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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

REBUTTAL TESTIMONY

OF

THOMAS M. BYRNE

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
January 2017

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REBUTTAL TESTIMONY

OF

THOMAS M. BYRNE

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I. INTRODUCTION

Q. Please state your name and business address.

A. Thomas M. Byrne, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am Senior Director of Regulatory Affairs.

Q. Please describe your educational background and employment experience.

A. In 1980, I graduated from the University of Missouri-Columbia with Bachelor of Journalism and Bachelor of Science-Business Administration degrees. In 1983, I graduated from the University of Missouri-Columbia law school. From 1983-1988, I was employed as an attorney for the Staff of the Missouri Public Service Commission ("Commission"). In that capacity, I handled rate cases and other regulatory proceedings involving all types of Missouri public utilities. In 1988, I was hired as a regulatory attorney for Mississippi River Transmission Corporation, an interstate gas pipeline company regulated by the Federal Energy Regulatory Commission ("FERC"). In that position, I handled regulatory proceedings at the FERC and participated in some cases at the Missouri Commission. From 1995-2000, I was employed as a regulatory attorney for Laclede Gas Company. In that position, I handled rate cases and other regulatory proceedings before the Commission. In 2000, I was hired as a regulatory attorney by Ameren Services Company and I originally handled regulatory matters involving local gas distribution companies owned by operating subsidiaries of Ameren Corporation (now Ameren Illinois Company and Ameren Missouri). In 2012, I was promoted to the position of Director and Assistant General Counsel, and I was assigned to handle both gas and electric cases in Missouri. In 2014, I was promoted to my current position, Senior Director of Regulatory Affairs.

Q. Have you previously filed testimony before the Commission?

A. Although I have litigated many cases before the Commission over my 33-year career, this is the second case in which I have submitted testimony. I also submitted testimony in File No. ET-2016-0246.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. My rebuttal testimony addresses three topics. First, I respond to the discovery issues raised in the direct testimony of Office of the Public Counsel ("OPC") witness Charles R. Hyneman. Second, I respond to the proposed treatment of Ameren Missouri's rate case expenses, which is addressed in the Commission Staff's Report on Revenue Requirement/Cost of Service ("Staff Report") (p. 105) and by Mr. Hyneman's direct testimony. Third, I address Ameren Missouri's earnings and the impact that regulatory lag has on them, in response to the direct testimony of Missouri Industrial Energy Consumers ("MIEC") witness Greg R. Meyer, a topic that is also addressed by Ameren Missouri witness Jerry Grant.

II. DISCOVERY

Q. What discovery issues did Mr. Hyneman raise in his direct testimony?

A. Mr. Hyneman accused Ameren Missouri of obstructing OPC's audit for the rate case by (a) refusing to provide OPC with basic audit data, (b) refusing to allow OPC to meet with certain of its witnesses, and (c) requiring OPC to travel to St. Louis to review Board of Directors information. Mr. Hyneman suggests that, as a consequence of Ameren Missouri's claimed bad behavior with regard to discovery issues, the Commission should consider granting Ameren Missouri a return on equity on the low end of a range of reasonableness.

Q. Does Mr. Hyneman's direct testimony provide a fair characterization of Ameren Missouri's responses to OPC's discovery requests?

A. No, it does not. Ameren Missouri did not refuse to provide OPC with basic audit data. OPC sent us a total of 443 separate data requests. When the subparts to those data requests are counted, OPC has sent us approximately 754 distinct questions. Of those 443 data requests, we provided at least partial responses to 425 of them, meaning we objected to the entirety of a data request only 18 times.[1] Of those 18, nine related to cyber/physical security matters that we would not even have provided in written form to the Commission Staff or the Commission, but rather, would have provided verbally due to security concerns. OPC has since agreed that a meeting on these cyber/physical security questions is acceptable. This means there were only 9 data requests from OPC for which a response was not provided. Based on the sheer number of data requests that Ameren Missouri answered, and the volume of data that has been

[1] As noted below, the Company lodged objections to a total of 70 OPC data requests out of 443; 52 were partial objections and 18 were total objections.

provided, OPC has gotten much more information from Ameren Missouri than it has in any of the prior Ameren Missouri rate cases over the past ten-plus years. In addition, OPC has ready access to all the data request responses Ameren Missouri has provided to all the other parties to this case. So far, the Company has received from non-OPC parties nearly 700 additional data requests. Counting the subparts of each data request, we estimate that the total number of questions reflected in these non-OPC data requests exceeds 2,500. Adding those to OPC's requests (including subparts) means the Company has received more than 3,000 separate questions in this case. We have responded to the vast majority of them without any objection at all, and for those to which an objection was lodged, most objections were partial objections with a response still having been provided.

Q. Why are objections to data requests ever necessary?

A. Because parties sometimes ask questions that call for information that does not meet the basic standards of discovery. While a rate case certainly touches a wide scope of a utility's operations, not every single fact, data point and document becomes relevant just because a rate case is pending, and under basic, longstanding discovery standards, any tangential relevance of a question is also weighed against the burden of answering the question. As noted, these kinds of considerations led Ameren Missouri to object to a total of 70 OPC data requests, while providing full or partial answers to the other 373 (plus we agreed to meet on the nine cyber/physical security questions).

Q. Can you provide some examples of Ameren Missouri's objections?

A. Yes. Ameren Missouri objected to a data request submitted by OPC that would have called for it to pull, assemble and copy more than 1,000 expense reports (a report, attachments, etc.), but indicated a response would be provided. To resolve the objection, we offered to produce a list of the reports and asked OPC if it could then pull a sample. OPC responded by limiting the request to expense reports of $500 or more. We then fully responded to the more limited request. There were other questions to which we objected and, in response to our objections, OPC substantially clarified or effectively re-wrote the question, sometimes because the original question was vague or difficult to understand, and sometimes because it was simply too broad as originally written.

At times parties (and this was true of OPC in this case) submit data requests that ask utilities to model various "what-ifs." Discovery is limited to obtaining data, known facts, or documents that exist, but a party (whether it be the utility or another party) is not required to manufacture analyses or model what-ifs that it doesn't already have.

Q. If Ameren Missouri had refused to provide OPC with "basic audit data," did OPC have any recourse to compel Ameren Missouri to provide that information?

A. Absolutely. For one thing, the procedural schedule approved by the Commission in this case provides for several discovery conferences, on October 13, 2016, January 10, 2017, and February 3, 2017. The first of these conferences (October 13) was canceled when all parties, including OPC, agreed that there were no discovery issues that merited holding the conference. The second conference (January 10) was cancelled for the same reason. The bottom line is that OPC never availed itself of the opportunity to raise any of the claimed discovery issues Mr. Hyneman complains about at these conferences, which were scheduled for exactly that purpose. In addition, the Commission's Rules of Practice and Procedure provide a specific process for addressing discovery disputes, which can be used by any party at any time. First, counsel for a party seeking discovery must in good faith confer or attempt to confer by telephone or in person with opposing counsel. If the issues remain unresolved after the attorneys have conferred, counsel for the party seeking discovery is to arrange with the Commission for an "immediate" telephone conference with the presiding officer and opposing counsel. If the issues still remain unresolved, at that point the party seeking discovery may file a written discovery motion with the Commission. 4 CSR 240-2.090(8).

Q. In this case, did OPC avail itself of the process for addressing discovery disputes contained in the Commission's Rules of Practice and Procedure to obtain the "basic audit data" that Mr. Hyneman alleges was not provided?

A. No. Although on several occasions counsel for Ameren Missouri and OPC conferred and resolved some disputed issues, counsel for OPC never once took any discovery dispute to the next step, which would have involved a prompt telephone conference with the regulatory law judge. And, of course, OPC never filed a motion to compel or any other kind of discovery motion. Having failed to pursue these simple remedies that the Commission's rules provide for discovery disputes, OPC cannot now complain that it has been denied "basic audit data" or that the Company's handling of discovery in this case was somehow improper and merits a return on equity penalty.

Q. What about Mr. Hyneman's claim that Ameren Missouri denied him the opportunity to meet with its witnesses?

A. OPC is simply not entitled to insist on informal meetings with Ameren Missouri's witnesses. Again, the Commission's Rules of Practice and Procedure are instructive. They provide: "Discovery may be obtained by the same means and under the same conditions as in civil actions in the circuit court." 4 CSR 240-2.090(1). In civil court proceedings, parties are not entitled to "meet with" the experts of the opposing side to discuss issues. If a party wants to ask questions of an opposing party's witness, it must schedule a deposition, or submit questions in writing.

Nonetheless, in this case, like other Ameren Missouri rate cases, the Company agreed to meet for informal discussions with Staff and OPC on some issues. Ameren Missouri was not willing to meet with OPC to discuss all of the issues OPC desired, but it was willing to schedule depositions with the witnesses whose testimony addressed those issues at mutually convenient times. OPC did not choose to take the deposition of any of those witnesses.[2] Nor did it pursue its unsupported request to insist on meeting with the Company's witnesses through the process established in the Commission's rules, by scheduling a discussion with the regulatory law judge and filing a motion to compel. But the bottom line is that OPC has no legal right to demand a meeting with any of Ameren Missouri's witnesses at any time. Instead, OPC has the right to avail itself of discovery options "by the same means and under the same conditions as in civil actions in the circuit court." No more and no less.

Q. Does the fact that the Company may elect to meet with Staff auditors on a particular issue mean that it also has to meet with OPC on that or any other issue?

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[2] OPC did request to depose one witness. On the same day the request was made, the Company agreed to produce the witness for deposition on the requested date. OPC later cancelled the deposition.

A. No. First of all, it is important to remember that Ameren Missouri is not obligated to hold informal meetings with any party on any topic. But the Company does meet with the Staff with some frequency to discuss issues regarding the Staff's audit. This is because the Staff plays a unique role in utility rate cases. Its job is to conduct a comprehensive audit of the utility's books and records with the expectation being that it will present a more fair and even-handed view of the utility's rate request than other parties. That is not to say that the Company agrees with all the Staff's positions, but in general, it has been the Company's experience that Staff auditors request to meet with Company personnel to gain an understanding of data or information the auditor genuinely does not understand and are not attempting to gain a litigation advantage via such meetings. At times, the Company attempts to provide that understanding through meetings, but even in the case of Staff, the Company sometimes decides that a meeting is not appropriate. In those cases, if the Staff believes it needs further information or explanation, then it can utilize the discovery tools that are available to it.

From the Company's perspective, other parties occupy a different role than does the Staff. Consequently, while we do from time-to-time agree to meet with OPC and other parties, we generally meet with them less often than we do with the Staff.

Q. What about Mr. Hyneman's claim that he was inconvenienced by having to drive to St. Louis to review Board of Directors documents?

A. Although Ameren Missouri generally makes its Board of Directors documents available to parties (subject to any valid objections), we have special concerns about maintaining the confidentiality of highly sensitive Board information. Specifically, potential mergers and acquisitions are discussed at board meetings, as are major contracts that the Company is negotiating, as are cyber and physical security threats. In light of the sensitivity of that information, the parties to our rate cases have generally agreed to come to our offices to review Board materials.

OPC submitted a data request seeking access to expense reports for Board members. We lodged an objection (because there were no limits on their requests, e.g., documents having nothing to do with Ameren Missouri arguably were within the scope of the request), but we responded to the data request on August 1, 2016, and indicated the documents would be made available for review at our St. Louis offices. The response stated: "Subject to the Company's objection, please make arrangements to view these documents at Ameren's St. Louis office by contacting [Ameren Missouri's designated contact]."

Q. Did OPC contact Ameren Missouri, or otherwise complain about or disagree with the objection or with the response?

A. OPC had no further communication with the Company about this data request until nearly three months later (October 25, 2016). At that time, Mr. Owen wrote counsel for the Company and raised concerns about having to travel to St. Louis to view the Board of Director expense reports. On November 1, the Company's counsel advised Mr. Owen that the Company would provide the expense reports on a disc and on November 3 followed up and advised Mr. Owen that the disc could be provided when Mr. Owen was at the Company's St. Louis office the following week.[3]

Q. Did Mr. Owen come to the Company's St. Louis offices the following week?

[3] Mr. Owen was already scheduled to be there.

A. Yes. The Company had set aside a conference room for his use for the entire week. Both Mr. Owen and OPC witness Geoff Marke came to the Company's St. Louis offices on November 7 (the Company was under the impression that they would be there more than one day). During the visit, Mr. Owen sent an e-mail to one of the Company's employees (who had shown him to the room), inquiring about documents that he thought were not in the room. That employee then retrieved additional documents, took them to Mr. Owen and indicated that she believed these were the documents he was looking for. At some point, Mr. Owen and Dr. Marke left and presumably returned to Jefferson City. They made no mention of not receiving the documents they wanted to see.

Q. Did they ask for the disc with the Board of Director expense reports?

A. They did not.

Q. Did OPC ever follow-up regarding the reports?

A. Yes. On November 29, 2016, Mr. Owen requested to depose one of the Company's witnesses (and the Company agreed) and also indicated he wanted to take a records deposition to get the Board expense reports. Counsel for the Company immediately replied and indicated that the Company had already said OPC would be given copies (on the disc) and suggested to Mr. Owen that he could pick up copies when he came the following week to depose the witness. However, as earlier noted, Mr. Owen then cancelled the witness deposition.

Q. Does OPC have the expense reports?

A. Yes. They were provided on December 16.

Q. Please summarize your response to Mr. Hyneman regarding these Board of Director expense reports.

A. Both parties – OPC and the Company – had some missteps on this particular DR. OPC need not have waited nearly three months to complain about the original response. All Mr. Owen had to do when he was in St. Louis on November 7 was to ask for the disc. At the same time, our employees could have offered the disc to him – this was overlooked. I can tell you that the Company employees involved were working late into the evening on many evenings at that time processing the thousands of DRs sent to the Company; arguably, it was an oversight on their part, but on Mr. Owen's part too. When the issue was raised three weeks later, Mr. Owen should have made alternative arrangements to get the copies since he cancelled the deposition, but again, I will agree that we could have proactively reminded him. The bottom line, however, is that there was no bad faith on anyone's part and OPC did ultimately receive the information.

Presumably in the more than a month between when OPC got the information and when it filed rebuttal testimony, OPC had sufficient time to review the information and take whatever position it deems appropriate based on that review.

Q. Should the Commission reduce Ameren Missouri's return on equity as a result of the discovery disputes Mr. Hyneman alleges?

A. Absolutely not. Mr. Hyneman may have a different view on whether the Company ought to accede to any meeting demand he makes. Mr. Hyneman may also have speculative ideas about why he did not have the Board of Director expense reports at an earlier time, but the facts show mistakes – honest mistakes – occurred on both sides. The idea that an ROE penalty ought to be imposed is completely meritless.

III. <u>RATE CASE EXPENSE</u>

Q. Turning to the second issue you are addressing, rate case expense, what are the recommendations of the Staff and of Mr. Hyneman?

A. Staff recommends that the Commission allocate responsibility for the prudently incurred rate case expenses between Ameren Missouri's customers and shareholders using the same method that it first utilized in a recent Kansas City Power & Light Company ("KCPL") rate case, File No. ER-2014-0370. Specifically, this method allocates rate case expenses to customers based on the percentage of the increase in the revenue requirement that the Commission ultimately finds to be just and reasonable as compared to the increase in the revenue requirement initially requested by the utility. The remaining percentage of the prudently-incurred rate case expenses would be borne by Ameren Missouri's shareholders. Staff would then normalize the amount allocated to customers over 24 months, based on Ameren Missouri's rate case history and future expectations regarding the timing of rate cases. Mr. Hyneman also supports the allocation method from File No. ER-2014-0370, but he proposes to normalize the expenses over 36 months.

Q. When the Commission utilized this approach in File No. ER-2014-0370, was it adopting a policy that would apply to all rate cases in the future?

A. No. In its appeal of the Commission's decision to the Missouri Court of Appeals for the Western District, KCPL argued that the Commission had engaged in unlawful rulemaking because it had adopted a new policy of general applicability (the sharing method) without going through the steps required for a rulemaking. The Commission responded by arguing that it did not engage in improper rulemaking "because the method devised to determine a just and reasonable inclusion of rate case expenses ***was tied to the facts of this case and was not a statement of general applicability."*** [Emphasis added.] *Kan. City Power & Light Co.'s Request v. Mo. Pub. Serv. Comm'n*, Nos. WD79125, WD79143, WD79189, 2016 Mo. App. LEXIS 886, *38 (Mo. App. W.D. Sept. 6, 2016)

Specifically, the Court quoted the following case-specific facts which the Commission claimed justified the imposition of sharing in that case, but which did not reflect a policy of general applicability:

> The evidence shows that the expenses in this case are driven primarily by issues raised by KCPL, which has complete control over the content and methodologies proposed when it files its rate cases. In this case, KCPL has requested three new trackers, two of which have never been requested before in Missouri. KCPL has also requested recovery in rates of the expenses from the Clean Charge Network, which is a type of expense that has never been raised in a rate case before the Commission. Each of these issues are unique to KCPL, and while KCPL always has the opportunity to pursue new and unique issue in a rate case, the decision to do so is entirely with[in] KCPL's power. In addition, KCPL has pursued some issues that only directly benefit shareholders, such as the La Cygne accounting authority and, of course, a higher ROE. In recent rate cases, KCPL has incurred rate case expenses substantially higher than historical levels and higher than utilities in Missouri.

Q. Do the case-specific facts that justified the sharing of rate case expenses in the KCPL case apply to this case?

A. No, the facts are readily distinguishable:

- KCPL requested three trackers, two of which had never been requested before. In this case, Ameren Missouri is seeking one tracker – covering transmission costs and revenues – which has been requested previously. The Company's tracker request is straightforward and sponsored by Company employee Lynn M. Barnes. Any rate case expense associated with the request is minor.
- KCPL pursued a large amount of costs for the Clean Charge Network, an issue never raised before in a rate case. There is no analogous new expense in this rate case.

- KCPL also sought an accounting order which has no analog in this case.

- Ameren Missouri is requesting a higher ROE than other parties are recommending, but so has every major utility in every rate case in the last 50 years. If this fact alone were determinative, the Commission indeed would have been establishing a policy of general applicability. Moreover, in this case Ameren Missouri's proposed ROE request is only slightly above the recent national average ROE awards for integrated utilities, certainly closer than other ROE recommendations in this case.

- KCPL was also criticized for incurring rate case expenses that were substantially higher than those incurred in recent rate cases, and that were higher than rate case expenses incurred by other utilities in Missouri. Those criticisms do not apply to Ameren Missouri.

Aside from the ROE request, none of the KCPL factors are applicable to this case – in fact, the lower rates of counsel for Ameren Missouri's rate case as compared to those charged by attorneys for KCPL were specifically cited by OPC in an effort to disallow rate case costs for KCPL. (Report and Order, p. 65).

Ameren Missouri has been diligent in keeping its rate case expenses low in this case. We have minimized the use of outside experts; we are using in-house counsel to litigate many issues; we have hired outside counsel from mid-Missouri where rates are reasonable; and we have not raised unusual issues. The bottom line is that the circumstances of this case are substantially different from those in the KCPL rate case, and they do not justify the imposition of the sharing of rate case expenses.

Q. Are rate case expenses commonly allocated between customers and shareholders in other jurisdictions?

A. Not at all. Even if the Commission were to adopt a general policy of allocating rate case expenses to shareholders via a rulemaking proceeding, it would be placing itself far outside the mainstream of regulatory practice in the United States. In 2011, the Commission opened a workshop docket, File No. AW-2011-0330, to investigate how rate case expenses have been or should be treated in rate cases. As part of that proceeding Staff investigated the treatment of rate case expenses across the country, and it was unable to cite even a single example of a jurisdiction that had required utility shareholders to pay a portion of prudently incurred rate case expenses. (See Staff Report, August, 2013). There is extensive case law on this topic dating back to the 1930's which holds that reasonable and prudently-incurred rate case expenses should be included in rates, even in cases where the utility does not prevail, and specifically rejects the sharing of such expenses.[4] *See, e.g., E.g.*, *W. Ohio Gas Co. v. Pub. Util. Comm'n*, 294 U.S. 63, 73 (1935); *Oncor Elec. Delivery Co. LLC v. Pub. Util. Comm'n*, 406 S.W.3d 253, 263–64 (Tex. App. 2013) (citing *Suburban Util. Corp. v. Pub. Util. Comm'n*, 652 S.W.2d 358, 362–63 (Tex. 1983)); *People ex rel. Madigan v. Ill. Commerce Comm'n*, 964 N.E.2d 510, 517 (Ill. App. 2011); *Kan. Indus. Consumers Grp. v. Kan. Corp. Comm'n*, 138 P.3d 338, 357–58 (Ks. App. 2006); *In re PNM Gas Servs.*, 1 P.3d 383, 406 (N.M. 2000) (citing *Driscoll v. Edison Light & Power Co.*, 307 U.S. 104, 120–21 (1939)); *Me. Water Co. v. Pub. Utils. Comm'n*, 482 A.2d 443, 453 (Me. 1984); *Butler Twp. Water Co. v. Pub. Util. Comm'n*, 473 A.2d 219, 221 (Pa. Commw. Ct. 1984). In contrast, aside from the fact-specific Court of Appeals case in which the Commission's case-specific sharing of KCPL's rate case expenses was approved, we could find no cases supporting the assignment of rate case expenses to shareholders. As a consequence, sharing of rate case expenses is inappropriate.

Q. What approach must appropriately be utilized by the Commission when dealing with rate case expense in a rate case?

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[4] Counsel for the Company will further address the legality of rate case expense sharing when this case is briefed.

A. The Commission should use the same approach utilized for all of the expenditures that make up a utility's costs: recognition of prudently incurred costs in setting the revenue requirement. While there are ratemaking concepts that can be employed regarding rate case expense (e.g., normalizing the expense as proposed by the Staff), what the Commission cannot do is arbitrarily force sharing of *prudently-incurred* rate case expenses on a utility.

Ameren Missouri prudently evaluates its needs for services, such as legal services or services from consultants, in properly preparing, processing, and trying its rate cases. We negotiate billing rates with our outside counsel and they typically freeze those rates for a period of time. Moreover, we require thorough documentation for the work of our service providers, and we subject approval of invoices to multiple reviews. The General Counsel department reviews and approves all invoices, and we utilize CounselLink software owned by LexisNexis. The software requires outside service providers to submit their bills electronically, subject to extensive billing guidelines and CounselLink's ability to flag as exceptions instances where an invoice departs from those guidelines. I am also very familiar with the work performed by our service providers on this rate case, and am involved in approving the engagement of those providers and in reviewing their work. Given the quantity and complexity of the work required to process and litigate rate cases involving dozens of witnesses and a myriad of issues – including issues not raised by the utility and not infrequently, issues that were not anticipated – their work is a reasonable and necessary part of our ability to seek to establish rates that are just and reasonable.

Q. How do you respond to the contention that rate case expense partially benefits shareholders, or that achieving a higher rate increase in a rate case benefits shareholders and thus rate case expense ought to be shared?

A. As I noted earlier, the courts have consistently held that prudently-incurred rate case expenses cannot simply be ignored, which is what sharing does. In discussing why rate case expense must be recognized in setting rates (and not shared, absent proper findings of imprudence), the Supreme Court said:

> [W]e think they [rate case expenses] must be included among the costs of operation in the computation of a fair return. The company had complained to the commission that an ordinance regulating its rates was in contravention of the statutes of the state and of the Constitution of the nation. In that complaint it prevailed. The charges of engineers and counsel, incurred in defense of its security and perhaps its very life, were as appropriate and even necessary as expenses could well be.

West Ohio Gas, 294 U.S. at 73.

Note that the Supreme Court was talking about a rate case, i.e., the "complaint" by the utility was that the utility's rates were too low. Note also that the Court was not foreclosing a utility commission's ability to disallow imprudent rate case expenses. The Court continued: "A different case would be here if the company's complaint [rate increase request] had been unfounded, or if the cost of the proceeding had been swollen by untenable objections." *Id.* at 73.

But where the rate case was appropriately brought and where the utility's objections were not "untenable," the expenditures must be recognized:

> There is neither evidence nor even claim that the conduct of the company's representatives was open to that reproach. The statute laid a duty on the commission, when it found the ordinance unjust, to prescribe its own schedule. The [schedule the commission] adopted, though higher than the one condemned, did not satisfy the company, but *there was nothing unreasonable or obstructive in laying before the commission*

> *whatever data might be helpful* to that body in reaching a considered judgment (emphasis added).

Id. at 73-74.

Arbitrarily using a ratio of the ultimate award versus the initial request has no basis in any claim of imprudence or untenable objection.

Q. Are there other problems with utilization of such a ratio?

A. Yes. When utilities file for a rate increase, they typically start with a set of historical test year figures (with appropriate normalization/annualization adjustments) and then utilize a series of pro forma adjustments through the end of the anticipated true-up date in an attempt to predict what the final figures will be. In a rising cost environment – which is the environment we have been in for some time now – the utility must use these pro forma adjustments lest it file a rate case and ask for a revenue requirement based on an historical period that is out of date the minute it ends.

In the current case, for example, Ameren Missouri was in the middle of many capital projects that were not in-service as of March 31, 2016 (the end of the historical test period), but that it expected to be in-service as of December 31, 2016 (the end of the true-up period). It was appropriate to ask for rates to cover those additional investments. It was known that there were other items, such as higher transmission charges and higher wages, etc., that would truly be "known and measurable" by the end of the true-up period. However, it certainly can be – and sometimes is – the case that the pro forma adjustment is based on an estimate that turns out to be too high, in which case not all of the increased costs materialize as of the end of the true-up period. When that happens, the Company's request is effectively lowered. This is not because the Company did anything wrong or asked for too much, but simply because capital projects were not completed by the true-up date, or an expense did not rise as much as estimated.

Thus, when a rate increase that is less than the initial request is awarded and then a ratio is applied using the initial request for purposes of sharing rate case expense, the utility is penalized absent any conduct that would warrant the penalty.[5]

Q. What normalization is appropriate for rate case expenses in this case?

A. Ameren Missouri supports Staff's proposed 24-month normalization period. As Staff has pointed out, this is consistent with recent history and expectations for the future. However, OPC's 36-month normalization proposal is unreasonable. The Company has not had a rate case interval of more than 24-months for the past decade and while it is impossible to perfectly predict the future, it is very difficult for me to envision a scenario where the Company is able to achieve a 36-month interval between its rate cases. In fact, its interval between rate cases has averaged approximately 21 months over the past five cases, which if anything would support a normalization over a shorter period than Staffs' recommended 24 months. However, because the exact timing of rate cases is uncertain, Staff's 24-month normalization is reasonable.

Q. Please summarize your position on rate case expense.

A. While it is true that the Company benefits if its rates are raised, so do customers. The same is true of the cost of building a power plant, or a transmission line or a substation. The utility can earn on that investment once it is recognized in rate base,

[5] There are other examples one could point to, such as higher-than-filed billing units that become apparent during the true-up period, producing more revenues and lowering the initial request. To some extent that happened in this case. The Company filed the case assuming the New Madrid smelter would have no consumption at all. However, it does in fact have a small (relative to its potential) consumption of about 1.3 megawatts, so some revenues from the smelter will be assumed in setting rates in this case. This lowers our initial request by approximately $110,000, as Ameren Missouri witness Bill Davis discusses in his rebuttal testimony.

but customers obtain service from it. There is no more reason to share rate case expenses than there is to share the cost of every capital investment that benefits both shareholders and customers.

Yes, utilities have a monopoly, but they have something else those in competitive businesses don't have: the obligation to serve as well as an inability to raise their prices without going through a rate case such as this one. The cost of doing so is a normal cost of doing business; part of a utility's cost of service, just as is paying salaries, rent, for supplies, to build assets, etc. If the utility was prudent in making an expenditure, it is entitled to recognition of that expenditure when its rates are set. No party has claimed any imprudence in our rate case expense. There is no basis to share it or otherwise reduce it for ratemaking purposes, although normalization is appropriate.

IV. REGULATORY LAG

Q. What is MIEC witness Meyer's testimony with regard to Ameren Missouri's earnings?

A. Mr. Meyer examined Ameren Missouri's earnings dating back to 2007. He compared the "reported" earnings to the Commission-authorized return on equity and concluded that (a) positive regulatory lag exists and Ameren Missouri can make needed investments while earning above its authorized return, and (b) Ameren Missouri can provide quality, reliable service while earning above its authorized return. As a consequence, Mr. Meyer implies that the Company's concerns about regulatory lag are overstated, and the Commission should be very careful before implementing what Mr. Meyers characterizes as a "surcharge" to allow the recovery of lost Noranda revenues, or before approving the implementation of a transmission cost and revenue tracker.

Q. Do you agree with Mr. Meyer's analysis and conclusions regarding Ameren Missouri's earnings?

A. No, I do not. To the extent that Mr. Meyer is implying that regulatory lag is not a problem for Ameren Missouri and other Missouri electric utilities, he is wrong. Missouri electric utilities experience detrimental regulatory lag on every capital investment that they make. As the charts attached hereto as Schedule TMB-R1 show, the return a utility earns on an incremental capital investment is negative in the first year, and it never equals the authorized ROE over the entire life of the asset.[6] In an environment of little or no load growth, the only way that a utility can have a chance to earn its authorized return is to relentlessly cut operations and maintenance expenses or depend on unusual events such as favorable weather. The historical information Mr. Meyer has presented does nothing to disprove this reality.

Ameren Missouri's historic earnings have, in the past few years, been close to its authorized return only because the relentless drag of regulatory lag has been offset by sharp and less-then-optimal reductions in operations and maintenance expenses, favorable weather, the timing of Callaway nuclear plant outages, and significantly restricting its capital investments in its infrastructure. In addition, the performance incentive that Ameren Missouri earned on its MEEIA 1 programs, which was supposed to provide an incremental incentive to the Company, offsets a portion of the detrimental impact of regulatory lag in 2016 because it was all realized in one year, although it pertained to a period of three years. As noted, in further response to the impact of regulatory lag, Ameren Missouri has sharply reduced its capital budget, and will continue

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[6] The problem exists for long-lived assets (as depicted on page 1 of Schedule LMB-R1) and is even worse for assets with shorter lives (as depicted on page 2).

to hold its capital budget at or near this reduced level, unless and until regulatory lag can be otherwise mitigated. The serious impact of regulatory lag was more thoroughly discussed in comments filed by Ameren Missouri in File No. EW-2016-0313, which are attached hereto as Schedule TMB-R2.

In summary, contrary to Mr. Meyer's implication, regulatory lag and its detrimental impact on electric utilities' opportunity to earn their authorized return, is having significant adverse impacts on electric utilities and the capital they can invest in their systems.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	**File No. ER-2016-0179**

AFFIDAVIT OF THOMAS M. BYRNE

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Thomas M. Byrne, being first duly sworn on his oath, states:

1. My name is Thomas M. Byrne. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Senior Director Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 22 pages, and Schedule(s) TMB-R1 to TMB-R2, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Thomas M Byrne
Thomas M. Byrne

Subscribed and sworn to before me this 17th day of January, 2017.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2018
Commission Number: 14839811

1 YEAR regulatory lag, 40 year investment

$100M investment:	$ 50	Equity Funding	Assumes 1 YEAR of regulatory lag
	$ 50	Debt Funding	Investment occurs at end of Year 0
	9.53%	Cost of Equity, after-tax	Recovery begins at start of Year 2
	5.56%	Cost of Debt, pre-tax	Extra year of revenue at the end (Year 41)
	39%	Tax Rate, all taxes assumed to be current for simplicity	

				Revenue Required for Cost Recovery					Utility Earnings							Cash Flows for Equity Investors			
Year	Equity Balance	Debt Balance	Net Plant In-Service	Recovery of Cost of Equity	Recovery of Depreciation Expense	Recovery of Interest Expense	Recovery of Income Taxes	Total Revenue Required	Revenue Received	(less): Depreciation Expense	(less): Interest Expense	(less): Income Taxes	Net Income	Realized Return on Equity (Current Year)	Realized Return on Equity (Life-to-Date)	Return ON Equity	Return OF Equity	Total Cash Flow	Discounted Cash Flow
																		$ (50.00)	$ (50.00)
1	$ 50.00	$ 50.00	$ 100.00	$ 4.77	$ 2.50	$ 2.78	$ 3.05	$ 13.09	$ -	$ (2.50)	$ (2.78)	$ 2.06	$ (3.22)	-6.44%	-6.44%	$ (3.22)	1.25	(1.97)	(1.80)
2	48.75	48.75	97.50	4.65	2.50	2.71	2.97	12.83	12.83	(2.50)	(2.71)	(2.97)	4.65	9.53%	1.39%	4.65	1.25	5.90	4.91
3	47.50	47.50	95.00	4.53	2.50	2.64	2.89	12.56	12.56	(2.50)	(2.64)	(2.89)	4.53	9.53%	3.86%	4.53	1.25	5.78	4.40
4	46.25	46.25	92.50	4.41	2.50	2.57	2.82	12.30	12.30	(2.50)	(2.57)	(2.82)	4.41	9.53%	5.08%	4.41	1.25	5.66	3.93
5	45.00	45.00	90.00	4.29	2.50	2.50	2.74	12.03	12.03	(2.50)	(2.50)	(2.74)	4.29	9.53%	5.79%	4.29	1.25	5.54	3.51
6	43.75	43.75	87.50	4.17	2.50	2.43	2.67	11.77	11.77	(2.50)	(2.43)	(2.67)	4.17	9.53%	6.26%	4.17	1.25	5.42	3.14
7	42.50	42.50	85.00	4.05	2.50	2.36	2.59	11.50	11.50	(2.50)	(2.36)	(2.59)	4.05	9.53%	6.59%	4.05	1.25	5.30	2.80
8	41.25	41.25	82.50	3.93	2.50	2.29	2.51	11.24	11.24	(2.50)	(2.29)	(2.51)	3.93	9.53%	6.83%	3.93	1.25	5.18	2.50
9	40.00	40.00	80.00	3.81	2.50	2.22	2.44	10.97	10.97	(2.50)	(2.22)	(2.44)	3.81	9.53%	7.01%	3.81	1.25	5.06	2.23
10	38.75	38.75	77.50	3.69	2.50	2.15	2.36	10.71	10.71	(2.50)	(2.15)	(2.36)	3.69	9.53%	7.16%	3.69	1.25	4.94	1.99
11	37.50	37.50	75.00	3.57	2.50	2.09	2.28	10.44	10.44	(2.50)	(2.09)	(2.28)	3.57	9.53%	7.27%	3.57	1.25	4.82	1.77
12	36.25	36.25	72.50	3.45	2.50	2.02	2.21	10.18	10.18	(2.50)	(2.02)	(2.21)	3.45	9.53%	7.37%	3.45	1.25	4.70	1.58
13	35.00	35.00	70.00	3.34	2.50	1.95	2.13	9.91	9.91	(2.50)	(1.95)	(2.13)	3.34	9.53%	7.45%	3.34	1.25	4.59	1.40
14	33.75	33.75	67.50	3.22	2.50	1.88	2.06	9.65	9.65	(2.50)	(1.88)	(2.06)	3.22	9.53%	7.51%	3.22	1.25	4.47	1.25
15	32.50	32.50	65.00	3.10	2.50	1.81	1.98	9.38	9.38	(2.50)	(1.81)	(1.98)	3.10	9.53%	7.56%	3.10	1.25	4.35	1.11
16	31.25	31.25	62.50	2.98	2.50	1.74	1.90	9.12	9.12	(2.50)	(1.74)	(1.90)	2.98	9.53%	7.61%	2.98	1.25	4.23	0.99
17	30.00	30.00	60.00	2.86	2.50	1.67	1.83	8.85	8.85	(2.50)	(1.67)	(1.83)	2.86	9.53%	7.65%	2.86	1.25	4.11	0.87
18	28.75	28.75	57.50	2.74	2.50	1.60	1.75	8.59	8.59	(2.50)	(1.60)	(1.75)	2.74	9.53%	7.68%	2.74	1.25	3.99	0.78
19	27.50	27.50	55.00	2.62	2.50	1.53	1.68	8.33	8.33	(2.50)	(1.53)	(1.68)	2.62	9.53%	7.71%	2.62	1.25	3.87	0.69
20	26.25	26.25	52.50	2.50	2.50	1.46	1.60	8.06	8.06	(2.50)	(1.46)	(1.60)	2.50	9.53%	7.73%	2.50	1.25	3.75	0.61
21	25.00	25.00	50.00	2.38	2.50	1.39	1.52	7.80	7.80	(2.50)	(1.39)	(1.52)	2.38	9.53%	7.75%	2.38	1.25	3.63	0.54
22	23.75	23.75	47.50	2.26	2.50	1.32	1.45	7.53	7.53	(2.50)	(1.32)	(1.45)	2.26	9.53%	7.77%	2.26	1.25	3.51	0.47
23	22.50	22.50	45.00	2.14	2.50	1.25	1.37	7.27	7.27	(2.50)	(1.25)	(1.37)	2.14	9.53%	7.78%	2.14	1.25	3.39	0.42
24	21.25	21.25	42.50	2.03	2.50	1.18	1.29	7.00	7.00	(2.50)	(1.18)	(1.29)	2.03	9.53%	7.80%	2.03	1.25	3.28	0.37
25	20.00	20.00	40.00	1.91	2.50	1.11	1.22	6.74	6.74	(2.50)	(1.11)	(1.22)	1.91	9.53%	7.81%	1.91	1.25	3.16	0.32
26	18.75	18.75	37.50	1.79	2.50	1.04	1.14	6.47	6.47	(2.50)	(1.04)	(1.14)	1.79	9.53%	7.82%	1.79	1.25	3.04	0.28
27	17.50	17.50	35.00	1.67	2.50	0.97	1.07	6.21	6.21	(2.50)	(0.97)	(1.07)	1.67	9.53%	7.82%	1.67	1.25	2.92	0.25
28	16.25	16.25	32.50	1.55	2.50	0.90	0.99	5.94	5.94	(2.50)	(0.90)	(0.99)	1.55	9.53%	7.83%	1.55	1.25	2.80	0.22
29	15.00	15.00	30.00	1.43	2.50	0.83	0.91	5.68	5.68	(2.50)	(0.83)	(0.91)	1.43	9.53%	7.84%	1.43	1.25	2.68	0.19
30	13.75	13.75	27.50	1.31	2.50	0.76	0.84	5.41	5.41	(2.50)	(0.76)	(0.84)	1.31	9.53%	7.84%	1.31	1.25	2.56	0.17
31	12.50	12.50	25.00	1.19	2.50	0.70	0.76	5.15	5.15	(2.50)	(0.70)	(0.76)	1.19	9.53%	7.85%	1.19	1.25	2.44	0.15
32	11.25	11.25	22.50	1.07	2.50	0.63	0.69	4.88	4.88	(2.50)	(0.63)	(0.69)	1.07	9.53%	7.85%	1.07	1.25	2.32	0.13
33	10.00	10.00	20.00	0.95	2.50	0.56	0.61	4.62	4.62	(2.50)	(0.56)	(0.61)	0.95	9.53%	7.85%	0.95	1.25	2.20	0.11
34	8.75	8.75	17.50	0.83	2.50	0.49	0.53	4.35	4.35	(2.50)	(0.49)	(0.53)	0.83	9.53%	7.86%	0.83	1.25	2.08	0.09
35	7.50	7.50	15.00	0.71	2.50	0.42	0.46	4.09	4.09	(2.50)	(0.42)	(0.46)	0.71	9.53%	7.86%	0.71	1.25	1.96	0.08
36	6.25	6.25	12.50	0.60	2.50	0.35	0.38	3.82	3.82	(2.50)	(0.35)	(0.38)	0.60	9.53%	7.86%	0.60	1.25	1.85	0.07
37	5.00	5.00	10.00	0.48	2.50	0.28	0.30	3.56	3.56	(2.50)	(0.28)	(0.30)	0.48	9.53%	7.86%	0.48	1.25	1.73	0.06
38	3.75	3.75	7.50	0.36	2.50	0.21	0.23	3.29	3.29	(2.50)	(0.21)	(0.23)	0.36	9.53%	7.86%	0.36	1.25	1.61	0.05
39	2.50	2.50	5.00	0.24	2.50	0.14	0.15	3.03	3.03	(2.50)	(0.14)	(0.15)	0.24	9.53%	7.86%	0.24	1.25	1.49	0.04
40	1.25	1.25	2.50	0.12	2.50	0.07	0.08	2.76	2.76	(2.50)	(0.07)	(0.08)	0.12	9.53%	7.86%	0.12	1.25	1.37	0.04
41	-	-	-	-	-	-	-	-	2.76	-	-	(1.08)	1.69		7.88%	1.69	-	1.69	0.04

MIEC cites this undiscounted "profit" total as if it has some significance >>> $ 91.38

7.88%

Actual earned return over the life of the investment

(7.25)

Zero is perfect cost recovery

Negative indicates costs not fully recovered

Schedule TMB-R1-1

1 YEAR regulatory lag, 5 year investment

$100M investment:	$ 50	Equity Funding	Assumes 1 YEAR of regulatory lag
	$ 50	Debt Funding	Investment occurs at end of Year 0
	9.53%	Cost of Equity, after-tax	Recovery begins at start of Year 2
	5.56%	Cost of Debt, pre-tax	Extra year of revenue at the end (Year 6)
	39%	Tax Rate, all taxes assumed to be current for simplicity	

				Revenue Required for Cost Recovery					Utility Earnings							Cash Flows for Equity Investors			
Year	Equity Balance	Debt Balance	Net Plant In-Service	Recovery of Cost of Equity	Recovery of Depreciation Expense	Recovery of Interest Expense	Recovery of Income Taxes	Total Revenue Required	Revenue Received	(less): Depreciation Expense	(less): Interest Expense	(less): Income Taxes	Net Income	Realized Return on Equity (Current Year)	Realized Return on Equity (Life-to-Date)	Return ON Equity	Return OF Equity	Total Cash Flow	Discounted Cash Flow
																		$ (50.00)	$ (50.00)
1	$ 50.00	$ 50.00	$ 100.00	$ 4.77	$ 20.00	$ 2.78	$ 3.05	$ 30.59	$ -	$ (20.00)	$ (2.78)	$ 8.88	$ (13.90)	-27.79%	-27.79%	$ (13.90)	10.00	(3.90)	(3.56)
2	40.00	40.00	80.00	3.81	20.00	2.22	2.44	28.47	28.47	(20.00)	(2.22)	(2.44)	3.81	9.53%	-10.21%	3.81	10.00	13.81	11.51
3	30.00	30.00	60.00	2.86	20.00	1.67	1.83	26.35	26.35	(20.00)	(1.67)	(1.83)	2.86	9.53%	-5.31%	2.86	10.00	12.86	9.79
4	20.00	20.00	40.00	1.91	20.00	1.11	1.22	24.24	24.24	(20.00)	(1.11)	(1.22)	1.91	9.53%	-3.29%	1.91	10.00	11.91	8.27
5	10.00	10.00	20.00	0.95	20.00	0.56	0.61	22.12	22.12	(20.00)	(0.56)	(0.61)	0.95	9.53%	-2.49%	0.95	10.00	10.95	6.95
6	-	-	-	-	-	-	-	-	22.12	-	-	(8.63)	13.49		4.15%	13.49	-	13.49	7.81
															4.15%				(9.22)
															Actual earned return over the life of the investment				Zero is perfect cost recovery
																			Negative indicates costs not fully recovered

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of a Working Case to Consider Policies to Improve Electric Utility Regulation.	)))	File No. EW-2016-0313

THE CRITICAL NEED TO REPLACE AGING ELECTRIC INFRASTRUCTURE AND BUILD A SMARTER AND MORE EFFICIENT GRID TO MEET CUSTOMERS' NEEDS AND EXPECTATIONS

A. Missouri's Electric Infrastructure is Aging

Missouri's electric infrastructure was, to a large degree, built decades ago to serve rapidly increasing electric energy usage. In particular, economic/industrial growth, the widespread use of air conditioning and larger houses in the suburbs fueled steady electric sales growth during the 1950s, '60s and '70s. Much of Ameren Missouri's generation, transmission and distribution system was built to serve our customers' rising energy needs, and paid for by the incremental revenues and cash flows that new electric sales brought. Now these facilities are reaching the end of their useful lives. For example:

- Ameren Missouri's four baseload coal generation plants are on average almost 50 years old;
- approximately half of Ameren Missouri's substations are over 40 years old; and
- Ameren Missouri's underground network serving downtown St. Louis has facilities that are 80 to 100 years old.

These aging facilities must be replaced and modernized to maintain the strong reliability that our customers have come to expect today, but also to meet their future energy needs and expectations. However, what has changed significantly from the past is that our customers' electric energy usage has been declining since 2007, even without taking into account the recent loss of Noranda Aluminum, the Company's largest customer. A variety of factors are driving this decline, including Ameren Missouri's very successful energy efficiency programs and national energy efficiency standards. The consequence of these declining electric sales is that there is simply no incremental revenue stream to timely pay for the replacement of these facilities. While it is true that Ameren Missouri has access to the capital markets to finance these important projects, it is also true that the regulatory lag built into Missouri's decades-old rate setting process prevents full recovery of the cost of these investments and other elements of Ameren Missouri's costs to serve its customers. These outdated policies impede electric service providers' ability to ramp up their investments to address the aging energy infrastructure.

B. <u>The Grid Must Evolve to Meet Customers' Future Needs and Expectations</u>

The need for electric utilities to invest goes beyond simply replacing facilities that are reaching the end of their useful lives today. In the future, customers, the State of Missouri and our country will require a more robust, resilient and secure electric grid to meet customers' changing energy needs and expectations. Greater levels of generation will come from cleaner intermittent resources as electric utilities incorporate greater levels of renewable energy (e.g.: wind, solar, biomass, etc.) into their generation portfolios and more customers utilize Distributed Energy Resources (DERs), such as private solar generation on rooftops. As the future unfolds we believe that the electric system will become fully integrated in that central station generation, transmission, distribution, DERs and customers will all work together in a coordinated fashion to continuously, instantaneously and reliably maintain the balance between resources and demand ("The Integrated Grid"). Energy flows will no longer be primarily in one direction (from generation to the load) but they will be bi-directional, where not only central station generation provides energy, but utility and customer distributed resources also provide energy and ancillary services. Increased complexity will require a much more sophisticated transmission and distribution infrastructure along with improved control, relaying and communication systems.

Distribution infrastructure (wires, switches, relaying, control systems and communication networks) will have to be replaced and upgraded to support the integrated system. Planning processes for transmission and distribution will have to be modified to accommodate bi-directional distribution flow, central station generation changes and evolving customer energy needs and expectations. Historically the grid was designed, constructed and operated to reliably transmit central station generation to meet customer demand. In the future the smart grid will not only have to continue to transmit generation to meet customer demand but it will also have to integrate micro-grids and DERs that are located on the distribution system in a much more dynamic nature than the system was ever designed or constructed to do.

When policies enable investment in advanced technologies such as smart meters, we also believe customer net demand (the difference between customer demand and their DERs) will become much more dynamic and aggregated on a real time basis to help shape and reduce overall system demand peaks, as well as minimizing environmental impacts. This will be a significant change in the way the electric system has been operated over the last 100 years in that customer net demand will also be "managed" just like central station generation and aggregated as part of the pool of resources. The ramifications of this change could reduce the need for central station generation along with adding complexity to the way that "the grid" is designed and operated today.

C. Additional Investment is Required to Build this Smarter, Cleaner and More Efficient Grid

Investment will be needed to support the smarter grid of tomorrow and to provide the benefits it promises to customers. Investment in the next generation of smart meters is necessary to allow customers to monitor their energy usage and implement the automated energy efficiency and conservation measures available. Smart distribution facilities are also needed to enable "self-healing," which quickly restores service after an outage without human intervention, to allow more sophisticated monitoring of the grid and provide modern security protections. Upgrades to transmission facilities provide similar benefits.

Investments will also have to be made to enable the interconnection of DERs and micro-grids to the system, and the integrated operation of a dynamic grid that can regularly accommodate multi-directional flows of power. Finally, investments in central station renewable generation will be needed as electric utilities transition their generation portfolios to cleaner and more diverse energy resources.

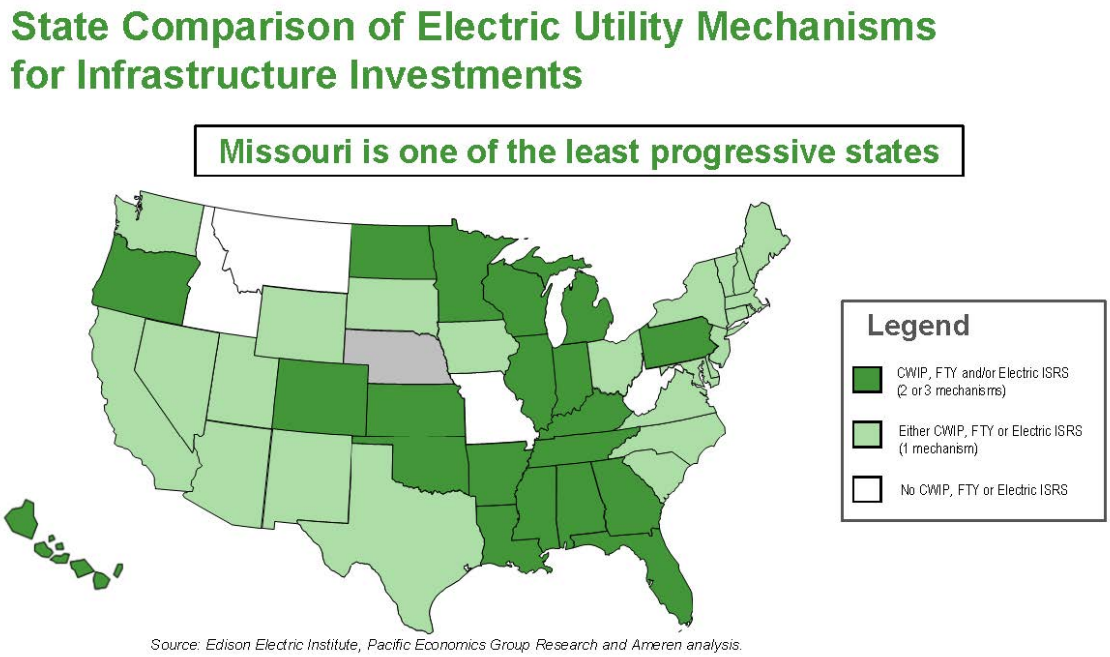
D. Infrastructure Investment Yields Long-Term Customer and Statewide Benefits

A modern, reliable, resilient infrastructure provides significant customer and statewide benefits. In particular, a modern grid improves reliability and reduces the duration of outages when they do occur, both of which result in meaningful customer savings. It can reduce operations and maintenance costs. It provides improved energy security, reducing the risk of physical and cyber-attacks. It provides enhanced customer choice, including enabling customers to take advantage of modern energy efficiency and energy conservation options, which helps them manage their peak energy usage, reduce their bills, as well as help the environment by deferring the need to construct additional baseload generation. Construction of a modern grid also facilitates economic development, increasing employment through the workers who construct the new electric facilities, and industrial customers that expand their footprint in Missouri to take advantage of a modern electric grid. Finally, a modern grid would facilitate the development of micro-grids and smart cities as well as the greater use of electric vehicles, bringing customers the advantages of these technological advances.

There is clear evidence that these benefits are real based on the experience in other states. For example, as a result of investing to upgrade and modernize its electric infrastructure, Illinois has materially reduced the number of outages its customers face each year, it has enabled customers to modify their usage during peak periods to reduce their bills and it has created thousands of new jobs, while maintaining affordable electric rates.

E. <u>Sound Energy Policy is Needed to Support Infrastructure Investments</u>

As many other states have recognized, sound energy policies that support infrastructure investments are a necessary prerequisite for electric energy companies to make incremental infrastructure investments that will provide these benefits. Particularly when demand for electricity is stagnant or declining, policies must be implemented that address the disincentive to invest that is caused by excessive regulatory lag. As we have already stated in previous filings in this proceeding, there are many ways to do this that have been successfully implemented in other states. For example, performance-based rates are used in states such as Illinois and Arkansas. FERC and Georgia are examples of jurisdictions that utilize formulaic rates to reduce or eliminate lag on capital investments. Other states have used forward test years or infrastructure riders, or permitted Construction Work in Progress (CWIP) to be included in rate base. Even Missouri has used “construction accounting” for specific construction projects, which, if implemented on a system-wide basis as Plant-In-Service Accounting (PISA), would significantly reduce the current financial disincentives created by regulatory lag. There are many ways to address the disincentive that regulatory lag provides. As the map below shows, one or more of these policies has been implemented in almost every state.



Independent organizations and numerous publications have also recognized this problem. For example, the American Society of Civil Engineers published its Report Card for America's Infrastructure that explains in detail the critical need for electric infrastructure improvements. See http://www.infratructurereportcard.org/a/#p/energy/conditions-and-capacity, as well as the 2016 update: http://www.infrastructurereportcard.org/wp-content/uploads/2016/05/ASCE-Failure-to-Act-Report-for-Web-5.23.16.pdf. See also, http://www.ibtimes.com/aging-us-power-grid-blacks-out-more-any-other-developed-nation-1631086 and "The Case for Smart Grid," a *Public Utilities Fortnightly* article attached hereto.

F. <u>Rate-Setting Policy in Missouri is Not Keeping Pace with Needed Investment</u>

Unfortunately, Missouri's rate-setting policy, which sets future rates based on a backward look at expenses and capital investment, maximizes regulatory lag and provides a strong financial disincentive for electric utilities to make needed investments. In a rising operating cost and capital investment environment (which we are clearly in now), rates set in this way are out of date from the moment they take effect. In an environment of no electric sales growth and increasing investment needs, rates never reflect electric utilities' true cost of service and losses are never made up. In this environment, limiting capital investment is necessary in order for an electric utility to have any reasonable chance to earn its authorized return, which is at odds with the State of Missouri's energy needs for the future.

The chart that Kansas City Power & Light Company (KCP&L) showed at the workshop held in this proceeding on September 13 provided a stark illustration of the deficiencies of Missouri's regulatory framework for a utility that aggressively invests in its infrastructure. KCP&L earned far below its authorized return for *10 years in a row* while it aggressively invested in its system.

A review of investment levels and achieved returns for Ameren Missouri tells a different, but in some ways similar, story to that of KCP&L's. From 2007 through 2011 Ameren Missouri invested at approximately 2X its depreciation rate and, like KCP&L, Ameren Missouri never came close to earning its authorized return. Beginning in 2011, Ameren Missouri reduced its capital investment levels, and by 2015 Ameren Missouri's ratio of capital investments to depreciation had fallen to 1.37—in the bottom 1/8th of electric utilities in the country—while it began earning returns closer to its authorized return. Although actual returns in any given year are influenced by a variety of factors, including weather and nuclear plant outages, reducing capital investments, along with reducing expenses, have been necessary to provide Ameren Missouri with any reasonable opportunity to earn its authorized return.

G. Missouri's Policies Must Keep Pace

If Missouri wants to facilitate the replacement of aging infrastructure and the modernization of the electric grid to provide the benefits that customers have come to expect, and to position Missouri for further economic growth, its policies must change. As stated above, there are many options to address the issue of regulatory lag, from forward test years, to formula rates, to infrastructure riders, to plant-in-service accounting, to including CWIP in rate base. But incremental steps, such as reducing discovery times in rate cases to slightly shorten the 11-month rate case process will not be sufficient to enable needed infrastructure investment.

H. Investments that Would Be Enabled

Attached hereto as Appendix A is a list of the infrastructure projects that Ameren Missouri could undertake over the next five years to benefit customers, if regulatory lag were appropriately mitigated. While beneficial incremental investments of $4 billion over a ten-year period have been identified, we have presented a detailed plan for incremental infrastructure investment of $1 billion over a five-year period to balance the need to address our aging infrastructure with related rate impacts. Additional projects of approximately $1 billion could be accelerated in this five-year time frame should it be deemed appropriate. These investments will allow Ameren Missouri to implement the following customer beneficial projects:

- Accelerate the replacement of substations in excess of 40 years old to preserve and enhance reliability and enhance system security.
- Upgrade several substations to a modern design that increases resiliency when short circuits occur, provides isolation points for service restoration, and includes smart diagnostics and advanced relaying to detect and correct problems faster.
- Proactively replace underground cable to preserve and enhance reliability.

- Automate distribution facilities to minimize outages and enhance security.
- Replace Ameren Missouri's out-of-date meters with smart meters that provide customers modern service options that would facilitate much greater penetration of energy efficiency programs as well as peak load management programs. These programs will be critical as Ameren Missouri retires more baseload generating units and works to minimize the need to construct additional large energy centers.

Although this list reflects realistic projects that could be undertaken, the scheduling of specific projects would depend on operational conditions. Moreover, these projects have not been engineered, so actual costs may vary from the high-level estimates provided. As noted earlier this list includes additional beneficial incremental investments beyond the $1 billion limit in years 1 through 5 and as a total for years 6 through 10. Although we believe it is important to implement as many customer-beneficial projects as are feasible in the current low interest environment, it is also critical to keep customer rates competitive to maintain the advantage of low electric rates that Missouri currently enjoys. We believe we can make the incremental investments and keep our rates very low.

If we are able to find a path forward that meaningfully mitigates regulatory lag, Ameren Missouri would be able to provide an even more detailed list of future investments that would be enabled by the specific mechanism that is adopted. We are also open to submittal of infrastructure plans and further discussion of these plans with stakeholders to ensure that these incremental investments are consistent with better meeting the needs of our customers.

Ameren Missouri remains committed to advancing the discussions of these important issues with all stakeholders. We realize changes to the regulatory structure will require changes for all parties, including electric energy companies. We welcome accountability measures requiring that we demonstrate improvements in the frequency of outages, duration of outages, customer engagement metrics, and other metrics that encourage the electric service provider to accomplish improvements aligned with better serving customers and providing broader benefits to the State of Missouri to attract and retain businesses. But we remain convinced that Missouri must take steps now to adopt a modern regulatory framework that promotes a smarter and stronger grid so:

- customers continue to receive the reliable service they have come to expect;
- customers can benefit from the greater conveniences, choices and controls afforded to them by the modern technology that is benefitting residents in other states;
- we can take advantage of the low interest environment to enhance our infrastructure; and
- we can create good-paying jobs in Missouri.

September 23, 2016

Respectfully submitted,

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ATTACHMENT A
Building a Smarter Energy Grid for the Future

Distribution[1, 2]:	Customer Benefits:	Years				
		2018	2019	2020	2021	2022
Aging Substation Infrastructure Investment	Replacing aging, end-of-life substations will result in far fewer customer outages due to failed equipment. Modern designs will be installed which will prevent violent failures and equipment misoperations, both of which result in lengthy outages for thousands of customers. The new equipment is expected to require less maintenance, reducing costs to customers. The smart equipment installed in modern substation designs also improves operations, enabling faster and less costly restoration of outages when they do occur.	$ 10	$ 30	$ 35	$ 40	$ 60
Downtown St. Louis Underground Grid Revitalization	Replacing the aging power cables, conduit, and manholes in the St. Louis downtown underground grid will prevent the catastrophic failures and outages to the 100,000+ downtown customers that may occur as equipment ages beyond its useful life. This investment will result in a more robust and reliable downtown grid that will experience very few failures and outages. The investment also enables implementation of smart devices which automatically restore power to customers when outages do occur, reducing the outage duration from multiple hours to a few seconds.	$ 5	$ 10	$ 10	$ 10	$ 10
Smart Meter Program	Replacement of the 1990s technology Automated Meter Reading (AMR) system with modern Smart Meter technology will reduce customer costs associated with metering customer energy usage. The present AMR system is maintenance intensive and is facing obsolescence, which results in high maintenance costs borne by customers. Smart meter technology also enables customers to better manage their energy usage and reduce their energy bill by providing customers more information about their energy usage. Smart meter technology enables the utility to provide better outage response and more seamless implementation of Distributed Energy Resource technologies. It could also provide benefits to customers in the form of pre-pay options, and reduced disconnect/reconnect charges which impact low-income customers.	$ 80	$ 80	$ 80	$ 80	$ 23
Distribution Automation upgrades	Investment in distribution automation will enable installation of modern technology smart devices on distribution power lines to meet the increasing expectations of customers. Installation of smart switches will enable automated restoration of customers who experience outages, reducing outage duration from multiple hours to a few minutes. Installation of faulted circuit indicators enables fast identification of the location on a circuit where a repair needs to be made, also enabling reduced outage duration. Installation of smart capacitor controls enable voltage swings experienced by customers to be eliminated and enhances the energy efficiency of the distribution system.	$ 2	$ 3	$ 7	$ 7	$ 13

Storm Hardening	Investment in storm hardening projects will enhance the distribution system in withstanding the physical forces associated with severe thunderstorms and ice storms. 1) Distribution lines that cross major highways and roads will be rebuilt with stronger structures or bored and installed underneath the highway. This will eliminate lengthy outages to customers and disruption to the community due to multi-hour traffic delays on major roads associated with failures of highway crossings during severe storms. 2) Major sub-transmission line structures will be modified with new designs which are more compact and have less hardware. These structures and are more reliable during high winds and more aesthetically appealing compared to traditional wooden crossarm designs. 3) Replacing fuses with reclosing devices at key locations on the distribution system will greatly reduce the duration of and the cost of responding to many storm related customer outages. Many customer interruptions are caused by temporary problems such as a branch coming loose from a tree and making contact with a circuit as it blows clear of the circuit. In this case, a fuse blows and must be manually replaced before customers' power can be restored. Installation of automatic reclosing devices on these circuits would allow restoration of these outages without requiring a manual response, reducing the outage duration to a few seconds, and reducing costs borne by customers 4) Convert overhead circuits to underground in locations that are prone to frequent outages due to exposure to dense woods and tall trees.	**$ 3**	**$ 3**	**$ 6**	**$ 6**	**$ 10**
Customer Service Self-Serve Technology Upgrade	Investing in customer self-serve technologies will provide customers with more personalized, low-effort interactions. It will also allow Ameren Missouri to provide more proactive communications to its customers.	**-**	**$ 1**	**$ 2**	**$ 2**	**$ 14**
Replace End of Life Overhead Conductor (#6 Copper)	By replacing end of life, brittle # 6 Copper wire, customers will benefit from improved reliability. Customer interruptions related to tree contact breaking this brittle wire will be greatly reduced. Upgraded wire will be more robust, less prone to failures, and enables the distribution system to integrate more Distributed Energy Resource technologies.	**-**	**$ 3**	**$ 5**	**$ 5**	**$ 10**
Total		**$100**	**$130**	**$145**	**$150**	**$140**

Transmission[1,2]:	Customer Benefits:					
Rebuild the Cape switching station and Viaduct bulk substation at a new joint location to avoid flood exposure. 161kV to be breaker and a half. (Cape ~1951, Viaduct ~1953)	Current flood control measures will not protect against major floods at this site. These stations are also vulnerable to seismic events. Current funding doesn't allow these high-impact / low-probability events to be addressed. Upon completion of this project, customers in southeast Missouri will not be subject to potential outages or rotating outages caused by major floods, securing the supply for residential, commercial, and industrial customers. The new station will also be designed to better withstand seismic events.	-	$ 17	$ 25	$ 8	-
Build 138kV 3-position ring bus with a 161/138kV transformer at Miller substation. Build a 161kV 4-position ring bus at Zion. (Miller ~1945, Zion ~1967)	This project will increase the reliability of central Missouri including the Jefferson City area. The new substation design increases resiliency when short-circuits occur and provides isolation points for service restoration. The new circuit breakers which will be installed as part of the ring bus projects will be equipped with smart diagnostics and advanced relaying that will allow faster detection of problems and thus restoration.	$ 11	$ 4	-	-	-
Construct 138kV breaker station at Carrollton substation. (Carrolton ~1978)	This project will increase the reliability of the northwest St. Louis County area. The new substation design increases resiliency when short-circuits occur and provides isolation points for service restoration. The new circuit breakers which will be installed as part of the project will be equipped with smart diagnostics and advanced relaying that will allow faster detection of problems and thus restoration.	-	-	-	-	$ 5
Install 138kV 4-position ring bus at Lakeside substation. (Lakeside ~1983)	This project will increase the reliability of the Lake of the Ozarks area. The new substation design increases resiliency when short-circuits occur and provides isolation points for service restoration. The new circuit breakers which will be installed as part of the ring bus project will be equipped with smart diagnostics and advanced relaying that will allow faster detection of problems and thus restoration.	-	-	$ 1	$ 7	$ 9
Relocate the existing 138/34kV Page substation to the new Bugle site. 138kV to be built as breaker and a half arrangement. (Page ~1917)	The current Page substation was an original hub in the transmission system development linking the Osage Plant, the Keokuk Plant, and the customer load in St. Louis. As electrical demands grew, Page continued to serve as an important hub to the St. Louis region. But those additions did not address the condition of the facility. This project will rebuild the capability of Page at a new site (because service must be maintained at Page during construction) so that customers in the St. Louis area can be assured of a reliable supply of electricity. With this rebuilding, advanced relay, control, and communication will be installed that provide smart grid analytics, high speed protection, next-generation physical security, and fiber optic capabilities.	-	-	-	$ 10	$ 20

Install 138kV 4-position ring bus at Lemay substation. (Lemay ~1958)	This project will increase the reliability of south St. Louis City and County. The new substation design increases resiliency when short-circuits occur and provides isolation points for service restoration. The new circuit breakers which will be installed as part of the ring bus project will be equipped with smart diagnostics and advanced relaying that will allow faster detection of problems and thus restoration.	**$ 10**	**$ 5**			
Install optical ground wire on existing transmission lines.	Smart grid is driven by data. The installation of optical ground on these lines will bring high-speed communications to the electric supply points and form part of a larger, robust communication network which will allow the needed information to flow bilaterally from customers and distributed energy resources back to Ameren systems and control room operators to assure reliability in the 21st century grid.	**$ 4**	**$ 4**	**$ 4**	**$ 5**	**$ 6**
Accelerate replacement of aging transformers, circuit breakers, relays and instrument transformers at existing substations across Ameren Missouri before equipment reaches end-of-life.	The current framework is run-to-failure and a significant number of customer outages are caused by substation equipment failures. Transmission substation outages due to equipment failure are often long-term and can lead to widespread customer outages, and proactive replacement of aging assets will reduce the number of such outages. Additionally, new devices supporting a smarter grid with increased diagnostics and capabilities will be installed. In some cases, the devices being replaced are oil-filled and thus this project would reduce environmental exposure. In addition, proactive replacement will help mitigate future increases in maintenance expenses.	**$ 10**	**$ 10**	**$ 10**	**$ 10**	**$ 15**
Total		**$ 35**	**$ 40**	**$ 40**	**$ 40**	**$ 55**

Sustainable Energy, Micro-Grid & Vehicle/Equipment Electrification[1,2]:

Solar Partnerships		$ 10	$ 10	$ 10	$ 10	-
Micro-Grid Projects		$ 10	-	$ 10	-	$ 10
EV Charging, Metro Link EV, Industrial Equip. Electrification		$ 5	$ 8	$ 10	$ 10	$ 10
Universal Solar (Montgomery)		-	-	-	-	$ 30
Total		$ 25	$ 18	$ 30	$ 20	$ 50

	Years					
	2018	**2019**	**2020**	**2021**	**2022**	**Years 1-5 Total**
Investment Supportive Regulatory Framework Incremental $s (M) - TOTAL:	$160	$188	$215	$210	$245	$1,018

1) Additional beneficial incremental investments have been identified in years 1 through 5 for distribution, transmission and sustainable and innovate energy technologies of approximately $1.9 to 2.0 billion.
2) Additional beneficial incremental investments have been identified in years 6 through 10 for distribution, transmission, and sustainable and innovative energy technologies of approximately $1.6 to. 1.7 billion.

The Case for Smart Grid

Funding a new infrastructure in an age of uncertainty.

BY MASSOUD AMIN

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We are witnessing today the birth of a new mega-infrastructure. It will emerge from the convergence of energy with telecommunications, transportation, Internet, and electronic commerce.

Starting with the electric grid, which underpins all of these interdependent systems, new ways are being sought to improve network efficiency and eliminate congestion problems without seriously diminishing reliability and security. But with these efforts come uncertainty – plus a general disruption to industry and commerce that may well prove greater than any transition yet seen.

Of course, the job of controlling a heterogeneous, widely dispersed, yet globally interconnected system like the electric grid poses serious technological problems. Yet it will prove even more complex and difficult to control for optimal efficiency and maximum benefit to ultimate consumers while still allowing all the various business components to compete fairly and freely.

Similar needs exist for other infrastructures, where future advanced systems are predicated on the near-perfect functioning of today's electricity, communications, transportation and financial services. But in the electric industry in particular – so necessary to our quality of life, economy and security – uncertainties persist and are growing at nearly every scale, including operational, policy, investment and market, education, and talent pipeline. Industry leadership must focus increasingly on managing uncertainties in wide-ranging areas – from policy and politics to environmental factors, from investment to business model innovation, and from disruptive technologies to workforce and talent development.

The most visible parts of these problems stem from years of inadequate investment in the infrastructure, R&D, and associated human capital. The reason for this neglect is caused partly by uncertainties over what government regulators will do next and what investors will do next.

As ComEd CEO Anne Pramaggiore notes, "Today's regulatory framework is keeping us locked into the 20th century."

What has caused this hindrance in development? Quite simply, we've wasted 15 years arguing the roles of the public and private sectors while our global competitors adapt and innovate. We need to renew public/private partnerships, cut red tape and reduce the cloud of uncertainty surrounding the return on investment (ROI) of modernizing and upgrading infrastructure.

As the digitization of society continues to expand, and as environmental issues grow in urgency, it becomes increasingly critical that we make investments in development if we want to accommodate the growing need for electricity. In fact, it is projected that the world's electricity supply will need to triple by 2050 to keep up with demand.

Our approach so far – to deal with outages by simply coping – is ultimately a defeatist strategy.

Let's frame the issues. As I see it, here are the top 10 drivers for change in the electric power sector, in no particular order:

- Acceleration of efficiency (energy intensity dropping 2%/yr.);
- Distributed generation and energy resources (DG & DERs), including energy storage & microgrids;
- More cities interested in charting their energy future;
- District energy systems;
- Smart Grid;
- Electrification of transportation;
- New EPA regulations, such as for greenhouse gases under Section 111(d) of Clean Air Act;
- Demand response (and 3rd-party aggregation of same);
- Combined heat & power (CHP), plus waste heat recovery; and
- The increasingly interstate and even trans-national nature of utilities (and contractors too, which leads to security concerns).

These drivers in turn lead to some important questions, both for the utility, as a business, and for regulators, as makers of policy:

- What business models may develop, and how will they successfully serve both upstream electricity market actors and energy consumers?

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- What effects could these new business models have on incumbent utilities, and what opportunities may exist for other industry sectors to capitalize on these changes?
- How will regulation need to evolve to create a level playing field for both distributed and traditional energy resources?
- What plausible visions do we see for the future of the power sector, including changes for incumbent utilities, new electricity service providers, regulators, policymakers, and consumers?
- What measures are practical and useful for critical infrastructure protection (CIP) and the security of cyber physical infrastructure?

To answer these questions, we must address a number of new challenges, such as how to integrate large-scale stochastic (uncertain) renewable generation, electric energy storage, distributed generation, plug-in hybrid electric vehicles, and demand response (smart meters). We must also realize methods to deploy and integrate new synchronized measurement technologies, new sensors, and new system integrity protection schemes.

What follows is a look at where we are, and what may lie ahead, with a focus on the (1) the scope of the problem, (2) regulatory reform initiatives now underway, and (3) how to go about rethinking the business models that might evolve. (In a future issue, I will follow up with an in-depth look at some related challenges, such as privacy rights and cyber security.)

But before going further, please allow me to thank the many industry leaders who have provided helpful feedback and insightful analyses, including several colleagues at the IEEE Smart Grid initiative, Energy Thought Summit (ETS), U.S. DOE, EPRI, EEI (Edison Electric Institute), NRECA (National Rural Electric Cooperative Association), various municipal utilities, FERC (Federal Energy Regulatory Commission), NARUC (National Association of Regulatory Utility Commissioners), NERC (North American Reliability Corporation), PUCs (state utility commissions), and elsewhere.

Overcoming Defeatism

Consider the factors that are hindering improvements to the nation's electric grid.

First, on any given day, there are half a million people in America who must go without electricity for two or more hours per day. The number of weather-caused, major outages in the U.S. has risen since the 1950s, from between two and five each year by the 1980s to 70–130 between 2008 and 2012. Two thirds of weather-related power disruptions have occurred in the past five years, affecting up to 178 million customers (meters), as changing weather patterns impact aging infrastructure. However, outages are not always in the same location, and because of that, we have a very short attention span.

Second, there is a lack of leadership in the public and private sectors. There is a lot of uncertainty, and that hinders the development of the smart grid. Congress should incentivize investment in the infrastructure. We can create jobs in this area – very high-paying jobs. Just to integrate distributed resources such as wind power, we need to add about 42,000 miles of high-voltage line, and that would create over 210,000 jobs.

Third, there is a divide between federal jurisdiction and local jurisdiction. The high-voltage grid, for the most part, is under federal jurisdiction, but the distribution systems are under the local jurisdiction – mostly public utility commissions. That basically kills the incentive for any utility group to do regional work and upgrade on a regional basis. We need coordination in the investment in the grid and in the research and development areas.

Regulatory restructuring, though well-intentioned, has not yet not fully answered the problem of lagging infrastructure investment. In fact, for the power industry in the United States, direct infrastructure investment has declined in an environment of regulatory uncertainty because of deregulation, and infrastructure R&D funding has declined in an environment of increased competition because of restructuring. Electricity investment was not large to begin with. Presently the power industry spends a smaller proportion of annual sales on R&D than do the dog foods, leather, insurance, or many other industries – less than 0.3 percent, or about $600 million per year. The electric power sector is second from the bottom of all major U.S. industries in terms of R&D spending as a percentage of revenue, exceeding only the pulp and paper industry. In the electric power sector, R&D represented a meager 0.3 percent of net sales in the six-year period from 1995 to 2000, before declining even further to 0.17 percent from 2001 to 2006. The pet food industry, hotel industry and the insurance industry all invest in R&D at a higher rate than electrical power.

A self-healing grid isolates problems as they occur, before they snowball into major blackouts.

Growth, environmental issues, and other factors also contribute to the difficult challenge of ensuring infrastructure adequacy and security. New environmental considerations, energy conservation efforts, and cost competition require greater efficiency throughout the grid. Not only are infrastructures becoming more complexly interwoven and more difficult to comprehend and control, there is less investment available to support their development.

And the most significant environmental issue concerns the development of renewable and sustainable energy recourses. For example, much of the renewable energy and natural gas potential in the United States is located in areas that are remote from population centers, lack high demand for energy, and are not well connected to our national infrastructure for transmission of bulk

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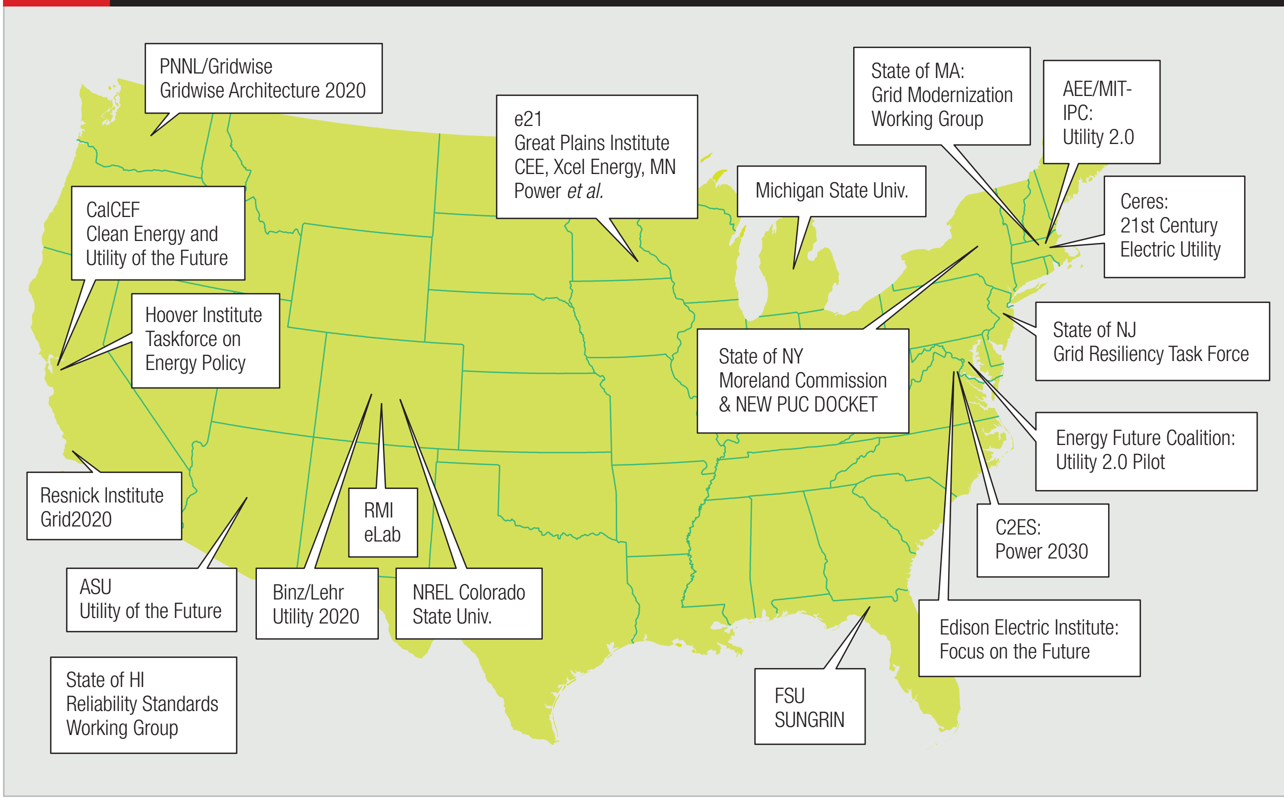
FIG. 1 **REGULATORY REFORM EFFORTS**



Source: The Energy Foundation

electrical power. The recent expansion of natural gas production in the U.S. has also affected development of the grid. To achieve public policy objectives, sufficient transmission capacity must link new natural gas generating plants, on-shore or off-shore wind farms, solar plants and other renewables to customers if those resources are to serve the energy needs of homes and businesses, and have the potential to replace significant portions of the oil used today in vehicle transportation.

New transmission will play a critical role in the transformation of the electric grid to enable public policy objectives, accommodate the retirement of older generation resources, increase transfer capability to obtain greater market efficiency for the benefit of consumers, and continue to meet evolving national, regional, and local reliability standards. With a stronger and smarter grid, 40 percent of our electricity in the U.S. can come from wind by 2030.

Meanwhile, electricity needs are changing and growing fast. Tweeting, and the devices and infrastructure needed to operate the underpinning communication network, data centers and storage alone adds more than 2,500 megawatt hours (MWh) of demand globally per year that did not exist five years ago. Kilowatt hour (kWh) is commonly used by power companies for billing, since the monthly energy consumption of a typical residential customer ranges from a few hundred to a few thousand kilowatt hours. One MWh is equal to 1,000 kilowatts of electricity used continuously for one hour. One MWh is the amount of electricity used by approximately 330 homes in one hour. On average 2500 MWh is equivalent to the electricity used by about 825,000 homes. Factor in Internet TV, video streaming, online gaming and the digitization of medical records, and the world's electricity supply will need to triple by 2050 to keep up.

The world's electric supply will need to triple by 2050.

These developments point out the many weaknesses in the current state of our electric grid. But our primary strategy till now for dealing with these problems – a strategy that is best described as simply coping – is ultimately a defeatist strategy.

Defining the Self-Healing Grid

What, then, is a smart, self-healing grid? And why is it needed? A self-healing grid uses digital components and real-time communications technologies installed throughout a grid to monitor the grid's electrical characteristics at all times and constantly tune itself so that it operates at an optimum state. It has the intelligence to constantly look for potential problems caused by storms, catastrophes, human error or even sabotage. It will react to real or potential abnormalities within a fraction of a second, just as a military fighter jet reconfigures itself to stay aloft after it is damaged. The self-healing grid isolates problems immediately as they occur, before they snowball into major blackouts, and reorganizes the grid and reroutes energy transmissions so that services continue for all customers while the problem is physically repaired by line crews.

A self-healing smart grid can provide a number of benefits that lend to a more stable and efficient system. Three of its primary functions include**:**

- **Real-time monitoring and reaction,** which allows the system to constantly tune itself to an optimal state;
- **Anticipation**, which enables the system to automatically look for problems that could trigger larger disturbances; and
- **Rapid isolation**, which allows the system to isolate parts of the network that experience failure from the rest of the system to avoid the spread of disruption and enables a more rapid restoration.

As a result of these functions, a self-healing smart grid system is able to reduce power outages and minimize their length when they do occur. The smart grid is able to detect abnormal signals, make adaptive reconfigurations and isolate disturbances, eliminating or minimizing electrical disturbances during storms or other catastrophes. And, because the system is self-healing, it has an end-to-end resilience that detects and overrides human errors that result in some of the power outages, such as when a worker error left millions of California residents without electricity in September 2011.

And how does a smart self-healing grid provide benefits to energy consumers?

Beyond, managing power disturbances, a smart grid system has the ability to measure how and when consumers use the most power. This information allows utility providers to charge consumers variable rates for energy based upon supply and demand. Ultimately, this variable rate will incentivize consumers to shift their heavy use of electricity to times of the day when demand is low and will contribute to a healthier environment by helping consumers better manage and more efficiently use energy.

Nevertheless, despite these advantages, a collection of various independent technologies will be required to transform our current infrastructure into a self-healing smart grid.

The ideal smart grid system consists of microgrids, which are small, mostly self-sufficient power systems, and a stronger, smarter high-voltage power grid, which serves as the backbone to the overall system.

Upgrading the grid infrastructure for self-healing capabilities also requires replacing traditional analog technologies with digital components, software processors and power electronics technologies. These must be installed throughout a system so that it can be digitally controlled, which is the key ingredient to a grid that is self-monitoring and self-healing.

Much of the technology and systems thinking behind self-healing power grids comes from the military aviation sector, where I worked for 14 years on damage-adaptive flight systems for F-15 aircraft, optimizing logistics and studying the survival of squadrons and mission effectiveness. In January 1998, when I joined the Electric Power Research Institute (EPRI), I helped bring these concepts to electricity power systems and other critical infrastructure networks, including energy, water, telecommunications and finance. Following the September 11, 2001, terrorist attacks, resilience and security has become even more important.

Microgrids: A Growing Role

Smart microgrids represent a key a growth area in recent years and will no doubt play a growing role in meeting local demand, enhancing reliability, and ensuring local control of electricity – at least where financial viable.

Microgrids are small power systems of several megawatts (MW) or less in scale with three primary characteristics: distributed generators with optional storage capacity, autonomous load centers, and the capability to operate interconnected with or "islanded" from a larger grids. Storage can be provided by batteries, super-capacitors, flywheels, or other sources.

Like a moon shot – and it will cost $25 billion a year for 20 years – this is just the sort of thing Americans do best.

Microgrids can serve as ideal platforms for realizing combined goals of a smart grid, including reliability, integration of renewables, diversification of energy sources, and flexible demand response. Because of their scale, they facilitate systematic, yet innovative, approaches to solve local as well as global energy needs. They can also provide facilities and communities a certain level of independence from grid disruptions while providing grid operators and utilities an additional resource for improving their operations.

In some respects, microgrids can be significantly more complex. For example, they might include DC elements and inverters for conversion. They can also exert greater control over a wider variety of loads, and the connection with the grid can be flexible. On the last point, microgrids can enable uninterrupted operation where grid supply might be unreliable. In this case, the islanding capability of a microgrid comes into play. Intelligent microgrids have to optimally manage interconnected loads and distributed energy resources (including renewables) both in grid-connected and islanded modes.

An autonomous microgrid is a microgrid operated and coordinated by intelligent automatic controls without significant reliance on human intervention. The principle of locality for an autonomous microgrid implies that it operates with maximal independence from other microgrids (*i.e.*, minimal

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Fig. 2 **Utility of the Future: Status of Various Initiatives**

Utility	Scope of the Utility of the Future Initiative
Ameren	Initial exploration/learning
Duquesne	Assessment & planning
Duke	Assessment & technology testing
Xcel	Policy engagement
Portland General Electric	Differentiated customer services re: BUGs
Puget Sound	Grid storage
Dominion	Advanced grid modernization
National Grid	NY REV scope
ConEdison	NY REV scope
Iberdrola-US	NY REV scope
Other NY utilities	NY REV scope
OG&E	Customer service and DR as a resource
NV Energy	Customer service and DR as a resource
PG&E	Range of CA activity related to grid modernization, DER integration and use as resource
SDG&E	Range of CA activity related to grid modernization, DER integration and use as resource
SCE	Range of CA activity related to grid modernization, DER integration and use as resource
APS	Utility investment in rooftop solar PV for customers
Tuscon Electric	Utility investment in rooftop solar PV for customers
Centerpoint	Various customer market facilitation services - shopping portal
HECO	Range of HI activity related to grid modernization, DER integration and use as resource
Southern	Just started

interdependencies among microgrids) subject to meeting its goals for reliability and cost limits on storage. A cellular power network is a large-scale dynamic-topology power network composed of autonomous microgrids that each exhibit self-similar properties to enable scale-up.

Already we can see many localities starting to build microgrids, to serve campuses, communities and cities. Many of those microgrids will draw their power from locally available and preferably renewable sources like wind and photovoltaics. Microgrids can be almost entirely self-sustaining. In fact, they can produce as much energy as they consume and generate "zero net" carbon emissions. We have shown this at the University of Minnesota, where we are building and demonstrating a microgrid on one of our campuses. Using biomass from nearby farms, as well as solar and wind resources, it will soon be energy-self-sufficient. It has been zero-net-carbon since 2008.

The microgrid concept eventually may be extended to higher voltage levels, to create self-contained, self-sufficient systems.

Storage: The Missing Link

The development and deployment of bulk energy storage will also play a key role in supporting the power delivery system infrastructure needed for consumer services and in enabling the integration of intermittent renewable sources throughout the electric grid.

Without an "inventory" to access, utilities have little flexibility in managing electricity production and delivery. Likewise, intermittent renewable resources – such as solar and wind – cannot be relied upon for hourly electricity supply. Although some commercially-proven technologies can store electricity by converting and storing it in another energy form – such as in flywheels, pumped storage, and batteries – only 2.5 percent of North American generation capacity, for example, uses such plants. That is because most storage options (except pumped-hydro and compressed air) remain relatively unproven. Also, their value propositions also are complex and poorly understood, while the uncertainties of changing regulatory rules makes storage options too risky for most investors.

The total price tag for the U.S. could approach $25 billion a year, for 20 years.

Public and private organizations need to collaborate to analyze the costs and benefits of existing storage options, including pumped hydro, compressed air, and battery plants. Additional recommended work includes considering the potential

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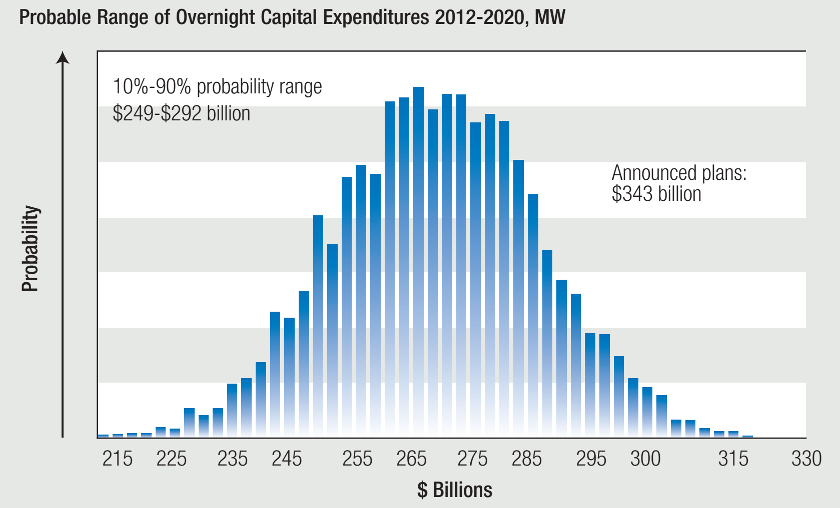
FIG. 3 UTILITY CAP-EX SPENDING



anomalous events. The overlay of a digital communications network to augment traditional SCADA systems will convey that data to distributed intelligence as well as operators and carry commands back to devices in the field.

Designing distribution networks in loop, rather than radial, arrangements allows greater sectionalizing, which in turn improves the specificity of fault detection, isolation and restoration (FDIR). That will keep the power on for unaffected businesses and homes and allow utilities to focus on damaged portions of the network. Automated switches and reclosers can speed the FDIR response beyond human capabilities and that will produce the self-healing abilities that characterize smart grid.

return-on-investment (ROI) of enhancing existing storage options and building new ones. Achieving these goals will involve the development of sophisticated tools to predict the costs of producing large-scale storage systems 5-20 years in the future. It will also require new models to simulate the economic characteristics of future power delivery system conditions to predict the potential benefits of storage options to generation, transmission, and distribution owners as well as end-use consumers. Once accurate cost, benefit, and ROI estimates are available, the next step will be a series of research and development projects designed to build large-scale, lower-cost storage modules and demonstrate them at appropriate utility sites under real-world conditions. During these demonstrations, the collection and analysis of cost and performance data will be a high priority. To address investor concerns about existing or new storage options, high-end communications to key stakeholders will be essential.

Reliability and Resiliency

Building a smart and self-healing intelligent grid also fits in well with hardening the grid and making it more resilient, all to mitigate the impacts of extreme weather events.

Hardening, for instance, might mean that substations in flood-prone areas should be optimized for location and design and construction standards against floods – especially for underground substations in, say, New York City. The design standards for feeders should be improved to the level applied to higher voltage lines. Selective undergrounding for critical lines may be cost effective. New materials can make power poles sturdier and cables more resilient.

For reliability and resilience, smart grid technologies will help. The application of sensors, from phasor measurement units in the substation, down the feeder to smart meters at the premise will provide rich data for monitoring performance and the impacts of

In addition, it would behoove communities to prioritize power reliability for public infrastructure such as street lights, shelters, police, fire, and hospital facilities. This would help maintain civil order and essential operations under chaotic conditions. Microgrids and distributed generation could "island" large end-users to maintain their capabilities when the grid fails. Microgrids also enable centralized grids to shed loads. Homes and businesses could also use distributed generation and energy storage to restore power. In time, home energy management systems will prioritize home loads for everyday efficiencies and in emergencies.

Economic analyses demonstrate that investments in power infrastructure deliver value that exceeds costs, producing greater reliability and improved resiliency that results in sustained economic growth and job creation. For individual consumers, less extensive, shorter outages from extreme weather and improved, everyday reliability are likely to be highly valued in an increasingly digital society. Economically, the societal payback for each dollar invested ranges from $2.80 to $6, based on my own research as well as work by EPRI.

Let's address traditional reliability indices. Using IEEE models, as well as my experience at military bases with 20,000-50,000 inhabitants and cities with 500,000 to 1 million population, we've seen improvements in SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) of 12-14 percent at the low end, and 30-40 percent at the high end. In a conservative forecast, CAIDI (Customer Average Interruption Duration Index) holds steady and at the higher end it can be improved 17-18 percent.

The proper measure of grid modernization is how these indices improve for blue sky days, not during anomalous events such as Sandy. So preparing for another Sandy pays dividends in reliability and resiliency under typical conditions.

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Fig. 4 **Sample Drivers**

State of the drivers	Electricity demand	Natural Gas*	Environment and energy policy
Low	Continuous decline in electricity supplied from grid resources leading to negative growth in future years	Sustained price under $4/million Btu	Limited to laws or regulations already in place
Medium	Flat load growth	Continued volatility and uncertainty in price ranging from $4-7/million Btu	Moderate increase of laws and regulations (focused on air, water, waste)
High	Robust load growth approaching 1-2% per year	Price > $8 with levels reaching >$10 at times	Expansive new set of laws and regulations (including clean energy or GHGs)

* In this table, these prices are based on U.S. Henry Hub Prices.

And utilities along the East Coast are now actively considering these measures.

For example, Consolidated Edison (ConEd) Co. of New York City and Public Service Electric & Gas (PSEG), based in Newark, New Jersey, both saw extensive damage to their grids and extended outages for their customers, but are taking action to safeguard their grids from future events.

ConEd has presented its "Post Sandy Enhancement Plan" to spend $250 million on a hardening program for Orange and Rockland counties that relies on many measures I've outlined. In contrast, PSEG has floated a nearly $4 billion proposal (the "Energy Strong Program Petition") for a five-year plan, which must be approved by the New Jersey Board of Public Utilities. PSEG's proposal includes budgets of $2.8 billion for electric infrastructure and $1.2 billion for natural gas.

In general, most fully funded smart grid-focused roadmaps could be accomplished in one to two years, with systems integration to achieve full value taking another year or two. Many of us are watching to see how ConEd's and PSEG's proposals are received.

Worldwide Efforts

Recent policies in the U.S., China, India, EU, UK and other nations throughout the world, combined with potential for technological innovations and business opportunities, have attracted a high level of interest in the smart grid.

Nations, regions, and cities that best implement new strategies and infrastructure may reshuffle the world pecking order. Emerging markets could leapfrog other nations.

United States. The U.S. Department of Energy's American Recovery and Reinvestment Act of 2009 (the stimulus bill) awarded the Office of Energy Efficiency and Renewable Energy $16.8 billion for its programs and initiatives. In addition, since 2009, the U.S. Department of Energy (DOE) and the electricity industry have jointly invested in 99 Smart Grid Investment Grant (SGIG) projects to modernize the electric grid, strengthen cybersecurity, improve interoperability and collect an unprecedented level of information on smart grid operations. The stimulus bill provided $3.4 billion in federal funding, and project recipients have invested an additional $4.5 billion in private funding, for a total SGIG budget of $7.9 billion. The 99 projects involve 228 participating utilities and other organizations, in every region of the country and almost every state.

Just to integrate distributed resources such as wind power, we need to add about 42,000 miles of high-voltage line, and that would create over 210,000 jobs.

China. The world's now largest economy has invested $7.3 billion, and will spend $96 billion in Smart Grid technology by 2020. Yet China's energy needs will double by 2020. Many changes will happen in the homes themselves. As of 2015, China is thought to account for some 18 percent of global smart grid appliance spending.

South Korea. Investment here has reached nearly $1 billion. A $65 million pilot program on Jeju Island is implementing a fully integrated grid for 6,000 homes, a series of wind farms, and four distribution lines. Its leaders plan to implement smart grid infrastructure nationwide by 2030.

Brazil. Brazil will see 60-percent growth in electricity consumption between 2007 and 2017, with a 16-34 percent increase in renewables from hydroelectric, biomass, and wind. However, Brazil has an aging grid that is currently a one-way power flow (but needs to move in two directions). The Regulator is pushing for mandatory replacement of 65 million meters starting in Q4 2012, and the new regulation of time of use (TOU) tariffs for residential customers, aiming to reduce peak load. Utilities, meanwhile, are launching several smart metering pilots and distribution automation projects.

Mexico. Comisión Federal de Electricidad (English: Federal Electricity Commission), or CFE, is acquiring a pilot for 23,000 meters in order to better understand the technology and prove the benefits. After CFE took over Luz y Fuerza del Centro concession area, the ultimate goal is to achieve higher quality/reliability indicators in the Mexico City metro area.

The Domestic Outlook

Considering the whole North American system, to address energy security and integration of available generation resources, as well as for increased environmental, economic and national security, our first strategy should be to expand and strengthen the transmission backbone by adding about 42,000 miles of high-voltages transmission lines to the existing 450,000 miles. This expansion will cost about $82 billion, and will provide 210,000-214,000 sustainable good-paying jobs, and will result in about 40% of electricity to come from integration of wind resources in the United States. Most of that new transmission will consist of HVDC lines. Locally, highly efficient microgrids combining heat, power and storage systems will be built out over twenty years, at a cost of $17-24 billion annually. At all levels, smarter grids will come to have self-healing capabilities.

Overall, the cost of a smarter grid for the United States would depend on how much instrumentation is actually put in, such as the communications backbone, enhanced security and increased resilience. The total price tag ranges around $340 billion to $480 billion, which, over a 20-year period, would be something like $20 billion-$25 billion per year. But right off the bat, the benefits are $70 billion per year in reduced costs from outages, and during a year where there are lots of hurricanes, lots of ice storms, and other disturbances, that benefit even goes further. Currently, outages from all sources cost the U.S. economy somewhere between $80 billion to $188 billion annually. Costs of outages reduced by about $49 billion per year, and reduced CO_2 emissions by 12-18% by 2030. In addition, it would increase system efficiency by over 4% – that's another $20.4 billion a year.

The costs cover a wide variety of enhancements to bring the power delivery system to the performance levels required for a smart grid. They include the infrastructure to integrate distributed energy resources and achieve full customer connectivity but exclude the cost of generation, the cost of transmission expansion to add renewables and to meet load growth and a category of customer costs for smart-grid-ready appliances and devices. Despite the costs of implementation, investing in the grid would pay for itself.

But this is also about 1) increased cyber/IT security, and overall energy security, with security built in the design as part of a layered defense system architecture, and 2) job creation and an economic benefit. With the actual investment, for every dollar, the return is about $2.80 to $6 to the broader economy. And this figure is conservative.

Can we foresee a widespread overhaul of the electric grid in America's future?

If you look at a macro picture, you see that we also succeed whenever we make this type of a big advancement, such as the moon shot or the national highway system, and when we put the American will, know-how, and passion behind this sort of audacious goal.

Finally, to modernize the whole end-to-end system, the smart grid represents a remaking of the electric power system encompassing all aspects of generation, delivery, and consumption. Benefits will accrue to individuals, societies, and industry: better use of renewable sources, reduction in carbon emissions from fossil plants, improved efficiencies across the power system, broad-based integration of electric and plug-in hybrid vehicles, real-time feedback to consumers on their electricity consumption, improved grid reliability, and more.

With a stronger and smarter grid, 40 percent of our electricity in the U.S. can come from wind by 2030.

But several challenges must first be addressed: Intermittent renewables and greater variability in load profiles will result in high uncertainty in both generation and consumption. Dynamic pricing and demand response will intricately couple economic factors and power flow. With communication technologies providing a system-wide integration infrastructure, the smart grid will represent a prototypical "system of systems." Multiple and often conflicting criteria will need to be coordinated: profits, grid reliability, environmental impacts, equipment constraints, and consumer preferences. Environmental and energy policy need to be supportive of this transformation.

The economic benefits of a modernized grid will accrue as investments are made. Indeed, in my view, our 21st century digital economy depends on us making these investments, in a risk-managed and systematic way.

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