't you wait"?

MS. JAISWAL: Objection.

EXAMINER PRICE: Grounds?

MS. JAISWAL: Lack of foundation. Mr. Schlissel does not know what -- can you have the question read back? I'm sorry.

(Question read.)

MS. JAISWAL: He does not know what is in the mind of the EPC contractors.

EXAMINER PRICE: He's been testifying as to cost of construction. Overruled.

A. Do I think they're going to do that? They might, they might not.

Q. They're not going to hold those bids for nine months while we wait on another proceeding at this board.

A. No, they'll probably give you new bids at that time.

Q. Do you think they would? Or do you think maybe they would think maybe this project isn't going to get built and not bid?

A. I don't know. That is really speculative.

Q. You don't know.

A. Do you want me to finish the answer or no?

Q. Yes. Go ahead.

A. I don't know specifically what's in their heads, but it would seem to me based on past experience with EPC contractors and vendors, which I have reviewed in a number of projects, that they're

more likely to want to bid on the work and to see if they can time it to fit in with their slack work or their open periods and they'll consider whether they're going to expand their capacity in order to do the work. That's the history of what's happened in the past and we'll see whether it happens now.

Q. And your testimony is, is it not, that one of the reasons construction costs are skyrocketing is because there's a lot of business out there for these guys?

MS. JAISWAL: Objection. Mr. Schlissel's testimony -- can you have the question read back, please?

(Question read.)

MS. JAISWAL: Mr. Schlissel's testimony speaks for itself.

EXAMINER PRICE: Overruled.

A. That's right. But whether that means they won't want to bid on this project is speculation.

Q. Tell me this, Mr. Schlissel, do you think that having a fewer number of bidders might drive the price up?

A. Sure.

Q. Thank you.

A. But are you sure there's going to be a fewer number of bidders? No.

Q. Do you know how many bidders we have on this project, sir?

A. No, I don't believe that's in the information. I don't believe I --

Q. Do you know how many contractors in the United States are financially technically able to build a project like this?

A. I think it's somewhere in the range of six to eight is the number I've seen.

Q. Six to eight?

A. Yes, that's the number I've seen.

Q. And do you know how many of them operate in this region?

A. Operate in this region? I'm not aware of any that don't -- won't go to where the work is so I don't know that there are any that will say "We don't want to go to southern Ohio."

Q. You discussed figure 3, figure 2, and figure 4 in your testimony in response to questions by your counsel. Do you recall that?

A. Yes, sir.

Q. And you also then discussed figures 5 and 6, and I believe that you said that figure 5 and figure 6 were appropriate because they just looked at current bills, correct?

A. I didn't say "appropriate." I said they just looked at current bills and that's why all the points from figure 3 are not in figures 5 and 6.

Q. But the previous bills were okay to use in figure 3, they're just not okay to use in figure 5 and figure 6; is that right?

A. Yes. In figure 3 I was attempting to give a portrait of how we developed our forecast in 2006. In figures 5 and 6 I was looking at a comparison with the bills, the studies of the bills that exist today. The bills from figure 3 no longer exist.

Q. And, once again, those were bills which were considered in your figure 3.

A. That's correct. That's why we have reevaluated our forecast as compared to analyses of the current bills and have concluded that it is still valid.

Q. Now, you talked about a lot of -- there was a lot of discussion about scale-up and your

experience in scale-up and you went back to the nuclear plants --

A. Yes, sir.

Q. -- that you talked about.

A. Yes.

Q. First of all, let me ask you this: How many hours did you spend studying Powerspan?

A. Looking at the documents, a couple of hours.

Q. And from a couple of hours reviewing documents on Powerspan you've become an expert?

A. I'm not saying I'm an expert on Powerspan. I'm talking about the risks associated with relying on a $20-per-ton estimate.

Q. Well, do you think two hours worth of research on Powerspan puts you in a position to talk about estimates about Powerspan and what it's going to cost?

A. Absolutely. I looked through all of the estimates of the costs that I could have -- that I could obtain and, firstly, none of them actually supported $20 per ton. There was no estimate that showed for the $20 per ton. And then applying all of my experience looking at the way costs had changed

during scale-up of other technologies, I believe that is adequate for a conclusion that the ultimate cost of the Powerspan CO2 technology may be significantly higher than $20 per ton.

Q. What exactly did you do in that two hours that you spent making yourself familiar with Powerspan?

A. I tried to follow through and see exactly how each of the cost estimates were calculated and what --

Q. How much --

A. Excuse me.

Q. Go ahead.

A. -- and what information was available to back up the assumptions in each of those estimates.

Q. So you didn't look at the process. You looked at cost estimates.

A. What do you mean by "the process"?

Q. The process of Powerspan. How it works.

A. Yes, I looked at the process of Powerspan and how it would -- how it is expected to work and how it has been tested in the lab. Yes, I looked at that. And it looks promising. But there's a big gap between promising and a done deal.

Q. Now, when we're talking about Powerspan here, why don't you tell me what you mean by "Powerspan."

A. The aqueous ammonia process using ammonium hydroxide in liquid, runs the CO2 through it, forms -- is it ammonium carbonate and ammonium bicarbonate which then go through a regenerative process where it's heated, the CO2 is released, the ammonium is captured for reuse in the process. That's what I believe the Powerspan CO2 process is.

Q. That wasn't my question. My question was --

A. I thought that was your question.

Q. No. My question is "What is Powerspan"?

A. I thought your question was what was the Powerspan process.

Q. It is. And your answer --

A. I just said what the Powerspan process -- my belief in the Powerspan aqueous ammonia process is. Powerspan is a company located in Portsmouth, New Hampshire.

Q. Okay. Now, you just gave me a description of the Powerspan CO2 capture process; did you not?

A. Yes, sir.

Q. And at least as currently proposed AMP-Ohio is not proposing to build in the Powerspan CO2 capture process in its plant; is it?

A. No, it's not.

Q. Okay. You do understand that AMP-Ohio is proposing to use the Powerspan ECO process for SO2 control.

A. That's correct.

Q. Okay. Well, you didn't say anything about SO2 control in that last answer when we said we were talking about Powerspan.

A. I thought your questions were -- we had been talking about the $20 per ton CO2 figure. I assumed you were talking about the CO2 process.

Q. You do understand, then, that when we talk about Powerspan, there is an SO2 process and there's a CO2 process.

A. Oh, of course.

Q. And in your determination about the $20 cost did you take into account that at least a certain portion of the costs associated with Powerspan was going to be included in the Powerspan SO2 process --

MS. JAISWAL: Can you have -- I'm sorry. I thought you were finished.

Q. -- that wouldn't have to be added then to come up with the Powerspan CO2 process?

A. Yes, I did consider it, but there's no estimate of how much and exactly what would be considered in the SO2 process. So yes, I considered it, but there's no evidence for calculating or quantifying how much of an effect that might have.

Q. No evidence that you looked at, correct?

A. I looked at all the evidence you folks gave me and that I could find, the NETL study, so I've looked at everything I could look at. If you're saying is there something that I didn't look at, yes, it's certainly possible that I wasn't given information that exists. Absolutely.

Q. Well, have you visited any of the Powerspan demonstrations?

A. Did I go to the lab? No, I didn't, for the CO2. And for the commercial demonstration unit, no, I didn't. I had a limited time to look at this project, and I'm not sure what information taking the time to go look at the absorber unit from the outside would really tell me.

Q. If your clients would have intervened earlier in this case, would you have perhaps had more time to look at that stuff?

A. I don't know.

Q. Can you tell me physically what gets added on in terms of physical plant when you take the Powerspan SO2 process and layer on the Powerspan CO2 process?

A. You'd have to have a --

MS. JAISWAL: Objection.

EXAMINER PRICE: Grounds.

MS. JAISWAL: Mr. Schlissel is an expert on costs, on CO2 costs and construction costs, and alternatives. I believe that Mr. Bentine is asking about technical expertise. We have not offered Mr. Schlissel on that basis.

EXAMINER BOJKO: Can I have the question reread?

(Question read.)

MR. BENTINE: If that is a stipulation, that this witness has no expertise with regard to the technical aspects of Powerspan, I'll certainly accept that.

EXAMINER PRICE: Are you willing to

stipulate that?

MS. JAISWAL: My objection was to the basis of his expertise on the process and what his testimony is offered for. No, we will not stipulate to that.

EXAMINER PRICE: Okay, objection's overruled.

Q. (By Mr. Bentine) Can you answer the question, sir?

A. Yes, you add on an absorption unit, a regeneration unit. You probably, in order to avoid ammonia slip into the environment, want to wash the flue gas after it exits from the absorption unit. You need some pumps. I think generally that's the equipment you'd have to add.

Q. And as we spoke earlier, some of the equipment is already there.

A. Well, there are pumps. For the CO2 process it's laboratory scale so we'd have to see what happens when you scale that up to large size.

Q. Well, the ammonia handling equipment is already there.

A. Oh, so do you physically have equipment to handle ammonia at the front end? Yes, but

remember you're going to be talking about a process that's regenerating ammonia constantly or else it's not economic. Excuse me, let me finish, so that the ammonia -- you have tanks on site to handle ammonia. You would have some kind of pump or piping to send some ammonia to the CO2 capture unit, but unless you're recapturing the ammonia and reusing it, I would imagine it probably would not be economical --

Q. I'm not asking you to imagine. I'm asking you to tell us what you know of your own personal knowledge.

A. I'm telling you what I would know of this if you let me finish.

Q. No; you're imagining.

MS. JAISWAL: Objection, your Honor. Statement's argumentative.

EXAMINER PRICE: Sustained.

MS. JAISWAL: I request an instruction to counsel.

EXAMINER PRICE: Your objection is sustained.

Finish your line of questioning.

THE WITNESS: Yes, I used the word "imagine" as thinking of that.

EXAMINER PRICE: Just finish your answer.

THE WITNESS: That my informed estimate is that you would want to recapture the ammonia or the process is more expensive; you're consistently buying more ammonia. I don't believe that that equipment for regenerating the ammonia and recapturing it is in the SO2 design. From the CO2 process, not the SO2 process.

Q. Now, can you tell me the difference in estimated costs for Powerspan if it is retrofitted completely as opposed to added on to a Powerspan SO2 process?

A. No, I've not seen that; I cannot.

MR. BENTINE: I want to go to Citizen Groups' 10 which I think is confidential.

EXAMINER PRICE: Mr. Bentine, are you doing all of your portions of your recross that are confidential at this time? Or let me rephrase that. It will be greatly helpful if you could do all of your portions that relate to confidential, if you cannot, you cannot. If you can, that would be helpful.

MR. BENTINE: I'll attempt to, your Honor.

(CONFIDENTIAL PORTION EXCERPTED.)

(OPEN RECORD.)

Q. (By Mr. Bentine) You were asked a couple of questions about overreliance on natural gas. Do you have an opinion as we sit here today on what upper limit of reliance on natural gas that an entity like AMP-Ohio should have for baseload generation?

A. No. You'd want to look at it as part -- see what the results of your sensitivity studies show. If the sensitivity studies show that your high price range is a severe problem, then you'd want to limit it. I think it depends on how you analyzed the results of your studies. But I have not done the studies so I can't tell you whether it's 10 percent, 20 percent.

Q. Should it be 50 percent?

A. I don't know that I'd recommend 50 percent. That's a high reliance for a system.

Q. I believe you indicated in response to questions by your counsel that you didn't think that

alternate Energy Resources could fill the entire 2,000-megawatt gap.

A. That's correct.

Q. And, by the way, just to make it clear, until you were on the stand here yesterday your belief was the 2,000-megawatt gap was a regional gap not an AMP-Ohio gap, correct?

A. No. I indicated as I sat here yesterday I made a mistake and thought it was a regional, not an AMP-Ohio gap.

Q. But you do --

A. And I acknowledged that I made that mistake. That's what I said. What I thought was referring to a regional was the AMP-Ohio.

Q. With regard to the alternate resources that you were talking about with your counsel, you said that there could be some capacity and then cheap energy. What cheap energy were you talking about there?

A. The wind is cheap energy.

Q. The wind is cheap --

A. In terms of its running cost.

Q. In terms of running cost. And hydro's cheap energy in terms of running cost, correct?

A. Correct.

Q. It's the capital cost that may or may not make them inexpensive.

A. That's correct.

Q. And in any event, when looking at the total cost of power supply, one must look at capital cost as well as operating cost, correct?

A. That's correct.

Q. Do you know whether or not AMP-Ohio has applied for clean renewable energy bonds?

A. I believe I saw some reference to the fact that they had.

Q. And do you know, have they applied for clean renewable energy bonds for both wind and hydro?

A. No; I don't know that. I recall looking through the documents and seeing a reference to renewable energy credits, bonds, but I don't recall any more details.

Q. Do you know whether or not AMP-Ohio is pursuing natural gas combined cycle?

A. It's in the supply plan. I don't know the current status of the pursuit, but it's in the supply plan.

Q. Let's go to customer group No. 9.

A. Which one is that?

Q. Citizen Group. Excuse me, Citizen Groups. Sorry.

Do you still have a copy of that in front of you?

A. Which one is it?

Q. That's the cost and performance baseline.

A. The NETL study?

Q. Yes.

A. Yes.

Q. First of all, I think, as reflected by your counsel holding up that weighty document, this is an overview of a detailed study, correct?

A. That's correct. I didn't prepare this overview. This was prepared by the authors of the study. They gave it in May and then in August. Just so we're clear that I didn't pick and choose the pages.

Q. No; I understand that. I understand that.

Would you turn to page 4?

A. Four?

Q. Yes.

A. Yes, sir.

Q. This is the study matrix that shows what was studied in this NETL study?

A. Yes.

Q. And the left-hand column is plant type?

A. Yes.

Q. And the next column to the right is steam conditions?

A. Correct.

Q. The next column is the kind of turbine that it has if it is a gas turbine?

A. Yes.

Q. The next column is the kind of gasifier or boiler according to whether it is a IGCC or some other kind of unit?

A. That's correct.

Q. And the next column is, what?

A. The methodology they used for -- they're talking about for CO2 separation, SO2, and NOx I believe.

Q. Okay. Now, let's look at the IGCC there under that same column that we just talked about. That has the kind of CO2 capture and acid gas capture that is estimated in this study, correct?

A. I believe that's true. I've not really

looked at this study for the IGCC. I've not spent a whole lot of time in my work the last year looking at IGCC, so in a lot of ways I'm exploring this with you as my first look at the IGCC piece of this.

Q. Let's look at the PC piece of this. Under Subcritical there are two cases looked at, one with CO2 capture and one without. The non-CO2 capture is a wet FGD with a by-product of gypsum?

A. Yes.

Q. And the PC unit is a wet FGD with Econamine and gypsum?

A. Yes.

Q. And that is the amine process; is it not?

A. Amine. Yes. A-m-i-n-e.

Q. You say "potato," and I say "potato."

A. Our Ohio and New York accents, yes.

Q. And for the supercritical the same two options, correct?

A. Yes, sir.

Q. This is not an aqueous ammonia study, is it?

A. That's correct. I assume they looked at what they thought was going to be developed.

Q. So this study on its face has nothing to

do with cost predictions for the Powerspan process or any other ammonia process for that matter, correct?

A. I wouldn't say "nothing." But it certainly gives numbers for the amine process; that's true.

Q. And doesn't give numbers for the ammonia process.

A. That's true, too.

Q. Your counsel asked you a couple of questions about shutdown of the Gorsuch plant. Do you have any reason to believe that AMP-Ohio or any of its members would mislead this board or anybody else with regard to its plans for Gorsuch?

A. No, but I'm just looking at what I believe the relative economics would be five, six years down the line if, in fact, there is CO2 regulation that affects the market price compared to the price of generating power at a power plant that has a free emission allowance.

Q. I thought we talked earlier in our cross-examination about the likelihood that if there were such allowances, they could be transferred from Gorsuch station to the AMPGS.

A. Yes, we discussed that some.

Q. So assuming that AMPGS goes ahead and Gorsuch would be shut down, that value could be transferred; don't you think?

MS. JAISWAL: Objection; asked and answered.

EXAMINER PRICE: Overruled.

A. It could be, but it may be more economic at the time to keep it at Gorsuch or to repower Gorsuch as an IGCC or other kind of coal unit. That will be a decision that the AMP members will have to make down the road when they see the economics.

Q. Do you know which AMP members will make the decision with regard to Gorsuch station?

A. I imagine the board.

Q. There we go again. You're imagining. Do you know?

A. No, I haven't studied what members vote on which project. That's outside the scope of what I've looked at for this case.

Q. Well, you did look at the Cleveland contract for the AMPGS project; did you not?

A. That's correct, and it didn't talk about who was going to vote on the possible retirement/ repowering of the Gorsuch plant.

Q. But it did talk about who was going to vote with regard to a large number of issues on the AMPGS plant; did it not?

A. Are you talking about the contract?

Q. Yes.

A. Yes, and you and I talked about that paragraph in the power supply contract.

Q. Well, are there more things than just the cancellation of the plant that the participants have authority over under that contract; if you know?

A. I've read the contract, maybe it's the late part of the day, I don't recall all the details in it. If you have a specific reference, I'm willing to accept -- I'll look at the language and agree with you or not.

Q. You indicated that with regard to Gorsuch, again, keeping it running, that there may be -- that there may be municipalities that are, quote, "starving for revenues." Do you recall that?

A. That's correct.

MS. JAISWAL: Can I have the -- I was going to have the question read back.

Q. If you know -- well, let me strike that. Let me ask it this way: Are you aware that the Ohio

constitution limits the amount of power that a municipality can sell outside of its corporate limits?

A. You mean power in terms of electricity? No, I wasn't aware of that.

Q. Are you also aware that to the extent a municipality has revenues in its municipal utility that is significantly in excess of the costs, that that too may be considered a tax and could be unconstitutional?

MS. JAISWAL: I'm sorry, I didn't hear the question, Mr. Bentine; you're turning away. I am trying to hear.

May I please have the question read back?

(Question read.)

A. No; that's far afield from anything I looked at in this case and testified to.

Q. But it may impact on your speculation as to what municipalities starving for revenues might do with the Gorsuch plant.

A. Right. And that's something the municipalities at the appropriate time, I assume, will study.

Q. Do you still have AMP-O 10?

A. Which is AMP-O 10?

Q. That is the Synapse proposal.

A. Yes.

Q. I believe you indicated that, and it's shown on page 16 that this proposal was to study the power supply for the city of Oberlin and you proposed, Synapse proposed, excuse me, to charge 49,500 for that.

A. Yes, sir.

Q. R.W. Beck did a similar power supply study and maybe you don't agree with all of it, but they did a similar power supply planning study for all 119 AMP-O members; did they not?

A. That's what it said, yes.

Q. And would you accept, subject to check, that 119 times 49,500 is a little over 5 million bucks?

A. Sure, but there are economies of scale in doing studies, doing a large number of studies.

Q. But you do accept that AMP-Ohio has provided that to its members.

A. Provided what? You've got to --

Q. The power supply studies for each of its members.

MS. JAISWAL: Objection; asked and answered.

A. Yes. They did provide them, yes.

EXAMINER PRICE: Overruled.

MR. BENTINE: Let me try to ask this question without going back to the confidential.

Q. AMP-O Exhibit 14 is the project feasibility study full tilt.

A. Okay.

Q. Would you accept, subject to check, that in section 6 of that exhibit there are comparisons to other resources?

A. If you hold on a second, I have section 6 in front of me and without disclosing anything confidential I think I can answer your question.

There's a bus bar cost chart between AMPGS, coal, combined cycle, and market.

Q. Thank you.

MR. BENTINE: If I might have a moment, your Honor, I may be done.

EXAMINER PRICE: Sir, I would like you to, without disclosing anything confidential, if you could restate your answer because I don't think that was very clear for the record. So if you could

restate your answer again, please.

THE WITNESS: Well, he asked me if they looked at alternatives, and I said there is a bar chart in that section that compares AMPGS to a coal plant, a combined cycle plant, and purchases from the market.

EXAMINER PRICE: Thank you.

THE WITNESS: Okay. I hope that's helpful.

EXAMINER PRICE: I think we misheard it.

MR. BENTINE: One more short line, hopefully, your Honor.

Q. (By Mr. Bentine) AMP-O 12, and I'm not sure you still have one of those up there with you.

A. Yeah, I do. We didn't use it during redirect, but I do have it.

Q. Very good.

A. Thank you. I figured you'd move to strike, but I wanted to say it anyway.

Q. No, that was too good to move to strike.

I want to turn your attention, and I will connect it to your redirect, to the AMP-O power supply strategy, and again, I apologize, but it's CWS 00237.

EXAMINER BOJKO: Thirty-seven?

MR. BENTINE: Yes, CWS 00237.

A. Yes, you and I talked about this during direct [sic].

Q. There is on that chart a hundred megawatts of new wind and landfill gas resources. Do you see that?

A. Yes.

Q. As you sit here today do you know what AMP-Ohio's efforts with regard to new wind and landfill gas resources are?

A. Beyond that they're attempting to line them up, no, I don't -- I've not looked at the specific efforts.

Q. Okay. Do you think this board should wait until we have those lined up and have firm cost figures for those to decide whether or not to approve AMPGS?

A. It depends on when you expect to have those firm cost figures. If it were nine months, I'd say no. If it were three or four months and you could incorporate them in new studies, I'd say yes. If it were nine months, I'd say do studies with the best cost estimates that you've got. But I don't

think -- it would depend on how long it would take to get the firm numbers.

Q. Regardless of what those numbers are, do you believe it would change the need for AMPGS?

A. Well, it might give you an essence of -- well, it probably won't change the need for new capacity, but tied in with the other points that we've made numerous times the last couple of days about other risks, it might change the bottom line of the analysis in terms of what is a lowest-cost, lowest-risk plant.

Do these numbers on their own, are they going to change it? Of course not. But studied in new circumstances the overall result may be a different result -- the overall result may be different.

I hope that's clear on the record.

MR. BENTINE: I think it's as clear as it's going to get on the record. That's all I have for this witness on redirect -- on recross; my God.

EXAMINER BOJKO: I have just a couple quick questions.

- - -

EXAMINATION

By Examiner Bojko:

Q. I've heard a lot about studies and I heard one study was going to take three to six months, I believe, but it seems like every issue that was raised more studying needs to be done, more estimation of costs, and also seeing that you were talking that things change over time so maybe more studies need to be done. I guess when do you suggest is enough study, enough study, and that we move forward? Can you pick a point in time where you think we've gathered all the information possible and that we can move forward?

A. Yes. It's not as hopeless as you make it seem. The resource -- the power supply plans that R.W. Beck prepared and gave to the AMP members in February of 2007 were based on plant cost estimates from February of 2006. They're now two years old, that is substantially below what the AMP now estimates for the cost.

Q. But, I mean, aren't there --

A. The cost has gone up significantly.

Q. Right. But --

A. Obviously -- I don't mean to interrupt

you.

Q. Well, but, I mean, you will admit that it does take some time to create a study. I mean it takes some time to go out and procure a consultant and it takes time to actually conduct a study and as you a consultant know, there's five reports that you give a client before a final one is approved.

EXAMINER PRICE: Isn't there always a lag?

Q. Yeah, it takes time to do those things and then you've also mentioned that they need to do more wind cost estimate studies. When is it enough?

A. Well, I believe it's enough when the cost has gone up significantly as it has to their current estimate from the estimate they used in the power supply cost, as I mentioned, that's now almost two years old, that when a range of CO2 estimates -- and that's why I put in figures 5 and 6 in my testimony, it's not only the Synapse numbers, it's a range of reasonable, independent CO2 price forecasts that show higher, much higher in some cases, possible CO2 costs than R.W. Beck has considered.

Q. So you --

A. Due to those changes you could see I want

you to -- any data you've got that you can agree to as of January 1st or January 10th, 2008, unless the world cracks in half, that's the data you base it on. That's going to be far more current data than what they did use.

Q. I mean, okay, say they pick January 1st, 2008, as the date certain, so to speak. Then what if legislation is enacted in February or March of 2008? I mean, right now you're saying pick January 1st when there's no legislation for CO2 that would be probably finalized by that time. So are you suggesting then when we do get a new bill that actually goes through and is signed into law, that we do more studies based on that new legislation?

A. Isn't it better to do more studies than to start building a project that may, and I'm not --

Q. Answer my question first. Would you recommend another study after any kind of legislation passes?

A. Sure. At some point they --

Q. Okay.

A. They may be under construction, but they certainly should reevaluate at that time. They may

find that the plant is more economic. I've looked at management --

Q. But you picked January 1st, 2008, as a date, and then I just told you that there, you know, let's assume legislation was enacted after that, and you said "Yeah, more studies need to be done." Well, then I could see us all back here and you saying that those studies weren't enough and that we need to do more studies. I mean, they did pick a date. They picked the date that was in their cost estimate and then they based their application on that, and you're saying that's insufficient and --

A. No.

Q. Wouldn't another date be insufficient, too?

A. I'm not being clear, I apologize.

Q. Okay. Please explain.

A. I think that if you could require -- you were so inclined to require them to do new studies, I don't think that they -- they should either get a thumbs up or thumbs down from the Power Siting Board based on the risk and the cost in the new studies.

Q. What new studies?

A. If you required them to do new studies,

I'm not saying they would have to come back to you in a year or two, but I think that they will evaluate, reevaluate the cost estimate as things change, they will reevaluate CO2 costs as things change, prudent management does those kind of things. They wouldn't have to come back to you for another approval. They wouldn't have to come back to you for reapproval.

All I'm saying is before you base -- make a decision as to your approval, you base it on the most current data considering the risks faced by the project.

Q. Well then I really don't understand your testimony here today before us because if you're saying that they should just go do new studies and that the board doesn't have to consider any new data --

A. No. No, that's --

Q. You said I could already approve it, just require more studies, but then --

A. I'm sorry; that's not what I'm saying. What I'm saying is my recommendation is they do studies based on more current data and then come back to you for a final approval.

Q. I'm sorry, you said they didn't have to

come back to us for approval.

A. No. No. Now, in the near future, after that, after you and the Power Siting Board issues its final approval, then I don't see that they have to come back to you if they reevaluate conditions as things change, then it's outside of the Power Siting Board's jurisdiction, I'm not saying as a legal matter, just my opinion as a consultant. So it would be outside of the Power Siting Board's jurisdiction. That's what management then decides, whether to continue or not based on changing circumstances.

But I just believe that you need to have your decision based on the most current data.

EXAMINER PRICE: Here's my question: There's always a lag in case preparation. This application was prepared in May. Previous to preparing the application they went through their feasibility studies, they went through all these other studies we've gotten a chance to look at today.

If we do a new round of studies, then we'll have a new proceeding, we'll have a new application, we'll have a new round of trial preparation, a new Staff Report perhaps, which may take 60 to 90 days, a new round of intervenors.

There's always going to be a lag. If we ordered a new set of studies, six months later there's going to be new information. I mean, when does this board draw the line and say "Enough is enough"?

THE WITNESS: I mean, that's a decision for you to make.

EXAMINER PRICE: I'm asking for your recommendation.

THE WITNESS: Okay. My recommendation is that because they haven't fully considered the possible impact of CO2 costs, that it's not enough yet.

Q. (By Examiner Bojko) Which impact of CO2 costs? That's where you're missing me on that.

A. Okay. Look at figure --

Q. There's no legislation --

A. That's right, there's no legislation. So what do you assume? It's possible that CO2 costs will be low, it's possible that CO2 costs will be high. So you need to evaluate that risk in your project because it will have a major effect on project costs.

Q. I thought we've already established through the hearing that they did look at pending

legislation. What I'm struggling with --

A. No.

Q. -- it seems to me you're asking them to do a study on every scenario of every legislation that may or may not come to fruition and I don't see where that ends.

A. Their response, which is in the record, is that their CO2 forecast is based on a December 2004 study. That's now three years old. The party that did it no longer supports that proposal, the National Commission on Energy Policy. On prices in Europe and certain other studies that were not listed, that's old data. There's no evidence that they've looked at their cost estimates in light of current pending legislation.

Our cost estimate we've looked at in light of pending legislation.

Q. So you'd like them to do a study on the current pending legislation, all of it, which I guess I missed something because I thought we had heard yesterday that that had happened, but I don't want to testify.

So I think that you're saying that they need to relook at that based on pending legislation

and then whatever that result is, that result is, so then if we -- and a month from now if something gets signed into law, okay, we don't need to study anymore because we already studied pending legislation. Is that your position?

A. No. There's going to be no federal legislation on CO2 gases until the current administration leaves the White House; whatever party you are, Democrat or Republican.

Q. So what year do you estimate that any legislation may even --

A. The current estimate is 2009 legislation will be passed.

EXAMINER PRICE: But whatever, it may or may not pass, if that were true, and I think we're starting to go far afield, and I appreciate your thoughts on legislative strategy, but I'm not sure you're qualified for that, but what we do know is if something were to pass in 2009, it will not be one of the bills you studied because, as you pointed out, when Congress expires on January 1st, 2009, all the pending bills will go away; isn't that correct?

THE WITNESS: Sure. It may be the Lieberman-Warner bill in 2009. But if you look at

the history of the bills before Congress, is that they're getting more strict over time, they're not getting less strict.

EXAMINER PRICE: Bills that are being introduced.

THE WITNESS: Bills that are being introduced and considered. And the Lieberman-Warner bill that passed committee is the one that's furthest advanced than any has actually made it in the Senate.

EXAMINER PRICE: Is it likely to have the highest carbon costs?

THE WITNESS: The studies of it are not out yet. The EIA and EPA are doing studies of it, they should be any day now literally, but certainly the reductions it would mandate are similar to some of the most stringent.

EXAMINER PRICE: I don't want to get too far afield, and I appreciate counsel's patience with our questions, but I do have one last question, Mr. Bentine. Ms. Bojko may have another one.

I would like to tie this back, and if you can't answer this question, you can't answer it.

THE WITNESS: Okay.

EXAMINER PRICE: If you can, you have to.

But you did indicate earlier you looked at the statute, and I want to know if you can tie back your recommendation for further studies to the board's statutory criteria for making a decision in this case.

THE WITNESS: I'm sorry, I can't.

EXAMINER PRICE: If you can't answer the question --

THE WITNESS: I didn't look at that. I apologize, I can't answer that one.

EXAMINER PRICE: Thank you.

Q. (By Examiner Bojko) I hope this to be my final question --

EXAMINER PRICE: Don't make any promises.

Q. -- or two questions. I was a little thrown off on representations of who your testimony is really here supporting today. Are you a witness for citizen groups or are you a witness for one or two of the entities underneath the collective citizen groups?

A. All I'm --

Q. Who are you here as a witness for today?

A. All I know is my testimony is sponsored by NRDC and Sierra Club.

Q. Okay. So it's not sponsored by all of the citizen groups that have intervened?

A. The answer -- all I know is what I've answered.

Q. Okay.

A. If there are more citizens groups, then we're clearly not. I know that at one point I was told it was going to be Ohio Environmental Council then I was told it was not. That's the complete -- my complete knowledge of the situation.

Q. Okay. Thank you, that helps.

EXAMINER BOJKO: I'm done.

MR. BENTINE: I'm not trying to testify here, but just so it's clear on the record, and I can do it through a question of this witness or not, but there is one thing I think is unclear on the record right now with regard to the cost estimates.

EXAMINER PRICE: I am most reluctant to allow examination after we finished our questions.

MR. BENTINE: Then just let me state for the record to clear it up that my belief is that the record reflects that there is going to be cost updates after the EPC contracts are in by R.W. Beck and a final report, and I believe this gentleman

testified to it. So that, I believe we said, was going to happen in the first quarter of next year. Those reports were going to come out in February, and there is the March 1st off-ramp date for our communities, which these folks are working very hard to see that everybody gets off.

EXAMINER PRICE: Let me observe that you can make that point in your posthearing brief if it does, in fact, the record does reflect that.

Thank you.

Are you done?

EXAMINER BOJKO: Yes.

EXAMINER PRICE: Thank you.

THE WITNESS: Think I'll make my 5 o'clock plane?

EXAMINER BOJKO: No. We knew you wouldn't.

THE WITNESS: Thank you very much for my indulgence yesterday when I couldn't be here.

(Witness excused.)

EXAMINER PRICE: Let's go off the record.

(Discussion held off the record.)

EXAMINER PRICE: Let's go back on the record.

Ms. Jaiswal, do you have a motion for me?

MS. JAISWAL: Yes, I do, your Honors. I have a motion to move Mr. Schlissel's written testimony into the record along with the exhibits that were introduced by the citizen groups.

EXAMINER PRICE: So we're talking about Citizen Groups' 6 --

MS. JAISWAL: Yes, and the exhibits that follow afterwards.

EXAMINER PRICE: -- 7, 8, 9, and 10.

MS. JAISWAL: And I believe you identified 7A.

EXAMINER PRICE: We're holding 7A for the color copies.

MS. JAISWAL: Thank you for clarifying.

EXAMINER BOJKO: Are you moving the entire 7 into the record?

MS. JAISWAL: That is up to the court. Whatever the court would prefer. Whatever the law judges would prefer, we will follow that.

EXAMINER PRICE: I really would prefer not to enter a 168-page exhibit when we did work on one page. Would it be possible to simply move pages 8, 9, and 10, which will be that entire section that

he's talking -- that paragraph?

MS. JAISWAL: Certainly.

EXAMINER BOJKO: Along with the cover page.

EXAMINER PRICE: Along with the cover page.

MS. JAISWAL: In color, that will be 7A; is that acceptable?

EXAMINER PRICE: Yes. We're not going to move 7 at all.

MS. MALONE: Page 7?

EXAMINER PRICE: No; we're not moving 7 yet.

EXAMINER BOJKO: No; pages, 8, 9, 10.

MS. MALONE: That was my question. Thank you.

EXAMINER PRICE: Pages 8, 9, 10, and we'll deal with 7 tomorrow.

MS. JAISWAL: And we'll be FedEx'ing that tomorrow to arrive Friday, I believe.

MR. BENTINE: With regard to Mr. Schlissel's testimony, I have no objection to that as modified by your Honors' rulings and that's 6. With regard to 7 --

EXAMINER PRICE: We're holding off on 7 anyways.

MR. BENTINE: I'm sorry?

EXAMINER PRICE: We're holding off on 7 anyways. We have to wait till we have the actual exhibit.

MR. BENTINE: Do you want to hear about 8, 9, and 10?

EXAMINER PRICE: Absolutely.

MR. BENTINE: Eight; no objection.

Nine; yes, we do object on relevance. I believe it was clear from the cross-examination that this document has nothing to do with AMP-O's proposed ammonia-based SO2 or potential CO2 capture. So we object to that one on that basis.

EXAMINER PRICE: Do you have an objection to 10?

MR. BENTINE: No, we don't object to 10.

EXAMINER PRICE: Okay. Then let's let the record reflect that 6, 8, and 10 will be admitted.

(EXHIBITS ADMITTED INTO EVIDENCE.)

EXAMINER PRICE: And we will let Ms. Jaiswal respond vis-a-vis 9.

MS. JAISWAL: Thank you.

EXAMINER PRICE: Citizen Groups' 9.

MS. JAISWAL: I have I believe three points on this, one is that on cross Mr. Bentine brought up the NETL study and he brought up the previous version of the NETL study. He brought up the May 2005 study -- I'm sorry, I'm not sure of the month. It was 2005. Mr. Schlissel on the stand corrected it and said no, actually, what I relied on was the newer version of it, the August 2007 study; this study and the whole study that is here as well. So he has brought it, made it relevant, therefore, we were entitled to ask about it on redirect.

MR. BENTINE: Could I respond?

MS. JAISWAL: The second --

EXAMINER PRICE: After she's done.

MR. BENTINE: I'm sorry, I thought she was.

MS. JAISWAL: Second, as Mr. Schlissel testified, page 27 of this document is directly relevant to the reliability and validating Mr. Schlissel's numbers and costs as he described in his testimony, therefore, it is relevant.

And my third point on it is that this was

also relied -- my third point is that this study also discusses the cost of pulverized coal plants and that is the central issue here. This is a proposed plant, the same type of plant that is analyzed in here, and the cost -- the title is the cost and performance of fossil energy plants.

MS. MALONE: So were you only moving page 27? I thought you were moving the whole exhibit.

MS. JAISWAL: Is that a question from the Bench? Is that from co-counsel?

MS. MALONE: I just want to understand.

EXAMINER BOJKO: She moved the whole exhibit.

MS. MALONE: That's what I thought.

MS. JAISWAL: And the basis for moving the whole exhibit is the completion rule in terms of exhibits; it's not voluminous. However, if the court would please, we will submit it in any format the court will like.

MR. BENTINE: Might I briefly respond on one point?

EXAMINER PRICE: Yes.

MR. BENTINE: That study and the study I'm talking about, our AMP-O 6, are studies of

different technology and that's my point. AMP-O 6 is a study of aqueous ammonia use in postcombustion emission control. That study is a study of an amine, or amine according to where you're from, postcombustion emission control which is different. The witness indicated it was different. It is different. That study is not an update of AMP-O 6 in any way, shape, or form, it's different technology, a different study.

EXAMINER PRICE: Ms. Jaiswal.

MS. JAISWAL: May I respond, please? Mr. Bentine's concerns largely, if they go to anything, go to weight, not to admissibility. The document should be, of course, as your Honor has said repeatedly today, these are the types of considerations you have to weight. In terms of the testimony, the costs in this study are relevant because if Powerspan doesn't work, this report would show what those costs could be.

EXAMINER PRICE: We're going to, in deference to the late hour, we're going to defer ruling on this until tomorrow morning.

MR. BENTINE: I would point out, your Honor, that, with regard to that, if we don't use

Powerspan, we have to come back to the board under the conditions in the --

EXAMINER PRICE: Well, that's the proposed conditions.

Mr. Bentine, do you have any motions?

MR. BENTINE: Yes, your Honor. AMP-O 14, which is the full copy of the Beck study, I'm going to hold off on that, I don't think we're going to move that. AMP-O 15, the power supply plan for the city of Cleveland, we would move that at this time, and that is the confidential portion.

Just a moment, your Honor.

AMP-O 11 is the initial project feasibility study, executive summary that was relied on by that witness in part, I would move it.

AMP-O Exhibit 12 was the presentation to Cuyahoga Falls which was one of the several that was reviewed by the witness in preparation for his testimony here.

AMP-O 13 is the Burns & Roe consulting engineer's report, I'm sorry, I'm having problems --

EXAMINER PRICE: Synapse study, AMP-O 10.

MR. BENTINE: Synapse, yes. Synapse is AMP-O 10, and I would move it at this time as that

was a Synapse document I crossed the witness on.

MS. JAISWAL: Can we ask a point of clarification?

EXAMINER PRICE: One minute, please.

MS. JAISWAL: Certainly.

EXAMINER PRICE: So you're moving the admission of AMP-O Exhibits 10, 11, 12, 13, and 15 at this time?

MR. BENTINE: Everything but 14, your Honor, and 9 I believe has not been admitted yet, I used that in the cross-examination with this witness and that was selected pages from the MIT study.

EXAMINER BOJKO: No, that one was admitted.

MR. BENTINE: That one was already admitted? I apologize.

EXAMINER PRICE: That's okay.

Ms. Jaiswal.

MS. JAISWAL: Your Honor, you asked the question I anticipated.

EXAMINER PRICE: Do you have any questions?

MS. JAISWAL: No, your Honor.

EXAMINER PRICE: At this time AMP-Ohio

Exhibits 10, 11, 12, 13, and 15 will all be admitted.

(EXHIBITS ADMITTED INTO EVIDENCE.)

EXAMINER PRICE: Anything further?

EXAMINER BOJKO: Yes, I would like to makes a motion. I am going to move on Miss Young's behalf -- did you do this yet?

EXAMINER PRICE: I did this. No faith.

With that we will adjourn until 9 o'clock tomorrow.

(Thereupon, the hearing adjourned at 6:00 p.m.)

- - -

CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by me in this matter on Tuesday, December 18, 2007, and carefully compared with my original stenographic notes.

Maria DiPaolo Jones, Registered Diplomate Reporter and CRR and Notary Public in and for the State of Ohio.

My commission expires June 19, 2011.

(MDJ-3116)

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EXHIBIT

Synapse
Energy Economics, Inc.

22 Pearl Street, Cambridge MA 02139
Tel 617-661-3248 Fax 617-661-0599
www.synapse-energy.com

November 29, 2007

Mr. Steve Dupee
Electric Director
Oberlin Municipal Light and Power System
289 South Professor Street
Oberlin, OH 44074

Dear Mr. Dupee:

Synapse Energy Economics is pleased to submit our attached qualification package to the City of Oberlin, Ohio to help the city assess clean and sustainable alternatives to its current electricity contract, which relies on coal. The scope of the proposed work goes to the heart of Synapse's core competencies.

One project referenced in our qualifications package requires further explanation. Synapse is currently working for NRDC, Sierra Club, and Ohio Environmental Council on AMPGS related issues including (1) preparing testimony for the Siting Power Board and (2) looking at possible alternatives for the City of Cleveland instead of the AMPGS project. We have contacted these clients. They have responded that they are comfortable with Synapse potentially working for the City of Oberlin, and they believe the potential City of Oberlin work would complement the on-going work mentioned above. We wanted to do our due diligence to make sure the City was fully aware of this as well.

Thank you for this opportunity to submit our qualifications package. We are excited about this potential project and hope to be able to work with you on it.

Sincerely,

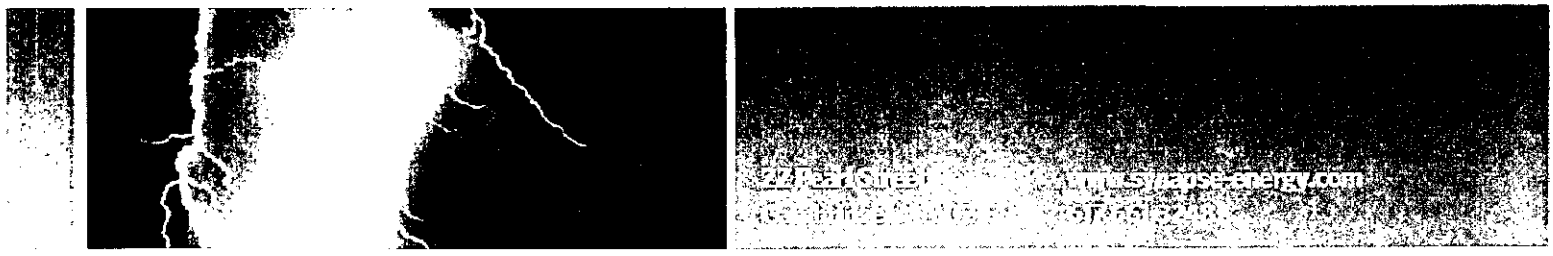
Bruce Biewald

EXHIBIT
tabbies AMPO Ex.10

Synapse
Energy Economics, Inc.

Proposal to Assist the City of Oberlin regarding Power Supply Procurement

November 28, 2007



1. Introduction and Overview

A. Overview

Synapse Energy Economics, Inc. (Synapse) is a research and consulting firm that specializes in energy, economic, and environmental topics. Our primary emphasis is on analyzing policies that lead to sustainable, efficient, and equitable energy production and use. Synapse's goal in submitting this proposal is to provide the City of Oberlin with expert assistance in power procurement issues. Specifically, we will identify opportunities to meet the City's power needs with non coal-based electricity that may include energy efficiency and demand side management (DSM) measures and renewable energy sources.

Below we include information about our organization and qualifications in areas relevant to this procurement.

B. Our Organization

Synapse Energy Economics, Inc. provides research, testimony, reports, and regulatory support to consumer advocates, environmental organizations, regulatory commissions, state energy offices, and others. The company was founded in May 1996 to specialize in consulting on electric industry regulatory, restructuring, and environmental issues. We have a professional staff of twenty.

Synapse assesses the many public policy implications of the energy industry, with an emphasis on consumer and environmental protection. Our work covers various interrelated technical issues, such as market monitoring, market design, load response, transmission expansion planning, regional transmission organizations, renewables, demand-side management, and more. Our research frequently incorporates economic analyses and computer modeling of wholesale markets to ensure that the bulk power system operates in a reliable, competitive, and efficient manner.

Synapse works for a wide range of clients throughout the United States, including attorneys general, offices of consumer advocates, public utility commissions and their staff, a variety of environmental groups, foundations, the Environmental Protection Agency, the Department of Energy, the Department of Justice, the Federal Trade Commission, the National Association of Regulatory Utility Commissioners, and others.

2. Qualifications

Synapse has extensive experience in developing and evaluating comprehensive power procurement strategies. We have recently worked on a variety of integrated resource plans and portfolio management projects, which emphasize diversity of generating technologies and increased utilization of renewables and conservation measures. We understand Oberlin's concerns regarding coal-based supply dependence and environmental effects. We look forward to working with the City on evaluating various strategies to serve the City's future base-load power requirements in an environmentally responsible and financially competitive way.

A. Renewable Energy Resources

Renewable generation resources offer a variety of benefits for electricity customers, and for society as a whole. They provide a hedge against the high cost of fossil fuels, increase the diversity of the electric generation mix, and reduce the risks of electric price volatility. In most cases, they result in little or no environmental impact, and thus represent one of the most promising opportunities for mitigating the environmental effects associated with electricity generation.

In addition, renewable resources help support the local economy and local jobs, while reducing the amount of money that is exported out of the region to support conventional generation fuels. Small renewable generators located on or near a customer's facility (i.e., distributed generation) can also help reduce the strain on transmission and distribution systems. However, market forces alone do not typically recognize these many benefits, thus public policies and regulations are needed to ensure that renewable resources fulfill their proper role in the development of the electricity industry.

Synapse's work covers a variety of topics related to renewable generation, including:

- Providing analytic and regulatory support for the development of regulations regarding renewable portfolio standards.
- Conducting technical analyses of the potential for renewable resources, and the likely economic and ratepayer impacts of renewable portfolio standards.
- Providing analytic support for the development of Renewable Energy Credit mechanisms or Generation Information Systems.
- Estimating the emissions that could be displaced by renewable resources, for the purpose of using renewables to comply with environmental regulations such as SO_2, NO_X, and CO_2 cap-and-trade mechanisms.
- Providing technical support for policies to encourage the inclusion of renewable resources in portfolio management practices and standard offer services provided by electric distribution utilities.
- Reviewing the potential for renewable resources as alternatives to conventional fossil-fired generation, in the context of electric utility integrated resource planning.
- We currently work with a diverse group of stakeholders to develop a clean load response capability in northeastern wholesale electricity markets and on incorporating environmental considerations into wholesale electricity market design and decision-making.
- *Conducting detailed technical analyses – using electricity dispatch and market* simulation models – of aggressive development of energy efficiency, renewable resources and distributed generation in regional and multi-state clean energy plans. In 2001 we prepared the *Repowering the Midwest* report (covering ten states in the Midwestern United States), in 2002 we prepared the *Powering the South* report (covering seven states in the Southeastern United States), and in 2004 we completed *A Balanced Plan for the Interior West* (covering seven states in the Interior Western United States). These studies utilized many of the

principle concepts of integrated resource planning, including detailed economic analysis and the integration of supply-side and demand-side resources.

- Providing analytic support for the rules and regulations that affect the integration of renewable resources in wholesale markets, Regional Transmission Organizations, and Independent System Operators.

B. Energy Efficiency and Conservation Programs

Numerous studies in different areas of the United States have identified large quantities of cost-effective energy efficiency opportunities. In most areas, less than half of the available reductions are targeted; frequently only ten to twenty percent of cost-effective measures are implemented. However, with significantly higher prices recently for gas, oil, and coal (the major fuels used for electricity production) and no indication that these prices will drop over the next several years, the value of energy reductions has never been greater.

Synapse has been actively engaged in numerous proceedings and investigations regarding least-cost planning and state mandated utility energy efficiency, conservation, and load management programs.

As part of an on-going project, Synapse represents a Rhode Island state agency in a collaborative process regarding utility energy efficiency programs. That work encompasses all aspects of energy efficiency program design and implementation, including efficiency measure assessment, program delivery options, program budgeting, cost-benefit analyses, utility performance incentives, and other relevant regulatory policies. In recent years, Synapse has reviewed and critiqued utility energy efficiency programs in Indiana, Massachusetts, Minnesota, Nevada, North Carolina, British Columbia, Nova Scotia, and Québec.

- Reviewing and critiquing energy efficiency programs proposed by electric and gas utilities, including participation in demand-side management collaborative processes, and review of energy efficiency programs within utility integrated resource plans
- Development of regulatory and legislative policies to encourage all forms of energy efficiency activities, including system benefit charges, integrated resource planning policies, energy efficiency cost recovery policies, shareholder incentive and revenue decoupling policies, and third-party implementation of energy efficiency programs
- Assisting with the design, development and implementation of the energy efficiency programs for the Cape Light Compact, the municipal aggregator for Cape Cod and Martha's Vineyard
- Representing several New England consumer groups and attorney's general offices at ISO-NE meetings and helping to shape ISO-NE policies on demand response programs

- Conducting detailed technical analysis – using electricity dispatch and market simulation models – of aggressive development of energy efficiency, renewable resources and distributed generation in regional and multi-state clean energy plans.

3. Representative Projects

Synapse works for local government agencies, state regulatory commissions, environmental groups, consumer advocates, and others. The broad range of our client mix demonstrates an ability to perform credible and objective research that is well respected by individuals and organizations with various perspectives. We are exceptionally well qualified to provide assistance to the City of Oberlin on power procurement issues, as we have undertaken many similar projects in the past. Below is a representative list of projects relevant to this procurement.

Review of AMP-Ohio's Proposed Coal-Fired Generating Plant
Clients: Natural Resources Defense Council, Ohio Environmental Council, Sierra Club
Synapse is evaluating American Municipal Power's proposed 960 MW coal-fired power plant in Meigs County, Ohio and whether AMP-Ohio has adequately considered the risks associated with that proposed plant in its resource planning for its member communities. Synapse also is examining the costs (including construction costs and the cost of CO2 regulations) of the proposed plant and of alternatives to the proposed plant. In addition, Synapse will investigate the energy efficiency and renewable resource alternatives for the City of Cleveland's share of the proposed plant. Project on-going.

Florida Climate Action Team
Client: Environmental Defense
In August 2007, Governor Crist of Florida appointed the Florida Governor's Action Team on Energy and Climate Change. Environmental Defense is a member of the Action Team that will be developing Florida's Energy and Climate Change Action Plan. Synapse is assisting Environmental Defense evaluate energy supply and energy efficiency policies that will be discussed by the Action Team during the first phase of this process. Synapse will also assist Environmental Defense identify strategies to help the state achieve its greenhouse gas reduction goals. Phase One will be completed in October 2007.

Energy Efficiency Program Review
Client: Southern Alliance for Clean Energy
On behalf of Southern Alliance for Clean Energy, Synapse is reviewing the Duke Energy Save-A-Watt Energy Efficiency Plan Proposal. The review is focused on Duke Energy's proposed programs and the proposed cost recovery mechanism. Also, joint intervenor comments on a Rulemaking Proceeding have been formally filed by the Southern Alliance for Clean Energy, Environmental Defense and the Southern Environmental Law Center with the North Carolina Public Utilities Commission. Concurrently, communications consisting of feedback and recommendations on the Save-A-Watt proposal are ongoing with Duke Energy. Project ongoing.

Greenhouse Gas Reduction Policy Working Groups in Colorado
Client: Center for Climate Strategies
Synapse is currently facilitating two Working Groups of the Colorado Climate Action Panel (CAP) to develop state policies that will lead to reductions in greenhouse gas emissions from the Energy Supply (ES) and Residential, Commercial, and Industrial (RCI) sectors in Colorado. The Working Groups include representatives from state and local governments, utilities, businesses, the building and green energy sectors, environmental groups, and the research community.

In addition to facilitating these Working Groups in the development of state policy proposals, Synapse has analyzed the cost of and potential for reducing greenhouse gas emissions through a number of policy mechanisms. For the energy supply sector, these include expanded use of renewable energy, recapture of waste energy, improved efficiency of new and existing power plants, and reduction of natural gas leakage. The workgroup also identified opportunities for the use of distributed renewable resources at customer sites, exploitation of small hydropower resources and other small renewables, and considered adoption of a carbon price. For the residential, commercial, and industrial sector, policies included expanded demand-side management, improved building codes and enforcement, combined heat & power, and other energy efficiency measures. The workgroup identified a total of 15 policies for the energy supply sector and 11 policies for the residential, commercial, and industrial sector that offer the potential for significant greenhouse gas reductions in the state. Project on-going.

Energy Efficiency Programs For the Municipal Aggregator on Cape Cod
Client: The Cape Light Compact
The Massachusetts restructuring law enables municipal aggregators to implement energy efficiency programs with funds raised from all customers through a system benefits charge. More than six years ago Synapse designed the energy efficiency programs that are being provided by the Cape Light Compact, the municipal aggregator on Cape Cod. Since then, Synapse has assisted the Compact in obtaining approval of its Energy Efficiency Plan from the Massachusetts regulatory body. Synapse continues to assist the Compact with refining the design of the efficiency initiative, which includes improvements to existing programs as well as innovative new programs. Project on-going

Emissions Impact of Green Energy Projects
Client: U.S. Environmental Protection Agency
Synapse was selected by the EPA's Office of Research and Development to identify and develop a methodology for calculating the emissions impact of "green energy" projects, such as wind power, municipal solid waste, and landfill gas projects. The goal is to investigate typical output characteristics of these resources on a regional basis, and to identify fossil fuel-based resources which are most likely to be displaced by the green resources in each region. Synapse will use industry data on resource operations together with the EPA's Emissions Tracking System (ETS) data, to produce a methodology capable of projecting emissions benefits from green energy projects throughout the United States. We expect to complete the final report for this project in spring 2008.

State Energy Planning
Client: New Jersey Division of the Ratepayer Advocate
Synapse is assisting the Division of the Rate Counsel on the state of New Jersey's Energy Master Planning (EMP) process. Our work includes reviewing input assumptions and modeling methods for electric sector policies. Key policy options considered in the

NJ EMP include energy efficiency programs, reform of the auction for Basic Generation Service, establishment of a state power authority, and various efforts to promote renewable energy and ensure reliable electricity service at reasonable cost to consumers. Project on-going.

2007 Avoided Energy Supply Component Study
Client: AESC Study Group
Synapse was retained to develop projections of marginal energy supply costs which will be avoided due to savings in electricity, natural gas and other fuels resulting from energy efficiency programs offered to customers throughout New England. In our report, we provided detailed projections for an initial fifteen year period beginning in 2007, and escalation rates for another fifteen years from 2022 through 2037, as well as a detailed simulation of the electric energy market in New England over the study period. In addition to projecting the costs of energy and capacity avoided directly by program participants, the report provides estimates of the Demand-Reduction-Induced Price Effect ("DRIPE") of efficiency programs on market prices for electric energy and capacity. The report also provides a projection of annual additional environmental costs associated with emissions of CO2 in New England. The estimates are equal to the cost of limiting CO2 emissions to a "sustainability target" level, estimated to be a control cost of $60/ton, and minus the forecast value of CO2 allowances under the cap and trade regulations expected over the study period. The 2007 AESC Study was sponsored by a group representing all of the major electric and gas utilities in New England as well efficiency program administrators, energy offices and regulators. Project completed in 2007.

Demand Side Management in Rhode Island
Client: Rhode Island Division of Public Utilities and Carriers
Synapse consults for the Division regarding on-going electric and gas DSM matters in Rhode Island. This involves on-going work with the RI DSM Collaborative, set up in 1991. In 2007, Synapse's Tim Woolf prepared testimony supporting a settlement among multiple parties on the design and funding for natural gas demand-side management programs in the state for 2007-2008. This groundbreaking settlement will result in increased energy efficiency in Rhode Island and offers to help increase efficiency of delivery of both electric and gas DSM programs, which will be jointly developed and implemented for future years. Project on-going.

Integrated Resource Planning and Demand-Side Management in Nova Scotia
Client: Nova Scotia Utility and Review Board
Synapse was retained to collaborate with Nova Scotia Power on its Integrated Resource Planning process. Synapse is reviewing the input assumptions and developing a modeling plan. The IRP analysis will use the Strategist model. Synapse's work on this IRP includes research on a wide range of issues including the DSM potential study, the fuel price forecasts, the construction costs of new generating capacity, the integration of variable output wind to the NS grid, the prospects for and implications of future carbon emissions regulations, and the evaluation of alternate resource plans. Project on-going.

Guidebook for Evaluating Clean Energy Programs
Client: U.S. Environmental Protection Agency
Clean energy programs and policies can help states achieve their goal of providing a less polluting, reliable, and affordable energy system. Working under Stratus Consulting, Synapse jointly authored a guidebook for evaluating energy system impacts and air emissions reductions from implementing clean energy measures. This guidebook

introduces state policymakers and analysts to the concepts, terms, methods, tools, assumptions and models that Public Utility Commissions and utilities use to compare traditional grid electricity with demand and supply-side clean energy resources (e.g., energy efficiency, renewable energy, CHP, and clean distributed generation). Short examples and case studies illustrate the challenges that states face in analyzing clean energy initiatives, as well as the methods they have used to successfully quantify and promote them. Project on-going.

Long Term Procurement Plans of California Utilities
Client: California Division of Ratepayer Advocates
Synapse is analyzing the Long Term Procurement Plans of three investor owned utilities for the California Division of the Ratepayer Advocate, including aspects of competitive procurement procedures, least cost planning, risk management metrics and processes, and prepared prefiled testimony on those topics. In addition, Synapse evaluated novel proposals under which the investor owned utilities are to auction off the energy rights to certain resources procured for their capacity value only, as well as providing support to the Division in mediation workshops on the energy rights auction issue. Project ongoing.

Clean Energy Action Plan for States
Client: U.S. Environmental Protection Agency
Synapse contributed four chapters to EPA's guidebook of policies that states can implement to advance clean energy activities. These chapters address
1) integrating energy efficiency and renewables into air quality planning,
2) integrating energy efficiency and renewables into state and regional energy planning,
3) identifying and describing the financial incentive (and disincentive) mechanisms for clean energy and energy efficiency associated with state-level ratemaking structures for electric and gas utilities, and
4) the role of clean energy in integrated resource planning and portfolio management.
The guidebook can be found on the EPA's website. Project completed in 2005.

Proposed Glades Power Park Coal Plants
Clients: Earthjustice, Sierra Club, Save our Creeks, Florida Wildlife Federation, Environmental Confederation of Southwest Florida
Synapse was asked to evaluate Florida Light & Power Company's justification for its proposed 2000 MW coal-fired Glades Park Power plants. The specific subjects addressed by Synapse in testimony included the likely future CO2 emission costs that will result from federal greenhouse gas regulations/restrictions; the Company's resource planning; and the results of the Company's economic analyses of the proposed Glades Project.

Synapse found that the proposed Project would be the more economic option only if the potential costs of CO2 regulations were not considered or if a very high difference was assumed between natural gas and coal prices. Synapse also found that the Company had not fully reflected the risk of increases in the actual capital cost of completing the proposed Project and placing the generating units in commercial operation. As a result, Synapse recommended that the Commission deny Florida Light & Power Company's need request because the Company had failed to demonstrate that the proposed Project was the least cost, least risk addition to its system. The Florida Public Service Commission agreed with the conclusion that the proposed Glades Project was not the most cost-effective option and, therefore, denied the request for a certificate to build the plants. Project completed in May 2007.

White Paper on Least Cost Electricity Procurement for Standard Offer Service in Rhode Island
Client: Rhode Island Greenhouse Gas (GHG) Working Group
In collaboration with Raab Associates, Synapse provided a summary overview of the background to, and context for implementation of the Least Cost Electricity Procurement in Rhode Island and an outline of the major issues associated with its implementation. Project completed in June 2007.

Economic Analysis of Proposed IGCC Coal Power Plant and Alternatives
Clients: Citizens Action Coalition of Indiana, Save the Valley, Valley Watch, Sierra Club
Synapse was hired by a coalition of public interest organizations to review the proposal by Duke Energy Indiana and Vectren to invest approximately $2 billion in a new integrated gasification combined cycle (IGCC) coal power plant at Edwardsport. The project included analysis and testimony by Bruce Biewald on computer modeling and resource planning, levelized cost comparisons, and ratemaking issues; by Phil Mosenthal of Optimal Energy on demand-side management potential and costs; Robert Fagan on renewable resource potential and costs; and David Schlissel on carbon dioxide regulations and power plant construction costs.

The project team found that the Companies' planning for Edwardsport was inadequate, that the IGCC plant would increase dependence upon coal for electricity generation and would subject the Companies' shareholders and customers to unnecessary costs and increased risks. Synapse witnesses recommended that the Commission reject the Companies' request for approval of the proposal to construct and own the Edwardsport IGCC project, and instead require the Companies to do complete and proper planning which should include: (1) up-to-date construction cost estimates for IGCC and other resources; (2) analysis of the cost impacts on customers that reflect the ratemaking treatment that the Companies' request be used for the resources; (3) use of a realistic range of low, mid, and high case projections for future carbon dioxide prices; (4) full consideration of cost-effective demand-side management, combined heat and power, and renewable resources, and (5) a proper risk analysis that recognizes a range of risks including but not limited to construction cost overruns and project delays as well as fuel prices and environmental compliance requirements. Project completed in June 2007.

Demand Side Management and Advanced Metering in Pennsylvania
Client: Pennsylvania Office of Consumer Advocate
Synapse represented the staff of the Pennsylvania Office of Consumer Advocate in the demand-side management (DSM) and advanced metering infrastructure (AMI) workgroup. We reviewed various aspects of DSM and AMI initiatives, prepared documents on good practices in these areas, recommended specific programs from other states, and participated in the workgroup. Project completed in June 2007.

Integrating Wind Power into British Columbia's Hydro Electric System
Clients: Sierra Club of Canada, BC Chapter, BC Sustainable Energy Association, Peace Valley Environment Association
Synapse examined three interrelated British Columbia wind power issues for a group of BC environmental organizations and provided expert witness testimony. We analyzed BC Hydro's $3/MWh "firming" premium used at the evaluation stage of their 2006 RFP for energy resources. Synapse also reviewed the liquidated damages (LD) provisions of BC Hydro's standard contract for wind energy providers and summarized existing wind integration operational cost studies. Synapse concluded that the firming premium is not supported as the storage and ramping capability of BC Hydro's hydroelectric resource base is more than sufficient to allow for monthly rather than hourly scheduling. Synapse also concluded that the LD provisions could cause wind projects to appear more expensive than they actually are. Lastly, Synapse recommended detailed technical analyses be conducted to analyze the impact of varying levels of wind penetration on BC Hydro's operational costs. The BC Commission order (May 2007) did direct BC Hydro to look carefully at wind capacity projections. Project completed in February 2007.

Introduction to Generation Technologies for Regulators
Client: National Regulatory Research Institute
Synapse provided technical consulting to NRRI in the preparation of a report on the factors regulators should understand and consider when deliberating on the selection between generation technologies. Project completed in December 2006.

Proposed Big Stone II Generating Plant
Clients: Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America - Midwest Office, Wind on the Wires, Union of Concerned Scientists
Synapse was asked to examine whether the co-owners of the proposed Big Stone II had demonstrated that the demand for electricity cannot be met more cost effectively through energy conservation and load-management measures or through renewable resources. The testimony filed by Synapse found that the Big Stone II co-owners had not adequately considered the risks associated with building a new coal-fired generating unit in their modeling analyses, including the risk of future greenhouse gas regulations, the potential for further increases in the Project's capital cost, and the potential for fuel supply disruptions that could affect plant operating performance and fuel costs. Synapse's testimony also found that the Big Stone II co-owners had not shown that their demand for electricity cannot be met more cost effectively through energy conservation and load-management measures or through renewable resources. A decision by the Minnesota Public Utilities Commission is pending.

Energy-Economic Situation Analysis of the Northern Forest
Client: Northern Forest Center
Synapse prepared a high level "thought" piece for the client, presenting the important issues and trends in the energy sector in the Northern Forest Region, a 34 county area stretching from Oswego, NY, across northern Vermont and New Hampshire, to eastern coastal Maine. The data collection, research and final report preparation were carried out on a compressed schedule of approximately one month to meet the needs of the client. Primary data, tables and detailed explanations were provided in separate appendices. The paper was written to be thought provoking, to raise critical issues and opportunities that will frame stakeholder dialogue, further analytical study and decision-making for the next phases in the development of the economic adjustment strategy, and to identify and choose among sustainable development options and recommendations in the Northern

Forest region. It introduced the important issues, trends, priorities and realities of the energy sector in the 34-county region and set them in context with energy issues and trends from relevant regions elsewhere in the nation. The paper was future oriented, synthesizing key issues and concepts drawn from data and the conclusions of previous analytical work, including detailed economic modeling studies previously conducted by Synapse to measure employment and air pollution impacts of regional strategies for renewable energy and energy efficiency. Project completed in May 2006.

Integrated Resource Planning for a Municipal Electric Utility
Client: City of Tallahassee
Synapse assisted the Tallahassee electric company in preparing an integrated resource plan. We played an advisory role to the electric company planners in four ways:
(a) reviewing the potential for demand-side management,
(b) assisting in developing strategies to assess large amounts of energy efficiency and renewable resources,
(c) developing methods to account for environmental factors, including CO2 emissions, and
(d) developing methods for evaluating and selecting among different electricity resource options. Project completed in September 2006.

Regulatory Tools for Electricity Portfolio Management
Client: National Association of Regulatory Utility Commissioners (NARUC)
Synapse was hired by the National Association of Regulatory Utility Commissioners (NARUC) to conduct an analysis and write a report on electricity portfolio management. Specifically, the paper critiques available models used for portfolio management and resource acquisition and provides advice for regulators on how to choose and utilize such models in making regulatory decisions. Measures for evaluating risks and hedging strategies are discussed, with an emphasis on the perspective of customers and regulators. Project completed in September 2006.

Mohave Generating Station Alternatives/Complements Study
Client: Southern California Edison
Synapse teamed with Sargent & Lundy to evaluate a set of supply- and demand-side technologies to replace or complement power flowing to Southern California Edison (SCE) from the coal-fired Mohave Generating Station in southern Nevada. The consultant team reported to a group of stakeholders including SCE, consumer and environmental advocates, the Navajo Nation and the Hopi Tribe. Technologies evaluated included IGCC with and without carbon capture and sequestration, wind, various solar technologies, and a unique option comprised of DSM procurement in nearby states coupled with a power purchase of "freed up" supply imported into California. Synapse was responsible for development and characterization of the DSM procurement option, as well as estimates of projected fuel prices, output profiles, emission costs, economics of carbon sequestration, various tribal issues, and employment impacts on and off the affected reservations. Project completed in February 2006.

4. Project Team

The Synapse project team will be led by Chris James, Senior Associate. Mr. James will be assisted by David Schlissel, Senior Consultant, and Research Associates Jeremy Fisher, Kenji Takahashi, and Robin Maslowski. Other Synapse staff may assist with technical research on various topics as called for by the needs of this project.

Directly below, please find short biographies of each project team member. Full resumes of our staff members are available on our website at www.synapse-energy.com.

Chris James

Chris James is a Senior Associate with Synapse Energy Economics. Mr. James has extensive experience in developing and implementing innovative energy and environmental policies. Prior to joining Synapse, Mr. James was the Director of the Air Planning and Standards Division at the Connecticut Department of Environmental Protection (DEP). In that capacity, he was responsible for overall air quality planning, including SIP development, air quality modeling, mobile sources, air toxics and regulatory development. Previously he served as the Assistant Director of the Engineering and Enforcement Division at the DEP, where he was responsible for Title V and New Source Review permit programs and directed Connecticut's participation in EPA's pollution prevention in permitting program.

Mr. James also served as the manager of Climate Change and Energy Programs at the DEP, where his chief responsibilities included implementing the state's climate change action plan and integrating energy and environmental policies. He represented the DEP on Connecticut's energy efficiency fund, an $87 million/year fund that invests in efficiency, conservation and load management efforts. He served as the Connecticut DEP staff lead on the Regional Greenhouse Gas Initiative.

Mr. James was Senior Environmental Engineer for seven years with the US EPA Region 10, where his responsibilities included permitting and compliance activities related to VOC sources, pulp and paper, wood products and aerospace industries, incinerators, biomass energy and CEM. He also served for four years with the Rhode Island Department of Environmental Management where he was responsible for the compliance and inspection program and the ambient air monitoring network, and assisted with permitting and modeling. Previously he also consulted for four years in air pollution related to utility industry and biomass energy recovery.

In addition, Mr. James was a member of the NEG/ECP climate change committee, co-chaired the STAPPA/ALAPCO global warming committee, and co-chaired the Regulatory Assistance Project and the Distributive Resources Collaborative, an NREL funded effort to develop national emissions standards for small generation. He also co-chaired a NESCAUM effort to write a model rule for environmental performance standards (EPS), output-based standards that apply to the retail sale of electricity to any customer within a state.

Mr. James holds a Bachelor's degree in Mechanical Engineering from Worcester Polytechnic Institute and a Master's in Environmental Studies from Brown University.

David A. Schlissel

David A. Schlissel is a Senior Consultant at Synapse Energy Economics. Since 1973, he has served as a consultant, expert witness, and attorney on complex management, engineering, and economic issues, primarily in the fields of energy and the environment. Prior to joining Synapse, Mr. Schlissel was the president of Schlissel Technical Consulting, Inc. and its predecessor, Schlissel Engineering Associates.

Mr. Schlissel has been retained by regulatory commissions, consumer advocates, publicly-owned utilities, non-utility generators, governmental agencies, and private organizations in 23 states to prepare expert analyses on issues related to electric, natural gas, and telephone utilities. He has presented testimony in more than 70 cases before regulatory boards and commissions in 21 states, two federal regulatory agencies, and in state and federal court proceedings.

Recent work has involved the evaluation of electric transmission and distribution system reliability, power plant operations and outages, industry restructuring including quantification of stranded costs, proposed nuclear and fossil power plant sales, and proposed utility mergers. Mr. Schlissel has also examined the impact of nuclear power plant life extension on plant decommissioning costs.

Mr. Schlissel holds BS and MS degrees in Astronautical Engineering from the Massachusetts Institute of Technology and Stanford University. He also received a Juris Doctor degree from Stanford University School of Law. He has also studied Nuclear Engineering and Project Management at MIT. He is a member of the New York State Bar, the National Association of Corrosion Engineers, the American Nuclear Society, Trial Lawyers for Public Justice, and is a Correspondent Member of the National Academy of Forensic Engineers.

Jeremy Fisher

Jeremy Fisher, Research Associate at Synapse Energy Economics, is a global change scientist with experience in tracking carbon exchange and determining the influence of climate change on the biosphere. Before joining Synapse, he worked to determine the footprint of Hurricane Katrina on Gulf Coast ecosystems and carbon budget, and coordinated scientific efforts to track recent climatic change in New England. Dr. Fisher specializes in complex system model development and extracting valuable information from extensive datasets.

Dr. Fisher holds a BS in Geology and a BA in Geography from the University of Maryland, and a Masters and Doctorate in Geological Sciences from Brown University.

Kenji Takahashi

Kenji Takahashi is a Research Associate at Synapse Energy Economics. He conducts economic, environmental, and policy analyses of electric system technologies, policies, and regulations associated with distributed energy resources. His recent research focuses on renewable energy portfolio standards, electric and natural gas demand-side management programs, and distributed energy resources for utility planning. He has also examined ratemaking issues such as standby rates for distributed generation and decoupling mechanisms for energy efficiency measures.

Prior to joining Synapse, he was a Research Associate at the Center for Energy and Environmental Policy (CEEP) of the University of Delaware. In one of his research projects at CEEP, he investigated the impacts of different distribution rate designs on the development of distributed energy resources (e.g., renewable energy, distributed generation, energy efficiency, and demand response). A report for this research was prepared for a local electric distribution company.

Mr. Takahashi also held a regulatory research intern position for Delaware Division of Public Advocate and a research intern position at Resources for the Future. At these organizations he gained extensive research experience in the field of distributed energy resource policy and electric utility regulation and restructuring.

Mr. Takahashi holds an MA in Urban Affairs and Public Policy with a concentration in Energy and Environmental Policy from the University of Delaware and a BA in Law with a concentration in Public Administration from Kansai University in Osaka Japan.

Robin Maslowski

Robin Maslowski is a Research Associate at Synapse Energy Economics, and is a recent graduate from Olin College of Engineering with a BS in mechanical engineering. Currently Ms. Maslowski is engaged in computer simulation modeling of electric power systems and economic analysis of power generating technologies including modeling-related research and analysis in new source review litigation cases, regional clean energy plans, resource planning projects, and analysis of energy efficiency and distributed generation technologies.

In the spring of 2007, Ms. Maslowski was involved with the Energy Star Benchmarking Program as an intern with the U.S. EPA. She also has experience at Green Energy Ohio, Lytron, Inc., and at the Utah Energy Office. While in college, Ms. Maslowski served as vice president of the Olin Collegiate Section of the Society of Women Engineers, founded the Greening Olin environmental organization, and was president of Olin's student government.

5. Project Scope

Synapse would complete the following tasks during Phase 1 of this project for the City of Oberlin:

Task 1: Synapse would review the City's current power supply portfolio including contractual arrangements, financial results, termination dates, etc.

Task 2: Synapse would review all AMPGS project analysis data related to the cost projections including; but not limited to,

Initial Project Feasibility Study

Long Term Power Supply Planning Study

Beneficial Use Analysis

Estimates of greenhouse gas emissions and uncertainties based on carbon taxes, carbon caps and/or carbon sequestration requirements.

To the extent possible, and to achieve economies of scale, Synapse would apply the results of our on-going work with the City of Cleveland to this task.

Task 3: Synapse would complete a high level economic, environmental and energy analysis of credible and viable non coal-based power supply alternatives to serve City's base-load future power supply needs including; but not limited to, the following technologies:

- Natural Gas Combined Cycle
- Hydro
- Wind
- Bio-mass
- Bio-gas
- Integrated Gasification Combined Cycle.

Synapse would provide examples of alternatives to City's current energy supply portfolio with future cost, risk and regulatory analyses. The analysis for this task would not include modeling, but that could be considered in phase 2.

Task 4: Synapse would prepare a brief technology analysis illustrating base-load capabilities of each non coal- based power supply alternative.

Task 5: Based on our experience in evaluating demand side management and renewable energy programs, Synapse would provide our analysis of potential energy efficiency and demand-side management programs with demonstrable results in reducing need for base-load, fossil-fueled power resources. Synapse maintains an on-going reference of state and local demand side and renewable energy programs. This analysis would include preliminary or indicative pricing for non coal-based power supply alternatives, and examples of financial and policy incentives that can be applied to reduce base and peak electric demand. Based on this analysis, we would recommend

the outline and framework for a program that the City could implement to cost-effectively achieve its demand-side management and renewable energy goals. Actual program design could be completed during phase 2.

Task 6: Synapse will complete a report inclusive of the components in Tasks 1 through 5 and present the information in-person to the Oberlin City Council, and others invited to attend. A draft report will be submitted to the City by February 15, 2008, with a presentation to the City Council to occur by the end of February or early March 2008. Synapse will provide monthly status reports to the designated point of contact for the contract.

6. Project Rates and Budget

The specific billing rates for this project for the Synapse project team members are as follows:

Consultant	Title	Hourly Rate
David Schlissel	Senior Consultant	$180
Chris James	Senior Associate	$150
Jeremy Fisher	Research Associate	$115
Kenji Takahashi	Research Associate	$115
Robin Maslowski	Research Associate	$105

As shown in the table below, Synapse anticipates that the completion of the Phase 1 scope of work will require a budget of $49,500.

Project Budget ($)

		Month 1						Month 2						Month 3						Total
Task	Labor Costs	Chris James	David Schlissel	Jeremy Fisher	Robin Maslowski	Kenji Takahashi	Total Budget For Task	Chris James	David Schlissel	Jeremy Fisher	Robin Maslowski	Kenji Takahashi	Total Budget For Task	Chris James	David Schlissel	Jeremy Fisher	Robin Maslowski	Kenji Takahashi	Total Budget For Task	Total Project Costs
	Billing Rate	$150	$180	$115	$105	$115		$150	$180	$115	$105	$115		$150	$180	$115	$105	$115		
1	Review current power supply portfolio	$600	$800	$0	$800	$600	$2,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,400
2	Review AMPGS project analysis data	$900	$800	$900	$1,200	$1,200	$4,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,800
3	Complete analysis of credible and viable non coal-based power supply alternatives	$900	$0	$1,200	$900	$1,200	$4,200	$900	$800	$1,200	$900	$1,200	$4,800	$0	$0	$0	$0	$0	$0	$9,000
4	Technology analysis illustrating base-load capabilities of each non coal- based power supply alternatives	$0	$0	$0	$1,200	$1,200	$2,400	$1,200	$800	$1,200	$2,100	$2,400	$7,500	$0	$0	$0	$0	$0	$0	$9,900
5	Complete DSM and RE potential analysis – high level	$0	$0	$0	$0	$0	$0	$1,200	$600	$1,200	$1,800	$2,400	$7,200	$900	$800	$900	$1,200	$1,500	$5,100	$12,300
6	Complete report, present findings to City Council	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,400	$1,800	$1,800	$1,800	$1,800	$9,600	$9,600
	Total Labor Cost Per Team Member	$2,400	$1,200	$2,100	$3,900	$4,200	$13,800	$3,300	$1,800	$3,600	$4,800	$6,000	$19,500	$3,300	$2,400	$2,700	$3,000	$3,300	$14,700	
		Total Month 1 Budget					$13,800	**Total Month 2 Budget**					$19,500	**Total Month 3 Budget**					$14,700	$48,000
	Travel																			$1,500
	Total Project Budget																			$49,500

The above includes labor to attend and present the findings of this study to the Oberlin City Council. Travel costs are included in the proposed Synapse budget as Fifteen Hundred Dollars ($1,500). The City of Oberlin will strive to provide Synapse with advance notice of the meeting scheduled for Task 6 so that less expensive airfare can be purchased.

EXHIBIT

BUSINESS CONFIDENTIAL:
PROPRIETARY INFORMATION - DO NOT DISTRIBUTE AS A PUBLIC RECORD

Initial Project Feasibility Study

American Municipal Power Generating Station Project

AMP OHIO

American Municipal Power - Ohio, Inc.

June 2007

RW BECK

EXHIBIT
Witness AMPO Ex. 11

This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. (R. W. Beck) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

EXECUTIVE SUMMARY

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 Falls. 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. The purpose of the Project Feasibility Study is to (1) address the technical, operational, and financial implications and risks of the Project, and (2) provide a comprehensive examination of the Project. Under the terms of the contract with AMP-Ohio with regard to the feasibility of the Project, R.W. Beck must provide the following: (i) an Initial Project Feasibility Study based on the most recent information available including updated costs of the Project, (ii) a Final Project Feasibility Study based on updated information available after the selection of an Engineer-Procure-Construct ("EPC") contractor; and (iii) summary reports for Project financing updated to reflect the most recent information available as of the date of the associated Official Statement. This report constitutes the Initial Project Feasibility Study (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.

Description of AMP-Ohio Organization

AMP-Ohio was formed in 1971 under Ohio Revised Code Chapter 1702 as a nonprofit corporation. AMP-Ohio operates on a cooperative basis for the mutual benefit of its members, each of which owns and operates an electric utility distribution system and in some cases generating assets. As of May 7, 2007, AMP-Ohio had 120 members ("Members") – 81 in Ohio, 26 in Pennsylvania, seven in Michigan, four in Virginia and two in West Virginia. Since May 7, 2007, an additional borough located in

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

Pennsylvania has become a member of AMP-Ohio. An additional city in Virginia, Front Royal, may become a member.

History and Development of Project

In 2002, AMP-Ohio completed a strategic plan which included a 20-year power supply needs analysis that identified the need for new base load generating capacity. The plan led AMP-Ohio to undertake a conceptual feasibility study and other studies, including evaluation of available base load power supply options, technology considerations, site alternatives, and fuel availability. In 2004, AMP-Ohio entered into a developmental agreement with Virginia-based Blue Ridge Power Agency ("BRPA" or "Blue Ridge") and Michigan South Central Power Agency ("MSCPA") to continue to investigate the development of a new base load resource on a joint basis. Certain members of BRPA and MSCPA are also Members of AMP-Ohio and potential participants in the new base load resource.

AMP-Ohio signed a contract with the engineering firm Sargent & Lundy ("S&L") in May of 2003 to provide various services associated with the early planning, evaluation and development of a base load generating facility. These services included: (i) technology analysis; (ii) site screening analysis; (iii) fuel availability and delivery cost analysis; (iv) site selection; (v) schematic design; (vi) summary project information for permitting; and (vii) Ohio Power Siting Board application. S&L provided a report for each task that summarized the methods and results of the investigations and evaluations. Based on the results of the site evaluation process and the final field surveys, the Letart Falls site in Meigs County, Ohio, was chosen as the preferred site. As follow-up to their initial services, S&L has provided information to support Project permit applications and other studies.

Overview of the Project Arrangement

As of the date of this Report, it is contemplated that approximately 97.5 percent of the AMPGS Project will be owned by AMP-Ohio and that AMP-Ohio will enter into take-or-pay power sales contracts with each of the participating AMP-Ohio Members (including those that are also members of BRPA or MSCPA). The remaining 2.5 percent of the AMPGS Project would be owned by the Central Virginia Electric Cooperative ("CVEC"). Contractual arrangements with respect to joint ownership and the operation of the AMPGS Project have not yet been developed. However, each of the two owners would be responsible for the financing of the respective ownership interest. In the event CVEC decides not to participate as a co-owner, AMP-Ohio expects to retain the CVEC share and own 100 percent of the AMPGS Project.

The AMP-Ohio Members that are participating in the AMPGS Project will execute power sales contracts with AMP-Ohio authorizing AMP-Ohio to finance, construct and operate the AMPGS Project and specifying 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.

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 a target of April 2013 for the commercial operation date of Unit 1 and October 2013 for Unit 2. As shown in the timeline below (Figure 1), the major milestones that are on the critical path of the Project schedule include:

- Ohio Members Ordinances passed by October 1, 2007
- Power Sales Contracts with Ohio Members signed by November 1, 2007
- Out-of-State (outside of Ohio) Power Sales Contracts signed by March 2008
- Exercise land options in July 2008
- Complete 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

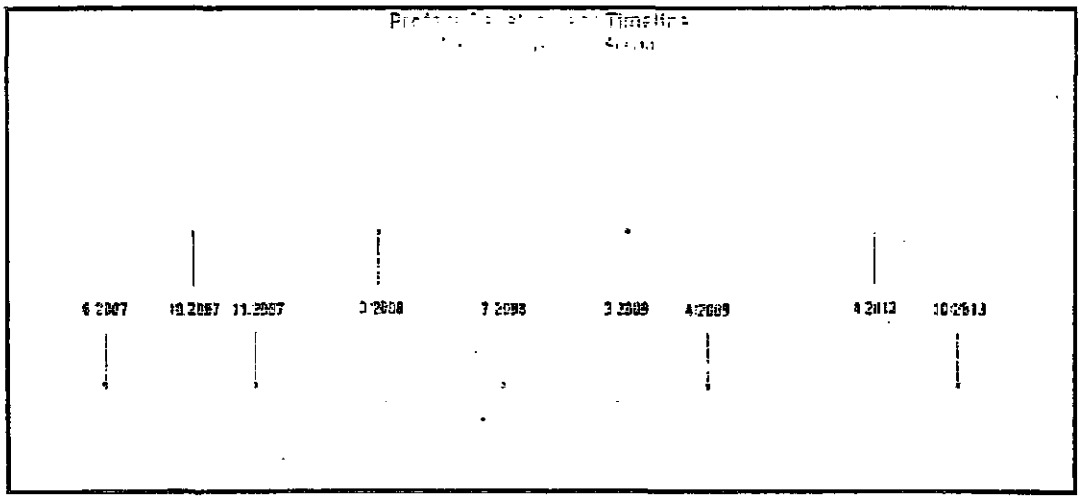


Figure 1 - Project Development Timeline

Project Description

The proposed AMPGS Project is a 960 MW[2] coal-fired generating station which is to be located in Meigs County, Ohio, in the township of Letart Falls. Figure 2 illustrates the AMPGS Project site location.

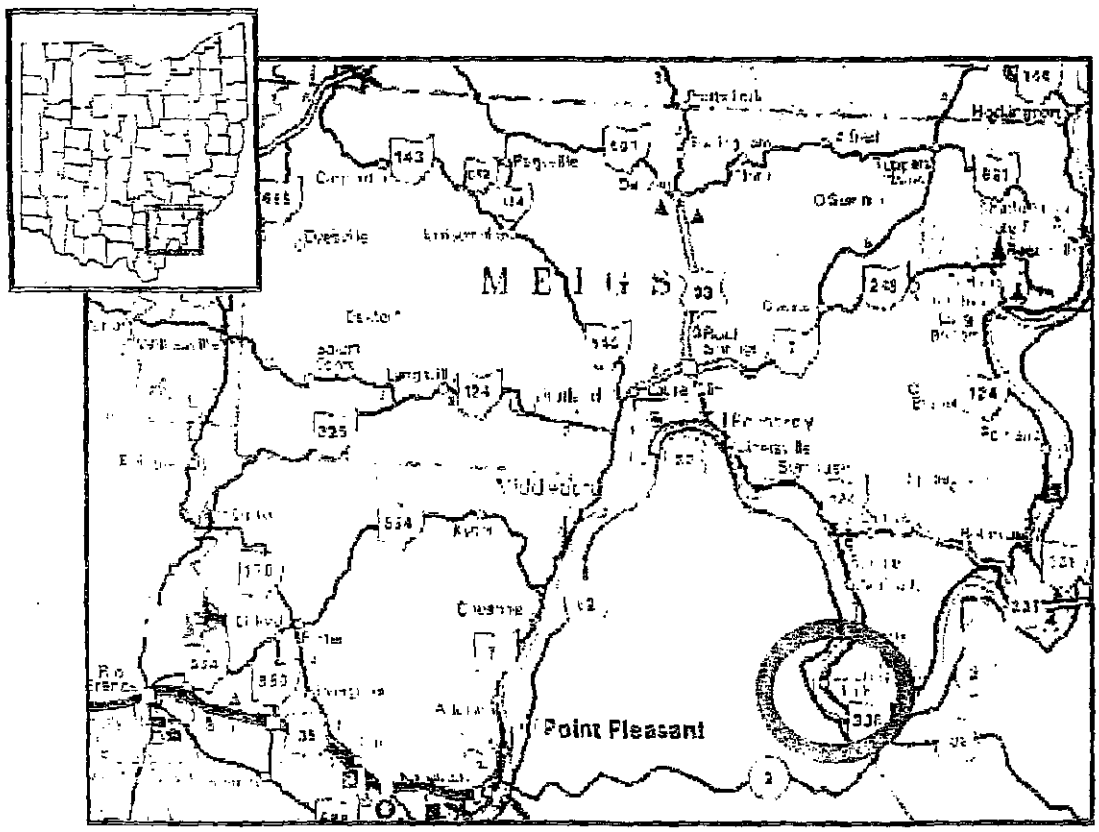


Figure 2 – AMPGS Site Location

The AMPGS Project site is a green field site with access to the Ohio River. Prior use of the site was primarily for agriculture. In total, the Project facilities, including the landfill, will have a footprint of approximately 1,000 acres, not including 600 acres of AMP-Ohio owned land to serve as a buffer.

The AMPGS Project will be operated as a base load plant comprised of two nominal 480 net MW generating units. Figure 3 provides a conceptual rendering of the Project site and equipment layout.

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

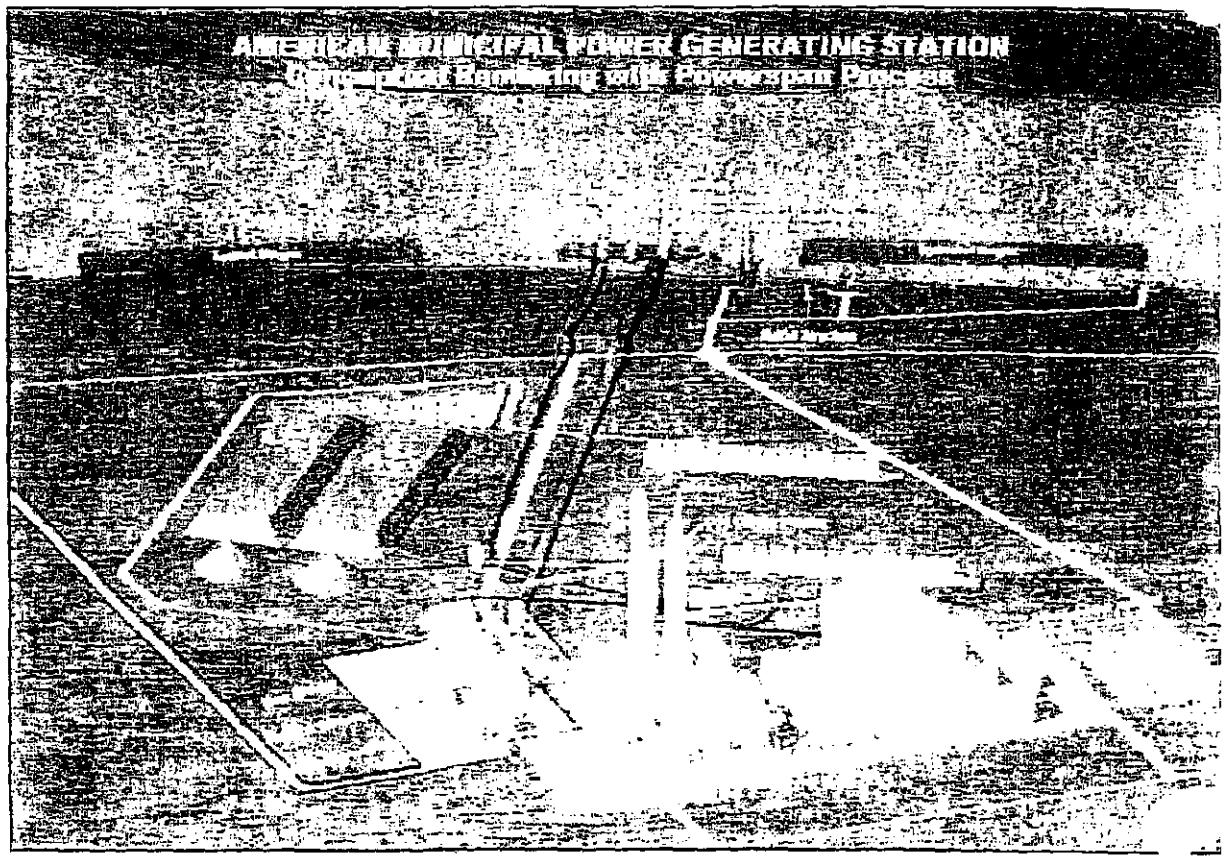


Figure 3 – Conceptual Rendering of AMPGS Project

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 EPA in May 2006. The application for the PTI specifies that the Project will install Best Available Control Technology ("BACT") for control of emissions from AMPGS, including a filter baghouse to control particulates, low nitrogen oxide ("NOx") burners and selective catalytic reduction ("SCR") for control of NOx and Powerspan Corporation's ("Powerspan") multi-pollutant control technology ("ECO-SO_2 ") which will control emissions of sulfur dioxide ("SO_2"), fine particulate matter using a wet electrostatic precipitation ("Wet ESP"), mercury ("Hg"), and sulfuric acid ("H_2SO_4").

The Powerspan technology is discussed in further detail in Section 3 and Appendix *D* of this Report. This new 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.

This technology has undergone a 50 MW demonstration test, but will need to be scaled up for application to the Project. 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 are to be capable of burning a blend of Ohio, Central Appalachian and/or Southern Powder River Basin ("SPRB") coals. Coal will be delivered by barge to the generating station and will be moved to the site using a conveyor system. The steam generators for each unit are proposed to be subcritical pulverized coal ("PC") boilers that use natural gas as the startup fuel.

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.

Estimated Capital Costs and Financing Requirements

The estimated capital costs for construction of the AMPGS Project are summarized in the following table. 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 $2.148 billion 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. A six percent contingency was included in this EPC contract estimate.

Other Project costs which 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 $134.3 million.

Owner's costs are estimated to be $250.3 million (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 $100 million contingency. As of the date of this Report, the total cost of construction is estimated to be approximately $2.532 billion as summarized in Table 1 below.

Table 1
Estimated Costs of Construction[1]

Description	Dollars in Thousands
Capital Costs	
EPC Costs [2]	$2,148,180
Other Costs:	
Transmission Line and Interconnection Switchyard	24,000
Transmission System Upgrades [3]	65,000
Land and Infrastructure Upgrades [4]	45,300
Total Capital Costs	$2,282,480
Owner's Costs	
AMP-Ohio Staff, Legal, Engineers and Consulting Costs [5]	$49,300
Taxes and Insurance	28,000
Initial Inventories and Spare Parts [6]	35,000
Start-up and Commissioning Expenses	10,000
Working Capital [7]	5,000
Owner's Cost Escalation	23,000
Owner's Contingency	100,000
Total Owner's Costs (w/o Financing Costs)	250,300
Total Estimated Costs of Construction	$2,532,780

[1] The development of the estimated costs of construction of the AMPGS Project is set forth in Section 3.5 herein.
[2] Amount includes allowance for cost escalation, EPC profit and 6% contingency on EPC costs.
[3] Estimated costs associated with transmission system upgrades related to interconnecting the Plant to the PJM system. Does not include costs for potential transmission system upgrades relating to transmission services required to deliver capacity to the MISO Participants.
[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 $20 million for initial fuel and other commodity inventories and $15 million 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 the table below, the total estimated amount of bonds to fund the 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 $2.912 billion. 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]	$2,532,780
Net Interest During Construction [2]	270,722
Deposit to Reserve Account [3]	71,336
Issuance Expenses [4]	37,303
Total Estimated Bond Amount [5]	$2,912,141

[1] Per Table 6-1.
[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 2005 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 $2,839,337,500.

Plans for Constructing and Operating the Plant

Schedule and Plan for Construction

Activities that are ongoing as of the date of this Report generally include permitting, Participant approvals, and the solicitation of EPC contractor proposals. It is expected that all the Participant contracts would be in place by March 2008. The initial EPC contract for preliminary design would begin in June 2008. The EPC contract is scheduled to be finalized by March 2009, followed by an EPC contract final NTP in April 2009. The final land purchase of the site is assumed to occur in July 2008. The last permit approval required is scheduled for February 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.

AMP-Ohio plans to contract with a single firm to engineer (and design), procure the equipment, and construct ("EPC") 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.

In conjunction with using the EPC contracting method, establishing the contract as a fixed-price contract will mitigate some of AMP-Ohio's risk in meeting the Project's

schedule and budget. The key to successfully implementing a fixed price EPC contract is a well defined scope of the project. A method for helping to assure that the scope of the Project is defined to a sufficient level of detail and that both AMP-Ohio and the EPC contractor understand and agree on the scope is to develop the design of the plant to a sufficient level of detail before fixing the price and the schedule. To assure that AMP-Ohio is receiving a fair price and schedule for the Project, this up-front design work will be conducted under an "open book" policy which 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 plans to contract with The Andersons (a national agriculture company) 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 ES-1. The estimated operation and maintenance expenses for the Project are summarized in Table 3 below. Details associated with these estimates are included in Section 4, Section 6 and Attachment ES-1.

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

Category	2013$
Total Fixed O&M, $/kW-year	38.60
Variable O&M, $/MWh	8.59
Fuel, $/MWh	19.94
Total Annual Operating Costs, $/MWh	33.72

[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

A blend of local high sulfur content coals with lower sulfur content coals is planned for the fuel supply to AMPGS. Such blending is due to the typically high sulfur content of the Ohio and other local bituminous coals. Blending Ohio coal is desirable even though it is higher in sulfur because it has lower transportation costs, which make it attractive for use in blending. In addition, there is also a possibility that a tax credit or another type of credit could be granted for using Ohio coal. Preliminary coal blending plans include options to blend Ohio coal and SPRB coal ("Western Blend") or a blend of Ohio coal and Central Appalachia coal ("Eastern Blend"). Table 4 below summarizes these coal blends and the estimated delivered cost.

Table 4
Fuel Supply Characteristics and Costs for Eastern and Western Blends [1]

	Eastern Blend	Western Blend
Percent Ohio Fuel (%)	34.00	51.80
Percent Lower Sulfur Fuel (%)	66.00	48.20
	(WV medium sulfur)	(SPRB)
Annual Tons for Blend [2]	2,815,705	3,338,354
Heating Value for Fuel Blend (Btu/lb)	12,051	10,535
Sulfur Content for Fuel Blend (%)	2.11	1.84
Ash Content for Fuel Blend (%)	10.83	7.85
Delivered Fuel Price for Blend ($/MMBtu) [3]	2.14	2.18

[1] Based on information from Sargent & Lundy's Fuel Forecast Update, Report Number SL-008668, dated January 2006.
[2] Fuel consumption values are based on average annual plant output of 987 MW (net); design heat rates of 9,233 Btu/kWh (Eastern Blend) and 9,570 Btu/kWh (Western Blend); and an annual average capacity factor of 85 percent.
[3] Fuel prices are escalated values for delivery in 2013.

The analyses in this Report reflect the Eastern Blend, since it results in the most cost effective fuel blend as of the date of this Report. However, coal prices and transportation costs are subject to market pressure that can affect the price of the blends. To allow the flexibility to use a cost effective fuel blend during the operation of the plant, a design basis fuel will be defined for the EPC Contract specifications; however, efforts will be made to use equipment that can process both an Eastern Blend and a Western Blend. A fuel supply plan will be developed, followed by the selection of the final coal blends and final contract negotiations with coal suppliers and with rail and barge transportation companies. It is anticipated that prior to issuing the EPC contract, the contracts (or letters of intent) for the coal supply and its transportation will be executed.

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	4.3×10^{-6}

[1] Hg limit allows flexibility for the use of varying fuel blends (i.e. Eastern and Western blends).

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 which states, including Ohio, may choose to participate; and (iv) potential 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 the these rules has been estimated in the projected operating results discussed in Section 6 by assuming that the Project will purchase allowances from the market. A carbon tax ranging between $5/ton to $15/ton (in 2006 dollars) is assumed to be in place beginning between 2012 and 2018. While there are different points of view and opinions on the CO_2 tax levels that may be imposed, the $5/ton to $15/ton range, in R. W. Beck's view, represents a reasonable assumption for the initial years of carbon regulation as supported by opinions expressed by other investigations and trading of CO_2 credits in European markets. Higher CO_2 tax levels may impact the AMPGS Project as well as the entire electric utility market in ways not identified in this Report. 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.

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. Based on our review, AMP-Ohio has identified the major permits and approvals necessary for the construction and operation of the Project. AMP-Ohio is presently in the process of applying for/obtaining the key permits and approvals required to construct and operate the Project.

Required Transmission Services

To deliver the output of the AMPGS Project, AMP-Ohio must: (i) interconnect with PJM[3] through PJM's generator interconnection process as a Capacity Resource; and (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[4] 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 $24 million include the construction of a double-circuit 345 kV transmission line from the Project 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 $58 million in transmission upgrades to the existing transmission system. These costs have been included in the capital costs of the Project. However, studies remain to be performed for point-to-point transmission service to MISO and for transmission service within MISO. There is also 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. For purposes of this

[3] 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.

[4] 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.

Feasibility Study, we have assumed a $7 million cost to purchase a backup transformer to mitigate this risk and have included this cost in the capital cost of the Project.

Lacking studies from PJM and MISO concerning additional transmission service or modifications to existing transmission service, we cannot know what potential transmission upgrades might be required. AMP-Ohio has initiated 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.

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[5] and are consistent with our understanding of the terms and conditions of the drafts of the Power Sales Contract and Master Trust Indenture, both dated as of April 2, 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.

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. 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.

[5] 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.

The Projected Operating Results are set forth as Attachment ES-2 at the end of this Executive Summary and are based on the principal considerations and assumptions set forth in Section 9 of the Report. A summary of the projections are shown below in Table 6 for selected years.

We have also estimated the Participant sales of energy from their share of the AMPGS Project which are projected to be in excess of their load requirements and are assumed to be sold into the market. The total estimated surplus energy amounts for each year are shown on line 65 of Attachment ES-2. Such amount represents approximately 2.5 percent of the AMPGS Project energy. The estimated revenues from the sale of the surplus energy into the wholesale market for each year are shown on line 64. The projected net costs to the Participants after the credits for surplus energy sales shown in dollars and on average ($/MWh) are set forth on lines 67 and 69 of Attachment ES-2.

Table 6
Summary of AMPGS Projected Operating Results

	Description		2015	2020	2025	2030	2032
	Revenues:						
1	Participant Revenues [1]	$000	$458,230	$537,820	$590,968	$654,258	$684,523
2	Other Revenues [2]	$000	41,360	48,195	51,150	53,025	53,178
3	*Total Revenues*	$000	$499,590	$586,014	$642,118	$707,283	$737,700
	Operating Expenses:						
4	Fixed Operating Costs [3]	$000	$43,723	$48,522	$53,925	$60,009	$62,651
	Variable Operating Costs:						
5	Fuel Costs	$000	152,332	168,821	183,838	224,709	238,191
6	Non-Fuel Variable Operating Costs [4]	$000	94,361	154,048	176,872	203,756	215,851
7	*Variable Operating Costs*	$000	246,693	322,869	370,710	428,465	454,042
8	Replacement Power [5]	$000	21,731	26,822	29,449	29,314	30,510
9	*Total Operating Expenses*	$000	312,148	398,213	454,084	517,788	547,204
10	Net Revenues [6]	$000	$187,442	$187,801	$188,034	$189,494	$190,497
11	Deposit to Working Capital Reserve Account [7]	$000	1,301	1,659	1,892	2,157	2,280
12	Debt Service [8]	$000	169,220	169,220	169,220	169,220	169,220
13	Deposit to Reserve & Contingency Fund [9]	$000	16,922	16,922	16,922	18,117	18,997
14	Total Revenue Requirements	$000	$499,590	$586,014	$642,118	$707,283	$737,700
	Unit Operation:						
15	Net Capacity	MW	960.0	960.0	960.0	960.0	960.0
16	Gross Energy	GWh	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2
17	Plus: Replacement Energy Purchases	GWh	303.0	303.0	303.0	303.0	303.0
18	Less: Surplus Energy Sales [10]	GWh	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)
19	Net Energy	GWh	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2
20	*Capacity Factor*	%	85.0%	85.0%	85.0%	85.0%	85.0%
	Average Project Costs (with CO2):						
21	*Net Fixed Costs*	*$/KW-mo*	18.36	18.66	19.12	19.60	20.01
22	*Net Non-Fuel Variable Costs*	*$/MWh*	13.20	21.55	24.74	28.50	30.20
23	*Net Fuel Costs*	*$/MWh*	20.73	22.97	26.38	30.58	32.41
24	*Average Costs to Participants*	*$/MWh*	64.10	75.24	82.67	91.53	95.75
	Average Project Costs (w/o CO2):						
25	*Average Costs to Participants [11]*	*$/MWh*	56.81	60.87	66.50	73.32	76.67

[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 without CO_2 emissions costs

The development of the average AMPGS Project costs in $/MWh is shown on lines 45 through 59 of Attachment ES-2. The major components of the average annual Project costs are shown below in Figure 4. Net debt service, which represents approximately 29 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. CO_2 costs make up approximately 18 percent of the total costs and assume that a CO_2 tax would be put in place sometime during the period 2012-2018. Other environmental costs represent approximately 6 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 13 percent of the total costs.

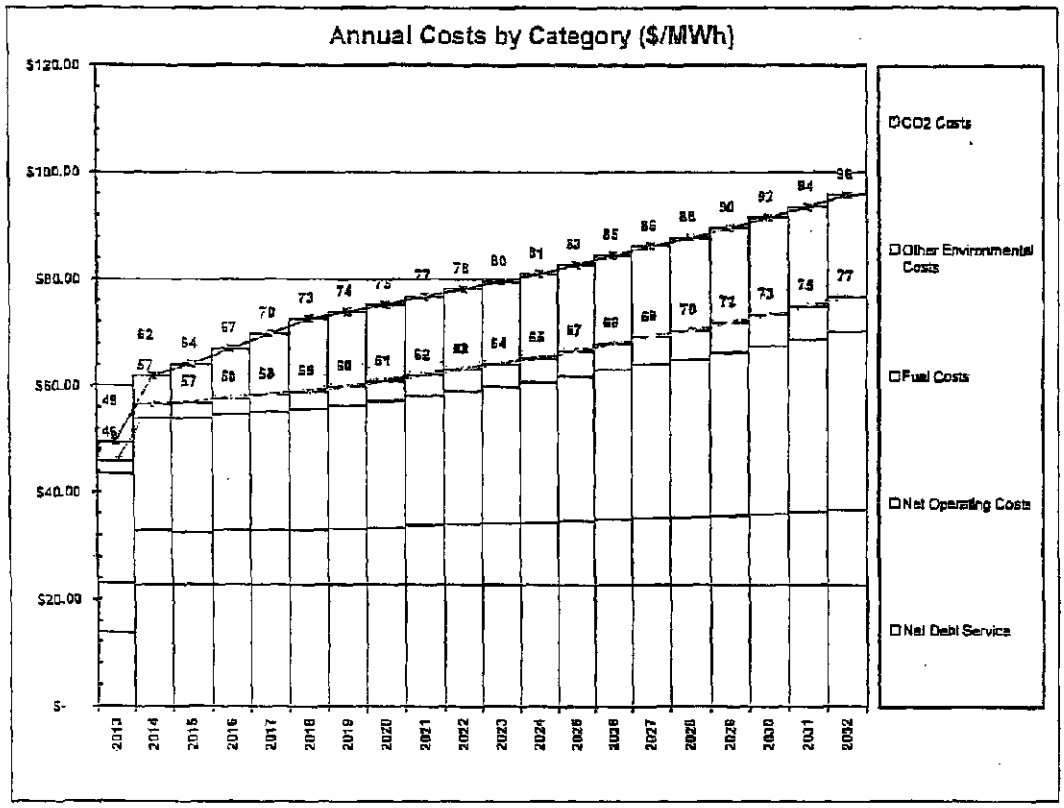


Figure 4 – Projected Annual Power Costs by Category ($/MWh)

AMPGS Project Participants

There are 87 Members[6] of AMP-Ohio that are participating in the development of the AMPGS Project (the "Participants"). The Participants consist of 29 cities and 46 villages in Ohio, 2 boroughs in Pennsylvania, 3 cities and 1 town in Virginia, 3 cities and 2 villages in Michigan and 1 city in West Virginia.

As set forth in Appendix A of the draft Power Sales Contract dated April 2, 2007, each of the AMPGS Participants has initially committed to a Project entitlement share of the AMPGS Project referred to as the Power Sales Contract Resource Share ("PSCR Share"). A list of the Participants and their respect PSCR Shares is shown on Attachment ES-3[7] included at the end of this Executive Summary.

The Participants' power supply arrangements may vary based on, among other things, the power pool or investor-owned utility service area in which their system is located. The majority of Members are associated with one of AMP-Ohio's power pools.

AMP-Ohio Members currently receive their power supply from a mix of resources that includes:

- wholesale power purchases through AMP-Ohio and on the open market from investor-owned utilities and marketers;
- energy produced at AMP-Ohio's 213 MW, coal-fired Richard H. Gorsuch Generating Station near Marietta, Ohio;
- individual community-owned generation facilities; and
- municipal generation joint ventures, including the 42 MW Belleville Hydroelectric Project at the Belleville Locks and Dam on the Ohio River; the 7.2 MW AMP-Ohio/Green Mountain Energy Wind Farm located near Bowling Green, Ohio and approximately 334 MW of distributed generation (either owned by AMP-Ohio or a municipal joint venture) strategically sited throughout the state, using natural gas and diesel technology.

The five Participants in Michigan are members of MSCPA which owns and operates a 50 MW (summer rating) power plant in Litchfield, Michigan on behalf of the MSCPA members. These five Participants also own 76 MW of peaking units and hydro resources. Also, MSPCA purchases partial requirements service from AMP-Ohio on behalf of the MSCPA members.

The four Participants in Virginia are members of BRPA. These four Members have purchased all requirements power from AMP-Ohio since July 2006.

Figure 5 below shows the total of the 87 Participants' projected peak demand, total capacity requirements (peak demand plus an allowance for 12 percent reserves),

[6] As of the date of this Report, there are 87 Participants. Front Royal, Virginia, is neither a Member of AMP-Ohio nor a Participant in the AMPGS Project. However, AMP-Ohio anticipates that Front Royal may become a Member and Participant in the AMPGS Project.

[7] Attachment ES-3 is a copy of Appendix A taken from a draft of the Power Sales contract dated April 2, 2007 discussed below.

existing power supply resources (coal, hydro, diesel, gas, wind and purchased power), the projected 960 MW of capacity from the AMPGS Project, and additional future power supply resource requirements over the period 2008-2027.

As can be seen from the figure, the capacity of the AMPGS Project is needed to fill the base-load requirements of the Participants on a total aggregate basis.

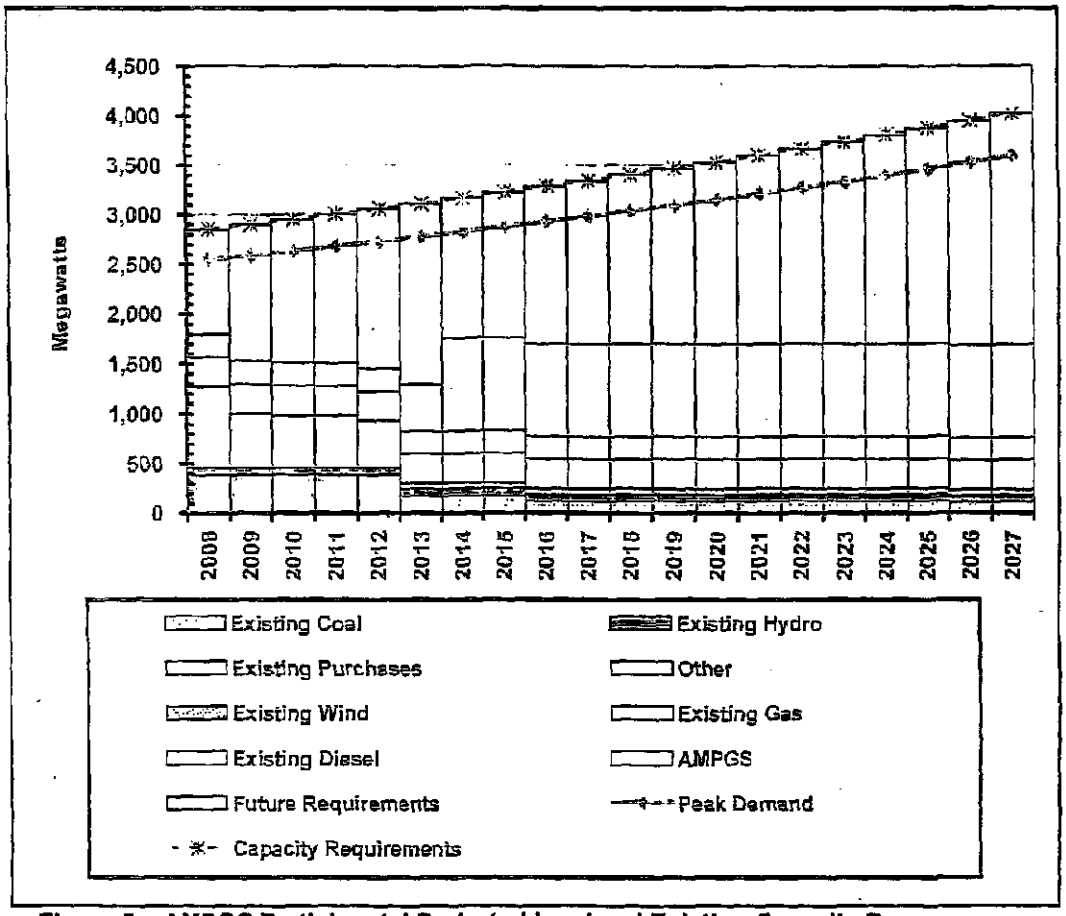


Figure 5 – AMPGS Participants' Projected Load and Existing Capacity Resources (Including AMPGS) [1]

[1] Excludes demand, existing capacity, resources, and capacity from AMPGS for Front Royal and CVEC. Assumed on-line dates of April 2013 for AMPGS Unit 1 and October 2013 for AMPGS Unit 2.

Power Sales Contracts Between AMP-Ohio and the Participants

The Power Sales Contract is the agreement that sets forth the rights and obligations of AMP-Ohio and each Participant with respect to the AMPGS Project. Given the corporate structure of AMP-Ohio, the governing bodies of the Members that enter into contractual arrangements with AMP-Ohio must authorize an ordinance that provides authority for the Member to enter into the Contract. Accordingly, with respect to the

Power Sales Contracts for the AMPGS Project, each Participant will be required to pass an ordinance by their local governing body. The ordinances for the AMPGS Project Power Sales Contract have been prepared for authorization by the governing body of each Participant to authorize execution of the Power Sales Contract by the Participant.

The Power Sales Contract referred to herein is the draft version of the document dated as of April 2, 2007. Under the Power Sales Contract, the Participant is entitled to receive its PSCR Share of the nominal power and associated energy from the Power Sales Contract Resources, which include the electric power and energy from AMP-Ohio's ownership share of AMPGS, all sources of replacement power, and certain transmission services. See Attachment ES-3 for the respective PSCR Share for each Participant. These are the amounts set forth in the Power Sales Contract as of April 2, 2007. The final BSPR Shares will be determined after all Participants have passed ordinances and executed the Power Sales Contract.

The Power Sales Contract is a "take or pay" contract between AMP-Ohio and each of the AMPGS Participants, whereby those Participants agree that, in order to obtain power and energy from the Power Sales Contract Resources, they are willing to pay for their respective rights to that power and energy at rates sufficient to enable AMP-Ohio to recover all of its costs incurred with respect to the AMPGS Project. The Participants are obligated to take or pay for their respective PSCR Share whether or not the Power Sales Contract Resources are complete, operable, or operating.

Under the Contract, all costs of the Project as set forth on monthly invoices from AMP-Ohio, including debt service, are to be recorded as an operation and maintenance expense of the Participant's electric system fund. Debt issued to finance the Project will be recorded on the books and records of AMP-Ohio. No AMPGS debt will be recorded on the books of the Participant.

The Board of Trustees, after consultation with the Participants Committee (discussed below), shall establish, maintain and adjust rates or charges, or any combination thereof, for the capacity and output of the Power Sales Contract Resources sold to Participants under this Contract. A Postage Stamp Rate and other rates and charges under the Contract will be set at levels that are sufficient to meet the Revenue Requirements of AMP-Ohio.

Project governance will be the responsibility of the AMP-Ohio Board of Trustees and the Participants Committee, which is a committee of the Board of Trustees formed by the Participants pursuant to provisions in the Power Sales Contract.

The by-laws of the Participants Committee are set forth in Appendix L of the Power Sales Contract. The Participants Committee will review construction progress, insurance, interim construction financing including capitalized interest, permanent financing and other plant operating matters. The Participants Committee will also make recommendations for rate setting to the Board of Trustees. The Participants Committee will consist of Participants that in total comprise at least 51% of the entitlement shares of AMPGS.

Some actions and authorizations require the approval of a Super Majority of the Participants. A Super Majority of the Participants is defined as 75% of the entitlements of all Participants.

Section 18 of the Power Sales Contract addresses the terms and conditions that are applicable in the event of a default by a Participant due to non-payment or other acts that would cause suspension of the rights of the defaulting Participant under the Contract. In certain default events, each non-defaulting Participant will be required to purchase a pro rata share of the defaulting Participant's entitlement to its PSCR Share, and this amount is referred to in the Contract as "Step Up Power". The amount of Step Up Power will not exceed an accumulated maximum kilowatts of 25% of the non-defaulting Participant's original PSBR Share in kilowatts without the consent of the non-defaulting Participant. Notwithstanding the provision for Step Up Power under the Power Sales Contract, a defaulting Participant is not relieved of its obligations under the Power Sales Contract.

Section 31 of the Power Sales Contract addresses various matters concerning the term of the Contract, including the effective date, the period over which the Contract will remain in effect, and termination by a Super Majority of Participants. Unless otherwise terminated, the Contract will remain in effect until February 28, 2057, and thereafter until all principal of, premium if any, and interest on all Bonds have been paid or deemed paid in accordance with the Trust Indenture. The Participant remains obligated to pay its respective share of the costs of terminating, discontinuing, disposing of, and decommissioning all Power Sales Contract Resources.

This section also includes a provision allowing Participants that execute the Contract prior to September 1, 2007, a one-time option to reduce the requested PSCR Share or repudiate the Contract upon certain notice provision to AMP-Ohio and prior to the defined "Effective Date" of the Contract. The Effective Date of the Contract is the date that is the later of March 1, 2008, and the date, not later than January 1, 2009, upon which Power Sales Contracts between AMP-Ohio and Participants have been executed such that the aggregate PSCR Shares of such Participants are not less than a nominal 750 MW.

Participant Need for AMPGS Project

In late 2006, AMP-Ohio contracted with R. W. Beck to develop long-term power supply plans for 119 of its Members. R. W. Beck prepared a report for each Member that included a 20-year load forecast, a 20-year optimal power supply plan and the key inputs and assumptions used to develop the plan. These reports were delivered to AMP-Ohio and its Members in February 2007 (the "February 2007 Member Power Supply Analysis").

In developing the plan for each Member, a generation expansion plan was developed assuming that the Member could participate in "slices" of future AMP-Ohio generating resources equal to 15 percent of the Member's projected 2027 peak demand (plus an allowance for 12 percent reserves). The generating resource options included in this study were future generic base load coal, natural gas-fired combined

cycle and peaking resources, the AMPGS Project, the Prairie State Energy Campus (a proposed mine-mouth coal plant in Illinois, referred to herein as "Prairie State"), proposed AMP-Ohio hydroelectric plants along the Ohio River, and future wind plants. The purchase power options included a 5-year peak load, 5x16 contract (five days a week for 16 hours per day) and a 10-year baseload, 7x24 (seven days a week for 24 hours per day) contract, as well as spot market purchases. The generation expansion plan was developed by considering shares (in terms of slices) of each of these options. The optimal power supply plan was developed by selecting the optimal power supply strategy (amount and timing of resource additions) that minimized the total net present value of power supply costs and risks over the 20-year period 2008-2027. The AMPGS Project was included as an option for those members that are participating in the development phase of the Project. The Prairie State project and hydro projects were included as an option for all Members.

The initial power supply plan developed for each member was intended to give that Member an indication of the optimal amount, timing, and type of power supply resources needed over the 20-year study period. Over the short-term, this plan provided each Member guidance on project participation levels among the future AMP-Ohio generation projects currently planned. Over the longer-term, the plan will be adjusted to take into consideration actual costs and other knowns that were projected in the initial plan and new market conditions and resource options.

In developing the plan for each Member, R. W. Beck utilized its Stochastic Econometric Regional Forecasting ("SERF") model and power supply planning approach. SERF generates stochastic[8] projections of fuel and power prices, utility loads and corresponding power costs for multiple portfolios of power supply resources. Using the SERF model, R.W. Beck developed stochastic projections of future power supply costs for each member using several alternative possible portfolios of resources, and identified the power supply portfolios that resulted in the lowest costs and risk to each Member over the 20-year period 2008-2027

A summary of power requirements and future resources for the aggregate of the optimal power supply plans for all the AMP-Ohio Members under the Base Power Supply Plan developed in February 2007 is summarized below. Figure 6 shows the aggregate of the 119 AMP-Ohio Members' projected peak demand, existing power supply resources and future power supply resources over the period 2008-2027. As can be seen from Figure 6, the need for future capacity and energy resources by 2013 is approximately 2,947 MW and increases to 3,360 MW by the end of the study period.

[8] Stochastic projections reflect the uncertainty and volatility in forecasting variables such as fuel costs and electric loads. A stochastic projection is usually captured by forecasting future values based on past economic behavior and numerous future outcomes. The resulting stochastic projection provides a range of potential values instead of one forecasted value.

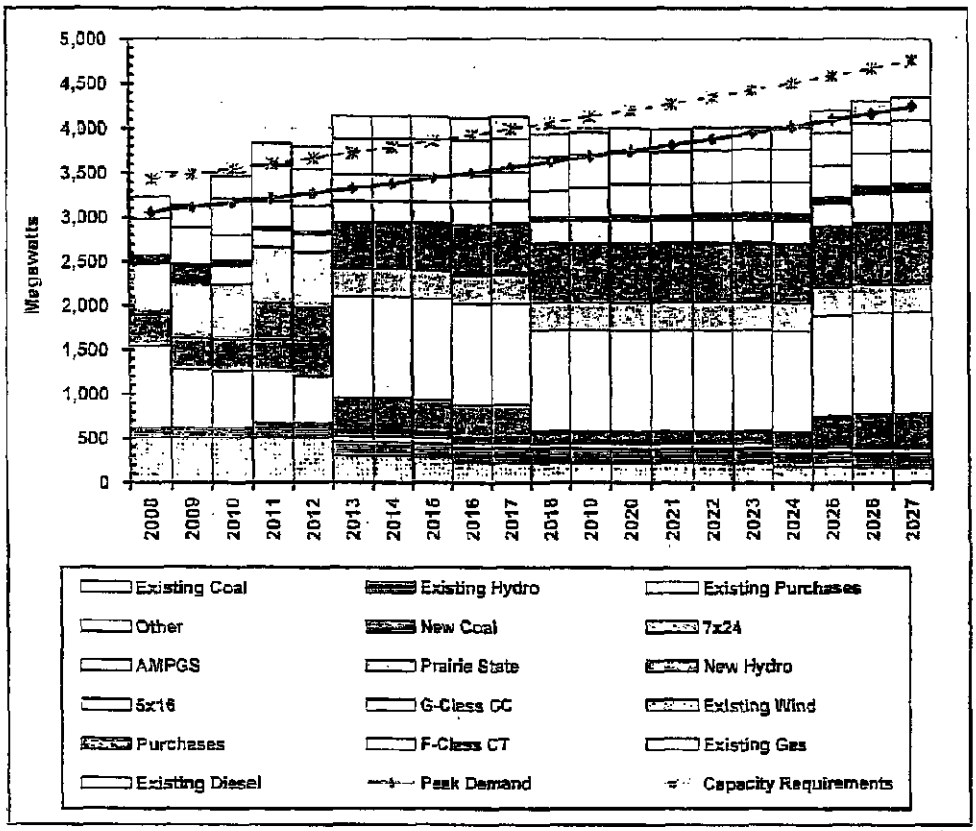


Figure 6 – AMP-Ohio Grand Total Power Supply Plan – Base Case

The timing, amount of capacity and type of capacity resources needed as indicated by the power supply plans is summarized in aggregate in Table 7 below. In addition to the capacity resource additions shown in the table, the power supply plans reflected annual forward purchases and short-term market purchases as needed to meet each Member's projected capacity and energy requirements.

Table 7
Summary of AMP-Ohio Total Power Supply Plan

	Cumulative Capacity Additions at Selected Years (MW)				
	2013	2015	2020	2025	2027
AMPGS [1]	1,140	1,140	1,140	1,140	1,140
Prairie State [2]	317	317	317	317	317
Hydro [3]	530	543	668	695	695
Coal	75	75	137	355	404
G-Class CC	228	228	251	251	345
F-Class CT	290	290	348	356	370
Contract Purchases [4]	367	367	62	71	89
Total	2,947	2,960	2,923	3,185	3,360

[1] The AMPGS Project was included as an option for those Members that are presently participating in the development phase of the Project. The total number of "slices" in the optimal power supply plans was not limited by the Members' actual participation level in the Project. However, each Member was limited to a maximum of two slices. The total capacity available from the AMPGS Project is estimated to be 960 MW, which is less (by 180 MW) than the total amount of AMPGS capacity needed as indicated from the power supply plans developed for all the Members in February 2007.

[2] The Prairie State project was included as an option for all Members. According to AMP-Ohio, as of the date of this Report, the total amount of capacity available to the AMP-Ohio Members from this project is 150 MW which is less (by 167 MW) than the amount needed indicated from the power supply plans.

[3] According to AMP-Ohio, the amount of capacity available from the proposed AMP-Ohio hydroelectric plants along the Ohio River is approximately 300 MW which is less (by 395 MW) than the amount of hydro capacity needed as indicated from the power supply plans developed for all the Members.

[4] Includes 5x16 and 7x24 forward contract purchases and other on-peak purchases estimated to be required in the future.

In summary, the February 2007 Member Power Supply Analysis indicates that in order to meet the Members projected power requirements, there is a requirement for additional base, intermediate and peaking type capacity and energy resources. The projected amount of additional capacity required is estimated to be 2,947 MW in 2013 growing to 3,360 MW by 2027. The amount of additional base load capacity projected (represented by AMPGS, Prairie State and new generic coal) totals 1,531 MW in 2013 growing to 1,861 MW by 2027.

In addition to identifying the amount and timing of future generating resources, the Power Supply Plans included a stochastic projection of the annual power supply costs reflecting the optimal Power Supply Plan for the period 2006 through 2027. The projected power supply costs for each Member were shown in terms of expected value, 5th percentile and 95th percentile[9].

[9] Expected value is the average of the 50 draws from the results of the stochastic model. There is a 5 percent probability that the results will be below the 5th percentile values and a 5 percent probability that the results will be above the 95th percentile values

Beneficial Use of the AMPGS Project

In accordance with Section 2 (B) (x) of the AMPGS Power Sales Contracts, we have prepared an analysis to determine if each Participant can beneficially utilize its PSCR Share (as defined in the Power Sales Contract) of the AMPGS Project. This analysis is based on each Participant's current PSCR Share. The PSCR Share may be modified and will be finalized after the execution of the Power Sales Contract which may differ from the PSCR Share assumed herein.

We have prepared three types of analysis to determine if the Participant can beneficially utilize its share of the AMPGS Project. The three analyses include:

- a comparison of AMPGS PSCR Share as a percent of peak demand for selected years,
- an analysis of potential surplus energy including identifying surplus energy sales from AMPGS and incremental surplus energy sales from existing Participant resources as a result of adding AMPGS, and
- an analysis of each Participant's projected power costs and risks, before and after its PSCR Share of AMPGS.

AMPGS Share Compared to Peak Demand

Power plants, such as AMPGS, that are designed to generate energy at its maximum capability when available are considered "base-load" plants because these plants are expected to be available to meet base (or minimum) load requirements. Therefore, in developing a power supply plan a utility will generally plan for enough capacity from base load plants or contracts at least equal to its projected minimum load. Most utilities plan for around 50-55 percent of their projected peak demand to be supplied from base-load type generation. If a utility has more base-load generation than its hourly load requirements, it must reduce the output of the base load plant or sell the surplus energy in a given hour. Because all the Participants are in regions where surplus energy can readily be sold, this planning criteria is not as important.

Attachment ES-4 at the end of this Executive Summary compares the AMPGS Participants' 2006, 2015 and 2025 peak demands with their respective shares in the AMPGS Project.

As shown in Attachment ES-4, the number of Participants with AMPGS Shares greater than 50 percent of their projected peak demand is:

- 22 based on the 2006 peak demand,
- 10 based on the 2015 projected peak demand, and
- 4 based on the 2025 projected peak demand (these four Participants represent approximately 45 MW of the Project capacity or approximately 5%).

On a total basis, the AMPGS capacity is approximately 30 percent of the aggregate peak demand in 2015. In aggregate, the AMPGS Participants can beneficially use the AMPGS capacity to meet their base load requirements.

This analysis does not take into consideration that some of the Participants have existing base-load type generation. However, the surplus energy analysis and the power cost and risk analyses described below do reflect existing base-load generation.

Surplus Energy Analysis

As discussed below, we have prepared stochastic projections of the total power supply cost for the period 2013 – 2027 for each of the AMPGS Participants for two cases. The first case includes the Participant's existing power supply resources (Existing Portfolio) and the second case includes the Participant's existing power supply resources and its current PSCR Share of the AMPGS Project (Portfolio with AMPGS). Based on the results of these projections, we computed the amount of the estimated surplus energy sales and associated revenues for each Participant from its share of AMPGS and the incremental surplus energy sales from the Participant's existing resources that result from adding its share of AMPGS. The results of this analysis are summarized below:

- Surplus energy from AMPGS
  - 28 Participants are projected to have surplus energy on an average annual basis ranging from 1 percent to 17 percent of the output from their AMPGS PSCR Shares
  - 13 Participants are projected to have surplus energy on an average annual basis greater than 5 percent of the output from their AMPGS PSCR Shares
- Additional surplus energy resulting from adding AMPGS to the Existing Portfolio
  - 50 Participants are projected to have surplus energy on an average annual basis ranging from 3 percent to 90 percent of the output from their AMPGS PSCR Shares
  - 28 Participants are projected to have surplus energy on an average annual basis greater than 15 percent of the output from their AMPGS PSCR Shares
  - 4 Participants are projected to have surplus energy on an average annual basis greater than 50 percent of the output from their AMPGS PSCR Shares (these four Participants represent approximately 36 MW of the Project capacity or approximately 4 percent)

Impact of AMPGS Project on Participant Costs and Risks

Using the power supply models developed for the February studies, R. W. Beck prepared stochastic projections of the total power supply costs for each of the AMPGS Participants reflecting the Participant's existing power supply resources (Existing Portfolio). The stochastic power cost projections produce a range of costs resulting from the estimated volatility in loads, fuel prices, market prices, and CO_2 costs. A sample of the projections for one Participant is shown in Figure 7 below.

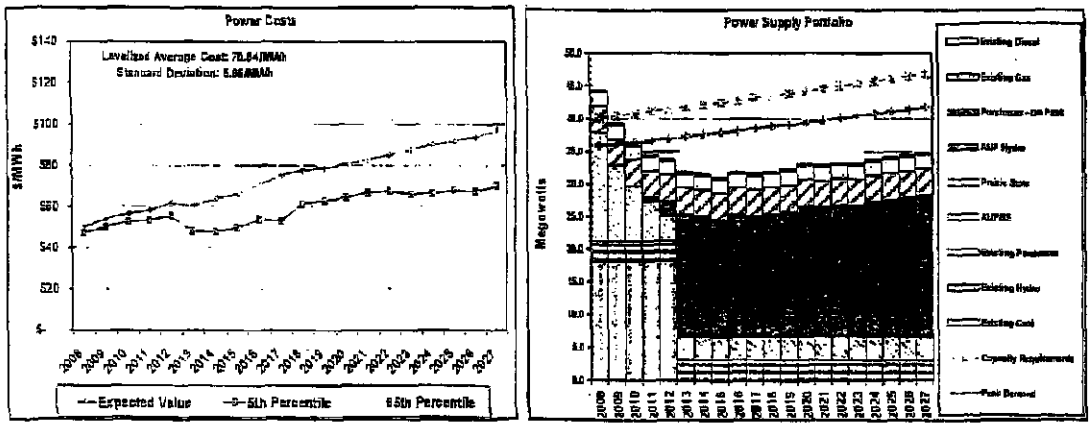


Figure 7 – Stochastic Projection of Participant Power Costs – Existing Portfolio

We also prepared stochastic projections of the total power supply costs for each AMPGS Participant reflecting the Participant's existing power supply resources and its current PSCR Share of the AMPGS Project (Portfolio with AMPGS). A sample of the projections for one Participant is shown in Figure 8 below.

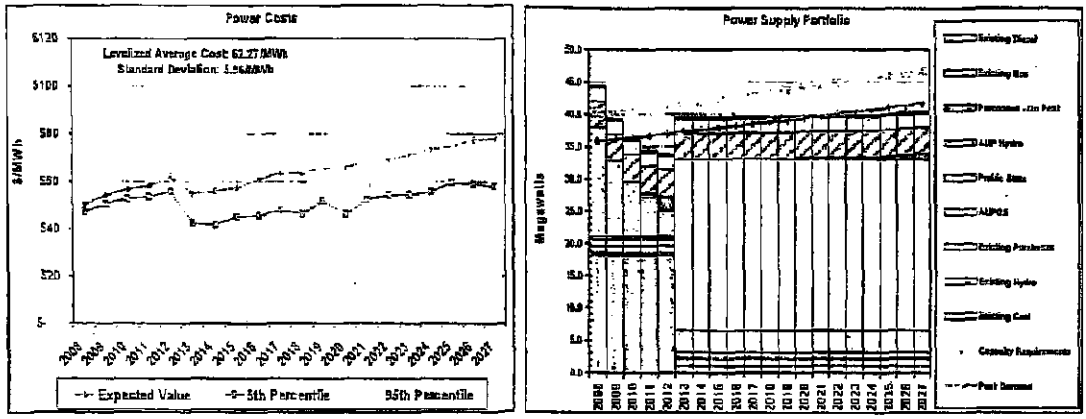


Figure 8 – Stochastic Projection of Participant Power Costs – Portfolio with AMPGS

Based on these power costs analyses, the projected power costs for every AMPGS Participant are lower under the portfolio with AMPGS than the existing portfolio.

In addition, we have prepared stochastic projections of the total power supply cost for the period 2013 – 2027 for each of the AMPGS Participants assuming that their respective AMPGS PSCR Share is increased by 25 percent. We have included this case to analyze the impact on the Participant's costs and risk of the 25 percent step-up provision under the Power Sales Contract.

The stochastic power cost projections produce a range of costs resulting from the estimated volatility in loads, fuel prices, market prices, and CO_2 costs. Based on this analysis we have developed an expected average annual cost (annual cost present valued to 2013 and averaged). From the results of the stochastic analysis we can estimate the uncertainty in future power costs (or risks) by computing the standard

deviation ("STD") in the projected average annual power costs under the 50 draws produced by the stochastic model.

The results of the stochastic analysis demonstrate that costs are lower under the Portfolio with AMPGS than the Existing Portfolio for all of the Participants. Also, costs are lower under the Portfolio with AMPGS including the 25 percent step-up than the Existing Portfolio for all of the Participants.

To illustrate the impact on costs versus risk for each Participant, we developed a chart that depicts expected costs (average annual costs) on the x-axis and risks (in terms of STD) on the y-axis for each of the three cases. A sample of the chart is shown in Figure 9 below.

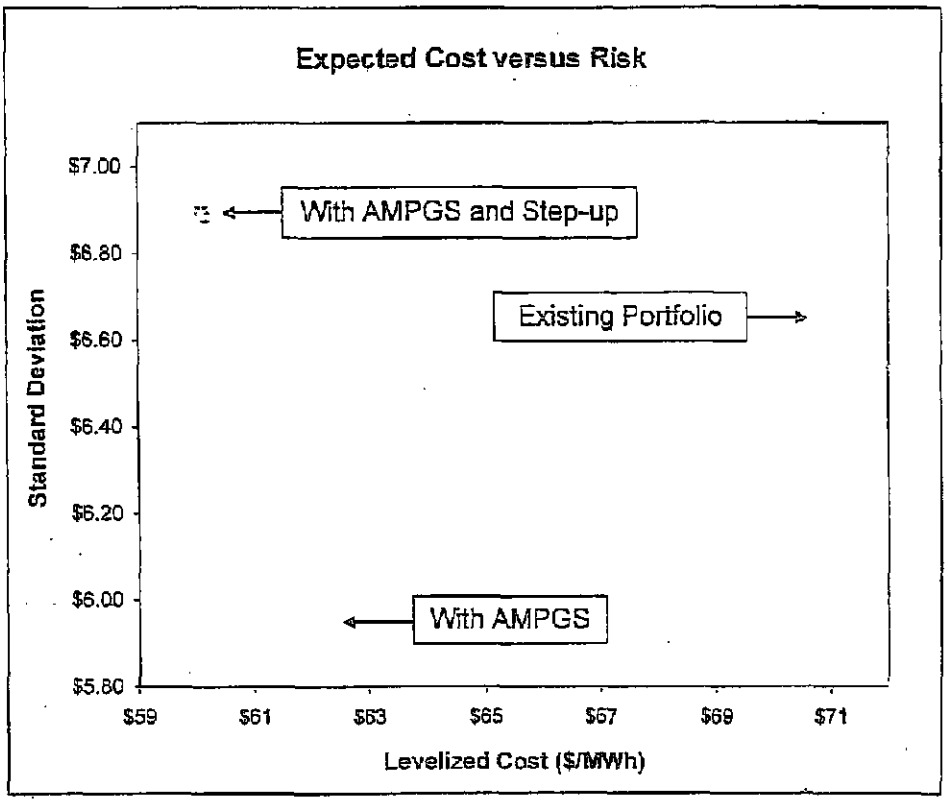


Figure 9 – Expected Cost versus Risk Chart for Sample Participant

Even though costs are lowered by the addition of the AMPGS PSCR Shares for all Participants, it is important to consider the impact on risks.

For all but four Participants, risks (as measured by the STD) are lower under the Portfolio with AMPGS than the Existing Portfolio. These four Participants represent approximately 36 MW or four percent of the AMPGS Project capacity. Also, for all but seven Participants, risks are lower under the Portfolio with AMPGS including the 25 percent step-up than the Existing Portfolio for all of the Participants. These seven Participants represent approximately 49 MW or 5 percent of the AMPGS Project capacity.

Analysis of Potential Project Risks

To address the potential risks of the AMPGS Project, we have prepared a qualitative risk assessment and a quantitative risk assessment. An overview of the major elements of the risk assessments are:

- Qualitative risk assessment
  - Develop risk inventory of all risks of the Project
  - Evaluate risk in terms of likelihood of occurrence and potential impact on Participant costs
  - Identify risk mitigation strategies
- Quantitative risk assessment
  - Develop stochastic projections of Participant power costs for beneficial use analysis (Discussed herein under Beneficial Use of AMPGS Project)
  - Develop stochastic projections of AMPGS annual power cost projections that quantifies major risks of the AMPGS Project

Qualitative Risk Assessment

R. W. Beck and AMP-Ohio worked together to develop the qualitative risk assessment of the AMPGS Project. The qualitative risk assessment involved developing a risk inventory of the risks that could occur for the AMPG Project, characterizing each relevant risk source as being "low," "moderate," or "high" and developing risk mitigation strategies for each risk source.

Developing the risk inventory was approached from the perspective of three risk environments. Internal risks are those risks that occur internal to the AMP-Ohio organization or the AMPGS Project and can be controlled by processes implemented by AMP-Ohio. Internal risks include: strategic risks, operational risks, financial risks and technology risks. AMP-Ohio will have moderate control over the risks that occur in the electric market environment. Risks included in the market environment include: price risks, transmission cost risks, and credit risks. There are market derivatives and hedging instruments available to manage market risks. External risks related to event risks, hazard risks, legal and contractual risks and risks related to the political, regulatory and environmental are the most difficult to control.

As demonstrated in Figure 10 below, in developing the overall risk level for each of the risk sources, both the likelihood of the event occurring and the impact on cost were considered. Risk were assessed both on a "Gross" and "Net" basis. The gross risk assessment reflects the characterization of the risks before risk mitigation strategies are considered. The net risk assessment reflects the characterization of the risks assuming risk mitigation strategies are in place and effective. As illustrated in the chart below, those risks that reside in the yellow, orange or red squares of the risk matrix are likely to have the greatest impact on the Project. All other risks would be considered low to moderate and would reside in the green and light green squares.

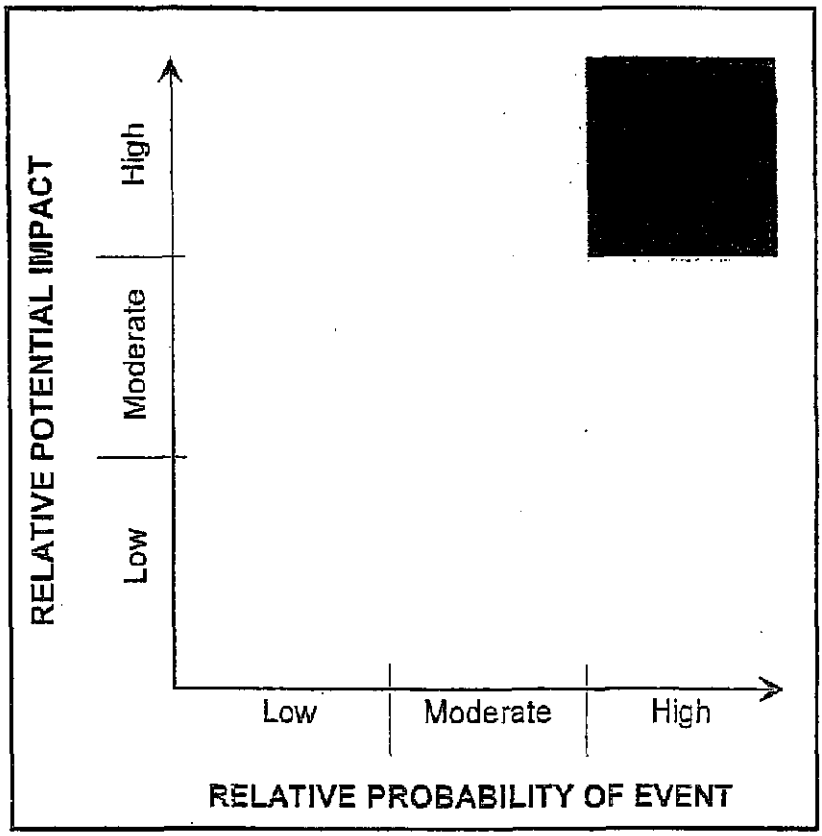


Figure 10 – Risk Matrix

In summary, for each of the three risk environments the risks that would be considered moderate to high risk are summarized below in Table 8. All other risks would be considered low to moderate.

Table 8
Summary of Qualitative Risk Assessment Results

Risk Category:	Major Source of Risk Characterized as Moderate to High
Internal Risk	▫ Developmental and Construction Cost Risks (potential delays, cost overruns and availability of human craft resources)
Market Risk	▫ Price Risks (related to volatility in coal prices, fertilizer prices and SO_2, NO_X allowance prices)
External Risk	▫ Regulatory Risks (related to more stringent environmental laws associated with CO_2 and mercury)

Risk Mitigation Strategies

The qualitative risk assessment process identified a number of potential, or existing, risk mitigation strategies which are summarized below:

Internal Risk Environment

Strategic risks related to potential changes in the Participants competitive position would be mitigated by keeping the costs (and cost increases) of the Project to the Participants as low (and stable) as possible though the use of longer-term debt, low cost tax-exempt financing and use of rate stabilization funds (if needed).

Operational risks would be mitigated by developing procedures to attract and maintain highly qualified staff, training programs, developing high standards for plant performance, sound maintenance programs, and state-of-the-art systems.

Financial risk would be mitigated by (i) the establishment of reserves for the Project, debt service coverage ratios, step-up provisions in the Power Sales Contracts; (ii) development of a financial plan and use of interest rate swaps to mitigate the risk of interest rate fluctuations; and (iii) AMP-Ohio's existing Member credit program.

Development and Construction risks deserve significant consideration. Mitigation strategies include close oversight as owner through an experienced Owner's Engineer, liquidated damages clauses, penalty clauses and incentive clauses in contracts and procurement documents, early procurements and sound planning.

Technology risks would be mitigated through the incorporation of design specifications and guarantees in the EPC contract.

Market Risk Environment

Price risks would be mitigated by (i) development of appropriate coal purchase agreements and designing the AMPGS plant with the flexibility to burn different types of coal; (ii) development of an agreement with The Andersons to provide urea for the Powerspan process and to market the sale of the fertilizer produced by the Powerspan process and (iii) installation of best available technology to control SO_2 and NO_X emissions.

Transmission risks would be mitigated by proper oversight of the processes required to interconnect the AMPGS Project to the PJM grid and the use of allocated FTRs and AARs to mitigate congestion costs.

Credit risks will be mitigated by screening of counterparties so that only large highly rated financial institutions are used and only proposals from a limited number of large nationally recognized firms are considered for the EPC contractor.

External Risk Environment

Event risks related to unplanned outages will be somewhat mitigated by the fact that the AMPGS plant is a two unit plant. Event risks related to unplanned transportation interruptions will be mitigated by the development of adequate storage for commodities inventories to carry operations through any delivery interruptions.

Hazard risks can be mitigated through training programs, good oversight as an owner, appropriate insurance instruments, establishment of reserves (if necessary) and implementing a reliable and sound design for the plant.

Legal and contractual risks surrounding counterparty performance creates the need to negotiate a comprehensive EPC contract prior to signing contracts. The contract will

need to contain strong provisions to protect AMP-Ohio from liability of actions of the counterparties. Legal and contractual risks related to potential Participant default are mitigated by the step-up provisions in the Power Sales Contract.

Regulatory risks related to more stringent environmental regulations associated with CO_2 and mercury emissions may be somewhat mitigated by continued monitoring of environmental regulations and planning for the potential impact on the Project. The Powerspan technology will somewhat mitigate the additional costs for carbon capture if required in the future.

Quantitative Risk Assessment

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 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.

Based on the 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 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 11, below, provides a graphical representation of the results of the probabilistic analysis, in terms of the average net costs to the Participants associated with the AMPGS Project with CO_2 cost (in $/MWh), for an expected value and a 90% confidence interval (area between the 5% and 95% confidence estimate). 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, you would expect the average annual net Participant costs to be within this band 90% of the time.

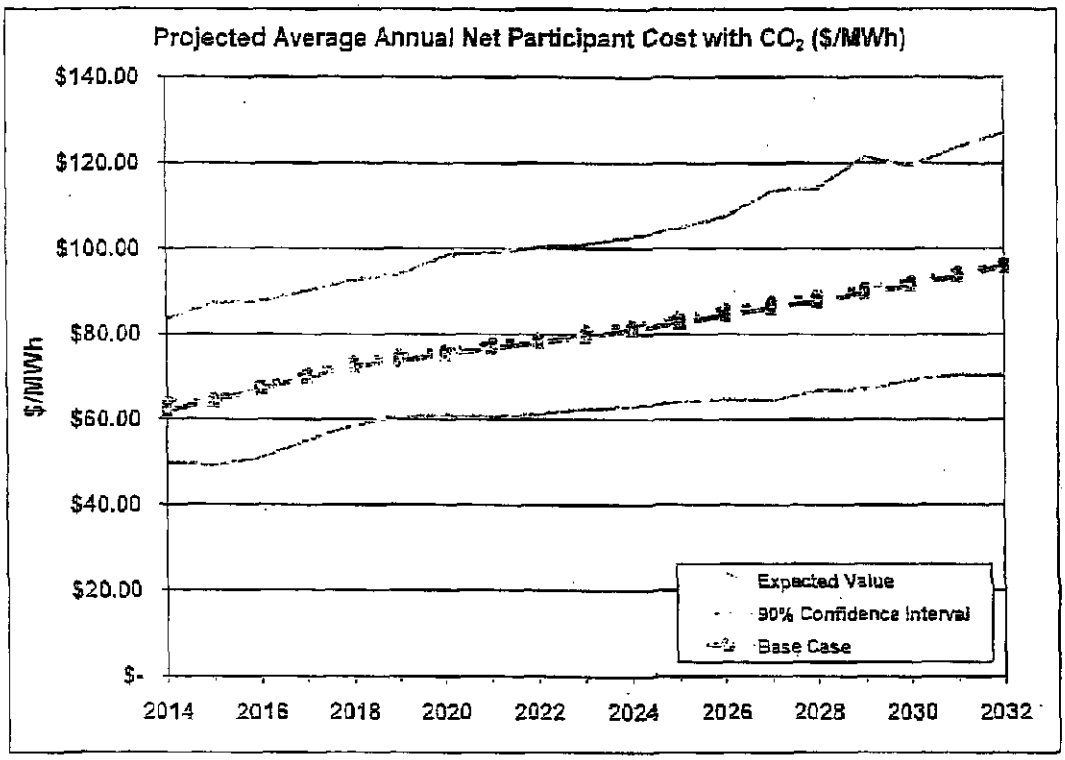


Figure 11 Net Participant Costs (with CO_2) at 90% Confidence Interval ($/MWh)

The projected net Participant power costs with CO_2 are projected to be approximately $77.55 / MWh on an average annual levelized[10] basis over the period 2013 through 2032. The projected uncertainty in future power costs as measured by the standard deviation in the projected average annual levelized power costs is estimated to be approximately $ 10.71 / MWh (or 14%).

In the case with CO_2, the major risk factors that cause the uncertainty in power costs and their contribution to the STD are shown in Table 9 below.

[10] The average annual levelized net Participant power 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
Risk Factors Contribution to STD with CO_2

Description	Contribution to STD	
	$/MWh	% of Total
Coal Prices	2.90	27%
Urea and Ammonium Sulfate Prices	2.58	24%
CO_2 Costs	2.34	22%
Construction Cost, Schedule, and Interest Rates	2.32	22%
Surplus & Replacement Energy Costs	0.36	3%
SO_2, NO_x, and Mercury Costs	0.21	2%
Total	10.71	100%

As shown above, in the case with CO_2, the uncertainty in the projected net power costs to the Participants is most influenced by CO_2 costs, coal prices, urea and ammonium sulfate prices, and construction and financing cost uncertainty.

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. In considering approval of the AMPGS Project, the individual Participants should carefully weigh the benefits and responsibilities of ownership of the AMPGS Project.

Initial Findings and Conclusions

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

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. 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 Report lists the principal considerations and assumptions made by R. W. Beck in preparing the studies and analyses set forth in this Report and rendering the initial findings and conclusions set forth in Section 9.3 of the Report and repeated below.

Based upon such considerations and assumptions and upon the analyses and studies as summarized in this Report, including all appendices, which Report and appendices should be read in their 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 9,325 Btu/kWh, assuming utilization of an eastern coal fuel blend, 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 $2.532 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 $2.912 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 $2.839 billion.

12. The Participants' PSCR Shares in the AMPGS Project can be beneficially utilized by the various AMPGS Participants as follows::

    a) The projected power costs over the period 2013 through 2027 for each AMPGS Participant are lower under the power supply arrangement including 100 percent their PSCR Share of the AMPGS Project compared to the existing power supply arrangement.

    b) The projected power cost risks (as measured by the estimated standard deviation in power costs for the risk variables evaluated, as discussed in Section 2.5.4 of this Report) over the period 2013 through 2027 for all but four of the AMPGS Participants are lower under the power supply arrangement including 100 percent their PSCR Share of the AMPGS Project compared to the existing power supply arrangement.

    c) The aggregate amounts of capacity and energy from the AMPGS Project, after giving effect to the sale of a portion of the AMPGS Project output in the short-term energy market, can be beneficially utilized by the Participants in serving the aggregate long-range base-load power and energy requirements of the Participants.

13. The Participants' PSCR Shares adjusted to reflect a 25 percent step-up requirement, (pursuant to Section 18 of the Power Sales Contract) can be beneficially utilized by the various AMPGS Participants as follows:

    a) The projected power costs over the period 2013 through 2027 for each AMPGS Participant are lower under the power supply arrangement including 125 percent of their PSCR Share of the AMPGS Project compared to the existing arrangement.

    b) The projected power cost risks (as measured by the estimated standard deviation in power costs for the risk variables evaluated, as discussed in Section 2.5.4 of this Report) over the period 2013 through 2027 are lower for all but seven of the AMPGS Participants under the power supply arrangement including 125 percent of their PSCR Share of the AMPGS Project compared to the existing power supply arrangement.

14. 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, which could cause the AMPGS Project postage stamp rates to increase. AMP-Ohio has initiated power flow studies to estimate the potential transmission upgrades and associated costs to provide firm transmission service from the Project to the MISO Participants.

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

16. 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.

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]	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325
7	Total Coal Consumption (BBtu) [6]	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531
8	Heating Value of Coal (Btu/lb)	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051
9	Coal Consumption (Tons x 10^3) [6]	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843
10	Total NO_x Allowances Purchased (Tons) [7]	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398
11	Mercury Allowances Purchased (Tons) [8]	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473
12	SO_2 Allowances Purchased (Tons) [9]	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140
13	CO_2 Allowances Purchased (Tons x 10^3) [10]	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357
14	Urea - SCR Consumption Rate (Tons) [11]	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587
15	Urea Consumption (Tons x 10^3) [12]	114	114	114	114	114	114	114	114	114	114
16	Ash Production (Tons x 10^3) [13]	356	356	356	356	356	356	356	356	356	356
	COMMODITY PRICES										
17	General Inflation (%) [14]	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
18	Coal Commodity Price ($/Ton) [15]	$43.86	44.84	45.59	46.47	47.43	48.28	49.36	50.52	51.85	53.21
19	Coal Transportation Price (Blended) ($/Ton) [16]	$7.69	7.85	7.98	8.14	8.31	8.45	8.65	8.85	9.08	9.32
20	All-In Average Coal Price Delivered ($/MMBtu)	$2.14	2.19	2.22	2.27	2.31	2.35	2.41	2.46	2.53	2.59
21	Urea Price ($/Ton) [17]	$310	318	325	333	341	349	358	366	375	384
22	SO_2 Allowances ($/Ton) [18]	$1,291	1,389	1,486	1,522	1,558	1,595	1,634	1,673	1,713	1,754
23	Mercury Allowances ($/Oz) [19]	$1,211	1,302	1,398	1,517	1,642	1,771	1,906	2,047	2,198	2,239
24	NO_x Allowances - Annual ($/Ton) [20]	$1,322	1,411	1,505	1,606	1,714	1,829	1,951	2,082	2,221	2,370
25	NO_x Allowances - Ozone ($/Ton) [21]	$2,163	2,320	2,487	2,666	2,859	3,065	3,286	3,523	3,777	4,049
26	CO_2 Allowances ($/Ton) [22]	$3.38	5.19	7.06	9.06	11.14	13.29	13.61	13.94	14.27	14.62
27	Activated Carbon Costs ($/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	$124,692	127,498	129,627	132,143	134,853	137,272	140,368	143,658	147,482	151,302
29	Coal Transportation	$21,841	$22,332	22,705	23,147	23,621	24,044	24,587	25,163	25,824	26,503
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	$15,334	15,702	16,079	16,465	16,860	17,264	17,679	18,103	18,537	18,982
33	Operator G&A	$576	590	604	619	634	649	665	681	697	714
34	Other Fixed [25]	$16,141	16,528	16,925	17,331	17,747	18,173	18,609	19,056	19,513	19,981
35	Fixed O&M	$32,051	32,820	33,608	34,415	35,241	36,086	36,953	37,840	38,747	39,677
	Variable O&M										
36	Major Maintenance/Capital Expenses [26]	$12,108	12,396	12,694	12,998	13,310	13,630	13,957	14,292	14,635	14,986
37	Other Variable [27]	$8,647	8,854	9,067	9,285	9,507	9,736	9,969	10,208	10,453	10,704
38	Variable O&M	$20,753	21,250	21,761	22,283	22,817	23,366	23,925	24,500	25,088	25,690
	Emissions Allowances										
39	SO_2 Emissions Allowances	$6,636	7,139	7,638	7,823	8,008	8,203	8,399	8,599	8,805	9,015
40	Mercury Emissions Allowances	$5,709	6,141	6,589	7,153	7,740	8,352	8,988	9,650	10,079	10,527
41	NO_x Emissions Allowances - Annual	$3,171	3,384	3,611	3,853	4,111	4,386	4,680	4,994	5,328	5,685
42	NO_x Emissions Allowances - Ozone	$2,152	2,318	2,485	2,665	2,857	3,063	3,284	3,521	3,775	4,047
43	CO_2 Emissions Allowances	$24,877	38,210	52,170	66,777	82,056	97,932	100,282	102,689	105,153	107,677
44	Emissions Allowances	$42,555	57,192	72,493	88,271	104,772	121,936	125,633	129,453	133,140	136,951
45	Activated Carbon	$0	0	0	0	0	0	0	0	0	0
46	Urea - SCR	$1,733	1,774	1,817	1,860	1,905	1,951	1,998	2,046	2,095	2,145
	Powerspan										
47	Urea Cost ($/Yr)	$35,454	36,305	37,176	38,068	38,982	39,917	40,875	41,856	42,861	43,890
48	Waste Disposal Cost ($/Yr)	$4,106	4,204	4,305	4,408	4,514	4,623	4,734	4,847	4,964	5,083
49	Auxiliary Power ($/Yr)	($1,017)	(1,041)	(1,066)	(1,092)	(1,118)	(1,145)	(1,172)	(1,200)	(1,229)	(1,259)
50	Renewals, Replacements & Maintenance	($71)	(72)	(74)	(76)	(78)	(79)	(81)	(83)	(85)	(87)
51	Other Operating Costs	$12,764	13,070	13,384	13,705	14,034	14,371	14,716	15,068	15,430	15,801
52	Labor	$657	673	689	706	723	740	758	776	794	814
53	Transportation	$4,120	4,219	4,321	4,424	4,530	4,639	4,750	4,864	4,981	5,101
54	Solid Fertilizer Credit	($44,385)	(45,451)	(46,541)	(47,658)	(48,802)	(49,973)	(51,173)	(52,401)	(53,659)	(54,946)
55	Liquid Fertilizer Credit	($1,088)	(1,114)	(1,141)	(1,168)	(1,196)	(1,225)	(1,254)	(1,284)	(1,315)	(1,347)
56	Powerspan [28]	$10,540	10,793	11,052	11,318	11,589	11,867	12,152	12,444	12,742	13,048
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]	$5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552
61	Corporate G&A [31]	$500	512	524	537	550	563	576	590	604	619
62	Total Operating Expenses	$260,217	279,723	299,140	319,526	340,901	362,637	371,745	381,245	391,224	401,487
	AVERAGE BUSBAR COST [32]										
63	Total Annual Costs	$260,217	279,723	299,140	319,526	340,901	362,637	371,745	381,245	391,224	401,487
64	Fixed Operating Cost ($000)	$36,103	36,884	39,684	40,504	41,343	42,201	43,081	43,982	44,903	45,848
65	Fixed Operating Cost ($/kW-yr) [33]	$38.60	39.40	40.21	41.04	41.89	42.76	43.65	44.56	45.49	46.45
66	Fixed Operating Cost ($/MWh)	$5.18	5.29	5.40	5.51	5.63	5.74	5.86	5.98	6.11	6.24
67	Total Variable Operating Cost ($000)	$222,114	240,839	259,456	279,022	299,558	320,436	328,664	337,263	346,321	355,639
68	Total Variable Operating Costs ($/MWh) [34]	$30.22	32.77	35.30	37.97	40.76	43.60	44.72	45.89	47.12	48.39
69	Fuel Cost ($/MWh)	$19.94	20.39	20.73	21.13	21.56	21.95	22.45	22.97	23.57	24.19
70	Non-Fuel Variable Operating Costs ($/MWh)	$10.28	12.38	14.58	16.84	19.20	21.65	22.28	22.92	23.55	24.20
74	AVG. OPERATING COST (with CO2) ($/MWh)	$35.41	38.06	40.70	43.48	46.39	49.34	50.58	51.86	53.23	54.63
75	AVG. OPERATING COST (without CO2) ($/MWh)	$32.02	32.86	33.60	34.39	35.22	36.02	36.94	37.90	38.83	39.98

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
5	Net Plant Heat Rate (Btu/kWh) [5]	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325
7	Total Coal Consumption (BBtu) [6]	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531
8	Heating Value of Coal (Btu/lb)	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051
9	Coal Consumption (Tons x 10^3) [6]	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843
10	Total NO_x Allowances Purchased (Tons) [7]	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398
11	Mercury Allowances Purchased (Tons) [8]	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473
12	SO_2 Allowances Purchased (Tons) [9]	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140
13	CO_2 Allowances Purchased (Tons x 10^3) [10]	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367
14	Urea - SCR Consumption Rate (Tons) [11]	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587
15	Urea Consumption (Tons x 10^3) [12]	114	114	114	114	114	114	114	114	114	114
16	Ash Production (Tons x 10^3) [13]	356	356	356	356	356	356	356	356	356	356
	COMMODITY PRICES										
17	General Inflation (%) [14]	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
18	Coal Commodity Price ($/Ton) [15]	$54.57	56.27	58.01	59.85	61.62	63.44	66.32	67.25	69.24	71.28
19	Coal Transportation Price (Blended) ($/Ton) [16]	$9.56	9.85	10.16	10.48	10.79	11.11	11.44	11.78	12.13	12.49
20	All-In Average Coal Price Delivered ($/MMBtu)	$2.66	2.74	2.83	2.92	3.00	3.09	3.18	3.28	3.38	3.48
21	Urea Price ($/Ton) [17]	$393	403	412	422	432	443	453	464	475	487
22	SO_2 Allowances ($/Ton) [18]	$1,796	1,840	1,884	1,929	1,975	2,022	2,071	2,121	2,172	2,224
23	Mercury Allowances ($/Oz) [19]	$2,332	2,436	2,544	2,657	2,775	2,899	3,028	3,163	3,303	3,450
24	NO_x Allowances - Annual ($/Ton) [20]	$2,529	2,599	2,879	3,072	3,278	3,498	3,732	3,982	4,249	4,534
25	NO_x Allowances - Ozone ($/Ton) [21]	$4,341	4,854	4,990	5,350	5,736	6,150	6,593	7,069	7,579	8,125
26	CO_2 Allowances ($/Ton) [22]	$14.97	15.33	15.69	16.07	16.46	16.85	17.26	17.67	18.09	18.53
27	Activated Carbon Costs ($/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	$155,173	160,011	164,945	170,171	175,207	180,389	185,724	191,216	196,869	202,688
29	Coal Transportation	$27,180	28,027	28,892	29,807	30,689	31,597	32,532	33,493	34,483	35,503
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	$19,438	19,904	20,382	20,871	21,372	21,885	22,410	22,948	23,499	24,063
33	Operator G&A	$731	748	766	785	803	823	842	863	883	905
34	Other Fixed [25]	$20,461	20,952	21,456	21,970	22,497	23,037	23,590	24,156	24,736	25,330
35	Fixed O&M	$40,630	41,604	42,603	43,626	44,672	45,745	46,842	47,967	49,118	50,298
	Variable O&M										
36	Major Maintenance/Capital Expenses [26]	$15,346	15,714	16,091	16,477	16,873	17,278	17,692	18,117	18,552	18,997
37	Other Variable [27]	$10,961	11,224	11,494	11,770	12,052	12,341	12,637	12,941	13,251	13,569
38	Variable O&M	$26,307	26,938	27,586	28,247	28,925	29,619	30,329	31,058	31,803	32,566
	Emissions Allowances										
39	SO_2 Emissions Allowances	$9,231	9,457	9,683	9,915	10,151	10,395	10,644	10,900	11,161	11,429
40	Mercury Emissions Allowances	$10,995	11,464	11,995	12,529	13,088	13,668	14,276	14,911	15,574	16,267
41	NO_x Emissions Allowances - Annual	$6,066	6,473	6,907	7,369	7,863	8,390	8,952	9,552	10,192	10,875
42	NO_x Emissions Allowances - Ozone	$4,339	4,652	4,987	5,347	5,733	6,146	6,589	7,065	7,574	8,121
43	CO_2 Emissions Allowances	$110,261	112,908	115,617	118,392	121,234	124,143	127,123	130,174	133,298	136,497
44	Emissions Allowances	$140,892	144,974	149,189	153,552	158,067	162,742	167,584	172,602	177,799	183,189
45	Activated Carbon	$0	0	0	0	0	0	0	0	0	0
46	Urea - SCR	$2,196	2,249	2,303	2,358	2,415	2,473	2,532	2,593	2,656	2,719
	Powerspan										
47	Urea Cost ($/Yr)	$44,943	46,022	47,126	48,257	49,415	50,601	51,816	53,059	54,333	55,637
48	Waste Disposal Cost ($/Yr)	$5,205	5,330	5,457	5,588	5,723	5,860	6,001	6,145	6,292	6,443
49	Auxiliary Power ($/Yr)	($1,289)	(1,320)	(1,352)	(1,384)	(1,417)	(1,451)	(1,486)	(1,522)	(1,558)	(1,596)
50	Renewals, Replacements & Maintenance	($89)	(92)	(94)	(96)	(98)	(101)	(103)	(106)	(108)	(111)
51	Other Operating Costs	$16,180	16,568	16,966	17,373	17,790	18,217	18,654	19,102	19,560	20,030
52	Labor	$833	853	874	894	916	938	960	983	1,007	1,031
53	Transportation	$5,223	5,349	5,477	5,608	5,743	5,881	6,022	6,166	6,314	6,466
54	Solid Fertilizer Credit	($56,265)	(57,615)	(58,998)	(60,414)	(61,864)	(63,349)	(64,869)	(66,426)	(68,020)	(69,653)
55	Liquid Fertilizer Credit	($1,379)	(1,412)	(1,446)	(1,481)	(1,516)	(1,553)	(1,590)	(1,628)	(1,667)	(1,707)
56	Powerspan [28]	$13,361	13,682	14,010	14,347	14,691	15,044	15,405	15,774	16,153	16,541
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]	$5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552
61	Corporate G&A [31]	$634	649	665	681	697	714	731	748	766	785
62	Total Operating Expenses	$411,926	423,687	435,746	448,341	460,915	473,875	487,231	501,004	515,199	529,841
	AVERAGE BUSBAR COST [32]										
63	Total Annual Costs	$411,926	423,652	435,746	448,341	460,915	473,875	487,231	501,004	515,199	529,841
64	Fixed Operating Cost ($000)	$46,816	47,805	48,820	49,859	50,921	52,011	53,125	54,267	55,436	56,635
65	Fixed Operating Cost ($/kW-yr) [33]	$47.43	48.43	49.46	50.52	51.59	52.70	53.82	54.98	56.17	57.38
66	Fixed Operating Cost ($/MWh)	$6.37	6.50	6.64	6.78	6.93	7.08	7.23	7.38	7.54	7.71
67	Total Variable Operating Cost ($000)	$365,110	375,982	386,926	398,482	409,994	421,864	434,106	446,737	459,763	473,206
68	Total Variable Operating Costs ($/MWh) [34]	$49.68	51.15	52.65	54.22	55.79	57.40	59.07	60.79	62.56	64.39
69	Fuel Cost ($/MWh)	$24.81	25.59	26.38	27.21	28.02	28.84	29.70	30.58	31.48	32.41
70	Non-Fuel Variable Operating Costs ($/MWh)	$24.87	25.56	26.27	27.01	27.77	28.55	29.37	30.21	31.08	31.98
74	AVG. OPERATING COST (with CO2) ($/MWh)	$56.05	57.66	59.29	61.01	62.72	64.48	66.30	68.17	70.10	72.10
75	AVG. OPERATING COST (without CO2) ($/MWh)	$41.05	42.29	43.56	44.90	46.22	47.59	49.00	50.46	51.96	53.52

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 9,325 Btu/kWh, as estimated by Sergeant Lundy ("S&L"), 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 12,051 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 4.30×10^{-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 2.11 percent sulfur fuel.

[12] Annual quantity of urea required for operation of the Powerspan Scrubber at the indicated capacity factors assuming 2.11 percent sulfur fuel.

[13] Annual quantity of bottom ash and fly ash produced, based on an ash content of the coal of 10.83 percent.

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

[15] FOB price of coal as projected by the latest S&L report, in 2009 dollars and escalated at R.W. Beck's coal price escalation rates from its most recent market price forecast.

[16] Based on estimates provided by S&L for coal delivery in early 2009, in 2009 dollars and escalated at a rate of 3 percent.

[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] Mercury allowance costs based on an assumed cost of $27.8 million per ton in 1999 dollars.

[20] NO_x annual allowance cost assumed to be $1,120 per ton in 2006. Projections of allowance costs are based on EPA estimates and R.W. Beck's proprietary model.

[21] NO_x ozone season allowance cost assumed to be $1,833 per ton in 2007 dollars. Projections are based on EPA estimates and R.W. Beck's proprietary model.

[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. CO_2 annual allowance cost assumed to be $10.24 per ton in 2007, escalated at the general rate of inflation thereafter.

[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.

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

[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.

[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.

	Description		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	REVENUES:											
1	Participant Revenues [1]	$000	$176,719	$442,575	$456,230	$479,191	$498,910	$519,937	$528,080	$537,620	$548,584	$558,630
2	Interest Earnings [2]	$000	5,181	8,541	6,253	6,212	6,196	6,184	6,178	6,214	6,249	6,286
3	Short-term (Market) Sales [3]	$000	5,548	29,749	30,571	31,829	35,481	37,977	37,952	39,016	39,330	40,386
4	Other Project Revenues	$000	0	0	0	0	0	0	0	0	0	0
5	Transfers from R&C Fund [4]	$000	0	0	4,526	4,226	3,924	3,612	3,292	2,965	2,630	2,287
6	Other Receipts	$000	0	0	0	0	0	0	0	0	0	0
7	*Total Revenues [5]*	$000	$187,448	$478,863	$499,580	$521,560	$544,481	$568,709	$575,503	$586,814	$596,803	$607,589
	OPERATING EXPENSES [6]:											
	Fixed Operating Costs:											
8	Fixed O&M	$000	$16,026	$32,820	$33,606	$34,414	$35,240	$36,086	$36,952	$37,839	$38,747	$39,677
9	Insurance & Property Taxes [7]	$000	2,804	5,607	5,607	5,607	5,607	5,607	5,607	5,607	5,607	5,607
10	Transmission Costs [8]	$000	1,837	3,763	3,853	3,945	4,040	4,137	4,237	4,338	4,442	4,549
11	AMP-Ohio A&G Costs [7]	$000	500	512	524	537	550	563	576	590	604	619
12	Bank and Trustee Fees [7]	$000	125	128	131	134	137	141	144	148	151	155
13	Other Direct Project Costs	$000	0	0	0	0	0	0	0	0	0	0
14	*Fixed Operating Costs*	$000	$21,291	$42,830	$43,723	$44,638	$45,575	$46,534	$47,516	$48,522	$49,552	$50,607
	Variable Operating Costs:											
15	Fuel Costs	$000	$73,257	$149,830	$152,332	$155,290	$158,474	$161,316	$164,955	$168,821	$173,256	$177,805
16	SO_2 Emissions Costs	$000	3,318	7,139	7,638	7,823	8,008	8,203	8,399	8,599	8,805	9,015
17	NO_x Emissions Costs	$000	2,667	5,702	6,096	6,517	6,958	7,449	7,964	8,514	9,103	9,732
18	Hg Emissions Costs	$000	2,826	6,080	6,524	7,063	7,664	8,289	8,999	9,554	9,979	10,423
19	CO_2 Emissions Costs	$000	12,438	38,208	52,167	66,773	82,051	97,926	100,276	102,983	105,147	107,571
20	Variable O&M	$000	4,324	8,855	9,067	9,285	9,507	9,736	9,969	10,209	10,454	10,704
21	Gross Urea and Powerspan Costs	$000	28,873	59,132	60,551	62,004	63,492	65,016	66,577	68,175	69,811	71,486
22	Fertilizer Credits [9]	$000	(22,737)	(46,564)	(47,682)	(48,826)	(49,998)	(51,198)	(52,427)	(53,685)	(54,974)	(56,293)
23	*Variable Operating Costs*	$000	$104,975	$228,381	$246,693	$265,849	$285,166	$306,717	$314,812	$322,869	$331,581	$340,544
	Replacement Power [10]:											
24	Capacity Purchases	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Energy Purchases	$000	0	20,295	21,731	23,440	25,111	25,737	26,619	26,822	27,824	28,547
26	Transmission Costs	$000	0	0	0	0	0	0	0	0	0	0
27	*Total Replacement Power Purchases*	$000	$0	$20,295	$21,731	$23,440	$25,111	$25,737	$25,619	$26,822	$27,824	$28,547
28	*Total Operating Expenses*	$000	$126,266	$291,507	$312,148	$334,027	$356,852	$378,988	$387,745	$398,213	$408,957	$419,698
29	Net Revenues [11]	$000	$61,182	$187,356	$187,442	$187,534	$187,629	$187,721	$187,757	$187,601	$187,846	$187,891
30	Deposit to Working Capital Reserve Account [12]	$000	$526	$1,215	$1,301	$1,392	$1,487	$1,579	$1,616	$1,659	$1,704	$1,749
	DEBT SERVICE:											
31	Principal	$000	$0	$60,015	$62,265	$64,600	$67,023	$69,535	$72,144	$74,849	$77,655	$80,568
32	Interest	$000	54,803	109,205	106,955	104,620	102,197	99,684	97,076	94,371	91,564	88,652
33	*Total Debt Service [13]*	$000	$54,803	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220
34	Other Debt Payments	$000	0	0	0	0	0	0	0	0	0	0
35	*Total Debt Service Requirement*	$000	$54,803	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220
	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	5,053	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922
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	$5,053	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922
	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	$0	$4,526	$4,226	$3,924	$3,612	$3,292	$2,965	$2,630	$2,287	$1,936
45	Total Revenue Requirements [17]	$000	$187,448	$478,863	$499,580	$521,560	$544,481	$568,709	$575,503	$586,814	$596,803	$607,589