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Claire M. Eubanks, PE
True-Up Rebuttal Testimony
File No. ER-2022-0337

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Witness:	*Claire M. Eubanks, PE*
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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

ENGINEERING ANALYSIS DEPARTMENT

REBUTTAL TESTIMONY

OF

CLAIRE M. EUBANKS, PE

UNION ELECTRIC COMPANY,
d/b/a AMEREN MISSOURI

CASE NO. ER-2022-0337

Jefferson City, Missouri
February 2023

** Denotes Confidential Information **

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CLAIRE M. EUBANKS, PE

UNION ELECTRIC COMPANY,
d/b/a AMEREN MISSOURI

CASE NO. ER-2022-0337

Q. Please state your name and business address.

A. My name is Claire M. Eubanks and my business address is Missouri Public Service Commission, P.O. Box 360, Jefferson City, Missouri, 65102.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission ("Commission") as the Manager of the Engineering Analysis Department of the Industry Analysis Division.

Q. Are you the same Claire M. Eubanks who previously filed direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to Ameren Missouri witnesses Mark Birk, Karl R. Moor, and Jeffrey R. Holmstead regarding Ameren Missouri's failure to obtain required permits for the work done at Rush Island during outages in 2007 and 2010. My testimony updates Staff's recommended adjustment related to Rush Island and High Prairie related to corrections made to Staff's market prices.

Additionally, I respond to Ameren Missouri witness Ryan Arnold regarding energy delivery investment justification framework.

Q. Do any other Staff witnesses discuss Rush Island?

A. Yes. Staff witness Keith Majors and Staff witness Shawn E. Lange, PE.

RUSH ISLAND

Q. What costs related to Ameren Missouri's decision to retire Rush Island early is Ameren Missouri seeking recovery for in this case?

A. Ameren Missouri is requesting that Rush Island continue to be recovered in base rates despite Rush Island's reduced availability, which is a result of Ameren Missouri's decision to retire Rush Island prematurely. Ameren Missouri is also seeking recovery of its legal fees associated with the Rush Island litigation (Staff excluded these costs from its direct case). The transmission upgrades needed for grid stability after the retirement of Rush Island are not expected to be in-service until ** [redacted] ** and are therefore not included in this rate request. Further, Ameren Missouri intends to seek securitization in a future case.[1]

Q. Please summarize Ameren Missouri's position regarding Rush Island.

A. Despite the Eastern District Court determining the Company violated the Clean Air Act, Ameren Missouri witness Mark Birk asserts that "Ameren Missouri has made prudent decisions designed to promote the best interests of [its] customers at every turn."[2] He goes on to assert that Ameren Missouri "acted prudently because we made reasonable decisions in light of what we knew or should have known when we completed the projects in 2007 and 2010 and in 2021 when we decided to retire Rush Island in lieu of installing expensive scrubbers."[3]

Q. Did the Eastern District of Missouri comment on what Ameren Missouri knew **at the time** it failed to obtain permits for the 2007 and 2010 outage work?

A. Yes. United States District Judge, Rodney W. Sippel, discussed this in his January 23, 2017, Memorandum Opinion and Order regarding the liability phase:[4]

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[1] Direct Testimony of Matt Michels, page 4, line 9.

[2] Direct Testimony of Mark Birk page 9, lines 19-23.

[3] Direct Testimony of Mark Birk page 10, lines 5-7.

[4] 229 F. Supp.3d 906 at 915-916.

> This standard for assessing PSD applicability was well-established when Ameren planned its component replacement projects for Units 1 and 2. Ameren's testifying expert conceded that the method used by the United States' experts—which showed that Ameren should have expected the projects to trigger PSD rules—has been ‘‘well-known in the industry’’ since 1999. **But Ameren did not do any quantitative PSD review for the project at Unit 1 and performed a late and fundamentally flawed PSD review for Unit 2.** And Ameren did not report its planned modifications to the EPA, obtain the requisite permits, or install state-of-the-art pollution controls. Instead, Ameren went ahead with the projects, spending $34 to $38 million on each unit to replace the problem components. It executed these projects as part of ‘‘the most significant outage in Rush Island history,’’ taking each unit completely offline for three to four months. Ameren's engineers justified the upgrade work to company leadership on the basis that the new components would eliminate outages and the investment would be returned in recovered operations.
>
> The evidence shows that by replacing these failing components with new, redesigned components, **Ameren should have expected, and did expect,** unit availability to improve by much more than 0.3%, allowing the units to operate hundreds of hours more per year after the project. And **Ameren should have expected, and did expect,** to use that increased availability (and, for Unit 2, increased capacity) to burn more coal, generate more electricity, and emit more SO2 pollution.
>
> Now that the projects have been completed, the evidence shows that Ameren's expected operational improvements actually occurred. Replacement of the failing components increased availability at both units by eliminating hundreds of outage hours per year. Unit 2 capacity also increased. Ameren's employees have admitted that those availability increases would not have happened but for the projects. As a result of the operational increases, the units ran more, burned more coal, and emitted hundreds of tons more of SO2 per year. [**Emphasis added.**]

Q. Did the Eastern District of Missouri comment on the Ameren Missouri process for assessing Prevention of Significant Deterioration (“PSD”) applications?

A. Yes. Judge Sippel discussed this in his January 23, 2017, Memorandum Opinion and Order regarding the liability phase in a section titled “Ameren does not have a legitimate process for assessing PSD applicability”:[5]

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[5] 229 F. Supp.3d 906 at 915-916.

> Ameren's PSD process suffered from two major flaws: the employees charged with assessing applicability started with an incorrect understanding of the law and lacked a meaningful understanding of the facts of the projects. In addition to these procedural flaws, for the reasons that follow, the actual analyses Ameren did ‘‘conduct'' (for Unit 2 only) provide no basis for finding that Ameren could have reasonably expected the project would not significantly increase net emissions.

In his September 30, 2019, Memorandum Opinion and Order regarding the remedy phase, Judge Sippel summarizes his previous findings:[6]

> 393. I have already concluded that a reasonable power plant operator would have known that the modifications undertaken at Rush Island Units 1 and 2 would trigger PSD requirements. I have also concluded that **Ameren's failure** to obtain PSD permits **was not reasonable**. Ameren Missouri, 229 F.Supp.3d at 915-916, 1010-14.
>
> 394. After the liability trial in this case, I found that **at the time** of the Rush Island modifications, ‘‘the standard for assessing PSD applicability was well-established.'' It was also ‘‘well-known'' that the types of unpermitted projects Ameren undertook **risked** triggering PSD requirements. Id. at 915. [**Emphasis added.**]

Q. Based on the above discussion, do you agree with Ameren witness Birk that Ameren Missouri made prudent decisions related to the 2007 and 2010 outages?

A. No. While I was not able to review all the transcripts and supporting documentation supporting Judge Sippel's Memorandum Opinion and Orders, I have reviewed numerous documents and transcripts that were available through discovery in this case. I also reviewed information in the Commission's electronic filing and information system provided by Ameren Missouri at the time and in the years after the outage work occurred. Additionally, I have read the direct testimony of all the Ameren Missouri witnesses providing testimony on this issue. Further, the Commission opened a docket related to the issues surrounding Rush Island, EO-2022-0215.

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[6] 421 F.Supp.3d 729 (E.D.Mo. 2019), page 794.

In this case, Ameren Missouri is presenting arguments that the Eastern District has already rejected, a rejection the Court of Appeals has upheld – Ameren Missouri's reading of Missouri Department of Natural Resources ("MDNR") regulations, that the projects would not be expected to cause an increase in actual emissions, and that the projects were routine maintenance, repair, and replacement "RMRR".[7]

Q. Did you review other information that was not obtained through discovery in this case?

A. Yes. I reviewed a study conducted by Black and Veatch ("B&V") on behalf of Ameren Missouri, dated July 2009, titled *Report on Life Expectancy of Coal-Fired Power Plants*.[8] This report is attached as Schedule CME-r1. The B&V report was to inform Ameren's depreciation rate consultants in their recommendation of depreciation rates for the four Ameren coal-plants. Ultimately, B&V recommended an increase in the life span of Ameren's coal-plants, including Rush Island. For Rush Island, the retirement date was extended from 2026 to 2045.

Q. What was the scope of this study?

A. Relevant to the issues at Rush Island, B&V discussed the capital projects and their implication on plant remaining life and environmental considerations affecting the remaining life of coal-fired power plants. Further, the recommended life span was based on several factors and assumptions including existing and contemplated environmental regulations (page 3-4).

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[7] Direct Testimony of Jeffrey R. Holmstead, page 3, lines 11-21.

[8] ER-2010-0036 Public version attached to Larry Loos Direct Testimony.

Q. Did the study discuss the Company's plans to install scrubbers at its coal plants or New Source Review ("NSR") requirements?

A. Yes, both. Importantly, the date of this study is July 2009, after the 2007 Outage but prior to the beginning of the 2010 Outage. B&V noted that "[u]pon completion of the scrubbers at the Sioux Plant next year, the Company has no definitive plans to install scrubbers at the other plants **unless required to do so**." [**Emphasis added.**] Regarding NSR, B&V explained:

> At the current time, activities at an existing plant, including Air Quality Control (AQC) retrofit projects, are subject to New Source Review (NSR) air permitting requirements if they are determined to be "major modifications" at a "major stationary source." The NSR regulations define major modification and major stationary source,,and [sic] those terms have also been addressed by court decisions, agency applicability determinations and other authorities. NSR includes both the Non-attainment NSR and Prevention of Significant Deterioration (PSD) programs. Evaluation of NSR/PSD applicability is complicated and has change over time. When a project triggers NSR/PSD requirements, a major modification pre-construction air permit is required, which generally includes application of Best Available Control Technology (BACT) and/or application of Lowest Achievable Emission Rate (LAER) technology depending on the NAAQS attainment status of the relevant area.
>
> The current permitting path (for both new units and for modifications to existing units which trigger the NSR/PSD requirements) is a difficult one that requires planning and preparation. Major challenges to such permits from concerned citizen groups, interveners, and possibly government officials can be expected, which can result in litigation and additional costs.
>
> **In addition to prospective permitting issues, over the last decade or so US EPA has initiated Section 114 investigations into whether prior activities at many coal-fired generating plants triggered NSR/PSD requirements. Some of these investigations have resulted in enforcement actions and additional controls at the targeted facilities. [Emphasis added.]**

Q. Did Judge Sippel note other documents from this timeframe in the remedy phase of the case?

Q. Yes.

> 398. Ameren's document's indicate that Ameren was aware of the possibility that NSR would be triggered at Rush Island. For example, on May 1, 2009, Ameren met with engineering firm Black & Veatch to review contracting strategies and to allow Black & Veatch to "understand internal AmerenUE drivers." May 13, 2009 Conference Memorandum (Pl. Ex. 1111), at AMERM-00319195. Included among the "Questions for thought" discussed at that meeting was "**What is the tolerance for risk?**" Id. at AM-REM-00319198, 319222. The Conference Memorandum summarizing the discussion of that question identified that ''**NSR is likely the biggest potential issue.**'' Id. at 319199. Addressing a question about cash flow for any FGDs at Rush Island, the May 2009 Conference Memo identified that ''**NSR or EPA will likely be the driver to shift the schedule early.**'' Id. [**Emphasis added.**]

This meeting occurred just a few months before the July 2009 B&V study and the August 2009 approval of the outage work. The Unit 2 outage work was initially approved in 2005 and was reassessed in 2009. The Unit 2 outage work was approved by the Capital Project Oversight Committee, Ameren's CEO, and Board of Directors.

Q. You previously mentioned that the B&V Study was used to inform Ameren Missouri's depreciation rates; did the Commission rely on the B&V Study to set rates in previous cases?

Q. Yes. The 2009 B&V Study was presented as an attachment to Larry Loos Direct Testimony in ER-2010-0036. Mr. Loos summarized the purpose of the B&V study in the following question and answer:

> Q. WHY DID THE COMPANY REQUEST THAT BLACK & VEATCH PREPARE THE INFORMED ESTIMATES SET FORTH IN THE REPORT YOU ATTACH AS SCHEDULE LWL-E1?

A. The Company informed me that in response to the Commission's Report and Order issued May 22, 2007, in Case No. ER-2007-0002, the Company desires to develop informed estimates of the dates for the anticipated retirement of its coal-fired generation stations. In Case No. ER-2007-0002, the Company proposed depreciation rates based on a life span method of calculating depreciation rates for its steam and hydroelectric production plants. Initially the Company relied on a 2026 retirement date for all four of its steam generating plants. Subsequently, the Company revised its proposal to reflect the retirement of its steam plants when they reach an age of approximately 60 years. With regard to the Company's proposal, the Commission noted that:

> Obviously, at some point, all of AmerenUE's electric production plants will be retired. But at this time, there is really no way to be sure when that retirement will occur…Without better evidence of when those plants are likely to be retired, allowing the company to increase its depreciation expenses based on what is little more than speculation about possible retirement dates would be inappropriate.

The Company requested that Black & Veatch develop informed estimates of the retirement dates, which reflect consideration of information available at this time.

Q. In his Direct Testimony in the 2010 rate case, did Mr. Loos discuss the addition of scrubbers at Rush Island?

A Yes.

> AmerenUE's planned capital expenditures include the completion of scrubbers at the Sioux Plant. However, as set forth in the Company's current ECP, the Company plans to add additional scrubbers **only if later required to do so** at the Labadie and Rush Island Plants.[1] The addition of scrubbers (if later required) at the Labadie and Rush Island plants would represent extraordinary capital outlays. I believe that the magnitude of these outlays will require an adequate period over which to recover such expenditures. As a result, I include allowance for a reasonable timeframe for AmerenUE to recover its investment in these extraordinary environmental projects. Based on the magnitude of the cost of adding scrubbers, I believe that realistically, recovery over nominally 20 years is reasonable. I therefore reflect consideration of the implications if the Company is required to add scrubbers **by adjusting the remaining life indicated by my retirement analysis to not less than 20 years at the time of possible installation**[2] of the environmental

> projects. My estimated final retirement dates allow a minimum 20 year recovery period for major environmental projects.
>
> In Table 3-3 of Schedule LWL-E1, I show how I explicitly consider the recovery of these extraordinary capital expenditures in my estimated retirement dates.
>
> [Footnote 1]The Company currently does not contemplate the addition of scrubbers at its Meramec plant.
> [Footnote 2] For the Labadie and Rush Island Plants, I relied on the Company's Environmental Compliance Plan (base case) for the timing of these capital additions, if the Company is required to add scrubbers.
> [**Emphasis added.**]

Q. Did the remaining life of Rush Island for Ameren's planning purposes and for depreciation rates change based on the B&V study?

A. Yes. The B&V study supported extending the expected remaining life of Rush Island from 2026 to 2045 based in part on the assumption that scrubbers would be added in 2016. In its 2020 IRP, Ameren Missouri reduced Rush Island's expected remaining life to 2039.

Q. What standard of prudence does Mr. Birk discuss in his Direct Testimony?

A. On page 10, lines 12-16 of his Direct Testimony in the current case, Mr. Birk states:

> Counsel tells me that under Missouri law, the question of whether a utility has made an imprudent decision and thus should bear the consequences of that decision is whether the utility's conduct "was reasonable at the time [the decision was made], under all circumstances, considering that the company had to solve its problem prospectively" without reliance on hindsight.

Q. Do you agree?

A. Yes. The Eastern District of Missouri has already concluded that Ameren Missouri should have and did expect emissions to increase as a result of the 2007 and 2010 outage work. The Eastern District has already concluded that Ameren Missouri's failure to obtain permits was not reasonable. The Eastern District has already concluded that the standard for assessing PSD applicability and the risks of undertaking the types of projects that Ameren Missouri undertook was well known at the time of the 2007 and 2010 outage work. Further, the US Court of Appeals has upheld the Eastern District's ruling, stating:[9]

> Instead, the district court, as the factfinder, was entitled to ''consider all relevant information available to [Ameren] **at the time of the project**, including prior operating data and [Ameren's] own statements and documents'' in determining whether Ameren ''should have predicted that a project would have caused a [significant] net increase.'' *Id.* at *19 (quoting Jury Instr. No. 23, *United States v. Cinergy*, 1:99-cv-1693-LJM-JMS (S.D. Ind. 2008), ECF No. 1335) [**Emphasis added.**]

Missouri SIP

Q. Mr. Moor and Mr. Holmstead assert it was reasonable for Ameren Missouri to rely on the language of Missouri State Implementation Plan (SIP). What did the Court conclude?

> The court concluded that Missouri's SIP incorporated the EPA's PSD regulations:
>
> ''The PSD program is primarily implemented by the states through 'state implementation plans' (SIPs).'' *Otter Tail*, 615 F.3d at 1011 (citing 42 U.S.C. § 7471). While ''[s]tates have broad discretion in designing their SIPs,'' their ''plans must include certain federal standards.'' *Id.* The EPA reviews and approves States' SIPs. *Id.* at 1011–12. **Missouri expressly incorporated the EPA's PSD regulations into its SIP (''Missouri SIP'').** *See* Mo. Code Regs. Ann. tit. 10, § 6.060(8)(A) (2007) (''All of the subsections of 40 CFR 52.21, other than [certain subsections], are hereby incorporated by reference.''). The EPA approved Missouri's SIP, explaining that ''the provisions of § 52.21 supersede the state provisions for purposes of the PSD program.'' Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. 36,486-02, 36,487 (June 27, 2006); *see also id.* at 36,489 (''This revision also incorporates by reference the other provisions of 40 CFR 52.21 as in effect on July 1, 2003, which supersedes any conflicting provisions in the Missouri rule. Section 9, pertaining to hazardous air pollutants, is not SIP approved.'').[10] [**Emphasis added.**]

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[9] 9 F.4th 989 (8th Cir. 2021) page 1007.

[10] 9 F.4th 989 (8th Cir. 2021) page 995.

Q. Ameren witness Karl R. Moor asserts that "MDNR's statements and actions represent crucial context for the evaluation of Ameren Missouri's actions to comply with the SIP's permitting requirements at Rush Island."[11] Do you agree?

A. Not in isolation. Importantly, the Commission should consider the roles of MDNR and EPA. Ms. Kyra Moore, MDNR's current Director of the Division of Environmental Quality, discussed in her deposition transcript[12] (which Ameren Missouri witnesses heavily cite to) that, in her opinion, if there was a disagreement on interpretation of the Missouri SIP, EPA's interpretation would govern:

> BY MR. HANSON:
> Q. Sure. Do you know whether Missouri DNR has a statutory obligation to implement the Missouri SIP consistent with the federal Clean Air Act?
> A. Yes.
> Q. And does?
> A. Yes. And -- and we do follow the Clean Air Act in the state of Missouri following our SIP, so.
>
> Q. How would you characterize EPA's role in implementing the SIP or the Clean Air Act in Missouri's boundaries?
> MR. BONEBRAKE: Objection, asked and answered. Go ahead.
> THE WITNESS: EPA provides the oversight of the implementation of the Clean Air Act in the state of Missouri and I would describe them as our partner in implementing the Clean Air Act in Missouri, because it is their federal regulations that our regs and SIP is based on.
>
> BY MR. HANSON:
> Q. Okay. If EPA and Missouri Department of Natural Resources disagreed on the interpretation of the Missouri SIP, whose interpretation of the Missouri SIP would you say it governs --
> MR. BONEBRAKE: Objection, foundation, legal conclusion.
>
> THE WITNESS: I would say EPA because it is EPA's federal rules, so.

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[11] Karl R. Moor Direct Testimony, page 11, lines 18-20.

[12] 30(b)(6) Deposition of Kyra Moore taken on behalf of Ameren Missouri September 18, 2013, pages 258-259.

> BY MR. HANSON:
> Q. And when you say it "is EPA's federal rules," are you referring to the Missouri SIP?
> A. Yes, our SIP is based on the EPA's federal rules and the Clean Air Act.

Emissions Calculations

Q. Ameren witness Karl R. Moor outlines certain actions that he would have expected Ameren Missouri to do to make a reasonable decision, what are those actions?

A. On page 11, lines 18-20 of his Direct Testimony, Karl R. Moor focuses solely on the Missouri SIP and the application of the SIP to the specific facts of the projects. However, as another Ameren Missouri witness on this issue, Jeffrey R. Holmstead, points out, NSR applicability determinations there "are basically two questions: (1) Will a proposed project be a "physical change or change in the method of operation"? and (2) will the project cause an increase in emissions? You don't trigger NSR unless the answer to both questions is "yes." Although you can conclude that an NSR permit is not required if the answer to either question is "no," **sources generally examine both questions out of an abundance of caution**." [**Emphasis added.**]

Q. Did Ameren Missouri examine both questions for the 2007 outage work?

A. No. As Judge Sippel notes:[13]

> 390. Ameren has admitted that it performed no emission calculations for purposes of determining PSD applicability prior to undertaking the 2007 project at Unit 1. Whitworth Test., Tr. Vol. 11–A, 94:23–25; Boll Test., Tr. Vol. 8–B, 38:3–5; Birk Dep., Sept. 24, 2013, Tr. 220:14–21; see also Knodel Test., Tr. Vol. 1–A, 88:10–12; Ameren Closing Arg., Vol. 12, 51:18–20.

Q. Did Ameren Missouri consult with MDNR, EPA, consultants, or other utilities when it made the decision not to seek a permit for the 2007 outage work?

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[13] 229 F. Supp.3d 906 at page 976.

A. Ameren Missouri's witness Steven Whitworth could not recall. (Whitworth trial phase Volume 11A, page 106, lines 3-7) and (Whitworth 30(b)(6) Deposition pages 28-29).

Q. Mr. Moor and Mr. Holmstead discuss various other utility projects which MDNR provided letters indicate no permits were required based on the information provided by the utility.[14] Did Ameren Missouri seek a no permit required determination from MDNR related to the 2007 and 2010 outage work?

A. MDNR representative Kyra Moore indicated in her deposition: "Based on my review, they did not."[15]

Q. Did Ameren Missouri perform an emissions calculation for the 2007 outage work?

A. No.

Q. Did Ameren Missouri perform an emissions calculation for the 2010 outage work?

A. Ameren Missouri witnesses indicated that an emissions calculation related to the 2010 outage work was completed "in early January of 2010" (Whitworth trial testimony page 95, lines 17-25). Recall the Unit 2 outage began on January 1, 2010.

Q. Did Ameren Missouri review any guidance from MDNR or EPA on the emissions calculations performed for Unit 2?

A. Ameren Missouri's then manager of Environmental Services (Steven Whitworth) testified[16] that a calculation was performed for Unit 2 because there was an

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[14] Direct Testimony of Karl R. Moor, page 15, lines 5-9; page 19, lines 1-12. Direct Testimony of Jeffrey R. Holmstead, pages 31-32.

[15] 30(b)(6) Deposition of Kyra Moore taken on behalf of Ameren Missouri September 18, 2013, page 268.

[16] Whitworth trial phase Volume 11A, page 96, lines 4-11.

understanding on Ameren Missouri's part that the Missouri regulations had been changed to incorporate some of the federal NSR revisions.[17] However, Judge Sippel notes:

> 396. The Ameren employee who was responsible for doing NSR calculations for Unit 2 was Michael Hutcheson. Mr. Hutcheson testified that he did not review any EPA or Missouri Department of Natural Resources guidance specifically as part of his work for the project at issue. Hutcheson Test., Tr. Vol. 11–A, 65:25–66:2.
>
> 397. Mr. Hutcheson admitted he had no personal knowledge of the project or whether the effects of the project were included in the projections he relied upon.
>
> > a. Mr. Hutcheson testified that in performing the company's NSR analysis, he did not speak to any of the engineers who planned and developed the project. He received information from his superiors in the Environmental Services Department, but he did not know the source of that information. Hutcheson Test., Tr. Vol. 11–A, 63:5–19.
> >
> > b. Mr. Hutcheson also testified that he did not review any of the project justification documents for the work. Hutcheson Test., Tr. Vol. 11–A 63:20–25.
> >
> > c. Mr. Hutcheson did not know whether the modeling runs that he relied on for his analysis included any projected improvements in capacity or availability. Mr. Hutcheson did nothing to check the validity of the modeling runs he received, but simply ''took them on their face.'' Hutcheson Test., Tr. Vol. 11–A, 65:4–20; Hutcheson Dep., April 24, 2014, Tr. 118:20–119:5.
> >
> > d. Mr. Hutcheson testified that he did not consider whether availability was expected to improve as a result of the projects because he did not think that information was ''relevant'' or ''necessary.'' Hutcheson Test., Tr. Vol. 11–A, 82:16–25.

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[17] Whitworth indicates he understood a change occurred in summer of 2009. The Memorandum and Order, Judge Sippel, January 21, 2016, recognizes that Missouri adopted and incorporated by reference EPA's PSD rules (10 CSR 10-6.060). EPA approved the Missouri SIP in 2006. 47 Fed. Reg. 26,833.

Q. Mr. Birk asserts that the outage work “did not increase the maximum rated design capacity of the units given continuous year-round operation,”[18] please explain what this statement means.

A. Mr. Birk’s statement is referring to the maximum output that a unit is capable of producing continuously under normal conditions over a year. This is also referred to as the maximum continuous rating. For the 2010 outage work, Ameren Missouri reported to Staff that there would be a significant capacity restoration of 22 MW and a true capacity increase of 12 MW. (Data Request No. 0257 from ER-2011-0028 attached as Confidential Schedule CME-r2). Judge Sippel discusses[19] the actual increases in Unit 2’s capability:

> 287. After the 2010 outage, Ameren also reported a substantial increase in Unit 2’s capability to its system operator, MISO, to NERC, and to the Missouri Public Service Commission. Specifically, in September 2010, Ameren reported to NERC that Unit 2’s <u>summertime</u> peak capability had increased to 648 MW (gross), 617 MW (net), ‘‘due to work completed in the 2010 major boiler outage (replacement low pressure turbines and ***numerous boiler modifications***).’’ October 27, 2010 MISO Verification Test Data (Pl. Ex. 139), at AM–02663830 (emphasis added). Ameren provided the same information to NERC in September 2010. September 15, 2010 Capability Validation (Pl. Ex. 133), at AM–02645178; see also Koppe Test., Tr. Vol. 3–B, 46:6–47:22.
>
> 288. Later in December 2010, Ameren responded to a request from the Missouri Public Service Commission to identify any plant upgrades that it expected to result in an increase in the amount of electricity the plant would produce in the future. MPSC Data Request 0257 (Pl. Ex. 222); Koppe Test., Vol. 3–B, 50:22–51:11.
>
> 289. Ameren told the Missouri Public Service Commission that the 2010 outage, including the component replacements at issue, would result in a 34 MW increase in Unit 2’s capability, which it characterized as having been based on a ‘‘significant capacity restoration[ ]’’ of 22 MW and a ‘‘true capacity increase[ ]’’ of 12 MW. Ameren Resp. to DR 0257 (Pl. Ex. 223); Koppe Test., Vol. 3–B, 51:12–52:22. Joe Sind, the Ameren engineer who performed the analysis supporting Ameren’s statements to

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[18] Direct Testimony of Mark Birk, page 5 lines 5-6.

[19] 229 F. Supp.3d 906 at page 963.

> the Missouri Public Service Commission, confirmed that the reported 12 MW ‘‘true capacity increase’’ was based on the company’s best expectation of the impact of the LP turbine replacement on the capability of the unit. Sind Test., Tr. Vol. 9–B, 20:3–12, 27:12–28:3. Mr. Sind’s work papers show that his capacity analysis only looked at changes in unit capability and air preheater differential pressures and that he reported increases in capability for other Ameren units where work had been done on air preheaters but no turbine work had occurred. Sind Test., Tr. Vol. 9–B, 22:3–23:17, 25:6–26:2.

Q. Mr. Birk asserts the outage work “did not increase actual emissions”[20], is that accurate?

A. No. Judge Sippel[21] summarizes the emissions monitoring after both the Unit 1 and Unit 2 outages:

> 242. Similar increases are shown in Ameren’s certified Continuous Emissions Monitoring System (‘‘CEMS’’) data, which show that Unit 1 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 1’s operating time increased by 320 hours per year, from 8,278 hours per year in the baseline to 8,598 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 1 emitted 21 more pounds per hour of SO2 than it had in the baseline (increasing from 3,593 pounds per hour in the baseline to 3,614 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1–A, 109:7–16, 110:8–111:7, 112:14–24.
>
> 243. Ameren’s CEMS data also show that in 2008, the first calendar year after the 2007 boiler upgrade, Rush Island Unit 1 emitted more SO2 than it had in any year since 1995. Knodel Test., Tr. Vol. 1–A 82:9–19. During the relevant post-project period, Unit 1 emitted 15,539 tons per year of SO2, which is 665 tons per year more than Unit 1 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 49:8–20, 111:7–16; Knodel Test., Tr. Vol. 1–A, 95:6–25.
>
> 265. Similar increases are shown in Ameren’s certified CEMS data, which show that Unit 2 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 2’s operating time increased by 123 hours per year, from 8,478 hours per year in the

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[20] Direct Testimony of Mark Birk, page 5, line 6.

[21] 229 F. Supp.3d 906 at page 959.

> baseline to 8,601 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 2 emitted 456 more pounds per hour of SO2 than it had in the baseline (increasing from 3,371 pounds per hour in the baseline to 3,827 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1–A, 109:7–16, 111:8–20, 112:3–10, 113:1–21.
>
> 266. Ameren's CEMS data also show that in 2011, the first calendar year after the 2010 boiler upgrade, Rush Island Unit 2 emitted more SO2 than it had in any year since 1995. Knodel Test., Tr. Vol. I–A 82:9–19. During the applicable period of highest post-project emissions, Unit 2 emitted 16,458.1 tons per year of SO2, which is 2,171 tons per year more than Unit 2 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 74:15–18, 78:9–12, 112:25–113:3; Knodel Test., Tr. Vol. 1–A, 97:11–98:5.

Routine Maintenance, Repair and Replacement ("RMRR")

Q. Ameren witness Moor asserts that Ameren Missouri "reasonably concluded that the Rush Island projects were excluded from permitting as RMRR." What did Ms. Kyra Moore state was her understanding of the RMRR exclusion?

A. In her deposition,[22] through questioning by the US Department of Justice (Mr. Hanson), Ms. Moore explains that in her experience the RMRR is narrowly interpreted:

> BY MR. HANSON:
> Q. Turning for a moment to -- back to routine maintenance.
> A. Okay.
> Q. Is it your understanding that the routine maintenance test is to be construed narrowly or is it to be construed broadly
> MR. BONEBRAKE: Objection, foundation, legal conclusion.
> THE WITNESS: In my experience and in conversations with EPA staff, routine maintenance and repair is fairly narrow in interpretation.

Q. At the time of the Unit 1 outage, how did Mr. Birk describe the outage work?

A. In his Memorandum and Order, Judge Sippel[23] referred to an email from Mark Birk highlighting the 2007 outage as the most significant outage in Rush Island history:

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[22] 30(b)(6) Deposition of Kyra Moore taken on behalf of Ameren Missouri September 18, 2013, pages 262.

[23] 229 F. Supp.3d 906 at page 943.

> 172. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2. After the 2007 major boiler outage, **Ameren's Vice President Mark Birk referred to the outage as the ''most significant outage in Rush Island history.''** May 29, 2007 Email (Pl. Ex. 31). Mr. Birk specifically called out the replacement of several components—including the economizer, reheater, lower slope, and air preheaters—as distinct from ''the routine maintenance that had to be performed'' during the outage. Id. The 2010 major boiler outage was similarly referred to as ''among the most significant in [company] history.'' Jerry Odehnal Report (Pl. Ex. 40); see Vasel Dep., Aug. 15, 2013, Tr. 272:2–23 (describing exhibit 40); see also 2010 State of the System presentation, Pl. Ex. 41, at AM–02493747 (distinguishing the air preheater, reheater and economizer replacements from the ''routine maintenance'' done during the 2010 outage). [**Emphasis added.**]

Q. Did Mr. Birk describe the Unit 1 outage as significant in his Direct Testimony in this case?

A. No. On page 5, lines 6-7, Mr. Birk refers to the projects as "the kind of projects routinely undertaken by Ameren Missouri."

Key decisions

Q. In his Direct Testimony on Pages 11 and 12, Mr. Birk outlines key decisions made with regard to Rush Island, which key decisions does he address?

A. The decisions Mr. Birk discusses include (1) whether to undertake the outage work which ultimately occurred in 2007 and 2010; (2) whether permits were required; and (3) whether to execute on the District Court's judgment to put scrubbers on Rush Island.

Q. Are there decision points Ameren Missouri witnesses did not discuss in its direct testimony?

A. There are several decisions Ameren Missouri does not address in its Direct Testimony, including, but not limited to:

- Ameren Missouri spent $8 million evaluating the economics of adding wet FGD technology at Rush Island from 2008-2010 but ultimately did not pursue the project. “Based on its evaluations, Ameren’s corporate project oversight committee agreed that wet FGD technology (1) was technically and economically feasible at Rush Island, (2) was the right choice for complying with, among other things, New Source Review, and (3) should be pursued further in contract development. Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 58:24-59:12, 59:25-60:22, 82:3-83:17.”[24]

- Despite receiving a notice of violation on January 26, 2010, while the Unit 2 outage was underway (the outage lasted from January 1, 2010 through April 9, 2010), Ameren Missouri continued with its second major outage project without the required permit.

- Ameren Missouri did not evaluate a comparison of the retirement of Rush Island to retrofitting Rush Island until the 2020 IRP. In response to Sierra Club, Ameren Missouri asserts: “[s]uch analysis would have been premature at the time given the highly uncertain outcome and timing of the litigation.”[25], [26]

- Despite the court ruling in January of 2017, Ameren Missouri did not evaluate the impact of the early retirement of Rush Island on the transmission system until MISO started the Attachment Y2 study process on November 2, 2021.[27]

Q. Does the Commission need to make a prudence determination in this case in order to adopt Staff’s Rush Island rate base adjustment?

A. No. At this time Ameren Missouri is not seeking recovery of the transmission projects (i.e., Statcoms) associated with the early retirement of Rush Island. Further, Ameren Missouri intends to seek securitization in a future case. It is Staff’s position that that case would

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[24] U.S. v. AMEREN MISSOURI, 421 F.Supp.3d 729 (E.D.Mo. 2019), pages 746-747.

[25] Response to Sierra Club 2-SC 002.8 attached as Schedule CME-r3

[26] The Commission ordered, on December 3, 2019, a special contemporary resource planning issue in EO-2020-0047: “Ameren Missouri to model scenarios related to environmental upgrades to the Rush Island and Labadie coal-fired plants as mandated by the federal courts.”

[27] Response to Staff Data Request No. 0001 in EO-2022-0215 attached as Schedule CME-r4.

be the most appropriate case for the Commission to consider the prudency of Ameren Missouri's decision-making and ultimate recovery of the stranded asset.

Q. Staff is recommending an adjustment to rate base associated with the reduced operations at Rush Island, how can the Commission order Staff's adjustment without making a prudency determination?

A. In this case, the reality is Rush Island is not fully available, not fully used and useful for service, in that there are limitations on its operations. Therefore, Staff recommends a rate base adjustment to reflect this reality. Staff also accounted for this reality in its fuel modeling.

SMART ENERGY PLAN

Q. Ameren Missouri witness Ryan Arnold discusses an evaluation framework for Ameren's energy delivery investments that resulted from a stipulation in the 2021 rate case. Please explain the stipulation requirement.

A. Ameren Missouri agreed in the last rate case to develop evaluation methodologies for major categories of energy delivery investments no later than the 3rd quarter of 2022. The agreement related to its energy delivery investments is contained in Paragraph 18 of the Unanimous Stipulation and Agreement filed on November 24, 2021.

Q. In the direct testimony of Ryan Arnold, he indicates that an additional meeting with Staff and The Office of the Public Counsel ("OPC") would occur in September 2022. What were the results of that meeting?

A. Ameren Missouri presented its framework, including its proposed baselines for its evaluation framework for six categories of investment. These categories are: Grid

Resiliency, Smart Grid, Substation CBM (condition based maintenance), System Hardening, Underground Cable, and Underground Revitalization.

Q. What type of feedback did Staff provide with regards to the proposed framework?

A. Staff appreciates Ameren Missouri's efforts in improving its evaluation methodologies for energy delivery investments. Staff's primary feedback in meeting with Ameren Missouri was to ensure that documentation is available and retained. Further, Staff desired that baselines would be established. Ameren Missouri presented its proposal on September 12, 2022, the slides from that meeting are attached as Schedule CME-r5.

Q. Is OPC supportive of the framework?

A. In Direct Testimony, Geoff Marke discusses Ameren Missouri's investments related to tripsavers and building a Private LTE network, both in category Smart Grid. Given OPC's concerns, Staff recommends the stakeholders engage in further discussions on evaluation criteria for the Smart Grid investments.

Q. For the other five categories, what is Staff's recommendation?

A. It is Staff's understanding that the previous stipulation contemplated that Ameren Missouri would provide its evaluations in EO-2019-0044 after the framework was established. Staff supports the framework for all categories, though additional discussion on Smart Grid investments is warranted. Therefore, Staff expects to see the evaluation results, by project, in Ameren Missouri's annual filing in EO-2019-0044 in February 2024. Staff expects to continue to receive the quarterly project documentation per paragraph 18B of the stipulation in ER-2021-0240.

CORRECTIONS TO DIRECT

Q. Do you have any corrections to your Direct Testimony related to Rush Island?

A. Yes. Staff recommended an adjustment in Direct Testimony to reflect the reality that Rush Island will no longer be operating at its full capacity as a result of the Rush Island litigation and subsequent designation of the resource as a System Support Resource by MISO and approved by FERC. This adjustment was ** [redacted] **% of the rate base associated with the Rush Island plant. Staff's Rush Island adjustment has been updated to reflect a correction to Staff's market prices. Staff's market prices are sponsored by Staff witness Justin Tevie and utilized by Staff witness Shawn E. Lange, PE in Staff's power production modeling. The revised adjustment is ** [redacted] **%.

Q. Do you have any clarifications to your Direct Testimony?

A. Yes. On line 7, page 8 I state that neither Rush Island units have air pollution equipment. To clarify, neither units have pollution equipment for Sulfur dioxide.

Q. Do you have corrections related to Staff's recommended adjustment related to High Prairie?

A. Yes. As discussed above, Staff made a correction to its market prices which were used in Staff's High Prairie adjustment related to Lost Off-system sales Revenue. The revised adjustment is -$11,663,657. Staff's adjustments related to lost Production Tax Credits ("PTCs") and the value of lost Renewable Energy Credits ("RECs") are unaffected by market prices and therefore have not changed:

Lost Off-system sales Revenue	$11,663,657
Lost PTCs	$14,754,013
Value of lost RECs	$2,890,841

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 Adjust) Case No. ER-2022-0337
Its Revenues for Electric Service)

AFFIDAVIT OF CLAIRE M. EUBANKS, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CLAIRE M. EUBANKS, PE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Rebuttal Testimony of Claire M. Eubanks, PE*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Claire M Eubanks
CLAIRE M. EUBANKS, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of February 2023.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public

BUILDING A WORLD OF DIFFERENCE®

AmerenUE

Report on
Life Expectancy of
Coal-Fired Power Plants

July 2009

BLACK & VEATCH
Building a world of difference.®

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DISCLAIMER

Black & Veatch Corporation (Black & Veatch) prepared this report for AmerenUE in June 2009 based on information available and conditions prevailing at that time. Any changes in that information or prevailing conditions may affect the conclusions, recommendations, assumptions, and forecasts set forth in this report. Black & Veatch makes no warranty, express or implied, regarding the reasonableness of any information, recommendation, or forecast set forth herein under any conditions other than those assumed in making such projections. Black & Veatch understands that AmerenUE has not made any decisions regarding the retirement of any of the plants addressed in this report. Black & Veatch's opinions are based on its professional engineering judgment of the estimated useful life of each plant for use in AmerenUE's depreciation analysis.

1.0 EXECUTIVE SUMMARY

In this report we provide informed estimates of the retirement dates for the four Union Electric Company d/b/a AmerenUE (AmerenUE or Company) coal-fired plants. We base our estimated retirement dates on AmerenUE's actual retirement history, our assessment of the plants' current condition, our understanding of planned capital expenditures, life spans of other US coal plants, and engineering and environmental compliance considerations.

The most important factor in determining the depreciation rate for unit property is the informed estimate of the final retirement date. In forecasting final retirement dates for AmerenUE's coal-fired plants we consider actuarial analysis of historical experience of the interim and final retirements of AmerenUE's coal-fired generating facilities, planned capital additions, the age at retirement of plants retired in the US, expected dates of retirement for comparable plants in the US, the current condition of AmerenUE's plants, and engineering and environmental considerations. Our condition assessments are based on site visits and interviews with key operating personnel at each plant. The four plants addressed in this report are Meramec, Sioux, Labadie, and Rush Island.

In addition to the above, at AmerenUE's request, we reflect consideration of the timing of the cost incident to the orderly construction of capacity required to replace capacity retired.

1.1 Overview of Study

We understand our report and informed estimates will be considered by AmerenUE's depreciation rate consultants in their recommendation of appropriate depreciation rates for the four plants. Our study of final retirement dates for AmerenUE's coal-fired plants includes:

- Consideration of plant life based on actuarial analysis of AmerenUE's continuing property records for its coal-fired power plants
- Consideration of the planned capital expenditures at the plants and their implication on plant remaining life
- The age at retirement of US plants which have been retired
- The life span of comparable plants located in the western US forecast in depreciation studies and Integrated Resource Plans (IRPs)
- Engineering considerations supporting the design life of major power plant components
- Environmental considerations affecting the remaining life of coal fired power plants[1]
- Onsite plant condition assessment

1.2 Findings and Conclusions

AmerenUE owns and operates four coal-fired power plants in the state of Missouri, having a combined installed capacity of nominally 5,650 MW. These plants began commercial operations between 1953 and 1977. Based on our life span estimate, and giving consideration to the orderly replacement of retired capacity, we forecast AmerenUE will retire its four coal-fired plants over the 24 year period 2022 through 2046. Unit ages at final retirement are forecast to range from nominally 62 to 73 years. For AmerenUE's plants to achieve these lives, AmerenUE must invest significant capital expenditures in the interim years.

We base our final retirement dates on consideration of a number factors and assumptions including:

- Actuarial analysis of AmerenUE's actual retirements of its coal-fired power plant investment:
    - ♦ The actuarial analysis indicates probable lives of AmerenUE's units ranging from 54 to 65 years
    - ♦ The probable life for the largest account (312, Boilers) ranges from 54 to 62 years

---

[1] In this Report, we have not included explicit recognition of the possible implications on plant life and cost recovery arising from *The American Clean Energy and Security Act of 2009* (Waxman-Markey Energy and Climate Bill) currently under consideration by Congress.

- Planned capital expenditures especially those related to environmental expenditures:
  - Over the next five years, AmerenUE expects to spend approximately $[redacted] billion ($[redacted] million per year) on capital projects at the four plants
  - Approximately ½ of the $[redacted] billion budgeted relates to environmental projects
- Available data regarding life spans realized and anticipated by plants operated by other utilities:
  - The average age at retirement used in depreciation studies and Integrated Resource Plan (IRP) filings is 55 years
  - The average and median reported age at retirement of all retired coal-fired plants in the US is 44 years
  - The average age of currently operating coal-fired power plants is 41 years with a median age of 42 years
- Existing and contemplated environmental regulations:
  - The locations of AmerenUE's plants are classified as non-attainment areas for 8-hour ozone and PM2.5 pollutants, meaning these areas currently do not meet National Ambient Air Quality Standards
  - Additional environmental controls will likely be imposed on the electric generating industry (and the Company's plants) aimed at limiting greenhouse gas, mercury, and other emissions, as well as environmental impacts associated with intake structures and the disposal of waste produced by the combustion of coal
  - Future environmental compliance costs will likely contribute to economic decisions regarding retirement of the coal-fired plants
- Engineering principals:
  - Due to high temperature creep rupture and high pressure creep fatigue failure, many of the high temperature and high pressure components of the boiler and steam systems have a finite design life and can fail after 20 to 40 years of operation and sometimes more frequently. It is routine for companies to replace such components when and as they fail
- Onsite plant condition investigations:
  - The current condition of AmerenUE's plants is good
  - With continued maintenance and capital expenditures, economic factors will likely drive retirement decisions, not physical limitations
- The retirement of the Company's Meramec Plant in 2022 as discussed in the Company's Integrated Resource Plan ("IRP") and Environmental Compliance Plan ("ECP")

Based on the above, we find the life span of the four plants to average 56 years. For the purpose of this report, we base our informed estimates on a nominal life span of 65 years. We increase the nominal life span by 9 years (over 15 percent) to be conservative and recognize:

- The good condition of the plants
- The period required to recover the capital investment *if* the Company is required to install Flue Gas Desulfurization (scrubbers or FGD) emissions control equipment at its Labadie and Rush Island Plants

Our informed estimates of the final retirement dates for AmerenUE's coal-fired power plants are summarized in Table 1-1. In forecasting these dates, we conclude an appropriate nominal life expectancy of the AmerenUE coal plants is 65 years. AmerenUE reviewed the resulting retirement schedule and advised that certain dates needed to be extended to allow for the timely replacement of capacity retired. At AmerenUE's direction, we performed the replacement capacity construction schedule and cost-spend analysis we show in Figures 3-1 and 3-2 to demonstrate the viability of the retirement schedule. We base capacity replacement on a 90 month planning and construction schedule for a new coal-fired plant. We show in Figure 3-2, over the 24 year retirement period there is minimal concurrent construction required for the replacement capacity.

Table 1-1
Final Retirement Date Summary

Plant	Unit	Commercial Operation	Final Retirement	Age
Meramec	1	1953	2022	70
Meramec	2	1954	2022	69
Meramec	3	1959	2022	65
Meramec	4	1961	2022	62
Sioux	1	1967	2033	67
Sioux	2	1968	2033	66
Labadie	1	1970	2042	73
Labadie	2	1971	2042	72
Labadie	3	1972	2038	67
Labadie	4	1973	2038	66
Rush Island	1	1976	2046	71
Rush Island	2	1977	2046	70

Our estimated retirement dates result in units retiring at nominally the age of 65 to 73 years. To achieve the plant lives set forth in Table 1-1 we and AmerenUE recognize that significant capital expenditures will be required and that as plants age, the level of capital expenditures may increase above the Company's current forecast of about [redacted] million per year over the next five years.

2.0 INTRODUCTION AND QUALIFICATIONS

2.1 Purpose

The purpose of this report is to provide informed estimates of future retirement dates for AmerenUE's coal-fired generating plants at Meramec, Sioux, Labadie, and Rush Island. Our report analyzes and presents industry experience with coal-fired plant lives, engineering and environmental factors that affect plant life, and sets forth a capital expenditure and construction plan to replace the retired capacity over a period spanning more than two decades.

2.2 Scope

In this report, we estimate retirement dates for four Union Electric Company d/b/a AmerenUE (AmerenUE or Company) coal-fired plants consistent with our understanding of the current condition, planned capital projects, engineering, and environmental compliance considerations for the plants and for coal-fired plants generally. In addition, we consider the age of plants that have been retired and the reported life expectancies of operating plants where information is publically available. Our condition assessments are based on site visits and interviews with key operating personnel at each plant. The four plants addressed in this report are Meramec, Sioux, Labadie, and Rush Island.

We understand our report and informed estimates will be considered by AmerenUE's depreciation rate consultants in their recommendation of appropriate depreciation rates for the four plants. We include in the report:

- A discussion of remaining life and end of plant life in the determination of power plant (unit property) depreciation rates,
- A discussion of plant life based on actuarial analysis of AmerenUE's continuing property records for its coal-fired power plants,
- A discussion of the planned capital projects at the plants and their implication on plant remaining life,
- A discussion of plant lives based on the age at retirement of plants retired throughout the US,
- A discussion of plant lives based a survey of utility depreciation studies and Integrated Resource Plans (IRP) for plants in 26 US states,
- A discussion of engineering considerations supporting the design life of power plants,
- A discussion of environmental considerations affecting the remaining life of coal-fired power plants, and
- A discussion of our plant site visits.

2.3 Subject Plants

AmerenUE owns and operates four coal-fired power plants in the State of Missouri. These plants have a combined installed capacity of nominally 5,650 MW, and began commercial operation during the 24-year period between 1953 and 1977. The plants, with limited exception, all currently burn low sulfur coal shipped by rail from the Powder River Basin in Wyoming (PRB). We summarize the unit operating characteristics of AmerenUE's coal-fired plants in Table 2-1.

Table 2-1

Coal Fired Steam Generating Units
Unit Operating Characteristics
December 2008

	[A]	[B]	[C]	[D]	[F]	[H]	[I]	[J]	[K]	[L]	[M]
Line No.	Plant	Unit	Nameplate Capacity	Heat Rate		Weighted Average Fuel and O&M			Inservice	Age	Supercritical
				Full Load	Average	Fuel	Variable	Fixed			
			MW	BTU/kWh	BTU/kWh	$/MWh	$/MWh	$/kW-yr		Years	
1	Meramec	1	137.50	12,445.00	12,609.00	13.93	1.24	32.56	May-53	55.58	N
2	Meramec	2	137.50	11,624.00	12,001.00	13.93	1.24	32.56	Jul-54	54.42	N
3	Meramec	3	289.00	10,788.00	10,854.00	13.93	1.24	32.56	Jan-59	49.92	N
4	Meramec	4	359.00	11,204.00	11,965.00	13.93	1.24	32.56	Jul-61	47.42	N
5	Sioux	1	549.70	9,625.00	9,932.00	13.57	1.08	28.13	May-67	41.58	Y
6	Sioux	2	549.70	9,106.00	9,687.00	13.57	1.08	28.13	May-68	40.58	Y
7	Labadie	1	573.70	9,096.00	9,596.00	11.34	0.53	15.48	Jun-70	38.50	N
8	Labadie	2	573.70	9,422.00	9,867.00	11.34	0.53	15.48	Jun-71	37.50	N
9	Labadie	3	621.00	9,682.00	10,235.00	11.34	0.53	15.48	Aug-72	36.33	N
10	Labadie	4	621.00	9,499.00	9,944.00	11.34	0.53	15.48	Aug-73	35.33	N
11	Rush Island	1	621.00	9,721.00	9,841.00	12.92	0.80	21.32	Mar-76	32.75	N
12	Rush Island	2	621.00	9,291.00	9,857.00	12.92	0.80	21.32	Mar-77	31.75	N
13	Total / MW Weighted		5,653.80	9,743.45	10,175.50	12.54	0.81	22.01		38.89	
14	Recap / MW Weighted										
15	Meramec		923.00	11,321.19	11,718.44	13.93	1.24	32.56		50.46	
16	Sioux		1,099.40	9,365.50	9,809.50	13.57	1.08	28.13		41.08	
17	Labadie		2,389.40	9,431.31	9,917.59	11.34	0.53	15.48		36.87	
18	Rush Island		1,242.00	9,506.00	9,849.00	12.92	0.80	21.32		32.25	

19 Notes:
20 Reference - Velocity Suite Database
21 All plants and units use sub bituminous coal (Powder River Basin, PRB) as the primary fuel

The Velocity Suite Database (EV Power) is a comprehensive database of North American power markets. Included in EV Power is information regarding the ownership, operating costs, in-service date, capacity, and a wealth of other information regarding individual generating stations (units) in North America. Velocity Suite is available to subscribers on-line and is a product offered by Ventex, a company which employs about 1,200 people.

In Table 2-2 we show the current and planned emissions and environmental controls at each of AmerenUE's coal fired plants.[2]

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[2] Again, for purposes of this report we make the conservative assumption that AmerenUE will be required to install scrubbers at its Labadie and Rush Island Plants. AmerenUE's ECP calls for the purchase of allowances in lieu of installing scrubbers.

Table 2-2

Coal Fired Steam Generating Units
Emissions and Envoirnmental Controls
December 2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line No.	Plant	Unit	Nameplate Capacity	Inservice	Emission Rates				Emission Control Equipment		
					SO2	NOX	CO2	Mercury	SO2	NOX	Mercury
			MW		lbs/MMBtu	lbs/MMBtu	lbs/MMBtu	ppm			
1	Meramec	1	137.50	May-53	0.63	0.13	209.76	0.07	None	2	None
2	Meramec	2	137.50	Jul-54	0.65	0.11	209.76	0.07	None	2	None
3	Meramec	3	289.00	Jan-59	0.64	0.18	209.76	0.07	None	None	None
4	Meramec	4	359.00	Jul-61	0.66	0.19	209.76	0.07	None	1	None
5	Sioux	1	549.70	May-67	1.79	0.22	209.76	0.07	2010	3	None
6	Sioux	2	549.70	May-68	1.78	0.22	209.76	0.07	2010	3	None
7	Labadie	1	573.70	Jun-70	0.69	0.11	209.76	0.07	2020	1	None
8	Labadie	2	573.70	Jun-71	0.69	0.11	209.76	0.07	2020	1	None
9	Labadie	3	621.00	Aug-72	0.70	0.11	209.76	0.07	2018	1	None
10	Labadie	4	621.00	Aug-73	0.71	0.10	209.76	0.07	2018	1	None
11	Rush Island	1	621.00	Mar-76	0.70	0.09	209.76	0.07	2016	1	None
12	Rush Island	2	621.00	Mar-77	0.69	0.10	209.76	0.07	2016	1	None
13	Total / MW Weighted		5,653.80		0.90	0.14	209.76	0.07			
14	Recap / MW Weighted										
15	Meramec		923.00		0.65	0.17	209.76	0.07			
16	Sioux		1,099.40		1.79	0.22	209.76	0.07			
17	Labadie		2,389.40		0.70	0.11	209.76	0.07			
18	Rush Island		1,242.00		0.70	0.10	209.76	0.07			

19 Notes:
20 Reference - Velocity Suite Database
21 All plants and units are equipped with electrostatic precipitators
22 SO2 Control Equipment - Flue Gas Desulfurization (FGD or Scrubbers)
23 The Company does not plan to add scrubbers to its Labadie and Rush Island plants unless required to do so. The dates shown represent
24 the base case set forth in the Company's Environmental Compliance Plan in the event the Company is required to add scrubbers.
25 NOX Control Equipment:
26 1 = Low NOx Burner Technology with Closed-coupled Separated OFA
27 2 = Low NOx Burner Technology with Separated OFA; Low NOx Burners
28 3 = Overfire Air

2.4 Qualifications

Black & Veatch is a leading global consulting, engineering, and construction company specializing in infrastructure projects primarily in the areas of power generation and delivery, energy, water and wastewater treatment, telecommunications, and government facilities. With a staff of over 9,600, Black & Veatch provides valuation, utility feasibility studies, financial management, asset management, information technology, environmental and management consulting services, conceptual and preliminary engineering services, engineering design, procurement, and construction. The company was founded in 1915 and maintains more than 100 offices worldwide. Black & Veatch is headquartered in Kansas City, Missouri and in 2008, was ranked the 11th largest majority employee-owned company in the United States. Black & Veatch was ranked 15th of the Top 500 Design Firms by Engineering News-Record, and ranked 4th in both the Top 25 in Power and the Top 25 in Fossil Fuel in 2008.

Our client base includes investor owned, publicly owned, and cooperatively owned utilities, customers of such utilities, and other entities involved in the energy, water, wastewater, and telecommunications industries, as well as government agencies.

3.0 DEPRECIATION CONSIDERATIONS

For analysis purposes, depreciable property is typically classified into two groups, mass property and unit property. Mass property represents relatively homogeneous property units that tend to be retired individually. Meters, conduit, conductor, services, and line transformers are examples of mass property. Conversely, unit property represents more heterogeneous property groups, which by the nature of their interconnected/integrated operations, tends to be retired simultaneously, or as a group. We normally consider power generation facilities for electric utilities as unit property. Generally, utilities maintain detailed unit property data by physical location. Utilities typically maintain mass property data on an aggregate level. For unit property, we typically define service life based on life span.[3]

Depreciation of unit property requires an informed estimate of the final retirement date in order to recover investment over the period of time the property is used to provide service to customers. A group of property units that will retire concurrently, such as a generating plant, is known as a life span group (unit property). A life span group is in contrast to a mass property group where typically each unit of property is retired independently of the other units of property in the group, and the units retire gradually over time. For example, if a pole requires replacement, the single pole can be retired without the entire pole line being retired from service. Mass property accounts are depreciated based on an age distribution of survivors and retirement dispersion pattern. Life span accounts are depreciated based on interim retirement dispersion and forecasted final retirement dates.

3.1 General Depreciation Considerations

"Life span property generally has the following characteristics:

1. Large individual units,
2. Forecasted overall life or estimated retirement date,
3. Units experience interim retirements, and
4. Future additions are integral part of initial installation."[4]

Coal-fired power plants consist of a large number of individual components which have a finite life expectancy. These individual components fail and must be replaced in order for the plant to continue to provide reliable service. In addition, throughout a plant's life the utility performs capital projects, including projects required to comply with regulatory requirements. However, at some point in time these expenditures become so costly that the more prudent course is to retire the entire plant and all of its many components.

The most important factor in determining the depreciation rate for unit property is the informed estimate of the final retirement date. In estimating final retirement dates for AmerenUE's coal-fired plants we consider actuarial analysis of interim and final retirements of AmerenUE's coal-fired generating facilities, planned capital expenditures, age distribution of plants retired in the US, expected dates of retirement for comparable plants, the current condition of AmerenUE's plants, and other factors explained below.

3.2 Interim and Final Retirements – Actuarial Analysis

At AmerenUE's request, Gannett Fleming, Inc., AmerenUE's depreciation consultant conducted an actuarial analysis of the Company's coal-fired steam production plant accounts. This analysis includes all retirements, both interim and final. The resulting average service lives and Iowa curves for each steam production plant account are shown in Table 3-1.[5] Knowing the current age of each unit, the average service life (including final retirements of units no longer in service) of each account, and the retirement dispersion (Iowa curve) of each account, we determine the probable life for each steam production plant account based on the age of each power plant unit. In Table 3-1 (Columns E through I), we show the probable life by account by unit for

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[3] Life span represents the period between the in service date and the date of retirement.
[4] National Association of Regulatory Utility Commissioners, "Public Utility Depreciation Practices," 141, 1996
[5] Further details supporting this analysis are included as Appendix C.

AmerenUE's coal-fired fleet. To forecast the probable life of each unit, we weigh the probable life of the unit's accounts by the account's surviving investment at December 31, 2008. We show this result in Table 3-1 (Column K). We calculate a unit's remaining life (Column L) as the probable life minus the current age.

We determine each plant's average year of final retirement by first weighing the current age and probable life by the capacity of the various units. We show in Table 3-1 lines 15 through 18 the nameplate capacity (MW) weighted age (Column D) and probable life (Column K) for each plant. We then calculate the plant's remaining life as its probable life minus its age (Column L). We show the indicated final retirement date for each plant in Table 3-1 (Column M).

Table 3-1

Coal Fired Steam Generating Units
Probable Life - Retirement Date
December 2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Line No.	Plant	Unit	Nameplate Capacity	Age	Probable Life					Total Original Cost	Probable Life	Remaining Life	Indicated Retirement
					311	312	314	315	316				
			MW	Years	Years	Years	Years	Years	Years	$	Years	Years	Year
1	Iowa Curve				R4	R1.5	R2	R2.5	R0.5				
2	Average Service Life -				53	45	47	51	47				
3	Meramec	1	137.50	55.58	61.50	65.00	64.10	65.40	71.70		64.89	9.30	Apr-18
4	Meramec	2	137.50	54.42	61.00	64.75	63.90	64.80	71.10		64.59	10.17	Mar-19
5	Meramec	3	289.00	49.92	58.80	61.50	61.00	61.90	68.10		61.49	11.57	Jul-20
6	Meramec	4	359.00	47.42	57.90	60.00	60.00	60.70	66.80		60.13	12.71	Sep-21
7	Sioux	1	549.70	41.58	56.70	57.40	56.50	58.70	64.30		57.40	15.82	Oct-24
8	Sioux	2	549.70	40.58	56.40	57.20	56.10	58.60	64.10		57.17	16.58	Aug-25
9	Labadie	1	573.70	38.50	55.90	55.40	56.10	57.00	62.20		55.85	17.35	May-26
10	Labadie	2	573.70	37.50	55.90	55.30	55.70	56.90	62.00		55.69	18.19	Mar-27
11	Labadie	3	621.00	36.33	55.30	54.90	55.10	56.70	61.50		55.25	18.92	Dec-27
12	Labadie	4	621.00	35.33	55.10	54.70	54.70	56.70	61.40		55.03	19.69	Sep-28
13	Rush Island	1	621.00	32.75	53.90	53.60	53.10	55.90	60.20		53.77	21.02	Jan-30
14	Rush Island	2	621.00	31.75	53.70	53.60	52.80	54.20	60.10		53.59	21.84	Nov-30
15	Total / MW Weighted		5,653.80	38.89	55.95	56.30	56.03	57.70	62.99		56.47	17.58	
16	Recap / MW Weighted												
17	Meramec		923.00	50.46	59.18	61.92	61.50	62.39	68.58		61.93	11.47	Jun-20
18	Sioux		1,099.40	41.08	56.55	57.30	56.30	58.65	64.20		57.28	16.20	Mar-25
19	Labadie		2,389.40	36.87	55.54	55.06	55.38	56.82	61.76		55.44	18.57	Jul-27
20	Rush Island		1,242.00	32.25	53.80	53.60	52.95	55.05	60.15		53.68	21.43	Jun-30
21	Original Cost Investment - Balance @ December 2008 - $ Million												
22	Meramec				39.82	415.49	83.43	43.15	19.15	601.04			
23	Sioux				36.43	392.05	99.34	34.54	10.34	572.69			
24	Labadie				64.98	594.75	208.38	81.06	19.33	968.50			
25	Rush Island				53.51	385.94	136.99	37.97	11.30	625.71			
26	Account 312.03					116.27				116.27			
27	Common				1.96	36.98		3.13	0.02	42.09			
28	Total				196.70	1,941.50	528.14	199.84	60.15	2,926.31			
29	Note:												
30	Probable Life of Unit is Weighted Based on Original Cost Investment of the Plant												

3.3 Capital Projects

Capital projects are an integral part of life span property. In the case of a coal-fired power plant, investment in capital projects over the life of the plant can exceed one to four times that of its original cost.[6] The most significant future capital projects that AmerenUE has budgeted for its coal-fired power plants are for

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[6] Thus the total investment which must ultimately be recovered through depreciation for a plant that initially cost $100 million may exceed $500 million.

environmental control . AmerenUE has budgeted approximately $[redacted] million on environmental projects[7] over the next five years. This $[redacted] million amounts to nearly 50 percent of total capital expenditures budgeted through 2013. We show in Table 3-2 AmerenUE's five year capital expenditure projection for its coal fired power plants.

Table 3-2

Budgeted Capital Expenditure by Plant
($000s)

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	Year 2009	2010	2011	2012	2013	5 - Year Total
1	Meramec						
2	Environmental	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Sioux						
6	Environmental	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Labadie						
10	Environmental	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Rush Island						
14	Environmental	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	Total						
18	Environmental	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.3.1 Environmental Projects

Upon completion of the scrubbers at the Sioux Plant next year, the Company has no definitive plans to install scrubbers at the other plants unless required to do so. In the Company's current Environmental Compliance Plan (ECP), the Company has included three planning scenarios setting forth the timing of the addition of scrubbers to the Labadie and Rush Island Plants, if required. In order to recognize the possibility that the Company may be required to expend the substantial amounts to install scrubbers, we have included consideration of the time required to recover the substantial investment. By so doing, we have increased the estimated life span, which (all other factors equal) results in lower depreciation rates.

We consider the addition of significant environmental projects and the impact of recovering the substantial investment of such projects over a reasonable period of time. In Table 3-3 (Column G) we show the dates that AmerenUE forecasts in its base case scenario that projects will go into service if the Company is required to install scrubbers. We consider a reasonable timeframe for recovery of environmental investment of the magnitude required to be nominally 20 years for planning purposes. To be conservative, we set the minimum

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[7] This $650 million cost includes only some incidental engineering and planning costs associated with the addition (if required) of scrubbers at the Labadie and Rush Island Plants.

time for recovery of environmental investment at 20 years. Table 3-3 (Column H) shows the expected remaining life after consideration of the environmental investments.

Table 3-3

Coal Fired Steam Generating Units
Final Retirement Date
December 2008

Line No.	[A] Plant	[B] Unit	[C] Nameplate Capacity MW	[D] In Service	[E] Age Years	[F] Expected Remaining Life Years	[G] Environmental Project	[H] Expected RL After Project Years	[I] Probable Retirement	[J] Age at Retirement
1	Meramec	1	137.50	May-53	55.58	9.30		9.30	Apr-18	64.89
2	Meramec	2	137.50	Jul-54	54.42	10.17		10.17	Mar-19	64.59
3	Meramec	3	289.00	Jan-59	49.92	11.57		11.57	Jul-20	61.49
4	Meramec	4	359.00	Jul-61	47.42	12.71		12.71	Sep-21	60.13
5	Sioux	1	549.70	May-67	41.58	15.82	Dec-10	21.92	Dec-30	63.50
6	Sioux	2	549.70	May-68	40.58	16.58	Nov-10	21.83	Nov-30	62.42
7	Labadie	1	573.70	Jun-70	38.50	17.35	Oct-20	31.75	Oct-40	70.26
8	Labadie	2	573.70	Jun-71	37.50	18.19	Oct-20	31.75	Oct-40	69.26
9	Labadie	3	621.00	Aug-72	36.33	18.92	Oct-18	29.75	Oct-38	66.08
10	Labadie	4	621.00	Aug-73	35.33	19.69	Oct-18	29.75	Oct-38	65.08
11	Rush Island	1	621.00	Mar-76	32.75	21.02	Jun-16	27.42	Jun-36	60.17
12	Rush Island	2	621.00	Mar-77	31.75	21.84	Jun-16	27.42	Jun-36	59.17
13	Total / MW Weighted		5,654		38.89	17.58		25.13		64.03
14	Recap / MW Weighted									
15	Meramec		923.00	Jul-61	50.46	11.47		11.47	Sep-21	64.89
16	Sioux		1,099.40	May-68	41.08	16.20		21.88	Dec-30	63.50
17	Labadie		2,389.40	Aug-73	36.87	18.57		30.71	Oct-40	70.26
18	Rush Island		1,242.00	Mar-77	32.25	21.43		27.42	Jun-36	60.17

19 Reference:
20 Column [F] - Acrual Analysis (Table 3-1)
21 Lines 15 through 18:
22 Column [D] - Youngest Unit
23 Column [I] - Last Unit
24 Column [J] - Longest Living Unit
25 Note: Age at retirement of the longest living unit does not equal the age on the probable date of retirement.

3.4 Estimated Retirement Dates

We present our estimated life span and final retirement dates for AmerenUE's coal-fired plants in Table 3-4 Column F and Column G respectively. We base our final retirement dates on consideration of a number factors and assumptions including:

1. Actuarial analysis of AmerenUE's actual retirements of its coal-fired power plant investment,
2. Recovery of required major environmental capital expenditures,
3. Available data regarding life spans of other coal-fired units,
4. Existing and contemplated environmental regulations,
5. Engineering principals,
6. Onsite plant condition investigations, and
7. The retirement of the Company's Meramec Plant in 2022 as discussed in the Company's Integrated Resource Plan ("IRP") and Environmental Compliance Plan ("ECP")

Based on all of these factors, we find the nominal life span of AmerenUE's four plants amounts to 64 years. Using a nominal life span of 65 years[8], we estimate that AmerenUE will retire its four coal-fired plants over the 20 year period 2022 through 2042. Unit ages at final retirement range from nominally 62 to 71 years. For AmerenUE's plants to achieve these lives, significant expenditures (both environmental and non-environmental) will be required,

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[8] 69 years for Labadie Units 1 and 2 to accommodate recovery of environmental project cost.

Table 3-4

Coal Fired Steam Generating Units
Recommended Retirement Date
December 2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Plant	Unit	Nameplate Capacity MW	In Service	Age Years	Recommended Life Span Years	Final Retirement	Period to Recover Project Cost	Recommended Remaining Life Years	Age at Final Retirement Years
1	Meramec	1	137.50	May-53	55.58	68.00	2022		14.75	70.33
2	Meramec	2	137.50	Jul-54	54.42	68.00	2022		14.75	69.16
3	Meramec	3	289.00	Jan-59	49.92	61.00	2022		14.75	64.66
4	Meramec	4	359.00	Jul-61	47.42	61.00	2022		14.75	62.16
5	Sioux	1	549.70	May-67	41.58	65.00	2033	22.83	25.75	67.33
6	Sioux	2	549.70	May-68	40.58	65.00	2033	22.91	25.75	66.33
7	Labadie	1	573.70	Jun-70	38.50	69.00	2040	20.00	32.75	71.25
8	Labadie	2	573.70	Jun-71	37.50	69.00	2040	20.00	32.75	70.25
9	Labadie	3	621.00	Aug-72	36.33	65.00	2038	20.00	30.75	67.08
10	Labadie	4	621.00	Aug-73	35.33	65.00	2038	20.00	30.75	66.08
11	Rush Island	1	621.00	Mar-76	32.75	65.00	2042	26.33	34.75	67.50
12	Rush Island	2	621.00	Mar-77	31.75	65.00	2042	26.33	34.75	66.50
13	Total / MW Weighted		5,653.80		38.89	65.50		22.33	28.45	67.34
14	Recap / MW Weighted									
15	Meramec		923.00	Jul-61	50.46	63.09	2022	-	14.75	65.21
16	Sioux		1,099.40	May-68	41.08	65.00	2033	22.87	25.75	66.83
17	Labadie		2,389.40	Aug-73	36.87	66.92	2038 - 2040	20.00	31.71	68.58
18	Rush Island		1,242.00	Mar-77	32.25	65.00	2042	26.33	34.75	67.00

3.5 Consideration of Replacement Capacity Construction Schedule

AmerenUE requested that we evaluate the reasonableness of our estimated retirement dates in Table 3-4 considering the need to replace capacity retired and the time and resources required to construct and finance replacement capacity. Based on our evaluation, we conclude that the retirement dates set forth in Table 3-4 do not realistically permit the orderly replacement of capacity retired. We therefore, in consultation with AmerenUE adjusted the retirement dates we show in Table 3-4 to reflect a more practical schedule to replace retired capacity. These adjusted retirement dates are set forth in Table 3-5.

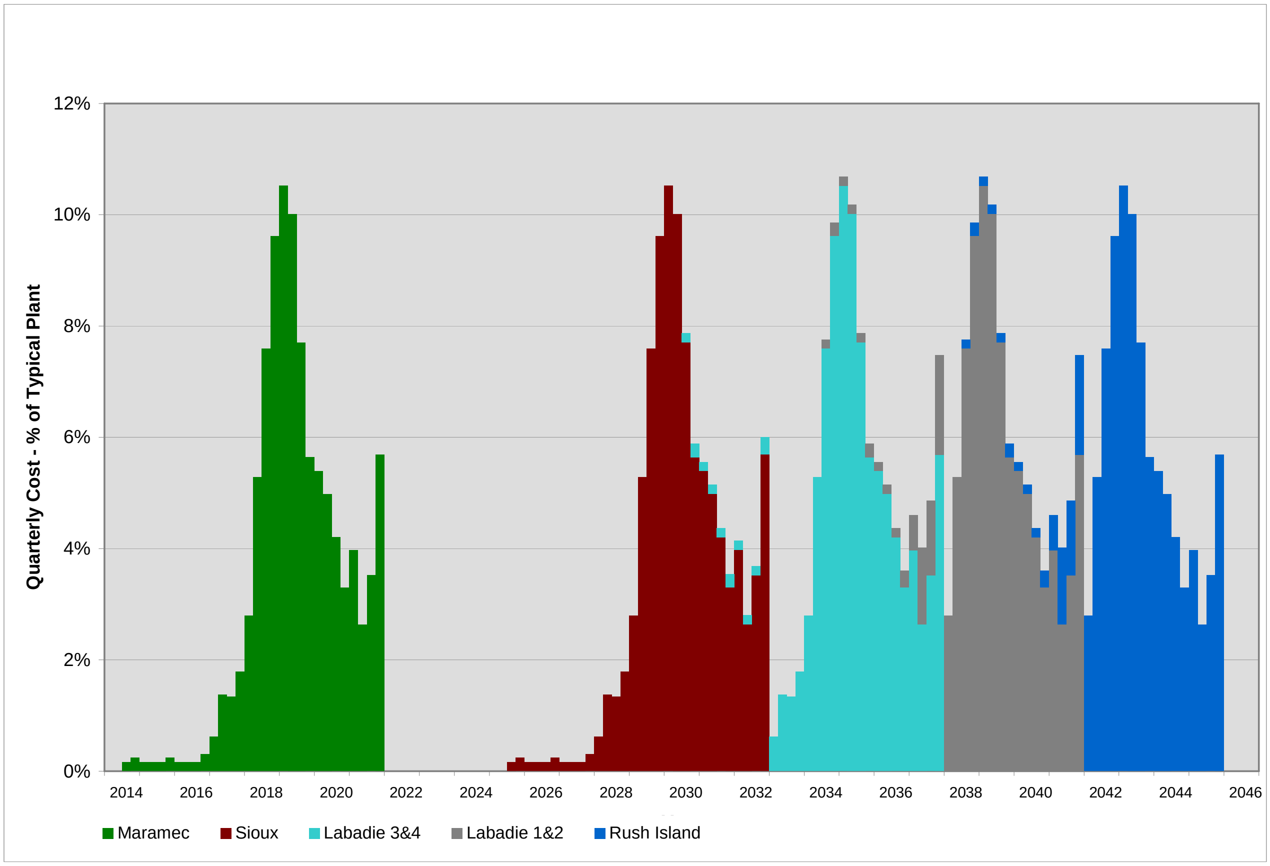
In Figure 3-1, we show the quarterly cash outlays associated with the construction of replacement capacity based on the adjusted retirement dates we show in Table 3-5. We show in Figure 3-1 the cash outlays incident to the replacement of capacity retired based on the cash outlays for a typical large base load coal-fired power plant construction project assuming a 90 month planning and construction schedule. We show the spend curves for replacing the capacity of the four existing plants as well as the overlap in new plant spending. As we show in Figure 3-1, in no one calendar quarter is more than 11 percent of the cost of a new plant expended. Further, the maximum spend in any 12-month period amounts to 38.61 percent. The maximum spend rate in any 12-month period for a single plant amounts to 37.87 percent.

Table 3-5

Coal Fired Steam Generating Units
Final Retirement Date
(Adjusted to Accommodate Replacement Capacity Construction Schedule)
December 2008

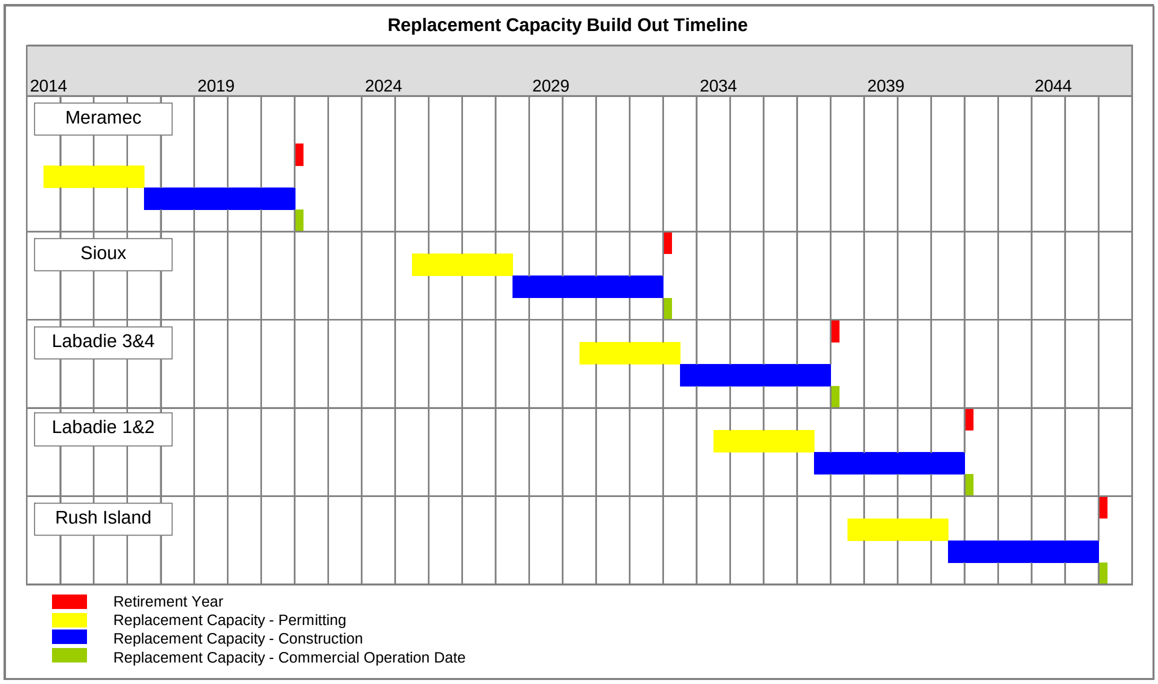
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Plant	Unit	Nameplate Capacity	In Service	Age	Recommended Final Retirement	Retirement Adjusted for Construction Schedule	Extension to Accommodate Construction Schedule	Remaining Life	Age at Final Retirement
			MW		Years			Years	Years	Years
1	Meramec	1	137.50	May-53	55.58	2022	2022	-	14.75	70.33
2	Meramec	2	137.50	Jul-54	54.42	2022	2022	-	14.75	69.16
3	Meramec	3	289.00	Jan-59	49.92	2022	2022	-	14.75	64.66
4	Meramec	4	359.00	Jul-61	47.42	2022	2022	-	14.75	62.16
5	Sioux	1	549.70	May-67	41.58	2033	2033	-	25.75	67.33
6	Sioux	2	549.70	May-68	40.58	2033	2033	-	25.75	66.33
7	Labadie	1	573.70	Jun-70	38.50	2040	2042	2.00	34.75	73.25
8	Labadie	2	573.70	Jun-71	37.50	2040	2042	2.00	34.75	72.25
9	Labadie	3	621.00	Aug-72	36.33	2038	2038	-	30.75	67.08
10	Labadie	4	621.00	Aug-73	35.33	2038	2038	-	30.75	66.08
11	Rush Island	1	621.00	Mar-76	32.75	2042	2046	4.00	38.75	71.50
12	Rush Island	2	621.00	Mar-77	31.75	2042	2046	4.00	38.75	70.50
13	Total / MW Weighted		5,653.80		38.89				29.73	68.63
14	Recap / MW Weighted									
15	Meramec		923.00	Jul-61	50.46	2022	2022	-	14.75	65.21
16	Sioux		1,099.40	May-68	41.08	2033	2033	-	25.75	66.83
17	Labadie		2,389.40	Aug-73	36.87	2038 - 2040	2038 - 2042	0.96	32.67	69.54
18	Rush Island		1,242.00	Mar-77	32.25	2042	2046	4.00	38.75	71.00

Figure 3-1



We show in Figure 3-2, the construction timeline for replacing the capacity of AmerenUE's present coal-fired generation. Using a 90 month planning and construction schedule, we demonstrate in Figure 3-2 the staged approach for replacing capacity where permitting the next facility can occur simultaneously with the construction of a plant. We also show how there will be minimal concurrent construction necessary for replacement capacity given the estimated retirement dates we show in Table 3-5.

Figure 3-2



4.0 PLANT LIFE SURVEYS

4.1 Depreciation and IRP Survey

Black & Veatch surveyed publicly available depreciation information to determine the depreciation rates and associated forecasted retirement dates (life span) for coal-fired plants in 26 states. The scope of our survey was to target approximately 24 states west of Ohio, excluding the Pacific coast.[9] The states we researched for our survey include Alabama, Arizona, Arkansas, Colorado, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Montana, Nevada, New Mexico, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, Texas, Utah, Wisconsin and Wyoming. We also surveyed publicly available Integrated Resource Plans (IRPs) to identify plant retirement dates. Our findings from these surveys are shown in Appendix A-1.

4.1.1 Depreciation Rates and Forecasted Retirement Dates

We researched depreciation rates for forecasted retirement dates using three different sources. First, we searched prior depreciation studies conducted by Black & Veatch for retirement dates provided by the client. Second we searched each state's utility commission website for electronic dockets with depreciation rate information. Third we used an online search engine to research information on plants located in the 26 states listed above.

4.1.2 IRP

The following information was taken from a report titled "Integrated Resource Planning: Process and Rules in the West"[10] dated June 8, 2006:

- The following states require electric utilities to prepare and file IRPs: Idaho, Nevada, Utah, Colorado, Montana, North Dakota, South Dakota, Minnesota, and Missouri
- The following states had (in 2006) open investigations about whether to establish IRP requirements: Arizona, New Mexico, and Arkansas
- Iowa only requires DSM planning
- Kansas, Wyoming, and New Mexico required limited resource planning
- Nebraska, Texas, Louisiana, and Oklahoma had no IRP requirements

For each of the states identified (excluding the ones with no IRP requirements), we searched the public utility commission web site for the most recent IRP studies for the utilities in those states.

We were able to locate IRP documents for utilities in Colorado, Idaho, Indiana, Minnesota, Missouri, Montana, New Mexico, North Dakota, Nevada, and Utah. We were able to identify some life span information from the IRP's we examined. However, many of the documents we reviewed either did not specify any retirements during the IRP planning period or information about loads and resources was redacted from publicly available documents.

4.1.3 Survey Findings and Conclusions

The coal-fired power plant retirement dates found in publicly available documents are shown in Table A-1 of Appendix A. We find that the average age at retirement used in depreciation studies and IRP filings is 55 years for coal-fired power plants. We find the minimum age at retirement of 22 years, the maximum age of 89 years, and a median age of 56 years. In Figure 4-1 we show the distribution of the age of generating units at planned retirement and the associated megawatts of capacity.

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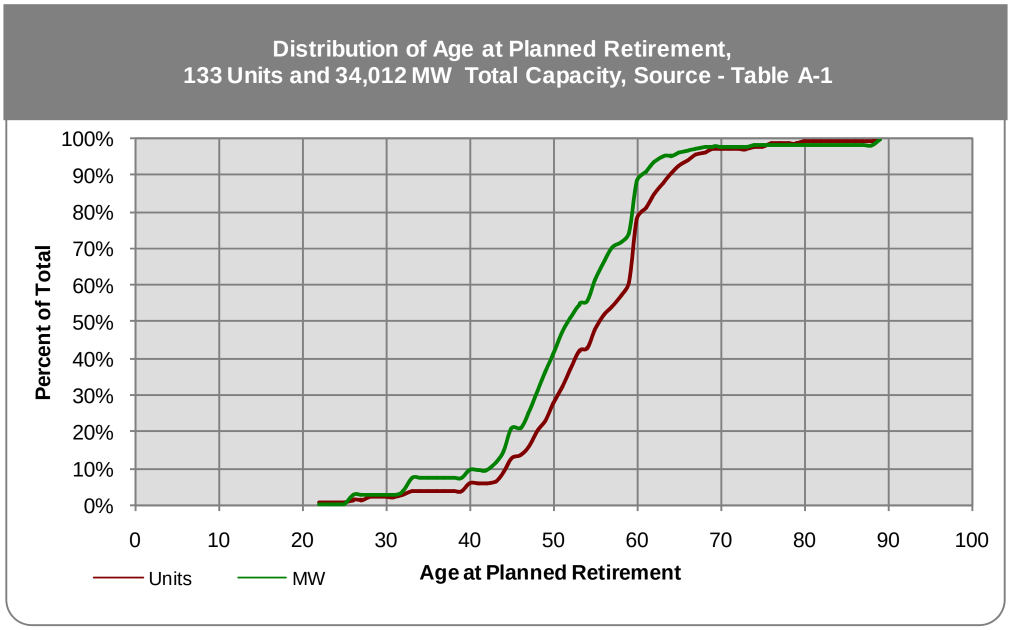
[9] We focus on these states because of the predominance of the use of coal from the Powder River Basin.

[10] Integrated Resource Planning: Process and Rules in the West, Sedano, Richard. New Mexico Public Regulation Commission, June 8, 2006

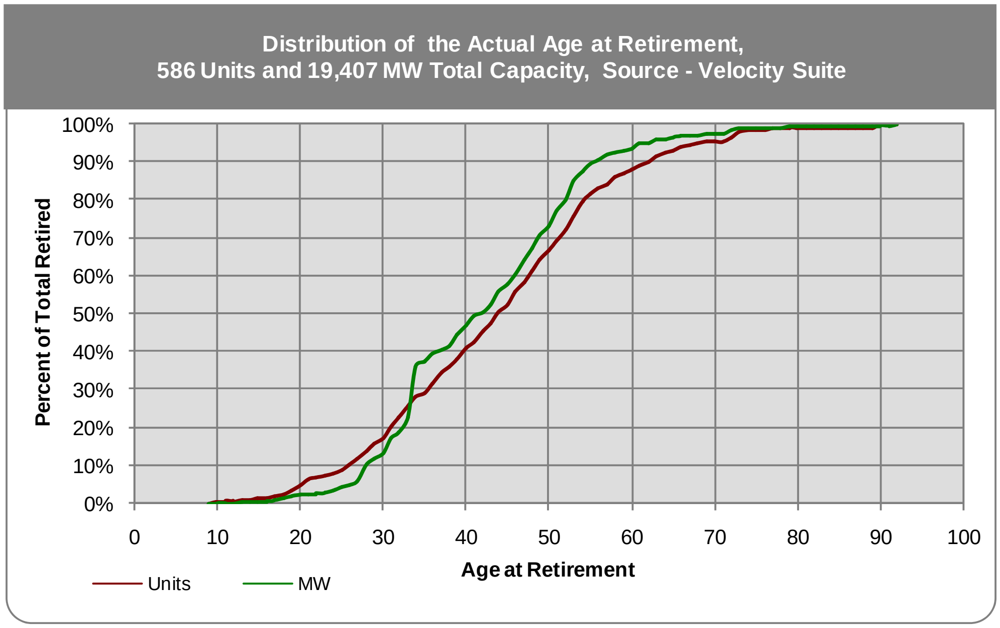
Figure 4-1



4.2 Retired Plant Survey

We researched the Velocity Suite database for the age at retirement of all coal fired power plants reported retired in the United States. The mean and median age of plants retired is 44 years. In Figure 4-2 we show the distribution of plants retired and megawatts of capacity retired by age. In Appendix A-2, we show the detailed information for units retired; their capacity, year of commercial operation, year of retirement, and their age at retirement. As shown in Figure 4-2, only about 10 percent of retired generating units and 5 percent of retired plant capacity experienced a life span of more than 62 years.

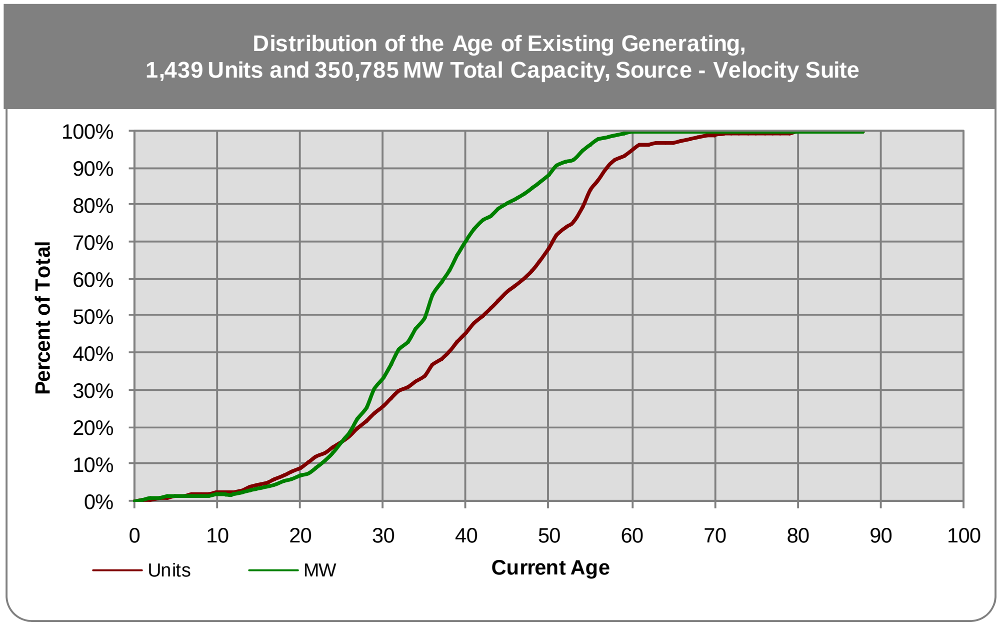
Figure 4-2



4.3 Age of Coal-Fired Plants Currently in Service

We researched Velocity Suite for the current age of operating coal-fired power plants in the United States. The average age is 41 years and the median age is 42 years. In Figure 4-3 we show the distribution of the age of existing generation and megawatts of capacity. Appendix A-3 shows the detailed findings for existing generation units; their capacity, year of commercial operation, and current age. As shown in Figure 4-3, 93 percent of existing generating units have been in service for less than 60 years, and 99 percent of generation capacity is less than 60 years old.

Figure 4-3



5.0 ENGINEERING CONSIDERATIONS

Analysis of steam plant lives should include consideration of engineering design life. When a new plant is initially placed in service, its depreciable life should equal its engineering life. As a unit ages, it is reasonable to reevaluate life span by considering the condition of the plant components, actual plant use and experience, and potential environmental costs and risks. The following sections discuss design life, the major components of steam plants, and factors that lead to component failure and ultimately influence plant life.

5.1 Design Life

Based on discussions with Original Equipment Manufacturers (OEMs), the expected or design "life" of a major power plant component such as the steam generator (boiler) or the turbine-generator is determined by various factors. The actual age of a piece of equipment is seldom the determining factor; rather a combination of hours connected to load, the pattern and practice of use, specific design, maintenance, and environment[11] determines the expected useful life.

5.1.1 Steam Turbines

Based on discussions with General Electric and Westinghouse regarding their turbine generator design, it is apparent that expected life and operation is normally specified by the number of starts and shutdowns. These criteria (expected number of starts and shutdowns) are used by the manufacturer to check design life and to define startup and shutdown procedures today as they were 40 years ago. With proper maintenance, and when operated according to the OEM's recommendations and expectations, a steam turbine can be expected to operate longer than the 30 year life that is typically specified. However, experience has shown that the operating regime of a generating unit often changes over its useful life, especially as technological enhancements in performance and capability advance during a plant's normal 30-35 year life.

It is actually more important to look at the steam turbine and its related equipment as a number of distinct pieces. Within the steam turbine housing there are numerous "components" all of which must be designed to meet the expected operating conditions and perform reliably for at least some portion of the economic life of the turbine generator. That said a number of these components should be expected to be replaced during the life of the unit. For example a typical turbine design from either General Electric or Westinghouse will include:

- Stop Valves
- Steam Chest
- Nozzles/diaphragms
- Control Valves
- Turbine Blades
- Rotor
- Inner and Outer Shell
- Other components

Each of these components is designed to operate reliably over a period of several years under certain specified, expected operating conditions. However with the exception of the rotor and shell, engineers expect to repair or replace many of these components over a typical 30+ year operating life.

Typical practice in the utility industry is to perform a major overhaul of steam turbines every 5 to 7 years. For a typical overhaul in the early stages of a steam turbine's useful life, repairs would include rebuilding diaphragms and replacing seals. As the number of thermal cycles, hours connected to load, and correspondingly the age of the turbine increases, capital repairs, such as selected blade and bearing replacements are expected. Recently turbine vendors have been marketing replacements of major sections of turbine blades. However these replacements are being marketed on the merits of improved capability and efficiency rather than reliability (remaining life) issues.

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[11] In this context, environment refers to conditions (water chemistry, steam temperature, and pressure, products of combustion, etc.) under which plant components operate.

The most critical and costly single item in the turbine/generator system is the rotor. Turbine/generator rotors are designed to withstand a number of thermal cycles, determined primarily by the expected operating regime of the power plant. The operating procedures are then specified in order to minimize internal stresses by carefully heating and cooling the rotor as it is brought into service and when the unit is shut down. Assuming expected conditions match the actual operation of the unit, the rotor should remain useful for the turbine's entire life. However actual operation, regardless of the capability of the operator, inevitably includes unexpected unit "trips," failed starts and other actions which produce stresses at an accelerated rate. The result is a compromise of the potential life of the rotor.

With regard to changes in the design philosophy or criteria for steam turbines today versus the 60's and early 70's, improved analysis tools, closer tolerances, and material improvements have allowed equipment to be designed for greater efficiency and greater capacity. Durability concerns have been addressed via enhancements in cooling designs, materials, and coatings are designed to protect against solid particle erosion (SPE). In addition these analysis tools have allowed designers to actually reduce the size of equipment and the total mass in order to improve the life expectations via fewer stress concentration points, more uniform heating, etc.

5.1.2 Boilers

As is the case with turbines, Black & Veatch's experience with boiler manufacturers has demonstrated that the expected or design life of major boiler components is determined by various factors. The actual age of a piece of equipment is not the primary determining factor, rather a combination of hours connected to load, the pattern and practice of use, specific design, fuel quality, water quality and chemistry, and maintenance procedures determine the expected useful life. In their reference manual "Combustion, Fossil Power" ABB-CE states, "The parameters that affect the life of a component are the local values of stress and temperature, and its material properties. Life does not only depend on these parameters, it is extremely sensitive to them."[12]

Babcock and Wilcox published information that describes the typical expectation for specific equipment replacement. Table 5-1 indicates that various components of the boiler system are expected to require replacement over its typical useful life.

Table 5-1
Example Component Replacement Schedule for a Typical High Temperature, High Pressure Boiler[13]

Typical Life (Years)	Component Replaced	Cause for Replacement
20	Miscellaneous tubing	Corrosion, erosion, overheating
25	Superheater (SH)	Creep
25	SH outlet header	Creep, fatigue
25	Burners and throats	Overheating, fatigue
30	Reheater	Creep
35	Primary economizer	Corrosion
40	Lower furnace	Overheating, corrosion

Note: The actual component life is highly variable depending on specific design, operation, maintenance, and fuel.

Babcock and Wilcox's "Steam" states, "high temperature creep rupture and creep fatigue failure are the two main aging mechanisms in the high temperature components of high temperature boilers. All components that operate above 900° F are subject to some degree of creep. As a result, most of the components have a finite design life and can fail after 20 to 40 years of operation."

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[12] Combustion Engineering, "Combustion Fossil Power," 4th Edition, 24-9, 1991

[13] Babcock & Wilcox, "Steam, its generation and use," 40th Edition, 46-4, 1992

Since the 1960's there have been numerous improvements in materials and design processes that have extended the length of time that various components of the boiler system can be used. Examples include wear resistant materials in high erosion areas, such as coal pulverizers and burner lines. Advanced design standards for reheater and superheater outlet headers have extended the expected time before creep fatigue is expected to cause failures.[14] Other design enhancements have reduced the onset of fatigue cracking in header and drum internals.

Over the course of the turbine's and boiler's normal operating life, a utility expects to replace various components of these systems merely in order to maintain the usefulness of the asset. The timing of these replacements is based strictly on failure mechanisms, the original design, the operating regime, fuel (boiler systems), and the maintenance practices.

Utilities spend significant capital (often exceeding one to four times the initial cost of a plant) in order to replace various components of a generating plant. However there is no time at which any single major system would have expended its useful life and by definition preclude the continued use of the plant if required capital expenditures and replacements are made. Boilers and turbines, as a whole, do not wear out. However the various components of each of those systems (boiler and turbine) do wear out for various reasons.

5.2 *Implications of Operating Conditions and Maintenance Practices*

Babcock and Wilcox defines component end of life according to any one of three situations: 1) the point at which failures occur frequently, 2) when the cost of inspection and repair exceed replacement cost, or 3) when personnel are at risk.[15] The end of useful life of the entire power plant would be determined in much the same manner, considering the potential costs of environmental compliance, expected O&M, and required capital investment. When these costs are expected to be greater than the cost (capital and expenses) for replacement power whether newly constructed capacity or purchased, the economic life of the plant is exhausted.

In examining the two most expensive major systems in a typical coal-fired generating plant, the boiler and the turbine/generator, there are specific mechanisms that result in individual components reaching the end of useful life. The manner in which these systems are operated and maintained has a significant influence on the rate at which the useful life of their components is expended.

5.2.1 Turbines

The operating procedures developed by turbine manufacturers are designed to protect turbine parts from thermal fatigue cracking caused by internal temperature gradients. The specific objective is to provide for the desired number of thermal cycles before fatigue cracking occurs. Due to its large diameter (and mass), the rotor is the most critical element with regard to thermal stress. The stationary parts are constructed to allow for thermal expansion, and being smaller, are not subject to the extreme internal temperature gradient.

The primary operating conditions that must be addressed in the operation of the turbine include; start-up procedures, load changing procedures, shut-down, turbine trips, load following cycling, daily (on/off) cycling and low load operation.

From the perspective of turbine design, a thermal cycle occurs when the rotor surface is heated to operating temperature and subsequently cooled. The OEM will provide the owner/operator with operating procedures designed to limit thermal stresses and thus prolong the life of the equipment. The temperature gradient in the rotor is the critical element in designing the hot and cold starting procedures. These procedures are designed to carefully warm the rotor so that the internal stresses generated from the temperature difference from external to internal do not prematurely induce cracking or brittle fracture.

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[14] Babcock & Wilcox, "Steam, its generation and use," 40th Edition, 46-4-46-6, 1992

[15] Babcock & Wilcox, "Steam, its generation and use," 40th Edition, 45-10, 1992

In addition to starting and shut down procedures, during normal operation there will usually be requirements to change loads. The OEM's provide procedures designed to limit stresses during this period as well. The procedures attempt to balance the need for timely load changes, heat rate performance, and avoidance of damage. Governor valve sequences affect these parameters. The various "modes" of governor valve sequences include; sequential valve position, single valve throttling, and sliding pressure operation.

Sequential valve operation is the most thermally efficient at lower loads. However this mode produces the greatest first stage temperature changes and therefore requires the slowest load changes. Sliding pressure minimizes the temperature changes and is very useful for units which are subject to daily "load following." However, since pressure is controlled via the boiler, reduced wear on the turbine is at the cost of increased stress on the boiler.

Careful adherence to the OEM's recommended procedures will increase the useful life of a steam turbine and its multiple components. However the number of "cycles" accumulated will be determined by the load regime on the unit over its life as well as by the overall unit availability. In this regard shutdown procedures are as important as starting and operating. Emergency trips of the steam turbine do not allow for the controlled reduction in metal temperatures.

The last concern that must be addressed in operation is low load operation. Most OEMs recommend not operating below 50 percent of the rated load. At extremely low load, operation can result in overheating of the low pressure turbine blading. This can lead to blade damage from rubbing between stationary and rotating elements due to differential expansion or distortion of stationary parts causing interference. These high temperatures occur from a combination of the high reheat steam, reduced flow, and high exhaust pressure.

5.2.2 Boiler

Both Babcock & Wilcox and Alstom[16], the major boiler manufacturers in the US, have published extensive information regarding the effect of operations and maintenance on the life of the boiler and its major components. Table 5-2 provides a description of the factors that will typically result in the need to replace major sections of a boiler. These factors are: corrosion, erosion, overheating, fatigue, and creep.

Table 5-2
Common Replacement Causes for Typical High Temperature, High Pressure Boiler

Component	Cause for Replacement	Operating Influences
Miscellaneous tubing	Corrosion	Oxygen levels, pH
	Erosion	Fuel and fuel blends
	Overheating	Water chemistry, fouling, and pluggage
Superheater (SH)	Creep	Overheating
SH outlet header	Creep, fatigue	Overheating
Burners and throats	Overheating	Off-design operation
	Corrosion	Reducing atmosphere
Reheater	Creep	Overheating
Primary economizer	Corrosion	Water chemistry, fuel
Lower furnace	Overheating	Water chemistry
	Corrosion	Fuel and fuel blends, reducing atmosphere

The following sections describe how operating philosophy and maintenance practices can influence each of the above referenced primary factors that lead to reduced component life (failure).

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[16] Alstom acquired ABB-CE and boilers in the US that were referred to as "CE" boilers are now commonly referred to as "Alstom" boilers.

5.2.2.1 Corrosion

Corrosion in a power plant boiler can occur on either the inside (water or steam side) or the outside (combustion or fuel side) of the headers, drums, pipes, and tubes. Boiler water pH, contaminants, and improper chemical cleaning are the primary causes of internal corrosion. External corrosion can be caused by fuel or combustion products, a reducing atmosphere in the furnace, and by moisture trapped in low temperature areas (i.e. under insulation).

Operating practices that can reduce these corrosion effects include careful and comprehensive pH control, and maintaining proper oxygen levels in the boiler water. The corrosive combustion products in the fuel are generally managed through careful control of minimum cold end average temperatures in order to stay above the acid dew point. Likewise maintaining adequate combustion air can reduce the occurrence of a reducing atmosphere in the boiler.

However, as cycling increases, which is common for older units, boilers become susceptible to oxygen leakage as a result of the design and/or the operation. Start-up of the boiler is the most common point during which oxygen is introduced into the feedwater. It is not uncommon to introduce more oxygen into the system during a single start-up than during months of normal continuous operation. During cold and to some degree even warm/hot starts, the air heater will cool below the acid dew point of the flue gas. During those periods, corrosion of the air heater baskets is unavoidable. Furthermore, minimizing air fuel ratios in order to reduce exit gas temperatures and NOx formation can easily result in a reducing atmosphere in the furnace.

5.2.2.2 Overheating

Internal overheating of water filled tubes is usually the result of deposits on the inside of the tube. However, in steam sections of the boiler, overheating will result from over-firing or non-uniform heat distribution. Over-firing occurs whenever the steam flow requirements increase and the boiler must be over-fired in order to maintain pressure. Cycling the unit and using a unit to “follow” load, with frequent load swings both up and down, will result in short term overheating of various components in the boiler. In addition, fouling of sections of the boiler can result in localized overheating and a resultant need for superheat or reheat attemperation. The most effective means of reducing the frequency and effects of overheating is to avoid cycling and load-following and keeping the furnace and boiler clean of ash.

5.2.2.3 Creep

Creep is the degradation of material properties that occurs with time and temperature. High temperature creep rupture and creep fatigue failures are the two main aging mechanisms in the high temperature components of modern power boilers. Replacement of the tubes, headers, and piping from the superheater outlet header to the turbine and the reheater outlet header to the reheat turbine should be expected for a unit that is expected to operate more than 25 to 35 years. Due to the effect of heat on creep formation, small increases above the design operating temperatures can have dramatic affects on the useful life of a component. For example, for a boiler operating at 1,000º F the expected service life is reduced by half if the boiler is operated at 17º F above design temperature. As is the case with overheating, avoiding cycling the unit and minimizing the time operated in a load following regime, while keeping the furnace and boiler as clean as possible of ash deposits, are the best means to reduce the effects of creep.

5.2.2.4 Fatigue

Fatigue is the process by which materials fail under cyclic loading. Cyclic loading in this instance refers to thermal expansion, contraction, and vibration. Most piping systems are designed with some degree of fatigue resistance via the hangers and support system. For thick-walled components of high-pressure boilers and high pressure steam lines, the principal loading that can cause damage is produced by the thermal transients that occur during start-up and shut-down. ASME codes for boiler component design specify materials and material thickness in order to accept up to a specified number of cycles (expansion and contraction). Daily load cycling of older units accelerates the accumulation of these cycles.

Careful adherence to the manufacturer's starting, loading, and shut-down procedures is the primary operating practice that the boiler operator can follow to minimize the effects of fatigue on thick-walled components. Maintaining pipe hangers and supports so that they perform their design function will reduce the effects of fatigue in piping systems.

5.2.2.5 Erosion

Erosion is the wearing away of material through impact with harder (and to a much lesser degree, softer) materials. Erosion can take place anywhere within a boiler but especially near sootblowers, high velocity flue gas areas or due to ash characteristics that are highly corrosive. Major sections of the superheater or reheater may need replacement due to erosion or corrosion, or just a small section of tubing. Coal pulverizers require frequent and costly maintenance due to the highly erosive nature of the ash in the coal. Advanced materials have been developed specifically for boiler fuel handling applications. It is now common to install ceramic linings in coal transport equipment, pulverizers, piping, exhaust fans, and burner nozzles. Erosion internal to the boiler in the back passes from the economizer through the air heater is usually not a major problem as long as the velocities are maintained at or near the original design.

The potential to influence erosion through O&M practices comes primarily from the ability to change from the design fuel to an alternative fuel with different composition. This can affect erosion in two ways, velocity, and volume. The volume of fuel required will change with changes in heat content. Likewise the velocities will change with volume in order to maintain the firing rates.

6.0 ENVIRONMENTAL CONSIDERATIONS

In addition to physical considerations, the economic implications of environmental requirements and risks affect the life of coal-fired generating plants. The following provides a high-level summary of important current environmental regulations that are directed specifically to the electric power generating industry. Prominent current requirements include the Clean Air Interstate Rule (CAIR), Maximum Achievable Control Technology (MACT) emission limits for hazardous air pollutants, New Source Review (NSR), and limitations placed on wastewater discharges to prevent the degradation of receiving water bodies under the Clean Water Act.

Beyond the current environmental regulatory programs mentioned above, there are several initiatives and trends as well as changes in the political landscape that indicate additional environmental controls will likely be imposed on the electric generating industry in the future.[17] These initiatives aim to limit greenhouse gas emissions (specifically carbon dioxide), mercury emissions, environmental impacts associated with water intake structures, and environmental impacts associated with coal combustion waste disposal. These initiatives will likely impose substantial capital and annual compliance costs on AmerenUE's coal-fired plants. These future compliance costs will come nearer the end of the plants' lives and will likely contribute to the decisions to retire existing coal-fired plants.

Each of the existing and anticipated environmental regulatory programs mentioned above and their potential impacts on coal-fired generating plants are briefly discussed below.

6.1 Clean Air Interstate Rule (CAIR)

CAIR originally proposed to regulate annual SO2 and NOx emissions as well as seasonal NOx emissions in 28 eastern states (including Missouri) under a cap-and-trade program. The rulemaking prompted utilities in the eastern United States to order billions of dollars of equipment to reduce SO2 and NOx emissions, or purchase emission allowances in anticipation of the annual NOx trading market which began January 1, 2009, seasonal NOx trading market which began in May 2009, and SO2 market scheduled to begin in January 2010. The first phase of CAIR was designed to reduce annual SO2 and NOx emissions by 45% and 53% respectively, with even greater reductions to begin under a subsequent phase in 2015.

The rule was challenged by several states and other petitioners, most of whom sought to have only certain provisions of the rule revised or set aside. After ruling in July 2008 that CAIR had "more than several fatal flaws" and that it would vacate the rule altogether, the court instructed all litigants to file responses in October 2008 to EPA's reconsideration petition. Based on these responses, the court concluded "notwithstanding the relative flaws of CAIR, allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR" and issued its order essentially reversing (at least temporarily) its decision to vacate the rule

EPA must now promulgate a new CAIR that addresses all the flaws and concerns identified in the court's July ruling. Realistically EPA will take years to finalize new regulations. Alternatively, Congress could enact legislation that implements CAIR's proposed SO2 and NOx emission reduction programs, but EPA would still likely have to develop rules to implement the new legislative program. In the meantime, both states and utilities must scramble to distribute allowances and manage emissions to meet the initial phase of CAIR's emission reduction requirements which now temporarily remain in effect.

Each utility subject to CAIR will develop a strategy to comply with CAIR. These strategies may include actions such as the installation of flue gas desulphurization equipment, the purchase of allowances, and the purchase of lower sulfur coal.

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[17] The *American Clean Energy and Security Act of 2009* (Waxman-Markey Energy and Climate Bill) currently before Congress is an example.

6.2 Mercury Reduction – Case by Case and State by State

Finalized by EPA in 2005, the Clean Air Mercury Rule (CAMR) sought to establish a cap-and-trade program to begin in 2010 for the regulation of mercury (Hg) emissions from coal-fired units (>25 MW) located in all 50 states, and performance standards for Hg emissions from new coal-fired units constructed or modified after January 30, 2004. EPA required all 50 states to enact and adopt laws and rules to implement the CAMR program through State Implementation Plans (SIPs). Although EPA offered model rules to follow, as many as 19 states adopted more stringent programs in developing their individual SIPs. Missouri was not one of those states.

CAMR was challenged by a number of parties. In February 2008, the CAMR was vacated by the federal District of Columbia Circuit Court of Appeals. EPA originally appealed the vacatur decision to the US Supreme Court; however on February 6, 2009, the Department of Justice, on behalf of EPA, asked the Supreme Court to dismiss EPA's appeal. EPA has decided to develop emissions standards for power plants under the Clean Air Act (Section 112), consistent with the D.C. Circuit's opinion. Meanwhile, new coal-fired plants must meet Maximum Achievable Control Technology requirements for Hg and other HAPs to be established by each state permitting authority on a case-by-case review basis. Future regulation of HAPs from existing coal-fired plants now seems likely under the MACT approach discussed below.

6.3 MACT and Startup, Shutdown, and Malfunction Exemption

The Clean Air Act (CAA) requires compliance with Maximum Achievable Control Technology (MACT) emission limits for hazardous air pollutants (HAPs). During normal operation, the HAP emission standard is typically defined as an emission limit, with compliance accomplished and demonstrated by direct measurement of the HAP itself; or as is commonly done, by association and correlation with a surrogate pollutant already subject to continuous monitoring with CEMs or COMs.

However, because of the erratic and generally unpredictable nature of emissions during startup, shut-down and malfunction (SSM) events, most permits have historically been written to exempt emission limit compliance with HAPs during SSM events. To fill the gap during SSM events, the EPA (since 1994) has maintained that the "general duty" clause is applicable (instead of a numeric emission limit), thus fulfilling the continuous compliance obligation of a HAP emission standard. The general duty clause requires an affected source to operate in a manner consistent with safety and good air pollution control practice for minimizing emissions. The EPA has argued that such a work practice standard under the "general duty" clause can satisfy the continuous compliance requirement under certain circumstances such as SSM, just like an emission limit does during normal operation.

The District of Columbia Circuit Court disagreed with EPA's position. In vacating the SSM exemption on December 19, 2008 the court agreed with the Sierra Club that the general duty clause, and thus the work practice standards implemented during SSM events, is not a CAA Section 112-compliant emission standard. Therefore, the continuous compliance requirement of MACT is not demonstrated during SSM, which violates the CAA.

Unless overturned, a few of the outcomes of this ruling may include: 1) permitting authorities may require affected sources to begin complying with existing HAP emission limits in their permits at all times, including SSM. 2) permitting authorities may require affected sources to submit plans with alternative emission limits or standards for SSM events that are consistent with CAA Section 112(h). This Section provides for a standard to be relaxed if it is not feasible in the judgment of the permitting authority to prescribe or enforce an emission standard for control of a HAP based on either a design or source specific basis.

Depending on the above potential outcomes, the effect on coal-fired power plants may range from business as usual, the implementation of additional limits, or revised control strategies.

6.4 New Source Review

At the current time, activities at an existing plant, including Air Quality Control (AQC) retrofit projects, are subject to New Source Review (NSR) air permitting requirements if they are determined to be "major modifications" at a "major stationary source." The NSR regulations define major modification and major stationary source,,and those terms have also been addressed by court decisions, agency applicability determinations and other authorities. NSR includes both the Non-attainment NSR and Prevention of Significant Deterioration (PSD) programs. Evaluation of NSR/PSD applicability is complicated and has changed over time. When a project triggers NSR/PSD requirements, a major modification pre-construction air permit is required, which generally includes application of Best Available Control Technology (BACT) and/or application of Lowest Achievable Emission Rate (LAER) technology depending on the NAAQS attainment status of the relevant area.

The current permitting path (for both new units and for modifications to existing units which trigger the NSR/PSD requirements) is a difficult one that requires planning and preparation. Major challenges to such permits from concerned citizen groups, interveners, and possibly government officials can be expected, which can result in litigation and additional costs.

In addition to prospective permitting issues, over the last decade or so US EPA has initiated Section 114 investigations into whether prior activities at many coal-fired generating plants triggered NSR/PSD requirements. Some of these investigations have resulted in enforcement actions and additional controls at the targeted facilities.

6.5 Additional Non-attainment Issues

The Missouri counties within which the facilities are located are classified as non-attainment areas for both the 8-hour Ozone and PM2.5 pollutants, meaning the areas currently do not meet the National Ambient Air Quality Standards (NAAQS) for these pollutants. In addition to the more stringent requirements of LAER technologies associated with permitting new or modified units (see discussion of modifications above) that are associated with non-attainment areas, the agency is tasked with planning for the future classification of these areas back to attainment. Federal law (section 110 of the Clean Air Act) requires that states having non-attainment areas develop written plans for cleaning the air in those areas. The plans are called State Implementation Plans, or SIPs, and it is the state's responsibility to produce these plans that document the strategy for bringing the non-attainment area into and then maintaining compliance with the NAAQS.

One of the central elements of a SIP is the air pollution emission control measures, including controls on both stationary sources and mobile sources. Control measures are techniques, practices, and equipment for reducing emissions of non-attainment pollutants and their precursors. In Missouri, the Control Measures Workgroup is responsible for the identification and technical evaluation of control strategies needed to achieve attainment.

One of Missouri's control strategies is to implement Reasonably Available Control Technologies (RACT) on major air pollution sources in the Missouri portion of the non-attainment areas. RACT is defined as the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. The agency must periodically review its RACT rules to assure that they support the goal of attainment.

In its most recent 2006 finding, Missouri certified that the current complement of RACT rules that apply to ozone precursors for sources located in the non-attainment areas fulfill the RACT requirements. The 2006 RACT SIP Revision was an evaluation of current air pollution rules that apply in the Missouri portion of the non-attainment areas resulting in no new or revised regulations. That is, the current controls, limits, and strategies in place are sufficient to address the issue of regaining attainment. However, it is important to note that if the area continues to not meet the NAAQS, the SIP may be revised to include more stringent RACT rules. Should this happen, the agency may be compelled to take action to further reduce emissions from existing sources such as those evaluated in this report.

6.6 Greenhouse Gas Regulation

To date the United States has generally encouraged the implementation of voluntary programs to address greenhouse gas (GHG) emissions. However, most people now believe that mandatory greenhouse gas reductions will likely be required sometime in the future, especially from large sources. Currently, the EPA stands poised to initiate the process for generating regulations governing GHG emissions under the Clean Air Act (CAA) and Congress has been presented a multitude of mandatory legislative proposals.

6.6.1 Federal Regulation

EPA recently fulfilled an overdue Congressional mandate to propose a mandatory GHG reporting rule. Announced on March 10, 2009 the proposed rule would require an estimated 13,000 sources to begin inventories of emissions of six GHGs on January 1, 2010 and file annual reports of these emissions beginning in 2011. Reporting requirements are specified for individual major industrial sectors, as well as for transportation sector fuel suppliers and vehicle/engine manufacturers. The rule also contains a catch-all provision that extends reporting requirements to all fossil-fuel combustion sources with a heat input of 30 mmBtu/hr or greater, that annually produce at least 25,000 tons of CO2 equivalent emissions. This level can encompass sources as small as large hospitals and office complexes.

In addition to the release of the mandatory GHG reporting rule, the EPA issued a proposed endangerment finding on April 17, 2009, a first step to establishing legal authority to regulate emissions of the six greenhouse gases (CO2, CH4, N2O, HFCs, PFCs, and SF6) under the CAA. The EPA did not concurrently propose any greenhouse gas regulation and has discretion in determining the manner in which to proceed with the rulemaking processes. While the EPA is not required to initiate the rulemaking progress, the endangerment finding situates the EPA in a manner allowing for the commencement of nationwide regulations in the near future.

While the EPA initiated the process for regulating GHGs under the Clean Air Act, according to the EPA administrator, the Clean Air Act is not particularly suited for addressing the more global nature of greenhouse gas pollution and would prefer a legislative solution that addresses climate change. Congress has the authority to amend the Clean Air Act or enact a new statute to address economy-wide and trans-boundary greenhouse gas emissions. This may include market-based regulatory approaches, such as cap-and-trade or carbon tax mechanisms. Currently, the leading Congressional proposal is the “American Clean Energy and Security Act.” This Act proposes an economy-wide cap-and-trade program to begin in 2012 and progressively achieves reductions of 20% below 2005 levels by 2020 and eventually 83% below 2005 levels by 2050.

6.6.2 Other Regulation

Various other GHG regulatory programs have been initiated and continue to evolve on international and regional levels. Internationally, nations will convene during December 2009 in Copenhagen, Denmark to negotiate and draft an agreement establishing the framework for addressing global climate change after the current Kyoto Protocol expires in 2012. The United States is expected to attend the conference and indicate its future role in reducing global GHG emissions.

Regionally, six Midwestern states joined the Midwest Greenhouse Gas Accord in November 2007. It is the third regional pact aimed at regulating greenhouse gases to reduce global warming. Missouri, however, has not signed as either a member or observer of this regional accord.

6.6.3 Potential Impact to Coal-Fired Power Generation Facilities

Any future regulation of GHG emissions (including cap and trade forms similar to CAIR) would likely result in additional expenditures for coal-fire power generation facilities in the form of purchases of allocations to offset all or a portion of its emissions of the regulated gases or investments in clean technology, energy efficiency, and sustainable design.

6.7 Clean Water Act Section 316(b)

Section 316(b) of the Clean Water Act (CWA) requires the Environmental Protection Agency (EPA) to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to minimize adverse environmental impacts. Potential harm from intake structures includes, but is not limited to, reduced fish populations due to losses of individual fish impinged on intake screens or entrained in a facility's cooling water system.

Federal regulations divide Section 316(b) into three rulemaking phases. Phase I applies to new electric generating plants and manufactures that withdraw more than 2 million gallons per day (MGD) of cooling water. Phase II applies to existing electric generating plants using at least 50 MGD of cooling water. Phase III applies to new offshore oil and gas extraction facilities that withdraw more than 2 MGD of cooling water.

The initial Phase II rulemaking was suspended in July 2007 and the EPA is now initiating a new 316(b) Phase II rulemaking process. The EPA expects this new rulemaking to apply to approximately 600 existing generating plants. The EPA may implement these regulations through the National Pollutant Discharge Elimination System (NPDES) permit renewal process. A facility's NPDES permit is typically renewed every 5-years.

The future cost of compliance with Section 316(b), Phase II for existing electric generating plants will vary widely and is dependent upon site specific conditions. Plant modifications employed in an effort to comply with Section 316(b) may include, but are not limited to, the installation of cooling towers, modifications to intake and discharge structures, and the optimization of cooling system design.

6.8 Waste Disposal

The EPA currently regulates coal combustion wastes disposed of and stored in landfills and surface impoundments as a solid waste under the Resource Conservation and Recovery Act (RCRA) Subtitle D. States were delegated the responsibility of regulating RCRA Subtitle D solid waste facilities. Recent EPA activities indicate that states may no longer solely regulate coal ash impoundments.

In March 2009, the EPA initiated an effort to address concerns associated with the disposal of coal combustion waste and by-products. The EPA's plan includes activities focused on the gathering of information regarding critical coal ash impoundments from electric utilities nationwide, conducting on-site assessments to determine the impoundments structural integrity and vulnerabilities, and ordering cleanup and repairs when necessary. By the end of 2009, EPA likely will develop new regulations covering these areas. The EPA likely will require appropriate remedial actions at those facilities found to pose a risk for potential failure. AmerenUE's Meramec, Sioux, Labadie, and Rush Island Power Stations are among the entities to which the EPA specifically sent letters directing participation in the above information collection effort.

As indicated above, federal scrutiny of existing coal combustion waste impoundments is ongoing and future federal regulation is anticipated in the near future. These federal actions may result in additional costs associated with physical changes to the facilities, clean-up and repairs, and/or other remedial actions. The actions necessary to comply with these impending federal activities are unknown at this time.[18]

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[18] On May 11, 2009, EPA took over the cleanup of TVA's Kingston coal ash spill under the Superfund law even though coal combustion waste is not currently regulated as a hazardous waste. This action may signal intent by EPA to revise its current position and begin to regulate coal combustion waste as a hazardous substance.

6.9 Antidegradation Requirements

In 2007, the Missouri Department of Natural Resources (MDNR) released the Antidegradation Rule and Implementation Procedure (the Procedure) (revised May 7, 2008) as part of its water quality regulations. The Procedure establishes a three-tired antidegradation program and requires compliance by all facilities with new or newly expanded discharges. Before the proposed discharge is authorized, the Procedure's steps must be complied with to ensure adequate protection of water quality. The specific steps to be followed depend upon which tier or tiers of antidegradation apply.

- Tier 1 protects existing uses and corresponding water quality conditions necessary to support such uses. Where an existing use is established, it must be protected even if it is not listed in the water quality standards as a designated use. Tier 1 requirements are applicable to all surface waters, regardless of ambient water quality.
- Tier 2 protects ”high quality” waters – water bodies where ambient water quality is better than the criteria associated with the designated water uses. Limited water quality degradation is allowed in high quality waters where it is demonstrated the degradation is necessary to fulfill important social or economic development.
- Tier 3 protects water quality in outstanding national resource waters. Except for temporary degradation, water quality cannot be lowered in such waters.

As seen in the differences in protection levels afforded the various tiers, the financial impact of complying with the Procedure will vary among facilities depending on the ambient water quality of the surface water where the discharge will occur; the quality and volume of the proposed wastewater discharge; the tier or tiers of antidegradation that will apply; and the corresponding social and economic impact of the proposed discharge. That said, compliance with the Procedure could result in significant financial expenditures associated with, not only the preparation of an antidegradation study to support a permit application, but extensive wastewater treatment technology in order to secure a wastewater discharge permit.

7.0 PLANT VISIT CONSIDERATIONS

On April 28-30, 2009, Black & Veatch conducted site visits at the Meramec, Sioux, Labadie, and Rush Island power plants. Detailed reports of our plant visits are included in Appendix B. Based on our findings from the site visits, we believe that AmerenUE's plants are in good condition. We find that, with continued maintenance and capital expenditures, economic factors will likely drive retirement decisions, not physical limitations.

APPENDIX A
POWER PLANT LIFE DATA

Appendix A-1
Age at Planned Retirement
Units Currently in Service – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age	Remaining Life	Retirement Year	Retirement IRP	Retirement Age
										(a)
1	Number of Units			133						
2	Maximum		1,300.00		2005	79.79				89
3	Minimum		3.50		1929	3.79				22
4	Median		172.80		1965	43.79				56
5	Average		255.73			41.71				55
6	Standard Deviation		253.37			12.81				9
7	95% Confidence Limit									
8	Maximum		752.34			66.81				74
9	Minimum		(240.89)			16.61				37
10	Cholla	Arizona	288.90	2	1978	30.79		2033		55
11	Cholla	Arizona	312.30	3	1980	28.79		2035		55
12	Cholla	Arizona	414.00	4	1981	27.79		2025	2025	44
13	Navajo	Arizona	803.10	NAV1	1974	34.79		2031		57
14	Navajo	Arizona	803.10	NAV2	1975	33.79		2031		56
15	Navajo	Arizona	803.10	NAV3	1976	32.79		2031		55
16	Arapahoe	Colorado	48.00	3	1951	57.79		2013	2012	62
17	Arapahoe	Colorado	112.00	4	1955	53.79		2013	2012	58
18	Cameo	Colorado	22.00	1	1957	51.79		2013	2010	56
19	Cameo	Colorado	44.00	2	1960	48.79		2013	2010	53
20	Cherokee (CO)	Colorado	125.00	1	1957	51.79		2017		60
21	Cherokee (CO)	Colorado	125.00	2	1959	49.79		2019		60
22	Cherokee (CO)	Colorado	170.40	3	1962	46.79		2022		60
23	Craig (CO)	Colorado	446.40	1	1980	28.79		2024	2024	44
24	Craig (CO)	Colorado	446.40	2	1979	29.79		2024	2024	45
25	Hayden	Colorado	190.00	1	1965	43.79		2024	2024	59
26	Hayden	Colorado	275.40	2	1976	32.79		2024	2024	48
27	Lakeside	Illinois	37.50	6	1961	47.79		2010		49
28	Lakeside	Illinois	37.50	7	1965	43.79		2010		45
29	Will County	Illinois	187.50	1	1955	53.79		2010		55
30	Will County	Illinois	183.70	2	1955	53.79		2010		55
31	Edwardsport	Indiana	40.20	7	1949	59.79		2011		62
32	Edwardsport	Indiana	69.00	8	1951	57.79		2011		60
33	H T Pritchard/Eagle Valley	Indiana	50.00	3	1951	57.79			2018	67
34	H T Pritchard/Eagle Valley	Indiana	69.00	4	1953	55.79			2018	65
35	H T Pritchard/Eagle Valley	Indiana	69.00	5	1953	55.79			2018	65
36	H T Pritchard/Eagle Valley	Indiana	113.60	6	1956	52.79			2018	62
37	Rockport	Indiana	1,300.00	1	1984	24.79		2044		60
38	Rockport	Indiana	1,300.00	2	1989	19.79		2022		33
39	Tanners Creek	Indiana	152.50	1	1951	57.79		2020	2015	69
40	Tanners Creek	Indiana	152.50	2	1952	56.79		2020	2015	68
41	Tanners Creek	Indiana	215.40	3	1954	54.79		2020	2015	66
42	Tanners Creek	Indiana	579.70	4	1964	44.79		2020		56
43	Whitewater Valley	Indiana	33.00	1	1955	53.79			2015	60
44	Whitewater Valley	Indiana	60.90	2	1973	35.79			2025	52
45	Burlington (IA)	Iowa	212.00	1	1968	40.79	9	2018		50
46	Clinton (IA ADM)	Iowa	7.50	GEN1	1954	54.79	3	2012		58
47	Clinton (IA ADM)	Iowa	3.50	GEN2	1940	68.79	7	2016		76
48	Dubuque	Iowa	28.70	3	1952	56.79	4	2012		60
49	Dubuque	Iowa	37.50	4	1959	49.79	4	2012		53
50	Dubuque	Iowa	15.00	ST2	1929	79.79	0	2009		80
51	George Neal North	Iowa	549.80	3	1975	33.79	13	2022		47
52	George Neal South	Iowa	640.00	4	1979	29.79	15	2024		45
53	Lansing	Iowa	11.50	2	1949	59.79		2013		64
54	Lansing	Iowa	37.50	3	1957	51.79		2013		56
55	Lansing	Iowa	274.50	4	1977	31.79		2009		32

Appendix A-1
(continued)
Age at Planned Retirement
Units Currently in Service – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age	Remaining Life	Retirement		
								Year	IRP	Age
										(a)
56	Louisa	Iowa	811.90	1	1983	25.79		2009		26
57	Muscatine	Iowa	25.00	7	1958	50.79		2010		52
58	Ottumwa (IA IPL)	Iowa	726.00	1	1981	27.79	21	2030		49
59	Prairie Creek 1 4	Iowa	23.00	1A	1997	11.79	16	2025		28
60	Prairie Creek 1 4	Iowa	23.00	2	1951	57.79	16	2025		74
61	Prairie Creek 1 4	Iowa	50.00	3	1958	50.79	16	2025		67
62	Prairie Creek 1 4	Iowa	148.70	4	1967	41.79	9	2018		51
63	Holcomb East	Kansas	348.70	1	1983	25.79	31	2040		57
64	Quindaro	Kansas	81.60	ST1	1965	43.79		2026		61
65	Quindaro	Kansas	157.50	ST2	1971	37.79		2026		55
66	Hugh L Spurlock	Kentucky	357.60	1	1977	31.79		2040		63
67	Hugh L Spurlock	Kentucky	592.10	2	1981	27.79		2042		61
68	Hugh L Spurlock	Kentucky	329.40	3	2005	3.79		2045		40
69	James de Young	Michigan	11.50	3	1951	57.79		2011		60
70	Presque Isle	Michigan	54.40	3	1964	44.79		2012		48
71	Presque Isle	Michigan	57.80	4	1966	42.79		2012		46
72	Allen S King Plant	Minnesota	658.40	1	1958	50.79			2047	89
73	Black Dog	Minnesota	114.00	3	1955	53.79	4	2013	2011	58
74	Black Dog	Minnesota	180.00	4	1960	48.79	4	2013	2011	53
75	Clay Boswell	Minnesota	75.00	1	1958	50.79	14	2023		65
76	Clay Boswell	Minnesota	75.00	2	1960	48.79	14	2023		63
77	Clay Boswell	Minnesota	364.50	3	1973	35.79	26	2035		62
78	Clay Boswell	Minnesota	558.00	4	1980	28.79	20	2029		49
79	Hoot Lake	Minnesota	54.40	2	1959	49.79		2017	2019	60
80	Hoot Lake	Minnesota	75.00	3	1964	44.79		2017	2019	55
81	Riverside Repowering Project (MN)	Minnesota	238.80	8	1964	44.79		2009	2008	45
82	Riverside Repowering Project (MN)	Minnesota	165.00	ST7	1987	21.79		2009	2008	22
83	James River Power St	Missouri	22.00	1	1957	51.79		2017		60
84	James River Power St	Missouri	22.00	2	1957	51.79		2017		60
85	James River Power St	Missouri	44.00	3	1960	48.79		2020		60
86	James River Power St	Missouri	60.00	4	1964	44.79		2024		60
87	James River Power St	Missouri	105.00	5	1970	38.79		2029		59
88	Southwest	Missouri	194.00	ST1	1976	32.79		2029		53
89	Colstrip	Montana	778.00	GEN3	1984	24.79		2029	2029	45
90	Colstrip	Montana	778.00	GEN4	1986	22.79		2029	2029	43
91	North Valmy	Nevada	277.20	1	1981	27.79		2031	2021	50
92	North Valmy	Nevada	289.80	2	1985	23.79		2035	2025	50
93	Reid Gardner	Nevada	114.00	1	1965	43.79		2012		47
94	Reid Gardner	Nevada	114.00	2	1968	40.79		2012		44
95	Reid Gardner	Nevada	114.00	3	1976	32.79		2016		40
96	Reid Gardner	Nevada	270.00	4	1983	25.79		2023		40
97	Four Corners	New Mexico	190.00	1	1963	45.79		2016		53
98	Four Corners	New Mexico	190.00	2	1963	45.79		2016		53
99	Four Corners	New Mexico	253.40	3	1964	44.79		2016		52
100	Coyote	North Dakota	450.00	1	1981	27.79			2029	48
101	Conesville	Ohio	161.50	3	1962	46.79		2012		50
102	Muskingum River	Ohio	219.60	1	1953	55.79		2015		62
103	Muskingum River	Ohio	219.60	2	1954	54.79		2015		61
104	Muskingum River	Ohio	237.50	3	1957	51.79		2015		58
105	Muskingum River	Ohio	237.50	4	1958	50.79		2015		57
106	Cross	South Carolina	590.90	1	1995	13.79		2055		60
107	Cross	South Carolina	556.20	2	1984	24.79		2044		60
108	Dolphus M Grainger	South Carolina	81.60	1	1966	42.79		2026		60
109	Dolphus M Grainger	South Carolina	81.60	2	1966	42.79		2026		60
110	Jefferies	South Carolina	172.80	3	1970	38.79		2030		60
111	Jefferies	South Carolina	172.80	4	1970	38.79		2030		60
112	Winyah	South Carolina	315.00	1	1975	33.79		2034		59
113	Winyah	South Carolina	315.00	2	1977	31.79		2037		60
114	Winyah	South Carolina	315.00	3	1980	28.79		2040		60
115	Winyah	South Carolina	315.00	4	1981	27.79		2041		60
116	Ben French	South Dakota	25.00	ST1	1961	47.79		2013		52

Appendix A-1
(continued)
Age at Planned Retirement
Units Currently in Service – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age	Remaining Life	Retirement		
								Year	IRP	Age (a)
117	Big Stone	South Dakota	456.00	ST1	1975	33.79			2024	49
118	Carbon (UT)	Utah	75.00	1	1954	54.79		2010	2020	66
119	Carbon (UT)	Utah	113.60	2	1957	51.79		2010	2020	63
120	Hunter	Utah	488.30	ST1	1978	30.79		2025	2031	53
121	Hunter	Utah	488.30	ST2	1980	28.79		2025	2031	51
122	Hunter	Utah	495.60	ST3	1983	25.79		2025	2031	48
123	Huntington (UT)	Utah	498.00	1	1977	31.79		2019	2025	48
124	Huntington (UT)	Utah	498.00	2	1974	34.79		2019	2025	51
125	Blount Street	Wisconsin	23.00	5	1948	60.79		2012		64
126	Dave Johnston	Wyoming	113.60	1	1959	49.79		2020	2020	61
127	Dave Johnston	Wyoming	113.60	2	1961	47.79		2020	2020	59
128	Dave Johnston	Wyoming	229.50	3	1964	44.79		2020	2020	56
129	Dave Johnston	Wyoming	360.00	4	1972	36.79		2020	2020	48
130	Jim Bridger	Wyoming	577.90	1	1974	34.79		2020	2026	52
131	Jim Bridger	Wyoming	577.90	2	1975	33.79		2020	2026	51
132	Jim Bridger	Wyoming	577.90	3	1976	32.79		2020	2026	50
133	Jim Bridger	Wyoming	584.00	4	1979	29.79		2020	2026	47
134	Naughton	Wyoming	163.20	1	1963	45.79		2022	2022	59
135	Naughton	Wyoming	217.60	2	1968	40.79		2022	2022	54
136	Naughton	Wyoming	326.40	3	1971	37.79		2022	2022	51
137	Neil Simpson	Wyoming	21.70	5	1969	39.79		2020		51
138	Neil Simpson II	Wyoming	80.00	2	1995	13.79		2045		50
139	Osage (WY)	Wyoming	11.50	1	1948	60.79		2012		64
140	Osage (WY)	Wyoming	11.50	2	1949	59.79		2012		63
141	Osage (WY)	Wyoming	11.50	3	1952	56.79		2012		60
142	Wyodak	Wyoming	362.00	1	1978	30.79		2030	2028	52

Notes:
(a) Retirement Date based on max of column [H] and [I]

Appendix A-2
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
1	Number of Units			586			
2	Maximum		818.10		1989	2008	92.00
3	Minimum		0.30		1900	1960	9.00
4	Median		12.25		1947	1985	44.00
5	Average		33.12				44.13
6	Standard Deviation		63.32				14.37
7	95% Confidence Limit						
8	Maximum		157.22				72.31
9	Minimum		(90.98)				15.96
10	Gorgas 2 & 3	AL	69.00	5	1944	1989	45
11	Gorgas 2 & 3	AL	69.00	4	1929	1977	48
12	U S Alliance Coosa Pines	AL	5.00	AOW3	1942	2003	61
13	Arapahoe	CO	44.00	2	1951	2002	51
14	Arapahoe	CO	44.00	1	1950	2002	52
15	Bayside Power Station	FL	187.50	4	1963	2003	40
16	Bayside Power Station	FL	179.50	3	1960	2003	43
17	Bayside Power Station	FL	125.00	2	1958	2003	45
18	Bayside Power Station	FL	125.00	1	1957	2003	46
19	Jefferson Smurfit Corp (FL)	FL	9.30	GEN4	1963	2003	40
20	Arkwright	GA	49.00	4	1948	2002	54
21	Arkwright	GA	40.20	3	1943	2002	59
22	Arkwright	GA	46.00	ST2	1942	2002	60
23	Arkwright	GA	46.00	ST1	1941	2002	61
24	Durango Georgia Paper Co	GA	18.70	NO3	1955	2006	51
25	Durango Georgia Paper Co	GA	6.70	NO2	1947	2006	59
26	Durango Georgia Paper Co	GA	4.00	NO1	1941	2006	65
27	International Paper Co Savannah	GA	20.00	GEN7	1957	2001	44
28	International Paper Co Savannah	GA	10.00	GEN6	1952	2001	49
29	International Paper Co Savannah	GA	7.50	GEN3	1940	2001	61
30	Mitchell (GA)	GA	27.50	1	1948	2002	54
31	Mitchell (GA)	GA	27.50	2	1948	2002	54
32	Pepeekeo	HI	23.80	GEN1	1974	2004	30
33	Ames Electric Services Power Plant (Ia Ames)	IA	12.60	ST4	1958	1986	28
34	Ames Electric Services Power Plant (Ia Ames)	IA	7.50	ST3	1950	1984	34
35	Boone (IA)	IA	3.50	3	1947	1977	30
36	Boone (IA)	IA	3.50	4	1923	1977	54
37	Bridgeport (IA)	IA	25.00	3	1957	1981	24
38	Bridgeport (IA)	IA	23.00	1	1953	1981	28
39	Bridgeport (IA)	IA	23.00	2	1953	1981	28
40	Carroll (IA)	IA	5.30	1	1952	1980	28
41	Carroll (IA)	IA	5.30	2	1953	1990	37
42	Denison (IA)	IA	3.00	4	1950	1986	36
43	Des Moines (IA MWPWR)	IA	113.64	7	1964	1994	30
44	Des Moines (IA MWPWR)	IA	75.00	6	1954	1993	39
45	Des Moines (IA MWPWR)	IA	5.00	3	1949	1990	41
46	Des Moines (IA MWPWR)	IA	30.00	2	1926	1990	64
47	Des Moines (IA MWPWR)	IA	20.00	1	1925	1990	65
48	Eagle Grove	IA	8.00	1	1949	1980	31
49	Hawkeye	IA	11.50	2	1954	1981	27
50	Hawkeye	IA	8.00	1	1949	1981	32
51	Humboldt	IA	20.30	4	1953	1999	46

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
52	Humboldt	IA	9.40	1	1950	1999	49
53	Humboldt	IA	9.40	2	1950	1999	49
54	Iowa State Univ	IA	3.00	1	1949	2004	55
55	Lansing	IA	15.00	1	1948	2004	56
56	Maynard Station	IA	54.40	7	1958	1988	30
57	Muscatine	IA	12.50	6	1949	1985	36
58	Muscatine	IA	7.50	5	1944	1985	41
59	Pella	IA	4.00	4	1952	1992	40
60	Pella	IA	1.50	3	1948	1990	42
61	Prairie Creek 1 4	IA	23.00	1	1950	1996	46
62	Riverside (IA)	IA	46.00	ST4	1949	1988	39
63	Riverside (IA)	IA	2.50	ST2	1937	1983	46
64	Riverside (IA)	IA	20.00	ST3	1937	1983	46
65	Sibley One	IA	2.50	1	1948	1984	36
66	Sixth Street (IA)	IA	7.50	5	1917	1981	64
67	Streeter	IA	5.00	5	1954	1984	30
68	Streeter	IA	5.00	4	1949	1984	35
69	Webster City	IA	8.00	5	1960	1979	19
70	Webster City	IA	4.00	4	1950	1979	29
71	Webster City	IA	2.00	3	1939	1979	40
72	Webster City	IA	1.00	2	1928	1979	51
73	Webster City	IA	1.00	1	1921	1979	58
74	Carlyle	IL	3.00	3	1949	1985	36
75	Dixon	IL	69.00	5	1953	1978	25
76	Dixon	IL	50.00	4	1945	1978	33
77	Fairfield (IL)	IL	4.00	3	1948	1975	27
78	Fairfield (IL)	IL	2.50	2	1942	1975	33
79	Fairfield (IL)	IL	1.80	1	1939	1975	36
80	Fisk Street	IL	25.00	11	1949	1977	28
81	Fisk Street	IL	173.00	18	1949	1977	28
82	Joliet 9	IL	107.00	5	1950	1978	28
83	Lakeside	IL	20.00	5	1953	1982	29
84	Lakeside	IL	20.00	4	1949	1982	33
85	Mascoutah	IL	1.50	2	1967	1976	9
86	Mascoutah	IL	2.00	1	1965	1976	11
87	Moline	IL	12.00	ST3	1950	1976	26
88	Mt Carmel	IL	7.50	3	1952	1983	31
89	Mt Carmel	IL	2.00	1	1941	1990	49
90	Peru (IL)	IL	2.50	2	1938	1975	37
91	Peru (IL)	IL	1.00	ST1	1936	1975	39
92	Powerton	IL	105.00	4	1940	1974	34
93	Powerton	IL	105.00	3	1930	1974	44
94	Powerton	IL	55.00	2	1929	1974	45
95	Powerton	IL	55.00	1	1928	1974	46
96	R S Wallace	IL	113.60	7	1958	1985	27
97	R S Wallace	IL	85.90	6	1952	1985	33
98	R S Wallace	IL	40.20	5	1949	1985	36
99	R S Wallace	IL	40.30	4	1941	1985	44
100	R S Wallace	IL	25.00	3	1939	1985	46
101	Waukegan	IL	130.00	5	1931	1978	47
102	Waukegan	IL	121.00	6	1952	2007	55
103	4 AC Station	IN	67.50	14TG	1963	1999	36

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
104	4 AC Station	IN	67.50	15TG	1963	1999	36
105	Breed	IN	495.55	1	1960	1994	34
106	Crawfordsville	IN	4.50	3	1947	1976	29
107	Crawfordsville	IN	5.00	1	1939	1970	31
108	Crawfordsville	IN	3.50	2	1928	1960	32
109	Dresser Station	IN	50.00	6	1945	1975	30
110	Dresser Station	IN	50.00	5	1944	1975	31
111	Dresser Station	IN	50.00	4	1941	1975	34
112	F B Culley	IN	46.00	1	1955	2006	51
113	Frankfort	IN	17.00	3	1962	1977	15
114	Frankfort	IN	10.00	2	1952	1977	25
115	Frankfort	IN	6.00	1	1941	1977	36
116	Jasper 1	IN	5.00	4	1949	1975	26
117	Jasper 1	IN	2.00	1	1938	1975	37
118	Johnson Street	IN	15.00	4	1948	1970	22
119	Johnson Street	IN	15.00	1	1934	1970	36
120	Johnson Street	IN	15.00	2	1934	1970	36
121	Johnson Street	IN	15.00	3	1934	1970	36
122	Lawton Park	IN	15.00	3	1941	1975	34
123	Lawton Park	IN	15.00	2	1934	1975	41
124	Michigan City	IN	4.00	11	1930	1980	50
125	Perry K	IN	12.50	5	1938	1984	46
126	Perry K	IN	5.00	HS	1938	2000	62
127	Perry K	IN	15.00	3	1924	1989	65
128	Perry W	IN	11.63	7	1980	1997	17
129	Peru (IN)	IN	5.00	1	1933	1977	44
130	Smurfit Wabash	IN	2.00	7240	1947	2001	54
131	Smurfit Wabash	IN	2.00	8323	1947	2001	54
132	State Line Energy	IN	150.00	ST2	1938	1979	41
133	State Line Energy	IN	200.00	ST1	1929	1978	49
134	Twin Branch	IN	77.00	3	1940	1974	34
135	Twin Branch	IN	40.00	1	1925	1974	49
136	Twin Branch	IN	40.00	2	1925	1974	49
137	Wahington (IN)	IN	5.00	2	1957	1977	20
138	Wahington (IN)	IN	5.00	4	1957	1977	20
139	Wahington (IN)	IN	5.00	1	1947	1977	30
140	Wahington (IN)	IN	3.00	3	1938	1977	39
141	Lawrence Energy Center (KS)	KS	38.00	2	1952	2000	48
142	Lawrence Energy Center (KS)	KS	10.00	ST1	1939	1993	54
143	Cane Run	KY	112.50	2	1956	1985	29
144	Cane Run	KY	112.50	1	1954	1985	31
145	Green River (KY)	KY	37.50	1	1950	2003	53
146	Green River (KY)	KY	37.50	2	1950	2003	53
147	Henderson I	KY	5.00	3	1951	1971	20
148	Henderson I	KY	5.00	4	1951	1971	20
149	Henderson I	KY	32.30	6	1968	2008	40
150	Henderson I	KY	11.50	5	1956	2008	52
151	Owensboro	KY	34.50	4	1954	1978	24
152	Owensboro	KY	8.00	3	1945	1974	29
153	Owensboro	KY	7.50	1	1939	1977	38
154	Owensboro	KY	7.50	2	1939	1977	38
155	Paddys Run	KY	69.00	4	1949	1981	32

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
156	Paddys Run	KY	74.70	6	1952	1984	32
157	Paddys Run	KY	74.70	5	1950	1983	33
158	Paddys Run	KY	69.00	3	1947	1981	34
159	Paddys Run	KY	25.00	1	1942	1979	37
160	Paddys Run	KY	25.00	2	1942	1979	37
161	Pineville	KY	37.50	3	1951	2002	51
162	Indeck Turners Falls Energy CNTR	MA	21.90	GEN1	1989	1999	10
163	R Paul Smith Power Station	MD	15.00	1	1900	1990	90
164	R Paul Smith Power Station	MD	35.00	2	1900	1990	90
165	Advance	MI	22.00	3	1967	2000	33
166	Advance	MI	7.50	1	1953	2000	47
167	Advance	MI	7.50	2	1953	2000	47
168	Bayside (MI)	MI	14.00	4	1968	2002	34
169	Bayside (MI)	MI	7.50	3	1954	2002	48
170	Bayside (MI)	MI	5.00	2	1950	1999	49
171	Bayside (MI)	MI	2.50	1	1946	2002	56
172	Cargill Salt Inc	MI	0.70	DCTG	1935	2001	66
173	Cargill Salt Inc	MI	1.20	DCT	1935	2002	67
174	Coldwater	MI	3.00	ST5	1962	1999	37
175	Coldwater	MI	5.00	6	1962	1999	37
176	Coldwater	MI	3.00	ST4	1940	1999	59
177	Conners Creek	MI	2.00	48	1938	1981	43
178	Conners Creek	MI	2.00	47	1937	1981	44
179	Conners Creek	MI	2.00	42	1936	1981	45
180	Conners Creek	MI	2.00	41	1935	1981	46
181	Gladston (MI GSTONE)	MI	3.00	1	1955	1980	25
182	Gladston (MI GSTONE)	MI	3.00	2	1955	1980	25
183	J B Simms	MI	10.00	1	1961	1999	38
184	James de Young	MI	8.00	1	1940	1983	43
185	James de Young	MI	8.00	2	1940	1983	43
186	Marysville	MI	2.00	45	1931	1981	50
187	Marysville	MI	2.00	44	1928	1981	53
188	Marysville	MI	2.00	43	1927	1981	54
189	Marysville	MI	50.00	6	1930	1995	65
190	Marysville	MI	10.00	3	1900	1972	72
191	Marysville	MI	30.00	2	1900	1972	72
192	Marysville	MI	30.00	4	1900	1972	72
193	Marysville	MI	30.00	5	1900	1972	72
194	Mistersky	MI	20.00	2	1927	1979	52
195	Mistersky	MI	20.00	3	1927	1979	52
196	Mistersky	MI	20.00	4	1927	1979	52
197	Ottawa Street	MI	25.00	3	1951	1993	42
198	Ottawa Street	MI	25.00	2	1949	1993	44
199	Ottawa Street	MI	4.00	5	1939	1988	49
200	Ottawa Street	MI	25.00	1	1940	1993	53
201	Pennsalt	MI	2.50	11	1964	1985	21
202	Pennsalt	MI	2.50	18	1964	1985	21
203	Pennsalt	MI	5.00	12	1964	1985	21
204	Pennsalt	MI	6.00	14	1964	1985	21
205	Pennsalt	MI	6.00	15	1964	1985	21
206	Pennsalt	MI	7.50	16	1964	1985	21
207	Pennsalt	MI	7.50	17	1964	1985	21

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
208	Port Huron	MI	4.00	3	1969	1985	16
209	Port Huron	MI	2.00	2	1966	1985	19
210	Presque Isle	MI	37.50	2	1962	2006	44
211	Presque Isle	MI	25.00	1	1955	2006	51
212	Saginaw Station	MI	100.00	ST1	1920	1973	53
213	Trenton Channel	MI	4.00	45	1930	1977	47
214	Trenton Channel	MI	50.00	4	1926	1974	48
215	Trenton Channel	MI	50.00	5	1926	1974	48
216	Trenton Channel	MI	50.00	6	1926	1974	48
217	Trenton Channel	MI	2.00	33	1927	1977	50
218	Trenton Channel	MI	4.00	44	1927	1977	50
219	Trenton Channel	MI	50.00	1	1924	1974	50
220	Trenton Channel	MI	50.00	2	1924	1974	50
221	Trenton Channel	MI	50.00	3	1924	1974	50
222	Trenton Channel	MI	4.00	42	1924	1977	53
223	Trenton Channel	MI	4.00	43	1924	1977	53
224	Wyandotte (MI)	MI	6.00	2	1942	1984	42
225	Wyandotte (MI)	MI	4.00	1	1939	1984	45
226	Alexandria (MN)	MN	3.00	ST3	1949	1981	32
227	Benson (MN BENSON)	MN	0.30	1	1940	1982	42
228	Benson (MN BENSON)	MN	0.30	2	1929	1981	52
229	Black Dog	MN	81.00	1	1952	2001	49
230	Blue Earth	MN	2.00	3	1944	1987	43
231	Blue Earth	MN	1.50	2	1938	1984	46
232	Canby	MN	5.00	2	1942	1975	33
233	Canby	MN	3.00	1	1931	1975	44
234	Crookston	MN	5.00	2	1949	1975	26
235	Crookston	MN	5.00	1	1948	1975	27
236	Detroit Lakes	MN	2.00	2	1937	1982	45
237	Hibbing	MN	2.50	2	1941	1983	42
238	Hibbing	MN	5.00	1	1941	1984	43
239	Hibbing	MN	1.50	4	1941	1995	54
240	High Bridge	MN	50.00	4	1944	1991	47
241	High Bridge	MN	163.20	6	1959	2007	48
242	High Bridge	MN	50.00	3	1942	1991	49
243	High Bridge	MN	113.60	5	1956	2007	51
244	High Bridge	MN	35.00	2	1928	1991	63
245	High Bridge	MN	32.00	1	1924	1991	67
246	Hoot Lake	MN	7.50	1	1948	2005	57
247	Litchfield	MN	3.00	ST1	1948	1990	42
248	Litchfield	MN	1.00	ST2	1930	1977	47
249	Madison (MN)	MN	1.00	1	1949	1970	21
250	Minnesota Valley	MN	46.00	3	1953	2006	53
251	Moorhead	MN	25.00	7	1970	1999	29
252	Moorhead	MN	6.00	5	1952	1984	32
253	Moorhead	MN	3.00	4	1948	1984	36
254	Moorhead	MN	3.00	3	1940	1984	44
255	New Ulm	MN	6.00	2	1946	1984	38
256	North Broadway	MN	8.00	2	1936	1982	46
257	North Broadway	MN	5.00	1	1931	1982	51
258	Ortonville	MN	16.50	1	1950	1983	33
259	Riverside Repowering Project (MN)	MN	6.00	7	1949	1976	27

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
260	Riverside Repowering Project (MN)	MN	35.00	2	1931	1987	56
261	Sleepy Eye	MN	1.25	4	1960	1986	26
262	Springfield (MN)	MN	0.80	1	1937	1976	39
263	Springfield (MN)	MN	4.00	4	1961	2002	41
264	Springfield (MN)	MN	2.00	3	1946	1998	52
265	Springfield (MN)	MN	1.00	2	1940	1994	54
266	Virginia	MN	5.00	1	1949	1992	43
267	Virginia	MN	2.50	4	1937	1996	59
268	Virginia	MN	1.50	3	1930	1996	66
269	Virginia	MN	1.00	2	1922	1990	68
270	Willmar	MN	1.00	2	1928	1976	48
271	Willmar	MN	4.00	ST1	1949	2006	57
272	Chillicothe	MO	2.50	4	1939	1982	43
273	Chillicothe	MO	6.00	6	1958	2004	46
274	Chillicothe	MO	1.50	3	1929	1980	51
275	Chillicothe	MO	5.00	5	1948	2004	56
276	Chillicothe	MO	2.50	4A	1938	2004	66
277	Coleman (MO)	MO	6.30	1	1959	1985	26
278	Columbia (MO CLMBIA)	MO	8.50	2	1947	1975	28
279	Columbia (MO CLMBIA)	MO	5.00	1	1938	1975	37
280	Columbia (MO CLMBIA)	MO	4.00	4	1929	1975	46
281	Fulton (MO)	MO	6.00	4	1959	1982	23
282	Fulton (MO)	MO	3.00	3	1949	1982	33
283	Fulton (MO)	MO	2.00	2	1940	1982	42
284	Fulton (MO)	MO	1.00	1	1935	1982	47
285	Grand Avenue	MO	30.00	8	1936	1982	46
286	Hannibal	MO	10.00	2	1951	1990	39
287	Hannibal	MO	17.00	3	1937	1990	53
288	Hannibal	MO	8.00	1	1936	1990	54
289	Hawthorne (MO)	MO	112.50	3	1953	1984	31
290	Hawthorne (MO)	MO	69.00	1	1951	1984	33
291	Hawthorne (MO)	MO	69.00	2	1951	1984	33
292	Southeast Missouri State Univ	MO	6.20	GEN3	1972	2007	35
293	Wright (MS)	MS	2.50	5	1926	1981	55
294	Buck Steam Station (NC)	NC	35.00	1	1926	1981	55
295	Buck Steam Station (NC)	NC	35.00	2	1926	1981	55
296	Cape Fear	NC	122.28	4	1943	1994	51
297	Cape Fear	NC	31.25	3	1942	1994	52
298	Enka	NC	0.30	GEN8	1984	2001	17
299	Enka	NC	5.00	GE12	1959	2001	42
300	Enka	NC	4.00	GE11	1957	2001	44
301	Enka	NC	4.00	GE10	1948	2001	53
302	Enka	NC	3.00	GEN9	1937	2001	64
303	Kannapolis Energy PRTNR Spencer	NC	2.50	GEN3	1965	2000	35
304	Kannapolis Energy PRTNR Spencer	NC	1.00	GEN1	1939	2000	61
305	Kannapolis Energy PTNRS	NC	15.00	GEN3	1971	2003	32
306	Kannapolis Energy PTNRS	NC	7.50	GEN2	1950	2003	53
307	Plymouth (NC)	NC	7.50	TG6	1956	2006	50
308	Plymouth (NC)	NC	7.50	TG4	1949	2002	53
309	Riverbend (NC)	NC	55.00	1	1929	1981	52
310	Riverbend (NC)	NC	55.00	2	1929	1981	52
311	Tobaccoville Utility Plant	NC	40.30	GEN1	1985	2004	19

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
312	Tobaccoville Utility Plant	NC	40.30	GEN2	1985	2004	19
313	Beulah	ND	7.50	3	1949	1986	37
314	Beulah	ND	2.50	1	1927	1985	58
315	Beulah	ND	3.50	2	1927	1985	58
316	Drayton (MNKOTA)	ND	6.80	1	1965	2002	37
317	G F Wood	ND	5.00	1	1949	1983	34
318	G F Wood	ND	11.50	3	1951	1985	34
319	G F Wood	ND	5.00	2	1950	1985	35
320	William J Neal	ND	25.00	1	1952	1991	39
321	William J Neal	ND	25.00	2	1952	1991	39
322	Fremont 1	NE	10.00	5	1950	1976	26
323	Fremont 1	NE	5.00	4	1946	1976	30
324	Fremont 1	NE	3.00	3	1932	1976	44
325	Fremont 1	NE	3.00	1	1928	1976	48
326	Fremont 1	NE	2.00	2	1924	1976	52
327	Harold Kramer	NE	45.50	3	1951	1991	40
328	Harold Kramer	NE	45.50	1	1949	1991	42
329	Harold Kramer	NE	45.50	2	1949	1991	42
330	Jones St	NE	10.00	10	1937	1974	37
331	Jones St	NE	25.00	9	1929	1974	45
332	Jones St	NE	20.00	8	1925	1974	49
333	Jones St	NE	20.00	7	1921	1974	53
334	Jones St	NE	15.00	6	1917	1974	57
335	Deepwater (NJ)	NJ	27.20	7	1957	1994	37
336	Deepwater (NJ)	NJ	20.00	5	1942	1994	52
337	Howard M Down	NJ	4.00	4	1936	1979	43
338	Missouri Avenue	NJ	29.00	6	1950	1974	24
339	Missouri Avenue	NJ	29.00	7	1950	1974	24
340	Raton	NM	1.50	3	1937	1970	33
341	Raton	NM	0.80	1	1937	1977	40
342	Raton	NM	0.80	2	1937	1977	40
343	Raton	NM	3.70	4	1951	1996	45
344	Mohave (NV)	NV	818.10	1	1971	2005	34
345	Mohave (NV)	NV	818.10	2	1971	2005	34
346	AES Greenidge	NY	20.00	2	1942	1985	43
347	AES Greenidge	NY	20.00	1	1938	1985	47
348	AES Westover	NY	30.00	6	1900	1972	72
349	Deferiet New York	NY	8.10	WEST	1946	2007	61
350	Huntley Generating	NY	100.00	66	1954	2007	53
351	Huntley Generating	NY	100.00	65	1953	2007	54
352	Huntley Generating	NY	100.00	64	1948	2005	57
353	Huntley Generating	NY	80.00	63	1942	2003	61
354	Kodak Park Site	NY	6.30	12TG	1941	2000	59
355	Lovett	NY	200.60	LOV5	1969	2008	39
356	Lovett	NY	179.50	LOV4	1966	2007	41
357	Rochester Beebee	NY	81.60	12	1959	1999	40
358	Russell Station	NY	81.60	4	1957	2008	51
359	Russell Station	NY	62.50	3	1953	2008	55
360	Russell Station	NY	62.50	2	1950	2008	58
361	Russell Station	NY	46.00	1	1948	2008	60
362	Samuel A Carlson	NY	15.00	3	1938	1983	45
363	Samuel A Carlson	NY	13.00	4	1930	1978	48

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(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
364	Samuel A Carlson	NY	5.00	2	1924	1973	49
365	Acme (OH)	OH	6.00	TOPR	1973	1992	19
366	Acme (OH)	OH	112.50	6	1949	1992	43
367	Acme (OH)	OH	72.00	2	1951	1995	44
368	Acme (OH)	OH	72.00	5	1941	1992	51
369	Acme (OH)	OH	25.00	1	1937	1992	55
370	Acme (OH)	OH	35.00	4	1929	1992	63
371	Ashtabula	OH	46.00	6	1972	2003	31
372	Ashtabula	OH	46.00	7	1972	2003	31
373	Ashtabula	OH	46.00	8	1953	2002	49
374	Ashtabula	OH	46.00	9	1953	2003	50
375	Avon Lake	OH	233.00	8	1959	1987	28
376	Avon Lake	OH	50.00	5	1943	1983	40
377	Avon Lake	OH	35.00	4	1929	1983	54
378	Avon Lake	OH	35.00	3	1928	1983	55
379	Avon Lake	OH	35.00	1	1926	1983	57
380	Avon Lake	OH	35.00	2	1926	1983	57
381	Columbus (OH)	OH	15.00	8	1966	1987	21
382	Columbus (OH)	OH	13.00	6	1950	1977	27
383	Columbus (OH)	OH	13.00	7	1957	1987	30
384	Columbus (OH)	OH	8.00	1	1929	1977	48
385	Columbus (OH)	OH	8.00	3	1925	1987	62
386	Conesville	OH	148.00	1	1959	2006	47
387	Conesville	OH	136.00	2	1957	2006	49
388	Dover (OH)	OH	4.00	2	1944	2007	63
389	East Palestine	OH	7.50	4	1962	1982	20
390	East Palestine	OH	5.00	3	1950	1982	32
391	East Palestine	OH	2.50	1	1945	1982	37
392	East Palestine	OH	1.50	2	1935	1982	47
393	Edgewater (OH)	OH	69.00	3	1949	1993	44
394	Edgewater (OH)	OH	20.00	2	1924	1983	59
395	Frank M Tait	OH	147.05	5	1959	1987	28
396	Frank M Tait	OH	147.05	4	1958	1987	29
397	Goodyear	OH	7.50	T 3	1984	2006	22
398	Goodyear	OH	12.50	T 2	1977	2006	29
399	Goodyear	OH	7.50	T 1	1975	2006	31
400	Goodyear	OH	12.50	T 4	1953	2006	53
401	Gorge (OH)	OH	40.24	7	1948	1993	45
402	Gorge (OH)	OH	40.24	6	1943	1993	50
403	Hamilton	OH	10.00	4	1976	1986	10
404	Hamilton	OH	3.00	1	1929	1975	46
405	Hamilton	OH	3.00	2	1929	1975	46
406	Hamilton	OH	7.50	3	1929	1986	57
407	Lake Road (OH)	OH	85.00	11	1967	1993	26
408	Mad River	OH	23.00	3	1949	1985	36
409	Mad River	OH	20.00	2	1938	1985	47
410	Mad River	OH	25.00	1	1927	1985	58
411	McCracken Power Plant	OH	3.10	NO2	1988	2005	17
412	McCracken Power Plant	OH	5.00	NO1	1951	2005	54
413	Miami Fort	OH	65.00	4	1942	1982	40
414	Miami Fort	OH	65.00	3	1938	1982	44
415	Norwalk (OH)	OH	18.00	5	1969	1982	13

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(continued)
Age at Retirement
Units Retired from Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
416	Norwalk (OH)	OH	6.00	4	1957	1982	25
417	Norwalk (OH)	OH	3.00	3	1949	1982	33
418	Norwalk (OH)	OH	3.00	2	1938	1982	44
419	Orrville	OH	2.50	6	1940	1984	44
420	Orrville	OH	1.50	5	1928	1984	56
421	Painesville	OH	25.00	6	1976	1989	13
422	Painesville	OH	3.00	2	1946	1983	37
423	Painesville	OH	3.00	1	1941	1983	42
424	Philo	OH	125.00	6	1957	1975	18
425	Philo	OH	85.00	4	1942	1975	33
426	Philo	OH	85.00	5	1942	1975	33
427	Philo	OH	40.00	2	1928	1975	47
428	Philo	OH	109.00	3	1928	1975	47
429	Picway	OH	34.50	4	1949	1980	31
430	Picway	OH	30.00	3	1943	1980	37
431	Piqua	OH	0.80	10	1987	2007	20
432	Piqua	OH	1.00	5	1947	1987	40
433	Piqua	OH	4.00	1	1933	1975	42
434	Piqua	OH	4.00	2	1933	1975	42
435	Piqua	OH	20.00	7	1961	2007	46
436	Piqua	OH	12.50	6	1951	2007	56
437	Piqua	OH	7.50	4	1947	2007	60
438	Piqua	OH	4.00	3	1940	2007	67
439	Poston	OH	75.00	4	1954	1987	33
440	Poston	OH	69.00	3	1952	1987	35
441	Poston	OH	44.00	2	1950	1987	37
442	Poston	OH	44.00	1	1949	1987	38
443	R E Burger	OH	62.50	2	1947	1994	47
444	R E Burger	OH	62.50	1	1944	1994	50
445	Shelby Munic Light Plant	OH	12.50	1	1967	1999	32
446	St Marys (OH)	OH	10.00	6	1967	2007	40
447	St Marys (OH)	OH	2.50	4	1946	1996	50
448	St Marys (OH)	OH	6.00	5	1957	2007	50
449	Tidd P FBC	OH	115.00	2	1948	1979	31
450	Tidd P FBC	OH	70.00	1	1903	1995	92
451	Toronto	OH	69.00	6	1949	2003	54
452	Toronto	OH	69.00	7	1949	2003	54
453	Toronto	OH	35.00	5	1940	2003	63
454	Woodcock	OH	10.00	5	1950	1979	29
455	Woodcock	OH	10.00	4	1947	1979	32
456	Woodcock	OH	8.00	3	1941	1979	38
457	Woodcock	OH	5.00	1	1938	1979	41
458	Woodcock	OH	5.00	2	1938	1979	41
459	Amalgamated Sugar Nyssa	OR	12.00	1	1987	2005	18
460	Amalgamated Sugar Nyssa	OR	0.50	3	1942	2005	63
461	Amalgamated Sugar Nyssa	OR	1.50	2	1942	2005	63
462	Crawford (PA)	PA	35.00	2	1926	1978	52
463	Crawford (PA)	PA	35.00	1	1924	1978	54
464	Crawford (PA)	PA	5.00	4	1900	1977	77
465	Crawford (PA)	PA	42.00	3	1900	1977	77
466	Erie Mill	PA	14.00	GEN8	1971	2002	31
467	Erie Mill	PA	19.00	GEN7	1971	2002	31

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
468	Erie Mill	PA	4.00	GEN4	1936	2002	66
469	Erie Mill	PA	7.50	GEN6	1936	2002	66
470	F R Phillips	PA	179.00	4	1956	2000	44
471	F R Phillips	PA	81.00	3	1950	2000	50
472	F R Phillips	PA	81.00	2	1949	2000	51
473	F R Phillips	PA	69.00	1	1943	2000	57
474	Front Street (PA)	PA	18.80	1	1953	1991	38
475	Front Street (PA)	PA	50.00	5	1952	1991	39
476	Front Street (PA)	PA	28.80	4	1944	1991	47
477	Front Street (PA)	PA	15.00	3	1928	1991	63
478	Front Street (PA)	PA	10.00	2	1917	1991	74
479	General Electric Erie PA Power	PA	14.00	STM3	1949	2003	54
480	General Electric Erie PA Power	PA	9.00	STM4	1939	2003	64
481	General Electric Erie PA Power	PA	5.00	STM2	1929	2003	74
482	Holtwood	PA	15.00	15	1900	1972	72
483	Holtwood	PA	15.00	16	1900	1972	72
484	Hunlock Power Station	PA	23.00	1	1959	1974	15
485	Lock Haven Mill	PA	24.70	GEN4	1984	2002	18
486	Lock Haven Mill	PA	5.00	GEN3	1946	2002	56
487	Lock Haven Mill	PA	5.00	GEN1	1938	2002	64
488	Martins Creek	PA	156.20	MC2	1956	2007	51
489	Martins Creek	PA	156.20	MC1	1954	2007	53
490	New Castle Plant	PA	35.00	2	1947	1993	46
491	New Castle Plant	PA	35.00	1	1939	1993	54
492	Richmond Generating Station	PA	165.00	12	1935	1983	48
493	Saxton	PA	11.00	2	1900	1979	79
494	Saxton	PA	37.00	3	1900	1979	79
495	Seward	PA	27.00	2	1942	1980	38
496	Seward	PA	35.00	3	1942	1980	38
497	Seward	PA	156.20	5	1957	2003	46
498	Seward	PA	62.00	4	1950	2003	53
499	Shippingport	PA	100.00	1	1957	1982	25
500	Sonoco Products Co	PA	2.50	2	1952	2005	53
501	Warren (PA)	PA	42.00	2	1949	2002	53
502	Warren (PA)	PA	42.00	1	1948	2002	54
503	Williamsburg	PA	28.30	5	1944	1991	47
504	Williamsburg	PA	6.00	1	1900	1990	90
505	Williamsburg	PA	9.00	3	1900	1990	90
506	Lockhart	SC	5.00	1	1921	1977	56
507	Kirk (SD)	SD	5.00	3	1961	1993	32
508	Kirk (SD)	SD	16.50	4	1956	1996	40
509	Kirk (SD)	SD	5.00	1	1935	1993	58
510	Kirk (SD)	SD	5.00	2	1935	1993	58
511	Lawrence (SD)	SD	23.00	3	1951	1977	26
512	Lawrence (SD)	SD	13.00	2	1949	1977	28
513	Lawrence (SD)	SD	12.00	1	1948	1977	29
514	Mitchell (SD)	SD	8.00	1	1948	1979	31
515	Mitchell (SD)	SD	8.00	3	1948	1979	31
516	Mitchell (SD)	SD	5.00	2	1929	1977	48
517	Mobridge	SD	8.00	2	1950	1977	27
518	Kingsport Mill	TN	4.00	NO4	1937	1999	62
519	Lowland	TN	0.30	GEN4	1985	2005	20

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
520	Lowland	TN	5.00	GEN3	1951	2005	54
521	Lowland	TN	5.00	GEN5	1951	2005	54
522	Lowland	TN	5.00	GEN1	1947	2005	58
523	Lowland	TN	5.00	GEN2	1947	2005	58
524	Old Hickory Plant	TN	3.00	G10	1933	2002	69
525	Sandow	TX	121.00	GEN2	1954	2006	52
526	Sandow	TX	121.00	GEN3	1954	2006	52
527	Sandow	TX	121.00	GEN1	1953	2006	53
528	Cedar	UT	7.50	1	1945	1987	42
529	Cedar	UT	7.50	2	1945	1987	42
530	Geneva Steel	UT	50.00	GEN1	1944	2002	58
531	Hale	UT	46.00	2	1950	1991	41
532	Hale	UT	15.00	1	1936	1979	43
533	Provo	UT	2.50	3	1941	1989	48
534	Provo	UT	2.00	1	1940	1989	49
535	Provo	UT	2.00	2	1940	1989	49
536	Brantly	VA	11.00	3	1953	1980	27
537	Brantly	VA	11.00	2	1952	1980	28
538	Brantly	VA	6.00	1	1949	1980	31
539	Chesterfield	VA	69.00	2	1949	1981	32
540	Dan River (VA)	VA	6.00	GEN2	1952	2006	54
541	Dan River (VA)	VA	3.00	GEN1	1947	2006	59
542	Glen Lyn	VA	34.00	4	1927	1974	47
543	Glen Lyn	VA	34.00	3	1924	1974	50
544	Rock Tenn Co (VA)	VA	2.00	1	1977	2000	23
545	J Edward Moran	VT	10.00	2	1954	1985	31
546	Longview (WA COWLITZ)	WA	3.00	5	1900	1973	73
547	Longview (WA COWLITZ)	WA	8.00	1	1900	1973	73
548	Longview (WA COWLITZ)	WA	8.00	2	1900	1973	73
549	Longview (WA COWLITZ)	WA	8.00	4	1900	1973	73
550	Longview (WA COWLITZ)	WA	8.00	3	1900	1974	74
551	Washington State Univ	WA	2.00	GEN1	1963	2005	42
552	Bay Front	WI	5.00	3	1925	1986	61
553	Columbus Street	WI	10.00	3	1941	2003	62
554	Columbus Street	WI	5.00	2	1935	2003	68
555	East Wells	WI	15.00	1	1939	1982	43
556	Edgewater (WI)	WI	30.00	2	1942	1985	43
557	Edgewater (WI)	WI	30.00	1	1931	1980	49
558	Green Bay West Mill	WI	25.00	GEN8	1977	2004	27
559	Green Bay West Mill	WI	2.50	GEN4	1947	2002	55
560	Green Bay West Mill	WI	3.00	GEN3	1940	2002	62
561	Green Bay West Mill	WI	3.00	GEN2	1933	2002	69
562	Green Bay West Mill	WI	1.50	GEN1	1929	2002	73
563	Menasha (MNSHA)	WI	4.00	1	1949	1989	40
564	Menasha (MNSHA)	WI	4.00	2	1949	1989	40
565	North Oak Creek	WI	130.00	4	1957	1988	31
566	North Oak Creek	WI	130.00	3	1955	1988	33
567	North Oak Creek	WI	120.00	2	1954	1989	35
568	North Oak Creek	WI	120.00	1	1953	1989	36
569	Port Washington	WI	80.00	5	1950	1991	41
570	Port Washington	WI	80.00	4	1949	2002	53
571	Port Washington	WI	80.00	3	1948	2004	56

Appendix A-2
(continued)
Age at Retirement
Units Retired from Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
572	Port Washington	WI	80.00	2	1943	2004	61
573	Port Washington	WI	80.00	1	1935	2004	69
574	Pulliam	WI	30.00	4	1947	2007	60
575	Pulliam	WI	30.00	3	1943	2007	64
576	Richland Center	WI	7.50	4	1966	1987	21
577	Richland Center	WI	4.00	3	1953	1987	34
578	Richland Center	WI	1.50	2	1939	1985	46
579	Richland Center	WI	1.25	1	1937	1985	48
580	Wildwood	WI	16.50	5	1968	1994	26
581	Wildwood	WI	12.50	4	1962	1994	32
582	Cabin Creek (WV)	WV	85.00	9	1943	1981	38
583	Cabin Creek (WV)	WV	85.00	8	1942	1981	39
584	Cabin Creek (WV)	WV	22.00	4	1921	1974	53
585	Cabin Creek (WV)	WV	25.00	3	1919	1974	55
586	Rivesville	WV	11.00	1	1900	1973	73
587	Rivesville	WV	13.00	2	1900	1973	73
588	Rivesville	WV	22.00	3	1900	1973	73
589	Rivesville	WV	27.00	4	1900	1973	73
590	Windsor	WV	60.00	7	1941	1975	34
591	Windsor	WV	60.00	8	1941	1975	34
592	Neil Simpson	WY	3.00	1	1961	1980	19
593	Neil Simpson	WY	2.00	4	1948	1982	34
594	Neil Simpson	WY	1.00	2	1928	1980	52

Appendix A-3
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1	Number of Units			1,439		
2	Maximum		1,425.60		2009	88
3	Minimum		0.40		1921	0
4	Median		150.00		1967	42
5	Average		243.77			41
6	Standard Deviation		260.52			15
7	95% Confidence Limit					
8	Maximum		754.40			70
9	Minimum		(266.86)			12
10	A E Staley Decatur Plant Cogeneration	IL	62.00	GEN1	1989	20
11	Sagamore Plant Cogeneration	IN	7.40	GEN1	1984	25
12	ACE Cogeneration Co	CA	108.00	GEN1	1990	19
13	AES Beaver Valley Partners Beaver Valley	PA	35.00	GEN2	1987	22
14	AES Beaver Valley Partners Beaver Valley	PA	114.00	GEN3	1987	22
15	AES Cayuga	NY	155.30	CAY1	1955	54
16	AES Cayuga	NY	167.20	CAY2	1955	54
17	AES Greenidge	NY	50.00	3	1950	59
18	AES Greenidge	NY	112.50	4	1953	56
19	AES Hawaii	HI	203.00	GEN1	1992	17
20	Aurora (PR)	PR	227.00	1	2002	7
21	Aurora (PR)	PR	227.00	2	2002	7
22	AES Shady Point Inc	OK	175.00	GEN1	1990	19
23	AES Shady Point Inc	OK	175.00	GEN2	1990	19
24	AES Somerset LLC	NY	655.10	GEN1	1984	25
25	AES Thames	CT	213.90	GEN1	1989	20
26	AES Warrior Run Cogeneration F	MD	229.00	GEN1	1999	10
27	AES Westover	NY	43.80	7	1943	66
28	AES Westover	NY	75.00	8	1951	58
29	Ag Processing Inc	IA	8.50	EC	1982	27
30	Stockton Cogeneration Co	CA	60.00	GEN1	1988	21
31	Charles R Lowman	AL	66.00	1	1969	40
32	Charles R Lowman	AL	236.00	2	1978	31
33	Charles R Lowman	AL	236.00	3	1980	29
34	E C Gaston	AL	272.00	1	1960	49
35	E C Gaston	AL	272.00	2	1960	49
36	E C Gaston	AL	272.00	3	1961	48
37	E C Gaston	AL	952.00	5	1974	35
38	E C Gaston	AL	244.80	ST4	1962	47
39	Gadsden	AL	69.00	1	1949	60
40	Gadsden	AL	69.00	2	1949	60
41	Gorgas 2 & 3	AL	788.80	10	1972	37
42	Gorgas 2 & 3	AL	125.00	6	1951	58
43	Gorgas 2 & 3	AL	125.00	7	1952	57
44	Gorgas 2 & 3	AL	187.50	8	1956	53
45	Gorgas 2 & 3	AL	190.40	9	1958	51
46	Greene County (AL)	AL	299.20	1	1965	44
47	Greene County (AL)	AL	269.20	2	1966	43
48	James H Miller Jr	AL	705.50	1	1978	31
49	James H Miller Jr	AL	705.50	2	1985	24
50	James H Miller Jr	AL	705.50	3	1989	20
51	James H Miller Jr	AL	705.50	4	1991	18
52	James M Barry Electric Generating Plant	AL	153.10	1	1954	55
53	James M Barry Electric Generating Plant	AL	153.10	2	1954	55
54	James M Barry Electric Generating Plant	AL	272.00	3	1959	50
55	James M Barry Electric Generating Plant	AL	403.70	4	1969	40

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
56	James M Barry Electric Generating Plant	AL	788.80	5	1971	38
57	Warrick	IN	144.00	1	1960	49
58	Warrick	IN	144.00	2	1964	45
59	Warrick	IN	144.00	3	1965	44
60	Warrick	IN	323.00	4	1970	39
61	Armstrong Power Station	PA	163.20	ARM1	1958	51
62	Armstrong Power Station	PA	163.20	ARM2	1959	50
63	Hatfields Ferry Power Station	PA	576.00	1	1969	40
64	Hatfields Ferry Power Station	PA	576.00	2	1970	39
65	Hatfields Ferry Power Station	PA	576.00	3	1971	38
66	Mitchell Power Station	PA	299.20	3	1963	46
67	R Paul Smith Power Station	MD	75.00	11	1958	51
68	R Paul Smith Power Station	MD	34.50	9	1947	62
69	Clay Boswell	MN	75.00	1	1958	51
70	Clay Boswell	MN	75.00	2	1960	49
71	Clay Boswell	MN	364.50	3	1973	36
72	Clay Boswell	MN	558.00	4	1980	29
73	Syl Laskin	MN	58.00	1	1953	56
74	Syl Laskin	MN	58.00	2	1953	56
75	Taconite Harbor Energy Center	MN	84.00	GEN1	1957	52
76	Taconite Harbor Energy Center	MN	84.00	GEN2	1957	52
77	Taconite Harbor Energy Center	MN	84.00	GEN3	1967	42
78	Amalgamated Sugar Co LLC (The)	ID	1.50	1500	1948	61
79	Amalgamated Sugar Co LLC (The)	ID	2.50	2500	1948	61
80	Amalgamated Sugar Co LLC (The)	ID	6.20	4000	1994	15
81	Amalgamated Sugar Co LLC Nampa	ID	2.20	2250	1948	61
82	Amalgamated Sugar Co LLC Nampa	ID	6.00	6500	1968	41
83	Coffeen	IL	388.90	1	1965	44
84	Coffeen	IL	616.50	2	1972	37
85	Hutsonville	IL	75.00	3	1953	56
86	Hutsonville	IL	75.00	4	1954	55
87	Meredosia	IL	57.50	1	1948	61
88	Meredosia	IL	57.50	2	1949	60
89	Meredosia	IL	239.30	3	1960	49
90	Newton (IL)	IL	617.40	1	1977	32
91	Newton (IL)	IL	617.40	2	1982	27
92	Duck Creek	IL	441.00	1	1976	33
93	E D Edwards	IL	136.00	1	1960	49
94	E D Edwards	IL	280.50	2	1968	41
95	E D Edwards	IL	363.80	3	1972	37
96	Labadie	MO	573.70	1	1970	39
97	Labadie	MO	573.70	2	1971	38
98	Labadie	MO	621.00	3	1972	37
99	Labadie	MO	621.00	4	1973	36
100	Meramec	MO	137.50	1	1953	56
101	Meramec	MO	137.50	2	1954	55
102	Meramec	MO	289.00	3	1959	50
103	Meramec	MO	359.00	4	1961	48
104	Rush Island	MO	621.00	1	1976	33
105	Rush Island	MO	621.00	2	1977	32
106	Sioux	MO	549.70	1	1967	42
107	Sioux	MO	549.70	2	1968	41
108	ACS Crookston	MN	3.50	G1	1954	55
109	ACS Crookston	MN	3.00	G2	1975	34
110	ACS Drayton	ND	6.00	G1	1965	44
111	ACS East Grand Forks	MN	2.50	G1	1990	19
112	ACS East Grand Forks	MN	5.00	G2	1990	19
113	ACS Hillsboro	ND	13.30	G1	1990	19
114	ACS Moorhead	MN	3.00	G1	1948	61
115	ACS Moorhead	MN	2.00	G2	1961	48

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
116	Richard H Gorsuch	OH	50.00	1	1988	21
117	Richard H Gorsuch	OH	50.00	2	1988	21
118	Richard H Gorsuch	OH	50.00	3	1988	21
119	Richard H Gorsuch	OH	50.00	4	1988	21
120	Ames Electric Services Power Plant (Ia Ames)	IA	71.30	ST6	1982	27
121	Anheuser Busch Inc St Louis	MO	11.00	GEN1	1947	62
122	Anheuser Busch Inc St Louis	MO	11.00	GEN3	1948	61
123	Anheuser Busch Inc St Louis	MO	4.10	GEN4	1939	70
124	Clinch River	VA	237.50	1	1958	51
125	Clinch River	VA	237.50	2	1958	51
126	Clinch River	VA	237.50	3	1961	48
127	Glen Lyn	VA	100.00	5	1944	65
128	Glen Lyn	VA	237.50	6	1957	52
129	John E Amos	WV	816.30	1	1971	38
130	John E Amos	WV	816.30	2	1972	37
131	John E Amos	WV	1,300.00	3	1973	36
132	Kanawha River	WV	219.60	1	1953	56
133	Kanawha River	WV	219.60	2	1953	56
134	Mountaineer	WV	1,300.00	1	1980	29
135	Phil Sporn	WV	152.50	1	1950	59
136	Phil Sporn	WV	152.50	2	1950	59
137	Phil Sporn	WV	152.50	3	1951	58
138	Phil Sporn	WV	152.50	4	1952	57
139	Phil Sporn	WV	495.50	5	1960	49
140	Lake Road (MO)	MO	90.00	4	1966	43
141	Sibley (MO)	MO	55.00	1	1960	49
142	Sibley (MO)	MO	50.00	2	1962	47
143	Sibley (MO)	MO	419.00	3	1969	40
144	Archer Daniels Midland Cedar Rapids	IA	31.00	GEN1	1988	21
145	Archer Daniels Midland Cedar Rapids	IA	31.00	GEN2	1988	21
146	Archer Daniels Midland Cedar Rapids	IA	31.00	GEN3	1988	21
147	Archer Daniels Midland Cedar Rapids	IA	31.00	GEN4	1988	21
148	Archer Daniels Midland Cedar Rapids	IA	31.00	GEN5	1995	14
149	Archer Daniels Midland Cedar Rapids	IA	101.10	GEN6	2000	9
150	Archer Daniels Midland Mankato	MN	6.10	GEN1	1987	22
151	Clinton (IA ADM)	IA	7.50	GEN1	1954	55
152	Clinton (IA ADM)	IA	3.50	GEN2	1940	69
153	Clinton (IA ADM)	IA	9.40	GEN3	1965	44
154	Clinton (IA ADM)	IA	4.00	GEN4	1974	35
155	Clinton (IA ADM)	IA	7.00	GEN5	1991	18
156	Decatur (IL ADM)	IL	31.00	GEN2	1987	22
157	Decatur (IL ADM)	IL	31.00	GEN3	1987	22
158	Decatur (IL ADM)	IL	31.00	GEN4	1987	22
159	Decatur (IL ADM)	IL	31.00	GEN5	1987	22
160	Decatur (IL ADM)	IL	31.00	GEN6	1994	15
161	Decatur (IL ADM)	IL	75.00	GEN7	1997	12
162	Decatur (IL ADM)	IL	105.00	GEN8	2004	5
163	Des Moines (IA ADM)	IA	7.90	GEN1	1988	21
164	Lincoln (NE)	NE	7.90	GEN1	1988	21
165	Peoria (IL)	IL	1.50	GEN1	1934	75
166	Peoria (IL)	IL	1.50	GEN2	1934	75
167	Peoria (IL)	IL	4.00	GEN3	1954	55
168	Peoria (IL)	IL	4.00	GEN4	1985	24
169	Apache Station	AZ	204.00	ST2	1979	30
170	Apache Station	AZ	204.00	ST3	1979	30
171	Cholla	AZ	113.60	1	1962	47
172	Cholla	AZ	288.90	2	1978	31
173	Cholla	AZ	312.30	3	1980	29

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
174	Cholla	AZ	414.00	4	1981	28
175	Four Corners	NM	190.00	1	1963	46
176	Four Corners	NM	190.00	2	1963	46
177	Four Corners	NM	253.40	3	1964	45
178	Four Corners	NM	818.10	4	1969	40
179	Four Corners	NM	818.10	5	1970	39
180	New Madrid (Memphis)	MO	600.00	1	1972	37
181	New Madrid (Memphis)	MO	600.00	2	1977	32
182	Thomas Hill	MO	180.00	1	1966	43
183	Thomas Hill	MO	285.00	2	1969	40
184	Thomas Hill	MO	670.00	3	1982	27
185	Battle River	AB	158.50	3	1969	40
186	Battle River	AB	158.50	4	1981	28
187	Battle River	AB	375.00	5	1981	28
188	Sheerness	AB	389.00	1	1986	23
189	Sheerness	AB	383.00	2	1990	19
190	Deepwater (NJ)	NJ	73.50	6	1954	55
191	Chena	AK	5.00	1	1952	57
192	Chena	AK	2.50	2	1952	57
193	Chena	AK	20.00	5	1975	34
194	Austin Northeast Station (MN)	MN	31.90	1	1971	38
195	Antelope Valley	ND	434.90	1	1984	25
196	Antelope Valley	ND	434.90	2	1986	23
197	Laramie River	WY	570.00	1	1981	28
198	Laramie River	WY	570.00	2	1981	28
199	Laramie River	WY	570.00	3	1982	27
200	Leland Olds 1 & 2	ND	216.00	1	1966	43
201	Leland Olds 1 & 2	ND	440.00	2	1975	34
202	HMP & L Station 2	KY	180.00	GEN1	1973	36
203	HMP & L Station 2	KY	185.00	GEN2	1974	35
204	W N Clark	CO	18.70	1	1955	54
205	W N Clark	CO	25.00	2	1959	50
206	Ben French	SD	25.00	ST1	1961	48
207	Neil Simpson	WY	21.70	5	1969	40
208	Neil Simpson II	WY	80.00	2	1995	14
209	Osage (WY)	WY	11.50	1	1948	61
210	Osage (WY)	WY	11.50	2	1949	60
211	Osage (WY)	WY	11.50	3	1952	57
212	Wygen	WY	88.00	1	2003	6
213	Black River Generation	NY	55.50	GEN1	1989	20
214	Canton North Carolina	NC	7.50	GEN8	1937	72
215	Canton North Carolina	NC	7.50	GEN9	1941	68
216	Canton North Carolina	NC	7.50	GN10	1946	63
217	Canton North Carolina	NC	7.50	GN11	1949	60
218	Canton North Carolina	NC	10.00	GN12	1952	57
219	Canton North Carolina	NC	12.50	GN13	1979	30
220	Bowater Newsprint Calhoun Operations	TN	19.00	GEN1	1954	55
221	Bowater Newsprint Calhoun Operations	TN	19.20	GEN2	1954	55
222	U S Alliance Coosa Pines	AL	5.00	AOW1	1942	67
223	U S Alliance Coosa Pines	AL	5.00	AOW2	1942	67
224	U S Alliance Coosa Pines	AL	5.00	AOW4	1942	67
225	U S Alliance Coosa Pines	AL	5.00	AOW5	1942	67
226	Bunge Milling Cogeneration Inc	IL	20.00	GEN1	1989	20
227	Rittman Paperboard	OH	5.00	GEN2	1940	69
228	Cardinal	OH	615.20	1	1967	42
229	Cardinal	OH	615.20	2	1967	42
230	Cardinal	OH	650.00	3	1977	32
231	Cargill Salt Inc	MI	2.00	ACTG	1968	41

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
232	Corn Wet Milling Plant	TN	25.00	GEN1	1985	24
233	Cargill Inc Corn Milling Divis	IA	20.00	GEN2	1952	57
234	Catalyst Paper Snowflake	AZ	27.20	GEN1	1961	48
235	Catalyst Paper Snowflake	AZ	43.30	GEN2	1974	35
236	Cinergy Solutions of Narrows	VA	6.00	GEN1	1942	67
237	Cinergy Solutions of Narrows	VA	6.00	GEN2	1942	67
238	Cinergy Solutions of Narrows	VA	6.00	GEN3	1944	65
239	Cinergy Solutions of Narrows	VA	9.20	GEN4	1966	43
240	Menominee Aquisition Corp	MI	2.50	ST2	1950	59
241	Chamois	MO	15.00	1	1953	56
242	Chamois	MO	44.00	2	1960	49
243	Fair Station	IA	25.00	1	1960	49
244	Fair Station	IA	37.50	2	1967	42
245	Central Soya Co Inc	IN	2.00	3516	1950	59
246	Carneys Point Generating Plant	NJ	285.00	GEN1	1993	16
247	Wygen II	WY	90.00	ST1	2008	1
248	Red Hills Generating Facility	MS	513.70	RHGF	2002	7
249	G F Weaton Power Station	PA	60.00	GEN1	1958	51
250	G F Weaton Power Station	PA	60.00	GEN2	1958	51
251	Perry K	IN	15.00	4	1925	84
252	Perry K	IN	5.00	6	1938	71
253	Dolet Hills	LA	720.70	1	1986	23
254	Rodemacher	LA	558.00	2	1982	27
255	Silver Bay Power Co	MN	50.00	GEN1	1955	54
256	Silver Bay Power Co	MN	81.60	GEN2	1962	47
257	Cedar Bay Generating Co LP	FL	291.60	GEN1	1993	16
258	Logan Generating Plant	NJ	242.30	GEN1	1994	15
259	Portsmouth Cogeneration Plant	VA	57.40	GEN1	1988	21
260	Portsmouth Cogeneration Plant	VA	57.40	GEN2	1988	21
261	Centennial Hardin (MT)	MT	115.70	ST1	2006	3
262	Trigen Colorado	CO	7.50	GEN1	1976	33
263	Trigen Colorado	CO	7.50	GEN2	1977	32
264	Trigen Colorado	CO	20.00	GEN3	1983	26
265	Trigen Colorado	CO	0.40	VBPT	1997	12
266	Martin Drake	CO	50.00	5	1962	47
267	Martin Drake	CO	75.00	6	1968	41
268	Martin Drake	CO	132.00	7	1974	35
269	Ray D Nixon	CO	207.00	ST1	1980	29
270	Columbia (MO CLMBIA)	MO	16.50	5	1957	52
271	Columbia (MO CLMBIA)	MO	22.00	7	1965	44
272	Conesville	OH	161.50	3	1962	47
273	Conesville	OH	841.50	4	1973	36
274	Conesville	OH	443.90	5	1976	33
275	Conesville	OH	443.90	6	1978	31
276	Picway	OH	106.20	5	1955	54
277	Carbon II	COA	350.00	1	1993	16
278	Carbon II	COA	350.00	2	1993	16
279	Carbon II	COA	350.00	3	1995	14
280	Carbon II	COA	350.00	4	1996	13
281	Jose Lopez Portillo (Rio Escondido)	COA	300.00	1	1982	27
282	Jose Lopez Portillo (Rio Escondido)	COA	300.00	2	1983	26
283	Jose Lopez Portillo (Rio Escondido)	COA	300.00	3	1985	24
284	Jose Lopez Portillo (Rio Escondido)	COA	300.00	4	1987	22
285	Edge Moor	DE	75.00	EM3	1954	55
286	Edge Moor	DE	176.80	EM4	1966	43
287	Brandon Shores	MD	685.00	1	1984	25
288	Brandon Shores	MD	685.00	2	1991	18
289	C P Crane	MD	190.40	1	1961	48

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
290	C P Crane	MD	209.40	2	1963	46
291	Herbert A Wagner	MD	136.00	2	1959	50
292	Herbert A Wagner	MD	359.00	3	1966	43
293	B C Cobb	MI	156.30	4	1956	53
294	B C Cobb	MI	156.30	5	1957	52
295	D E Karn	MI	272.00	1	1959	50
296	D E Karn	MI	272.00	2	1961	48
297	J C Weadock	MI	156.30	7	1955	54
298	J C Weadock	MI	156.30	8	1958	51
299	J H Campbell	MI	265.20	1	1962	47
300	J H Campbell	MI	403.90	2	1967	42
301	J H Campbell	MI	916.80	3	1980	29
302	J R Whiting	MI	106.30	1	1952	57
303	J R Whiting	MI	106.30	2	1952	57
304	J R Whiting	MI	132.80	3	1953	56
305	Earl F Wisdom	IA	33.00	ST1	1960	49
306	Corn Products International	IL	22.50	TGO1	1991	18
307	Corn Products International	IL	22.50	TGO2	1991	18
308	Corn Products Winston Salem	NC	0.90	900	1993	16
309	Cornell Univ Central Heating	NY	1.80	TG1	1988	21
310	Cornell Univ Central Heating	NY	5.70	TG2	1988	21
311	J K Spruce	TX	566.00	1	1992	17
312	J T Deely	TX	486.00	1	1977	32
313	J T Deely	TX	446.00	2	1978	31
314	Crawfordsville	IN	11.50	4	1955	54
315	Crawfordsville	IN	12.60	5	1965	44
316	Plant Crisp	GA	12.50	1	1957	52
317	Alma	WI	15.00	1	1947	62
318	Alma	WI	15.00	2	1947	62
319	Alma	WI	15.00	3	1951	58
320	Alma	WI	54.40	4	1957	52
321	Alma	WI	81.60	5	1960	49
322	Genoa No3	WI	345.60	ST3	1969	40
323	John P Madgett	WI	387.00	1	1979	30
324	J M Stuart	OH	610.20	1	1971	38
325	J M Stuart	OH	610.20	2	1970	39
326	J M Stuart	OH	610.20	3	1972	37
327	J M Stuart	OH	610.20	4	1974	35
328	Killen Station	OH	660.60	2	1982	27
329	O H Hutchings	OH	69.00	1	1948	61
330	O H Hutchings	OH	69.00	2	1949	60
331	O H Hutchings	OH	69.00	3	1950	59
332	O H Hutchings	OH	69.00	4	1951	58
333	O H Hutchings	OH	69.00	5	1952	57
334	O H Hutchings	OH	69.00	6	1953	56
335	Central Power & Lime Inc	FL	125.00	GEN1	1988	21
336	Bonanza	UT	499.50	1	1986	23
337	Belle River	MI	697.50	ST1	1984	25
338	Belle River	MI	697.50	ST2	1985	24
339	Harbor Beach	MI	121.00	1	1968	41
340	Monroe (MI)	MI	817.20	1	1971	38
341	Monroe (MI)	MI	822.60	2	1973	36
342	Monroe (MI)	MI	822.60	3	1973	36
343	Monroe (MI)	MI	817.20	4	1974	35
344	River Rouge	MI	292.50	2	1957	52
345	River Rouge	MI	358.10	3	1958	51
346	St Clair	MI	168.70	1	1953	56
347	St Clair	MI	156.20	2	1953	56

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
348	St Clair	MI	156.20	3	1954	55
349	St Clair	MI	168.70	4	1954	55
350	St Clair	MI	352.70	6	1961	48
351	St Clair	MI	544.50	7	1969	40
352	Trenton Channel	MI	120.00	7	1949	60
353	Trenton Channel	MI	120.00	8	1950	59
354	Trenton Channel	MI	535.50	9	1968	41
355	Brayton PT	MA	241.00	GEN1	1963	46
356	Brayton PT	MA	241.00	GEN2	1964	45
357	Brayton PT	MA	642.60	GEN3	1958	51
358	Salem Harbor	MA	81.90	GEN1	1952	57
359	Salem Harbor	MA	82.00	GEN2	1952	57
360	Salem Harbor	MA	165.70	GEN3	1958	51
361	Kincaid Generation LLC	IL	659.50	1	1967	42
362	Kincaid Generation LLC	IL	659.50	2	1968	41
363	Dover (OH)	OH	19.50	4	1968	41
364	TS Power Plant	NV	200.00	ST	2008	1
365	Belews Creek	NC	1,080.10	1	1974	35
366	Belews Creek	NC	1,080.10	2	1975	34
367	Buck Steam Station (NC)	NC	80.00	3	1941	68
368	Buck Steam Station (NC)	NC	40.00	4	1942	67
369	Buck Steam Station (NC)	NC	125.00	5	1953	56
370	Buck Steam Station (NC)	NC	125.00	6	1953	56
371	Cliffside	NC	40.00	1	1940	69
372	Cliffside	NC	40.00	2	1940	69
373	Cliffside	NC	65.00	3	1948	61
374	Cliffside	NC	65.00	4	1948	61
375	Cliffside	NC	570.90	5	1972	37
376	Dan River (NC)	NC	70.00	1	1949	60
377	Dan River (NC)	NC	70.00	2	1950	59
378	Dan River (NC)	NC	150.00	3	1955	54
379	G G Allen	NC	165.00	1	1957	52
380	G G Allen	NC	165.00	2	1957	52
381	G G Allen	NC	275.00	3	1959	50
382	G G Allen	NC	275.00	4	1960	49
383	G G Allen	NC	275.00	5	1961	48
384	Marshall (NC DUKE)	NC	350.00	1	1965	44
385	Marshall (NC DUKE)	NC	350.00	2	1966	43
386	Marshall (NC DUKE)	NC	648.00	3	1969	40
387	Marshall (NC DUKE)	NC	648.00	4	1970	39
388	Riverbend (NC)	NC	100.00	4	1952	57
389	Riverbend (NC)	NC	100.00	5	1952	57
390	Riverbend (NC)	NC	133.00	6	1954	55
391	Riverbend (NC)	NC	133.00	7	1954	55
392	W S Lee	SC	90.00	1	1951	58
393	W S Lee	SC	90.00	2	1951	58
394	W S Lee	SC	175.00	3	1958	51
395	Cayuga	IN	531.00	1	1970	39
396	Cayuga	IN	531.00	2	1972	37
397	Edwardsport	IN	40.20	7	1949	60
398	Edwardsport	IN	69.00	8	1951	58
399	Gibson Station	IN	667.90	1	1976	33
400	Gibson Station	IN	667.90	2	1975	34
401	Gibson Station	IN	667.90	3	1978	31
402	Gibson Station	IN	667.90	4	1979	30
403	Gibson Station	IN	667.90	5	1982	27
404	R Gallagher	IN	150.00	1	1959	50
405	R Gallagher	IN	150.00	2	1958	51

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
406	R Gallagher	IN	150.00	3	1960	49
407	R Gallagher	IN	150.00	4	1961	48
408	Wabash River	IN	112.50	2	1953	56
409	Wabash River	IN	123.20	3	1954	55
410	Wabash River	IN	112.50	4	1955	54
411	Wabash River	IN	125.00	5	1956	53
412	Wabash River	IN	387.00	6	1968	41
413	Wabash River	IN	304.50	IGCC	1995	14
414	East Bend	KY	669.30	2	1981	28
415	Miami Fort	OH	100.00	5	1949	60
416	Miami Fort	OH	163.20	6	1960	49
417	Miami Fort	OH	557.10	7	1975	34
418	Miami Fort	OH	557.70	8	1978	31
419	W H Zimmer	OH	1,425.60	ST1	1991	18
420	Walter C Beckjord	OH	115.00	1	1952	57
421	Walter C Beckjord	OH	112.50	2	1953	56
422	Walter C Beckjord	OH	125.00	3	1954	55
423	Walter C Beckjord	OH	163.20	4	1958	51
424	Walter C Beckjord	OH	244.80	5	1962	47
425	Walter C Beckjord	OH	460.80	6	1969	40
426	Baldwin Energy Complex	IL	625.10	1	1970	39
427	Baldwin Energy Complex	IL	634.50	2	1973	36
428	Baldwin Energy Complex	IL	634.50	3	1975	34
429	Havana	IL	488.00	6	1978	31
430	Hennepin Power Station	IL	75.00	1	1953	56
431	Hennepin Power Station	IL	231.30	2	1959	50
432	Vermillion Power Station	IL	73.50	1	1955	54
433	Vermillion Power Station	IL	108.80	2	1956	53
434	Wood River (IL)	IL	112.50	4	1954	55
435	Wood River (IL)	IL	387.60	5	1964	45
436	Danskammer Generating Station	NY	147.10	3	1959	50
437	Danskammer Generating Station	NY	239.40	4	1967	42
438	Kinston North Carolina Plant	NC	7.50	GEN1	1952	57
439	Kinston North Carolina Plant	NC	7.50	GEN2	1952	57
440	May Plant	SC	5.50	GEN1	1952	57
441	May Plant	SC	5.50	GEN2	1952	57
442	May Plant	SC	19.00	GEN3	1993	16
443	Old Hickory Plant	TN	1.00	IG	1993	16
444	Waynesboro Virginia	VA	3.00	GEN2	1929	80
445	Waynesboro Virginia	VA	3.40	GEN4	1929	80
446	Dale (KY)	KY	27.00	1	1954	55
447	Dale (KY)	KY	27.00	2	1954	55
448	Dale (KY)	KY	81.00	3	1957	52
449	Dale (KY)	KY	81.00	4	1960	49
450	Hugh L Spurlock	KY	357.60	1	1977	32
451	Hugh L Spurlock	KY	592.10	2	1981	28
452	Hugh L Spurlock	KY	329.40	3	2005	4
453	Hugh L Spurlock	KY	278.00	4	2009	0
454	J Sherman Cooper	KY	113.60	1	1965	44
455	J Sherman Cooper	KY	230.40	2	1969	40
456	Tenn Eastman Division A Division of East	TN	6.00	TG10	1946	63
457	Tenn Eastman Division A Division of East	TN	6.00	TG11	1949	60
458	Tenn Eastman Division A Division of East	TN	6.00	TG12	1953	56
459	Tenn Eastman Division A Division of East	TN	7.00	TG13	1960	49
460	Tenn Eastman Division A Division of East	TN	10.00	TG14	1962	47
461	Tenn Eastman Division A Division of East	TN	7.50	TG15	1963	46
462	Tenn Eastman Division A Division of East	TN	10.40	TG16	1966	43
463	Tenn Eastman Division A Division of East	TN	10.40	TG17	1966	43

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
464	Tenn Eastman Division A Division of East	TN	10.40	TG18	1967	42
465	Tenn Eastman Division A Division of East	TN	10.40	TG19	1970	39
466	Tenn Eastman Division A Division of East	TN	10.40	TG20	1972	37
467	Tenn Eastman Division A Division of East	TN	15.00	TG21	1969	40
468	Tenn Eastman Division A Division of East	TN	15.40	TG22	1982	27
469	Tenn Eastman Division A Division of East	TN	16.80	TG24	1983	26
470	Tenn Eastman Division A Division of East	TN	18.00	TG25	1994	15
471	Tenn Eastman Division A Division of East	TN	16.60	TG26	1994	15
472	Tenn Eastman Division A Division of East	TN	6.00	TGO7	1936	73
473	Tenn Eastman Division A Division of East	TN	6.00	TGO8	1939	70
474	Tenn Eastman Division A Division of East	TN	6.00	TGO9	1941	68
475	Kodak Park Site	NY	10.40	13TG	1948	61
476	Kodak Park Site	NY	10.40	14TG	1948	61
477	Kodak Park Site	NY	17.50	15TG	1956	53
478	Kodak Park Site	NY	15.00	17TG	1968	41
479	Kodak Park Site	NY	12.50	22TG	1954	55
480	Kodak Park Site	NY	25.60	41TG	1964	45
481	Kodak Park Site	NY	25.60	42TG	1967	42
482	Kodak Park Site	NY	25.60	43TG	1969	40
483	Kodak Park Site	NY	25.60	44TG	1987	22
484	Dwayne Collier Battle Cogeneration	NC	67.50	GEN1	1990	19
485	Dwayne Collier Battle Cogeneration	NC	67.50	GEN2	1990	19
486	Joppa Steam	IL	183.30	1	1953	56
487	Joppa Steam	IL	183.30	2	1953	56
488	Joppa Steam	IL	183.30	3	1954	55
489	Joppa Steam	IL	183.30	4	1954	55
490	Joppa Steam	IL	183.30	5	1955	54
491	Joppa Steam	IL	183.30	6	1955	54
492	Alloy Steam	WV	40.00	GEN3	1950	59
493	Asbury	MO	212.80	1	1970	39
494	Asbury	MO	18.70	2	1986	23
495	Riverton	KS	37.50	7	1950	59
496	Riverton	KS	50.00	8	1954	55
497	Independence (AR)	AR	850.00	1	1983	26
498	Independence (AR)	AR	850.00	2	1984	25
499	White Bluff	AR	850.00	1	1980	29
500	White Bluff	AR	850.00	2	1981	28
501	Roy S Nelson	LA	614.60	6	1982	27
502	Roxboro Cogeneration Facility	NC	67.50	GEN1	1987	22
503	Southport	NC	67.50	GEN1	1987	22
504	Southport	NC	67.50	GEN2	1987	22
505	Genesee (CAN)	AB	410.00	1	1994	15
506	Genesee (CAN)	AB	410.00	2	1989	20
507	Genesee (CAN)	AB	495.00	3	2005	4
508	Cromby Generating Station	PA	187.50	1	1954	55
509	Eddystone Generating Station	PA	353.60	1	1960	49
510	Eddystone Generating Station	PA	353.60	2	1960	49
511	Ashtabula	OH	256.00	5	1958	51
512	Bay Shore	OH	140.60	1	1955	54
513	Bay Shore	OH	140.60	2	1959	50
514	Bay Shore	OH	140.60	3	1963	46
515	Bay Shore	OH	217.60	4	1968	41
516	Bruce Mansfield	PA	913.70	1	1976	33
517	Bruce Mansfield	PA	913.70	2	1977	32
518	Bruce Mansfield	PA	913.70	3	1980	29
519	Eastlake (OH)	OH	123.00	1	1953	56
520	Eastlake (OH)	OH	123.00	2	1953	56
521	Eastlake (OH)	OH	123.00	3	1954	55

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
522	Eastlake (OH)	OH	208.00	4	1956	53
523	Eastlake (OH)	OH	680.00	5	1972	37
524	Lake Shore	OH	256.00	18	1962	47
525	R E Burger	OH	103.40	3	1950	59
526	R E Burger	OH	156.20	4	1955	54
527	R E Burger	OH	156.20	5	1955	54
528	W H Sammis	OH	190.40	1	1959	50
529	W H Sammis	OH	190.40	2	1960	49
530	W H Sammis	OH	190.40	3	1961	48
531	W H Sammis	OH	190.40	4	1962	47
532	W H Sammis	OH	334.00	5	1967	42
533	W H Sammis	OH	680.00	6	1969	40
534	W H Sammis	OH	680.00	7	1971	38
535	Marcus Hook	PA	17.50	1	1970	39
536	Green Bay West Mill	WI	28.20	GEN10	2005	4
537	Green Bay West Mill	WI	10.00	GEN5	1954	55
538	Green Bay West Mill	WI	18.70	GEN6	1963	46
539	Green Bay West Mill	WI	28.90	GEN7	1969	40
540	Green Bay West Mill	WI	43.20	GEN9	1985	24
541	Muskogee Mill	OK	25.00	GEN1	1978	31
542	Muskogee Mill	OK	44.50	GEN2	1979	30
543	Muskogee Mill	OK	44.50	GEN3	1982	27
544	Port of Stockton District Ener	CA	54.00	STG	1987	22
545	Franklin Heating	MN	6.50	GEN6	2006	3
546	Lon Wright	NE	16.50	6	1957	52
547	Lon Wright	NE	22.00	7	1963	46
548	Lon Wright	NE	91.50	8	1977	32
549	Deerhaven Generating Station	FL	250.70	2	1981	28
550	General Chemical	WY	15.00	TG1	1968	41
551	General Chemical	WY	15.00	TG2	1977	32
552	Bowen	GA	805.80	1	1971	38
553	Bowen	GA	788.80	2	1972	37
554	Bowen	GA	952.00	3	1974	35
555	Bowen	GA	952.00	4	1975	34
556	Hammond	GA	125.00	1	1954	55
557	Hammond	GA	125.00	2	1954	55
558	Hammond	GA	125.00	3	1955	54
559	Hammond	GA	578.00	4	1970	39
560	Harllee Branch	GA	299.20	1	1965	44
561	Harllee Branch	GA	359.00	2	1967	42
562	Harllee Branch	GA	544.00	3	1968	41
563	Harllee Branch	GA	544.00	4	1969	40
564	Jack McDonough	GA	299.20	1	1963	46
565	Jack McDonough	GA	299.20	2	1964	45
566	Kraft	GA	54.40	2	1961	48
567	Kraft	GA	103.50	3	1965	44
568	Kraft	GA	126.00	4	1972	37
569	Kraft	GA	50.00	ST1	1958	51
570	McIntosh (GA SAVNAH)	GA	177.60	1	1979	30
571	Mitchell (GA)	GA	163.20	3	1964	45
572	Scherer	GA	891.00	1	1982	27
573	Scherer	GA	891.00	2	1984	25
574	Scherer	GA	891.00	3	1987	22
575	Scherer	GA	891.00	4	1989	20
576	Wansley (GPC)	GA	952.00	1	1976	33
577	Wansley (GPC)	GA	952.00	2	1978	31
578	Yates	GA	122.50	1	1950	59
579	Yates	GA	122.50	2	1950	59

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
580	Yates	GA	122.50	3	1952	57
581	Yates	GA	156.20	4	1957	52
582	Yates	GA	156.20	5	1958	51
583	Yates	GA	403.70	6	1974	35
584	Yates	GA	403.70	7	1974	35
585	Healy	AK	28.00	1	1967	42
586	J B Simms	MI	80.00	3	1983	26
587	Platte	NE	109.80	1	1982	27
588	Grda 1 & 2	OK	490.00	1	1981	28
589	Grda 1 & 2	OK	520.00	2	1985	24
590	Coal Creek	ND	605.00	1	1979	30
591	Coal Creek	ND	605.00	2	1980	29
592	Stanton (ND)	ND	190.20	1	1967	42
593	Henderson (MS)	MS	20.00	H3	1967	42
594	Crist	FL	93.70	4	1959	50
595	Crist	FL	93.70	5	1961	48
596	Crist	FL	369.70	6	1970	39
597	Crist	FL	578.00	7	1973	36
598	Lansing Smith	FL	149.60	1	1965	44
599	Lansing Smith	FL	190.40	2	1967	42
600	Scholz	FL	49.00	1	1953	56
601	Scholz	FL	49.00	2	1953	56
602	Hamilton	OH	25.00	8	1965	44
603	Hamilton	OH	50.60	9	1975	34
604	Whelan Energy Center	NE	76.30	1	1981	28
605	Missouri Chemical Works	MO	8.60	GEN1	1943	66
606	Missouri Chemical Works	MO	8.60	GEN2	1943	66
607	Hibbing	MN	10.00	3	1965	44
608	Hibbing	MN	19.50	5	1985	24
609	Hibbing	MN	6.40	6	1996	13
610	James de Young	MI	11.50	3	1951	58
611	James de Young	MI	22.00	4	1962	47
612	James de Young	MI	29.30	5	1969	40
613	Frank E Ratts	IN	116.60	1	1970	39
614	Frank E Ratts	IN	116.60	2	1970	39
615	Merom	IN	540.00	1	1983	26
616	Merom	IN	540.00	2	1982	27
617	Blue Valley	MO	25.00	2	1958	51
618	Blue Valley	MO	65.00	3	1965	44
619	Blue Valley	MO	25.00	ST1	1958	51
620	Missouri City	MO	23.00	1	1954	55
621	Missouri City	MO	23.00	2	1954	55
622	Clifty Creek	IN	217.20	1	1955	54
623	Clifty Creek	IN	217.20	2	1955	54
624	Clifty Creek	IN	217.20	3	1955	54
625	Clifty Creek	IN	217.20	4	1955	54
626	Clifty Creek	IN	217.20	5	1955	54
627	Clifty Creek	IN	217.20	6	1956	53
628	Rockport	IN	1,300.00	1	1984	25
629	Rockport	IN	1,300.00	2	1989	20
630	Tanners Creek	IN	152.50	1	1951	58
631	Tanners Creek	IN	152.50	2	1952	57
632	Tanners Creek	IN	215.40	3	1954	55
633	Tanners Creek	IN	579.70	4	1964	45
634	AES Petersburg (IN)	IN	574.20	4	1986	23
635	AES Petersburg (IN)	IN	253.40	ST1	1967	42
636	AES Petersburg (IN)	IN	471.00	ST2	1969	40
637	AES Petersburg (IN)	IN	574.30	ST3	1977	32

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
638	H T Pritchard/Eagle Valley	IN	50.00	3	1951	58
639	H T Pritchard/Eagle Valley	IN	69.00	4	1953	56
640	H T Pritchard/Eagle Valley	IN	69.00	5	1953	56
641	H T Pritchard/Eagle Valley	IN	113.60	6	1956	53
642	Harding Street	IN	113.50	5	1958	51
643	Harding Street	IN	113.60	6	1961	48
644	Harding Street	IN	470.90	7	1973	36
645	Augusta Mill	GA	27.00	1	1960	49
646	Augusta Mill	GA	39.00	2	1965	44
647	Augusta Mill	GA	18.70	3	1965	44
648	International Paper Co Savannah	GA	82.80	GE10	1998	11
649	International Paper Co Savannah	GA	71.20	GEN9	1981	28
650	Plymouth (NC)	NC	7.50	TG7	1952	57
651	Plymouth (NC)	NC	25.00	TG8	1964	45
652	Roanoke Rapids North Carolina	NC	22.50	GEN1	1966	43
653	Sartell Mill	MN	20.40	ABB2	1982	27
654	Thilmany Pulp Paper	WI	15.60	GEN3	1962	47
655	Thilmany Pulp Paper	WI	12.00	GEN4	1967	42
656	Coleto Creek	TX	600.40	1	1980	29
657	Burlington (IA)	IA	212.00	1	1968	41
658	Dubuque	IA	28.70	3	1952	57
659	Dubuque	IA	37.50	4	1959	50
660	Dubuque	IA	15.00	ST2	1929	80
661	Lansing	IA	11.50	2	1949	60
662	Lansing	IA	37.50	3	1957	52
663	Lansing	IA	274.50	4	1977	32
664	M L Kapp	IA	218.40	2	1967	42
665	Ottumwa (IA IPL)	IA	726.00	1	1981	28
666	Prairie Creek 1 4	IA	23.00	1A	1997	12
667	Prairie Creek 1 4	IA	23.00	2	1951	58
668	Prairie Creek 1 4	IA	50.00	3	1958	51
669	Prairie Creek 1 4	IA	148.70	4	1967	42
670	Sutherland (IA)	IA	37.50	1	1955	54
671	Sutherland (IA)	IA	37.50	2	1955	54
672	Sutherland (IA)	IA	81.60	3	1961	48
673	Seaford Delaware Plant	DE	10.00	GEN1	1939	70
674	Seaford Delaware Plant	DE	10.00	GEN2	1939	70
675	Seaford Delaware Plant	DE	10.00	GEN3	1939	70
676	Iowa State Univ	IA	13.20	GEN3	1978	31
677	Iowa State Univ	IA	6.20	GEN4	1960	49
678	Iowa State Univ	IA	11.50	GEN5	1970	39
679	Iowa State Univ	IA	15.10	GEN6	2005	4
680	Birchwood Power Facility	VA	258.30	1	1996	13
681	Cogentrix Hopewell	VA	57.40	GEN1	1987	22
682	Cogentrix Hopewell	VA	57.40	GEN2	1987	22
683	Samuel A Carlson	NY	28.70	5	1951	58
684	Samuel A Carlson	NY	25.00	6	1968	41
685	Jasper 2	IN	14.50	1	1968	41
686	St Johns River Power Park	FL	679.00	1	1987	22
687	St Johns River Power Park	FL	679.00	2	1988	21
688	Jefferson Smurfit Corp (FL)	FL	74.40	GEN6	1982	27
689	John Deere Dubuque Works	IA	3.50	GEN2	1949	60
690	John Deere Dubuque Works	IA	3.00	GEN3	1989	20
691	John Deere Dubuque Works	IA	7.50	GEN4	1964	45
692	Nearman Creek	KS	261.00	ST1	1981	28
693	Quindaro	KS	81.60	ST1	1965	44
694	Quindaro	KS	157.50	ST2	1971	38
695	Hawthorne (MO)	MO	594.30	5	1969	40

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
696	Iatan	MO	726.00	1	1980	29
697	La Cygne	KS	893.00	1	1973	36
698	La Cygne	KS	685.00	2	1977	32
699	Montrose	MO	188.00	1	1958	51
700	Montrose	MO	188.00	2	1960	49
701	Montrose	MO	188.00	3	1964	45
702	Kucc	UT	50.00	1	1943	66
703	Kucc	UT	25.00	2	1943	66
704	Kucc	UT	25.00	3	1946	63
705	Kucc	UT	82.00	4	1958	51
706	Big Sandy	KY	280.50	1	1963	46
707	Big Sandy	KY	816.30	2	1969	40
708	E W Brown	KY	113.60	1	1957	52
709	E W Brown	KY	179.50	2	1963	46
710	E W Brown	KY	446.30	3	1971	38
711	Ghent	KY	556.90	1	1974	35
712	Ghent	KY	556.30	2	1977	32
713	Ghent	KY	556.50	3	1981	28
714	Ghent	KY	556.20	4	1984	25
715	Green River (KY)	KY	75.00	3	1954	55
716	Green River (KY)	KY	113.60	4	1959	50
717	Tyrone (KY)	KY	75.00	3	1953	56
718	Kimberly Clark Corp Munising M	MI	6.20	M387	1930	79
719	Lafarge Corp Alpena	MI	3.20	GE10	1999	10
720	Lafarge Corp Alpena	MI	12.00	GEN6	1952	57
721	Lafarge Corp Alpena	MI	10.00	GEN7	1955	54
722	Lafarge Corp Alpena	MI	11.00	GEN8	1991	18
723	Lafarge Corp Alpena	MI	11.00	GEN9	1994	15
724	C D McIntosh Jr	FL	363.80	3	1982	27
725	Lamar Plant	CO	25.00	4	1972	37
726	Eckert Station	MI	44.00	1	1954	55
727	Eckert Station	MI	44.00	2	1958	51
728	Eckert Station	MI	47.00	3	1960	49
729	Eckert Station	MI	80.00	4	1964	45
730	Eckert Station	MI	80.00	5	1968	41
731	Eckert Station	MI	80.00	6	1970	39
732	Erickson	MI	154.70	1	1973	36
733	Logansport	IN	18.00	4	1958	51
734	Logansport	IN	25.00	5	1964	45
735	Intermountain	UT	900.00	ST1	1986	23
736	Intermountain	UT	900.00	ST2	1987	22
737	Big Cajun 2	LA	626.00	ST1	1981	28
738	Big Cajun 2	LA	626.00	ST2	1982	27
739	Big Cajun 2	LA	619.00	ST3	1983	26
740	Louisiana Pacific Corp	MI	7.50	GEN1	1957	52
741	Cane Run	KY	163.20	4	1962	47
742	Cane Run	KY	209.40	5	1966	43
743	Cane Run	KY	272.00	6	1969	40
744	Mill Creek (KY)	KY	355.50	1	1972	37
745	Mill Creek (KY)	KY	355.50	2	1974	35
746	Mill Creek (KY)	KY	462.60	3	1978	31
747	Mill Creek (KY)	KY	543.60	4	1982	27
748	Trimble Station (LGE)	KY	566.10	1	1990	19
749	Fayette Power Project	TX	615.00	1	1979	30
750	Fayette Power Project	TX	615.00	2	1980	29
751	Fayette Power Project	TX	460.00	3	1988	21
752	Big Brown	TX	593.40	1	1971	38
753	Big Brown	TX	593.40	2	1972	37

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
754	Martin Lake	TX	793.20	1	1977	32
755	Martin Lake	TX	793.20	2	1978	31
756	Martin Lake	TX	793.20	3	1979	30
757	Monticello (TX)	TX	593.40	1	1974	35
758	Monticello (TX)	TX	593.40	2	1975	34
759	Monticello (TX)	TX	793.20	3	1978	31
760	Sandow No 4	TX	590.60	4	1981	28
761	Blount Street	WI	23.00	5	1948	61
762	Blount Street	WI	50.00	6	1957	52
763	Blount Street	WI	50.00	7	1961	48
764	Brandon	MB	105.00	5	1970	39
765	Columbus Street	WI	10.00	4	1950	59
766	Columbus Street	WI	22.00	5	1956	53
767	Shiras	MI	21.00	2	1972	37
768	Shiras	MI	44.00	3	1983	26
769	Marshall (MO)	MO	6.00	4	1956	53
770	Marshall (MO)	MO	16.50	5	1967	42
771	H R Milner	AB	150.30	1	1972	37
772	Heskett	ND	40.00	1	1954	55
773	Heskett	ND	75.00	2	1963	46
774	Lewis & Clark	MT	50.00	1	1958	51
775	Luke Mill	MD	35.00	GEN1	1958	51
776	Luke Mill	MD	30.00	GEN2	1979	30
777	Tyrone (PA)	PA	7.50	TG6	1958	51
778	Menasha (MNSHA)	WI	6.90	5	2006	3
779	Endicott Generating	MI	55.00	1	1982	27
780	T B Simon Power Plant	MI	12.50	GEN1	1965	44
781	T B Simon Power Plant	MI	12.50	GEN2	1966	43
782	T B Simon Power Plant	MI	15.00	GEN3	1974	35
783	T B Simon Power Plant	MI	21.00	GEN4	1993	16
784	T B Simon Power Plant	MI	24.00	GEN5	2006	3
785	George Neal North	IA	147.00	1	1964	45
786	George Neal North	IA	349.20	2	1972	37
787	George Neal North	IA	549.80	3	1975	34
788	George Neal South	IA	640.00	4	1979	30
789	Louisa	IA	811.90	1	1983	26
790	Riverside (IA)	IA	5.00	3HS	1949	60
791	Riverside (IA)	IA	136.00	5	1961	48
792	Walter Scott Jr Energy Center	IA	49.00	ST1	1954	55
793	Walter Scott Jr Energy Center	IA	81.60	ST2	1958	51
794	Walter Scott Jr Energy Center	IA	725.80	ST3	1978	31
795	Walter Scott Jr Energy Center	IA	790.00	ST4	2007	2
796	E J Stoneman	WI	18.00	1	1951	58
797	E J Stoneman	WI	35.00	2	1954	55
798	Crawford (IL)	IL	239.30	7	1958	51
799	Crawford (IL)	IL	358.10	8	1961	48
800	Fisk Street	IL	374.00	19	1959	50
801	Homer City Station	PA	660.00	1	1969	40
802	Homer City Station	PA	660.00	2	1969	40
803	Homer City Station	PA	692.00	3	1977	32
804	Joliet 29	IL	660.00	7	1965	44
805	Joliet 29	IL	660.00	8	1966	43
806	Joliet 9	IL	360.40	6	1959	50
807	Powerton	IL	892.80	5	1972	37
808	Powerton	IL	892.80	6	1975	34
809	Waukegan	IL	326.40	7	1958	51
810	Waukegan	IL	355.30	8	1962	47
811	Will County	IL	187.50	1	1955	54

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
812	Will County	IL	183.70	2	1955	54
813	Will County	IL	299.20	3	1957	52
814	Will County	IL	598.40	4	1963	46
815	Hillsboro	ND	13.30	1	1986	23
816	Milton R Young	ND	257.00	ST1	1970	39
817	Milton R Young	ND	477.00	ST2	1977	32
818	Chalk Point	MD	364.00	1	1964	45
819	Chalk Point	MD	364.00	2	1965	44
820	Dickerson	MD	196.00	2	1960	49
821	Dickerson	MD	196.00	3	1962	47
822	Dickerson	MD	196.00	ST1	1959	50
823	Morgantown Generating Station	MD	626.00	ST1	1970	39
824	Morgantown Generating Station	MD	626.00	ST2	1971	38
825	Potomac River	VA	92.00	1	1949	60
826	Potomac River	VA	92.00	2	1950	59
827	Potomac River	VA	110.00	3	1954	55
828	Potomac River	VA	110.00	4	1956	53
829	Potomac River	VA	110.00	5	1957	52
830	Jack Watson	MS	299.20	4	1968	41
831	Jack Watson	MS	578.00	5	1973	36
832	Victor J Daniel Jr	MS	548.30	1	1977	32
833	Victor J Daniel Jr	MS	548.30	2	1981	28
834	Mobile Energy Services Co LLC	AL	43.10	GEN5	1985	24
835	Albright	WV	69.00	1	1952	57
836	Albright	WV	69.00	2	1952	57
837	Albright	WV	140.20	3	1954	55
838	Fort Martin	WV	576.00	1	1967	42
839	Fort Martin	WV	576.00	2	1968	41
840	Harrison (WV)	WV	684.00	1	1972	37
841	Harrison (WV)	WV	684.00	2	1973	36
842	Harrison (WV)	WV	684.00	3	1974	35
843	Pleasants	WV	684.00	1	1979	30
844	Pleasants	WV	684.00	2	1980	29
845	Rivesville	WV	35.00	5	1943	66
846	Rivesville	WV	74.70	6	1951	58
847	Willow Island	WV	50.00	1	1949	60
848	Willow Island	WV	163.20	2	1960	49
849	Morton Salt Rittman	OH	1.50	GEN1	1978	31
850	MT Poso Cogeneration	CA	62.00	TG01	1989	20
851	Mount Tom	MA	136.00	1	1960	49
852	Muscatine	IA	25.00	7	1958	51
853	Muscatine	IA	75.00	8	1969	40
854	Muscatine	IA	18.00	8A	2000	9
855	Muscatine	IA	175.50	9	1983	26
856	Gerald Gentleman	NE	681.30	1	1979	30
857	Gerald Gentleman	NE	681.30	2	1982	27
858	Sheldon (NE)	NE	108.80	1	1961	48
859	Sheldon (NE)	NE	119.90	2	1965	44
860	Reid Gardner	NV	114.00	1	1965	44
861	Reid Gardner	NV	114.00	2	1968	41
862	Reid Gardner	NV	114.00	3	1976	33
863	Reid Gardner	NV	270.00	4	1983	26
864	Belledune	NB	510.00	1	1993	16
865	Grand Lake	NB	60.00	8	1964	45
866	Juniata Locomotive Shop	PA	2.00	GEN1	1955	54
867	Juniata Locomotive Shop	PA	2.00	GEN2	1955	54
868	Marshall (TX)	TX	2.00	8511	1921	88
869	Bailly	IN	190.40	7	1962	47

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
870	Bailly	IN	413.10	8	1968	41
871	Michigan City	IN	540.00	12	1974	35
872	R M Schahfer	IN	540.00	14	1976	33
873	R M Schahfer	IN	556.40	15	1979	30
874	R M Schahfer	IN	423.50	17	1983	26
875	R M Schahfer	IN	423.50	18	1986	23
876	Allen S King Plant	MN	658.40	1	1958	51
877	Black Dog	MN	114.00	3	1955	54
878	Black Dog	MN	180.00	4	1960	49
879	Riverside Repowering Project (MN)	MN	238.80	8	1964	45
880	Riverside Repowering Project (MN)	MN	165.00	ST7	1987	22
881	Sherburne County	MN	689.00	2	1977	32
882	Sherburne County	MN	859.00	3	1987	22
883	Bay Front	WI	20.00	4	1949	60
884	Bay Front	WI	20.00	5	1952	57
885	Bay Front	WI	28.00	6	1957	52
886	Lingan	NS	150.40	1	1979	30
887	Lingan	NS	150.40	2	1980	29
888	Lingan	NS	150.40	3	1983	26
889	Lingan	NS	150.40	4	1984	25
890	PT Tupper	NS	150.00	2	1973	36
891	Trenton	NS	160.00	6	1991	18
892	Dunkirk Generating Station	NY	96.00	DUN1	1950	59
893	Dunkirk Generating Station	NY	96.00	DUN2	1950	59
894	Dunkirk Generating Station	NY	217.60	DUN3	1959	50
895	Dunkirk Generating Station	NY	217.60	DUN4	1960	49
896	Dover Energy (NRG)	DE	18.00	ST1	1985	24
897	Huntley Generating	NY	218.00	67	1957	52
898	Huntley Generating	NY	218.00	68	1958	51
899	Indian River Generating Station (DE)	DE	81.60	1	1957	52
900	Indian River Generating Station (DE)	DE	81.60	2	1959	50
901	Indian River Generating Station (DE)	DE	176.80	3	1970	39
902	Indian River Generating Station (DE)	DE	442.40	4	1980	29
903	Limestone (NRG)	TX	893.00	1	1985	24
904	Limestone (NRG)	TX	956.80	2	1986	23
905	W A Parish	TX	734.10	5	1977	32
906	W A Parish	TX	734.10	6	1978	31
907	W A Parish	TX	614.60	7	1980	29
908	W A Parish	TX	614.60	8	1982	27
909	Gavin	OH	1,300.00	1	1974	35
910	Gavin	OH	1,300.00	2	1975	34
911	Kammer	WV	237.50	1	1958	51
912	Kammer	WV	237.50	2	1958	51
913	Kammer	WV	237.50	3	1959	50
914	Mitchell (WV)	WV	816.30	1	1971	38
915	Mitchell (WV)	WV	816.30	2	1971	38
916	Muskingum River	OH	219.60	1	1953	56
917	Muskingum River	OH	219.60	2	1954	55
918	Muskingum River	OH	237.50	3	1957	52
919	Muskingum River	OH	237.50	4	1958	51
920	Muskingum River	OH	615.20	5	1968	41
921	Kyger Creek	OH	217.30	1	1955	54
922	Kyger Creek	OH	217.30	2	1955	54
923	Kyger Creek	OH	217.30	3	1955	54
924	Kyger Creek	OH	217.30	4	1955	54
925	Kyger Creek	OH	217.30	5	1955	54
926	Muskogee	OK	572.00	4	1977	32
927	Muskogee	OK	572.00	5	1978	31

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
928	Muskogee	OK	572.00	6	1984	25
929	Sooner	OK	569.00	1	1979	30
930	Sooner	OK	569.00	2	1980	29
931	Nebraska City	NE	651.60	1	1979	30
932	North Omaha	NE	73.50	1	1954	55
933	North Omaha	NE	108.80	2	1957	52
934	North Omaha	NE	108.80	3	1959	50
935	North Omaha	NE	136.00	4	1963	46
936	North Omaha	NE	217.60	5	1968	41
937	Atikokan GS	ON	227.00	1	1982	27
938	Lambton GS	ON	520.00	1	1969	40
939	Lambton GS	ON	520.00	2	1969	40
940	Lambton GS	ON	520.00	3	1969	40
941	Lambton GS	ON	520.00	4	1969	40
942	Nanticoke	ON	505.00	1	1973	36
943	Nanticoke	ON	505.00	2	1973	36
944	Nanticoke	ON	510.00	3	1973	36
945	Nanticoke	ON	505.00	4	1973	36
946	Nanticoke	ON	505.00	5	1973	36
947	Nanticoke	ON	505.00	6	1973	36
948	Nanticoke	ON	505.00	7	1973	36
949	Nanticoke	ON	505.00	8	1973	36
950	Thunder Bay GS	ON	165.00	2	1981	28
951	Thunder Bay GS	ON	165.00	3	1981	28
952	Avon Lake	OH	86.00	7	1949	60
953	Avon Lake	OH	680.00	9	1970	39
954	Cheswick Power Plant	PA	637.00	1	1970	39
955	Elrama Power Plant	PA	100.00	UNT1	1952	57
956	Elrama Power Plant	PA	100.00	UNT2	1953	56
957	Elrama Power Plant	PA	125.00	UNT3	1954	55
958	Elrama Power Plant	PA	185.00	UNT4	1960	49
959	New Castle Plant	PA	98.00	3	1952	57
960	New Castle Plant	PA	114.00	4	1958	51
961	New Castle Plant	PA	136.00	5	1964	45
962	Niles (OH ORION)	OH	132.80	UNT1	1954	55
963	Niles (OH ORION)	OH	132.80	UNT2	1954	55
964	Stanton Energy Center	FL	464.50	1	1987	22
965	Stanton Energy Center	FL	464.50	2	1996	13
966	Orrville	OH	25.00	10	1971	38
967	Orrville	OH	25.00	11	1971	38
968	Orrville	OH	22.00	9	1961	48
969	Big Stone	SD	456.00	ST1	1975	34
970	Coyote	ND	450.00	1	1981	28
971	Hoot Lake	MN	54.40	2	1959	50
972	Hoot Lake	MN	75.00	3	1964	45
973	Elmer Smith	KY	163.20	1	1964	45
974	Elmer Smith	KY	282.10	2	1974	35
975	Chillicothe (OH)	OH	10.60	T 10	1952	57
976	Chillicothe (OH)	OH	24.00	T 11	1958	51
977	Chillicothe (OH)	OH	31.00	T 12	1967	42
978	Chillicothe (OH)	OH	27.20	T 13	1978	31
979	P H Glatfelter Co	PA	6.00	GEN1	1948	61
980	P H Glatfelter Co	PA	5.10	GEN3	1948	61
981	P H Glatfelter Co	PA	7.50	GEN4	1962	47
982	P H Glatfelter Co	PA	45.90	GEN5	1989	20
983	Carbon (UT)	UT	75.00	1	1954	55
984	Carbon (UT)	UT	113.60	2	1957	52
985	Dave Johnston	WY	113.60	1	1959	50

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
986	Dave Johnston	WY	113.60	2	1961	48
987	Dave Johnston	WY	229.50	3	1964	45
988	Dave Johnston	WY	360.00	4	1972	37
989	Hunter	UT	488.30	ST1	1978	31
990	Hunter	UT	488.30	ST2	1980	29
991	Hunter	UT	495.60	ST3	1983	26
992	Huntington (UT)	UT	498.00	1	1977	32
993	Huntington (UT)	UT	498.00	2	1974	35
994	Jim Bridger	WY	577.90	1	1974	35
995	Jim Bridger	WY	577.90	2	1975	34
996	Jim Bridger	WY	577.90	3	1976	33
997	Jim Bridger	WY	584.00	4	1979	30
998	Naughton	WY	163.20	1	1963	46
999	Naughton	WY	217.60	2	1968	41
1000	Naughton	WY	326.40	3	1971	38
1001	Wyodak	WY	362.00	1	1978	31
1002	Grandmother	WI	6.30	GEN1	1948	61
1003	Grandmother	WI	9.40	GEN2	1978	31
1004	Painesville	OH	16.50	5	1965	44
1005	Painesville	OH	22.00	7	1990	19
1006	Park 500 Philip Morris USA	VA	6.10	TG2	1984	25
1007	Park 500 Philip Morris USA	VA	13.00	TG3	1983	26
1008	Pella	IA	11.50	5	1964	45
1009	Pella	IA	26.50	6	1972	37
1010	Peru (IN)	IN	22.00	2	1959	50
1011	Peru (IN)	IN	12.50	3	1949	60
1012	Rawhide	CO	293.60	ST1	1984	25
1013	Twin Oaks Power	TX	174.60	1	1990	19
1014	Twin Oaks Power	TX	174.60	2	1991	18
1015	Boardman (OR)	OR	601.00	1	1980	29
1016	Potlatch (Crow Wing)	MN	0.60	VPLS	1959	50
1017	Natrium Plant	WV	7.50	GEN3	1943	66
1018	Natrium Plant	WV	7.50	GEN4	1943	66
1019	Natrium Plant	WV	26.00	GEN6	1954	55
1020	Natrium Plant	WV	82.00	GEN7	1966	43
1021	PPL Brunner Island	PA	363.30	BI1	1961	48
1022	PPL Brunner Island	PA	405.00	BI2	1965	44
1023	PPL Brunner Island	PA	790.40	BI3	1969	40
1024	Colstrip	MT	358.00	GEN1	1975	34
1025	Colstrip	MT	358.00	GEN2	1976	33
1026	Colstrip	MT	778.00	GEN3	1984	25
1027	Colstrip	MT	778.00	GEN4	1986	23
1028	J E Corette Plant	MT	172.80	GEN1	1968	41
1029	Montour	PA	820.00	MT1	1972	37
1030	Montour	PA	17.20	MT11	1973	36
1031	Montour	PA	833.00	MT2	1973	36
1032	Pearl Station	IL	22.00	1	1967	42
1033	Ivorydale	OH	12.50	GEN1	1965	44
1034	Asheville	NC	206.60	1	1964	45
1035	Asheville	NC	207.00	2	1971	38
1036	Cape Fear	NC	140.60	5	1956	53
1037	Cape Fear	NC	187.90	6	1958	51
1038	H B Robinson	SC	206.60	1	1960	49
1039	L V Sutton	NC	112.50	1	1954	55
1040	L V Sutton	NC	112.50	2	1955	54
1041	L V Sutton	NC	446.60	3	1972	37
1042	Lee	NC	75.00	1	1952	57
1043	Lee	NC	75.00	2	1951	58

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1044	Lee	NC	252.40	3	1962	47
1045	Mayo	NC	735.80	1	1983	26
1046	Roxboro	NC	410.80	1	1966	43
1047	Roxboro	NC	657.00	2	1968	41
1048	Roxboro	NC	745.20	3	1973	36
1049	Roxboro	NC	745.20	4	1980	29
1050	W H Weatherspoon	NC	46.00	1	1949	60
1051	W H Weatherspoon	NC	46.00	2	1950	59
1052	W H Weatherspoon	NC	73.50	3	1952	57
1053	Crystal River	FL	440.50	1	1966	43
1054	Crystal River	FL	523.80	2	1969	40
1055	Crystal River	FL	739.20	4	1982	27
1056	Crystal River	FL	739.20	5	1984	25
1057	Bridgeport Station	CT	400.00	3	1968	41
1058	Hudson Generating Station	NJ	659.70	2	1968	41
1059	Mercer Generating Station	NJ	326.40	1	1960	49
1060	Mercer Generating Station	NJ	326.40	2	1961	48
1061	Arapahoe	CO	48.00	3	1951	58
1062	Arapahoe	CO	112.00	4	1955	54
1063	Cameo	CO	22.00	1	1957	52
1064	Cameo	CO	44.00	2	1960	49
1065	Cherokee (CO)	CO	125.00	1	1957	52
1066	Cherokee (CO)	CO	125.00	2	1959	50
1067	Cherokee (CO)	CO	170.40	3	1962	47
1068	Cherokee (CO)	CO	380.80	4	1968	41
1069	Comanche (CO)	CO	382.50	1	1973	36
1070	Comanche (CO)	CO	396.00	2	1975	34
1071	Hayden	CO	190.00	1	1965	44
1072	Hayden	CO	275.40	2	1976	33
1073	Pawnee	CO	552.30	1	1981	28
1074	Valmont	CO	191.70	5	1964	45
1075	Merrimack	NH	113.60	1	1960	49
1076	Merrimack	NH	345.60	2	1968	41
1077	Schiller	NH	50.00	4	1952	57
1078	Schiller	NH	50.00	6	1957	52
1079	San Juan	NM	369.00	1	1976	33
1080	San Juan	NM	369.00	2	1973	36
1081	San Juan	NM	555.00	3	1979	30
1082	San Juan	NM	555.00	4	1982	27
1083	Northeastern	OK	473.00	3	1979	30
1084	Northeastern	OK	473.00	4	1980	29
1085	Purdue Univ	IN	30.80	GEN1	1995	14
1086	Purdue Univ	IN	10.60	GEN2	1969	40
1087	Raton	NM	7.50	5	1961	48
1088	B L England	NJ	136.00	1	1962	47
1089	B L England	NJ	163.20	2	1964	45
1090	Conemaugh	PA	936.00	1	1970	39
1091	Conemaugh	PA	936.00	2	1970	39
1092	Keystone (PA)	PA	936.00	1	1967	42
1093	Keystone (PA)	PA	936.00	2	1968	41
1094	Portland (PA)	PA	172.00	1	1958	51
1095	Portland (PA)	PA	255.00	2	1962	47
1096	Shawville	PA	125.00	1	1954	55
1097	Shawville	PA	125.00	2	1954	55
1098	Shawville	PA	188.00	3	1959	50
1099	Shawville	PA	188.00	4	1960	49
1100	Titus	PA	75.00	1	1951	58
1101	Titus	PA	75.00	2	1951	58

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1102	Titus	PA	75.00	3	1953	56
1103	Whitewater Valley	IN	33.00	1	1955	54
1104	Whitewater Valley	IN	60.90	2	1973	36
1105	Rio Bravo Jasmin	CA	38.20	UP9	1989	20
1106	Rio Bravo Poso	CA	38.20	UP8	1989	20
1107	Silver Lake (MN)	MN	8.00	1	1948	61
1108	Silver Lake (MN)	MN	12.00	2	1953	56
1109	Silver Lake (MN)	MN	25.00	3	1962	47
1110	Silver Lake (MN)	MN	54.00	4	1969	40
1111	Muskegon	MI	19.10	GEN4	1968	41
1112	Muskegon	MI	28.30	GEN5	1989	20
1113	Norton Powerhouse	MA	2.50	GEN1	1939	70
1114	Norton Powerhouse	MA	3.10	GEN2	1954	55
1115	Coronado	AZ	410.90	CO1	1979	30
1116	Coronado	AZ	410.90	CO2	1980	29
1117	Navajo	AZ	803.10	NAV1	1974	35
1118	Navajo	AZ	803.10	NAV2	1975	34
1119	Navajo	AZ	803.10	NAV3	1976	33
1120	San Miguel	TX	410.00	1	1982	27
1121	Cross	SC	590.90	1	1995	14
1122	Cross	SC	556.20	2	1984	25
1123	Cross	SC	591.00	3	2007	2
1124	Cross	SC	600.00	4	2008	1
1125	Dolphus M Grainger	SC	81.60	1	1966	43
1126	Dolphus M Grainger	SC	81.60	2	1966	43
1127	Jefferies	SC	172.80	3	1970	39
1128	Jefferies	SC	172.80	4	1970	39
1129	Winyah	SC	315.00	1	1975	34
1130	Winyah	SC	315.00	2	1977	32
1131	Winyah	SC	315.00	3	1980	29
1132	Winyah	SC	315.00	4	1981	28
1133	Boundary Dam	SK	66.00	1	1959	50
1134	Boundary Dam	SK	66.00	2	1960	49
1135	Boundary Dam	SK	150.00	3	1969	40
1136	Boundary Dam	SK	150.00	4	1970	39
1137	Boundary Dam	SK	150.00	5	1973	36
1138	Boundary Dam	SK	292.50	6	1977	32
1139	Poplar River	SK	307.80	1	1983	26
1140	Poplar River	SK	315.00	2	1981	28
1141	Shand	SK	297.80	1	1992	17
1142	Savannah Sugar Refinery	GA	3.00	GEN2	1959	50
1143	Savannah Sugar Refinery	GA	2.70	GENA	1948	61
1144	Savannah Sugar Refinery	GA	1.00	GENC	1946	63
1145	Savannah Sugar Refinery	GA	5.00	GEND	1985	24
1146	Argus Cogeneration Plant	CA	27.50	TG8	1978	31
1147	Argus Cogeneration Plant	CA	27.50	TG9	1978	31
1148	Seminole (FL)	FL	714.60	1	1984	25
1149	Seminole (FL)	FL	714.60	2	1985	24
1150	Shelby Munic Light Plant	OH	12.50	1A	1968	41
1151	Shelby Munic Light Plant	OH	12.50	2	1973	36
1152	Shelby Munic Light Plant	OH	7.00	4	1954	55
1153	North Valmy	NV	277.20	1	1981	28
1154	North Valmy	NV	289.80	2	1985	24
1155	Sikeston	MO	261.00	1	1981	28
1156	Smurfit Stone Container Corp (MI)	MI	15.60	GEN1	1966	43
1157	Indian Orchard 1	MA	5.70	TG	1985	24
1158	Somerset Station	MA	100.00	SOM6	1959	50
1159	Canadys Steam	SC	136.00	1	1962	47

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1160	Canadys Steam	SC	136.00	2	1964	45
1161	Canadys Steam	SC	217.60	3	1967	42
1162	Cogeneration South	SC	99.20	1	1999	10
1163	Cope	SC	417.30	ST1	1996	13
1164	McMeekin	SC	146.80	1	1958	51
1165	McMeekin	SC	146.80	2	1958	51
1166	Urquhart	SC	100.00	3	1955	54
1167	US DOE SRS (D Area)	SC	9.40	HP 1	1952	57
1168	US DOE SRS (D Area)	SC	9.40	HP 2	1952	57
1169	US DOE SRS (D Area)	SC	9.40	HP 3	1952	57
1170	US DOE SRS (D Area)	SC	12.50	LP 1	1952	57
1171	US DOE SRS (D Area)	SC	12.50	LP 2	1952	57
1172	US DOE SRS (D Area)	SC	12.50	LP 3	1952	57
1173	US DOE SRS (D Area)	SC	12.50	LP 4	1952	57
1174	Wateree	SC	385.90	1	1970	39
1175	Wateree	SC	385.90	2	1971	38
1176	Williams (SC SCGC)	SC	632.70	ST1	1973	36
1177	R D Morrow	MS	200.00	1	1978	31
1178	R D Morrow	MS	200.00	2	1978	31
1179	Marion	IL	33.00	1	1963	46
1180	Marion	IL	33.00	2	1963	46
1181	Marion	IL	33.00	3	1963	46
1182	A B Brown	IN	265.20	ST1	1979	30
1183	A B Brown	IN	265.20	ST2	1986	23
1184	F B Culley	IN	103.70	2	1966	43
1185	F B Culley	IN	265.20	3	1973	36
1186	Flint Creek (AR)	AR	558.00	1	1978	31
1187	Pirkey	TX	721.00	1	1985	24
1188	Welsh Station	TX	558.00	1	1977	32
1189	Welsh Station	TX	558.00	2	1980	29
1190	Welsh Station	TX	558.00	3	1982	27
1191	Harrington	TX	360.00	1	1976	33
1192	Harrington	TX	360.00	2	1978	31
1193	Harrington	TX	360.00	3	1980	29
1194	Tolk	TX	568.00	1	1982	27
1195	Tolk	TX	568.00	2	1985	24
1196	SP Newsprint (GA)	GA	45.00	GEN1	1989	20
1197	James River Power St	MO	22.00	1	1957	52
1198	James River Power St	MO	22.00	2	1957	52
1199	James River Power St	MO	44.00	3	1960	49
1200	James River Power St	MO	60.00	4	1964	45
1201	James River Power St	MO	105.00	5	1970	39
1202	Southwest	MO	194.00	ST1	1976	33
1203	Dallman	IL	90.20	1	1968	41
1204	Dallman	IL	90.20	2	1972	37
1205	Dallman	IL	207.30	3	1978	31
1206	Lakeside	IL	37.50	6	1961	48
1207	Lakeside	IL	37.50	7	1965	44
1208	Cogentrix of Richmond Inc	VA	57.40	GEN1	1992	17
1209	Cogentrix of Richmond Inc	VA	57.40	GEN2	1992	17
1210	Cogentrix of Richmond Inc	VA	57.40	GEN3	1992	17
1211	Cogentrix of Richmond Inc	VA	57.40	GEN4	1992	17
1212	State Line Energy	IN	225.00	ST3	1955	54
1213	State Line Energy	IN	388.00	ST4	1962	47
1214	Capitol Heat & Power	WI	1.50	1	1963	46
1215	Capitol Heat & Power	WI	1.50	2	1964	45
1216	UW Madison Charter St Plant	WI	9.70	1	1965	44
1217	Waupun Correctional Inst CTR	WI	1.00	1	1951	58

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1218	Stone Container Corp Florence	SC	79.10	GEN3	1987	22
1219	Biron Mill	WI	17.00	GEN1	1964	45
1220	Biron Mill	WI	7.50	GEN3	1947	62
1221	Biron Mill	WI	15.60	GEN4	1957	52
1222	Biron Mill	WI	21.50	GEN5	1987	22
1223	Niagara Mill	WI	2.50	1ST	1940	69
1224	Niagara Mill	WI	9.30	2ST	1964	45
1225	Whiting Mill	WI	4.10	GEN4	1951	58
1226	Tuscola	IL	6.00	TG2	1953	56
1227	Smart Papers LLC	OH	6.00	GEN3	1924	85
1228	Smart Papers LLC	OH	7.50	GEN5	1930	79
1229	Smart Papers LLC	OH	10.50	GEN6	1930	79
1230	Holcomb East	KS	348.70	1	1983	26
1231	Trigen Syracuse Energy Corp	NY	90.60	GEN1	1991	18
1232	Trigen Syracuse Energy Corp	NY	10.50	GEN2	2002	7
1233	Big Bend (FL)	FL	445.50	1	1970	39
1234	Big Bend (FL)	FL	445.50	ST2	1973	36
1235	Big Bend (FL)	FL	445.50	ST3	1976	33
1236	Big Bend (FL)	FL	486.00	ST4	1985	24
1237	Polk Station	FL	326.30	1	1996	13
1238	Allen Steam Plant (TN)	TN	330.00	1	1959	50
1239	Allen Steam Plant (TN)	TN	330.00	2	1959	50
1240	Allen Steam Plant (TN)	TN	330.00	3	1959	50
1241	Bull Run (TN)	TN	950.00	1	1967	42
1242	Colbert	AL	200.00	1	1955	54
1243	Colbert	AL	200.00	2	1955	54
1244	Colbert	AL	200.00	3	1955	54
1245	Colbert	AL	200.00	4	1955	54
1246	Colbert	AL	550.00	5	1965	44
1247	Cumberland (TN)	TN	1,300.00	1	1973	36
1248	Cumberland (TN)	TN	1,300.00	2	1973	36
1249	Gallatin (TN)	TN	300.00	1	1956	53
1250	Gallatin (TN)	TN	300.00	2	1957	52
1251	Gallatin (TN)	TN	327.60	3	1959	50
1252	Gallatin (TN)	TN	327.60	4	1959	50
1253	John Sevier	TN	200.00	1	1955	54
1254	John Sevier	TN	200.00	2	1955	54
1255	John Sevier	TN	200.00	3	1956	53
1256	John Sevier	TN	200.00	4	1957	52
1257	Johnsonville (TN)	TN	125.00	1	1951	58
1258	Johnsonville (TN)	TN	172.80	10	1959	50
1259	Johnsonville (TN)	TN	125.00	2	1951	58
1260	Johnsonville (TN)	TN	125.00	3	1952	57
1261	Johnsonville (TN)	TN	125.00	4	1952	57
1262	Johnsonville (TN)	TN	147.00	5	1952	57
1263	Johnsonville (TN)	TN	147.00	6	1953	56
1264	Johnsonville (TN)	TN	172.80	7	1958	51
1265	Johnsonville (TN)	TN	172.80	8	1959	50
1266	Johnsonville (TN)	TN	172.80	9	1959	50
1267	Kingston	TN	175.00	1	1954	55
1268	Kingston	TN	175.00	2	1954	55
1269	Kingston	TN	175.00	3	1954	55
1270	Kingston	TN	175.00	4	1954	55
1271	Kingston	TN	200.00	5	1955	54
1272	Kingston	TN	200.00	6	1955	54
1273	Kingston	TN	200.00	7	1955	54
1274	Kingston	TN	200.00	8	1955	54
1275	Kingston	TN	200.00	9	1955	54

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1276	Paradise (KY)	KY	704.00	1	1963	46
1277	Paradise (KY)	KY	704.00	2	1963	46
1278	Paradise (KY)	KY	1,150.20	3	1970	39
1279	Shawnee (KY)	KY	175.00	1	1953	56
1280	Shawnee (KY)	KY	175.00	10	1956	53
1281	Shawnee (KY)	KY	175.00	2	1953	56
1282	Shawnee (KY)	KY	175.00	3	1953	56
1283	Shawnee (KY)	KY	175.00	4	1954	55
1284	Shawnee (KY)	KY	175.00	5	1954	55
1285	Shawnee (KY)	KY	175.00	6	1954	55
1286	Shawnee (KY)	KY	175.00	7	1954	55
1287	Shawnee (KY)	KY	175.00	8	1955	54
1288	Shawnee (KY)	KY	175.00	9	1955	54
1289	Widows Creek	AL	140.60	1	1952	57
1290	Widows Creek	AL	140.60	2	1952	57
1291	Widows Creek	AL	140.60	3	1952	57
1292	Widows Creek	AL	140.60	4	1953	56
1293	Widows Creek	AL	140.60	5	1954	55
1294	Widows Creek	AL	140.60	6	1954	55
1295	Widows Creek	AL	575.00	7	1961	48
1296	Widows Creek	AL	550.00	8	1965	44
1297	Tes Filer City Station	MI	70.00	GEN1	1990	19
1298	Gibbons Creek	TX	453.50	1	1983	26
1299	Fox Valley Energy Center	WI	6.50	1	1999	10
1300	Centralia Complex	WA	729.90	BD21	1972	37
1301	Centralia Complex	WA	729.90	BD22	1973	36
1302	Keephills	AB	392.00	1	1983	26
1303	Keephills	AB	393.00	2	1984	25
1304	Sundance	AB	304.00	1	1970	39
1305	Sundance	AB	304.00	2	1973	36
1306	Sundance	AB	380.00	3	1976	33
1307	Sundance	AB	433.00	4	1977	32
1308	Sundance	AB	380.00	5	1978	31
1309	Sundance	AB	433.00	6	1980	29
1310	Wabamun Generation Station	AB	300.00	4	1967	42
1311	Craig (CO)	CO	446.40	1	1980	29
1312	Craig (CO)	CO	446.40	2	1979	30
1313	Craig (CO)	CO	463.40	3	1984	25
1314	Escalante	NM	257.00	1	1984	25
1315	Nucla	CO	11.50	1	1959	50
1316	Nucla	CO	11.50	2	1959	50
1317	Nucla	CO	11.50	3	1959	50
1318	Nucla	CO	79.30	ST4	1991	18
1319	Grand Avenue Steam Plant	MO	5.00	ST	1998	11
1320	H Wilson Sundt Generating Station	AZ	173.30	4	1967	42
1321	Springerville Generating Station	AZ	424.80	1	1985	24
1322	Springerville Generating Station	AZ	424.80	2	1990	19
1323	Springerville Generating Station	AZ	450.00	ST3	2006	3
1324	Eielson Air Force Base Central	AK	2.50	TG1	1952	57
1325	Eielson Air Force Base Central	AK	2.50	TG2	1952	57
1326	Eielson Air Force Base Central	AK	5.00	TG3	1955	54
1327	Eielson Air Force Base Central	AK	5.00	TG4	1969	40
1328	Eielson Air Force Base Central	AK	10.00	TG5	1987	22
1329	Utility Plants Section	AK	5.00	GEN1	1955	54
1330	Utility Plants Section	AK	5.00	GEN3	1955	54
1331	Utility Plants Section	AK	5.00	GEN4	1955	54
1332	Utility Plants Section	AK	5.00	GEN5	1989	20
1333	Radford Army Ammunition	VA	6.00	GEN1	1990	19

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1334	Radford Army Ammunition	VA	6.00	GEN2	1990	19
1335	Radford Army Ammunition	VA	6.00	GEN3	1990	19
1336	Radford Army Ammunition	VA	6.00	GEN4	1990	19
1337	Txi Riverside Cement	CA	12.00	GEN1	1954	55
1338	Txi Riverside Cement	CA	12.00	GEN2	1954	55
1339	Hunlock Power Station	PA	49.90	3	1959	50
1340	Union Carbide South Charleston	WV	6.00	GEN8	1953	56
1341	Univ of Alaska Fairbanks	AK	10.00	GEN3	1981	28
1342	Univ of Illinois Abbott	IL	12.50	T10	2004	5
1343	Univ of Illinois Abbott	IL	12.50	T11	2004	5
1344	Univ of Illinois Abbott	IL	7.00	T12	2004	5
1345	Univ of Illinois Abbott	IL	7.50	T6	1959	50
1346	Univ of Illinois Abbott	IL	7.50	T7	1962	47
1347	Univ of Iowa Main	IA	3.00	GEN1	1947	62
1348	Univ of Iowa Main	IA	3.00	GEN2	1956	53
1349	Univ of Iowa Main	IA	15.00	GEN6	1974	35
1350	UNC Chapel Hill Cogeneration	NC	28.00	ST1	1991	18
1351	Univ of Northern Iowa	IA	7.50	GEN1	1982	27
1352	Univ of Notre Dame	IN	3.00	GEN1	1962	47
1353	Univ of Notre Dame	IN	1.70	GEN2	1952	57
1354	Univ of Notre Dame	IN	2.00	GEN5	1956	53
1355	Univ of Notre Dame	IN	5.00	GEN6	1967	42
1356	Univ of Notre Dame	IN	9.40	GEN7	2000	9
1357	Escanaba	MI	11.50	1	1958	51
1358	Escanaba	MI	11.50	2	1958	51
1359	Indiantown Cogeneration Facility	FL	395.40	GEN1	1995	14
1360	Vanderbilt Univ	TN	6.50	GEN1	1988	21
1361	Vanderbilt Univ	TN	4.50	GEN2	1989	20
1362	Howard M Down	NJ	25.00	10	1970	39
1363	Virginia	MN	4.00	1A	1992	17
1364	Virginia	MN	7.50	5	1954	55
1365	Virginia	MN	18.70	6	1971	38
1366	Bremo Bluff	VA	69.00	3	1950	59
1367	Bremo Bluff	VA	185.20	4	1958	51
1368	Chesapeake	VA	185.20	3	1959	50
1369	Chesapeake	VA	112.50	ST1	1953	56
1370	Chesapeake	VA	112.50	ST2	1954	55
1371	Chesapeake	VA	239.30	ST4	1962	47
1372	Chesterfield	VA	112.50	3	1952	57
1373	Chesterfield	VA	187.50	4	1960	49
1374	Chesterfield	VA	359.00	5	1964	45
1375	Chesterfield	VA	693.90	6	1969	40
1376	Clover	VA	424.00	1	1995	14
1377	Clover	VA	424.00	2	1996	13
1378	Mecklenburg Cogeneration Facil	VA	69.90	GEN1	1992	17
1379	Mecklenburg Cogeneration Facil	VA	69.90	GEN2	1992	17
1380	MT Storm	WV	570.20	1	1965	44
1381	MT Storm	WV	570.20	2	1966	43
1382	MT Storm	WV	522.00	3	1973	36
1383	North Branch (WV)	WV	80.00	1	1992	17
1384	Yorktown	VA	187.50	1	1957	52
1385	Yorktown	VA	187.50	2	1959	50
1386	Rhinelander Mill	WI	4.00	GEN3	1940	69
1387	Rhinelander Mill	WI	9.30	GEN6	1958	51
1388	Jeffrey Energy Center	KS	720.00	1	1978	31
1389	Jeffrey Energy Center	KS	720.00	2	1980	29
1390	Jeffrey Energy Center	KS	720.00	3	1983	26
1391	Lawrence Energy Center (KS)	KS	49.00	3	1955	54

Appendix A-3 (continued)
Age of Existing Coal Fired Units
Generating Units Currently in Service
Velocity Suite Database – April 2009

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Plant	State	Capacity MW	Unit	Year in Service	Current Age
1392	Lawrence Energy Center (KS)	KS	114.00	4	1960	49
1393	Lawrence Energy Center (KS)	KS	403.00	5	1971	38
1394	Tecumseh Energy Center	KS	82.00	7	1957	52
1395	Tecumseh Energy Center	KS	150.00	8	1962	47
1396	Hugo (OK)	OK	446.00	ST 1	1982	27
1397	D B Wilson	KY	440.00	UN1	1984	25
1398	Kenneth Coleman	KY	174.20	GEN1	1969	40
1399	Kenneth Coleman	KY	174.20	GEN2	1970	39
1400	Kenneth Coleman	KY	172.80	GEN3	1971	38
1401	R A Reid	KY	96.00	GEN1	1966	43
1402	Robert D Green	KY	264.00	GEN1	1979	30
1403	Robert D Green	KY	264.00	GEN2	1981	28
1404	Altavista Power Station	VA	71.10	1	1992	17
1405	Hopewell	VA	71.10	1	1992	17
1406	Southampton	VA	71.10	1	1992	17
1407	Roanoke Valley 1	NC	182.30	GEN1	1994	15
1408	Roanoke Valley II	NC	57.80	GEN2	1995	14
1409	White Pine Copper Refinery Inc	MI	20.00	GEN1	1954	55
1410	White Pine Copper Refinery Inc	MI	20.00	GEN2	1954	55
1411	Willmar	MN	18.00	3	1970	39
1412	Milwaukee County	WI	11.00	NA	1996	13
1413	Pleasant Prairie	WI	616.50	1	1980	29
1414	Pleasant Prairie	WI	616.50	2	1985	24
1415	Pleasant Prairie	WI	1.70	4	2008	1
1416	Presque Isle	MI	54.40	3	1964	45
1417	Presque Isle	MI	57.80	4	1966	43
1418	Presque Isle	MI	90.00	5	1974	35
1419	Presque Isle	MI	90.00	6	1975	34
1420	Presque Isle	MI	90.00	7	1978	31
1421	Presque Isle	MI	90.00	8	1978	31
1422	Presque Isle	MI	90.00	9	1979	30
1423	South Oak Creek	WI	275.00	5	1959	50
1424	South Oak Creek	WI	275.00	6	1961	48
1425	South Oak Creek	WI	317.60	7	1965	44
1426	South Oak Creek	WI	324.00	8	1967	42
1427	Valley (WI)	WI	136.00	1	1968	41
1428	Valley (WI)	WI	136.00	2	1969	40
1429	Columbia (WI)	WI	512.00	1	1975	34
1430	Columbia (WI)	WI	511.00	2	1978	31
1431	Edgewater (WI)	WI	60.00	3	1951	58
1432	Edgewater (WI)	WI	330.00	4	1969	40
1433	Edgewater (WI)	WI	380.00	5	1985	24
1434	Nelson Dewey	WI	100.00	1	1959	50
1435	Nelson Dewey	WI	100.00	2	1962	47
1436	Pulliam	WI	50.00	5	1949	60
1437	Pulliam	WI	69.00	6	1951	58
1438	Pulliam	WI	81.60	7	1958	51
1439	Pulliam	WI	149.60	8	1964	45
1440	Weston	WI	60.00	1	1954	55
1441	Weston	WI	81.60	2	1960	49
1442	Weston	WI	350.50	3	1981	28
1443	Weston	WI	500.00	4	2008	1
1444	Wyandotte (MI)	MI	11.50	4	1948	61
1445	Wyandotte (MI)	MI	22.00	5	1958	51
1446	Wyandotte (MI)	MI	7.50	6	1969	40
1447	Wyandotte (MI)	MI	32.00	7	1986	23

APPENDIX B
PLANT SITE VISIT MEMORANDA

Appendix B-1
Meramec Station Site Visit Memorandum

Black & Veatch Memorandum May 13, 2009

Meramec Generating Station Site Visit Conducted April 30, 2009

Participants included:
AmerenUE
John Beck, Plant Manager
Jim Zelah,

Black & Veatch
Jim Hurt
Debashis Bose

The Meramec Generating Station (Meramec Facility), which has 4 pulverized coal subcritical power generating units, is located south east of the city of St. Louis, Missouri on the banks of the Meramec and Mississippi Rivers. The Meramec River flows into the Mississippi River adjacent to the plant. Units 1 and 2 are identical units built in 1953 and 1954 respectively, each with a capacity of 138 MW. Unit 3 with capacity of 289 MW was built in 1959 while Unit 4 with capacity of 359 MW was built in 1961.

The Meramec Facility was originally designed to burn Illinois coal, which has a heat content of around12,000 btu/lb (HHV). However a decision was made in around 1980 to switch to Powder River basin (PRB) coal. The average heat content of the PRB coal is approximately 8,400 btu/lb and is transported to the site by rail (unit train). Each unit train includes 135 railcars and delivers about 15,000 tons of PRB coal. The Meramec Facility also has a barge loading and unloading facility at site that is currently not operated. A coal loading system allows loading of coal to barges for transport to other AmerenUE plants. In addition the Meramec Facility has a natural gas pipeline coming into the site. Units 1 and 2 can make full load firing gas; however, natural gas is primarily used for start-up of all units.

Black & Veatch Professionals (Black & Veatch) visited the Meramec Facility power generation station site on April 30, 2009 in order to determine if there were any currently known issues that could affect the life expectancy of the generating facility. During the site visit:

- Black & Veatch conducted a walk down of each unit to observe the condition of the:
  - control room,
  - boiler and associated systems,
  - air quality control equipment,
  - ash systems,
  - fuel yard,
  - turbine deck and associated systems,
  - major electrical equipment.
- Black & Veatch met with plant personnel to discuss:
  - Recent and planned expenditures required to maintain the economic viability, safety, and reliability of each unit,
  - Programs that are being utilized to develop, update and justify the capital projects budget,
  - Equipment outage plans and reports,
  - Corrective action programs,
  - Predictive and preventive maintenance programs,

- Unit operating routines (historical and projected).

During the site visit of the Meramec Facility, Black & Veatch noted a few challenging issues with respect to plant operations:

- The plant site is landlocked with low probability of expanding beyond its existing boundaries.
- Since the plant was built in 1950-1960, significant development has taken place around the plant including an elementary school, a new residential neighborhood and a large municipal solid waste treatment plant. This could expose the plant to stricter environment regulation which in turn might limit future operations of the plant.
- No scrubbers are currently planned to be installed on any of the units at the Meramec Facility.
- The site at the plant is too small to accommodate scrubbers without affecting the coal yard area. If the scrubbers are to be built, the coal yard would have to be reduced and the plant will have to decrease the level of coal stock pile adjacent to the units.
- There is no spare capacity on the coal mills, when the plant is operating at full load all mills are required.

Black & Veatch reviewed NERC GADS data provided by AmerenUE for 2003-2008 and compared with industry data for units of similar size and equipment. Specifically, equivalent availability factor, forced outage rate, and equivalent forced outage rate were reviewed and compared. The units at Meramec Facility were better than the industry averages in all three categories.

Based on interviews with plant personnel conducted during a site visit of the Meramec Facility along with technical information provided by AmerenUE, Black & Veatch did not identify issues that it believes would shorten the physical life of the plant, provided the existing operations and maintenance practices as well as capital investment programs are continued. Major issues appeared to be fully disclosed and discussed. Most of the issues identified are typical for assets of this type and age and nearly all have technical solutions. It is also recognized that these are aging units that will experience equipment and systems failures over the years unless significant expenditures are made. Based on available information, the (2001-2013) historical and long term forecast capital expenditure plan developed by AmerenUE and reviewed by Black & Veatch includes cost estimates for addressing the equipment and system issues which are most critical.

Black & Veatch personnel did not find evidence that would indicate that these units cannot continue to operate in a manner similar to recent experience based on the following assumptions:

- The units will continue to be operated in a mode consistent with industry practice for units of this type and age.
- Information provided by AmerenUE personnel regarding the generating station is complete and accurate.
- Application of operations and maintenance programs consistent with industry practices for units of the type and age will continue.
- Application of corrective action, and predictive and preventive maintenance programs that will enable AmerenUE to minimize exposure to catastrophic failures.
- Application of programs at the plant as well as corporate level to assure that personnel are competent to operate and maintain the facilities in a manner consistent with prudent industry practices.
- The capital expenditure estimates in the long term capital plan developed by AmerenUE will be periodically reviewed and adjusted in a timely manner to accomodate changing regulations, or as differing conditions are encountered. AmerenUE will implement the long term capital plan in a timely manner.

Based on the foregoing, Black & Veatch does not foresee any technical reasons that would cause the currently operating generation assets at the Meramec Facility to be retired prematurely. Black & Veatch can not opine as to whether there will be economic, operational, or environmental issues which might adversely affect the viability of the generating assets in the future.

Plant staff appeared knowledgeable and conducted themselves professionally. Operating practices at the plant appear prudent and consistent with generally accepted utility practices.

Appendix B-2
Sioux Station Site Visit Memorandum

Black & Veatch Memorandum May 13, 2009

Sioux Generating Station Site Visit Conducted April 28 & 29, 2009

Participants included:
AmerenUE
Karl Blank, Plant Manager
Mike Romano, Superintendent of Production
Harry Benhardt, Superintendent of Tech Support
Patrick Weir, Supervising Engineer
Jim Riegerix, Outage Coordinator

Black & Veatch
Jim Teaney
Matt Oakes

The Sioux Generating Station (Sioux Facility), which has 2 supercritical cyclone fired, power generating units, is located on the north side of the city of St. Louis, Missouri on the south banks of the Mississippi river. Unit 1 was built in 1967 and has a nameplate capacity of 550 MW. Unit 2 was built in 1968 and also has a nameplate capacity of 550 MW.

The Sioux Facility has the capability to burn both Illinois coal and Power River Basin (PRB) coal. The PRB coal is delivered to the site by rail while the Illinois coal is received by barge. In the past, the Sioux Facility had also blended in pet coke as well as chipped rubber tires into the coal fuel, but not at the current time. There is no natural gas supply at the Sioux Facility site.

Black & Veatch Professionals (Black & Veatch) visited the Sioux power generation station site on April 28 and 29, 2009 in order to determine if there were any currently known issues that could affect the life expectancy of the generating facility. During this visit:

- Black & Veatch conducted a walk down of each unit to observe the condition of the:
  - control room,
  - boiler and associated systems,
  - air quality control equipment,
  - ash systems,
  - fuel yard,
  - turbine deck and associated systems,
  - major electrical equipment.
- Black & Veatch met with plant personnel to discuss:
  - Recent and planned expenditures required to maintain the economic viability, safety, and reliability of each unit,
  - Programs that are being utilized to develop, update and justify the capital projects budget,
  - Equipment outage plans and reports,
  - Corrective action programs,
  - Predictive and preventive maintenance programs,
  - Unit operating routines (historical and projected).

During the site visit of the Sioux facility, Black & Veatch noted a few issues, some of which are being addressed. These issues include:

- No black start capability at the plant site. An emergency generator is on site.
- No natural gas supply at the plant site.
- Units are run in load following operation. Previously during minimum load the cyclones were cycled off. In 1999, the plant stopped cycling the cyclones off during minimum load. This change reduces the thermal stress on the cyclone tubes, thereby reducing tube failures.
- In 2006, the plant quit burning a blend of chipped tires. This seemed to reduce the boiler tube leaks.
- There is limited space remaining in the on-site ash ponds for disposal. The plant has purchased an additional area of land which is being prepared for landfill of fly ash and scrubber waste.
- Twice annually the plant treats the circulating water intake for zebra mussels.

Black & Veatch reviewed and compared NERC GADS data provided by AmerenUE for 2003-2008 with industry data for units of similar size and technology. Specifically, equivalent availability factor, forced outage rate, and equivalent forced outage rate were reviewed and compared. The units at Sioux were better than the industry averages in all three categories.

Based on interviews with plant personnel conducted during a site visit of the Sioux power generating station along with technical information provided by AmerenUE, Black & Veatch did not identify issues that it believes would shorten the physical life of the plant, provided the existing operations and maintenance practices as well as capital expenditure programs are continued. Major issues appeared to be fully disclosed and discussed. Most of the issues identified are typical for assets of this type and age and nearly all have technical solutions. It is also recognized that these are aging units that will experience equipment and systems failures over the years unless significant expenditures are made. Based on available information, the (2001-2013) historical and long term forecast capital expenditure plan developed by AmerenUE and reviewed by Black & Veatch includes cost estimates for addressing the equipment and system issues which are most critical.

Black & Veatch did not find any evidence that would indicate that these units cannot continue to operate in a manner similar to industry norms based on the following assumptions:

- The units continue to be operated in a mode consistent with industry practice for units of this type and age.
- Information provided by AmerenUE personnel regarding the generating station is complete and accurate.
- Application of operations and maintenance programs consistent with industry practices for units of the type and age will continue.
- Application of corrective action, and predictive and preventive maintenance programs that will enable AmerenUE to minimize exposure to catastrophic failures.
- Application of programs at the plant as well as corporate level to assure that personnel are competent to operate and maintain the facilities in a manner consistent with prudent industry practices.
- The capital expenditure estimates in the long term capital plan developed by AmerenUE will be periodically reviewed and adjusted in a timely manner to accomodate changing regulations, or as differing conditions are encountered. AmerenUE will implement the long term capital plan in a timely manner.

Based on the foregoing, Black & Veatch does not foresee any technical reasons that would cause the currently operating generation assets at the Sioux Facility to be retired prematurely. Black & Veatch cannot opine as to whether there will be economic, operational, or environmental issues which might adversely affect the viability of the generating assets in the future.

Plant staff appeared knowledgeable and conducted themselves professionally. Operating practices at the plant appear prudent and consistent with generally accepted utility practices.

Appendix B-3
Labadie Station Site Visit Memorandum

Black & Veatch Memorandum May 13, 2009

Labadie Generating Station Site Visit Conducted April 30, 2009

Participants included:
AmerenUE
Wes Straatman, Power Operations Services Engineer

Black & Veatch
Jim Teaney
Matt Oakes

The Labadie Generating Station (Labadie Facility), which has 4 pulverized coal subcritical power generating units, is located south west of the city of St. Louis, Missouri on the banks of the Missouri river. Units 1 and 2 were built in 1970 and 1971, respectively and both have a nameplate capacity of 574 MW. Units 3 and 4 were built in 1972 and 1973, respectively and both have a nameplate capacity of 621 MW.

The Labadie Facility currently only burns Power River Basin (PRB) coal which is delivered to the site by one rail provider. A natural gas main supply is available at the south side of the site, but the plant is not currently tied into it.

Black & Veatch Professionals (Black & Veatch) visited the Labadie power generation station site on April 28 and 29, 2009 in order to determine if there were any currently known issues that could affect the life expectancy of the generating facility. During this visit:

- Black & Veatch conducted a walk down of each unit to observe the condition of the:
  - control room,
  - boiler and associated systems,
  - air quality control equipment,
  - ash systems,
  - fuel yard,
  - turbine deck and associated systems,
  - major electrical equipment.
- Black & Veatch met with plant personnel to discuss:
  - Recent and planned expenditures required to maintain the economic viability, safety, and reliability of each unit,
  - Programs that are being utilized to develop, update and justify the capital projects budget.
  - Equipment outage plans and reports
  - Corrective action programs
  - Predictive and preventive maintenance programs
  - Unit operating routines (historical and projected).

During the site visit of the Labadie facility, Black & Veatch noted a few challenging issues, some of which were being addressed.

- No black start capability at the plant site. A 5 MW emergency generator is on site.
- No auxiliary boiler at the site.

- A natural gas main was available at the south side of the site, but the plant is not currently tied into it.
- Coal is only available by rail and from one rail service provider.
- There was limited space remaining on-site for disposal and storage of bottom ash and fly ash. An additional area of land has been purchased near the site to do so.
- Some issues with the burners wearing out prematurely. Plant cannot replace them with an improved burner design due to current fit and lack of additional space required.

Black & Veatch reviewed NERC GADS data provided by AmerenUE for 2003-2008 and compared with industry data for units of similar size and equipment. Specifically, equivalent availability factor, forced outage rate, and equivalent forced outage rate were reviewed and compared. The units at Labadie were better than the industry averages in all three categories.

Based on interviews with plant personnel conducted during a site visit of the Labadie power generating station along with technical information provided by AmerenUE, Black & Veatch did not identify any issues that it believes would limit the physical life of the plant, provided the existing operations and maintenance practices as well as capital expenditure programs are continued. Major issues appeared to be fully disclosed and discussed. Most of these issues are typical for assets of this type and age and nealy all have technical solutions. It is also recognized that these are aging units that will experience equipment and systems failures over the years unless significant expenditures are made. Based on information available at the time, the (2001-2013) historical and long term forecast capital expenditure plan developed by AmerenUE and reviewed by Black & Veatch includes cost estimates for addressing these equipment and system issues.

Black & Veatch personnel did not find evidence that would indicate that these units cannot continue to operate in a manner similar to recent experience based on the following assumptions:

- The units will continue to be operated in a mode consistent with industry practice for units of this type and age.
- Information provided by AmerenUE personnel regarding the generating station is complete and accurate.
- Application of operations and maintenance programs consistent with industry practices for units of the type and age will continue.
- Application of corrective action, and predictive and preventive maintenance programs that will enable AmerenUE to minimize exposure to catastrophic failures.
- Application of programs at the plant as well as corporate level to assure that personnel are competent to operate and maintain the facilities in a manner consistent with prudent industry practices.
- The capital expenditure estimates in the long term capital plan developed by AmerenUE will be periodically reviewed and adjusted in a timely manner to accomodate changing regulations, or as differing conditions are encountered. AmerenUE will implement the long term capital plan in a timely manner.

Based on the foregoing, Black & Veatch does not foresee any technical reasons that would cause the currently operating generation assets at the Labadie Facility to be retired prematurely. Black & Veatch can not opine as to whether there will be economic, operational, or environmental issues which might adversely affect the viability of the generating assets in the future.

Plant staff appeared knowledgeable and conducted themselves professionally. Operating practices at the plant appear prudent and consistent with generally accepted utility practices.

Appendix B-4
Rush Island Station Site Visit Memorandum

Black & Veatch Memorandum May 13, 2009

Rush Island Generating Station Site Visit Conducted April 28 & 29, 2009

Participants included:

AmerenUE
David L. Strubberg, Plant Manager
Gregory Vasel, Superintendent, Technical Support
Andrew Williamson, Superintendent, Productions
Paul Starks, Superintendent, Maintenance
Gary Blessing, Supervising Engineer

Black & Veatch
Jim Hurt
Debashis Bose

The Rush Island Facility, which has 2 pulverized coal (PC) subcritical power generating units, is located in Festus, Missouri on the banks of the Mississippi river. The two units are identical units built in 1976 and 1977 respectively, each with a nameplate capacity of 621 MW.

The Rush Island Facility was originally designed to burn Illinois coal, which has a heat content of around 12,000 btu/lb. The plant now burns Powder River basin (PRB) coal. The average heat content of the PRB coal is approximately 8,400 btu/lb (HHV) and is transported to the site by rail. The Rush Island Facility also has a barge unloading facility at site, which gives an alternative coal transportation option. However, due to current coal supply restrictions, the Rush Island Facility cannot use the barge facility for delivery of coal. The coal contract for the Rush Island Facility was renewed in 2008 and runs through 2018. The plant uses fuel oil for start-up because natural gas is not available at the site. Plant personnel are not aware of any natural gas pipelines near the site. A competing railroad is not available to the site.

Black & Veatch Professionals (Black & Veatch) visited the Rush Island Facility power generation station site on April 30, 2009 in order to determine if there were any currently known issues that could affect the life expectancy of the generating facility. During the site visit:

- Black & Veatch conducted a walk down of each unit to observe the condition of the:
  - control room,
  - boiler and associated systems,
  - air quality control equipment,
  - ash systems,
  - fuel yard,
  - turbine deck and associated systems,
  - major electrical equipment.

- Black & Veatch met with plant personnel to discuss:
  - Recent and planned expenditures required to maintain the economic viability, safety, and reliability of each unit,
  - Programs that are being utilized to develop, update and justify the capital projects budget,

- Equipment outage plans and reports,
- Corrective action programs,
- Predictive and preventive maintenance programs,
- Unit operating routines (historical and projected).

Black & Veatch noted that both units were operating very well at high reliability levels. On the day of the visit, Unit 1 had been operating continuously for 235 days since its last outage. Based on the information provided by the plant personnel, Black & Veatch noted that the plant had made change to its coal handling facility to accommodate the higher volume of PRB coal needed in comparison to the Illinois coal. The fly ash is marketed to an adjacent concrete plant and the bottom ash is collected in the ash pond. Black & Veatch did not find any significant issues with any of the systems in the plant. However Black & Veatch made certain observations regarding future expansion of the site:

- The plant site is landlocked with low probability of expanding beyond its existing boundaries.
- The plant site was originally planned for four units; however only two have been built and so the plant has sufficient room to add scrubbers or possibly a third unit.

Black & Veatch reviewed NERC GADS data provided by AmerenUE for 2003-2008 and compared with industry data for units of similar size and equipment. Specifically, equivalent availability factor, forced outage rate, and equivalent forced outage rate were reviewed and compared. The units at Rush Island Facility were better than the industry averages in all three categories.

Based on interviews with plant personnel conducted during a site visit of the Rush Island Facility along with technical information provided by AmerenUE, B& V did not identify any issues that it believes would limit the physical life of the plant, provided the existing operations and maintenance practices as well as capital expenditure programs are continued. Major issues appeared to be fully disclosed and discussed. Most of these issues are typical for assets of this type and age and nearly all have technical solutions. It is also recognized that these are aging units that will experience equipment and systems failures over the years unless significant expenditures are made. Based on information available at the time, the (2001-2013) historical and long term forecast capital expenditure plan developed by AmerenUE and reviewed by Black & Veatch includes cost estimates for addressing these equipment and system issues.

Black & Veatch personnel did not find evidence that would indicate that these units cannot continue to operate in a manner similar to recent experience based on the following assumptions:

- The units will continue to be operated in a mode consistent with industry practice for units of this type and age.
- Information provided by AmerenUE personnel regarding the generating station is complete and accurate.
- Application of operations and maintenance programs consistent with industry practices for units of the type and age will continue.
- Application of corrective action, and predictive and preventive maintenance programs that will enable AmerenUE to minimize exposure to catastrophic failures.
- Application of programs on the plant as well as corporate level to assure that personnel are competent to operate and maintain the facilities in a manner consistent with prudent industry practices.
- The capital expenditure estimates in the long term capital plan developed by AmerenUE will be periodically reviewed and adjusted in a timely manner to accomodate changing regulations, or as differing conditions are are encountered. AmerenUE will implement the long term capital plan in a timely manner.

Based on the foregoing, Black & Veatch does not foresee any technical reasons that would cause the currently operating generation assets at the Rush Island Facility to be retired prematurely. Black & Veatch can not opine as to whether there will be economic, operational, or environmental issues which might adversely affect the viability of the generating assets in the future.

Plant staff appeared knowledgeable and conducted themselves professionally. Operating practices at the plant appear prudent and consistent with generally accepted utility practices.

APPENDIX C
ACTUARIAL ANALYSIS RESULTS

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               AmerenUE - Electric

        PROGRAM OPTIONS IN EFFECT:

          MAXIMUM DATA FILE EXPERIENCE BAND      1913-2008

          TRAN CODES INCLUDED AS RETIREMENTS       0,0,0,7
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                     AmerenUE - Electric

           ACCOUNT 311 STRUCTURES & IMPROVEMENTS

             INPUT CONTROL TOTALS THROUGH 2008

TRAN       -------- T O T A L   I N P U T   D A T A --------
CODE                AGED            UNAGED            TOTAL

  0         15,551,130.77-                   15,551,130.77-
  3          5,010,932.15-                    5,010,932.15-
  7         26,988,405.06-                   26,988,405.06-
  9        244,246,701.53                   244,246,701.53

TOTAL DATA 196,696,233.55                   196,696,233.55

  8        196,696,232.35                   196,696,232.35

TOTAL DATA
 LESS CD 8           1.20                             1.20
```

AmerenUE - Electric

ACCOUNT 311 STRUCTURES & IMPROVEMENTS

ORIGINAL LIFE TABLE

AVG AGE RET 41.6 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	243,657,711	114,534	0.0005	0.9995	100.00
0.5	232,071,333	335,602	0.0014	0.9986	99.95
1.5	230,324,346	881,502	0.0038	0.9962	99.81
2.5	227,861,082	348,877	0.0015	0.9985	99.43
3.5	223,858,468	425,748	0.0019	0.9981	99.28
4.5	219,925,794	182,710	0.0008	0.9992	99.09
5.5	215,293,576	672,931	0.0031	0.9969	99.01
6.5	207,600,762	235,040	0.0011	0.9989	98.70
7.5	196,379,434	442,088	0.0023	0.9977	98.59
8.5	193,995,379	419,663	0.0022	0.9978	98.36
9.5	191,495,864	413,212	0.0022	0.9978	98.14
10.5	190,564,399	530,721	0.0028	0.9972	97.92
11.5	187,910,242	113,755	0.0006	0.9994	97.65
12.5	182,151,747	345,694	0.0019	0.9981	97.59
13.5	179,672,727	292,634	0.0016	0.9984	97.40
14.5	174,924,650	244,948	0.0014	0.9986	97.24
15.5	172,064,172	264,070	0.0015	0.9985	97.10
16.5	168,643,762	474,912	0.0028	0.9972	96.95
17.5	164,440,486	393,385	0.0024	0.9976	96.68
18.5	157,806,071	130,954	0.0008	0.9992	96.45
19.5	155,591,828	606,268	0.0039	0.9961	96.37
20.5	153,348,509	490,047	0.0032	0.9968	95.99
21.5	151,570,704	1,137,358	0.0075	0.9925	95.68
22.5	149,276,305	426,339	0.0029	0.9971	94.96
23.5	147,813,527	230,243	0.0016	0.9984	94.68
24.5	146,604,297	222,003	0.0015	0.9985	94.53
25.5	137,989,039	805,269	0.0058	0.9942	94.39
26.5	136,361,422	428,652	0.0031	0.9969	93.84
27.5	134,786,968	632,342	0.0047	0.9953	93.55
28.5	131,262,186	1,072,388	0.0082	0.9918	93.11
29.5	129,539,159	84,611	0.0007	0.9993	92.35
30.5	129,144,807	376,945	0.0029	0.9971	92.29
31.5	119,951,459	399,919	0.0033	0.9967	92.02
32.5	88,954,084	141,130	0.0016	0.9984	91.72
33.5	88,306,288	198,163	0.0022	0.9978	91.57
34.5	87,556,318	380,745	0.0043	0.9957	91.37
35.5	81,341,120	184,068	0.0023	0.9977	90.98
36.5	74,396,080	242,158	0.0033	0.9967	90.77
37.5	68,904,014	416,994	0.0061	0.9939	90.47
38.5	58,505,178	223,423	0.0038	0.9962	89.92

AmerenUE - Electric

ACCOUNT 311 STRUCTURES & IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

AVG AGE RET 41.6 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	58,243,273	436,324	0.0075	0.9925	89.58
40.5	53,624,314	173,839	0.0032	0.9968	88.91
41.5	47,617,438	343,731	0.0072	0.9928	88.63
42.5	47,266,864	209,254	0.0044	0.9956	87.99
43.5	46,980,914	68,082	0.0014	0.9986	87.60
44.5	46,835,957	82,897	0.0018	0.9982	87.48
45.5	46,742,666	78,137	0.0017	0.9983	87.32
46.5	46,624,590	160,709	0.0034	0.9966	87.17
47.5	41,996,393	532,002	0.0127	0.9873	86.87
48.5	41,437,336	639,274	0.0154	0.9846	85.77
49.5	35,573,981	245,668	0.0069	0.9931	84.45
50.5	35,234,478	842,884	0.0239	0.9761	83.87
51.5	34,085,824	1,707,952	0.0501	0.9499	81.87
52.5	31,472,832	4,581,053	0.1456	0.8544	77.77
53.5	17,867,638	5,779,777	0.3235	0.6765	66.45
54.5	11,498,515	1,618,110	0.1407	0.8593	44.95
55.5	9,827,997	1,237,914	0.1260	0.8740	38.63
56.5	8,536,830	200,371	0.0235	0.9765	33.76
57.5	8,221,240	6,195	0.0008	0.9992	32.97
58.5	8,150,341	743,973	0.0913	0.9087	32.94
59.5	7,391,430	2,592,585	0.3508	0.6492	29.93
60.5	4,491,639	3,072,968	0.6842	0.3158	19.43
61.5	1,333,196	613,343	0.4601	0.5399	6.14
62.5	719,488		0.0000	1.0000	3.31
63.5	610,173		0.0000	1.0000	3.31
64.5	610,173		0.0000	1.0000	3.31
65.5	610,173		0.0000	1.0000	3.31
66.5	610,173		0.0000	1.0000	3.31
67.5	610,173		0.0000	1.0000	3.31
68.5	610,173		0.0000	1.0000	3.31
69.5	610,173		0.0000	1.0000	3.31
70.5	610,173		0.0000	1.0000	3.31
71.5	610,173		0.0000	1.0000	3.31
72.5	610,173		0.0000	1.0000	3.31
73.5	610,173	610,173	1.0000	0.0000	3.31
74.5					0.00
75.5					
76.5					
77.5					
78.5	276	276	1.0000		

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                      AmerenUE - Electric

             ACCOUNT 311 STRUCTURES & IMPROVEMENTS

                      ORIGINAL LIFE TABLE, CONT.

AVG AGE RET 41.6              1          EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008           EXPERIENCE BAND 1923-2008

 AGE AT   EXPOSURES AT   RETIREMENTS                   PCT SURV
BEGIN OF  BEGINNING OF   DURING AGE  RETMT    SURV    BEGIN OF
INTERVAL  AGE INTERVAL    INTERVAL   RATIO    RATIO   INTERVAL

  79.5

TOTAL   7,030,332,650   42,539,536
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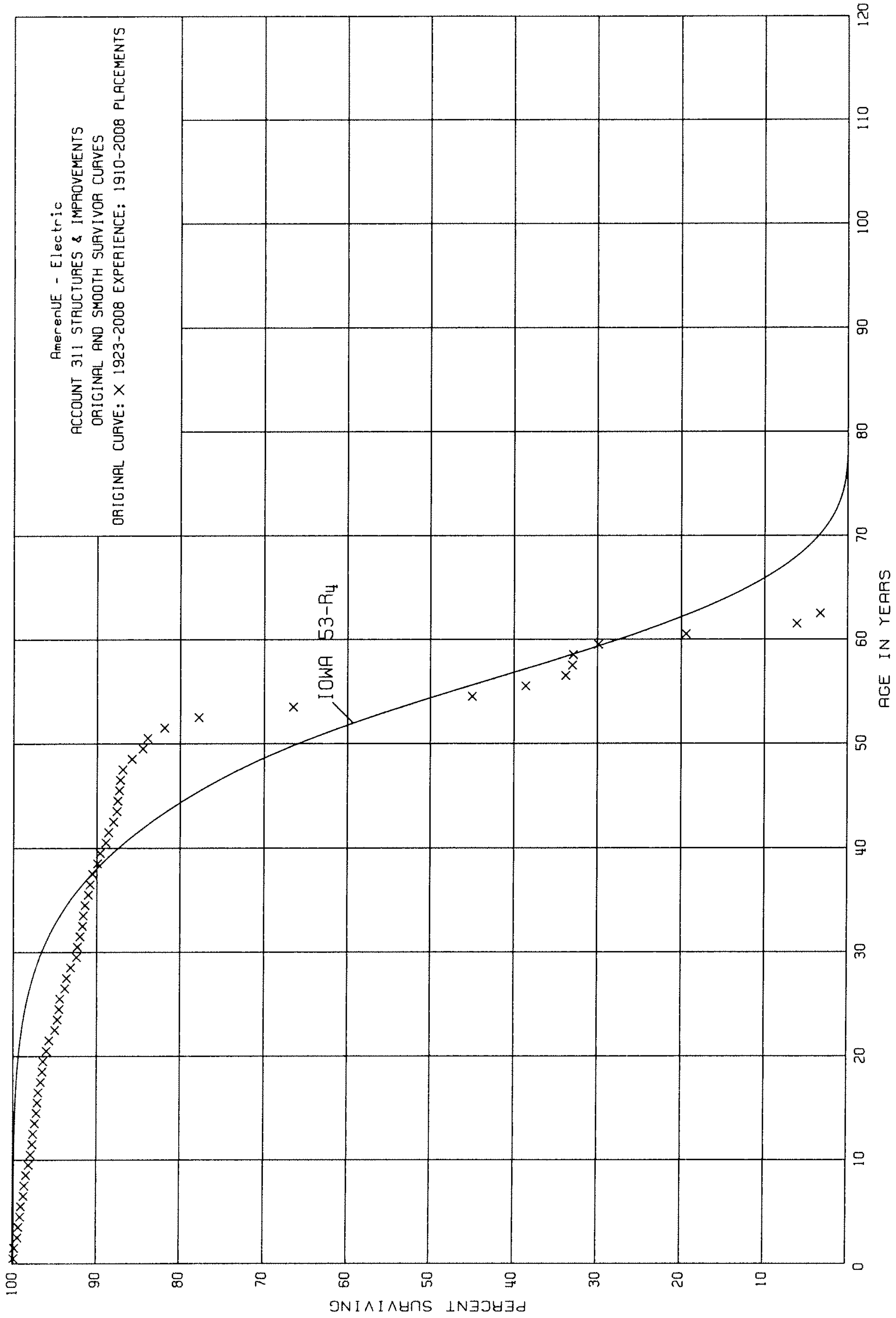
AmerenUE - Electric
ACCOUNT 311 STRUCTURES & IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1923-2008 EXPERIENCE; 1910-2008 PLACEMENTS
IOWA 53-R4
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

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                    AmerenUE - Electric

             ACCOUNT 312 BOILER PLANT EQUIPMENT

             INPUT CONTROL TOTALS THROUGH 2008

TRAN       -------- T O T A L   I N P U T   D A T A --------
CODE                AGED            UNAGED            TOTAL

  0         315,947,491.60-                  315,947,491.60-
  3          32,613,510.43-                   32,613,510.43-
  7          42,942,836.68-                   42,942,836.68-
  9       2,216,727,908.93                 2,216,727,908.93

TOTAL DATA1,825,224,070.22                 1,825,224,070.22

  8       1,825,224,069.44                 1,825,224,069.44

TOTAL DATA
 LESS CD 8            0.78                             0.78
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AmerenUE - Electric

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

AVG AGE RET 21.6 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,216,467,344	215,633	0.0001	0.9999	100.00
0.5	2,163,240,798	1,240,296	0.0006	0.9994	99.99
1.5	2,063,311,227	12,416,083	0.0060	0.9940	99.93
2.5	1,990,338,784	12,737,737	0.0064	0.9936	99.33
3.5	1,931,998,558	8,018,114	0.0042	0.9958	98.69
4.5	1,803,836,400	8,740,020	0.0048	0.9952	98.28
5.5	1,716,810,022	12,210,969	0.0071	0.9929	97.81
6.5	1,562,163,327	9,301,882	0.0060	0.9940	97.12
7.5	1,417,074,670	11,203,030	0.0079	0.9921	96.54
8.5	1,373,874,735	12,267,040	0.0089	0.9911	95.78
9.5	1,320,524,451	11,464,287	0.0087	0.9913	94.93
10.5	1,298,207,121	11,030,104	0.0085	0.9915	94.10
11.5	1,243,701,441	5,318,661	0.0043	0.9957	93.30
12.5	1,114,426,650	6,736,718	0.0060	0.9940	92.90
13.5	1,046,481,964	6,477,772	0.0062	0.9938	92.34
14.5	981,559,368	25,048,654	0.0255	0.9745	91.77
15.5	904,096,412	5,635,560	0.0062	0.9938	89.43
16.5	862,823,272	6,987,008	0.0081	0.9919	88.88
17.5	850,294,418	6,087,687	0.0072	0.9928	88.16
18.5	829,507,874	9,248,482	0.0111	0.9889	87.53
19.5	817,085,966	3,397,322	0.0042	0.9958	86.56
20.5	813,179,527	6,142,331	0.0076	0.9924	86.20
21.5	804,067,507	4,306,511	0.0054	0.9946	85.54
22.5	784,622,809	5,574,540	0.0071	0.9929	85.08
23.5	776,413,649	3,373,288	0.0043	0.9957	84.48
24.5	770,880,025	5,558,587	0.0072	0.9928	84.12
25.5	715,186,383	6,383,439	0.0089	0.9911	83.51
26.5	688,502,718	17,409,623	0.0253	0.9747	82.77
27.5	623,909,145	6,467,962	0.0104	0.9896	80.68
28.5	611,927,917	8,762,962	0.0143	0.9857	79.84
29.5	601,287,404	13,639,815	0.0227	0.9773	78.70
30.5	586,590,255	12,760,973	0.0218	0.9782	76.91
31.5	488,616,647	15,697,048	0.0321	0.9679	75.23
32.5	369,963,712	6,410,500	0.0173	0.9827	72.82
33.5	362,918,132	5,215,469	0.0144	0.9856	71.56
34.5	357,273,013	7,385,359	0.0207	0.9793	70.53
35.5	288,563,255	4,404,279	0.0153	0.9847	69.07
36.5	223,207,660	2,392,406	0.0107	0.9893	68.01
37.5	176,412,164	4,063,591	0.0230	0.9770	67.28
38.5	122,508,869	1,867,211	0.0152	0.9848	65.73

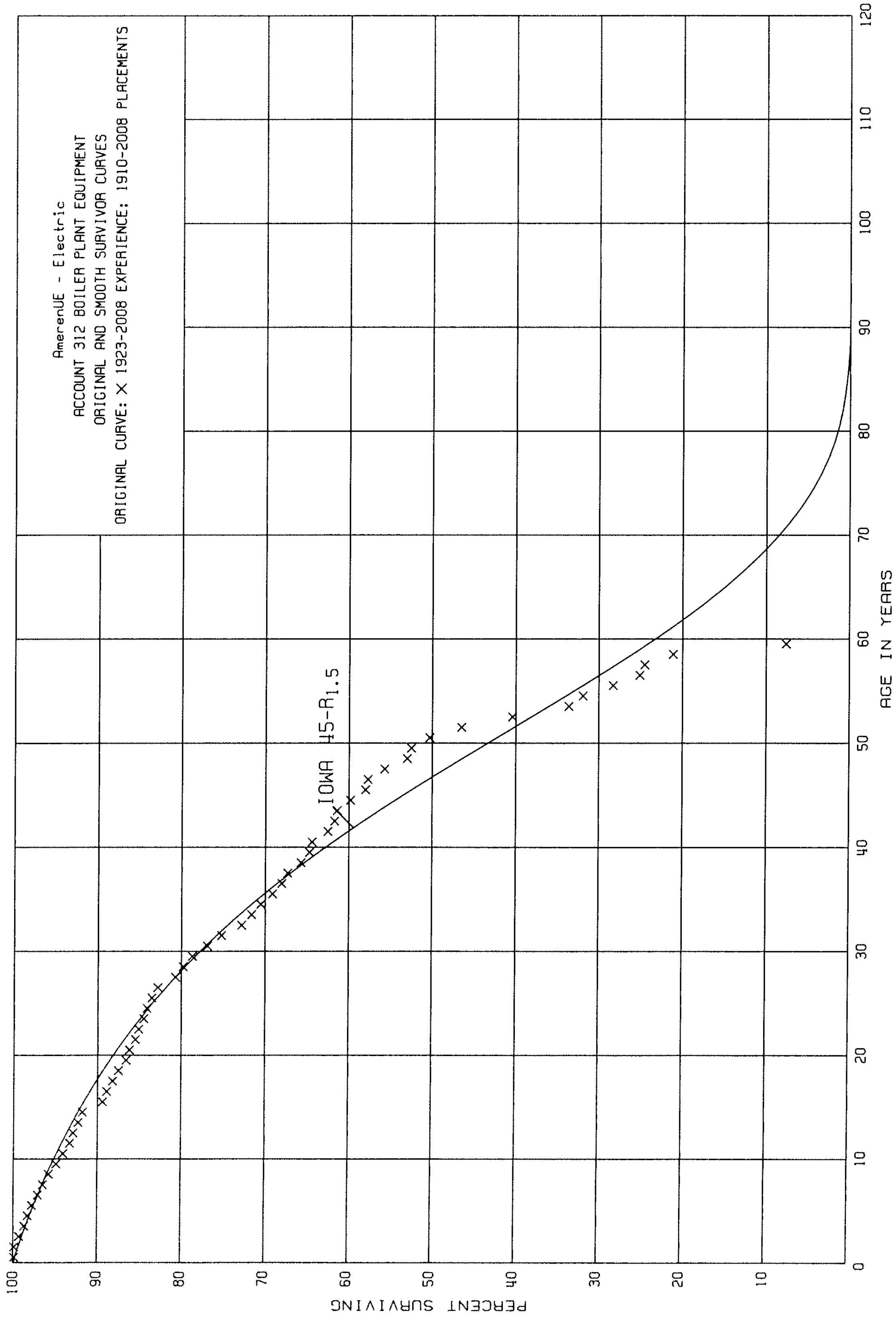
AmerenUE - Electric

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

AVG AGE RET 21.6 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	119,884,646	556,795	0.0046	0.9954	64.73
40.5	101,082,698	2,989,639	0.0296	0.9704	64.43
41.5	76,829,332	1,020,637	0.0133	0.9867	62.52
42.5	75,639,101	306,245	0.0040	0.9960	61.69
43.5	73,962,199	1,991,520	0.0269	0.9731	61.44
44.5	71,150,589	2,119,509	0.0298	0.9702	59.79
45.5	69,177,691	390,975	0.0057	0.9943	58.01
46.5	68,626,425	2,354,432	0.0343	0.9657	57.68
47.5	49,859,713	2,410,870	0.0484	0.9516	55.70
48.5	47,393,220	444,560	0.0094	0.9906	53.00
49.5	33,629,839	1,432,163	0.0426	0.9574	52.50
50.5	32,096,390	2,404,897	0.0749	0.9251	50.26
51.5	29,636,321	3,891,502	0.1313	0.8687	46.50
52.5	25,744,814	4,340,681	0.1686	0.8314	40.39
53.5	20,689,006	1,058,156	0.0511	0.9489	33.58
54.5	14,213,500	1,579,029	0.1111	0.8889	31.86
55.5	5,987,457	672,314	0.1123	0.8877	28.32
56.5	5,308,513	144,528	0.0272	0.9728	25.14
57.5	5,164,153	709,223	0.1373	0.8627	24.46
58.5	4,454,930	2,841,608	0.6379	0.3621	21.10
59.5	1,625,606	1,472,502	0.9058	0.0942	7.64
60.5	159,589	142,752	0.8945	0.1055	0.72
61.5	16,837	2,544	0.1511	0.8489	0.08
62.5	14,293	14,293	1.0000	0.0000	0.07
63.5					0.00
64.5					
65.5					
TOTAL	40,606,202,455	358,890,327			


AmerenUE - Electric
ACCOUNT 312 BOILER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1923-2008 EXPERIENCE; 1910-2008 PLACEMENTS
IOWA 45-R1.5
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10

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                    AmerenUE - Electric

              ACCOUNT 314 TURBOGENERATOR UNITS

             INPUT CONTROL TOTALS THROUGH 2008

TRAN       -------- T O T A L   I N P U T   D A T A --------
CODE                AGED            UNAGED            TOTAL

  0          92,606,815.79-                  92,606,815.79-
  3           9,143,452.22                    9,143,452.22
  7          28,342,230.61-                  28,342,230.61-
  9         639,941,566.65                  639,941,566.65

TOTAL DATA  528,135,972.47                  528,135,972.47

  8         528,135,972.70                  528,135,972.70

TOTAL DATA
 LESS CD 8            0.23-                           0.23-
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                    AmerenUE - Electric

              ACCOUNT 314 TURBOGENERATOR UNITS

                    ORIGINAL LIFE TABLE

AVG AGE RET 30.0              1          EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008          EXPERIENCE BAND 1923-2008

 AGE AT   EXPOSURES AT   RETIREMENTS                   PCT SURV
BEGIN OF  BEGINNING OF   DURING AGE  RETMT    SURV    BEGIN OF
INTERVAL  AGE INTERVAL    INTERVAL   RATIO    RATIO   INTERVAL

   0.0    639,901,478      208,770  0.0003  0.9997   100.00
   0.5    604,167,385       49,089  0.0001  0.9999    99.97
   1.5    617,582,703      561,741  0.0009  0.9991    99.96
   2.5    580,220,455    2,571,127  0.0044  0.9956    99.87
   3.5    540,536,269    1,248,691  0.0023  0.9977    99.43
   4.5    517,164,995    1,748,581  0.0034  0.9966    99.20
   5.5    454,987,632    2,589,512  0.0057  0.9943    98.86
   6.5    408,849,148    6,389,418  0.0156  0.9844    98.30
   7.5    373,775,740      304,049  0.0008  0.9992    96.77
   8.5    362,669,290      565,369  0.0016  0.9984    96.69

   9.5    331,607,760    2,717,527  0.0082  0.9918    96.54
  10.5    327,025,741      477,272  0.0015  0.9985    95.75
  11.5    322,055,521      171,847  0.0005  0.9995    95.61
  12.5    320,136,888    4,332,210  0.0135  0.9865    95.56
  13.5    309,397,047       73,444  0.0002  0.9998    94.27
  14.5    301,523,106    1,734,493  0.0058  0.9942    94.25
  15.5    299,221,090    4,173,014  0.0139  0.9861    93.70
  16.5    294,170,941       20,804  0.0001  0.9999    92.40
  17.5    291,564,230      262,040  0.0009  0.9991    92.39
  18.5    289,081,973    3,050,905  0.0106  0.9894    92.31

  19.5    285,683,382      106,050  0.0004  0.9996    91.33
  20.5    285,095,460      584,800  0.0021  0.9979    91.29
  21.5    283,892,591    1,301,726  0.0046  0.9954    91.10
  22.5    282,453,056      185,329  0.0007  0.9993    90.68
  23.5    282,028,917    1,651,993  0.0059  0.9941    90.62
  24.5    269,967,853    1,100,307  0.0041  0.9959    90.09
  25.5    268,372,951    7,472,680  0.0278  0.9722    89.72
  26.5    260,579,846      939,049  0.0036  0.9964    87.23
  27.5    259,214,377    5,255,907  0.0203  0.9797    86.92
  28.5    244,076,167    3,709,980  0.0152  0.9848    85.16

  29.5    237,988,195   11,148,016  0.0468  0.9532    83.87
  30.5    226,800,420    9,350,945  0.0412  0.9588    79.94
  31.5    196,187,779    3,266,053  0.0166  0.9834    76.65
  32.5    154,628,674    2,634,429  0.0170  0.9830    75.38
  33.5    151,990,890      907,017  0.0060  0.9940    74.10
  34.5    151,083,872       31,041  0.0002  0.9998    73.66
  35.5    137,003,254    2,256,380  0.0165  0.9835    73.65
  36.5    116,370,219      250,410  0.0022  0.9978    72.43
  37.5    103,165,694    4,247,375  0.0412  0.9588    72.27
  38.5     82,787,381    1,244,148  0.0150  0.9850    69.29
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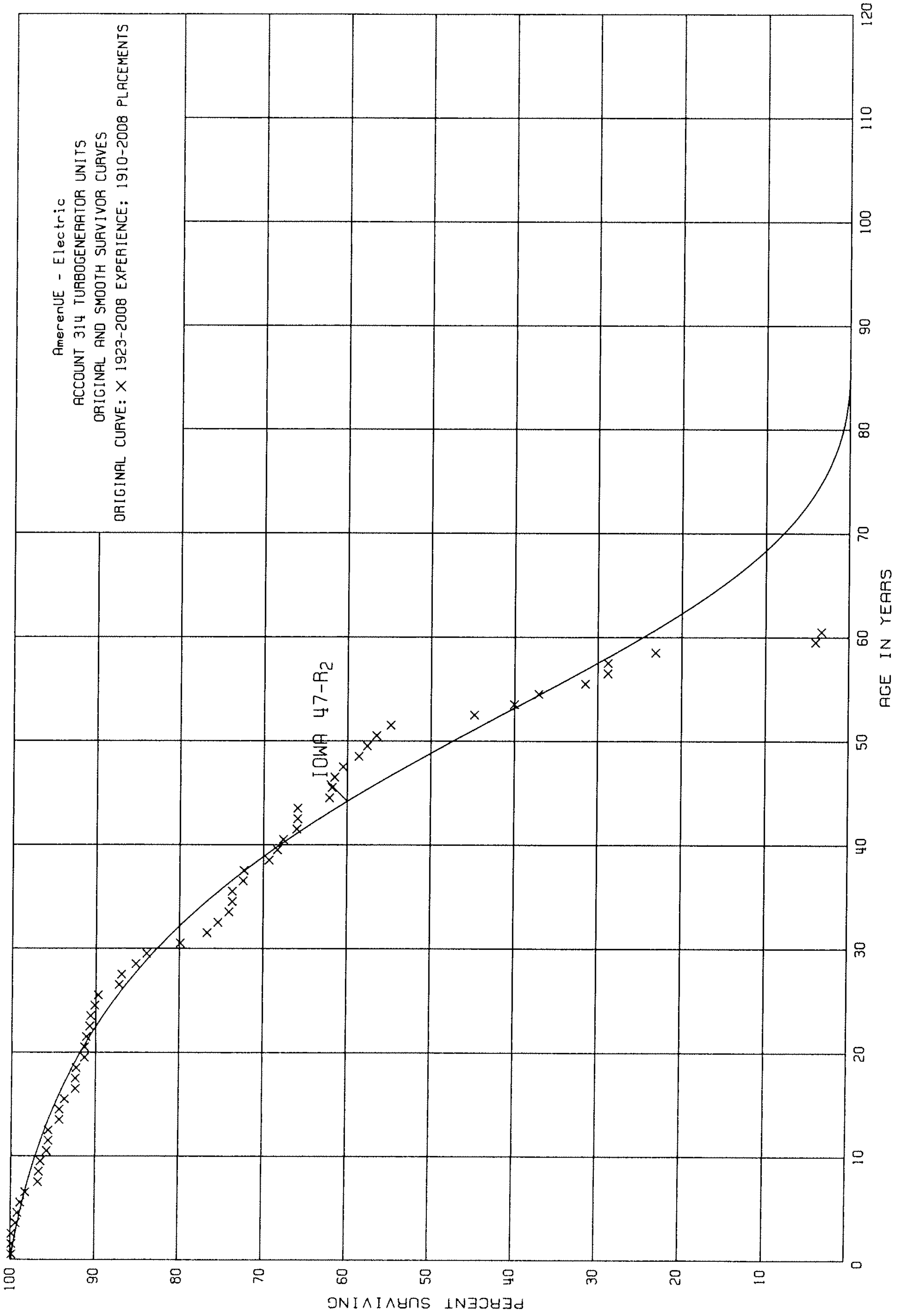
AmerenUE - Electric

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

AVG AGE RET 30.0 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	81,501,283	778,102	0.0095	0.9905	68.25
40.5	70,049,999	1,686,874	0.0241	0.9759	67.60
41.5	59,054,234	35,182	0.0006	0.9994	65.97
42.5	58,972,051	48,789	0.0008	0.9992	65.93
43.5	58,907,204	3,421,010	0.0581	0.9419	65.88
44.5	55,486,194	233,595	0.0042	0.9958	62.05
45.5	55,251,059	242,669	0.0044	0.9956	61.79
46.5	55,007,243	912,280	0.0166	0.9834	61.52
47.5	42,095,088	1,361,641	0.0323	0.9677	60.50
48.5	31,423,538	501,081	0.0159	0.9841	58.55
49.5	30,316,379	571,258	0.0188	0.9812	57.62
50.5	29,817,178	943,599	0.0316	0.9684	56.54
51.5	29,150,202	5,318,697	0.1825	0.8175	54.75
52.5	24,605,130	2,642,264	0.1074	0.8926	44.76
53.5	22,390,003	1,608,153	0.0718	0.9282	39.95
54.5	15,769,185	2,363,952	0.1499	0.8501	37.08
55.5	5,856,448	510,889	0.0872	0.9128	31.52
56.5	5,282,529	888	0.0002	0.9998	28.77
57.5	5,395,037	1,065,582	0.1975	0.8025	28.76
58.5	4,519,127	3,729,309	0.8252	0.1748	23.08
59.5	1,698,431	309,992	0.1825	0.8175	4.03
60.5	1,769,809	1,470,878	0.8311	0.1689	3.29
61.5	298,826		0.0000	1.0000	0.56
62.5	298,826	3,276	0.0110	0.9890	0.56
63.5	295,550		0.0000	1.0000	0.55
64.5	295,550		0.0000	1.0000	0.55
65.5	295,550		0.0000	1.0000	0.55
66.5	295,550		0.0000	1.0000	0.55
67.5	295,550		0.0000	1.0000	0.55
68.5	295,550		0.0000	1.0000	0.55
69.5	295,550		0.0000	1.0000	0.55
70.5	295,550	295,550	1.0000	0.0000	0.55
71.5					0.00
TOTAL	13,212,289,773	120,949,048			


AmerenUE - Electric
ACCOUNT 314 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1923-2008 EXPERIENCE; 1910-2008 PLACEMENTS
IOWA 47-R2
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10

```
                           AmerenUE - Electric

              ACCOUNT 315 ACCESSORY ELECTRICAL EQUIPMENT

                  INPUT CONTROL TOTALS THROUGH 2008

TRAN        -------- T O T A L   I N P U T   D A T A --------
CODE                 AGED             UNAGED             TOTAL

  0          19,718,157.33-                        19,718,157.33-
  3          47,573,347.94                         47,573,347.94
  7          16,319,497.99-                        16,319,497.99-
  9         188,300,326.90                        188,300,326.90

TOTAL DATA  199,836,019.52                        199,836,019.52

  8         199,836,018.79                        199,836,018.79

TOTAL DATA
 LESS CD 8            0.73                                  0.73
```

AmerenUE - Electric

ACCOUNT 315 ACCESSORY ELECTRICAL EQUIPMENT

ORIGINAL LIFE TABLE

AVG AGE RET 34.1 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	188,294,250	143,083	0.0008	0.9992	100.00
0.5	179,947,913	1,618,118	0.0090	0.9910	99.92
1.5	178,634,490	569,518	0.0032	0.9968	99.02
2.5	175,801,734	388,435	0.0022	0.9978	98.70
3.5	169,628,663	90,371	0.0005	0.9995	98.48
4.5	152,256,516	60,732	0.0004	0.9996	98.43
5.5	147,921,953	276,033	0.0019	0.9981	98.39
6.5	136,157,050	175,756	0.0013	0.9987	98.20
7.5	128,271,676	215,786	0.0017	0.9983	98.07
8.5	128,872,061	262,927	0.0020	0.9980	97.90
9.5	123,775,850	291,071	0.0024	0.9976	97.70
10.5	124,528,069	1,047,534	0.0084	0.9916	97.47
11.5	123,182,178	365,143	0.0030	0.9970	96.65
12.5	116,176,247	734,779	0.0063	0.9937	96.36
13.5	113,602,361	442,499	0.0039	0.9961	95.75
14.5	109,130,562	990,443	0.0091	0.9909	95.38
15.5	103,381,963	375,301	0.0036	0.9964	94.51
16.5	102,457,526	261,342	0.0026	0.9974	94.17
17.5	101,412,774	249,810	0.0025	0.9975	93.93
18.5	100,308,558	67,477	0.0007	0.9993	93.70
19.5	97,157,833	164,851	0.0017	0.9983	93.63
20.5	94,252,575	106,381	0.0011	0.9989	93.47
21.5	93,995,926	128,497	0.0014	0.9986	93.37
22.5	92,938,963	662,648	0.0071	0.9929	93.24
23.5	91,903,216	564,242	0.0061	0.9939	92.58
24.5	91,399,978	533,495	0.0058	0.9942	92.02
25.5	89,101,200	619,183	0.0069	0.9931	91.49
26.5	88,396,642	443,241	0.0050	0.9950	90.86
27.5	86,877,146	1,658,674	0.0191	0.9809	90.41
28.5	85,188,812	868,615	0.0102	0.9898	88.68
29.5	85,501,856	1,895,180	0.0222	0.9778	87.78
30.5	83,616,739	1,318,372	0.0158	0.9842	85.83
31.5	77,603,439	1,544,922	0.0199	0.9801	84.47
32.5	64,477,305	565,816	0.0088	0.9912	82.79
33.5	64,247,805	339,984	0.0053	0.9947	82.06
34.5	64,795,585	55,501	0.0009	0.9991	81.63
35.5	58,563,834	82,784	0.0014	0.9986	81.56
36.5	49,591,730	446,552	0.0090	0.9910	81.45
37.5	43,908,876	311,034	0.0071	0.9929	80.72
38.5	33,592,387	787,218	0.0234	0.9766	80.15

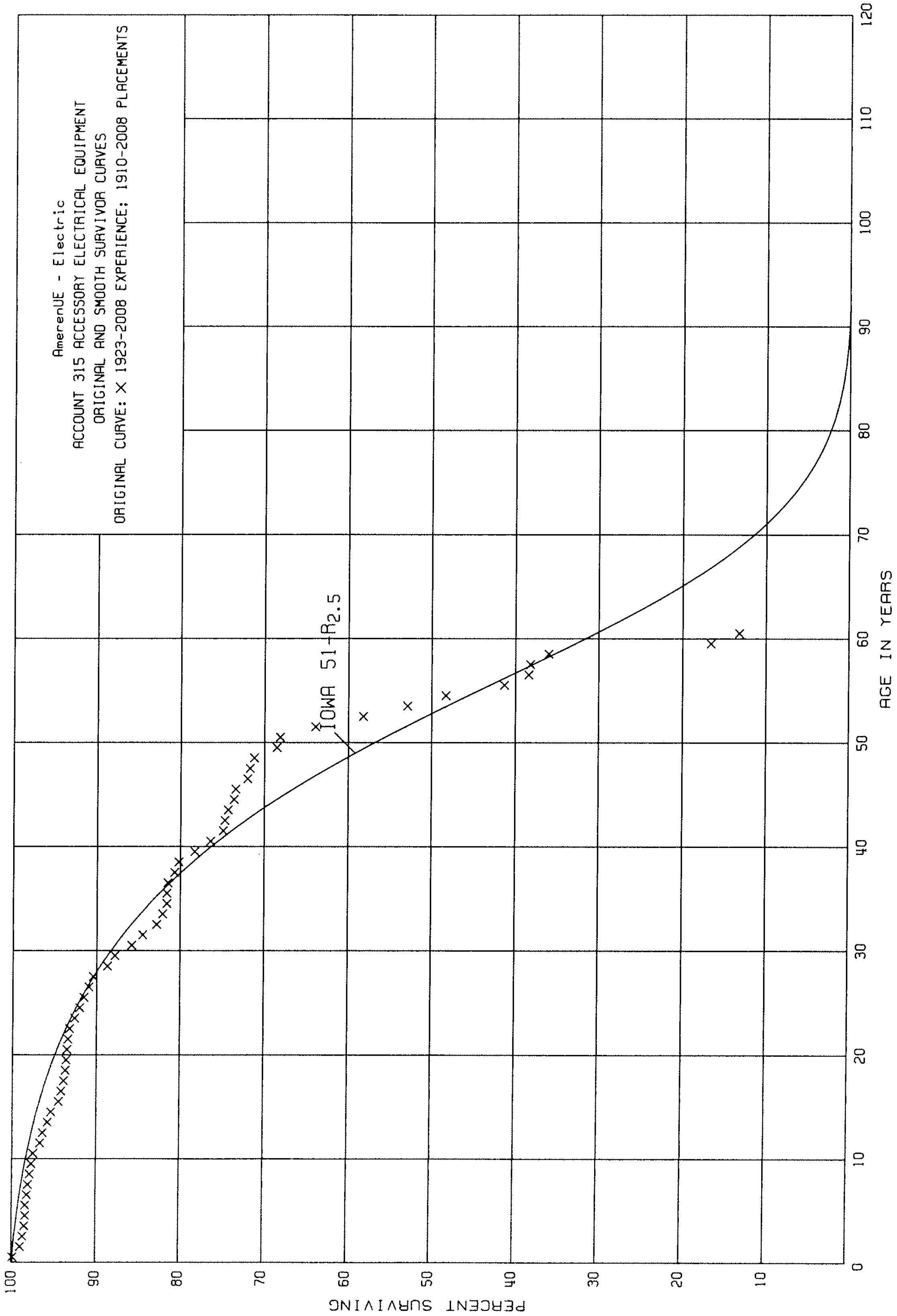
AmerenUE - Electric

ACCOUNT 315 ACCESSORY ELECTRICAL EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

AVG AGE RET 34.1 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	32,722,637	770,463	0.0235	0.9765	78.27
40.5	28,629,035	590,873	0.0206	0.9794	76.43
41.5	23,914,429	54,741	0.0023	0.9977	74.86
42.5	23,859,253	116,395	0.0049	0.9951	74.69
43.5	23,737,791	226,847	0.0096	0.9904	74.32
44.5	23,867,990	81,915	0.0034	0.9966	73.61
45.5	23,775,891	445,689	0.0187	0.9813	73.36
46.5	23,284,075	95,072	0.0041	0.9959	71.99
47.5	19,162,423	134,024	0.0070	0.9930	71.69
48.5	19,363,341	721,765	0.0373	0.9627	71.19
49.5	16,154,078	100,574	0.0062	0.9938	68.53
50.5	16,768,155	1,048,815	0.0625	0.9375	68.11
51.5	15,692,011	1,396,066	0.0890	0.9110	63.85
52.5	14,247,310	1,283,836	0.0901	0.9099	58.17
53.5	12,836,553	1,117,044	0.0870	0.9130	52.93
54.5	9,689,424	1,404,807	0.1450	0.8550	48.33
55.5	4,925,861	347,688	0.0706	0.9294	41.32
56.5	4,578,172	28,898	0.0063	0.9937	38.40
57.5	4,488,943	256,191	0.0571	0.9429	38.16
58.5	4,107,573	2,213,445	0.5389	0.4611	35.98
59.5	1,879,159	382,502	0.2035	0.7965	16.59
60.5	1,496,657	1,491,205	0.9964	0.0036	13.21
61.5	5,452		0.0000	1.0000	0.05
62.5	5,452	5,452	1.0000	0.0000	0.05
63.5					0.00
TOTAL	4,590,045,906	36,037,655			


AmerenUE - Electric
ACCOUNT 315 ACCESSORY ELECTRICAL EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: × 1923-2008 EXPERIENCE; 1910-2008 PLACEMENTS
IOWA 51-R2.5
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

```
                    AmerenUE - Electric

      ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

             INPUT CONTROL TOTALS THROUGH 2008

TRAN       -------- T O T A L   I N P U T   D A T A --------
CODE                AGED            UNAGED            TOTAL

  0           9,889,861.43-                    9,889,861.43-
  3             531,829.74-                      531,829.74-
  7           1,360,455.23-                    1,360,455.23-
  9          71,930,869.97                    71,930,869.97

TOTAL DATA   60,148,723.57                    60,148,723.57

  8          60,148,723.57                    60,148,723.57
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AmerenUE - Electric

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

AVG AGE RET 14.1 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	71,919,576	15,346	0.0002	0.9998	100.00
0.5	64,962,634	167,548	0.0026	0.9974	99.98
1.5	61,577,615	517,821	0.0084	0.9916	99.72
2.5	58,456,010	144,963	0.0025	0.9975	98.88
3.5	55,821,039	530,144	0.0095	0.9905	98.63
4.5	52,613,015	442,705	0.0084	0.9916	97.69
5.5	49,757,533	942,108	0.0189	0.9811	96.87
6.5	45,605,543	970,148	0.0213	0.9787	95.04
7.5	42,147,514	885,173	0.0210	0.9790	93.02
8.5	38,855,434	619,972	0.0160	0.9840	91.07
9.5	36,862,856	838,859	0.0228	0.9772	89.61
10.5	35,059,581	355,798	0.0101	0.9899	87.57
11.5	33,175,386	415,108	0.0125	0.9875	86.69
12.5	30,978,160	524,740	0.0169	0.9831	85.61
13.5	28,309,316	302,389	0.0107	0.9893	84.16
14.5	25,310,303	296,599	0.0117	0.9883	83.26
15.5	22,617,332	190,182	0.0084	0.9916	82.29
16.5	20,800,820	237,663	0.0114	0.9886	81.60
17.5	19,616,781	191,275	0.0098	0.9902	80.67
18.5	18,454,064	79,198	0.0043	0.9957	79.88
19.5	17,601,706	116,684	0.0066	0.9934	79.54
20.5	16,976,258	119,675	0.0070	0.9930	79.02
21.5	16,314,018	186,653	0.0114	0.9886	78.47
22.5	15,532,075	249,308	0.0161	0.9839	77.58
23.5	14,417,915	155,350	0.0108	0.9892	76.33
24.5	13,777,985	258,752	0.0188	0.9812	75.51
25.5	12,917,037	119,557	0.0093	0.9907	74.09
26.5	11,699,025	143,035	0.0122	0.9878	73.40
27.5	11,005,002	42,850	0.0039	0.9961	72.50
28.5	10,348,427	58,795	0.0057	0.9943	72.22
29.5	9,863,152	85,996	0.0087	0.9913	71.81
30.5	9,345,330	98,752	0.0106	0.9894	71.19
31.5	8,537,837	63,913	0.0075	0.9925	70.44
32.5	6,399,162	63,436	0.0099	0.9901	69.91
33.5	6,219,967	48,953	0.0079	0.9921	69.22
34.5	6,001,763	126,979	0.0212	0.9788	68.67
35.5	5,236,055	30,370	0.0058	0.9942	67.21
36.5	4,152,469	21,067	0.0051	0.9949	66.82
37.5	3,574,893	20,256	0.0057	0.9943	66.48
38.5	2,325,241	15,616	0.0067	0.9933	66.10

AmerenUE - Electric

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

AVG AGE RET 14.1 1 EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008 EXPERIENCE BAND 1923-2008

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,237,551	38,410	0.0172	0.9828	65.66
40.5	2,032,682	31,489	0.0155	0.9845	64.53
41.5	1,457,093	10,671	0.0073	0.9927	63.53
42.5	1,397,070	6,318	0.0045	0.9955	63.07
43.5	1,315,770	33,114	0.0252	0.9748	62.79
44.5	1,187,291	15,029	0.0127	0.9873	61.21
45.5	1,110,635	7,020	0.0063	0.9937	60.43
46.5	986,244	6,765	0.0069	0.9931	60.05
47.5	1,010,254	51,142	0.0506	0.9494	59.64
48.5	856,127	1,419	0.0017	0.9983	56.62
49.5	767,494	14,019	0.0183	0.9817	56.52
50.5	726,976	64,957	0.0894	0.9106	55.49
51.5	634,097	101,023	0.1593	0.8407	50.53
52.5	499,882	25,132	0.0503	0.9497	42.48
53.5	464,803	13,937	0.0300	0.9700	40.34
54.5	412,278	10,417	0.0253	0.9747	39.13
55.5	274,324	7,051	0.0257	0.9743	38.14
56.5	149,430	8,661	0.0580	0.9420	37.16
57.5	134,529	7,706	0.0573	0.9427	35.00
58.5	126,779	13,191	0.1040	0.8960	32.99
59.5	111,472	24,767	0.2222	0.7778	29.56
60.5	77,615	56,811	0.7320	0.2680	22.99
61.5	16,195	4	0.0002	0.9998	6.16
62.5	16,936	7,426	0.4385	0.5615	6.16
63.5	16,732		0.0000	1.0000	3.46
64.5	16,732		0.0000	1.0000	3.46
65.5	8,947		0.0000	1.0000	3.46
66.5	1,091		0.0000	1.0000	3.46
67.5	975		0.0000	1.0000	3.46
68.5	902		0.0000	1.0000	3.46
69.5	902		0.0000	1.0000	3.46
70.5	902		0.0000	1.0000	3.46
71.5	849		0.0000	1.0000	3.46
72.5	755		0.0000	1.0000	3.46
73.5	755		0.0000	1.0000	3.46
74.5	733		0.0000	1.0000	3.46
75.5	431		0.0000	1.0000	3.46
76.5	405		0.0000	1.0000	3.46
77.5	405		0.0000	1.0000	3.46
78.5	405		0.0000	1.0000	3.46

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                    AmerenUE - Electric

      ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

                    ORIGINAL LIFE TABLE, CONT.

AVG AGE RET 14.1              1          EXPERIENCE ANALYSIS
PLACEMENT BAND 1910-2008          EXPERIENCE BAND 1923-2008

 AGE AT    EXPOSURES AT   RETIREMENTS                 PCT SURV
BEGIN OF   BEGINNING OF   DURING AGE  RETMT    SURV   BEGIN OF
INTERVAL   AGE INTERVAL    INTERVAL   RATIO    RATIO  INTERVAL

  79.5           129                  0.0000  1.0000     3.46
  80.5           101                  0.0000  1.0000     3.46
  81.5           101                  0.0000  1.0000     3.46
  82.5           101           101    1.0000  0.0000     3.46
  83.5                                                   0.00

TOTAL   1,033,201,709   11,250,316
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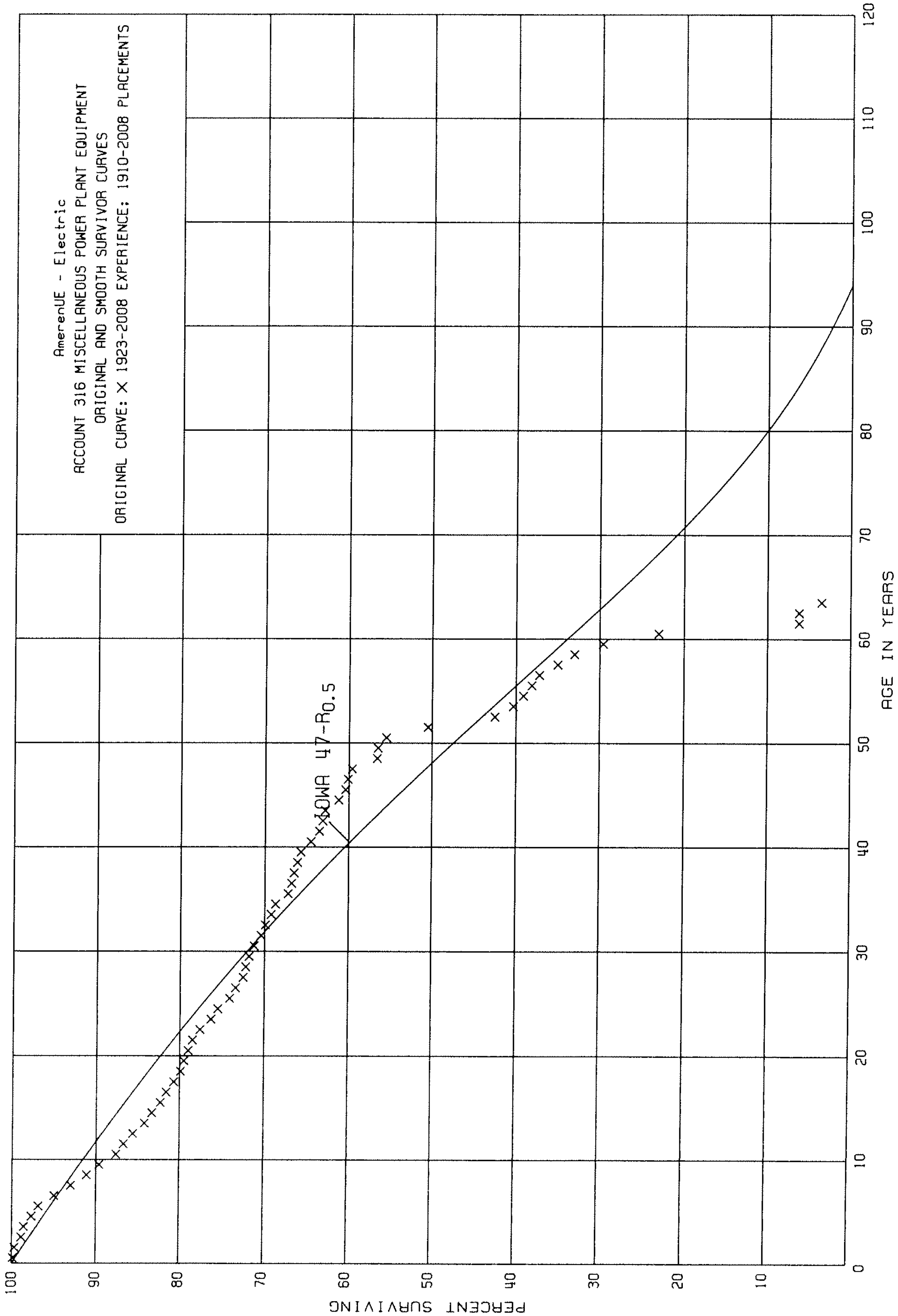

AmerenUE - Electric
ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1923-2008 EXPERIENCE; 1910-2008 PLACEMENTS
IOWA 47-R0.5
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0

Ameren Missouri
Response to MPSC Staff Data Request
MPSC Case No. ER-2011-0028
In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area

Data Request No.: MPSC 0257 – Lisa Hanneken

Please provide a listing and the dates of completion for each and all Power Plant outages and upgrades from 1/1/09 to present which a) has provided a change in the amount of energy the power plant is expected to produce on a going forward basis, b) changed the future outage or maintenance schedule c) provided a cost reduction or increase. For each a, b, and c, provide a detailed discuss of the impact of such a change (i.e. number of MW change, number of months/years maintenance was deferred, amount of cost difference, and reasons for each). This data should be provided on a separate power plant basis for each and all power plant owned and operated by Ameren Missouri.

RESPONSE

Prepared By: David Bullard
Title: Managing Supervisor, Project Controls
Date: December 15, 2010

HIGHLY CONFIDENTIAL

See attachment for requested data.

remainder of

SCHEDULE CME-r2

HAS BEEN DEEMED

CONFIDENTIAL

IN ITS ENTIRETY

Ameren Missouri
Case Name: ER-2022-0337
Docket No(s): 2022 Electric Rate Review

Response to Discovery Request: SIERRA 2-SC 002.8
Date of Response: 11/14/2022
Witness: N/A

<u>Question</u>:Refer to the Direct Testimony of Matt Michels.

a. Provide all retrofit-retirement analyses for Rush Island, including the underlying workpapers in native format, with formulae intact, from 2011 to present.
b. In 2011, when EPA filed its Clean Air Act lawsuit against Ameren, did the Company conduct any economic evaluation of the costs of retrofitting versus retiring Rush Island? If so, provide all such analyses, including the underlying workpapers in their native format with formulae intact. If not, why didn't the Company conduct that analysis?
c. In 2017, when the District Court concluded that Ameren violated the Clean Air Act lawsuit against Ameren, did the Company conduct any economic evaluation of the costs of retrofitting versus retiring Rush Island? If so, provide all such analyses, including the underlying workpapers in their native format with formulae intact. If not, why didn't the Company conduct that analysis?

<u>Response:</u>

Prepared By: Matt Michels
Title: Director, Corporate Analysis
Date: November 14, 2022

CONFIDENTIAL
20 CSR 4240-2.135(2)(A)8

a. In addition to the analysis and workpapers provided in support of my direct testimony in this case and in response to data request SC 001.12, please see the following:
    - Ameren Missouri's 2020 IRP filing – Files marked 'Highly Confidential' at the time of filing are attached and marked 'Confidential': "SC 2.8 Attach Chapter 10 – Strategy Selection CONFIDENTIAL," "SC 2.8 Attach Chapter 10 – Appendix A CONFIDENTIAL," "SC 2.8 Attach Chapter 9 Integrated Resource Plan and Risk Analysis CONFIDENTIAL," and "SC 2.8 Attach Chapter 9 – Appendix A CONFIDENTIAL."
    - Confidential workpapers showing the economic evaluation results for Ameren Missouri's 2020 IRP filing – "SC 2.8 Attach PVRR CONFIDENTIAL."
b. No. Such analysis would have been premature at the time given the highly uncertain outcome and timing of the litigation.
c. Yes. See part a.

SCHEDULE CME-r4

HAS BEEN DEEMED

CONFIDENTIAL

IN ITS ENTIRETY

ED Project Evaluation Methodologies– 3rd OPC & PSC Staff Meeting

September 2022

DRAFT Evaluation Methodology – Grid Resiliency

Ameren

Criteria	Variable	Definition	Threshold	Documentation / Data Required	Baseline
Age / Asset Vintage	Exceeding Expected Engineered Life/Useful Life	Age of Asset	✓ Above expected life	Quantify age; Include documentation on which quantification is based	Assets Over Expected Life
Asset Condition	Engineering Risk Analysis	Estimated asset condition based on known risks of asset degradation or change to landscape	✓ Failed or unfavorable tests/inspections; likelihood of near-term failure	Documentation of asset condition or landscape impacting asset if criteria is to be used as a justification factor	No prior negative assessments
Potential For Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), a large employer, a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Documentation of impact to the local community is required	N/A
Capacity *(Sub and Line Capacity)*	Current Capacity Constraints or Projected Future Capacity Constraints	Peak load increases/projections are approaching normal or emergency asset emergency ratings	✓ Peak load projections are approaching asset normal operating ratings within next 5 years ✓ Peak load projections are approaching asset emergency ratings within next 5 years	Include documentation of current load, future load, and max capacity	Asset Rating
Operating Flexibility	Ability to switch power flow on demand	Feeder or Substation does not have a tie to a neighboring asset with capacity to provide support in contingent scenarios	✓ Feeder or substation without tie to neighboring asset with sufficient capacity to serve additional load	Include documentation of substation or feeder design and loading with switching limitations	Substations on manual or substations with active ALR (Automatic Load Reduction)
Final Evaluation		Two check marks result in eligibility for a Grid Resiliency capital project			

Category Strategy and Related Benefits

Grid resiliency investments support customer reliability through the grid's ability to respond and reconfigure during severe weather events and other outages

Upgrade Strategy

Grid Flexibility Constraints – addressed on targeted basis

- Line capacity constraints
  - Upgrade conductor to higher capacity rating OR
  - Construct new lines
- Substation capacity constraints
  - Construct new substation OR
  - Upgrade existing transformers OR
  - Add transformers to existing substations
- Convert select 4kV substations to 12kV substations

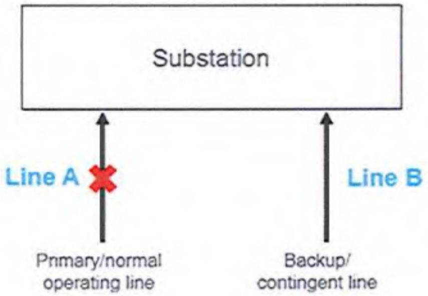
Why Invest?

- Conservative operations
  - Operational flexibility
  - Improved ability to handle severe weather events due to the upgrading and replacement of old infrastructure at new standards
  - Less stress on assets & increased asset longevity
- Supports future load growth

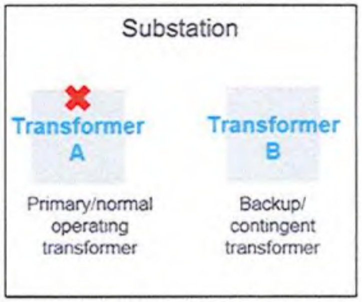
Select Grid Resiliency Projects

Grid resiliency supports customer reliability by providing a contingent supply across lines and substations in the case of a failure or storm damage

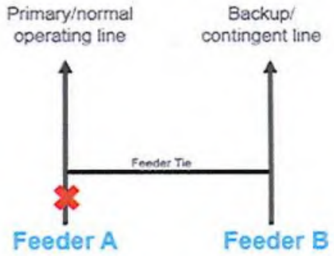
SubTX Line Capacity Increases



Substation Capacity



Distribution Tie Capacity



Select Projects

- **Pershall**: This substation upgrade project provides tie capacity to a nearby substation and provides load relief to additional substations in the area which will improve their ability to serve customers
- **Hayti**: A new line was added as the primary supply to Steele substation, leaving the original line as an alternative supply to reduce risk of outages

DRAFT Evaluation Methodology – Downtown Underground Revitalization

Criteria	Variable	Definition	Threshold	Documentation / Data Required	Baseline
Age / Asset Vintage	Exceeding Expected Engineered Life/Useful Life	Age of Cable, Conduit and/or Duct Banks	✓ Above expected life ✓ >1.5x above expected life	Quantify age; Include documentation on which quantification is based	Assets over expected life
Asset Condition	Engineering Risk Analysis	Estimated asset condition based on known risks of asset degradation or change to landscape	✓ Failed or unfavorable tests/inspections; indicates a likelihood of near-term failure, routes not appropriately diverse *(three primary feeders from a single sub per manhole, no more than 2 network cables in a single manhole, no more than 4 switching locations on radial feeders and no more than 6 on network feeders)*	Documentation of asset condition or landscape impacting asset if criteria is to be used as a justification factor	No prior negative assessments
Asset Performance	Cable Failure(s)	Cable interruption(s) or instance(s) of non-availability due to malfunction has occurred	✓ Historical cable interruption(s) or instance(s) of non-availability	Quantify historical interruption(s); Include documentation of specific interruptions	Average Annual Circuit Interruptions per Substation (Downtown)
Potential For Community Impact	Number or type of potentially-affected customers or duration of outages	High-impact customers (e.g. school or university, hospital, airport), a large employer, or a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Documentation of impact to the local community is required	N/A
Safety	Physical safety risk to stakeholders (employees, community, etc.)	Potential for safety issue due to old or improperly functioning equipment including abnormal joints, indoor rooms (lack of access/maintain)	✓ Asset has known safety concerns, cannot be inspected/maintained while operating, potential for fire	Include documentation of safety issue	No Known Safety Risks
Final Evaluation		Two check marks result in eligibility for a UG Revi capital project			

Underground Revitalization Category Strategy

Underground revitalization will increase reliability and safety by upgrading aging infrastructure and reduce single points of failure

Why Revitalize?

- **Age Of The System**
  - Much of the downtown system was originally installed in the early 20th century
- **Infrastructure Failure**
  - Many original cables and routes are no longer viable due to cable failures and duct bank collapses
- **Lack of Route Diversity**
  - Increased risk of a manhole fire, which could cut power to much of downtown for an extended time
- **Increasing Safety Risk**


Clay tile duct bank in disrepair (still in use with existing fiber)

5" plastic (EB-35) conduit duct face


Abnormal PILC cable joints

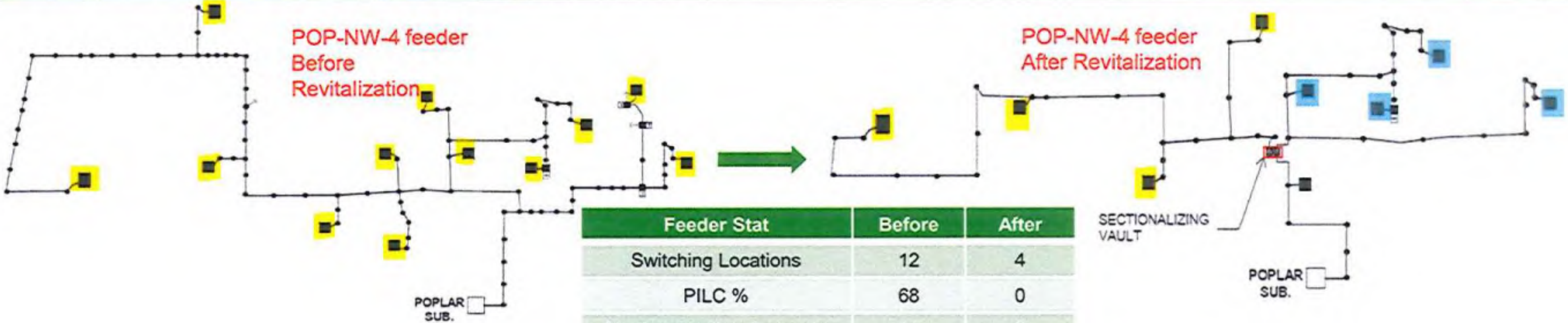

Highly congested manhole on 7th St.

Category Strategy and Related Benefits

Underground revitalization is providing a host of benefits which is positively impacting customers and the community

Upgrade Strategy

- **Fully rebuild the Downtown St. Louis system**
  - Conduit replacement
  - Cable upgrades
  - Install pathways for fiber optic command, control, and monitoring protocols
  - Work with the City of St. Louis to limit any potential impact on downtown commerce and street repair/paving efforts
- **Reduce outage frequency and impact risk**
  - Deploy a system where any 2 network primary circuits & any 1 radial circuit can be out of service without additional customer outages or overloading remaining cables
- **3 radial cables and 2 network cables per manhole / duct bank**
  - Limits the risk of one failure impacting many additional cables
- **Limit switching locations to a maximum of 4**



Feeder Stat	Before	After
Switching Locations	12	4
PILC %	68	0
Manholes with > 6 circuits	14	0
PILC Joints	17	0

DRAFT Evaluation Methodology – Smart Grid

Criteria	Variable	Definition	Threshold	Documentation / Data Required	Baseline
Circuit Topology/Grid Visibility	Engineering Risk Assessment	Ability for Ameren Missouri to remotely and/or locally monitor and control the performance of a substation or circuit	✓ No remote visibility or control of substation/circuit ✓ Feeder design has 400 or more customers without a sectionalizing device	Test/inspection records required if criteria is to be used as a justification factor	No Visibility
Asset Performance	Circuit Interruptions(s)	Customer interruption(s) resulting from asset failure(s)	✓ On Worst Performing Circuit or Multiple Device Interruption List in most recent 5 years ✓ Circuit adjacent to Worst Performing Circuit or Multiple Device Interruption List in most recent 5 years	Quantify historical interruption(s); Include documentation of specific interruptions	Not on WPC
Potential For Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), or a large employer	✓ Potential for substantial community impact	Documentation of impact to the local community is required	N/A
Final Evaluation	Two check marks results in eligibility for a Smart Grid capital project				

Smart Grid Deployment Strategy

Smart grid supports customer reliability through new technologies that enable a smarter and more modernized grid

Strategy

Install Smart Switches System Wide

- Provides increased reliability benefits, up to ~40% improvement
- Allows for fault isolation to smaller zones
- Rapidly restore sensitive loads (hospitals, 911 call centers, large schools, large commercial centers)

Target installations on yearly 12kV Worst Performing Circuits

- Sectionalizes feeders into sections of approximately 400 customers
- Limits the magnitude of any outage
- Limited 4kV deployment

Install cutout reclosing devices (Tripsavers) in place of fuses

- 140T, 100T, 80T, 65T, and 40T fuses on 12kV
- Help resolve MDI (multiple device interruption) issues
- ~40% of Ameren Missouri's fuse outages in 2018 had no repair action other than replace fuse, reclosers minimize outage time and truck rolls

Install FCI's on feeder terminal poles & key midpoints

- More quickly identify the cause and location of an outage
- Rapidly resolve and restore if possible or isolate to smallest zone and quickly restore other customers
- ~12% of all feeder outages are from failing feeder exit cables
- CAIDI improvement

Build a Private LTE network

- Allows us to more economically connect and operate smart grid devices for customer reliability benefit

Smart Grid Benefits

Smart grid technologies offer a wide range of benefits from reliability and safety to enabling the grid of the future and customer productivity

Benefits

- Distribution Automation switches power sources to isolate damage and is delivering up to 40% improvement in reliability on circuits equipped with the technology and other associated upgrades
- Customers experience nearly 9,000 extended outages annually caused by a blown fuse in which no other damage to the system can be found. We expect trips savers will eliminate most of these and customers will only experience a momentary as the device opens to clear the fault & restores service
- FCIs (Faulted Circuit Indicator) will reduce the time customers are out by allowing Ameren Missouri to inspect predetermined points of a circuit for damage and make faster switching decisions
- Storm Impact Mitigation Examples
  - *July 10th 2021: A storm caused over 50,000 customers to lose power, but an additional 12,000 customers were protected from outages due to the over 200 DA operations over the several days of storms and restoration*
  - *August 12th 2021: Severe weather led to over 90,000 customers without power, but around 8,500 customers were protected from outages due to DA, reducing the total outage count from the storm by 8%*

Appendix – Previously Reviewed Methodologies

DRAFT Evaluation Methodology – System Hardening

Ameren MISSOURI

Criteria	Variable	Definition	Threshold	Documentation / Data Required	Baseline (Category Level)
Age/Asset Vintage	Exceeding Expected Engineered/Useful Life	Age of critical components	✓ Beyond expected life ✓ >1.5x beyond expected life	Quantify age; Include documentation on which quantification is based.	Assets Over Expected Life
Asset Condition	Engineering Risk Assessment	Estimated asset health and risk of failure based on inspection results and/or operating history of similar vintages	✓ Failed or unfavorable tests/inspections; likelihood of near-term failure	Test/inspection records required if criteria is to be used as a justification factor	No prior negative assessments
Asset Performance	Circuit Interruption(s)	The number of times asset-driven circuit interruption(s) have occurred	✓ 2 interruptions in a year or 5 interruptions over 3 years	Quantify historical interruptions; Include documentation of specific interruptions.	Average Annual Interruptions per Circuit
Potential for Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), a large employer, or a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Documented impact to the local community is required	N/A
Final Evaluation		Two check marks result in eligibility for a System Hardening capital project			

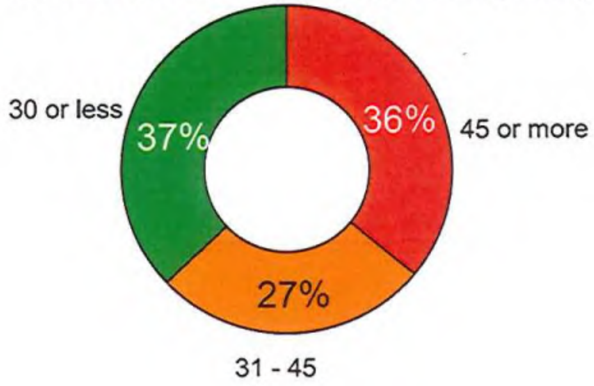
The Infrastructure That Supplies Dx Substations Is Rapidly Aging

Each subtransmission circuit feeds an average of 2,500 customers, ~36% of them have a majority of assets that are beyond their expected life

Asset	Total OH Miles	Expected Life (Years)	Timeline to Refresh System at Current Investment Levels	Current Average Age of the System	Miles Over Expected Life Today	# of Customers Served by Old Asset
Subtransmission System (Proxy: Wood Poles[1] Age)	~4,200	45	~76 years (@ forecasted 55 mi/yr.)	~35 years	~1,600	~460,000

[1] *On average, one line mile includes 26 poles*

What's the distribution of the age of our poles (years)?



What's the inspection failure rate by age group?

**Based on ground line inspections*

1. Poles age 31 – 45 are **four times more likely** to fail inspections than those 30 or less.
2. Poles age 45 or more are **eight times more likely** to fail inspections than those 30 or less.

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected

DRAFT Evaluation Methodology – Underground Cable

Ameren MISSOURI

Criteria	Variable	Definition	Threshold	Documentation / Data Required	Baseline (Category Level)
Age/Asset Vintage	Exceeding Expected Engineered/Useful Life	Age of Cable	✓ Beyond expected life ✓ >1.5x beyond expected life	Quantify age; Include documentation on which quantification is based	Assets Over Expected Life
Asset Condition	Engineering Risk Assessment	Estimated asset condition based on known risks of asset degradation or change to landscape	✓ Direct Buried or Route Inappropriate	Documentation of asset condition or landscape impacting asset if criteria is to be used as a justification factor	No prior negative assessments or locational issues
Asset Performance	Cable Failure(s)	Customer interruption(s) resulting from cable failure(s)	✓ Historical Cable Failure(s)	Quantify historical interruption(s); Include documentation of specific interruptions	Average Annual Interruptions per Circuit
Potential for Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), a large employer, or a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Documentation of impact to the local community is required	N/A
Safety	Physical safety risk to stakeholders (employees, community, etc.)	Potential for safety issue due to old or improperly functioning equipment	✓ Asset has known safety concerns, cannot be inspected/maintained while operating	Include documentation of safety issue	No Known Safety Risks
Final Evaluation	Two check marks result in eligibility for a UG Cable capital project				

The Age of Our Underground System Continues to Increase

Ameren MISSOURI

2,900+ miles of our underground system has already exceeded its expected life, and presents an increasing risk to customer reliability and safety

URD Cable Vintage	Mileage	Cable Age (Years)	Expected Life (Years)	Lateral Failures per Mile
First Generation & Older	**~850**	**45+**	40	2.42
Second Generation	**~1,600**	**38 – 45**	40	1.70
Third Generation	**~700**	**32 – 38**	40	1.22
Fourth Generation	**~4,300**	**Present - 32**	40	0.88

Obsolete Feeder Exit Cable Type	Mileage	Cable Age (Years)	Expected Life (Years)	Feeder Outages Due to Lead Cable
Lead Cable (PILC)	**~450+**	**32 – 101**	60	~60 outages per year

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected

DRAFT Evaluation Methodology – Substation Condition Based Maintenance

Criteria	Variable	Definition	Threshold	Documentation / Data Required	Baseline (Category Level)
Age/Asset Vintage	Exceeding Expected Engineered/Useful Life	Age of critical components *(Transformers or Breakers)*	✓ Beyond expected life ✓ >1.5x beyond expected life	Quantify age; Include documentation on which quantification is based	Assets Over Expected Life
Asset Condition	Engineering Risk Assessment	Estimated asset health and risk of failure based on inspection results and/or operating history of similar vintages	✓ Failed or unfavorable tests/inspections; likelihood of near-term failure	Test/inspection records required if criteria is to be used as a justification factor	No prior negative assessments
Asset Performance	Substation Interruption(s)	Substation interruption(s) or instance(s) of non-availability due to malfunction has occurred	✓ Historical substation interruption(s) or instance(s) of non-availability	Quantify interruption(s) or instance(s) of non-availability; Include documentation of specific interruptions or instance(s) of non-availability	Average Annual Interruptions per Circuit
Potential for Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), a large employer, or a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Document impact to the local community is required	N/A
Safety	Physical safety risk to stakeholders (employees, community, etc.)	Potential for safety issue due to old or improperly functioning equipment	✓ Asset has known safety concerns, cannot be inspected/maintained while operating	Include documentation of safety issue	No Known Safety Risks
Final Evaluation		Two check marks result in eligibility for a Substation CBM capital project			

Distribution Substation Key Components

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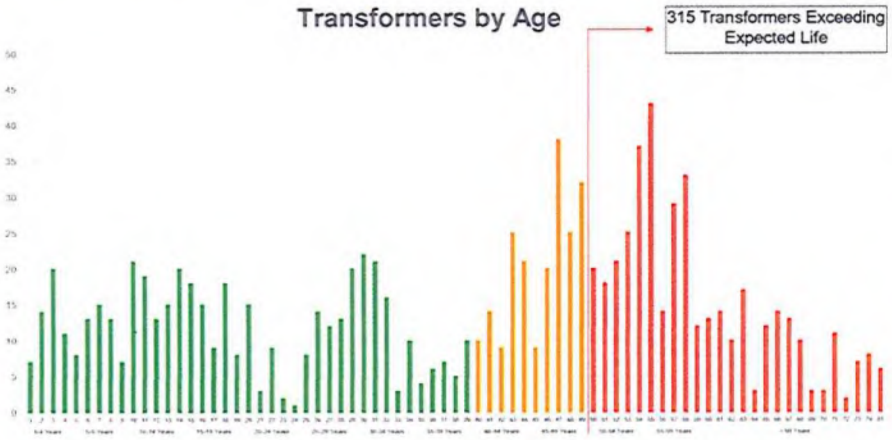
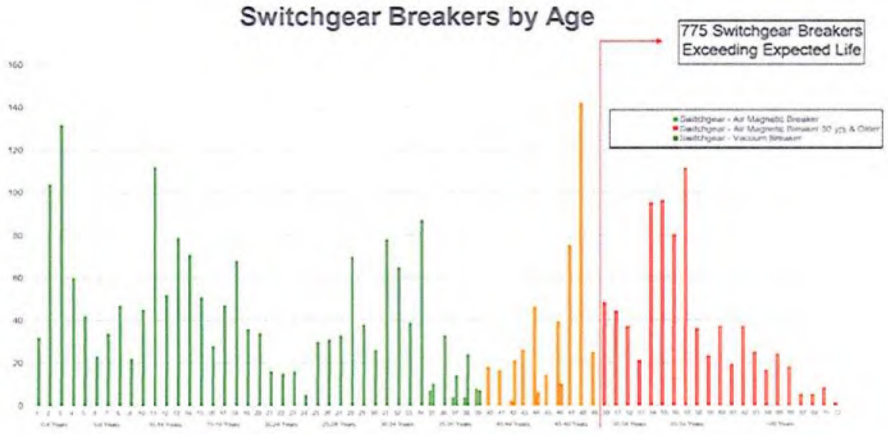
Distribution substations, with critical components beyond their expected life, serve over 700,000 of our ~1.2 million customers

Asset Type	Total Distribution Assets	Expected Life	Average Age (Years)	Assets Over Expected Life	Customers Served by Assets over expected life
Transformer	~800	50	~41	~315	~430k
Oil Circuit Breakers	~350	50	~53	~250	~700k
Air Circuit Breakers	~1,200	50	~53	~775	~400k


Transformers by Age

315 Transformers Exceeding Expected Life


Switchgear Breakers by Age

775 Switchgear Breakers Exceeding Expected Life

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected

Expected Life of Substation Transformers – 50 Years

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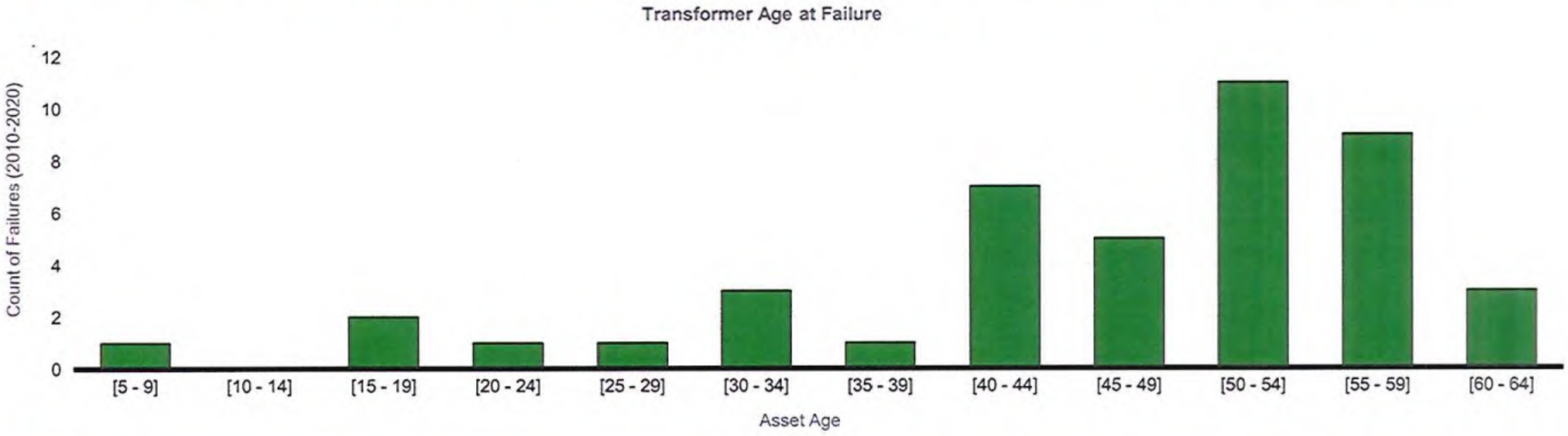
Transformer Failure Data Illustrates Risk Of Aged Assets, Particularly At 50+ Years Old And Confirms That Certain Vintages Are Problematic (1960 To 1969)

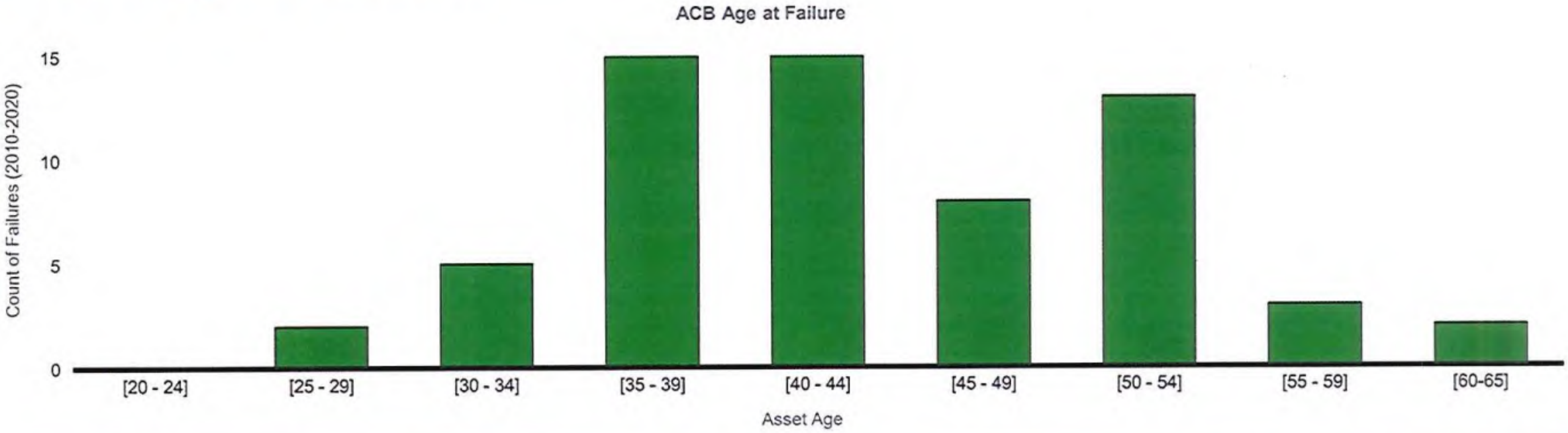


Observations

- **Transformer Age at Failure**: Transformer failures increasingly occur as assets near and exceed 50 years in service.
- **Manufacturer Year of Transformer at Failure:** Most of the transformers experiencing failures were manufactured between 1960 and 1969, suggesting that these units are failure prone. In particular, from 1964 to 1969, manufacturers were producing transformers quickly with lower quality in response to a rapid increase in demand from the growth of the electrical system from around the country.

Substation ACB (Air Circuit Breaker) Failure Trends

ACB designs are more complex and generally less reliable than modern technology and standards



Observations

- **ACB Age at Outage**: Greater counts of outages around 35-45 years old
- **Asset Design Challenges:** The air blast technology used across the industry up to the 1980's has proven to cause stress on the asset components due to the force exerted to extinguish the electrical current and arc. Over time, this repeated circuit breaking operation impacts the asset's future ability to successfully break the flow of electricity and restore service as intended.

Documentation Examples

J0T3Z – ESTR-73 Reconductor to Bonne Terre

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Grid Resiliency: Line

Description: Reconductor approximately 4.8 miles of parallel 34kV 1/0Cu with 954 ACSR (aluminum conductor steel reinforced) and optical ground shield wire from 34kV SW#205 to Bonne Terre Substation along Old Rt. 67.

Category	Driver For Investment	Justification	Back-Up Data Required
Age / Asset Vintage	✓	Critical components of this subtransmission circuit are known to be over their useful life, with poles up to 61 years old, beyond their expected life of 45 years. In addition, the distribution underbuild is #6 Copper, conductor which Ameren Missouri has not used since the 1970s.	• Inspection data showing age information for key assets
Asset Condition	✓	Existing line consists of very old construction with multiple degraded and decayed poles and cross-arms. The last inspection completed in April of 2022 indicated that 72 poles are showing signs of decay.	• Line inspection data
Potential For Community Impact	✓	Bonne Terre substation serves approximately 5,700 customers.	• Documentation of the number of customers supplied by asset
Capacity (Sub and Line) Overload		N/A	N/A
Operating Flexibility	✓	This 4.8 mile segment of 34 kV line requires Bonne Terre distribution substation to be placed on manual during peak load conditions with the system in normal configuration. This means that automatic transferring between the two 34kV supply lines that feed the substation to prevent outages if the primary supply loses power will not be possible in contingency situations and limits our ability to quickly restore customers in the event of an outage.	• Records showing the limitations by ESTR-73 that require the substation to be on manual

J0WRT – Hilltop Pad-mount Transformer

Grid Resiliency: Substation

Description: Install a single, 34.5kV-4kV, 2.5 MVA pad-mount transformer. Install a 4kV voltage regulator and Intellirupter recloser with a fused bypass switch. Eliminate the existing Hilltop substation after project completion.

Category	Driver For Investment	Justification	Back-Up Data Required
Age / Asset Vintage	✓	Substation is over 70 years old, above the expected life of 50 years.	- Records showing age information for key assets
Asset Condition	✓	Hilltop is a deteriorating Ameren owned substation, located in a small rural area on a 4kV circuit. Two of the three single-phase transformers show elevated dissolved moisture content and insulating oil fluid quality for an extended period of time (15+ years), increasing their probability of failure due to weakened dielectric strength of the oil and cellulose insulation.	- Inspection report stating condition
Potential For Community Impact			
Capacity (Sub and Line Capacity)	✓	The substation's 800 kVA capacity was recently exceeded during peak 2020/2021 Winter loading after a new load was added in Hermann, Missouri in late 2020. Substations Maintenance has confirmed that spare transformers are not available to upgrade the sub. This project will increase the capacity of the substation to 2.5 MVA and be sufficient to meet the projected load requirements of 1.2 MVA at peak loading for the entirety of the customer based it serves.	- Records of load analysis
Operating Flexibility		N/A	N/A

J0JFS – 0A321-POP55 Reroute Cable

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Underground Revitalization

Description: This project reroutes the POP-55 cable north on 11th St, east on Clark, north on 10th, west of where it will terminate in a new DA Sectionalizing Switchgear with the KSDK Indoor Room. The sectionalized feeder will then head north 10th, west on market, north on 11th, west on Chestnut, south on 20th, west on Market, and south on Jefferson. The feeder would split off to the respective customer loads that meet the Poplar Master Plan. The total circuit length installed by this project would be 2,800 feet of 3-750, CNR (concentric neutral rubber), 6,000 feet of 3-750AL (aluminum), CNR and 5,000 feet of 3-4/0AL, CNR.

Category	Driver For Investment	Justification	Back-Up Data Required
Age/Asset Vintage	✓	Circuit contains PILC cable, nearly all of which is past its useful life of 60 years. Circuit almost completely contained in clay tile duct bank, all of which is also past its useful life of 50 years.	• Records showing age information for key assets
Asset Condition	✓	Current condition contains 15 individual switching locations, without any sectionalizing on the feeder, while running in a non-route diverse path though a majority of 3" Clay Tile ducts from as early as 1960s in some area.	• One line showing excess of 10 switching locations and not diverse route
Asset Performance		N/A	N/A
Potential for Community Impact	✓	This project reduces the number of common manholes which could result in a catastrophic outages impacting government offices and other significant customers.	• Documentation of the number of customers supplied by asset • Documentation of the high-impact customers supplied by asset
Safety	✓	Increased risk of manhole fire due to congested cable routing in manholes. Some manholes have 10 total feeders in it.	• One line & photos showing congestion

J0T73 – DA (Distribution Automation) Concord Upgrade

Smart Grid

Description: This project objective is to improve the performance of the Concord circuits. This circuit has experienced reliability issues and the customers have experienced frequent outages.

Category	Driver For Investment	Justification	Back-Up Data Required
Circuit Topology/Grid Visibility	✓ ✓	There is a lack of remote grid visibility and control illustrated by the fact that all switches on this circuit are manually operated (feeders 223-051 and 223-052). Feeder 223-051 serves approximately 1,200 customers. Feeder 223-052 serves approximately 1,000 customers.	• One line showing extent of grid visibility and control of circuit • Documentation of the number of customers supplied by asset
Asset Performance	✓	Feeder 223-051 was on the WPC (worst performing circuit) list in 2020 and on the MDI (Multiple Device Interruption) list 2017-2021.	• Historical data showing the number of instances in the past 5 years in which a circuit appeared on WPC and MDI lists
Potential For Community Impact	✓	Feeder 223-052 feeds Mercy (St. Anthony's) Hospital.	• Documentation of the high-impact customers supplied by asset

J0NT9 – SAND-74 Circuit Improvement

System Hardening

Description: Rebuild SAND-74 along HWY 61/67 from switch JRF581 to Front St./HWY 61-67 intersection with 954ACSR (aluminum conductor steel reinforced) conductor and OPGW (optical ground wire) static wire. This project will include two (2) 1200A new switches and one (1) 34.5KV viper. Build the line up to current storm hardening standard.

Category	Driver For Investment	Justification	Back-Up Data Required
Age/Asset Vintage		N/A	N/A
Asset Condition	✓	Existing line consists of multiple degraded and decayed poles and cross-arms. Further, the line is mainly not roadway accessible, which causes longer outages due to the inability for crews to easily reach the feeder for repairs. It is also protected by lighting arrestors which need to be replaced every time they are blown and therefore result in the loss of future protection for the circuit. The last inspection completed in January of 2020 indicated that all 90 poles are showing signs of decay.	• Line inspection data
Asset Performance	✓	This circuit has experienced 13 outages in the last five years (2018-2022).	• Historical data showing the number of outages in the last 5 years
Potential for Community Impact	✓	This circuit feeds Ardagh Glass Plant, Metal Tek Foundry, and Air Liquide liquid nitrogen plant. All three industrial customers have experienced multiple prolonged outages due to the damage conductor and even the smallest interruption can result in a total shutdown of their plants that can last for hours. Ardagh Glass Plant manufactures close to ~$1B per year in glass for other large retailers in the US, including Schlafly. Even a short interruption can cause large delays in production costing the company money, and the ~400 employees' time. Metal Tek Foundry provides metal products and machinery manufacturing in the among of ~$250M per year, supporting ~500 employees. Even a short interruption can cause large delays in production costing the company money. Air Liquide provides industrial and medical gases. Delays in this production present a large potential for community impact due to the nature of their products. SAND-74 serves approximately 4,400 customers, including the three large manufacturers.	• Documentation of the number of customers supplied by asset

J0X0C – Cable Upgrade Union 555-54 Woodland Oaks

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Underground Cable

Description: Upgrade/relocate all the direct buried primary, secondary, service, and streetlight cables in the Woodland Oaks Subdivision in Union, MO that has 1970 & 1980 vintage underground system. Upgrade all underground equipment including transformers, pedestals, and streetlights within the limits of the project. Upgrade approximately 9900 ft. of 1-#2 Al (aluminum) primary, 4600 ft. of secondary, 2900 ft. of service, and 1900 ft. of streetlight cable with new cable in directional bored conduit in Woodland Oaks Subdivision.

Category	Driver For Investment	Justification	Back-Up Data Required
Age/Asset Vintage	✓	Woodland Oaks Subdivision is a 1970 & 1980 direct buried vintage underground system and beyond it's 40 year expected life.	• Records showing age information for key assets
Asset Condition	✓	The primary, secondary, service, and streetlight cables are all direct buried without protective conduit. This project would update all remaining direct buried cables in the subdivision to current design standard cable in directional bored conduit.	• Plats, other records to show direct bury
Asset Performance		N/A	N/A
Potential for Community Impact		N/A	N/A
Safety		N/A	N/A

J0P3C – Jungerman Upgrade W Switchgear & 2 Transformers

Substation - Condition Based Maintenance

Description: Rebuild Jungerman switchgear W and replace both transformers W and D.

Category	Driver For Investment	Justification	Back-Up Data Required
Age/Asset Vintage		N/A	N/A
Asset Condition	✓	Transformer W and D main tank dissolved gas analysis indicates insulation deterioration. Gassing concentrations are associated with a low level thermal fault, which spiked in 2016 and have been rising slowly ever since. Transformer W and D LTCs are each a type (Federal Pacific TC25) that require excessive maintenance to maintain reliable performance, involving a relatively high frequency of interventions. The LTC (load tap changer) design includes the arcing and the selector switches in the same compartment which creates a higher rate of contact wear and risk of high resistance connections overheating. This can result in an electrical failure of the LTC and potentially the transformer windings. Transformer W LTC has required oil to be added multiple times in less than a 5 year interval; which is indicative a barrier board (oil) leak between the LTC and main tank. This leak poses the risk of introduction moisture into the main tank which can result in an electrical failure of the windings. While Transformer D LTC is not yet exhibiting a similar leak, it is the same design/vintage and therefore subject to the same leak. Switchgear W is experiencing partial discharge (PD) activity. PD activity has accelerated to the point where it is audible to the human ear. PD over time will compromise the electrical insulation of the switchgear, which increases the likelihood of an electrical flashover or fault. A fault/failure of this nature has the potential for soot, smoke and carbon to damage the switchgear bus; causing a sustained outage. Switchgear W breakers are Federal Pacific DST. Switchgear D breakers are Westinghouse DHP. Both models of ACB (air circuit breaker) have mechanisms that require excessive maintenance to maintain reliable performance.	• Inspection reports stating condition
Asset Performance	✓	In August 2017, we experienced a sustained outage event where a Federal Pacific (DST) ACB failed catastrophically, impacting a total of 6,841 customers. Transformer W and D are each Federal Pacific. This specific OEM has a poor performance history within Ameren and at other utilities.	• Historical data showing outages in the last 5 years
Potential for Community Impact	✓	Jungerman substation supplies approximately 6,900 customers.	• Documentation of the number of customers supplied by asset
Safety	✓	This switchgear has had partial discharge problems in the past which creates a safety hazard for our co-workers. Job history for the site show that on 6/27/18 a partial discharge was observed/recorded. This event(s) is considered to be a high level of potential risk which could cause serious injury and necessitates the substation be de-energized for maintenance work.	• Dated inspection or safety report(s) on the partial discharges