Environmental, Energy & Technical Committee Meetings

December 7-8, 2010
Radisson Hotel, Reagan National Airport
Arlington, VA
(703) 920-8600

M I N U T E S

TUES-WED DECEMBER 7-8, 2010

FOCUS GROUP SESSION

Focus Group Moderator – Frederick (Fred) P. Fendt, The Dow Chemical Company

Greenhouse Gas BACT – **Tom Fitzpatrick**, SSOE
Jerry Carter, SSOE

Tom Fitzpatrick of SSOE reported on "top down" BACT for GHG. Greenhouse gases are recognized as CO2, N2O, CH4, HFC-32, and PFC- 14. As a result of the Supreme Court decision on GHGs, EPA issued an endangerment finding identifying GHGs as a "pollutant". A pollutant becomes official on the date a regulation " takes effect". EPA issued the light duty vehicle rule, which takes effect January 1, 2011. New Sources or major modifications at major sources require an air permit. New source review applies. For attainment areas, prevention of significant deterioration (PSD) applies. For non-attainment areas, lowest achievable emissions rates are required. As there are no ambient air quality standards for GHGs, only PSD applies. For PSD, Best Available Control Technology applies (BACT). EPA has issued the Tailoring Rule so that only units with the potential to emit 75,000 ton/yr of CO2 equivalent would be subject to BACT. EPA recommends a "top down" approach on a case by case basis. There are no New Source Performance Standards (NSPS) for GHGs. This would set the floor for emissions when they become available.

The recommendations that are GHG specific emphasize energy efficiency. There are 5 steps in the top down process. Step 1 is to identify all available control options. Step 2 is to eliminate the technically infeasible options (technical, chemical, space limitations, etc.). Step 3 is to rank the remaining options. Step 4 is to evaluate the economic, energy, and environmental impacts. Step 5 is to select the best option as BACT for the source. New facilities should consider source wide energy efficiency measures. Modified facilities should look at emission unit efficiency measures. Carbon capture and sequestration should be considered for large CO2 emitters, although it is not generally considered to be "available". BACT technologies that are considered applicable to boilers include adding economizers, adding air heaters, flow modifications (to increase heat transfer), insulation, reduced leakage, energy capture, condensate returns, reduced slagging or fouling, carbon capture and storage, alternative biomass fuels, co firing, fuel switching, and cogeneration.

Jerry Carter of SSOE pointed out that the EPA guide emphasizes energy efficiency as BACT for GHGs. Permitting agencies will be looking for energy efficiency beyond what is done at the source or modification. BACT reviews may look everywhere within the fence line of the facility for efficiency improvements. Industrial Boiler MACT also has an energy assessment component requirement. A proactive energy management strategy could help optimize compliance efforts for both of these requirements. Identifying the common goals from the 3 tasks provides a base line for decision making. The unique features of the GHG BACT process are the requirement to classify as "suite of technologies" that can be reviewed as part of the BACT process. This analysis should document the uncertainty in expected versus guaranteed efficiency improvements. For Boiler MACT, there is a one time energy assessment and report requirement. Qualified personnel are required (Certified Energy Management).

For proactive energy management, the business objectives and considerations will be unique to each facility. An energy master plan would integrate all of the energy generating and consuming equipment and identify potential savings. The common features include the need to identify large users first and then the small users. A formal list should be prepared that is current for the analysis. Measurement and data reporting requirements need to be identified and upgrades as necessary. A plan to manage energy use and implement energy savings concepts should be prepared. Programs such as Energy Star or other structured system should be used. A prioritized list of energy efficiency improvements should be prepared. Performance benchmarking is expected to be a tool for compliance. Regulators will be looking to the Energy Star database for comparative data. However, competitors are typically reluctant to share this type of data, thus making specific comparisons difficult. Energy Performance Indicators are available for 9 industrial product categories (i.e. cement, corn refining, juice processing, etc.). EPIs are being developed for an additional 5 categories.

The DOE also has the Manufacturing Energy Consumption Survey (MECS) that provides energy consumption data by manufacturing industry and region. Outside energy audits can be done when inside resources are not available. These can range from specific issue resolution through small (one day) reviews to detailed reviews (a week or more on site). Strategic energy master plans can also be developed. Good record keeping and benchmarking of performance will be key to successful permitting. Sources of information include the DOE Industrial Technologies Program and the EPA Energy Star program.

Economizers and Turbulators for Industrial Boilers

Robert (Bob) Stemen, Applied Heat Recovery, LLC

Economizers recover energy from the flue gas that would otherwise go up the stack. The gas flows over a tube bundle and then proceeds to the emissions control system (or stack). The water goes through the tubing. Typically this is the boiler water (condensate returns) so that the energy is retained in the system. Design variables include water and gas pressure drops and surface modifications (i.e. fins). Often emissions control devices require that the gas temperature be reduced. For every 40 F reduction in stack temperature, there is about a 1% reduction in fuel consumption. A typical economizer will reduce gas temperature from 620 F to 300 F, representing an 8% improvement in fuel consumption (and energy efficiency).

In order to recover more energy, a condensing economizer would be required. Since the feed water flow rate follows the firing rate, the system should be self regulating. For a condensing economizer, a water temperature that is cold enough is required. The cold water reduces the metal temperatures of the economizer, causing the water in the flue gas to condense on the tubing. Materials of construction need to take corrosion considerations into account. This condensed water can be recovered with good mechanical design. Inside corrosion is also a consideration. Stainless steel tubing is typically required to prevent corrosion. Sulfur in the fuel presents a real challenge. Teflon coated tubing has been used. Proper stainless steel selection can also resist the corrosive environment. Cold flue gas can also cause corrosion problems for the duct work and the stack. Low sulfur fuels are easier to adapt. With high levels of condensate return, there are low levels of cold make up water. This fact tends to limit the amount of heat recovery.

If plants are highly efficient, there is a problem with recovering the low level heat for which there is no use. Looking elsewhere in the plant for heat applications can provide alternative solutions. There needs to be a place to utilize the recovered heat in order to realize the savings. If the flue gas temperature is above 140 F, the condensed water will typically be re-entrained and be carried out the stack. If the flue gas temperature is below 140 F, the condensed water will "rain down" the stack and a drainage system will be required. This water will likely need to be treated for disposal. The 3 main questions for condensing economizers are:

- Is the fuel sulfur free?
- Is there a place to put the recovered heat?
- Is there a way to handle the condensate?

With fire tube boilers, economizers can also be used. However, for boilers that start and stop, the economizer may not pay off. For these units, twisted metal (or tape) can be put inside the fire tubes to assure that the gas flow is always in the turbulent regime. At reduced loads, the gas flow may be low enough to revert to laminar flow, which reduces heat transfer. The turbulator keeps the gas flow in the turbulent regime, thus improving the heat transfer and reducing the stack temperature. There is a consideration for gas pressure drop that has to be evaluated.

CHP technology Update – **Richard Sweetser**, Exergy Partners Corporation

The US DOE has created 8 regional energy application centers aimed at combined heat and power and energy efficiency improvements. Combined heat and power is considered as a potential energy improvement for GHG BACT. There are quite a few technologies that can be used for CHP. Sterling engines and micro reciprocating engines are small and can be used, but tend to be relatively expensive. Fuel cells also tend to be expensive. Steam turbines, gas turbines, and reciprocating engines tend to be the main sources of energy for use in CHP.

Microturbines are sized in the 30 - 250 Kw units packaged in a 1000 Kw box. These units fire natural gas or bottled gas. The efficiency of these units tends to be rather low. Part load efficiency is low. High ambient temperatures also reduce efficiency. Reciprocating engines include spark ignition and Diesel engines. Spark ignition engines can be either stoichiometric or rich burn or lean burn air/fuel ratios. Sizes run from 100 Kw to 5 Mw. Roughly 8% of capacity and 12% of generation comes from cogeneration. There are 4 sources of usable heat from reciprocating engines: exhaust gas, jacket cooling, lube oil cooling, and turbocharger cooling. Heat can be recovered as hot water or steam in the case of exhaust gas.

Combustion turbines are available in larger sizes. The exhaust gas is at a high enough temperature to run combined cycles. For cogeneration applications, the steam from the heat recovery steam generator can be sent directly to process. Thermal systems make use of available heat that is rejected from other systems. These include absorption chillers, liquid - liquid heat exchangers, air conditioners, and organic rankine cycles. Organic rankine cycles are useful where low ambient temperatures prevail (avoids water freezing). Packaged systems are available.

Future technologies include fuel cells, if the cost can be reduced. Right now, the fuel cell stack has to be replaced every 8 years (at a cost about equal to the original installation). Carbon calculation complexity should be similar to that used for net emissions for a CHP unit. Calculating the emissions saved by thermal energy recovered from the CHP system requires a knowledge of the thermal system. EPA has a cogeneration partnership. This program has developed a calculator that can estimate the savings from displaced thermal and displaced electricity generation. In a case study, a CHP system using a recriprocating engine provides 328 Kw(e) of power and thermal energy to drive an 80 ton (281 Kw(th)) absorption chiller. Using engine performance and emissions data, comparative fuel consumption and emissions can be calculated.

A key factor in estimating the energy and CO_2 emissions savings for CHP is determining the nature of the avoided central station generation. Looking at the load duration curves, the base load nuclear and base load coal units will not be displaced. Renewables are not likely to be displaced. The displacement will be taken from natural gas combined cycle plants as well as coal, oil, and gas cycling and peaking plants. EPA refers to this as the " fossil average " . EPA has created an " air shed " approach which has identified eGRID sub-regions. These can be used to estimate the emissions that can be reduced by displaced electricity production. The CHP Emissions Calculator estimates NO_x, SO_2, CO_2, and fuel impacts of operating a CHP system.

ENERGY COMMITTEE SESSION

Frederick P. Fendt, The Dow Chemical Company, *Energy Committee Chairman*
Robin Mills Ridgway, Purdue University, *Energy Committee Vice-Chairman*

Bob Corbin introduced the new members and prospective members to the committee. The usual "round the table" introductions were done. Fred Fendt gave the anti-trust admonition.

Energy Forecast - **Kevin Petak**, ICF International

Kevin Petak, provided an energy forecast concerning oil and natural gas. The recession caused gas demand to decline during the past few years. Instead of growing modestly from the 2007 level, gas use declined by about 5%. Nearly all of the decline was in the "non-core" use, primarily in the industrial sector. Industrial production dropped significantly during the recession, which was a primary driver.

On the supply side, natural gas production has increased slightly. Unconventional, on shore gas has been the primary source. The largest contributor has been "shale gas". Conventional gas production will continue to decline. Rig activity tends to lag gas prices by about 6 months. The rig count has increased modestly in the last year. With the shale gas, horizontal wells are used. These wells get more production per well.

Working gas storage levels have risen over the last 5 years. Natural gas prices reflect the loose supply/demand balance and the relatively high working gas levels. Going forward, the ICF assumptions are that US GDP average growth will be 2.8%/yr and electric demand growth will be half that, or 1.4%. Projections for electric generating capacity assume that tighter emissions controls and some kind of CO_2 regime will evolve. This tends to drive substitution of gas for coal in electric generation. In total, the US and Canada have over 3,700 TCF of natural gas resources (of which 1,900 TCF is shale gas). Current consumption is at 27 TCF/yr. While less than the theoretical reserves in Russia or the Middle East, the resource would still provide 140 years supply at current consumption rates.

The existing North American resource base includes about 1500 TCF available at $5/MMBTU. In order to obtain the rest of the resource, prices would have to increase. Gas demand is likely to turn around and grow at a relatively modest rate. Production is likely to continue growing, spurred by growth in the shale gas production. Depending upon the timing of the economic recovery, the price level will likely remain low over the next year. The winter price will be closer to $5/MMBTU and cycle back down to $4/MMBTU in the summer. This forecast is similar to that shown in the futures markets for US natural gas.

In the longer term, gas consumption in the power sector is likely to double over the next 20 years. This projection reflects about 70 Gw of coal fired plants that will be retired between 2016 and 2020. Out to 2035, there is very little demand growth in the other sectors. Efficiency improvements will likely offset any growth increases. A cap and trade rule is not a requirement for this growth in the power industry. Environmental regulations aimed at older coal fired plants will require significant expenditures, which will be called into question with the threat of cap and trade legislation. Many of these plants will decide that it is not worth making new investments in a 50 year old plant that could be subject to GHG regulations as well.

Total US and Canadian gas production is expected to increase from about 8 BCF in 2009 to 45 BCF by 2035. The largest shale formations include Hanynesville, Marcellus, and Western Canada. There are several other shale fields under development. There are also shale fields that are known, but not being exploited at this time. In some cases, the shale gas also has higher alkanes such as ethane or other liquids. In the Gulf Coast area, gas processing is readily available and the liquids are separated and sold for higher value. In the Marcellus, there may be situations where the ethane that is separated does not find a market. This would likely be considered as Gas 2 for Industrial Boiler MACT, as it does not fit the definition of natural gas.

Currently, there are differences in prices on a regional basis. The shale developments will tend to reduce the price differentials. There has been preliminary interest on LNG exporting. There has been one permit application in the Gulf Coast area for a true export terminal. Historically, the price of gas in Europe and Asia has been roughly the equivalent to oil on a BTU basis (with the exception of North Sea gas in its heyday). The opportunity to export will depend on the development of shale gas in other parts of the world, which would break the 1/1 relationship with oil.

Coal Outlook **– Bob Beck**, National Coal Council

Bob Beck of the National Coal Council talked about the coal outlook. The Council did a study on the implications of carbon capture and storage for coal plants in the US. DOE Secretary of Energy Chu requested the study in July of 2009. The focus of the study was on the existing fleet of coal based generation plants. Varying amounts of CO2 capture were investigated. At the level of 50 - 60%, the CO2 footprint of an existing coal fired unit is about the same as a gas fired combined cycle plant. The 83% level is the level the Obama administration has signed up for. Power plants are expected to do more at 90%. Global consumption of coal is expected to increase by 112% in the next 25 years. This is being driven by China and India. China installed more coal fired capacity last year than the UK has built in its entire history. Thus, retrofits will be needed.

The US and China are collaborating on CCS technology, notably in China's GreenGen project. President Hu Jintao is coming to the US at the end of January and another agreement of some sort is expected to be announced. The US burns 1.1 billion tons/yr of coal (more than double the amount in 1970). The National Research Council identified coal based generation with CCS to be a low cost, low carbon alternative. Over time, the entire US fleet could be replaced with CCS coal power. A potential deployment pattern of 360 Gw of coal with CCS could be in place by 2050. Roughly 50 - 70 Gw of older coal fired units will likely be retired.

While we are somewhat familiar with the problems of getting a permit for a power plant, it is an order of magnitude more difficult to do a transmission line. The costs are likely to be high, but the numbers of jobs required will be high as well (perhaps more than 800,000 jobs altogether). GDP increases of on the order of $1.4 trillion are anticipated by 2050. The DOE NETL has found that " next generation " CO2-EOR technology will provide access to 70 billion barrels of economically recoverable oil and create enough demand for CO2 to offset the emissions from 70 Gw of coal fired capacity. It takes about 3 tons of CO2 to drive up 1 ton of oil.

The NCC report indicated that CCS was doable. However, demonstration plants are needed to show that the CO2 can not only be captured, but realistically and safely stored. Deep storage locations and pipeline infrastructure are needed to accommodate. " The urgency of getting started on these demonstrations to clarify future deployment options cannot be overstated. "

GOVERNMENT AFFAIRS SESSION

Anthony Reed, Archer Daniels Midland Company**,** *Government Affairs Committee Chairman*

There will be a lot of new members in the next Congress. A lot of education will need to take place. There should be limited changes in the Senate. The major committees impacting energy and the environment will remain the same. In the House, Congressman Boehner will be the new Speaker of the House. The House Energy & Commerce Committee will be led by Congressman Upton. The Energy subcommittee has not been announced as yet. EPA oversight has been a key issue in this committee. EPA will be spending a lot of time producing documents. The new Chairman of the Appropriations Committee will be Congressman Rogers.

In the next Congress, energy bills will most likely be the legislative vehicle for any GHG actions (ie Renewable Portfolio Standards, energy efficiency, nuclear support, etc.). With regard to the Boiler MACT, the EPA will be " reviewing the data " in regard to re- proposing the rule. That review will still require a lot of work in the form of comments, input, data, etc. A particular issue will be the start up/shut down/malfunction issue (SSM). There is clear legislative language that allows for an SSM exemption that EPA is ignoring. Jeff Holmstead of B&G has publicly stated that there is a de facto permit moratorium as states are not in a position to issue permits.

ENVIRONMENTAL COMMITTEE SESSION

Maxine D. Dewbury, The Procter & Gamble Company, *Environmental Committee Chairman*
Rob Kaufmann, Koch Companies Public Sector, LLC, *Environmental Committee , Vice-Chairman*

Environmental Session - **Rob Kaufmann**, Koch Companies Public Sector, LLC

The minutes of the September meeting were approved. Rob pointed out that there are many regulations coming our way in the next couple of years, which will keep us very busy.

Litigation Update - **Lisa Jaeger**, Bracewell & Giuliani L.L.P.

The HIMIWI litigation case went to oral argument last month. The key issues are MACT on MACT and the individual limits versus achieving all limits simultaneously. Judging by the questions from the Court during oral argument, the bench did not seem favorably disposed to industry arguments. On the NSPS case, a voluntary remand was allowed. This case will not be resolved easily. On the ozone NAAQS, the states have petitioned the Court to direct EPA to finalize a rule by the end of the year. EPA has requested an extension on response. In the SO2 NAAQS, industry has asked for the rule to be issued or denied as the rule is currently in effect while the Court is reviewing. On the CEM rule revision, the order is in abeyance. Settlement proceedings are ongoing. The Portland Cement MACT, the parties have filed for petitions for reconsideration. The Reciprocating Internal Combustion Engine (RICE) MACT case is also being held in abeyance pending settlement discussion regarding emergency demand response.

For Climate Change litigation, the Supreme Court granted certification to the law suit by Connecticut and the New England states against 5 mid-west utilities. The claim was for nuisance in that the GHG emissions from coal fired units were causing damage to the coastal cities in the Eastern States. The Southern District Court of New York claimed that the Courts did not have jurisdiction. The Second Circuit Court of New York reversed this decision. The utilities then went to the Supreme Court. This is a two step process. The first step is that the Supreme Court has to agree to hear the case (ie grant certification). The Supreme Court did that yesterday. The case will revolve around whether the states can file these nuisance suits " piece meal " under federal common law or whether the states should allow the executive and legislative branches to handle the issue. If the states prevail, any emitter of GHGs could be sued by any party at any time as a nuisance (i.e. not under the Clean Air Act). The earliest this case could be decided is by June 2011. The latest is likely to be June 2012. If there is a coalition that plans to file an amicus brief supporting the petitioners, CIBO might consider signing on to the brief.

The CIBO Comments chart covers regulations that CIBO has supplied comments or plans to provide comments. There is guidance coming on Environmental Justice that will require comments.

Industrial Boiler MACT - **John C. deRuyter**, E.I. DuPont de Nemours & Co.

EPA proposed 4 rules that are inter-related. These are the Industrial Boiler MACT, the Area MACT, the CISWI rule (incinerators), and the definition of solid wastes (which determines which materials can be considered fuels and hence are burned in boilers and not incinerators). The CIBO study on the impact of the Industrial Boiler MACT rule on jobs and the economy got the attention of the EPA. The costs and the jobs numbers have attracted a lot of attention. NACAA has done a study to rebut the CIBO study. The Dept of Commerce has reportedly also done a study with costs much higher than EPA estimates. Congress has requested that this study be released. EPA has gone back to the Court to request an extension of the 3 rules to be reissued in June of 2011 with the final rules being issued April 13, 2012. EPA has received 4800 individual comments with an additional 30,000 e-mail comments on just the Boiler MACT rule. There were similar levels of comments on the other rules. The request to the Court did not include the definition of solid waste. EPA would be looking for a 60 day comment period after the re-proposal. CIBO will need to be in a position to support such a comment period. The Court has to reply with 14 days and EPA has 7 days to respond to the Court.

The Sierra Club opposes this request. There are also start up, shut down, and malfunction issues. The EPA position assumes that units can meet the emissions limits during start up and shut down and that malfunctions do not occur. EPA has proposed that during malfunctions, a unit must report the exceedances within 2 days and provide a full report within 30 days. Presuming that this report proves that the incident was indeed a malfunction and that the unit took appropriate steps to minimize the emissions during the event, the report can be used as a defense against law suits. Repairs have to be made as soon as possible. Overtime and extra shifts must be used to expedite repair. Bypass would only be allowed if loss of life was implicated. A root cause analysis has to be submitted within 30 days. Documented operating logs need to be submitted for verification. These steps would be used as " affirmative defense " in the event of law suits against the site (except 3rd party law suits).

RCRA Ash - **Gary Merritt**, Inter-Power/AhlCon Partners, L.P.

CIBO submitted comments on November 19. There were a number of comments from the membership. Individual members submitted examples of issues. Comments included that data does not support treating ash as a hazardous waste, the subtitle D can provide an enforceable standard, and that the rule was supposed to be only applicable to the utility sector but the rule was unclear under subtitle D. The states would end up regulating industrials. The EPA did not do any economic analysis on the industrial sectors. There were over 6,000 comments submitted. New comments are being posted every day. Form letters by email were up to 60,000 comments. Both the environmental groups and the industry groups issued form letters to constituents to be sent in.

NAAQS - **Rob Kaufmann**, Koch Companies Public Sector, LLC

EPA is actively working on the revised NAAQS. A new CO standard will be proposed in January with promulgation in August. EPA is also on a Court ordered schedule for secondary standards for NOx and SO2 to be finalized March 2012. The new ozone standard now has a Court ordered date of December 31st. Before the election, the rumor was that the standard would be 65 ppb. It is not clear what level will be proposed at this time. The EPA intends to issue guidance along with the rule. One issue to be addressed is whether or not compliance with the Clean Air Transport Rule for EGUs would be considered compliance for the ozone NAAQS. (EPA subsequently asked for an extension on this rule also.) The new final SO2 standard is 75 ppb. States have until June 2011 to recommend non-attainment areas. EPA has until early 2012 to approve and designate non-attainment areas.

The major concern for this rule is that EPA has recommended modeling over measurement for designating non-attainment areas. States would have 18 months to propose SIPS. Compliance would be required by 2017. The significant impact level is around 3 ppb. For PM2.5, the proposal is due in February 2011 with finalization by October. The annual standard is going down to the range of 11 - 13 micrograms/m3. The 24 hour standard could be reduced from 35 mg/m3 down to 30 mgr/m3. The segment between PM10 and PM2.5 is also proposed to be reduced.

A secondary standard for particulate matter is being considered for visibility. Designations would be effective in December 2013. The first attainment date would be December 2018. The modeling requirement causes problems for particulate matter as well. At one plant, a monitor exists right out side the plant site in a down wind location. The monitor shows that particulate concentrations are well below the standard. However, detailed modeling calculates that the concentrations would be 3 times higher than the monitor. The largest contributor is dust from roadways outside of the site (and outside of the control of the site). This illustrates the problems associated with using modeling.

VII. EPA GHG Permitting Guidance - **Rob Kaufmann,** Koch Companies Public Sector, LLC**,**

The EPA Guidance Document is careful to include all the caveats about how the document is guidance and not rule making. The GHGs are to be treated the same way as the criteria pollutants using the 5 step, top down BACT approach. The real decision making is in the hands of the state. The guidance lacks clarity on how states should address energy efficiency projects. State inexperience with GHG permitting will likely lead to delays in permit issuance.

There is a two step applicability process. In step 1, the question is whether or not the project results in a significant emissions increase. No emissions decrease may be considered. In step 2, the project can include " creditable " emissions decreases from the modification itself plus from the source over the " contemporaneous period " (5 years before). EPA does not allow exclusion of CO2 emissions from biomass combustion under PSD, though it may address this issue in future guidance. Instead, EPA says that states may take federal and state policies into consideration when evaluating environmental, energy, and economic benefits of biomass fuels.

The guidance is silent on how energy efficiency projects can be used to provide quantifiable, enforceable, and permanent reductions. The issue comes from projects that were done in the past that could be used to "net out" of the PSD requirement. Going forward, GHG monitoring would provide the appropriate data that could support quantifiable reductions. None the less, the guidance is very aggressive at emphasizing that "energy efficiency should be considered in BACT determinations for all regulated NSR pollutants". Performance benchmarking is deemed" particularly useful " with no caveats. For new "greenfield" facilities, the rules provide discretion to evaluate BACT on a facility wide basis.

For existing sources, BACT applies only to the units being modified or added. However, permit authorities are required to look beyond the unit being modified to consider upstream/downstream increases or decreases. States should not look at indirect emission decrease that might result from reduced electricity purchases in Step 2. States may consider such emissions in Step 4. No guidance is provided on how to treat CHP projects. In Step 1, all available technologies need to be identified. All inherently, lower emitting processes/practices/designs, clean fuels, add on controls, energy efficiency projects, or some combination should be considered. Coal fired units should consider IGCC. Sources with lower efficiency designs should consider higher efficiency designs. CCS should be considered as an available technology.

The Step 1 list of options need not necessarily include inherently lower pollutant processes that would fundamentally redefine the nature of the source. Permit authorities should take a hard look at an applicant's design to see which elements could be changed. When a fuel is incorporated into a project design as an auxiliary or start up fuel, it is considered to be available. In Step 2, the technically infeasible options are eliminated. Clear documentation is required. Controls are not to be eliminated solely on the inability to obtain a commercial guarantee from a vendor. For CCS, if there are "significant and overwhelming technical issues" involved with the application, the technology can be eliminated. In Step 3, the list of potential options are ranked. In Step 4, economic, energy, and environmental impacts are evaluated. There was no guidance on the cost per ton of CO_2 avoided that would be considered "too costly" . In Step 5, the BACT technology is selected.

Permit authorities may select limits "that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis". Lots of documentation will be required. States are "encouraged" to consider output based limits. With regard to Title V, sources with the "potential to emit" 100,000 tons/yr or more of CO_2e and also have a potential to emit 100 tons/yr of GHGs on a mass basis need a Title V permit. This arises from the other 5 GHGs that are stronger GHGs than CO_2. For some of these GHGs, 100 tons/yr could be close to the equivalent of 100,000 ton/yr of CO_2 (N_2O is around 450 times the impact of CO_2 as a GHG, as an example).

Next, Technical Focus Group/Environmental & Energy Committee Meetings
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