BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO	)	(Rulemaking – Air)
35 ILL. ADM. CODE 225.233,	)	
MULTI-POLLUTANT STANDARDS (MPS)	)	

NOTICE

TO: Don Brown
Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601-3218

SEE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today electronically filed with the Office of the Clerk of the Illinois Pollution Control Board the ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S RESPONSES TO PREFILED QUESTIONS, a copy of which is herewith served upon you.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: /s/ Gina Roccaforte
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DATED: January 12, 2018

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ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S RESPONSES TO PREFILED QUESTIONS

NOW COMES the Illinois Environmental Protection Agency ("Illinois EPA" or "Agency"), by one of its attorneys, and submits the following responses to the prefiled questions submitted by (1) the Illinois Pollution Control Board ("Board") with the Hearing Officer Order dated January 2, 2018; (2) the Illinois Attorney General's Office dated January 2, 2018; and (3) the Environmental Groups dated January 2, 2018. Due to time constraints, the Illinois EPA was unable to finalize responses to the prefiled questions filed by Dynegy Midwest Generation, LLC, Illinois Power Generating Company, Illinois Power Resources Generating, LLC and Electric Energy, Inc. (collectively, "Dynegy"), but will respond to such questions at the first hearing.

Questions from the Board

1. On pages 1-2, you state that the proposal to combine the two MPS Groups and change the rate-based emission limits to mass emission limits is intended to simplify compliance with fleet-wide emission limits of all units owned by the same company, and provide operational flexibility as well as regulatory certainty. Davis Test. at 1-2.

   a. Please clarify whether the units under the two MPS Groups are currently in compliance with the applicable MPS.

      Yes, the units within both MPS groups are currently in compliance.

   b. Comment on whether the Agency considered a combined MPS Group with fleet-wide rate-based emission limits for SO2 and NOx to simplify compliance, and provide operational flexibility and regulatory certainty. If so, explain why this option was rejected. If not, comment on the drawbacks of this option.

      A combined MPS Group under a single new rate-based limit was considered; however, this would not have provided the operational flexibility to the

Group that was referenced in the TSD, as Dynegy could still need to operate certain units strictly for the purposes of meeting fleet-wide average emission rates.

c. Comment on whether the Agency considered the option of fleet-wide mass emission limits, as well as, mass emission limits/caps based on the allowable emissions under the MPS for individual power stations. If so, explain why this option was rejected. If not, comment on the drawbacks of this option.

No, the Agency did not consider this option. Doing so would remove the operational flexibility this proposal is intended to provide. Additionally, the MPS has never included source-specific emission standards that would restrict the MPS groups from averaging fleet-wide among the affected units.

d. The combined MPS Group does not include EGUs that are not in operation at Vermillion, Wood River, Hutsonville, Meredosia, or Edwards Unit 1. However unlikely, would the proposed rule allow for the units at these facilities to be restarted again without belonging an MPS Group anymore? If so, what regulations would apply to these EGUs?

For the units mentioned above that no longer have operating permits, the New Source Review process and New Source Performance Standards would apply in order to restart a unit. Limits for units considered "new units" established in this permitting process would be far more stringent than any in the current MPS or other State or federal regulations that had applied to them previously.

2. On page 2, you state, "[t]he proposed amendments were reviewed by the U.S. Environmental Protection Agency ("USEPA") prior to their filing with the Board, and USEPA has indicated that the amendments are indeed approvable as a SIP revision."

a. Please comment on whether USEPA expressed any concerns regarding "hotspots" or local impacts with the elimination of rate-based emission limits for many of the affected EGUs.

No, USEPA expressed no such concerns.

b. Did USEPA suggest any changes to IEPA's proposal?

Yes, USEPA requested that the Agency include language in Section 225.233(e)(1)(E)(i) further clarifying that all NOx emissions from each EGU are covered by the mass emissions cap and do not go unaccounted for. The Agency added an amendatory provision which reads as follows:

"All NO_x emissions from each EGU, regardless of whether the SCR is operational or non-operational, must be included in determining compliance

with the emission standards set forth under subsections (e)(1)(C), (e)(1)(D), and (f)(1) of this Section, as applicable."

c. Please submit into the record any correspondence between IEPA and USEPA regarding USEPA's review of the IEPA's proposal.

The Agency is attaching the written correspondence between USEPA and Illinois EPA regarding its review as Attachment 1.

3. Also on page 2, you note, "[t]he proposed amendments do not relieve the owners of the affected EGUs from obligations to comply with other current requirements intended to limit the emissions of criteria pollutants. These rules include the Cross-State Air Pollution Rule ("CSAPR"), sulfur limitations set forth in 35 IAC Part 214, and other State and federal requirements for the affected EGUs.

a. Please clarify what other state and federal requirements pertaining to SO2 and NOx apply to the affected units. Do any of these provisions require the affected units to comply with any rate or mass limitations for SO2 and NOx?

The table included as Attachment 2 lists, to the best of the Agency's knowledge, applicable State, federal, and consent decree requirements for NOx and SO_2 for the affected units.

b. Do the other state and federal regulations require any of the affected units to install emissions control equipment?

There are currently no State or federal regulations that require the installation of additional controls at any of the affected units.

4. On page 3, you state that the all sources affected by the proposed amendments have either been modeled in accordance with the federal SO2 Data Requirements Rule (DRR) or were previously addressed due to monitoring that showed nonattainment in an area near the source. Please comment on whether the Agency's determination under DRR has been reviewed and approved by USEPA. In this regard, please provide any federal register citations to USEPA determination or submit relevant documents into the record.

The Agency's modeling under the DRR and the Agency's designation recommendations have been reviewed and approved by USEPA. Specifically, USEPA indicated agreement with the modeling, and USEPA's designations/ proposals for all areas containing Dynegy sources have been in accordance with the Agency's recommendations.

Citations:

- **Initial nonattainment designations for the Lemont and Pekin areas: 78 *Federal Register* 47191 (August 5, 2013)**

- **Proposed approval of the Attainment Demonstration SIP revisions for the Lemont and Pekin areas: 82 *Federal Register* 46434 (October 5, 2017)**
- **"Round 2" area designations: 81 *Federal Register* 45039 (July 12, 2016)**
- **"Round 3" area designations resulting from the DRR modeling that has been conducted: To date, designations have not yet been published in the *Federal Register*. However, Illinois received notification from USEPA Administrator E. Scott Pruitt of the designations in a letter dated December 20, 2017. The draft *Federal Register* notice can be found on USEPA's website at** https://www.epa.gov/sites/production/files/2017-12/documents/final_frn-so2-noa_round_3_final_0.pdf**. The USEPA Technical Support Document associated with these designations can also be found on the USEPA website at** https://www.epa.gov/sites/production/files/2017-12/documents/12-il-so2-rd3-final.pdf**.**

5. On page 3, you note that the Agency determined that a separate source-specific limit was needed at the Joppa plant to ensure compliance with the SO2 NAAQS. Please comment on why the Agency did not rely on a mass limit based on allowable emissions under the current MPS (13,902 tons) instead of the proposed higher limit (19,680 tons).

   Assuming the 13,902 figure was calculated from the last column in the TSD Table 1, the individual figures from that table do not reflect allowable emissions for any given unit. The figures in that column represent contributions to a calculated fleet-wide allowable mass figure (66,354 tons) at the applicable current MPS fleet average emission rates for SO_2. No single unit is required to meet the fleet-wide emission rate given for the unit in that table.

6. Also on page 3, you state that E.D. Edwards plant is subject to the hourly limits under Part 214 that were adopted by the Board in docket R15-21. Please clarify what is the combined SO2 limit is for the Edward Units 2 and 3 under 35 Ill. Adm. Code 214.603. Please comment on whether this combined hourly limit places an annual SO2 emissions cap on Units 2 and 3.

   In the absence of Edwards 1 operating, the emission limit from Section 214.603 for Edwards Unit 2 is 2,100.00 lb/hr. The limit for Edwards Unit 3 is 2,756.00 lb/hr. The combined limit for both units is therefore 4,856.00 lb/hr, however it should be noted that these limits cannot be combined; as noted above, each unit is limited individually. These limits would amount to an annual SO_2 emissions cap for both units of 21,269 tons per year (at 8,760 hours).

7. On page 4, you assert that the proposed rules require units with SCR to operate those controls always when those units are in operation, and require those units to meet an average NOx emission rate standard of 0.10 lb/mmBtu during the ozone season. Since the rule requires the operation of SCR at all times when the units are in operation, explain why compliance with the proposed rate limit is not required year-round. In this regard, please comment on whether operation of SCR as required by Section 225.233(e)(1)(E)(i) would achieve the proposed average rate limit for SO2.

The proposal does not include a requirement to meet the 0.10 lb/mmBtu emission rate year-round because the requirement was primarily intended to address potential concerns by "downwind" states that have historically claimed that some EGUs in "upwind" areas of the Midwest do not always run their NOx controls at higher levels during the ozone season, thus contributing to transport of NOx and ozone to those states. While some Northeast states have recognized that this is not a problem in Illinois, the Agency wanted to ensure that such concern was addressed proactively going forward.

The Agency presumes the second question is asking about NOx as well rather than SO_2, since SCRs do not control SO_2. Under such presumption, the Agency believes that operation of the SCR as required by Section 225.233(e)(1)(E)(i) would achieve that proposed rate limit.

8. Also on page 4, you note the Agency considered localized impact in drafting the proposed amendments. Please explain how the Agency evaluated the localized impact at each of the affected power stations. If modeling was employed, clarify whether the modeling was based on allowable emissions or the power station's potential to emit. If modeling was based on allowable emissions, please comment on how the proposed amendments protect the public from localized impact, given that the proposal, for the most part, has no emission rate limit or mass limit for individual power stations.

The Agency evaluated the localized impact by reviewing previous modeling results performed for DRR purposes (because the Coffeen power plant had emissions that fell well below the DRR modeling threshold, that source did not need to be specifically modeled). Such modeling was based on actual emissions, per the DRR. Review of these results showed that most areas had design values well below the level where attainment of the NAAQS would be threatened. The one area that was close enough to cause concern was the area around the Joppa plant; thus, the Agency proposed a limit specifically for Joppa to ensure emissions remained below the level that would cause concern under the DRR.

It should be noted that the MPS was not originally designed or relied upon to specifically protect local air quality.

TSD & Proposed Rule

9. TSD at page 3 identifies the affected units are currently subject to fleet-wide emission rates for nitrogen oxides ("NO/') and sulfur dioxide ("SO2") in Section 225.233(e). Please provide a map showing the location of affected EGUs. Also, include the location of IEPA's air monitoring stations and the boundaries of any non-attainment areas.

It is not possible to put all of the requested information on a single map and have it be meaningful. As such, the Agency is attaching maps of the State by pollutant that

show the Dynegy plants, monitors for the particular pollutant, and any nonattainment areas for that pollutant. These maps are included as Attachment 3.

10. TSD at page 4 states, “Since the MPS regulations were promulgated, pollution control equipment has been installed on several EGUs, while others have ceased operation, in the Dynegy and Ameren MPS groups. The current MPS rule does not specifically require installation of any additional pollution control equipment.” Please clarify which of the eighteen MPS units that are currently operating have pollution control equipment installed to control SO2 and NOx. Provide a table listing each facility and unit along with the current pollution control equipment. (Similar tables were provided by petitioners in PCB 12-126 and PCB 14-10 that included a list of pollution control equipment for each facility and unit. PCB 12-126 Petition Exh. 2, PCB 14-10 Petition Exh. 6.)

Below is a table containing information for the affected units relevant to NO_x and SO_2 control.

Plant	Unit	NO_x Controls	SO_2 Controls
Baldwin	1	OFA, SCR	SDA
Baldwin	2	OFA, SCR	SDA
Baldwin	3	LNB, OFA	SDA
Havana	9	LNB, OFA, SCR	SDA
Hennepin	1	OFA	
Hennepin	2	LNB, OFA	
Coffeen	1	OFA, SCR	FGD
Coffeen	2	OFA, SCR	FGD
Duck Creek	1	LNB, SCR	FGD
E D Edwards	2	LNB, OFA	
E D Edwards	3	LNB, OFA, SCR	
Joppa	1	LNB	
Joppa	2	LNB	
Joppa	3	LNB	
Joppa	4	LNB	
Joppa	5	LNB	
Joppa	6	OFA, LNB	
Newton	1	OFA, LNB	

OFA = Overfire Air; LNB = Low NO_x Burners; SCR = Selective Catalytic Reduction; SDA = Spray Dry Absorber; FGD = Wet Flue Gas Desulfurization

11. TSD Table 4 lists “Historical Heat Input of the Affected Units” from 2010 through 2016. Please provide a trend graph for each of the units and for the total of all the units?

These graphs are included as Attachment 4.

12. TSD Table 5 lists "Historical NOx Emissions of the Affected Units" and Table 6 includes "Historical SO2 Emissions of the Affected Units". Please provide updated tables adding the following additional details:

The updated tables (a-e) and associated graphs (f) are included as Attachment 5.

a. Emission units associated with each of the facilities.

b. Base Year Heat Input (1000 mmBTU).

c. Adjusted Heat Input (1000 mmBTU).

The Agency does not understand what the Board means by Adjusted Heat Input, therefore this has not been added to the updated tables.

d. Presumptive BART (Best Available Retrofit Technology): (lbs/mmBTU) and (Tons/Year Reduction).

e. Actual annual and seasonal NOx and SO2 emissions for the period 2012 through 2016.

f. Based on these tables, please provide separate trend graphs for NOx and SO2 from 2012 through 2016 for each of the units and for the total of all the units. On each graph, please show the relationships to the respective facility's potential to emit.

g. Comment on how the actual annual NOx and SO2 mass emissions from the MPS Groups for the period 2012 through 2016 compare to the proposed combined annual NOx and SO2 emissions caps of 25,000 tons and May-September emissions cap of 11,500 tons under (e)(1)(C) and (D)?

As stated in Section 5.3 of the TSD, as a result of some of the factors discussed in Section 5.2, the utilization from these units has been relatively low in more recent years, which is reflected in lower emissions of NO_x and SO_2 in those years. However, this utilization could change in the future due to changes in the factors discussed.

13. Please also provide a graph(s) for the total of all the units showing the following relationships:

These graphs are included as Attachment 6.

a. Maximum allowable annual mass emissions under the current rule.

b. Maximum allowable annual mass emissions under the proposal.

c. Maximum allowable seasonal mass emissions under the current rule.

d. Maximum allowable seasonal mass emissions under the proposal.

e. Maximum allowable mass emissions from the Joppa Units under the current rule.

f. Maximum allowable mass emissions from the Joppa Units under the proposal.

14. TSD Table 7 lists "Regional Haze Projected NOx Emissions from the EGUs in the Current MPS Groups", and Table 8 is "Regional Haze SIP SO2 Emissions from the EGUs in the Current MPS Groups". "Projected Emissions Under Current MPS Rate (Tons)" are shown for facilities that are currently not operating, such as Vermilion 1,2; Wood River 4,5; ED Edwards 1; Hutsonville 5,6; Meredosia 1,2,3,4,5; and Newton 1,2. Please provide updated tables with the currently operating units with 2 additional columns on: "Projected Emissions Under Proposal (tons)" and "Tons/Year Reduction Under Proposal"?

These updated tables are included as Attachment 7.

15. Section 5 of the TSD addresses Environmental Impact in terms of annual and seasonal mass emissions for the proposed combined MPS Group. For individual units, the TSD refers to unit- and source-specific SO2 limits in 35 Ill. Adm. Code 214 and the federal Cross State Air Pollution Rule (CSAPR). TSD at 8. Please address the environmental impact of the proposal for rescinding the overall annual and seasonal rate-based emission limits in terms of a worst-case scenario, e.g. units operating at the maximum source-specific limits under Part 214.

The Agency is not certain exactly what the Board is asking.

Allowable emission limits, by definition, represent the worst-case scenario. Because the Agency has proposed allowable limits, even a worst-case scenario would not cause environmental impact problems. As discussed in the TSD, Illinois would still meet its goals under Regional Haze. And as discussed in response to Question 8, above, review of prior modeling showed that all areas except the Joppa area had design values well below the level where attainment of the NAAQS would be threatened, and this proposed regulation caps the Joppa emissions for that reason. Furthermore, the DRR requires that Illinois annually review areas where SO_2 emissions increase to determine if further modeling is necessary in relation to the SO_2 NAAQS. And as explained in the TSD (p. 11), the allowable emission levels under the proposed changes are lower than the allowable emission levels under the existing MPS rule, meaning the worst-case scenario under the modified MPS would have lower emissions than the worst-case scenario under the current MPS.

16. On page 12, the TSD considers a potential future scenario with the price of natural gas at historical norms that may result in increased utilization of affected EGUs. Please clarify whether this scenario is supported by any future short-term or long-term trends in natural

gas prices. Also, comment on whether utilization and emissions from EGUs would be affected by the growth in renewable energy generation in the MISO region.

Natural gas prices can fluctuate over both the short and long term due to various factors. Illinois EPA did not forecast future natural gas prices; rather, the proposed limits reflect the ability for a combined MPS Group to operate at greater utilization rates in case there is a need due to the various factors mentioned in the TSD.

It is possible that coal-fired EGU utilization could be affected by growth in renewable energy generation; however, it is more likely that more intermittent sources of generation (e.g. natural gas peaking units) would be impacted to a greater extent by growth in renewables.

17. TSD states that the proposed amendments limit the combined MPS Group to 55,000 tons per year (TPY) of SO2, 25,000 TPY of NOx, and 11,500 tons of NOx during the Ozone Season to allow for emissions that could occur from greater utilization of the affected units. TSD at 11-12. Please clarify how the Agency projected future utilization considering the declining trend in the utilization of the affected units. In this regard, did Dynegy provide any projection forecasts for heat input for these units for 2017 and beyond? If so, please submit such information into the record.

    Illinois EPA did not perform an analysis projecting future utilization of the affected units. The proposed limits reflect the possibility of greater utilization from the units without the need to curtail generation if the market calls for it. The proposed limits take into account future utilization, while also reducing allowable emissions from the units and setting a hard cap on future emissions.

18. Proposed 225.233(e)(1)(E)(i) would require existing SCRs to be operated "in accordance with good operating practices…" However, the proposed rule does not contain a similar provision for operation of a Flue Gas Desulfurization (FGD) system.

    a. In PCB 14-10, the conditions of the variance contained requirements that the FGDs be run at a minimal 98 percent efficiency on a calendar year annual average basis. Illinois Power Holdings, LLC and AmerenEnergy Median Valley Cogen, LLC, Ameren Energy Resources, LLC v. IEPA, PCB 14-10, slip op. at 103 (November 21,2013). Please comment on including a performance requirement in the proposed rule for both FGDs and SCRs that is similar to the one in the PCB 14-10 variance.

        The Agency is neutral on this point. However, it should be noted that a requirement of that stringency is not necessary to meet Regional Haze requirements or air quality standards.

    b. PCB 14-10 also contained a condition requiring IPH to burn low sulfur coal at the E.D. Edwards, Joppa, and Newton Energy Centers. *Id.* at 103. What means will Dynegy use to maintain compliance SO2 limits? Please comment on including a requirement to burn low sulfur coal at certain EGUs in the proposed rule similar to the one in the PCB 14-10 variance.

The Agency is neutral on this point. However, it should be noted that such a requirement is not necessary to meet Regional Haze requirements or air quality standards. Additionally, the current MPS does not require the use of low sulfur coal, and the Agency expects that low sulfur coal will continue to be used as a means of compliance for the proposed mass emission limits.

19. Section 225.233(e)(1)(E)(i) requires the owner or operator to minimize emissions to the extent reasonably practicable during periods in which the SCR is not operational.

a. Please explain the circumstances under which an owner or operator may not operate the SCR control system. If the shut-down is related to routine maintenance, should the rule specify a time limit for the operation of the EGU without an operational SCR system.

Possible circumstances under which the SCR would not be in operation would be during the startup and shutdown of the EGU when SCRs are generally not operated due to technological limitations related to the temperatures during these periods. From reviewing emissions data, these instances are infrequent and of a short duration. Routine maintenance of SCR controls is generally performed either while the EGU and SCR continue to operate or during a planned shutdown of the EGU itself. As such, the Agency does not believe a time limit for operation of the EGU without an operational SCR is necessary. Any and all emissions occurring while an SCR control is down must be counted toward the annual and seasonal mass emission limits as well as toward the 0.10 lb/mmBtu average emission rate during the ozone season.

b. Please describe the measures that an owner or operator may implement to minimize the emissions of NOx when the SCR system is not operational.

Minimization of emissions during an SCR outage could be achieved by limiting operation of the EGU.

20. In Section 225.233(e)(1)E)(ii), please clarify whether averaging is limited only to the seven EGUs identified in Section 225.233(e)(1)(E) or all 18 EGUs in the same MPS Group to show compliance with the proposed NOx Ozone Season average emission rate of 0.10 lb/mmBtu.

Averaging is limited to the seven EGUs identified in Section 225.233(e)(1)(E).

21. In Section 225.233(f)(2) provides the allocation amounts for EGUs in the event of transfer of EGUs.

a. Please explain how the Agency determined the proposed allocation amounts for each power station. Also, explain why the total allocation amount for SO2 and NOx is less than the proposed annual mass emissions limits. For example, the total allocation amount for SO2 (52,000 tons) is less than the proposed SO2 mass emissions limitation (55,000 tons).

A number of methodologies were considered in order to determine the allocation amounts in the event of a transfer of EGUs. The values in the proposed rule were reached with input from Dynegy, and are based upon historical emissions, utilization, and the level of control achievable at each plant. These figures were rounded to multiples of 50 or 100 for annual SO_2 and NOx, and to multiples of 5 or 10 for seasonal NOx. When these numbers were agreed upon by both the Agency and Dynegy, the Agency was not concerned that the totals did not sum to the emission limits, because in the event of the transfer of some units, this could only have an environmental benefit. Due to this rounding and estimations considering a number of variables for the plants, an exact calculation methodology is not available, but the Agency and Dynegy agreed that these values were appropriate going forward for a given plant in the event of transfer to a new owner, and the values in the proposal have no possible negative impact.

b. The allocation amounts are proposed on generating station basis rather than on EGUs. Please clarify whether transfer of ownership is assumed to include all EGUs at a power station. If not, explain how allocations are handled for transfer of individual EGUs at a power source. If necessary, revise Section 225.223(f)(2) to include allocation amounts for each EGU at the affected generation stations.

Transfer of ownership would include all EGUs at a power station, as the Agency does not expect a company to sell individual units within a facility.

c. Please comment on using these allocations as caps on mass emission limits for each facility in the proposed rule in addition to the overall cap for mass emission limits. If these allocations would not be suitable for a cap, please comment on proposing other mass emission limits on each facility, such as a cap for each facility based on the allowable emission rates under the current rule in addition to the proposed overall annual and seasonal caps.

These allocation amounts were never intended by the Agency to be used as mass emission limits for each facility. Specifying facility-by-facility emission caps would be contrary to the structure of the MPS, which has never contained facility-specific emission standards, and would hinder the operational flexibility that the MPS is intended to provide.

d. Also, comment on whether shutdown of individual EGUs at a power source or shutdown of the power source itself should also result in reduction of the Group's mass emission limits for SO2 and NOx.

If an EGU shuts down, the power that had been generated by that EGU will likely be generated from elsewhere, meaning the emissions will be coming from another EGU. As such, shutdown of an EGU does not necessarily mean the fleet-wide mass emission limit should be reduced, especially since, as previously noted, such reduction is not necessary to meet Regional Haze requirements or air quality standards.

22. In Section 225.233(g), please explain why an EGUs would no longer need to obtain a construction permit for any new or modified air pollution control equipment for mercury, NOx, or SO2?

As indicated in the Statement of Reasons, since this provision only applied during the first year of the MPS, it is now obsolete. Subsection (g), notwithstanding 35 Ill. Adm. Code 201.146(hhh), requires the owner or operator of an EGUto obtain a construction permit for any new or modified air pollution control equipment until the EGU has complied with the applicable mercury ("Hg"), NOx, or SO_2 emission standards for 12 months. Both the Ameren and Dynegy MPS Groups have complied with the applicable Hg, NOx, and SO_2 emissions standards under Section 225.233 for well over 12 months. Further, EGUs must still meet the criteria under Section 201.146(hhh), if they wish to utilize that permitting exemption.

23. In Section 225.233(i), even though compliance is proposed on a mass basis, could reporting of actual emissions also include emissions on a rate basis? Would there be any additional expense or monitoring equipment be required to do this beyond administrative costs?

Yes, though the Illinois EPA does not believe there would be a purpose for such reporting. To the Agency's knowledge, there would not be any additional expense or monitoring equipment required. Additionally, NOx emission rates are reported to USEPA, and the information to determine SO_2 emission rates (mass emissions and heat input) is also reported to USEPA. All of this information is available to the public from USEPA'S Air Markets Program Data website: https://ampd.epa.gov/ampd/.

Questions from the Illinois Attorney General's Office

1. At pages 2 and 4 of Rory Davis's testimony, he states that Illinois EPA's proposed amendments will reduce the overall allowable emissions from the MPS Groups. Does Illinois EPA agree that the MPS should be amended only if amendments offer a substantial environmental benefit relative to the MPS as currently drafted?

   No. Not every rulemaking offers an environmental benefit, and it is not clear what is meant by the term "substantial" in this context.

2. At page 2 of Rory Davis's testimony, he states that one of the purposes of this rulemaking is to provide Dynegy with "operational flexibility."

   a. What is Illinois EPA's understanding of the term "operational flexibility"?

      Operational flexibility, in the context of this rulemaking, refers to the ability for Dynegy to meet fleet-wide emission limits that include all of its affected units in both MPS Groups, and to operate those units as they are called upon by the market without being forced to operate certain units strictly for the purpose of meeting a fleet-wide rate-based limit.

   b. In what way(s) would Dynegy receive greater "flexibility" as a result of Illinois EPA's proposed amendments?

      A fleet-wide mass emission limit, as proposed, would potentially allow the owner of the affected units to operate the units as they are called upon in the market based upon the cost of generation at those units and the demand at the time. The proposed amendments also combine both MPS Groups into one Group with all units subject to the same limits for each pollutant.

   c. In what way would Illinois EPA's proposed amendments allow Dynegy to change its current operations?

      Dynegy may choose to not operate more costly units at times that are financially disadvantageous strictly for the purpose of meeting a fleet-wide rate-based limit.

   d. Why is Dynegy's "operational flexibility" a concern for the Illinois EPA?

      It is not atypical for a source to approach the Illinois EPA or the Board about being able to operate in an economically viable manner, and rules have been modified or other regulatory steps have been taken in the past to address such concerns.

3. At page 4 of Rory Davis's testimony, he states that Illinois EPA's amendments "have been proposed to provide operational flexibility that Dynegy has stated is necessary . . . ."

   a. When and where has Dynegy stated that "operational flexibility . . . is necessary"?

      Dynegy has stated such to the Illinois EPA in conversations and meetings, for example as discussed in Section 2.4 of the TSD.

   b. Did Dynegy provide Illinois EPA with any documents or communications explaining Dynegy's meaning of the term "operational flexibility" and its necessity? If so, the People request that Illinois EPA supplement the record with any such documents or communications, so that all of the participants in the rulemaking can evaluate Dynegy's claims.

      The term appears in the documents "Support for Revising the IMR and MPS," dated 1/20/2017, and "Follow up information," dated 2/21/2017, in Attachments 8 and 9, respectively.

4. The Technical Support Document states at page 5 that:

   "Dynegy informed the Agency that in recent years the structure of the current MPS has led to the company operating some units at a financial loss in order to operate other units in their MPS Groups."

   a. Did Dynegy identify for Illinois EPA which of its units had been operated at a financial loss, to facilitate the operation of which of its other units?

      Dynegy used the Coffeen plant as an example in discussions, though that is not necessarily the only such unit.

   b. What steps did Illinois EPA take to verify the information provided by Dynegy?

      A review of the relative capacities of the units in the two MPS Groups and the emission rates at which those units regularly operate indicates that well controlled units in each fleet would need to operate in order for either current group to meet current MPS limits. It is also reasonable to assume that those controlled units would be more costly to run.

   c. Did Dynegy provide Illinois EPA with any documents or communications to substantiate the information it provided? If so, the People request that Illinois EPA supplement the record with any such documents or communications, so that all of the participants in the rulemaking can evaluate Dynegy's claims.

Dynegy did not provide any such documents or communications to the Illinois EPA.

5. The Technical Support Document (TSD) states at page 6 that:

"While the EGUs affected by this rulemaking are currently meeting their fleet-wide average emission rates, the combination of these MPS Groups under the proposed mass emission limits will allow greater operational flexibility as well as regulatory certainty moving forward as scenarios involving the individual sources may arise."

a. What is Illinois EPA's understanding of the term "regulatory certainty" generally and as it applies to Dynegy's MPS units? Please explain the bases for your answer.

Circumstances have arisen since the inception of the MPS that have precipitated regulatory relief from the Board. The proposed mass emission limitations reduce the likelihood that similar relief will be needed by Dynegy moving forward, as they provide greater operational flexibility than under the current rate-based standards.

b. Did the concept of switching to a mass-based emission limit originate from Dynegy or Illinois EPA? If it was Dynegy's idea, why did Illinois EPA agree to propose the change? Please explain the bases for your answer.

The idea originated with Dynegy. The Agency's reasons for proposing the changes are set forth in detail in the Agency's Statement of Reasons and Technical Support Document, filed with this rulemaking proposal.

c. How does moving to a mass-based emission limit provide additional "regulatory certainty" when Dynegy already has "regulatory certainty" through the current rate-based limits under the MPS?

See the Agency's response to Questions 5a and 5d.

d. What "scenarios" in the TSD statement quoted above is Illinois EPA referring to?

One example might be a prolonged outage at one or more relatively well-controlled units that would limit utilization at other units that may be called upon to operate, as they would not be able to due to the MPS fleet-wide emission rate. Another scenario would be a very cold period in a winter that leads to natural gas supply issues for gas-fired EGUs. This could drive greater utilization of all units, and would likely come at the end or beginning of a compliance period. This could make some units unavailable late in a year due to MPS concerns, or it could make compliance difficult for the rest of a period if the issue happened early in the year.

e. Why does Illinois EPA believe there is a need to switch the MPS units to a mass-based emission standard, when all of the pollution reductions under the MPS to date have occurred under the current rate-based standards? Please explain the bases for your answer.

There have indeed been great reductions in SO_2 and NOx emissions since the adoption of the MPS. These reductions have come from additional pollution control equipment, the retirement of a number of coal-fired EGUs, and changes in the energy sector. The proposed mass emission limits will set hard caps on future emissions that are lower than current allowable MPS emission levels for each pollutant, and will provide flexibility to continue to operate those units in an economically viable manner while maintaining air quality in Illinois.

6. On page 1 of Rory Davis's testimony, he states that one of the purposes of the amendments is also to "simplify compliance with fleet-wide emission limits now that all units in both current MPS Groups are owned by the same company."

a. Did Illinois EPA consider simply combining the current MPS Groups into one group, under fleet-wide emission rates? Please explain the rationale for Illinois EPA's position to move to an exclusively mass-based standard.

A combined MPS Group under a single new rate-based limit was considered; however, this would not have provided the operational flexibility to the Group that was referenced in the TSD, as in that situation, Dynegy could still find itself needing to operate certain units strictly for the purposes of meeting fleet-wide average emission rates.

b. Would Illinois EPA consider employing both emission rates and mass-based caps for the MPS units? Please explain the bases for your answer.

The Agency does not believe it is necessary to employ fleet-wide annual standards in terms of both mass and emission rate. One of the main reasons for the proposal, operational flexibility, would not be achieved by layering an emission rate on top of the proposed mass emission limits.

7. On page 3 of Rory Davis's testimony, he states that the units affected by this rulemaking are subject to the Cross-State Air Pollution Rule (CSAPR).

a. Has Illinois EPA considered how its proposed amendments would affect the number of allowances that Dynegy would be permitted to sell or trade under Section 225.233(f)?

Yes.

b. If so, what effect would Illinois EPA's proposed amendments have on the number of allowances that Dynegy would be permitted to sell or trade under Section 225.233(f)?

The number of allowances would fluctuate with the market in a similar fashion as it does currently. For that reason, any conclusions would be highly speculative. The proposed amendments may allow Dynegy to sell or trade more allowances than allowed currently.

8. Regarding proposed requirements related to NOx emissions, including a proposed maximum emission rate for some units, applicable only during ozone season, Rory Davis states at page 4 of his testimony:

"These requirements were included to ensure that these units [with selective catalytic reduction ("SCR") control devices] would continue to operate existing controls and continue to operate with emission rates that are considered well controlled during the ozone season."

a. Does Illinois EPA not believe it would be important for **all** of Dynegy's units to be operated at emission rates that are "considered well controlled" for both NOx and SO2, year-round—not just **some** units, for NOx, during part of the year? Please explain the rationale for your answer.

As discussed in response to the Board's Question 7, this proposed requirement is intended to address potential concerns by "downwind" states regarding ozone season NOx emissions. Thus, the additional requirement was placed on SCR units above and beyond the other requirements.

b. Does Illinois EPA have any bases to conclude that Dynegy's plants are not currently continuously operating all installed SCR control devices? If so, please explain any such bases.

No. Generally, EGUs equipped with SCRs have an economic incentive to operate the controls rather than purchase allowances for NOx emissions in trading programs such as CSAPR.

9. The Technical Support Document states at page 5 that permits to operate the Meredosia, Hutsonville, Vermillion, and Wood River facilities have been withdrawn. Does this mean that electricity generation through coal combustion has permanently ceased at these facilities? Please explain the rationale for your answer.

Yes. Without such permits, the sources cannot legally operate.

10. On September 27, 2017, the *Chicago Tribune* reported that "Alec Messina, director of the Illinois Environmental Protection Agency, said the goal [of Illinois EPA's proposed amendments] is to keep the financially struggling coal plants open by giving Houston-

based Dynegy more flexibility to operate individual generating units, several of which are not equipped with modern pollution controls."1 Does Illinois EPA agree that a goal of this rulemaking is to keep plants within the MPS Groups open? Please explain the rationale for your answer.

First, the Agency notes that the quote in question is from the Tribune article, not Director Messina. The Agency does not agree with the Tribune's characterization of the Director's statements. The proposed amendments are intended to provide operational flexibility, while still maintaining air quality in Illinois. The Agency's focus was not preventing the closure of additional EGUs in Illinois.

11. Illinois EPA has stated that the proposed rule will reduce the overall allowable SO2 emissions from the MPS Groups. In the Technical Support Document (TSD), Illinois EPA sets forth a table for allowable SO2 emissions. In Table 1, the Illinois EPA states that the total allowable mass-based SO2 emissions for all of the MPS units are 66,354 tons/year. However, Dynegy has mothballed Baldwin 3 (October 17, 2016) with 5,326 allowable tons/year, and it proposes to mothball Baldwin 1 (mid to late 2018)2 with 5,359 allowable tons/year.

a. In determining the SO2 mass-based emission cap for the combined MPS units, and the purported allowable emission reductions obtained by switching to a mass-based standard, did Illinois EPA account for the mothballing of two of Dynegy's cleanest plants: 1) Baldwin 3 (October 17, 2016) with 5,326 allowable tons/year, and 2) Baldwin 1 (Dynegy proposes mothballing in mid to late 2018) with 5,359 allowable tons/year? Please explain why or why not.

The Agency included these units in the proposal because the units are still permitted to operate. Baldwin 3 could restart and operate at any time, and Baldwin 1 is not required to cease operation in 2018.

b. Isn't it true that, with Baldwin 1 and 3 mothballed, the total allowable mass-based SO2 emissions in Table 1 would actually be 66,354 - 5,326 (Baldwin 1) - 5,359 (Baldwin 3) = 55,669 tons/year of SO2?

The "mothballing" of one or more units would not impact the allowable emissions of those units, as they are still allowed to operate and emit under their permits. A permanent shutdown requires the surrender of an operating permit for an emission unit.

c. If the allowable mass-based emissions of SO2 are actually 55,669 tons/year, with a proposed cap of 55,000 tons, aren't Illinois EPA's purported reductions of allowable SO2 emissions overstated? Please explain the bases for your answer.

As noted in the Agency's response to Questions 11.a and b, the allowable mass-based emissions of SO_2 are not actually 55,669 tons/year. Therefore, the answer is no.

12. Illinois EPA has stated that the proposed rule will reduce the overall allowable NOx emissions from the MPS Groups. In the TSD, Illinois EPA sets forth a table for allowable NOx emissions. In Table 2, the total allowable mass-based NOx emissions for all of the MPS units are 32,841 tons/year. However, Dynegy has mothballed Baldwin 3 (October 17, 2016) with 2,803 allowable tons/year, and it proposes to mothball Baldwin 1 (mid to late 2018) with 2,820 allowable tons/year.

a. In determining the NOx mass-based emission cap for the combined MPS units, and the purported allowable emission reductions obtained by switching to a mass-based standard, did Illinois EPA account for the mothballing of two of Dynegy's cleanest plants: 1) Baldwin 3 (October 17, 2016) with 2,803 allowable tons/year, and 2) Baldwin 1 (Dynegy proposes mothballing in mid to late 2018) with 2,820 allowable tons/year? Please explain why or why not.

See response to Question 11a.

b. Isn't it true that, with Baldwin 1 and 3 mothballed, the total allowable mass-based NOx emissions in Table 2 would actually be 32,841 - 2,803 (Baldwin 1) - 2,820 (Baldwin 3) = 27,218 tons/year of NOx?

See response to Question 11b.

c. If the allowable mass-based emissions of NOx are actually 27,218 tons/year, with a proposed cap of 25,000 tons/year, aren't Illinois EPA's purported reductions of allowable NOx emissions overstated? Please explain the bases for your answer.

As noted in the Agency's response to Questions 11a and b, the allowable mass-based emissions of NOx are not actually 27,218 tons/year. Therefore, the answer is no.

Questions from the Environmental Groups

Many of the Environmental Groups' questions are either duplicative or vary only slightly from one another. Further, the questions are broken down into numerous subquestions, and subquestions to those subquestions. Accordingly, in some instances the Agency did not respond to each individual subquestion, rather the Agency provided a narrative that responds to applicable portions of the question.

I. Basis for the Rulemaking

1. In the Illinois Environmental Protection Agency's ("IEPA's") Technical Support Document ("TSD") you state "the EGUs affected by this rulemaking are currently meeting their fleetwide average emission rates." IEPA, *Technical Support Document for Proposed Rule Amendments for Multi-Pollutant Standards Electrical Generation Units, AQPSTR 17-06* at 6 (Sept. 2017).

    a. If the affected EGUs are meeting the requirements of the rule, why is a revision justified? Why is it necessary?

    In accordance with the Board's regulations, the Agency's justifications for the rulemaking are set forth in its Statement of Reasons and Technical Support Document.

2. For this rulemaking you state "Dynegy informed the Agency that in recent years the structure of the current [Multi-Pollutant Standards] ("MPS")] has led to the company operating some units at a financial loss in order to operate other units in their MPS Groups. This leads to distortions in the power market, grid inefficiencies, and possibly increased overall emissions." TSD at 5.

    a. What exactly is meant by "financial loss" in this context?

    A financial loss in this context would mean operating a unit when the cost of generating electricity at a given EGU is greater than the proceeds from the sale of that electricity.

        i. How is "financial loss" calculated?

        The Agency's understanding is that a loss would be calculated by subtracting the cost of generation from the proceeds of the sale, resulting in a negative number.

        ii. Did Dynegy make any demonstration to IEPA that the structure of the current MPS has led the company to operate units at Baldwin, Coffeen, Duck Creek, Edwards, Havana, Hennepin, Joppa, or Newton ("Proposed MPS Group") at a financial loss?

It is unclear what is meant by a "demonstration." The Agency did not receive any documentation from Dynegy on this point. The Agency spoke with representatives of Dynegy and determined that their statements were consistent with the Agency's understanding of Dynegy's compliance strategy with regard to the MPS. Further, a review of the relative capacities of the units in the two MPS Groups and the emission rates that those units regularly operate at indicates that well controlled units in each fleet would need to operate in order for either current group to meet current MPS limits. It is also reasonable to assume that those controlled units would be more costly to run.

1. If yes, how did Dynegy make this demonstration?

2. If yes, can you please provide a written copy of this demonstration?

iii. Did IEPA conduct any independent analysis to see if the structure of the current MPS has led the company to operate units in the Proposed MPS Group at a financial loss?

See response to Question I.2.a.ii above.

1. If yes, how was this analysis conducted?

2. If yes, can you please share your findings and calculations?

3. If no, why did IEPA not conduct an independent analysis?

iv. Which units were/are being run at a financial loss?

Dynegy used the Coffeen plant as an example in discussions, though that is not necessarily the only such unit.

v. Why does IEPA need to resolve the concern of Dynegy's operating "some units" at a financial loss? How is that a part of IEPA's mission?

It is not atypical for a source to approach the Illinois EPA or the Board about being able to operate in an economically viable manner, and rules have been modified or other regulatory steps have been taken in the past to address such concerns.

The Illinois EPA's website, in the "About Us" section, notes, "The mission of the Illinois EPA is to safeguard environmental quality, consistent with the social and economic needs of the State, so as to protect health, welfare, property and the quality of life." This

proposal safeguards environmental quality, protects health and welfare, and is also consistent with the economic needs of the State.

vi. Did IEPA verify that operating "some units" at a financial loss meant that Dynegy was operating the whole Illinois fleet at a financial loss? What about the company as a whole?

This question incorrectly presumes that Dynegy has made such a representation and seems to suggest that the Agency has similarly made such a representation; no representation to that effect was made to or by the Illinois EPA in relation to this rulemaking. Dynegy did not offer financial information to the Agency indicating that its Illinois fleet was operating at a loss or that the company as a whole was operating at a loss.

b. What exactly is meant by "distortions in the power market" in this context?

When an EGU is operated for the sole purpose of bringing down a fleet-wide average, the generation from that unit could offset generation at another coal-fired EGU, or it could offset generation of intermittent natural gas-fired generation, or could offset generation of any type that would be more suitable due to its geographical location.

i. Can you please provide examples of distortions in the power market that have resulted from the current MPS?

The Agency does not have any specific examples of these situations, however, they would naturally arise if certain coal-fired units are operated solely for the purpose of environmental compliance.

ii. Did Dynegy make any demonstration to IEPA that the structure of the current MPS has led to distortions in the power market?

It is unclear what is meant by a "demonstration." The Agency did not receive any documentation from Dynegy on this point. The Agency based its analysis on its understanding of how generation is dispatched in the region.

1. If yes, how did Dynegy make this demonstration?

2. If yes, can you please share a written copy of this demonstration?

iii. Did IEPA conduct any independent analysis to see if the structure of the current MPS has led to distortions in the power market?

See response to Question I.2.b.ii above.

1. If yes, how was this analysis conducted?

2. If yes, can you please share your findings and calculations?

3. If no, why did IEPA not conduct an independent analysis?

c. What exactly is meant by "grid inefficiencies" in this context?

i. Can you please provide examples of grid inefficiencies that have resulted from the current MPS?

Grid inefficiency in this context would have a similar meaning to answers in previous questions. Electricity is generally dispatched on a lowest cost basis. When units are operated for the sole purpose of complying with a rate-based limit, this can prevent operation of units that may be more appropriate geographically or would normally be operated at the market price.

ii. Did Dynegy make any demonstration to IEPA that the structure of the current MPS has led to grid inefficiencies?

It is unclear what is meant by a "demonstration." The Agency did not receive any documentation from Dynegy on this point. The Agency based its analysis on its understanding of how generation is dispatched in the region.

1. If yes, how did Dynegy make this demonstration?

2. If yes, can you please share a written copy of this demonstration?

iii. Did IEPA conduct any independent analysis to see if the structure of the current MPS has led to grid inefficiencies?

See response to Question I.2.c.ii above.

1. If yes, how was this analysis conducted?

2. If yes, can you please share your findings and calculations?

3. If no, why did IEPA not conduct an independent analysis?

d. IEPA stated that the structure of the current MPS "possibly" could lead to increased overall emissions.

i. Can the agency confirm whether this in fact leads to increased emissions? If not, why not?

No, the Agency based its statements on its understanding of the way generation is dispatched in the region.

ii. Can you please provide examples of or explain how the current MPS may have led to increased overall emissions?

In a given day, if coal-fired units are forced to operate, this could displace generation from cleaner units (like natural gas units) that would have operated instead.

iii. Did Dynegy make any demonstration to IEPA that the structure of the current MPS has led to increased overall emissions?

It is unclear what is meant by a "demonstration." The Agency did not receive any documentation from Dynegy on this point. The Agency based its analysis on its understanding of how generation is dispatched in the region.

1. If yes, how did Dynegy make this demonstration?

2. If yes, can you please provide a written copy of this demonstration?

iv. Did IEPA conduct any independent analysis to see if the structure of the current MPS has led to increased overall emissions?

See response to Question I.2.d.iii above.

1. If yes, how was this analysis conducted?

2. If yes, can you please share your findings and calculations?

3. If no, why did IEPA not conduct an independent analysis?

v. Is it correct that if there are in fact no increased overall emissions as a result of the revisions to the MPS, there would also be no environmental benefit to those revisions? If this is not correct, what would be the environmental benefit?

The Agency does not understand this question and thus cannot answer it.

vi. Assume that the scrubbed units are being operated in order to operate units with higher emission rates and bring down the fleetwide average to achieve the MPS rate as indicated in the TSD. *See* TSD at 5. If the electricity generated by the units with lower emission rates is being sold and these units are displacing some MWs from other Dynegy units (or displacing some capacity from other higher-emitting Dynegy units), isn't the MPS effectively bringing down the fleetwide average? And isn't the MPS in this scenario operating as intended—to bring down the fleetwide average where market incentives alone would not do so?

The Agency finds this question confusing. Under the scenarios above, the MPS would not be "bringing down the fleetwide average," the MPS establishes a fleet-wide emission rate standard.

Putting that aside, the origin of the MWs being displaced in the scenarios above is unknown. Depending on the day and the market, it could be displacing electricity generated by natural gas plants, by nuclear power plants, by EGUs outside of Illinois, or by other Dynegy plants.

3. Is it or was it IEPA's understanding that some Dynegy/IPH plants were being run exclusively for the purpose of bringing down the fleetwide average emissions rate (above and beyond demand not just for the plant but for the fleet) and achieving the MPS average? If so:

The Agency's understanding is that, in some instances, units are being operated solely in order to lower a fleet's average emission rate. In other cases, such as during periods of high electrical demand, the units operate as a part of normal fleet operations.

a. Is/was it IEPA's understanding that this is/was causing excess/unnecessary emissions? If so:

See the Agency's response to questions in Section I.2.

i. How is/was IEPA aware of this?

ii. Did IEPA receive any documentation from Dynegy about this happening?

iii. Did IEPA conduct any independent analysis to determine whether this was happening?

b. Is/was it IEPA's understanding that capacity is/was not being used/sold into the power market, thus is/was not displacing other MWs? If so:

No, that is not the Agency's understanding.

i. How is/was IEPA aware of this?

ii. Did IEPA receive any documentation from Dynegy about this happening?

iii. Did IEPA conduct any independent analysis to determine whether this was happening?

4. Is/was it IEPA's understanding that scrubbed units in the proposed MPS group have been operated when the power from those units could not be and was not sold on the market?

No, that is not the Agency's understanding.

5. Is/was it IEPA's understanding that scrubbed units in the Proposed MPS Group have displaced other Dynegy sources when operated to bring down the average?

The origin of the MWs being displaced is unknown. Depending on the day and the market, it could be displacing electricity generated by natural gas plants, by nuclear power plants, by EGUs outside of Illinois, or by other Dynegy plants.

6. In your testimony, you state that the proposed rule will "simplify compliance." *Testimony of Rory Davis* at 1 (Dec. 11, 2017) ("Davis Testimony").

a. What do you mean by "simplify compliance?"

The TSD states, "The combination of the two MPS Groups is intended to simplify compliance… now that all units in both current MPS Groups are owned by [Dynegy]." The Agency's responses to the remaining portions of this Question 6, therefore, pertain only to the Agency's proposal to combine the two MPS Groups.

b. How does this proposed rule simplify compliance?

The proposed amendments simplify what is necessary to demonstrate compliance by combining the two MPS groups into one group, and by setting one emission limit for the combined Group for each pollutant.

c. Why is it necessary to simplify compliance with a rule that has been in place for more than ten years?

Dynegy, in recent years, has acquired all units currently subject to the MPS. It was logical to combine the two Groups during the rulemaking process, but this simplification was not the only purpose of the rulemaking as a whole.

7. In your testimony, you state that the amendments "have been proposed to provide operational flexibility that Dynegy has stated is necessary due to changes in the

electricity market and its EGU fleet since the original MPS was promulgated." Davis Testimony at 4.

a. What exactly do you mean by "operational flexibility?"

Operational flexibility, in the context of this rulemaking, refers to the ability for Dynegy to meet fleet-wide emission limits that include all of its affected units in both MPS Groups, and to operate those units as they are called upon by the market without being forced to operate certain units strictly for the purpose of meeting a fleet-wide rate-based limit.

b. Did IEPA request any analyses and modeling to demonstrate this operational flexibility was necessary? If no, why not?

No, and it is not clear what kind of modeling would be used to make such a demonstration.

c. Did Dynegy provide any analyses and modeling to demonstrate this operational flexibility was necessary? If so, can you please provide this information?

No, and it is not clear what kind of modeling would be used to make such a demonstration.

d. Is it IEPA's understanding that operational flexibility for Dynegy would entail operating its pollution control equipment less (either operating a unit without its pollution control equipment or operating a unit with pollution control equipment less)?

It is not the Agency's understanding that this would entail "operating its pollution control equipment less" on a given unit, but it possibly could entail operating units with that equipment installed less.

8. In your testimony you state that "the proposed amendments require affected units that currently have selective catalytic reduction [("SCR")] control devices to operate those controls at all times when the units are in operation." Davis testimony at 4.

a. What is the origin and/or regulatory basis of that requirement?

Transport of NOx emissions remains an issue outside of the months that the Agency has defined as the ozone season for the purposes of this rulemaking (just not as great an issue as during the ozone season). This requirement is intended to address this issue.

b. Why is there not a parallel requirement for scrubbers?

SO_2 does not cause transport problems in the same manner as NOx does.

c. Your testimony states this SCR requirement is in part "To ensure that these units would continue to operate existing controls." *Id*.

i. Why does this goal not apply to existing controls in the form of scrubbers?

As stated above, SO_2 does not cause transport problems in the same manner as NOx does.

ii. The phrase "continue to operate with emission rates that are considered well controlled" is referring to a rate based emission rate, correct? Not an annual tonnage, right?

Yes, the 0.10 lb/mmBtu rate.

iii. Why does this rationale not apply to sulfur dioxide ("SO2") emissions rates on units with scrubbers?

Because SO_2 is a different type of pollutant, as explained above.

9. Is it your understanding that each MPS unit is subject to multiple nitrogen oxides ("NOx") and SO2 emission standards?

Yes, see Attachment 2.

a. What are the relevant permit limits for each of the referenced emissions standards for each plant in the proposed combined MPS group? Please indicate whether each is hourly or annual.

See Attachment 2.

b. If there are multiple emissions standards for NOx and SO_2 for each MPS unit, why are there redundancies?

Some of the limits that apply are hourly, some of the limits apply on a daily, monthly, or annual basis, and some like CSAPR require only that an owner of a unit hold an adequate number of emission allowances to cover a given time period. Also, some of the limits are relatively old, but still apply, and others (like the consent decree limits) are newer and more stringent than limits from other State and federal regulations.

c. If IEPA's proposed revisions to the MPS rules are adopted, would any of these redundancies be eliminated?

No, these limits would all still apply.

i. If not, how is this consistent with the MPS statement of reasons?

The Agency is uncertain what part of the Statement of Reasons this question suggests would be inconsistent with these answers.

II. Mass-based vs. Rate-based Emissions Limits

1. In your testimony you state: "The amendments to change fleet-wide rate-based emission standards to mass-based emission limits is intended to provide Dynegy operational flexibility and regulatory certainty moving forward while also reducing the overall allowable emissions from the MPS group." Davis Testimony at 2.

In this context, the Agency's use of the term "regulatory certainty" was intended to address the fact that circumstances have arisen since the inception of the MPS that have precipitated regulatory relief from the Board. The proposed mass emission limitations reduce the likelihood that similar relief will be needed by Dynegy moving forward, as they provide greater operational flexibility than under the current rate-based standards.

a. Can IEPA explain what regulatory uncertainty Dynegy is experiencing?

b. How is an unchanging rate-based limit (whether it is .19 or .23 lb/MMBtu SO_2) causing regulatory uncertainty?

c. Do mass-based emissions limits provide regulatory certainty? If so, how so?

d. Do fleet-wide rate-based limits provide less regulatory certainty than mass-based limits? If so, how?

e. Why did IEPA propose and select a fleetwide rate-based emissions level—as opposed to a mass-based level—in the original MPS?

The original MPS was negotiated with stakeholders, including industry and environmental groups, over 10 years ago. The Agency's witnesses do not recall all of the details of those negotiations.

2. What was the benefit of the original fleetwide rate-based emissions limit used in the MPS?

See response to Question II.1.e.

3. With the change to a mass-based (fleetwide except for Joppa) emissions limit:

a. Is it possible for a plant to generate less electricity than it did for the same period of time under the previous fleetwide rate-based limit, but then emit at a higher rate-based emission level and have the same annual emissions?

The Agency does not understand this question and thus cannot answer it.

b. Is it possible for a plant to operate for fewer hours than it did under the previous fleetwide rate-based limit, but then emit at a higher rate-based emission level and have the same annual emissions?

The Agency does not understand this question and thus cannot answer it.

c. Is it possible for a scrubbed plant to operate less and not use its scrubber, yet have the same annual emissions than it does under the current rate-based standard?

The Agency does not understand this question and thus cannot answer it.

4. Would the proposed annual mass-based limit allow Dynegy to:

a. Use its pollution controls less than it does under the current MPS regulations?

The current MPS does not dictate how Dynegy must use its controls. There are a number of variables that affect which units are operated and the way controls are operated.

b. Run its scrubbers less than it does under the current MPS regulations?

The current MPS does not dictate how Dynegy must use its controls. There are a number of variables that affect which units are operated and the way controls are operated.

c. Operate its pollution controls less efficiently than it does under the current MPS regulations?

The current MPS does not dictate how Dynegy must use its controls. There are a number of variables that affect which units are operated and the way controls are operated.

5. Why did IEPA select 55,000 tons as the mass-based emission cap for SO2?

Dynegy had originally proposed higher limits, but the Agency proceeded with lower limits to ensure the allowable emissions would be low enough to maintain Illinois' Regional Haze SIP requirements.

a. Can you please provide the analysis that led to this selection?

As stated in the TSD and in other answers given to pre-filed questions, the limits reflect a reduction in allowable emissions and maintain commitments of the State in its Regional Haze SIP submittals.

6. Did IEPA ever consider any mass-based emissions caps for SO2 lower than 55,000 tons? If so:

   a. What were these limits?

      The Agency considered limits in a range between 44,000 and 65,000 tons per year.

   b. Why did IEPA initially consider these limits?

      The Agency was considering a range of limits based on discussions with Dynegy.

   c. Why did IEPA choose not to use these limits?

      Again, the proposed limits are the result of negotiations between the Agency and Dynegy in discussions prior to proposal.

7. Why did IEPA select 25,000 tons as the mass-based emission cap for nitrogen oxides ("NOx")?

   Dynegy had originally proposed higher limits, but the Agency negotiated lower limits. This limit is also sufficient to reduce allowable emissions and to continue to meet the State's Regional Haze commitments.

   a. Can you please provide the analysis that led to this selection?

      As stated in the TSD and in other answers given to pre-filed questions, the limits reflect a reduction in allowable emissions and maintain commitments of the State in its Regional Haze SIP submittals.

8. Did IEPA ever consider any mass-based emissions caps for NOx lower than lower than 25,000 tons? If so:

   a. What were these limits?

      The Agency considered limits in a range between approximately 23,000 and 26,000 tons per year.

   b. Why did IEPA initially consider these limits?

      The Agency was considering a range of limits based on discussions with Dynegy.

c. Why did IEPA choose not to use these limits?

Again, the proposed limits are the result of negotiations between the Agency and Dynegy in discussions prior to proposal.

9. Is it IEPA's understanding that plants may be less expensive to operate with their scrubbers turned off?

Yes, it may be less expensive to operate units without scrubbers, but the Agency is not certain what "turned off" means with regard to the particular controls at the Dynegy units. The Agency does not believe that the Dynegy units with scrubbers will operate without control. At the Baldwin and Havana units, Dynegy is required by federal consent decree to operate controls, and the controls at Coffeen and Duck Creek units (wet FGD) are a type of control that cannot easily be bypassed.

10. Has Dynegy stated to IEPA that it may operate its scrubbers less for units in the Proposed MPS Group under this new rule?

No.

a. If so, did Dynegy provide any justification for why it may operate its scrubbers less under this new rule?

i. What was this justification?

ii. Does IEPA agree with this justification?

11. Has IEPA considered whether under the proposed MPS revisions Dynegy may operate any of its scrubbed units in the Proposed MPS Group without running their scrubbers?

Yes.

a. Would IEPA have any concerns if Dynegy were to do so? If not, why not?

Yes, which is why the Agency discussed this topic with representatives of Dynegy, who conveyed that they had no intention of changing their operations in such a manner. Also, see response to Question II.9, above.

12. Has Dynegy stated to IEPA that it may retire or mothball its units with scrubbers in the Proposed MPS Group under this new rule?

No.

a. If so, did Dynegy provide any justification for why it may retire or mothball its units with scrubbers under this new rule?

i. What was this justification?

ii. Does IEPA agree with this justification?

13. Has IEPA considered whether under the proposed MPS revisions Dynegy may retire or mothball units with scrubbers in the Proposed MPS Group?

Yes.

a. Would IEPA have any concerns if Dynegy were to do so? If not, why not?

No. The emissions cap at the proposed level ensures that emissions remain below those that are necessary to meet the State's Regional Haze obligations, and removal of certain units would not affect that level.

b. Has IEPA considered the implications that this might have for local air quality? If so, can you please provide a copy of any analyses and conclusions on this matter?

The Agency did not analyze scenarios specifically involving local air quality impacts from the mothballing or retirement of units. Efforts that the Agency undertook to analyze local air quality impacts of the proposal are discussed in response to Board Question 8. Additionally, the MPS has never been relied upon to address localized air quality issues.

14. In Table 6 of the TSD, you indicated several yearly decreases in SO2 emissions at the Baldwin and Havana plants. *See* TSD at 9.

a. Can you please confirm that the three entries for Baldwin are for Units 1, 2, and 3 in ascending order?

That is correct. It can be assumed that other plants with multiple units are listed in numerical order. The omission of a column with unit numbers was unintentional.

b. In the first row for Baldwin, there was a decrease in emissions from 2011 to 2012; in the second row for Baldwin, there was a decrease in emissions from 2012 to 2013; in the third row for Baldwin, there was a decrease in emissions from 2010 to 2011; and in the entry for Havana, there was a decrease in emissions from 2012 to 2013.

i. Can IEPA explain the major factors that contributed to these decreases in emissions?

These reductions are likely the result of additional controls installed that were required by a federal consent decree.

ii. Is one of the factors that contributed to these decreases in emissions the installation of scrubbers?

Yes.

iii. If the MPS regulations are revised to eliminate a rate-based emission limit, could Dynegy operate one or more of these units with the scrubbers turned off?

No. The referenced units are required by a consent decree to operate at emission rates of less than 0.100 lb/mmBtu for SO_2.

iv. Has IEPA considered that Dynegy may be incentivized to operate its units without scrubbers if the rate-based fleetwide limits are removed?

For the units referenced above, that scenario is not possible because, as stated, the units are required by a consent decree to operate at the referenced emission levels.

1. If so, and in light of the incentives, how did IEPA still consider the revision to deliver an environmental benefit?

a. Can IEPA justify this environmental benefit in terms other than annual allowable emissions?

b. Can IEPA calculate or identify this benefit in rate-based lbs/mmBtu terms?

15. Has IEPA calculated the highest possible fleetwide rate-based emissions rates in lbs/MMBtu under its proposed revision to the MPS? If so:

No, there are too many variables to attempt to make such a calculation.

a. What is the highest possible rate?

b. Can you please share these calculations?

16. Is true that under IEPA's proposal, the more that units in the MPS group retire or are mothballed (or the less the units run), the higher the rate of emissions for the remaining units could go in lb/mmBtu?

If there were no other limits that applied, then theoretically, yes. But collectively, the EGUs are still restricted by other State and federal requirements. Also, it is unlikely that emission rates at uncontrolled units will increase.

17. If IEPA's proposal to revise the MPS is adopted, could the fleetwide average rate of emissions exceed what the fleetwide average emissions rates were before the MPS was adopted?

Such a situation would be extremely unlikely. Emission rates before the adoption of the MPS were much higher for many units than would be likely under the Agency's proposal.

18. Could implementing this proposal undo all the emissions reductions (on a rate basis) that were achieved by the MPS?

It is difficult to answer this question, as individual units operate at varying emission rates in order to meet a fleet-wide average rate-based limit. Additionally, the Agency is unclear as to what the phrase "all the emission reductions (on a rate basis)" means, or how that would be quantified. However, as stated in earlier responses, emission rates at units such as Baldwin and Havana will not be allowed to increase beyond consent decree rate limits. It is also unlikely that individual emission rates at units like Joppa or Hennepin or others will increase.

III. Allowable Emissions vs. Actual Emissions

1. Did IEPA do any air quality analysis of the impacts of the change to the rule?

Yes.

a. If not, why was there no analysis?

b. If so:

i. Can you please provide us with a copy of this analysis?

The analysis involved reviewing DRR modeling to ensure local impacts would not threaten the NAAQS (as discussed in response to Board Question 8), and analyzing impacts on Regional Haze. As such, there is no specific document to provide. More detailed discussions of the Agency's analyses are set forth in the TSD.

ii. Was that air quality analysis based on actual emissions or allowable emissions?

Both.

iii. If it was based on allowable emissions, why was it not based on actual emissions?

2. Did IEPA ever consider basing its proposed changes on actual emissions rather than allowable emissions? If so, why did IEPA decide not to base it on actual emissions?

The Agency considered the actual emissions of the affected units in drafting its proposal. As stated in the TSD, actual emissions have been relatively lower in recent years due to a number of factors. As such, the Agency did not base the proposal on actual emissions from the most recent years.

3. IEPA's June 2011 original Regional Haze submittal and its February 2017 Five-Year Progress Report forecasted or referenced actual emissions, which the reports also referred to as "projected emissions." What would explain the inconsistent approach IEPA is taking regarding whether it analyzes actual emissions?

The Agency disagrees that its approach is inconsistent with its Regional Haze SIP submittals. The forecasted emissions in both Regional Haze SIP submittals were projected from a 2002 base year as was required by the Regional Haze Rule. Prior to the original Regional Haze SIP submittal, analysis was performed using modeling to demonstrate that by implementing BART-level control at BART-eligible units, visibility goals would be met for Illinois (and for other states in the Midwest Regional Planning Organization). The plan that Illinois submitted, including anticipated reductions from the MPS and other measures, was considered "better than BART" because it resulted in greater emission reductions.

In the current proposal, the Agency considered the projected actual emissions from affected units in those SIP submittals as commitments that the State needs to meet going forward. That is why the proposal sets hard caps on allowable limits below the projections of actual emissions. This is not at all inconsistent. Setting allowable emissions ensures that actual emissions under the proposal will remain below the projected actuals from SIP submittals. This ensures that these commitments will be met in all future years.

4. How does IEPA plan to address the fact that U.S. EPA used expected actual emissions as a basis for its Regional Haze SIP decision-making?

The Agency is not clear what this question is asking. However, USEPA has agreed that lowering allowable emissions below the expected emissions set forth in Illinois' Regional Haze SIP submittals ensures that emissions cannot possibly be higher than what was anticipated in those SIP submittals. Indeed, reducing allowable emissions below expected actuals goes above and beyond the commitments previously made by Illinois.

5. In IEPA's view, do actual emissions matter when considering the implications of this rulemaking proposal?

Yes, but actual emissions can and do fluctuate for the affected EGUs as described in the TSD.

6. When considering this rulemaking, how much weight and/or importance did IEPA assign to actual emissions compared to allowable emissions?

   Allowable and actual emissions are interwoven concepts. Limitations on allowable emissions are nothing more than restrictions on actual emissions. The Agency considered both actual and allowable emissions, as explained in the Agency's TSD. The analysis required by USEPA to demonstrate that the proposed rule amendments will not cause backsliding under the Clean Air Act must be based on maximum allowable emissions.

7. Did IEPA do any modeling of the impacts of the change to the rule?

   See response to Board Questions 8 and 15, above.

   a. If not, why was there no modeling?

   b. If so:

      i. Can you please provide us with a copy of this analysis?

         As noted above, the analysis involved review of prior modeling, so there is no specific document to provide.

      ii. Was that air quality analysis based on actual emissions or allowable emissions?

         Both.

      iii. If it was based on allowable emissions, why was it not based on actual emissions?

         The DRR modeling was based on actual emissions because that was the direction given under the DRR. Attainment Demonstration modeling of the Pekin NAA was done based on allowables because that is the method to demonstrate the area will be in attainment even in the worst-case scenario.

8. Did IEPA look at actual emissions and how they would be affected by a change to the MPS? If so:

   As stated in the TSD, actual emissions could fluctuate under the proposed amendments and the factors affecting EGU emissions discussed in the TSD. However, it is also noted in the TSD that actual emissions also fluctuate and could rise under the current MPS.

a. Can you please provide us with a copy of this analysis? If not:

The analysis and reasoning discussed in the TSD is qualitative and does not make specific numerical predictions of future actual emissions.

b. Why did IEPA not conduct this modeling?

The Agency is not aware of the type of modeling being referenced or the type of modeling that would yield any meaningful results responsive to this question.

9. Considering that a lot of other factors including natural gas prices and weather affect actual emissions:

a. Did IEPA model or calculate actual emissions while holding/assuming all of these other factors stay constant? If so, can you please provide us with a copy of this analysis?

No, because doing so would be unrealistic and meaningless. Weather is not constant. Fuel prices are not constant. There is no reason to assume they are when that is not the case.

b. Did IEPA consider modeling or calculating actual emissions while holding/assuming all of these other factors stay constant? If this was considered but not employed, why did IEPA choose not to model in this way?

No. See above.

c. Did IEPA consider how this change to the MPS alone would affect actual emissions while holding/assuming all of these other factors stay constant? If so, can you please provide us with a copy of this analysis?

See above.

10. IEPA has argued that the rule will reduce overall allowable emissions. Can the same be said of actual emissions?

See TSD, Section 5.2.

11. Under the proposed rule:

a. Could there be an increase in fleetwide rate-based emissions compared to current levels?

It is possible, but the total mass of emissions is capped.

b. Could there be an increase in actual emissions compared to current levels?

Again, it is possible, but the same possibility exists under the current MPS.

12. Under the previous version of the rule, while there could be an increase in actual emissions, there could not be an increase in fleetwide rate-based emissions, correct?

Correct. Not above the allowable fleet-wide rate.

13. In Table 1 of the TSD you list that Joppa's current allowable emissions based on its nominal capacity and MPS rate is 13,902 TPY (2,317 * 6). TSD at 9. Why is Joppa's limit under IEPA's MPS proposal 19,860, TSD at 6, and not the lower level of 13,902?

The current MPS rate for the current Dynegy Group is a fleet-wide average and not a unit- or source-specific limit. The figures given in the TSD table are not intended to assign individual allowable emissions for any given unit, rather they detail a contribution to the overall allowable mass emissions of the entire proposed combined MPS Group.

IV. Communities and Stakeholders

1. A February 15, 2017 email from Gina Roccaforte at IEPA to Brad Frost at IEPA asks Mr. Frost if he has "an outreach list pertaining to the Illinois mercury rule or, if not, an outreach list for informing those interested in BOA rulemakings involving power plants." Email from Gina Roccaforte, Assistant General Counsel, Division of Legal Counsel, IEPA, to Brad Frost, Manager, Office of Community Relations (Feb. 15, 2017, 4:04 pm CST), attached hereto as "Attachment A." This email was written more than five months before IEPA contacted stakeholders about this rulemaking on July 27, 2017. Why did IEPA wait five months since the time of this email to notify stakeholders that IEPA was in the process of developing its rulemaking proposal?

The Illinois EPA was engaging in early preparation for stakeholder involvement. At that point in time, the Illinois EPA did not have a draft proposal to share with stakeholders and was not fully prepared for public outreach.

2. Are any of the eight Dynegy plants subject to this rulemaking located in an Environmental Justice Community?

Yes.

a. If so, which of the plants are located in an Environmental Justice Community?

Hennepin Power Station.

b. If so, has IEPA done any outreach to these Environmental Justice Communities?

The Illinois EPA did not do targeted outreach to the community located near the Hennepin Power Station. However, as discussed below, the Environmental Justice (EJ) Officer did participate in outreach sessions with statewide and regional environmental groups.

i. If the answer is yes, what type of outreach has IEPA done and when was this outreach done?

The Illinois EPA's EJ Officer participated in a public outreach session at Springfield's Lincoln Library on August 9, 2017. In addition, the Illinois EPA's EJ Officer met with representatives of Illinois People's Action on August 30, 2017, at Illinois EPA's Springfield Headquarters. The Illinois EPA's EJ outreach focused on explaining the Agency's methodology for determining potential EJ areas and the significance of an EJ designation.

ii. If the answer is no, why did IEPA not conduct this outreach?

c. What methodology or metrics did IEPA use to determine whether these plants were located in Environmental Justice Communities?

The Illinois EPA utilizes EJ START, which is a Geographic Information System (GIS) application that was developed by Agency staff. Potential EJ Communities are identified based on demographic screening criteria. EJ START looks at demographics on a census block group level, utilizing data from the American Community Survey five-year average. The Illinois EPA defines a "potential" Environmental Justice community as a community with an income below poverty (low income) and/or minority population greater than twice the statewide average. A one-mile buffer is added to the census block groups meeting the demographic criteria to include persons located near a facility.

d. Has IEPA done any kind of analysis of the communities where these plants are located to determine whether they might have higher than average representation of residents that are in demographics used to determine whether a community is an Environmental Justice Community?

Illinois EPA's EJ demographic screening process is designed to do exactly that, identify census block groups within the State that have higher concentrations of minority and/or low-income persons.

3. In your testimony you wrote that IEPA considered "localized impacts around the affected sources." Davis Testimony at 4.

a. In what manner/ways did IEPA consider such localized impacts?

See response to Board Question 8.

b. In what geographic areas did you consider these localized impacts? For example, did IEPA look at the impacts within a 50-mile, 10-mile, or 5-mile radius around the affected sources? Did IEPA instead look at impacts by town or by county?

As discussed previously, review of localized impacts was primarily based on prior DRR modeling. Such modeling began by choosing a circle that would encompass sources to be considered in the modeling; such circles ranged from 10 to 50 km in radius, depending on the number and size of sources in the area. The area modeled also varied in size depending upon the number and size of sources in the area, as well as other geographic and boundary features such as the State line. The modeled areas were square or rectangular and ranged from approximately 15 km on one side to as much as 35 km. Within the modeled areas, receptors were placed at 50-100 meters apart nearer to the modeled sources, with spacing gradually increasing to 500 meters apart in areas that were further away from the sources.

c. Can you please share these calculations and/or analyses?

The Agency's DRR modeling is voluminous and was not performed in relation to this rulemaking. The public has already had an opportunity to comment on the modeling at the federal level in relation to the Agency's attainment designation recommendations to USEPA. The Agency does not believe that introducing this modeling data into the docket would be helpful in the rulemaking proceedings.

d. If a source retires, does the fleetwide annual tonnage get reduced by the tonnage proportional to that source's emissions?

The Agency is unsure what this question is asking and thus cannot answer it. It is not clear what is meant by the term "annual tonnage" – whether that refers to actual emissions from the fleet, the size of the emissions cap, or something else.

e. One source could increase its annual tonnage (through either an increase in capacity or an increase in its rate-based emissions) to account for some or all of the fleetwide portion of emissions that would have been allocated to the unit that has since retired or been mothballed, correct?

The Agency does not understand this question and thus cannot answer it.

f. An increase in emissions from one source increases risk of localized impacts around that source, correct?

As previously discussed in response to Board Question 8 and elsewhere, the Agency has reviewed previous DRR modeling in order to ensure the NAAQS will not be threatened. The NAAQS is the federal air quality standard, based on scientific information, designed to protect human health with an adequate margin of safety.

g. Did IEPA consider the localized impacts if emissions from one source increase to account for the emissions from a different source that has shut down or been mothballed? If not, why not?

See above. Also, as previously discussed, the proposed change to the MPS is at least as protective to the NAAQS as the current MPS. Additionally, as discussed in response to Board Question 15, the DRR requires that Illinois annually review areas where SO_2 emissions increase to determine if further modeling is necessary in relation to the SO_2 NAAQS.

4. The Environmental Law & Policy Center ("ELPC"), the Natural Resources Defense Council ("NRDC"), the Respiratory Health Association ("RHA"), and the Sierra Club submitted comments to IEPA on this rule on August 25, 2017. These organizations stated that "any substantive revision to the MPS should address CO2 in addition to NOx and SO2." ELPC, NRDC, RHA, and Sierra Club, *Stakeholder Comments Re: Proposed Modification to 35 Ill. Adm. Code 225.233* at 15 (Aug. 25, 2017), attached hereto as Attachment B.

a. In what ways did IEPA take this specific comment into consideration?

It was discussed internally.

b. Why did IEPA choose not to incorporate CO2 into this rulemaking?

This regulation has nothing to do with CO_2. Furthermore, the Agency does not have any analyses relating to how CO_2 would be regulated within this rule. It is also unlikely that Part 225 would be the appropriate place to regulate CO_2.

c. Does IEPA have any plans to propose a rulemaking that would address CO2?

Not at this time.

V. Other Supporting Documentation

4. A March 16, 2017 email from Jeff Ferry at Dynegy to Sherrie Elzinga at IEPA states that "Rick and Jim had a meeting this morning with staff to review modeling and discuss some tech matters." Email from Jeffrey A. Ferry, Senior Director State Government Affairs, Dynegy Inc., to Sherrie Elzinga, IEPA (Mar. 16, 2017, 12:25pm CST), attached hereto as "Attachment C."

   a. Did IEPA receive a copy of this modeling? If so, can you please share this modeling information?

      No. The Agency does not know what modeling is being referenced here.

   b. Did Dynegy discuss this modeling with IEPA? If so, what was discussed?

      No, the Agency did not discuss any modeling performed by Dynegy with the company.

   c. Did this modeling affect any elements of IEPA's MPS proposal? If so, which elements were affected and how?

      No, any modeling performed was not shared or discussed, so it did not affect the Agency's proposal.

   d. Is this modeling reflected in the TSD?

      No.

      i. If not, then why is it not?

         The Agency did not receive or rely on any such modeling.

      ii. If so, then what elements of this modeling are reflected in the TSD?

   e. If IEPA did its own modeling, please explain any differences between Dynegy and IEPA modeling and any changes IEPA made to its modeling or analysis in light of Dynegy's modeling.

      The Agency did not receive any modeling information or perform any modeling specific to this rulemaking.

5. A January 24, 2017 email from Dana Vetterhoffer at IEPA references a submittal from Dynegy. Email from Dana Vetterhoffer, Acting Deputy General Counsel, Air Regulatory Unit, IEPA, to Julie Armitage, IEPA, et al. (Jan. 24, 2017, 09:33am CST), attached hereto as "Attachment D."

   a. Can you please share this submittal?

This document, "Support for Revising the IMR and MPS," dated 1/20/2017, has already been released to the Environmental Law & Policy Center under its Freedom of Information Act Request dated August 21, 2017. See Attachment 8.

b. Did this submittal affect any elements of IEPA's MPS proposal? If so, which elements were affected and how?

This document served as an early discussion point for the proposal, some elements of which were accepted and some of which were rejected.

c. Is this submittal reflected in the TSD?

The Agency is unsure what is being asked. The TSD is the Illinois EPA's technical justification for the proposal, while this document is Dynegy's rationale.

i. If not, then why is it not?

ii. If so, then what elements are reflected in the TSD?

d. The January 24, 2017 email in Attachment D also attaches a memo titled "The Impact of Emissions Averaging Time on the Stringency of an Emission Standard." *Id.*

i. Did this memorandum affect any elements of IEPA's MPS proposal?

No, it did not.

1. If so, which elements were affected, and how were these elements affected?

2. If not, why did this memo not affect any elements of the proposal?

The Agency determined the memo did not have any bearing on the rulemaking, and thus was not applicable.

ii. Did IEPA reach out to the authors of this memo about its contents and related issues?

No.

iii. If so, what was discussed?

6. January 23, 2017 email from PJ Becker to David Bloomberg and Dana Vetterhoffer states "I dropped off a copy of Dynegy's MPS/CPS/IMR documents in your mail box or office." Email from PJ Becker, IEPA, to David E. Bloomberg, IEPA, et al. (Jan. 23, 2017, 08:03am CST), attached hereto as "Attachment E"

   a. By whom were these documents written?

      The Agency does not know who at Dynegy authored the document.

   b. Can you please provide a copy of these documents?

      The Illinois EPA believes that the reference is to "Support for Revising the IMR and MPS," dated 1/20/2017, which has already been released to the Environmental Law & Policy Center under its Freedom of Information Act Request dated August 21, 2017. See Attachment 8.

7. IEPA shared a draft of this proposal with an attorney from Dynegy on May 11, 2017. *See* Email from Dana Vetterhoffer, Deputy General Counsel, Air Regulatory Unit, IEPA, to Renee Cipriano, Schiff Hardin LLP (May 11, 2017 4:03pm CST), attached hereto as "Attachment F." This draft contained a provision that would adjust the proposed mass-based caps on SO2, NOx and seasonal ozone downward were a unit to shut down. *Id*. At 15-16.

   a. Why did IEPA's proposal originally contain a provision that would decrease the mass-based caps in the event of a shutdown?

      As noted in the question, that was an Agency proposal. This provision had not been previously discussed with Dynegy. The Agency was considering the idea while the first draft of the proposed modifications were being made, so it was included as a possible addition.

   b. Counsel for Dynegy submitted marked up revisions to this proposal deleting IEPA's proposed provision that would decrease Dynegy's mass-based caps were units to shut down. Email from Renee Cipriano, Schiff Hardin, to Dana Vetterhoffer, IEPA, and Gina Roccaforte, IEPA at 13-16 (May 17, 2017, 11:17am CST), attached hereto as "Attachment G." Why did IEPA accept these revisions?

      As noted above, the language was an Agency proposal. In any rulemaking, the Agency and affected sources frequently exchange and/or discuss proposals, which may be accepted, rejected, or modified through such discussions. In this particular case, Dynegy indicated the decrease could negatively impact the operational flexibility it was seeking because, as discussed in response to the Board's Question 21.d, if an EGU shuts down, the power will likely be generated from somewhere else, which could entail an increase in emissions at other EGUs. Furthermore, as previously noted, the emissions cap at the proposed level already ensures that emissions remain

below those that are necessary to meet the State's Regional Haze obligations. As such, no additional reduction in the cap is necessary. With all of this in mind, the Agency did not move forward with the proposed change.

8. IEPA's May 11, 2017 version of the proposal contained weights for which the caps would be adjusted downward in the event of a transfer. *See* Attachment F at 15-16. These weights are different from those delineated in IEPA's final draft of the proposal that it filed with the Pollution Control Board in October.

a. How did IEPA calculate the numbers that were in the May 11, 2017 draft of this proposal?

Those numbers were calculated by using a share of a unit's heat input proportional to the fleet. After discussion with Dynegy, it was agreed by the Agency and the company that these numbers were not appropriate from either the Agency's or company's perspective. This is because basing the figures on heat input alone resulted in some units being assigned values that were much too large, and some units being assigned values that were much too small. After additional discussion, it was agreed that this was not an appropriate method of calculation.

b. On May 24, 2017, counsel for Dynegy sent IEPA employees unit allocations that were different from those in the May 11, 2017 version of the proposal. Email from Renee Cipriano, Schiff Hardin, to Dana Vetterhoffer, IEPA, and Gina Roccaforte, IEPA (May 24, 2017 at 5:02pm), attached hereto as "Attachment H." On May 31, 2017 Ms. Vetterhoffer responded to this email by saying "The Agency is likely ok with the numbers, pending receipt of an explanation of how Dynegy arrived at them (for our understanding and for the TSD)." Email from Dana Vetterhoffer, IEPA, to Renee Cipriano, Schiff Hardin (May 31, 2017, 3:25pm CST), attached hereto as "Attachment I."As the author of the TSD, did you receive an explanation for these numbers?

Yes.

i. If so, what was the explanation?

As explained in other answers to questions, the values are based upon historical emissions, utilization, and the level of control achievable at each plant.

ii. Did IEPA independently verify the accuracy of these numbers?

Both the Agency and Dynegy agreed that the figures were based upon the above factors and appropriate in the event of the transfer of a source to a new owner.

c. The numbers sent by Ms. Cipriano on May 24, 2017 were included in a revised version of the proposal that IEPA sent to Ms. Cipriano on June 6, 2017. Email from Gina Roccaforte, IEPA, to Renee Cipriano, Schiff Hardin at 14-15 (June 6, 2017, 2:48pm CST), attached hereto as "Attachment J." Dynegy subsequently sent new transfer allocations. Email from Renee Cipriano, Schiff Hardin, to Gina Roccaforte, IEPA (June 9, 2017, 2:44pm CST), attached hereto as "Attachment K." The transfer allocations in Attachment K are the same transfer allocations that were incorporated in the draft rule filed with the Pollution Control Board.

i. Did Dynegy explain why these numbers were selected before IEPA incorporated them into the rulemaking proposal? If so, can you please share this explanation/analysis?

Some minor changes were made to the figures because Dynegy thought they were more appropriate, and the Agency agreed to them.

ii. Did IEPA independently verify that these numbers were appropriate before filing its rulemaking proposal with the PCB? If so, can you please share your analysis?

Yes. The analysis consisted of verifying that the values in the proposal were appropriate and in line with historical emission rates and utilizations at the sources.

iii. Why was an analysis of how these numbers were calculated not included in the TSD?

As stated in answers to other questions, there was not an exact calculation method for the values in the proposal. It should be noted that the provisions in the proposal regarding transfer allocations were desired by the Agency. This was in order to have clear rules in place in the event of transfers without revisiting Part 225 in the future. These provisions were only meant to provide regulatory certainty for the Agency and any future new owner of a current MPS source.

9. IEPA produced a March 22, 2017 document titled "Illinois MPS Proposed Rule Change—Negotiated Terms" in response to a Freedom of Information Act request, attached hereto as "Attachment L."

The Agency would like to note that this document was drafted by Dynegy, not the Illinois EPA, to reflect Dynegy's understanding of agreed upon terms at that point in negotiations.

a. Who from IEPA and Dynegy were involved in negotiating the terms memorialized in this document?

From the Illinois EPA: Director Alec Messina, Julie Armitage, Bureau of Air Chief; David Bloomberg, Air Quality Planning Section Manager; and Rory Davis, Environmental Protection Engineer within the Air Quality Planning Section. From Dynegy: Rick Diericx, Jim Ross, and Jeff Ferry. Also involved were legal counsel from the Agency and Dynegy.

b. Were people from any other organizations involved in negotiating the terms memorialized in this document?

No.

c. Were earlier drafts of these negotiated terms exchanged with IEPA? If so, can you please share these drafts?

No.

d. Can you please share communications with IEPA and other organizations that pertain specifically to negotiating these terms?

This question is duplicative and vague. Any communications pertaining to this document have already been released to the Environmental Law & Policy Center under its Freedom of Information Act Requests.

Respectfully submitted,

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: /s/ Gina Roccaforte
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DATED: January 12, 2018

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	)	**SS**
COUNTY OF SANGAMON	**)**	
	)	

CERTIFICATE OF SERVICE

I, the undersigned, an attorney, state the following:

I have electronically served the attached ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S RESPONSES TO PREFILED QUESTIONS upon the persons on the attached Service List.

My e-mail address is gina.roccaforte@illinois.gov.

The number of pages in the e-mail transmission is 136.

The e-mail transmission took place before 5:00 p.m. on January 12, 2018.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY,

/s/ Gina Roccaforte
Gina Roccaforte
Assistant Counsel
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Dated: January 12, 2018

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Attachment 1

From: Bloomberg, David E.
Sent: Thursday, July 27, 2017 2:30 PM
To: Aburano, Douglas (aburano.douglas@epa.gov)
Subject: Draft Modification to the Multi-Pollutant Standards for Your Review
Attachments: Part 225 Public Outreach Draft.pdf

Doug,

As I mentioned to you briefly, the Illinois EPA intends to propose a modification to the Multi-Pollutant Standards (MPS) rule within Part 225 of the Illinois Pollution Control Board's air regulations (35 Ill. Adm. Code 225). This revision would combine the two existing MPS groups – formerly owned by Dynegy and Ameren – into a single group, as all the applicable units are now owned by Dynegy or a subsidiary. The rules would also be modified to alter the NOx and SO_2 emissions limits from a rate-based average for the MPS Group to an emissions cap on all such units. This would have the effect of limiting the allowable emissions from the sources (which is not currently accomplished through the rate-based average) while also providing more efficient environmental compliance.

It is our intent to file this proposal with the Board soon, so we are hoping you and your staff will be able to review the rule expeditiously – when we sent the draft out to other parties, we told them we would accept comments until August 25, and intend to move to filing very soon thereafter. Just so you know, I will be out of the office from August 11-18 and August 23-25. If you or your staff has any questions, let's set up a call as soon as possible after your/their review so we can discuss them.

Thanks.

- David

Attachment 2

IPCB Question 3.a NOx Limits for Affected Units

		NO_x			
Newton	1	NSPS	40 CFR 60.43(a)(3)	Annual	0.70 lb/mmBtu
		ARP	40 CFR Part 76.5(a)(1)	Annual	0.45 lb/mmBtu
		Fees	39.5(18)(a)(ii)	Annual	2,000 Tons
Coffeen	1,2	Fees	Section 39.5(18) of the Act	Annual	2,525 Tons
		ARP	40 CFR Part 76.6(a)(2)	Annual	0.86 lb/mmBtu
			35 IAC 217.706(a)	Seasonal	0.25 lbs/mmBtu
Duck Creek	1	Fees	Section 39.5(18) of the Act	Annual	$250,000
		NSPS	40 CFR 60.43(a)(3)	Annual	0.70 lb/mmBtu
			35 IAC 217.706(a)	Seasonal	0.25 lbs/mmBtu
Edwards	2,3	Fees	Section 39.5(18) of the Act	Annual	$250,000
		ARP	40 CFR 76.11	Annual	0.46 lb/mmBtu
			35 IAC 217.706(a)	Seasonal	0.25 lbs/mmBtu
Havana	9/6	Fees	Section 39.5(18) of the Act	Annual	$250,000
		CD 99-833	Para. 51	30-Day RA	0.1 lb/mmBtu
		NSPS	40 CFR 60.43(a)(3)	Annual	0.70 lb/mmBtu
			35 IAC 217.706(a)	Seasonal	0.25 lbs/mmBtu
Hennepin	1,2	Fees	39.5(18)(a)(ii)	Annual	1617 Tons
		CD 99-833	Para. 118 (b)	Annual	2,650 Tons
		ARP	40 CFR Part 76.5(a)(1)	Annual	0.45 lb/mmBtu
			35 IAC 217.706(a)	Seasonal	0.25 lbs/mmBtu
Baldwin	1-3	Fees	39.5(18)(a)(ii)	Annual	4,000 Tons
		CD 99-833	Para. 51, 54	30-Day RA	0.1 lb/mmBtu
		ARP 1-2	40 CFR Part 76.6(a)(2)	Annual	0.86 lb/mmBtu
		ARP 3	40 CFR Part 76.5(a)(1)	Annual	0.45 lb/mmBtu
			35 IAC 217.706(a)	Seasonal	0.25 lbs/mmBtu
Joppa	1-6	Fees	39.5(18)(a)(ii)(A)	Annual	Max
		ARP 1-5	40 CFR Part 76.5(a)(1)	Annual	0.45 lb/mmBtu
		ARP 6	40 CFR Part 76.6(a)(2)	Annual	0.86 lb/mmBtu
			35 IAC 217.706(a)	Seasonal	0.25 lbs/mmBtu

IPCB Question 3.a SO2 Limits for Affected Units

		SO_2			
Newton	1	NSPS	40 CFR 60.43(a)(2)	Annual	1.2 lb/mmBtu
		Fees	39.5(18)(a)(ii)	Annual	10,000 Tons
Coffeen	1,2	Fees	Section 39.5(18) of the Act	Annual	660 Tons
			35 IAC 214 (7.1.4(h) in permit)	Hourly	55,555 lb/hour
Duck Creek	1	Fees	39.5(18)(a)(ii)(A)	Annual	Max
		NSPS	40 CFR 60.43(a)(2)	Annual	1.2 lb/mmBtu
			35 IAC 214.121(a)	Hourly	1.2 lb/mmBtu
Edwards	2,3	Fees	39.5(18)(a)(ii)(A)	Annual	Max
			35 IAC 214.561(a)	Daily	4.71 lb/mmBtu
			35 IAC 214.561(b)	Daily	6.6 lb/mmBtu
			35 IAC 214.561(c)	Daily	34,613 lb/hour
Havana	9/6	Fees	39.5(18)(a)(ii)(A)	Annual	Max
		CD 99-833	Para. 66	30-Day RA	0.1 lb/mmBtu
		NSPS	40 CFR 60.43(a)(2)	Annual	1.2 lb/mmBtu
			35 IAC 214.121(a)	Hourly	1.2 lb/mmBtu
Hennepin	1,2	Fees	39.5(18)(a)(ii)	Annual	6588 Tons
		CD 99-833	Para. 118 (b)	Annual	9,050 Tons
			35 IAC 214 (7.1.4(c) in permit)	Hourly	17,050 lb/hour
Baldwin	1-3	Fees	39.5(18)(a)(ii)	Annual	4,214 Tons
		CD 99-833	Para. 66	30-Day RA	0.1 lb/mmBtu
			PCB 79-7	Hourly	101,966 lbs/hour
			PCB 79-7		6 lbs/mmBtu
Joppa	1-6	Fees	39.5(18)(a)(ii)(A)	Annual	Max
			35 IAC 214	Hourly	36,865 lb/hour

Attachment 3

Dynegy EGUs and CO Air Monitoring Sites

(There are no CO Nonattainment Areas in Illinois)

Legend

▲ CO Air Monitoring Sites

■ Dynegy Facilities


Dynegy EGUs, Lead NAAs, and Lead Air Monitoring Sites
Chicago/Pilsen NAA
Granite City NAA
Hennepin
Edwards
Duck Creek
Havana
Coffeen
Newton
Baldwin
Joppa
JO DAVIESS
STEPHENSON
WINNEBAGO
BOONE
MCHENRY
LAKE
CARROLL
OGLE
DEKALB
KANE
DUPAGE
COOK
WHITESIDE
LEE
KENDALL
ROCK ISLAND
HENRY
BUREAU
LASALLE
WILL
MERCER
PUTNAM
GRUNDY
KANKAKEE
STARK
MARSHALL
KNOX
HENDERSON
WARREN
PEORIA
WOODFORD
LIVINGSTON
IROQUOIS
MCDONOUGH
FULTON
TAZEWELL
MCLEAN
FORD
HANCOCK
SCHUYLER
MASON
LOGAN
DEWITT
CHAMPAIGN
VERMILION
ADAMS
BROWN
CASS
MENARD
MACON
PIATT
MORGAN
SANGAMON
DOUGLAS
EDGAR
PIKE
SCOTT
CHRISTIAN
MOULTRIE
COLES
GREENE
CALHOUN
MACOUPIN
MONTGOMERY
SHELBY
CUMBERLAND
CLARK
JERSEY
FAYETTE
EFFINGHAM
JASPER
CRAWFORD
MADISON
BOND
CLAY
RICHLAND
LAWRENCE
MARION
CLINTON
ST. CLAIR
WAYNE
EDWARDS
WABASH
WASHINGTON
JEFFERSON
MONROE
PERRY
WHITE
RANDOLPH
FRANKLIN
HAMILTON
JACKSON
WILLIAMSON
SALINE
GALLATIN
UNION
JOHNSON
POPE
HARDIN
ALEXANDER
PULASKI
MASSAC
N
Legend
Lead Air Monitoring Sites
Dynegy Facilities
Lead Nonattainment Areas

Dynegy EGUs and NO2 Air Monitoring Sites

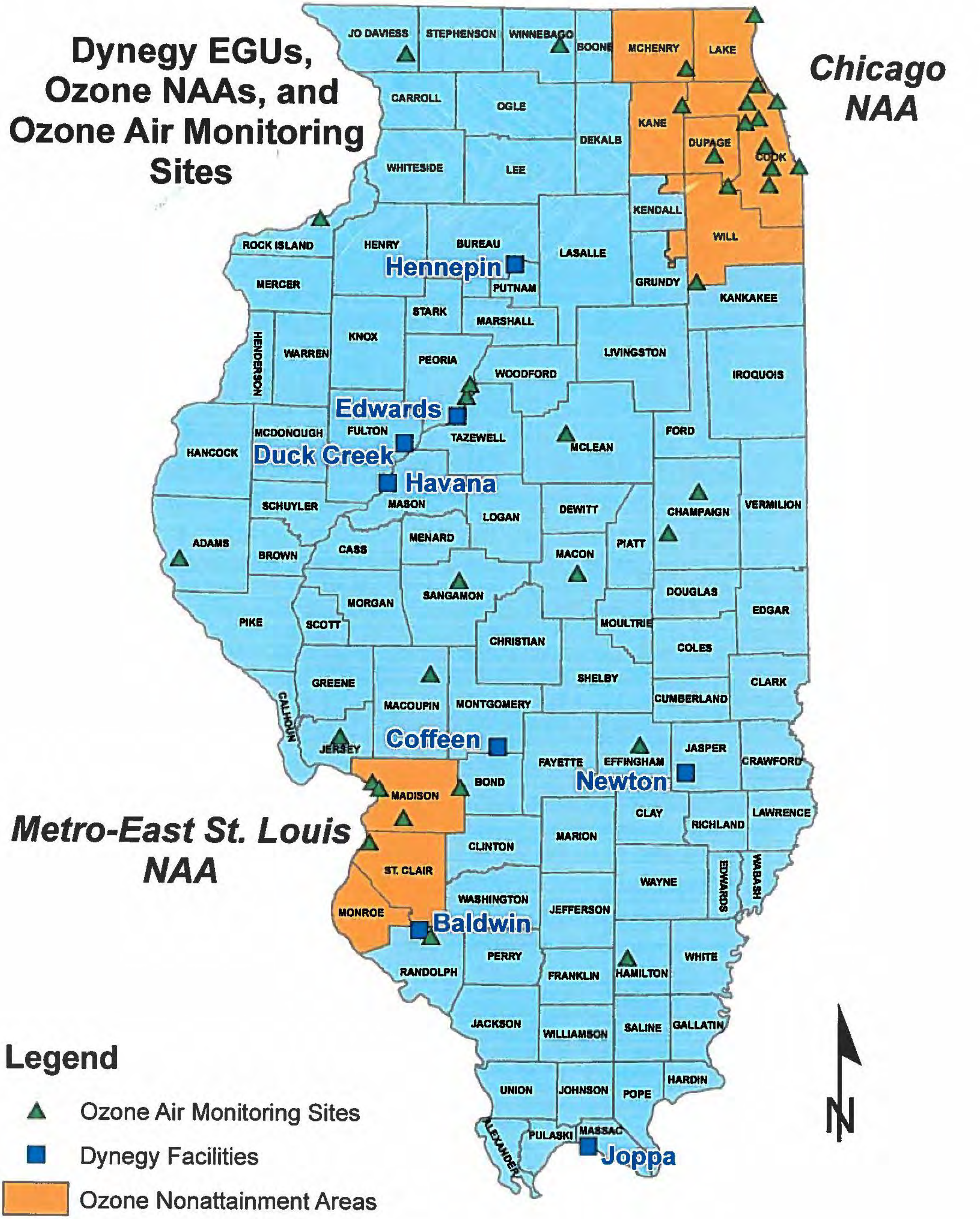
(There are no NO2 Nonattainment Areas in Illinois)

Legend

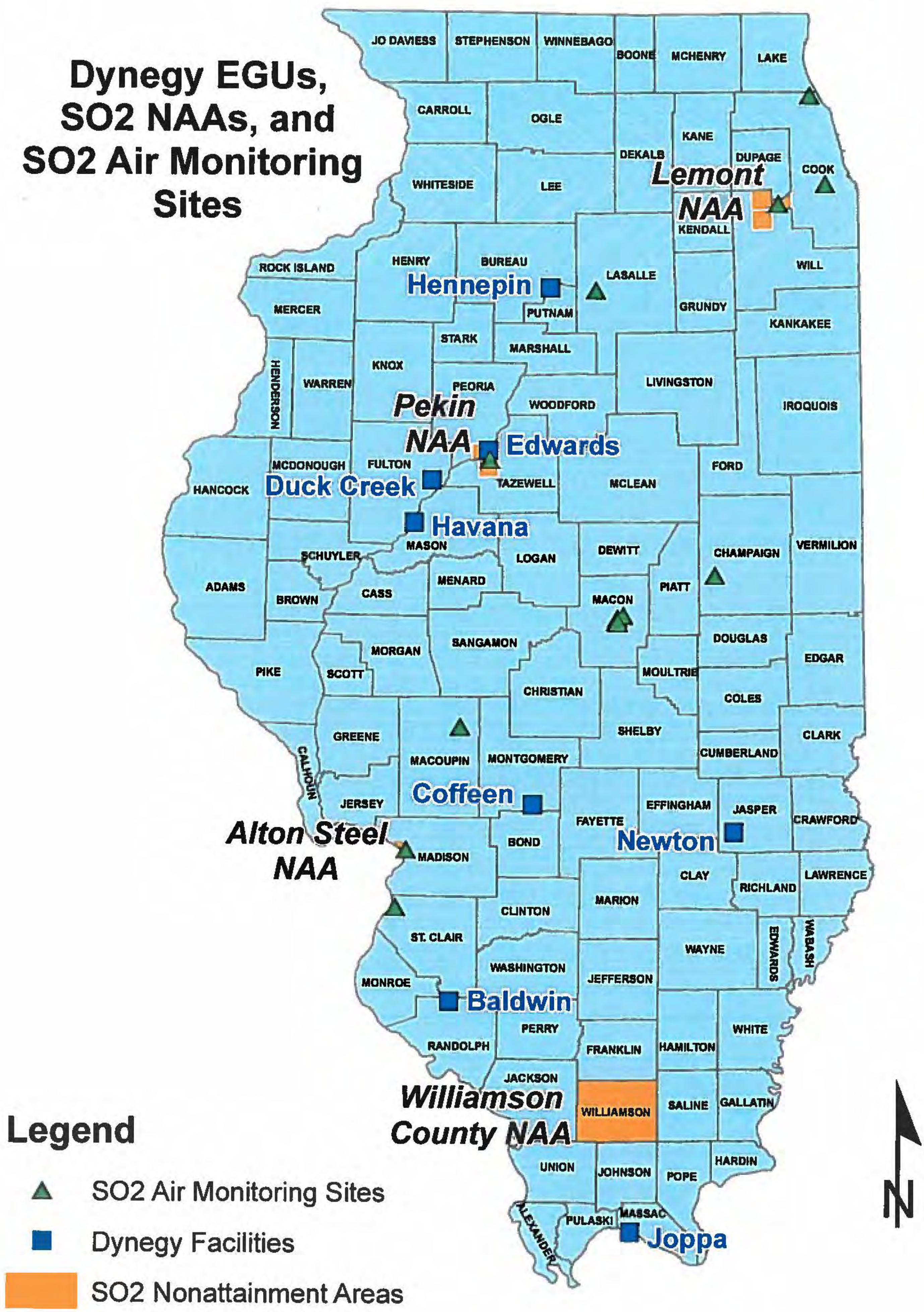
▲ NO2 Air Monitoring Sites

■ Dynegy Facilities

Dynegy EGUs, Ozone NAAs, and Ozone Air Monitoring Sites

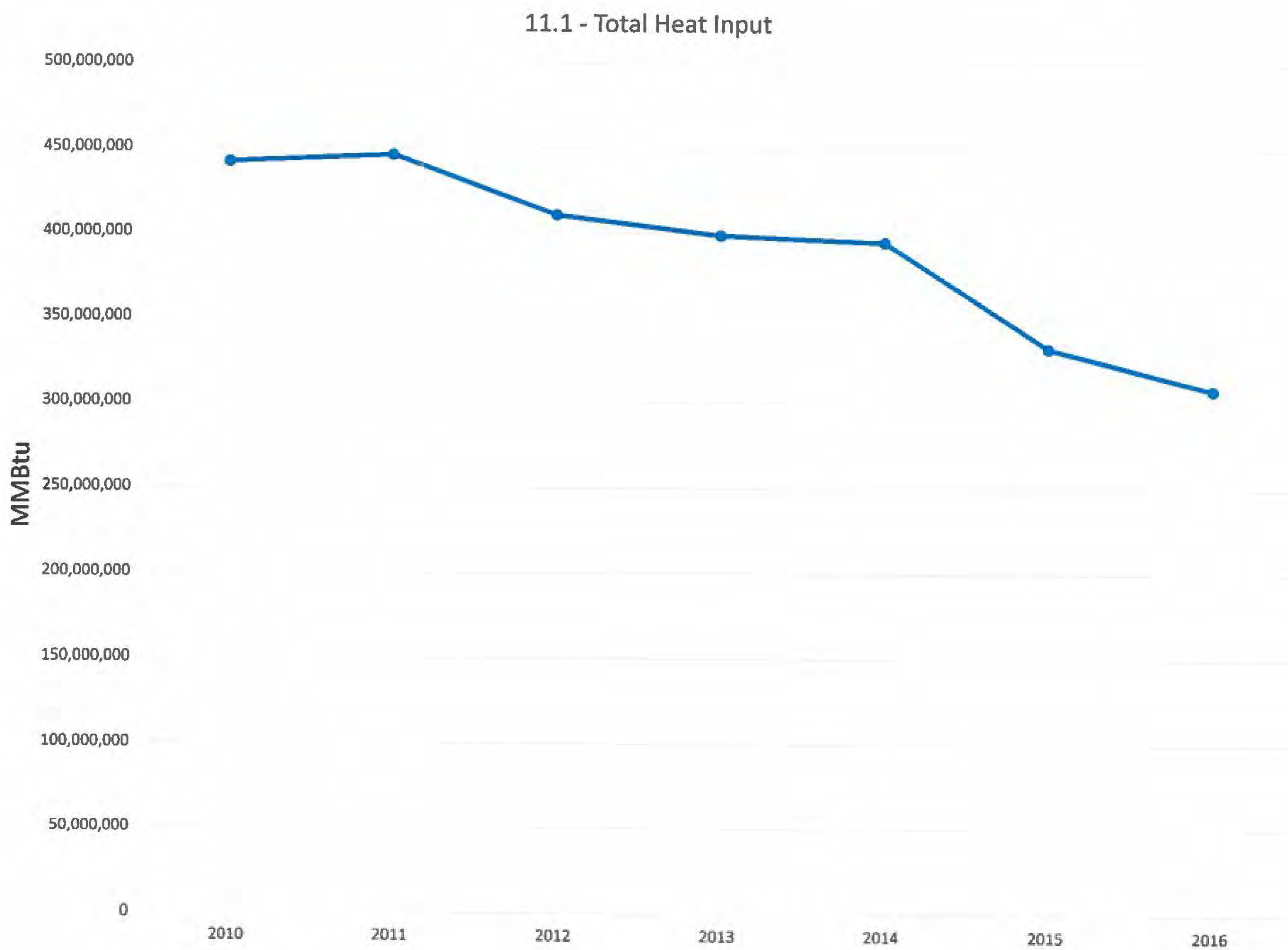


Dynegy EGUs, PM2.5 NAA, and PM2.5 Air Monitoring Sites
Metro-East St. Louis NAA
Hennepin
Edwards
Duck Creek
Havana
Coffeen
Newton
Baldwin
Joppa
JO DAVIESS
STEPHENSON
WINNEBAGO
BOONE
MCHENRY
LAKE
CARROLL
OGLE
DEKALB
KANE
DUPAGE
COOK
WHITESIDE
LEE
KENDALL
WILL
ROCK ISLAND
HENRY
BUREAU
LASALLE
GRUNDY
KANKAKEE
MERCER
PUTNAM
STARK
MARSHALL
KNOX
HENDERSON
WARREN
PEORIA
WOODFORD
LIVINGSTON
IROQUOIS
MCDONOUGH
FULTON
TAZEWELL
MCLEAN
FORD
HANCOCK
SCHUYLER
MASON
LOGAN
DEWITT
CHAMPAIGN
VERMILION
ADAMS
BROWN
CASS
MENARD
MACON
PIATT
MORGAN
SANGAMON
DOUGLAS
EDGAR
PIKE
SCOTT
CHRISTIAN
MOULTRIE
COLES
GREENE
CALHOUN
MACOUPIN
MONTGOMERY
SHELBY
CUMBERLAND
CLARK
JERSEY
FAYETTE
EFFINGHAM
JASPER
CRAWFORD
MADISON
BOND
CLAY
RICHLAND
LAWRENCE
CLINTON
MARION
ST. CLAIR
WAYNE
EDWARDS
WABASH
MONROE
WASHINGTON
JEFFERSON
PERRY
RANDOLPH
FRANKLIN
HAMILTON
WHITE
JACKSON
WILLIAMSON
SALINE
GALLATIN
UNION
JOHNSON
POPE
HARDIN
ALEXANDER
PULASKI
MASSAC
N
Legend
PM2.5 Air Monitoring Sites
Dynegy Facilities
PM2.5 Nonattainment Area



Dynegy EGUs, SO2 NAAs, and SO2 Air Monitoring Sites
JO DAVIESS
STEPHENSON
WINNEBAGO
BOONE
MCHENRY
LAKE
CARROLL
OGLE
KANE
DEKALB
DUPAGE
COOK
WHITESIDE
LEE
Lemont NAA
KENDALL
ROCK ISLAND
HENRY
BUREAU
Hennepin
LASALLE
WILL
MERCER
PUTNAM
GRUNDY
KANKAKEE
STARK
MARSHALL
KNOX
HENDERSON
WARREN
PEORIA
LIVINGSTON
Pekin NAA
WOODFORD
IROQUOIS
Edwards
MCDONOUGH
FULTON
FORD
HANCOCK
Duck Creek
TAZEWELL
MCLEAN
Havana
MASON
DEWITT
VERMILION
SCHUYLER
LOGAN
CHAMPAIGN
ADAMS
BROWN
CASS
MENARD
PIATT
MACON
MORGAN
SANGAMON
DOUGLAS
EDGAR
PIKE
SCOTT
MOULTRIE
CHRISTIAN
COLES
GREENE
SHELBY
CLARK
CALHOUN
MACOUPIN
MONTGOMERY
CUMBERLAND
JERSEY
Coffeen
EFFINGHAM
JASPER
FAYETTE
CRAWFORD
Alton Steel NAA
MADISON
BOND
Newton
CLAY
RICHLAND
LAWRENCE
MARION
CLINTON
ST. CLAIR
WAYNE
EDWARDS
WABASH
WASHINGTON
MONROE
JEFFERSON
Baldwin
PERRY
WHITE
RANDOLPH
FRANKLIN
HAMILTON
JACKSON
Williamson County NAA
WILLIAMSON
SALINE
GALLATIN
UNION
JOHNSON
POPE
HARDIN
ALEXANDER
PULASKI
MASSAC
Joppa
N
Legend
SO2 Air Monitoring Sites
Dynegy Facilities
SO2 Nonattainment Areas

Attachment 4


11.1 - Total Heat Input
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400,000,000
350,000,000
300,000,000
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50,000,000
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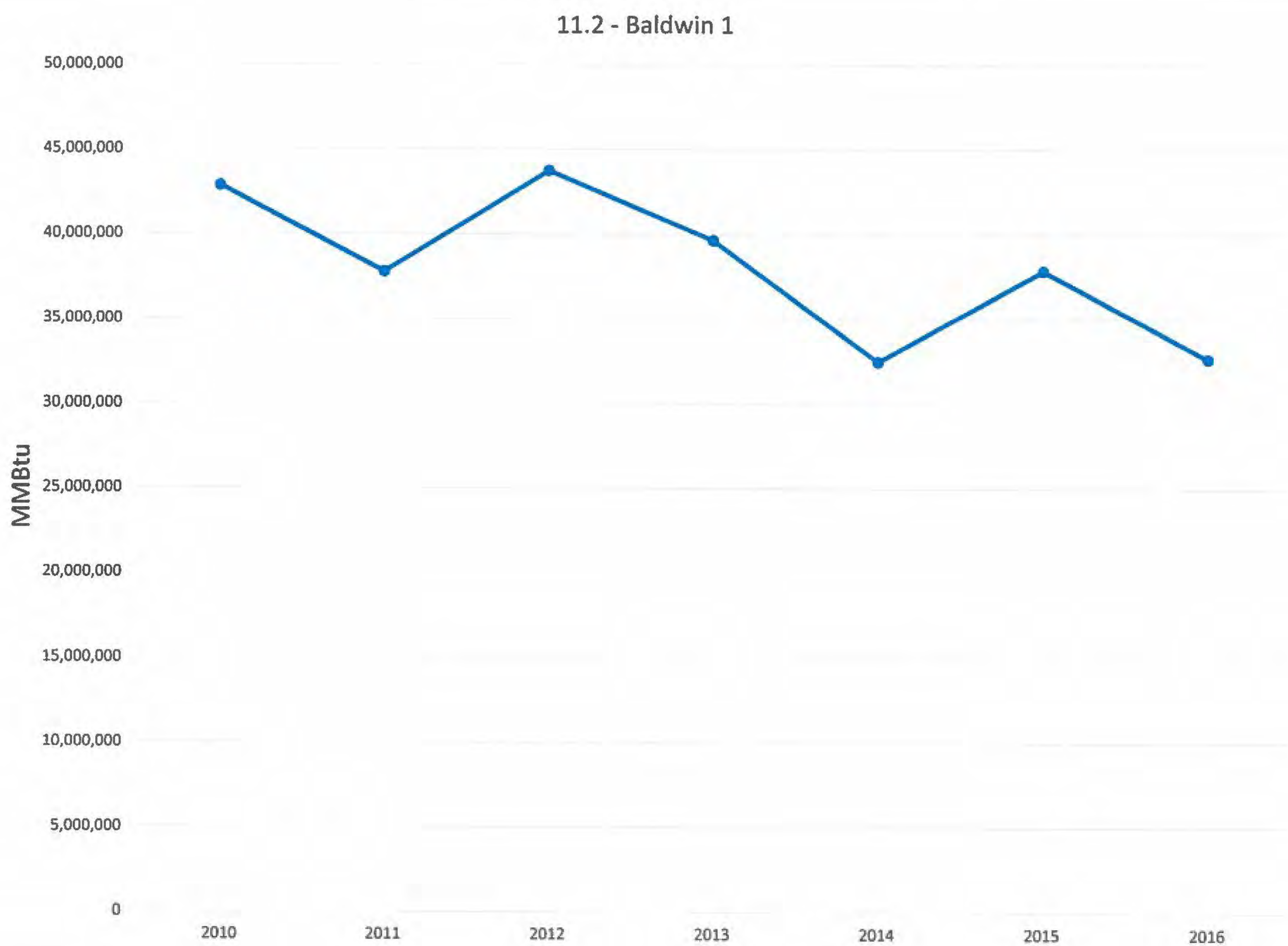
2010
2011
2012
2013
2014
2015
2016


11.2 - Baldwin 1
MMBtu
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35,000,000
30,000,000
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10,000,000
5,000,000
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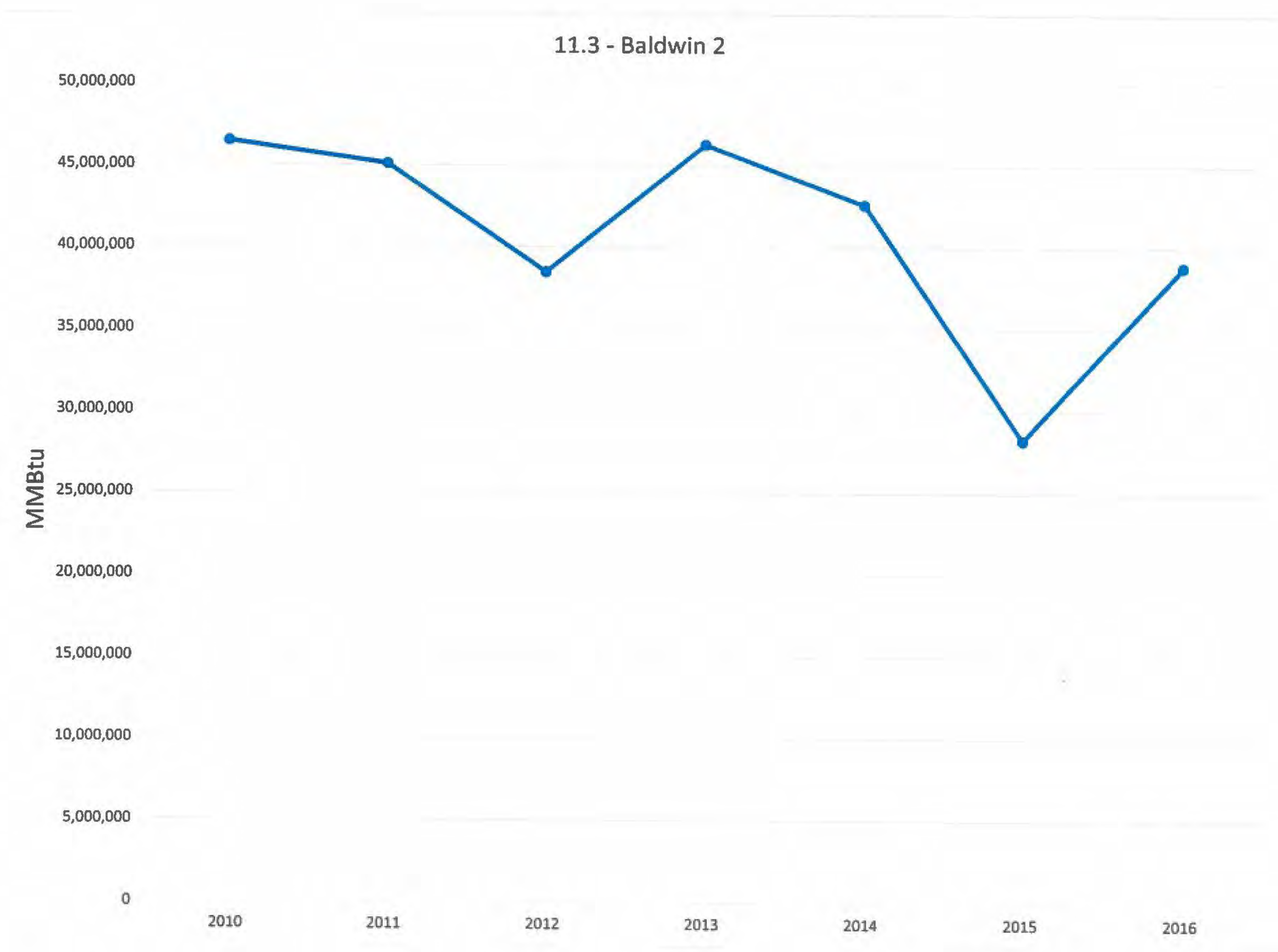
2010
2011
2012
2013
2014
2015
2016


11.3 - Baldwin 2
MMBtu
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35,000,000
30,000,000
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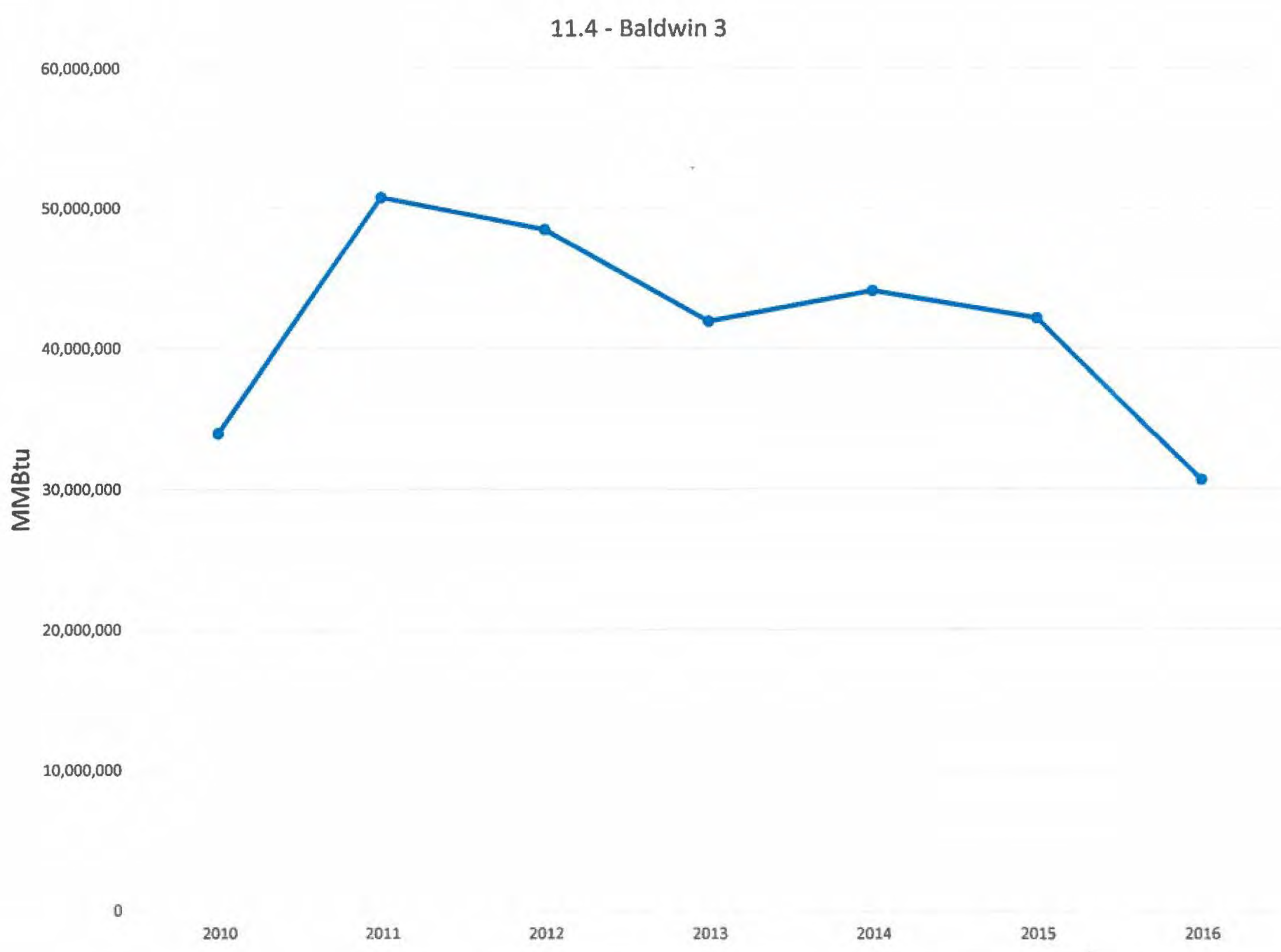
15,000,000
10,000,000
5,000,000
0
2010
2011
2012
2013
2014
2015
2016


11.4 - Baldwin 3
MMBtu
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20,000,000
10,000,000
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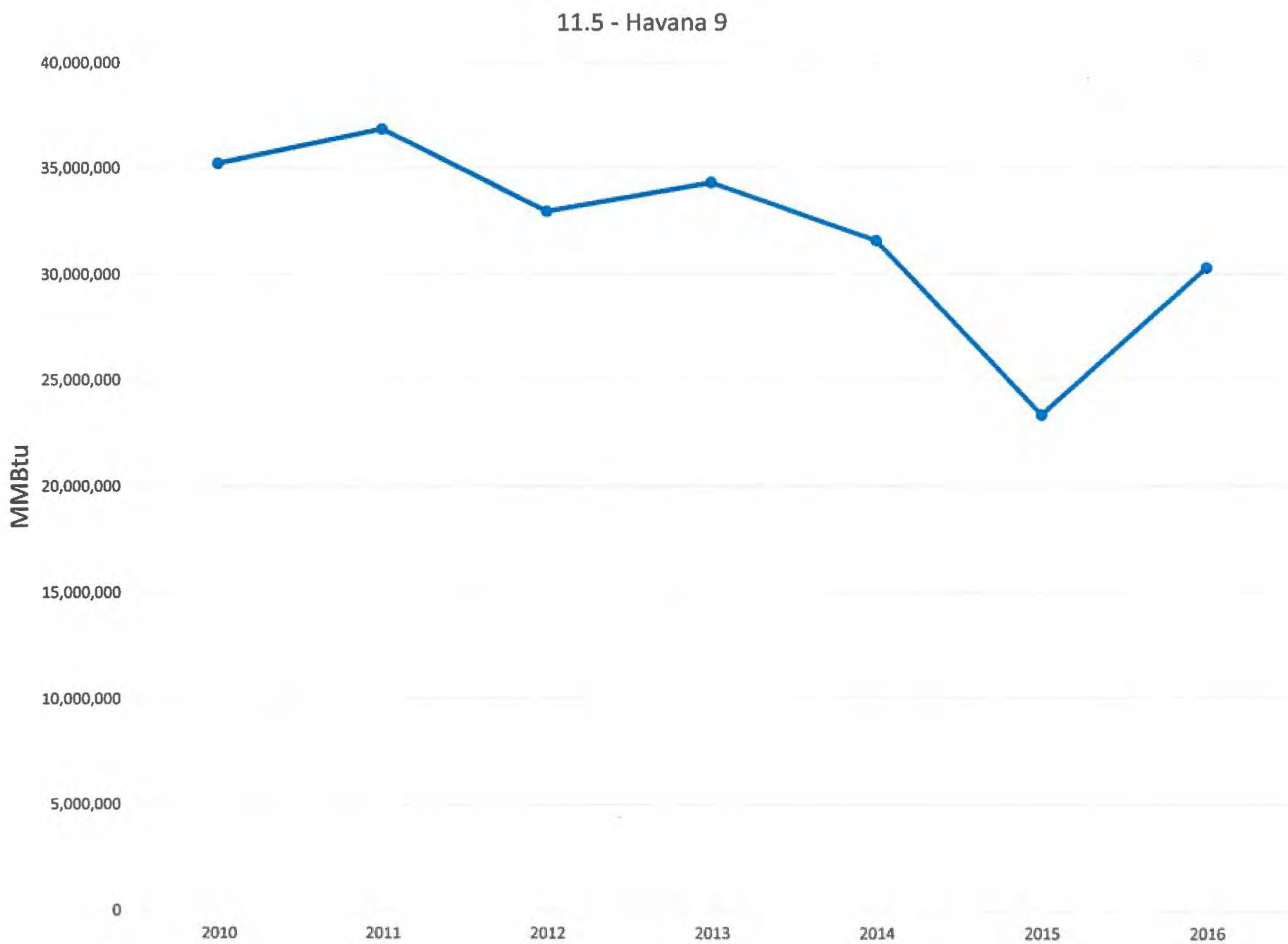
2012
2013
2014
2015
2016


11.5 - Havana 9
MMBtu
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35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
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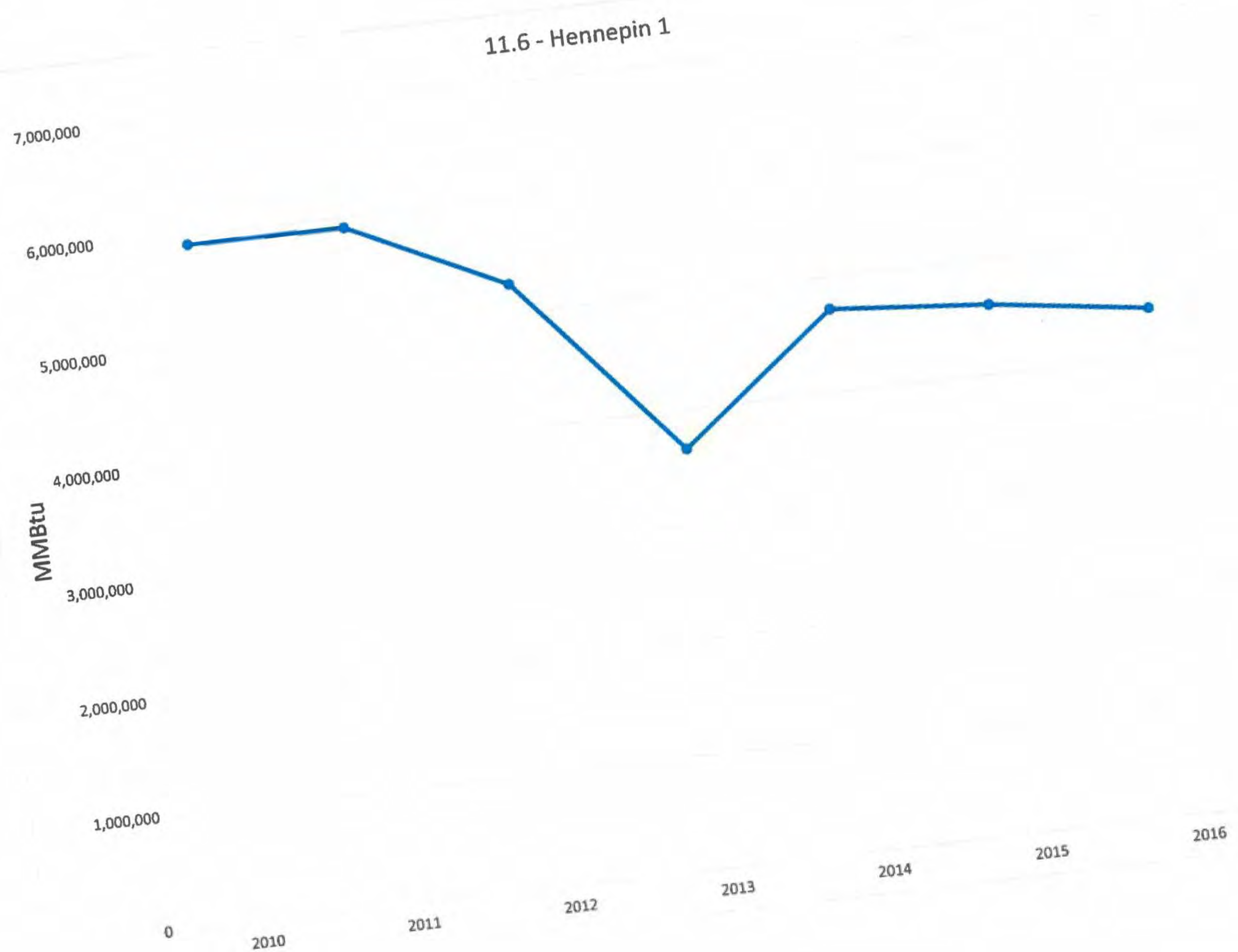
2012
2013
2014
2015
2016


11.6 - Hennepin 1
MMBtu
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
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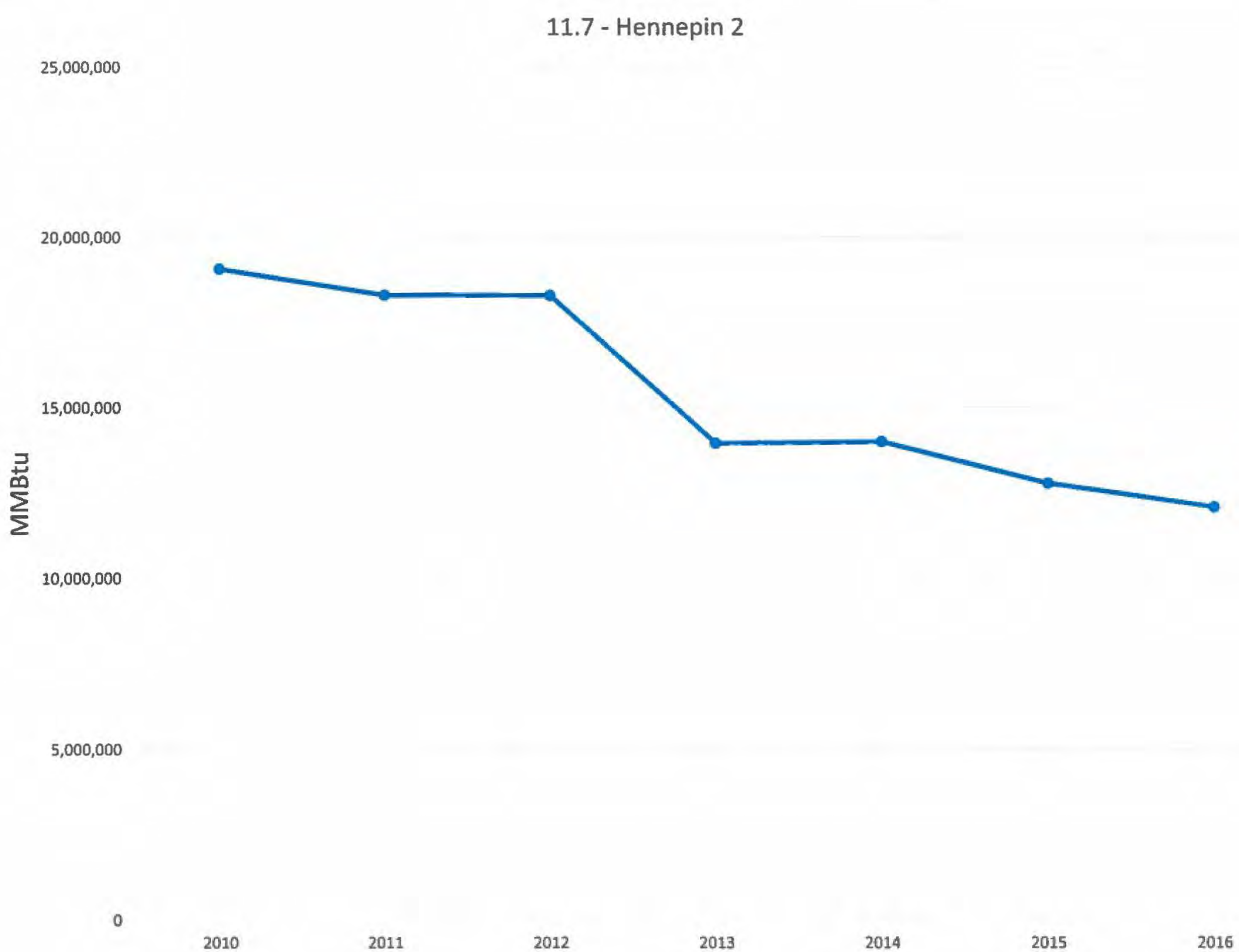
2012
2013
2014
2015
2016


11.7 - Hennepin 2
MMBtu
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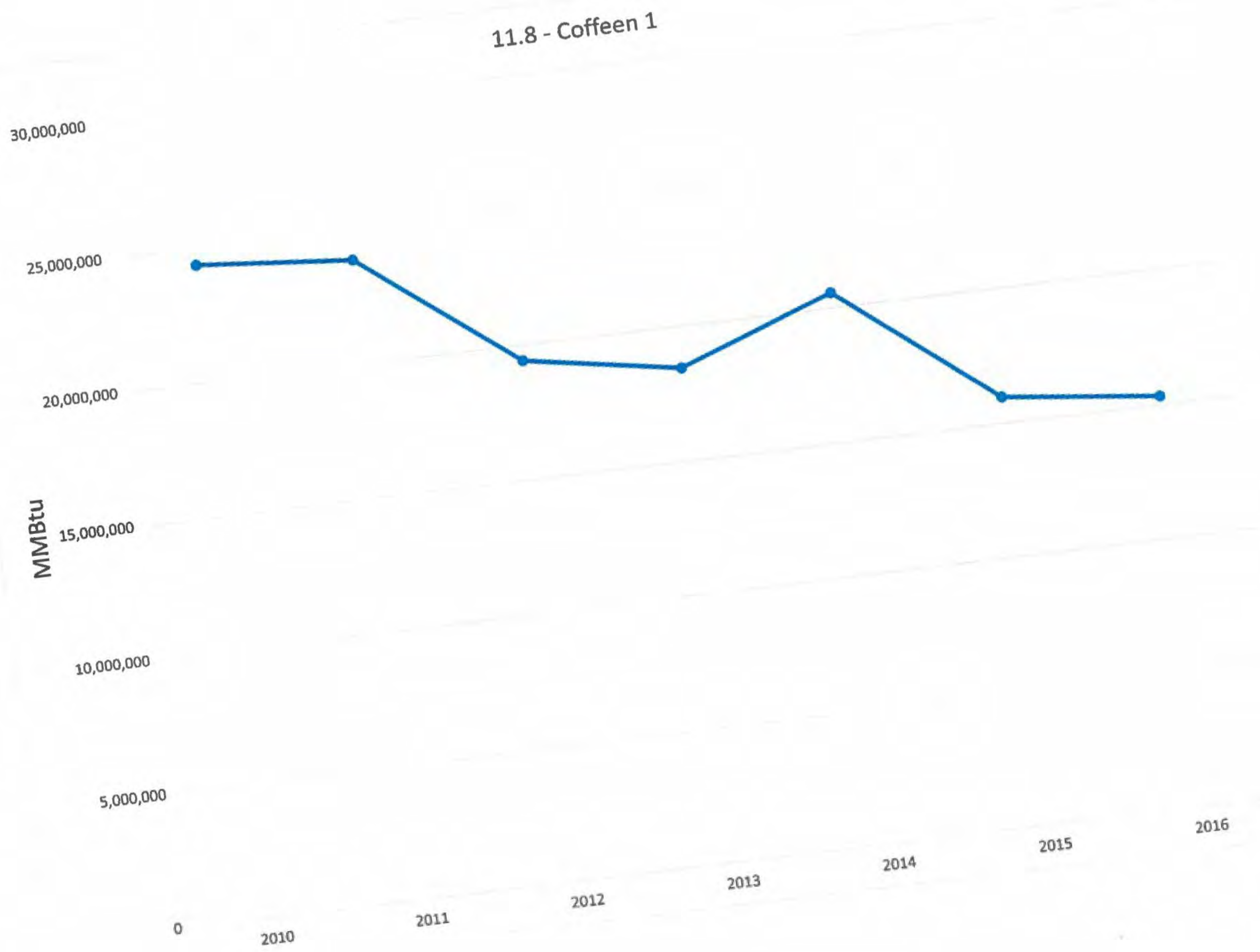
2012
2013
2014
2015
2016


11.8 - Coffeen 1
MMBtu
30,000,000
25,000,000
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15,000,000
10,000,000
5,000,000
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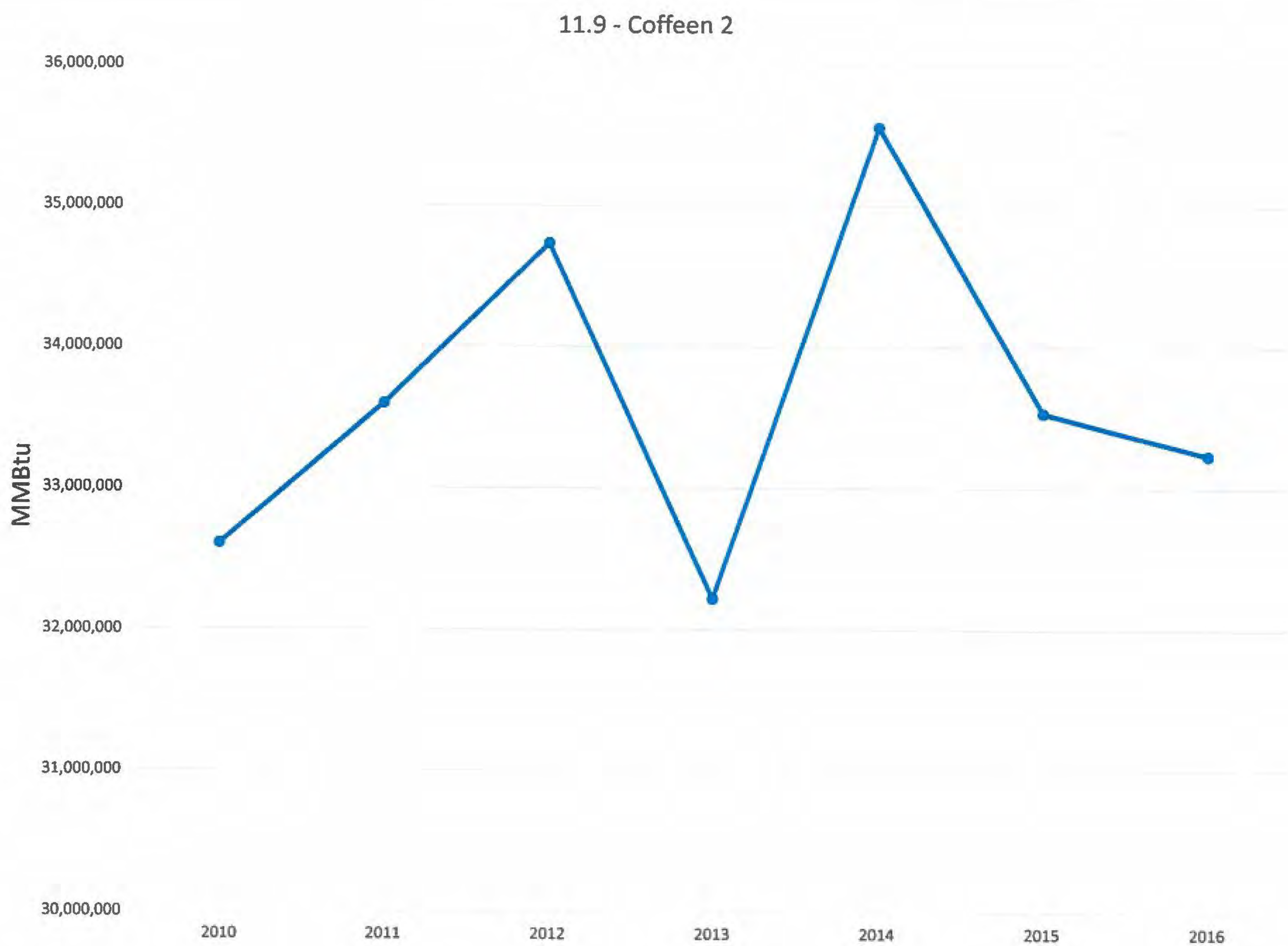
2011
2012
2013
2014
2015
2016



11.9 - Coffeen 2
MMBtu
36,000,000
35,000,000
34,000,000
33,000,000
32,000,000
31,000,000
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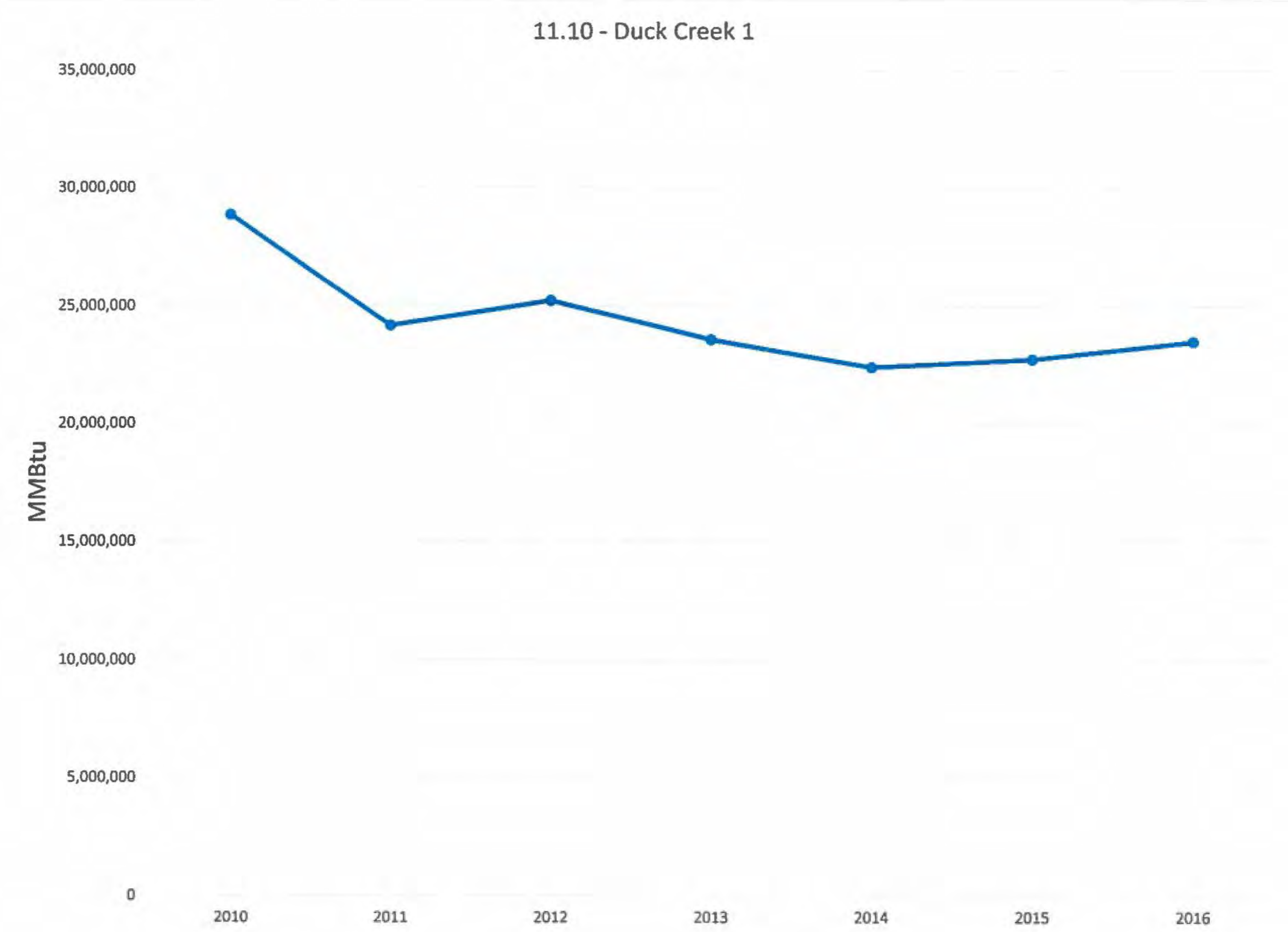
2011
2012
2013
2014
2015
2016


11.10 - Duck Creek 1
MMBtu
35,000,000
30,000,000
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15,000,000
10,000,000
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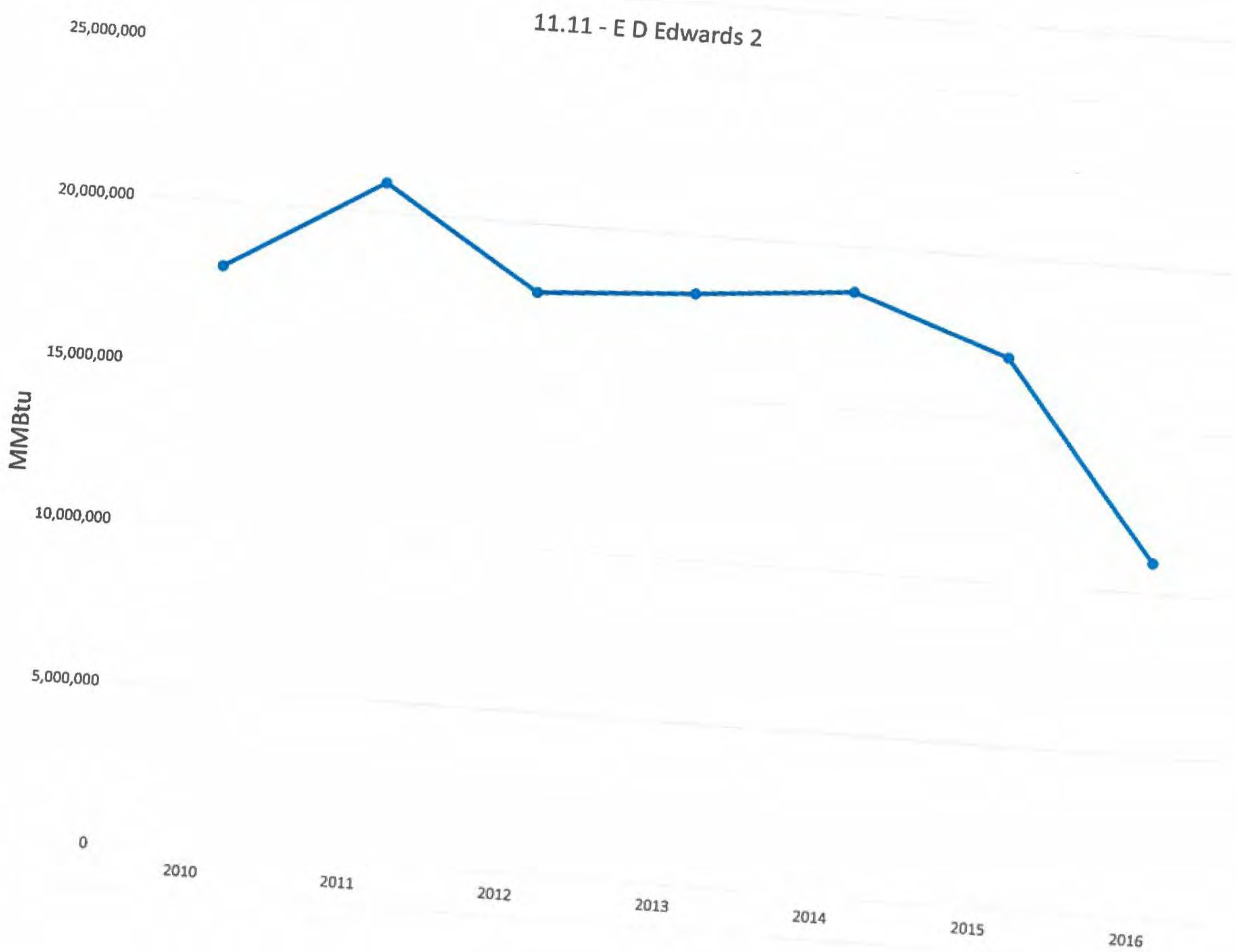
2012
2013
2014
2015
2016


11.11 - E D Edwards 2
MMBtu
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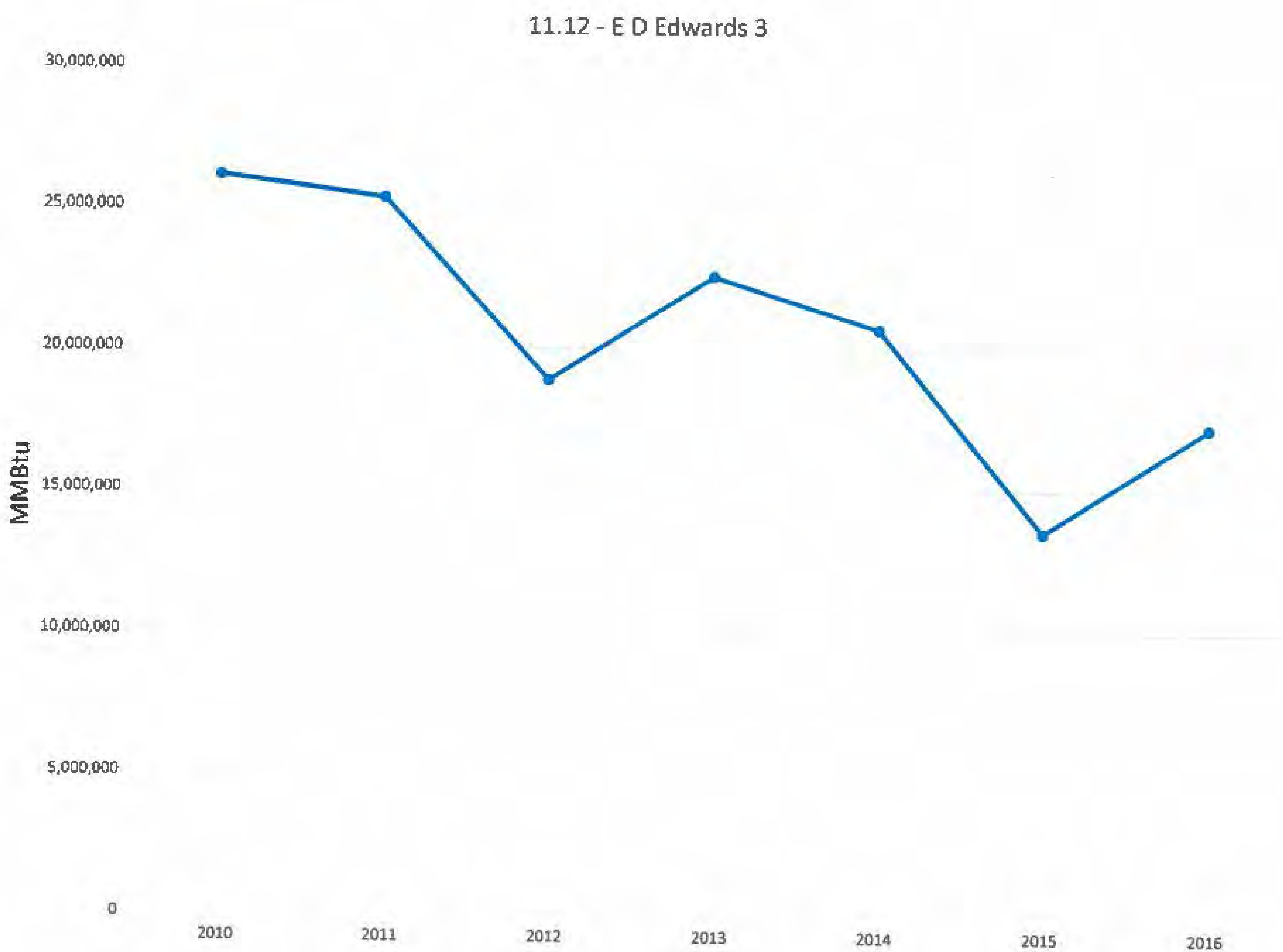
2012
2013
2014
2015
2016


11.12 - E D Edwards 3
MMBtu
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2010
2011
2012
2013
2014
2015
2016


11.13 - Joppa 1
MMBtu
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
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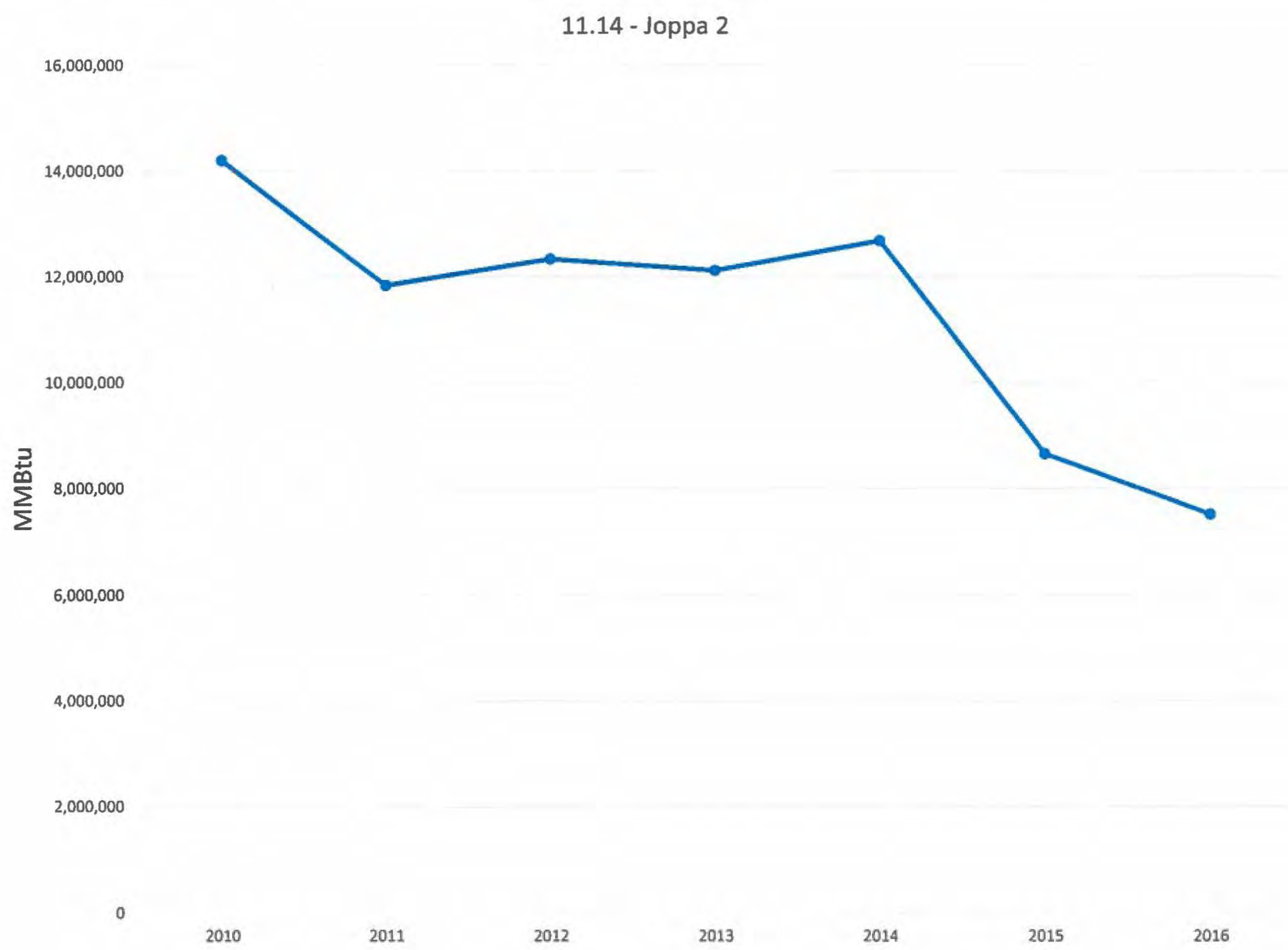
2012
2013
2014
2015
2016


11.14 - Joppa 2
MMBtu
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14,000,000
12,000,000
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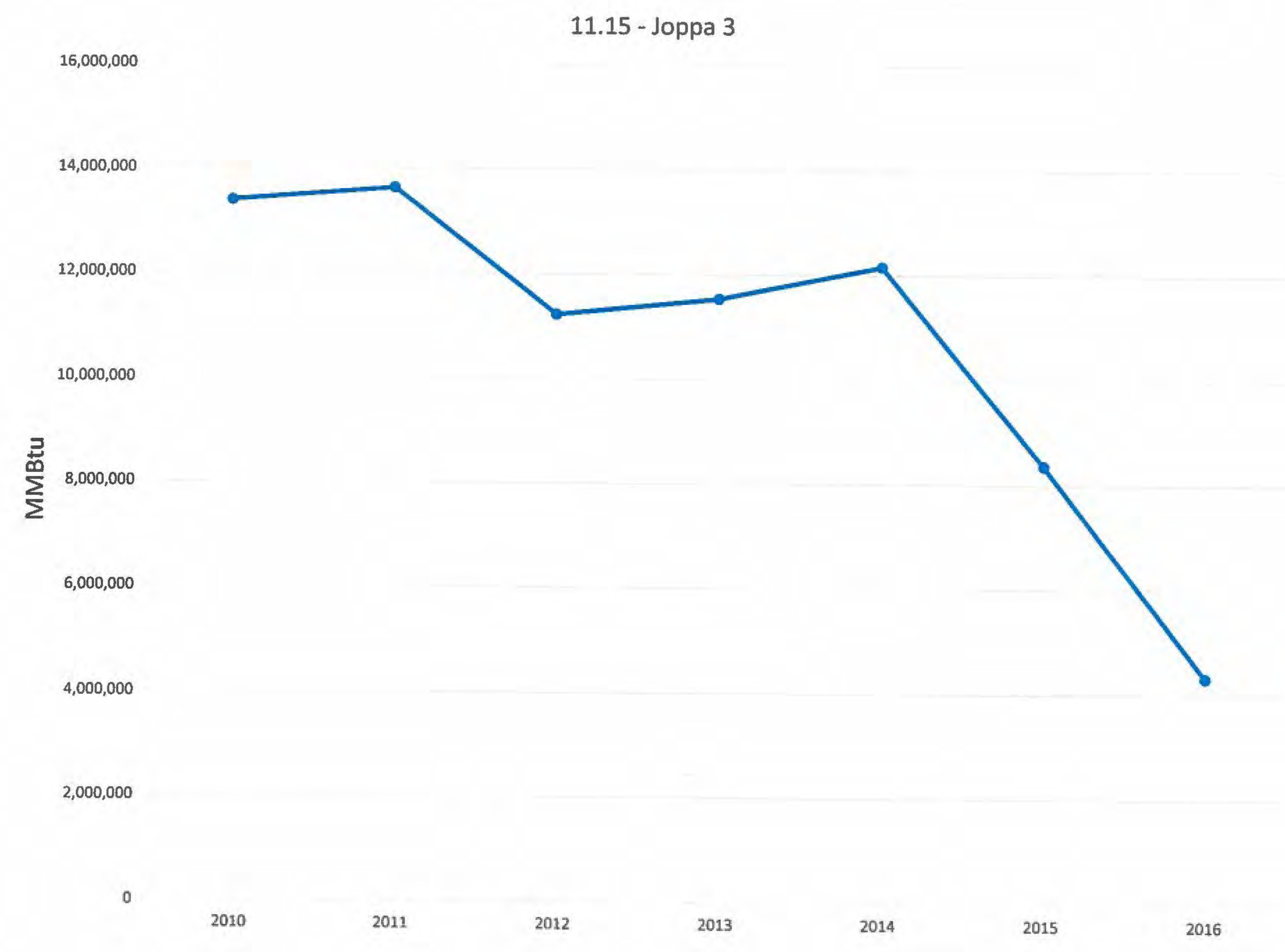
2012
2013
2014
2015
2016



11.15 - Joppa 3
MMBtu
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
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2012
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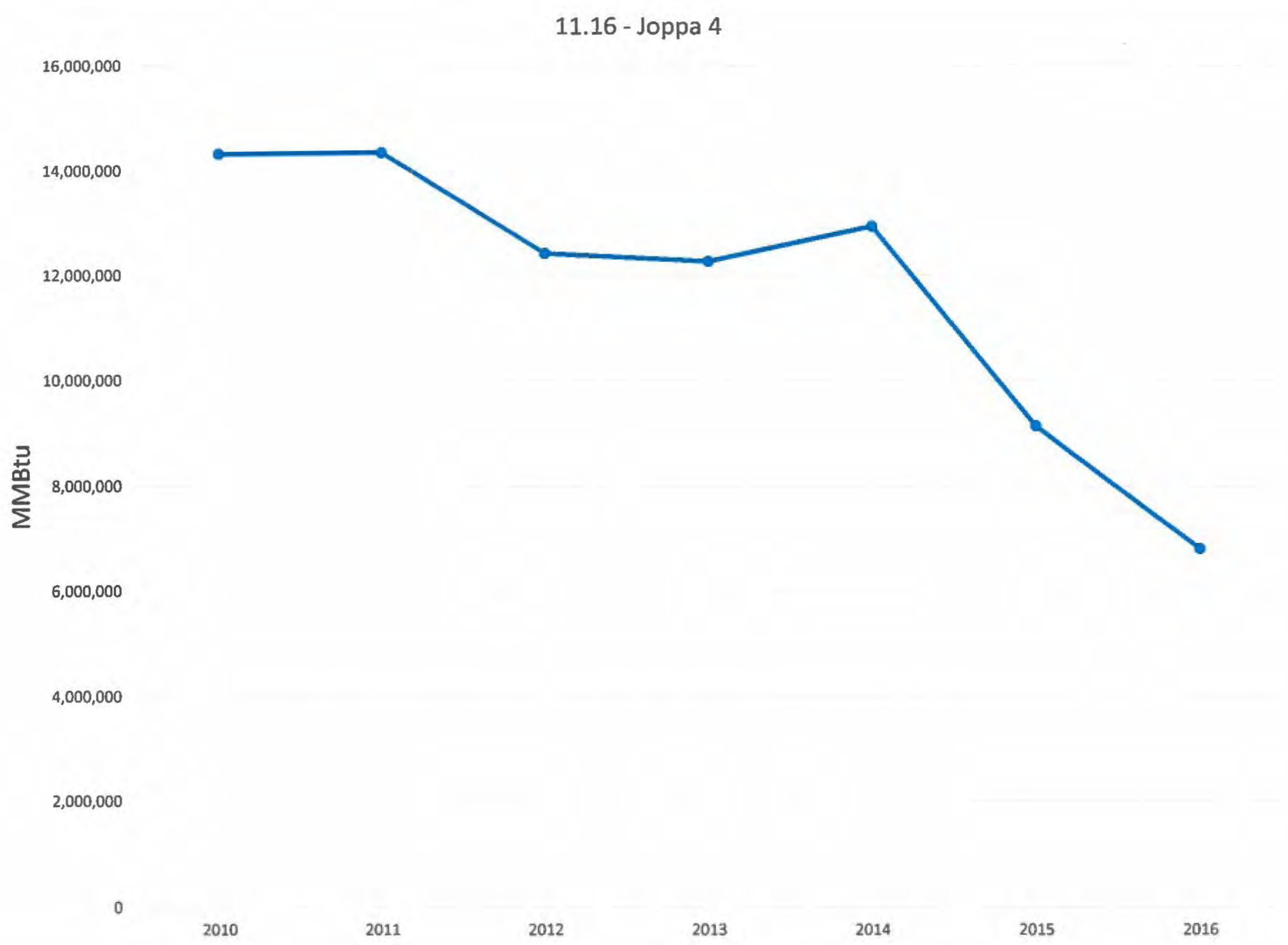
2014
2015
2016



11.16 - Joppa 4
MMBtu
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
2010
2011
2012
2013
2014
2015
2016


11.17 - Joppa 5
MMBtu
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
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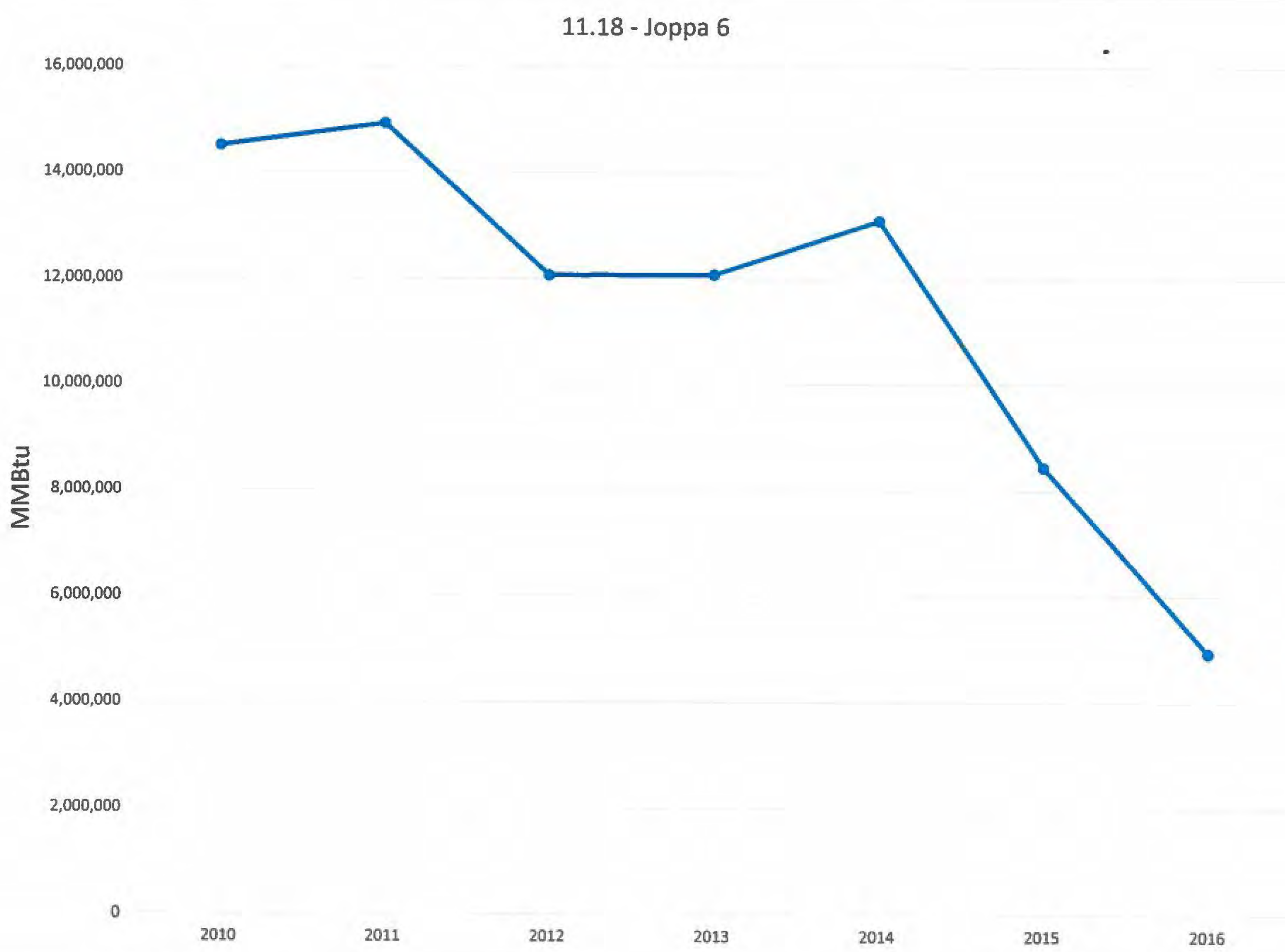
2012
2013
2014
2015
2016



11.18 - Joppa 6
MMBtu
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
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2011
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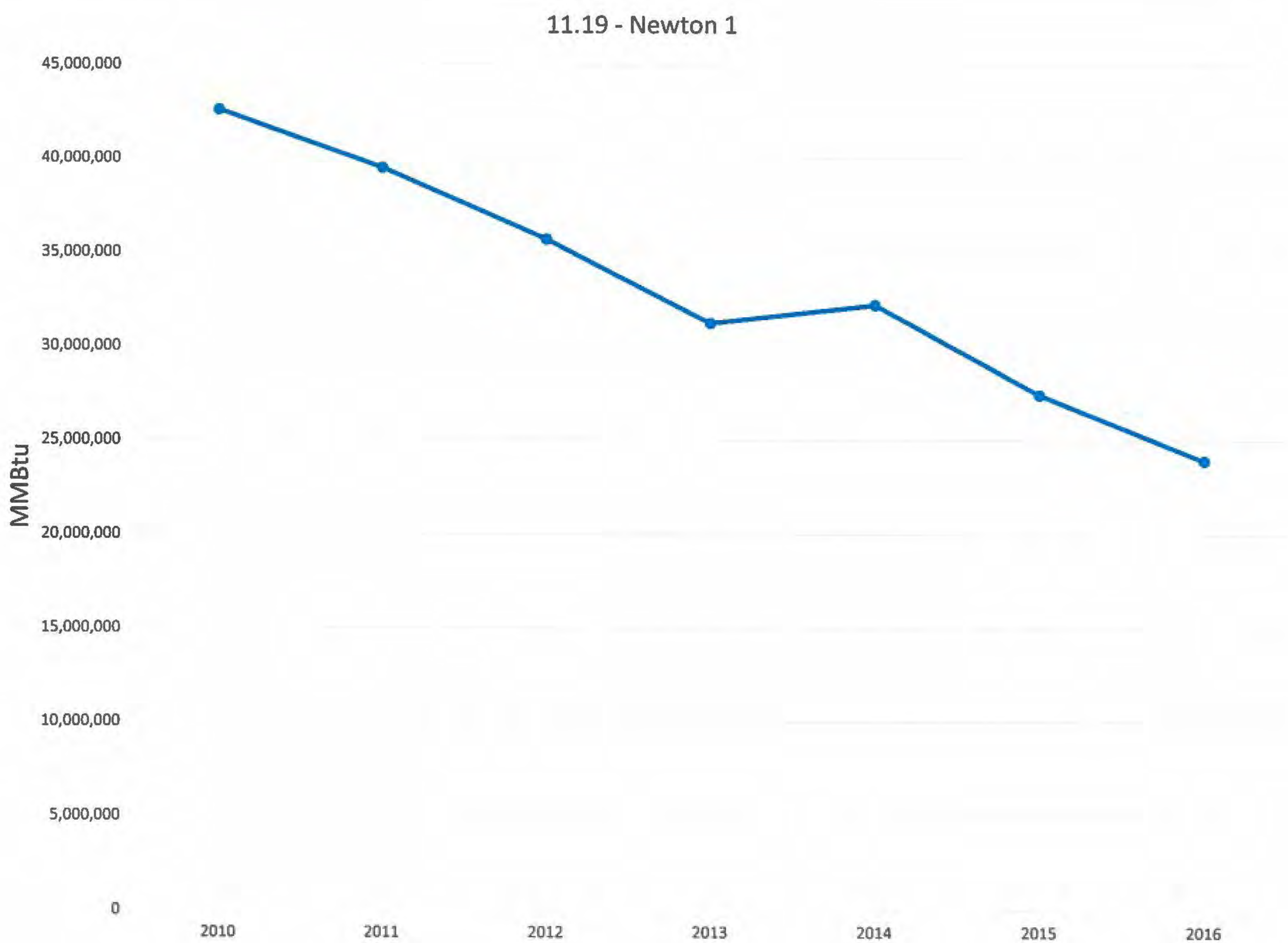
2015
2016


11.19 - Newton 1
MMBtu
45,000,000
40,000,000
35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2010
2011
2012
2013
2014
2015
2016

Attachment 5

Question 12(a), (b), (c), (d), & (e) - Updated Table 5 NOx

			Presumptive BART									
Plant	Unit	Base Year Heat Input	lb/mmBtu	Nominal Capacity (mmBtu/hr)	2012	2013	2014	2015	2016	Potential to Emit (lb/hr)	Potential to Emit (lb/mmBtu)	Potential to Emit (Tons)
Baldwin	1	43,884	0.10	6,439	1,610	1,388	1,188	1,384	1,214		0.10	2,820
Baldwin	2	37,135	0.10	5,985	1,375	1,670	1,475	985	1,428		0.10	2,621
Baldwin	3	46,403	0.15	6,400	2,125	1,902	2,040	1,879	1,397		0.10	2,803
Havana	9	28,514	NA	5,518	1,219	1,336	1,181	892	1,188		0.10	2,417
Hennepin	1	4,684	NA	802	381	259	347	317	330		0.25	2,650
Hennepin	2	17,575	NA	2,518	1,313	989	1,019	893	873		0.25	
Coffeen	1	18,570	0.10	3,282	703	635	656	567	490		0.25	3,594
Coffeen	2	37,545	0.10	5,544	1,270	1,251	1,223	1,048	1,207		0.25	6,071
Duck Creek	1	22,635	0.39	5,025	1,247	1,268	1,065	1,012	1,071		0.25	5,502
E D Edwards	2	17,222	0.23	3,321	1,891	1,752	1,723	1,683	1,153		0.25	3,636
E D Edwards	3	15,972	0.23	4,594	611	777	704	458	609		0.25	5,030
Joppa	1	13,548	NA	2,300	774	730	701	548	430		0.25	2,519
Joppa	2	16,258	NA	2,300	758	711	710	502	428		0.25	2,519
Joppa	3	15,396	NA	2,300	599	614	654	458	219		0.25	2,519
Joppa	4	13,402	NA	2,300	662	657	696	501	340		0.25	2,519
Joppa	5	15,094	NA	2,300	604	670	602	515	219		0.25	2,519
Joppa	6	16,063	NA	2,300	669	657	662	441	259		0.25	2,519
Newton	1	40,631	NA	7,449	1,946	1,583	1,440	1,226	1,070		0.25	8,157
Total		420,531			19,757	18,849	18,086	15,309	13,925			60,413

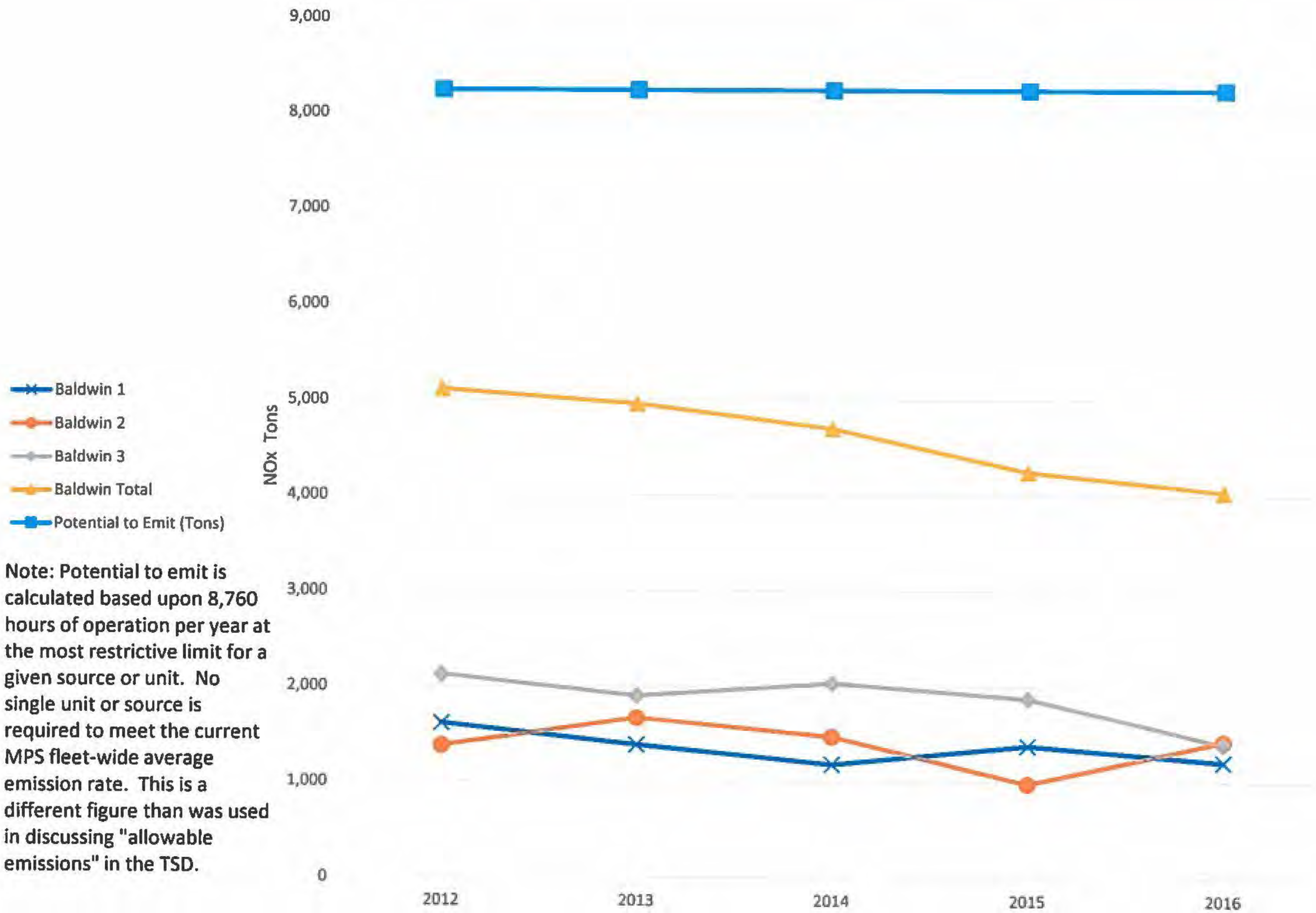
Baldwin Total					5,110	4,960	4,703	4,248	4,039			8,245
Joppa Total					4,066	4,039	4,025	2,965	1,895			15,111
Coffeen Total					1,973	1,886	1,879	1,615	1,697			9,664
ED Edwards Total					2,502	2,529	2,427	2,141	1,762			8,667
Hennepin Total					1,694	1,248	1,366	1,210	1,203			2,650

Question 12(a), (b), (c), (d), & (e) - Updated Table 6 SO2

Plant	Unit	Base Year Heat Input	Presumptive BART lb/mmBtu	Nominal Capacity (mmBtu/hr)	2012	2013	2014	2015	2016	Potential to Emit (lb/hr)	Potential to Emit (lb/mmBtu)	Potential to Emit (Tons)
Baldwin	1	43,884	0.15	6,439	1,591	1,513	1,213	1,503	1,275		0.10	2,820
Baldwin	2	37,135	0.15	5,985	6,765	1,714	1,490	1,062	1,577		1.20	31,457
Baldwin	3	46,403	0.15	6,400	1,847	1,576	1,706	1,595	1,168		0.10	2,803
Havana	9	28,514	NA	5,518	5,814	1,130	1,068	858	1,141		0.10	2,417
Hennepin	1	4,684	NA	802	1,313	883	1,002	1,048	1,099	17,050		9,050
Hennepin	2	17,575	NA	2,518	4,593	3,396	2,959	2,922	2,966			
Coffeen	1	18,570	0.15	3,282	43	61	22	21	13	55,555		660*
Coffeen	2	37,545	0.15	5,544	60	47	10	16	20			
Duck Creek	1	22,635	0.15	5,025	296	231	240	78	10		1.20	26,411
E D Edwards	2	17,222	0.15	3,321	4,871	4,107	4,021	3,609	2,306	2,100		9,198
E D Edwards	3	15,972	0.15	4,594	4,958	4,852	4,244	2,826	3,584	2,756		12,071
Joppa	1	13,548	NA	2,300	3,005	2,843	3,080	2,360	1,576	6,144		26,911
Joppa	2	16,258	NA	2,300	2,918	2,741	3,093	2,131	1,562	6,144		26,911
Joppa	3	15,396	NA	2,300	2,727	2,622	2,950	2,070	911	6,144		26,911
Joppa	4	13,402	NA	2,300	3,007	2,783	3,137	2,268	1,333	6,144		26,911
Joppa	5	15,094	NA	2,300	2,521	2,802	2,866	2,332	1,015	6,144		26,911
Joppa	6	16,063	NA	2,300	2,812	2,751	3,154	2,070	1,237	6,144		26,911
Newton	1	40,631	NA	7,449	10,538	7,270	8,126	6,938	4,827		1.20	39,152
Total		**420,531**			**59,680**	**43,324**	**44,382**	**35,707**	**27,621**			**296,849**

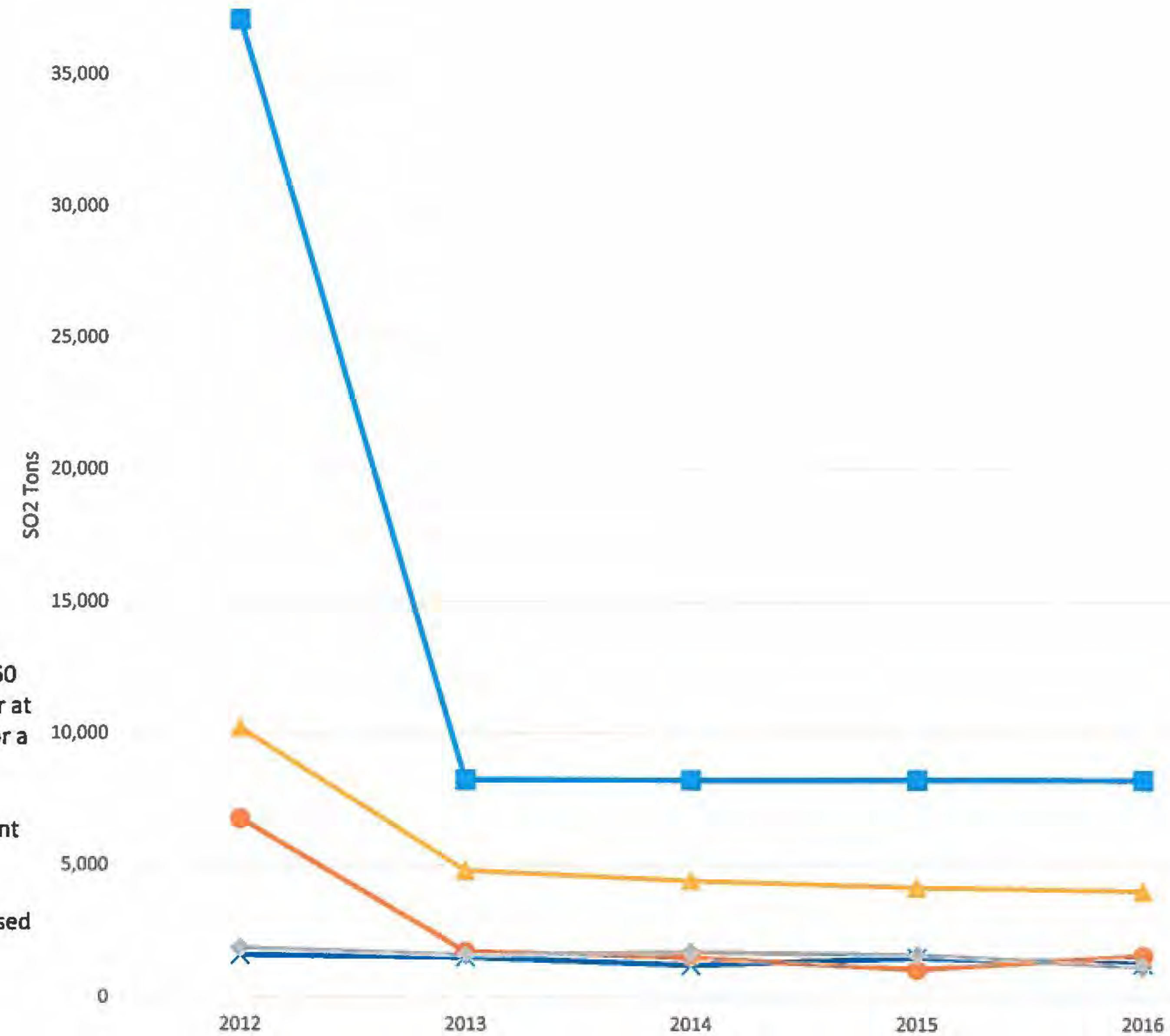
Baldwin Total					10,203	4,803	4,409	4,160	4,020			37,081
Joppa Total					16,990	16,542	18,280	13,231	7,634	36,865		161,469
Coffeen Total					103	108	32	37	33			660
ED Edwards Total					9,829	8,959	8,265	6,435	5,890			21,269
Hennepin Total					5,906	4,279	3,961	3,970	4,065			9,050

12.f.1 - Baldwin NOx Potential to Emit and Actual Emissions per Year



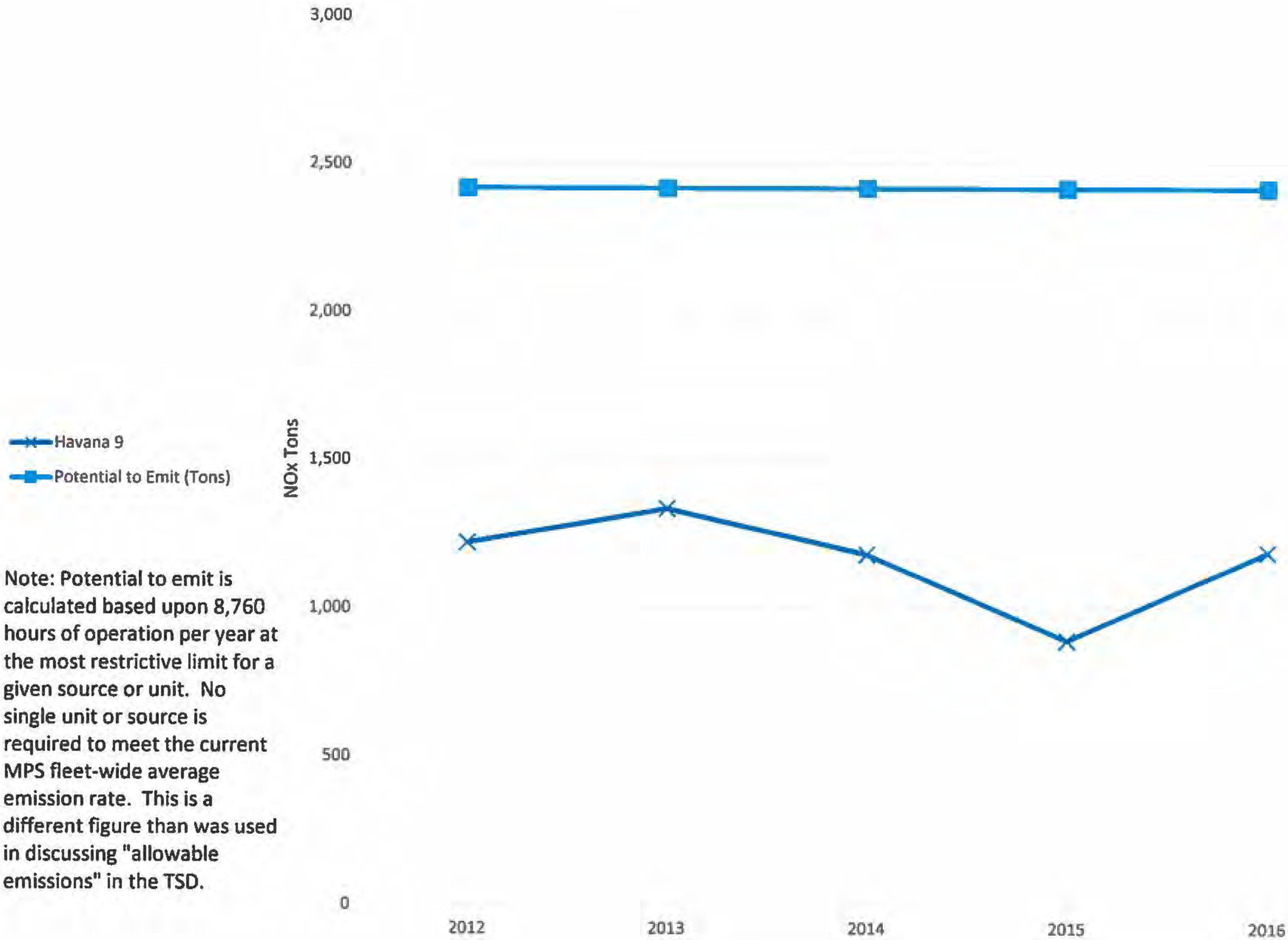
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.2 - Baldwin SO2 Potential to Emit and Actual Emissions per Year

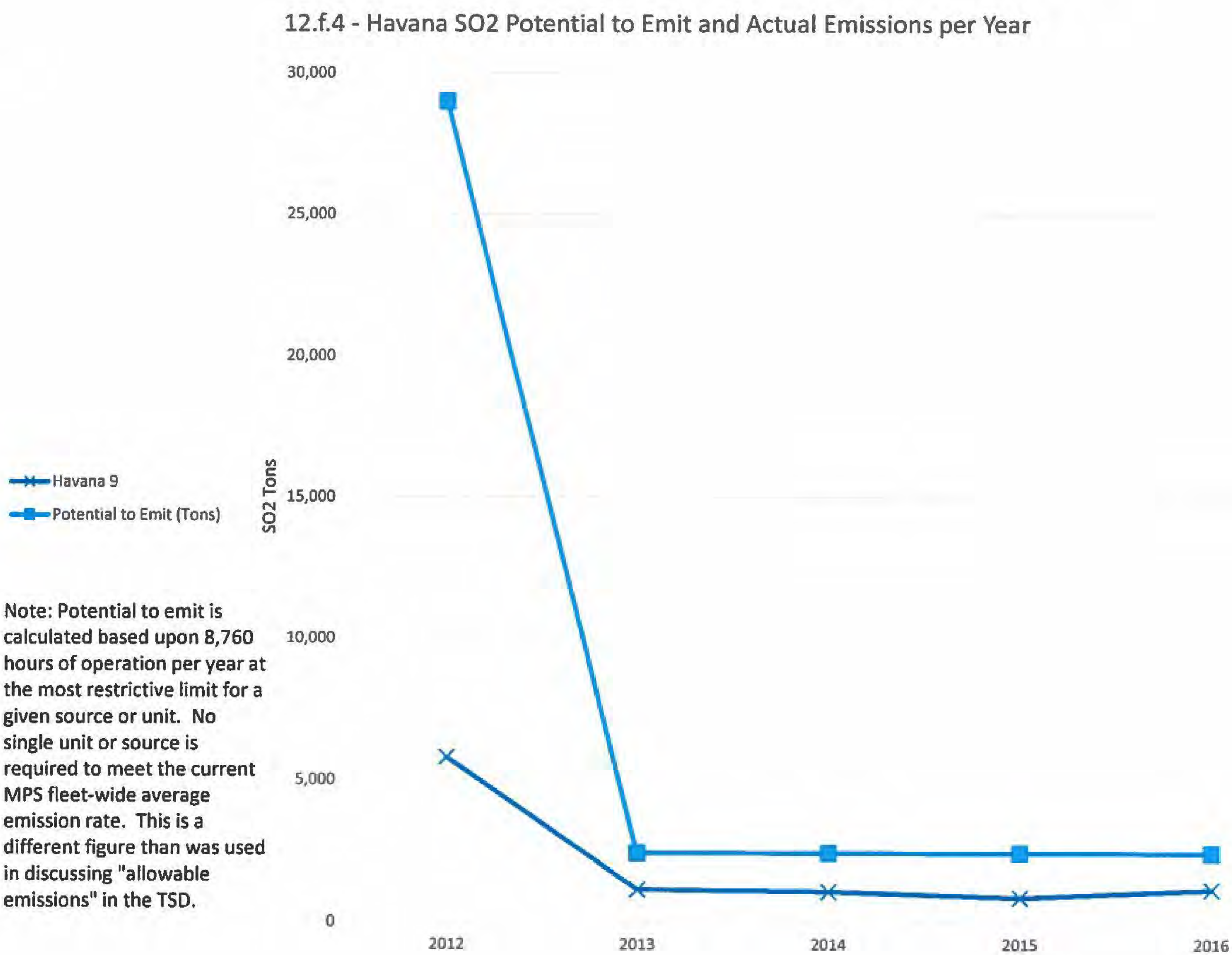


Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.3 - Havana NOx Potential to Emit and Actual Emissions per Year



Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

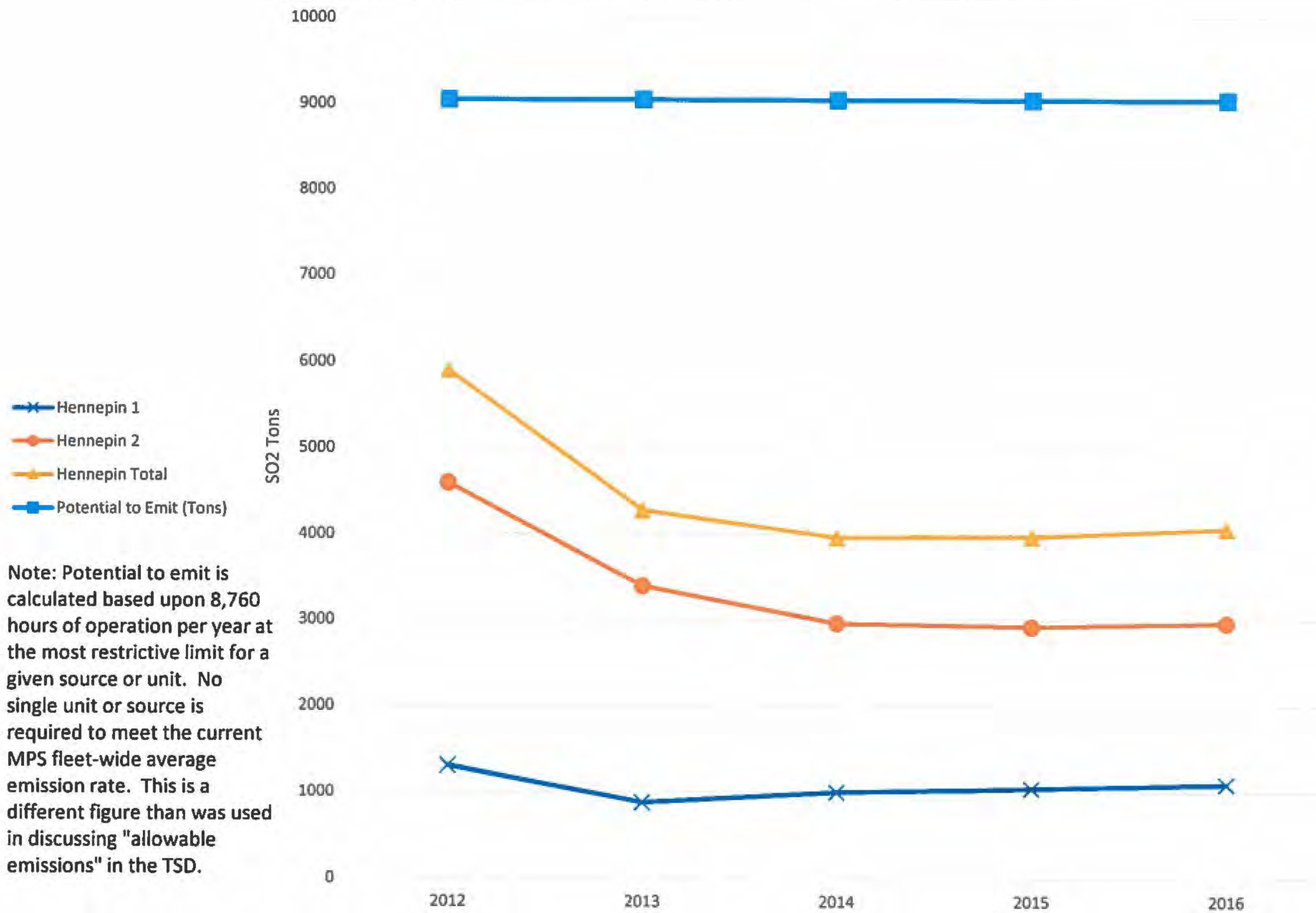


Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

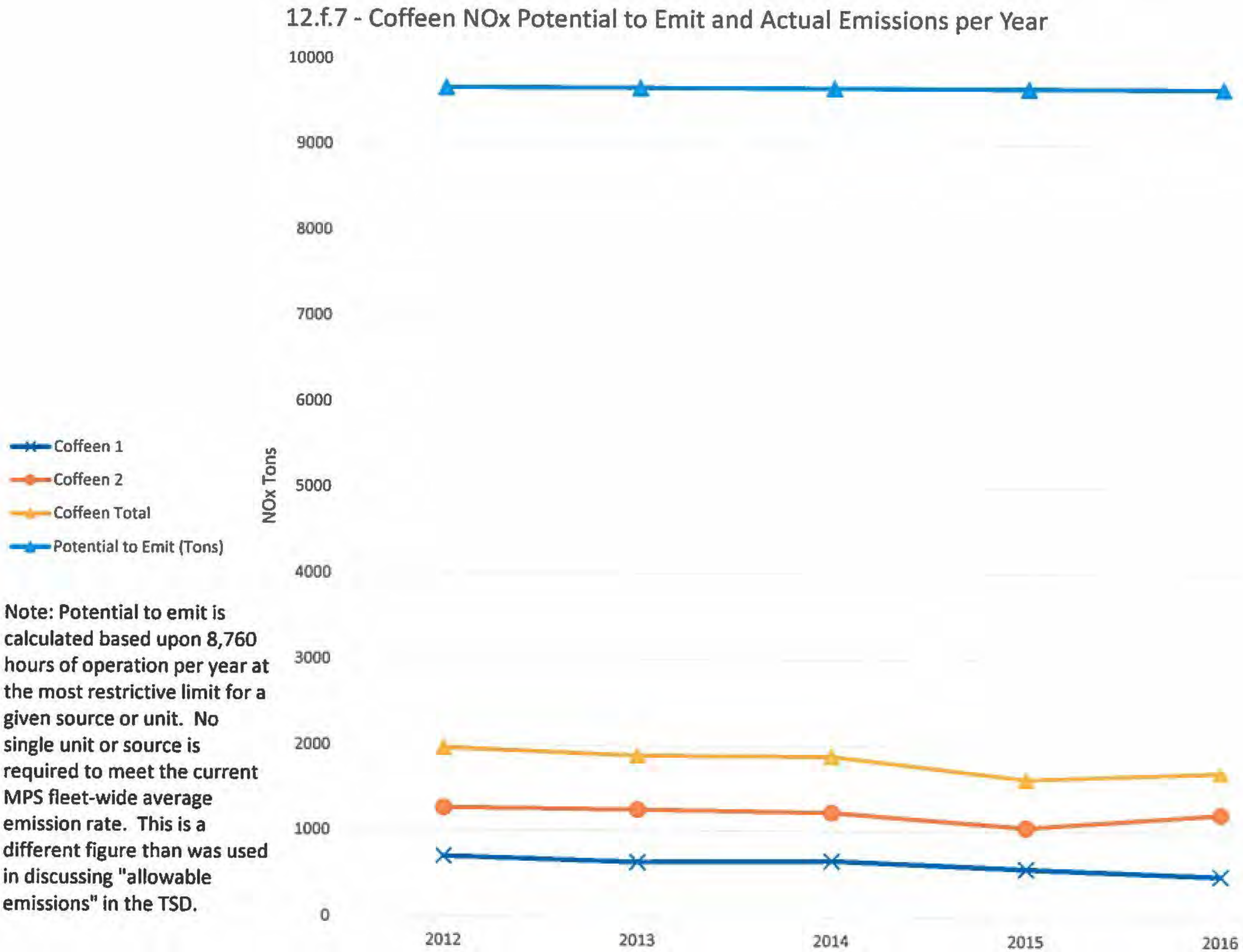
12.f.5 - Hennepin NOx Potential to Emit and Actual Emissions per Year

Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.6 - Hennepin SO2 Potential to Emit and Actual Emissions per Year

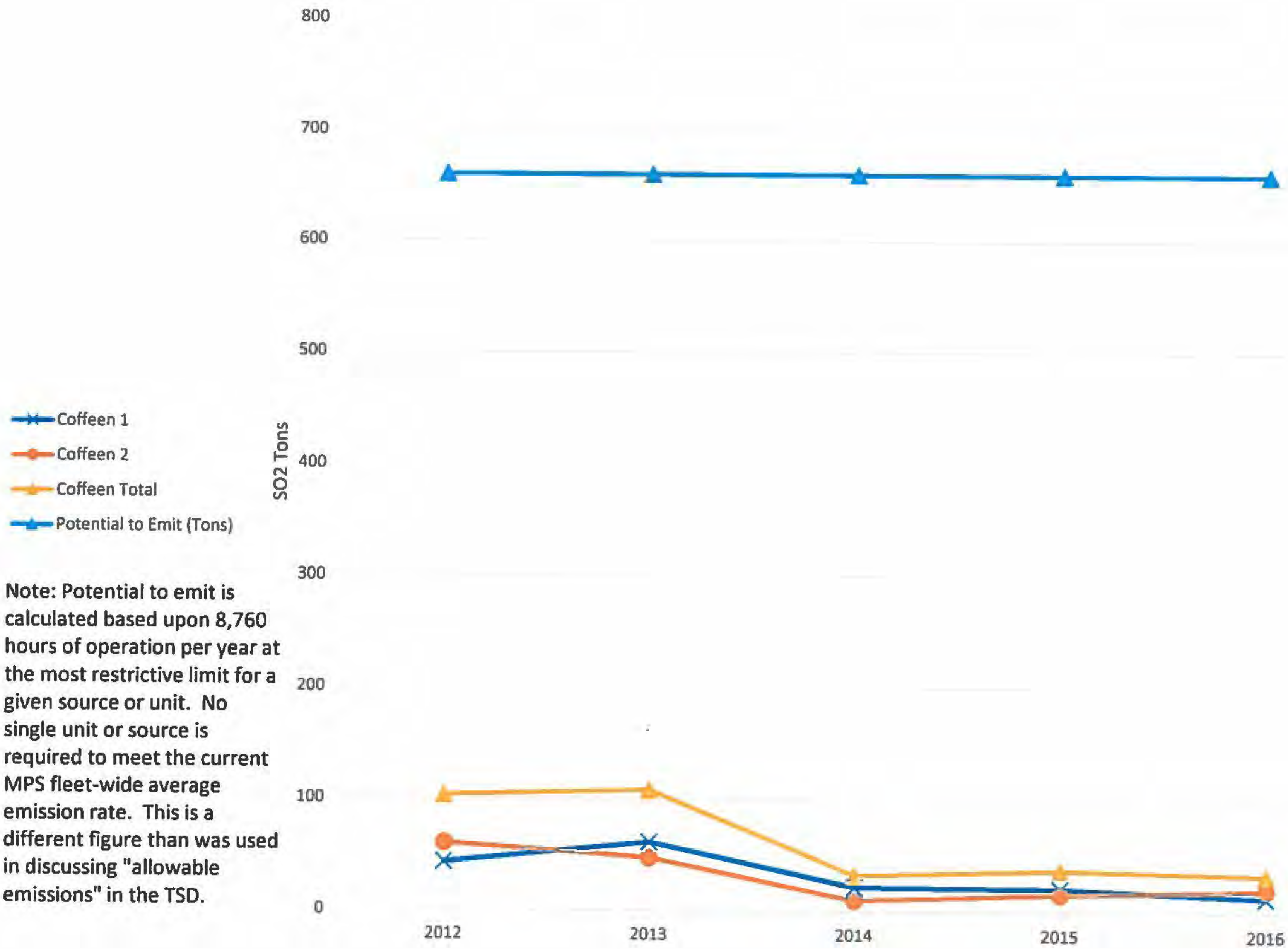


Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

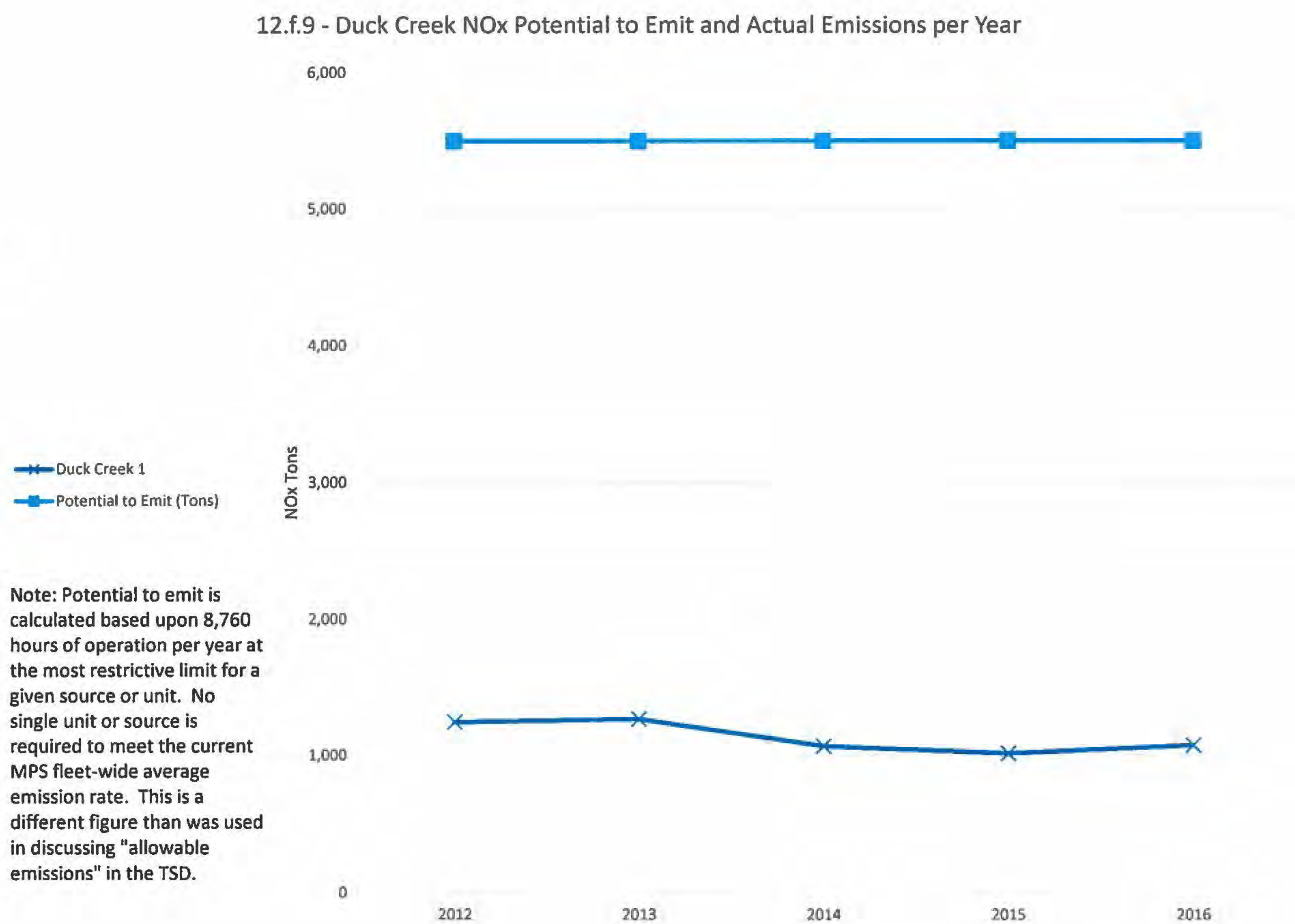


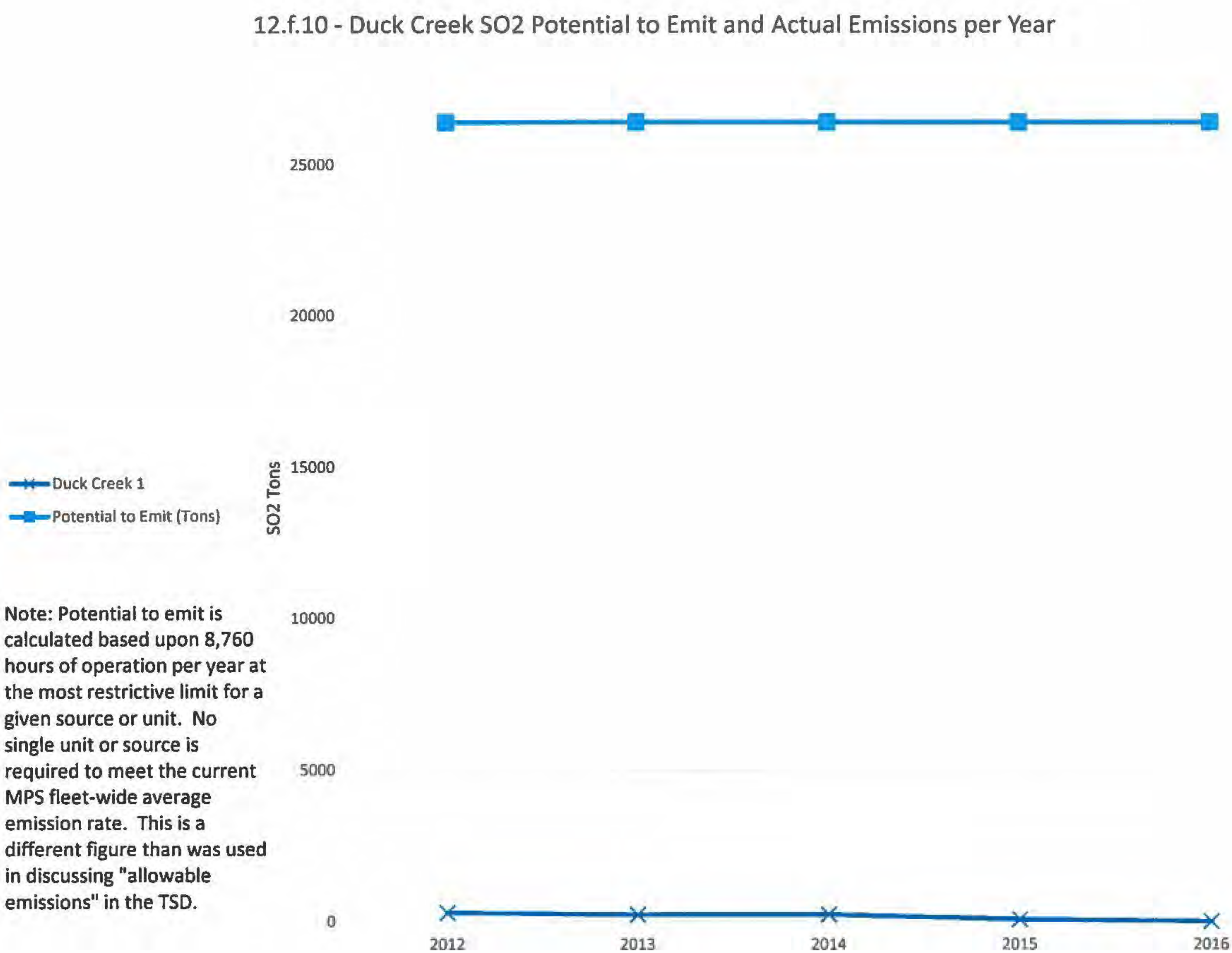
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.8 - Coffeen SO2 Potential to Emit and Actual Emissions per Year



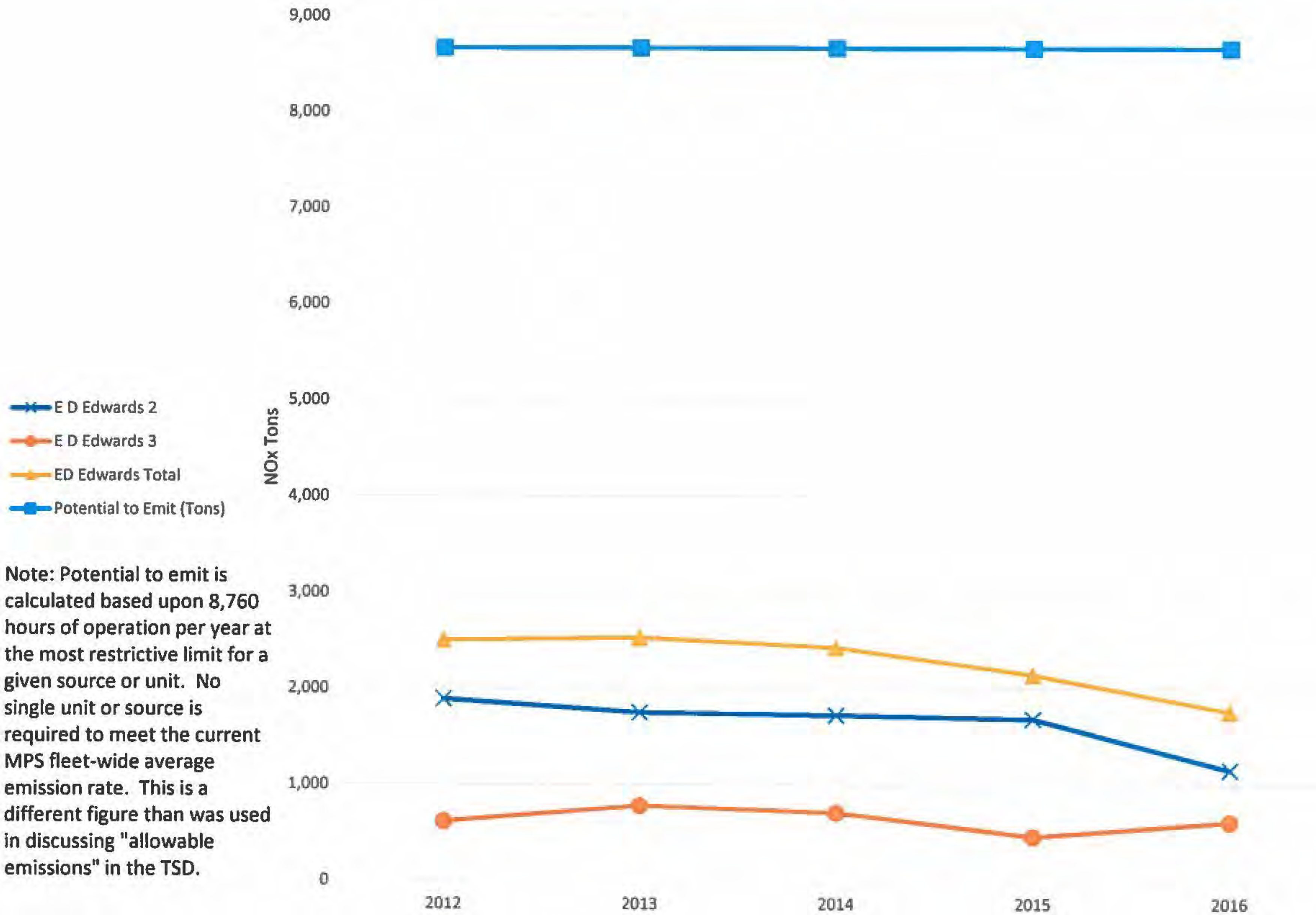
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.


12.f.9 - Duck Creek NOx Potential to Emit and Actual Emissions per Year
6,000
5,000
4,000
3,000
2,000
1,000
0
NOx Tons
2012
2013
2014
2015
2016
Duck Creek 1
Potential to Emit (Tons)
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.



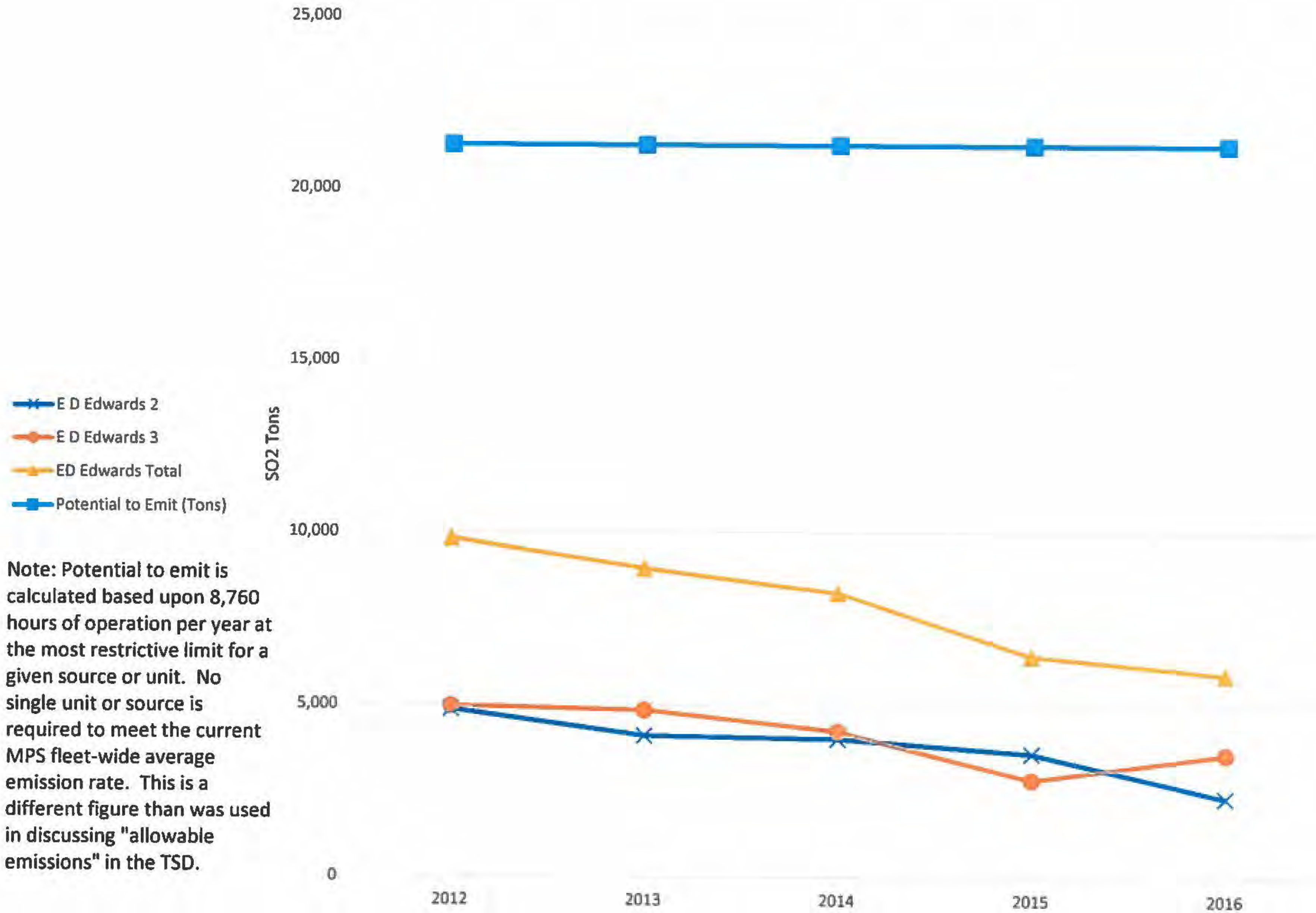
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.11 - ED Edwards NOx Potential to Emit and Actual Emissions per Year



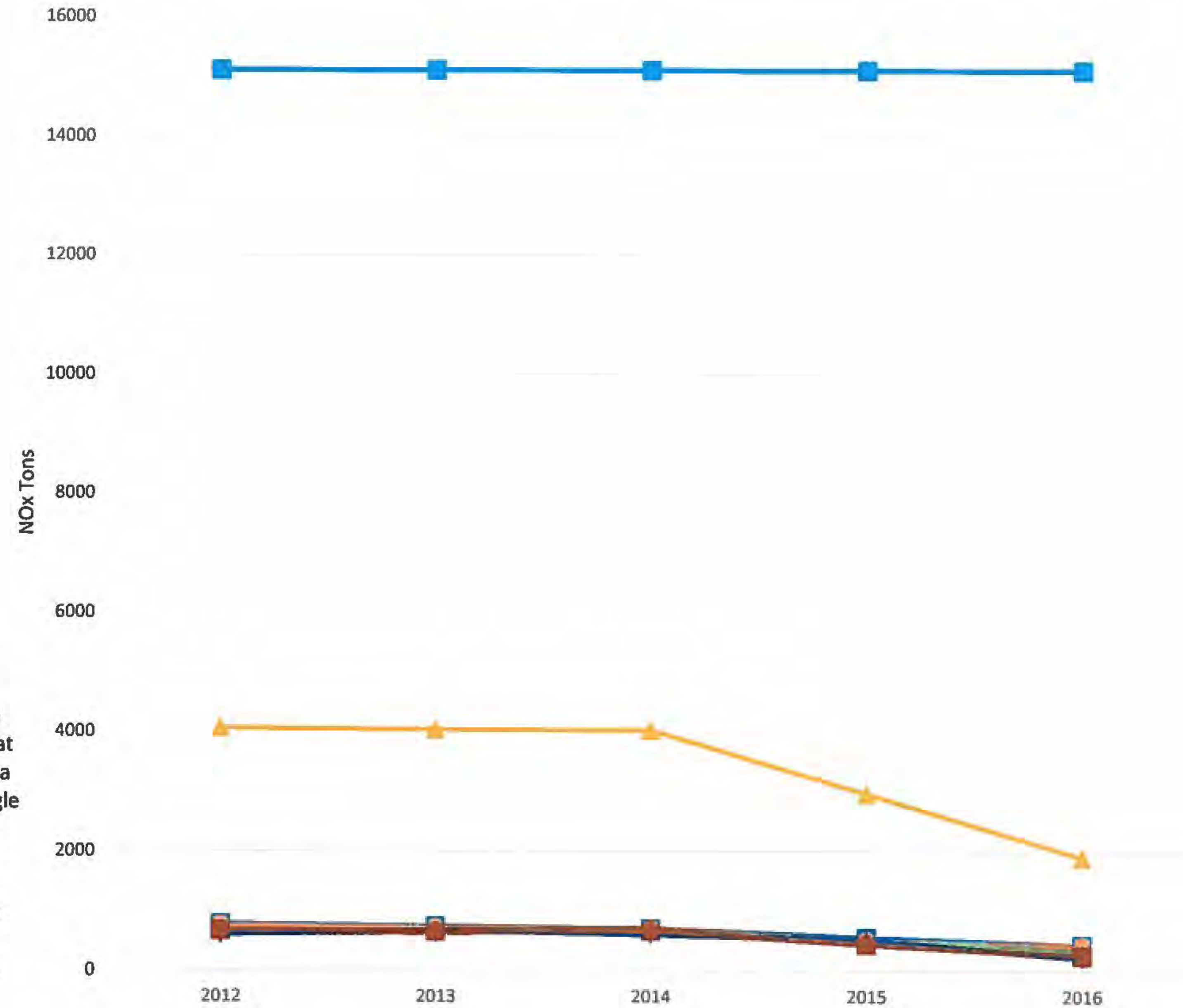
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.12 - ED Edwards SO2 Potential to Emit and Actual Emissions per Year

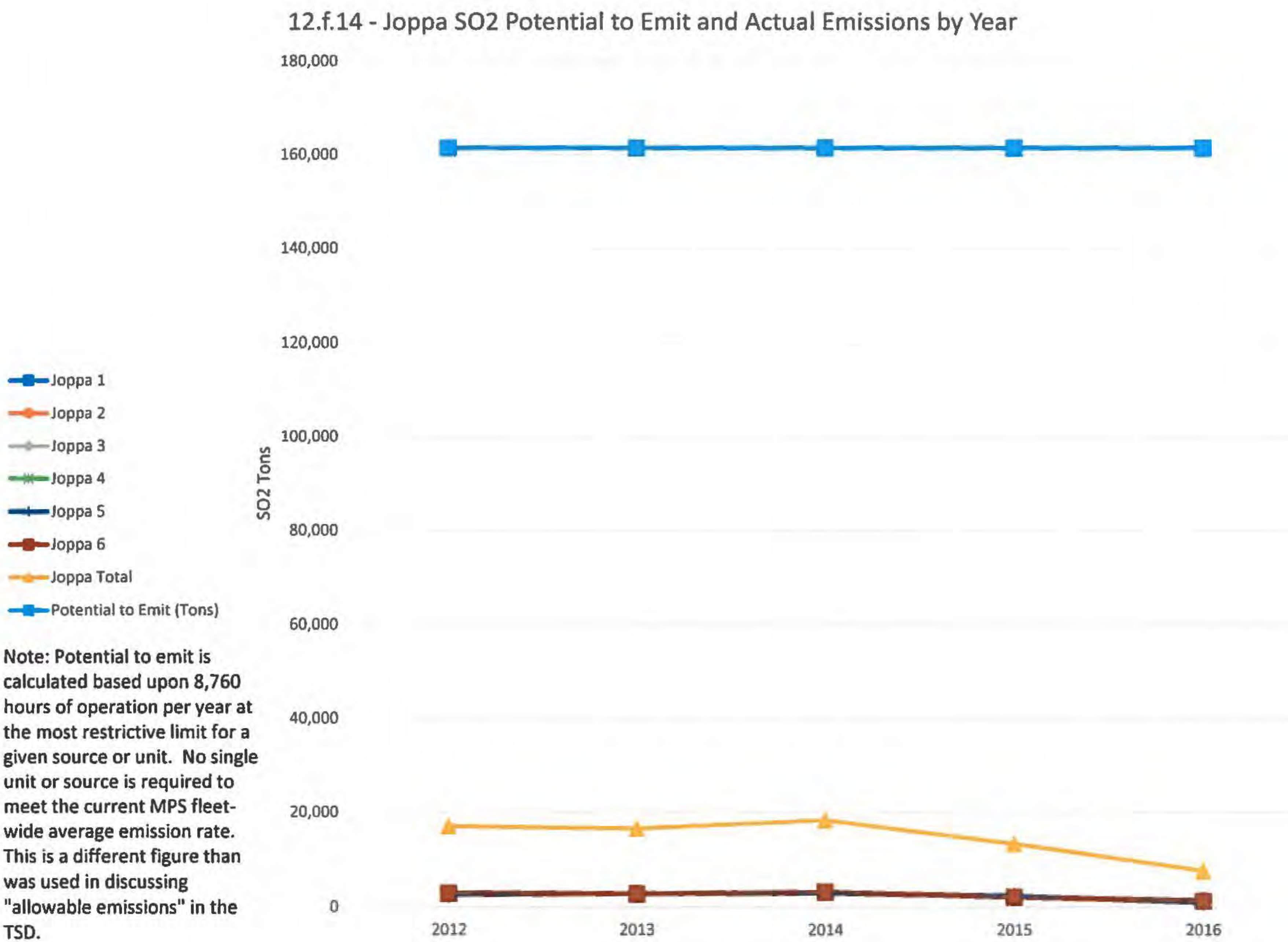


Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.13 - Joppa NOx Potential to Emit and Actual Emissions by Year

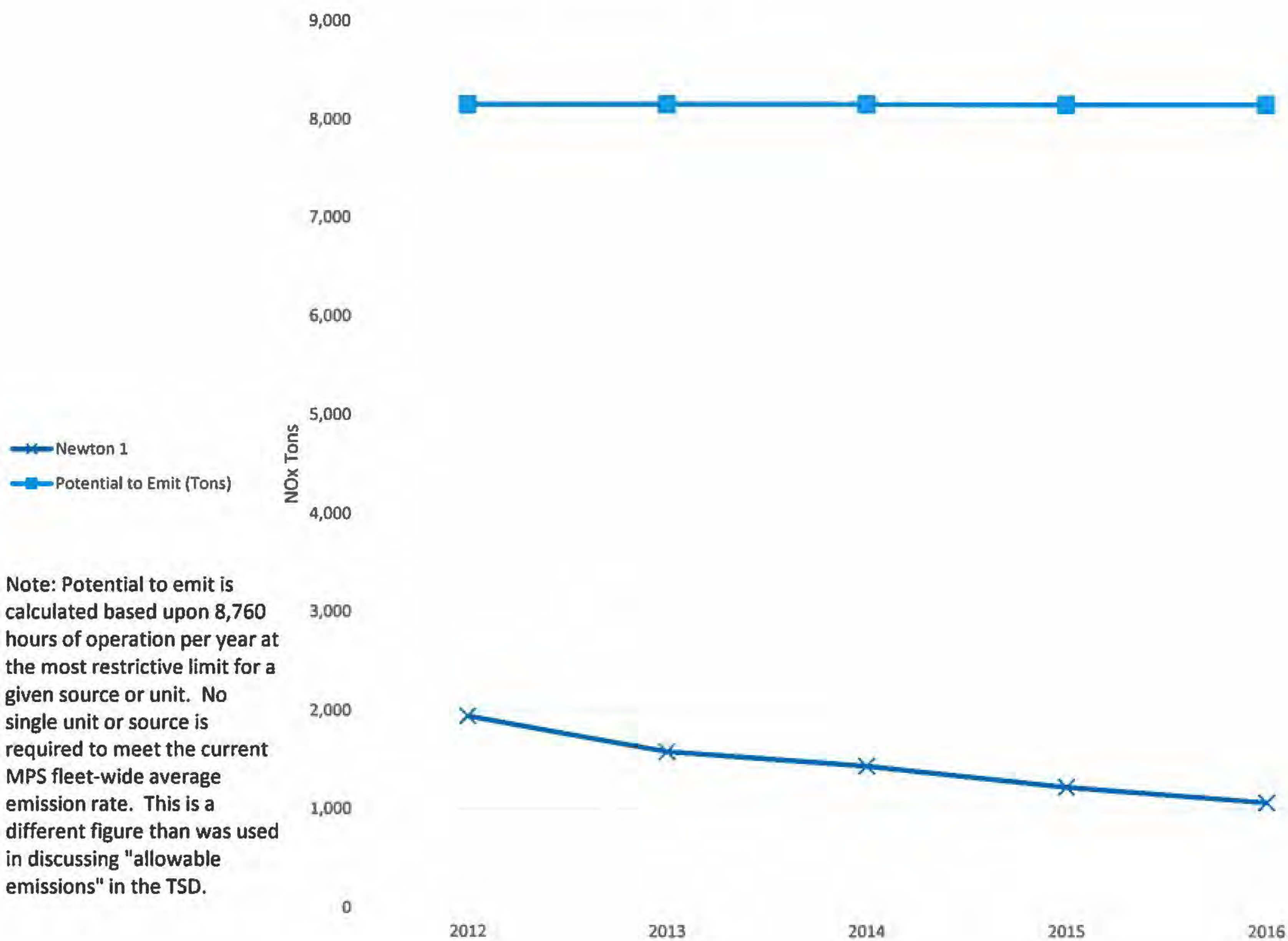


Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

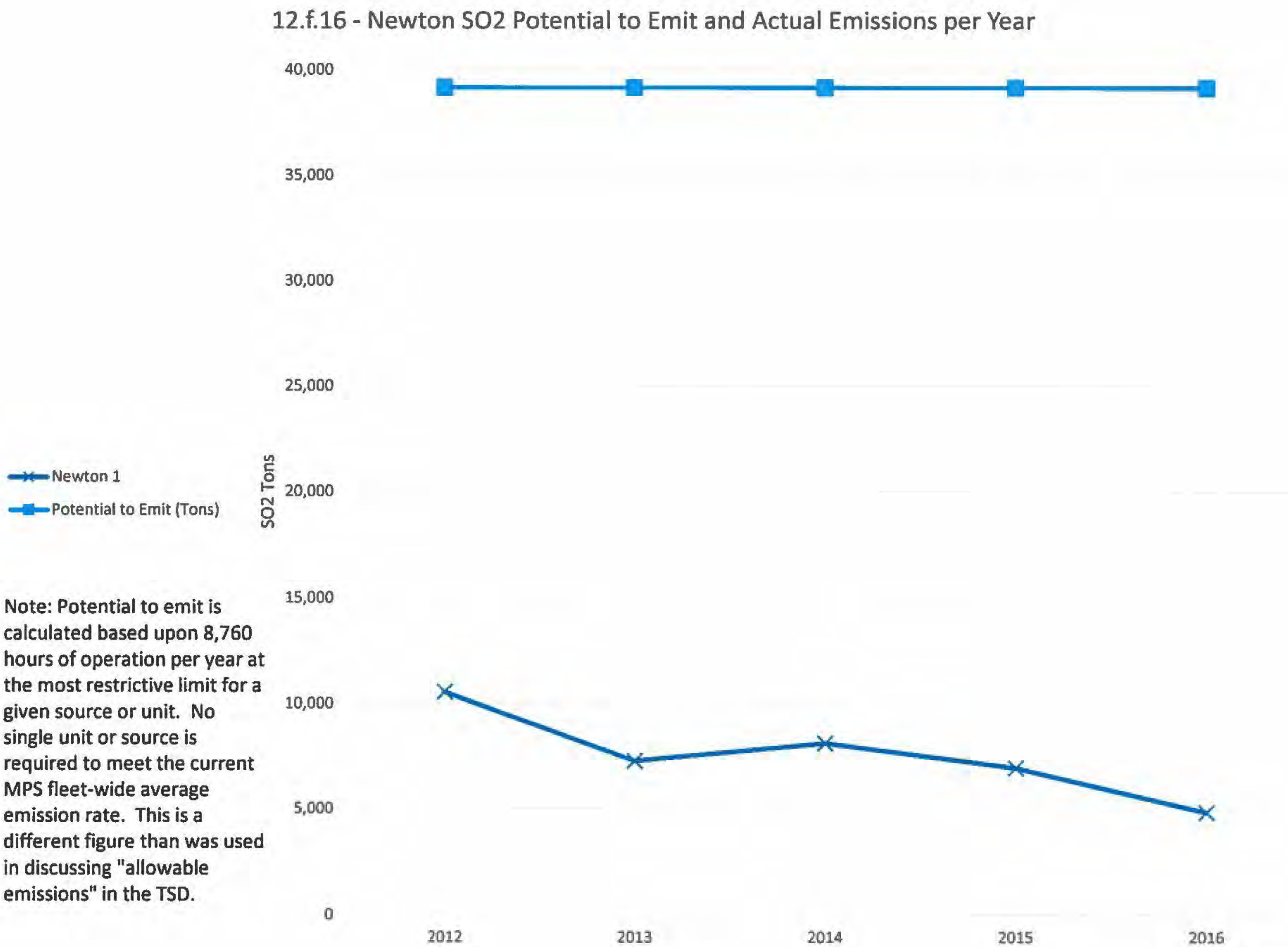


Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

12.f.15 - Newton NOx Potential to Emit and Actual Emissions per Year

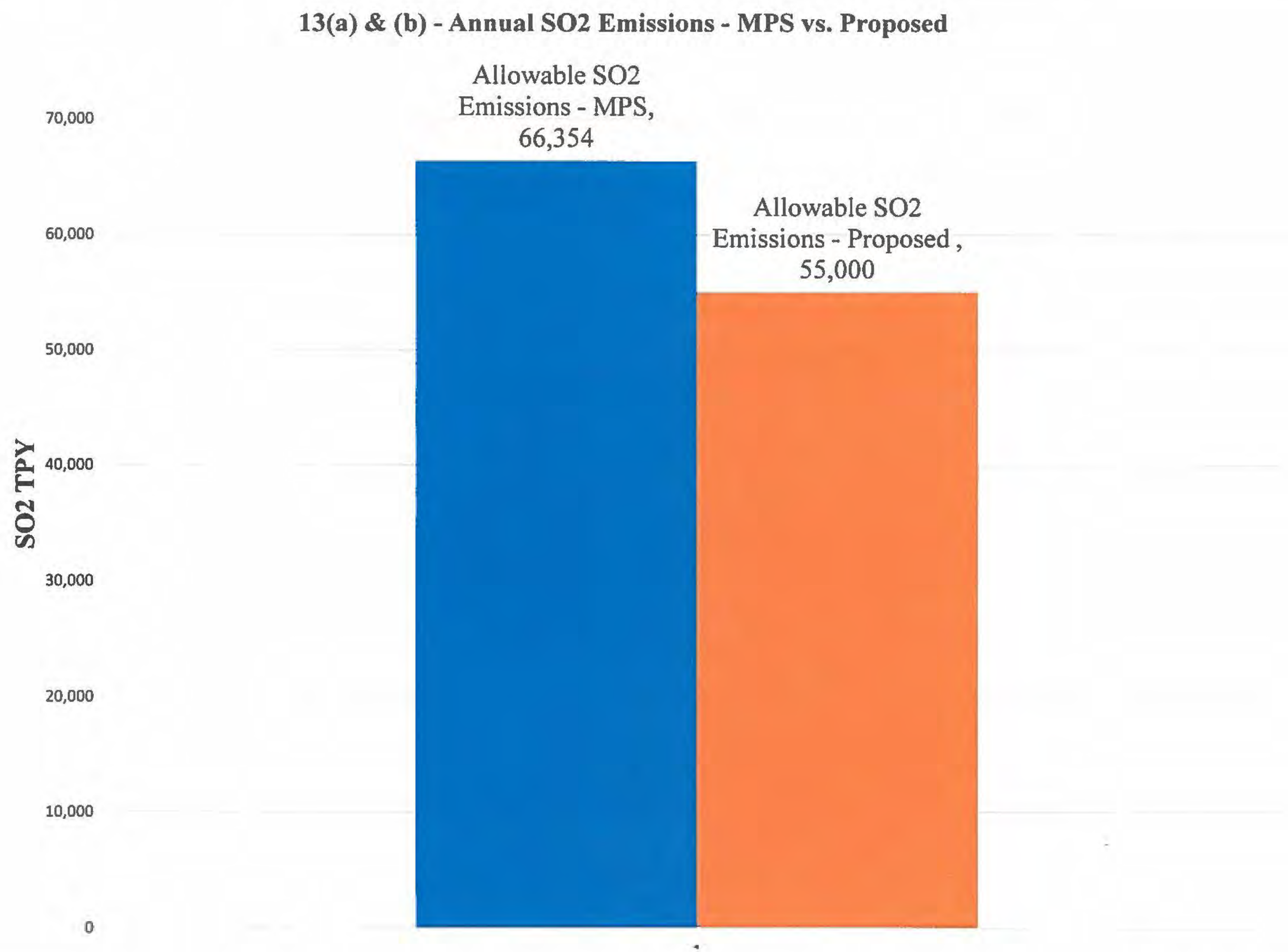


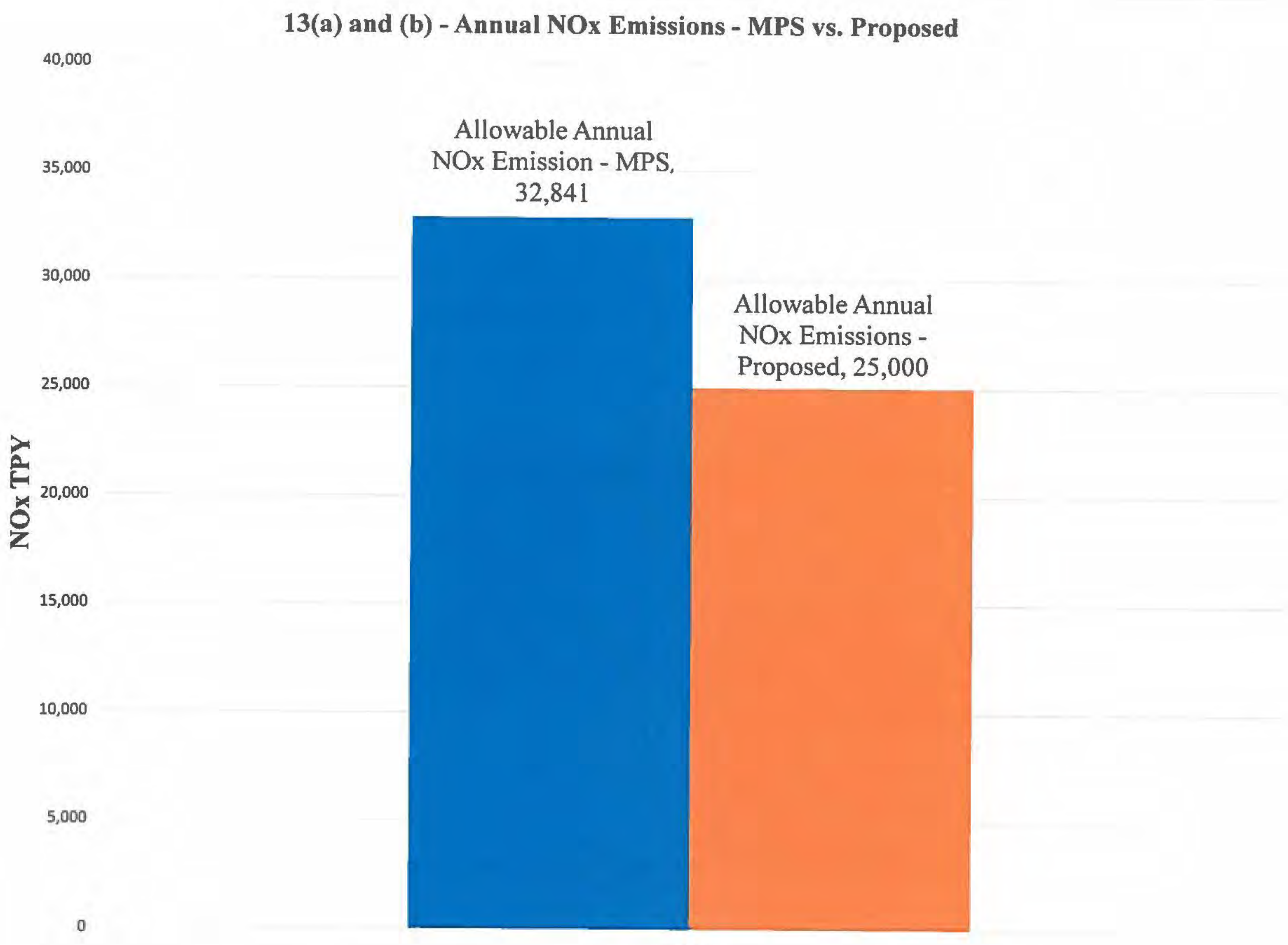
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

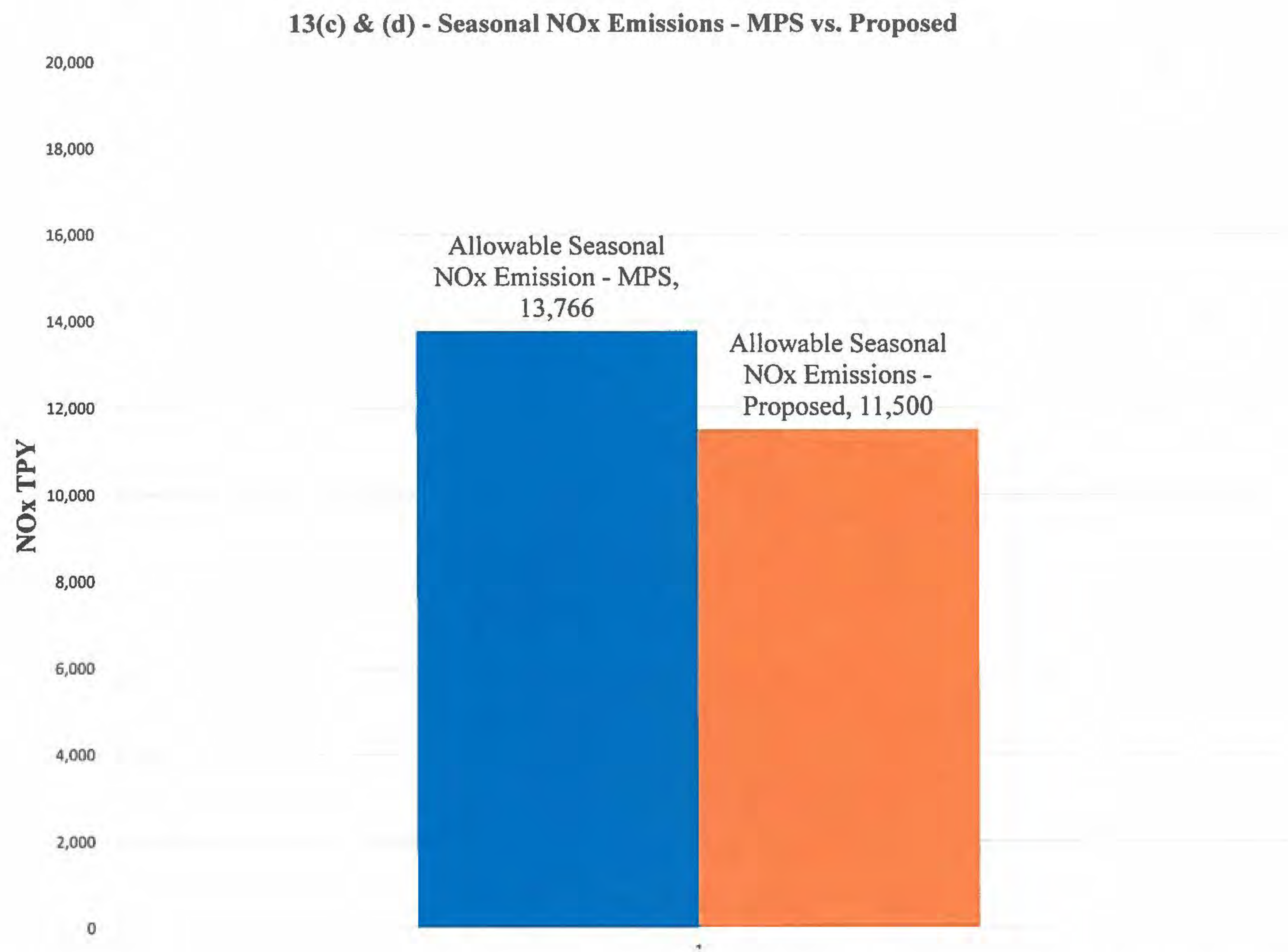


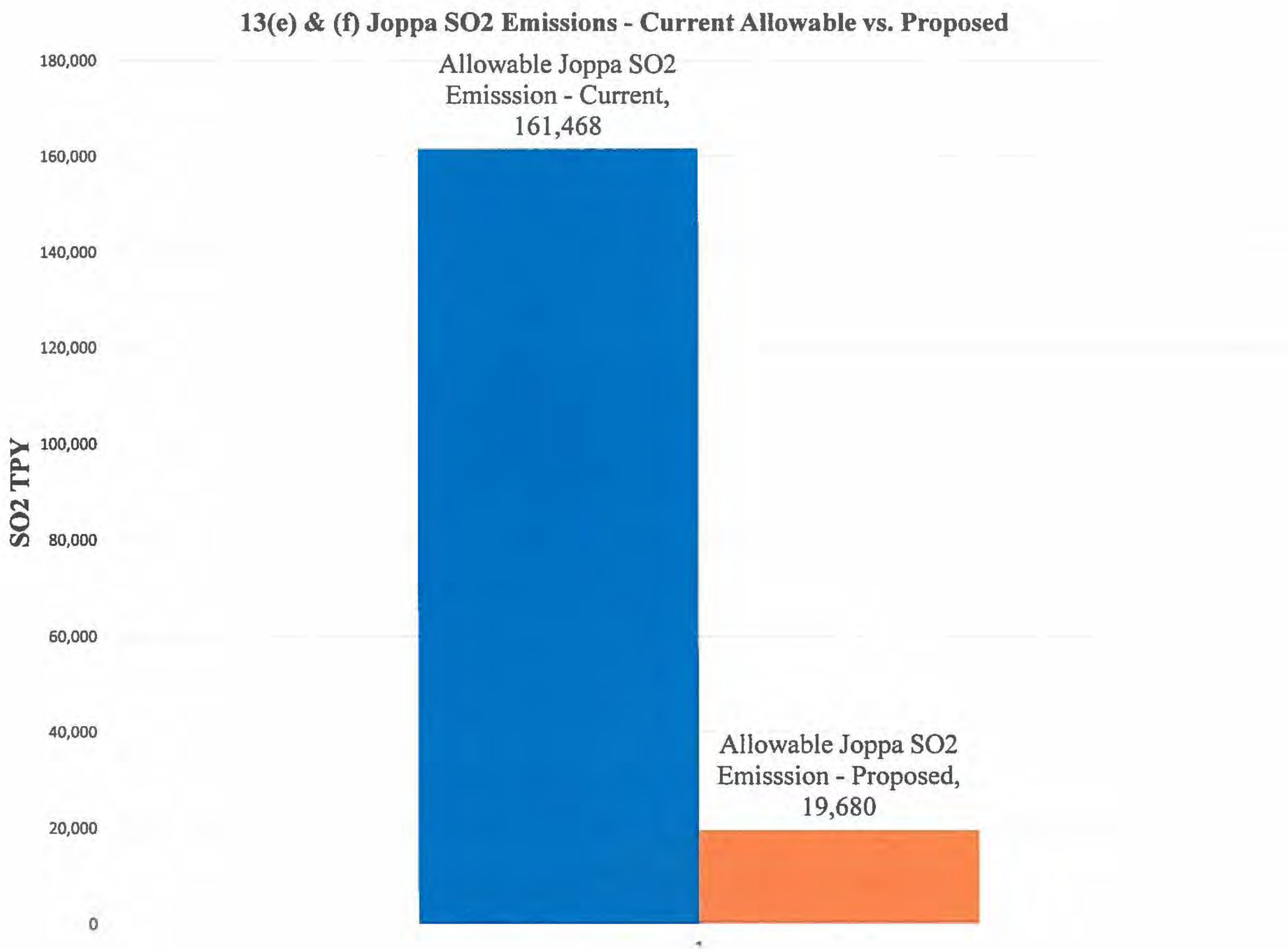
Note: Potential to emit is calculated based upon 8,760 hours of operation per year at the most restrictive limit for a given source or unit. No single unit or source is required to meet the current MPS fleet-wide average emission rate. This is a different figure than was used in discussing "allowable emissions" in the TSD.

Attachment 6


13(a) & (b) - Annual SO2 Emissions - MPS vs. Proposed
Allowable SO2 Emissions - MPS, 66,354
Allowable SO2 Emissions - Proposed , 55,000
SO2 TPY
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0


13(a) and (b) - Annual NOx Emissions - MPS vs. Proposed
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
NOx TPY
Allowable Annual NOx Emission - MPS, 32,841
Allowable Annual NOx Emissions - Proposed, 25,000


13(c) & (d) - Seasonal NOx Emissions - MPS vs. Proposed
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
NOx TPY
Allowable Seasonal NOx Emission - MPS, 13,766
Allowable Seasonal NOx Emissions - Proposed, 11,500


13(e) & (f) Joppa SO2 Emissions - Current Allowable vs. Proposed
SO2 TPY
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Allowable Joppa SO2 Emisssion - Current, 161,468
Allowable Joppa SO2 Emisssion - Proposed, 19,680

Attachment 7

Question 14 - Updated Table 7 NOx

Plant	Unit	2002 Actual Heat Input (1000 mmBtu)	Base Year Emission Rate (Lbs/ mmBtu)	Base Year Emissions (Tons)	Current MPS Emission Rate (Lbs/ mmBtu)	Projected Emissions Under Current MPS Rate (Tons)	Tons/Year Reduction
Baldwin	1	43,884	0.55	12,119	0.1	2,194	9,925
Baldwin	2	37,135	0.4	7,405	0.1	1,857	5,548
Baldwin	3	46,403	0.12	2,850	0.1	2,386	464
Havana	9	28,514	0.27	3,901	0.1	1,477	2,424
Hennepin	1	4,684	0.32	760	0.1	245	515
Hennepin	2	17,575	0.33	2,862	0.1	841	2,021
Coffeen	1	18,570	0.53	4,918	0.11	1,018	3,900
Coffeen	2	37,545	0.5	9,422	0.11	2,101	7,321
Duck Creek	1	22,635	0.47	5,328	0.11	1,254	4,074
E D Edwards	2	17,222	0.45	3,901	0.11	973	2,928
E D Edwards	3	15,972	0.46	3,639	0.11	844	2,795
Joppa	1	13,548	0.13	876	0.11	741	135
Joppa	2	16,258	0.13	1,048	0.11	885	163
Joppa	3	15,396	0.13	1,030	0.11	876	154
Joppa	4	13,402	0.13	904	0.11	770	134
Joppa	5	15,094	0.12	939	0.11	864	75
Joppa	6	16,063	0.12	999	0.11	919	80
Newton	1	40,631	0.15	3,037	0.11	2,224	813
Total				**65,938**		**22,469**	**43,469**

Question 14 - Updated Table 8 SO2

Plant	Unit	2002 Actual Heat Input (1000 mmBtu)	Base Year Emission Rate (Lbs/ mmBtu)	Base Year Emissions (Tons)	Current MPS Emission Rate (Lbs/ mmBtu)	Projected Emissions Under Current MPS Rate (Tons)	Tons/Year Reduction
Baldwin	1	43,884	0.41	9,053	0.19	4,226	4,827
Baldwin	2	37,135	0.39	7,283	0.19	3,569	3,714
Baldwin	3	46,403	0.43	9,931	0.19	4,363	5,568
Havana	9	28,514	0.9	12,815	0.19	2,693	10,122
Hennepin	1	4,684	0.43	1,000	0.19	438	562
Hennepin	2	17,575	0.43	3,792	0.19	1,683	2,109
Coffeen	1	18,570	1.54	14,332	0.23	2,169	12,163
Coffeen	2	37,545	1.49	27,999	0.23	4,346	23,653
Duck Creek	1	22,635	0.97	11,026	0.23	2,651	8,375
E D Edwards	2	17,222	1.7	14,666	0.23	2,008	12,658
E D Edwards	3	15,972	1.21	9,683	0.23	1,857	7,826
Joppa	1	13,548	0.51	3,441	0.23	1,544	1,897
Joppa	2	16,258	0.51	4,139	0.23	1,863	2,276
Joppa	3	15,396	0.51	3,947	0.23	1,792	2,155
Joppa	4	13,402	0.52	3,488	0.23	1,545	1,943
Joppa	5	15,094	0.52	3,932	0.23	1,743	2,189
Joppa	6	16,063	0.52	4,182	0.23	1,853	2,329
Newton	1	40,631	0.45	9,046	0.23	4,577	4,469
Total				**153,755**		**44,920**	**108,835**

Attachment 8

Support for Revising the IMR and MPS

This document provides initial justification for revising both the Illinois Mercury Rule (IMR) and the Illinois Multi-Pollutant Standards (MPS) rule.

I. Illinois Mercury Rule – Proposed Revision and Support

The proposed revision would allow electric generating unit (EGU) owners or operators to comply with the IMR by complying with the federal Mercury and Air Toxics Standards (MATS rule (i.e., compliance with MATS would be deemed compliance with the IMR).

The justification for adding this compliance alternative to the IMR is the fact that the federal MATS rule is demonstrably more stringent than (or, at least, as stringent as) the IMR in terms of the mercury emission standards. For sources that choose to implement this option, the proposed alternative compliance method would eliminate any conflicting and/or duplicative technical requirements (e.g., monitoring and testing) and administrative requirements (e.g., recordkeeping and reporting) between the IMR and federal MATS rule without loss in the protection of the environment and public health.

The following information is provided to demonstrate that the federal MATS rule is more stringent than, or as stringent as, the IMR and to justify a revision to the IMR that would allow affected sources to use compliance with the MATS as compliance with the IMR. It is recommended that the IMR be revised to add a provision providing that compliance with the federal MATS rule shall be deemed compliance with all requirements of the IMR, including the IMR mercury emission standard, recordkeeping, reporting, monitoring and testing provisions.

Justification for this proposed rule revision includes:

1. No loss in the protection of the environment and public health.

   While the IMR has a lower numeric mercury limit (i.e., 0.0080 lbs Hg/GWh) than the federal MATS rule (i.e., 0.011 or 0.013 lbs Hg/GWh), the stringency cannot be directly compared because each rule employs different averaging periods. The IMR employs a rolling 12-month averaging period whereas the MATS rule employs a 90-day or 30-day averaging period. Because the IMR and the MATS employ different averaging periods, a conversion is required to compare the limits in the two rules. USEPA provides a basis for making this conversion. In the course of developing the MATS, USEPA conducted an analysis to "evaluate the impact of averaging time on variability and to predict the upper predictive limit (UPL) value for different averaging times for the MACT floor facilities" (Memorandum from Stephen Boone, et al., RTI re: The Impact of Emissions Averaging Time on the Stringency of an Emission Standard (Dec. 9, 2011), referenced at 77 Fed. Reg. at 9385 (Feb. 16, 2012)).

   On the basis of CEMS data from 23 EGUs, USEPA calculated the MACT floor emission limits for different averaging periods as follows:

Averaging Period (days)	Calculated UPL With Control CEMS Data (lbs Hg/mmbtu)
30	1.32E-06
90	1.03E-06
360	7.60E-07

Therefore, in order to convert a 360-day limit to a 30-day limit of equivalent stringency, the 360-day limit is multiplied by a ratio of 1.74 (1.32E-06/7.60E-07); the appropriate ratio for a 360-day to 90-day conversion is 1.36 (1.03E-06/7.60E-07).

Using these ratios to convert the IMR limit of 0.0080 lbs Hg/GWh and assuming the IMR utilized a 360-day averaging period, the 30-day and 90-day equivalent values in terms of the federal MATS provides the following results:

Averaging Period	MATS Limit	IMR Equivalent
30 days	0.013 lbs Hg/GWh	0.014 lbs Hg/GWh
90 days	0.011 lbs Hg/GWh	0.011 lbs Hg/GWh

Notably, a 360-day averaging period is more stringent than the 12 month rolling averaging period of the IMR. Given this, and as seen above, the MATS mercury limits are more stringent than, or at least as stringent as, the IMR limit.

The federal MATS rule is also more stringent than the IMR in the following ways:

- While the IMR requires compliance determinations at the end of each month (i.e., 12-month rolling average), the MATS rule requires daily (i.e., 30-day or 90-day rolling average) compliance determinations.
- The MATS rule does not allow compliance on the basis of a percentage reduction in mercury emissions as an alternative to the lbs Hg/GWh limit, however, the IMR does. The IMR percentage reduction provision allows for higher mercury emissions when the mercury concentration in the coal supply increases.
- The MATS rule places a number of limits and conditions on emissions averaging whereas the IMR automatically allows plant-wide emissions averaging across all EGUs.
- The MATS rule includes a separate, more stringent mercury limit for new EGUs whereas the IMR does not.

Given that the federal MATS rule provides greater or equivalent mercury control than the IMR, the proposed revision would result in no loss in the protection of the environment and public health. Compliance with the more stringent or equally stringent MATS mercury limits inherently ensures compliance with the IMR mercury limit.

2. Clearly delineates applicable requirements and compliance demonstrations and eliminates duplicative requirements.

   In 2008, after promulgation of the IMR, the federal rule (i.e., CAMR, the Clean Air Mercury Rule) that established a regulatory need for Illinois mercury control requirements, and upon which portions of the IMR were based, was vacated. Subsequently, a new federal rule -- MATS -- was promulgated and remains in effect. The vacatur of CAMR and promulgation of MATS have led to inconsistencies between the Illinois and federal mercury control requirements. For example, Appendix B of the IMR utilizes mercury monitoring requirements that mirror monitoring provisions originally contained in the vacated CAMR, and identical requirements are not contained in the MATS. Many of these monitoring requirements and provisions were updated in the more recent MATS rule. Further, there are numerous inconsistencies between the IMR and MATS requirements on averaging times (e.g., 12 month rolling versus 30 day), recordkeeping, reporting (e.g., separate compliance reports and timing of report submittal required under each rule), monitoring (e.g., separate data requirements under each rule) and testing.

   The proposed revision would completely remove these inconsistencies and duplicative requirements if the source chooses the MATS compliance option. Also, retaining the initial IMR requirements would allow sources the ability to choose to continue complying with the original IMR requirements. It is therefore recommended that the original IMR requirements be retained and that an option be added that allows sources to instead comply with the IMR by complying with the MATS requirements. This approach is preferred over the more difficult and burdensome task of changing all of the individual IMR requirements to make them consistent with the MATS requirements, which would be more administratively difficult for the agency and potentially disruptive for sources that wish to continue to comply with the original IMR requirements.

3. Consistent with the Illinois Administrative Procedures Act (IAPA) Provisions on Overlapping Regulations and Executive Order 2016-13.

   IAPA Section 5-150(b)(1) addresses overlapping state and federal regulations, providing that "Any persons subject to a rule imposed by a State agency and to a similar rule imposed by the federal government may petition the agency administering the State rule for a declaratory ruling as to whether compliance with the federal rule will be accepted as compliance with the State rule." Further, IAPA Sections 5-150(b)(3) and (4) authorize State agencies to initiate rulemaking proceedings or issue a declaratory ruling to accept compliance with a federal rule as compliance with a State rule. Consistent with these provisions of the IAPA, the IMR and federal MATS rules are a clear example of overlapping regulations where compliance with the federal rule should be accepted as compliance with the State rule.

   Moreover, Executive Order 2016-13 (Oct. 17, 2016) establishes the Illinois Competitiveness Council and identifies that "many of the State's agencies have outdated, redundant or inconsistent regulations, resulting in an inconsistent and unnecessary regulatory framework across the State and public frustration". The Executive Order provides that "a comprehensive review of existing administrative rules and internal agency policies is essential to determine their current necessity and relieve citizens, businesses and social service providers from the crush of unnecessary, outdated and inconsistent regulations" and that "without compromising the health, safety or welfare of Illinois' citizens, this review should result in the elimination or simplification of unnecessary or unduly burdensome and anti-competitive administrative rules and policies".

The Executive Order requires that, by May 1, 2017, all agencies under the jurisdiction of the Governor "conduct a comprehensive review of their administrative rules and policies" and directs such reviews to meet specified guidelines, including the following, many of which support the proposed rule revision providing that compliance with the federal MATS shall be deemed compliance with the IMR:

- Regulation is drafted in such a way as to be understood by the general public. Regulations should be clear, concise and drafted in readily understood language. Regulations should not create legal uncertainty.
- Regulation is consistent with other rules across Agencies. Agencies should coordinate to ensure rules are not conflicting or have duplicative requirements.
- Regulation does not impose unduly burdensome requirements on business, whether through time or cost, or have a negative effect on the State's overall job growth. In considering this criterion, the Agency should consider whether there are less burdensome alternatives to achieve the Regulation's purpose.
- There is a clear need and statutory authority for the Regulation. Regulation should not exceed the Agency's statutory authority and should be drafted so as to impose statutory requirements in the least restrictive way possible. In considering these criteria, the Agency should also consider whether the Regulation exceeds federal requirements or duplicates local regulations or procedures.

II. Multi-Pollutant Standards – Proposed Revision and Support

The MPS became a regulatory requirement in 2007 as part of the IMR flexibility provisions. The MPS requires that group-wide ozone season NOx and annual average SO2 and NOx emission rate limits be met.

The proposed revision would convert the MPS rate limits to annual SO2 and NOx tonnage caps and an ozone season NOx tonnage cap and provide that MPS EGUs that are currently in two separate MPS Groups, but which have a common parent company owner, be combined into a single MPS Group.

The justification for converting the MPS SO2 and NOx rate limits to mass-based caps includes the fact that the proposed mass-based caps are demonstrably more stringent than the allowable emissions under the current MPS limits. Further, the placement of all MPS EGUs under common parent company ownership into a single MPS Group is consistent with the original intent of the MPS rule (including the operational flexibility provisions of the MPS), promotes streamlined understandable regulation and reduces administrative burdens.

This proposal includes:

A. Support for revising the MPS, including:
   1. Explanation of why there is no loss in the protection of the environment and public health,
   2. Additional benefits of revising the MPS, and
   3. Rationale for combining MPS EGUs under common ownership into a single MPS Group.

B. Proposed mass emission caps for:
   1. Annual SO_2
   2. Annual NO_x
   3. Ozone Season NO_x

C. A demonstration that the proposed mass emission caps are more stringent than the mass emissions allowed by the MPS rate limits.

A. Support for revising the MPS

1. <u>No loss in the protection of the environment and public health.</u>

The proposed mass-based caps are more stringent than the mass emissions allowed under the current MPS limits, as demonstrated and explained in the following.

The current MPS limits for annual SO_2, annual NO_x and ozone season NO_x employ a rate-based approach (lbs of pollutant per million btu of heat input), that are applicable to EGUs contained within the defined MPS Groups. The rate-based limits do not contain any regulatory limits on the total amount, or mass, of pollutants that can be emitted either annually or seasonally. In other words, each MPS-affected unit could theoretically operate at capacity and the MPS Group could remain in compliance with its MPS limits. Under the proposed mass-based approach, a mass-based cap on SO_2 and NO_x emissions is established such that the combined emissions from all EGUs in an MPS Group would not be allowed to exceed the defined mass-based cap. The proposed mass-based caps are more stringent than the current MPS limits in that they limit mass emissions well below the mass emission levels currently allowed in the MPS.

Further, compared to a rate-based approach, mass-based caps more clearly establish and define the maximum emissions allowed, thereby facilitating compliance and verification and enhancing protection of the environment and public health.

As a result, the proposed revision is demonstrably more protective of the environment and public health.

2. Additional benefits of revising the MPS.

The proposed revision identifies the applicable emission limits in a more beneficial form with regards to identifying allowable emissions and streamlines compliance demonstrations. For example, if a group of units is subject to a rate-based limit of 50 lbs/mmbtu of pollutant X, it cannot readily be determined how much pollution may actually be emitted in any given timeframe unless the amount of heat input during the associated time period is also known. Conversely, if the same group of units is subject to a mass emission cap of 70,000 tons per year of pollutant X, it is readily understood that no more than 70,000 tons of pollutant X are allowed to be emitted in any year.

A mass-based compliance approach also allows compliance to be more readily verified and determined since all of the MPS EGU's have SO_2 and NO_x continuous emission monitoring systems (CEMS) that directly measure and record their emissions. Under a rate-based approach several variables need to be gathered in order to calculate the actual emission rate.

With mass-based caps, the annual and seasonal MPS compliance demonstrations would become less resource intensive for both the Illinois EPA and affected sources.

Additionally, mass-based caps would assist the Illinois EPA in making demonstrations to USEPA in such matters as State Implementation Plans (SIPs). Mass-based cap demonstrations are more readily made, understandable and accepted since the maximum allowed air pollution is more easily defined than with a rate-based limit.

3. Appropriate to have a single MPS limit applicable to all MPS units under a common owner:

Combining all MPS EGUs currently under common control but in different MPS Groups into a new single MPS Group is consistent with the original intent of the MPS. While Dynegy's ownership of the DMG MPS Group has not changed since the original promulgation of the MPS in 2007, unforeseen and dramatic changes have occurred to Illinois' energy system and MPS sources. Ownership of the MPS sources has significantly changed such that the previous owner (Ameren) of the state's largest fleet of coal-fired units no longer owns any coal-fired units in Illinois. In addition, many of the previously-owned Ameren MPS units that were part of the "Ameren MPS Group" have been permanently retired with the remaining operating units now owned and operated by IPH (a subsidiary of Dynegy).[1] Several units in the DMG MPS Group also have been permanently retired. EGUs previously in the DMG MPS Group or the Ameren MPS Group that have been retired are: Vermilion 1 and 2, Meredosia 1, 2, 3, 4 and 5, Hutsonville 5 and 6, Edwards 1, and Wood River 4 and 5. Further, another large previous owner of coal-fired EGUs in Illinois (Midwest Generation) has either sold or permanently retired all of their units. Altogether, approximately 26 coal-fired units have retired in Illinois since promulgation of the MPS rule and these units no longer emit any air pollutants.

[1] Since 2007, Dynegy also has acquired the Kincaid Power Station, but the Kincaid Power Station is not subject to the MPS rule.

These changes, along with others, have resulted in a regulatory landscape that is inconsistent with the original MPS grouping rationale that resulted in different MPS limits for different MPS Groups. Further, such dramatic changes to the Illinois energy landscape were not contemplated during the development of the MPS. A primary reason for the MPS rule's provisions on grouping of MPS units was that a single owner/operator would be responsible for, and manage and report on, compliance of all their Illinois coal-fired EGUs. Grouping all EGUs under common ownership or control together allowed for emissions averaging across the entire commonly owned fleet, thereby providing owners/operators of the MPS Group an important means of operational flexibility. However, as a result of the significant changes in coal-fired EGU ownership in Illinois identified above, the sole remaining owner of EGUs subject to the MPS (i.e., Dynegy) now has MPS EGUs in two separate MPS Groups that are subject to different MPS emission limits and cannot avail itself of the fleet-wide operational flexibility originally intended with the MPS. Under the proposed revision, consistent with the original grouping rationale, all MPS units under the sole remaining owner of MPS units would be included in a single MPS Group.

Specifically, as proposed, the remaining operating EGUs in the DMG MPS Group and Ameren MPS Group would be combined into a single MPS Group, comprised of Baldwin 1, 2 and 3, Havana 6, Hennepin 1 and 2, Coffeen 1 and 2, Duck Creek 1, Edwards 2 and 3, Joppa 1, 2, 3, 4, 5 and 6, and Newton 1 and 2. For simplicity, the proposed newly combined MPS Group is referred to herein as the "Merged MPS Group" or MMPS.

Combining all MPS EGUs under common control into a new single group offers benefits. Since the existing MPS requires separate compliance demonstrations for each MPS Group, revising the MPS as proposed would result in only a single compliance demonstration for the new combined MPS Group, thereby streamlining and facilitating compliance verification. MPS compliance demonstrations would become less resource intensive for both the Illinois EPA and affected sources. Further, a single MPS Group provides clarity in regards to the applicable emissions limits to the fleet of the MMPS owned coal-fired EGUs throughout Illinois.

Although it is preferable to have all EGUs subject to the MPS under a single mass cap and in a single MPS Group, there is the potential that existing MPS affected EGUs are sold by the current owner of all such EGUs to a different company (i.e., owner or operator). If this were to occur, the proposed MPS rule would require that the mass-based cap be adjusted for the remaining MMPS Group and that a corresponding mass cap be transferred to the new owner/operator of the purchased EGUs. The amount of the adjustment and transferred mass-based cap would be equal and would be calculated by using the rated capacity of the EGUs. For example, the adjusted mass cap for the MMPS Group would be determined by the product of the mass-based cap for all of MMPS EGUs multiplied by the ratio of the sum of the purchased EGUs rated capacities to the total combined rated capacities of all of the MMPS affected EGUs. This product (i.e., adjustment amount) would then be subtracted from the mass cap applicable to the MMPS Group to arrive at the new-based mass cap, and the same product would equal the newly established mass-based cap applicable to the new owner or operator of the purchased units.

B. **Proposed mass-based caps.**

1. Annual SO2

Under the existing MPS rule, different emission rate limits apply to the IPH MPS Group (i.e., the "Ameren MPS Group" identified in 35 IAC 225.233(e)(3)) and the DMG MPS Group:

- The IPH MPS Group (i.e., units at Coffeen, Duck Creek, Newton, Edwards and Joppa) is subject to an annual SO2 rate limit in 2017 and beyond of 0.23 lbs/mmbtu.
- The DMG MPS Group (i.e., units at Baldwin, Havana and Hennepin) is subject to an annual SO2 rate limit in 2017 and beyond that is the more stringent of 0.25 lbs/mmbtu or a rate equivalent to 35 percent of the Base Rate of SO2 emissions (i.e., 0.19 lbs/mmbtu).

To determine the current allowable emissions under the MPS, the heat input capacity of the existing EGUs is multiplied by the allowable MPS annual SO2 rate limit (lbs/mmbtu) and divided by 2,000 pounds. Using this methodology, the MPS rate limit for the IPH MPS Group is equivalent to 50,474 tons per year and 23,020 tons per year for the DMG MPS Group. The annual allowable SO2 emissions for the combined IPH and DMG MPS Groups would be 73,494 tons.

In order to provide additional environmental benefits beyond the objectives of the MPS rule, the Merged MPS Group (i.e., the combined IPH and DMG MPS Groups) would be subject to an annual fleet-wide SO2 emission cap of 60,000 tons.

2. Annual NOx

Under the existing MPS rule, different emission rate limits apply to the IPH and DMG MPS Groups:

- The IPH MPS Group annual NOx rate limit in 2017 and beyond is 0.11 lbs/mmbtu.
- The DMG MPS Group annual NOx rate limit in 2017 and beyond is the more stringent of 0.11 lbs/mmbtu or a rate equivalent to 52 percent of the Base Annual Rate of NOx (i.e., 0.10 lbs/mmbtu).

To determine the current allowable under the MPS, the heat input capacity of the existing EGUs is multiplied by the allowable MPS annual NOx rate limit (lbs/mmbtu) and divided by 2,000 pounds. Using this methodology, the MPS rate limit for the IPH MPS Group is equivalent to 24,140 tons per year and 12,116 tons per year for the DMG MPS Group. The allowable NOx emissions for the combined IPH and DMG MPS Groups would be 36,256 tons.

In order to provide additional environmental benefits beyond the objectives of the MPS rule, the Merged MPS Group (i.e., the combined IPH and DMG MPS Groups) would be subject to an annual fleet-wide NOx emission cap of 26,000 tons.

3. Ozone Season NOx

Under the existing MPS rule, different emission rate limits apply to the IPH MPS Group and the DMG MPS Group:

- The IPH MPS Group ozone season NOx rate limit in 2017 and beyond is 0.11 lbs/mmbtu.
- The DMG MPS Group ozone season NOx rate limit in 2017 and beyond is the more stringent of 0.11 lbs/mmbtu or a rate equivalent to 80 percent of the Base Seasonal Rate of NOx (i.e., 0.10 lbs/mmbtu).

To determine the current allowable under the MPS, the heat input capacity of the existing EGUs is multiplied by the allowable MPS seasonal NOx rate limit (lbs/mmbtu) and divided by 2,000 pounds. Using this methodology, the MPS rate limit for the IPH MPS Group is equivalent to 12,070 tons per ozone season and 6,058 tons per ozone season for the DMG MPS Group. The allowable NOx emissions for the combined IPH and DMG MPS Groups would be 18,128 tons over the period April 1 to September 30 each year.

In order to provide additional environmental benefits beyond the objectives of the MPS rule, the Merged MPS Group (i.e., the combined IPH and DMG MPS Groups) would be subject to a seasonal fleet-wide NOx emission cap of 12,000 tons.

C. **Demonstration that the proposed mass-based caps are more stringent than the mass emissions allowed by the MPS rate limits.**

The proposed annual and seasonal mass caps, when compared to the allowable mass emissions under the MPS, are more protective of the environment and public health. This is because the proposed mass-based caps are lower than the mass emissions allowed under the current MPS rule, as shown below.

The baseline year for the MPS was the average annual actual emissions from 2003 to 2005. The average annual 2003 to 2005 actual tons of SO2 emitted from the original IPH and DMG MPS Groups was 226,245 tons/yr (combined total). The objective, and requirement, of the original MPS rule was a 65% reduction from this amount. In calendar year 2017 and beyond, the MPS rule allows 77,067 tons of SO2 annually from the IPH and DMG Groups (combined total). The proposed mass-based cap for SO2 is 60,000 tons per year, resulting in a decrease in the amount of SO2 allowed of 17,067 tons per year. The 60,000 tons cap would also represent a 73% ton reduction in SO2 emissions from the 2003 to 2005 baseline, which is greater than the 65% reduction identified in the MPS.

The average annual 2003 to 2005 actual tons of NOx emitted from the original IPH and DMG MPS Groups was 56,826 tons/yr (combined total). The objective, and requirement, of the original MPS rule was a 48% reduction from this amount. In calendar year 2017 and beyond the MPS rule allows 38,046 tons of NOx annually from the IPH and DMG Groups (combined total). The proposed mass-based cap for NOx is 26,000 tons per year, resulting in a decrease in the amount of NOx allowed of 12,046 tons per year. The 26,000 tons cap would also represent a 54% reduction in NOx emissions from the 2003 to 2005 baseline, which is greater than the 48% reduction identified in the MPS.

The average ozone season emissions from 2003 to 2005 from the original IPH and DMG MPS Groups were 15,761 tons per season (combined total). The objective, and requirement, of the original MPS rule was a 20% reduction from this amount. In the 2017 ozone season and subsequent ozone seasons, the MPS rule allows 19,023 tons of NOx from the IPH and DMG Groups (combined total). The proposed mass-based cap for NOx is 12,000 tons per ozone season, resulting in a decrease in the amount of NOx allowed of 7,023 tons per year. The 12,000 tons cap would also represent a 24% reduction in seasonal NOx emissions from the 2003 to 2005 baseline, which is greater than the 20% reduction identified in the MPS. The ozone season applicable to the MPS is from the April 1st to September 30th.

CONFIDENTIAL BUSINESS INFORMATION
Revised: 1/20/2017

III. Additional Supporting and/or Relevant Information:

Overlapping and redundant SO2, NOx and mercury regulations applicable to coal-fired power plants:

Sulfur Dioxide Regulations

Plant			Baldwin	Havana	Hennepin	Coffeen	Duck Creek	Edwards	Joppa	Kincaid	Newton
SO2 Control Equipment			x	x		x	x			x	
Low Sulfur Coal			x	x	x	x	x	x	x	x	x
Rule	Averaging Time	Unit of Measurement									
Illinois MPS	Annual	Lbs. per million Btu of heat input	x	x	x	x	x	x	x	x	x
Acid Rain	Annual	Allowances (tons)	x	x	x	x	x	x	x	x	x
CSAPR	Annual	Allowances (tons)	x	x	x	x	x	x	x	x	x
Consent Decree	30-day Rolling	Lbs. per million Btu of heat input	x	x	x					x	
Consent Decree	Annual	Tons	x	x	x					x	
New Source Performance Standards	3-Hours	Lbs. per million Btu of heat input		x			x				x
Memorandum of Agreement	1-hour	Lbs. per Hour						x			
IL SIP	1-hour	Lbs. per Hour	x		x	x			x	x	
IL SIP		Lbs. per million Btu of heat input		x			x	x			x

Nitrogen Oxide Regulations

Plant			Baldwin	Havana	Hennepin	Coffeen	Duck Creek	Edwards	Joppa	Kincaid	Newton
Selective Catalytic Reduction Equipment			x	x		x	x	U3		x	
Low NOx Burners			x	x	x		x	x	x	x	x
Rule	Averaging Time	Unit of Measurement									
Illinois MPS	Annual	Lbs. per million Btu of heat input	x	x	x	x	x	x	x	x	x
Acid Rain	Annual	Allowances (tons)	x	x	x	x	x	x	x	x	x
CSAPR	Annual	Allowances (tons)	x	x	x	x	x	x	x	x	x
Consent Decree	30-day Rolling	Lbs. per million Btu of heat input	x	x						x	
Consent Decree	Annual	Tons	x	x	x					x	
New Source Performance Standards	3-Hours	Lbs. per million Btu of heat input		x			x				x
IL SIP	1-hour	Lbs. per Hour	x		x	x			x	x	
IL SIP		Lbs. per million Btu of heat input		x			x	x			x

Mercury Regulations

Plant			Baldwin	Havana	Hennepin	Coffeen	Duck Creek	Edwards	Joppa	Kincaid	Newton
Carbon Injection System			x	x	x	x	x	x	x	x	x
Refined Coal			x	x	x		x	x	x	x	x
Rule	Averaging Time	Unit of Measurement									
Illinois MPS	30-day	Lbs. per Trillion Btu	x	x	x	x	x	x	x	x	x
MATS	30-day or 90-day	Lbs. per Trillion Btu	x	x	x	x	x	x	x	x	x

Applicable Mercury, NOx and SO2 Requirements

	SO2 Requirements							NOx Requirements							Mercury Requirements		
	Acid Rain	CSAPR	MPS	Consent Decrees	MOA	35 IAC Part 214	Permit Limits	Acid Rain	CSAPR	MPS	Consent Decrees	MOA	35 IAC Part 217	Permit Limits	IL Mercury Rule	MATS	Permit Limits
Baldwin	x	x	x	x		x	x	x	x	x	x		x	x	x	x	x
Havana	x	x	x	x		x	x	x	x	x	x		x	x	x	x	x
Hennepin	x	x	x	x		x	x	x	x	x	x		x	x	x	x	x
Coffeen	x	x	x			x	x	x	x	x			x	x	x	x	x
Duck Creek	x	x	x			x	x	x	x	x			x	x	x	x	x
Edwards	x	x	x		x	x	x	x	x	x			x	x	x	x	x
Joppa	x	x	x			x	x	x	x	x			x	x	x	x	x
Kincaid	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Newton	x	x	x			x	x	x	x	x			x	x	x	x	x

1. Unnecessary and Redundant: Recent federal regulations to control SO2, NOx and mercury make the IMR and MPS unnecessary and redundant. Mercury is regulated under the federal Mercury and Air Toxics Standards (MATS and both NOx and SO2 are regulated under the federal Cross State Air Pollution Rule (CSAPR). USEPA has deemed CSAPR equivalent to its Regional Haze Rule.

2. No Regulatory Basis or Authority Remains for either the IMR or MPS: When CAMR (the federal Clean Air Mercury Rule) was vacated in 2008, a key basis for the IMR was eliminated. The USEPA created MATS to replace CAMR; MATS has similar mercury control requirements that are more stringent than (or, at least as stringent as) the IMR. Since USEPA has stated that implementation of CSAPR satisfies a state's BART requirements and since Illinois EPA is implementing CSAPR identical to the federal CSAPR, Illinois EPA can use CSAPR in its Regional Haze SIP in lieu of the MPS. Also, for NOx and SO2, the MPS was originally established solely to provide temporary relief for affected sources in regards to mercury control under the IMR, there was arguably never true authority under the Illinois Environmental Protection Act Section 10(B) (i.e., the law that gives authority for Illinois EPA to establish rules) to establish the MPS.

3. No Demonstrated or Justified Environmental or Health-Based Benefit: USEPA conducted broad outreach, including the performance of cost-benefit analysis, regulatory impact analysis, and environmental and economic modeling, for the MATS and CSAPR rules to show that the environment and public health are appropriately protected under the federal rules. The Illinois EPA provided no technical support for the MPS in its rulemaking. Given the protection demonstrated by the federal rules and that the MATS rule is more stringent than the IMR, the IMR and MPS are redundant of the federal rules.

4. Competitive Disadvantage for Illinois Sources: Since neighboring states with coal units (e.g., Missouri, Indiana, and Kentucky) do not have rules similar to the IMR and MPS, Illinois sources are more burdened with regulations than sources in other states. This leads to a competitive disadvantage for Illinois sources and inhibits their ability to appropriately sell their product, electricity. This disadvantage has, and may further, contributed to the shutdown of Illinois sources and an associated loss of Illinois jobs. Also, such a disadvantage may lead to increased air pollution in Illinois since, for example, less controlled sources such as those in Missouri may be dispatched before cleaner Illinois sources.

5. Consistent with the Illinois Administrative Procedures Act on Overlapping Regulations and Governor Rauner's Statements on "Regulatory Burden": The federal MATS and CSAPR are clearly similar to the state IMR and MPS and repeal and/or revision of the state regulations would result in streamlined environmental requirements and more appropriate and effective evaluation and demonstration of compliance.

6. Streamline and minimize overlapping and redundant requirements:
Since promulgation of the IMR and MPS, and even prior to such time, there are numerous applicable requirements that coal-fired EGUs must comply with for mercury

and the MPS regulated pollutants of NOx and SO2, as identified throughout this document.

The IMR and MPS are decade old rules that, at the time of promulgation, filled a gap in mercury, SO2 and NOx control requirements. That gap no longer exists, given the subsequent adoption of additional federal rules and other developments. Federal rules, by the nature of the rulemaking process, are more scientifically based, publicly vetted and supportable.

Potential Issues:

Issue: Illinois EPA needs to retain the current version of the MPS for its regional haze SIP.
A: Illinois EPA could elect to use CSAPR = BART in place of using the MPS, which USEPA has accepted. Doing so would alleviate the need to rely upon the MPS at all.

Also, the proposed limits are demonstrably more stringent than the original and current MPS limits; therefore, revising the Illinois SIP to reflect the proposed changes should be accepted by USEPA. Further, if determined necessary, the Illinois EPA could also rely upon the emission reductions associated with the numerous shutdowns in coal-fired power plants, along with the MMPS limits. Doing so would allow Illinois EPA to readily show that the reductions identified in previous SIP submittals will continue to be met or exceeded. Illinois EPA should only identify and rely upon the level of emission reductions necessary to achieve SIP revision approval from USEPA in order to preserve other such reductions for potential future use.

Issue: Illinois EPA will have to submit a 110(l) anti-backsliding demonstration to USEPA in order to revise or remove the MPS from its SIP.
A: Such a demonstration can be made based on:

1. The proposed limits are more stringent than the original and current MPS, and/or
2. There have been numerous shutdowns of coal plants in Illinois such that the emission reductions expected under the original and current MPS (which did not account for any shutdowns) have been exceeded. Accounting for these shutdowns, along with the MMPS limits, will allow IEPA to readily show that the reductions identified and relied upon in previous SIP submittals will continue to be met or exceeded.

Issue: Environmental groups/NGO's (NGOs) will oppose this.
A: There are strong, justifiable reasons to repeal and/or revise both rules; however, revising the rules is assumed preferable by the NGOs. Also, with the recent enactment of SB 2814, the NGO's received a huge win that will have a tremendous negative impact on Illinois' coal-fired power plants. This proposed action would help to preserve thousands of jobs in Illinois related to coal-fired power plants. Dynegy strongly opposed SB 2814 based on the likelihood that it will ultimately cost Illinois thousands of coal plant jobs, if other actions, including this proposed action, are not taken. In essence, revising the IMR and MPS are job preservation measures that both Illinois EPA and the Governor's office should strongly support.

Issue: What are the overlapping requirements for mercury, NOx and SO2?
A: See above charts and below.

NOx and SO2 now have overlapping requirements contained in:

- MPS – 35 IAC Part 225, Subpart B
- Consent Decrees
- Acid Rain Program
- SO2 and NOx regulations under 35 IAC Part 214 and Part 217, respectively
- CSAPR
- NSPS
- Memorandum of Agreements
- MATS (limits SO2 as a surrogate)
- Permit limits (construction and CAAPP)

Mercury now has overlapping requirements contained in:

- IMR – 35 IAC Part 225, Subpart B
- MATS
- Permit limits (construction and CAAPP)

Attachment 9

Follow up information

- The MPS currently imposes limits on emission rates in lbs/mmbtu for NOx and SO2. These emission rate limits are federally enforceable as a result of inclusion in Illinois' Regional Haze SIP. USEPA's approval of Illinois' Regional Haze SIP states that "this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law."
- The MPS does not limit Heat Input (HI), maximum capacity or hours of operation. Emission rate limits, such as those in the MPS, do not limit mass emissions because they do not limit HI or operating hours and, therefore, allow for growth in generation. This is a primary reason power plant owners often prefer emission rate limits over mass emissions caps, such as in the MPS.
- A mass cap associated with an emission rate limit can readily be calculated by multiplying the emission rate by the maximum HI capacity of a unit. This calculation was performed in Dynegy's proposal to demonstrate that the proposed mass caps were substantially lower than the existing allowable based on maximum HI.
- Allowable emissions are defined as those allowed under a rule or other applicable requirement. Projected, estimated or expected emissions are those actual emissions forecasted to occur (i.e., "expected actual emissions").
- Illinois EPA's original regional haze submittal (June 2011) took the approach that the MPS would satisfy the Clean Air Act's Best Available Retrofit Technology (BART) obligations for the affected EGUs and that an analysis of emission reductions expected from the MPS conclusively demonstrated that Illinois' approach would yield much larger reductions of NOx and SO2 than BART implementation on EGUs subject to BART. Illinois EPA's analysis identified expected actual emissions by multiplying 2002 HI by the MPS emission rates. As discussed below, this was an overly conservative approach. Illinois EPA's February 2017 Five-Year Progress Report for the Illinois Regional Haze SIP takes the same approach, but refers to "expected emissions" as "projected emissions."
- USEPA approved Illinois' Regional Haze SIP based on analysis of expected emission reductions under the MPS. In particular, USEPA approved the Illinois SIP because it achieved significantly greater reductions than through imposition of source-specific BART. The numbers in USEPA's final approval (which rely upon fewer reductions than estimated by Illinois EPA) are as follows:

	2002 Base Year Emissions		Emission Reductions under the MPS – Table 1 of USEPA final rule approving SIP		Difference between 2002 Base Year Emissions (Cols. A&B) and Expected Emission Reductions (Cols. C&D) = Expected Actual Emissions	
	NOx tons (Col. A)	SO2 tons (Col. B)	NOx tons (Col. C)	SO2 tons (Col. D)	NOx tons	SO2 tons
Dynegy	34,538	67,653	23,867	47,378	10,671	20,275
Ameren	45,141	170,108	24,074	111,997	21,067	58,111
				Total = Expected Actual Emissions	31,738	78,386

Numbers obtained from Illinois EPA's Technical Support Document for Best Available Retrofit Technology Under the Regional Haze Rule (April 29, 2011), USEPA's proposed rule to approve Illinois' original Regional Haze SIP (77 Fed. Reg. 3966 (Jan. 26, 2012)), USEPA's final rule approving Illinois' original Regional Haze SIP (77 Fed. Reg. 39943 (July 6, 2012)), and IEPA's February 1, 2017 Five-Year Progress Report for the Illinois Regional Haze SIP.

- The above table provides the actual emission reductions relied upon by USEPA in its final approval of Illinois' Regional Haze SIP.
- Based upon discussions with IEPA, IEPA is concerned that USEPA would not accept expected actual emissions above those relied upon for SIP approval. Per the above table, USEPA approved Illinois' SIP based on expected actual emissions of 31,738 tons per year for NOx and 78,386 tons per year for SO2. Although allowable emissions are greater than expected actual emissions, Dynegy will agree to limit its proposed allowable mass emissions caps below these expected actual emissions levels to allow for a readily approvable SIP revision.
- USEPA does not state in any of its Illinois' Regional Haze SIP approvals that a future SIP revision request must contain federally enforceable limits on mass emissions below the expected actual emission levels used in previous approvals. There is no statutory or regulatory prescribed methodology for complying with Regional Haze requirements through alternative non-BART limitations. Accordingly, USEPA originally approved the alternative emission rate approach on grounds that it provided more significant emission reductions than BART. Dynegy's proposed tonnage-based limits would do nothing to alter this approach. As a result, Dynegy's proposal does not run afoul of any restrictions on revising SIPs aimed at ensuring reasonable further progress. Section 110(l) of the Clean Air Act does not prohibit USEPA approval of a SIP revision that alters an emissions limitation provided that the revised limit continues to demonstrate reasonable further progress. In fact, USEPA recently opined in approving a revision to the Arizona Regional Haze SIP that:

> The critical question under section 110(l) is not whether the SIP revision will cause an increase in actual emissions, it is whether that increase in actual emissions will interfere with attainment of the NAAQS or [reasonable further progress], or if the SIP revision interferes with any other applicable requirement of the CAA. The fact that actual emissions will increase means that the EPA's analysis must include an evaluation of how that emission increase affects attainment and [reasonable further progress] and other applicable requirements of the CAA.

See EPA Approval and Revision of Air Plans; Arizona; Regional Haze State and Federal Implementation Plans (Jan. 13, 2017). Here, Dynegy's proposal will not even cause an increase in actual emissions. Thus, concern over the proposals conflict with Clean Air Act Section 110(l) restrictions is unfounded.

- In fact, USEPA approved the IPH variance as part of Illinois' Regional Haze SIP and, in doing so, recognized reduced expected emissions reductions at IPH from 131,367 tons (original SIP) to 119,833 tons (revised SIP to reflect variance). Thus, so long as expected reductions remain significantly greater than BART, greater progress to visibility protection occurs compared to BART and USEPA can approve a SIP revision.
- At the recent meeting, Illinois EPA indicated that any revision to the Regional Haze SIP would not be approved unless the revision shows that annual SO2 and NOx emissions are limited to 44,920 and 22,469 tons, respectively. These numbers reflect projected emissions based on 2002 actual HI multiplied by the MPS rates.
- The 44,920 tons per year "projected" emissions of SO2 should not be considered a cap that cannot be exceeded. This number is simply an estimate of future expected actual emissions. USEPA's responsibility in approving a revision to the Regional Haze SIP is to ensure that reasonable further progress is maintained and that emissions do not impact a NAAQS or other Clean Air Act requirement. Simply lowering the allowable emissions under the MPS via establishment of the Dynegy proposed cap merely changes the methodology and standard by which to ensure compliance with the regional haze requirements.
- Even after the MPS revision proposed by Dynegy, if necessary, Illinois EPA can readily show that "projected" emissions will remain below 44,920 tons per year of SO2 by changing the emission estimation method and by utilizing all applicable limits to NOx and SO2 emission from the EGUs. While Illinois EPA has historically relied solely on projected emission reductions under the MPS to demonstrate reasonable progress in addressing regional haze, multiple options exist for demonstrating reasonable progress. For example, Illinois EPA can use CSAPR in combination with MATS, MPS, consent decree emission rate limits (i.e., lbs/mmbtu) acid rain and other requirements. Since the allowable mass emissions would decrease under a newly established mass cap, it is reasonable to expect that any projection of actual emissions would also likely decrease. This is because affected sources are cognizant of a lower allowable emission limit and operate accordingly.

1. The Clean Air Act does not require that USEPA disapprove any revision to Illinois's Regional Haze SIP unless it shows that annual SO2 and NOx emissions are limited in a federally enforceable manner to less than 44,920 and 22,469 tons, respectively. USEPA's approvals of Illinois' Regional Haze SIP did not approve or expressly identify either such cap.[1] USEPA did not require federally enforceable limits on mass emission levels in previous approvals of Illinois' Regional Haze SIP. Instead, USEPA relied upon "expected" emissions reductions. Given that Illinois EPA under Dynegy's proposal can continue to project emissions to show that regional haze requirements are met, and that the revised MPS would significantly reduce the allowable mass emissions of both SO2 and NOx, Dynegy's proposal is consistent with Clean Air Act requirements.

2. USEPA's rulemaking notices regarding approval of Illinois' Regional Haze SIP demonstrate that USEPA relied upon and approved the emission rate limits of the MPS into the SIP. While USEPA estimated the associated mass expected emission reductions, these expected emission reductions are not federally enforceable, as USEPA identifies. Rather, the expected emission reductions were only estimated and provided in an illustrative manner of reductions to be "expected" per the MPS emission rate limits, and not as independently enforceable limits. Notably, USEPA (and IEPA) used the term "expected" emission reductions, not "required" reductions. Regardless, Dynegy's proposed mass caps are below the combined total emissions USEPA estimated in its approval of Illinois' Regional Haze SIP (i.e., SO2: 56,000 tons vs. 78,386 tons; NOx: 25,000 tons vs. 31,738 tons).

   Moreover, the proposed mass caps provide a substantial cushion of compliance compared to implementation of BART on only the Illinois EGUs subject to BART (e.g., DMG & IPH presumptive BART tons/year SO2 reductions compared to baseline = 85,812 v. tons/year SO2 reductions under Dynegy's proposed cap compared to baseline = 181,761). In fact, Dynegy's proposed caps provide more compliance margin relative to BART implementation than IEPA/USEPA's analysis in the original Regional Haze SIP (i.e., tons/year SO2 reductions under Dynegy's proposed cap = 181,761 v. tons/year SO2 reductions under the existing SIP analysis = 178,654 (in 2015)).

3. The current Regional Haze SIP does not restrict the amount of an acceptable mass cap under the MPS. Indeed, Illinois' Regional Haze SIP submittals have not relied upon any mass caps under the MPS, but instead have relied solely upon the MPS emission rate limits. "Expected" emission reductions for the combined Dynegy DMG and IPH units

[1] In its most recent approval of Illinois' Regional Haze SIP, USEPA identified expected SO2 emissions from the IPH units that are substantially higher than the IPH portion of the 44,920 tons of projected emissions. 80 Fed. Reg. 21681, 21683-84 (April 20, 2015) (USEPA identified IPH's expected emissions of SO2 at 50,275 tons in 2017 under the former variance).

under the proposed mass caps are greater than the expected emission reductions estimated by both Illinois EPA and USEPA in the Regional Haze SIP submittals and approvals. Therefore, Dynegy's proposal will continue to result in improved emission reductions consistent with reasonable further progress requirements.

4. Further, the SO2 and NOx caps identified by Illinois EPA (44,920 and 22,469) appear to be calculated using 2002 heat inputs multiplied by the MPS allowable emission rate. This is only one of many ways to forecast expected actual emissions. Using this method and concluding that Dynegy cannot exceed those amounts in essence limits Dynegy to its 2002 heat inputs, which is contrary to the reason why Illinois power plant owners selected a rate based emission limit over a mass cap in the MPS rulemaking negotiations. Illinois power plants preferred emission rate limits to allow for growth in energy demand, as emission rates allowed affected units to operate both more often and at higher capacities as long as they complied with the emission rate. There was, and is, no limit in the current MPS on mass emissions, other than that inherent in the rated/operational capacities of the units.

5. Regarding Newton Unit 2, Dynegy has provided revised proposed mass caps with Newton Unit 2 removed. Dynegy will agree to remove Newton Unit 2 from the CAAPP permit.

6. Regarding continuance of an MPS emission rate limit on ozone season NOx emissions, Dynegy believes this is problematic for several reasons, including:
    a. There is no environmental or public protection reason to maintain NOx emission rate limits during the ozone season. The proposed mass caps during the ozone season are, in fact, more protective in that they will lower the overall amount of NOx emissions allowed than currently allowed under the MPS.
    b. The MPS NOx ozone season emission rate limits are not more protective during "peak" hours because the MPS ozone season NOx limit is averaged over the entire ozone season., Dynegy could operate without SCR controls for an extended period during the ozone season and still comply with the MPS emission rate limit by increasing operation of the SCR's at other times during the ozone season.
    c. Notably, the CSAPR uses mass caps during the ozone season.
    d. Ozone season NOx reductions are not specifically regulated in the Regional Haze rule. Rather, annual NOx emissions are the targeted emissions. USEPA's review of Illinois's Regional Haze SIP only considered annual NOx emissions, not seasonal NOx emissions.
    e. It undermines the argument that mass caps are more useful and protective of the environment if Illinois EPA takes the position that they need keep any emission rate limits during the ozone season for environmental reasons.

f. Any use of the MPS for other than what it was proposed or it has already been used for is inappropriate and beyond the intent of the original rule. The MPS was not meant to be the "go to rule" for any reductions needed from Illinois coal-fired power plants.

Revised MPS Support

This document supplements and revises previous portions of the original proposal in regards the Illinois Multi-Pollutant Standards (MPS) rule.

The below revisions to the proposed mass-based caps reflect the removal of Newton Unit 2.

I. Multi-Pollutant Standards – Proposed Revision and Support

Specifically, as proposed, the remaining operating EGUs in the DMG MPS Group and Ameren MPS Group would be merged into a single MPS Group, comprised of Baldwin 1, 2 and 3, Havana 6, Hennepin 1 and 2, Coffeen 1 and 2, Duck Creek 1, Edwards 2 and 3, Joppa 1, 2, 3, 4, 5 and 6, and Newton 1. For simplicity, the proposed newly merged MPS Group is referred to herein as the "Merged MPS Group" or MMPS.

A. Proposed mass-based caps.

1. Annual SO2

Under the existing MPS rule, different emission rate limits apply to the IPH MPS Group (i.e., the "Ameren MPS Group" identified in 35 IAC 225.233(e)(3)) and the DMG MPS Group:

- The IPH MPS Group (i.e., units at Coffeen, Duck Creek, Newton, Edwards and Joppa) is subject to an annual SO2 rate limit in 2017 and beyond of 0.23 lbs/mmbtu.
- The DMG MPS Group (i.e., units at Baldwin, Havana and Hennepin) is subject to an annual SO2 rate limit in 2017 and beyond that is the more stringent of 0.25 lbs/mmbtu or a rate equivalent to 35 percent of the Base Rate of SO2 emissions (i.e., 0.19 lbs/mmbtu).

To determine the current allowable emissions under the MPS, the HI capacity of the existing EGUs is multiplied by the allowable MPS annual SO2 rate limit (lbs/mmbtu) and divided by 2,000 pounds. It is appropriate and necessary to use maximum HI capacity because there is no limit on HI and therefore allowable emissions must be calculated using the maximum HI capacity and not actual or expected HI. This method of calculating the allowable emissions has been established over decades of environmental practice and outlined in numerous permitting regulations and guidelines (e.g., PSD and NSR). This is similar to calculating the maximum allowable emissions for a unit that only has an emission limit in lbs/hr and no limit on hrs/yr. In order to calculate the allowable emissions, 8,760 hrs/hr are used and not the historic actual operating hrs/yr (e.g., 2,000 hrs/yr). Using this methodology, the MPS rate limit for the IPH MPS Group is equivalent to 45,210 tons per year and 24,716 tons per year for the DMG MPS Group. The annual allowable SO2 emissions for the merged IPH and DMG MPS Groups would be 69,926 tons.

In order to provide additional environmental benefits beyond the objectives of the MPS rule, the Merged MPS Group (i.e., the merged IPH and DMG MPS Groups) would need to be subject to an annual fleet-wide SO2 emission cap below 69,926 tons.

Dynegy proposes an annual SO2 emission cap of 56,000.

Note: The mass caps were carefully selected to be substantially below the allowable mass emissions and yet still provide operational flexibility for Dynegy. Also, consideration was given to the potential use of such emission caps for Illinois Regional Haze SIP and other needs.

2. Annual NOx

Under the existing MPS rule, different emission rate limits apply to the IPH and DMG MPS Groups:

- The IPH MPS Group annual NOx rate limit in 2017 and beyond is 0.11 lbs/mmbtu.
- The DMG MPS Group annual NOx rate limit in 2017 and beyond is the more stringent of 0.11 lbs/mmbtu or a rate equivalent to 52 percent of the Base Annual Rate of NOx (i.e., 0.10 lbs/mmbtu).

To determine the current allowable under the MPS, the heat input capacity of the existing EGUs is multiplied by the allowable MPS annual NOx rate limit (lbs/mmbtu) and divided by 2,000 pounds. Using this methodology, the MPS rate limit for the IPH MPS Group is equivalent to 21,622 tons per year and 13,009 tons per year for the DMG MPS Group. The allowable NOx emissions for the merged IPH and DMG MPS Groups would be 34,631 tons.

In order to provide additional environmental benefits beyond the objectives of the MPS rule, the Merged MPS Group (i.e., the merged IPH and DMG MPS Groups) would need to be subject to an annual fleet-wide NOx emission cap below 34,631 tons.

Dynegy proposes an annual NOx emission cap of 25,000 tons.

3. Ozone Season NOx

Under the existing MPS rule, different emission rate limits apply to the IPH MPS Group and the DMG MPS Group:

- The IPH MPS Group ozone season NOx rate limit in 2017 and beyond is 0.11 lbs/mmbtu.

- The DMG MPS Group ozone season NOx rate limit in 2017 and beyond is the more stringent of 0.11 lbs/mmbtu or a rate equivalent to 80 percent of the Base Seasonal Rate of NOx (i.e., 0.10 lbs/mmbtu).

To determine the current allowable under the MPS, the heat input capacity of the existing EGUs is multiplied by the allowable MPS seasonal NOx rate limit (lbs/mmbtu) and divided by 2,000 pounds. Using this methodology, the MPS rate limit for the IPH MPS Group is equivalent to 10,811 tons per ozone season and 6,504 tons per ozone season for the DMG MPS Group. The allowable NOx emissions for the merged IPH and DMG MPS Groups would be 17,315 tons over the period April 1 to September 30 each year.

In order to provide additional environmental benefits beyond the objectives of the MPS rule, the Merged MPS Group (i.e., the merged IPH and DMG MPS Groups) would be subject to a seasonal fleet-wide NOx emission cap below 17,315 tons.

Dynegy proposes a seasonal NOx emission cap of 11,500 tons.

B. **Demonstration that the proposed mass-based caps are more stringent than the mass emissions allowed by the MPS rate limits.**

The proposed annual and seasonal mass caps, when compared to the allowable mass emissions under the MPS, are more protective of the environment and public health. This is because the proposed mass-based caps are lower than the mass emissions allowed under the current MPS rule, as shown below.

The baseline year for the MPS was the average annual actual emissions from 2003 to 2005. The average annual 2003 to 2005 actual tons of SO2 emitted from the original IPH and DMG MPS Groups was 226,245 tons/yr (combined total). The objective, and requirement, of the original MPS rule was a 65% reduction from this amount. In calendar year 2017 and beyond, the MPS rule allows 69,926 tons of SO2 annually from the IPH and DMG Groups (combined total). The proposed mass-based cap for SO2 is 56,000 tons per year, resulting in a decrease in the amount of SO2 allowed of 25,026 tons per year. The 56,000 tons cap would also represent a 75% reduction in SO2 emissions from the 2003 to 2005 baseline, which is greater than the 65% reduction identified in the MPS.

The average annual 2003 to 2005 actual tons of NOx emitted from the original IPH and DMG MPS Groups was 56,826 tons/yr (combined total). The objective, and requirement, of the original MPS rule was a 48% reduction from this amount. In calendar year 2017 and beyond the MPS rule allows 34,631 tons of NOx annually from the IPH and DMG Groups (combined total). The proposed mass-based cap for NOx is 22,469 tons per year, resulting in a decrease in the amount of NOx allowed of 12,162 tons per year. The 25,000 tons cap would also represent a 56% reduction in NOx emissions from the 2003 to 2005 baseline, which is greater than the 48% reduction identified in the MPS.

The average ozone season emissions from 2003 to 2005 from the original IPH and DMG MPS Groups were 15,761 tons per season (combined total). The objective, and requirement, of the original MPS rule was a 20% reduction from this amount. In the 2017 ozone season and subsequent ozone seasons, the MPS rule allows 19,023 tons of NOx from the IPH and DMG Groups (combined total). The proposed mass-based cap for NOx is 11,500 tons per ozone season, resulting in a decrease in the amount of NOx allowed of 7,023 tons per year. The 11,500 tons cap would also represent a 27% reduction in seasonal NOx emissions from the 2003 to 2005 baseline, which is greater than the 20% reduction identified in the MPS. The ozone season applicable to the MPS is from the April 1st to September 30th.