BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In re: Union Electric Company's	)	
2011 Utility Resource Filing pursuant	)	File No. EO-2011-0271
to 4 CSR 240 – Chapter 22.	)	

COMMENTS OF NRDC, SIERRA CLUB, RENEW MISSOURI, MID-MISSOURI PEACEWORKS, AND GREAT RIVERS ENVIRONMENTAL LAW CENTER

PUBLIC VERSION

I. INTRODUCTION

Missouri's resource planning rules require each electric utility to conduct a transparent and prescriptive analytical process by which it develops candidate long term resource plans, and from among them select a preferred plan that transparently and explicitly balances well-defined objectives.

Our comments will show that Ameren Missouri (hereinafter "Ameren" or "the Company) has failed to comply with these rules. Specifically,

(1) We will demonstrate that there are significant flaws in the assumptions and methodology by which Ameren conducted its analysis which warrant a decision by the Commission that Ameren should conduct a new analysis with more realistic and unbiased inputs;

(2) We will show that, despite Ameren's numerous efforts to bias the analytical results against aggressive energy efficiency deployment and toward continued reliance on the existing fleet of aging coal plants, the results of the analysis nonetheless indicate that a plan that more fully captures the benefits of energy efficiency best achieves the objectives set by both the rules and by the Company itself;

(3) Ameren has selected a preferred plan that slashes its investment in efficiency by more than 60% compared to its previous plan, which itself fell far short of capturing even Ameren's low estimates of the potential for cost-effective energy efficiency. Moreover, the Company's preferred plan continues to rely on a fleet of aging coal plants based on a scenario under which new environmental regulations do not emerge, which even Ameren admits is not a likely scenario. This course of action is not justified by its own analysis in that it neither optimizes achievement of the policy objectives set out by the rules nor optimizes achievement of Ameren's own objectives. Ameren's plan selection process amounts to a violation of 4 CSR 240-22.070(6) which specifies that, in the selection of a preferred plan, the utility must demonstrate that "In the judgment of utility decision-makers, the preferred resource plan shall strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2)." That section specifies that:

- The fundamental objective of the process is to provide safe, reliable and efficient electric service at just and reasonable rates;
- To achieve these objectives the utility must consider demand-side options on an "equivalent basis" with supply-side alternatives;
- The utility must use minimization of present worth of long-run utility costs as the primary selection criterion; and
- The utility must: "Explicitly identify and where possible quantitatively analyze any other considerations which are critical to meeting the fundamental objectives of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs.

Ameren's selection of its preferred plan is not consistent with the foregoing planning objectives, nor has it documented a rationale that supports its plan selection as required by 4 CSR 240-22.010(2)(C).

To the contrary, Ameren's plan is a flat dismissal of not only the planning objectives but also a long series of actions that Missouri policymakers have taken to encourage aggressive deployment of energy efficiency as a resource to reduce customer costs, enhance reliability, reduce environmental impacts of electricity service and the risks of costs related to environmental regulations, and promote economic growth.

Although Ameren characterizes its resource plan as low-risk, the Company's preferred plan is, in reality, a high risk resource delivery strategy that will burden customers with unnecessarily high electricity costs, as well as greater exposure to price volatility and greater environmental damage, with coal continuing to comprise 66% of the company's total energy supply through 2030. Ameren opens its plan with a description of the very real energy challenges, then refuses to adopt a resource plan that has any hope of meeting those challenges in a way that maintains safe, reliable, efficient and affordable service. We urge the Commission to require Ameren to go back to the drawing board to create a plan that does meet those challenges.

II. Plan Deficiencies Related to Demand-Side Resources

A. Ameren did not consider demand-side options on an "equivalent basis" with supply-side alternatives as required under 4 CSR 240-22.010(2)(A).

According to 4 CSR 240-22.010(2)(A), the objective of the DSM rules is to select a preferred plan that considers and analyzes demand side resources on an equivalent basis with supply-side resources. 4 CSR 240-22.060(4)(D) provides further guidance by stating that:

*The modeling procedure shall treat supply-side and demand-side resources on a **logically consistent** and **economically equivalent** basis.*

However, the Company's modeling procedures failed to compare (or treat) supply-side resources in a logically consistent manner with demand-side management. As a consequence, the economic benefits of DSM were inappropriately discounted. The Company's modeling procedures fail the 4 CSR 240-22.060(4)(D) test because:

1. <u>Ameren's analysis rests on a fatally flawed DSM potential study</u>. Inasmuch as Ameren's IRP rests in large part on its DSM potential study, the Commission must seriously evaluate the assumptions underlying the results of that study in this docket. As described in detail in the Attachment 1 to these comments, the potential study upon which Ameren bases its integrated plan is riddled with unsubstantiated assumptions all of which conspire to underestimate the potential for cost-effective savings. To summarize here:

- Ameren begins with the premise that maximum achievable potential is not, in fact, achievable;
- Ameren's methodology for reducing the anticipated savings from Maximum Achievable to Realistically Achievable Potential assumes an unrealistically slow ramp-up of customer awareness, employs "budget constraints" that preclude any comparison of DSM and supply-side options on equivalent terms; uses a 1-year payback period to estimate participation rates for MAP

in defiance of standard industry practice of using instant payback assumptions for the purposes of determining MAP; uses different payback timeframes for purposes of participation levels versus those used for purposes of incentive levels; assumes that no more than 70% of respondents will participate regardless of the actual survey results; and uses entirely unfounded estimates of the number of customers eligible for opting out of the program who do so. Please refer to Attachment 1 for a full description of these methodological deficiencies.

2. Timing and amounts of energy efficiency were predetermined for capacity planning purposes. For the equivalency test to be met, DSM resources and supply side resources must have been compared to each other within the economic model on a fair and comparable basis. Despite the equivalency requirements, the company acknowledged that the timing and amounts of energy efficiency were predetermined for capacity planning purposes. (Plan at 9-4) This means that DSM resources were considered for further analysis only after supply side resources were identified and a capacity need was established. Had Ameren treated resources on an equivalent basis, energy efficiency resources would have been input into the models along with supply side resources and allowed to "compete" on cost.

3. Ameren's modeling assumes widespread use of emerging CCS technology for supply side planning purposes but omits all emerging and emergent technologies from its DSM analysis. In several planning scenarios, the company assumes 90 percent of the CO_2 emitted from dirty coal facilities will be eliminated by installing CCS technologies. (Plan at 2-26) However, CCS technologies are new and emerging, with CCS not yet

operating on a coal power plant at commercial scale. In the event that CCS technology does not provide the assumed benefits in 2025 (or beyond), Ameren will need to continue purchasing larger amounts of renewable energy credits or pay larger financial penalties. These types of costs and risks have not been considered in the planning scenarios nor compared in a logically consistent manner with DSM-only costs.

The pursuit of new and emerging supply-side technologies, such as CCS, is logically inconsistent with the company's DSM analysis. Under its analysis of DSM potential, the company only includes commercially available technologies to estimate energy efficiency potential. What the company omits from its DSM analysis are new and emerging technologies such as LEDs. According the 4 CSR 240-22.060(4)(D) test, the Company is prohibited from excluding new and emerging technologies for purposes of estimating DSM potential. It is important to note that Ameren has also excluded technologies it deems "emerging" despite many of them being commercially available and cost-effective. For example, many utilities now offer incentives for LED lighting in their efficiency programs. As an example, Vermont DSM programs captured roughly 30% of all their commercial and industrial lighting savings in 2010 from cost-effective LED installations.[1]

4. <u>Selection criteria discount the effects of energy efficiency, and undermine the primary purpose of the IRP—to minimize the present value of revenue requirements</u>. To reduce the number of preliminary candidate resource plans, Ameren screened 216 alternative plans by applying a scorecard. The scorecard is reported to include 6 diverse performance measures with various assigned weights. The scorecard, shown below, maps

[1] Personal communication with Gabe Arnold, Lighting Markets Coordinator for Efficiency Vermont.

the Company's policy objectives to the measures designed to achieve its objectives and the weight assigned to each measure.

Policy Objective Category(ies)	Measure	Weighting
Environmental/Renewable/ Resource Diversity	Total plan carbon emissions	20%
Energy Efficiency	EE Portfolio	10%
Financial/Regulatory	PV Free Cash Flow	20%
Customer Satisfaction	Rate Increases	15%
Economic Development	Primary Job Growth (FTE-years)	10%
Cost	PVRR	25%
TOTAL		100%

One of the primary purposes of the resource plan is to minimize long-run utility costs (PVRR). But according to Ameren's scorecard, factors other than costs are assigned a 75% weight. Because cost minimization is assigned such importance, one could safely assume that PVRR should be assigned a much higher weight than 25%.

Another Company objective is to enhance its financial health. This objective is measured by PV free cash flow and is assigned a weight of 20%. Throughout its resource plan, the company acknowledges that DSM-only programs provide the highest levels of free cash flow. (Plan at 9-7–9-10) Nevertheless, the company elected a low-risk DSM plan that generates less than optimal free cash flow. This election is illogical. Had the Company correctly applied the above-noted test and screened alternative resource plans in a consistently logical manner, aggressive DSM programs would have been a significant component of the Company's preferred plan.

Another Company objective is "customer satisfaction." At first glance, this objective should benefit DSM compared to supply-side resources because it is the single resource that directly provides customers with benefits, including reduced bills, cash rebates, better comfort, etc. DSM evaluations overwhelming tend to show extremely high customer satisfaction levels. However, the Company has chosen minimization of *rates* as its surrogate to represent customer satisfaction. Rather than focusing on the bill reductions customers enjoy from DSM, and the better levels of service and improved utility relationships, using short-term rate increases as the objective measure explicitly biases Ameren's analysis against least-cost efficiency solutions and toward more expensive supply-side investments.

5. <u>Ameren assumes a "perfect ratemaking" regulatory framework when analyzing supply side resources but rejects aggressive DSM because a "perfect ratemaking" framework does not exist</u>. The Company states that because its planning analysis had been based solely on "perfect ratemaking" assumptions, a closer review of each remaining resource plan was necessary in order to take into account "realistic ratemaking and financial constraints." (Plan at 9-25) Ameren's "closer look" resulted in the removal of realistically achievable potential DSM resources. Although the DSM rules do not consider perfect ratemaking scenarios, the company nevertheless applied such assumptions to its selection of supply side resources but not DSM. This is an illogical and inconsistent treatment of DSM resources. Under the Company's selection process, all supply-side resources are assumed to be treated under a perfect ratemaking paradigm. But this is not an accurate assumption. Proposals to build new generation, for example, are thoroughly scrutinized and always subject to an after-the-fact prudency review. This type

of review subjects utilities to cost recovery risks. In the event that certain costs are found to be imprudent, utilities may not recover their full investment. Such a review is necessary to hold companies accountable and is part of a utility's regulatory compact. The regulatory compact applies equally to Ameren's investment in DSM and its supply-side investments.

As noted above, Missouri's DSM rules do not consider (nor should they) perfect ratemaking scenarios for the purposes of selecting a preferred resource plan. IRP modeling procedures should instead focus on analyzing and identifying the least-cost resource plan that appropriately balances utility costs and system reliability. What regulatory framework is necessary or desirable for Ameren is a separate issue, and the DSM and IRP rules provide a clear opportunity for the Company to make its case for the regulatory treatment it desires at a later date. 4 CSR 240-20.094(2) and (3); 22.080(2). Had the Company logically and consistently considered the application of ratemaking principles to DSM, it would not have eliminated the realistically achievable DSM potential.

B. Ameren's Selection Criteria Failed to Prioritize Minimizing Present Value Worth, and Failed to Adequately Justify the Use of Alternative Criteria. 22.010(2)(B) and (C), 22.060(2) and (4)

Under Missouri's resource planning rules, Ameren must use minimization of the present worth of long-run utility costs as the primary selection criterion. However, Ameren's selection process did not use long term cost minimization as its primary criterion. The Company readily admits it's rejection of this criterion on several occasions. Two examples of such admission are highlighted below:

"The IRP showed aggressive DSM plans are likely to result in the lowest cost to customers over the planning horizon, so if regulatory barriers to implementation are removed the aggressive DSM plan could become the preferred plan." (ES at 20)

"Two plans, Simple Cycle (B3) and RAP (R0), are lower cost than the Preferred Plan (B1). Table 10.C.1 excludes those plans to conclude the Expected Value of Better Information is zero. The two lower cost plans were excluded because of the use of decision factors and <u>a scorecard designed to reflect multiple planning objectives other than merely PVRR</u>" [emphasis added], (Chapter 10, Appendix C.)

Early in the executive summary, Ameren also reported that with a levelized cost of $0.04/kWh, energy efficiency was less expensive than existing generation resources ($0.05/kWH) and considerably less than the cost of new generation. (ES-8–ES-10) Cost comparisons with existing generation do not however consider the incremental costs of environmental compliance or the risks associated with installing CCS, as noted above. Adding these types of costs to existing supply side resources would have made the cost comparison even more favorable for DSM solutions. In fact, it is highly likely that DSM resources in excess of Ameren's claimed "maximum achievable potential" would reduce revenue requirements even more, had they been considered.

A utility can add planning objectives or performance measures, within limits. "Other considerations" must be "critical to meeting the fundamental objective" of the process and such that they "may constrain or limit the minimization of the present worth of expected utility costs." 22.010(2)(C) Additional performance measures must be relevant to the planning objectives. 22.060(2) and (4) ((4) is a waiver). Several criteria in Ameren's "scorecard" (Plan, Table 9.2) deviate from the rule.

- **Efficiency (10% weight).** This represents "spending on energy efficiency for the values of this sub-attribute of DSM" (Plan at 9-10). Ameren does not justify its selection of this metric or the assignment of a 10% weight to the benefits of efficiency. These benefits could have been, but were not, captured in other planning objectives as well, such as customer satisfaction, environmental/diversity and economic development. By corralling DSM into this objective and assigning it such a low weight, Ameren fails to give equal treatment to demand-side and supply-side resources.
- **Environmental. "**Environmental/renewable resource diversity was represented by total carbon emissions" (Plan 9-8). Ameren does not justify assigning no value to the reduction of criteria or toxic air emissions or using carbon emission reductions as a substitute for every environmental externality as well as resource diversity. Moreover, when applied to selecting the PRP (Figure 10.5, p. 10-13), in the Meramec retirement with RAP case, DSM is not credited with beneficial contributions to Ameren's overall portfolio diversity despite DSM's inherent diversification of benefits. Instead, this case is penalized because there is "no addition to <u>generation</u> diversity". This is a clear example of Ameren's failure to consider supply and demand side resources on an equal basis as well as failure to ensure that selection criteria other than

minimization of PVRR are necessary to the achievement of the fundamental planning objectives.

- **Financial/regulatory.** As represented by the present value of free cash flow, this initially gives the advantage to DSM: With a shorter amortization period than that used to depreciate supply side resources, the DSM-only plans performed better on PVFCF than other plans. (Plan at 9-8). However, Figure 10.5 indicates that "DSM plans score low" because of DSM's "potential for stranded costs" with no documentation that typically incremental demand-side investments are more highly exposed to cost stranding than are very large investments in new fossil or nuclear generation. "Stranded costs" is apparently used here synonymously with "regulatory lag" as Ameren uses that term in relation to lost revenues. In this instance, Ameren has selected a measure of financial health (present value of free cash flow), given that objective a weight of 20%, and when faced with the reality that RAP DSM performs better according to this metric, simply substituted another poorly defined and utterly unsupported metric related to its perceived inability to gain approval for timely cost recovery and lost revenue recovery. As noted above, Ameren is encouraged by the DSM Rules to propose lost revenue recovery mechanisms that would resolve any concerns about free cash flow and recovery lag. Rather, they seem to simply assume that any future DSM regulatory rules would negatively impact the Company.

- **Economic Development," quantified as jobs.** This is a laudable goal but Ameren does not explain how non-utility employment relates to the goals of resource planning. It ascribes the same number of jobs to nuclear plant construction whether Ameren is a 30% or 50% owner. (Plan at 9-9)

Ameren favors late retirement of Meramec on the assumption that retirement will mean a net loss of jobs regardless of what resource replaces Meramec (Plan at 9-9). It also favors nuclear over DSM, but we have a hard time seeing how nuclear would create more jobs than DSM. Basically, however, job-creation is external to there source planning process and is not a proper planning objective or performance measure. Even if it is considered proper, Ameren's use of it is not.

Ameren's analysis only considered a narrow spectrum of the economic impacts that would result from its resource choices. In particular, it conspicuously failed failure to consider the larger "indirect" and "induced" economic impacts of lower customer energy bills resulting from large scale energy efficiency programs such as the RAP or MAP portfolios[2].

Despite a statewide poverty rate approaching 15% the Ameren economic analysis also makes no assessment of the impacts of its resource options on the state's low income population[3]. One such recent economic study, was entitled "<u>Energy Efficiency Equals Economic Development: The Economics</u>

2 "Examples of "direct" job creation, such as that referenced by Ameren, include program staff and contractors required for the installation of energy efficient equipment. In contrast, "indirect" jobs include the manufacturing and service positions that supply the equipment rebated by the DSM programs. Finally, "induced jobs" result when the utility bill savings of program participants are either saved or spent for non-energy products.

3 See Missouri Department of Social Services, http://www.dss.mo.gov/mis/pdfs/ftsheets.pdf.

of Public Utility System Benefit Funds", was commissioned by the Entergy Electric System in 2008 to look at this issue in each of its service territories. The authors concluded that low-income energy efficiency investments are not only a major vehicle for economic development, but potentially significantly more successful than programs aimed at bringing manufacturing to a region for the purpose of creating jobs. In general, the study concluded that energy efficiency investments in the low income sector would produce 250 jobs for every $1 million investment[4].

Finally, Ameren also did not assess the comparative economic impacts of out of state revenue flows compared to the instate creation of employment for the installation of energy efficiency improvements in Missouri homes and businesses. For example, 99% of the coal burned in the state's coal fired power plants is imported from out of state (primarily from Wyoming), resulting in considerable revenue outflows from the state. According to a national analysis of coal imports by electric utilities Ameren Missouri spent $465 million on imported coal in 2008. Statewide, Missouri residents spend approximately $190 per person on out of state imported coal. [5] Similarly, it is likely that the new natural gas resources identified in the IRP will also result in revenue outflows, likewise resulting in job stimulation in fuel development and transportation sectors outside the state. In contrast, energy efficiency

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[4] "Energy Efficiency Equals Economic Development: The Economics of Public Utility System Benefit Funds," Jerrold Oppenheim and Theo MacGregor, June 2008, pp 56; http://www.xxx xxx.com/global/our_community/advocate/Poverty_book.pdf.

[5] Missouri's Dependence on Imported Coal, Union of Concerned Scientists, http://www.ucsusa.org/assets/documents/clean_energy/UCS-BCBC-factsheet-Missouri.pdf

projects will create jobs inside the state for contractors, engineers, electricians and other energy professionals.

- **Proposed remedy:** Ameren should rescreen its candidate resource plans without this "economic development" criterion, and should assign its 10% weight to PVRR, to better reflect the importance of that objective.

C. Ameren Refuses to Acknowledge the Existing Regulatory Framework for Energy Efficiency

Ameren makes it abundantly clear that it is not satisfied with the regulatory framework that Missouri policymakers have created for investment in energy efficiency and for that matter for utility resource investment more broadly. However, the regulatory framework that does exist does not envision or tolerate Ameren refusing to take advantage of the least-cost resource choices, effectively holding hostage the consumer benefits of doing so in order to gain leverage in securing more favorable ratemaking policies for shareholders. It suggests only partial remedies, pinning its hopes on the outcome of its pending rate case (ES-7, 16–7, 21–2), ignoring the rule's provision for proposing nontraditional ratemaking treatments. 22.080(2).

Missouri policymakers from the General Assembly to the Governor to this Commission have all expressed a desire for ratepayers to reap the benefits of utility investment in energy efficiency and have created a regulatory framework for securing these benefits. For example:

- This Commission stated in its previous Order in EO-2007-0409: "Ameren UE contends it has already modeled a very aggressive approach in this IRP filing, however, the Commission agrees that demand-side management is vitally important and may be effective enough to reduce the need for development of costly supply-side alternatives. Therefore, the Commission directs Ameren UE to model an even more aggressive approach to encourage participation in demand-side management programs in its next IRP filing."

- The 2009 Missouri Energy Efficiency Investment Act (MEEIA) sets a statutory goal for electric utilities of "achieving all cost-effective demand-side savings." § 393.1075.4, RSMo.
- The Commission has adopted rules to implement MEEIA including two critical components designed to enable utilities to meet the "all cost-effective" goal:
    - The Commission will evaluate utility efficiency plans' adequacy toward achieving the goal of all cost-effective savings using the combination of market potential studies and targets reflecting the savings captured by leading utilities in the region and across the nation. 4 CSR 240-20.094(2)
    - Moreover, those rules invite Ameren to propose cost recovery, lost revenue recovery and performance incentives that would allow Ameren to more closely align its shareholders' interests with the customers' interest in efficiency. 4 CSR240-20.093

Compared to the state's statutory savings requirements, Ameren's low-risk DSM plan anticipates cumulative savings that will fall well short of Missouri's savings goals, as shown in the figure below.[6] In addition, Ameren did not even consider a scenario that meets or exceeds the minimum goals articulated in the DSM Rules. In other words, Ameren started out arbitrarily constraining DSM to such an extent that an aggressive DSM scenario that met the minimum requirements starting in July 2011 was not even allowed to be analyzed. The MEEIA rules require that any DSM plan is "included in the electric utility's preferred plan or have been analyzed through the integration process required by 4 CSR 240-22.060 to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility." 4 CSR 240-20.094 (3)(A)3. For this reason alone, the Commission should reject Ameren's IRP. Further, Ameren failed to seriously consider scenarios that capture incremental savings of 1% and 2% per year, as required under its stipulation with MDNR.[7]

Figure 1 **

Figure 2 **

Were Ameren to fully fund, implement and support an aggressive DSM program, like those in Iowa and Illinois, it could address its forecasted annual average growth of approximately 1.0 percent in electricity load over the planning horizon without adding additional supply-side resources even with Meramec retirement (ES-19)). But the company contends that it is unable to implement an aggressive portfolio of energy efficiency programs due to its false perception about the state's regulatory framework.

The Company's primary concern centers on the opportunity to recover lost revenues and earn stockholder incentives. Without these opportunities, the company

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[6] Ameren EE cumulative Goal source: Portfolio Rollup viewer.xlsx.

[7] ER-2010-0036, First Non-unanimous Stipulation and Agreement, paragraph 12a.

asserts that a DSM-only plan creates so many risks for stockholders that it would be imprudent to pursue maximum achievable potential energy efficiency resources. In order to make this assertion, however, the Company deviates widely from the objectives of 4 CSR 240-22.010 and ignores its own adopted measure of financial health, that of free cash flow, by which measure energy efficiency produces the greatest benefits.

D. **Sensitivity Analysis; ROE as critical uncertain factor, 22.070(1) – (2), EO-2007-0409 Stip. #34**

1. Although the company provides an earnings sensitivity analysis indicating (but not proving) ROE deterioration as a result lost revenues (assuming they could never achieve compensation), the company's claim that it is constrained from adopting a lower cost DSM-only program is without merit. The company asserts that an uncertain regulatory framework prohibits adoption of a lower cost DSM-only program. If Ameren believes that the current regulatory framework is not conducive to the selection of an aggressive DSM-only plan over supply-side resources, the company not only has the right to seek alternative regulatory remedies but an obligation. Furthermore, there is nothing in the MEEIA rules that prevents the company from petitioning the Commission and seeking approval of each claimed barrier noted above. In fact, they are explicitly invited to do so. 4 CSR 240-20.093(2)(E). The Company, moreover, must seek such remedies in order to uphold its fiduciary responsibilities to stockholders. As noted earlier, the Company acknowledges that a DSM-only resource plan would result in lower costs, higher cash flow

and additional economic benefits. Therefore, it must seek to reduce barriers to attain these additional benefits that would mostly accrue to stockholders.

2. Ameren assigns to return on equity low, base and high case values of 10.16%, 11.35% and 13.27% (Table 9.10, p. 9–18). These values are way out of line with what appears in Ameren's reply brief in its current rate case, ER-2011-0028, particularly the map of "Most Recent Authorized Electric Utility ROEs in Midwestern States:" Arkansas 10.20%; Iowa 10.44%; Illinois 10.50% (unbundled); Minnesota 10.74%; Wisconsin 10.30%; Kentucky 10.50%; Kansas 10.00%; Oklahoma 10.15%; Michigan 10.30%; Indiana 10.40% Missouri (Murray recommendation) 8.75% (Reply brief p. 13; ROEs authorized in 2010–11). The overstated ROE values appear calculated to support Ameren's contention that the MEEIA rules are unfair to its shareholders, thus biasing the results of the IRP against DSM.

Proposed remedy: Ameren should rerun its modeling using realistic values for ROE.

III. Remedies to the Demand-Side Deficiencies

a. Ameren should recreate its modeling, risk analysis and plan selection process to treat energy efficiency on an equivalent basis with supply-side resources. Accordingly, Ameren analysis must (1) Use a corrected potential study that accurately reflects the true potential for cost-effective energy efficiency for all customer classes throughout its service territory; (2) Allow DSM to freely compete with supply side resources on price for the purposes of capacity planning; (3) Include emerging technologies for DSM as well as supply-side analysis; (4) Employ assumptions about the favorability of ratemaking policies that are consistent between the demand and supply-side resources; (5) Analyze a DSM scenario that at least meets the minimum goals articulated in the MEEIA DSM Rules; and (6) Credit DSM with providing resource diversity in the selection criteria.

b. Ameren should be required to articulate and follow clear plan selection criteria that, when deviating from minimization of present value of revenue requirement, have a reasonable relationship to the fundamental planning objectives specified by the rule and are consistent with the equivalent treatment of demand-side resources.

c. While Ameren is revising its potential study and plan analysis to remedy the deficiencies, the Commission should require the company to continue to offer its current suite of programs at the current budget levels.

d. Ameren should be required to simultaneously file a revised DSM potential study, IRP analysis and a plan under the MEEIA statute, including a proposed demand-side investment mechanism by no later than 90 days following a final order in this docket.

IV. Plan Deficiencies Related to Supply-Side Resources

The Commission's IRP regulations require a careful analysis of a range of supply-side resources that are available for meeting the energy needs of the Company's customers. In particular, the Company is required to "identify a variety of potential supply-side resource options which the utility can reasonably expect to develop and implement." 4 CSR 240-22.040(1). Such resources are to include new plants using existing or new technologies, life extension and refurbishment of existing plants, enhancement of pollution controls at existing or new plants, power purchases, efficiency improvements, and transmission and distribution system upgrades. *Id*. Such resources are to be evaluated on a "logically consistent and economically equivalent basis" with demand-side resources. 4 CSR 240-22.060(4)(D).

Unfortunately, the Company's IRP filing fails to satisfy these requirements. Instead, Ameren's IRP assumed the continued operation of the Meramec units for at least eight years after the retirement date ** **, ignored the significant increased costs and decreased operating efficiencies facing Ameren's aging coal units, overestimated projected natural gas prices, failed to adequately account for likely carbon emission costs, and ignored the significant risk of vastly higher costs for building a new nuclear plant. The Commission should require Ameren to remedy these deficiencies and engage in further planning that adequately reflects each of these points.

A. Ameren Erroneously Failed to Evaluate Critical Factors Regarding Whether the Company's Existing Coal Units Would Retire or Continue to Operate During the Planning Period.

1. The Company's analysis is deficient because it assumes the continued operation of the Meramec coal generating units far past their likely retirement date in contravention of 4 CSR 240-22.040(1).

One significant flaw in the Company's analysis is the assumption that the Meramec units would continue operating long after the ** **. While Ameren carried out a flawed evaluation of retiring Meramec in 2015, 2016, or 2022 (IRP at 4-14), it also evaluated an "as-is" scenario that assumed the plant would continue operating throughout the planning period and to a 2042 retirement date. (*Id*.). The Company then selected the "as-is" scenario for Meramec as part of its Preferred Resource Plan. (IRP at 10-15).

Ameren's approach here is inconsistent with 4 CSR 240-22.040(1), which calls on the Company to evaluate supply-side resources that the utility "can reasonably expect to develop and implement." Ameren cannot reasonably expect to continue using the Meramec units through the entire planning period because those units would be 69 to 77 years old by 2030, which is past both the typical operating lives of coal units and even the ** ** for the Meramec units.

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In short, Ameren's IRP was inadequate because the Company failed to base its resource planning on supply-side resource options that it could reasonably expect to be able to use for a significant portion of the planning period.

2. **The Company's analysis is deficient in failing to consider the effect of aging on the capital requirements and operating performance of its existing coal fleet as required by 4 CSR 240-22.040(1)(E)-(J) and 4 CSR 240-22.040(8)(B)-(C).**

A second major deficiency in Ameren's analysis is that the Company ignored critical factors regarding the cost and operating performance of its aging coal fleet in deciding when or if the Meramec units would be retired. Instead of considering the potential for the aging of coal plant components, equipment and structures to lead to higher operating costs (including capital expenditures) and degraded plant performance, Ameren Missouri assumed that each coal unit could continue to operate through 2039 as efficiently and economically as it has in recent years. This was an extremely optimistic assumption considering the ages of some of the Company's coal-fired units. It improperly biased the results of the IRP analyses in favor of continued operation and upgrading of Ameren's existing coal plants.

a. **Ameren's Missouri coal plants are aging.**

The Company acknowledges that it is heavily dependent on plants that are reaching the end of their useful lives, stating:

> Across the nation and our region, large coal-fired plants that provide most of our power are growing older. The average age of Missouri's large plants is 40 years, and that's at least middle age for a power plant. These plants will not operate forever. (ES-4)

In fact, Ameren Missouri's oldest coal unit, at Meramec, already is 58 years old. Its youngest coal unit, at Rush Island, already is more than 33 years old.

- The first of four units at Labadie began operations in 1970 with the plant fully operational by 1973.
- The fist unit at Rush Island began operations in 1976. The second unit in 1977.
- Meramec's first two unit began operations in 1953, with the remaining units in operation by 1961.
- The two units at the Sioux plant began operations in 1967 and 1968.

b. The Company Erroneously Assumes That Capital and Operating Costs for its Meramec Units Will Decrease, Rather Than Increase, As the Units Age.

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Burns & McDonnell's ** **recommended capital expenditures biased the analysis in favor of the continued operation of Meramec through 2040.

c. The Company Unreasonably Assumes No Age-Related Increase in Operating Costs or Performance Degradation

In addition to failing to properly account for increased capital costs for its aging coal units, Ameren did not consider any uncertainties in the future operating costs (including capital expenditures) for Meramec or its other existing coal-fired units in its IRP analyses. (IRP at 4-16 to 4-17). This is a critical flaw, as the aging of plant equipment, structures and components may lead to significant increases in plant O&M and capital expenditures than the Company now projects.

Ameren Missouri also did not examine any scenarios in its IRP analyses in which the aging of coal plant equipment, structures and components leads to diminished operating performance at Meramec or any of its other existing coal-fired units. Instead, Ameren assumes that there will be no changes in the equivalent forced outage rates or heat rates of its existing coal plants even though the Meramec coal units would be more than 59–67 years old by 2020 and 69–77 years old by 2030.[8]

The following two Figures are based on the results of Ameren's modeling analyses. They show that the Company assumes that each of the Meramec units will be able to achieve annual capacity factors in the range of the ** **. The first Figure shows the average capacity factors in those resource plans where Ameren assumes that Meramec continues to operate "As-Is" without major new environmental controls beyond ACI and a fine mesh screen. The second Figure shows the average annual capacity factors in those resource plans where Ameren assumes that Meramec is controlled with a scrubber, a wastewater plant, and ash and landfill systems, in addition to the ACI and fine mesh screen.

Figure 3: ** **

Figure 4: ** **

Assuming such continued high performance from aging coal plants appears to be an extremely optimistic assumption given ** ** Indeed, given the large number of older, less efficient coal plants being retired around the nation (many of which are less than 60 years old), it is very likely that some of Ameren's existing coal units would retire before the end of the planning period.

3. The Company's analysis is deficient because it failed to include an assessment of Ameren's coal units besides Meramec in contravention of 4 CRS 240-22.040(1)(E)-(J).

While the IRP purports to evaluate the condition of and retirement or continued operation of Ameren's Meramec units, it does not do the same for the other coal units at Labadie, Sioux, and Rush Island. In fact, the IRP assumes their continued operation, apparently without any analysis. In response to discovery requests, Ameren acknowledged that it does not have any

8 Ameren Missouri Response to Data Request No. SC-NRDC-01-022.

condition assessments for any of its coal plants other than Meramec.[9] The Company also does not have any retirement, continued unit operation or life extension studies, analyses or assessments for any of its other coal-fired plants.[10] Such analyses, however, needed to be carried out and incorporated into the IRP in order for Ameren to satisfy the requirements of 4 CRS 240-22.040(1)(E)-(J).

REMEDY: Ameren's own studies, including those done by Black & Veatch and Burns & McDonnell provide strong evidence that Meramec's four units will retire for age-related reasons (setting aside environmental regulations) well before the end of the planning period, or will be operating at a much lower capacity factor by 2022. To ignore this reality is to undermine the goal of the planning process itself, which is to ensure that the Company has put in place the resources to safely, reliability and efficiently provide service at just and reasonable rates. 4 CSR 240-22.010(2). In order to remedy these deficiencies, the Commission should require Ameren to conduct a new risk assessment and plan selection process that: (1) does not include the four Meramec units after 2022, (2) uses a reasonable range of assumptions about age-related increases in operating, maintenance and capital costs, and a reasonable range of assumptions about age-related increases in forced outages or reduction in operating efficiency, and (3) evaluates all of Ameren's coal units, rather than just the Meramec units. Such evaluations should be based on independent studies that reflect the experience of plants across the country.

B. The Company's Analysis Is Deficient in That It Fails to Adequately Assess Fuel Prices as Required by 4 CSR 240-22.040(8)(A).

1. Ameren's natural gas price forecasts are unreasonably high

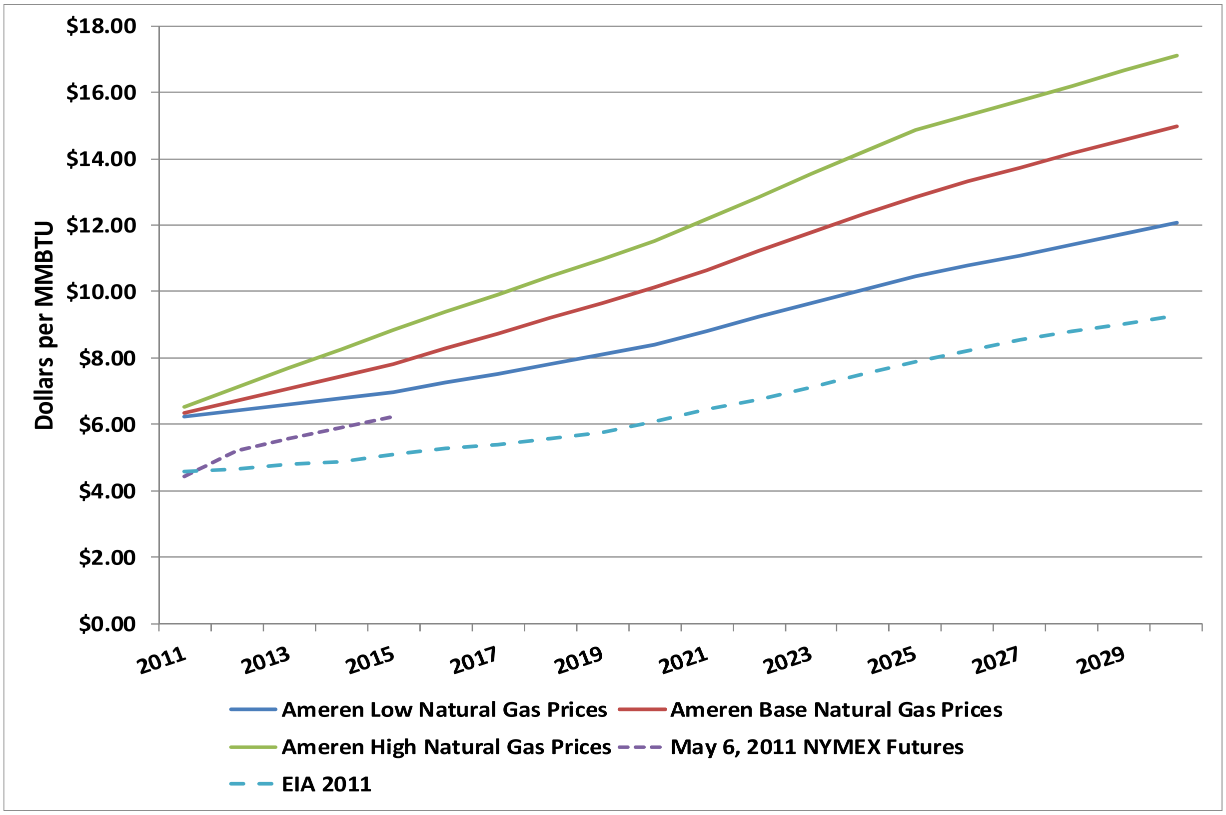
[9] Ameren Missouri Response to Data Request No. SC-NRDC 1-014.

[10] Ameren Missouri Response to Data Request No. SC-NRDC 1-039.

Ameren uses a very high range of natural gas prices in its IRP analyses, which biases the results in favor of the continued operation of the Meramec coal plant and against the natural gas-fired supply-side options.

For example, as shown in Figure 5, below, the Base and High Henry Hub natural gas price forecasts that underlie the gas prices used by Ameren in its IRP modeling analyses are significantly higher than current NYMEX futures prices for the years 2011–2015 and the long-term Henry Hub natural gas price forecasts by the US Department of Energy's Energy Information Administration. Indeed, as this graph shows, Ameren's 2025 "low" forecast is 30% higher than the EIA's projection for 2025, and Ameren's "high" forecast is almost 90% higher than EIA's projection for 2025. Yet, Ameren assigns its "high" forecast a 50% likelihood in the probability tree, significantly distorting the analysis against plans that include new natural gas capacity, and toward the continued operation of Meramec.

Figure 5: Ameren Natural Gas Price Projections Versus EIA's



Ameren's description of the planning scenario process does not adequately explain the large difference between its natural gas price forecasts and those of the EIA. Ameren claims that CRA's model for forecasting natural gas prices has been extensively peer-reviewed. (Plan, p. 2-19) However, the Company provides no evidence that CRA's model in recent years has correctly, or even approximately accurately, projected natural gas prices, despite the requirement to do so under 4 CSR 220-22.010(8)(A)(2).

Ameren states that its gas price experts prefer to use NYMEX futures of Henry Hub natural gas prices for the short term (that is, until 2014) before the High and Low forecasts begin to diverge. (Plan, p. 2-16) However, the High and Low Henry Hub natural gas prices that Ameren actually used (as shown in the Table on page 44 of Chapter 2 of the 2011 IRP) start to diverge by 2011.[11] Moreover, all three of the Henry Hub natural gas price forecasts (Base, High and Low) used by Ameren Missouri are significantly higher than actual natural gas prices in 2011 and recent NYMEX futures prices for 2012 through 2015.

In fact, Ameren's experts' projections are already 30–35% higher for the current year than actual 2011 prices. One would expect that the first year of a forecast would be the least uncertain and closest to actual prices. However, as shown in the Table on page 44 of Chapter 2 of the IRP, Ameren Missouri's modeling analyses assumed that Henry Hub natural gas prices would be between $6.15 per MMBTU and $6.54 per MMBTU in 2011. Actual 2011 Henry Hub natural gas prices this year are averaging only $4 to $4.50 per MMBTU — approximately $2.15 to $2.50 per MMTU below what Ameren's experts projected for the current year. Thus the actual Henry Hub prices for 2011 already are somewhere in the range of 30–35% below the prices that Ameren used in developing its IRP.

Moreover, as can be seen from Figure 5 above, Ameren's projected Henry Hub prices remain much higher than recent NYMEX prices for the years 2012–2015. This is further evidence that the natural gas prices that Ameren used cannot be relied upon and the conclusion that these prices are far too high cannot be avoided. For this reason, the Commission should not accept Ameren Missouri's conclusion that continued operation of the Meramec coal plant is the preferred option over the unit's early retirement and replacement.

2. Ameren apparently underestimates the significance of increased gas production through unconventional technologies on gas prices

Ameren repeatedly mentions natural gas price volatility in the IRP. (ES-5, 9, 19) All fuel prices will exhibit some degree of price uncertainty and volatility — that is daily, weekly or monthly variations based on fluctuations in the relationships between supplies and demand, and weather. Of course,

[11] Consequently, the Henry Hub prices shown in the Figure on page 16 of Chapter 2 of the IRP are not consistent with the annual prices shown in the Table on page 44 of Chapter 2, even if an allowance is made for the conversion from 2010$/MMBTU to nominal dollars.

commissions should be concerned about such volatility and should require utilities to take reasonable actions to hedge natural gas supplies in order to minimize volatility.

However, there is no evidence that future natural gas prices will have the same degrees of uncertainty and volatility as has been experienced in the past. In fact, the new supplies of natural gas that have been identified since 2008 have been described (by Entergy Corporation, for example) as a structural change and a "seismic shift" in the natural gas market. This structural change has two important impacts on resource planning for companies like Ameren: (1) as a result of the existing and expected supply glut, current and projected prices of natural gas have been reduced, and (2) at the same time, the dramatically larger domestic supplies of natural gas should be able to accommodate any increased demands from fuel switching due to federal regulation of greenhouse gas emissions without causing significant increases in natural gas prices.

The structural change in the natural gas markets already has had a significant impact on utilities' resource planning. For example, in early 2009, Entergy Louisiana informed the Louisiana Public Service Commission of its intent to defer (and perhaps cancel) the proposed retirement of an existing gas-fired power plant and its replacement by a new coal-fired unit. Entergy explained that it no longer believed that a new coal plant would provide economic benefits for its customers due to its current expectation that future gas prices would be much lower than previously anticipated:

> Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently — and for the first time — projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.[12]

4. Recent Natural Gas Developments

12 *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6–8.

> Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $13.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.
>
> *　　　*　　　*　　　*
>
> However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" — so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract — emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run….
>
> *　　　*　　　*　　　*
>
> Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods…[13]

Entergy's conclusion that there has been a seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the American Gas Association and an independent organization of natural gas experts known as the Potential Gas

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[13] Id, at pages 17, 18 and 22.

Committee, the authority on gas supplies. This report concluded that natural gas reserves in the United States are 35% higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[14]

A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to Boom" similarly reported that huge new gas fields have been found in Louisiana, Texas, Arkansas and Pennsylvania and cited one industry-backed study as estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of current natural gas demand.[15] It further noted that

> Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
>
> But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand.[16]

Entergy's conclusion that there has been a structural change in the natural gas market has been recognized by other utilities. For example, Xcel Energy explained in its 2010 Resource Plan that it filed with the Minnesota Public Utility Commission:

> Economically recoverable shale gas has been a major contributor to increasing reserves and declining natural gas prices…..
>
> * * * *
>
> A long-term lower price for natural gas will produce significant benefits to our customers. It will reduce the production cost at both current and new resources. In addition to lowering the cost of energy from our natural gas-fired facilities, the

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14 *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009.

15 Available at http://online.wsj.com/article/SB12410459891270585.html.

16 Id.

> lower cost of energy is expected to put downward pressure on wind prices, which are a close competitor. Lower natural gas production costs also reduce the integration costs of wind on our system since our ability to follow the wind with flexible gas generation becomes less expensive. Today's natural gas forecasts also predict reduced price volatility.
>
> The Commission has expressed concern in the past that more extensive use of natural gas for electric generation would hamper the supply and increase the cost of natural gas for residential heating customers. The substantial increase in supply due to the ability to economically recover shale gas may result in the ability to expand natural gas-fired generation while reducing the cost to all users of natural gas. Still, natural gas is a commodity that comes with some price volatility and the impacts of federal regulations on shale extraction will be a key factor in whether the same level of volatility that we have seen in the past decade returns.[17]

A recent report from the Bipartisan Policy Center and American Clean Skies Foundation's Task Force on Ensuring Stable Natural Gas Markets has similarly noted that:

> Recent developments allowing for the economic extraction of natural gas from shale formations reduce the susceptibility of gas markets to price instability and provide an opportunity to expand the efficient use of natural gas in the United States.[18]

And:

> The currently understood and projected shale gas resource has allowed the United States to project a significant increase in economically recoverable gas resources for the first time in the last 15 years. And for the first time since the 1990s, it now appears that deliverability (i.e., available production) could be adequate to meet increasing gas demand, meaning that the United States will no longer be in the tight supply/demand regime that has historically made natural gas markets vulnerable to price instability.[19]

Such changes in the natural gas market provide even further evidence of the deficiencies inherent in Ameren's unreasonably high natural gas price projections.

3.

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17 Xcel Energy Minnesota 2010 Resource Plan, at pages 2-5 to 2-7.

18 At page 67 of 76. Available at http://www.cleanskies.org/wp-content/uploads/2011/05/63704_BPC_web.pdf

19 Id, at page 45 of 76.

4. Hedging against remaining risk from natural gas price volatility does not warrant retrofitting aging coal plants

Even if Ameren does not build a new combined cycle unit, there are other actions besides retrofitting aging coal-fired power plants that a utility can take to mitigate the risk of natural gas price uncertainty and volatility. For example, many utilities regularly limit their exposure to natural gas price uncertainty and volatility through financial or physical hedging. In fact, Ameren already uses both physical and financial measures to hedge natural gas prices, as the Company has explained in its Form 10-K for the year ending December 31, 2010:

> In addition to physical transactions, Ameren uses financial instruments, including some in the NYMEX futures market and some in the OTC financial markets, to hedge the price paid for natural gas.
>
> UE's and Genco's natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to their generating units. This is accomplished by optimizing transportation and storage options and minimizing cost and price risk through various supply and pricing-hedging agreements that allow access to multiple gas pools, supply basins and storage services. As of December 31, 2010, UE had price-hedged about 30% and Genco had price-hedged about 84% of its expected natural gas supply requirements for generation in 2011.[20]

Repowering older natural gas-fired units (in particular, older combustion turbines) with newer, more efficient combined cycle technology is another option for reducing a company's exposure to changing natural gas prices. This is because the repowered combined cycle unit would burn gas much more efficiently, with a heat rate that is significantly lower than that of the older unit. Ameren reports having ten combustion turbine facilities that are fueled entirely or partially with natural gas, with a combined capacity of approximately 2,700 MW. (IRP at 4-5). Yet the Company proposes to convert only one of those facilities (Venice) to combined cycle, and acknowledges that it did not evaluate the "technical or economic feasibility of converting any or all of the CTGs at the Audrain, Goose Creek, Pinckneyville, or Kimmundy sites to natural gas combined cycle facilities." (Ameren Resp. to Data

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20 At page 12.

Request SC-NRDC 1-016). As such, Ameren has failed to carry out the thorough evaluation of supply-side resources required by 4 CSR 240-22.040(1).

Ameren's analysis is also deficient because it failed to look at purchasing unused capacity at existing natural gas facilities. For example, a recent analysis from Energy Ventures Associates found that the average annual capacity factor for natural gas units in the West North Central census region in which Missouri is located was 14.8% in 2009, and has ranged between 13.1% and 26.4% every year since 2000.[21] In the neighboring East North Central region, natural gas capacity was 14.8% in 2009, and has been below 25% every year since 2000.[22] Similarly, a recent analysis by MJ Bradley and Associates found that the 12,051 MW of installed natural gas combined cycle turbines that are larger than 500 MW each operated at a capacity factor of 32% in 2008.[23] In order to comply with the requirements of the Commission's IRP rules, Ameren should have evaluated the increased use of these existing facilities as a supply-side resource option.

5. Ameren's Coal Price Forecasts Do Not Reflect Expected Upward Pressure on Coal Prices

Ameren has reported that 97% of its coal comes from the Powder River Basin, with the remaining coal coming from the Illinois Basin. A number of factors suggest there will be significant upward pressures on PRB coal prices in coming years, as well as price volatility.

In particular, there is an increasing emphasis on exporting domestic U.S. coal at the very same time that traditional sources are being depleted. This is expected to lead to upward pressure on coal prices as Central Appalachian reserves are depleted and mining in the PRB is intensified due to rising domestic

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[21] Energy Ventures Analysis, Inc., Outlook for Natural Gas Demand for 2010-2011 Winter (2010), at Exhibit A-5.
[22] Id.
[23] M.J. Bradley & Associates, Ensuring a Clean, Modern Electric Generating Fleet While Maintaining Electric System Reliability (Aug. 2010), at 13.

and international demands and reduced supplies at other sources.[24] A recent coal industry market commentary expressed a concern that appears to be felt by many in the industry: "If the near-term sense of helplessness against the tide of seemingly incurable market dilemmas portends longer-term problems, if a season of wild price volatility truly is a precursor to a more complex and domestically threatening energy environment, we might all be about to catch a falling knife."[25]

For example, a presentation by John Drexler, Senior VP and CFO, Arch Coal, Inc., at the BMO Capital Markets 2011 Global Metals/Mining Conference in February 2011 noted the following:

> Even modest increases in export activity can have significant market implications:
>
> - Arguably the most significant driver in the 2008 market run-up was a 32 million ton increase in exports from 2006 to 2008.
> - U.S. exports appear to be in the midst of an even greater expansion at present.
> - The market implications of such an increase could prove dramatic.[26]

In addition, there are indications that intensified mining efforts will lead to rising costs of production in the Powder River Basin.[27] In 2008 the USGS issued a study of the PRB's Gillette coal beds. This study, which reflected forty years of USGS research on coal reserve methodology throughout the United States, concluded that the methods used by the United States government to calculate coal reserves had significantly overstated the amount of economically recoverable coal. The study explained that as existing mines and new mines in the area are more intensively exploited, production costs would rise substantially, perhaps to a level that could not be covered by the market price.[28] This is an important

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24 See, for example, Scott Learn, *Mining companies aim to export coal to China through Northwest points,* The Oregonian, September 8, 2010, the most recent reporting on plans to ship PRB coal through the Pacific Northwest.

25 Energy Publishing, In *Coal and Energy Price Report,* Volume 12, No. 88, May 10, 2010.

26 In Slide No. 15.

27 United States Geological Survey, *Assessment of Coal Geology Resources and Reserves in the Gillette Coalfield River Basin, Wyoming,* Open-File Report – 2008-1202.

28 The study offers precise calculations for existing mines in the Gillette coal beds as well as cost curves based on various production levels. These models allow for a dynamic understanding of the relationship between rising costs of production and the need for higher coal prices in the market place.

observation as the Gillette coal bed contains most of the coal produced in the Powder River Basin, and, overall, accounts for 37% of the nation's coal production. There is no evidence that Ameren evaluated these upward pressures in projecting the cost of coal as part of the IRP. (IRP at 2-19 to 2-24).

REMEDY: Ameren should conduct new scenario modeling and analysis using the Energy Information Administration's natural gas price forecasts as the "low" price projection in the IRP, the Company's current "low" forecast as their "base" case, and their current "base" case price forecast as their "high" case. Ameren should also assign a probability of at least one-third to the Energy Information Administration price forecasts in the probability tree, and should evaluate converting existing natural gas combustion turbines to natural gas combined cycle facilities and purchasing unused capacity at existing underutilized natural gas combined cycle facilities as additional resource options in the IRP. Moreover, Ameren should adjust its coal price forecasts to take into consideration new factors including increased coal exports and revised coal reserve estimates, or document that its model already takes those factors into consideration.

C. The Company's Analysis Consistently and Significantly Underestimates the Value of Carbon Emission Reductions Rendering the Plan Deficient in Meeting 4 CSR 240-22.040(2)(B) and 4 CSR 240-22.010(2)(C)(2)

Ameren discusses in its 10-K filing for the year ending 2010[29] what it describes as "… continually developing and complex environmental laws, regulations and issues, including air and water-quality standards, mercury regulations and **increasingly likely greenhouse gas limitations** and ash management requirements." (Emphasis added) However, Ameren assumes that there will be no CO_2 costs whatsoever through 2030 in scenarios that are given a 67%

[29] Ameren Corp., Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the Fiscal Year Ended December 31, 2010 (Feb. 24, 2011), at 13.

weight in its Scenario Probability Tree. In other words, Ameren Missouri assumes that it will be twice as likely that there will be no CO_2 regulation before 2030 (or later) than that a cost will be assigned to CO_2 emissions at some point during this period. This assumption biases the results of the Company's modeling analyses in favor of the continued operation of its existing coal units as coal is the largest emitter of CO_2, with new natural gas combined cycle units expected to emit approximately 50-60% of what a coal unit would emit and with new renewable resources being essentially carbon free.

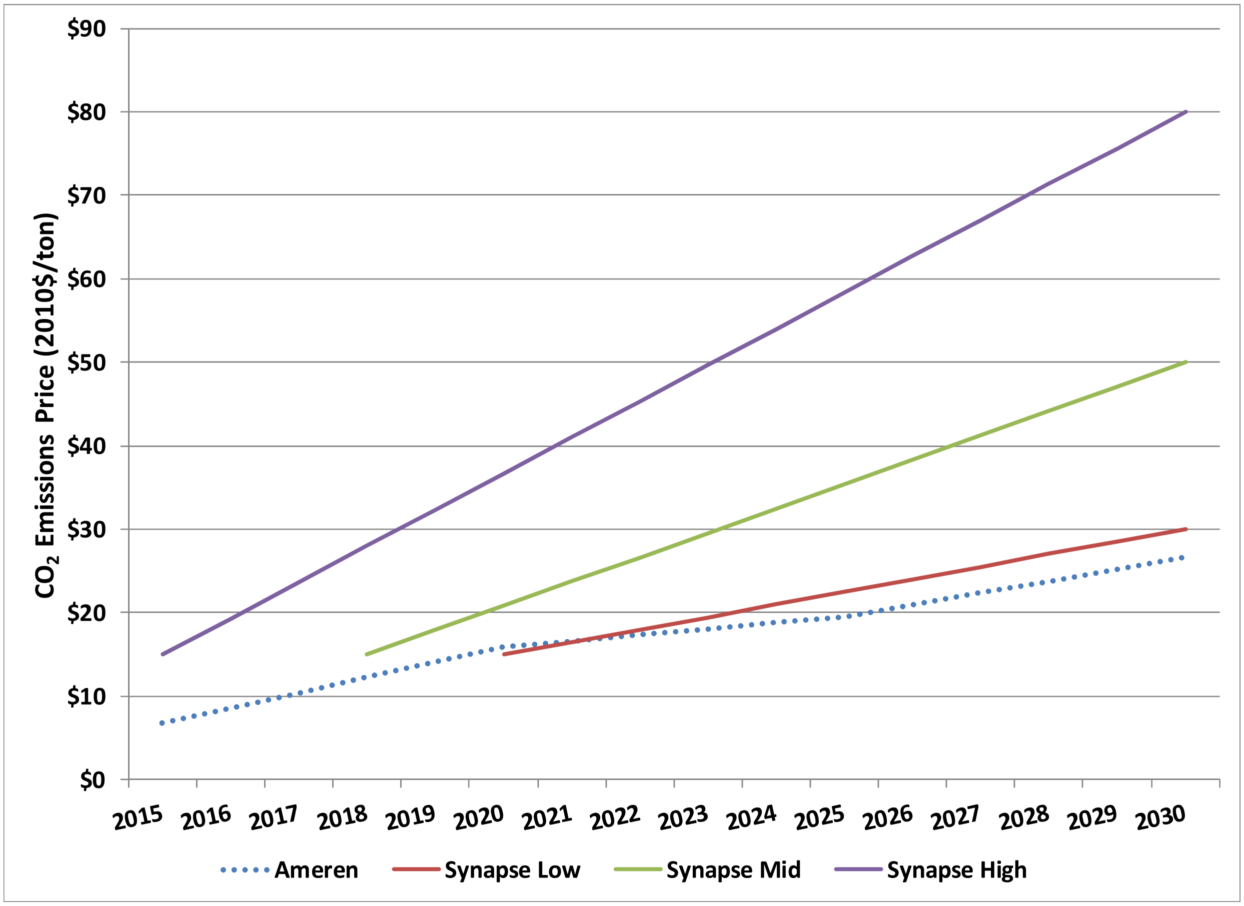
Although the current U.S. Congress is unlikely to act on climate change, it is not reasonable to expect that the federal government (or state governments) will fail to act to reduce greenhouse gas emissions in the next couple of decades — especially given the widespread support for such actions among the public, business leaders and utilities.

Making matters worse, in the limited scenarios where Ameren does consider that there will be some CO_2 regulation before 2030, it assumes only a single, fairly low price trajectory (IRP at 2-31) that is inconsistent with ** **

It is not appropriate to examine only a single set of CO_2 prices given the uncertainties surrounding the timing, stringency and design of any federal regulatory regime for greenhouse gas emissions. Instead, the Company should examine a wide range of CO_2 prices to allow for these uncertainties.

Figure 6 below compares the CO_2 prices used by Ameren in the limited set of scenarios where it does assume there will be regulation of greenhouse gas emissions with the 2011 CO_2 price forecasts from Synapse Energy Economics.

Figure 6: CO$_2$ Prices - Ameren vs. Synapse 2011



As can be seen from this figure, the single set of CO_2 prices used by Ameren is lower than even the Synapse Low Forecast. See Synapse's *2011 Carbon Dioxide Price Forecast* for an explanation of how the Synapse Low, Mid and High CO2 price forecasts were developed.

** **

Ameren's assumption that there would be no or very limited costs associated with carbon dioxide emissions once again biases the analysis against retiring Meramec in 2015. Figure 8, below, shows the average annual CO_2 emissions for three different sets of resource plans modeled by Ameren Missouri — (1) Meramec continues to operate "as-is," only adding activated carbon injection ("ACI") and a fine mesh screen on its water intake structure, (2) Meramec is controlled with a FGD scrubber, a wastewater plant, ash and landfill systems plus

ACI and a fine mesh screen; and (3) Meramec is retired in 2015. Each line represents the annual CO_2 emissions for each set of plans averaged over all of the scenarios considered by Ameren.

Figure 8: ** **

** **

Remedy: Ameren should revise its planning scenarios and risk analysis to reflect a more realistic range of probabilities for carbon regulation in the 5, 10, 15 and 20 year timeframes, and assume CO2 costs that are consistent with those ** ** and Synapse.

D. Ameren Fails to Adequately Account for the Risk to Ratepayers Caused by the Company's Overreliance on Coal Generation As Required by 4 CSR 240-22.010(2)(C) and 4 CSR 240-22.070(2)

Ameren Missouri acknowledges that the Company is heavily dependent on coal, relying on coal for 75% of its generation. (ES-1) This is confirmed by data presented in the Company's 10-K for the year ending December 31, 2010 that shows that the Company depended on coal for 77% of its generation in 2008 and 2010 and 75% in 2009. In fact, under the Company's Preferred Resource Plan, Ameren Missouri would depend on coal for 66%, or two-thirds, of its generation as late as 2030.

This overreliance on coal puts ratepayers at increased risk for significant rate increases and potential reliability issues resulting from a variety of factors either already discussed above or discussed below, including (1) the risk that the operating costs of its existing coal-fired units will increase significantly as they age and/or that the units' performance will degrade, (2) the risk that increasingly stringent emission limits, including carbon emission limits, will result in additional unplanned costs; (3) the risk that coal prices could be higher than projected by Ameren.

For these reasons, an increasing number of other utilities have decided to retire their unscrubbed coal units and to replace the retired coal capacity with new combined cycle units. For example, Xcel Energy has replaced three of its coal-fired power plants with efficient new combined cycle capacity since 2002 and is now seeking permission from the Minnesota Public Utility Commission to repower another two coal units with combined cycle technology.[30]

Other utilities, such as Progress Energy and Duke Energy are taking similar actions. For example, in its 2010 Integrated Resource Plan filing in North Carolina Utilities Commission Docket No. E-100, Sub 128, Progress Energy Carolinas explained why it had decided to replace approximately 1,500 MW of existing coal-fired capacity with new combined cycle units:

> As stated in last year's plan, the current environment presents many significant challenges to deal with from a resource planning perspective, e.g., historic levels of fuel price volatility, tremendous economic uncertainty, potential federal environmental legislation dealing with regulation of carbon emissions, proposals for Federal renewable portfolio standards, the proposed new Environmental Protection Agency ("EPA") Transport Rule, the expected EPA Maximum Achievable Control Technology ("MACT") mercury rule, the potential consideration of coal ash as hazardous waste by EPA, and customer behavior and usage changes. What continues to be one of the most notable examples of such uncertainty is the potential for environmental and climate change legislation. Even though at the time of this filing there appears to be a temporary loss in legislative momentum with respect to climate change it is widely assumed there will ultimately be legislation of some form resulting in a mandate to reduce the carbon output from the Company's generation fleet. This potential legislation paired with proposed and expected EPA regulations regarding greenhouse gas emissions led to the Company's decision to retire three coal units at each of its Lee and Sutton facilities and construct new state of the art efficient natural gas combined cycle units at those sites.
>
> These same considerations have caused the Company to conclude that it should plan to retire its remaining uncontrolled coal units in North Carolina at the beginning of 2015. It should be noted that this projected date is still subject to movement pending the outcome of many of the legislative initiatives listed in the

[30] Xcel Energy Minnesota 2010 Resource Plan, at pages 6-2 and 6-3.

> Company's Coal Retirement Plan approved by the North Carolina Utilities Commission as well as continued movement in underlying fuel prices. As a cumulative result of the new gas fired combined cycles being constructed at the Lee and Sutton sites and the associated retirement of eleven coal units at the Lee, Sutton, Weatherspoon and Cape Fear sites, the Company will have replaced approximately 1500 MWs of unscrubbed coal generation with 1500 MWs of state of the art gas fired generation. Benefits of this portfolio modernization include both environmental benefits, in the form of significant reductions in the output of SO_2, NO_x, mercury and CO_2, as well as fuel diversification benefits resulting from the addition of the new gas fired generation. [Progress Energy Carolinas] continues to evaluate the best course of action with regard to its South Carolina Robinson coal plant.[31]

American Electric Power ("AEP") just issued a detailed plan to comply with the proposed EPA air regulations by shutting down about 25% of its coal generation, i.e., 6,000 MW, while upgrading or installing controls on another 10,000 MW of coal-fired capacity. AEP also plans to refuel 1,070 MW of coal generation as 832 MW of natural gas capacity and to build 1,220 MW of new natural gas capacity.[32]

Ameren's IRP is long on rhetoric about the challenges posed by new environmental regulations, the need for resource diversity, and the need for infrastructure modernization. However, both in its modeling and risk analysis, as well as in its plan selection, Ameren chose to use unrealistic assumptions to justify maintaining its current resource mix, and selected a Preferred Resource Plan that reflected a future scenario that the company admits is unlikely. On the very first page of the Executive Summary, Ameren states that its preferred plan is "optimal for our customers should existing environmental regulations remain largely unchanged over our planning horizon. Should environmental regulations become more stringent, ***which we expect to be the case***, Ameren Missouri has developed a robust set of contingency options to consider." (Emphasis added).

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31 Progress Energy Carolinas *2010 Integrated Resource Plan – NCUC Docket No. E-100, Sub 128*, September 13, 2010, at page 3.

32 http://www.aep.com/newsroom/newsreleases/?id=1697.

REMEDY: The Commission should require Ameren to carry out additional resource planning that is based on assumptions that are consistent with the regulatory and other conditions facing Ameren's electric generating units, rather than on scenarios that the Company itself does not think will occur.

E. Ameren Significantly Underestimates the Risk of Nuclear Construction Cost Overruns

** **the actual construction experience of the existing generation of nuclear power plants and the construction experience to-date of the leading EPR nuclear units in Finland and France. Indeed, PPL, which like Ameren is considering whether to build a new U.S. EPR nuclear reactor, has said that its estimated total cost for such a unit would be in the range of $13 to $15 billion including escalation, financing costs, initial nuclear fuel, contingencies and reserves.[33]

There are a number of factors for the great uncertainty regarding the ultimate construction cost of Ameren's proposed nuclear unit:

- Construction cost uncertainty represents the most significant risk for a new nuclear power plant — no nuclear power plant with an EPR design has been completed, let alone operated, anywhere in the world. Without such actual experience, the estimated costs of any proposed units are highly uncertain. As will be reported below, the actual costs of the existing generation of nuclear power plants were, on average, between two to three times the costs that were estimated during licensing or at the start of construction. And this does not include the experiences of most of the most expensive nuclear power plants like Plant Vogtle Units 1 and 2 whose actual costs were more than ten times the initial cost estimated by Georgia Power.

[33] See http://www.bellbend.com/faqs.htm.

- The first four reactors with EPR designs are under construction in Finland, France and China. Unanticipated problems may be experienced during the construction or initial operation of these projects that may require extensive, expensive and time-consuming modifications to the design of any EPR's built in the U.S. Indeed, one clear lesson from the existing generation of nuclear power plants is that significant problems may be discovered during construction, startup testing or operations of new units that will require modifications and, consequently, increased costs at other plants with the same or similar designs.
- There is a reduced infrastructure in the U.S. for building new nuclear power plants: many experienced construction workers have retired and have been replaced with new, less experienced workers. This may lead to reduced labor productivity; there are fewer workers with the specialized skills required for building new nuclear power plants; suppliers who provided nuclear-quality equipment and materials during the construction of the existing generation of nuclear plants no longer do so; as a result there is a tight supply chain with potential bottlenecks.

Until the 1970s, building new nuclear power plants appeared to be a relatively low risk investment because construction and operating costs were relatively stable and easy to predict. However, starting in the 1970s, the costs of building new nuclear power plants began to spiral out of control. As a result, the actual costs of new plants were two to three times higher than the costs that had been estimated during licensing or at the start of construction. Consequently, the nuclear industry has a very poor track record in predicting plant construction costs and avoiding cost overruns. Indeed, as shown by data in a study by the Department of Energy, the actual costs of 75 of the existing nuclear power plants in the U.S. exceeded the initially estimated costs of these units by over 200%. The following table shows the overruns experienced by these 75 nuclear plants by the year in which construction of the nuclear power plant began.[34]

Table 1: U.S. Nuclear Plant Cost Overruns

Projected and Actual Construction Costs for Nuclear Power Plants

Construction Starts		Average Overnight Costs[a]		
Year Initiated	Number of Plants[b]	Utilities' Projections (Thousands of dollars per MW)	Actual (Thousands of dollars per MW)	Overrun (Percent)
1966 to 1967	11	612	1,279	109
1968 to 1969	26	741	2,180	194
1970 to 1971	12	829	2889	248
1972 to 1973	7	1,220	3,882	218
1974 to 1975	14	1,263	4,817	281
1976 to 1977	5	1,630	4,377	169
Overall Average	**13**	**938**	**2,959**	**207**

Source: Congressional Budget Office (CBO) based on data from Energy Information Administration, An Analysis of Nuclear Power Plant Construction Costs, Technical Report DOE/EIA-0485 (January 1, 1986).

Notes: Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.
The data underlying CBO's analysis include only plants on which construction was begun after 1965 and completed by 1986.
Data are expressed in 1982 dollars and adjusted to 2006 dollars using the Bureau of Economic Analysis's price index for private fixed investment in electricity-generating structures. Averages are weighted by the number of plants.

a. Overnight construction costs do not include financing charges.
b. In this study, a nuclear power plant is defined as having one reactor. (For example, if a utility built two reactors at the same site, that configuration would be considered two additional power plants.)

The **average cost overrun** for these 75 nuclear units was **207%**. In other words, the actual average cost of the plants was about triple their estimated costs. In fact, the data in the previous table understate the cost overruns experienced by the U.S. nuclear industry because (1) the cost figures do not reflect escalation and financing costs and (2) the database does not include some of the most expensive nuclear power plants built in the U.S. — e.g., Comanche Peak, South Texas, Seabrook, and Vogtle. For example, the cost of Plant Vogtle Units 1 and 2 increased from $660 million to $8.7 billion in nominal dollars – a 1,200% overrun.

34 This table is from the May 2008 report by the Congressional Budget Office, *Nuclear Power's Role in Generating Electricity,* at page 17.

Based on the industry's demonstrated failure to accurately project nuclear plant costs, any new estimates must be assessed with a great deal of skepticism and should be considered to be very uncertain, to say the least. However, Ameren claims that there is only a 35% probability that the actual cost of a new nuclear plant will be higher than its current estimate, though it may be more than a decade before the unit is completed.

It is reasonable to expect that the industry will experience significant cost overruns if it builds new nuclear power plants in the United States. Given the industry's poor track record in estimating plant costs and the substantial uncertainties associated with building new nuclear power plants it is reasonable to expect that the actual costs of new plants, like the Lee Nuclear Station, will be much higher than the industry now claims. At the same time, it does appear that the nuclear industry has learned some important lessons from the problems experienced during the building and operation of the existing generation of nuclear power plants and, therefore, can be expected to avoid some of those problems.

The Olkiluoto 3 power plant in Finland was the first truly "new generation" nuclear unit to begin construction.[35] Construction began in 2005 with a scheduled completion date of 2009, but Olkiluoto has experienced many problems. Indeed, it is reported that completion of the plant is currently scheduled for the end of 2012, with a start of operations in early 2013 and that the projected cost of the plant has increased by more than 70% or about $4 billion.[36] A second EPR project has been under construction in France for several years and has also experienced construction and schedule problems.[37] The plant began construction in 2007 with an expected construction duration of 54 months. In 2010, the plant's owner, EDF, announced that the estimated cost of the project had increased by 50% to 5 billion euros and

35 Olkiluoto 3 is a European Pressurized Water Reactor ("EPR") design.

36 http://www.world-nuclear-news.org/NN-Startup_of_Finnish_EPR_pushed_back_to_2013-0806104.html

37 For example, see "Regulator stops flow of concrete at Flamanville," *Nuclear Engineering International*, June 18, 2008, at page 4.

that the start of commercial operations had been delayed until 2014.[38] The nuclear disaster in Japan can be expected to delay the licensing of any new reactors in the U.S. and increase the costs of construction.

REMEDY: In order to ensure that Ameren's IRP accurately reflects the costs of various energy alternatives, the Commission should require Ameren to re-evaluate the projected cost of pursuing a new nuclear facility, rely on up-to-date cost estimates in doing so, and factor in the industry's history of cost overruns.

V. Plan Deficiencies Related to Renewable Energy and Storage

A. Ameren Does Not Adequately Justify its Choice of Pumped Storage Over Compressed Air In Violation of 22.040(2)(C) and 22.040(9)(A)3

Ameren selects pumped storage over compressed air energy storage even though CAES outperforms PS on cost (Plan at 9-6) and probably would outperform it on environmental grounds if those were considered. No attempt is made to justify this choice though an explanation for rejecting a candidate resource option is required by 22.040(4)(C) and 040(9)(A)3. Ameren also characterizes CAES as a peaking resource and thus fails to take into account its chief value of compensating for the variability of wind.

Proposed remedy: In its Table 9.5 (Plan at 9–12) of preliminary resource plans, Ameren should substitute CAES for PS and Wind/CAES for Wind/SC.

B. Ameren fails to include wind at 100 meters, 22.040(1) and EO-2007-0409 Stip. #14

Ameren eliminates wind at 100m because it says the capacity factors in its service territory are too low (Plan at 5-33–5-34). Wind Capital Group is taking advantage of the

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[38] Tara Patel (30 August 2010). "French Nuclear Watchdog Says EDF Has Problems With Flamanville EPR Liner". Bloomberg. http://www.bloomberg.com/news/2010-08-30/edf-has-welding-problems-at-flamanville-epr-reactor-french-watchdog-says.html. Retrieved 31 August 2010.

improved performance of wind at that hub height to develop a wind farm in Schuyler County. Ameren says it must do site-specific evaluations (Plan at 5-33) despite the directive of 22.040(1) to use generic information.

Proposed remedy: Ameren should re-evaluate wind at hub heights of 100 and 120 meters.

C. Ameren fails to justify its elimination of wind as a stand-alone resource, 22.040(2)

Ameren admits that wind is competitive with thermal resources on a LCOE basis but devalues it as a capacity resource and insists on combining it with simple-cycle gas (Plan at 5–32, 5-33). Wind is not built with accompanying gas capacity but as a stand-alone energy resource. Ameren admits that it has ample natural gas peaking capacity (Plan at 9-21). Nothing in 22.040 gives precedence to capacity over energy. There is no need or justification for the Wind/SC package.

Proposed remedy: Remove Wind/SC from the list of preliminary candidate resource plans (Table 9.5) and add Wind-only and Wind-CAES.

VI. Conclusion

We ask the Commission to reject Ameren’s Plan and order the company to implement the remedies we have proposed herein.