Bryan W. Shaw, Ph.D., P.E., *Chairman*
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Richard A. Hyde, P.E., *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

June 24, 2014

Environmental Protection Agency
Air Docket
Mail code: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Docket ID No. EPA-HQ-OAR-2013-0809

Dear Sir or Madam:

The Texas Commission on Environmental Quality (TCEQ) appreciates the opportunity to respond to the United States Environmental Protection Agency's (EPA) Notice of Availability of the EPA's 2018 Emissions Modeling Platform (79 FR 2437), published in the *Federal Register* on January 14, 2014.

Detailed comments on the draft modeling platform are enclosed. If there are any questions concerning the TCEQ's comments, please contact Mr. Steve Hagle, P.E., Deputy Director, Office of Air, at 512-239-1295 or steve.hagle@tceq.texas.gov.

Sincerely,

Richard A. Hyde, P.E.
Executive Director

Enclosure

cc: Guy Donaldson, EPA R6

COMMENTS BY THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY REGARDING THE 2018 EMISSIONS MODELING PLATFORM

DOCKET ID NO. EPA-HQ-OAR-2013-0809

I. Summary

On January 14, 2014, the United States Environmental Protection Agency (EPA) published in the *Federal Register* a Notice of Availability of the EPA's 2018 Emissions Modeling Platform (79 FR 2437). The Texas Commission on Environmental Quality (TCEQ) provides the following comments on this notice and the modeling platform.

II. Comments

The EPA should consider modeling multiple years to form a rational basis for nationwide rules or use a more appropriate base year, such as 2012, because 2011 is not representative of historical ozone formation for Texas and surrounding states. Using 2011 meteorology and related emissions may not be conducive to good model performance for Texas due to the atypical meteorology (e.g., extreme temperatures) and related events (e.g., wildfires, exceptional drought). If the EPA relies on the 2011 meteorology and projects the emissions from 2011 for its 2018 Emissions Modeling Platform, the EPA should account for any poor model performance for Texas and surrounding states, and the EPA should explain why any controls developed based on 2011 data would be appropriate for the majority of years which have more normal meteorological conditions.

In the TCEQ's comments to the EPA's 2011 Emissions Modeling Platform, we provided irrefutable evidence that 2011 was an exceptional (more severe than extreme) drought and wildfire year for Texas and surrounding states. For more evidence that 2011 was exceptional for Texas, see the recently-released National Climate Assessment (NCA)[1]. Typical meteorological and emissions years should be relied upon for modeling. As an atypical year, 2011 will likely result in poor model performance during the base case for Texas and similar areas. Even if the EPA achieves acceptable performance for Texas, the potential for developing inappropriate control strategy requirements remains. Because 2011 represents such an exceptional drought year, it is likely that any emissions reduction strategies based on 2011 will not be appropriate for more normal meteorological years. Similarly, the Midwest suffered extreme drought in 2012, and, since 2013, California continues to suffer a drought of historic proportions. It is challenging to find a single representative year for the entire country; therefore, the EPA should consider modeling multiple years to form a rational basis for nationwide rules such as the Transport Rule. If multiple meteorological years and emissions are too resource intensive for the EPA to implement at this time, then the TCEQ recommends using a recent year such as 2012, which was still characterized by drought but not at the exceptional level.

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[1] http://nca2014.globalchange.gov/highlights/regions/great-plains and the full report at http://nca2014.globalchange.gov/downloads. Page 453 of the report discusses 2011 as, "...exceptional drought and recording-setting temperatures in Texas and Oklahoma and flooding in the northern Great Plains. Many locations in Texas and Oklahoma experienced more than 100 days over 100°F, with both states setting new high temperature records. Rates of water loss were double the long-term average, depleting water resources and contributing to more than $10 billion in direct losses to agriculture alone."

As with its 2011 base case, the EPA should address how it is accounting for a season or more of widespread wildfires and exceptional drought, and their aftereffects, in its biogenic emissions modeling estimates for the 2018 future case.
In the TCEQ's comments to the EPA's 2011 Emissions Modeling Platform, we documented that the 2011 Texas drought and wildfires destroyed many millions of acres of biomass, including crops, forests, and scrublands. The EPA should address how it is accounting for wildfires and drought in its biogenic emissions modeling. For accurate estimates, land use/land cover data must be adjusted to account for drought-related vegetation loss and fires and biomass density of surviving vegetation must be adjusted for drought stress. Further exacerbating these factors, the Biogenic Emissions Inventory System (BEIS) model assumes well-watered vegetation emitting at a rate tied to drought-induced high temperatures, leading to even greater over-prediction of biogenic emissions of volatile organic compounds in Texas and Oklahoma. Likewise, biogenic nitrogen oxides emissions should be much less than typically predicted by BEIS in 2011 because crop failures affected soil moisture and the amount of fertilizer applied. These issues will continue to be a concern to the TCEQ if the EPA uses these same non-representative 2011 BEIS outputs for its 2018 future case modeling.

The EPA should use average or "typical" emissions instead of 2011-based temporalization for wildfires and electric generating unit (EGU) emissions or explain the rationale for not using a typical baseline that is projected to the future.
The EPA has not followed its own guidance, as provided in "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." In this guidance document[2], the EPA provides a methodology to account for those emissions activities that are not appropriate to use directly in the future case because they are not expected to behave the same in the future case year as in the base case year. Footnote 25 on page 34 of this EPA document reads "The year may be the same, but the emissions may still differ. The base case inventory may include day specific information (e.g., wildfires, biogenic emissions, CEM data) that is not appropriate for using in future year projections. Therefore the baseline inventory may need to replace the day specific emissions with average or "typical" emissions (for certain types of sources)." The EPA should explain why fires, biogenic emissions, and EGU emissions would not be better represented in a baseline with "typical" (average year) emissions and then projected to the future year.

The EPA should use state-submitted inventory and projection data where available.
The TCEQ has spent considerable resources to develop more detailed and area appropriate emissions estimates and has submitted this information to the EPA. The EPA should use this information for Texas point and non-point growth factors and operational changes at point sources for use in projecting the 2011 National Emissions Inventory (NEI) to future years. The TCEQ submitted this information to provide the EPA better data to predict future emissions growth.

If the EPA makes changes to state-submitted emissions inventory data, the EPA should allow states the opportunity to review and comment on the changes.

The EPA should use data and emissions development methods equivalent in quality and refinement to the data and methods used by the TCEQ to develop the original 2011 NEI on-road mobile submission for Texas.
The EPA is providing the opportunity for states to supply MOVES2014 inputs that the EPA will use for the development of an updated 2011 NEIv2 on-road emissions inventory, which will then be used to develop the 2011 and 2018 modeling platforms. While the TCEQ appreciates the

[2] http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf

opportunity to supply MOVES2014 inputs, the on-road emissions estimation approach proposed by the EPA for the NEIv2 will produce less accurate results than those produced by the TCEQ's methodology due to the absence of link based activity assessments. The TCEQ methodology uses local link based activity assessments combined with emission rates from the MOVES model to produce a more accurate inventory. The TCEQ methodology produces inventories that are consistent with the requirements for use in state implementation plans (SIPs) and transportation conformity assessments. When updating the 2011 NEIv2 for use with the 2011 and 2018 modeling platforms, the EPA should use Texas emissions developed by the TCEQ or use SIP quality on-road inventory methods comparable to those used by the TCEQ.

When implementing national consistency for NEI projection values, the EPA should not select the most conservative assumptions to predict future emissions growth when more specific information is available.

The EPA should allow states to comment on the process that the EPA proposes to use to ensure national consistency for NEI projection values, particularly for emissions from source categories that have the greatest potential to impact regional transport. The EPA should identify the assumptions and methodologies submitted by all states for transport-related categories. For example, the EPA should make the information provided by each state available in an easily accessible format, post its preferred approaches for review and comment, and allow states to provide comment on how the EPA will ensure that emissions data are accurate and consistent among states. The states' input should be considered in making the final selection of a method for projection from the NEI.

The EPA should acknowledge the possibility that results from the Integrated Planning Model (IPM) may not account for all business scenarios and outline mechanisms to adjust IPM's output to account for other outcomes, especially when specific retrofit and compliance options that differ from IPM outputs are identified.

The TCEQ has reviewed the EPA's "Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model." The IPM is a deterministic model that is focused on cost only, i.e., it chooses the least costly option available subject to pre-specified constraints. In reality, EGU owners do not always make decisions based solely on cost. Decisions are often made based on business and financial realities such as strategic timing, minimization of risk and uncertainty, profit maximization, bankruptcy, mergers, etc. The IPM, being a deterministic cost minimization model, does not account for profit seeking or risk minimization behaviors that sometimes lead EGU owners/operators to choose more costly options. The EPA should consult with appropriate state agencies and industry leaders, rather than relying solely on IPM predictions. If IPM results are used, the EPA should acknowledge that IPM may not be the best tool for predicting future emissions for Texas EGUs.

The TCEQ takes exception to certain aspects of the IPM and the IPM results provided in the 2018 Emissions Modeling Platform. Specific concerns include: IPM's focus on cost minimization alone; the long projection timeframe; the accuracy of inputs, assumptions, and constraints; the lack of transparency in IPM post processing; and the EPA's reliance on IPM outputs alone in formulating regulatory components such as state emission budgets.

The EPA should choose a shorter projection time frame, such as 2017-2019, to allow a more refined representation of the EGU sector.

The EPA has not clearly explained its rationale for using the 2016-2054 projection time frame. A frequently-used explanation for approximations in IPM is "model size and computational considerations." Approximations include aggregation of existing units into model plants of combined capacity instead of individual representation. Such approximations could lead to the model predicting operational and control behavior that might not match the realities of individual units. The TCEQ contends the use of a long projection timeframe and associated seven model runs contributes to the need for such approximations and may lead to localized over prediction of modeled values, and ultimately to the perceived need for additional reductions due to decisions based modeling and computational limitations, rather than the best available science.

The EPA should vet the inputs, assumptions, and constraints used in IPM for Texas EGUs more thoroughly. The EPA should use Texas-specific information from the Electric Reliability Council of Texas (ERCOT) and the Public Utility Commission of Texas (PUCT) to characterize Texas EGUs.

The TCEQ relies on ERCOT and PUCT reports and data in addition to the Energy Information Administration (EIA) Form 860 for SIP modeling. For example, the TCEQ relies on ERCOT's "Report on Capacity, Demand, and Reserves in the ERCOT Region" (CDR)[3] as a source for planned units, retired units, seasonal availability, etc. The CDR is compiled from information provided by EGU owners and operators, is updated frequently[4], and includes the capacity offsets to fossil-fuel generation with renewable (mainly wind and solar) generation. As shown below, the new capacity (units with signed interconnection agreements and issued air permits) expected to be online between 2013 and 2015 is significantly different in ERCOT's CDR compared to that specified in the National Electric Energy Data System (NEEDS), and by extension in IPM[5], for all fuel types. The EPA should use the TCEQ's updates to NEEDS in IPM.

Fuel Type	ERCOT's CDR	NEEDS/IPM
New natural gas capacity	2144.2 megawatts (MW)	166.15 MW
New wind capacity	5624.3 MW	410.5 MW
New solar capacity	167.6 MW	47.65 MW

The EPA should clearly explain how the number of new model plants for each source type was determined and respond to other concerns about IPM results as discussed below.

While Table 4-7 "Aggregation Profile of Model Plants as Provided at Set Up of EPA Base Case v.5.13"[6] provides the number of new model plants pre-specified in IPM with a footnote[7] as documentation, specific details and the logic used to determine the number of potential units are not clearly explained. For example, Table 4-7 states there are 305 New Future Technology IPM Model Plants that were specified during set up. The EPA should define and provide details on "new future technology" and in which regions these units are expected to be built so states and interested parties can evaluate the validity of the potential new units. For example, ERCOT's CDR anticipates the addition of 668 MW of new wind capacity between 2016 and 2017 in the ERCOT region; however, IPM's output reflects no new wind capacity in its 2018 results.

3 Last accessed on May 6, 2014 at http://www.ercot.com/content/news/presentations/2014/CapacityDemandandReserveReport-May2014.pdf

4 CDR's are biannual reports. In the 2012-2014 time period CDR's were published May 2012, Dec 2012, May 2013, February 2014 (delayed from Dec 2013 due to demand projection updates), and May 2014.

5 Values from NEEDS_v513.xlsx and Web-Ready_Parsed_File_EPA5-13_Base_Case_2018.xlsx

6 Page 4-7 of EPA's "Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model," November 2013 (http://www.epa.gov/powersectormodeling/BaseCasev513.html#documentation)

7 Page 4-7 footnote 20 of Chapter 4: Generating Resources

Additionally, when using 2018 modeling results, the EPA should verify IPM outputs such as retirements and controls for Texas-specific sources. For example, retirements should be verified against ERCOT's CDR for the ERCOT region or the PUCT's generation table[8] for all of Texas and not rely on IPM-predicted retirements alone.

The EPA should address the resources needed for IPM-predicted controls, such as the constraints due to the marketplace demand for control devices and likely necessity for extended compliance dates due to that demand.

The EPA should provide additional details and documentation on the post-processing "parsing" tool used to translate the model plant level outputs (emissions, generation, retrofits, etc.) to individual existing unit-specific values.

EPA should consider other EGU projection tools, such as the Eastern Regional Technical Advisory Committee (ERTAC) EGU projection model, to provide error bounds on IPM results.

The EPA is aware of the ERTAC model and has a representative on the review team. The EPA should review ERTAC's publically-provided model results and be able to explain how ERTAC results differ from IPM results. This comparison could provide some bounds and independent corroboration of IPM results, especially, since ERTAC's inputs regarding retirements, new units, and control are updated quarterly by states and industry representatives.

The TCEQ questions the IPM results for future sulfur dioxide (SO_2) reductions from the electric utility power sector. The EPA may be overestimating SO_2 reductions in the IPM future base case data.

According to the EPA base case emission projections for Texas, SO_2 annual emissions from fossil-fuel fired power generation greater than 25 megawatts will decrease to approximately 124,600 tons per year by 2016, then rise slightly in 2018 to approximately 143,500 tons per year. The EPA's predicted SO_2 emission levels represent more than a 60% reduction from Texas' 2013 annual electric power sector SO_2 emissions of approximately 365,400 tons per year based on the EPA's Clean Air Markets Database. This substantial predicted reduction in power sector SO_2 emissions is not limited to Texas. The EPA's IPM results show similar predictions for many other states, such as Indiana, Ohio, and Pennsylvania. The EPA's IPM results for SO_2 emissions from the electric utility power sector in 2018 appear to be overly optimistic and the TCEQ questions the basis of IPM's prediction of these large decreases in SO_2 emissions. The environmental regulations that the EPA cites in IPM's Documentation for Power Sector Modeling Platform, v.5.13 do not appear to be sufficient regulatory drivers to bring about the level of SO_2 emission reductions that IPM is predicting. While some additional SO_2 reductions may occur as a result of Clean Air Interstate Rule (CAIR) Phase II implementation, the EPA's predicted SO_2 emissions for Texas power plants is significantly less than Texas' CAIR Phase II budget of 224,662 tons per year. While some coal-fired utility units in Texas may need additional controls to meet the Mercury and Air Toxics Standard (MATS) acid gas requirements, leading to some SO_2 reductions, the TCEQ anticipates that many coal-fired units in Texas will either already meet the primary MATS hydrogen chloride (HCl) standard or the alternate SO_2 surrogate standard if the unit is equipped with flue gas desulfurization (FGD).

The TCEQ cannot confirm some of IPM's specific predictions for Texas coal-fired utility units based on the information the EPA has made available. The EPA should make the assumptions being used for IPM more transparent.

The EPA claims that IPM "does not model the alternative SO_2 standard offered under MATS for units to demonstrate compliance with the rule's HCl control requirements." (Documentation for

[8] Last accessed on May 6, 2014 at http://www.puc.texas.gov/industry/maps/elecmaps/gentable.pdf

Power Sector Modeling Platform, v.5.13, Chapter 3, Power Systems Operations Assumptions, Section 3.9.3, page 3-26). However, the TCEQ notes that the EPA is modeling SO_2 reductions between 50 and 80% from the units' 2011 SO_2 emission rates on nine of the ten coal-fired power plant units in Texas that IPM predicts will install dry sorbent injection (DSI) technology. These nine units include: Harrington Units 1 – 3; Tolk Units 1 and 2; WA Parish Units 5 – 7; and Welsh Unit 1. The EPA should clarify whether the SO_2 reductions for these nine units are estimated co-benefits of using DSI to meet the MATS HCl limit. It is possible that some of these facilities may indeed require additional acid gas control for compliance with MATS and some reductions in SO_2 would occur with the installation of DSI for HCl control. However, while modeling SO_2 co-benefits from DSI would not be directly contrary to the EPA statement in Chapter 3 of the IPM documentation, the EPA should be more transparent about the assumptions being put into IPM. Furthermore, the EPA appears to be basing these SO_2 reductions on an assumption that the facilities will need DSI control for HCl purposes. Some of the facilities identified as installing DSI may not need additional control to meet the acid gas limit in MATS, in which case the EPA is modeling SO_2 reductions that would not actually occur. Even if these companies do install DSI for HCl control, the concurrent SO_2 reductions would not be enforceable. If the SO_2 reductions on these nine units are not based on assumed co-benefits of using DSI to meet the MATS HCl standard, then the EPA should explain the basis of IPM's projection that the facilities will need DSI.

The IPM parsed data file also indicates that four coal-fired units (Big Brown Units 1 and 2, and Monticello Units 1 and 2) in Texas are predicted to install dry Flue Gas Desulfurization (FGD) SO_2 controls. The TCEQ does not have any information at this time that dry FGD systems will be installed on these units. If, as the EPA claims, IPM is not applying the alternative SO_2 surrogate standard from MATS, the EPA needs to clarify the basis of IPM's prediction that these four units will require installation of dry FGD systems for SO_2 control. Additionally, IPM is predicting substantial SO_2 reductions for some units for which the parsed data files do not indicate any installation of SO_2 retrofit controls, most notably on Martin Lake Units 1 – 3, Monticello Unit 3, and Sandow No. 4. Based on the estimated pound per million British thermal unit SO_2 emission rates, predicted 2018 nitrogen oxides emissions, and predicted 2018 level of activity, the SO_2 reductions in IPM for these units are not based on decreased operation. The EPA should clearly provide the basis of IPM's assumed large reductions in SO_2 emission rates on these Texas coal-fired power plants apparently without the application of additional control technology. If the reductions on these units are based on assumed scrubber upgrades or scrubber bypass elimination, the EPA should be identifying such assumptions in the parsed data files so that stakeholders can comment on such assumptions.

The TCEQ also notes that the IPM parsed data files indicate that Welsh Unit 3 currently has a wet scrubber installed. Based on the TCEQ's information, and the information that the TCEQ relies upon, Welsh Unit 3 is not currently equipped with any form of FGD scrubber, which is consistent with information from EPA's Clean Air Markets Database and the Energy Information Administration on this unit. However, the EPA is modeling SO_2 reductions on Welsh Unit 3 greater than 80%. If the EPA intended that the IPM data show that the wet scrubber on Welsh Unit 3 is an SO_2 retrofit control, then the basis of EPA's assumption that the unit will install a wet FGD scrubber needs to be clearly documented. If the listing of a wet scrubber as a control on this unit is simply an error, the EPA still needs to explain the basis for IPM's predicted SO_2 reductions on Welsh Unit 3.

The EPA should not speculate on potential facility closures for modeling. Only announced shutdowns should be included in the IPM modeling results.

Three of the coal-fired utility unit retirements in the 2018 IPM results for Texas have been publicly announced by the companies, specifically Welsh Unit 2 and JT Deely Units 1 and 2. However, IPM also predicts that the San Miguel unit in Atascosa County will retire before 2018 even though the San Miguel Electric Cooperative has made no announcement of plans to retire their unit. Only announced shutdowns should be included in the IPM modeling. The EPA should not be speculating about a plant's financial viability into the future. A company's decision to retire an asset as substantial as a coal-fired utility unit is based on many factors the EPA is not privy to and that cannot be factored into IPM. In addition to possibly modeling reductions that may not actually occur, such speculation could have an adverse impact on a company's financial standing.

The EPA should clarify and take specific public comment on certain other aspects of the modeling platform.

The EPA states that it will use "Oil and gas spatial surrogate updates for sources in the northeast and western US." The EPA should clearly identify the geographic areas covered by these spatial surrogates and should use surrogates provided by the states if available. This is the case for 2018, as it is for 2011.

The EPA states that it is using detailed shipping lane emissions in the Great Lakes region. The EPA should provide the same amount of detail in its modeling of the Gulf of Mexico. The TCEQ is prepared to share its modeling files for Texas. If the EPA chooses not to use the TCEQ files, then the EPA should justify the use of the other data. This is the case for 2018, as it is for 2011.

Beginning on page 78 of the proposed Technical Support Document, the EPA generally describes the projection techniques used for each sector of the emissions inventory. For example, the 2011-specific point source fires and area source fires are used directly for 2018. The EPA should consider that this may be an over-estimate for 2018 for Texas.

The EPA claims that it performed reconciliation with state consent decrees and settlement information for the future case cement manufacturing sector. It is not readily discernable that the EPA applied the cement kiln caps and/or previously-approved SIP limitations within Texas. The EPA should ensure that these limitations are accounted for and documented in its 2018 modeling platform. These caps and limitations have been modeled and documented in each of the past four Texas SIP revisions.

This draft modeling platform projects future livestock animal population for Texas from 2005 United States Department of Agriculture data. The TCEQ contends that 2005 will overestimate the 2011 livestock population and all animal feedstock grown in Texas for 2011, due to the huge Texas losses in the drought of 2011 and preceding losses between 2006 and 2011[9]. Since this 2005 dataset is also being used for 2018 agriculture emission estimates, the emissions estimated from these sectors are likely much too large for Texas.

[9] See livestock loss estimates between 2006 and 2011, inclusively, at http://today.agrilife.org/2012/03/21/updated-2011-texas-agricultural-drought-losses-total-7-62-billion/