EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, D.C. INTERNATIONAL

April 30, 2014

RECEIVED

APR 30 2014

PUBLIC SERVICE
COMMISSION

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Via Courier

Re: Case No. 2013-00475, In the Matter of Kentucky Power Company's Integrated Resource Planning Report

Dear Mr. Derouen:

Enclosed for filing are an original and ten copies of ***Sierra Club's Comments on Kentucky Power Company's Integrated Resource Planning Report*** and a certificate of service in docket 2013-00475 before the Kentucky Public Service Commission. This filing contains no confidential information.

Sincerely,

Grant Tolley
Earthjustice
1617 John F. Kennedy Boulevard
Suite 1675
Philadelphia, PA 19103
(215) 717-4523

RECEIVED

APR 30 2014

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
KENTUCKY POWER COMPANY'S INTEGRATED	)	**CASE NO. 2013-00475**
RESOURCE PLANNING REPORT	)	

SIERRA CLUB'S COMMENTS ON KENTUCKY POWER COMPANY'S INTEGRATED RESOURCE PLANNING REPORT

Intervenor Sierra Club hereby comments on Kentucky Power Company's ("KPC" or "Company") 2013 Integrated Resource Planning Report ("IRP"). After decades of being almost entirely reliant on coal-fired power generation, KPC's IRP reflects important and laudatory progress that the Company is planning to make over the next few years towards having a more diverse energy portfolio. For example:

- KPC is scheduled to retire Unit 2 of the Big Sandy coal plant in 2015, which will avoid the more than 30% rate increase that would have been needed to keep that uneconomic coal unit operating.

- As a result of the retirement of Big Sandy Unit 2 and the conversion of Big Sandy Unit 1 to natural gas, KPC will no longer obtain nearly 99% of its capacity and energy from coal-fired generation.

- Following the settlement of the Mitchell Transfer Proceeding, KPC is committed to double its investment in demand side management ("DSM") from $3 million in 2013 to $6 million per year in each of 2016 through 2018.

- KPC has signaled its intent to pursue 100 megawatts ("MW") of low-cost wind resources in 2015.

Each of these steps should reduce costs and risks for KPC ratepayers, help KPC adjust to fundamental changes in today's energy markets, and enable the Company to start seizing the opportunities presented by the growing availability of low cost DSM and renewable energy resources.

Unfortunately, KPC's IRP suggests that the Company's progress is limited to the short term. In particular, under the Company's preferred resource plan:

- Fifteen years from now, 85% of KPC's energy would still be produced from fossil fuels, and 71% of KPC's capacity would still be coal-fired generation.

- While 100MW of wind capacity is assumed to be added in 2015, no additional wind resources are added through 2028.

- Energy savings from existing and future energy efficiency programs amount to only 3.2% savings by 2028.

In short, after some positive developments over the next few years, KPC's IRP suggests a disappointing return to business as usual, with the Company planning long-term overreliance on coal-fired generation and a failure to accurately assess, much less pursue, low cost and low risk DSM and renewable resource opportunities.

Such disappointing results stem from a fundamental shortcoming in KPC IRP – namely, that the Company failed to meaningfully evaluate a range of potential resource plans. As a result, the IRP does not incorporate the type of thorough and reasonable planning needed for KPC to achieve a least cost and least risk energy future.

As discussed in detail below, the IRP is a flawed document that fails to satisfy the standards of Kentucky law because, among other things:

- The portfolios modeled by KPC all involved virtually identical generation resources, rather than evaluating meaningfully different levels of DSM, solar, wind, and coal generation;

- The IRP ignores or understates the significant environmental compliance costs that the Company faces;

- The IRP failed to evaluate scenarios in which KPC declines to renew its contract with the Rockport Generation Station in Indiana, or terminates that contract in advance of its current 2022 expiration date;

- The IRP failed to evaluate a reasonable range of likely future carbon prices;

- The IRP evaluated only a single level of DSM energy savings, and improperly discounted potential demand response savings;

- KPC failed to consider bidding its energy efficiency and demand response savings into the PJM Base Residual Auction ("BRA");

- The IRP's analysis of solar generation ignores ways in which solar resources provide significant value, and relies on an unreasonable 10MW cap on the level of solar generation that can be added each year;

- KPC's preferred resource plan unreasonably fails to add any wind capacity after 2015; and

- The IRP overstates future load by unreasonably assuming that coal mining energy demand will remain steady over the planning period.

Until these serious shortcomings in KPC's IRP are remedied, the reasonableness of the Company's future actions relying on this resource planning is suspect. As such, the Commission Staff should find the IRP to be inadequate and require KPC to address each of these shortcomings in all future resource planning and decision making.

I. IRP STANDARDS

The IRP process in Kentucky is governed by 807 K.A.R 5:058, which requires KPC to submit every three years a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of KPC's system. 807 K.A.R. 5:058 Section 1(2). Core elements of the filing include:

- A base load forecast that is "most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system." 807 K.A.R. 5:058 Section 7(3).

- A "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost," and that includes consideration of "key uncertainties" and an "assessment of potentially cost-effective resource options available to the utility." 807 K.A.R. 5:058 Section 8(1).

- The revenue requirements and average system rates resulting from the plan set forth in the IRP. 807 K.A.R. 5:058 Section 9.

As the Commission Staff stated in reviewing KPC's last IRP filing:

> The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost[1]

The Staff has further explained that, in reviewing an IRP, its goals are to ensure that:

---

[1] Kentucky PSC, Staff Report on the 2009 Integrated Resource Plan of Kentucky Power Company, Case No. 2009-00339 (Mar. 2011), at 1 (hereinafter "2009 IRP Staff Report").

1. All resource options are adequately and fairly evaluated;

2. Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and

3. The report also includes an incremental component, noting any significant changes from Kentucky Power's most recently filed IRP.[2]

Evaluation of an IRP should also be guided by the overall requirement that utility rates are "fair, just, and reasonable." KRS § 278.030(1); KRS § 278.040; *Kentucky Public Service Com'n v. Com. ex rel. Conway*, 324 S.W.3d 373, 377 (Ky. 2010). As the Commission has explained, it has long been recognized that "'least cost' is one of the fundamental principles utilized when setting rates that are fair, just, and reasonable." *In the Matter of: Application of Kentucky Power Co.*, Case No. 2009-00545, 2010 WL 2640998 (Ky. P.S.C. 2010). A utility's rates will almost certainly not be fair, just, and reasonable if they do not result from planning processes that seek to determine the least cost, least risk resource plan.

It is with these standards in mind that the Sierra Club offers the following comments.

II. THE IRP FAILS TO CONSIDER A REASONABLE RANGE OF RESOURCE PORTFOLIO OPTIONS.

One of the central requirements of the IRP process is that a utility develop a plan that provides "an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost." 807 KAR 5:058 Section 8; *see also id.* Section 8(4). To achieve this goal, a utility must "describe and discuss all options considered for inclusion in the plan," including an assessment of existing generation sources, potential new generation sources, and nonutility generation options. *Id.* Section 8(2). The resource plan must also "consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility." *Id.* Section 8(1). Implicit within that requirement is the notion that a utility will not limit itself to a single resource portfolio, but will instead consider alternative portfolios so "that all reasonable options for the future supply of electricity were being examined and pursued."[3]

KPC's 2013 IRP filing fails to meet these requirements in several respects. *First*, the IRP fails to consider an array of resource options but, instead, evaluates resource portfolios that each assume virtually the same mix of generating assets. *Second*, KPC compounds this error by failing to adequately assess the capital costs associated with its generating facilities. In particular, the IRP does not consider the significant capital costs associated with the installation of pollution control equipment needed to ensure that the Rockport and Mitchell coal-fired units

---

[2] *Id.* at 2-3.

[3] 2009 IRP Staff Report at 1.

meet environmental compliance requirements. The failure to consider these environmental compliance costs is not only an independent breach of the IRP rules, it also skews the IRP's financial analysis. *Third*, with respect to the Rockport Power Plant specifically, from which KPC currently purchases 393 MW (15% of the plant's capacity), the IRP improperly assumes that KPC will continue to purchase that stake throughout the entire planning period, rather than evaluating scenarios in which the Rockport contract is not renewed in 2022 or is cancelled before then.

For all of these reasons, the IRP's analysis of the costs and risks of its preferred resource portfolio and its comparison of that portfolio with alternatives fails to live up to the requirements of the IRP rules. Sierra Club therefore respectfully requests that the Commission Staff note these deficiencies in its report on the Company's IRP and call on KPC to engage in resource planning that looks at a wide range of resource options.

A. The Five Resource Portfolios Evaluated In The IRP All Consist Of Virtually The Same Mix Of Generating Assets.

As noted above, one of the central purposes of the IRP process is to consider a variety of resource portfolios and evaluate how they perform under different future conditions. 807 KAR 5:058 Section 8(2). A robust analysis of different resource alternatives helps ensure that a utility will meet the overarching goal of providing a reliable supply of electricity at the lowest possible cost. KPC's IRP fails this requirement because all of the resource portfolios considered in the IRP involve virtually the same set of generating resources.

In the IRP, the Company developed its preferred portfolio by examining five commodity pricing scenarios:

- a base case based on the vacatur of the Cross-State Air Pollution Rule ("CSAPR"), by the D.C. Circuit Court of Appeals, implementation of the Mercury and Air Toxics ("MATS") rule in 2015, an initial drop in natural gas prices, and the imposition of a price on CO_2 starting in 2022;
- a case assuming lower than expected gas prices;
- a case assuming higher than expected gas prices;
- a scenario assuming higher than expected CO_2 prices; and
- a scenario assuming no price on CO_2.

IRP at 154-56. Any potential differences in the impacts of these commodity pricing scenarios, however, were obscured by the fact that each of the resource portfolios modeled under the scenarios were virtually identical. In particular, all of the portfolios considered in the IRP assume that KPC will rely on the same existing generation assets – namely 50% of the Mitchell coal-fired power plant and 15% of the Rockport plant – throughout the planning period. *See* Resp. to SC 2-13(a)(ii); Resp. to Staff 1-33; IRP at 123. And, as discussed more fully below, every modeled portfolio assumed the same level of DSM, and capped utility solar resources at no more than 10MW per year starting in 2020. No portfolios were modeled in which Rockport and/or Mitchell were retired before 2028, in which higher levels of DSM were pursued, or in which higher levels of solar resources could be pursued.

In short, the IRP failed to consider a broad mix of "potentially cost-effective resource options," thereby limiting the Company's ability to evaluate different resource portfolios and identify the least-cost, least-risk plan for the future. 807 KAR 5:058 Section 8. Instead, the IRP created a fait accompli in which the preferred resource plan identified by KPC was essentially pre-determined. Indeed, the IRP implicitly acknowledges as such, noting that "[b]ecause much of Kentucky Power's resource portfolio is already in place, the differentiation that such different economic scenarios provided was somewhat muted." IRP at 161. But the point of an IRP process is to evaluate alternative portfolios and scenarios in order to assess whether or in what circumstances a utility should be taking a different resource approach in the future than it is today. By assuming that the resource portfolio currently in place would remain so for the entire fifteen year planning period, the Company short-circuited such assessment and undercut the primary reason for carrying out an IRP to begin with.

KPC's approach here was especially problematic because the available evidence suggests a more robust evaluation of resource options may have led to a different preferred resource portfolio. In particular, when KPC compared its preferred portfolio, which included a small amount of DSM and the 10MW maximum solar per year, to a portfolio based on the fossil-only sources and the EcoPower biomass facility, it found that "the addition of EE and solar generation, both distributed and utility-scale, worked to reduce the risk or revenue requirement volatility," IRP at 169, and that "the addition of wind, solar, and customer and grid energy efficiency resources serve to reduce overall costs." *Id.* at 170. Such results suggest that an evaluation of portfolios with increased levels of DSM, solar, and wind, and/or reduced levels of coal-fired generation would have been even lower cost and lower risk. But the IRP never investigates such a portfolio.

Because the IRP did not consider any resource portfolios without all of the existing generating assets, KPC failed to fully "consider the potential impacts of selected, key uncertainties and [] include assessment of potentially cost-effective resource options available to the utility." 807 KAR 5:058 Section 8; *see also id.* KAR 5:058 Section 8(e) ("The utility shall describe and discuss all options considered for inclusion in the plan including . . . ."). This means that the Commission, and KPC's customers, cannot be ensured that KPC is pursuing a least-cost, least-risk resource plan. The Staff should address this shortcoming by calling on KPC to evaluate and model resource portfolios that assume a range of options regarding coal plants, renewable resources, and DSM, rather than simply assuming the continued operation of existing resources for the entire planning period.

B. The IRP's Modeling Failed To Properly Account For Pollution Control Costs.

In order to ensure that a utility will deliver a "reliable supply of electricity . . . at the lowest possible cost," 807 KAR 5:058 Section 8, the IRP rules require utilities to fully consider both the capital and operating and maintenance ("O&M") costs of generating assets over the 15-year planning period, 807 KAR 5:058 Section 8(2)(b)12, and to report, among other things, the average system rates per year. 807 KAR 5:058 Section 9(4). And because environmental compliance costs represent a significant share of a coal-fired plant's total costs, it is critical that those compliance costs be incorporated into an assessment of the resource portfolios being evaluated.

The IRP, however, failed to do so. Although the IRP purports to show the "Financial Effects" of KPC's preferred portfolio through a year-by-year breakdown of the average "rate per kWh expected to be paid by Kentucky Power customers . . . that results directly from the costs and energy consumption impacts associated with this plan," IRP at 17, these rates do not reflect the capital costs of installing the pollution control equipment that will be needed at Mitchell and Rockport during the 15-year planning period. *See* Resp. to Staff 1-33; Resp. to SC 2-13(a)(ii); Resp. to SC 2-25(d), (e) (noting that Table 7 does not include the costs of installing pollution control equipment at Rockport required by AEP's consent decree). In other words, these capital costs were omitted from the economic modeling that resulted in KPC's preferred portfolio. IRP at 17 (noting that "[t]he Financial Effects represented do not consider the prospect of . . . increases in base generation-related costs not uniquely incorporated into the planning/modeling process").

The failure to consider these environmental compliance costs is an independent breach of the IRP rules, which specifically require that such costs be considered. 807 KAR 5:058 Section 8(2)(b)12. Equally important, the omission of these capital costs from KPC's modeling likely means that the modeling results are skewed, thereby calling into question KPC's conclusion that its preferred portfolio represents the least-cost option for customers. *Cf.* 807 KAR 5:058 Section 8.

It is important to note that these omitted costs are significant: in the first three years of the planning period alone, KPC has estimated that Rockport and Mitchell will incur $79.3 million in capital environmental compliance costs, with the Rockport plant expected to incur another $42.3 million in costs for the installation of pollution control equipment during the 2017-19 timeframe. SC 2-12 Attachment 1; Resp. to SC 2-13. Moreover, the two Rockport units face the need to install flue gas desulfurization ("FGDs" or "scrubbers") in 2025 and 2028, respectively, if they are to continue operating. *See* IRP at 118, 121, 154. And, as discussed in Section II.C below, the Rockport units especially face the likelihood of larger or earlier costs due to the likely reinstatement of the federal Cross-State Air Pollution Rule ("CSAPR") and the implementation of the one-hour National Ambient Air Quality Standards ("NAAQS") for sulfur dioxide ("SO2").[4]

Nevertheless, KPC concluded that there was no need to include incremental fixed costs -- such as those resulting from the installation of pollution controls -- in its economic modeling, "[b]ecause all of the portfolios evaluated in Kentucky Power's 2013 IRP included the same existing generation assets." Resp. to SC 2-13(a)(ii). But this merely compounds the error discussed above in Part II.A above: by limiting its resource planning to scenarios that rely on the same generation assets, and by omitting the capital costs of pollution controls needed for those assets, the IRP's analysis is skewed in favor of existing (and potentially more costly) assets such as Rockport and Mitchell. The Commission Staff should reject this circular analysis.

Curiously, although the IRP modeling omits the *capital* costs of new pollution control equipment, the modeling includes the *O&M* costs of those controls once installed. *See* Resp. to SC 2-25(b); Resp. to Staff 1-33 (stating that the modeling "takes into account all variable costs and the incremental fixed costs that vary among the resource portfolios").[5] While such O&M costs should be included in the modeling, the inclusion of these costs merely underscores the inappropriateness of omitting the capital costs of pollution control equipment in identifying the revenue requirements and rate impacts of KPC's preferred resource portfolio.

The Commission Staff should remedy this shortcoming by requiring KPC to incorporate all reasonably foreseeable future capital costs (including both environmental and non-environmental capital investments) into its assessment of the revenue requirements and rate impacts of the resource portfolios being evaluated in the IRP.

---

[4] In this respect, the IRP has failed to adequately address one of the recommendations of the Commission Staff from KPC's last IRP. The Staff noted that "the possibility of either federal emissions-limiting legislation or targeted EPA actions limiting various emissions may have significant impacts on Kentucky Power's service territory," and directed KPC to "explicitly account for potential federal legislation imposing stricter emissions limits on its generation in its forecasts and risk analysis." IRP at 53. The Staff further stated that "[p]otential EPA actions limiting emissions should also be explicitly accounted for in the forecasts and risk analysis." *Id.* Despite these admonitions, the IRP fails to fully address environmental compliance costs, omitting them from the modeling performed to develop its preferred portfolios. *See* Resp. to SC 2-13(a)(ii); *see also* IRP at 53 (asserting that the "Company's risk analysis for its resource portfolio considers the impacts of various Federal mandates, but conceding that "[t]he timing and impact of specific rules and regulations have not been evaluated").

[5] At the Informal Conference held on April 16, 2014, Sierra Club queried KPC about this issue, and KPC stated that the O&M costs associated with pollution control equipment were included in the modeling.

C. The IRP Should Have Evaluated Scenarios In Which KPC Ends Its Interest In The Rockport Power Plant In 2022 Or Earlier.

KPC's failure to evaluate portfolios with different mixes of generation resources skews, among other things, the IRP's treatment of the Rockport Power Plant in Indiana. All of the resource scenarios considered in the IRP, including the preferred portfolio, assume that KPC will continue to purchase 15% of the Rockport plant's power – representing 393 MW of capacity – throughout the entire 15-year planning period. IRP at 5-6; *see also id.* at 123 ("For planning purposes, it has been assumed that the Rockport agreements extend indefinitely beyond [the 2022] expiration date."). Thus, in addition to maintaining its current agreement to purchase 15% of Rockport's output, the IRP assumed that KPC would renew this purchase agreement, such that KPC would continue to rely on Rockport beyond the planning period. *Id.* at 6. Although KPC's continued reliance on Rockport is an assumption that undergirds the IRP planning process, KPC's resource portfolio fails to account for the future environmental compliance costs facing this plant. Nor does the IRP adequately address the potential uncertainties of higher compliance costs than those already anticipated by the Company.

Rather than assume continued purchases of Rockport for the next 15 years, the Company should be evaluating, and planning for, the possibility of terminating the Rockport contract prior to December 2022. And even if KPC decides not to terminate that contract early, the Company should still be evaluating resource scenarios that do not include energy from Rockport for the last six years of the IRP planning period. These steps are necessary to ensure that KPC has identified the least-cost least-risk resource plan, because Rockport faces significant known environmental compliance costs and potentially even higher costs as discussed below.

1. Costs Associated with the MATS Rule and NSR Consent Decree.

As the IRP acknowledged, Rockport will face substantial environmental compliance costs in the coming years due to (a) EPA's implementation of the Mercury and Air Toxics ("MATS") rule and (b) the terms of AEP's New Source Review ("NSR") consent decree. To comply with these mandates, the Rockport plant must be retrofitted with an array of pollution equipment, including:

- By April 16, 2015, the Rockport units must be retrofitted with dry sorbent injection ("DSI") technology and an associated landfill to control mercury emissions. IRP at 117-18; Resp. to SC 2-12(c);

- By December 31, 2017 and December 31, 2019, the Rockport units must be retrofitted with selective catalytic reduction ("SCR") systems to control NOx emissions, IRP at 118; and

- By December 31, 2025, and December 31, 2028, the Rockport units must be retrofitted with flue gas desulfurization ("FGD") systems to control SO2 emissions, IRP at 118.

Under the consent decree, the Rockport units are also subject to an annual SO2 cap, in which SO2 emissions from the plant must be steadily decreased over the IRP planning period. Thus, for example, whereas Rockport will be subject to an annual cap of 28,000 tons of SO2 starting in 2016, that limit will drop to 22,000 tons starting in 2020, and 18,000 tons starting in 2026. IRP at 119.

Collectively, the costs of these pollution control requirements will be significant. The MATS rule, NSR consent decree, and other regulatory requirements at Rockport are expected to cost KPC nearly $38.5 million during the 2014-16 timeframe. SC 2-12 Attachment 1. And KPC estimates that it will be responsible for $42.3 million in compliance costs over 2017-19 due to the installation of SCRs. Resp. to SC 2-13. In addition, these compliance costs will likely pale in comparison to the cost of installing FGD systems at the Rockport in 2025 and 2028. As KPC's December 2011 proposal in PSC Case No. 2011-00401 to install a scrubber on Big Sandy Unit 2 demonstrated, an FGD can cost nearly a billion dollars, and Rockport needs two of them. Even though KPC's share of the Rockport plants is only 15%, that does not excuse KPC's obligation to factor its portion of those costs into an evaluation of whether continuing to purchase 393MW of capacity from Rockport for the entire planning process is reasonably part of a least-cost, least-risk portfolio.

2. Costs Associated With the Cross-State Air Pollution Rule ("CSAPR").

In addition to compliance costs from the existing MATS rule and NSR consent decree, the Rockport plant faces the strong possibility of additional costs from other likely environmental standards that are erroneously ignored in the IRP. Perhaps most significantly, the IRP fails to address the impact on the Company's preferred resource plan from the likely reinstatement of CSAPR.[6]

On April 29, 2014, the U.S. Supreme Court reversed the lower court decision vacating CSAPR. *See U.S. EPA v. EME Homer City Generation, LP*, Nos. Nos. 12–1182, 12–1183, 2014 WL 1672044 (U.S. Apr. 29, 2014). The Court's decision will likely result in the reinstatement of this EPA regulation. Although KPC was aware that the Supreme Court would be ruling on this issue in 2014, IRP at 116, the IRP did not attempt to analyze the impact that a reinstated CSAPR might have on the Rockport plant's future costs. Thus, for example, the IRP lacks any analysis of whether a reinstated CSAPR would force an acceleration of the projected timeline for installing air pollution controls at Rockport (DSI in 2015; SCR in 2018/2020; FGD in

[6] *See* SCOTUSblog, *Environmental Protection Agency v. EME Homer City Generation,* Docket No. 12-1182, *at* http://www.scotusblog.com/case-files/cases/environmental-protection-agency-v-eme-homer-city-generation/.

2025/2028).[7] The IRP similarly does not address whether the DSI systems that will be installed at Rockport in 2015 to comply with MATS and the NSR Consent Decree will enable the plant to comply with CSAPR's SO2 requirements if CSAPR is reinstated, or if (as KPC's affiliate I&M found in 2011) compliance with CSAPR at Rockport would require installing an SCR system on at least one Rockport unit in the near future. Instead, all of KPC's resource scenarios assumed that CSAPR would remain vacated. *See* IRP at 154 (noting that the base "case recognizes the vacatur of CSAPR by decision of the U.S. Court of Appeals"). And KPC prepared no cost estimates or other assessments evaluating the costs that Rockport could face if CSAPR were reinstated or replaced by EPA. When Sierra Club sought further clarification of the SO2 and NOx emissions reductions that might be necessary should CSAPR be reinstated, KPC failed to quantify them, simply asserting that "[t]he level of reductions necessary would have been determined by the availability and price of CSAPR allowances in the market at the time they were needed." Resp. to SC 2-11(a).

Even if CSAPR's likely reinstatement does not impact the timing of environmental retrofits at Rockport, at a minimum the imposition of a more stringent rule governing interstate transport of air pollution would likely increase the cost to KPC of any purchases of SO2 or NOx emission allowances need to comply with CSAPR. Yet the Company does not evaluate these possible future costs and risks at all in the IRP.

3. Costs Associated With the 1-Hour SO2 NAAQS.

Another potential compliance cost facing the Rockport plant stems from EPA's recent revision of the one-hour NAAQS for SO2, and the strong likelihood that additional SO2 emission reductions from Rockport will be needed to avoid exceedances of that NAAQS. Although the IRP includes a cursory mention of these new SO2 NAAQS, *see* IRP at 121, KPC failed to address the possible future costs and risks to its preferred portfolio that could result from implementation of the new standard. Instead, the IRP simply noted that "[t]he scope and timing of potential requirements is uncertain." *Id.* But the way to address such uncertainty is to evaluate a range of reasonable options regarding the types and timing of controls that the NAAQS could lead to, rather than pretending as if the Rockport plant will not face any additional compliance costs related to the NAAQS.

In 2010, EPA promulgated stringent NAAQS requiring ambient SO2 concentrations of less than 75 ppb over one-hour averaging periods; EPA found this limit necessary to protect public health because exposure to even small amounts of SO2 over short periods of time can

---

[7] By contrast, in 2011, before CSAPR was stayed by a federal appeals court, KPC's affiliate I&M found that CSAPR could have very significant impacts on the Rockport plant. I&M requested that Indiana's Utility Regulatory Commission ("IURC") issue a Certificate of Public Convenience and Necessity to install both FGD and SCR on one of the Rockport units to comply with CSAPR and MATS. *See* IURC, Cause No. 44033, Direct Testimony of Paul Chodak III & Scott C. Weaver (Aug. 1, 2011), available at: https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b63180170fd7.

cause adverse health effects.[8] While NAAQS are not emission limitations on individual sources, they impact emission limitations because states are required to develop plans to implement the NAAQS in areas that exceed the required concentrations ("nonattainment areas").[9] EPA's most recent SO2 NAAQS implementation strategy would require states to complete all SO2 NAAQS implementation plans by 2019 or 2022, with corresponding deadlines for bringing any non-attainment areas back into attainment (through measures such as more stringent emissions limits on individual sources) by 2022 or 2025, respectively. The earlier schedule applies to areas designated nonattainment through modeling, while the later schedule applies to areas designated through monitoring.[10] Even before non-attainment designations are completed and state implementation plans approved, major sources of SO2 emissions such as the Rockport plant may also be subject to emission limits ensuring compliance with the one-hour SO2 NAAQS if they are found to contribute significantly to violations of NAAQS in other states,[11] or in connection with seeking approval for any physical modifications at the facility that would cause a significant emissions increase.[12] In short, there are multiple legal mechanisms, and potential timeframes, under which the Rockport plant may be subject to emission limits designed to ensure that the SO2 NAAQS is not violated.

The current emission control plans for Rockport would not ensure compliance with the one-hour SO2 NAAQS until at least 2025, if not 2028. Those are the years in which KPC's affiliate, Indiana and Michigan Power ("I&M"), plans to install the FGD systems per the requirements of the NSR consent decree. *See* IRP at 118. In 2015, I&M plans to add cheaper, less effective dry sorbent injection ("DSI") SO2 controls to both Rockport units as a stopgap attempt to comply with the MATS rule and the NSR consent decree. *See* IRP at __. Even assuming that DSI enables Rockport to comply with the MATS rule and the NSR consent decree, this equipment does not ensure that Rockport will not cause violations of the one-hour SO2 NAAQS. And nothing in the NSR consent decree addresses what types of controls or levels of emission reductions would be needed to achieve to ensure that Rockport complies with the 1-hour SO2 NAAQS. *See United States of America v. Am. Elec. Power Serv. Corp.*, Civil Action No. C2-99-1182 (S.D. Ohio May 14, 2013).

In fact, modeling has shown that Rockport will likely cause violations of the one-hour SO2 NAAQS in surrounding parts of Indiana and Kentucky until Rockport installs FGD, a period of more than 10 years. In a report dated December 10, 2012, expert air quality modeler Camille Sears concluded, using EPA's AERMOD air dispersion model, that Rockport's SO2 emissions will violate the one-hour NAAQS and may result in EPA's designation of the surrounding area as nonattainment even if Rockport is retrofitted with DSI controls with 50%

---

[8] *See* Primary National Ambient Air Quality Standard for Sulfur Dioxide, 75 Fed. Reg. 35,520 (June 22, 2010) (to be codified at 40 C.F.R. pt. 50).
[9] *See* 42 U.S.C. § 7410(a).
[10] *See* U.S. EPA, Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard at 5 (Feb. 6, 2013), *available at* http://www.epa.gov/airquality/sulfurdioxide/pdfs/20130207SO2StrategyPaper.pdf.
[11] 42 U.S.C. §§ 7410(a)(2)(D)(ii), 7426(b)-(c).
[12] 40 C.F.R. § 52.21(k).

SO2 control efficiency.[13] Even after DSI controls are added, Sears's report projects peak ambient SO2 concentrations of up to 145% of the one-hour NAAQS.[14] Furthermore, Sears's modeling showed that Rockport would need to install SO2 controls with an efficiency rate of at least 82% to ensure compliance with the NAAQS.[15] Consistent with this finding, modeling showed no violations of the one-hour SO2 NAAQS at Rockport with 95% efficient FGD on both units.[16]

KPC does not refute the modeling results in its IRP materials, asserting instead that "the scope and timing of potential [NAAQS-related] requirements is uncertain." IRP at 121. Put differently, the Company is gambling that the one-hour SO2 NAAQS will not be enforced at the Rockport plant until at least 2025, if not 2028. This approach imprudently dismisses both the economic and health risks associated with the Company's preferred portfolio, and puts the portfolio at an unrealistic advantage as compared with alternative portfolios that KPC should have considered, such as one in which KPC terminated the Rockport contract early or elected not to renew that contract after 2022. Either of these alternatives could have reduced the risks to KPC's ratepayers of unexpected increases in environmental compliance costs and, therefore, should have been evaluated as part of this IRP process.

4. Costs Associated With the ELG and CCR rules.

Although it provides some aggregate figures for the first three years of the planning period, the IRP does not fully disclose KPC's assumed capital expenditures at the Rockport plant that will likely be necessitated by EPA's proposed effluent limitation guidelines for wastewater discharges from steam electric sources (ELG rule) and EPA's proposed rule for handling coal combustion residuals (CCR rule).[17] *See* Resp. to SC 2-12 Attachment 1 (estimating $769,000 in compliance costs in 2016). The amount of and basis for KPC's assumed capital expenditures to satisfy these regulatory should have been fully considered in the IRP. Under the IRP rules, a utility must not only provide actual data and projections of capital costs at the start of the planning period, it must also provide estimates of capital and variable costs for the entire 15-year period. 807 KAR 5:058 Section 8(3)(b)(12).

KPC acknowledges that the ELG and CCR rules will require capital expenditures for projects at its coal-fired units. For example, KPC anticipates that the CCR rule "would require plant modifications and capital expenditures (which are factored into this IRP) to address these requirements by, approximately, the 2018 timeframe." IRP at 120. And as a result of the upcoming ELG rule, KPC "anticipates that wastewater treatment projects will be necessary at the

---

[13] *See* Camille Sears, Air Dispersion Modeling Analysis for Verifying Compliance with the One-Hour SO2 NAAQS: AEP – Rockport Power Plant at 12, attached as Exhibit A.
[14] *Id.* at 12.
[15] *Id.* at 11.
[16] *Id.*
[17] *See* Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Source Category, 78 Fed. Reg. 34,432 (June 7, 2013); Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35,128 (June 21, 2010).

Rockport and Mitchell units and these have been considered as part of the respective long-term unit evaluations." *Id.* But KPC does not identify, let alone quantify, its assumptions concerning these expenditures in the IRP, some of which may be significant. As a result, the Commission and interested parties have no way to determine whether the Company's estimates are reasonable, or whether they have been appropriately factored into the resource portfolios.

For example, EPA's proposed ELG includes some regulatory options that would require the Company to retrofit its bottom ash handling at Rockport to a dry handling or closed loop system that would result in zero discharge of bottom ash sluice water.[18] EPA estimates that, on average, each plant undertaking such a retrofit would incur $17 million in capital costs and $2 million in annual O&M costs.[19] Moreover, these costs may be larger for a 2,600 MW power plant such as Rockport than the average plant costs estimated by EPA. KPC's IRP filing, however, contains no discussion of whether the Company factored into its IRP modeling the risk that it will have to meet these significant additional compliance costs at Rockport or took any steps to evaluate what the costs of a bottom ash retrofit would be for the plant. And when the Commission Staff sought further clarification of these future costs, KPC provided no information beyond 2016, simply noting that "any estimates of future compliance costs, and the timing of those investments, is highly uncertain." Resp. to Staff 1-33.

5. Costs Associated With Carbon Regulations.

KPC's fossil-fuel generating resources, including Rockport, will likely incur significant costs due to the implementation of GHG regulations. Even accepting KPC's assumptions about the timing and magnitude of a carbon price, the shortcomings of which are discussed in Section III below, Rockport would face substantial compliance costs. Under the IRP's base case for CO_2 pricing, KPC's customers will face $525 million in costs between 2014-2040. IRP at 169-70. As the second largest source of CO_2 emissions in KPC's portfolio, Rockport will represent a meaningful proportion of those costs.

6. Recommendation Regarding Rockport.

The Commission Staff should ensure that future options regarding KPC's share of the Rockport plant are fully evaluated by calling on KPC to provide a full accounting of potential environmental costs facing the plant, and to evaluate resource portfolios in which KPC does not renew its Rockport contract in 2022 and/or ends that contract early.

---

[18] 78 Fed. Reg. at 34,458.

[19] EPA, Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 9-40 (Apr. 2013), Docket No. EPA-HQ-LW-2008-0819-2257, *available at* http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_TDD_Proposed-rule_2013.pdf.

III. THE IRP FAILS TO ROBUSTLY ANALYZE LIKELY FUTURE CARBON PRICES.

With a preferred resource plan that continues to have 85% of its energy coming from fossil fuels, and 71% of its capacity being coal plants for the next fifteen years, KPC has significant exposure to likely future carbon regulation. To its credit, KPC factored a carbon price into its analysis in this IRP. Given the ongoing efforts of the U.S. Environmental Protection Agency ("EPA") to regulate greenhouse gas ("GHG") pollution, building this assumption into the IRP is necessary to ensure that the resource portfolios accurately estimate the costs of carbon-intensive generating facilities such as coal-fired power plants. Assuming a future price on carbon is also consistent with the terms of KPC's recently-approved settlement in Case No. 2012-00578. Under that settlement agreement, KPC is required to file, as part of its IRPs, "an economic analysis of all generating unit costs, including the costs of complying with greenhouse gas emission regulation." Order, Case No. 2012-00578, at 34 (Oct. 7, 2013); *see also id.*, Appx. A ¶ 21(c) (Stipulation and Settlement Agreement).

But although KPC's assumption of a carbon price is an important first step, its analysis still falls short of IRP requirements. Specifically, by evaluating only a narrow range of fairly low carbon prices that do not begin until 2022 and decline over time, the IRP underestimates the potential cost of carbon regulation to a system that continues to be over-reliant on fossil fuels, and the benefits of pursuing low carbon resources such as DSM, wind, and solar. In particular, the IRP's carbon pricing assumptions fall short in two fundamental respects. First, all of the commodity pricing scenarios examined in the IRP, which were used to develop KPC's preferred portfolio, assume an unreasonably low and small range of potential carbon prices. Second, the IRP fails to consider the potential that a carbon price would take effect prior to the 2022 date assumed by KPC. IRP at 16, 121-22, 154-56.

A. The IRP Failed To Consider A Reasonable Range Of Likely Carbon Prices.

The IRP contains no serious evaluation of the sensitivity of alternative resource portfolios to potential carbon prices. Despite recent developments in federal greenhouse gas policies, KPC assumes that the cost of CO2 will "stay within the $15-20/metric ton range over the long-term analysis period."[20] IRP at ES-2. KPC's three main commodity pricing scenarios for evaluating alternative resource portfolios in its 2013 IRP assume a nominal carbon price of $15/metric ton. Resp. to SC 1-32(c); IRP at 157. In terms of real dollars, KPC assumes that a carbon price, once established in 2022, will decrease over the remaining six years in the planning period. *See id.* at 157 (showing that the assumed price of carbon, in 2011 dollars, will fall slightly between 2022 and 2028). Although the IRP does include one scenario assuming a zero carbon cost and one assuming a $25/metric ton cost, *id.* at 156, usch a narrow and low range of carbon prices fails to reflect the potential impacts that carbon regulations could have on KPC.

---

[20] KPC does not specify, but this price appears to be given in nominal dollars; the commodity price graph in Figure 19 of the IRP show the prices KPC assumed for CO_2 in 2011 dollars. *See* IRP at 157. Under the base case, the CO2 price in 2011 dollars starts at approximately $11/metric ton in the year 2022 and gradually *drops* in the following years. *Id.*

A more reasonable and supported estimate of future carbon prices has been published and regularly updated by Synapse Energy Economics ("Synapse"). Synapse projects three levels of carbon prices based on its evaluation of regulatory developments, the carbon price used to assess the climate benefit of federal rulemakings, carbon forecasts in IRPs from 28 utilities, and the results of a multi-year Energy Modeling Forum ("EMF") research effort on the costs of U.S. emissions abatement.[21] In its November 2013 update, Synapse published low, mid, and high cases for the years 2020-2040.[22]

Synapse's low case is based on the type of scenario KPC believes is most likely: one in which federal policies to limit greenhouse gases exist, but are not stringent.[23] Yet, Synapse's low case forecasts a price of $10/ton beginning in 2020, increasing to $13/ton in 2022 and $22/ton in 2028 (2012 dollars), expressed in American tons.[24] By contrast, KPC's assumed $15/metric ton (nominal dollars) carbon price, expressed in the same units, would yield a price of approximately $11/ton that would take effect in 2022, with a slight decrease in the carbon price over the following six years. IRP at 157. Thus, Synapse's low price forecast begins two years earlier than KPC's, is approximately $2 higher in 2022, rises during the planning period, and finishes at approximately $10/ton more than what KPC considers likely.

Synapse's mid case represents a future in which federal policies implement more ambitious but "reasonably achievable" goals.[25] In this forecast, CO2 costs $15/ton in 2020 and increases steadily to reach $19.50/ton by 2022 and $33/ton in 2028.[26] Again, these prices begin two years earlier. Synapse's high case assumes that "somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions" will influence the CO2 price.[27] Synapse's high case forecast begins at $25/ton in 2020, reaches $31.50 by 2022, and reaches $51 by 2028.[28] Thus, Synapse's high case forecast results in a carbon price approximately three times greater than the High CO_2 case modeled in the IRP. *Cf.* IRP at 156, 157.

KPC's carbon price assumptions ignore more than Synapse's forecast. Other utilities have recognized that carbon prices pose serious risks that their IRP processes should take into

---

[21] Synapse Energy Economics, *2013 Carbon Dioxide Price Forecast* (Nov. 1, 2013) [hereinafter Synapse 2013 Carbon Price Forecast], *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf.
[22] *See id.* at 20, Table 1.
[23] *Id.*
[24] *See* Synapse 2013 Carbon Price Forecast, at 20, Table 1.
[25] *Id.* at 3.
[26] *Id.* at 20, Table 1.
[27] *Id.* at 3.
[28] *Id.* at 20, Tbl. 1.

account. Of the 29 high case forecasts from utility planning processes in 2012-2013 that Synapse reviewed, all but three modeled prices higher than \$20/ton (American tons, 2012 dollars) after 2022.[29] The list includes Duke Energy Indiana, which has a carbon price in its reference case that begins at \$17/ton in 2020 and rises to \$50/ton by 2033.[30] In addition, the vast majority of the IRPs cited in the Synapse report assume that carbon prices will rise over time, in contrast to KPC's assumption that they will gradually decline.

B. The IRP Should Evaluate The Potential For A Carbon Price To Go Into Effect Earlier Than 2022.

KPC assumes that any price on carbon will not go into effect until 2022. IRP at 154-56. The IRP itself does not clearly identify the basis for this assumption, and KPC's data request responses offer varying rationales for this assumption. *Compare* Resp. to SC 1-32(a) (justifying 2022 start date based on the unlikelihood of near-term congressional action) *with* Resp. to SC 2-16(c) (justifying start date based on assumption that EPA regulations will not be implemented until 2022).

Regardless of its rationale, KPC's assumption that CO_2 will not be regulated until 2022 does not appear reasonable in light of recent developments that confirm the Obama Administration's intention to finalize and implement new GHG regulations for existing sources within the next two years. On June 25, 2013 (approximately six months before KPC submitted its IRP), President Obama announced a comprehensive plan to cut the carbon pollution that causes climate change and endangers public health. Noting that nearly 40 percent of this pollution is produced by the power sector, the President directed EPA to revise its proposal for carbon pollution standards for new power plants by September 20, 2013, to issue proposed standards, regulations, or guidelines addressing carbon pollution from existing power plants by June 1, 2014, and to finalize those limits by June 1, 2015.[31] Moreover, the guidelines for existing power plants must include a requirement that States submit their implementation plans to EPA no later than June 30, 2016.[32]

The President's announcement only confirmed and publicized a regulatory process that has been underway for years. In 2007, the Supreme Court held that carbon dioxide and other greenhouse gases are covered by the Clean Air Act's broad definition of "air pollutant" and that the EPA must decide whether greenhouse gases endanger public health.[33] After analyzing the available climate science, the EPA issued a formal finding that current and projected emissions of six greenhouse gases, including CO2, threaten the public health and welfare of current and

---

[29] *Id.* at 25, Fig. 8.

[30] *Id.* at 17, Fig. 2; *see also id.* at 16.

[31] *See* Presidential Memorandum -- Power Sector Carbon Pollution Standards (June 26, 2013), *available at*: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[32] *Id.*

[33] *Massachusetts v. Envtl. Prot. Agency*, 127 S. Ct. 1438, 1462–63 (2007).

future generations. This finding has since been upheld by the U.S. Court of Appeals for the District of Columbia Circuit.[34] That court also confirmed that the Clean Air Act requires the EPA to address greenhouse gas emissions under its stationary source permitting programs.[35] As confirmed by these decisions, Section 111 of the Clean Air Act requires the EPA to issue performance standards for air pollutants from both new and existing electric generating units.[36]

While the precise details of these rules are still uncertain, it is clear that utilities will need to meet new regulatory requirements (and their associated costs) in the near future. Therefore, at a minimum, KPC should have considered scenarios in which there is an effective price on carbon emissions earlier than 2022.

C. Recommendation Regarding Carbon Prices.

In order to help ensure that the risks of KPC's proposed fossil fuel heavy future and the benefits of pursuing low-carbon renewable and DSM options are fully accounted for, the Commission Staff should recommend that KPC evaluate in its resource planning a range of carbon prices similar to those set forth by Synapse.

IV. KPC FAILS TO ADEQUATELY EVALUATE ENERGY EFFICIENCY IN THE LONG-TERM AND UNDERESTIMATES THE POTENTIAL FOR INCREASED SAVINGS.

Energy efficiency is the least-cost, least-risk system resource. With an average levelized cost of roughly 2-3 cents per KWh, no emissions, and the ability to defer or avoid the need for generation and related infrastructure, energy efficiency programs are a critical part of a cost-effective utility resource mix that can lower system costs and risk, thereby reducing customer bills. As KPC observed in its IRP, energy efficiency is a readily deployable, relatively low cost, and clean energy resource that provides many benefits and reduces portfolio risk. (IRP at 88, 169). Moreover, as this Commission has observed, energy efficiency and other demand-side programs are critical resources that will "become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation." (Case No. 2010-00204, PSC Order September 30,2010, p. 14; *see also* Case No. 2010-00222, PSC Order, February 17, 2011, p. 15; Case No. 2008-00408, PSC Order October 6, 2011, p. 22).

The Commission's IRP rules require that utilities fully consider these critical resource options in developing their plans to meet their customers' power needs for the 15-year forecast period. Specifically, utilities must identify and describe existing DSM programs and estimate their load impact; account for existing and continuing DSM programs in their 15-year load forecast; describe DSM resources that are not already in place and are considered for inclusion in

---

[34] *See Coal. for Responsible Regulation v. Envtl. Prot. Agency*, 684 F.3d 102, 120–22 (D.C. Cir. 2012).
[35] *Id.* at 134–36.
[36] *See* 42 U.S.C. § 7411(b) & (d).

the plan; provide detailed information about each new DSM program, including the energy and peak savings and cost savings; and describe the criteria used to screen each resource alternative, including DSM. 807 KAR 5:05 Sections 7, 8. Moreover, the Commission has adopted an IRP standard that requires each electric utility to "integrate energy efficiency resources into its plans and [] adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options" and, in each IRP, "fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission's IRP regulation (807 KAR 5058)." (Case No. 2008-00408, PSC Order, July 24, 2012, p. 10). In so doing, the Commission has affirmed "its support for greater energy efficiency." (*Id.)*

Although KPC's IRP reflects increased DSM investment in the near term pursuant to the Mitchell Transfer Stipulation, the plan fails to adequately evaluate and pursue the energy efficiency resource during the planning period and, as such, fails to meet the requirements set out in the IRP standard. The Company projects that incremental savings from existing demand-side programs end roughly midway through the planning period, and annual growth of new efficiency programs remains flat from 2016-2022 and then declines. Overall, this leads to a declining rate of efficiency growth during the IRP period. Critically, and as mentioned above, the IRP fails to model any variation in the level of DSM savings in the five scenarios it evaluated, thereby foreclosing consideration of a higher level of DSM resources. Moreover, the Company does not sufficiently explain or justify the restriction it imposed to arrive at the selected amount in its Preferred Portfolio. This is especially troubling because the Company's projected savings remain low, in large part due to its assumptions that federal lighting standards eliminate much of the future cost-effective savings opportunities and its failure to account for the substantial savings opportunity in the energy-intensive industrial sector.

A. KPC's IRP Reflects a Commitment to Increase its Energy Efficiency Investment in the Near Term.

KPC projects the largest period of growth in terms of energy savings in the first three years of the planning period. This increase in DSM investment is the result of the Company's obligation to ramp up its annual spending on cost-effective DSM to $6 million by 2016. In the Mitchell transfer proceeding, Case No. 2012-00578, KPC, Sierra Club and Kentucky Industrial Utility Customers, Inc. entered into a Stipulation and Settlement Agreement ("Stipulation"), which provides, among other things, that:

> KPC agrees to increase its aggregate annual spending on cost-effective DSM and energy efficiency measures through Commission-approved DSM programs to $4 million in 2014; $5 million in 2015; and $6 million in 2016, 2017, and 2018. The Company also will seek to maintain a minimum spending level of $6 million for Commission-approved cost-effective DSM and energy efficiency measures in years after 2018.

October 7, 2013 Order, Appendix A, ¶12, Case No. 2012-00578. The Commission approved the Stipulation subject to several modifications, including the requirement that the Company seek prior Commission approval should it want to spend less than $6 million on DSM or energy efficiency programs after 2018, *id.* at Appendix B, ¶4, and the Company accepted the modifications on October 14, 2013.

In its pending application to amend its 2014 DSM Plan, which is before the Commission in Case No. 2013-000487, KPC seeks to comply with the first required increase in DSM investments. Specifically, the Company has proposed an expanded 2014 DSM portfolio with an estimated annual cost of $4,115,956 in direct program expenses, which represents a roughly 58% increase over 2013 direct program expenses. As Sierra Club noted in comments filed in that case, although KPC's 2014 projected energy savings remains low and further DSM program improvements and additions should be implemented, the Company's increased DSM investment is expected to enhance program participation in several existing programs in the near term, and is a step in the right direction. (Sierra Club Comments at 2, Case No. 2013-00487).

Recognizing the benefit of energy efficiency, the Commission has "strongly encourage[d] Kentucky Power to promote its DSM programs, educate applicable customers who would qualify for DSM program participation, and work to increase participation levels in its DSM programs."[37] The increase in DSM investments required by the Stipulation, and resultant expansion of certain existing programs and projected increase in new efficiency resources, provides KPC with an opportunity to accomplish all of these tasks and increase energy savings through DSM.

B. KPC Did Not Consider Higher Levels of Energy Efficiency and its Modeling Assumptions Constrain the Growth of this Resource in the Long Term.

Although KPC plans to ramp up its efficiency investment in the near term, the IRP fails to adequately integrate efficiency throughout the planning period. KPC evaluated two categories of DSM impacts in its IRP, "existing programs" and "future impacts." IRP at 85. The impacts of existing programs are embedded in the Company's load forecast whereas impacts from future programs are reflected as incremental savings estimated through modeling. *(Id.)*. While KPC projects the continued growth of the efficiency resource, the savings achieved from approved programs ends in 2022 and the growth of future programs flattens and then declines for most of the planning period. (*See* IRP at 61, 101 and Resp. to Staff 2-18, Attachment 2).[38]

KPC incorporates existing programs into its IRP by adjusting its load forecast to account for the program impacts. While forecasts must include the utility's estimates of existing and continuing demand-side programs, 807 KAR 5:058 Section7(3), existing resources should be allowed to increase based on need. Here, the Company did not specifically evaluate an expansion of current programs. (KPC Resp. to SC 1-11). This is surprising given the Company's position that the required increased investment in cost-effective DSM will come from existing

[37] *In re Application of Kentucky Power Co.*, KPSC Case No. 2011-00300 (Jan. 23, 2012).

[38] Although Figure 10 (IRP at 101) depicts steady incremental savings of 10 GWh in 2016-2028, Attachment 2 to KPC's response to Staff's Request No. 2-18 shows a steady decrease in incremental savings from 10 GWh in 2022 to 3 GWh in 2028.

programs, at least initially. (IRP at 18) ("In the near term, an expansion of current programs is the most practical way to adhere to the stipulated settlement agreement."). As the Company recognized, the impacts of the approved efficiency program are "relatively minor and do not significantly affect the long-term load growth rates." (IRP at 9). Thus, the Company should continue to look for ways to expand and improve current program offerings (beyond the pending proposal in the 2014 DSM docket) in addition to developing new programs.

The Company models future efficiency impacts from new programs using generic cost and impact data. Specifically, KPC utilizes an optimization model, Plexos® Linear Program, to develop a least cost resource plan that includes "the appropriate level" of additional demand-side resources. (IRP at ES-3). While modeling additional demand-side resources as "demand-side power plants," IRP at 138, can facilitate comparable treatment to supply-side alternatives, the Company appears to have assumed a single level of DSM resources in each of the five economic scenarios studies. (IRP at 100, 165). Higher levels of DSM were not evaluated. KPC asserts that "[o]ptimization under the five economic scenarios yielded five unique resource portfolios." (IRP at 161). However, this is not accurate with respect to DSM. Rather, KPC did not model *any* variation in DSM and, as a result did not conduct a comprehensive analysis of DSM options consistent with least cost planning recognized in the Commission's integrated resource planning standards. As discussed above, an IRP should consider a variety of resource portfolios and evaluate how they perform under different future conditions. *See* 807 K.A.R. 5:058 Section 8(2). In evaluating only one potential efficiency future, KPC's IRP falls short.

1. KPC's Assertion of "Realistically Achievable Levels" of Savings is not Adequately Supported.

KPC limited the addition of new efficiency resources – incremental to those included in the Company's load forecast – to what it called "realistically achievable levels" in each year. (IRP at 153). KPC asserts that efficiency resources "optimized in equal amounts under all five economic scenarios." (*Id.* at 100). The IRP includes a brief discussion of the "assessment of achievable potential," *id.* at 87, however, it is unclear from that discussion how the Company arrived at the ceiling it placed on new efficiency. As the Company admits in discovery, "[n]o assessment of EE potential was performed by or for the Company." (KPC Resp. to SC 1-14). Indeed, the Company has not performed a market potential study in the last five years. (Sierra Club Comments at 10, Case No. 2013-00487).

The Company's limited discussion of achievable potential underscores the need for a comprehensive assessment of the potential for efficiency savings in the KPC service territory. Fortunately, in its 2014 DSM Plan, the Company has proposed to conduct a market potential study to support its DSM strategy and resource deployment over a ten-year planning period. A potential study is a quantitative analysis of the amount of energy savings that exists, is cost-effective, and/or could be realized by implementing energy efficiency programs and policies.[39] Such studies have long been used as an effective tool to assess the efficiency resource and help develop program plans.[40] As noted in comments in the DSM docket, Sierra Club strongly supports the Company's proposal to conduct a market potential study.

2. KPC's Incremental Energy Efficiency Cost Assumptions Appear Unreasonably High.

KPC modeled additional energy efficiency resources based on measure and cost assumptions that it derived from Efficiency Vermont data. (IRP at 95). KPC "adapted" the Efficiency Vermont data to "fit the climate of Kentucky." (*Id.*). However, the result is incremental cost assumptions that appear to be out of step with the cost of efficiency across the country.

In Table 12 of the IRP (p. 108), KPC presents its assumptions of the costs of the additional efficiency resource options it considered. At the outset, it is important to note that the "$/first year savings" cost metric that KPC presents, also called "energy efficiency acquisition costs," represents the annual cost to administer an efficiency measure/program (or install a resource) divided by the first year of savings that the installed measures produce.[41] However, the savings for a given installed measure will continue to accrue throughout the life of the measure. By capturing only first-year savings, this metric of incremental efficiency costs does not reflect the full value of investments in energy efficiency and "thus misrepresent[s] the full benefits of efficiency."[42] As such, the cost per first-year savings is not comparable to the cost of generating electricity ($/MWh) and should not be used to compare demand- and supply-side resources.

Instead, for a comparison to supply-side resources, it is widely accepted that the levelized cost of energy efficiency (or electricity saved) over the measure life of savings should be used. This apples-to-apples comparison shows the clear benefit of efficiency. For example, two recent national studies found that energy efficiency has an average levelized cost of 2-3 cents per kWh,

---

[39] National Action Plan for Energy Efficiency, *Guide for Conducting Energy Efficiency Potential Studies*, prepared by Optimal Energy, Inc., p. 2-1, (Nov. 2007), available at http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.
[40] *Id.* at ES-1.
[41] *See* Maggie Molina, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs ("National Review of the Cost of Utility Energy Efficiency Programs"), p. 8, ACEEE (Mar. 2014), available at http://www.aceee.org/research-report/u1402.
[42] *Id.*

as compared to 6.5-14.5 cents per kWh for coal and 6-9 cents per kWh for natural gas.[43] This national trend is reflected in KPC's service territory. KPC's average cost of energy savings from 2009-2011 was 2.7 cents/kWh and its annual cost of savings decreased in 2012 and 2013 to 2.6 cents/kwh and 1.9 cents/kWh, respectively. (KPC Resp. to Staff 3-1, Docket No. 2013-00487).

KPC's "$/first year savings" cost assumptions for efficiency additions range from $158 - $1,654/MWh for commercial and $453-$1,156/MWh for residential measures, with total first-year cost of $873/MWh and $545/MWh, respectively. IRP at 108. KPC appears to have adjusted the Efficiency Vermont data to account for different heating and cooling days and for its assumptions regarding the limits of lighting measures going forward. (KPC Resp. to SC 1-19; Informal Conference). However, the resultant assumptions of incremental efficiency resource costs appear high in comparison to estimates from other states. For example, the four-year average (2009-2012) of electric efficiency program first-year acquisition costs from 20 states across the country is $230 per first-year MWh.[44] Efficiency Vermont (the source of the data KPC uses) delivered energy efficiency at an average cost of $330/first year MWh from 2009-2012.[45] This discrepancy in cost calls into question the reasonableness of KPC's assumptions[46] and the results of "optimization" of incremental efficiency resources.

C. KPC's Energy Savings Projections Are Far Below the Levels Being Achieved by Other Utilities.

KPC's failure to model different levels of DSM is compounded by the fact that the level of DSM KPC selected in its Preferred Portfolio, presumably as a result of its questionable incremental cost assumptions, is far below what has been or is expected to be cost effectively achievable by states and utilities throughout the country.

KPC's Preferred Portfolio is projected to include efficiency programs (excluding VVO and Distributed Solar) that save roughly 213 GWh, or 3.2% of retail sales, by 2028. (KPC Resp. to Staff 2-18). Averaged over the 15-year planning period, the annual incremental energy

---

[43] For efficiency estimates, see *id.* at p. 18-19, tbl 3 (based on 2009-2012 data); Megan A. Billingsley *et al.*, The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs, p. xi tbl.ES-1, Ernest Orlando Lawrence Berkeley National Laboratory (March 2014), available at http://emp.lbl.gov/publications/program-administrator-cost-saved-energy-utility-customer-funded-energy-efficiency-progr (based on 2009-2011 program administrator costs in 2012 $ and levelized gross savings). For supply-side estimates, *see* Lazard's Levelized Cost of Energy Analysis – Version 7.0 (2013), available at http://gallery.mailchimp.com/ce17780900c3d223633ecfa59/files/Lazard_Levelized_Cost_of_Energy_v7.0.1.pdf.

[44] National Review of the Cost of Utility Energy Efficiency Programs at 21-22. (2011$ per first-year net kWh at meter).

[45] *Id.*

[46] To the extent KPC's cost estimates include participant costs, such an estimate is not comparable to KPC's cost of supply-side resources because it captures costs that KPC does not incur.

savings amounts to roughly 0.21% of sales per year.[47] This level of energy savings is inadequate. As Sierra Club discussed in comments filed in the DSM docket, the experience of other regional utilities underscores not only the low levels of savings that KPC has achieved, but also the opportunity that the Company has for substantial increases in cost effective efficiency. For example, from 2009-2011, KPC saved roughly 0.13% total, or 0.02%, 0.03%, and 0.07% on an annual incremental basis at an average cost of 2.7 cents per kWh. During this same period, KPC's sister utility in the neighboring state of Ohio, AEP Ohio, achieved 2.4% savings, or 0.5%, 0.8%, and 1.1% incrementally, at a cost of approximately 1 cent per kWh.[48] AEP Ohio and the other investor owned utilities in Ohio are not alone in achieving 1% savings in 2011. In fact, Ohio is among 14 states that have achieved annual energy savings of 1% of retail sales or more in 2011.[49] In Michigan, electric utilities have, on average, exceeded the state's energy efficiency standard, which escalated from 0.3% in 2009 to 1% in 2012, in each of those years.[50] In 2012, the Michigan utilities achieved savings that were 125% of the 1% standard, at a cost of $20 per MWh of energy saved.[51] By contrast, KPC projects that in the 15-year planning period at issue here, the Company's energy efficiency programs will achieve, on average, only 1/5 of the 1% savings that is regularly being achieved or exceeded by utilities and states throughout the country.

The level of savings achieved in KPC's territory does not reflect the critical role energy efficiency is expected to play in Kentucky's energy future. Although Kentucky is not among the 26 states that have long-term binding energy efficiency savings targets,[52] DSM is a priority resource in the Commonwealth and, as such, Kentucky law provides for the three components of cost recovery to facilitate the successful implementation of utility-administered energy efficiency.[53] Specifically, pursuant to KRS 278.285(2) a proposed demand-side management mechanism can include (i) full program cost recovery; (ii) lost revenue recovery; and (iii) financial incentives. Sierra Club is supportive of properly designed cost-recovery for

---

[47] The annual incremental energy savings from existing and future efficiency programs can be derived from the information provided in KPC Resp. to Staff 2-18.

[48] Max Neubauer *et al.*, Ohio's Energy Efficiency Resource Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State, p.14, ACEEE (Apr. 2013), available at http://www.aceee.org/sites/default/files/publications/researchreports/e138.pdf.

[49] Annie Downs *et al.*, The 2013 State Energy Efficiency Scorecard, p. 31, ACEEE (Nov. 2013), available at
http://www.aceee.org/research-report/e13k.

[50] Michigan Public Service Commission, 2013 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs (Nov. 26, 2013), at 4, available at https://www.michigan.gov/documents/mpsc/eo_report_441092_7.pdf.

[51] *Id.* at 4, 6.

[52] ACEEE, State Energy Efficiency Resource Standards (EERS) (Feb. 2014), available at http://www.aceee.org/files/pdf/policy-brief/eers-02-2014.pdf.

[53] *See, e.g.*, National Action Plan for Energy Efficiency, Aligning Utility Incentives with Investment in Energy Efficiency (Nov. 2007) at ES-5, available at http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

EE and DR investments as well as incentive mechanisms with proper consumer protections tied to strong performance. Ensuring these mechanisms are beneficial to both KPC and its customers will likely result in lower bills for KPCs customers by capturing higher levels of available energy and demand savings.

The Governor's 2008 Energy Strategy[54] identified energy efficiency as the first strategy to ensure Kentucky's energy security, create jobs and maintain low-cost, reliable energy into the future, setting a goal of reducing 18% of Kentucky's projected 2025 energy demand through energy efficiency.[55] Further, in 2010, the Kentucky Department for Energy Development and Independence ("DEDI"), along with Midwest Energy Efficiency Alliance, utilities (including KPC), Sierra Club, and other stakeholders, participated in the Stimulating Energy Efficiency in Kentucky ("SEE KY") process to expand Kentucky's energy efficiency efforts, which has the "*ultimate goal of ... achieve[ing] one percent annual electric savings in Kentucky through energy efficiency*" by 2015.[56] The SEE KY Action Plan for Energy Efficiency, which was developed through two years of stakeholder engagement and is the primary means of achieving the efficiency goals in the Governor's Energy Strategy and the SEE KY process, outlines annual electric savings goals ramping up from 0.2% in 2012 to 1% in 2015 and each year thereafter through 2025.[57] KPC remains far from achieving the levels outlined in the Action Plan.

D. KPC Must Continue to Pursue Cost-Effective Savings Opportunities.

Although KPC has made progress in terms of achieving efficiency savings, the Company unreasonably limits the growth of the efficiency resource going forward. KPC projects a limited role for efficiency going forward in large part due to the phasing in of federal lighting standards under the Energy Independence and Security Act of 2007 (EISA), which began in 2012. (IRP at 81-82). As KPC notes, a substantial amount of utility efficiency savings comes from lighting-focused programs (e.g. residential and commercial lighting programs). (*Id.*). A significant

---

[54] The Governor's Energy Strategy, *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence*, is available at http://energy.ky.gov/resources/Pages/EnergyPlan.aspx.

[55] *See* Governor's Energy Strategy, *Strategy 1: Impove the Energy Efficiency of Kentucky's Homes, Buildings,*
Industries and Transportation Fleet, available at
http://energy.ky.gov/Energy%20Plan/Strategy%201-%20Improve%20the%20energy%20efficiency%20of%20Kentucky%27s%20homes,%20buildings,%20industries%20and%20transportation%20fleet.pdf.

[56] DEDI, Stimulating Energy Efficiency in Kentucky: Kentucky's Action Plan for Energy Efficiency ("SEE KY Action Plan"), p.3 (May 15, 2013), http://energy.ky.gov/Programs/Documents/Action%20Plan%205-15-2013.pdf (emphasis in original).

[57] SEE KY Action Plan at 55.

amount of cost effective savings potential remains for lighting technologies, including CFLs, even after accounting for federal efficiency standards.[58]

KPC does not have an estimate of the socket saturation rate for CFLs in its service territory. (KPC Resp. to SC 1-12). However, inefficient light bulbs still occupy more than 70% of the lighting sockets in the U.S. and federal standards alone will not eliminate inefficient lighting.[59] Moreover, the price for light-emitting diode (LED) bulbs continues to decline.[60] Thus, a substantial amount of energy savings from lighting has not yet been realized.

As baselines increase in lighting and other technologies, KPC should continue to explore emerging technologies and different marketing approaches for existing measures. For example, in response to increasing baselines and other challenges in the CFL market, Efficiency Vermont developed new approaches to increase consumer participation in the residential CFL market.[61] Efficiency Vermont launched a specialty CFL campaign and new collaboration with food banks targeting low-income customers, which resulted in a combined 15% increase in socket saturation of CFLs. As discussed in the IRP, KPC should also evaluate ways to expand its program offerings in the commercial sector. (IRP at 102).

Other regions of the country with a long history of substantial efficiency savings continue to save energy at high levels through efficiency programs – and plan to do so long into the future – despite the phase out of the least efficient light bulbs. The most recent power plan from the Northwest Power and Conservation Council, for example, projects that cost-effective, available energy efficiency will meet 85% of the region's growing power needs through 2030.[62] Although KPC and other utilities will need to adapt to changing baselines, significant cost-

---

[58] *See, e.g.*, Dan York *et al.*, Frontiers of Energy Efficiency: Next Generation Programs Reach for High Energy Savings, ACEEE (2013) p.5, http://www.aceee.org/sites/default/files/publications/researchreports/u131.pdf ("Frontiers of Energy Efficiency"); Seth Craigo-Snell, Is it Still Cost Effective to Promote Light Bulbs? Should We?, Applied Proactive Technologies, Inc., Presented at the International Energy Program Evaluation Conference (2013); Bonn, The Once and Future CFL Efficiency Vermont, (2013), http://efficiencyvermont.com/docs/about_efficiency_vermont/whitepapers/White_Paper_Bonn.pdf.

[59] Frontiers of Energy Efficiency at 30; U.S. EPA, Next Generation Lighting Programs: Opportunities to Advance Efficient Lighting for a Cleaner Environment (2011), pp. 1,11 http://www.energystar.gov/ia/partners/manuf_res/downloads/lighting/EPA_Report_on_NGL_Programs_for_508.pdf

[60] *See, e.g.*, U.S. Energy Information Administration, LED Bulb Efficiency Expected to Continue Improving as Cost Declines (March 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=15471#.

[61] Lara Bonn, A Tale of Two CFL Markets: An Untapped Channel and the Revitalization of an Existing One, Efficiency Vermont, (2012), available at http://www.aceee.org/files/proceedings/2012/data/papers/0193-000197.pdf.

[62] Sixth Northwest Conservation and Electric Power Plan, http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf.

effective savings opportunities remain. KPC should continue to evaluate additional programs, measures and delivery options in an effort to increase cost-effective efficiency saving. This is particularly important in light of the Company's "even more-pressing *energy* position prospectively." (IRP at ES-8) (emphasis in original).

E. KPC Should Explore Opportunities to Pursue Industrial Efficiency Programs.

KPC projects energy savings from existing and future programs targeting the residential and commercial sectors. KPC does not, however, account for the most energy intensive customer-sector, industrial customers. The industrial sector represents roughly 44 % of all energy consumption in Kentucky and 43% in the KPC service territory. Yet, KPC does not currently offer any programs to its industrial customers and does not plan to offer any during the IRP planning period. The Company should begin now to explore efficiency opportunities in the industrial sector and work to develop a program to offer this critical customer sector.

Industrial energy efficiency generally has the most cost-effective potential of all of the sectors. Specifically, industrial efficiency resources can be half the cost of resources in other sectors, in terms of dollars per kWh saved, and offer higher benefit-to-cost ratios than measures in the residential and commercial sectors.[63] For this reason, investing in industrial energy efficiency should be a priority for resource planning and acquisition purposes, and for providing ratepayer benefits across customer sectors.[64]

The Company has not discussed efficiency programs with its industrial customers since it discontinued industrial programs in 1998. (KPC Resp. to Staff 2-8). However, stakeholder feedback during the SEE KY process indicated that the industrial community is underserved with respect to energy efficiency programs and services.[65] In light of the critical role the industrial sector plays in Kentucky's economy and KPC's electric resource planning, efficiency opportunities must be evaluated. KPC's obligation to provide adequate, efficient and reasonable service to customers in its service territory, *see* KRS 278.030(2), can be accomplished through the provision of low-cost, reliable resources, like energy efficiency. As a resource that lowers system cost and customer bills, efficiency should be offered to all customer sectors, including industrials.

Moreover, while KRS 278.285 permits "individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs," this opt out provision does not preclude a utility from offering an industrial DSM program. In fact, K.R.S. 278.285 is premised upon the notion that utilities will offer industrial customers DSM programs (i.e. "*in lieu*

[63] Anna Chittum, Follow the Leaders: Improving Large Customer Self-Direct Programs, ACEEE, p. 5 (2011), available at http://www.aceee.org/research-report/ie112.
[64] *Id.*
[65] SEE KY Action Plan at 38.

of measures approved as part of the utility's demand-side management programs") and some Kentucky utilities, such as EKPC and Big Rivers, offer industrial programs to their customers.[66]

As discussed in the DSM case, KPC's planned market potential study "will review *all customer sectors* within the Company service territory to access the market potential for implementing cost-effective DSM programs." (Sierra Club Comments at 10, Case No. 2013-00487, quoting KPC's Response to Sierra Club's Initial Request No. 11) (emphasis added). Sierra Club supports the Company's proposal to study all customer sectors, a critical component of a comprehensive study, and the Company should work with stakeholders to develop programs to capture the potential available in the industrial sector.

V. KPC'S IRP FAILS TO ADEQUATELY CONSIDER DEMAND RESPONSE AS A RESOURCE.

The IRP also contravenes Kentucky's regulatory requirements by failing to sufficiently assess the potential to deploy cost-effective demand response within KPC's territory. 807 KAR 5:058, Section 8(2), mandates that "[t]he utility shall describe and discuss all options considered for inclusion in the plan including... (b) conservation and load management or other demand-side programs not already in place." KPC's failure to incorporate cost-effective demand response program options into its planning process is unjustified in light of significant potential benefits to ratepayers. As a result, KPC has not demonstrated that the IRP "adequately and fairly evaluated" all resource options. *See* Staff Report, Case No. 2012-00149 (outlining standards applied by staff in assessing the reasonableness of EKPC's IRP).

A. Demand Response Can Supply Quantifiable and Substantial Benefits Within KPC's Territory.

Demand response can provide many important benefits to both the utility and its customers. As KPC itself acknowledges, a robust demand response program can forestall the need to construct additional capacity. IRP at 90. Moreover, demand response can serve the same function as other non-traditional supply resources that benefit a utility because they are "not subject to the same price volatility as conventionally fueled units [and so] have a stabilizing impact on overall system costs, acting as a hedge against volatility."[67] Demand response can also provide price mitigation and improve system stability, increase grid reliability, and significantly reduce operating system costs, particularly by reducing use of the highest-cost generating units.[68]

---

[66] *Id.*

[67] See KPC Resp. to Staff 2-3. While the request referenced biomass and utility-scale solar, the same principle applies to energy efficiency and demand response.

[68] DOE Oak Ridge National lab, "Assessment of Industrial Load for Demand Response across US Regions of the Western Interconnect," Sept 2013; NREL, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," Dec. 2013.

For example, in one study of a Colorado system, the National Renewable Energy Laboratory found that implementing demand response led to $7.9M in operational savings, higher than the revenue that the demand response could earn in a market setting.[69] In addition, because demand response can be deployed more flexibly than traditional supply-side resources, it can better complement renewable energy development.[70] These benefits and others highlight the importance of evaluating demand response on a level playing field with supply-side resources in the IRP process.

B. The IRP Fails to Quantify the Cost Effective Demand Response Potential from its Major Sectors.

Despite KPC's general acknowledgement of the benefits of demand response, the IRP makes little effort to assess the availability of cost effective demand response within its territory, abrogating KPC's responsibility to adequately explore all resource options. Of the utility's total 2012 internal energy requirements of 7,155 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 31.3%, 18.9%, and 42.8%, respectively. IRP at 5. A properly conducted IRP should thus evaluate the cost-effective demand response potential from all three major sectors. Instead, KPC conducted only a limited, back-of-the-envelope calculation of industrial demand response potential, and no analysis of its residential and commercial sectors. IRP at 91-92. In its industrial "demand response potential survey," KPC tallied participants in AEP affiliate companies' territories to determine the percentage of their load they committed as demand response to PJM. IRP at 91-92. From this brief survey, KPC concludes that its own territory may contain approximately 97 MW of demand response potential, including 24 MW from the mining industry[71] and 67 MW from other large industrials. IRP at 92. Contrary to KPC's assertion, however, this back-of-the-envelope calculation does not qualify as an analysis of demand response "potential" for KPC as no information is presented regarding whether the AEP affiliates are achieving their potential for demand response or whether the levels of demand response being achieved constitute all of the cost-effective demand response that is reasonably achievable.

While KPC's assessment of industrial demand response is incomplete at best, an assessment of its residential and commercial demand response potential is missing altogether. KPC provides no justification for failing to evaluate the demand response potential of its

[69] NREL, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," at viii, Dec. 2013.
[70] NREL, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," Dec. 2013.

[71] Mining accounts for 10.2% of KPC's retail sales and 7.7% of its peak internal demand, and so represents a large potential source of savings. KPC Resp. to Staff 2-5. A study by the U.S. Department of Energy demonstrates that there are significant cost-effective energy efficiency savings available from mining operations, including coal, minerals and metals mining. US Department of Energy, "Mining Industry Energy Bandwidth Study, Industrial Technologies Program," June 2007, pp. 21-24.

residential sector, but instead only summarily claims that demand response resources in its territory are limited to commercial or industrial demand response. IRP at 91. While KPC does not have an advanced metering network, KPC did conduct a pilot load management program for its residential sector; but the IRP does not explain why the pilot was dismantled or summarize the pilot's findings. *See* KPC's Response to Staff's Initial Request Nos. 16 and 21. Elsewhere in the IRP, KPC states only that residential demand response "may be considered in the future." IRP at 97. Similarly, with respect to small commercial and industrial loads, KPC admits that the "introduction of a tariff that allows for the aggregation of smaller commercial and industrial loads would likely result in meaningful resources becoming available," but nonetheless decided not to evaluate these resources "due to Kentucky Power's current reserve margin." IRP at 97.

These brief and conclusory remarks fall far short of a fair evaluation of demand response potential, and do not provide the information needed to weigh it against other resource options. This failure makes it impossible to evaluate whether KPC has in fact selected the least-cost, least-risk approach, undermining the usefulness of the IRP process. As such, KPC should be required to give fair and adequate consideration to this potentially valuable resource, through a comprehensive study of the cost-effective demand response potential of all three of its customer sectors.

C. The IRP Fails to Incorporate Any Demand Response Programs into KPC's Resource Portfolio.

Given KPC's failure to adequately evaluate the cost-effective demand response potential for any of its major customer sectors, it is unsurprising that KPC does not include a single demand response program in its resource plan. KPC validates its planning decision by claiming that, "[g]iven Kentucky Power's current and expected capacity position within PJM, it is not necessary to aggressively pursue all available demand response at this time." IRP at 92; *see also* IRP at 99 (alleging "little incentive to offer such enrollment program in the near-term" given current capacity length). Even if KPC is in fact long on capacity at present, however, this does not mean KPC cannot derive substantial economic benefit from investing in demand response now. Not only would investment in demand response assist KPC in diversifying its resource portfolio, but it could also serve to displace higher-cost supply-side resources and provide significant operational benefits, among others.

D. Recommendation Regarding Demand Response.

Because KPC failed to adequately and fairly assess cost-effective demand response potential in its territory, the Company should be required to complete a comprehensive demand response potential study that examines a variety of demand response program structures for all customer classes, and that analyzes market and policy barriers to increased investment in this potentially cost-saving resource.

VI. KPC SHOULD BID ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES INTO THE PJM BASE RESIDUAL AUCTIONS.

Despite the shortfalls in KPC's evaluation of all EE and DR potential within its resource plan, KPC is currently investing additional dollars in its portfolio of efficiency programs. Both its current programs and future programs, which should become more aggressive and effective, have the potential to help reduce energy bills and avoid risk. In order to maximize this potential, KPC must utilize the peak savings from its energy efficiency ("EE") and demand response ("DR") programs in its capacity plans by bidding such savings into PJM's Base Residual Auction ("BRA"). Utilizing these coincidental peak savings will provide the greatest protection for all KPC customers from unnecessary cost increases, while at the same time achieving several other desirable outcomes, notably the creation of more Kentucky jobs and reducing the potential environmental impacts caused by the provision of electricity service to KPC customers at the lowest possible cost. By bidding EE and/or DR peak savings into the PJM auction, KPC could also generate revenue that can be used to finance additional cost-effective EE and DR programs.

To date, KPC has declined to evaluate the benefit to its customers of utilizing the peak demand savings from EE or DR programs into the PJM auction.[72] The Companies' decision, if unchanged, will have at least three adverse financial consequences for its customers:

1. KPC customers will forgo a substantial revenue stream from an investment for which they are committed to pay;

2. KPC's customers will pay much more than they would otherwise need to pay because they will have to acquire capacity that will be redundant with the capacity savings produced by KPC's efficiency programs; and

3. KPC will undervalue the benefit to its customers of pursuing additional EE and DR savings, and will leave on the table revenue that could be used to help fund such programs.

1. Peak Demand Benefits from Efficiency Programs.

In addition to the direct energy benefits resulting from efficiency programs, there are also capacity price reductions that stem from reductions in peak demand. However, at least in the short term, the full value of the peak demand reduction benefit will only be realized if the savings are accounted for in KPC's capacity planning and bid into the PJM auction.

It is important to emphasize that the value of these peak demand savings is significant. PJM allows efficiency savings to receive capacity payments for four years.[73] The revenue earned from these capacity auctions can then be used to offset the cost of implementing energy efficiency programs and can have a profound price lowering impact on the total cost of energy

[72] KPC Resp. to Staff 1-22(b).
[73] See PJM Manual 18b

efficiency programs. When considering a bid into PJM, it should be emphasized that most efficiency measures last much longer than a year and PJM allows efficiency measures to receive capacity payments for up to four years. After this time, PJM assumes that the efficiency savings have been reflected in load forecasting, and are therefore automatically built into capacity expectations. Bidding these planned resources into the BRAs at PJM results in significant revenue for customers to use to offset efficiency program costs and/or to finance additional cost-effective EE and DR programs.

2. The Commission Staff and Commissions in Other States Have Recognized the Value of Utilities Bidding Efficiency Resources Into the PJM Auction.

The Commission Staff have already recognized the value of utilities bidding efficiency resources into the PJM auctions. In particular, with regards to the 2012 IRP filed by East Kentucky Power Cooperative ("EKPC"), the Staff explained that EKPC should "continue to study and pursue all cost-effective energy-efficiency and peak-demand reductions achievable so that all benefits of PJM integration can be realized" and included "EKPC bidding its peak savings from DSM into the PJM capacity markets" in such benefits.[74]

The Staff's finding regarding EKPC is supported by a recent decision of the Public Utilities Commission of Ohio ("PUCO) to adopt its Staff's recommendation and require the First Energy Electric Distribution Utilities ("FirstEnergy") to bid 75% "of the planned energy efficiency resources for the 2016/2017 delivery year under their program portfolio."[75] PUCO found that such bidding would "substantially benefit ratepayers by lowering capacity auction prices and reducing Rider DSE costs." PUCO ordered such bidding after careful consideration of any "uncertainty of future PJM BRAs, including resources planned, but not yet installed, unknown clearing prices for capacity in incremental auctions, risk of PJM penalties for obligations cleared, but not delivered, and other uncertainties."[76] PUCO stated that by adopting the Staff's recommendation[77] and requiring the Companies to bid 75% of the planned energy efficiency resources it was striking an appropriate balance between benefiting ratepayers and mitigating the Companies' risk.[78] Although this bid requirement was required for only the 2016/2017 planning year, PUCO stated that, "Thereafter, the Commission may issue an order addressing the Companies' bids for the remaining two planning years."[79]

---

[74] EKPC 2012 IRP Staff Report at p. 30 and n. 49.
[75] *In the Matter of the Application of the Cleveland Electric Illuminating Company*, Pub. Util. Comm. No. 12-2190-EL-POR, Opinion and Order at 20 (March 2, 2013). In addition, several parties recommended a more substantial PJM auction bid.
[76] Id.
[77] Staff noted that bidding in 75% of planned resources would mitigate any potential "performance or quantity risks." Staff Initial Brief at 10-11 (November 20, 2012).
[78] Id. at 20-21.
[79] Id. at 20-21.

In a July 17, 2013 Entry on Rehearing, PUCO reiterated its Order that the Companies bid in 75% of all eligible, planned resources into the auction.[80] PUCO denied[81] FirstEnergy's Application for Rehearing that the requirement to bid in planned resources was unjust and unreasonable because, *inter alia*, of the perceived risk such a bid posed to customers.[82]

3. KPC's Status as an FRR Should Not Hinder Its Ability to Bid EE and DR Resources Into the PJM BRA

Fixed Resource Requirement ("FRR") status should not hinder KPC's ability to bid such savings into the PJM auction, as the company has acknowledged.[83] To the extent that KPC demonstrates that its status as an FRR restricts the amount of EE and/or DR that it can bid into the PJM auction, such restriction should be factored into the company's annual decision as to whether to continue as an FRR, or whether to elect to be an RPM company.

4. The Commission Should Implement a Process to Ensure that KPC Bids 75% of its Efficiency Savings Into the PJM Auction.

While KPC should be required to incorporate the bidding of EE and DR savings into PJM as part of its next IRP, the company should not wait the three years until that filing to pursue the significant benefits that can result from such bidding. Instead, the Commission should implement a process now to ensure that KPC is effectively bidding at least 75% of all planned efficiency resources into the annual BRAs.

An important component of doing so is for Kentucky Power to provide a general description of its anticipated bid structure to the Commission and the DSM Collaborative. This anticipated bid structure should be reviewed annually by the Commission and interested parties prior to submission to PJM in order to ensure that the Company's customers accrue the additional, potential benefits from their investments in energy efficiency programs through the PJM auction process. Any anticipated bid structure must seek to obtain the potential energy efficiency and peak demand reduction resources that are installed, planned or otherwise expected to be generated for the time period covered by the auction.

As part of the bidding process, KPC should be provided with full recovery of PJM monitoring and evaluation costs and any applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. Accordingly, any of the Companies' perceived risks would be greatly diminished, if not eliminated, and the potential benefits to customers would be appropriately sought through participation in the PJM auctions.

---

[80] *In the Matter of the Application of the Cleveland Electric Illuminating Company*, Pub. Util. Comm. No. 12-2190-EL-POR, Entry on Rehearing, at 4 (July 17, 2013).
[81] Id.
[82] Id. at 2. The Commission also rejected the assertion that the bid should be diminished or eliminated due to legislative activities (Entry at ¶8).
[83] KPC Resp. to SC 1-43, Case No. 2012-00578.

A second important component for ensuring effective bidding of efficiency resources into the PJM auction is for the Commission to develop a process for KPC to receive a share of any revenue returned from bidding efficiency resources into the auction as a mechanism to incentivize bids above 75% of all planned resources, while also mitigating any potential risk of bidding.[84] For example, In its Entry on Rehearing in the FirstEnergy proceeding discussed above, PUCO chose to "better align the interests of the electric distribution utility and the interests of its customers in support of the implementation of energy efficiency and peak demand reduction programs" by adopting a Staff recommendation to split the proceeds between the FirstEnergy EDUs and their customers.[85] The Commission proposed and adopted a pilot program to split auction proceeds 80/20 between the Companies' customers and FirstEnergy.[86] A similar structure for KPC would entitle the Company to 20% of any revenue obtained from successfully bidding greater than 75% of all planned energy efficiency and demand response resources into the PJM auctions while 80% of the revenue would be used to offset the costs to customers of implementing the energy efficiency and demand response programs.

5. Conclusion Regarding Bidding Efficiency Into the PJM BRA.

In order to save customer money, minimize risk, and maximize investment in cost effective energy efficiency and demand response, KPC should be required to factor bidding of efficiency savings into the PJM BRA into its resource planning, and the Commission should implement a process to ensure that KPC bids at least 75% of its efficiency savings into the auction.

VII. THE COMPANY FAILED TO ADEQUATELY CONSIDER THE VALUE OF SOLAR RESOURCES.

Solar resources can play a significant role in delivering low cost and reliable power to KPC customers. In addition to the fuel-free energy it provides, solar has a natural coincidence with peak summer demand; can avoid transmission capacity costs and line losses through smaller systems sited on the distribution grid closer to load, is scalable and modular, among other attributes. KPC appears to generally recognize the range of benefits and costs of utility- and distributed-scale solar generation in the IRP. Despite these substantial benefits, however, the Commonwealth's potential for solar energy development has remained almost entirely untapped to date.

---

[84] See, e.g., *In the Matter of the Application of the Cleveland Electric Illuminating Company*, Pub. Util. Comm. No. 12-2190-EL-POR, Opinion and Order at 30 (March 2, 2013) (concurring opinion of PUCO Commission Slaby explaining that incentives for the utility will help overcome any risks of bidding efficiency savings into the PJM auction).

[85] Id. at 5.

[86] Id. at 4-5.

The failure to realize the potential of solar in Kentucky and in KPC's service territory more specifically stems from the absence of a robust analysis of solar resource value. In order to properly compare solar and other alternative resources in an IRP, each resource must be valued correctly. As summarized below and discussed in detail in the attached technical comments from Karl R. Rábago of Rábago Energy LLC (Exhibit B), which is incorporated herein by reference, KPC does not adequately assess the value of solar energy resources, particularly distributed solar generation. Instead, KPC offers an incomplete analysis that artificially constrains the amount of utility scale solar that can be modeled and ignores the full suite of benefits distributed solar generation provides. The result is an inaccurate assessment of the value of the solar resource and underrepresentation of solar generation in the Company's Preferred Portfolio.

Although KPC recognizes that the costs of solar are falling rapidly and concludes that solar costs are expected to become "nominally flat" on or about 2020, the Company does not model any utility-scale solar until 2020, at which point it limits the amount of solar that can be added to 10 MW per year. This 10 MW ceiling amounts to a flat annual growth rate of about 0.33 percent. The Company cites no basis for these and other solar-related assumptions, nor does it propose any alternative growth scenarios in any of its analysis. As discussed in the Rábago report, Exhibit B at p. 7, the modeling results suggest that the constraints and assumptions imposed on utility-solar in the model limited the amount of solar selected.

KPC concludes that distributed solar generation (which represented all distributed generation resources via net metering in the Company's analysis) is uneconomic from the utility's perspective. (IRP at 98, 102). However, a careful review of the IRP and the responses provided by the Company to information requests shows that the only benefits KPC quantified were assumptions of wholesale energy and generation capacity value in PJM, ignoring several significant benefits, as discussed in the Rábago report, Exhibit B at pp. 5-7. Moreover, KPC assumes, without explanation, that the rate of distributed solar adoption decreases as solar prices fall.

KPC's analysis of utility and distributed solar generation contains several questionable and largely untested assumptions and ignores several benefits that these resources provide and the vast amounts of solar data available from similar locations across the United States. In short, the analysis is incomplete and insufficient, and falls short of the requirements contained in the IRP rules, as the analysis cannot be considered a real "assessment of [a] potentially cost-effective resource option," nor can KPC show that it has fully considered potentially lower cost, lower risk resources when it has ignored significant benefits of such resources. 807 KAR 5:058 Section 8(1).

Consistent with the recommendations discussed in the Rábago report, Exhibit B at pp. 11-13, KPC should develop a comprehensive value of solar methodology and assessment that identifies and characterizes the value attributes of solar energy generation through a third-party administered process that engages solar energy. The results of this process should be reported to the Commission on or before December 31, 2014. Additionally, KPC should work with Staff and interveners in this proceeding to develop a more robust set of portfolio alternatives or scenarios, sensitivity analyses, and risk assessment analyses to be used in the next IRP. Finally, KPC should develop a program aimed at supporting the development and use of cost-effective distributed solar generation, which can leverage the benefits of net energy metering, encourage the creation of new jobs, put downward pressure on rates, strengthen the grid, and overcome commercialization barriers that exist today.

VIII. THE IRP FAILS TO FAILS TO PROVIDE FOR CONTINUING INVESTMENTS IN WIND POWER.

One of the strong points of the IRP is its assumption that KPC will add 100MW of wind capacity in 2015. IRP at ES-3, 171. This assumption arose out of the settlement agreement in Case No. 2012-00578, in which KPC committed to issuing a non-binding Request for Proposals ("RFP") for 100MW of wind power, with the results to be incorporated into this IRP. Order, Case No. 2012-00578, Appx. A ¶19 (Oct. 7, 2013). KPC received numerous responses to its RFP, *id.* at 153-54, so the Company should little difficult meeting this assumption.

Pursuing wind projects like this one is a crucial component in developing a resource portfolio that provides a "reliable supply of electricity . . . at the lowest possible cost." 807 KAR 8:058 Section 8. As the IRP acknowledged, "the addition of *wind*, solar, and customer and grid energy efficiency resources serve to reduce overall costs." IRP at 170 (emphasis added). Unfortunately, KPC's preferred portfolio fails to fully realize these potential cost savings because – other than the wind project KPC is already pursuing – the IRP assumes that no additional wind capacity will be added. *See id.* at ES-7, 3 (assuming that 100MW of wind capacity will be added in 2015, but no further wind capacity will be added during 2016-2028). KPC offers no explanation for why it failed to pursue additional wind projects for the last 13 years of the planning period. KPC's failure to consider additional wind capacity is all the more puzzling because, despite assuming the expiration of the federal production tax credit, KPC's cost assumptions show a continuing decline in the cost of wind power throughout the 15-year period. *See* IRP at 135.

The declining price of wind power is already leading utilities throughout the country to ramp up their acquisition of wind resources. For example, a recent U.S. Department of Energy ("DOE") wind technologies market report found that in 2012, 13.1 GW of new wind energy capacity was installed in the US, accounting for 43% of all new energy capacity installed, and that wind power produced more than 12% of energy generation in nine states.[87] The DOE report also found that the average levelized prices for long-term wind energy power purchase agreements dropped to $40 per MWh in 2011-2012. Alabama Power executed a long-term wind PPA in 2011 that will deliver energy at a price that is "expected to be lower than the cost the Company would incur to produce that energy from its own resources (i.e., below the Company's avoided costs), with the resulting energy savings flowing directly to the Company's customers."[88] Similarly, Southwestern Electric Power Company entered into a contract for wind

[87] U.S. Dept. of Energy, 2012 Wind Technologies Market Report (Aug 2013), at iv to ix (*available at* http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf).
[88] Order, Alabama Public Service Commission, Docket No. 31653 (Sept. 9, 2011) at 3

power at a price that is lower than their current average cost of energy.[89] American Electric Power's Oklahoma affiliate – the Public Service Co. of Oklahoma – "originally planned to purchase up to 200 megawatts of wind energy but contracted for an additional 400 megawatts after seeing pricing opportunities that will lower utility costs by an estimated $53 million in the first year and even more thereafter."[90]

The Commission Staff should note KPC's failure to explain its decision to not pursue additional wind resources after 2015, and should recommend that KPC fully evaluate and pursue cost-effective wind opportunities in its resource planning.

IX. KPC'S LOAD FORECAST LIKELY OVERESTIMATES FUTURE DEMAND FROM THE COAL MINING SECTOR.

One of the central requirements of an IRP is that it provide an accurate forecast of the load expected over the 15-year planning period. *See* 807 KAR 8:058 Section 7(3) (for each year of the planning period, utility must "provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system"); *see also id.* Section(7)(d) (forecast must discuss "[t]he utility's treatment and assessment of load forecast uncertainty"); Section(7)(e)2 (forecast must discuss the extent to which the utility considered "[c]hanges in population and economic conditions in the utility's service territory and general region"). Accurate load forecasts are not only an express requirement of the IRP rules, but they are also necessary to ensure that the utility's resource portfolio addresses customers' needs in a cost effective manner. Overestimating a utility's load could skew the IRP modeling, prompting a utility to overinvest in generating capacity and exposing ratepayers to unnecessary costs.

The IRP appears to overestimate future energy demand from the coal mining sector, which has likely resulted in an overestimate of KPC's total demand over the planning period. It is well-documented that the coal mining sector within KPC's service territory has decreased significantly in recent years. The IRP acknowledges these steep declines, noting that over the last four years "mining sector sales have been sharply reduced." IRP at 15. KPC's sales to the mining sector certainly bear this out, with energy sales to the mining sector having fallen continuously since 2009. Staff 1-5 Attachment 1. Demand from this sector declined at an annual rate of between 1.8% and 5.7% prior to 2012, and has seen declines of greater than 10% since then. *Id.*

---

[89] Direct Testimony of Sandra S. Bennett for Southwestern Electric Power Company, http://www.apscservices.info/pdf/13/13-033-u_4_1.pdf, at 7 ("[T]he combined impact of the new wind REPAs is expected to lower SWEPCO's projected overall energy supply cost to customers. SWEPCO estimates the decrease will average approximately $28.7 million over the 10 year period of 2013 to 2022.").

[90] *See* http://m.tulsaworld.com/business/aep-pso-agrees-to-buy-wind-energy-citing-substantial-savings/article_5b273a3a-9a91-59cc-a984-38af5b2e7923.html?mode=jqm.

Despite these ongoing (and accelerating) declines, the load forecast assumes that energy use from the coal mining sector will remain steady throughout the IRP planning period and beyond, with only minor changes to the sector expected all the way through 2042. *Id.* This assumption is at odds with recent historical experience, which suggests that the sector's energy use will continue to decrease throughout the planning period, and also runs counter to current forecasts of the Eastern Kentucky coal mining sector.

At the Informal Conference, KPC clarified that its forecast of the sector's future energy demand was based on regional Energy Information Administration ("EIA") data, rather than data specific to Eastern Kentucky. *See also* IRP at 40 (noting that mining forecast was produced through "a model relating mine power energy sale to regional coal production").[91]

The IRP's use of that regional data is likely why the load forecast is skewed, thereby predicting a higher demand from the coal mining sector than KPC should reasonably expect. Both historical data and future projections indicate that Eastern Kentucky's coal mining sector is decreasing much more quickly than other parts of the eastern U.S., including the Illinois Basin, western Kentucky, and other parts of Appalachia. To take just a few examples:

- A 2013 report issued by Kentucky's Energy and Environment Cabinet ("EEC") found that in 2012 coal production in Eastern Kentucky decreased 26.7% from 2011, while Western Kentucky coal production increased by 2.5%.[92] These trends are mirrored by EIA data, whose figures are slightly different, but which also estimated a significant decrease in Eastern Kentucky coal production in 2012 while Western Kentucky production increased.[93]

- A January 2014 report issued by EEC noted that in 2013, Eastern Kentucky coal production decreased by 19.2%, while Western Kentucky production dropped only 2.7%.[94]

- Citing EIA data, a 2012 report by Mountain Association for Community Economic Development ("MACED") noted "that Central Appalachian coal production is expected to decline from 175 million tons in 2012 to 77 million tons in 2020," and that "future coal production in eastern Kentucky could decrease even more

---

[91] At the Informal Conference, KPC further clarified that the forecasts had been generated using information up through the first quarter of 2013.
[92] EEC, *Kentucky Coal Facts* at 4 (13 ed. June 20, 2013), *available at*: http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Coal%20Facts%20-%2013th%20Edition%20(2013).pdf.
[93] *See* EIA, *Annual Coal Report 2012* at 2 (Dec. 2013), *available at*: http://www.eia.gov/coal/annual/pdf/acr.pdf.
[94] EEC, *Kentucky Quarterly Coal Report: October to December 2013* at 2-3 (Jan. 2014), *available at*: http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q4-2013%20year%20end).pdf.

dramatically than Central Appalachia's already steep decline." Using EIA data, the MACED report estimated that coal production in eastern Kentucky would decline 70% between 2012 and 2020, and with production below 20 million tons by 2028, the end of the IRP planning period.[95] This is approximately half of the eastern Kentucky coal production in 2013, and yet the IRP assumes that this mining sector's energy use will be fairly stable throughout the planning period. *Cf.* Staff 1-5 Attachment 1.

These differences indicate that the Eastern Kentucky mining sector has decreased much more quickly than other parts of the eastern coal market, such that KPC's reliance on that regional data overestimates the likely future energy demand from this sector.[96] The Commission Staff should note these deficiencies in its report on the IRP filing, and recommend that KPC's next IRP provide a more accurate forecast of the coal mining sector's future demand.

X. CONCLUSION

In order to help ensure that KPC continues its recent laudatory steps towards increasing DSM and renewable resources, and reducing high cost high risk coal generation, rather than reverting to business as usual, KPC should address and correct the above errors in their IRP so that a full evaluation of a reasonable range of resource portfolios can occur.

Respectfully submitted,

Joe Childers, Esq.
Joe F. Childers & Associates
300 Lexington Building
201 West Short Street
Lexington, Kentucky 40507
859-253-9824
859-258-9288 (facsimile)

---

[95] MACED & Kentucky Center for Economic Policy, *Promoting Long-Term Investment in Appalachian Kentucky: A Permanent Coal Severance Tax Fund*, at 1-2 (Mar. 2012), *available at*: http://www.maced.org/files/MACED_Coal_Severance_Tax_Brief.pdf.

[96] Indeed, KPC has acknowledged that its load forecast does not account for these steep declines. The IRP states that the forecast do not reflect "do not reflect the experience for the summer season of 2013 and later, or other relevant changes." IRP at 7. In response to a data request seeking clarification on the "other relevant changes" that were not incorporated into the load forecast, KPC stated that "[t]here were no significant 'other relevant changes' other than the further deterioration of the coal mining sector." Resp. to SC 1-8(b).

Of counsel:

Shannon Fisk
Earthjustice
1617 John F. Kennedy Blvd.
Suite 1675
Philadelphia, PA 19103
(215) 717-4522
sfisk@earthjustice.org

Jill Tauber
Michael Soules
Earthjustice
1625 Massachusetts Ave., NW
Suite 702
Washington DC 20036
jtauber@earthjustice.org
msoules@earthjustice.org

Laurie Williams
Sierra Club
50 F St. NW, 8th Floor
Washington DC 20001
(202) 548-4597
laurie.williams@sierraclub.org

Dated: April 30, 2014

CERTIFICATE OF SERVICE

I certify that I had filed with the Commission and served via U.S. Mail the foregoing Comments of the Sierra Club on April 30, 2014 to the following:

Mark R. Overstreet
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KY 40602-0634

Lila P. Munsey
Managing, Regulatory Services
Kentucky Power Company
101 A Enterprise Drive
Frankfort, KY 40601

Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Grant Tolley

Grant Tolley

Air Dispersion Modeling Analysis For Verifying Compliance with the One-Hour SO_2 NAAQS: AEP – Rockport Power Plant

Prepared by:

Camille Sears

December 10, 2012

TABLE OF CONTENTS

FIGURES

ATTACHMENTS

1. Introduction

Indiana Michigan Power Company (doing business as American Electric Power (AEP)) operates the Rockport Power Plant located in Spencer County, Indiana, which is a major source of sulfur dioxide (SO_2) emissions. This facility, which is permitted by the Indiana Department of Environmental Management (IDEM), includes two coal-fired boiler units (Units MB1 and MB2 at 1300 net MW each).[1] Emissions from these units vent to a common stack (Stack CS012).[2] An aerial view of the Rockport facility is shown in Figure 1.

I was asked to determine whether Rockport's SO_2 emissions, after SO_2 controls are installed, would result in air impacts exceeding the recently promulgated one-hour National Ambient Air Quality Standard (NAAQS), or would prevent maintenance of the standard. In response, I prepared air dispersion modeling analyses for calculating ambient SO_2 air concentrations from the Rockport facility. The modeled impacts are then compared with the one-hour SO_2 NAAQS. This report presents my modeling results and discusses the technical methodology I used for performing these analyses. Lindsey Sears assisted me in preparing model inputs and the attached maps.

The one-hour SO_2 NAAQS takes the form of a three-year average of the 99th-percentile of the annual distribution of daily maximum one-hour concentrations, which cannot exceed 75 ppb.[3] EPA recommends verifying compliance with this standard using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu g/m^3$. The one-hour SO_2 NAAQS of 75 ppb equals 196.2 $\mu g/m^3$, and this is the value I used for determining whether modeled Rockport impacts exceed the NAAQS.[4] The 99th-percentile of the annual distribution of daily maximum one-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

I modeled several scenarios for Rockport's SO_2 emissions: allowable (or permitted emissions), allowable emissions with 50% controls from installing dry sorbent injection (DSI), and 95% controls from installing an SO_2 scrubber. I also determined the percentage control necessary for the Rockport facility to comply with the SO_2 one-hour NAAQS. Existing uncontrolled Rockport SO_2 emissions result in modeled one-hour SO_2 NAAQS violations.

I specialize in atmospheric dispersion modeling, which uses regulatory-approved computer programs to estimate chemical concentrations in the air and deposition fluxes to the ground. In the past 30

---

[1] USEPA eGRID2010 Version 1.0 Plant File (Year 2007 Data).
[2] IDEM, Part 70 Operating Permit for AEP Rockport, August 7, 2008, p. 7 of 64.
[3] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010.
[4] The ppb to $\mu g/m^3$ conversion is found in the source code to AERMOD v. 12060, subroutine Modules. The conversion calculation is $75/0.3823 = 196.2\ \mu g/m^3$.

years, I have prepared over 1,000 air dispersion modeling analyses. I hold B.S. (1978) and M.S. (1980) degrees in Atmospheric Science from the University of California at Davis. A copy of my curriculum vitae is included in Attachment 1.

2. Modeling Methodology

This section describes the dispersion model, control options, and output options I used for verifying Rockport's compliance with the one-hour SO_2 NAAQS.

2.1 Air Dispersion Model

I performed one-hour SO_2 NAAQS modeling with USEPA's AERMOD program, version 12060, obtained from the Support Center for Regulatory Atmospheric Modeling (SCRAM) website. AERMOD is the USEPA preferred air dispersion model for determining air impacts within 50 kilometers of air pollution emission sources.[5] Version 12060 is the latest version of the AERMOD model, which was completed on February 29, 2012 (Julian day 60 of 2012).

2.2 AERMOD Input Control Options

I ran AERMOD model with the following control options:

- One-hour average air concentrations
- Regulatory defaults
- Flagpole receptors
- Rural dispersion coefficients

To correspond to a representative inhalation level, I used a flagpole height of 1.5 meters for all modeled receptors. This parameter is added to the receptor file when running AERMAP, as described in Section 3.4.

I determined that Rockport should be modeled with the default AERMOD rural dispersion control option. I reached this finding using USEPA's methodology outlined in Section 7.2.3 of the Guideline on Air Quality Models.[6]

[5] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005.
[6] Id., Section 7.2.3.

2.3 Output Options

My AERMOD modeling analyses of the Rockport facility includes five years of meteorological data – years 2006 through 2010. Consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations, I used the MXDYBYYR (maximum day by year) output options to create a table of fourth-high one-hour SO_2 impacts for each year of meteorological data modeled.[7] This provides five separate files of one-hour concentrations for each pollutant. I then averaged the one-hour values for each receptor across the five years of modeled data to calculate concentrations in the form of the one-hour SO_2 NAAQS.

3. Model inputs

The AERMOD air dispersion model requires a lengthy list of input values. Key inputs to this dispersion model include local geography, air emission rates of the released pollutant, source parameters (how and where the material is released to the air), receptors (locations where the offsite concentrations and deposition are calculated), and meteorological data (determines how and where the material is dispersed in the air). Each of these inputs is discussed below.

3.1 Geographical Inputs

The "ground floor" of all air dispersion modeling analyses is establishing a coordinate system for identifying the geographical location of emission sources and receptors. These geographical locations are used to determine local characteristics (such as land use and elevation), and also to ascertain source to receptor distances and relationships.

I used the Universal Transverse Mercator (UTM) NAD83 zone 16 coordinate system for identifying the easting (x) and northing (y) coordinates of the modeled sources and receptors. I obtained NAD27 source locations from modeling files developed by AEP and provided to IDEM, as described in Attachment 2.[8] I verified and transformed the source coordinates using Google Earth orthoimagery, which ensures consistency with the UTM NAD83 coordinate system.

As mentioned above, I determined that Rockport's emission sources should be modeled with rural dispersion coefficients. If less than 50% of the surrounding area is urban and developed, then a rural

[7] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 24-26.

[8] The modeling files were sent via email by Brian Callahan, IDEM. The email from IDEM, and a description of the modeling files prepared by David Long, are included in Attachment 2.

classification is supported. Also, the default rural option may apply if the population density in the three-kilometer radius surrounding each facility is less than 750 people per square kilometer. The population density in a three-kilometer radius around the Rockport facility is about 16 people per square kilometer. This population analysis was performed using ESRI's ArcGIS geographic information system (ArcMap v. 10), applying buffers (circles) with a three-kilometer radius around the stack coordinates of this facility. This analysis also used block level U.S. Census 2010 TIGER line files and tabular population data, which were joined together. The population data is also at the block level and were obtained from the 2010 U.S. Census Summary File 1. Areal weighted interpolation was then used to determine the population within the three-kilometer buffer. Any potential error with this approach is lessened by using sample data consisting of the smallest units possible, which in this case is U.S. Census data at the block level.

ArcGIS was also used for estimating the urban percentage in a three-kilometer radius around the Rockport facility. Using the 2006 National Land Cover Dataset (NLCD), the area of land use categories 23 (medium intensity developed) and 24 (high intensity developed) were summed and then divided by the area in a three-kilometer radius circle. 2006 NLCD categories 23 and 24 are a surrogate for Auer's urban area designations.[9] Using this approach, about three percent of the area in a three-kilometer radius around the Rockport facility is classified as urban.

These findings support modeling Rockport's emissions with AERMOD's default rural dispersion coefficients.[10]

3.2 Emission Rates and Source Parameters

My modeling analysis is limited to SO_2 emissions from the common coal-fired boiler stack at the Rockport facility (CS012), as described in the Introduction.[11] There are other intermittent SO_2 emission sources at Rockport, including the auxiliary boilers 1 and 2 (each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12) and three diesel generators (DG1, DG2, and DG3, each with 25.16 MMBtu/hr heat input capacity).[12] I did not include these intermittent emission sources in my modeling analysis.

---

[9] Glass, John, A Land Use Tool for AERMOD Urban/Rural Classification, South Carolina BAQ, 2009; Auer, August H., Correlation of Land Use and Land Cover with Meteorological Anomalies, Journal of Applied Meteorology, May 1978, pp. 636-643.

[10] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, Section 7.2.3.

[11] There are other SO_2 emission sources at or near Rockport's facility that would tend to add to modeled impacts.

[12] IDEM, Part 70 Operating Permit for AEP Rockport, August 7, 2008, p. 10 of 64 and p. 43 of 64.

I modeled several emission scenarios for the Rockport facility: allowable (also called permitted emissions), allowable emissions with 50% controls from installing dry sorbent injection (DSI), and 95% controls from installing an SO_2 scrubber. I also determined the level of controls needed for Rockport to comply with the one-hour SO_2 NAAQS. The permitted SO_2 emissions from Rockport's coal-fired boilers are as follows:

Units MB1 & MB2 (combined):
SO_2: 28,663 lb/hr = 3611.46 grams/sec[13]

Installing DSI controls, at 50% control efficiency would reduce Rockport's SO_2 emissions to 1805.73 grams/sec, and installing SO_2 scrubbers, at 95% control efficiency would reduce Rockport's SO_2 emissions to 180.57 grams/sec.

Coal-fired boiler stacks are treated as point sources in AERMOD. Point sources are modeled with the following stack parameters:

- Source Location X (Easting) coordinate (UTM NAD83);
- Source Location Y (Northing) coordinate (UTM NAD83);
- Source base elevation (meters above sea level);
- Stack emission rate (g/s);
- Stack height (meters);
- Stack gas exit temperature (Kelvin);
- Stack gas exit velocity (meters/second);
- Stack diameter (meters).[14]

[13] IDEM, Part 70 Operating Permit for AEP Rockport, August 7, 2008, p. 37 of 64.
[14] USEPA, User's Guide for the AMS/EPA Regulatory Model – AERMOD, EPA-454/B-03-101, September 2004 (with revisions), pp. 3-16 – 3-18.

I obtained stack release parameters from an AEP modeling file provided to IDEM. The allowable SO_2 emission rate and stack parameters for Rockport's coal-fired boiler stacks are as follows:

Stack	XUTM (meters)	YUTM (meters)	Base Elevation (meters)	SO_2 Emission Rate (g/s)	Release Ht. (meters)	Stack Temp. (K)	Stack Exit Vel. (m/s)	Stack Diam. (m)
CS012	496743.0	4197568.0	122.0	3611.46	219.46	429.7	33.58	12.95

I did not attempt to refine stack gas exit velocity and temperature for the DSI and scrubber control modeling scenarios. I recognize that these parameters can vary with installed SO_2 controls and that this assumption will possibly understate modeled air quality impacts. This is because stack gas temperatures and exit velocities for the controlled emissions are not likely to be as high as the values modeled for the uncontrolled emissions scenario.

3.3 Building Dimensions for Downwash

Adjacent buildings and other structures may cause plume downwash, a condition where plumes can be dispersed towards the ground in the downwind wake-effect from these buildings. USEPA's Building Profile Input Program (BPIPPRM v. 04274 with Plume Rise Model Enhancement (PRIME)) is used to determine stack-specific good engineering practice (GEP) values and wind direction-specific building downwash parameters for each 10-degree azimuth.[15]

The AEP modeling file provided to IDEM included a BPIPPRM analysis to determine building downwash parameters and GEP stack height for Rockport. I used these data as input to my AERMOD modeling analysis. I note that AEP's BPIPPRM analysis did not include the cooling towers, but I do not know what effect this will have on building downwash and GEP stack height.

3.4 Receptors

We created receptors in 100 meter increments in a 10 km by 10 km Cartesian grid centered on the stack location for the Rockport facility. Outside this grid, we generated receptors in 500 meter increments in a 20 km by 20 km area centered on the stack location for Rockport. The 500 meter grid of receptors encompasses the nested 100 meter receptors, so any duplicate receptors with the exact same location were extracted from the data set. And outside the grid of 500 meter receptors, we created receptors in 1,000 meter increments in a 70 km-by-70 km area. The 1,000 meter grid of

[15] USEPA, User's Guide to the Building Profile Input Program, EPA-454/R-93-038, April 21, 2004.

receptors encompasses the nested 100 and 500 meter receptors, so any duplicate receptors with the exact same location were extracted from the data set. As discussed earlier, we used a flagpole height of 1.5 meters for all modeled ground-level receptors.

Modeled source and receptor locations require terrain elevation data, in meters above sea level. We obtained terrain elevation data for these locations using National Elevation Dataset (NED) GeoTiff data for the area encompassing the Rockport facility and the modeled receptors. GeoTiff is a binary file that includes data descriptors and geo-referencing information necessary for extracting terrain elevations. For the 100 meter and 500 meter receptors, we extracted terrain elevations from the NED files using USEPA's AERMAP program, v. 11103, with 1/3rd arc-second (10 meter horizontal) resolution. We used 1 arc-second (30 meter horizontal resolution) NED files for extracting terrain elevations for the 1,000 meter receptor grid.

3.5 Meteorological Data

USEPA's definition of preferred meteorological data includes the most recent five years of National Weather Service (NWS) data. Currently, this condition is satisfied using 2007 through 2011 Automated Surface Observing Station (ASOS) data collected at the most site-appropriate airport. From Section 8.3.1.2 of the Guideline on Air Quality Models:

> a. Five years of representative meteorological data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data should be *adequately representative*, and may be site specific or from a nearby NWS station. Where professional judgment indicates NWS-collected ASOS (automated surface observing stations) data are inadequate [for cloud cover observations], the most recent 5 years of NWS data that are observer-based may be considered for use.
>
> The use of 5 years of NWS meteorological data or at least 1 year of site specific data is required. If one year or more (including partial years), up to five years, of site specific data is available, these data are preferred for use in air quality analyses. Such data should have been subjected to quality assurance procedures as described in subsection 8.3.3.2. (Italics in original.)[16]

More importantly, pre-2006 meteorological data are usually based on airport wind measurements that include an over-stated number of calm conditions. In their modeling guidance for SO_2 NAAQS

[16] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005.

designations, USEPA addresses the concern of calm hours in verifying compliance with the one-hour SO_2 NAAQS:

> In AERMOD, concentrations are not calculated for variable wind (i.e., missing wind direction) and calm conditions, resulting in zero concentrations for those hours. Since the SO_2 NAAQS is a one hour standard, these light wind conditions may be the controlling meteorological circumstances in some cases because of the limited dilution that occurs under low wind speeds which can lead to higher concentrations. The exclusion of a greater number of instances of near-calm conditions from the modeled concentration distribution may therefore lead to underestimation of daily maximum 1-hour concentrations for calculation of the design value.[17]

Due to the short time-frame for this analysis, I did not have time to develop 2007 through 2011 AERMOD-ready meteorological data for the Rockport facility. Instead, I used 2006 through 2010 meteorological data developed by IDEM that incorporate methods to reduce calm and missing hours (e.g. use one-minute data and USEPA's AERMINUTE program).[18] IDEM's AERMOD-ready meteorological data address USEPA's concerns regarding calm winds and there should be little, if any, difference in modeling results using 2006 – 2010 data rather than measurements from 2007 – 2011.

The meteorological data required by AERMOD is prepared by AERMET. Required data inputs to AERMET are: surface meteorological data, twice-daily soundings of upper air data, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. AERMET creates the model-ready surface and profile data files required by AERMOD. Using AERMET v. 11059, IDEM created AERMOD-ready meteorological data sets to be used for various regions of Indiana. The data sets cover five years, 2006 through 2010. The IDEM meteorological data to be used for Rockport (Spencer County, IN) are summarized as follows:

Surface data: Evansville Regional Airport (KEVV);
Upper air data: Lincoln/Logan County Airport (KILX).[19]

I did not fill missing hours in the meteorological data sets as the data files easily exceed USEPA's 90% data completeness requirements.[20] Annual wind roses of the IDEM's AERMOD-ready meteorological data, individually by year for 2006 through 2010 for Evansville/Lincoln, are included

[17] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19.
[18] USEPA, AERMINUTE User's Instructions, v. 11325, p. 1.
[19] IDEM's meteorological data can be downloaded at: http://www.in.gov/idem/4659.htm
[20] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 – 5-5.

in Attachment 3.

The representativeness of airport meteorological data is a potential concern in modeling industrial source sites.[21] The meteorological data sources I used are the most site-appropriate available for modeling the Rockport facility. In addition, I modeled the Rockport facility with AERMOD's default rural dispersion option. Given these considerations, I believe that the meteorological data I used (developed by IDEM with one-minute winds) represent the best data available for modeling Rockport's SO_2 emissions.

4. Background Air Concentrations

I used an SO_2 background concentration that is consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations. The appropriate background value is a uniform concentration based on the monitored design value for the latest three-year period.[22] For the Rockport facility, I used the 2008 – 2010 design value SO_2 concentration from a monitoring site in Warrick County, IN (Site ID 18-173-0002).[23] This site location is sufficiently distant to minimize double-counting impacts from Rockport's coal-fired power plant in the background SO_2 concentrations.

The 2008 – 2010 SO_2 background design value from Site ID 18-173-0002 is 56 parts per billion, which equals 146.5 $\mu g/m^3$. The design value (equal to the three-year average 99^{th}-percentile of the measurements) preserves the form of the one-hour SO_2 standard, and is added to the 99^{th} percentile of the annual distribution of daily maximum one-hour concentrations averaged across the number of years modeled.[24]

5. Modeling Results

As discussed above, I modeled four scenarios for Rockport's SO_2 emissions: allowable (or permitted emissions), DSI emission controls with 50% control efficiency, scrubber emission controls with 95% control efficiency, and the level of controls necessary for the Rockport facility to comply with the one-hour SO_2 NAAQS. The modeling analyses show that Rockport's allowable emissions, without controls and with DSI controls, will violate the one-hour SO_2 NAAQS. There are no modeled one-hour SO_2 NAAQS violations with scrubber controls at 95% efficiency. A control efficiency of about 82% is needed for Rockport's emissions to meet the one-hour SO_2 NAAQS (196.2 $\mu g/m^3$).

---

[21] USEPA, AERMOD Implementation Guide, March 19, 2009, pp. 3-4.
[22] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 20-23.
[23] See http://www.epa.gov/airtrends/values.html. Site 18-173-0002 did not operate in 2011.
[24] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 20-23.

For this analysis, the one-hour SO_2 ambient air impacts (Facility H4H – highest fourth high value) are based on the 99th percentile of the annual distribution of daily maximum one-hour concentrations averaged across the five years of modeled meteorological data. The peak modeled one-hour SO_2 ambient air impacts, using 2006 through 2010 KEVV/KILX meteorological data, steady state stack exit velocities and temperatures associated with allowable emissions, and background design value SO_2 concentrations, are presented in the table below. Concentrations are for surface-based receptors with a flagpole height of 1.5 meters, and are in the form of the NAAQS.

Rockport SO_2 Impacts	KEVV 2006-2010 meteorological data, AERMINUTE				
Scenario	Facility H4H Conc. (µg/m^3)	99th %tile Design Value Background (µg/m^3)	Total Conc. (µg/m^3)	XUTM (m)	YUTM (m)
Allowable Emissions	274.7	146.5	421.2	500000	4201300
DSI, with 50% control efficiency	137.4	146.5	283.9	500000	4201300
Scrubber, with 95% control efficiency	13.7	146.5	160.2	500000	4201300
82% control efficiency	49.4	146.5	195.9	500000	4201300

The modeled impacts can also be shown graphically. The attached figures (2 and 3) are maps showing isopleths (lines of equal air concentration) overlaid onto basemaps included with ArcMap v. 10. I created the isopleths using AERMOD output plotfiles and Golden Software's Surfer, v. 10. I used kriging algorithms to grid the data for the isopleths.

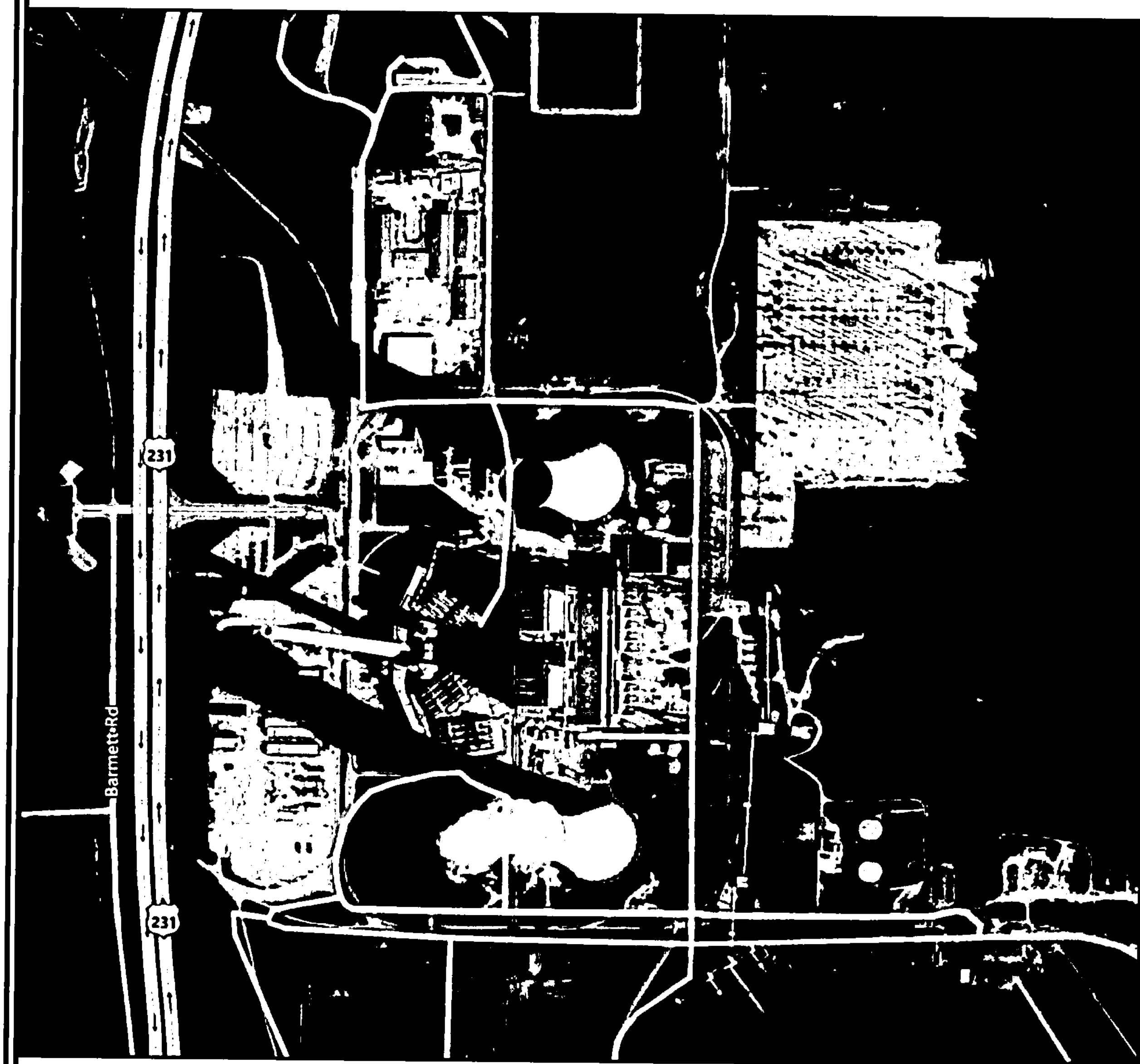
Figure 2 shows modeled one-hour SO_2 concentrations from allowable Rockport emissions, with background values. This map shows two SO_2 concentration levels: 250 and 325 µg/m^3. The regions within each isopleth have air concentrations that exceed the levels found on each isopleth. The areas encompassed by these isopleths significantly exceed the 196 µg/m^3 one-hour SO_2 NAAQS and could result in a designation of nonattainment for that region. The 196 µg/m^3 one-hour SO_2 NAAQS isopleth extends well beyond the region shown on this map, but was not included due to the distance limitations in AERMOD modeling.

Figure 3 shows modeled one-hour SO_2 concentrations caused by DSI-controlled Rockport emissions (50% reduction), with background concentrations. This map shows one SO_2 concentration level: 196 µg/m^3. The area encompassed by this isopleth also exceeds the 196 µg/m^3 one-hour SO_2 NAAQS and could result in a designation of nonattainment for that region.

The isopleth maps in attached Figures 2 and 3 were created using ArcMap v. 10 with Bing basemaps. Since there are no modeled NAAQS violations for scrubber-controlled Rockport SO_2 emissions (95% reduction), we did not create an isopleth map for that scenario.

Figure 1: AEP Rockport Facility

Sears Affidavit - Attachment 1



0 0.2 0.4 Miles

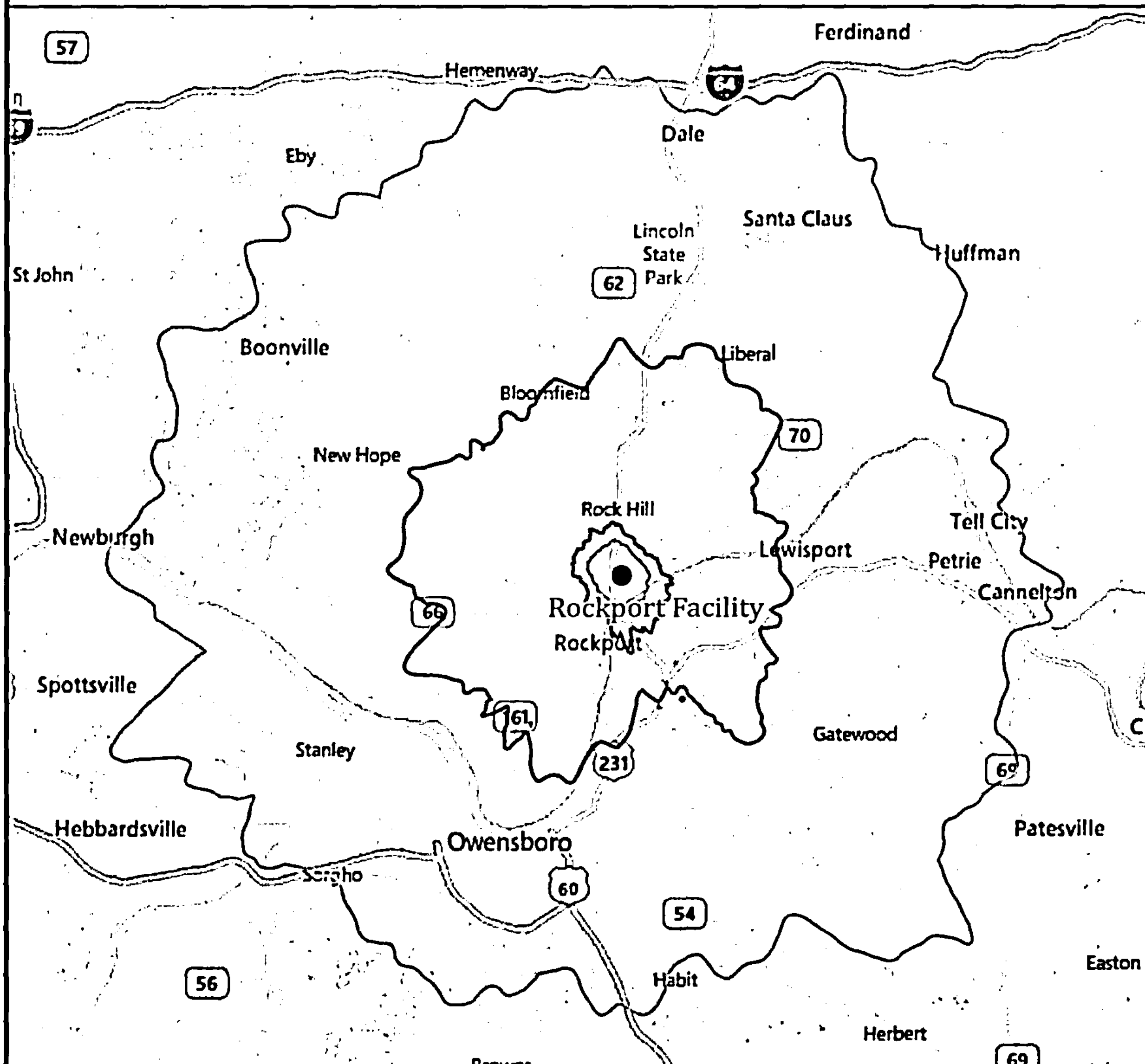
N

Basemap: Bing Maps ©2010 Microsoft Corporation and its data suppliers

Figure 2: AEP Rockport Facility

Sears Affidavit - Attachment 1

One-hour sulfur dioxide concentrations from allowable emissions, with background levels.



250 µg/m³

325 µg/m³

0 5 10 Miles

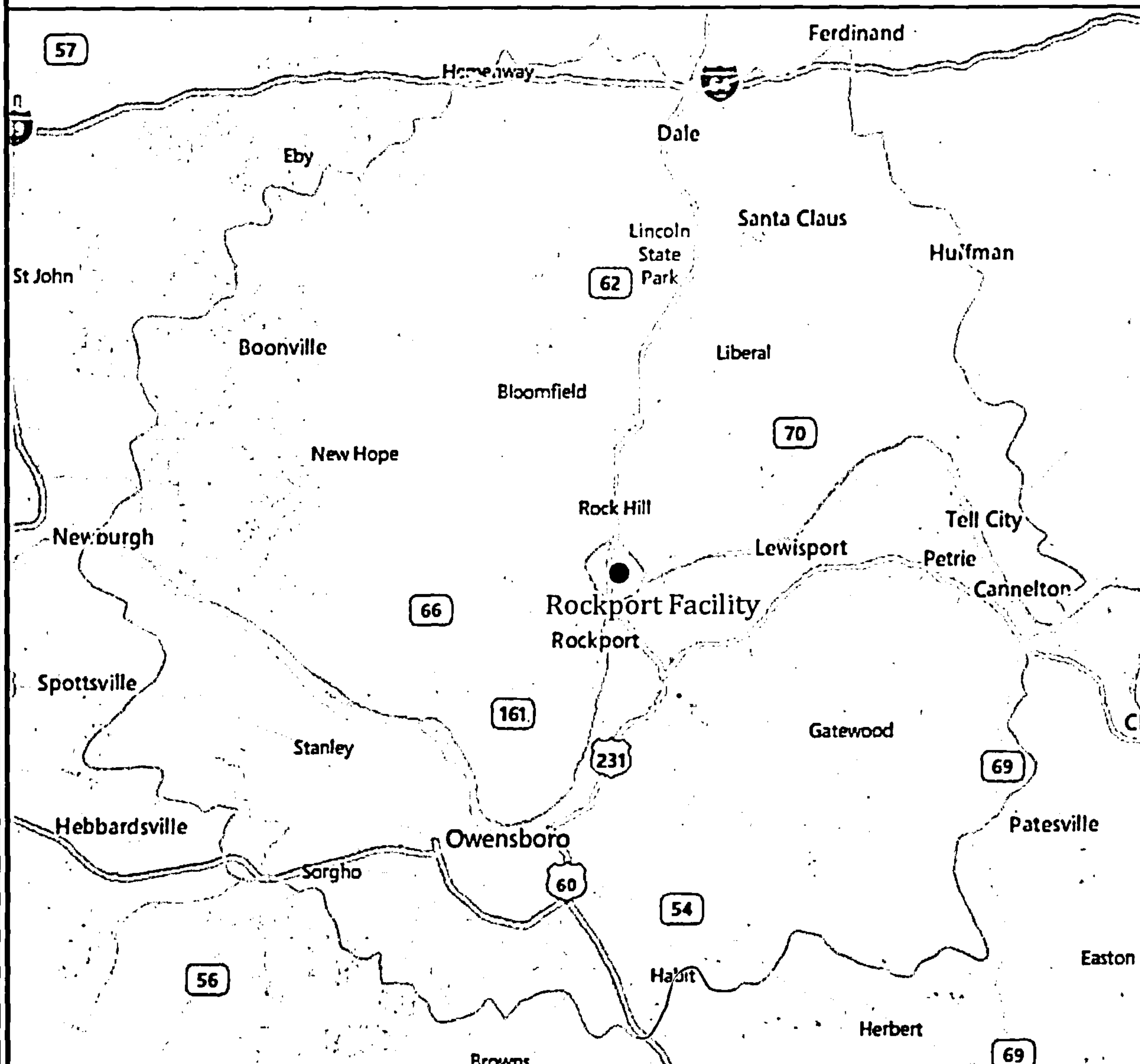
N

Basemap: Bing Maps

Figure 3: AEP Rockport Facility

Sears Affidavit - Attachment 1

One-hour sulfur dioxide concentrations from DSI-controlled emissions (50% reduction), with background levels.



196 µg/m³

0 5 10 Miles

Basemap: Bing Maps

ATTACHMENT 1:

Curriculum Vitae

Camille Marie Sears 502 W. Lomita Ave., Ojai, CA 93023

Tel: (805) 646-2588 e-mail: camille.marie@sbcglobal.net

Summary

I have over 30 years of regulatory and private-sector experience in air quality impact analyses, health risk assessments, meteorological monitoring, and geographic information systems. I specialize in litigation support; I have successfully provided testimony in numerous cases, both as an individual consultant and as part of a team of experts.

Education

- M.S., Atmospheric Science, University of California, Davis, 1980.
- B.S., Atmospheric Science, University of California, Davis, 1978.

Air Dispersion Modeling

- I am experienced in applying many different air dispersion models, including programs still in the development phase. I have prepared well over 1,000 air dispersion modeling analyses requiring the use of on-site or site-specific meteorological data. These runs were made with the USEPA ISC, OCD, MESOPUFF, INPUFF, CALPUFF, ISC-PRIME, AERMOD, COMPLEX-I, MPTER, and other air dispersion models.
- I prepared and submitted technical comments to the USEPA on beta-testing versions of AERMOD; these comments are being addressed and will be incorporated into the model and instructions when it is ready for regulatory application.
- I am experienced in performing air dispersion modeling for virtually every emission source type imaginable. I have modeled:
  Refineries and associated activities;
  Mobile sources, including cars, trains, airplanes, trucks, and ships;
  Power plants, including natural gas and coal-fired;
  Smelting operations;
  Area sources, such as housing tracts, biocides from agricultural operations, landfills, highways, fugitive dust sources, airports, oil and gas seeps, and ponds;
  Volume sources, including fugitive emissions from buildings and diesel construction combustion emissions;
  Small sources, including dry cleaners, gas stations, surface coating operations, plating facilities, medical device manufacturers, coffee roasters, ethylene oxide sterilizers, degreasing operations, foundries, and printing companies;
  Cooling towers and gas compressors;
  Diatomaceous earth, rock and gravel plants, and other mining operations;
  Offshore oil platforms, drilling rigs, and processing activities;
  Onshore oil and gas exploration, storage, processing, and transport facilities;
  Fugitive dust emissions from roads, wind erosion, and farming activities;
  Radionuclide emissions from actual and potential releases.
- I have extensive experience in modeling plume depletion and deposition from air releases of particulate emissions.
- As a senior scientist, I developed the Santa Barbara County Air Pollution Control District (SBAPCD) protocol on air quality modeling. I developed extensive modeling capabilities for the SBAPCD on VAX 8600 and Intel I-860 computer systems; I acted as systems analyst for the SBAPCD air quality modeling system; I served as director of air quality analyses for numerous major energy projects; I performed air quality impact analyses using inert and photochemical models, including EPA, ARB and private-sector models; I performed technical review and evaluating air quality and wind field models; I developed software to prepare model inputs consistent with the SBAPCD protocol on air quality modeling for OCD, OCDCPM, MPTER, COMPLEX-I/II and ISC.
- I provided detailed review and comments on the development of the Minerals Management Service OCD model. I developed the technical requirements for and

supervised the development of the OCDCPM model, a hybrid of the OCD, COMPLEX-I and MPTER models.

- I prepared the "Modeling Exposures of Hazardous Materials Released During Transportation Incidents" report for the California Office of Environmental Health Hazard Assessment (OEHHA). This report examines and rates the ADAM, ALOHA, ARCHIE, CASRAM, DEGADIS, HGSYSTEM, SLAB, and TSCREEN models for transportation accident consequence analyses of a priority list of 50 chemicals chosen by OEHHA. The report includes a model selection guide for adequacy of assessing priority chemicals, averaging time capabilities, isopleth generating capabilities, model limitations and concerns, and model advantages.
- I am experienced in assessing uncertainty in emission rate calculations, source release, and dispersion modeling. I have developed numerous probability distributions for input to Monte Carlo simulations, and I was a member of the External Advisory Group for the California EPA *Air Toxics Hot Spots Program Risk Assessment Guidelines, Part IV, Technical Support Document for Exposure Assessment and Stochastic Analysis.*

Health Risk Assessment

- I have prepared more than 300 health risk assessments of major air toxics sources. These assessments were prepared for AB 2588 (the Air Toxics "Hot Spots" Information and Assessment Act of 1987), Proposition 65, and other exposure analysis activities. More than 120 of these exposure assessments were prepared for Proposition 65 compliance verification in a litigation support setting.
- I reviewed approximately 300 other health risk assessments of toxic air pollution sources in California. The regulatory programs in this review include AB 2588, Proposition 65, the California Environmental Quality Act, and other exposure analysis activities. My clients include the California Attorney General's Office, the Los Angeles County District Attorney's Office, the SBAPCD, the South Coast Air Quality Management District, numerous environmental and community groups, and several plaintiff law firms.
- I am experienced in assessing public health risk from continuous, intermittent, and accidental releases of toxic emissions. I am experienced in generating graphical presentations of risk results, and characterizing risks from carcinogenic and acute and chronic noncarcinogenic pollutants.
- I am experienced in communicating adverse health risks discovered through the Proposition 65 and AB 2588 processes. I have presented risk assessment results in many public settings -- to industry, media, and the affected public.
- For four years, I was the Air Toxics Program Coordinator for the SBAPCD. My duties included: developing and managing the District air toxics program; supervising District staff assigned to the air toxics program; developing District air toxics rules, regulations, policies and procedures; management of all District air toxics efforts, including AB 2588, Proposition 65, and federal activities; developing and tracking the SBAPCD air toxics budget.
- I have prepared numerous calculations of exposures from indoor air pollutants. A few examples include: diesel PM_{10} inside school buses, formaldehyde inside temporary school buildings, lead from disturbed paint, phenyl mercuric acetate from water-based paints and drywall mud, and tetrachloroethene from recently dry-cleaned clothes.

Litigation Support

- I have prepared numerous analyses in support of litigation, both in Federal and State Courts. I am experienced in preparing F.R.C.P. Rule 26(a)(2) expert reports and providing deposition and trial testimony (I have prepared eight Rule 26 reports). Much of my work is focused on human dose and risk reconstruction resulting from multiple air emission sources (lifetime and specific events).

- I am experienced in preparing declarations (many dozens) and providing expert testimony in depositions and trials (see my testimony history).
- I am experienced in providing support for legal staff. I have assisted in preparing numerous interrogatories, questions for depositions, deposition reviews, various briefs and motions, and general consulting.
- Recent examples of my work include:
  DTSC v. Interstate Non-Ferrous; United States District Court, Eastern District of California (2002).
  In this case I performed air dispersion modeling, downwind soil deposition calculations, and resultant soil concentrations of dioxins (TCDD TEQ) from historical fires at a smelting facility. I prepared several Rule 26 Reports in my role of assisting the California Attorney General's Office in trying this matter.
  Akee v. Dow et al.; United States District Court, District of Hawaii (2003-2004).
  In this case I performed air dispersion modeling used to quantify air concentrations and reconstruct intake, dose, excess cancer risk, and noncancer chronic hazard indices resulting from soil fumigation activities on the island of Oahu, Hawaii. I modeled 319 separate AREAPOLY pineapple fields for the following chemicals: DBCP, EDB, 1,3-trichloropropene, 1,2-dichloropropane, and epichlorohydrin. I calculated chemical flux rates and modeled the emissions from these fumigants for years 1946 through 2001 (56 years) for 34 test plaintiffs and 97 distinct home, school, and work addresses. I prepared a Rule 26 Expert Report, successfully defended against Daubert challenges, and testified in trial.
  Lawrence O'Connor v. Boeing North America, Inc., United States District Court, Central District of California, Western Division (2004-2005).
  In this case I performed air dispersion modeling, quantified air concentrations, and reconstructed individual intake, dose, and excess cancer risks resulting from approximately 150 air toxics sources in Los Angeles and Ventura Counties, California. I prepared these analyses for years 1950 through 2000 (51 years) for 173 plaintiffs and 741 distinct home, school, and work addresses. I prepared several Rule 26 Reports, and the case settled on the eve of trial in September, 2005. Defendants did not attempt a Daubert challenge of my work.
- I have prepared hundreds of individual and region-wide health risk assessments in support of litigation. These analyses include specific sub-tasks, including: calculating emission rates, choosing proper meteorological data inputs, performing air dispersion modeling, and quantifying intake, dose, excess cancer risk, and acute/chronic noncancer health effects.
- I have prepared over 120 exposure assessments for Proposition 65 litigation support. In these analyses, my tasks include: reviewing AB 2588 risk assessments and other documents to assist in verifying compliance with Proposition 65; preparing exposure assessments consistent with Proposition 65 Regulations for carcinogens and reproductive toxicants; using a geographic information system (Atlas GIS) to prepare exposure maps that display areas of required warnings; calculating the number of residents and workers exposed to levels of risk requiring warnings (using the GIS); preparing declarations, providing staff support, and other expert services as required. I have also reviewed scores of other assessments for verifying compliance with Proposition 65. My proposition 65 litigation clients include the California Attorney General's Office, the Los Angeles County District Attorney's Office, As You Sow, California Community Health Advocates, Center for Environmental Health, California Earth Corps, Communities for a Better Environment, Environmental Defense Fund, Environmental Law Foundation, and People United for a Better Oakland.

Geographic Information Systems

- ArcGIS: I am experienced in preparing presentation and testimony maps using ArcView versions 3 through 9.3. I developed methods to convert AutoCAD DXF files to ArcView polygon theme shape files for use in map overlays.

- I have created many presentation maps with ArcView using MrSID DOQQ and other aerial photos as a base and then overlaying exposure regions. This provides a detailed view (down to the house level) of where air concentrations and health risks are projected to occur.
- Using ArcView, I have created numerous presentations using USGS Topographic maps (as TIFF files) as the base on to which exposure regions are overlaid.
- MapInfo for Windows: I prepared numerous presentation maps including exposure isopleths, streets and highways, and sensitive receptors, labels. I developed procedures for importing Surfer isopleths in AutoCAD DXF format as a layer into MapInfo.
- Atlas GIS: I am experienced in preparing presentation maps with both the Windows and DOS versions of Atlas GIS. In addition to preparing maps, I use Atlas GIS to aggregate census data (at the block group level) within exposure isopleths to determine the number of individuals living and working within exposure zones. I am also experienced in geocoding large numbers of addresses and performing statistical analyses of exposed populations.
- I am experienced in preparing large-scale graphical displays, both in hard-copy and for PowerPoint presentations. These displays are used in trial testimony, public meetings, and other litigation support.
- I developed a Fortran program to modify AutoCAD DXF files, including batch-mode coordinate shifting for aligning overlays to different base maps.

Ozone and Long-Range Transport

- I developed emission reduction strategies and identified appropriate offset sources to mitigate project emissions liability. For VOC offsets, I developed and implemented procedures to account for reactivity of organic compound species for ozone impact mitigation. I wrote Fortran programs and developed a chemical database to calculate ozone formation potential using hydroxyl radical rate constants and an alkane/non-alkane reactive organic compound method.
- I provided technical support to the Joint Interagency Modeling Study and South Central Coast Cooperative Aerometric Monitoring Program. With the SBAPCD, I provided technical comments on analyses performed with the EKMA, AIRSHED, and PARIS models. I was responsible for developing emissions inventory for input into regional air quality planning models.
- I was the project manager for the Santa Barbara County Air Quality Attainment Plan Environmental Impact Report (EIR). My duties included: preparing initial study; preparation and release of the EIR Notice of Preparation; conducting public scoping hearings to obtain comments on the initial study; managing contractor efforts to prepare the draft EIR.
- I modified, tested, and compiled the Fortran code to the MESOPUFF model (the precursor to CALPUFF) to incorporate critical dividing streamline height algorithms. The model was then applied as part of a PSD analysis for a large copper-smelting facility.
- I am experienced in developing and analyzing wind fields for use in long-range transport and dispersion modeling.
- I have run CALPUFF numerous times. I use CALPUFF to assess visibility effects and both near-field and mesoscale air concentrations from various emission sources, including power plants.

Emission Rate Calculations

- I developed methods to estimate and verify source emission rates using air pollution measurements collected downwind of the emitting facility, local meteorological data, and dispersion models. This technique is useful in determining whether reported source emission rates are reasonable, and based on monitored and modeled air concentrations, revised emission rates can be created.

- I am experienced in developing emission inventories of hundreds of criteria and toxic air pollutant sources. I developed procedures and programs for quantifying emissions from many air emission sources, including: landfills, diesel exhaust sources, natural gas combustion activities, fugitive hydrocarbons from oil and gas facilities, dry cleaners, auto body shops, and ethylene oxide sterilizers.
- I have calculated flux rates (and modeled air concentrations) from hundreds of biocide applications to agricultural fields. Emission sources include aerial spraying, boom applications, and soil injection of fumigants.
- I am experienced in calculating emission rates using emission factors, source-test results, mass-balance equations, and other emission estimating techniques.

Software Development

- I am skilled in computer operation and programming, with an emphasis on Fortran 95.
- I am experienced with numerous USEPA dispersion models, modifying them for system-specific input and output, and compiling the code for personal use and distribution. I own and am experienced in using the following Fortran compilers: Lahey Fortran 95, Lahey Fortran 90 DOS-Extended; Lahey F77L-EM32 DOS-Extended; Microsoft PowerStation 32-bit DOS-Extended; and Microsoft 16-bit.
- I configured and operated an Intel I-860 based workstation for the SBAPCD toxics program. I created control files and recoded programs to run dispersion models and risk assessments in the 64-bit I-860 environment (using Portland Group Fortran).
- Using Microsoft Fortran PowerStation, I wrote programs to extract terrain elevations from both 10-meter and 30-meter USGS DEM files. Using a file of discrete x,y coordinates, these programs extract elevations within a user-chosen distance for each x,y pair. The code I wrote can be run in steps or batch mode, allowing numerous DEM files to be processed at once.
- I have written many hundreds of utilities to facilitate data processing, entry, and quality assurance. These utility programs are a “tool chest” from which I can draw upon to expedite my work.
- While at the SBAPCD, I designed the ACE2588 model - the first public domain multi-source, multi-pathway, multi-pollutant risk assessment model. I co-developed the structure of the ACE2588 input and output files, supervised the coding of the model, tested the model for quality assurance, and for over 10 years I provided technical support to about 200 users of the model. I was responsible for updating the model each year and ensuring that it is consistent with California Air Pollution Control Officer's Association (CAPCOA) Risk Assessment Guidelines.
- I developed and coded the ISC2ACE and ACE2 programs for distribution by CAPCOA. These programs were widely used in California for preparing AB 2588 and other program health risk assessments. ISC2ACE and ACE2 contain "compression" algorithms to reduce the hard drive and RAM requirements compared to ISCST2/ACE2588. I also developed ISC3ACE/ACE3 to incorporate the revised ISCST3 dispersion model requirements.
- I developed and coded the "HotSpot" system - a series of Fortran programs to expedite the review of air toxics emissions data, to prepare air quality modeling and risk assessment inputs, and to prepare graphical risk presentations.
- I customized ACE2588 and developed a mapping system for the SBAPCD. I modified the ACE2588 Fortran code to run on an Intel I-860 RISC workstation; I updated programs that allow SBAPCD staff to continue to use the "HotSpot" system – a series of programs that streamline preparing AB 2588 risk assessments; I developed a risk assessment mapping system based on MapInfo for Windows which linked the MapInfo mapping package to the "HotSpot" system.
- I developed software for electronic submittal of all AB 2588 reporting requirements for the SBAPCD. As an update to the "HotSpot" system software, I created software that allows facilities to submit all AB 2588 reporting data, including that needed for risk prioritization, exposure assessment, and presentation mapping. The data submitted

by the facility is then reformatted to both ATDIF and ATEDS formats for transmittal to the California Air Resources Board.

- I developed and coded Fortran programs for AB 2588 risk prioritization; both batch and interactive versions of the program were created. These programs were used by several air pollution control districts in California.

Air Quality and Meteorological Monitoring

- I was responsible for the design, review, and evaluation of an offshore source tracer gas study. This project used both inert tracer gas and a visible release to track the onshore trajectory and terrain impaction of offshore-released buoyant plumes.
- I developed the technical requirements for the Santa Barbara County Air Quality/Meteorological Monitoring Protocol. I developed and implemented the protocol for siting pre- and post-construction air quality and meteorological PSD monitoring systems. I determined the instrumentation requirements, and designed and sited over 30 such PSD monitoring systems. Meteorological parameters measured included ambient temperature, wind speed, wind direction, sigma-theta (standard deviation of horizontal wind direction fluctuations), sigma-phi (standard deviation of vertical wind direction fluctuations), sigma-v (standard deviation of horizontal wind speed fluctuations), and sigma-w (standard deviation of vertical wind speed fluctuations). Air pollutants measured included PM_{10}, SO_2, NO, NO_x, NO_2, CO, O_3, and H_2S.
- I was responsible for data acquisition and quality assurance for an offshore meteorological monitoring station. Parameters measured included ambient temperature (and delta-T), wind speed, wind direction, and sigma-theta.
- In coordination with consultants performing air monitoring for verifying compliance with Proposition 65 and other regulatory programs, I wrote software to convert raw meteorological data to hourly-averaged values formatted for dispersion modeling input.
- Assisting the Ventura Unified School District, I collected air, soil, and surface samples and had them analyzed for chlorpyrifos contamination (caused by spray drift from a nearby citrus orchard). I also coordinated the analysis of the samples, and presented the results in a public meeting.
- Using summa canisters, I collected numerous VOC samples to characterize background and initial conditions for use in Santa Barbara County ozone attainment modeling. I also collected samples of air toxics (such as xylenes downwind of a medical device manufacturer) to assist in enforcement actions.
- For the California Attorney General's Office, I purchased, calibrated, and operated a carbon monoxide monitoring system. I measured and reported CO air concentrations resulting from numerous types of candles, gas appliances, and charcoal briquettes.

Support, Training, and Instruction

- For 10 years, I provided ACE2588 risk assessment model support for CAPCOA. My tasks included: updating the ACE2588 risk assessment model Fortran code to increase user efficiency and to maintain consistency with the CAPCOA Risk Assessment Guidelines; modifying the Fortran code to the EPA ISC model to interface with ACE2588; writing utility programs to assist ACE2588 users; updating toxicity data files to maintain consistency with the CAPCOA Risk Assessment Guidelines; developing the distribution and installation package for ACE2588 and associated programs; providing technical support for all users of ACE2588.
- I instructed approximately 20 University Professors through the National Science Foundation Faculty Enhancement Program. Instruction topics included: dispersion modeling, meteorological data, environmental fate analysis, toxicology of air pollutants, and air toxics risk assessment; professors were also trained on the use of the ISC2ACE dispersion model and the ACE2 exposure assessment model.
- I was the instructor of the Air Pollution and Toxic Chemicals course for the University of California, Santa Barbara, Extension certificate program in Hazardous Materials Management. Topics covered in this course include: detailed review of criteria and

noncriteria air pollutants; air toxics legislation and regulations; quantifying toxic air contaminant emissions; criteria and noncriteria pollutant monitoring; air quality modeling; health risk assessment procedures; health risk management; control/mitigating air pollutants; characteristics and modeling of spills and other short-term releases of air pollutants; acid deposition, precipitation and fog; indoor/occupational air pollution; the effect of chlorofluorocarbons on the stratospheric ozone layer. I taught this course for five years.

- I have trained numerous regulatory staff on the mechanics of dispersion modeling, health risk assessments, emission rate calculations, and presentation mapping. I provided detailed training to SBAPCD staff in using the HARP program, and in comparing and contrasting ACE2588 analyses to HARP.
- Through UCSB Extension, I taught a three-day course on dispersion modeling, preparing health risk assessments, and presentation mapping with Atlas GIS and MapInfo.
- I hold a lifetime California Community College Instructor Credential (Certificate No. 14571); Subject Matter Area: Physics.
- I have presented numerous guest lectures – at universities, public libraries, farm groups, and business organizations.

Indoor Air Quality

- I prepared mercury exposure assessments caused by applying indoor latex paints containing phenylmercuric acetate as a biocide.
- Using a carbon monoxide monitor, I examined CO concentrations inside rooms of varying sizes and with a range of ventilation rates. Indoor sources of CO emissions included gas appliances and candles. I also examined CO concentrations within parking garages.
- I calculated air concentrations of tetrachloroethene inside homes and cars from offgassing dry-cleaned clothes.
- I examined air concentrations of formaldehyde inside manufactured homes and school buildings. I also calculated formaldehyde exposures from carpet emissions within homes.
- I assessed lead air exposures and surface deposition from deteriorating lead-based paint applications within apartments. I also calculated lead air concentrations and associated exposures resulting from milling of brass pipes and fittings.
- While employed by the SBAPCD, I assisted with exposure assessment and awareness activities for Santa Barbara County high-exposure radon areas.
- I calculated BTEX air concentrations and health risks inside homes from leaking underground fuel tanks and resultant contaminated soil plumes. I also assessed indoor VOC exposures and remediation options with the AERIS model.
- I have assessed indoor air concentrations from numerous volatile organic compound sources, including printing operations, microprocessor manufacturing, and solvent degreasing activities.
- I calculated indoor emission flux rates and air concentrations of elemental mercury for plaintiff litigation support purposes. This analysis included an exposure reconstruction (home, school, workplace, outside, and other locations) for 16 plaintiffs who had collected spilled mercury in their village. The study required room volume calculations, air exchange rates, exposure history reconstruction, mercury quantity and droplet size estimation, elemental mercury flux rate calculations (including decay with time), and resultant air concentration calculations. I calculated both peak acute (two-hour) and 24-hour average concentrations.
- I calculated emission rates of lead from disturbed paint surfaces. I then calculated indoor air concentrations of lead for plaintiff litigation support purposes.

Publications

- To establish a legal record and to assist in environmental review, I prepared and submitted dozens of detailed comment letters to regulatory and decision-making bodies.
- I have contributed to over 100 Environmental Impact Statements/Reports and other technical documents required for regulatory decision-making.
- I prepared two software review columns for the *Journal of the Air and Waste Management Association.*
- Correlations of total, diffuse, and direct solar radiation with the percentage of possible sunshine for Davis, California. Solar Energy, 27(4):357-360 (1981).

Employment History

• Self-Employed Air Quality Consultant	1992 to 2012
• Santa Barbara County APCD, Senior Scientist	1988 to 1992
• URS Consultants, Senior Scientist	1987 to 1988
• Santa Barbara County APCD, Air Quality Engineer	1983 to 1987
• Dames and Moore, Meteorologist	1982 to 1983
• UC Davis, Research Associate	1980 to 1981

Testimony History

- People of the State of California v. McGhan Medical, Inc.
  Deposition: Two dates: June - July 1990
- People of the State of California v. Santa Maria Chili
  Deposition: Two dates: August 1990
- California Earth Corps v. Johnson Controls, Inc.
  Deposition: October 26, 1995
- Larry Dale Anderson v. Pacific Gas & Electric
  Deposition: January 4, 1996
  Arbitration: January 17, 1996
- Adams v. Shell Oil Company
  Deposition: July 3, 1996
  Trial: August 21, 1996
  Trial: August 22, 1996
- California Earth Corps v. Teledyne Battery Products
  Deposition: January 17, 1997
- Marlene Hook v. Lockheed Martin Corporation
  Deposition: December 15, 1997
- Lawrence O'Connor v. Boeing North America, Inc.
  Deposition: May 8, 1998
- Bristow v. Tri Cal
  Deposition: June 15, 1998
- Abeyta v. Pacific Refining Co.
  Deposition: January 16, 1999
  Arbitration: January 25, 1999
- Danny Aguayo v. Betz Laboratories, Inc.
  Deposition: July 10, 2000
  Deposition: July 11, 2000
- Marlene Hook v. Lockheed Martin Corporation
  Deposition: September 18, 2000
  Deposition: September 19, 2000
- Tressa Haddad v. Texaco
  Deposition: March 9, 2001

- California DTSC v. Interstate Non-Ferrous
  United States District Court, Eastern District of California,
  Case No. CV-F-97 50160 OWW LJO
    Deposition: April 18, 2002
- Akee v. Dow et al.
  United States District Court, District of Hawaii,
  Case No. CV 00 00382 BMK
    Deposition: April 16, 2003
    Deposition: April 17, 2003
    Deposition: January 7, 2004
    Trial: January 17, 2004
    Trial: January 20, 2004
- Center for Environmental Health v. Virginia Cleaners
  Superior Court of the State of California
  County of Alameda, Case No. 2002 07 6091
    Deposition: March 4, 2004
- Application for Certification for Small Power Plant Exemption – Riverside Energy Resource Center. Docket No. 04-SPPE-01.
    Evidentiary Hearing Testimony before the California Energy Resource Conservation And Development Commission: August 31, 2004
- Lawrence O'Connor v. Boeing North America, Inc.
  United States District Court, Central District of California,
  Western Division. Case No. CV 97-1554 DT (RCx)
    Deposition: March 1, 2005
    Deposition: March 2, 2005
    Deposition: March 3, 2005
    Deposition: March 15, 2005
    Deposition: April 25, 2005
- Clemente Alvarez, et al, v. Western Farm Service, Inc.
  Superior Court of the State of California
  County of Kern, Metropolitan Division. Case No. 250 621 AEW
    Deposition: April 11, 2005
- Gary June et al. v. Union Carbide Corporation & UMETCO Minerals Corporation
  United States District Court, District of Colorado,
  Case No. 04-CV-00123 MSK-MJW
    Deposition: January 9, 2007
- Alberto Achas Castillo, et al. v. Newmont Mining Corporation, et al.
  District Court, Denver County, Colorado,
  Case No. 01-CV-4453
    Deposition: February 19, 2007
    Deposition: February 20, 2007
    Arbitration: March 6, 2007
    Arbitration: March 7, 2007
- Jacobs Farm/Del Cabo Inc. v. Western Farm Service, Inc.
  Superior Court of the State of California
  County of Santa Cruz, Case No. CV 157041
    Deposition: May 8, 2008
    Deposition: August 26, 2008
    Trial: September 18, 2008
    Trial: September 24, 2008

- Environmental Law Foundation et al. v. Laidlaw Transit Inc. et al.
  Superior Court of the State of California
  County of San Francisco, Case No. CGC-06-451832
  Deposition: July 8, 2008
- Application of NRG Texas Power, LLC for State Air Quality Permit No. 79188 and Prevention of Significant Deterioration Air Quality Permit PSD-TX-1072.
  State Office of Administrative Hearings Docket No. 582-08-0861;
  TCEQ Docket No. 2007-1820-AIR.
  Deposition: February 12, 2009
  Hearing: February 24, 2009
- Application of IPA Coleto Creek, LLC for State Air Quality Permit No. 83778 and Prevention of Significant Deterioration Air Quality Permit PSD-TX-1118 and for Hazardous Air Pollutant Major Source [FCAA § 112(G)] Permit HAP-14.
  State Office of Administrative Hearings Docket No. 582-09-2045;
  TCEQ Docket No. 2009-0032-AIR.
  Deposition: September 21, 2009
  Hearing: October 16, 2009
- Application of Las Brisas Energy Center, LLC for State Air Quality Permit No. 85013 and Prevention of Significant Deterioration Air Quality Permit PSD-TX-1138 and for Hazardous Air Pollutant Major Source [FCAA § 112(G)] Permit HAP-48 and Plantwide Applicability Permit PAL41.
  State Office of Administrative Hearings Docket No. 582-09-2005;
  TCEQ Docket No. 2009-0033-AIR.
  Deposition: October 9, 2009
  Hearing: November 5, 2009
  Hearing: November 6, 2009
- Abarca, Raul Valencia, et al. v. Merck & Co., Inc., et al.
  United States District Court, Eastern District of California,
  Case No. 1:07-CV-00388-OWW-DLB
  Deposition: April 13, 2010
  Daubert Hearing: October 7, 2010
  Daubert Hearing: October 13, 2010
  Daubert Hearing: October 14, 2010
  Rule 706 Expert Hearing: December 2, 2010
  Trial: February 10, 2011
- Commonwealth of Kentucky, Energy and Environment Cabinet, File No. DAQ-41109-048. Sierra Club, Kentucky Environmental Foundation, and Kentuckians for the Commonwealth v. Energy and Environment Cabinet, Division for Air Quality, and East Kentucky Power Cooperative, Inc.
  Deposition: August 31, 2010

ATTACHMENT 2:

Email from IDEM transmitting AEP modeling files;

Description of modeling files by David Long, AEP

Camille Sears

From: "CALLAHAN, BRIAN" <BCALLAHA@idem.IN.gov>
To: <camille.marie@sbcglobal.net>
Cc: "RITTER, KEN" <KRITTER@idem.IN.gov>
Sent: Thursday, September 06, 2012 7:15 AM
Attach: IMPRockportData.zip
Subject: re: AEP Rockport

Camille,

My name is Brian Callahan. I am an air modeler and work for IDEM under Ken Ritter. I recently modeled the AEP Rockport facility (for SO2 only). Take a look at the attached zip file. This file came directly from AEP Rockport and contains data that should help you in your modeling analysis.

If you have any questions, please email.

BEC

Brian E. Callahan

Indiana Department of Environmental Management
Office of Air Quality – Air Programs Branch
100 N. Senate Ave.
MC 61-50 IGCN 1003
Indianapolis, IN 46204-2251

Work: 317-232-8244
Fax: 317-233-2342
Email: bcallaha@idem.in.gov

Attached are the following files used to develop the fenceline receptors and BPIP data along with other plant data and AERMOD Sample Input files:

1. AERMAP Data - Input file aermap.rpplt.inp containing the fenceline receptors, Rp.dem, the dem file used to determine the fenceline receptor elevation and RPMPLTFence.out containing the final receptor set with elevations. The receptor set covers the fence surrounding the main plant site only. Indiana Michigan Power owns siginficantly more land around the plant which is not included in this file.

2. BPIP Data - Input file rpbpip.inp, rpbpip.out which contains the parameterizations for use in AERMOD, and rpbpip.dat which gives the information on how the parameterization was conducted.

3. AERMOD Sample Input - A sample input file with the input data for the five sources included in this study. The input stream is set up for SO2 emissions at the current permit limits with all sources operating at full load.

4. RP Stack Data Information Sheet - Two tables that contain full load stack and emissions data for all sources by STACK. Annual data from the 2009 emission statement (filed in June 2010) is also included in table 2.

The surfer plot used to establish the coordinates is not included due to its size (approximately 100 MB). If you desire a copy of this file, please contact David Long at AEPSC at 614-716-1245 or djlong@aep.com.

David Long
3/21/2011

ATTACHMENT 3:

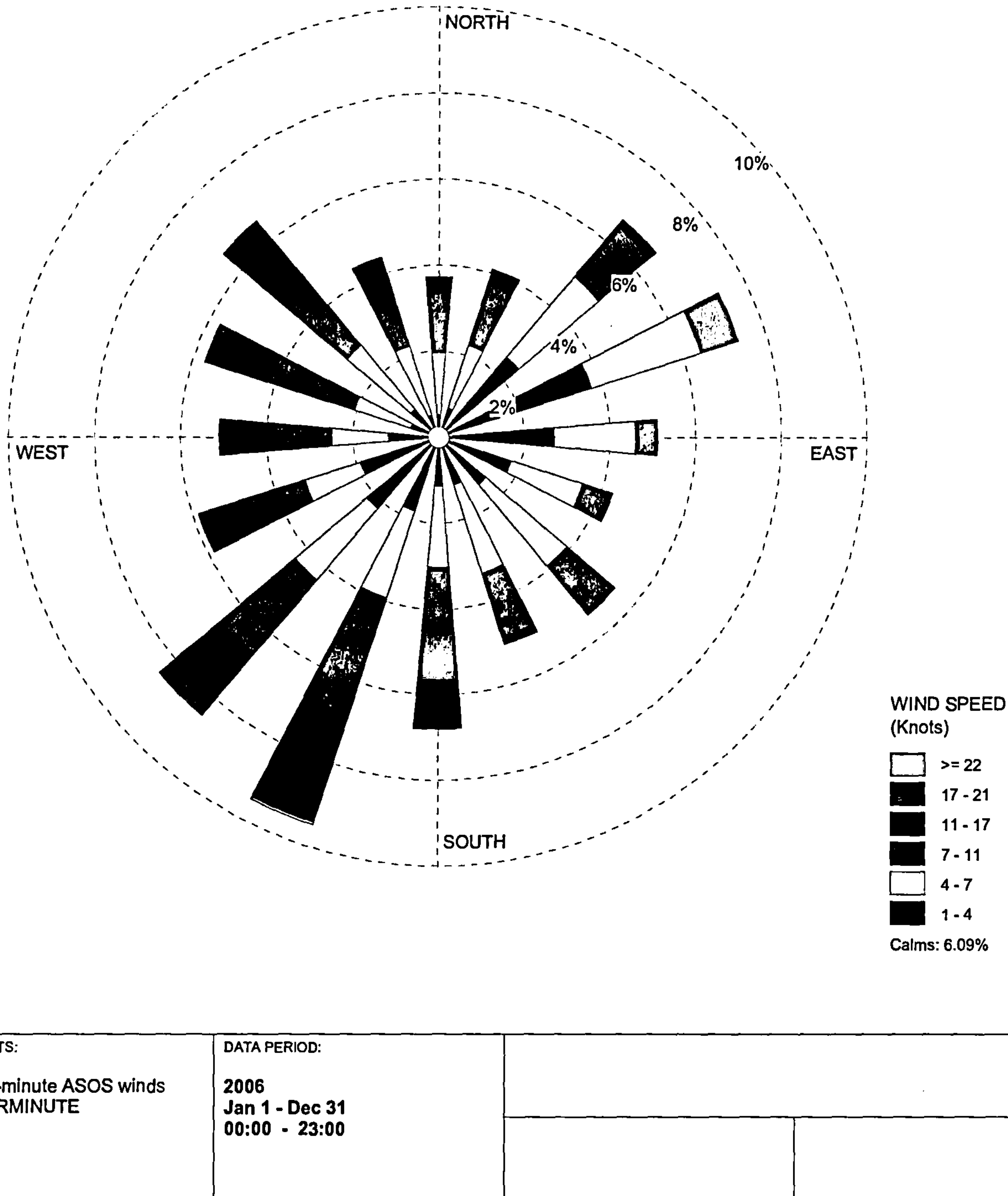
2006 through 2010 Wind Roses

Surface met: KEVV – Evansville Regional Airport
Upper air: KILX – Lincoln-Logan County Airport

Used as AERMOD inputs for:
AEP Rockport Power Plant

WIND ROSE PLOT:

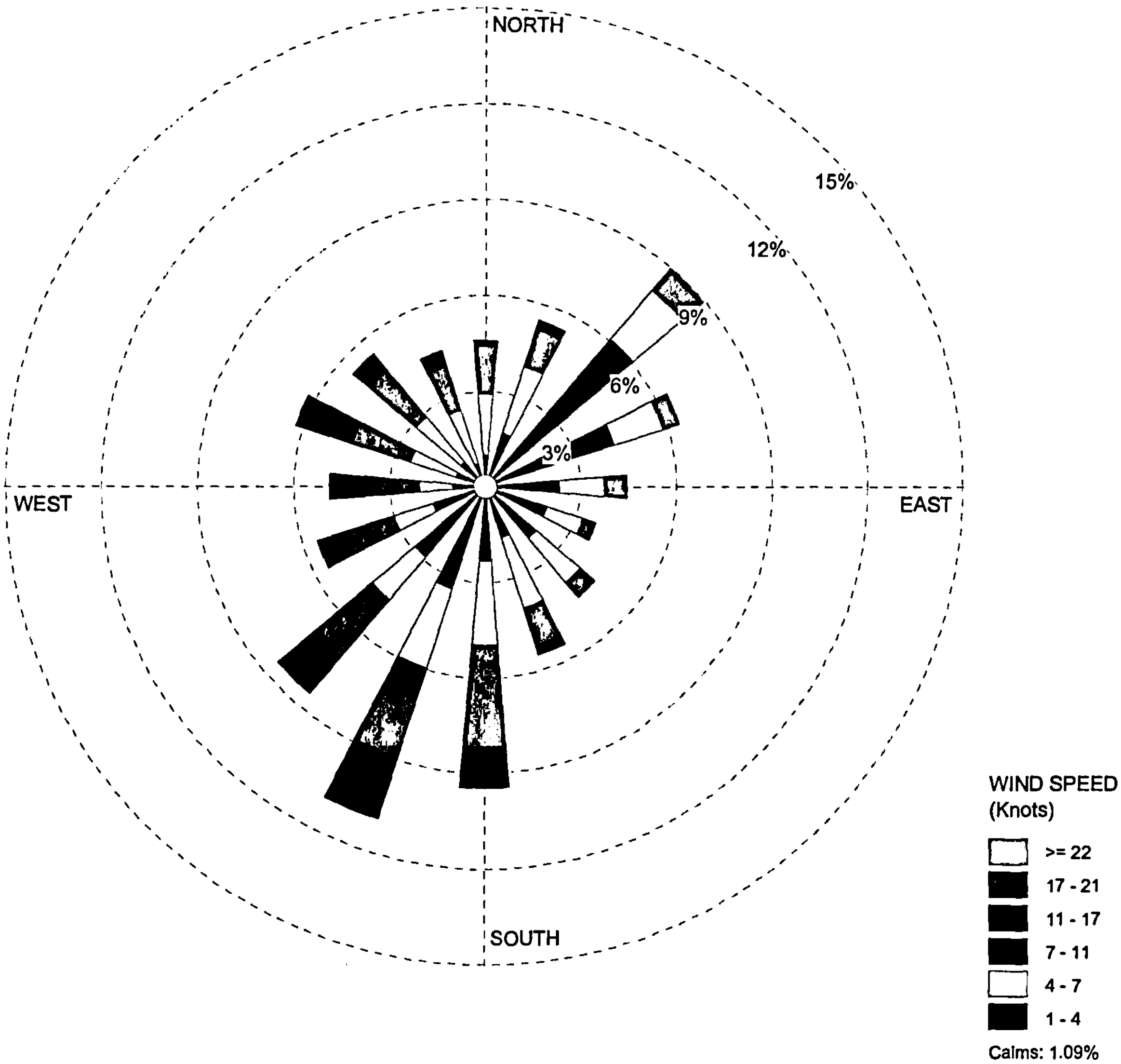
Surface met: KEVV
Upper air: KILX



COMMENTS: Using 1-minute ASOS winds with AERMINUTE	DATA PERIOD: **2006 Jan 1 - Dec 31 00:00 - 23:00**	
	CALM WINDS: **6.09%**	TOTAL COUNT: **8717 hrs.**
	AVG. WIND SPEED: **6.41 Knots**	PROJECT NO.:

WIND ROSE PLOT:

Surface met: KEVV
Upper air: KILX

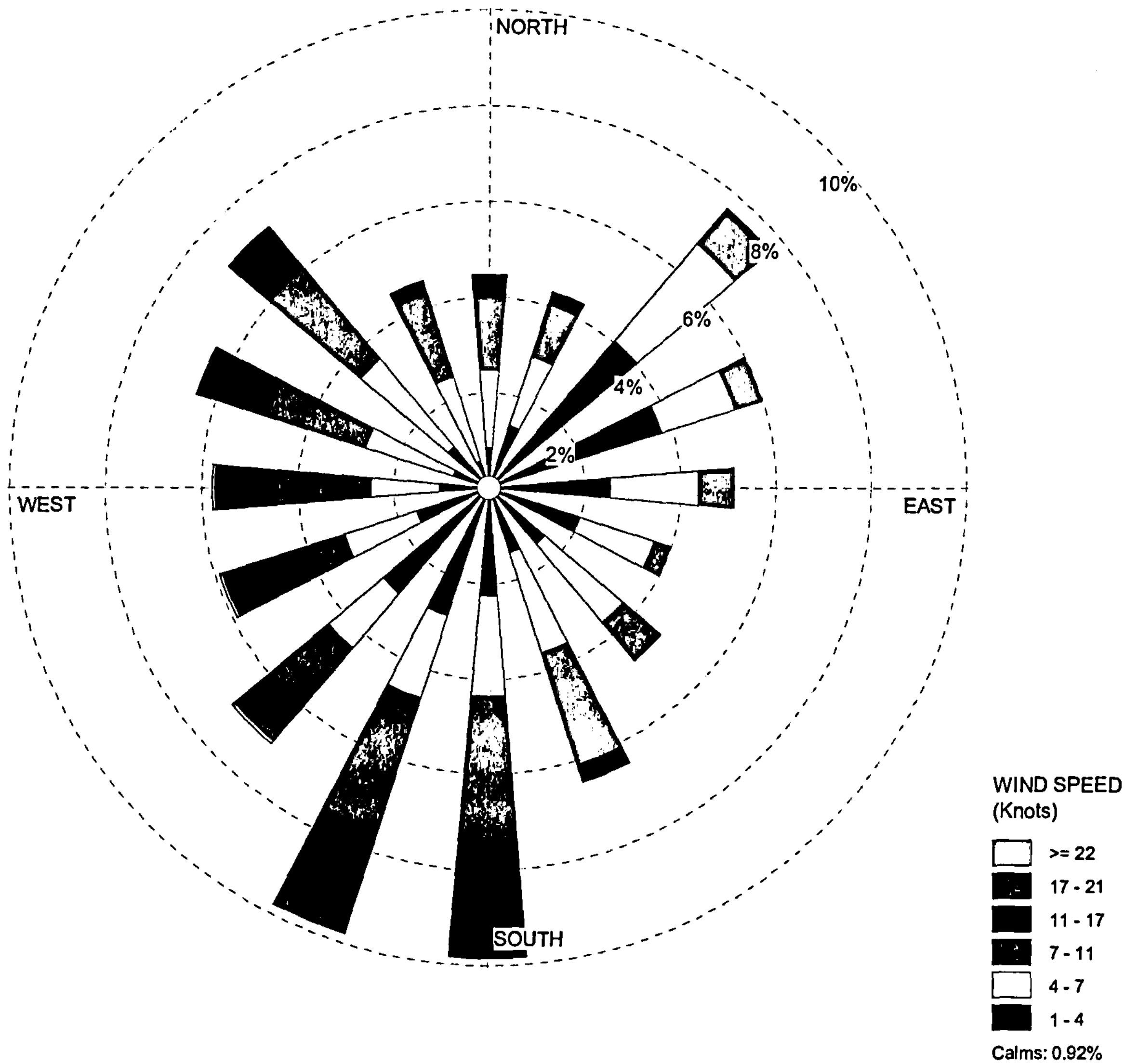


COMMENTS: Using 1-minute ASOS winds with AERMINUTE	DATA PERIOD: **2007** **Jan 1 - Dec 31** **00:00 - 23:00**	
	CALM WINDS: **1.09%**	TOTAL COUNT: **8719 hrs.**
	AVG. WIND SPEED: **6.06 Knots**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

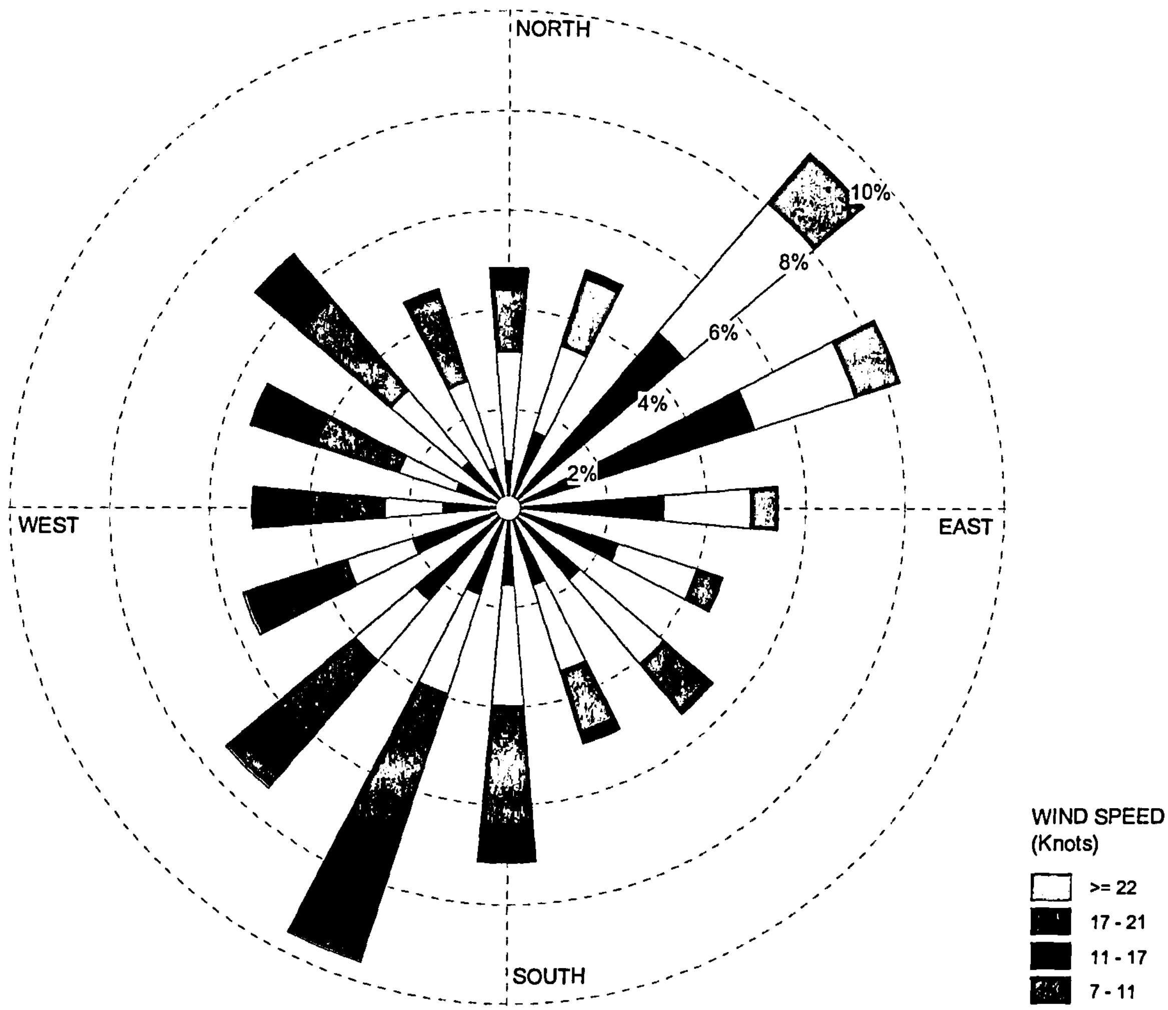
Surface met: KEVV
Upper air: KILX



COMMENTS: Using 1-minute ASOS winds with AERMINUTE	DATA PERIOD: **2008** **Jan 1 - Dec 31** **00:00 - 23:00**		
	CALM WINDS: **0.92%**	TOTAL COUNT: **8757 hrs.**	
	AVG. WIND SPEED: **6.47 Knots**		PROJECT NO.:

WIND RDSE PLDT:

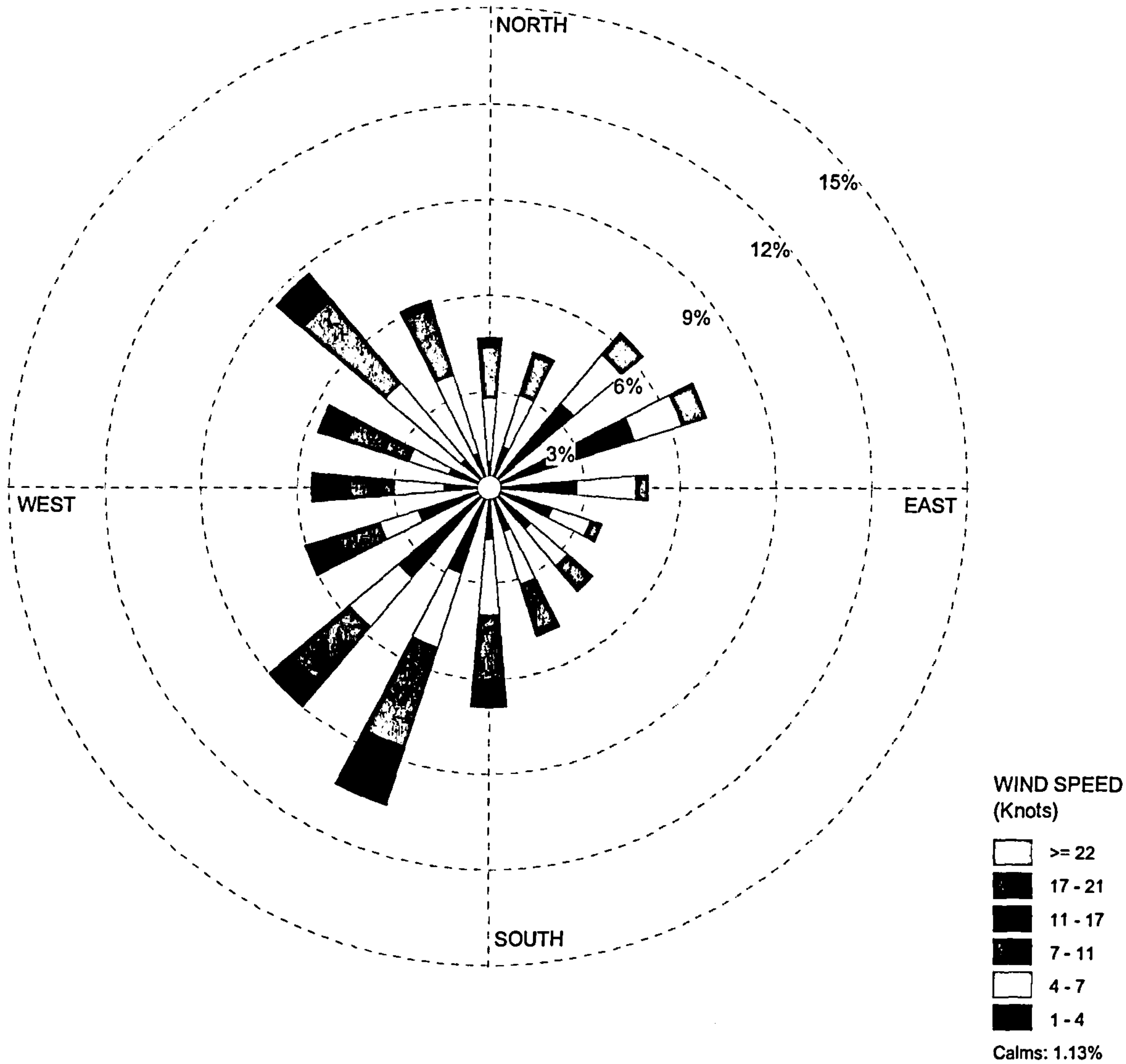
Surface met: KEVV
Upper air: KILX



CDMMENTS:	DATA PERIDD:	
Using 1-minute ASOS winds with AERMINUTE	2009 Jan 1 - Dec 31 00:00 - 23:00	
	CALM WINDS: 0.51%	TOTAL CDUNT: 8745 hrs.
	AVG. WIND SPEED: 6.17 Knots	PROJECT ND.:

WIND ROSE PLOT:

Surface met: KEVV
Upper air: KILX



COMMENTS: Using 1-minute ASOS winds with AERMINUTE	DATA PERIOD: **2010 Jan 1 - Dec 31 00:00 - 23:00**	
	CALM WINDS: **1.13%**	TOTAL COUNT: **8744 hrs.**
	AVG. WIND SPEED: **5.94 Knots**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

rE

RÁBAGO ENERGY LLC

2025 EAST 24th AVENUE
DENVER, COLORADO 80205
KARL@RABAGOENERGY.COM
512.968.7543

Date: 30 April 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Integrated Resource Planning Report	)	
Of Kentucky Power Company To The	)	Case No. 2013-00475
Kentucky Public Service Commission	)	

* * * * * * * * *

Comments of Karl R. Rábago, Rábago Energy LLC

On Behalf of

Sierra Club

I. Introduction

A. Background of Karl R. Rábago

Karl Rábago earned a B.B.A. in management (1977) from Texas A&M University, a J.D. with honors (1984) from the University of Texas School of Law, and LL.M. degrees in military law (1988) and environmental law (1990) from, respectively, the U.S. Army Judge Advocate General's School and Pace University School of Law. He served for more than twelve years as an officer in the U.S. Army, including in the Judge Advocate General's Corps and as an assistant professor of law at the United States Military Academy at West Point, New York. Mr. Rábago has worked for more than 24 years in the electricity industry and related fields. He served as a Commissioner with the Texas Public Utility Commission (1992-1994) and as a Deputy Assistant Secretary for the Office of Utility Technologies with the U.S. Department of Energy (1995-1996). More recently, he served as Director of Government and Regulatory Affairs for the AES Corporation (2006-2008) and as Vice President of Distributed Energy Services for Austin Energy, a large urban municipal electric utility in Texas. In 2012, he founded and became the principal of Rábago Energy LLC. He currently serves as Chairman of the Board of Directors of the Center for Resource Solutions (1997-present) and as a member of the Board of Directors of the Interstate Renewable Energy Council (2012-present). Mr. Rábago's education and work experience is set forth in detail on his resume, attached as Exhibit KRR-1.

Mr. Rábago has more than 20 years of experience working with the regulatory, technology, and business issues associated with solar energy. As a public utility commissioner in the early 1990s, he worked with utilities in Texas to craft line extension rules and supported utility pilot and demonstration projects in

Texas. He worked with stakeholders around the country as the Vice-Chair of the NARUC Energy Conservation Committee to establish the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology ("PV-COMPACT"), a supporting organization to the Utility PhotoVoltaic Group ("UPVG"), funded by an innovative and successful new approach to public/private partnership in technology demonstration and deployment. As Deputy Assistant Secretary at the U.S. Department of Energy, he was responsible for the solar photovoltaic research, development, and demonstration, and supervised research programs conducted at the National Renewable Energy Laboratory, Sandia National Laboratory, universities, and other organizations. He testified before and worked with Congress to grow solar research programs funded at the Department of Energy. While at the Environmental Defense Fund, Mr. Rabago worked with all the major utilities in Texas on deliberative polling exercises in the context of integrated resource planning to gauge and report strong public support in Texas for solar energy, and to reflect that in the RPS enacted in utility restructuring. At Rocky Mountain Institute, Mr. Rabago co-authored "Small Is Profitable," a definitive reference that characterizes the operational, engineering, financial, and economic benefits of right-sized energy resources, including solar PV. At Austin Energy, Mr. Rabago led the utility's $5 million annual capital program for solar project development on public buildings, and managed commercial and residential rebate and net metering programs. While there, he developed the award winning "Value of Solar Tariff" now used in Austin and recently adopted in Minnesota law. Mr. Rabago is widely regarded as one of the nation's experts in solar rates and valuation, and has published in several articles and, working with IREC, issued a highly-respected study entitled "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation." Mr. Rabago has testified and/or submitted formal comments on solar valuation in Georgia, North Carolina, Minnesota, Michigan, Louisiana, Missouri, Virginia, and Iowa.

B. Purpose of Comments

These comments make the following key points:

1. The goal of utility operations should ultimately be the procurement and operation of the most cost-effective and economically efficient portfolio of resources to meet the demand for electricity services. In order to properly compare alternative resources, each resource must be valued correctly. Under-valuation of resources, like over-valuation, results in suboptimal resource procurement across the portfolio. The Integrated Resource Plan is the best place for that valuation.

2. Valuation techniques for solar energy resources have significantly improved over time and with decades of deployment experience, allowing utilities, regulators, and policy makers to make better-informed decisions about how much solar maximizes benefits to the utility and ratepayers. Though the price paid by utilities to purchase or support solar generated electricity has dropped dramatically over the past ten years—a trend that is expected to continue—this is only part of the equation. The "value" of solar to the Company and ratepayer is now well documented and should be properly reflected in resource planning.

3. Numerous published solar valuation studies confirm that distributed solar resources offer cumulative energy, capacity, and ancillary services valued in excess of retail rates. This means that not only is net metering cost effective, but also there is evidence that net metered solar customers actually provide excess energy and benefits to other customers and the grid. Utility scale solar resources similarly provide value in excess of conventionally calculated avoided costs. These studies show that in addition to the energy-related value, solar offers financial and security benefits, environmental services benefits, and economic development benefits. While the Company recognizes the existence of some of these benefits and values, the analysis and quantification in this IRP comes up significantly short.

4. Based on research available on the value of solar ("VOS") and the record in this proceeding, it is reasonable to conclude that the Company's analysis of solar electric generation options is inadequate and incomplete. The Company should be directed (in the short term) to modify and improve its assessment and evaluation techniques to align with best practices in solar valuation and in order to support and/or procure additional solar resources beyond the levels the Company has set for these resources. The Company can identify and benefit from the true resource potential for solar by supporting and/or purchasing electricity from solar resources at an effective price likely well below its value.

5. Based on experience gained in other regions, the Company should be directed to conduct a full value of solar analysis and to use that analysis to inform the development of new goals, programs, and rates and incentives relating to solar energy resources.

II. Solar Energy Resources Can Contribute to a Least Cost Plan

Kentucky is home to great solar energy development potential, almost entirely untapped to date. According to a report by Downstream Strategies, entitled "The Opportunities for Distributed Renewable Energy in Kentucky," published in June 2012, a conservative estimate of solar development potential is more than 5,600 MW of solar by 2025. This could meet 6% of the state's energy needs with significant additional economic, operational, and environmental benefits. Kentucky has better or equivalent solar resources than many nearby and neighboring states that surpass Kentucky in development of solar energy, including North Carolina, Tennessee, Virginia, Ohio, and Pennsylvania.

Solar energy generation technology, at both the utility and distributed scale, allows utilities to avoid a wide range of costs associated with conventional generation options. In a recent avoided cost docket in North Carolina, for example, the North Carolina Sustainable Energy Association ("NCSEA") provided evidence that objectively quantified the benefits and costs of solar generation to North Carolina utilities through a report by Crossborder Energy.[1] This report found that the benefits to a utility from wholesale solar generation range from 9 to 15.6 cents per kilowatt-hour, which are 40% greater than a utility's costs to purchase and integrate solar resources.[2] These benefits are inherent to solar generation's innate characteristics – its natural coincidence with peak summer demand; its ability to avoid transmission capacity costs and line losses by siting smaller systems on the distribution grid closer to load; its scalability and modularity; its lack of fuel volatility; and other characteristics.[3] The Crossborder North Carolina study confirms what other solar valuation analyses have found – that solar offers significant benefits that are not being quantified through traditional utility resource valuation and avoided cost methodologies. As summarized in Rocky Mountain Institute's eLab Project report entitled, "A Review of Solar PV Benefit and Cost Studies," at Exhibit KRR-2, numerous published VOS studies are now available that confirm that solar resources offer energy, capacity, line loss savings, financial, and security benefits that exceed retail rates for electricity and, therefore, these resources should be paid their full avoided costs. There is good reason to believe that analysis such as conducted in North Carolina and other states would reveal similarly significant economic benefits to Kentucky from increased solar energy development. These empirical data make clear that a more robust analysis of solar resource value is now required.

---

[1] Crossborder Energy, *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina* (Oct. 18, 2013), Exhibit KRR-7, Tr. Vol. 2 at 180 (Docket No. E-100, Sub 136) (hereinafter, "Crossborder Study").
[2] Id. at 3.
[3] Id. at 7-18.

Renewable energy generation systems have dramatically different characteristics compared to combustion turbines—most critically, the capital-to-fuel cost relationship. Under traditional resource assessment and avoided cost methodologies, where least cost is derived only from a simple or generic calculation of avoided energy and capacity costs, several real and measurable costs are ignored. As a result, traditional resource assessment methodologies, such as that used by Kentucky Power Company ("KPC") in this IRP, lead to calculations of value that are incomplete and inaccurate, and therefore creates a very real likelihood that the utility resource plan erroneously fails to pursue a low cost and valuable resource.

Value of Solar Analysis

In contrast to KPC's deficient approach here, a Value of Solar ("VOS") analysis identifies and characterizes the value attributes of solar energy generation. Full and updated evaluation of resource value improves the chance that a forward-looking resource plan will strike the economically efficient balance in crafting a robust and least-cost resource portfolio. If a renewable generation resource is under-valued by the Company, it will be under-selected and under-utilized in the IRP. If the plan under-values a resource with greater value and lower cost, there is an unnecessary upward pressure on rates because the next best resource with lower value and/or greater cost will be selected. Likewise if the plan overvalues a resource with lower value and higher cost, there is also unnecessary upward pressure on rates. Updating value calculations of generation resources on a frequent basis enables the Commission and the Company to capture changes in technology, performance, costs, and risks. This is especially important in rapidly evolving market segments like the solar energy market. Stated simply, unless resources are identical, differences in current market price only tell part of the essential value story. It is not enough to say that one resource is "expensive" compared to another unless the benefits of the competing resources are also assessed and compared.

A VOS analysis is, in essence, a full avoided cost approach with a long term valuation perspective. Most VOS studies share a common general approach and fairly common general structure. VOS analysis identifies and characterizes the value attributes of distributed solar energy generation in two steps: First, benefits and costs are identified and grouped. Second, the benefits and costs are quantified. Valuation results vary depending on specific methodologies, local energy markets, and other factors, but a growing body of VOS research consistently demonstrates that distributed solar energy has value that significantly exceeds electric utility and ratepayer costs.

The benefits and costs studied in a VOS analysis are those that accrue to the utility and its ratepayers as a result of meeting demand for electricity services using a distributed solar electric facility rather than the incumbent electric utility's current and planned system resources. These benefits and costs are created when energy generated at the solar facility is generated and consumed over the entire useful life of the facility and are quantified using system average and locationally-specific values associated with displaced utility "system" energy.

Traditional avoided cost analysis differs from VOS analysis in two key ways. First, most avoided cost analysis is not a "full avoided cost" calculation. Second, traditional avoided cost analysis differs from more far-reaching, forward-looking analyses used to evaluate new resource additions.

A major difference between the two approaches relates to risk. Not all resources bear the same risks. Risk is not well addressed even in full avoided cost methodologies. A resource that depends on long-term availability of fuel at an affordable price is very different from distributed solar, which has no fuel cost, now or in the future. This risk of price volatility is not captured in avoided cost calculations or in the Company's IRP. Risk, therefore, is often either ignored or undervalued. In this IRP, the Company acknowledged risk reduction benefits from renewable resources in its risk analysis, but assigned no value to these findings.

Undervaluing fuel volatility risk means that a resource option like distributed solar is seen to avoid less cost than it actually does. This results from adjustments made to traditional ratemaking and cost recovery decades ago. Utilities increased their dependence on generation run on fuels with volatile pricing patterns. They sought pass-through cost recovery mechanisms for fuel costs in fuel cost reconciliation charges or "fuel adjustment charges," as they are called in Kentucky. Generally, regulations approved the addition of fuel costs recovery riders on customer bills, over and above basic rates for electricity to address potential regulatory lag issues arising from price volatility.

As a result, utility finances were largely immunized from the deleterious impacts of regulatory lag in fuel cost recovery, but also less sensitive to fuel price volatility than even their customers. The typical "peaker" approach to avoided cost calculations confirms this—it is a methodology that essentially gives no value to resources that reduce fuel price volatility and instead affirmatively favors resources with low capacity costs, even if the long-run fuel and capacity costs of the resource are extremely variable. By undervaluing distributed solar, this approach can lead a utility to procure or support solar at a sub-optimal levels in its planning, systematically rejecting resources that reduce portfolio exposure to fuel price volatility risk.

A similar undervaluation arises regarding security risk and vulnerability to disruptions due to natural and man-made events and risks associated with obtaining water at affordable prices, for example. Economic efficiency is maximized by an analysis that quantifies the full future stream of benefits and costs avoided over the full operational life of distributed solar and expressly addresses the volatility associated with all costs over the life of each resource option. There is significant value in a generation resource that has no fuel or water cost over its entire life—a value that appears to be unquantified in the Company's planning process.

Understanding risk reduction value of all types associated with increased deployment of distributed generation is key to constructing an optimally diverse portfolio of resources.

Recommendations for Assessment of Solar Value Components

The Company considers only wholesale energy and capacity value in its evaluation of solar energy. In order to correctly, completely, and objectively evaluate the solar energy option, a more comprehensive analysis is required.

In order to fairly value the costs and benefits of different technologies, the contributions they can each make must be objectively and quantitatively analyzed. Each technology must be fully characterized in order to understand the energy, capacity, transmission, distribution, line loss reduction, operating risk, environmental, and other known and measurable costs that can be avoided with their deployment and operation in order to support a true least cost plan.

The location, scale, timing and other operating characteristics of generation and other resource options should also be recognizable and recognized in determining their respective costs and benefits. The use of solar-specific load shapes is one example of the application of this principle. Rather than attempting to normalize all deployment options against the performance of the marginal generation resource (typically, a CT or CCCT), the range of potential avoided cost benefits must be fully documented and incorporated into a flexible methodology that calculates avoided cost benefits for each unique technology configuration.

The following values need to be quantified in order to calculate the full costs and benefits of solar generation:

Energy Value – this is the energy value provided by solar electric generation. There is a natural coincidence of solar output with summer peak demand, when air conditioning load is highest. Energy value should be calculated based on the difference between long-term production costs with the solar generation, compared to the production costs without the solar generation. I recommend that utilities calculate the value of energy based upon technology-specific and location-specific load shapes. For example, tracking photovoltaic ("PV") systems produce more energy late in the afternoon than south-facing fixed-mount PV systems.

Avoided System Loss Value – the line-loss savings that accrue where solar displaces generation from remote, central station plants. This should be calculated based on marginal losses, which should be load-weighted and distinguished between distribution and transmission losses.

Generation Capacity Value – the cost of generation that is deferred or avoided due to non-utility solar generation. First, the capacity value should be based on the technology and location of the qualifying facility ("QF") based on a model of historical solar availability correlated to historical system load during peak hours. The preferred approach is known as Effective Load Carrying Capacity ("ELCC"). Second, the capacity value should be fixed at the time that the system owner commits to interconnect the system to the grid so that the owner can be certain what value the utility will attribute to the QF facility. Third, as solar is scaled up on the system, the capacity attributed to new QF generation sources will likely be different from that attributed in earlier years.

Transmission and Distribution Capacity Value – the cost of transmission or distribution that is avoided due to non-utility solar generation, after netting the utility's costs to integrate solar resources. This calculation should utilize the approach described for generation capacity, and should not be limited to large planning increments.

Fuel Price Hedge Value – the utility's costs associated with fuel price volatility that are avoided due to solar generation. Long-term fixed-rate contracts with QFs provide a hedging value against fuel price volatility and escalation. A long-term contract provides a guarantee that the rate paid to the QF will not fluctuate with fuel prices. Moreover, unlike "traditional" PURPA QFs that rely on natural gas or biomass fuels, with fuel-free resources like solar and wind there is no risk that the QF supplier's business will fail due to changes in fuel costs, because there are no fuel costs. While quantifying the fuel-price hedging benefits of renewable energy resources may be challenging, the value should not be set at zero.

Market Price Response Value– the costs that a utility avoids by purchasing from a solar QF due to decreases in its average price of fuel. Purchasing electricity from fuel-free solar or wind QFs allows utilities to dispatch their natural gas or coal power plants less frequently, which in turn decreases the average cost of fuel used by the utilities to generate electricity in two ways. First, the utilities are able to reduce the number of hours in which they dispatch higher fuel cost power plants. Second, the utilities buy less fuel, thus impacting the market price of fuel overall.

Avoided Environmental Costs – the costs that a utility avoids by purchasing from a solar QF, including avoided costs related to environmental regulation not already reflected in energy costs. While current energy prices should reflect current environmental compliance costs, long-lived renewable energy resources also avoid additional environmental costs associated with future compliance costs. While these costs must be estimated like any long-term avoided cost, planning numbers associated with regulation of greenhouse gas emissions reflect imminently real costs that are not zero.

III. Findings from the KPC IRP

Solar Valuation and Impacts

Selection Criteria for Utility Scale Solar – IRP Section 4.3.4.5.a. – The Company recognizes that solar costs are falling rapidly and relied on consultants to conclude that average in some unspecified market and at some unspecified scale, solar costs are expected to become "nominally flat" on or about 2020. The

Company then imposes a ceiling of 10 MW per year starting in 2020. This amounts to a growth rate of about 1/3 of 1% per year. The growth rate is never increased above 10 MW per year, even as experience grows. The Company cites no basis for these assumptions, nor does it propose any alternative growth scenarios in any of its analysis. The Company makes additional simplifying assumptions, also unsupported by analysis, including that the capacity credit for all solar should be 38% (the PJM-wide default value), and points out that peak solar output under unspecified technical configurations and in unspecified locations occurs typically at 1 p.m., while noting that PJM's peak is in the late afternoon, around 5 p.m.. It is important to note that use of the default 38% capacity credit for solar is a vast improvement on use of a simple capacity factor. However, analysis specific to the Company system, which does not require actual solar operating data, could well lead to a much higher capacity credit value.

In IRP Section 4.6.3, the Company explains that it constrained its Plexos model's consideration of solar with a single set of forecast costs, the 38% capacity credit, and no more than 10 MW of solar per year starting no earlier than 2020. According to the Company's response to Sierra Club Request 1-3, in Attachment 2, the Plexos model also used an unusually high 15% weighted average cost of capital for utility scale solar. As explained in IRP Section 4.7, the model selected exactly 10 MW of solar per year for every modeled year after it was allowed to. The model's selection of 10 MW of utility solar per year only deviated by a total of 10 MW under the low-cost gas and high-cost CO2 alternative scenarios. This creates a strong indication that the constraints and assumptions imposed on the model's selection of utility solar acted to limit the amount of solar that the model would have identified as cost-effective. Rather than concluding that "time will tell" whether solar grow rates can exceed the constraints forced on the modeling analysis, the Company should allow the model to operate without those constraints.

As discussed below, even though the Company recognized a hedge value in wind and solar resources, that value was not monetized or quantified in the modeling exercise. Nor were other risk reduction benefits associated with renewable resources, even though the Company identified in IRP Section 4.8.1, a significantly reduced Revenue Requirement at Risk benefit from both large and small scale renewable resources.

Selection Criteria for Distributed Solar – IRP Section 4.7.1 – The Company concludes that distributed solar generation was not selected as a resource "primarily because of the way net metering credits are determined." The Company explains that credits are given for full retail cost of electricity, which it sees as the cost of distributed net metered generation, and that system benefits are primarily energy and generation capacity benefits. In fact, careful review of the IRP and the responses provided by the Company to information requests shows that the only benefits it quantified were assumptions of wholesale energy and generation capacity value in PJM.

While the Company does not select distributed solar as a resource in its IRP, it recognizes some level of adoption of solar by customers based on economic value. In response to Sierra Club Request 2-39, the Company provided Attachment 1 that reveals the surprising assumption that distributed solar adoption grows at a 40% rate until 2016, then in 2016 grows at 1800%, then slows to 30% until 2019, and then grows at a flat rate of 25% per year through 2030. These assumptions are not tested under an alternative scenario, and no explanation is provided for the surprising assumption that the rate of solar adoption decreases as solar prices fall.

Common Assumptions for Utility and Distributed Solar – IRP Section 4.7.1 - Figure 22, at page 162 in the IRP captures the primary assumptions and major errors in the Company's approach to evaluating distributed and utility scale solar. That chart reflects the following questionable and largely untested assumptions:

- Utility scale and distributed solar each have a single price curve over the next 10 years, to 2025, converging in about 2018. Alternative price scenarios for solar were not included in the Plexos modeling or in alternative curves in Figure 22.
- Utility scale and distributed solar costs become "nominally flat" in 2020, though cost effective several years earlier.
- Distributed solar can never be cost effective because it can never be worth more than PJM value and because retail rates will always be higher than PJM value. The Company stated in response to Staff Request 2-11 that distributed solar costs were evaluated only on the basis of net metering credit cost to the utility.
- Distributed solar has higher cost and lower utility value, even though net metering customers pay a substantial fraction of the cost of their solar systems, and bear all the operational and insurance risk associated with the system.

Load Reduction and Solar Integration Costs - IRP Section 3.5.1.5-6 – The Company states that behind the meter generation results in a reduction to load and additional incremental costs to the utility to accommodate.

The Company did not quantify either the value of reduction to load or accommodation costs except to consider that distributed solar had a cost of either full retail rate under net metering or the PJM avoided cost for energy and capacity.

In response to Staff Request 1-27, the Company further stated that it is "unlikely that greater net metering will have an impact on the distribution and transmission system" because it assumed no change in current net metering limits of 30 kW per premise and an aggregate of 1% of peak load. The Company stated that determining whether changes in limits would change impacts would require additional study.

In response to Staff Request 1-37, the Company stated that its assessment of "economically justifiable" was limited to a test of present value of revenue requirements with the only determinants being installed costs of solar and prevailing PJM market costs.

Hedge Value - IRP Section 4.7 – The Company correctly states that non-traditional resources, including solar and wind generation, "would then serve as a hedge to reduce exposure to (PJM) markets," and indicated that this "may be particularly desirable, depending on CO2 costs."

When asked to explain this statement in response to Staff Request 1-44, and Staff Request 2-3, the Company provided no quantitative analysis of hedge value, no explanation of why hedge value would depend on CO2 costs, and no estimate of reduction in impacts in market driven price spikes. Nowhere in the IRP does the Company adjust its assessment of the economics of solar and wind resources in recognition of the hedge value and, therefore, KPC's analysis fails to account for a major value of solar generation.

Transmission and Distribution Capacity Value – IRP Section 4.7.1 – The Company reports that solar power advocates argue for recognition of value for off-setting grid investments, including transmission and distribution addition. Without any analysis, the Company reports that a single chart at Figure 23 "nullifies" this argument because in a chart depicting hypothetical solar production in an unknown location and configuration against system demand, there is little or no solar output at the point of highest system demand. The Company confirmed in response to Sierra Club Request 2-20 that it had not quantified the transmission and distribution system value that might accrue from solar generation.

In response to Sierra Club Request 2-34, the Company stated that "As described in section 4.7.1, transmission costs were not included in the evaluation of distributed generation because of the winterpeaking nature of Kentucky Power" and that "Kentucky Power does not have sufficient data to incorporate incremental operational, maintenance, or outage costs or cost savings that may result from distributed solar installations."

The Company acknowledges, in response to Staff Request 1-46 that solar generation has capacity value during the summer and that PJM capacity value was used, but conducted no analysis such as Effective Load Carrying Capability analysis to quantify the value on its system. (See Company response to Sierra Club Request 2-38.) Nor did the Company apparently consider different solar configurations or the opportunities presented from solar generation operating in conjunction with other non-traditional resources such as other forms of distributed generation. Other forms of distributed generation were not evaluated at all (see IRP Section 3.5.1.6).

The Company also reports that is has conducted no examination of potential sites for solar facilities in response to Staff Request 2-1.c., and Sierra Club Request 2-22. As a result the IRP does not address additional potential value from the targeted siting of solar generation to address transmission and distribution system needs.

Systems Losses – IRP Section 4.7.1 – The Company reported, in response to Sierra Club Request 2-39, Attachment 1, that it factored line losses of 8% across the board through all years in calculating energy produced by net metering customers. The Company also reported data in response to Sierra Club Request 2-27, Attachment 1 that shows that losses vary according to customer class, month, season, and, apparently, load. Line loss credit for distributed solar was not weighted by these factors, nor was line loss reduction value applied to the calculation of capacity value for distributed solar.

Options, Risk, and Scenario Analysis – IRP Section 4.7.1 – As explained in several places, above, the Company estimates that distributed solar generation could be potentially cost effective for customers within a few years, and that all solar will be cost effective no later than 2018, with prices becoming nominally flat by 2020. The Company conducts no assessment of variations from its assumptions about the prices, price reduction rates, deployment configurations, or deployment rates for solar. See the Company response to Sierra Club Request 2-19, confirming that it had conducted no analysis of accelerated cost-effectiveness (sooner than 2020) because "any result [of that analysis] would be hypothetical and would not result in any action on the part of Kentucky Power." The Company also confirmed in that response that it had not conducted any sensitivity analysis around cost-effectiveness and market uptake of distributed solar generation because "[t]here is not sufficient information available given the low retail rates, low insulation, and prevalence of low income customers" in its service territory.

The Company also reports, in response to Staff Request 2-2, that is has conducted no analysis of price sensitivity of customers and willingness to invest in self-generation or take other actions to manage their electricity bills.

In response to Staff Request 2-9, the Company confirmed that it had not conducted any assessment relating to specific options available if the Federal imposition of the greenhouse gas emissions limits, or the costs of those available options. The Company did test a scenario that included higher costs for carbon emissions, but, as described above, constrained the ability of the Plexos model to respond to those costs with more than 10 MW of new utility scale solar in any one year.

Environmental Regulation Risks and Benefits – The Company states, in response to Sierra Club Request 2-16.b. & c., that it did not consider costs for environmental emissions of NOx or SO2, and that it did not consider carbon costs before 2022. The Company stated that it did not believe costs for NOx and SO2 were likely, and that it was not unreasonable to assume that EPA greenhouse gas regulations would not take effect until 2022. The Company conducted no sensitivity analysis and did not consider scenarios that differed in these assumptions, except one scenario that considered a high cost of carbon when carbon costs were expected to begin. The Company did not consider water requirements and availability, water-related regulations, or other environmental regulatory risks. The Company assigned no value to renewable resources for their immunity from environmental regulatory risk.

IV. Conclusions

Solar Resource Assessment and Selection in the IRP

The Company's Integrated Resource Planning Report reveals that the Company and its staff are generally aware of the range of benefits and costs of solar generation at both the utility and distributed scales. The IRP Report indicates, for example, that solar generation can provide hedge value against fuel and market price volatility. The Report acknowledges the environmental benefit of renewable energy resources as well. The Company recognizes that solar generation is falling rapidly in cost.

However, the Company falls short in meeting its obligations regarding the IRP and its treatment of solar generation. Numerous requests for data and information confirmed that the Company has not collected the data or conducted the analysis necessary to adequately address solar generation as a resource. In several places, the Company advanced the self-fulfilling conclusion that because there is only a tiny amount of solar generation in its service territory, there is inadequate data to conduct the required analysis. This ignores the vast amounts of solar data available from similar locations across the United States.

In spite of the lack of data and the failure to comprehensively assess the solar generation option, the Company offers no proposal for closing the analysis gap. Given the growing body of evidence regarding the value of solar generation being revealed across the United States, this creates the great likelihood that solar generation is undervalued in the Company's service territory.

807 KAR 5:508. Section 7. Load Forecasts - The record in this proceeding fails to show a complete description and discussion of the Company's key assumptions and judgments relating to its forecasts of solar generation deployment or the constraints imposed on the resource in the Company's modeling exercises. Also incomplete is the Company's discussion of the extent to which the Company's forecasting methods address and incorporate changes in prices, demographic factors, economic factors, and other market and regulatory conditions likely to impact solar generation cost-effectiveness. The record fails to show these descriptions because, as revealed in responses to requests for information, the Company has not conducted the underlying analysis.

807 KAR 5:508. Section 8. Resource Assessment and Acquisition Plan - The Company has not adequately considered the potential impacts of key uncertainties and lacks a comprehensive assessment of solar generation resource options, in spite of the Company's own conclusion that solar generation will be cost-effective at any scale within a few years. Rather than evaluating the several criteria impacting the potential selection of solar generation as a resource, such as described above, the Company never significantly departs from an over-simplified analysis that limits the quantification of any solar generation value to PJM energy and capacity prices, and that assumes net metered solar will always be uneconomic to the utility.

Risk and Sensitivity Analysis

Under 807 KAR 5:508 Section 7.(7)(e), the Company is required to address how its forecasts are impacted by a range of potential changes in prices, market conditions, and other factors. The IRP must include "a complete description and discussion" of reasonably likely risks to the preferred plan and an examination of the sensitivity of the IRP to such changes in key factors.

The Company's evaluation of alternatives was highly constrained by the fact that it held constant almost every key variable impacting both utility scale and distributed solar resource value. The Company's economic scenarios tested only commodity prices and a single carbon price starting in 2022, and all assumed the same large scale generation sources. None included testing of variation in price curves, adoption rates, or environmental regulation.

The Preferred Plan was tested in the risk analysis against a fossil-only (with ecoPower) scenario, but no scenario with higher reliance on renewable energy and energy efficiency was developed in spite of the Company's finding that energy efficiency and solar generation both work to reduce the risk or revenue requirement volatility.

V. Recommendations

Value of Solar Report

The Company should be directed to engage an independent third-party expert and, in a transparent process that engages solar energy stakeholders, develop a comprehensive Value of Solar methodology and assessment. The Value of Solar methodology and calculations, along with recommendations for its implementation in current and future solar programs, should be reported to the Commission on or before December 31, 2014. The Value of Solar report should address the following, in line with the considerations discussed above:

- Calculations to convert the 25-year levelized value of solar into a current value;
- A standard photovoltaic ("PV") rating convention;
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin;
- Requirements for calculating the electricity losses of the transmission and distribution systems;
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity; and
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.).

Risk and Sensitivity Analysis

The Company should be directed to work with Staff and interveners in this proceeding to develop a more robust set of portfolio alternatives or scenarios, sensitivity analyses, and risk assessment analyses. This work should be completed and reported to the Commission in time for the Commission to take any appropriate action prior to the preparation of the next Integrated Resource Plan.

Develop and Launch a Distributed Solar Generation Program

The Company should be directed to develop one or more programs aimed at supporting the development and use of cost-effective distributed solar generation ("DSG"). Specific programs aimed at developing more distributed solar generation can leverage the benefits of net energy metering, encourage the creation of new jobs, put downward pressure on rates, strengthen the grid, and overcome commercialization barriers that exist today.

The primary goals for a strong DSG program should include:

- The Program and incentives should ultimately lead to a self-sustaining rooftop/small scale solar energy market in Kentucky.
- The Program should provide fair compensation for solar energy value and additional financial incentives that are economically efficient, i.e., incentives that prompt customers to make solar energy investments they would not otherwise make, without being excessive.

The Company should focus not just on numbers of systems, dollars, kilowatts, and kilowatt hours. For a pilot program that could mature into a full program, it is the direction that the numbers are moving that is most important, and whether continued progress is being made toward program objectives designed to achieve program goals. Some of the key indicators of a sound solar program include:

- Progressive reduction in the incentives stimulating customer investment in DSG.
- Progressive and systematic reductions in system and component costs.
- Progressive reduction in the fraction of system cost represented by incentives.
- Progressive increases in DSG capacity per dollar of program budget.
- Progressive increases in the numbers of solar contractors and full-time, year-round employees.

The Company program managers should track several factors on an ongoing basis that could impact local solar market conditions in order to reach a judgment about those market conditions so as to inform the setting of economically efficient solar incentive levels. Factors impacting emerging solar markets are local, regional, national, and even international. These include:

- Local and regional solar installer workloads
- Availability of skilled workforce
- Local and regional economic conditions
- Local customer awareness
- Local markets for solar financing
- Other local economic incentives
- Utility incentive programs offered by adjacent utilities
- Regulatory and legislative policy development in the state, region, and nation
- National solar module prices
- National solar incentive levels and status of programs
- National tax policy and incentives relating to solar energy
- International solar incentive programs (which impact global solar module prices)

In combination, these factors can impact customer demand for incentives and program participation. For example, when prices for modules drop quickly, customer demand for incentives can grow quickly. If such a trend is long-term in nature, adjustments to incentive levels may be warranted. In fact, recent reductions in installed solar costs as well as the availability of substantial federal tax incentives have been drivers of downward adjustments in rebates and incentives across the United States.

I have several other recommendations. These include:

- Good DSG programs feature regular meetings of program staff with solar installation contractors and stakeholders, featuring two-way dialogue about market conditions, program performance, administrative requirements, and other issues. These meetings provide invaluable "ground-truthing" for solar program managers.
- Program managers should continually reviews the state of the art in solar promotion programs to stay abreast of innovations and opportunities for program improvements.
- While solar programs should be designed to provide predictability regarding incentives and program requirements, it is also appropriate to grant flexibility to program managers to respond to unexpected or sooner-than-expected changes in DSG market conditions. When program adjustments are required they should not be a surprise to the Commission or stakeholders.
- Program managers should also be prepared for increases in the average size of installed systems as solar prices fall. Larger system sizes consume larger incentives per customer, and in a fixed budget environment, potentially reduce the number of systems receiving incentives. On the other hand, per-unit fixed and system costs decline with system size, allowing for more kilowatts per incentive dollar expended.
- Robust DSG programs should account for repeat customers. Distributed solar is modular in nature, meaning customers can install a system one year, and expand the system in later years as demand or household budget grows. These system expansion investments can be a relatively low cost path to valuable incremental market growth.