BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

ILLINOIS POWER HOLDINGS, LLC and AMERENENERGY MEDINA VALLEY COGEN, LLC;	)	
Petitioners,	)	
AMEREN ENERGY RESOURCES, LLC	)	PCB No. 13-
Co-Petitioner,	)	(Variance – Air)
v.	)	
ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,	)	
Respondent.	)	

NOTICE OF FILING

To: ALL PARTIES ON THE ATTACHED SERVICE LIST

Please take notice that today we have electronically filed with the Office of the Clerk of the Illinois Pollution Control Board a **PETITION FOR VARIANCE**, and the **APPEARANCE OF CLAIRE A. MANNING, WILLIAM D. INGERSOLL, RENEE CIPRIANO, AND AMY ANTONIOLLI**, copies of which are herewith served upon you.

Claire A. Manning

Dated: July 19, 2013

BROWN, HAY & STEPHENS, LLP
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CERTIFICATE OF SERVICE

I, the undersigned, certify that on this 19th day of July, 2013, I have served electronically the attached **PETITION FOR VARIANCE**, and **APPEARANCES OF CLAIRE A. MANNING, WILLIAM D. INGERSOLL, RENEE CIPRIANO, AND AMY ANTONIOLLI**, upon the following persons:

John Therriault, Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
Suite 11-500
100 West Randolph
Chicago, Illinois 60601

and by first class mail, postage affixed upon:

Division of Legal Counsel
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P.O. Box 19276
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Claire A. Manning

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Co-Petitioner,	)	PCB No. 13- (Variance – Air)
v.	)	
ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,	)	
Respondent.	)	

APPEARANCE

I, Claire A. Manning, hereby file my appearance in this proceeding on behalf of Petitioner, ILLINOIS POWER HOLDINGS, LLC.

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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

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	)	PCB No. 13-
Co-Petitioner,	)	(Variance – Air)
v.	)	
ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,	)	
Respondent.	)	

APPEARANCE

I, William D. Ingersoll, hereby file my appearance in this proceeding on behalf of Petitioner, ILLINOIS POWER HOLDINGS, LLC.

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Dated: July 19, 2013

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

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Petitioners,	)	
AMEREN ENERGY RESOURCES, LLC	)	PCB No. 13-
Co-Petitioner,	)	(Variance – Air)
v.	)	
ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,	)	
Respondent.	)	

APPEARANCE

I, Renee Cipriano, hereby file my appearance in this proceeding on behalf of Petitioner, AMERENENERGY MEDINA VALLEY COGEN, LLC, and Co-Petitioner, AMEREN ENERGY RESOURCES, LLC.

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Dated: July 19, 2013

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

ILLINOIS POWER HOLDINGS, LLC and AMERENENERGY MEDINA VALLEY COGEN, LLC;	)	
Petitioners,	)	
AMEREN ENERGY RESOURCES, LLC	)	
Co-Petitioner,	)	PCB No. 13- (Variance – Air)
v.	)	
ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,	)	
Respondent.	)	

APPEARANCE

I, Amy Antoniolli, hereby file my appearance in this proceeding on behalf of Petitioner, AMERENENERGY MEDINA VALLEY COGEN, LLC, and Co-Petitioner, AMEREN ENERGY RESOURCES, LLC.

Amy Antoniolli

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Dated: July 19, 2013

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

ILLINOIS POWER HOLDINGS, LLC and AMERENENERGY MEDINA VALLEY COGEN, LLC;	)	
	)	
Petitioners,	)	
	)	
AMEREN ENERGY RESOURCES, LLC	)	
	)	PCB No. 14-10
Co-Petitioner,	)	(Variance – Air)
	)	
v.	)	
	)	
ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,	)	
	)	
Respondent.	)	

PETITION FOR VARIANCE

NOW COME PETITIONERS ILLINOIS POWER HOLDINGS, LLC ("IPH") and AMERENENERGY MEDINA VALLEY COGEN, LLC ("Medina Valley") (collectively, "Petitioners") and, along with AMEREN ENERGY RESOURCES, LLC ("AER"), ("Co-Petitioner"), and pursuant to Sections 35 and 37 of the Illinois Environmental Protection Act ("Act"), 415 ILCS 5/35, 37, and 35 Ill. Adm. Code Part 104, Subpart B, respectfully request that the Illinois Pollution Control Board ("Board") grant Petitioners dual variances from the sulfur dioxide ("SO_2") annual emission rates provided for in 35 Ill. Adm. Code 225.233(e)(3)(C)(iii) and (iv),[1] the Illinois Multi-Pollutant Standard ("MPS") applicable specifically to the fleet of seven coal-fired power plants that are together the entities subject to this rule ("MPS Group" or "Ameren MPS Group").

[1] Hereinafter, citations to the Board's regulations will be by section number only.

The timing of this Petition is necessary in order to allow a seamless regulatory transition in concert with a planned change in ownership of the MPS Group from the current owner, Co-Petitioner AER, to the new owners, Petitioners IPH and Medina Valley.

I. PROCEDURAL BACKGROUND

On May 5, 2012, AER filed a Petition for Variance with the Board and, on September 20, 2012, the Board granted AER the relief requested. *Ameren Energy Resources v. Illinois Environmental Protection Agency* ("*AER v. IEPA*" or "PCB 12-126"), PCB 12-126 (Sept. 20, 2012). The September 20, 2012, Opinion and Order ("Variance Opinion") in that proceeding informs this Petition, which involves the same facilities, the same regulations, and the same requested relief.[2]

The PCB 12-126 variance involved alternative emission rates for SO_2 from those promulgated in Sections 225.233(e)(3)(C)(iii) and (iv) of the Board's rules, known as the Ameren MPS Group Multi-Pollutant Standard ("Ameren MPS Rule"). 35 Ill. Adm. Code 225.233(e)(3)(C)(iii) and 225.233(e)(3)(C)(iv). The Ameren MPS Rule is a system-wide rule applicable to a discreet group of seven coal-fired power plants, specifically: Coffeen Energy Center (Montgomery County); Duck Creek Energy Center (Fulton County); E.D. Edwards Energy Center (Peoria County); Newton Energy Center (Jasper County); Joppa Energy Center (Massac County); Hutsonville Energy Center (Crawford County) and Meredosia Energy Center (Morgan County). Variance Opinion, at 1. The Board granted relief from Section 225.233(e)(3)(C)(iii)[3] for five years beginning January 1, 2015, and ending December 31, 2019,

[2] The Petitioners request that the Board take administrative notice of its record in PCB 12-126.
[3] Section 225.233(e)(3)(C)(iii) reads: "Beginning in calendar year 2015 and continuing in calendar year 2016, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.25 lb/million Btu."

and relief from Section 225.233(e)(3)(C)(iv)[4] for three years, beginning January 1, 2017, and ending December 31, 2019, making both variances expire simultaneously on January 1, 2020. Without this relief, the Ameren MPS Rule would have required the plants to achieve a system-wide (all seven plants) annual SO_2 emission limit of 0.25 pounds per million Btu ("lb/mmBtu") beginning in 2015 and 0.23 lb/mmBtu beginning in 2017. *Id*. at 7. In accordance with Section 35(a) of the Act, the Board found that immediate compliance with the 2015 and 2017 SO_2 annual emission rates would have posed an arbitrary or unreasonable hardship.[5] *Id*. at 68.

In its compliance plan in PCB 12-126, AER voluntarily committed to make earlier SO_2 emission reductions than otherwise required by the Ameren MPS Rule during the years 2012 through 2014. *Id*. Subsequent to discussions with the Illinois Environmental Protection Agency ("the Agency" or "IEPA"), AER committed to, and the Board's Order imposed, mitigation SO_2 annual emission rates to be met during the variance term. *Id*. The Board-ordered compliance plan also required AER not to operate the generating units at two of the plants from 2012 through 2020, and set certain milestones and reporting dates related to the construction of the flue gas desulfurization ("FGD") project at the Newton Energy Center ("Newton scrubber" or "Newton FGD project"). *Id.* at 68-69.

The Board found that AER had demonstrated that requiring compliance with the MPS overall SO_2 annual emission rates by 2015 and 2017 would impose an unreasonable hardship on AER and on September 20, 2012, granted the requested relief. *Id*. at 68. In granting the relief, the Board also determined that the earlier, more stringent SO_2 annual emission rates provided for in the compliance plan would result in a net benefit to Illinois air quality. *Id*.

[4] Section 225.233(e)(3)(C)(iv) reads: "Beginning in calendar year 2017 and continuing in each calendar year thereafter, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.23 lb/mmBtu."

[5] A hearing was held in PCB 12-126 on August 1, 2012, and the Board received over 3,000 public comments, both oral and written, in that proceeding. *See* Variance Opinion, at 2.

Subsequent to the Variance Opinion and due to the continued volatility of the merchant generating business, historically low power prices and a bleak financial outlook, Ameren Corporation ("Ameren"), AER's parent company, made a fundamental business decision to exit the merchant generating business. Exhibit 1, *Affidavit of Martin Lyons* ("Ex. 1, *Lyons Affidavit*"), ¶6. Thereafter, Ameren entered into a Transaction Agreement ("Agreement") with IPH, an indirect subsidiary of Dynegy Inc. ("Dynegy"), dated March 14, 2013. Exhibit 2, *Affidavit of Mario E. Alonso* ("Ex. 2, *Alonso Affidavit*"), ¶7. The Agreement was negotiated and carefully crafted to change ownership of the MPS Group and secure the variance relief and concomitant compliance obligations deemed appropriate by the Board in PCB 12-126. *Id.* ¶¶7, 8; Ex. 1, *Lyons Affidavit*, ¶9. In connection with the closing of the transaction, Ameren will initiate a reorganization of AER, which creates "New AER" for the acceptance of the active generating facilities of the MPS Group (Coffeen, Duck Creek, E.D. Edwards, Joppa, Newton) which will then be acquired by IPH.[6] Ex. 2, *Alonso Affidavit*, ¶7; Ex. 1, *Lyons Affidavit*, ¶9. IPH will then acquire New AER and the five active generating plants. Ex. 2, *Alonso Affidavit*, ¶4. The facilities required to remain shuttered under the Order in PCB 12-126 (Meredosia and Hutsonville) will be acquired by Petitioner Medina Valley, an indirect subsidiary of Ameren. Ex. 1, *Lyons Affidavit* ¶¶9, 15.

On May 2, 2013, in order to effectuate the transaction, IPH and AER filed a joint Motion to Reopen the Docket and Substitute Parties in PCB 12-126 ("Motion"). On June 6, 2013, the Board issued an Order denying the Motion which nonetheless stated:

> IPH may file a variance petition consistent with Section 104.202(a) of the Board's regulations, or may make any other appropriate filing concerning the facilities consistent with this order.

[6] In accordance with the Agreement, once the transaction closes, IPH will rename the acquired entity to remove all references to "Ameren" from its organization documents and representation materials.

PCB 12-126, slip op. at p. 11 (Jun. 6, 2013) ("Board Order on Motion").

As a result of the Board's discussion in the Board Order on Motion, Petitioners and Co-Petitioner wish to address preliminarily two aspects of this Petition for relief. First, Petitioners wish to make clear that any petition for relief from the Ameren MPS Rule must include an analysis of all seven plants and not only the five plants to be acquired by IPH. This is because all seven plants remain part of the MPS Group regardless of ownership. Second, this Petition for relief is timely and includes all necessary parties.

A. The Regulatory History and Framework of the Underlying MPS Regulations Requires that any Variance Address all Seven Facilities That Comprise the MPS Group.

In its analysis of this variance request, the Board must consider the electrical generating units ("EGUs") located at all seven plants in the MPS Group. Accordingly, this Petition seeks relief applicable to all seven plants, and is supported by an analysis of the factors based on all seven plants as any variance requesting relief from the MPS Rule should.

As a principal foundation of the MPS, the MPS applies fleet-wide and, once an owner or operator opts its EGU fleet into the MPS as an identified MPS group, those EGUs remain permanently part of that MPS group for regulatory purposes even if one or more of the EGUs are subsequently sold to a new owner. The Board must analyze, as it did for AER's request, how the variance will apply to all seven facilities in the MPS Group, not just those five that will be owned by IPH. This is so for three reasons.

First, the EGUs at all seven facilities must permanently remain part of the MPS Group for regulatory purposes because the Board relied on system-wide information in promulgating the Ameren MPS Group emission rates. The original MPS, found at Section 225.233, became effective on January 5, 2007. *In the Matter of: Proposed New 35 Ill. Adm. Code 225 Control of Emissions from Large Combustion Sources (Mercury)*, R06-25 (Dec. 21, 2006). Sections

225.233(e)(3)(C)(iii) and (iv) were added to the MPS on June 18, 2009, and became effective July 15, 2009.[7] *In the Matter of: Proposed Amendments to 35 Ill. Adm. Code 225: Control of Emissions from Large Combustion Sources (Mercury Monitoring)*, R09-10 (June 18, 2009). As promulgated, the MPS delayed compliance with the mercury emission standards from July 1, 2009, to January 1, 2015, but required compliance with stringent system-wide emission rates for nitrogen oxides ("NOx") and SO_2. Ameren opted all twenty-one steam electric generating units at seven plants into the MPS on December 27, 2007,[8] and has since been required to meet progressively declining emission rates for NOx and SO_2, as well as to meet interim requirements for controlling mercury emissions before January 1, 2015. The MPS allows the MPS Group to average compliance across all EGUs in the system, thus enabling AER to over-comply at some units for the benefit of other units.

In the initial MPS analysis, the Illinois Environmental Protection Agency ("IEPA" or "Agency") employed a method relying on data from the EGUs at all seven facilities to calculate an average heat input based on the three highest years between 2000 and 2007.[9] In the 2009 revisions to the MPS, AER used the same Agency methodology, but included calendar year 2008 to calculate the average heat input of 340,446,252 lb/mmBtu for the Ameren MPS Group. PCB 12-126, AER's Responses to the Illinois Pollution Control Board Technical Unit's Questions, 8-9 (July 30, 2012) (citing *Mercury Monitoring*, R09-10, Testimony of Michael L. Menne on Behalf of Ameren Companies, 15 (Feb. 2, 2009)). In both cases, the MPS rates were developed by relying on data from all seven facilities.

[7] The 2009 amendments added a section entitled "Ameren MPS Group Multi-Pollutant Standard," the 2015 SO_2 annual emission rate of 0.25 lb/mmBtu and the 2017 SO_2 annual emission rate of 0.23 lb/mmBtu.
[8] PCB 12-126, Petition, Ex. 4 (filed May 3, 2012).
[9] PCB 12-126, Petition, Ex. 4, Attach. B (filed May 3, 2012) (relying on years 2003, 2004, and 2005).

During the variance proceeding, the Agency supported the approach of considering the closures of Hutsonville and Meredosia in calculating emissions reductions (*i.e.*, using a baseline heat input that includes Meredosia and Hutsonville), noting that "providing credit for actions (*e.g.*, unit shutdowns) that result in emission reductions is an acceptable part of the established regulatory process." PCB 12-126, Recommendation, 21 (filed July 23, 2012). The Variance Opinion in PCB 12-126 affirmed the appropriateness of this approach. Again, the variance rates are founded on data from all seven facilities used to assess environmental impact and establish system-wide SO_2 and NOx emission rates for the MPS Group.

As the owner of the units at the Newton, E.D. Edwards, Coffeen, Joppa, and Duck Creek Energy Centers, Petitioner IPH will be required to comply with the requirements currently applicable to the MPS Group. As the owner of Hutsonville and Meredosia, Petitioner Medina Valley will be required to keep those facilities shuttered during the term of the requested variance. In other words, the units at all seven of the Energy Centers that comprise the MPS Group will remain part of the same group and subject to the same emission rates even though ownership has changed. In fact, this regulatory construct will continue beyond the variance period.

Second, the EGUs at all seven facilities must be analyzed together because the language of Section 225.233(a) plainly states that the MPS applies to all owners or operators of EGUs that make up an MPS group. 35 Ill. Adm. Code 225.233(a). Section 225.233(a) further provides the general requirements for opting into the MPS in lieu of complying with the otherwise applicable emissions standards. *Id*. This provision contains what has been referred to as the "once in, always in" language, which states, "all EGUs [the owner] owns in Illinois *as of* July 1, 2006, . . . must be *thereafter* subject to the standards and control requirements of this Section. . . ." *Id*. (emphasis added). The same Section further states: "When an EGU is subject to the requirements of this Section, *the requirements apply to all owners or operators of the EGU*." *Id*. (emphasis added). This latter statement clearly anticipates that there could be multiple owners and/or operators of the EGUs included in an MPS group. Once part of an MPS group, the plain language of Section 225.233(a) applies the MPS requirements to all owners of that EGU, including future owners. The regulation is not ambiguous. *See Lee v. John Deere Ins. Co*., 208 Ill. 2d 38, 43 (2003) (explaining the plain language of a statute or regulation is the best indicator of its intended meaning).

Third, Agency testimony during the underlying rulemaking supports the conclusion that the seven facilities in the MPS Group must be considered together for regulatory purposes even if sold or transferred. It was well-established through Agency testimony during the promulgation of the MPS that it was the Agency's intent that once a unit becomes subject to the MPS regulations as part of an MPS group, that unit remains part of that group even if sold or transferred to another owner. The clear intent of structuring the MPS in such fashion is to keep the units that comprise an MPS group together for purposes of regulating annual emissions of SO_2, NOx, and mercury, as well as ozone season emissions of NOx. As one of the chief architects of the MPS, the Agency explained its position at hearing during the original mercury rulemaking, stating that once an owner or operator opts into the MPS, the MPS emission rates apply fleet-wide—even if one or more units are sold. When posed with a hypothetical involving the sale of some but not all units in an MPS group, Mr. Jim Ross, Bureau of Air Division of Air Pollution Control Manager, and Mr. Chris Romaine, Bureau of Air Manager of the Construction Unit in the Permit Section, both on behalf of the Agency, maintained that the "system-wide" average applicable to an MPS group would continue to apply to the same units even if some were owned by a new company. The Agency witnesses further explained that compliance would need to be accounted for in the sale of units.

> MR. ROSS: What happens if a non-MPS company purchases EGUs that are subject to the MPS after July 1, 2006? We did not contemplate that occurrence. The new owner, however, would be responsible for compliance of the units. And if the new owner is not using the MPS, then the units have to comply with the non-MPS provisions.
>
> MS. BASSI: I'm sorry. Did you just say that the MPS units would have to stay in the MPS but the non-MPS units would not?
>
> MR. ROMAINE: I believe so, yes. There's nothing, as this rule is drafted, that would say somebody purchasing a unit out of the multi-pollutant standard group would then be excused from compliance requirements of the multi-pollutant standards. It wouldn't necessarily trigger compliance with the multi-pollutant standard because they haven't opted in before, but that obligation would apply to units that have accepted that option.
>
> * * *
>
> MR. ZABEL: My hypothetical would be that assuming Ameren opts in and for whatever reason decides to sell its Coffeen plant to the Northern Indiana Public Service Company, how do you enforce a system-wide average when somebody just dropped out of the system?
>
> MR. ROMAINE: Actually, I think that's the easier part of it. It's simply as a group of the Ameren units that Ameren still owns plus at the Coffeen unit because the appropriate owners must comply with a particular emission rate. So the particular aspect, there are some things like allowances because there could be over-compliance from Coffeen separate from over-compliance of other units. Hopefully, when Ameren entered into such an agreement, it would work out those details to avoid the need for litigation to resolve how those matters should be handled.
>
> MR. ZABEL: Well, assuming in that hypothetical, that for whatever reason Ameren makes a mistake and emits too much sulfur, you're going to sue Northern Indiana Public Service? Let's assume it happened at Newton, which Ameren still owns, or three of their plants, however you like. Who gets sued?
>
> MR. ROMAINE: Good question. Who do you sue?
>
> MR. ZABEL: That's why I asked it.
>
> MR. ROMAINE: Obviously there's complications that this type of arrangement would pose in a particular circumstance. Obviously that makes sale of units more complicated if Ameren would ever elect to do that.

MR. ZABEL: Thank you.

Mercury, R06-25, Aug. 15 (am) Tr., 344-47 (Aug. 15, 2006). While the Agency, in its testimony, did not detail exactly how companies were to ensure compliance with the MPS rates after some, but not all, of the units in an MPS group are sold, the testimony is clear that the Agency expects compliance from the entirety of the MPS group as originally formulated by the Agency and AER in 2007. Accordingly, the Petitioners and Co-Petitioner must, as they have, address regulatory and compliance obligations in their transaction agreements. Therefore, in considering any request for relief from the Ameren MPS Rule, the Board must include in its analysis all seven facilities which comprise the Ameren MPS Group, as a whole, as it did in PCB 12-126, regardless of who owns the facilities.

In keeping with the plain language of the regulation and the Agency's stated "once in, always in" intent of the MPS, IPH and Ameren have entered into an agreement for the sale of five of the seven facilities that comprise the MPS Group while taking special care to account for the continued compliance with the MPS emission rates of the units at all seven of the Energy Centers. Likewise, any analysis of the variance requested in this Petition must consider the EGUs at all seven of the facilities, regardless of ownership. This is how the Agency intended the MPS regulations to operate and it is based on the framework used to develop the original as well as current Ameren MPS Rule emission rates. Further, the Board adopted this system-wide regulatory approach, as is evident from the plain language of the rule.

B. The Request is Timely and The Petitioners and Co-Petitioner Are All Necessary Parties.

The Petitioners and Co-Petitioner meet the criteria for who may file a petition for variance. Section 104.202(a) is entitled "Who May File" and states "[a]ny person seeking a variance from any rule or regulation, requirement or order of the Board *that would otherwise be* *applicable* to that person may file a variance petition." 35 Ill. Adm. Code 104.202(a) (emphasis added). Consistent with the Board Order on Motion, the Petitioners and Co-Petitioner are here prepared to demonstrate, on this record, that denial of the requested relief will present an arbitrary or unreasonable hardship that outweighs any adverse impact to the environment. Upon closing of the transaction, the Ameren MPS Rule will otherwise be applicable to both IPH and Medina Valley together unless a variance is granted and, accordingly, each is a proper Petitioner. As the current owner of the MPS Group, with a direct and substantial interest in this proceeding, AER is a proper Co-Petitioner.

The proposed Order included herein has been crafted to create the obligations and secure the same relief as that found appropriate for the MPS Group in PCB 12-126. As to IPH, the proposed Order (a) grants the same relief as that secured by AER as it relates to the five plants it will own; and (b) sets forth compliance conditions that ensure ultimate compliance with the Ameren MPS Rule by the MPS Group and achieves environmental protection. As to Medina Valley (as well as to IPH), the proposed Order provides that the shuttering of Hutsonville and Meredosia is an enforceable obligation.

The Petitioners here are the entities that will own and control the facilities that comprise the MPS Group. They are the persons to whom the Ameren MPS Rule for the MPS Group would "otherwise be applicable," as stated in Section 104.202(a). It is imperative that the Board provide regulatory certainty to the new owners of the MPS Group without requiring existing ownership as a prerequisite. Nothing in the Act, or the Board's rules, requires, mandates, or justifies a different result.

In the Board's Order on Motion, the Board relied primarily on an interim order in *Ensign-Bickford Company v. IEPA*, PCB 02-159 (April 3, 2003). In denying IPH and AER's joint motion to reopen the docket and substitute parties, the Board quoted the following portion of the interim order in *Ensign-Bickford*:

> [t]he Board's procedural rules do not provide for a third party to seek a variance or have a variance transferred on Dyno Nobel's behalf. If in fact the . . . closing occurs, consistent with Section 104.202(a), Dyno Nobel may file a variance petition or other appropriate filing concerning this facility.

PCB 12-126, Board Order on Motion, at 10-11. The quoted excerpt of the interim order is, however, immediately preceded in the original *Ensign-Bickford* text by the statement: "Although EBCo asks that the variance be transferred to Dyno Nobel Inc., Dyno Nobel is not a party to the motion." *Ensign-Bickford*, PCB 02-159, slip op. at 2. Read in its entirety, the select paragraph of the Board's interim order in *Ensign-Bickford* clearly denied the request to transfer because the future owner, Dyno Nobel, was not a party to the motion. This conclusion is further evidenced by the Board's statement that a third party cannot have a variance transferred on another party's behalf as well as the subsequent reference to Section 104.202(a) (the Board's procedural rules for variance proceedings specifying "Who May File"). *Id.* In contrast to *Ensign-Bickford*, all the necessary parties are parties to this Petition for Variance.

The Board's single statement that Dyno Nobel may file a variance petition if closing occurs is dicta, petitioner-specific and respectfully should be read in full context. Importantly, dicta does not have precedential value. Further, this single statement without full context does not prevent Dyno Nobel or any other petitioner from filing a petition for variance before it becomes the owner of a facility. In denying the request to transfer variance relief because the company was not a party to the motion, the Board invited Dyno Nobel to file a petition for variance after closing (which was scheduled 30 days from the date of the order), and it did not find that the company could not or should not do so before closing. *Id*. There is simply no foundation for reading the *Ensign-Bickford* interim order to mean that Dyno Nobel or any other petitioner could not seek a variance prior to owning the facility.[10]

The Board has a long history of reading the Act and its procedural rules in a manner that provides the regulated community with the certainty it needs, as well as providing appropriate relief where justified and allowed pursuant to the Act—relief such as that which the MPS Group Petitioners seek here. *See Allied Chem. Corp. & Inverness Mining Co. v. IEPA*, PCB 80-92 Order (May 1, 1980); Opinion and Order (June 12, 1980). There, the Board granted relief to Inverness, who filed for a variance petition prior to its intended purchase of two mines in Southern Illinois (Hardin County) from Allied Chemical Corporation. The variance was granted because the Board found: "At the time this petition was filed [Allied] was in the process of selling these operations to Inverness. The parties agree and the Board finds that Inverness would suffer substantially the same arbitrary and unreasonable hardship if variances similar to those granted Allied were not granted. The previous Opinions in PCB 77-203 and PCB 79-149 are incorporated by reference." *Id*.

Here, the variance granted in PCB 12-126 applies to the same MPS Group facilities that are the subject of this Petition and concerns the same specific regulatory framework relevant to that MPS Group. That relief is an essential term of the transaction and, as set forth below, is as

[10] Given other Board cases, *see Allied Chem. Corp. & Inverness Mining Co.*, PCB 80-92 Order (May 1, 1980); Opinion and Order (June 12, 1980), the Board should not rely upon the dicta in the *Ensign-Bickford* interim order as precedent to exclude a variance petition prior to closing. *See Exelon Corp. v. Dep't of Revenue*, 234 Ill. 2d 266 (2009) (quoting *United States v. Crawley*, 837 F.2d 291, 292 (7th Cir.1988)) ("A dictum is 'any statement made by a court for use in argument, illustration, analogy or suggestion. It is a remark, an aside, concerning some rule of law or legal proposition that is not necessarily essential to the decision and lacks the authority of adjudication.'"); *Cates v. Cates*, 156 Ill. 2d 80, 76 (1993) ("The term '*dictum*' is generally used as an abbreviation of *obiter dictum*, which means a remark or opinion uttered by the way. Such an expression or opinion as a general rule is not binding as authority or precedent within the *stare decisis* rule.").

relevant to IPH as it is to AER and the same arbitrary and unreasonable hardship results to IPH if the relief is not granted.

Moreover, the Board has previously granted variances as to multiple petitioners concerning future compliance dates such as those relevant here where, as here, petitioners established that such regulatory relief is warranted because the hardship of immediate compliance outweighs any injury to the environment. *See Ill. Petroleum Marketers Ass'n. v. IEPA*, PCB 95-3 (May 4, 1995) (granting 157 gas stations in the Chicago nonattainment area an extension of the compliance date otherwise required for implementation of Stage II Vapor Recovery systems).

II. REGULATION FROM WHICH VARIANCE IS SOUGHT

A. The Petitioners Seek Temporary Relief from the 2015 and 2017 SO_2 Annual Emission Rates of the Ameren MPS Rule.

The Petitioners jointly seek relief from Section 225.233(e)(3)(C)(iii) and (iv) of the Ameren MPS Rule. As explained, this regulatory provision was created specifically for the seven coal-fired power plants in the MPS Group that are the subject of this Petition. Section 225.233(e) states in relevant part:

> e) Emission Standards for NOx and SO_2.
>
> ***
>
> 3) Ameren MPS Group Multi-Pollutant Standard
>
> ***
>
> C) SO_2 Emission Standards
>
> ***
>
> iii) Beginning in calendar year 2015 and continuing in calendar year 2016, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.25 lb/million Btu.
>
> iv) Beginning in calendar year 2017 and continuing in each

> calendar year thereafter, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.23 lb/million Btu.

The original MPS became effective on January 5, 2007. *Mercury*, R06-25, (Dec. 21, 2006). Sections 225.233(e)(3)(C)(iii) and (iv) were added to the MPS on June 18, 2009, and became effective July 15, 2009. R09-10 (June 18, 2009).

Consistent with Section 35(a) of the Act, in PCB 12-126, the Board found adequate proof that compliance with the Ameren MPS Rule would impose an arbitrary or unreasonable hardship. In doing so, the Board effectuated the balance the Act requires, by finding that the hardship caused by a denial of such request "outweighs any injury to the public or the environment." PCB 12-126, at 48 (citing *Marathon Oil Co. v. EPA*, 242 Ill. App. 3d 200, 206 (5th Dist. 1993)). Although not required to so find, the Board also concluded that the PCB 12-126 variance "will result in a net benefit to the environment." PCB 12-126, at 48, 51-56, 58, 68.

Utilizing the framework the Board established in that proceeding, relative to the very same MPS Group relevant here, as well as the same relevant regulation, this Petition seeks the identical relief. This Petition does take into account current economic, market, and regulatory conditions, even though those conditions are materially the same as existed at the time of the filing of PCB 12-126 on May 3, 2012.

The variance relief in PCB 12-126 was granted on September 20, 2012, prospectively, since it was not triggered simultaneously with the date of the Board's final opinion and order. Variance Opinion, at 68-69. Instead, the variance set a new SO_2 emission rate during the years of 2015 through 2019 in lieu of compliance with Sections 225.233(e)(3)(C)(iii) and 225.233(e)(3)(C)(iv). *Id*. Further, the compliance plan imposed more stringent interim SO_2 emission rates during the years of 2012 through 2014. *Id*. Here, the Petitioners seek, and justify, that same relief. This variance request is, likewise, prospective and must be so that regulatory obligations and commitments under any order will be seamless and certain for the Board and the transacting parties.

The relief granted in PCB 12-126 was deemed to be justified in order to allow for market conditions to improve prior to completing the Newton FGD project as scheduled, without any concomitant increase in total SO_2 emissions. At the end of the variance period, compliance with the Ameren MPS Rule, as written, will be achieved. This variance request, likewise, would allow for market conditions to improve prior to completing the Newton FGD project as scheduled, without any concomitant increase in total SO_2 emissions, and achieve compliance with the Ameren MPS Rule, as written, beginning in 2020.

B. Each of the Dual Variances Does Not Exceed Five Years.

The Petitioners seek relief from Section 225.233(e)(3)(C)(iii) for five years beginning January 1, 2015, and ending December 31, 2019, and relief from Section 225.233(e)(3)(C)(iv) for three years, beginning January 1, 2017, and ending December 31, 2019. In PCB 12-126, the Board previously granted AER this exact relief, for the very same seven power plants in the MPS Group that are the subject of this Petition, which are the sole subjects of Section 225.233(e)(3)(C). *See* PCB 12-126.

III. THE MPS GROUP FLEET INFORMATION AND NATURE OF ACTIVITY

A. The MPS Group Includes Seven Illinois Coal-Fired Energy Centers.

The seven coal-fired power plants that constitute the MPS Group, and which are the subject of this variance request, are all located in Central and Southern Illinois. *See* Exhibit 3, Map of MPS Group ("Ex. 3, *Map of MPS Group*"). Exhibit 3 shows the location of these plants and the air monitoring stations maintained by IEPA that are near them.[11] These seven Energy Centers are located in Montgomery County (Coffeen); Fulton County (Duck Creek); Jasper County (Newton); Peoria County (E.D. Edwards); Massac County (Joppa); Crawford County (Hutsonville); and Morgan County (Meredosia). As of the filing of this Petition, electricity continues to be generated at five of these facilities, since AER committed in PCB 12-126 to cease operation of the electric generating units at Meredosia and Hutsonville during the term of the granted variance. All of the counties are currently designated attainment for all pollutants.[12]

B. The Fleet Operates Pollution Control Equipment to Minimize Emissions of SO_2 and Other Constituents.

The principal emissions at the MPS Group power plants are SO_2, NOx, and particulate matter ("PM"). The MPS Group power plants generally control SO_2 emissions with pollution control equipment at several facilities as well as through the use of low sulfur coal, including blending low sulfur coal with Illinois coal that contains higher levels of sulfur. In particular, three scrubbers (a.k.a. "FGD units") are in service at the Duck Creek and Coffeen Energy Centers. NOx emissions are generally controlled by selective catalytic reduction systems ("SCRs"), low NOx burners ("LNB"), over-fired air ("OFA"), and burning various combinations of low sulfur coal. PM is generally controlled through the use of flue gas

[11] Exhibit 3, which consists of selected pages of the Agency's *Illinois Annual Air Quality Report 2011*, includes a copy of the map at page 34, depicting the locations of the air quality monitoring stations with the locations of MPS Group superimposed. *See* http://www.epa.state.il.us/air/air-quality-report/2011/air-quality-report-2011.pdf.
[12] *See* United States Environmental Protection Agency ("USEPA") Green Book Nonattainment Areas for criteria Pollutants (2012)(listing national attainment and nonattainment designations) *available at* http://www.epa.gov/oar/oaqps/greenbk/. However, USEPA is considering the inclusion of a portion of Peoria County, which would include E.D. Edwards Energy Center, as a designated nonattainment area with respect to the one-hour SO_2 National Ambient Air Quality Standard ("NAAQS"). As explained later in this Petition, Ameren has filed a comment in USEPA Docket QA-OAR-2012-0233 objecting to such inclusion, which is attached hereto and incorporated herein as Exhibit 4 ("Ex. 4, *Ameren Comment in Docket QA-OAR-2012-0233*").

conditioning and electrostatic precipitators (“ESPs”). Mercury emissions are controlled through the use of scrubbers and sorbent injection technologies.

In 2012, the MPS Group achieved an overall NOx annual emission rate of 0.11 lb/mmBtu and an overall SO_2 annual emission rate of 0.36 lb/mmBtu. Exhibit 5, *MPS Group 2012 Emissions Data* (“Ex. 5, *MPS Group Emissions Data*”). The addresses of the seven Energy Centers, their IEPA identification numbers, permit application numbers, and other pertinent information regarding their output, pollution control equipment, and SO_2 emissions are provided in Exhibit 6, attached to this Petition (“Ex. 6, *MPS Group Information*”).

C. The Facilities Provide A Significant Economic Benefit to the State of Illinois.

The operating Energy Centers are of significant economic benefit to the State of Illinois and its workforce, accounting for an estimated total economic impact on Illinois of approximately $1.5 billion annually and approximately 6,200 total direct and indirect jobs.

The direct and indirect economic impacts have been analyzed by Development Strategies and are provided here as Exhibit 7, *Group Exhibit of Five Memoranda* (“Ex. 7, *Group Exhibit*”). Direct impacts include money spent on capital expenditures, operating costs, and salaries; indirect impacts include the multiplier effect of those dollars being spent in the community at local businesses for goods and services. See below table (Table A):

Table A

	Coffeen	Duck Creek	Newton	E.D. Edwards	Joppa	TOTAL ECONOMIC IMPACT
Output (Total Economic Activity)	$534,944,000	$307,429,000	$288,339,000	$108,118,000	$193,530,000	$1,432,360,000
Earnings	$123,228,000	$66,590,000	$288,339,000	$29,941,000	$46,007,000	$554,105,000
Direct Jobs at the Energy	161	65	142	111	125	604

Center[13]						
Total Direct and Indirect Jobs	2,481	1,325	1,292	471	725	6,294

If relief is not granted, and the transaction fails to close, Ameren will need to pursue other options. *See* Ex. 1, *Lyons Affidavit* ¶16. Ameren's stated intention to exit the merchant generation business to better focus on its core regulated business, inevitably means that AER will no longer be in a position to ensure the operation of these plants. Ameren would continue to explore exit possibilities which could include sale of the assets, the restructuring of debt and equity in AEG, or some combination thereof. *Id*. While it is difficult to predict the outcome of Ameren's exit strategy, there is no reason to believe that any other potential buyer will be willing to acquire the plants without this variance, unless the buyer intended to close one or more of the Energy Centers. Under a restructuring scenario, control and operation of the merchant business would be dependent on negotiation with bondholders thereby creating uncertainty for employees, suppliers, and local communities. *Id.* IPH, with a continuation of the variance relief granted to AER, represents the best path forward for the continued operation of those facilities in a manner that achieves ultimate compliance with the Ameren MPS Rule. *Id.* As the Board is well aware from the public comments and testimony during AER's PCB 12-126 variance proceeding, the Energy Centers are an integral part of the Southern and Central Illinois economy. Granting the Petitioners the requested variance relief represents the best alternative for the merchant business as it struggles through very distressed and uncertain economic and power market conditions.

[13] Table A only reflects employees who reside in Illinois. Some of the Energy Centers employ personnel from neighboring states. The total direct jobs at the Energy Centers are as follows: Coffeen 162 employees; Duck Creek 66 employees; E.D. Edwards 111 employees; Joppa 176 employees; Newton 143 employees. Ex. 7, *Group Exhibit.*

D. Prior Variance Relief.

The key relevant prior variance is the one granted by the Board in PCB 12-126. In petitioning for that variance, AER explained that it had never previously received variances of similar relief; however, it detailed variances previously received by it and other Ameren affiliated companies in other contexts. *See* PCB 12-126, AER Pet., at 6, 8. Medina Valley has not been the subject of any prior variance relief.

As IPH is a new entity, it has sought no previous variance relief. Dynegy Midwest Generation ("DMG"), a separate Dynegy affiliate, sought and received a variance in *Dynegy Midwest Generation v. IEPA*, PCB 09-048. There, the Board granted a temporary nine-month deferral in implementation of mercury emission controls at Baldwin Unit 3 (Randolph County), while beginning mercury controls six months early on Havana Unit 6 (Mason County) and Hennepin Unit 2 (Putnam County). The PCB 09-048 variance resulted in an overall net reduction of 41.7 pounds of mercury emissions.

DMG has previously obtained 45-day provisional variance relief from the Board on unrelated matters, such as effluent discharge limitations. *See* PCB 03-027 and PCB 03-234. Finally, DMG has a variance petition pending before the Board related to the SO_2 allowance restrictions under the MPS rule. *See Dynegy Midwest Generation v. IEPA*, PCB 12-135 (seeking a variance from 35 Ill. Adm. Code 225.233(f)(2)).

IV. DETAILED DESCRIPTION OF COMPLIANCE PLAN

A. Petitioners' Compliance Plan Will Achieve Compliance with All of the Terms of the Variance Opinion in PCB 12-126.

As an integral part of its Compliance Plan accompanying this variance request, and in mitigation of the relief requested, the Petitioners propose that the MPS Group will meet an overall SO_2 annual mitigation emission rate of 0.35 lb/mmBtu through 2019. Committing to this

SO_2 annual mitigation emission rate in the Compliance Plan will impose significant operational restrictions on the Petitioners. The proposed rate will effectively commit Petitioner IPH to (a) maximize FGD performance at the Duck Creek and Coffeen Energy Centers, (b) continue to burn low sulfur coal (0.55 lbs sulfur/mmBtu) from the Powder River Basin at the E.D. Edwards, Joppa and Newton Energy Centers, and (c) manage generation as necessary to maintain compliance. The coal and performance commitments are discussed in more detail below. Further, in order to meet the proposed mitigation emission rate, Petitioner Medina Valley also will commit to the continued cessation of operations of the electrical generating units at the Hutsonville and Meredosia Energy Centers through December 31, 2020, with the exception of the FutureGen project at the Meredosia Energy Center. That obligation is formalized in the proposed Order, making the commitment to maintain cessation of operations at Hutsonville and Meredosia an enforceable condition as to both IPH and Medina Valley, and as consistent with the enforcement approach of IEPA as to the MPS Group.

Further, Petitioner IPH will maintain a continuous program of construction at the Newton Energy Center, on the existing schedule set forth in the Variance Opinion, so as to be in a position to have the Newton FGD project completed and operational to meet compliance obligations. All major equipment components required to complete the Newton FGD project have been procured. Engineering design will continue through 2014. Field construction work will be staged so as to facilitate future construction sequencing. Ductwork and insulation activities will occur, the absorber building will be constructed, and electrical systems and piping connections will be completed. Proceeding in this manner will position the Petitioners for compliance with the Ameren MPS Rule’s final overall SO_2 annual emission rate (0.23 lb/mmBtu) beginning in 2020, with the installation and operation of the Newton FGDs.

The Petitioners request a three-year variance from Section 225.233(e)(3)(C)(iv) to comply with the final overall SO_2 annual emission rate. As the Board determined in the prior proceeding, a shorter variance is not feasible because it would not allow sufficient time for financially viable completion of the Newton FGDs. The requested variance term also will allow Petitioners to properly stage and stagger the in-service date of each of the two Newton FGDs and to ensure that the FGD project achieves the expected SO_2 reductions. Petitioner IPH has analyzed all of the commitments made by AER in the prior proceeding, and has agreed to assume each and every commitment. As AER pointed out in its various filings with the Board in PCB 12-126, these obligations are not insubstantial. In sum, they are as follows:

(i) From January 1, 2013 to December 31, 2019, IPH will comply with an overall SO_2 annual emission rate of 0.35 lb/mmBtu.

(ii) Beginning January 1, 2020, IPH will comply with an overall SO_2 annual emission rate of 0.23 lb/mmBtu.

(iii) With respect to the EGUs at the Meredosia and Hutsonville Energy Centers, the Petitioners will ensure that the EGUs will not be operated through December 31, 2020 (one year beyond the entire term of the variance relief), with the exception of the FutureGen project at Meredosia Energy Center.

(iv) With regard to the FGD project at the Newton Energy Center, IPH will comply with the obligations set forth in the PCB 12-126 variance, including all construction milestone commitments and reporting obligations.

1. IPH Will Continue to Use Low Sulfur Coal.

As indicated above, agreeing to a mitigation emission rate during the variance term requires operational commitments above and beyond what is currently required by law. AER committed to limiting the use of higher sulfur coal to the Duck Creek and Coffeen Energy Centers, both of which have wet FGD systems, and to using low sulfur Powder River Basin ("PRB") coal (0.55 lb/mmBtu) at the E.D. Edwards, Newton, and Joppa Energy Centers. Variance Opinion, at 50. By agreeing to the same SO_2 mitigation emission rate during the requested variance term, IPH will also be required to limit the use of high sulfur coal to the Duck Creek and Coffeen Energy Centers and use low sulfur coal at the E.D. Edwards, Newton, and Joppa Energy Centers. *See* Exhibit 8, Affidavit of Daniel P. Thompson ("Ex. 8, *Thompson Affidavit*), ¶14. In fact, as a result of the transaction, IPH's acquired operating subsidiaries will inherit and be bound by the low sulfur coal purchase contracts that AER has already signed for coal purchases in 2013, 2014, 2015, 2016, and 2017. *Id*.

Furthermore, in order to meet the requested variance's 0.35 lb/mmBtu SO_2 annual mitigation emissions rate, IPH anticipates the potential to purchase even lower sulfur coal than included in AER's commitment for Newton, E.D. Edwards and Joppa. *Id*. ¶¶ 14, 28. Based on DMG's coal purchasing experience, IPH understands that 0.50 lb/mmBtu sulfur PRB coal is available from one supplier. *Id*. ¶15. While IPH is committed to the 0.55 lb/mmBtu low sulfur coal contracts entered by AER for 2013–2017 as well as to using 0.55 lb/mmBtu low sulfur coal at Newton, E.D. Edwards and Joppa during the term of the variance, IPH anticipates potentially purchasing certain quantities of even lower sulfur coal, consistent with availability, performance risk, price, and the MPS Group's emission performance. *Id.*

2. IPH Will Continue to Optimize Scrubber Performance.

IPH also will operate the existing FGD systems at the Duck Creek and Coffeen Energy Centers at a 98-99 percent SO_2 removal rate. *Id.* ¶24. While achieving and maintaining 98-99 percent SO_2 removal is challenging, IPH is confident that it can operate the Duck Creek and

Coffeen Energy Centers at those removal efficiencies. Indeed, such efficiencies will be required (and are budgeted) in order to meet the mitigation emission rate presented as part of its Compliance Plan.

B. Costs to Achieve Compliance Are Staggering.

The costs required to achieve compliance with the MPS are staggering. Specifically, compliance with the MPS Group 2015 SO_2 annual emission rate (0.25 lb/mmBtu) as it exists without the variance will require the near immediate shut down of the E.D. Edwards and Joppa Energy Centers. *Id.* ¶12; Ex. 2 *Alonso Affidavit*, ¶8. As further explained below, such shutdown will have a devastating impact on the local economies and materially undermine the State's struggling economy. As the Board found in its Variance Opinion, the shutdown of E.D. Edwards and Joppa would adversely impact 274 direct jobs, 1,374 indirect jobs, over $121 million per year in the local economies near the two plants, and over $338 million per year in the State's economy.

To date, AER has spent over $1 billion in capital expenditures to comply with its MPS Group environmental obligations. Variance Opinion, at 62-63; Pet. 17, 18; Tr., at 16; Post Hearing Brief, at 31. That includes installation of SO_2 scrubbers on three units at a cost of over $813 million, installation of SCR systems to reduce NOx emissions at three plants at a cost of over $177 million, and installation of activated carbon injection ("ACI") technology on 12 units at a cost of over $20 million. Variance Opinion, at 13. In addition, AER has spent over $7 million annually in operating costs for the SCRs and a total of about $17 million for operation of the ACI systems. *Id.* at 17.

Total costs of construction for the two FGD units at the Newton Energy Center are estimated to be approximately $500 million. Ex. 8, *Thompson Affidavit*, ¶25. Approximately one half of the total costs have been spent to date. *Id.* In accordance with the construction milestones in the proposed variance order, IPH has budgeted $18 million in annual expenditures through 2017 with the remainder of total estimated spending scheduled for 2018 and 2019 to complete construction of the Newton FGDs and achieve compliance at the end of the variance period. *Id.* In addition, for the five Energy Centers, IPH estimates several million dollars in average annual Operations and Maintenance ("O&M") expenditures through 2019 to comply with the MPS NOx and mercury emission limits. *Id*.

Without the variance, IPH's compliance with the MPS Rule 2015 SO_2 emission rate would require virtually immediate completion of the Newton FGD project which, at this time, given the variance relief afforded AER, and the anticipated construction schedule contained in that variance, is virtually impossible. *Id.* ¶13. Moreover, upon closing IPH simply will not have the financial resources to cover such immediate construction expenditures. Ex. 2, *Alonso Affidavit*, ¶24. Thus, the Board's endorsement of a multi-year (2015–2019) construction schedule in PCB 12-126 is quite relevant to this Petition.

V. ARBITRARY OR UNREASONABLE HARDSHIP

The very same hardship factors recognized by the Board in its Variance Opinion, decided less than ten months ago, are also relevant here. Given current conditions, those factors are even more onerous and immediate.

A. Regulatory Uncertainty Still Exists at the Federal Level and Illinois Stands Alone.

As the Board recognized in its Variance Opinion, the Ameren MPS Rule was developed with the belief that federal regulations related to the MPS Group were imminent. Variance Opinion, at 5. Yet, the expected federal regulations have not materialized, and Illinois stands alone in its stringent MPS requirements, putting the MPS Group at a disadvantage to its competitors. *Id*. at 10. None of that changes under the new ownership.

In May 2005, USEPA promulgated the Clean Air Mercury Rule ("CAMR") that established a cap on mercury emissions from coal-fired EGUs serving generators with nameplate capacity greater than 25 megawatts. 70 Fed. Reg. 28606 (May 18, 2005). However, in February 2008, the United States. Court of Appeals for the District of Columbia vacated CAMR. *New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008).[14]

Also in May 2005, USEPA promulgated the Clean Air Interstate Rule ("CAIR"), which required reductions of SO_2 and NOx to address interstate ozone and fine particulate matter ("$PM_{2.5}$") pollution. 70 Fed. Reg. 25162 (May 12, 2005). CAIR established a cap on emissions of SO_2 and NOx for coal-fired EGUs. *Id.* But, in July 2008, the D.C. Circuit Court of Appeals vacated CAIR. *See North Carolina v. EPA*, 531 F.3d 896, 929-30 (D.C. Cir. 2008). Later, upon request of USEPA, the court remanded CAIR without vacatur and ordered CAIR to remain effective until USEPA replaced it with a new rule. *See North Carolina v. EPA*, 550 F.3d 1176, 1777-78 (D.C. Cir. 2008).

In an attempt to promulgate a replacement rule for CAIR, USEPA adopted the Cross-State Air Pollution Rule ("CSAPR") in 2011. 76 Fed. Reg. 48208 (Aug. 8, 2011). The rule was designed to reduce annual and seasonal SO_2 and NOx emissions from EGUs in upwind states to areas in downwind states. *Id.* at 48349. The D.C. Circuit Court of Appeals also vacated this rule in August 2012. *EPA v. EME Homer City*, 696 F.3d 7 (D.C. Cir. 2012), *cert. granted*, 2013 WL 1283840 (June 24, 2013). On June 24, 2013, the United States Supreme Court issued *certiorari* and will review the decision vacating CSAPR next term. *Id.* This recent development puts in

[14] The USEPA subsequently adopted the Mercury and Air Toxics Standards ("MATS") to control EGU emissions, 77 Fed. Reg. 9304 (Feb. 16, 2012), but that rule is currently being appealed to the District of Columbia Circuit Court of Appeals. *See White Stallion Energy Ctr., LLC v. EPA*, No. 232200 (D.C. Cir., Feb. 16, 2012).

play more directly the uncertainty coal-fired power generators face as they await both how the Supreme Court will rule and whether USEPA will continue to move forward on developing a CAIR/CSAPR replacement yet again.

The uncertainty involving the future applicability of any federal rule to control the interstate transport of air pollution is further compounded by President Obama's Climate Action Plan announced on June 25, 2013.[15] The Presidential Memorandum, issued together with the President's Climate Action Plan, directs USEPA to issue final carbon pollution reduction standards for existing power plants "no later than" the ambitious deadline of June 1, 2015.[16] Indeed, in no uncertain terms, President Obama has made power plant carbon pollution reduction a top priority of this Administration. How this action may specifically implicate the five operating Energy Centers in the MPS Group is, at this point, anyone's guess. While the Presidential Memorandum states that USEPA must ensure that carbon standards are developed and implemented in a manner "consistent with the continued provision of reliable and affordable electric power for consumers and businesses,"[17] no one yet knows *how* USEPA will interpret its mandate to set new carbon pollution standards.

Given the uncertainty and lack of detail surrounding federal regulatory initiatives and structures, including the President's climate change mandate, planning for the future regulatory compliance is now even more complex for merchant generators, as such regulatory uncertainty complicates decision-making and negatively impacts markets and power prices. The Board's denial of this variance request would only complicate these matters further. Until the federal regulatory obligations are sufficiently clear, it is even more imperative that the State of Illinois,

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[15] Exec. Office of the President, The President's Climate Action Plan (June 2013).
[16] The White House, Office of the Press Secretary, Memorandum for the Administrator of the Environmental Protection Agency, Subject: Power Sector Carbon Pollution Standards (June 25, 2013). 78 Fed. Reg. 39535 (July 1, 2013).
[17] *Id.* at §1(c)(v).

through the Board, stay on the course that the Board found appropriate in PCB 12-126; if changes requiring plant closures occur at the federal level, those changes will be implemented nation-wide, in a manner that does not unfairly implicate Illinois merchant generation.

B. Due To An Unforeseen Sequence of Events, Illinois Power Generators Operate At An Economic Disadvantage Compared to Competitors In Surrounding States.

The hardship the Ameren MPS Group now faces was not foreseeable. While the impact of the CSAPR stay has been felt nationally, it has been felt acutely in Illinois where the MPS imposes a uniquely structured emission program in a state that has also experienced drastic changes in power prices and market conditions in the very recent past. This series of events makes compliance with the emission rates at issue an arbitrary and unreasonable hardship for any owner of the MPS Group.

The Illinois General Assembly adopted the Electric Service Customer Choice and Rate Relief Law of 1997. *See* 220 ILCS 5/16-101. *One* of the primary purposes of this law was to incent the Illinois utilities to transfer their generating plants into either affiliates or third parties, where they could no longer be controlled by the utilities and would instead compete in a wholesale power market to provide power to retail customers at prices determined by competition. The 1997 law created an expeditious process for transferring generating plants that was available for a limited amount of time (the mandatory transition period). As a result of the legislature's deregulation of Illinois' energy markets in 1997, Illinois generators cannot recover the costs of capital projects, *including those relating to environmental mandates*, through captive consumer rates. Rather, merchant power companies' investment decisions such as the installation of pollution control equipment are based on the ability to recoup such expenditures from expected future market prices for power.

The deregulated market does not alone create the hardship that the MPS Group now faces. It is well-recognized that in promulgating the MPS rule in 2006, Illinois adopted emission reduction requirements significantly more stringent than other states—with the unintended consequence of putting the Illinois merchant generation business at a substantial disadvantage to its out-of-state competitors. Those mandates, however, were adopted in anticipation of federal mandates—which, as explained below, have been subsequently vacated, remanded or are currently on appeal. Meanwhile, Illinois' MPS regulations are now among the strictest in the nation; quite simply, other neighboring states have not adopted state air regulations in advance of a federal mandate.[18]

Since the MPS was adopted in 2006, economic conditions have fallen beyond any price declines that were foreseeable when the 1997 law was passed or even when the MPS was enacted in 2006. The new methods of gas extraction are a "game-changing" technology that have fundamentally altered the outlook for gas supplies and pricing. The general recessionary economic conditions have also depressed the demand for power and, therefore, power prices. Further, mandatory requirements that certain percentages of the total retail electric supply come from renewable resources, enacted in Illinois in 2007, have also reduced the demand for power from traditional sources, and consequently prices. In sum, the MPS was premised on the expectation that the power market would continue to support the capital expenditures necessary to meet the proposed emission rates. Today, however, market prices for power cannot support the necessary capital expenditures to complete the Newton FGD project in time to meet the MPS

[18] For example, Indiana, Kentucky, Missouri, Iowa, and Ohio have no mercury emission rules. Wisconsin requires that large coal-fired EGUs apply control technology to reduce mercury emissions 90 percent by January 1, 2015, or comply with a multi-pollutant option that achieves 90 percent mercury reduction by January 1, 2021. Wis. Adm. Code, Dept. of Natural Res., NR 446 *et seq.* Michigan requires mercury reductions from coal-fired EGUs by January 1, 2015, or achieve 75 percent reduction under a multi-pollutant option. Mich. Adm. Code, Part 15, R 336.2501 *et seq.* Minnesota requires 90 percent mercury reduction by 2015 from the State's three largest electric power plants; remaining facilities must reduce mercury emissions 70-90 percent by 2025. Minn. Stat. §115A.932 *et seq.* Moreover, none of our neighboring states have as stringent SO_2 standards as in the Illinois MPS.

2015 and 2017 SO_2 emission rates. Market conditions and new technologies and policies that have come about since that time were not self-imposed and simply not foreseeable. It is the convergence of these factors that amount to the arbitrary and unreasonable hardship that any owner of the MPS Group now faces.

Generators in neighboring states who have not had to make such emission control equipment investments or are able to recover such costs through the consumer rate base are able to offer their power into the marketplace, including the Illinois marketplace, without any such cost considerations. Also, as Illinois proceeded towards deregulation, regional transmission organizations formed through which power generators were more easily and efficiently able to sell power across state lines. As a result, AER now competes with generators in several nearby states that have neither deregulated their energy markets nor invested significant capital in environmental pollution control projects to address stringent state requirements. Thus, when Illinois requires merchant generators to install controls not required of companies in surrounding states, or by the federal government, at a time when the Illinois economy is abysmal,[19] the Board must engage in a responsible cost-benefit analysis, as the legislature has provided for in Section 35(a) of the Act.

C. Hardship Caused by Plant Closures.

Unless Petitioners receive the requested variance relief, plant closures are inevitable. It is for this reason that the Petition has been filed now.[20] If the Board does not allow the Petitioners the MPS variance relief it deemed appropriate as to AER, for the very same MPS Group, and

[19] *See* Sarah Burnett, *Illinois Credit Rating: State's Worst In Nation Costing Tax Payers Millions*, Huffington Post, June 25, 2013, available at http://www.huffingtonpost.com/2013/06/25/illinois-credit-rating-st_n_3496264.html.

[20] A Board decision requiring this variance petition to be filed after IPH acquires ownership of the plants, without any review of the appropriateness of the requested relief pursuant to Section 35(a) and this Petition, would inject a great and unnecessary uncertainty regarding the continued viability and operation of the Energy Centers. As stated in Section I.B above, such result is not legally required and any policy interpretation otherwise is tantamount to a determination that, in Illinois, corporations cannot transact with certainty as to existing Illinois regulatory obligations.

IPH nonetheless moves forward with the transaction, IPH's only compliance option would be to shut down a combination of Energy Centers by January 1, 2015. Ex. 2, *Alonso Affidavit*, ¶8. Given depressed power prices that have existed over the past several years and which will continue for several more years, compliance with the MPS 2015 and 2017 overall SO_2 annual emission rates in Sections 225.233(e)(3)(C)(iii) and (iv) is not achievable without the shutdown of Energy Centers, in this case the E.D. Edwards and Joppa Energy Centers. Assuming the transaction closes, IPH and Ameren anticipate closing on the transaction in the fourth quarter of 2013. *Id*. IPH will not have the financial resources required to complete installation of the Newton FGDs at that time; in any event, even if the needed financial resources were available (which they are not), the Newton FGDs could not, absent the variance, now be completed in time to avoid shutting down the E.D. Edwards and Joppa Energy Centers. *Id.* ¶¶8, 20.

Should the IPH transaction not close, Ameren would continue to explore exit possibilities, which could include the sale of assets, the restructuring of debt and equity in GENCO, or some combination thereof. Ex. 1, *Lyons Affidavit*, ¶16. As previously noted, under a restructuring scenario, control and operation of the merchant business would be dependent on negotiations with the GENCO bondholders and, ultimately, the result of such restructuring proceedings thereby creating uncertainty for employees, suppliers and local communities. Ameren has no reason to believe that any other potential buyer would be willing to acquire the Energy Centers without the variance, unless such buyer intended to close one or more plants. *Id.* IPH, with a continuation of the variance relief granted to AER, represents the best path forward for the continued operation of the Energy Centers and in a manner that achieves ultimate compliance with the Ameren MPS Rule.

The shutdown of the E.D. Edwards and Joppa Energy Centers would, as previously considered by the Board in PCB 12-126, adversely affect 274 direct jobs, 1,374 indirect jobs, over $121 million per year in the local economies near the two plants, and over $338 million per year in the State's economy. Variance Opinion, at 62. In short, the economic impact of shutting down the E.D. Edwards and Joppa Energy Centers would devastate their local communities and materially undermine the State's struggling economy. The shuttering of these plants will create an arbitrary or unreasonable hardship on IPH, the local economies served by those facilities and, more generally, the State's economy. See, for example, the public comments made by local and state officials and others at the Board's hearing in PCB 12-126, held less than one year ago, about the E.D. Edwards, Joppa and Newton Energy Centers:

> **Senator Gary Forby (Tr., at 57-59)**
> Sen. Forby discussed the Joppa Power Plant. While he recognized it needs some improvements, he stated that the issues before the Board in that proceeding were "all about jobs" which is the main thing the State of Illinois, especially southern Illinois, needs. He wants southern Illinois to "stay a part of Illinois" and keep its economic development going. He is just asking for their "fair share."
>
> **Representative Brandon Phelps (Tr., at 59-62)**
> Rep. Phelps' comments focused on the Joppa Power Plant, also in his district. As Chairman of the House Public Utilities Committee, he recognized that the government and private sectors are facing a huge financial crisis. He explained that Joppa provides 164 well-paying jobs for southern Illinois which, when compared to Chicago demographics, is the equivalent to 10,000 jobs in southern Illinois. Economics must factor into Illinois' environmental regulations and pollution control because these rules were adopted assuming that federal rules would soon follow their adoption. While he recognized the commitment of the power companies to reduce emissions, he recommended that compliance be deferred to a later date given the current economic situation.
>
> **Representative David Reis (Tr., at 63-66)**
> The Newton Plant, which is located in his district, is the largest private employer in Jasper County. The plant employees 155 people and losing those jobs would crush Jasper County's economy and the local school system. Those 155 jobs in a county of less than 10,000 people equates to losing 41,800 jobs in Chicago (pop. 2.7 million).

Rep. Reis stated that the United States emissions are only a "thimble of water in the pond" and that unilateral American reductions in greenhouse gases and SO_2 will have a negligible impact on atmospheric conditions worldwide. He believes it is not unreasonable to give the Newton plant the time requested to come into compliance. Speaking for the people of Jasper County, he stated that they don't have big organizations representing them, or lobbyists or lawyers, just themselves and their concern for their community, schools, and jobs.

Mayor Mark Bolander of Newton (Tr., at 79-81)
Newton has an annual economic impact on the state, in direct spending, of $71.5 million; total economic activity, over $231 million; direct jobs at plant 158; and total direct and indirect jobs 978. The $71.5 million in direct spending triggers an additional $141.6 million in value added activity in Illinois, of which $40.5 million was household earning that supported 820 jobs. The $213 million in total economic activity triggers nearly $56.9 million in household earnings for Illinois workers including $16.4 million in direct compensation and $40.5 million in added earnings from the multiplier effects.

For the labor market, the Newton plant provides a direct spending of $67.5 million; total economic activity of $154.3 million; direct jobs of 120; and total direct and indirect 553 jobs in Newton's labor market. The $67.6 million in direct spending triggered an additional $86.7 million in value added activity in the market area ($22.7 million was household earnings, supporting 433 jobs). The $153.4 million of total economic activity supported $35.1 million in household earnings for the market area including $12.4 million in direct compensation for employees, and $22.7 million in added earnings.

Jasper County Board Member Bill Webber (Tr., at 81-84)
The Newton Energy Center recently gave a $7 million check to the Jasper County treasurer, for the payment of local taxes which support the schools, the community college district, the library board, fire department district, the county, the extension service and various other government services. It represents a little over 51% of the total tax revenue for the county.

Mayor Billy McDaniel of Metropolis (Tr., at 103-106)
There are 235 well-paying jobs at the Joppa plant—well above the average income in the area. The plant pays about $800,000 a year in property taxes and real estate taxes. The plant and its employees spend hundreds of thousands of dollars on vendors in the city.

Jasper County School Board Superintendent Dan Cox (Tr., at 106-108)
The Newton Energy Center represents 60% of the local tax revenues for Jasper County Schools, which translates into $4 million per year to the school district.

Jean Ellen Boyd from Shawnee Community College (Tr., at 111-112)
The property taxes from the Joppa facility provide $86,000 per year to the college.

Vicky Clark President of Economic Development Council for Central Illinois (Tr., at 189-191)
The E.D. Edwards Energy Center provides 110 jobs in Bartonville. The wages generated from those jobs create an additional 450 jobs through spending in the local economy. Closing of Edwards would result in a loss of over $124 million annually to the local economy.

Bill Sheppard from Joppa Plant (Tr., at 192-195)
In 2011, there were approximately 150,000 man-hours of building trade/crafts man hours worked at Joppa. The Joppa plant spent $116 million per year over the last five years with Illinois vendors and suppliers.

D. Poor Market Conditions for the Power Generation Industry Continue to Contribute to an Arbitrary and Unreasonable Hardship.

Due to AER's limited financial resources caused by depressed power prices and poor economic conditions over the past several years and its inability to obtain external financing, IPH will not be able to fund completion of the Newton FGDs in time to comply with either the 2015 or 2017 MPS SO_2 annual emission rates. Ex. 2, *Alonso Affidavit*, ¶24. Nor is adequate funding available to implement any other feasible MPS compliance alternatives available to IPH as demonstrated in Section VI. These financial considerations lead to an inevitable conclusion that, without the variance, the plant closures discussed above will occur—causing a significant hardship to the Petitioners, employees who work at the Energy Centers, the local communities the Energy Centers support, and the State of Illinois. Moreover, the same financial considerations the Board addressed in PCB 12-126 as it relates to hardship continue to be equally relevant here.

1. Power Prices/Market Conditions Remain Depressed and Are Not Expected to Begin Gradual Recovery Until 2015.

Construction of the Newton FGD in time to meet the existing MPS is an impossibility both in terms of construction timeframe and required financial resources. Because IPH will not acquire ownership of the Acquired Plants until late 2013 and because construction activities needed to install the Newton FGDs are expected to take up to 24 months, IPH could not complete construction of the Newton FGDs in time to comply with the MPS 2015 overall SO_2

annual emission rate, even if IPH were financially able to ramp up construction immediately upon acquiring ownership, which it is not. Ex. 8, *Thompson Affidavit*, ¶ 12. The lack of financial resources needed to complete installation of the Newton FGDs in order to meet the MPS is the direct result of severely depressed power prices which are expected to continue for the next several years. Ex. 2, *Alonso Affidavit*, ¶¶11, 20, 23, 24. As a merchant generator, the source of revenues for IPH[21] is the sale of electricity; thus, IPH is largely dependent on the commodity price of electricity. *Id.* ¶11. As relevant to the Energy Centers, power prices declined from approximately $60 per megawatt hour in 2006-2007 to approximately $29.50 to $33.50 per megawatt hour in 2012. *See* Variance Opinion, at 63; Ex. 2, *Alonso Affidavit*, ¶11. The steep decline in power prices is largely due to the combination of excess natural gas supplies resulting from increasing unconventional natural gas production from shale deposits, which has resulted in low natural gas prices, and lower demand resulting from poor overall economic conditions. *See* Variance Opinion, at 62 (recognizing AER's contentions that the new methods of gas extraction are a "game changing" technology that have "fundamentally altered" the outlook for gas supplies and pricing); *see also* Exhibit 9, *Affidavit of George W. Bilicic* ("Ex. 9, *Bilicic Affidavit*"), ¶6.

Power prices remain depressed today, currently at approximately $31.85 per megawatt hour. Ex. 2, *Alonso Affidavit*, ¶11. Current forecasts by independent market observers and financial analysts expect power prices to remain depressed for the next several years. Ex. 9, *Bilicic Affidavit*, ¶6. Objective market expectations for the next several years are that power prices will remain depressed and natural gas prices will remain at distressed levels. See below Table B:

[21] As a holding company, IPH will conduct substantially all of its business operations through its subsidiary New AER, as acquired from Ameren, and New AER's subsidiaries, including Ameren Energy Generating Company ("GENCO"), AmerenEnergy Resources Generating Company ("AERG"), Ameren Energy marketing Company ("Ameren Marketing"), Electric Energy, Inc., and Midwest Electric Power, Inc. *See* Ex. 2, *Alonso Affidavit*, ¶6.

Table B

MISO Gas Price ($/mmBtu)	**2013**	**2014**	**2015**	**2016**	**2017**
6/28/2013	$3.70	$3.96	$4.17	$4.37	$4.61
MISO Power Price ($/MWhr)	**2013**	**2014**	**2015**	**2016**	**2017**
6/28/2013	$31.85	$30.67	$31.78	$33.14	$34.47

Ex. 2, *Alonso Affidavit*, ¶11. These forecasts of future power prices suggest that earnings pressure at IPH (or New AER as referred to by Mr. Bilicic) will continue in the near term. Ex. 9, *Bilicic Affidavit,* ¶6 (citing Moody's *Unregulated Utility & Power Companies: Still No Sign of Recovery* (Feb. 6, 2013)). Other source data reflects slightly different price forecasts than those reflected in Table B, but confirms the same basic trend. *Id*. ¶6 (citing SNL, prices as of 7/5/2013).

2. IPH Will Not Have Sufficient Financial Resources to Comply with the MPS 2015 and 2017 SO_2 Compliance Deadlines.

With power prices remaining depressed, IPH will continue to face the continuing financial pressures that AER faced at the time of its variance petition. *Id.*; Ex. 2, *Alonso Affidavit*, ¶¶13, 14. These depressed power prices have severely eroded operating margins of the Energy Centers in the MPS Group and will continue to limit the ability of the Energy Centers to generate cash flow for the next several years. Ex. 2, *Alonso Affidavit,* ¶24. Without those operating margins, IPH will not have the cash flow from power sales to fund large scale capital expenditures needed to comply with the MPS, such as completion of the Newton FGDs. *Id.*

The power industry is a cyclical commodity business with significant price volatility requiring considerable investment requirements. As such, it is imperative to build and maintain a balance sheet with manageable debt supported by a multi-faceted liquidity program to support daily operations. Importantly, IPH will sell power primarily into the regional electricity market known as “MISO” (the Midcontinent Independent System Operator, Inc.). Participants in MISO include both regulated utilities and merchant generators. *Id*. ¶11. As previously discussed, merchant generators like IPH do not have a regulated consumer rate base, meaning that environmental or other compliance costs cannot be recovered by rates from captive consumers. Instead, to cover their costs of doing business, merchant generators rely primarily on revenues obtained from selling power in the competitive wholesale electricity market. *Id*. Thus, as a merchant generator, IPH and the Energy Centers will face significant exposure to market prices, swings in load demand, and commodity price volatility. *Id.* ¶13.

Furthermore, as previously discussed, because the Energy Centers are at the mercy of the marketplace, they are more challenged by Illinois’ stringent environmental mandates than (a) merchant generators in neighboring states that are not required to invest in capital intensive pollution controls and (b) regulated utilities that can recover compliance costs through customer rates; thus, they are at a competitive disadvantage. Ex. 9, *Bilicic Affidavit,* ¶7; Ex. 2, *Alonso Affidavit,* ¶13. With depressed power prices, merchant generators, such as IPH, cannot easily, if at all, generate sufficient cash flows to fund large-scale capital projects. Ex. 2, *Alonso Affidavit*, ¶24.

AER does not currently have, and as a result IPH will not at closing have, the financial resources to complete construction of the Newton FGDs or otherwise comply with the MPS. *Id*. ¶¶20, 24. The above market factors are compounded by the fact that AER’s financial outlook, credit profile and access to third-party capital have weakened further since AER received the variance, as a result of persistently low power prices and ongoing uncertainty regarding federal environmental regulations. Ex. 9, *Bilicic Affidavit,* ¶8 (“Since receiving the Variance Relief, AER’s financial outlook has worsened, as market expectations of power prices have not improved, but, in fact, have deteriorated further beyond the 2014 time horizon,") (footnote omitted).

Further, AER's recurring net income declined from $359 million in 2008 to $41 million in 2011 with net income losses of $415 million in 2010 and $396 million in 2012. *Id*. In addition in the first quarter of 2013, AER had a $151 million net income loss. Ex. 2, *Alonso Affidavit*, ¶14.

Moreover GENCO, AER's largest subsidiary and the owner of the Newton Energy Center, has approximately $825 million in long-term public bond debt outstanding, with approximately $300 million of this debt maturing in 2018 and $250 million maturing in 2020. GENCO's existing debt requires approximately $59 million in annual interest payments. *Id*. Notably, the credit rating of GENCO has been cut by 4 and 3 notches by Standard & Poor's ("S&P") and Moody's, respectively, since AER was granted the variance. Ex. 9, *Bilicic Affidavit*, ¶8. GENCO "has less than adequate liquidity" and "poor standing in the credit markets." Ex. 2, *Alonso Affidavit*, ¶14 (quoting S&P, *Research Update: Ameren Energy Generating Co. Ratings Lowered to 'CCC+' On Weak Power Prices; Outlook Negative* (Feb. 8, 2013)).

GENCO will continue to be responsible for repayment of its $825 million debt, including the annual $59 million interest payment obligation, after being acquired by IPH. *Id*. Given depressed power prices, GENCO's existing debt and the significant capital expenditure needed to complete the Newton FGDs, maintaining liquidity for GENCO is at a premium. In sum, IPH will in the near term face almost the identical balance sheet challenges as those currently faced by AER.

More specifically, at closing, IPH will have approximately $220 million in cash. *Id.* ¶20. Of that $220 million, approximately $203 million will be at GENCO and approximately $17 million will be at AERG/Ameren Marketing. *Id.* The proceeds from exercising the put option (a minimum of $133 million) are part of the approximate $203 million in cash that GENCO will have when acquired by IPH.[22] IPH will utilize the vast majority (depending largely on the volatility of commodity markets) of this $220 million in cash available at closing over the next several years to fund operations, potential losses, pay interest, and provide some working capital and credit support needed to keep the businesses running day-to-day in the prevailing challenging market conditions. *Id*. Moreover, two years after closing, IPH will need the financial resources to replace its existing credit support from Ameren, which, if replaced today, would use up a significant amount of the $220 million in cash available at closing. *Id*. As a result, the approximate $220 million in cash on hand at IPH upon closing will not be available to fund completion of the Newton FGDs or make any other MPS compliance alternatives feasible. *Id.* ¶21.

In addition to the cash on hand at closing discussed above, IPH will have approximately $160 million in net working capital at closing. *Id*. ¶22. This $160 million, however, is necessary for day-to-day capital business expenses: fuel inventory; materials/supplies (*e.g.*, spare parts), etc. *Id*. Thus, the $160 million in net working capital at closing will not be available to fund completion of the Newton FGDs or make any other MPS compliance alternatives feasible.

IPH expects that, at closing, it will have sufficient liquidity to meet anticipated operating obligations, including sufficient funds to (a) continue construction of the Newton FGDs in accordance with the requested Compliance Plan; (b) maximize the existing FGD systems at

[22] As explained in PCB 12-126, the Put Option Agreement was designed as a mechanism to provide cash liquidity to GENCO by selling its three natural gas fired power plants (Elgin, Gibson City and Grand Tower). Depending on the results of the sale process of the put assets, the total cash available for GENCO at closing could be higher than $203 million (*i.e*., the amount that includes the minimum $133 million resulting from GENCO having exercised the put option in March 2013). Any additional proceeds would be used for GENCO operating needs. Notably, the sale of the three natural gas plants also means that GENCO no longer can derive cash flow from those plants.

Duck Creek and Coffeen; and (c) utilize low sulfur coal at Newton, Edwards and Joppa. It is not feasible over the next several years to simultaneously have adequate liquidity necessary to continue operating the Energy Centers and also spend hundreds of millions on capital investments to accelerate installation of the Newton FGD project, install alternative air pollution controls or otherwise comply with the MPS without the requested variance relief. Ex. 2, *Alonso Affidavit*, ¶¶25, 27.

IPH will continue to face financial challenges over the next several years. In fact, given depressed power prices and the volatile nature of the merchant energy business, the approximate $220 million in cash available at closing would not be sufficient to fund IPH's operations over the next several years without the approximate $60 million in annual cost–based operational synergies that Dynegy, IPH's ultimate parent company, estimates it will realize in the transaction by 2015. *Id*. ¶25. The synergies will result from gross margin and cost improvements at IPH based on the successful implementation of Dynegy programs addressing, among others, reduction in forced outage rates, fuel and rail procurement practices, and vendor optimization, and the combination of Dynegy's engineering, maintenance, and outage planning expertise. *Id*. Implementation of Dynegy's PRIDE initiative (Producing Results through Innovation by Dynegy Employees) at IPH is also expected to result in significant margin and cost improvements, as it has at Dynegy over the past two years, by continuously improving performance wherever possible based on the advice of its employees. *Id*. ¶25.

Importantly, IPH does expect that the gradual recovery of power prices (anticipated to begin after April 2015) will provide IPH with sufficient cash flow and liquidity to ramp up and complete construction of the Newton FGDs by year end 2019. *Id*. ¶23. Dynegy has made clear in its public statements that it believes power prices will begin to recover when compliance with the federal Mercury and Air Toxics Standards ("MATS") tightens supply as environmentally noncompliant or uneconomic generation units in the Midwest continue to retire.[23] *Id*. MATS generally requires compliance beginning in April 2015, but one and two year extensions of the compliance deadline are allowed in certain circumstances. As publicly stated, Dynegy expects IPH will not generate free cash flow until 2015.[24] *Id*. ¶24.

However, free cash flow in 2015 by IPH does not mean that IPH would have sufficient liquidity or financial resources in 2015 to spend the significant capital needed to complete construction of the Newton FGDs in time to meet the 2015 and 2017 MPS emission rates. *Id*. The recovery of power prices will not be immediate in 2015, nor will market recovery in 2015 be sufficient to generate the cash flow and liquidity needed to accelerate completion of the Newton FGDs in time to meet the MPS. *Id*. Rather, the recovery of power prices and associated generation of positive cash flows is expected to occur gradually over time. *Id*. Thus, the five-year term of the requested variance is critical to allowing adequate time for both recovery of power prices and for IPH to accumulate the significant financial resources needed to comply at the end of the variance period. *Id*. In short, IPH will not have the financial resources to complete the Newton FGD project or otherwise meet the MPS 2015 and 2017 compliance deadlines without the variance. *Id*.

3. IPH Cannot Currently Obtain Financing From External Third Party Lenders.

Due to the distressed power market in which the Energy Centers operate and AER's deteriorated balance sheet at closing, IPH will not be able to secure financing from external third

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[23] *See also* Dynegy Inc. Form 8-K (Mar. 14, 2013), Ex. 99.2 at 2 (*available at* www.dynegy.com/investor-relations/sec-filings); DYN-Q4 2012 Dynegy Inc. Earnings Conference Call (Mar. 14, 2013), Tr., at 17 ("in a post-MATS compliance world, [Dynegy] certainly expect[s] higher capacity payments, higher power prices").
[24] DYN-Q4 2012 Dynegy Inc. Earnings Conference Call (Mar. 14, 2013), Tr., at 10 (Dynegy "expect[s] the [Ameren-IPH] transaction to be accretive to adjusted EBITDA in 2014 and free cash flow in 2015….").

party lenders. Ex. 2, *Alonso Affidavit*, ¶15. Before entering the Agreement, Dynegy approached several financial institutions to inquire about the possibility of obtaining a credit facility to support IPH. *Id.* Given the low cash flow profile, negligible lien capacity of the Energy Centers, existing debt, and weak credit profile of the businesses, the financial institutions contacted replied that they would not extend a credit facility. *Id.*

As noted above, GENCO holds approximately $825 million in long-term public bond obligations, debts that GENCO will continue to owe after being acquired by IPH. *Id*. ¶14. Approximately $300 million of this debt matures in 2018, and approximately $250 million of the debt matures in 2020. *Id*. GENCO's failure to repay the bonds when due would constitute a default under the GENCO bond indenture, which would likely lead to a GENCO bankruptcy. *Id*. While IPH generally would seek to refinance those bonds in the public market at some point in the future in order to extend the maturity dates, covenants in GENCO's bond indenture restrict GENCO's ability to incur additional indebtedness from external sources if GENCO's interest coverage ratio is less than 2.5 or its leverage ratio is greater than a specified maximum. *Id*. ¶16. During the first quarter of 2013, GENCO's interest coverage ratio fell to a level less than the specified minimum level required for external borrowings. Ex. 9, *Bilicic Affidavit*, ¶10. Due to the decline in GENCO's earnings and operating cash flows resulting from depressed power prices, GENCO's interest coverage ratio is expected to remain less than this minimum level through at least 2015. *Id*. As a result, until power prices recover post 2015, GENCO's ability to borrow additional funds from external, third-party sources is restricted. *Id*. Moreover, given GENCO's poor financials, even after GENCO regains its ability to borrow external funds, refinancing may not be possible as a practical matter due to onerous terms imposed by external lenders. Ex. 2, *Alonso Affidavit*, ¶16.

In addition, because IPH, New AER and AERG are not and will not be publicly registered companies and will not be rated by the credit rating agencies, they will have limited financing options. *Id*.¶15.

If GENCO's interest coverage ratios do not improve significantly by the debt maturity dates, GENCO would have to repay its outstanding debts ($300 million in 2018; $250 million in 2020) to the bondholders. *Id*.¶14. Given these looming significant debt maturities and the continuing financial challenges, including depressed power prices, it is critical that IPH, including GENCO, preserve and accumulate cash until power market prices recover, operating results improve, cash flows increase, and the ability to obtain external lender financing returns. That will not be possible under IPH without the requested variance relief.

4. Dynegy Cannot Support the Capital Needs of IPH.

As Dynegy has publicly communicated to its investors, IPH and the Energy Centers must succeed on their own financially, without support for major capital projects coming from the ultimate parent or affiliated companies. Ex. 2, *Alonso Affidavit*, ¶¶5, 13, 18. This is no different than the situation presented to the Board by AER (and Ameren) in PCB 12-126. The same credit pressures that prevented Ameren from financially supporting the Energy Centers at the time of the PCB 12-126 petition impose similar constraints on Dynegy as IPH's ultimate parent company. Indeed, the credit pressures and overall financial pressures on Dynegy are, in fact, worse.[25]

As solely a merchant generation company without any regulated rate-based subsidiaries, Dynegy has had to face several years of economic challenges caused by depressed power pricing

[25] In granting the variance in PCB 12-126, the Board did not accept arguments that Ameren, as AER's ultimate parent company, must financially support AER's MPS compliance efforts. That same conclusion should apply to IPH's request for variance relief, particularly given that Ameren has a stronger credit rating than Dynegy. Ex. 9, *Bilicic Affidavit*, ¶12.

and a weakened national economy. *Id.* ¶26. In fact, Dynegy filed for Chapter 11 bankruptcy protection in July 2012. *Id*. While successfully emerging from bankruptcy in October 2012, Dynegy continues to face near-term economic challenges posed by depressed power prices. *Id.* For example, Dynegy reported operating losses of $104 million for the fourth quarter of 2012 and $142 million for the first quarter of 2013. *Id.* Thus, in a very real sense, while Dynegy expects power pricing and market conditions to improve over the longer-term beginning in 2015, Dynegy is not a “deep pocket” with limitless funds that could now or in the next several years be made available to IPH to complete construction of the Newton FGDs sooner than the proposed variance conditions. *Id.*

More importantly, Dynegy cannot integrate IPH into the Dynegy capital structure without severe adverse consequences that would imperil its financial future. *Id.* ¶17. As part of its due diligence process prior to entering the Agreement, Dynegy contacted the credit rating agencies (Moody’s and S&P) to understand the credit rating implications, if any, of the transaction on Dynegy. *Id.* Both credit rating agencies clearly indicated that the transaction would negatively affect Dynegy’s credit rating if IPH were integrated into the Dynegy financial structure or if Dynegy were to provide financial support to IPH, other than limited amounts of working capital. *Id*. Having only recently emerged from bankruptcy in October 2012, Dynegy cannot take actions that would downgrade its credit rating. *Id.* A downgrade would mean less favorable terms and conditions for Dynegy’s financing (*e.g.*, increased interest rates for borrowing, more restrictive covenants) and loss of investor confidence, which would ultimately jeopardize Dynegy’s balance sheet and liquidity. *Id.* ¶18. Simply stated, Dynegy will not—and, in effect, cannot—endanger its balance sheet or its credit rating by integrating IPH into the Dynegy capital structure. *Id.*

In April 2013, Dynegy completed a refinancing in which it again made clear to the credit rating agencies, as well as to equity and debt investors, that IPH would not be integrated into the Dynegy capital structure. *Id.* While the new refinancing agreement itself would allow Dynegy to invest certain amounts in its subsidiaries, including IPH, Dynegy cannot inject those funds into IPH without risking its credit rating and credibility—something Dynegy cannot do. *Id.* ¶19.

Consistent with Dynegy's need to protect its financial soundness and its commitments to the credit rating agencies and investors concerning the IPH transaction, Dynegy, if it is needed, may provide very limited financial support to IPH for the sole purpose of providing necessary working capital needed to maintain day-to-day operations of the businesses. *Id.* ¶25. As was the case at the time of the Variance Opinion, under IPH ownership the Energy Centers still must be economically viable on their own and operate as independent, self-sustaining and self-funding businesses. *Id.* ¶¶5, 13. Moreover, given the potential adverse reaction of the credit rating agencies, equity investors and debt investors were Dynegy to provide financial support, affiliation of the Energy Centers (or their operating companies) with Dynegy will not improve their financial outlook or their ability to fund environmental-related expenditures on a more accelerated timeframe. Ex. 9, *Bilicic Affidavit*, ¶15. In short, the various challenges faced by IPH are the same, if not worse, than those faced by AER when it was granted the variance. *See id.* ¶14. The rationale for the variance remains unchanged—it will continue to play a critical role in allowing IPH to manage its liquidity and credit quality in the midst of a currently challenged merchant generation operating environment. *Id.*

Given depressed power prices over the past several years which are expected to remain depressed for several more and given the overall financial challenges that result, economic viability for the plants is only possible with the relief requested in the Petition.

E. The Petitioners' Hardship is Not Self-Imposed.

The Board's regulations at issue here, the Ameren MPS Rule, has been promulgated to apply system-wide: to all seven plants in the MPS Group. The IEPA recognizes the regulatory basis and structure of that system-wide approach. The transaction negotiated by Ameren and IPH also recognizes that regulatory structure and responsibly tries to implement it as part of the transaction. Ex. 2, *Alonso Affidavit*, ¶ 8. Thus, any argument that the Board should dismiss this Petition based upon a line of Board cases finding the hardship to be "self-imposed" is simply wrong. The cases in which the Board denied variance relief by finding the hardship was "self-imposed" present factual scenarios much different than that presented here. The inquiry the Board engages in to determine a self-imposed hardship is whether the company seeking relief is in a quagmire of its own making, due to lack of diligence or despite knowledge of requirements. Consider, for example, the following cases where the Board denied variance relief because it found that the claimed hardship was self-imposed:

- *Ecko Glaco v. IEPA*, PCB 87-41 (Dec. 17, 1987). Company, that was in a poor financial position due to procrastination and poor business decisions, exhibited continuous unwillingness to commit to a compliance plan;
- *Skyway Realty v. IEPA*, PCB 75-249 (Sept. 18, 1975). Company sought relief after proceeding with a construction project with full knowledge of the regulations;
- *City of Ottawa v. IEPA*, PCB 86-165 (Jan. 22, 1987). City claims to be unaware of existing regulations;
- *Marathon Oil Co. v. IEPA*, PCB 95-150 (May 16, 1996). Variance denied because of company's faulty decision-making.

See also Copley Mem'l Hosp., Inc. v. City of Aurora, 99 Ill. App. 3d 217, 222, 425 N.E.2d 493 (2d Dist. 1981) (suing for zoning change following purchase and assuming property with the restrictions).

The circumstances warranting denial of variance relief due to a finding the hardship was self-imposed simply do not exist here. IPH's relief is not requested because of lack of due diligence. For the Board to hold that this variance is not warranted because the claimed hardship would be self-imposed would be tantamount to ruling that a business could not contract for, and achieve through the Board's processes, a variance relief for the same exact facilities, pursuant to the same exact regulatory provisions, that the current owner had achieved under virtually the same circumstances. Such result is inconsistent with the Board's statutory responsibility to provide regulatory relief where warranted, and such a result would be inconsistent with prior Board rulings. *See Allied Chem. Corp. & Inverness Mining Co.*, PCB 80-92 Order (May 1, 1980); Opinion and Order (June 12, 1980).

Quite simply, IPH is not before this Board requesting variance relief due to faulty decision-making or lack of knowledge of the requirements. In fact, IPH is demonstrating sound decision-making and knowledge of the requirements by acknowledging the need for the continuation of variance relief to provide the best path forward for the operating plants before the transaction is completed. The Petitioners have exhibited through the structure of the transaction, and this Petition, a full understanding of the regulatory construct of the MPS and the obligations that result, as well as the need to substantiate the request for relief instead of appearing before the Board, after-the-fact, assuming the Board would provide the lifeboat. The hardship faced by the plants is anything but self-imposed.

VI. COMPLIANCE ALTERNATIVES

Petitioners have performed an independent analysis of compliance alternatives, consistent with the Board's procedural rule at Section 104.204(e) which requires that a variance petitioner provide a description of the efforts that would be necessary to achieve immediate compliance (here, with the existing MPS rule) and a discussion of the compliance alternatives.

The range of those alternative compliance options and the issues related to the consideration afforded them by AER in PCB 12-126 still exist today, and are relevant to this Petition. Ex. 8, *Thompson Affidavit*, ¶12. During the PCB 12-126 variance proceeding, which concluded less than one year ago, the Board fully vetted a variety of suggested compliance alternatives and concluded that: "AER adequately detailed the range of compliance alternatives that AER examined in support of its petition." Variance Opinion, at 49. The costs and technological limits prevailing at the time of the Board's opinion in September 2012 have not changed in any material way. IPH's own projections show that it remains the case that, notwithstanding the IPH acquisition, completing construction of the Newton FGD project remains the most prudent and cost effective control technology that can be used to achieve ultimate compliance with the MPS. Ex. 8, *Thompson Affidavit*, ¶11.

A. Curtailing Plant Operations Is Not Economically Feasible.

As explained above, to meet the MPS 2015 SO_2 emission rate without the variance, IPH would need to shut down a combination of the Newton, Joppa and E.D. Edwards Energy Centers. *Id.* ¶12. A curtailment of operations by piecemeal shutdowns of specific units at various Energy Centers does not make sense economically, since the fixed costs would be the same while revenue would be less– defeating the ability of IPH to garner the final necessary financial resources to complete the Newton FGDs and meet the strict emission standards required at the end of the variance period. *Id.* Curtailing operations at any of the five Energy Centers as a compliance strategy would prevent the plants from generating sufficient funds to sustain their operations and obligations. *Id.* Such curtailment would mean reduced sales of electricity, less revenue generated, and less funds to run the business and cover fixed operating costs. *Id.* IPH's analysis indicates meeting the 2015 MPS SO_2 emission rate with all five operating Energy Centers continuing to operate would effectively require Newton, E.D. Edwards and Joppa to limit each of their respective generation to approximately one-third of its capacity. *Id*. Given their fixed costs, such a limit on generation would eliminate any potential ability of these Energy Centers to generate positive cash flows going forward. *Id.*

While it would be infeasible for IPH to curtail operations of specific units on a temporary basis to meet the MPS, IPH expects that during the term of its requested relief E.D. Edwards Unit 1 will be permanently retired. *Id*. ¶27. In December 2012, Ameren filed a request with the MISO to retire E.D. Edwards Unit 1 effective December 31, 2012. *Id.* MISO's analysis determined the unit was needed for reliability purposes until such time as numerous transmission system reinforcements were put into service in order to mitigate thermal and voltage issues. *Id.* MISO filed an unexecuted System Support Resource ("SSR") Agreement, pursuant to attachment Y-1 of MISO's tariff, with the Federal Energy Regulatory Commission ("FERC") on July 11, 2013 (the "July 11 SSR Filing"). *Id.* The maximum term of an SSR Agreement is twelve months and the July 11 SSR Filing covers the 2013 calendar year, however an SSR Agreement can be renewed and continue subject to an annual review of mitigation alternatives. *Id.* As noted in the July 11 SSR Filing, MISO expects that E.D. Edwards 1 will continue as an SSR unit until all of the required transmission system reinforcements are implemented in December 2016, though newly available alternatives will be sought in considering the annual review of the SSR

Agreement. Therefore, annual renewal of the SSR Agreement seems likely. *Id.* Thus, IPH cannot commit to retiring E.D. Edwards Unit 1 by a date certain, but based on MISO information currently available, IPH does expect that E.D. Edwards Unit 1 will be retired before the end of the requested variance term. *Id.*

B. Alternative Control Technologies.

IPH also has reviewed the availability of alternative control technologies and agrees with AER's prior conclusion, which the Board endorsed in its Variance Opinion, that these technologies are infeasible because they would cost more than the Newton FGD project. *Id.* ¶16. At hearing in PCB 12-126, some participants asserted that dry sorbent injection ("DSI") would be an appropriate and economically feasible technology to reduce SO_2 at the Joppa and E.D. Edwards Energy Centers. Tr., at 119, 120. The overall cost of DSI as applied to the Joppa and/or E.D. Edwards Energy Centers makes it infeasible as a compliance alternative. Ex. 8, *Thompson Affidavit*, ¶17. Based upon its analysis of DSI at other coal-fired plants, IPH estimates that the capital cost of installing DSI alone would be in the range of $60 million at Joppa (all six units) and $30 million at E.D. Edwards (Units 2 and 3). *Id.* IPH will not have the sufficient liquidity to fund any such large-scale projects over the next several years. Ex. 2, *Alonso Affidavit*, ¶20.

Further, as AER demonstrated in its Post Hearing Brief and reaffirmed here, the capital costs of installing DSI at Joppa and/or E.D. Edwards would not be limited to the DSI technology only. Ex. 8, *Thompson Affidavit*, ¶¶ 17-18. Because of the size of the existing particulate control equipment and the use of ACI for mercury control at E.D. Edwards and Joppa, the use of DSI would result in a significant increase in PM emissions necessitating installation of PM control technologies (*e.g.*, baghouses). *Id.* Thus, the real expected capital cost of installing DSI at Joppa would be approximately $433 million and approximately $280 million at E.D. Edwards (Units 2 and 3). *Id. See also* Post Hearing Brief, at 15 (citing 2011 URS report and attaching a cost table therein as Post Hearing Brief, Exhibit 1).

Moreover, the annual O&M expense of DSI is significant. Ex. 8, *Thompson Affidavit*, ¶18. As AER demonstrated, the estimated annual cost of dry sorbent ranges from $15 million to $44 million depending upon the type of material used and the location of injection (before or after the air heater). *See* Post Hearing Brief, at 20 (citing 2010 report completed by the Shaw Group, Post Hearing Brief, Exhibit 2). Those estimated O&M costs cited by AER are consistent with IPH's analysis of DSI O&M expenses. Ex. 8, *Thompson Affidavit*, ¶18. The impact of DSI annual O&M costs is even more pronounced given the cash flow challenges the Energy Centers face. *Id.* IPH will not have the sufficient liquidity to fund any such large-scale projects over the next several years. Ex. 2, *Alonso Affidavit*, ¶20. Thus, IPH concludes that, as the Board determined in the AER variance proceeding, it is economically infeasible to employ DSI technology at Joppa or E.D. Edwards, especially when construction of the Newton FGD project is already underway.

C. Conversion to Natural Gas is Economically Infeasible.

The Board also examined AER's analysis of converting to natural gas at E.D. Edwards and Joppa. Variance Opinion, at 50. In PCB 12-126, the Board accepted AER's conclusion that conversion to natural gas did not represent a viable compliance alternative because, quoting from AER's Post Hearing Brief, at 23-24: "under current market conditions, a natural gas conversion at Joppa would reduce operations to a season basis only and lead to reduced revenue and a loss of jobs." *Id.*

IPH has also considered firing natural gas as a means to comply with the MPS. Natural gas pipelines are not currently connected to the E.D. Edwards or Newton Energy Centers. Ex. 8, *Thompson Affidavit*, ¶19. The cost of constructing natural gas pipelines to either facility would be cost prohibitive. *Id.* An initial estimate of the cost to bring a natural gas supply pipeline to E.D. Edwards is $100 million and $70 million to Newton. Further, the additional capital expenditures needed to convert the coal–fired boilers at E.D. Edwards or Newton to natural gas firing are expected to be significant. In the absence of detailed, site-specific natural gas conversion engineering studies at E.D. Edwards or Newton, based on reported industry trade literature and case studies involving natural gas conversion of existing coal-fired boilers, the cost of converting each plant would be expected to be tens of millions of dollars, if not more. *Id.* (identifying cost range of $50 to $75/kW by referencing F.J. Binkiewicz Jr. et al., Babcock & Wilcox, Natural Gas Conversions of Existing Coal-Fired Boilers (2010)).[26] In addition, converting the Newton units to natural gas firing in lieu of completing construction of the Newton FGDs also would waste the several hundred million spent, to date, on the Newton FGD project. Accordingly, conversion to gas is not feasible and is cost prohibitive. *Id.*

Moreover, natural gas firing at Newton or E.D. Edwards would not be a cost-effective compliance alternative because dispatch on natural gas is more expensive than on coal, with the result that natural gas firing would result in significantly lower production by the plant, and, thus, generate lower revenues needed for the recovery of fixed operating costs and capital expenditures. *Id.* ¶20. Based on current power market conditions in Illinois, production costs related to fuel are roughly $20-$25/MWh on PRB coal and would be roughly $40/MWh on natural gas. *Id.* Based on MISO published clearing prices in 2012, power prices at, for example, the Newton busbar averaged in excess of $22/MWh during 76 percent of the on-peak days while only two percent on the on-peak day averages exceeded $40/MWh. *Id.* In other words, Newton

[26] *Available at www.babcock.com/library/pdf/MS-14.pdf.*

fired on natural gas during 2012 would have been dispatched approximately only two percent of the time. *Id.* Thus, IPH concludes that it is infeasible to convert E.D. Edwards or Newton to natural gas. *Id.*

Further, IPH concludes that, for several reasons, converting Joppa to natural gas would be cost prohibitive and not economically feasible. *Id.*¶21. First, an order of magnitude cost estimate to convert the relevant Joppa units to natural gas ranges from $25 million (*i.e.*, convert to 50 percent capacity on natural gas) to $38 million (*i.e.*, convert to 100 percent capacity on natural gas), with an additional estimated $4.5 million in capital expenditures needed for gas supply pipeline and equipment improvements. *Id*. ¶21. Second, natural gas firing at Joppa would not be a cost effective compliance alternative because, as discussed in the paragraph above, dispatch on natural gas is more expensive than on coal, with the result that natural gas firing would result in lower production at Joppa and, thus, generate lower revenues, revenues needed for the recovery of fixed operating costs and capital expenditures. *Id.* Finally, as determined by the Board in AER's variance proceeding, conversion of Joppa to natural gas firing would reduce the plant's operations to a seasonal basis only, thereby resulting in reduced revenues and, ultimately, a loss of jobs. Variance Opinion, at 21, 50. IPH will not have the sufficient liquidity to fund any such large-scale capital projects over the next several years. Ex. 2, *Alonso Affidavit*, ¶20.

In evaluating all potential compliance options, IPH also considered that two units at Joppa (Units 1 and 4) have the physical capability to co-fire natural gas up to approximately 45 percent of heat input at full load. *Id.* ¶22. Based on DMG's experience with analyzing natural gas co-firing as an option to reduce SO_2 emissions at its coal-fired plants in Illinois, IPH concludes that natural gas co-firing at these two Joppa units, even at levels less than 45 percent, is not cost effective. *Id*. Because dispatch on natural gas is more expensive, natural gas co-firing would result in lower production and, thus, generate lower revenues for the recovery of fixed operating costs and capital expenditures. *Id.* The key factor for sustained use of natural gas co-firing is the price differential between natural gas and coal. *Id*.

Based on current market conditions, production costs related to fuel are roughly $20/MWh to $25/MWh on PRB coal and would be roughly $40/MWh on natural gas. *Id.* In general, it would only be cost effective to co-fire natural gas if natural gas prices approached $2.50/mmBtu. *Id.* Thus, even at the historically low natural gas prices in recent times, natural gas co-firing does not make economic sense. *Id.* Accordingly, IPH concludes that natural gas co-firing at Joppa Units 1 and 4, while technically possible, is not a cost effective compliance alternative, nor would it achieve compliance with the MPS overall SO_2 emission rates. *Id.*

Thus, IPH concludes that, as the Board determined in the AER variance proceeding, it is economically infeasible to convert E.D. Edwards, Newton or Joppa to natural gas, especially when construction of the Newton FGD project is already underway. Ex. 8, *Thompson Affidavit*, ¶¶19-22.

VII. ENVIRONMENTAL IMPACT

A. Any Adverse Environmental Impact From the Variance Does Not Outweigh the Arbitrary or Unreasonable Hardship of Immediate Compliance.

The appropriate standard the Board must employ in any analysis of any variance, as the legislature has provided in Section 35(a) of the Act, is one of arbitrary and unreasonable hardship:

> The Board may grant individual variances beyond the limitations prescribed in this Act, whenever it is found, *upon presentation of adequate proof, that compliance with any rule or regulation, requirement or order of the Board would impose an arbitrary or unreasonable hardship*.

415 ILCS 5/35(a) (emphasis added).

In order to make that finding, a great body of case law requires that the Board weigh any such hardship against any adverse impact to the environment. In a variance proceeding, a petitioner must demonstrate that the hardship resulting from a denial would "outweigh any injury to the public or the environment" from granting the relief. *Marathon Oil Co. v. EPA*, 242 Ill. App. 3d 200, 206, 610 N.E.2d 789, 793 (5th Dist. 1993). The Board has previously found an arbitrary and unreasonable hardship would result where technically and economically feasible means of compliance have not been identified despite diligent efforts by the petitioner. *Mobil Oil Co. v. IEPA*, PCB 86-45, slip op. at 6 (Aug. 14, 1986). The Board has granted variance relief on many occasions after finding the variance would cause minimal or no adverse environmental impact. *Vill. of Princeville v. IEPA*, PCB 93-227, slip op. at 4 (Jan. 20, 1994); *Vills. of Granville & Mark v. IEP*A, PCB 93-163, slip op. at 3 (Nov. 4, 1993): *Amerock Corp. v. IEPA*, PCB 92-120, slip op. at 2-3 (Feb. 4, 1993); *City of Galva v. IEPA*, PCB 89-131, slip op. at 2 (Dec. 20, 1989). The Board has even granted variance relief after finding an adverse environmental impact based on a showing that the impact was "not great" and did not outweigh the "huge cost of compliance." *Shell Oil Co. v. IEPA*, PCB 83-24, slip op. at 2 (Mar. 21, 1984).

Although Section 35(a) of the Act does not require that the Board find a "net benefit to the environment" as a condition precedent to granting relief, and no court has interpreted the Act as requiring such net benefit, AER's compliance plan in PCB 12-126 relative to the MPS Group in fact so provided. Variance Opinion, at 48, 51-56, 58, 68. Given that the Petitioners here seek to implement that compliance plan pursuant to identical variance relief, for the identical MPS Group, concerning the identical regulatory framework, little more than one year later, the Board should again recognize the net benefit to the environment that will be achieved by the MPS Group subject to this variance. That the Petitioners here will be the new owners of the MPS

Group should be of no consequence in the Board's analysis of environmental impact in this variance proceeding.

B. IPH/Dynegy is Committed to Environmental Protection in Illinois.

Dynegy, through other wholly owned subsidiaries, such as DMG and Dynegy Kendall Energy, LLC, has historically enjoyed a meaningful presence in Illinois since its February 2000 acquisition of Illinova Corporation (*i.e.*, the fossil fuel-fired electric generating assets of Illinois Power Company), which formed the basis of DMG's current generating fleet. Ex. 8, *Thompson Affidavit*, ¶6. As IPH's parent company, Dynegy is very cognizant of its environmental impact in Illinois and has taken proactive steps to minimize its imprint.[27] *Id.* ¶8. Through its subsidiaries, Dynegy owns and operates five coal and natural gas-fired power generation facilities in Illinois, with the capacity of producing approximately 4,200 MW of reliable, low cost energy for wholesale customers. *Id.* ¶6. DMG's generating assets include four operating coal-fired electric generating stations located in Southern Illinois: the Baldwin Energy Complex (Randolph County), the Havana Power Station (Mason County), the Hennepin Power Station (Putnam County), and the Wood River Power Station (Madison County). *Id*. ¶7. In November 2011, DMG permanently retired a fifth coal-fired power plant, the Vermilion Power Station (Vermilion County). *Id.*

Through its subsidiaries, Dynegy employs approximately 600 full-time employees in Illinois, employing approximately 550 persons at its Illinois power stations and approximately 50 persons at its corporate office located in O'Fallon, Illinois. *Id.* The economic impact of Dynegy's operations in Illinois and in the affected local Illinois communities is significant. *Id.* For

[27] For example, Dynegy has been involved in carbon sequestration efforts, with tree-planting projects covering more than 45,000 acres in a portion of the Shawnee National Forest. The Lower Mississippi River Valley reforestation project is registered under the Verified Carbon Standard and was the first United States forest carbon offset project to receive this certification. Dynegy has also donated 1,100 acres along the Middle Fork Vermilion River to the Illinois Department of Natural Resources and has sponsored activities preserving 1,200 acres of forests in Illinois. Each year, these trees will sequester increasing levels of carbon dioxide. Ex. 8, *Thompson Affidavit,* ¶9.

example, in 2012 Dynegy's direct investments in Illinois (*i.e.*, maintenance, capital, and taxes) totaled approximately $261 million. *Id.*

Dynegy and its subsidiaries have a strong commitment to safe and environmentally responsible operations in Illinois. *Id.* ¶8. DMG has invested approximately $1 billion in air pollution controls at its Illinois facilities (including installation of FGDs, activated carbon injection systems, and/or baghouses on select generating units) to comply with the Illinois Mercury Rule, including the MPS, and DMG's Consent Decree.[28] *Id.* Dynegy is very familiar and experienced with the Illinois MPS requirements. *Id.* DMG's five coal-fired stations elected into the MPS in 2007 (*i.e.*, the DMG MPS Group) and Dynegy's environmental support group staff was directly involved in the MPS rulemakings. *Id.* DMG has met its MPS limits. *Id.* Indeed, DMG met the MPS's mercury emission rate limit at all but one of its MPS generating units three years earlier than the required January 1, 2015 deadline. *Id.* Combined with DMG's statewide conversion to low sulfur coal, the company's environmental efforts in Illinois have reduced emissions of NOx, SO_2 and mercury, as well as particulate matter and other emissions. Since 1998, emissions levels from DMG have dropped almost 90 percent.[29] *Id.*

C. Description of Environmental Impacts.

Pursuant to Section 104.204(g) of the Board's procedural rules, a petitioner for variance must describe the environmental impact of the activity.

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[28] *United States v. Illinois Power Co.*, No. 99-CV-833-MJR (S.D. Ill.) (Consent Decree entered May 27, 2005) (a copy of the Consent Decree as originally entered is available at: http://www.epa.gov/compliance/resources/decrees/civil/caa/dmgfinal-cd.pdf).

[29] DMG's Baldwin and Havana facilities have installed and are operating dry FGD systems for the control of SO_2 emissions, and ESPs and baghouses for the control of particulate emissions. DMG's Hennepin facility has ESPs and baghouses for the control of particulate matter. The baghouses at DMG's facilities also control hazardous air pollutants in particulate form, such as most metals. ACI or mercury oxidation systems for the control of mercury emissions have been installed and are operating on all of DMG's coal-fired capacity. SCR technology to control NOx emissions has been installed and is operational at Havana and two units at Baldwin. *See* Ex. 8, *Thompson Affidavit*, ¶8.

1. The nature and amount of emissions if the variance is granted compared to that which would result if immediate compliance is required.

Section 104.204(g)(1) requires the Petitioners to discuss, as relevant, the nature and amount of emissions that will be released if the variance is granted, compared to that which would result if immediate compliance is required. As the Petitioners have demonstrated, without the variance, immediate compliance (compliance with the 2015 and 2017 MPS SO_2 emission rates) is simply not achievable, absent further plant closures. Ex. 2, *Alonso Affidavit*, ¶8; Ex. 8, *Thompson Affidavit*, ¶13. The Ameren-IPH transaction has been carefully crafted to allow for the operation of the plants in a manner that achieves compliance with the Ameren MPS Rule. Ex. 2, *Alonso Affidavit*, ¶8. Dynegy, the ultimate parent of IPH, has a history of achieving compliance with MPS rules in Illinois. Ex. 8, *Thompson Affidavit*, ¶8. IPH, with a continuation of the variance relief granted to AER, represents the best path forward for the continued operation of the Energy Centers in a manner that achieves ultimate compliance with the Ameren MPS Rule. Ex. 1, *Lyons Affidavit*, ¶16.

Neither Section 35(a) of the Act nor Section 104.204(g) of the Board's rules requires, in justifying the variance, that emissions *be less* than they would be if immediate compliance is required. Indeed, such result is generally not the case and, indeed, rather somewhat of a juxtaposition. Nonetheless, because AER agreed to mitigation rates in advance of a prospective compliance date, such was achieved in PCB 12-126. That benefit will continue with the extension of the variance to the new owners of the MPS Group, as the Petitioners here propose the same compliance plan.

The Petitioners have demonstrated this net environmental benefit by both estimating the tons of SO_2 emissions reduced from 2010 through 2020 (Table 1) and from 2013 through 2020 (Table 2), Exhibit 10. Both Tables demonstrate over the relevant period, fewer tons of SO_2 will be emitted into the air by the end of the variance term than would be under the Ameren MPS Rule.

Table 1 shows a net environmental benefit of 74,303 fewer tons of SO_2 emitted.[30] Exhibit 11, *Affidavit of Aric D. Diericx* ("Ex. 11, *Diericx Affidavit*"), ¶6. It is critical to view the overall reductions during the time period from 2010 through 2020. This time period illustrates what would have been allowed under the Ameren MPS Rule and compares those emissions with those from the MPS Group factoring in: (1) actual emissions; (2) the mitigation rates from the 2012 variance (same as those in the requested relief); and (3) the shuttering of Hutsonville and Meredosia. Table 1 shows the actual SO_2 emissions for 2010, 2011, and 2012. *Id.* The actual tons of SO_2 emitted during 2012 were even less than projected in PCB 12-126. *Id.* All of these factors have resulted in benefits to human health and the environment not otherwise required under the MPS. Further, the requested relief includes a provision to not operate the electric generating units at Hutsonville and Meredosia through December 31, 2020, thereby providing a benefit through the end of 2020.[31]

Even if the Board were to look only at the years in the requested relief that IPH and Medina Valley are scheduled to take ownership of the MPS Group—the time period from 2013 through 2020—in analyzing the environmental impact of the variance, Table 2 shows the MPS

[30] Over the period 2012-2020, Table 1 reflects a 47,178 net reduction in SO_2 emissions for the MPS Group, a 13,633 ton increase in net reductions compared to the Variance Opinion, which recognized a net reduction of 33,545 tons. Variance Opinion, at 54. The increase in net reductions reflects that actual SO_2 emissions from the MPS Group in 2012 were less than had been projected in PCB 12-126 and that FutureGen 2.0 project (to be constructed at the Meredosia Energy Center) SO_2 emissions are not included for 2013-2016 because the FutureGen 2.0 project is not expected to begin operations until September 2017. Ex. 11, *Diericx Affidavit*, ¶6.

[31] In keeping with the "once in, always in" intent of the MPS that was previously endorsed by both IEPA and the Board in PCB 12-126 (IEPA Recommendation, at 21; Variance Opinion, at 54), the cumulative SO_2 reduction in both Tables is based on a baseline heat input that reflects the cessation of operations at the Hutsonville and Meredosia plants through 2020. In analyzing environmental impact, the Board has considered emission reductions not exclusively attributable to a particular individual petitioner in a particular variance proceeding. *ExxonMobil Oil Corp. v. IEPA*, PCB 11-86, 12-46 (Dec. 1, 2011) (considering the significant environmental benefit of NOx reductions achieved through the installation of selective catalytic reduction that was installed under a consent decree). Thus, in this MPS variance context, the Board should consider the "benefit" provided by the entire MPS Group and not only as it relates to one isolated petitioner.

Group will achieve a net environmental benefit of 7,748 fewer tons of SO_2 if the variance is granted compared to current the Ameren MPS Rule requirements. *Id.* ¶7. Under either scenario, a net environmental benefit exists. *Id.* ¶8. Certainly, both Tables demonstrate that no adverse environmental impact exists to outweigh the hardships associated with plant closures.

2. Qualitative and Quantitative Impact on Human Health and the Environment.

In order to ensure that the Board is informed as to any adverse impacts to human health and the environment, Section 104.204(g)(2) of the Board's rules requires that variance petitioners discuss, as relevant, such potential impacts in the variance petition. In PCB 12-126, AER provided the Board with a letter from toxicology experts from AECOM. Post Hearing Brief, Ex. 3. The Petitioners here have again commissioned AECOM to review this variance request, and provide the Board with a toxicologist's perspective on the Petition. The AECOM Memorandum is attached as Exhibit 12, *AECOM Memorandum* ("Ex. 12, *AECOM Memorandum*").

As AECOM concludes, "there would be no adverse impact as a result of implementing the requested variance and proposed compliance plan, in fact, a net environmental benefit would be realized." *Id.* In reaching this conclusion, the AECOM Memorandum not only provides information directly related to the variance request (an analysis of the impact of the requested variance, a discussion of the health effects information available regarding exposure to SO_2, and potential implications from SO_2 emissions at issue), it also provides an overview of the Clean Air Act's National Ambient Air Quality Standards ("NAAQS"), a summary of SO_2 emissions in the United States and Illinois, and a discussion of the variance request as it may be related to the USEPA December 2012 revision of the NAAQS for annual $PM_{2.5}$ (airborne particulate matter of 2.5 micrometer in diameter and smaller). Given the earlier reductions in SO_2 emissions that have already occurred and the commitment to adhere to the mitigation rate granted in PCB 12-126, the requested variance will result in an overall benefit to human health and the environment compared to the potential of the existing Ameren MPS Rule. *Id.* The AECOM Report demonstrates there will be fewer adverse health effects overall over the term of the variance. *Id.* The earlier, more stringent mitigation rates provide a benefit to human health and the environment. Indeed, in terms of the appropriate Board query, there will be no adverse impacts to the environment that outweigh the impacts from plant closures and other identified hardships.

3. Impacts of Discharge of Contaminants on Human, Plant and Animal Life.

Section 104.204(g)(1) of the Board's rules requires that variance petitioners discuss, as relevant, discharge impacts to human, plant and animal life in the variance petition. Again, the AECOM Memorandum is relevant to this inquiry and is provided for the Board's analysis of this Petition. *Id.* Again, the proposed mitigation rate imposes significant restriction on how Petitioners IPH and Medina Valley must manage the MPS Group once the companies acquire ownership. In order to comply with the proposed compliance plan, including the mitigation rate that will apply during the term of the variance, Petitioners IPH and Medina Valley must implement specific measures that will minimize the impact of the variance on human, plant and animal life. *Id.* Petitioner IPH must operate the scrubbers at Duck Creek and Coffeen to optimize performance levels and procure low sulfur PRB coal on an ongoing basis to be used at the E.D. Edwards, Joppa and Newton facilities. *Id.* Petitioner Medina Valley must maintain the Hutsonville and Meredosia Energy Centers shuttered through the end of the variance term. *Id.*

D. Probable Further Emission Reductions Through IPH Performance.

Furthermore, for several reasons, the Petitioners expect that the MPS Group will achieve even more SO_2 emissions reductions during the term of the requested variance period than the reductions identified in Tables 1 and 2. Ex. 10. First, based on MISO information currently available, Petitioner IPH expects that E.D. Edwards Unit 1 will be retired before the end of the requested variance term. The Tables do not reflect the expected retirement of E.D. Edwards Unit 1 given that the retirement date for the unit rests with MISO and is beyond IPH's control.[32] Ex. 8, *Thompson Affidavit*, ¶27. Second, IPH anticipates that, in order to meet the 0.35 lb/mmBtu overall SO_2 annual mitigation emission rate, it may, at times, use even lower sulfur coal than included in AER's commitment for Newton, E.D. Edwards and Joppa. *Id.* ¶28. Tables 1 and 2 do not account for IPH's expectation that lower than 0.55 lb/mmBtu sulfur coal may be used to some extent at these three Energy Centers, based on availability, performance risk, price, and MPS Group emission performance. *See* Ex. 11, *Diericx Affidavit*, ¶¶6, 7, 8. Third, the Tables do not reflect the expected reduction in SO_2 emissions that will occur in 2019 due to the extended unit outages at Newton that will be required to complete the installation of the two FGDs and the fact that the FGDs will, in all likelihood, be installed in series (*i.e.*, after FGD installation is completed on one unit, the second FGD would be installed on the second unit), meaning that one of the FGDs will most likely be operating for a portion of calendar year 2019. Ex. 8, *Thompson Affidavit*, ¶29. While these expected emission reductions cannot at this point be reasonably quantified, the Board should be aware that such will likely occur, especially in the later years of the variance.

E. The Requested Variance Will Cause No Additional Environmental Impacts.

The requested variance relief addresses only SO_2 emissions and would not impact emissions of other pollutants from the MPS Group. The MPS Group currently complies and will continue to comply with the applicable MPS mercury and NOx emission limitations under

[32] The retirement of Edwards Unit 1 would reduce "Net Variance SO_2 Tons", as identified in Table 1 and Table 2, by approximately 2,000 tons per year beginning in the first full year the unit is retired. Ex. 8, *Thompson Affidavit*, ¶27.

the new ownership. Ex. 6, *MPS Group Information* (identifying pollution control equipment installed and operating at the MPS Group facilities). AER has spent over $20 million installing ACI technology on twelve units at four plants, with $17 million in operating costs to date. Variance Opinion, at 37 (citing Tr., at 16-17, Hearing Ex. 1 at 3). In fact, the Board found in PCB 12-126 that "[t]here is no question that the environment in Illinois is benefitting from these early [mercury] reductions." *Id.* at 60.

AER has taken additional steps since the date of the Variance Opinion to reduce mercury emissions from the fleet beyond what is required by the MPS. Exhibit 13, *Affidavit of Steven C. Whitworth* ("Ex. 13, *Whitworth Affidavit*"), ¶4. AER early elected five EGUs to meet the 0.008 lb/GWh mercury emission limit in 2013 a year to a year and a half earlier than the January 1, 2015 date required under the rule (35 Ill. Adm. Code 225.233(d)(1)): Coffeen Units 1 and 2 beginning February 1, 2013, Newton Units 1 and 2 beginning April 1, 2013, and E.D. Edwards Unit 3, beginning July 1, 2013. Also, Duck Creek and Joppa Units 1 through 6 have qualified as "Low Mass Emitting" units by demonstrating that potential mercury emissions are *de minimis* (<29 lbs/year). *Id.*

Moreover, IPH ownership will bring with it the environmental compliance experience of Dynegy. As stated above, Dynegy has a solid history of positive environmental compliance in Illinois. Since 1998, emissions levels from DMG have dropped almost 90 percent. Ex. 8, *Thompson Affidavit*, ¶8.

In addition, cross media impacts are not an issue. *See* Ex. 12, *AECOM Memorandum*.

VIII. CONSISTENCY WITH FEDERAL LAW

The Board may grant the variance consistent with federal law and, specifically, with the Clean Air Act, 42 U.S.C. 7401 *et seq.* The requested variance is consistent with current federal law.

A. The Terms of the Requested Variance Will Not Jeopardize Illinois' BART Compliance Demonstration.

In 2012, USEPA approved revisions to the Illinois state implementation plan ("SIP") to address regional haze. 77 Fed. Reg. 39943 (July 6, 2012). USEPA regulations mandate that regional haze plans include emission limitations representing Best Available Retrofit Technology ("BART") for each BART-eligible source. 40 C.F.R. § 51.308(e). BART is defined as: an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. 40 C.F.R. § 51.301.

USEPA approved relevant sections of the MPS and Illinois Combined Pollutant Standards ("CPS"), and two permits, and incorporated them into the SIP as satisfying BART requirements for the affected Illinois power plants and refineries. USEPA noted in response to public comments that Illinois' plan would achieve greater reasonable progress (*i.e.*, meaning greater emissions reductions) and greater visibility protection by the BART compliance deadline (in 2017) than the application of BART on BART-subject units.

When compared to emissions reductions pursuant to the MPS, this variance will impart even greater emissions reductions by the BART compliance deadline in 2017. Accordingly, a SIP amendment incorporating this variance would only serve to enhance Illinois' ability to comply with the Clean Air Act's regional haze rules.

B. The MPS Group Could Comply with CSAPR.

While CSAPR is not yet, and may never be, effective, Petitioners point out that the CSAPR is not as onerous as the MPS, because while the MPS imposes stringent emission rates, CSAPR is based on mass emissions. Also, the CSAPR is a cap-and-trade program that would allow compliance to be achieved through the purchase of emission allowances while the MPS does not. The anticipated cost of buying allowances pursuant to the CSAPR is not expected to be as financially challenging to Petitioners as installing the pollution control technology in the current time frame required to meet current MPS emission rates.

C. MPS Group Must Also Comply with MATS.

In response to the vacatur of the CAMR in 2008, USEPA adopted national emissions standards for hazardous air pollutants from coal and oil-fired EGUs in February 2012, known as the Mercury and Air Toxic Standards ("MATS"). 77 Fed. Reg. 9304 (Feb. 16, 2012). For coal-fired EGUs, MATS sets emission limits for mercury, PM, hydrogen chloride, and trace metals and also establishes alternative numeric emissions limits. The rule requires compliance by April 16, 2015, and in certain circumstances, allows an additional one or two years to achieve compliance. IPH will comply with the MATS at each of the five operating Energy Centers through the use of a combination of existing FGD systems, sorbent injection technologies and ESPs.

D. Compliance with NAAQS

The variance relief requested by IPH is consistent with the NAAQS and the Illinois SIP, *see* Variance Opinion, at 63, including two recent federal rulemaking developments, one involving the NAAQS for $PM_{2.5}$, the other involving the one–hour SO_2 NAAQS.

First, in December 2012, USEPA adopted a revised primary annual $PM_{2.5}$ NAAQS. 78 Fed. Reg. 3086 (Jan. 15, 2013) (effective Mar. 18, 2013). In accordance with Clean Air Act section 107(d)(1), USEPA anticipates promulgating initial $PM_{2.5}$ nonattainment area designations by December 12, 2014.[33] The USEPA intends to classify all initially designated $PM_{2.5}$ nonattainment areas as "moderate," meaning that, in accordance with Clean Air Act section 188(c), designated $PM_{2.5}$ nonattainment areas will not be required to achieve attainment until six years after the designation, *i.e.*, December 2020.[34] Notably, the MPS does not establish emission limits for particulate matter or $PM_{2.5}$, and none of the Energy Centers are located in an area that USEPA has preliminarily identified as exceeding the revised primary annual $PM_{2.5}$ NAAQS.[35] The AECOM Memorandum further concludes that there is no evidence to suggest that the Energy Centers are contributing to elevated $PM_{2.5}$ concentrations or, in the case of the Coffeen and Newton Energy Centers, concentrations in excess of the NAAQS. Ex. 12, *AECOM Memorandum*, Attachment 2, at 5. Moreover, the requested variance relief would end December 31, 2019, almost one year before the anticipated $PM_{2.5}$ attainment deadline. Thus, the requested variance relief would not be inconsistent with Illinois' $PM_{2.5}$ NAAQS obligations.

Second, in 2010, USEPA adopted a new primary one-hour SO_2 NAAQS. 75 Fed. Reg. 35520 (June 22, 2010). The USEPA had intended to make final its initial one-hour SO_2 NAAQS nonattainment area designations in June 2013, but has not yet taken such action. In accordance with Clean Air Act section 192, states with areas designated nonattainment for the one-hour SO_2 NAAQS have five years from the date of designation to achieve attainment.

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[33] USEPA Memorandum, From: Gina McCarthy, Assistant Administrator, To: Regional Administrators, Regions 1-10, Subject: Initial Area Designations for the 2012 Revised Primary Annual Fine Particulate National Ambient Air Quality Standard, 2-3, 9 (April 16, 2013).
[34] *Id*. at 6-7.
[35] USEPA, Summary of 2009-2011 $PM_{2.5}$ Design Values & Map showing counties with sites violating the annual $PM_{2.5}$ air quality standard for 2009-2011 (2012) *available at* http://www.epa.gov/airquality/ particle pollution/designations/2012standards/techinfo.htm.

Subsequent to the Board's issuance of the variance in PCB 12-126, USEPA recommended to Illinois that Hollis Township in Peoria County, Illinois, the location of the E.D. Edwards Energy Center, be designated as nonattainment with the one-hour SO_2 NAAQS. AER has disputed that recommended designation. Ex. 4, *Ameren Comment in Docket QA-OAR-2012-0233*. While the outcome of the designation recommendation concerning the Hollis Township area remains uncertain, Petitioner IPH recognizes that the requested variance relief would not exempt E.D. Edwards from compliance with any federal Clean Air Act requirements adopted in the future, including Illinois regulations, if any, needed to implement SIP obligations concerning the one-hour SO_2 NAAQS.

IX. RELEVANT PERMITS

As required by 35 Ill. Adm. Code 104.204(i), relevant permits are listed in Exhibit 6, *MPS Group Information*. Additionally, the Newton FGD construction permit is included as Exhibit 14.

X. AFFIDAVITS OF FACTS CONTAINED IN PETITION

As required by 35 Ill. Adm. Code 104.204(m), affidavits from the following individuals are attached to this Petition as Exhibits:

- *Ex. 1 - Martin J. Lyons*, Ameren, Executive Vice President and Chief Financial Officer
- *Ex. 2 - Mario E. Alonso*, IPH, Vice President Strategic Development
- *Ex. 8 - Daniel P. Thompson*, IPH, Vice President
- *Ex. 9 - George W. Bilicic*, Lazard Freres & Co. LLC, Managing Director and Vice Chairman of Investment Banking
- *Ex. 11 - Aric D. Diericx*, Dynegy Operating Company, Senior Director – Environmental Compliance
- *Ex. 13 - Steven C. Whitworth*, Ameren Services Company, Director of Environmental Services

XI. REQUEST FOR HEARING

Should the Board decide to hold a hearing in this matter, Petitioners respectfully request that any hearing take place in Springfield, Illinois, due to its proximate location to the affected facilities, as soon as practicable. As time is of the essence in this matter given the pending financial considerations underlying the planned transaction, Petitioners also respectfully request that the Board act on this Petition within 120 days as required by the Act, and that any hearing be consistent with Board procedures as utilized in PCB 12-126.

XII. PROPOSED VARIANCE ORDER AND CONDITIONS

Petitioners recommend the same conditions as provided in the Variance Opinion, but only revised to reflect the applicability to the new owners of the MPS Group and the more current operable dates and to be conditioned to reflect its effectiveness upon closing of the transaction. This will allow all facilities in the MPS Group to remain bound together in the same regulatory framework as envisioned by the Board in the regulatory proceedings that created the MPS Rule applicable to the MPS Group. Therefore, Petitioners respectfully recommend the following variance Order and conditions:

The Board grants Petitioners, ILLINOIS POWER HOLDINGS, LLC and AMERENENERGY MEDINA VALLEY COGEN, LLC, combined dual variances for the electrical generating units in the Ameren multi-pollutant standard (MPS) Group from the applicable requirements of 35 Ill. Adm. Code 225.233(e)(3)(C)(iii) for a period beginning January 1, 2015 through December 31, 2019 and 35 Ill. Adm. Code 255.233(e)(3)(C)(iv) for a period beginning January 1, 2017 through December 31, 2019, subject to the following conditions:

1. If at any time Illinois Power Holdings, LLC (IPH) acquires ownership or control of the five operating power stations in the Ameren MPS Group, IPH must assure compliance with Condition 2 of this Order and must comply with an overall SO_2 annual emission rate of 0.35 lb/mmBtu through December 31, 2019, and beginning January 1, 2020, must comply with an overall SO_2 annual emission rate of 0.23 lb/mmBtu.

2. At any time AmerenEnergy Medina Valley Cogen, LLC acquires ownership or control of the Meredosia and Hutsonville Power Stations, it shall not operate the electrical generating units at those plants until after December 31, 2020. The FutureGen project at the Meredosia Energy Center is exempt from this restriction.

3. Regarding the Flue Gas Desulfurization project at the Newton Power Station (I.D. No. 079808AAA) (Newton FGD project), at the time IPH acquires ownership or control of the Newton Power Station:

   a. On or before July 1, 2015, IPH must complete engineering work on the Newton FGD project.

   b. On or before December 31, 2017, IPH must obtain a new or extended construction permit, if needed, for the installation of the FGD equipment at the Newton Power Station.

   c. On or before December 31, 2018, IPH must complete construction of the absorber building on the Newton FGD project.

   d. On or before July 1, 2019, IPH must complete steel fabrication of ductwork and insulation activities on the Newton FGD project.

   e. On or before July 1, 2019, IPH must complete installation of electrical systems and piping on the Newton FGD project.

   f. On or before September 1, 2019, IPH must set major equipment components into final position on the Newton FGD project.

   g. Beginning with calendar year 2013 and continuing through 2019, annual progress reports must be filed with the Agency as to the status of construction activities relating to the Newton FGD project by the end of each calendar year. These annual progress reports must include an itemization of activities completed during the year, activities planned to be completed in the forthcoming year, progress of the Newton FGD project to comply with the timelines specified in this variance, and the estimated in-service date. Annual progress reports must be submitted to:

      Illinois Environmental Protection Agency
      Attn: Ray Pilapil, Manager

Bureau of Air-Compliance Section
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276

and

Illinois Environmental Protection Agency
Attn: Gina Roccaforte, Assistant Counsel
Division of Legal Counsel-Air Regulatory Unit
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276

WHEREFORE, for the reasons set forth above, Petitioners ILLINOIS POWER HOLDINGS, LLC, and AMERENENERGY MEDINA VALLEY COGEN, LLC, and Co-Petitioner AMEREN ENERGY RESOURCES, LLC, respectfully request that the Board grant the requested variance from the requirement that the seven affected MPS Group facilities comply with a system-wide SO_2 annual emission rate of 0.25 lb/mmBtu for the period from January 1, 2015, through December 31, 2019, and from the requirement that they comply with a system-wide SO_2 annual emission rate of 0.23 lb/mmBtu for the period from January 1, 2017 through December 31, 2019.

Respectfully submitted,

ILLINOIS POWER HOLDINGS, LLC

By: Claire A. Manning
One of Its Attorneys

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