Delaware Air Regulation Development

Regulation 1142 Section 2
"Control of NOx Emissions from Large Boilers and Process Heaters
At Petroleum Refineries"

Committee Meeting #4 (July 19, 2006) Minutes
(Finalized by the committee on September 14, 2006)

1. Committee members present

John Deemer, Premcor's Delaware City Refinery
Kevin Stewart, American Lung Association
Pete Jacoby, Power Tech Solution
Taras Lewus, Environmental Resources Management
Alan Muller, Green Delaware
Jerry Llewellyn, DHSS
Michael Fiorentino, Mid-Atlantic Environmental Law Center
Ron Amirikian, AQM (via telephone)
Bruce Steltzer, AQM
Bill Harris, AQM
Mark Lutrzykowski, AQM
Frank Gao, AQM

2. Meeting Minutes

Frank Gao opened the meeting at 10:10 AM, and outlined the agenda items.

The committee first discussed the meeting 3 minutes updated by Frank in the afternoon of July 14 (Friday) after John Deemer sent in his comments. The committee had no further issues regarding the meeting 3 minutes and approved it.

Next, John Deemer presented to the committee control and cost effectiveness data (4 tables) for various affected units at the refinery. The first table listed possible control techniques and related cost data for the cracker CO boiler (23-H-3). John explained that the cracker CO boiler had been covered under the Consent Decree (CD) with DNREC, which required its emission rate to be reduced from its current 120 ppm to 20 ppm in 2009. Alan asked if the requirements in the CD would be enforceable. Bruce said that what was agreed on in the CD would be enforceable. John added that according the CD, the refinery had to apply a permit from DNREC for the 20 ppm emission rate, and under the permit, the 20 ppm requirement would become enforceable.

For the coker CO boiler (22-H-3) on the third table, John explained that this boiler currently has an SNCR with a reduction efficiency of about 30%. Michael pointed out that the 30% efficiency was about the lower end of the SNCR control. He asked why the refinery selected this low-end efficiency. John explained that the SNCR on the coker boiler was required by EPA and DNREC “consent decree” in 2001, and at that time the refinery hired GE Energy Service as a consulting firm to propose and design the SNCR. Both EPA and DNREC agreed with the control design and its control efficiency. Ron asked what the current rate of this boiler with SNCR. John estimated it to be around 100 ppm. John added that Valero’s position is to install relevant control for the coker boiler to achieve a lower NOx emission rate, but not to LAER levels *(John Deemer’s post-meeting comment, August 31, 2006: I do not believe that I stated that it was Valero's position to install "relevant control to achieve a lower NOx emission rate, but not to LAER levels." My position was that we had already installed the required controls (SNCR)(as required by the CD). This is in agreement with the paraphrased version of my last statement in this paragraph that "the coker CO Boiler should be excluded from the rule.")*. Alan stated that Green Delaware’s position was to support LAER controls for all CO boilers. Ron mentioned that if we set up an average rate limit in the rule and a larger unit (such as the coker boiler) operates at higher rates, then other smaller units must operate at much lower rates to compensate. John replied that then the coker boiler should be excluded from the rule.

Michael Fiorentino asked if Delaware’s NOx trading program (Regulation 39) covered all units affected by this proposed rule. Frank’s answer was “it does not”. Michael further asked whether this proposed rule would be for ozone season only or year round. Ron explained that this proposed rule would be for year round, because we had to reduce NOx emission to solve the PM2.5 non-attainment problem during the winter season. In addition, Ron said, after the NOx trading program (Reg. 39) expires in 2008, its affected units will be subject to RACT level controls only, and that is why we are proposing this beyond-RACT rule.

Pete Jacoby raised an issue regarding boilers smaller that 200 mmBTU/hr. He believed there are a large number of small boilers operating in Delaware with much higher emission rates. For example, he said most small boilers (over 70%) are in New Castle, emitting NOx with rates greater then 100 ppm. He wondered what the total NOx emission from those small units would be. Kevin Stewart supported Pete’s question and cited that in the first committee meeting AQM reported a 49 TPD NOx emission in 2002 from point sources but only 10.5 TPD from Valero. Kevin asked where the rest 38.5 TPD NOx emission was from. Ron explained that a large portion of it was from electric generating units (EGUs), which are currently under consideration for controls in the proposed multi-p regulation. Frank said that we could get that information for the committee (Post-meeting review of DE’s 2002 emission inventory indicated that the EGUs contributed about 28 TPD NOx emission in Kent and New Castle).

Alan pointed out that in Europe small boilers such as residential heating boilers are regulated for protecting air quality and public health, and that if there are a large number of smaller boilers as Pete said, their NOx emissions should also be addressed and controlled. Ron replied that, although we did not know the exact number of those small boilers at this moment, we knew that NOx emissions from EGUs and large industrial boilers took over 90% of Delaware’s total point source NOx emission. He said that the small boilers might be included in the inventory as area sources. Kevin pointed out that we need to know what the bulk numbers of emissions are to separate area-source boilers and point-source boilers, so Pete's concern over the small boilers could be addressed appropriately. Frank replied that this was a good suggestion, however, the smaller boilers should be dealt with under another rule-making effort if necessary. (Post-meeting review indicated that less than 2 TPD NOx emission were from area sources in Kent and New Castle in 2002, which was about 4% of the total point source NOx emission.)

Kevin cited that in the third committee meeting, AQM estimated that by 2008 a total of 78 TPD NOx reduction would be needed. He asked if we could not get enough reduction from the affected units here (in particular, the two CO boilers), how Delaware could meet the RFP reduction requirements. For example, he said, if we expected 7 TPD reduction but could only achieve 5.5 TPD due to a not-stringent-enough limit in the rule, how we could take care the 1.5 TPD shortfall. Ron replied that we would be depending on regional controls that OTC and MARAMA are currently working on. Kevin stated that American Lung Association would be concerned about timely implementation of the regional control, and worry about any delay of emission reduction due to its adverse health impacts.

(After the meeting adjourned, Kevin and Frank further discussed the reduction estimates and shortfall. In particular, Kevin and Frank discussed Slide 9 of Meeting 3, which presented AQM's reduction estimates. Frank explained (1) the 2008 reduction shortfall would be about 20 TPD, (2) we would need more reduction for the 2008-2010 period for attainment, (3) the point source reduction estimate (about 13 TPD) in Side 9 did not include reductions from the multi-p rule, the lightering rule and this large industrial boiler rule, (4) we don't know the exact number of reductions to be needed, (5) if we could be successfully implement the multi-p rule, the lightering rule and this rule, we are positive that we are moving toward the right direction to meet the reduction requirements for both RFP and attainment. Kevin was satisfied with the results of the discussion.)

Mark asked John about how to estimate the emission reductions in the table. John said they were based on a 0.04 lb/mmBTU average rate. Bruce asked if the refinery did some estimates for any lower rate limit. John's answer was "no" because the refinery believed that the 0.04 would be the lowest rate that could be reached by the selected controls for those affected units.

Alan pointed out that the cost effectiveness data in the tables seemed to be high. For example, the cost of ultra LNB should not be over $10,000 per ton reduction, but the refinery's table seemed to present much higher number. John explained that the data were based on the actual costs of the installed control system on Boiler 80-2. In addition, Valero had special situation, such as Heater 37-H-1, which has 500 burners that need to be controlled, which would significantly increase the cost as well as the difficulty of installation. Michael mentioned that an important question would be how DNREC incorporate the cost effectiveness data into its rule making decisions. Bruce mentioned that the cost factor would not be included in this rule making. John argued that was not correct. Ron replied that the department would consider the cost factor in this rule, plus the technology availability and feasibility. Michael asked if DNREC would simply accept Valero's cost data, or would get cost data independently. Frank replied that we would consider Valero's data, but we would collect our own cost data independently and consider both sets of cost data when we propose rate limit in the rule.

Next, Frank explained AQM's Table 1. He explained that most information in Table 1 was introduced to the committee already in the previous meetings. One new column contained 2002 NOx emission rates of the affected units, calculated from their 2002 actual heat inputs and emissions. Another column provided the units' weighted rates (weighted by their actual heat inputs). At the bottom of this column was the weighted average of all affected units, which was 0.19 lb/mmBTU, indicating that all units as a group had an emission rate at about the RACT level (0.2 lb/mmBTU). This supported AQM's decision on pursuing beyond-RACT controls over these boilers and heaters.

Next, Bruce started to explain AQM's Tables 2 and 3, which compiled control and cost information from other states. Taras Lewus asked for citations for these information, and Bruce said he would get the citations for the committee in the future. Michael asked if the 3 California units in Table 3 were existing units or new units. Bruce said he would need to review the source of the information to determine. (Bruce's post-meeting review indicated that the two units with 5 ppm standard were new units, while the third one with 7 ppm standard was a unit of 1995 with controls installed in 1999-2000.) Michael further asked that while other states such as California had rate limits as low as 5 ppm, why Delaware is developing a regulation with 80-100 ppm limit. (A response to Michael's question was not captured in Frank's notes, but the answers are: Delaware is seeking "beyond-RACT" controls and emission levels to reduce NOx from the identified refinery units. California has rate limits of 5 ppm because they have much worse air quality problems and have required LAER, the most stringent levels, to be applied to their refinery units. AQM is not seeking that level of control, but our proposed limits are much lower than 80-100 ppm.) Ron pointed out that California's NOx rule includes trading programs and that might be why they could include a lower limit in the rule. He said that Texas' rule had the same trading nature. Michael pointed out that although with trading programs, the standards in CA and TX, as cited in Tables 2 and 3, indicated that a limit as low as to 0.02 lb/mmBTU should be feasible.

Kevin stated that he thought that Bruce's tables should help the committee select a reasonable and feasible rate for the regulation, but data in the tables did not support a 0.04 starting point, rather a lower number. Ron replied that we now had the lowest number of 0.02, and our suggested starting point was 0.04, so we should select a number in between. Alan said that lower limits had been set in other states and the question was what Delaware would want to do with those lower limits implemented in other states. At this point, Kevin raised a question: what the lowest emission rate for a new boiler and what the lowest rate for an existing unit. Michael pointed out that the CA SCAQMD's number was 0.03. Alan pointed out that the Arizona's heaters with LNB had rates of 0.0125. John replied that the Arizona's facility is not built yet. For such a new unit, he said, you can design it that way to reach a lower rate, but for an old unit and considering retrofitting, it is not feasible to reach even a 0.03 rate. At this point, a committee member

(Frank's note did not write down the name of this member) asked John the ages of the affected units. John mentioned most of them were 20 or more years old. John did give age numbers for some individual units, for example, boilers 80-1,2,3,4 perhaps 50 years old, 42-H-1,2,3 20-25 years, 37-H-1 35 years, etc. Frank asked John to provide precise age numbers to the committee in the next meeting. Alan asked to add the design years of each unit. Bill added that the life-length of initial design and improvement should be also provided.

Regarding cost data, Alan questioned why the cost for 37-H-1 was estimated so high at about $150,000 per ton reduction. John explained that this heater unit has 500 burners and all 500 burners would need to be replaced with ultra low NOx burners (ULNBs). Alan said that not blaming the number was inflated, he still doubted the cost number for the 500 burners. John replied that his cost estimates on ULNBs were based on the cost data from boiler 80-2, which installed controls with a rate limit of 0.04 in 2004. He said the cost data for this heater was real and true. Ron asked that with a design limit of 0.04, what the actual rate of this boiler (80-2) is now. John replied that he believed the actual operating rate is 0.02 to 0.03. Ron commented that the refinery did a good job in controlling boiler 80-2.

(Post-meeting comment from Kevin, 08/25/06: "My recollection is that Alan's doubting the cost number for 37-H-1 had a lot to do with the issue of why control of the two stacks was not explored and costs of controls determined; it was simply the issue of whether an end-of-pipe solution in this case might be more cost-effective than a solution controlling 500 individual burners. Alan and others should feel free to modify or correct my perception of what was said on July 19 in this regard." Frank's post-meeting check with other AQM committee members confirmed Kevin's recollection.)

Regarding retrofitting boilers 80-1,3, and 4, Alan asked what would the cost for a new boiler be. Pete said that would be between $25 million to $35 million. Then, Alan said he wondered why the refinery would spend $17 million to retrofit those 50-year old boilers. Pete replied that so many other factors would have to be considered, such as piping system, control system, steam capacities of other connecting units, gas distribution system, etc., and perhaps 20 to 25% of the whole facility would be affected. He added that his $25m to $35m number was just for a single new boiler sitting there, and if one wanted to fit it into the whole system, all the above factors must be included, and the cost would be increased accordingly. At the end, Pete said that he wished he hadn't stated the cost of $25 to $35 million because the actual cost for installing a new boiler would be much higher. Alan said that he understood that it was a business decision of the refinery to do the retrofit not the new boiler, but, if that decision would limit our capability to achieve environmental and health benefits, it is a problem, and he did not know the solution. (*Alan's post-meeting comment, Sept. 8, 2006: I do not recall exactly what I said, but what I intended to say is that if the refinery makes a business decision to retain old equipment, this should not be accepted as an excuse for higher emissions. To put it another way, by accepting these excuses DNREC would be giving the refinery a double incentive NOT to modernize it's equipment.... This does not seem like sound public policy*.)

Michael asked if the average limit would mean the actual limit would harder (tighter) for some units but looser for some other units. Ron answered yes. He further pointed out that the limit for boiler 80-2 was designed to be 0.04lb/mmBTU and John told us the actual rate was 0.02 to 0.03, so there was an extra reduction credit from this boiler already. John added that when we (refinery staff) designed the control, we did not design on the regulation limit, but at a lower limit to ensure compliance.

Alan noted that John's cost data ware based on the rate limit of 0.04. He stated to John that if the cost had been based on the actual lower rate, then the cost per ton estimates should have been lower. John said that statement was correct. Michael asked that, for example, if the rate could be from 0.04 to 0.02, then there could be a 50% reduction in cost effectiveness. *(John Deemer's post-meeting comment, August 31, 2006: I have since verified that this is not the case. By reducing the allowable emissions by 50% (from 0.04 to 0.02 lb/MMBTU) for Boiler 3, the actual reductions (which is the denominator in the cost effectiveness calculation) increases from 113.2 tons to 167.3 tons. On this basis, the cost effectiveness is reduced from $31,514/ton to $21,317/ton. Thus a 50% reduction in potential does not reduce the cost effectiveness by 50%.)* John replied that the actual cost reduction could be estimated between 0.04 and 0.02, but could not reach 0.02. *(John Deemer's post-meeting comment, August 31, 2006: I stated that the cost effectiveness calculation is based upon the potential to emit (PTE), not the actual emissions. My recollection was that Ron Amerikian agreed with me on this point. Ron's response to this comment: "I generally agree that cost effectiveness calculations should be based on PTE. But I don't agree with John's statement above. He appears to be using actual emissions in his comparison of a 0.04 lb/mmbtu limit to a 0.2 lb/mmbtu limit. I don't believe that using actual emissions in one part of the equation and PTE in another part makes sense when determining cost effectiveness.")* Mark asked John if they consider the future heat input increase when estimating cost. John answered yes and the cost estimates were total costs.

At this point, Michael suggested that, considering averaging rate standards of LNBs and ULNBs in other states, a 0.03 lb/mmBTU limit be considered in the regulation. Alan agreed with the 0.03 limit, and said that from the information in AQM's tables it was hard to defend a limit greater than 0.03. Ron commented that AQM would need to review and analyze all cost information and determine if a 0.03 limit would cost too much, and we needed to review the 500-burner case and the costs cited for boiler 80-2. Kevin stated that the cost data of today must be reviewed and looked at independently, and Valero's data should be regarded as information from the regulated party. John stated that DNREC should gather and prepare solid cost data and compare with Valero's, and DNREC's data should be also regarded as independent data by the committee.

Alan raised an issue of cost-benefit ratio. He said in general the ratio should be 10-to-1, and the committee should develop this rule in a broader way for environmental and health benefits. John argued that the high cost-benefit ratio was judged for improving ambient air quality, not for a specific pollutant from specific sources at one facility.

Kevin stated that American Lung Association would support a 0.03 lb/mmBTU rate limit, not higher, but would reserve the right to revise its position after reviewing more technical and cost information.

At this point, Frank summarized that (1) AQM suggested an average 0.04 lb/mmBTU rate limit as a starting point, (2) Valero in general agreed with this starting rate and provided cost data based on it *(John Deemer's post-meeting comment, August 31, 2006: I do not recall stating that we (Valero) agreed with the starting rate of 0.04 lb/MMBTU. I did however agree to provide the cost effectiveness calculations on that basis. That may have been viewed by the department as acceptance of that emission level. Please refer to my power point presentation for meeting 2 in which I stated it may be more appropriate to set the limit at 0.06 lb/MMBTU.),* (3) three committee members, representing American Lang association, Green Delaware, and Mid-Atlantic Environmental Law Center, supported a 0.03 lb/mmBTU rate. Frank stated that AQM would review carefully all information from this committee meeting, would gather additional information if necessary, would consider positions of all parties expressed in this meeting, and would propose relevant rate limit(s) and associated regulatory language for the next committee meeting on August 16.

The meeting adjourned at 12:45 PM.

Reminder: See my notice below.

July 27, 2006
Dear Committee Members,

Due to a critical scheduling conflict in AQM, we have to postpone our fifth meeting for one week, from August 16 to August 23 (also a Wednesday). The meeting will be in Conference Room A, DNREC's office at 391 Lukens Drive, New Castle, from 10 to 12.

Please follow the link below for driving direction to our Lukens Drive office:
http://maps.yahoo.com/py/maps.py?BFCat=&Pyt=Tmap&newFL=Use+Address+Below&addr=391+Lukens+Drive&csz=New+Castle%2C+DE+19720&country=us&Get%A0Map=Get+Map

I am sorry for the postponement, and hope this early notice will minimize any inconvenience for you. Thank you and see you all on August 23. By the way, I have talked to Ali and hopefully he will join us in this meeting.

Frank