Advanced Coal Technology Work Group Meeting
Double Tree Hotel (Crystal City)
300 Army Navy Drive, Arlington, VA 22202
February 8, 2007

Welcome and Overview of Meeting Objectives

Ben Henneke, Clean Air Action Corporation, began the meeting by reviewing the meeting objectives written on the agenda. None of the Work Group members had any questions or comments about the objectives.

Recap of Information Obtained from January 8th & 9th Meeting

Anna Wood, EPA, next provided a recap of the January 8th & 9th meeting. During this meeting, Work Group members identified key opportunities for the Work Group. Some of the opportunities highlighted included: identifying a suite of technologies to enable the use of coal in an environmentally responsible manner; recognizing that management of carbon emissions from coal is a critical component; capitalizing on current opportunities and not taking any technology off the table; learning from each other; and identifying recommendations to accelerate the use of advanced coal technology.

Another key concept discussed at the meeting was the six month interim and one year reports. It was decided that it a workable construct would be to develop a set of recommendations to be undertaken by different stakeholders. This will advance the use of clean coal technology more quickly.

In the meeting, Work Group members provided comments or questions related to various topics. After the January meeting, Ms. Wood read all the comments and sorted them into logical groupings and topic areas. She arrived at six key focus areas that include: (1) advanced coal technology (ACT); (2) carbon capture and storage (CCS); (3) statutory and regulatory considerations;(4) incentives; (5) education and outreach; and (6) work group process. Ms. Wood discussed each of these focus areas in more detail.

1. Advanced Coal Technology

For ACT, a salient point that came out of the January meeting was that there is no common definition or understanding of what qualifies as ACT; is it one technology or a suite of technologies? Other areas of interest included practical experience available for the use of ACT, the costs and timeframes for commercial use of ACT, the concept of "carbon capture ready" and what it means, how the actions of public utility commissions affect the use of ACT, the life cycle and other environmental impacts of ACT, and there was an interest in polygeneration and coal to liquids projects.

2. Carbon Capture and Storage

The Work Group asked about existing opportunities for CCS given the variables affecting its use and the costs of the technology (i.e., transport, storage location, monitoring, and verification). Members also asked how the CCS timeframe correlated the development of the capture technology for power plants. Another comment is whether the Work Group could look at best practices that might exist to address regulatory framework, liability and property right issues. Lastly, there was an interest in other options beyond geologic storage to address mitigation and reduction of CO_2.

3. <u>Statutory and Regulatory Considerations</u>

What assumptions should be made about the Clean Air Act; should the group assume authority exists to regulate CO_2? Beyond the Clean Air Act, what other regulations may be implicated that may affect CCS? There was also a strong interest in learning more about the provisions under the Clean Air Act that might impact, impede or incentivize the use of ACT and CCS. The Work Group was also interested in exploring actions outside the Clean Air Act that will accelerate the use of ACT and CCS.

4. <u>Incentives</u>

During the last meeting, the group listened to presentations from the public utility commissions (PUCs), Department of Energy (DOE), and the State Council of Legislatures that provided a broad overview of existing incentives and how these incentives might work. One of the questions posed by Work Group members was if the use and timing of incentives could be coordinated and prioritized to make sure the incentives are used for the most beneficial technology, given the existing challenges. Ms. Wood said the coordination of Federal, State and Tribal efforts might be a possibility. The PUCs treatment of cost recovery was identified as an area for further exploration. Members also asked if there was flexibility in complying with environmental regulations for new technology and whether a technology forcing approach would be a better. Additional questions involving incentives included: how do opportunities for co-production, polygeneration, and enhanced oil recovery (EOR) accelerate the use of ACT and CCS? What role do CO_2 credits play and are there opportunities for trading the credits to promote ACT and CCS.

5. <u>Education and Outreach</u>

A number of questions arose regarding education and outreach. For example, Work Group members asked what actions could be taken to educate consumers and create awareness about the importance of ACT and CCS, particularly in the context of cost recovery cases. Another question was whether technical expertise and capacity existed at State and Federal levels to address issues related to ACT and CCS and if not, what is needed to make sure the expertise is available. Who is responsible for education and outreach to public on CCS – is it the responsibility of States, EPA, or companies?

6. <u>Work Group Process</u>

Ms. Wood asked how the work group wanted to prioritize issues. Should the group address some issues and not others? This is to be discussed later in the agenda.

Ms. Wood next quickly reviewed additional questions that were asked that did not fit into any of the other categories.

Finally, Ms. Wood stated that the Co-chairs' current thinking is that for future meetings, part of each meeting would be used to reach a common level of understanding on topics related to ACT and also to focus on the Work Group charge to enable the Group to develop the six month and one year reports in a timely manner.

Tom Acker, Northern Arizona University, suggested using common metrics. Ms. Wood asked if he was inquiring about a common set of criteria in terms of a metric. Mr. Ackron confirmed that he was.

John Campbell, Caterpillar, said he wanted to better understand the costs of technologies.

Mr. Henneke said they would have more opportunities to discuss these issues later in the day. The purpose of Ms. Wood's presentation was to let the committee members know that they were being heard.

Paul Bollinger, Air Force, said that when discussing IGCC, it may be valuable to include coal to liquids as one of processes discussed. It may also be valuable to include other studies being done in this area; the studies will serve as resources.

Geologic Storage of Carbon Dioxide

Ben Henneke, Clean Air Action Corporation, introduced James Dooley, Senior Staff Scientist, Battelle’s Joint Global Change Research Institute, who would be giving a presentation about the geologic storage of carbon dioxide.

After Mr. Henneke’s introduction, Mr. Dooley thanked everyone for having him at the meeting. He said he directs Batelle’s research on Carbon Capture and Storage and brought a book published recently that was an attempt to summarize 10 years of research focused on the storage of carbon dioxide. He also mentioned that he was the lead author on carbon capture on a report that came out in 1995. It was a consensus document that was meant to provide details on usage of the technology for the Inter-Governmental Council on Climate Change. He said that he hoped to share his insight about this issue with the Work Group and welcomed any questions during his presentation.

Mr. Dooley began his presentation by stressing that carbon capture and sequestration (CCS) is explicitly a climate change technology. There are no other reasons to develop this technology other than for climate change mitigation. He said this point is very important for understanding how to incentivize the deployment of technologies.

He next presented a slide that showed how climate change is a long-term strategic problem with implications for today. He pointed out on the slide the red line, which would mean business as usual. The area underneath the curve maps to a finite amount of carbon that can be emitted to the atmosphere. Green house gases (GHG) are a stock problem, not a flow problem. With GHG, stabilizing annual emissions leads to rising concentrations. You have to have decreasing global emissions over time and increasingly stringent disincentives for emitting greenhouse gases. The disincentive can take a number of different forms. Mr. Dooley said that carbon tax is something he would mention throughout the presentation, but it is strictly an example.

The important issue is that the disincentive needs to be increasingly stringent over time. He said that putting CCS in power plants is a bargain compared to other ways of reducing CO_2 if we are shooting for more stringent decrease in emissions. He added that there is an inherent uncertainty that is a key reason why the technology is not being employed. The literature on the topic is very robust that CCS technologies do not deploy until you reach a certain threshold. The prices and our expectations matter.

Mr. Dooley explained that fossil fuels on this planet are not scarce. The amount of fossil fuels used since the industrial revolution is 1/80 the amount we have left. He said that there are plenty of fossil fuels available. However, if we address climate change now, there will be fundamental changes in the global energy system.

Showing a second chart, Mr. Dooley said in the future, coal cannot be used sustainably without mating it to CCS. The world has and will continue to draw upon a multiplicity of energy sources. He said that it is a competitive market to provide energy sources, and it is a competitive market to provide emissions reductions.

Jeff Hopkins, Rio Tinto, asked about the assumptions made in terms of technological advances. Mr. Dooley responded that in the reference case, you have by the end of the century everyone driving efficient automobiles. Technologies continue to improve; it is mainly the carbon tax that starts to change the market. He offered to send out a paper with all of the details.

Vicki Sullivan, Southern Company, asked about the level of carbon tax. Mr. Dooley responded that by about the middle of the century it is \$50/ton of CO_2 and it is headed up well above 100 by the end of the century. With an economically efficient manner, people understand you want a low carbon price and want to increase it over time. This sends the message that in the future things have to change.

Mr. Dooley said that all of these technologies have limits and challenges that need to be overcome. There is no silver bullet, so there needs to be a portfolio of solutions.

The big picture on CCS is that there is plenty of theoretical storage capacity in the world, but it is very unevenly distributed throughout the world. The important issue at this point in time is knowing whether CCS is even an option for your area. Japan and Korea have a fundamentally different and narrower set of options for addressing climate change than the United States does because they lack CO_2 storage reservoirs. The potential market though for this technology is huge. The economics of coal facilities and the economics of addressing climate change draw us towards large facilities that run around the clock. You have to know that you have tons of potential storage capacity available, which is an important site decision. The use of CCS technologies for coal is fundamentally different than how it has been used to remove CO_2 from gas fields. We cannot always use analogies from our current set of information to predict our future energy situation.

Mr. Dooley next showed a simple graphic depicting CCS that he said actually overly simplifies the CCS process. He stressed that when thinking about advanced coal technology (ACT) and ACT incentives, it is important to challenge people's perception of the CCS process (i.e., do they think CCS is analogous to this picture?) Many people do not take into account the economics of how this is going to work for industry.

Mr. Dooley next showed a geologic map showing the burial of carbon. The idea is to bury the carbon under different levels of permeable rock in order to keep the carbon underground. It is a very engineered system. They know how to do the process, but this still is not the same as dedicated systems for addressing climate change.

Like all natural resources, CO_2 storage capacity is abundant, valuable, and very heterogeneously scattered throughout the world. However, it is not distributed equally throughout the world. China and India have less storage capacity than the United States and many think this is a problem. Mr. Dooley said the real question is if they have enough capacity. We could say that China and Korea do have enough, unless we are pushing for a really tight emissions constraint.

The marketplace is also heterogeneously distributed. Economic development is also heterogeneously distributed throughout the world. There are just certain places were CCS might work better in other places, but it is more than just power plants. For example, cement manufacturers have the opportunity to reduce carbon emissions. There are other opportunities for industries to use CCS directly.

Paul Bollinger, Air Force, asked a question about off shore storage opportunities. Mr. Dooley responded that Japan's and Korea's numbers specifically took into account whether there were below-the-sea-floor storage opportunities. The numbers do not take into account Japan's proposal to inject CO_2 directly into the water column itself.

Mr. Dooley said the U.S. has large carbon storage potential. He said that the vast majority of potential storage is the deep saline formations. Mr. Dooley explained that it is good if CO_2 prices start low, increase slowly, and gradually rise over time. Each different class of large anthropogenic point sources has different capture technologies that can be applied to them. Some of them involve just compressing and dehydrating the CO_2; it is hard to get much cheaper than this option. The most advanced power plants cannot undercut this price. Power plants are not going to set the price; consumers will set the price.

A Work Group member asked about the costs. Mr. Dooley responded that it was about $20/ton in one of the basins; but this is due to the narrow market with a few large suppliers and fixed infrastructure.

Most CO_2 used in the U.S. commercially is used for enhanced oil recovery. In this part of the country, there are dedicated pipelines that come down and serve it. Those pipelines were paid for by tax incentives from federal government. Those 3,000 miles of pipeline hold 7,000,000 tons of CO_2. CO_2 used in enhanced oil recovery is based on water alternating gas. Each of the wells is connected to a hugely valuable infrastructure. If you try to take that and use it in Northeast Ohio, you need to account for this large subsidy of the infrastructure. A lot of thinking about incentivizing this technology does not fully appreciate the uniqueness of this process.

John Thompson, Clean Air Task Force, asked a question about the cost. Mr. Dooley responded that most literature assumes that the cost of capture also includes compression of pipelines, but you do have to transport it.

Mr. Dooley next showed a slide with the abatement curve associated with the use of CCS in the U.S. He said right now there is some CO2 being used for oil recovery. He said that the vast majority of this CO2 has a positive carbon price associated with it. If there are value added markets and if there are ways of incentivizing this technology early on the ground, it is not necessarily about power plants. People who are buying this CO_2 are going to want it as cheap as possible. To the extent that there is a price, once you start to have a huge imbalance with quantity versus demand, the price will drop and you will get a tipping fee.

Mr. Dooley next said that he wanted to spend some time talking about the electric power sector. He mentioned a study that will soon be published. The study analyzes the electric power sector in each of the regions of the United States, taking into account the fact that natural gas prices have increased, which fundamentally changes the electric power sector. There were four different scenarios in the study.

Mr. Dooley mentioned early opportunities. An environment that has high natural gas prices and low carbon permit prices is an environment that uses more coal. Natural gas sets the clearing price for electricity, but it is expensive. In the early days of a price regime, there was a powerful market signal to build more coal plants. If you are going to think about incentivizing this technology, you should think about the market that this technology is going to go into; the electric power market's economics are unique.

Mr. Dooley gives an example of the modeling done in the Ohio River Valley (ECAR). The carbon price is low and slowly coming up over time. As the carbon permit price starts, you start to slide in IGCC and CCS. The most recent literature says the difference between IGCC and CCS may not be that different. The carbon price says that natural gas is really valuable. In order to drive the carbon out of peaking units, you need extremely high carbon prices.

Mr. Dooley next referred to an early question about CO_2 storage. He said depending upon whether there is a carbon tax or a cap and trade with allocations, the power companies still have a huge amount of emissions. It is best to think about CCS as a non-emission, something that you do not report on your emissions inventory. The idea about incentivizing the technology must involve consideration of economics.

Mr. Thompson asked for more information on ECAR in 2035. Mr. Dooley responded that in the paper they assumed that nuclear doubles in the country and there is a 10% renewable portfolio for all regions. In ECAR in 2035, there would be dozens of CCS plants.

Mr. Dooley next showed six maps, and said that just in the U.S., the rest of economy is also reducing their emissions. However, he said that climate change is fundamentally different than other issues like acid rain. Changing 10 or 15 power plants in the Ohio River Valley is not going to make that much of a dent in terms of climate change. This is a large scale technology that needs a huge infrastructure that does not exist in a lot of regions.

Mr. Dooley next listed some questions he would have if he were going to invest in this technology. As important as driving down the cost of capture is, it will be an ongoing process that is going to evolve over time; there is no end point. It is never going to get so cheap that you will do this in the absence of a climate mitigation strategy. Instead, some questions someone might ask before investing in this technology include how many injector wells are needed? How close can they be? What is the performance standard? Can you inject as fast as you want? Can the same injector wells be used for fifty years? If you have to go back and recomplete these wells all the time, that will change the cost. Do you use one injector field for ten years and then switch to another one? These are examples of critical decisions that people in the power industry would care about. Also, what kind of measuring/monitoring tools are used? How long would you monitor? What is the liability going to be?

Mr. Dooley next went back to the issue of enhanced oil recovery. He gave an example from Alberta, where there are 36,000 non commingled gas pools that could be used for CO2 storage. Only 227 of those have a capacity of more than 5 million tons/CO2 storage per year. The market for CO_2 is not robust enough for someone to link together all these reservoirs. The challenge is if you want to build a plant in Ohio/West Virginia, what are the operational opportunities? For example, what is the permeability or the gas storage potential?

Mr. Dooley next shows modeling of a single injector well and a horizontal injector well, with which you do not get to inject any more CO_2, you just contact more of the surface area quicker. This brings up an interesting economic question of whether or not it is worth paying to build a horizontal well if it does not give you storage volume but lets you access the area more quickly.

Mr. Dooley next talks about the scope of our experiential knowledge with this technology. He said that there are three commercial CCS facilities, including one in Canada, one in Algeria, and one on the North Sea. Each injects about 1 million tons CO2/year. The rest are experimental facilities, including one in Australia. Currently on this planet there are 3,000,000 tons of anthropogenic CO_2 injected underground for climate mitigation reasons that are monitored.

This is an important technology, but it is really in its infancy in terms of deployment. The ability to have CCS in society's portfolio of options addressing climate change is worth trillions of dollars. Being able to have the same level of environmental protection for lower costs allows society to meet its other goals. You need a carbon price above $20/ton to see this technology deploy. It has to be a carbon price that is high enough, but also durable.

Mr. Dooley next addressed the concept of "carbon capture ready." He showed several maps, including a map of deep abandoned oil and gas wells, a map of seismic risk in the U.S., a map of regions of the country heavily dependent on ground water, and a map indicating the economics of the power sector. He said none of these are the picture-perfect vacuum cleaner for CCS. He said that society may want to save an aquifer for a source of water rather than use it for storage. In terms of incentivizing a carbon capture ready plant, its locational aspect is just as important as the power cycle to be built.

Mr. Dooley concludes his presentation and questions from the audience begin.

Marty Smith, Xcel Energy, asked if there was anywhere in the study that shows IGCC versus PC. Mr. Dooley responded that he would provide everyone with a copy of the paper. He said that what was found was that in Texas, there are a lot of new gas plants coming online. With a high enough carbon price that rises quickly and high gas prices, PC plants were retrofitting to capture their CO_2. In other parts of the country, you do not see that behavior because you are growing your way out of it. When you are trying to incentivize this technology, keep in mind that it seems to be that you are buying an option. In this modeling you did not see CO_2 being stripped in gas turbines, but if we went beyond 2050 and had higher carbon prices, we would have seen that too.

A Work Group member asked a question about net CO_2 and energy penalties. Mr. Dooley responded that the price of electricity is going to increase because of the carbon tax. This means that energy prices are going to go up if we address climate change. The metric that needs to be addressed is: is this technology a cost competitive way of generating electricity in that time period? For CCS, a power plant that is built today, it will live through three fundamentally different economic environments. In the environment of today and the near future, you are going to emit CO_2 into the atmosphere because there is no other reason. There will next be a period where it is cheaper to capture and store. And then there will be an interim period. So yes there is an energy penalty, but the metric may not be correct in comparing it to what it may cost today.

The Work Group member followed up and asked about the assumptions for the costs of CCS and electricity. Mr. Dooley responded that electricity can be at least 1/3 more expensive. However he said this has happened before, such as in the early 70s with the oil crisis when the electricity prices skyrocketed and then dropped eventually. He said that this is something that slots in over time. A PUC could really effect how much the costs showed up on people's bills. The bottom line is that there is a cost that someone needs to pay.

A Work Group member next asked a question about translation energy. Mr. Dooley responded that the cost of decarbonizing the transportation sector is hundreds of dollars. It is fundamentally a different challenge. Society does not care where CO_2 comes from, it is about delivering competitively priced electricity. Society needs to make a decision that it wants to do it.

Judi Greenwald, Pew Center on Global Climate Change, asked Mr. Dooley what he would do to incentivize ACT. Mr. Dooley said he had an idea, but he was not advocating this idea and needed to think through it. He presented the scenario of someone receiving a couple million dollars as a capital subsidy to go build a new IGCC that is carbon capture ready, but is still going to vent all of its CO_2 into the atmosphere until carbon prices get up to a certain level. He said what happens if the government instead says, every time someone wants to build a power plant, here is 10 million dollars to do a really thorough geologic study of that area that is made into a public record. We do not have that experiential knowledge base. Maybe it is more important to know that people are not building power plants on areas of high seismicity, or areas where there is not injectability than to get too wrapped up in whether it is an IGCC or ultra supercritical plant.

Mr. Dooley continued by saying that one thing he would not do is have a plant with an extra gasifier that is not used. This scenario would bring questions back to the government about why they did not put public money into something else to reduce emission systems. An experiential knowledge base would probably be more helpful. He also said that another thing that would help, although he is not advocating it, is if there was a Price Anderson Act for CO_2 storage that cleared up the liability issue. It may not be a good idea, but with a lot of power departments, the liability issue is unclear.

Mr. Dooley also said the PUCs, the National Association of Regulatory Commissioners, and state EPA officials have a huge role to play that is not understood. This is an audience that needs to be educated. Mr. Dooley said he would give EPA more resources to deal with this.

Tom Acker, Northern Arizona University, asked about the impact of having big reservoirs of carbonic acid. Mr. Dooley responded that CO_2 is injected into a deep saline formation, for example. The overlying layers of dense rocks hold the CO_2. CO_2 begins to dissolve into water, giving weak carbon acid, which detaches minerals in water, then forms carbonates. At some level, this weak acid is a good thing because it helps it move through the formation, but in terms of health and safety, we are relying on this overburden to hold it in place.

A Work Group member responded that there is a lot of ongoing research about whether the carbonic acid would attack the well cement. Mr. Dooley said that there is a lot of research that needs to be done, but there are still things can be done in the meantime. He presented a question to the Work Group that they need to think about what exactly they are incentiving, such as optionality for the future.

A Work Group member asked if you assume IGCC displaces PC for reasons aside from CO_2 capture two or five years from now, does this change what the next 20 years of deployment timing and cost looks like? Mr. Dooley responded that the benefit of IGCC for climate change is that is cheaper to capture the CO_2. Without a climate imperative, it just generates more expensive electricity. The question would be were those IGCCs built in such a way to facilitate later CO_2 capture, and who handled the extra cost of that.

The presentation ended and Mr. Henneke suggested that the group take a break.

<u>Discussion re: Future Meeting Dates and Revised Work Group Charter</u>

Bob Henneke, Clean Air Action Corporation, said the next two Advanced Coal Technology (ACT) Work Group meetings would be held on March 6th and March 29th. He presented the idea of holding a future meeting in Baltimore. For the March 29th meeting, he thought the work group may enjoy a half day field trip to a facility engaged in ACT. Dan Cunningham, PSEG Services Corporation, and John Campbell, Caterpillar, said they would like to have a field trip sooner rather than later. Mr. Cunningham also mentioned wanting to see a carbon capture plant. Bob Wyman, Latham & Watkins, asked that they not do the field trip during the March 29th meeting. He also emphasized that the meetings were a two day commitment for those living on the West Coast and encouraged the group to think about flight schedules. Judi Greenwald, Pew Center, said she liked the idea of a field trip. She has never seen CO_2 injection, so visiting an enhanced oil recovery (EOR) facility would be interesting to her.

Rick Bolton, Center for Toxicology & Environmental Health, said the Tennessee Eastman folks who have a coal gasifier that has been in operation for over ten years, recently extended an invitation to the work group to view the gasifier. Marty Smith, Xcel Energy, suggested viewing an operating plant in Florida.

John Thompson, Clean Air Task Force, said he would like to postpone the field trip until after the 6 month interim report is written because the group has a lot of work to do before now and then. Mark MacLeod, Environmental Defense, complimented Ms. Wood on her recap from January's meeting. In response to Mr. Thompson, he said that he saw the first interim report as being informational and the second phase of their work involving recommendation development. If this was true, he did not think the field trip would interfere with their first interim report. If the June report is purely informational, he thought a field trip was possible. Mr. Wyman suggested drafting a small set of recommendations for the June report. He also thought they may lose people if they stray too far from Washington DC and did not think they had time to lose people. He also was unsure how informational a field trip would be at this point. Mr. MacLeod suggested that between now and next meeting they list all the issues. Next, he suggested developing a matrix of various venues and then populating the matrix cells. Then, by April and May, he suggested the group pick five cells that they would like to concentrate on.

Mr. Henneke said that if the members had any additional ideas, they should share them with Ms. Wood.

James Dooley, Battelle's Joint Global Change Research Institute, mentioned a PowerPoint presentation that he helped put together that included information about the Warrior Run Power Plant in Maryland which captures CO_2. He said there might be educational resources the group could utilize that do not require the group to relocate.

Ms. Wood confirmed that the future meeting dates were March 6, March 29th, May 8th, and June 5th.

Mr. Henneke said that the first report was due June 5th. In response, Mr. MacLeod said in order to get the report done by June, he thought they would need to begin drafting the paper today.

A member mentioned that May 8th conflicted with the Department of Energy (DOE) Carbon Sequestration conference. She thought work group members may be interested in this; however, she realized that this meeting was in conjunction with the main CAAAC meeting.

Mr. Henneke wrapped up the discussion by asking if anyone had an issue with posting the meeting notes on the general CAAAC website. Ms. Greenwald said she would like the notes posted on the website. Ms. Wood reminded the members that meeting minutes from the January meeting had already been sent to the members.

Pat Childers, EPA, said that the ACT work group was a Clean Air Act Advisory Committee (CAAAC) work group under Federal Advisory Committee Act (FACA). They have opened the meeting up to the public; however, the meeting is not a FACA meeting, so it is not required to be open to the public. The Work Group's recommendations are given to CAAAC which then decides which recommendations will be given to EPA. Under the work group rules, the work group could have a closed website if they wish.

Mr. Henneke said that if anyone had any comments on the revised Work Group charter, they should approach him or Ms. Wood at the end of the meeting.

Carbon Capture and Compression Technology

Anna Wood, EPA, introduced Ed Rubin, Carnegie Mellon University, who would be giving a presentation about carbon capture and compression technology for Integrated Gasification Combined Cycle (IGCC) plants, pulverized coal (PC) plants, and natural gas combined cycle plants. This was an area that many Work Group members had expressed interest in during the January 8th and 9th meeting.

Mr. Rubin began by outlining his presentation. He then explained why there was an interest in CO_2 capture and storage (CCS).   One reason is that energy models indicate that including CCS in a portfolio of options significantly lowers the cost of achieving the deep long-term reductions needed to mitigate climate change. Mr. Rubin underscored this point, saying that a portfolio including CCS is being used to assess deep long term reductions of greenhouse gases over a century scale.

Mr. Rubin presented a diagram showing the schematics of a CCS system. During his presentation, he would be focusing on the CO_2 capture and compression stage of the CCS system. The compression stage of the process is attributed to the capture piece of the system, so when he speaks of capture, he is referring to both capture and compression. The purpose of the compression is to liquefy CO_2 so it is easily transported through pipelines to storage. Therefore, his first message is that the compression stage could just as easily be attributed to transport and storage, but tends to be associated with capture because this is the stage where the CO_2 is typically compressed. Mr. Rubin said his second message was that in order to determine the price of different stages, it is necessary to look at the whole system.

In regard to the status of capture technology, Mr. Rubin said that CO_2 capture technologies are commercial and widely used in industrial processes, mainly in the petroleum and petrochemical industries; has been applied to several gas-fired and coal-fired boilers in order to produce commodity CO_2 for sale; and the integration of CO_2 capture, transport and geological sequestration has been demonstrated in several industrial applications, but not yet at an electric power plant.

Mr. Rubin next showed a map highlighting current CO_2 capture projects around the world. As shown on the map, there are capture projects in Europe, the US, Australia, Japan, and China. These countries are interested in the same types of technologies as the Work Group.

In regard to the options available for power plants, there are many ways of separating and capturing CO_2. The choice of technology and process depends on the application and technical conditions. Choice of process conditions, therefore, dictates the types of technology that work and are cost effective.

Mr. Rubin next introduced the IPCC Special Report that examines CO_2 capture technology in detail. There are three documents included in this report: Summary for Policymakers, Technical Summary, and Full Technical Report. Mr. Rubin said he would spend the remainder of the morning discussing applications to the three types of fossil fuel plants. These fossil fuel plants are the leading candidates for CSS because the majority of projected CO_2 (80%) will come from power plants. The other 20% will come from industrial processes including facilities in the oil and gas industry. Mr. Rubin said the focus of his talk, however, would be on power plants.

Mr. Rubin continued his presentation by introducing the three general approaches for capturing CO_2: post-combustion, pre-combustion, and oxyfuel. Oxyfuel is at a less advanced stage of development, so Mr. Rubin said he would be focusing on post-combustion and pre-combustion. For post-combustion, CO_2 is captured after the fuel is burned, and for the pre-combustion capture option, the carbon is collected before the fuel is burned. For oxyfuel, pure oxygen is used in place of air to create a CO_2 enriched stream that avoids the need for a separate capture technology.

Mr. Rubin next showed a schematic that shows what a PC plant would look like with post-combustion CO_2 capture. The schematic was a screen shot from a model that was developed for the Department of Energy (DOE) which looks at the cost and performance of a particular system. Mr. Rubin explained that the green box at the end of the plant diagram in the schematic is a CO_2 scrubber, which follows an SO_2 scrubber. This CO_2 scrubber is the capture system that would collect concentrated CO_2 for storage.

Mr. Rubin next showed a schematic of an amine capture system in order to visually demonstrate the CO_2 capture process for available technologies. In order to capture the CO_2, it is necessary to chemically grab it from the flue gas. The typical concentrations of CO_2 from flue gas at a typical coal plant are approximately 13% by volume, so it is a fairly dilute stream. Amines are a class of organic chemicals that are used routinely in various applications. In the amine capture system, flue gas enters the system and a liquid mixture of amines and water are introduced in the absorber; CO_2 reacts chemically with these substances. Typical removal efficiencies for these technologies today are in the 85-90% capture range. Once this chemical reaction occurs, the amines go to another process called the regenerator where the CO_2 is stripped out of the chemical. In order to do this, it is necessary to supply a large amount of energy typically in the form of heat. Electricity is also needed to move the amines and later to compress the CO_2. Twenty-five percent of the output of a modern power plant is needed just to operate this system. It is therefore an order of magnitude larger than the energy requirements of any of the environmental control systems currently used.

Judi Greenwald, Pew Center, asked about specific issues with the amine sorbent and how it would affect the presented system. Mr. Rubin said there are three commercial vendors of these technologies and each have their own chemical mixes. The technology is well understood and a lot of the sorbent technology is focused on developing amine systems that have lower energy requirements than the commercially available ones. There are also other capture systems such as the chilled ammonia system. This system uses a different sorbent that may have other benefits, but it is still too soon to tell what these benefits may be.

Mr. Rubin next introduced two of the three post-combustion CO_2 capture coal-fired plants currently operating in the U.S.: Shady Point Power Plant in Panama, OK and Warrior Run Power Plant in Cumberland, MD. He said these look more like chemical plants than power plants.

James Dooley, Battelle's Joint Global Change Research Institute, said it was important to point out that Warrior Run Power Plant is strictly a CO_2 capture plant. Mr. Rubin concurred; the purpose of the collection is to produce CO_2 for commercial purposes.

Mr. Rubin continued his presentation by showing a schematic of a PC plant with CCS visualization produced by Carnegie Mellon. The schematic visually shows what a PC plant with CCS would look like. The pipe on the side of the schematic would deliver the CO_2 to a capture system.

Mr. Rubin next showed a screen shot schematic of a natural gas combined cycle plant with post-combustion CO_2 capture. This system would use the same technology as the PC post-combustion capture system. The gas stream, however, would be cleaner. Most of the applications of post-combustion capture systems today are natural gas systems rather than coal systems. Examples of post-combustion CO_2 capture at gas-fired plants include: Bellingham Cogeneration plant in Bellingham, MA, USA and Petronas Urea Plant Flue Gas in Keda, Malaysia. Mr. Rubin suggested viewing the Bellingham plant on Google Earth.

Mr. Rubin next switched his focus from post-combustion capture to pre-combustion capture by showing a screen shot schematic of an IGCC plant with pre-combustion capture. Without CO_2 capture, the gas steam would be cleaned to remove the particulates and NOx and sulfur removal would leave a syngas that would then go to a combined cycle plant. With CO_2 capture, there are two additional pieces of technology that are added. Therefore, if starting with a syngas gas that has been cleaned from the gasifier, its main constituents are CO and hydrogen carbon monoxide. Chemical reactions will produce CO_2 and hydrogen, called shifted syngas, which will then go through another physical absorption system, which separates the mixture into a concentrated stream of CO_2 and a concentrated stream of hydrogen. The hydrogen is then burned to generate electricity.

Mr. Rubin said there are currently no examples of this technology at power plants. There are a number of IGCC plants throughout the world; however, none of these plants are capturing CO_2. There are, however, other types of plants that do have this CO_2 capture at a commercial scale. An example of a pre-combustion CO_2 capture system is the Petcoke gasification plant that produces H_2 in Coffeyville, KS, USA. The hydrogen from this plant, however, is used to produce chemicals rather than being used for electricity generation. Part of the CO_2 produced at the plant is used at the plant to produce other chemicals and the rest is emitted to the atmosphere. Another example of a pre-combustion CO_2 capture system is a coal gasification plant in Beulah, ND, USA, operating to produce synthetic natural gas (SNG). Until recently, all of the CO_2 produced has been vented to the atmosphere. Today approximately half of the CO_2 produced is shipped to Canada for enhanced oil recovery (EOR). Mr. Rubin next showed a photograph of the Polk Power Station, an IGCC plant in Tampa, FL. This is one of two IGCC plants operation in the United States; however, it does not capture CO_2.

Mr. Rubin next briefly discussed the third capture option, a PC power plant with oxyfuel combustion. He said oxyfuel is interesting because it uses pure oxygen instead of air to burn coal which produces a concentrated stream of CO_2 and H_2O. H_2O is easily removed as a liquid, so this would avoid the need for a CO_2 capture unit. On the other hand, using oxyfuel requires an air separation unit, which would need to produce roughly 3x as much oxygen as the air separation unit at an IGCC plant. Therefore, this option requires the addition of an expensive piece of equipment and an energy intensive piece of equipment.
Until recently, this option has only been looked at in a small scale. The first larger scale operation is expected in Germany. Mr. Rubin provided a schematic to show what this plant would look like. The notion is that when using oxygen, temperatures tend to increase, so in order to use the same boilers used in conventional coal, the stream must be diluted to control temperatures. This is done by recycling about 70% of the flue gas.

Daniel Chartier, EPA, asked about the construction of these oxyfuel plants. Mr. Rubin said if this process works and can be done effectively, it may be a solution; however, there are still several unknowns associated with this process. This technology is a work in process. He said a large project was also recently announced in Canada to retrofit a lignite-fired boiler with oxyfuel.

In summary, Mr. Rubin said there are several existing applications of CO_2 capture at scales that are still small as compared to a modern power plant (roughly a factor of 10).   There are, however, several new large-scale projects worldwide that have been planned or announced at more than the several hundred megawatt scale. In Europe alone, there are at least 8 or 10 projects that cover the range of these 3 technologies that are planned over the next 5 to 10 years.

Mr. Rubin next went on to discuss the effectiveness of current CO_2 capture systems. Most plants that are currently operating have capture efficiencies of roughly 90% +/- 5%. Mr. Rubin showed a bar graph illustrating CO_2 emission rates with CCS and without CCS for new power plants (units - kg CO_2/megawatt hour (MWh)) including super critical pulverized coal (SCPC) plants, IGCC plants, and natural gas carbon capture (NGCC) plants. He reminded the Work Group that gas plants are inherently less carbon intensive than coal plants. A 90% capture leads to an 85-86% reduction in avoided cost.

In response to a question by a Work Group member, Mr. Rubin said that energy penalties can vary, but not in a very large range.

In regard to optimal capture efficiency, Mr. Rubin said the 85-90% is the sweet spot. If looking at the overall efficiency profile, there is a little valley, but in the 85-90% range from a cost effectiveness point of view ($/ton of avoided CO_2), there is a fairly flat range that tends to be in the 85-90% range and this is true both for the amine systems and PC applications and systems in IGCC applications. Mr. Rubin mentioned that there are other complicating factors when examining these plants at a larger scale.

In regard to the impact on other plant emissions, Mr. Rubin said the CSS "energy penalty" is important. Mr. Rubin said that he is defining energy requirements as the increase in fuel energy input per unit of net electrical output (relative to a similar plant without capture). He said the energy requirements directly affect the plant-level resource requirements and emissions per MWh of fuel and reagent use, air pollutant emissions, solid and liquid wastes, and upstream (life cycle) impacts. Mr. Rubin next reviewed some characteristic energy requirements/MWh for the 3 different plant types. For PC plants, the energy requirement is 31% more coal to generate the same kilowatt hours without the 90% reductions. For IGCC plants, the energy penalty is about half that because IGCC plants operate at a higher pressure, so less energy is needed for addition compression and also because the nature of the process is physical absorption versus a chemical absorption which does not require the same amount of energy. Natural gas plants have lower energy requirements because there is less CO_2 in the gas streams to begin with and this significantly decreases the energy penalty.

A Work Group member asked Mr. Rubin to break down the percentages to how much energy is contributed to compression versus capture. Secondly, he asked Mr. Rubin to forecast breakthrough technologies that might address the compression aspect of the process. Mr. Rubin did not have these exact percentages, but would provide them later. Most of the energy, he said, is used for the capture; he thought the compression might be on the order of 25-30% of the total energy requirement. Secondly, he often asks if there are ways of getting better compressors. This is not something that has been high on the research agenda. Compressor efficiencies are on the order of 80-85% efficient. As long as there is a need to compress CO_2 for transport and injection, there will always be a minimum energy requirement, which is approximately 1/3 of what the energy requirement is now.

Mr. Rubin next presented several case studies of plants using bituminous coal. The first case study showed the increase in fuel requirements per MWh and reagent consumption per MWh associated with the energy requirements for CO_2 capture. The reagent consumption issues are not as prominent in the IGCC and NGCC systems because the SO_2 scrubbers and SCR systems are not there. The second case study showed the increase in solid wastes and plant byproducts associated with the energy requirements for CO_2 capture. The increase in fly ash and slag residues is beneficial if reused, but not useful if disposed. The third case study showed the increase of air emission rates associated with the energy requirements for CO_2 capture.

Mr. Rubin next explained that new or improved power generation and CO_2 capture technologies promise to reduce CCS environmental impacts. In terms of the cost, some of the factors that affect reported costs of CCS are choice of CCS technology, process design and operating variables, economic and financial parameters, choice of system barriers, and the time frame of interest.

Mr. Rubin went on to say that there are many different measures of cost. Sometimes there is confusion because some of the measures have the same units. There are many factors that go into these costs. Cost of CO_2 avoided is the cost of avoiding a ton of CO_2 while still producing a KWh of electricity.

Mr. Rubin next reviewed his list of the ten ways to reduce the estimated cost of CO_2 abatement. He reminded the group that none of these plants have actually been built yet, so the list is developed from paper studies. For #10, high power plant efficiency, Mr. Rubin said that super-critical is better than sub-critical, and ultra super-critical is better than super-critical. For #9, Mr. Rubin said that high quality fuels are better than low quality fuels. For #7, Mr. Rubin said to assume EOR credits for CO_2 storage can make a huge difference in $/ton relative to assumptions where you have to pay for storage. For #6, omitting capital costs, Mr. Rubin gave the example of leaving out interest during construction from the total cost. For #5, reporting $/ton CO_2 in short tons versus metric tons, Mr. Rubin said that most of the world uses metric tons. For #4 and #3, assuming long plant lifetime and assuming low interest rates will reduce cost of electricity. For #2, high capacity factors are rampant in most cost estimates. This will reduce the price of electricity. Mr. Rubin said the reason for developing the list was that each of the ideas mattered a lot and none of them have anything to do with the capture system. It is a systems issue and focusing on the capture technology alone may not be the place where you have the most leverage.

Mr. Rubin next reminded everyone that no one has yet built and operated a CO_2 capture and sequestration system at a large scale power plant; all costs Mr. Rubin said he was about to show are projections based on other applications. In the last few years plant construction costs have escalated considerably, so if asking about costs today, many of the numbers that have been reported in the last few years might be on the low side. It is for this reason Mr. Rubin said he wanted to show relative costs that he thinks are more robust than absolute costs.

Mr. Rubin presented a graph showing the cost of electricity in 2002 dollars as a function of the CO_2 emission rate. He pointed out that because SCPC and IGCC plants are more efficient; they have lower emission rates and slightly higher costs. The graph also included natural gas plants with CCS.

Mr. Rubin next presented the results from some of the IPCC Special Report. The costs all have ranges, but Mr. Rubin used the cost of a representative plant which was obtained through an average of several studies. The cost excludes the cost of transport and storage. What matters most overall is how much CCS adds to the cost of the electricity that is generated. The next two costs on the chart include the cost of CSS with storage and transportation. Depending on the types of credits received for EOR in the near term, incremental costs could decrease to zero or there could be negative costs.

Mr. Dooley disagreed on the added cost of CCS with EOR storage for IGCC plants. Mr. Rubin said the information is hypothetical. Mr. Dooley said he does not think the power sector benefits from EOR because carbon from elsewhere gets there first. Mr. Rubin said he could not agree more.

Ms. Greenwald asked why EOR helps the coal plants versus the gas plants. Mr. Rubin said this is because they capture more CO_2. Gas plants have relatively low CO_2 concentrations, so if there is a price on CO_2, the coal plants have more to sell.

Mr. Rubin next presented some work Carnegie Mellon had just done that was pending publication. Up until recently there have not been many studies that look at the effects of coal quality; however, Carnegie Mellon has just done a study looking at effect of four types of coal on the cost of electricity for PC and IGCC with CCS. The presented graph shows the results. The dotted lines show what the cost would be if the price of energy were the same right now.

In regard to the outlook for improved capture technology, Mr. Rubin said there are two ways to estimate future technology costs. Method 1 is through an engineering-economic analysis. Mr. Rubin showed projections by DOE's National Energy and Technology Lab (NETL) for the latest analysis for IGCC, PC, and oxy-combustion plants. The numbers shown are percent increases in the cost of electricity relative to a plant without capture. A member of the Work Group asked Mr. Rubin to put a time dimension on the bars (i.e., the time to bring the commercial product to the market). Mr. Rubin said he did not know. The second method involves the use of historical experience curves. Mr. Rubin showed the estimated learning rate for CCS plants.

In terms of key needs, Mr. Rubin stressed deployment. In conclusion, he said there are not any strong incentives to deploy a technology without a climate policy based on CO_2 emissions. Additionally, market based policies aimed broadly at reducing CO_2 emissions are not likely to stimulate CCS until carbon prices increase. Mr. Rubin said that the Work Group can make a significant contribution to these efforts.

Bob Wyman, Latham & Watkins, asked if in making a decision about power plants in the western U.S., it matters that the power plants do not have CCS technology. Mr. Rubin responded that today there are not any carbon constraints, so pulverized coal is the logical technology. He said there are analyses that can be done to look at these issues, especially site-specific analysis; it also depends a lot on risk aversion for IGCC. Mr. Wyman responded that Mr. Rubin's presentation suggested that costs will be less with Powder River basin coal. Mr. Rubin said this was correct; however, cost of capital and government incentives are also determining factors.

Paul Bollinger, Air Force, said he would make a modification to Mr. Rubin's concluding comments. For coal-to-liquid plants, he thinks only fuel from plants that have significant capture options will be sought. He also thinks the Senate committee will develop additional incentives for plants developing carbon capture technology. Mr. Rubin responded that for coal-to-liquid plants, there are some downsides. The real issue, however, is whether sequestration is occurring. He asked if programs would require the sequestration portion as well as the capture portion.

A committee member commented on the cost difference of storing CO2 underground versus releasing it into the atmosphere. Mr. Rubin responded that sequestration really has to be part of the process.

Ms. Wood thanked Mr. Rubin and ended the session.

<u>Discussion re: Barriers/Opportunities to the deployment of Advanced Coal Technology</u>

Ben Henneke, Clean Air Action Corporation, said that the group would discuss the barriers and opportunities to the deployment of Advanced Coal Technology (ACT). He said that the group would first discuss barriers with the people at their tables. He suggested that the group spend five minutes discussing ideas and come up with three specific barriers. He added that the barriers could be within or outside of the Clean Air Act. Below is a list of barriers that were generated by the group:

Barriers to the deployment of Advanced Coal Technology

- Lack of regulatory drivers
- PUCs require the least cost service
- Too costly electricity for generator when competing with dispatch
- Uncertainty caused by NSR
- Integrated Permitting Air/CCS injection
- Financial risk of new technologies
- Lack of market demand
- Lack of familiarity with technology and CCS technology (state and feds)
- Uncertainty on technology (i.e. cost, performance, and timing availability)
- Global nature of problem
- Public perception of coal being too dirty
- Liability on CCS
- R&D is not being spent on critical issues
- Complexity of problem – confusion of constituencies
- Political pressure from potential losers
- Lack of climate change national policy
- Difference between Federal and State definition of ACT
- NUMBY-CCS
- Technical complexities based on coal type and geology
- No system to monetize value of CO_2

After the groups generated a list of barriers, Mr. Henneke suggested that the group talk about the opportunities to deploy ACT. He again said the groups should spend five minutes thinking about three specific opportunities to accomplish deployment of ACT. Below are a list of opportunities generated by the groups:

Opportunities to deploy Advanced Coal Technology

- Streamline Permitting for ACT (includes NSR Exemption)
- a) Demo projects to show it can work; b) commercial projects to show feasibility
- Loan guarantees
- Federal government assume responsibility for certain business risks
- Federal government has long-term contracts for off take
- Liability limitation scheme
- Eliminate BACT/LAER when unit is covered by cap and trade
- Performance standards to incentivize ACT
- Opportunity to become an international leader
- Take advantage of CAIR/CAMR to site new facilities

- Tax incentives
- Early CO_2 action reduction credits (see Bob Wyman for details); Fully Bankable
- CCS R&D dollars for building ACT
- Multimedia impact fees
- Funds to do geological assessment CCS provided to industry
- IGCC included in BACT for conventional coal
- Consider impact of CO_2 in BACT/permitting process
- Subsidize the performance wrap
- Spread costs more broadly across state, as opposed to specific utility
- Climate investment fund
- Helpful if EPA would develop CO_2 credit generation protocols
- Life cycle analysis electric generation (regulatory flexibility)
- Soft landing for ACT failures (EPA specific)
- Global regulatory driver
- Specific consideration of CO_2 cost required in PUC approval process
- Demand for skilled labor
- Regulatory drivers to reduce CO_2

After this list was generated, Mr. Henneke said that some of these items, such as BACT determination, could have cut both ways. He also noted that the groups were suggesting that the international aspect of the deployment could be both a barrier and an opportunity. He added that perhaps with technology growth in the United States, the opportunity is to be a technological leader.

A Work Group member said that these issues were starting to weave throughout as common threads. He suggested that the group consider these themes.

Work Group Member Panel Discussion

Ben Henneke, Clean Air Action Corporation, introduced the next item on the agenda. He explained that the panel discussion was on IGCC, but that all issues the Work Group wanted to cover could not be addressed in one meeting. He added that this would be the first panel discussion among many. He also said that this was not necessarily the technology chosen by the group.

Anna Marie Wood, EPA, introduced each of the panelists and said that the fourth panelist, James Burns from Shell, was ill and unable to make a presentation. She said that each panelist would provide some information on their views of advanced coal technology and carbon capture and storage and that there would be plenty of time at the end for questions.

Frank Blake, American Electric Power (AEP), gave the first panelist presentation. He explained that AEP is involved in a number of new generation projects, several of which include advanced coal technology (ACT). He said he wanted to talk about those projects and outline lessons learned. AEP is one of the largest utilities in the US, operating in 11 states with approximately 5 million customers. Extensive transmission distribution lines and generating capacity are roughly 36,000 MW, primarily from coal.

Mr. Blake explained that the need for new generation is continuing to become greater and greater. This week the Midwest experienced cold temperatures and some parts AEP's service territory set records for demand. This demand highlights AEP's need going forward to provide reliable and sustainable energy to customers. AEP has not added baseload capacity since 1991. AEP has evaluated a number of new generation technologies; coal is included as a key component in many of the strategies being considered.

AEP's new generation development program has grown quite a bit over the last few years. Mr. Blake said that he is involved in the licensing and permitting of facilities. Among AEP's activities, they have developed over 300 MW of wind capacity since 2001 and have acquired nearly 3,000 MW of natural gas capacity since 2005. AEP is developing two ultra-super critical units in the west that use sub-bituminous coal. The eastern focus includes two IGCC projects.

Mr. Blake next addressed the question of why choose advanced coal technology. In 2004, AEP created a report to shareholders that looked at the challenges facing the company with respect to existing and future technologies. The central challenge in the report is "making large investments that will be long-lived assets in a setting of uncertain public policy and rapidly evolving technology…" The report also recommends that AEP pursue a variety of steps, including: forceful advocacy of efficient controls programs; proactive leadership on technology development and implementation; discipline in capital allocation; continued transparency of action; and declared commitment to be an industry leader and first-mover in advancing IGCC. The report is available on the AEP website (www.aep.com).

Mr. Blake next listed the advantages of ACT. These include: enhanced environmental profiles with respect to all media (i.e. more efficient use of water and solid by-products); increased process efficiency; increased flexibility for using affordable domestic fuel options; polygeneration opportunities (i.e. looking for other fuel options and chemicals); cost-effective options for reducing CO_2 emissions; and promises vs current capabilities of ACT. All of these advantages can be achieved at some level now. However, there must though be an incremental development of the technologies for these advantages to be taken to full potential.

Next Mr. Blake described the challenges to ACT deployment. These challenges include: cost-effective strategies to manage first of a kind risks; availability of guarantees that reduce technology and performance risks; IGCC performance guarantees that support baseload utility options; and commercially available and cost-effective IGCC processes for lower rank coals.

Judi Greenwald, Pew Center on Global Climate Change, asked what a performance guarantee looks like for a conventional plan. Mr. Blake responded that there is the known factor of what is going to have to be dealt with, as well as having to put some type of value on the known type of risk.

Mr. Blake next discussed the AEP IGCC program. He said that AEP is looking at two IGCC plants in Ohio and West Virginia. The efforts are in four different phases to manage risk incrementally. Phase I is a feasibility study; phase II is front-end engineering and design; phase III is engineering procurement and construction; and phase IV is commercial operations. AEP is still in phase II for both projects. The configuration for each unit is 620 MW and it is designed to have turndown facilities to follow load. They are looking at a broader fuel specification and using radiant quench gasifier design. There is also space provisions for CO_2 capture.

Mr. Blake next talked about regulatory activities. In Ohio, AEP has filed for cost recovery in three phases. Phase I is the fee costs and the other two phases deal with the capital and financing cost. Phase II has been appealed.

A Work Group member asked what is the basis of the appeal? Mr. Blake responded that there are several factors, including the cost itself.

Mr. Blake continued with a discussion of permitting and licensing activities. He said that AEP was developing applications for water and land permits. Some of the licensing challenges include the recognition of current technology capabilities vs. promises of future performance; development of technical competency; assimilation of existing regulatory programs to IGCC; development of representative data to support permitting; balancing the need for timely permits and the availability of design information; and performing timely air modeling analyses in context with available agency guidance and resources. Mr. Blake next said that we need to set realistic expectations for what IGCC can do.

Next Mr. Blake said that he wanted to quickly talk about CCS. He said that there were both technical and regulatory issues preventing it from going forward. He added that there are standards of how to design and implement the process and that there are regulations that must work, too. Finally, he said that he wanted to emphasize the promises of the technology versus the current technologies.

Next, Vicki Sullivan from Southern Company made a short presentation. First she talked about the definition of ACT. There is pulverized coal, supercritical and ultras-supercritical. IGCC and oxy-fueled combustion are out there and need to be more researched. Ms. Sullivan next talked about the advantages of IGCC, including the combustion turbines. With this process, you take the other gas from coal and marry it with a combustion turbine. The design cycle can be shorter than PC due to standardization to fit gas turbine. IGCC is also easier to permit than new pulverized coal and is versatile. IGCC is more efficient than the existing fleet, so it can be less expensive to capture CO_2.

Southern Company has developed a unique IGCC process – the Transport Reactor Integrated Gasification (TRIG) technology in Wilsonville, Alabama. It was developed with Department of Energy (DOE) funding. The gasifier is suited to powder river basin and lower BTU coals. The technology will be further demonstrated in Orlando, Florida.

Ms. Sullivan next described the schematic of the TRIG gasifier. It does not have burners and is based on a catalytic cracking. It is a refractory-lined loop of pipes. The coal is fed in dry so there is no slag. The coal circulates around the loop and combusts and operates at lower temperatures than other combustors (1800 degrees Fahrenheit). It can operate in an air-blown manner, so there is no cost for an air separation unit. The rest is standard and includes gas clean up and a gas turbine.

Ms. Sullivan next described rendition for the TRIG in Orlando. There is already an existing power plant. Southern Company will add a gasified island and a new combined cycle. It will be 285 MW. Southern Company has received the air permit and there is an EIS underway. The startup will be mid-2010.

Ms. Sullivan next talked about CO_2 capture. She said there are three types of plants and challenges. The three types include post-combustion, pre-combustion, and oxy-fuel combustion. She said that pre-combustion with IGCC is much more efficient and less costly for capturing CO_2. Transitioning to CO_2 capture adds a lot of complexity and cost. When you add your gasifier, there is more complexity. When you add CO_2 capture, it is more complicated. You have to have a water-gas shift reaction. With CO_2 capture, the turbine has to be ready to burn hydrogen. They have not been used at utility scale so far. There is also the transportation issue, such as when there are thousands of miles of CO_2 pipelines. For example, in Georgia and Carolina, there is not much CO_2 sequestration-ready geology. If your load is in Atlanta, you have to figure out where you are going to ship the CO_2.

Southern Company is involved in a DOE Regional Carbon Sequestration Partnerships to address some of these challenges mentioned above. For example, Southern Company is involved in saline reservoirs in the Mississippi gulf coast as well as coal seams in Alabama and Virginia.

Ms. Sullivan next talked about the commercialization pathway and the FutureGen project. She said that FutureGen is a public-private partnership. She mentioned the challenges, which include the cost, the successful demonstration at full-scale achieving utility-required reliability, and permitting. The opportunities include the continued research, development, and demonstration to address technical issues (which add costs) and demonstrate reliability. Other opportunities include state and federal regulators help facilitate permitting.

Next John Thompson, Clean Air Task Force (CATF), gave a presentation on IGCC Barriers and Opportunities. CATF is a non-profit environmental organization that addresses air quality and atmospheric protection issues.

Mr. Thompson discussed several environmental issues that advanced coal technology must address. First is SO_2 and NO_X. The level of emissions must be driven down to prevent premature deaths, which has become increasingly important in places like China. Second is mercury. It is not enough to just remove it from the stack, but it must be kept from remobilizing into the biosphere once converted to a solid. The problem with mercury is that it does not have a half life. Third is CO_2. Global warming has two challenges of both deep reductions and on a rapid schedule.

With SO_2 and NO_X, the good news is that there are recent IGCC air permit applications that incorporate lower SO_2 and NO_X emissions to levels that rival natural gas. There were five IGCC air permit applications filed in the last few months, all of which use Selexol and over half incorporate SCR. The adoption of SCR and Selexol has been much faster than expected.

Mr. Thompson next talked about IGCC Plants in the air permitting phase. He showed a slide with a map and said that the yellow dots are SCR only and the green dots have Selexol.

Mr. Thompson next talked about regulatory barriers. He posed the question of why would you build an IGCC plant and achieve radically lower SO_2 and NO_X when your conventional PC competitor can get an air permit for vastly more pollution. He responded that he would suggest requiring that IGCC be evaluated in the BACT determination for proposed PC plants. Another barrier is the unintended consequences of “netting.” Many plants today are proposed at sites of existing facilities. These sites often “net out” of BACT through added controls on the existing plant.

Next Mr. Thompson talked about mercury. He said there has been scant attention paid to the problem of remobilized Hg once removed from the air emissions. With PC, mercury is dispersed in tens of thousands of tons of scrubber sludge, where with IGCC mercury is collected in vastly smaller volumes. He said that there need to be some regulations that would require mercury to be contained over time.

Next Mr. Thompson talked about carbon dioxide. He said there must be deep reductions of CO_2 on a relatively short schedule. However, most of the attention has focused on creating the technology aspects of Geological Carbon Sequestration (capture technologies, geologic mapping), not the very real challenges in assimilating these technologies into the power sector.

Next Mr. Thompson gave the scenario of a 750 MW plant that would today capture roughly 100,000 tons of SO_2 and 5,000 tons of NO_X. He said that there are certain pollution removal requirements in the gas phase, and that the CO_2 must be captured, compressed, transported, injected, and monitored. The challenge is to consider what a utility needs to meet societal demand.

There are lots of components to GCS and they all have different development and deployment schedules. IGCC helps with this issue. Most people focus with IGCC on the 90% capture. Mr. Thompson said that he would invite everyone to think about the no-shift reaction plants using today’s technology without any changes to the turbines.

Mr. Thompson then talked about gasification’s key contribution to GCS deployment. He gave the example of the Midwest and said that there was the potential to offer relatively cheap sources.

He then talked about the case for picking technologies. He said that like it or not, picking technologies happens everyday in boardrooms across the globe. He asked the question of why build a coal plant. He said should we allow investments in new PC plants?

Mr. Thompson explained that there is a pioneer penalty because the first IGCC plants involve more cost and risk. He said that the challenge is to turn the pioneer’s penalty into an early adopter’s reward. There is a time and place for incentives, but subsidizing industry-wide costs runs significant risks. Some possible incentives aimed at reducing risk include subsidizing a portion of the “wrap” for the first few IGCC plants; using an EOR Deployment Fund; allowing rate-basing of first few GCS plants that are needed to prove geologic formations; and having a price collar for the first few IGCC plants.

A Work Group member asked what kind of coals were burning in the maps shown? Mr. Thompson responded that Southern Company was using sub-bituminous, while the rest are bituminous coal, except Texas which was petroleum coke and Minnesota which was sub-bituminous.

Alvaro Linero, Florida Department of Environmental Protection, said that it sounded like AEP was not looking at SCR deep sulfur removal, and asked if there was a cost differential. Mr. Blake responded that AEP had looked at SCR and continues to look at it. However, they think that there is enough risk with IGCC plant in development, that adding on an SCR at this point does not make the most sense. He said that eventually AEP will get to the point where an SCR will make sense.

Mr. Thompson continued that the problem with being a pioneer is that the costs/risks are high enough that they will not be the plant, and you end up losing a globally important gasification project. It is important just to get the AEP plants built and eventually move into the SCR arena.

Ms. Greenwald asked what is a price collar for the first IGCC plants, and would the incentives listed help Southern Company and AEP?

Mr. Thompson responded that people are worried about availability of IGCC plants in the first few years and they will have to be exposed to the spot market to buy retail electricity. He said that they want a fund for the plants that will pick up the delta on the price. That is to collar the risk.

Mr. Blake responded that AEP was still involved in the fee process and was refining those numbers, so it would be hard to say specifically what costs do and do not make sense. Having the vendor and the supplier share the risk is essential. He added that wrap is a wrap on the whole project, to be able to share the first of a kind risk on all of the guarantees.

Ms. Sullivan said that Southern Company's project is different from AEP's because Southern Company's already had DOE funding. She added that they have already earned tax credits, too, so there are federal financial incentives helping out.

A Work Group member asked Mr. Thompson why he would go with IGCC versus PC. Mr. Thompson responded that he would not do a PC plant today. He said that given the rapid demands for CO_2 reduction in 2035 and looking at what realistically has to happen, the advantages of IGCC are great in terms of the maturity of the capture. He said there was a compelling reason why you should be building an IGCC plant today.

A Work Group member asked how much would each incentive cost and would they be effective? Mr. Thompson responded that he skipped over a key slide on this issue. He said that the group needs to think about whether they are subsidizing risk on a few first plants, or subsidizing costs.

He said that we need to pick up chunks of costs with projects like FutureGen, but with the pioneer's problem, we should subsidize those risks on the initial plants.

Mr. Thompson next said that with the wrap, you are looking at liquidated damages if you build a plant and it does not work. Funders want some money in the bank to know that the problem will be fixed. The structure of bullet 1 is a 100 million per plant and there is a good chance it would never be called on. He said that with the EOR deployment fund, the oil and gas industry is reluctant to lose money, so a deployment fund would help out. He then said that the incremental cost on the last issue is under a 100 million per plant.

The presentations concluded and the Work Group members took a short break.

Work Group Discussion

Ms. Wood said that the Work Group would talk in small groups about the tools or actions needed to address the barriers and opportunities previously identified. She said each small group should spend give minutes focusing on the top three tools that could be used.

Mark MacLeod, Environmental Defense, said that many of the actions and tools seemed to be the same as the opportunities already discussed. He asked if it may be a better time to talk about how to start to coalesce some of the thoughts.

Mr. Henneke responded that the discussion was repetitive, but still different. He said that there are opportunities listed, but for example, cap and trade is not listed as a tool. He suggested moving through the discussion quickly so that they could start to organize everything.

Mr. MacLeod said that if they used a matrix approach to start narrowing on which things they wanted to focus on, they could more easily figure out the steps. For example, if each opportunity has five action items listed, we have to come up with hundreds of action items.

Ms. Wood suggested that they should go ahead and give it a try since it might generate some different aspects and approaches that may not have been considered before. She asked each group to spend five minutes coming up with ideas. Below is a list of tools that were presented.

Tools that would help with the deployment of ACT

1. Accelerated permitting tool
2. Benchmark existing state permitting progress
3. Define an emissions performance standard to meet the goal (CO_2)
4. Carbon tax to fund incentive programs (Fee-bate)
5. Carbon sequestration requirement for future date
6. Race to meet standard with a monetary prize
7. Include carbon adders as part of permitting
8. Build it and they will come…
9. Legislative status on ACT
10. Pre-permit plant with performance standards
11. Educational tools for regulators and public

12. More regulators
13. Provide long-term contracts
14. Cap and trade for CO_2
15. NSR exemption for existing power plans meeting certain performance standards
16. Viable loan guarantees
17. Government subsidies for performance wraps
18. John Thompson's recommendations
19. Government authority for contracts with price collar

<u>Request for Agenda Items for Upcoming Meetings</u>

Next Mr. Henneke suggested coming up with agenda items for future meetings. He said that the following should be included for the agenda:

- Streamline permitting for ACT (including NSR exemptions)
- Cap and trade for CO_2
- Regulatory drivers to reduce CO_2
- Define emissions performance standards to meet goals to include CO_2
- Demo projects to show it can work and commercial projects to show feasibility
- Mitigate financial and liability risk

Mr. Henneke asked if these items were covered in the next two months, would everyone believe it would be a helpful set of technical discussions that was making progress on the Work Group Charge? Everyone agreed.

Rick Bolton, Center for Toxicology & Environmental Health, L.L.C, said that for the people who voted, cap and trade was a consensus. He asked though if it meant that they were really going to spend two months on it? Mr. Henneke responded that he did not know.

Ms. Greenwald said that they were coming up with some good things, but with a scatter-plot approach, some issues are big and some are not. The big issues are regulatory drivers, demo projects, and deployment. One other big thing that may be missing is the education piece, R&D, and PUCs.

Mr. Henneke responded that we ought to keep thinking about it and that some items will have been missed. He asked though if for the next meeting, would everyone be happy to be on this path, and if not, what other issue should be covered technically?

Ms. Sullivan responded that she would like to know about the legal and liability issues associated with injecting CO_2 underground.

A Work Group member said that he would like to understand the process for streamlining permitting, for the whole environmental footprint. He said he would like to hear more about what is possible that could be done.

Mr. Henneke said that he would like to see that after the recommendation has been outlined, if they could have some permitting people come in.

Mr. MacLeod said that he wanted to see something on how the Clean Air Act treats technology today.

Robert Hilton, ECS Global ALSTOM Power, Inc., said that there have been a lot of things already written into the law. He said he would like to know more about what has worked and what has not.

Patrice Simms, National Resources Defense Council, responded that there was a broad range of knowledge about the existing regulatory framework, and that he would like to get to a baseline. He said that it may be counterproductive to get into the nuisances, but we should get to the common standpoint.

David Foerter, Institute of Clean Air Companies (ICAC), said that we should use more information on the incentives that are out there, for example a baseline on incentives. Also, he said that he hoped that at some point we can come up with a definition on ACT that we can agree on.

Ms. Greenwald added that a briefing on permitting would be helpful.

Mr. Bolton said that more information on the state of the technology would be helpful, and that they should make sure that we are not over promising the technology. He suggested including Jeff Gerrad from DOE as well as the Coal Utilization Council.

Mr. Henneke responded that they would go through everything and email the comments to everyone. He added that he would like to include a briefing on life cycle implications.

A Work Group member said that some more information on why certain plants permits were not approved would help everyone to better understand the finances. He suggested a lessons-learned sort of panel.

Mr. Bolton added that a briefing on ACT for PC plants and operators would be helpful too.

Meeting Wrap-up and Adjournment

Mr. Henneke said that the next meeting was March 6, from 8:30-5:00 at the same hotel. He added that there turned out to be complex budgeting issues associated with having facilitators. He asked if they should spend the time and effort to get some trained and qualified facilitators, or just go ahead with the Co-chairs. Everyone agreed to keep the committee chairs as facilitators.

Advanced Coal Technology Work Group Meeting
Double Tree Hotel (Crystal City)
300 Army Navy Drive, Arlington, VA 22202
February 8, 2007

List of Attendees

Name	**Affiliation**
John Thompson	Clean Air Task Force
Dan Chartier	EPA
James Burns	Shell
Robert Hilton	Alstom
Paul Bollinger	USAF
Jeff Hopkins	Rio Tinto
Vicky Sullivan	Southern Company
Anna Marie Wood	EPA
David Foerter	Institute of Clean Air Companies (ICAC)
Bob Wyman	Latham & Watkins
Anhar Karimjee	EPA
Frank Blake	American Electric Power (AEP)
Steve Jenkins	URS Corporation
Chris Romaine	Illinois EPA
Bob Wayland	EPA/OAQPS
Bob Gruenig	National Tribal Environmental Council
Michael Ling	EPA/OAQPS
Mark MacLeod	Environmental Defense
Barbara Bankoff	Siemens Power Generation
Daniel Cunningham	PSEG
David Berg	Department of Energy (DOE)
Ben Henneke	Clean Air Action Corporation
Judith Greenwald	Pew Center
John Campbell	Caterpillar
Alvaro Linero	Florida Department of Environmental Protection
Greg Schaefer	Arch Coal
Rick Bolton	Center for Toxicology & Environmental Health, L.L.C. (CTEH)
Lisa Stolzenthaler	General Electric (GE)
Patrice Simms	Natural Resources Defense Council (NRDC)
Tom Acker	Northern Arizona University
Marty Smith	Xcel Energy