Ex. AA-D-3

Exhibit No:
Issues: Steam Plant Life Span
Witness: Larry W. Loos
Exhibit Type: Direct Testimony
Sponsoring Party: Union Electric Company
File No: ER-2014-0258
Date: July 3, 2014

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2014-0258

DIRECT TESTIMONY

OF

LARRY W. LOOS

ON BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

Maricopa, Arizona
July, 2014

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DIRECT TESTIMONY

OF

LARRY W. LOOS

NO. ER-2014-0258

QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Larry W. Loos, 42830 W Kingfisher Dr., Maricopa, AZ 85138.

Q. WHAT IS YOUR OCCUPATION?

A. In this engagement, I am working as an independent contractor to Black & Veatch Corporation ("Black & Veatch"). Prior to my retirement from full time employment in May 2011, I was employed continuously by Black & Veatch for 41 years. Since my retirement, I have provided consulting services as an independent contractor on a number of occasions.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I am a graduate of the University of Missouri at Columbia, with a Bachelor of Science Degree in Mechanical Engineering and a Master's Degree in Business Administration.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A. Yes, however my status as a registered Professional Engineer in the state of Missouri is currently inactive. I have dropped my registration in eight other states since I am no longer employed full time.

Q. TO WHAT PROFESSIONAL ORGANIZATIONS DO YOU BELONG?

A. I am a member of the American Society of Mechanical Engineers.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I have been responsible for numerous engagements involving electric, gas, and other utility services. Clients served include both investor-owned and publicly-owned utilities; customers of such utilities; and regulatory agencies. During the course of these engagements, I have been responsible for the preparation and presentation of studies involving valuation, depreciation, cost classification, cost allocation, cost of service, allocation, rate design, pricing, financial feasibility, weather normalization, normal degree days, cost of capital, and other engineering, economic and management matters.

Q. PLEASE DESCRIBE BLACK & VEATCH.

A. Black & Veatch has provided comprehensive construction, engineering, consulting, and management services to utility, industrial, and governmental clients since 1915. Black & Veatch specializes in engineering and construction associated with utility services including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, cost studies, rate and financial reports, valuation and depreciation studies, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries. Including professionals assigned to affiliated companies, Black & Veatch currently employs approximately 10,000 people.

Q. HAVE YOU PREVIOUSLY APPEARED AS AN EXPERT WITNESS?

A. Yes, I have. I have presented expert witness testimony before this Commission on several occasions, including addressing the issue of the life span of coal-fired power plants in Ameren Missouri's 2010 rate case, File No. ER-2010-0036. I have also testified before the Federal Energy Regulatory Commission ("FERC") and regulatory bodies in the states of Colorado, Illinois, Indiana, Iowa, Kansas, Minnesota, New Mexico, New York, Pennsylvania, North Carolina, South Carolina, Texas, Utah, and Vermont. I have also presented expert witness testimony before District Courts in Colorado, Iowa, Kansas, Missouri, and Nebraska and before Courts of Condemnation in Iowa and Nebraska. I have also served as a special advisor to the Connecticut Department of Public Utility Control.

INTRODUCTION

Q. FOR WHOM ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to sponsor the May 2014 Black & Veatch report titled *Report on Life Expectancy of Coal-Fired Power Plants.* A copy of this report is included as Schedule LWL-1 in this case. This 2014 report represents an update to the informed estimates set forth in Black & Veatch's July 2009 report of the same name.

In early 2009, Ameren Missouri asked Black & Veatch to develop informed estimates of retirement dates (life span) for its four coal-fired, steam-generating stations located in the St. Louis area. The study and report were prepared under my supervision and direction. The resulting July 2009 report, titled *Report on Life Expectancy of Coal-Fired Power Plants,* was subsequently identified as Schedule LWL-E1 to my direct testimony in File No. ER-2010-0036. I understand that Ameren Missouri witness John Spanos relies on the life spans resulting from my estimated retirement dates set forth in Schedule LWL-1 in developing his recommended depreciation rates.

Q. WHY DID THE COMPANY REQUEST THAT BLACK & VEATCH UPDATE THE JULY 2009 REPORT?

A. The Company informed me that it desired to update the prior report in order to reflect more current information regarding environmental requirements, technology, and reserves than was reflected in the prior study and the resulting retirement dates found reasonable by the Commission in File No. ER-2010-0036.

Q. WHAT INFORMATION DID YOU CONSIDER IN DEVELOPING YOUR ESTIMATED RETIREMENT DATES?

A. As more fully discussed in Schedule LWL-1, the retirement dates that I estimate are based on consideration of:

1) Ameren Missouri's actual historical interim and final retirement experience,

2) Ameren Missouri's planned capital expenditures and the implication of capital projects on plant remaining life,

3) Age at retirement of coal-fired plants actually retired in the United States,

4) Publicly available information regarding the age of coal-fired plants currently in service in the United States,

5) Publicly available information regarding the life span of coal-fired plants which underlie depreciation expense rates used by utilities in 26 states,

6) Publicly available information regarding the retirement dates of coal-fired plants that are used to prepare integrated resource plans in 26 states,

7) General engineering considerations relating to design life and factors leading to the failure of major plant components and ultimately to the retirement of coal-fired generating stations,

8) Implications of existing and contemplated environmental requirements on coal-fired generating plants in general, and on Ameren Missouri plants specifically,

9) An assessment of the existing condition of Ameren Missouri's plants,

10) Allowance for a reasonable period over which to recover capital costs incident to the addition of scrubbers at the Sioux Plant,

11) Allowance for a reasonable period over which to recover capital costs incident to the expected addition of scrubbers at the Labadie or Rush Island Plants, in the event the Company is required to add scrubbers on two units at one of these plants,

12) The planned retirement of the Company's Meramec Plant by 2022 as discussed in the Company's draft 2014 Integrated Resource Plan ("IRP"), and

13) The practical consideration of the need for the orderly replacement of capacity when large blocks of base load capacity are retired.

Q. BASED ON CONSIDERATION OF THESE FACTORS, WHAT CONCLUSIONS DO YOU REACH?

A. As more fully discussed in Schedule LWL-1, I estimate that based on consideration of the above factors, the Company will retire its existing coal-fired plants during the 23-year period beginning in 2022 and ending in 2045. At retirement, the plants' ages will range from 65 to 70 years. The age of the individual generating units will range from 61 to 70 years at retirement.

The above dates include adjustment to accommodate the orderly replacement of capacity retired. Specifically, I extended the estimated retirement dates of Rush Island Units 1 and 2 by 3 years.

Q. HOW DO YOU ORGANIZE THE BALANCE OF YOUR TESTIMONY?

A. Following this introduction, I have organized my testimony into the following sections:

1) Description of Ameren Missouri's existing coal-fired fleet

2) General condition of Ameren Missouri's plants

3) Historical retirements

4) Implications of and need for capital expenditures

5) Life span used by other utilities

6) Implication of need to replace retired capacity

7) Final estimated retirement dates

AMEREN MISSOURI'S EXISTING COAL-FIRED FLEET

Q. WHAT AMEREN MISSOURI PLANTS DID YOU CONSIDER IN YOUR STUDIES?

A. The plants I studied comprise Ameren Missouri's regulated coal-fired fleet. These plants include the Meramec, Sioux, Labadie, and Rush Island Energy Centers. The combined, installed capacity of these four plants is nominally 5,650 MW, with commercial operation dates ranging from 1953 through 1977. The primary fuel used by these plants is low sulfur coal shipped by rail from the Powder River Basin in Wyoming.

Table 2.1 of Schedule LWL-1 shows unit operating characteristics of these four plants. As I show, with the exception of Labadie, each plant has a total nameplate capacity of about 1,000 MW (923 to 1,242 MW). The Meramec Plant consists of four relatively small units (137.5 to 359 MW); whereas the Sioux and Rush Island plants each consist of two relatively large units (549.7 to 621 MW). The Labadie Plant on the other hand consists of four relatively large units (573.7 to 621 MW). The larger units have a full load heat rate ranging from about **[redacted]** BTU per kWh. For the smaller units the heat rates range from about **[redacted]** BTU per kWh.

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PLANT CONDITION

Q. HOW DID YOU ASSESS THE CONDITION OF AMEREN MISSOURI'S PLANTS?

A. To assess the condition of Ameren Missouri's plants, in November and December 2014, Black and Veatch engineers visited each of the plants. During these plant visits, we conducted a walk down of each unit to observe the condition of the structures, systems, and equipment, and met with and interviewed plant personnel regarding capital improvements, maintenance and operating procedures. In addition, we requested of plant and corporate engineering personnel certain technical data, which we subsequently reviewed and evaluated. Based on our review and assessment, we conclude that the current condition of Ameren Missouri's plants is good relative to the respective ages of the plants. Based on these assessments, with continued maintenance and capital expenditures, we believe that, with the exception of the Meramec Plant, economic factors, not physical limitations, will likely drive retirement decisions.[1]

HISTORICAL RETIREMENTS

Q. DID YOU CONSIDER AMEREN MISSOURI'S RETIREMENT HISTORY IN YOUR DETERMINATION OF RETIREMENT DATES?

A. I gave some consideration to Ameren Missouri's actual retirement history in my determination of the probable life for each unit. In this regard, I relied on the Iowa Curve

[1] We believe that a combination of economic and physical limitations are the drivers behind the planned retirement of the Meramec Plant by 2022.

and average service life for each steam production account based on Ameren Missouri's complete retirement (interim and final) history developed by Company witness John Wiedmayer in File No. ER-2010-0036. With the mortality distribution, average service life and age of each unit, I determined the probable life, probable remaining life, and resulting retirement date of each unit. I developed the probable life for each unit based on the probable life of the investment reported in each account weighted by the outstanding balance at December 31, 2008. I developed the probable life for each plant based on the capacity weighted probable life of the units in service.

In Table 3-1 of Schedule LWL-1, I show the mortality distributions and average service lives that Mr. Wiedmayer provided me. I also show the probable life by account and unit based on that mortality distribution, average service life, and age. Consideration of the existing age of the individual units and the Company's actual retirement history by itself would suggest a probable life of the four plants would be within a range from 54 to 62 years and would suggest resulting retirement dates ranging from the year 2020 to 2030. However, consideration of this data was only a starting point, particularly given the limited final retirement data available for Ameren Missouri's plants.

Q. HAVE YOU UPDATED THE ANALYSIS CONDUCTED IN 2009 TO REFLECT MORE RECENT DATA?

A. No, I didn't believe it was necessary to do so. Instead, I have relied on the actuarial analysis conducted by Mr. Wiedmayer in 2009 based on retirements through December 31, 2008. Since Ameren Missouri has not retired any coal-fired generating units since the time of the prior study, I do not believe that the results of an updated study would be particularly meaningful beyond the results of the earlier analysis conducted in 2009.

CAPITAL EXPENDITURES

Q. WHAT ARE THE IMPLICATIONS OF CAPITAL EXPENDITURES ON PLANT LIFE?

A. Capital expenditures and continuing maintenance are integral to the continued operation of a power plant and are routine in the industry. Without ongoing capital expenditures, a plant will become increasingly less reliable and ultimately cannot operate. In addition, especially for coal-fired plants, major capital expenditures for environmental compliance are expected to occur perhaps more than once over the life of a particular plant. These environmental projects are beyond the routine capital expenditures that may be required for reliable plant operation.

Ameren Missouri's planned capital expenditures, as set forth in the Company's draft IRP documents, include the addition of scrubbers at either the Labadie or Rush Island Energy Centers,[2] only if they are required. The addition of scrubbers (if required) at Labadie or Rush Island plant 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 Ameren Missouri to recover its investment in these extraordinary environmental projects. Based

[2] Though the Company shows in the reference case of its 2014 draft IRP, the addition of scrubbers at its Meramec plant (Units 3 and 4), the Company currently plans to retire the plant in lieu of making this uneconomic investment.

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[3] of the environmental projects. My recommended final retirement dates allow a minimum 20 year recovery period for major environmental projects.

In Table 3-3 of Schedule LWL-1, I show how I explicitly consider the recovery of these extraordinary capital expenditures in my estimated retirement dates.

Q. DOESN'T AMEREN MISSOURI SHOW, IN ITS 2014 DRAFT INTEGRATED RESOURCE PLAN, THE ADDITION OF SCRUBBERS TO MERAMEC UNITS 3 AND 4?

A. Yes, in its reference case the Company's draft 2014 IRP reflects the timing of the addition of scrubbers to Units 3 and 4 at the Meramec Energy Center at an estimated cost $383 million ($591/kW) in the 2019 to 2025 time frame. The economics of investing nearly $400 million in generating capacity that at the time (assuming a 2022 in service date for the scrubber) will be over 60 years old is questionable at best. Therefore, consistent with the Company's plan, I assume that the Company will retire the Meramec Energy Center by 2022 in order to avoid this uneconomic investment.[4]

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[3] I have made the assumption that if the Company is required to install scrubbers, the installation will be made to Units 3 and 4 of the Labadie Plant, as the Company currently expects. For the Labadie Plant, I relied on the Company's draft IRP for the timing of these capital additions, if the Company is required to add scrubbers.

[4] See Page 4 of Schedule LWL-1 for a more detailed discussion of historical and forecast capital expenditures at the Meramec Plant.

OTHER UTILITIES

Q. HOW DID YOU EVALUATE THE LIFE SPANS USED BY OTHER UTILITIES?

A. I consider the life spans used by other utilities as a benchmark or test of the reasonableness of my informed estimated plant lives. In researching publically available depreciation studies and IRP filings in 26 states, I found the average age at retirement used by other utilities for coal-fired power plants is 57 years. The median age is 59 years.

The life spans used by other utilities in depreciation studies and IRPs exceed the average and median age at retirement of coal-fired power plants that have been retired in the U.S. In researching Velocity Suite[5] data, I found that the average and median age of all retired coal-fired power plants in the U.S. is 46 years.

Given the 57-year life span used by other utilities and the 46-year life span actually experienced, the plant lives I estimate for Ameren Missouri – all of which are longer than those life spans -- are reasonable and conservative.

[5] The Ventyx 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 Ventyx, a company that employs about 1,200 people.

CAPACITY REPLACEMENT

Q. HOW DID YOU EVALUATE WHETHER YOUR INDICATED RETIREMENT DATES WILL PERMIT THE ORDERLY REPLACEMENT OF RETIRED CAPACITY?

A. I factored into my final retirement date estimates consideration of the replacement capacity that Ameren Missouri will need as it retires its plants.[6] I developed a timeline assuming that retired coal-fired base load generation would be replaced with gas-fired, combined-cycle generation with a 52-month planning and construction schedule and a staged approach for replacing capacity where two units are constructed at a time with no other overlap in new plant construction. To accommodate this construction timeline, I extended the estimated final retirement date of Rush Island by three years.

My estimated retirement dates are based on the assumption that Ameren Missouri will do whatever is necessary to continue to operate the Rush Island plant beyond its estimated final retirement so as to have available adequate system capacity to provide safe and reliable electric service to its native customer base. This extended operation may be as a standby, peaking, or something other than as a base load resource.

Q. IN THE JULY 2009 REPORT DID YOU ASSUME THAT COAL-FIRED BASE LOAD CAPACITY WOULD BE REPLACED WITH GAS-FIRED, COMBINED-CYCLE GENERATION?

A. No, I did not. In the 2009 report, I assumed that coal-fired base load capacity would be replaced with coal-fired generation. When preparing the 2009 report, I considered

[6] As shown in its 2014 draft IRP, Ameren Missouri currently forecasts that it will have adequate resources to meet reserve requirements in the event the Meramec Plant is retired.

assuming capacity would be replaced with gas-fired, combined-cycle generation but in order to be conservative and to reflect that based on market conditions at that time, replacement of the capacity could be with coal-fired generation, I assumed replacement with coal-fired generation. Since the time the 2009 report was prepared, I believe that an assumption of replacing capacity with coal-fired generation has become increasingly unreasonable, given the cost and environmental advantages of gas-fired, combined-cycle generation in today's energy markets.

ESTIMATED RETIREMENT DATES

Q. WHAT RETIREMENT DATES DO YOU ESTIMATE?

A. As I show in Table 1-1 of Schedule LWL-1, I estimate the following final retirement dates:

Meramec	2022
Sioux	2033
Labadie - Units 1 and 2	2036
Labadie - Units 3 and 4	2042
Rush Island	2045

My final retirement date estimates consider Ameren Missouri's specific retirement history, Ameren Missouri's planned capital improvements, industry accepted life span forecasts for comparable facilities, the retirement experience of plants throughout the U.S., a viable plan for timely replacement of Ameren Missouri's retired capacity, and

Ameren Missouri's decision to retire its Meramec Plant by 2022 as discussed in the Company's draft IRP documents.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

Ex. AA-D-3

DRAFT

REPORT ON LIFE EXPECTANCY OF COAL-FIRED POWER PLANTS

BLACK & VEATCH PROJECT NO. 181958

PREPARED FOR

Ameren Missouri

MAY 2014

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Building a world of difference.

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Disclaimer

Black & Veatch Corporation (Black & Veatch) prepared this report for Ameren Missouri in May 2014 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 Ameren Missouri has not made any final definitive 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 Ameren Missouri's depreciation analysis.

1 Executive Summary

In this report we provide informed estimates of the retirement dates for the four Union Electric Company d/b/a Ameren Missouri (Ameren Missouri or Company) coal-fired power plants. We base our estimated retirement dates on Ameren Missouri's actual retirement history, our assessment of the plants' current condition, our understanding of planned routine capital expenditures, life spans of other US coal plants, and engineering and environmental compliance considerations. This report builds upon the Black & Veatch's July 2009 report for Ameren Missouri (f/k/a AmerenUE) titled *Report on Life Expectancy of Coal-Fired Power Plants.*

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 Ameren Missouri's coal-fired plants we consider actuarial analysis of historical experience of the interim and final retirements of Ameren Missouri's coal-fired generating facilities, planned routine capital additions, the age at retirement of plants retired in the US, expected ages at retirement for comparable plants in the US, the current condition of Ameren Missouri's plants, and engineering and environmental considerations. Our condition assessments are based on site visits, interviews with key operating personnel at each plant, and discussions with engineering and other professionals. The four plants addressed in this report are the Meramec Energy Center, the Sioux Energy Center, the Labadie Energy Center, and the Rush Island Energy Center.

In addition to the above, as we did in our July 2009 report, we reflect consideration of the timing of capacity requirements incident to the orderly construction of capacity required to replace capacity retired.

1.1 OVERVIEW OF STUDY

As was the case for our July 2009 report, we understand our report and informed estimates will be considered by Ameren Missouri's depreciation rate consultants in their recommendation of appropriate depreciation rates for the four plants. Our study of final retirement dates for Ameren Missouri's coal-fired plants includes:

- Consideration of plant life based on the 2009 actuarial analysis of Ameren Missouri's continuing property records for its coal-fired power plants
- Consideration of the planned routine 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 used in depreciation studies and forecast in 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
- Onsite plant condition assessment

1.2 FINDINGS AND CONCLUSIONS

Ameren Missouri 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 Ameren Missouri will retire its four coal-fired plants over the 23 year period 2022 through 2045. Unit ages at final retirement are forecast to range from nominally 61 to 70 years. For Ameren Missouri's plants to achieve these lives, Ameren Missouri must invest capital expenditures in the interim years.

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

- Actuarial analysis conducted in 2009 of Ameren Missouri's actual retirements of its coal-fired power plant investment. This analysis indicates the probable lives (in 2009):
  - of Ameren Missouri's units ranges from 54 to 65 years
  - for the largest account (312, Boilers) ranges from 54 to 62 years
- Planned capital expenditures especially those related to environmental expenditures:
  - Over the next five years, Ameren Missouri expects to spend approximately $860 million ($172 million per year) on capital projects at the four plants of which only about 6 percent is expected to be expended at the Meramec plant, which accounts for about 16 percent of the Company's coal-fired generating capacity.
  - Approximately 40% of the $860 million budgeted relates to environmental projects[1]
- Available data regarding life spans realized and anticipated by plants operated by other utilities[2]:
  - The average age at retirement used in depreciation studies, Integrated Resource Plan (IRP) filings, and reflecting Ventyx Velocity Suite Online (Velocity Suite) EV Power database information is 57.4 years, with a median age of 59.3 years
  - The average reported age at retirement of all retired coal-fired units in the US is 46.1 years with a median of 46.1 years
  - The average age of currently operating coal-fired units is 43.2 years with a median age of 44.5 years

[1] This level of capital expenditures assumes that no new major environmental initiatives will require extensive modifications (e.g. the addition of scrubbers at Labadie and/or Rush Island) to any of the four plants.

[2] For the purpose of this report we generally refer to the owners and/or operators of coal-fired generating stations as utilities, even though we recognize that not all coal-fired generating stations are owned and operated by regulated utilities.

- Existing and contemplated environmental regulations:
  - The locations of Ameren Missouri's plants are classified as non-attainment areas for 8-hour ozone and PM2.5 pollutants[3], 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 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 principles:
  - 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 utilities to replace such components when and as they fail
- Onsite plant condition investigations:
  - The current condition of Ameren Missouri's plants is generally good relative to the respective ages of the plants, although Sioux plant faces some challenges with regard to plant operations
  - The Meramec plant will increasingly face challenges as it continues to age. The challenges include:
    - Safety considerations as plant components age and wear. This is of special concern with respect to high pressure piping. Ameren Missouri is having a safety assessment of the plant done by an engineering contractor. Ameren Missouri plans to fund maintenance and capital expenditures necessary to maintain the safe operation of the plant.
    - The availability of spare and replacement parts. The plant has experienced some difficulty in obtaining some replacement parts through traditional suppliers.
    - Increasing unit cost of maintenance and reduced reliability. As the plant continues its operation as a cycling plant, Ameren Missouri has reduced maintenance and capital expenditures for Meramec due to the age of the plant and planned retirement in 2022.
    - Environmental constraints, especially with respect to the plant's inability to meet one-hour sulfur dioxide emissions standards and the cost of compliance relative to the plant's small size and age.
  - With continued maintenance and capital expenditures, economic factors will likely drive retirement decisions, not physical limitations

[3] In the December 5th, 2013 Missouri Air Conservation Commission Adoption of the Missouri Department of Natural Resources Recommendation for Area Boundary Designations for the 2012 Annual Fine Particulate Matter National Ambient Air Quality Standard, the State of Missouri recommends each county in the State for designation as attainment/unclassifiable under the 2012 Annual PM2.5 NAAQS.

- The retirement of the Company's Meramec Plant in 2022 as discussed above and in the Company's Integrated Resource Plan ("IRP") and Environmental Compliance Plan ("ECP")

In our 2009 report, we found the life span of the four plants to average 56 years[4]. For the purpose of that report, we recommended an average life span of 68 years[5]. We increased the nominal life span by 12 years (over 18 percent) to be conservative and recognize:

- The good condition of the plants relative to their ages and planned operations.
- 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 or Rush Island Energy Centers in response to various environmental regulations that are currently pending or may be promulgated in the coming years
- The period required to recover the capital investment incurred by the Company in installing scrubbers at its Sioux Energy Center in 2010
- Accommodation of the orderly and reasonable replacement of capacity retired

Our informed estimates of the final retirement dates for Ameren Missouri's coal-fired power plants are summarized in Table 1-1. In forecasting these dates, we conclude an appropriate nominal life expectancy of the Ameren Missouri coal plants is 65 years. As in our July 2009 report we reviewed the resulting retirement schedule and adjusted certain dates to allow for the timely replacement of capacity retired. In Figure 3-1 we demonstrate the viability of the retirement schedule we are recommending in this report. We base capacity replacement on a 36-month construction schedule (52 months including permitting) for new gas-fired combined cycle generation[6]. We show in Figure 3-1, over the 23 year retirement period there is minimal concurrent construction required for the replacement capacity.

[4] Black & Veatch 2009 report Table 3-3:

Average Age of AmerenUE plants	38.89 yrs
Expected Remaining Life	17.58 yrs
Life Span	56.47 yrs

[5] Black & Veatch 2009 report Table 3-5, corrected to reflect that Column J of Table 3-5 overstated age at final retirement by one year.

[6] For the purpose of our 2009 report, we assumed replacement of base capacity with new coal-fired steam generating capacity. In this report, we have assumed base capacity will be replaced with new gas-fired combustion turbine combined cycle capacity. Our current assumption is consistent with Ameren Missouri's draft 2014 IRP.

Table 1-1 Final Retirement Date Summary

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	Unit	Capacity	In-Service	Final Retirement 2009 Report		2014 Report	
			MW	Date	Date	Age - Yrs	Year	Age - Yrs
1	Meramec	1	137.5	May-53	Sep-22	69.3	Sep-22	69.3
2	Meramec	2	137.5	Jul-54	Sep-22	68.2	Sep-22	68.2
3	Meramec	3	289.0	Jan-59	Sep-22	63.7	Sep-22	63.7
4	Meramec	4	359.0	Jul-61	Sep-22	61.2	Sep-22	61.2
5	Sioux	1	549.7	May-67	Sep-33	66.3	Sep-33	66.3
6	Sioux	2	549.7	May-68	Sep-33	65.3	Sep-33	65.3
7	Labadie	1	573.7	Jun-70	Sep-42	72.3	Sep-36	66.3
8	Labadie	2	573.7	Jun-71	Sep-42	71.3	Sep-36	65.3
9	Labadie	3	621.0	Aug-72	Sep-38	66.1	Sep-42	70.1
10	Labadie	4	621.0	Aug-73	Sep-38	65.1	Sep-42	69.1
11	Rush Island	1	621.0	Mar-76	Sep-46	70.5	Sep-45	69.5
12	Rush Island	2	621.0	Mar-77	Sep-46	69.5	Sep-45	68.5
13	Total		5,654					
14	MW Weighted Average					67.6		67.1
15	Minimum			May-53	Sep-22	61.2	Sep-22	61.2
16	Maximum			Mar-77	Sep-46	72.3	Sep-45	70.1

The principal factors that contribute to differences between the estimated final retirement dates recommended in this report and the dates set forth in our 2009 report are:

- In our 2009 report, we assumed that the coal-fired generation capacity retired would be replaced by coal-fired generation. In this report we assume that coal-fired generation capacity will be replaced by gas-fired combined-cycle generation.
- In our 2009 report, consistent with the Company's then current IRP, we assumed that if scrubbers were required at the Labadie and Rush Island Energy Centers they would be added to all six units between 2016 and 2020. In this report, we assume that if scrubbers are required they will be added in 2022 and then only to Labadie Units 3 and 4.

Our research of publicly available depreciation information related to coal fired unit lifespans shows that, on average, our estimated retirement dates are conservative from a cost recovery perspective. Our recommended average age at retirement for Ameren Missouri's coal-fired generating capacity of 67.1 years exceeds the average age found in IRP filings by 10 years, and exceeds the average age of units actually retired by 22 years.

Our estimated retirement dates result in units retiring at nominally the age of 61 to 70 years. To achieve the plant lives set forth in Table 1-1 we and Ameren Missouri recognize that 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 $175 million per year (approximately 4.5 percent of original cost) over the next five years.

2 Introduction and Qualifications

2.1 PURPOSE

The purpose of this report is to provide informed estimates of future retirement dates for Ameren Missouri's coal-fired generating plants at its Meramec, Sioux, Labadie, and Rush Island Energy Centers. 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 Ameren Missouri (Ameren Missouri 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, interviews with key operating personnel at each plant, and discussions with engineering and other professionals.

We understand our report and informed estimates will be considered by Ameren Missouri'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 Ameren Missouri'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

Ameren Missouri owns and operates four coal-fired energy centers 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 all currently burn low sulfur coal shipped by rail from the Powder River Basin in Wyoming (PRB). We summarize the unit operating characteristics of Ameren Missouri's coal-fired plants in Table 2-1.

Table 2-1 Unit Operating Characteristics

Coal Fired Steam Generating Units
Unit Operating Characteristics
December 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line			Nameplate	Heat Rate		Weighted Average Fuel and O&M Costs					
No.	Energy Center	Unit	Capacity	Full Load	Average	Fuel	Variable	Fixed	In-Service	Age	Supercritical
			MW	BTU/kWh	BTU/kWh	$/MWh	$/MWh	$/kW-yr		Years	
1	Meramec	1	137.50	11,562.00	12,171.00	19.51	1.50	37.21	May-53	60.63	N
2	Meramec	2	137.50	11,680.00	12,295.00	19.51	1.50	37.21	Jul-54	59.46	N
3	Meramec	3	289.00	9,997.00	10,300.00	19.51	1.50	37.21	Jan-59	54.96	N
4	Meramec	4	359.00	10,720.00	10,901.00	19.51	1.50	37.21	Jul-61	52.46	N
5	Sioux	1	549.70	9,638.00	10,381.00	21.43	1.53	34.46	May-67	46.63	Y
6	Sioux	2	549.70	9,666.00	10,220.00	21.43	1.53	34.46	May-68	45.63	Y
7	Labadie	1	573.70	9,893.00	10,136.00	15.54	0.61	17.13	Jun-70	43.54	N
8	Labadie	2	573.70	9,917.00	10,643.00	15.54	0.61	17.13	Jun-71	42.54	N
9	Labadie	3	621.00	9,722.00	9,882.00	15.54	0.61	17.13	Aug-72	41.38	N
10	Labadie	4	621.00	10,108.00	10,219.00	15.54	0.61	17.13	Aug-73	40.38	N
11	Rush Island	1	621.00	9,297.00	9,798.00	18.71	0.80	21.41	Mar-76	37.79	N
12	Rush Island	2	621.00	9,496.00	9,858.00	18.71	0.80	21.41	Mar-77	36.79	N
13	Total / MW Weighted		5,653.80	9,886.21	10,291.95	18.03	0.98	24.72		43.94	
14	Recap / MW Weighted										
15	Meramec		923.00	10,762.07	11,109.68	19.51	1.50	37.21		55.50	
16	Sioux		1,099.40	9,652.00	10,300.50	21.43	1.53	34.46		46.13	
17	Labadie		2,389.40	9,910.20	10,213.29	15.54	0.61	17.13		41.92	
18	Rush Island		1,242.00	9,396.50	9,828.00	18.71	0.80	21.41		37.29	
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 EV Power database (EV Power) used in this report 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 Ventyx, a company which employs approximately 900 people (as of 2010).

In Table 2-2 we show the current and planned emissions and environmental controls at each of Ameren Missouri's coal fired plants.[7]

[7] Again, for purposes of this report, we assume, consistent with the Company's draft 2014 Integrated Resource Plan, that Ameren Missouri will be required to install scrubbers on Units 3 and 4 at the Labadie Energy Center in 2022.

Table 2-2 Emissions and Environmental Controls

Coal Fired Steam Generating Units
Emissions and Environmental Controls
December 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
					Emission Rates				Emission Control Equipment		
Line No.	Energy Center	Unit	Nameplate Capacity	In-Service	SO2	NOX	CO2	Mercury	SO2	NOX	Mercury
			MW		lbs/MMBtu	lbs/MMBtu	lbs/MMBtu	lb/Tbtu			
1	Meramec	1	137.50	May-53	0.44	0.12	209.76	2.24	None	LNBT	2016
2	Meramec	2	137.50	Jul-54	0.41	0.11	209.76	2.24	None	LNBT	2016
3	Meramec	3	289.00	Jan-59	0.42	0.17	209.76	2.39	None	None	2016
4	Meramec	4	359.00	Jul-61	0.44	0.18	209.76	3.27	None	LNBT	2016
5	Sioux	1	549.70	May-67	0.11	0.26	209.76	1.67	FGD	OA	2015
6	Sioux	2	549.70	May-68	0.12	0.24	209.76	1.67	FGD	OA	2015
7	Labadie	1	573.70	Jun-70	0.56	0.10	209.76	7.05	None	LNBT	2016
8	Labadie	2	573.70	Jun-71	0.56	0.10	209.76	7.05	None	LNBT	2016
9	Labadie	3	621.00	Aug-72	0.58	0.10	209.76	7.05	2022	LNBT	2016
10	Labadie	4	621.00	Aug-73	0.58	0.09	209.76	7.05	2022	LNBT	2016
11	Rush Island	1	621.00	Mar-76	0.56	0.08	209.75	5.75	None	LNBT	2015
12	Rush Island	2	621.00	Mar-77	0.56	0.08	209.76	5.75	None	LNBT	2015
13	Total / MW Weighted		5,653.80		0.46	0.13	209.76	5.01			
14	Recap / MW Weighted										
15	Meramec		923.00		0.43	0.16	209.76	2.69			
16	Sioux		1,099.40		0.11	0.25	209.76	1.67			
17	Labadie		2,389.40		0.57	0.10	209.76	7.05			
18	Rush Island		1,242.00		0.56	0.08	209.76	5.75			

19 Notes
20 All plants and units are equipped with electrostatic precipitators
21 Columns [E], [F], [G] - Velocity Suite Database
22 Column [H] - Data provided by Ameren Missouri
23 Column [I] - SO2 Control Equipment - Flue Gas Desulfurization (FGD or Scrubbers)
24 The company does not plan to add scrubbers unless required to do so. The dates shown for Labidie 3 and 4 represent the Reference Case
25 set forth in the Company's 2014 Draft Environmental Compliance Plan in the event the Company is required to add scrubbers.
26 Column [J] - NOX Control Equipment
27 LNBT= Low Nox Burner Technology
28 OA = Overfire Air (The Company's 2014 Draft Environmental Compliance Plan calls for the addition of SCR at Sioux in 2020)
29 Column [K] - Mercury Control Equipment - Activated Carbon Injection (ACI)

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 approximately 10,000 professionals, 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 Overland Park, Kansas and in 2013, was ranked the 13th largest majority employee-owned company in the United States. Black & Veatch was ranked 14th of the Top 500 Design Firms by Engineering News-Record, and ranked 3rd in the Top 25 in Power and 1st in the Top 25 in Fossil Fuel in 2013.

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 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.[8]

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.[9] 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."[10]

Coal-fired power plants consist of a large number of individual components which have a finite life expectancy. These individual components are expected to fail and be replaced in order for the plant to continue to provide reliable service. In addition, throughout a plant's life the utility regularly 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. Additionally, there are practical limitations on the life of a plant due to ever expanding environmental requirements and safety considerations.

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[8] Life span represents the period between the in service date and the date of retirement.

[9] In addition, unit property tends to occupy a relatively confined geographic area. Mass property, on the other hand, tends to be much more geographically dispersed. For example, the costs of a coal-fired power plant may be confined within an area of 2,000 acres, whereas the costs of distribution poles may be confined within the entire service area of the utility of perhaps 100,000 square miles.

[10] National Association of Regulatory Utility Commissioners, "Public Utility Depreciation Practices," 141, 1996

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 Ameren Missouri's coal-fired plants we consider actuarial analysis of interim and final retirements of Ameren Missouri'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 Ameren Missouri's plants, and other factors explained below.

3.2 INTERIM AND FINAL RETIREMENTS – ACTUARIAL ANALYSIS

In preparing our 2009 report, at Ameren Missouri's request, Gannett Fleming, Inc., Ameren Missouri's depreciation consultant, conducted an actuarial analysis of the Company's coal-fired steam production plant accounts. This analysis included 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, reproduced from our July 2009 report. 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 Ameren Missouri'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 (to be consistent with the data used in the most recent depreciation analysis). 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).

In this report, we have relied on the actuarial analysis conducted by Gannett Fleming for our July 2009 report. A more recent actuarial analysis was not available at the time this report was prepared. Since Ameren Missouri has not retired any coal-fired generating units since the time of the prior study, we do not believe that the results of an updated study would be particularly meaningful beyond the results of the earlier analysis conducted in 2009.

Table 3-1 Coal Fired Steam Generation Units Probable Life

Coal Fired Steam Generating Units
Probable Life - Retirement Date
December 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Line No.	Plant	Unit	Nameplate Capacity	Age	Probable Life 311	312	314	315	316	Total Original Cost	Probable Life	Remaining Life	Indicated Retirement
			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 - Years				53	45	47	51	47				
3	Meramec	1	137.50	60.63	61.50	65.00	64.10	65.40	71.70		64.89	4.26	Apr-18
4	Meramec	2	137.50	59.46	61.00	64.75	63.90	64.80	71.10		64.59	5.13	Feb-19
5	Meramec	3	289.00	54.96	58.80	61.50	61.00	61.90	68.10		61.49	6.53	Jul-20
6	Meramec	4	359.00	52.46	57.90	60.00	60.00	60.70	66.80		60.13	7.67	Aug-21
7	Sioux	1	549.70	46.63	56.70	57.40	56.50	58.70	64.30		57.40	10.77	Oct-24
8	Sioux	2	549.70	45.63	56.40	57.20	56.10	58.60	64.10		57.17	11.54	Jul-25
9	Labadie	1	573.70	43.54	55.90	55.40	56.10	57.00	62.20		55.85	12.31	Apr-26
10	Labadie	2	573.70	42.54	55.90	55.30	55.70	56.90	62.00		55.69	13.15	Feb-27
11	Labadie	3	621.00	41.38	55.30	54.90	55.10	56.70	61.50		55.25	13.87	Nov-27
12	Labadie	4	621.00	40.38	55.10	54.70	54.70	56.70	61.40		55.03	14.65	Aug-28
13	Rush Island	1	621.00	37.79	53.90	53.60	53.10	55.90	60.20		53.77	15.98	Dec-29
14	Rush Island	2	621.00	36.79	53.70	53.60	52.80	54.20	60.10		53.59	16.79	Oct-30
15	Total / MW Weighted		5,653.80	43.94	55.95	56.30	56.03	57.70	62.99		56.47	12.53	
16	Recap / MW Weighted												
17	Meramec		923.00	55.50	59.18	61.92	61.50	62.39	68.58		61.93	6.42	Jun-20
18	Sioux		1,099.40	46.13	56.55	57.30	56.30	58.65	64.20		57.28	11.16	Feb-25
19	Labadie		2,389.40	41.92	55.54	55.06	55.38	56.82	61.76		55.44	13.53	Jul-27
20	Rush Island		1,242.00	37.29	53.80	53.60	52.95	55.05	60.15		53.68	16.39	May-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 2008 Original Cost Investment of the Plant, consistent with the data used in the probable life analysis												

3.3 CAPITAL PROJECTS

Capital projects are an integral part of maintaining a coal-fired power plant. 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.[11] The most significant future capital projects that Ameren Missouri has budgeted for its coal-fired power plants are for environmental control. Ameren Missouri has budgeted an average of $70 million annually on environmental projects over the next five years. This $70 million annual average amounts to nearly 41 percent of total average annual capital expenditures budgeted for 2014 through 2018. We show in Table 3-2 Ameren Missouri's five year capital expenditure projection for its coal fired power plants.

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

Table 3-2 Budgeted Capital Expenditures by Plant

($000s)

[A]		[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Line No.	Plant	Annual Average 2004-2008	Annual Average 2009-2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017	Budget 2018	Annual Average 2014-2018
1	Meramec								
2	Environmental	9,516	1,772	3,151	10,464	11,001	648	1,465	5,346
3	Other	27,361	13,738	3,793	3,310	5,740	3,613	8,407	4,973
4	Subtotal	36,877	15,510	6,945	13,773	16,740	4,261	9,872	10,318
5	Sioux								
6	Environmental	66,793	67,367	6,826	7,316	1,102	1,169	26,164	8,516
7	Other	25,511	10,969	27,148	30,134	9,832	57,262	71,190	39,113
8	Subtotal	92,303	78,336	33,975	37,450	10,933	58,431	97,355	47,629
9	Labadie								
10	Environmental	2,023	26,158	94,306	65,978	30,746	1,380	22,986	43,079
11	Other	29,264	25,769	39,301	41,772	48,249	31,650	23,226	36,839
12	Subtotal	31,286	51,927	133,607	107,749	78,995	33,030	46,212	79,919
13	Rush Island								
14	Environmental	1,948	4,322	10,761	5,220	23,738	24,588	2,983	13,458
15	Other	25,519	22,242	7,295	17,488	29,738	37,267	11,197	20,597
16	Subtotal	27,467	26,564	18,057	22,708	53,475	61,856	14,180	34,055
17	Total								
18	Environmental	80,279	99,619	115,045	88,977	66,586	27,786	53,598	70,398
19	Other	107,655	72,718	77,538	92,703	93,558	129,792	114,020	101,522
20	Grand Total	187,934	172,337	192,583	181,681	160,144	157,578	167,618	171,921

As shown above, except for the Meramec plant and capital additions at the Sioux plant related to environmental initiatives, capital expenditures are budgeted to increase during the 2014-2018 period to levels substantially above the actual levels for the 2004-2013 period. However, capital expenditures at the Meramec plant (environmental plus non environmental) during the 2009-2013 were 58 percent below the level recorded during the 2004-2008 period. Budgeted capital expenditures for the 2014-2018 period are 33 percent below actual expenditures during the 2009-2013 period. This drop in current and planned level of capital expenditures at the Meramec plant indicates that the Company is investing to maintain the plant's safety and reliability for the next few years. The expenditure levels budgeted for the 2014-2018 period continue this pattern.

3.3.1 Environmental Projects

Completion of the scrubbers at the Sioux Energy Center in 2010 represents the final extraordinary environmental project currently planned by the Company[12]. Ameren Missouri has no definitive plans to install scrubbers at other plants unless required to do so. In the Company's draft 2014 Integrated Resource Plan (IRP), the Company has included in its planning scenario the addition (in the 2019 to 2025 time frame) of scrubbers to Units 3 and 4 at the Labadie Energy Center. In order to recognize the possibility that the Company may be required to expend the substantial amounts to install scrubbers, we included consideration of the time required to recover the substantial

[12] Of the $1.2 billion original cost investment at the Sioux Energy Center at 12/31/2013, approximately $600 million (50%) relates to the 2010 scrubber addition.

investment (estimated at $552 million, $442/kW) incident to the addition of scrubbers in 2022. By so doing, we increased the estimated life span, which (all other factors equal) results in lower depreciation rates.

The Company's draft 2014 IRP also reflects the timing of the addition of scrubbers to Units 3 and 4 at the Meramec Energy Center at an estimated cost $383 million ($591/kW) in the 2019 to 2025 time frame. The economics of investing nearly $400 million in generating capacity that at the time (assuming a 2022 in service date for the scrubber) will be over 60 years old is questionable at best. Therefore, for the purpose of this report, we assume that the Company will retire the Meramec Energy Center in 2022 in order to avoid the uneconomic investment.

As in our June 2009 report, 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 Ameren Missouri forecasts in its reference case scenario that projects will go into service if the Company is required to install scrubbers at Labadie. 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 time for recovery of extra-ordinary environmental investment at 20 years. Table 3-3 (Column H) shows the expected remaining life after consideration of the environmental investments at Sioux and Labadie.

Table 3-3 Final Retirement Dates Considering Environmental Projects

Coal Fired Steam Generating Units
Final Retirement Date Considering Environmental Projects
December 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
											Recommended			
Line No.	Energy Center	Unit	Nameplate Capacity	In Service	Age	Expected Remaining Life	Environmental Project	Expected RL After Project	Probable Retirement	Age at Probable Retirement	Life Span	Final Retirement	Remaining Life	Age at Final Retirement
			MW		Years	Years		Years			Years		Years	Years
1	Meramec	1	137.50	May-53	60.63	4.26		4.26	Apr-18	64.89	68.00	2022	8.71	69.34
2	Meramec	2	137.50	Jul-54	59.46	5.13		5.13	Feb-19	64.59	68.00	2022	8.71	68.17
3	Meramec	3	289.00	Jan-59	54.96	6.53		6.53	Jul-20	61.49	61.00	2022	8.71	63.67
4	Meramec	4	359.00	Jul-61	52.46	7.67		7.67	Aug-21	60.13	61.00	2022	8.71	61.17
5	Sioux	1	549.70	May-67	46.63	10.77	Dec-10	16.92	Dec-30	63.55	65.00	2033	19.71	66.34
6	Sioux	2	549.70	May-68	45.63	11.54	Nov-10	16.84	Nov-30	62.46	65.00	2033	19.71	65.34
7	Labadie	1	573.70	Jun-70	43.54	12.31		12.31	Apr-26	55.85	65.00	2036	22.71	66.25
8	Labadie	2	573.70	Jun-71	42.54	13.15		13.15	Feb-27	55.70	65.00	2036	22.71	65.25
9	Labadie	3	621.00	Aug-72	41.38	13.87	Oct-22	28.75	Oct-42	70.13	69.00	2042	28.71	70.09
10	Labadie	4	621.00	Aug-73	40.38	14.65	Oct-22	28.75	Oct-42	69.13	69.00	2042	28.71	69.09
11	Rush Island	1	621.00	Mar-76	37.79	15.98		15.98	Dec-29	53.78	65.00	2042	28.71	66.50
12	Rush Island	2	621.00	Mar-77	36.79	16.79		16.79	Oct-30	53.59	65.00	2042	28.71	65.50
13	Total / MW Weighted		5,654		43.94	12.53		16.83		60.77	65.57		22.48	66.41
14	Recap / MW Weighted													
15	Meramec		923.00	Jul-61	55.50	6.42		6.42	Aug-21	64.89	63.09	2022	8.71	64.21
16	Sioux		1,099.40	May-68	46.13	11.16		16.88	Dec-30	63.55	65.00	2033	19.71	65.84
17	Labadie		2,389.40	Aug-73	41.92	13.53		21.06	Oct-42	70.13	67.08	2036 - 2042	25.83	67.75
18	Rush Island		1,242.00	Mar-77	37.29	16.39		16.39	Oct-30	53.78	65.00	2042	28.71	66.00

19 Reference:
20 Column [F] - Actuarial 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 CONSIDERATION OF REPLACEMENT CAPACITY CONSTRUCTION SCHEDULE

In our June 2009 report we included consideration of the reasonableness of our estimated retirement dates considering the need to replace capacity retired and the time and resources required to construct and finance replacement capacity. Based on our evaluation, we concluded that the unadjusted retirement dates did not realistically permit the orderly replacement of capacity retired. Therefore, in consultation with Ameren Missouri we adjusted the retirement dates we recommended based on the assumption that all capacity would be replaced by base load coal-fired generation requiring a 90 month planning and construction schedule.

Current market conditions however, indicate that gas-fired combined cycle generation is a far more reasonable assumption for the replacement of base load capacity for Ameren Missouri's coal-fired plants. Additionally, Ameren Missouri forecasts it will not require new capacity to replace the capacity lost from its planned retirement of the Meramec Energy Center in 2022, since its capacity is not required to meet Ameren Missouri's reserve margin. We have therefore adjusted our retirement date estimates to reflect a more practical schedule to replace the retired capacity of the Labadie, Rush Island and Sioux Energy Centers with base load gas-fired generation. These adjusted retirement dates are set forth in Table 3-4.

Table 3-4 Final Retirement Dates Adjusted for Replacement Schedule

Coal Fired Steam Generating Units
Final Retirement Date
(Adjusted to Accommodate Replacement Capacity Construction Schedule)
December 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Energy Center	Unit	Nameplate Capacity	In Service	Age	Recommended Final Retirement	Final 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	60.63	2022	2022	-	8.71	69.34
2	Meramec	2	137.50	Jul-54	59.46	2022	2022	-	8.71	68.17
3	Meramec	3	289.00	Jan-59	54.96	2022	2022	-	8.71	63.67
4	Meramec	4	359.00	Jul-61	52.46	2022	2022	-	8.71	61.17
5	Sioux	1	549.70	May-67	46.63	2033	2033	-	19.71	66.34
6	Sioux	2	549.70	May-68	45.63	2033	2033	-	19.71	65.34
7	Labadie	1	573.70	Jun-70	43.54	2036	2036	-	22.71	66.25
8	Labadie	2	573.70	Jun-71	42.54	2036	2036	-	22.71	65.25
9	Labadie	3	621.00	Aug-72	41.38	2042	2042	-	28.71	70.09
10	Labadie	4	621.00	Aug-73	40.38	2042	2042	-	28.71	69.09
11	Rush Island	1	621.00	Mar-76	37.79	2042	2045	3.00	31.71	69.50
12	Rush Island	2	621.00	Mar-77	36.79	2042	2045	3.00	31.71	68.50
13	Total / MW Weighted		5,653.80		43.94				23.13	67.07
14	Recap / MW Weighted									
15	Meramec		923.00	Jul-61	55.50	2022	2022	-	8.71	64.21
16	Sioux		1,099.40	May-68	46.13	2033	2033	-	19.71	65.84
17	Labadie		2,389.40	Aug-73	41.92	2036 - 2042	2036 - 2042	-	25.83	67.75
18	Rush Island		1,242.00	Mar-77	37.29	2042	2045	3.00	31.71	69.00

In Figure 3-1, we show the construction timeline associated with the construction of replacement capacity based on the adjusted retirement dates we show in Table 3-4. Using a 52 month planning and construction schedule, typical of a large base load natural gas-fired power plant construction project, we demonstrate in Figure 3-1 the staged approach for replacing capacity where permitting the next facility can occur simultaneously with the construction of another plant. As we show in Figure 3-1, we project replacement capacity to be constructed two units at a time with no other overlap in new plant spending.

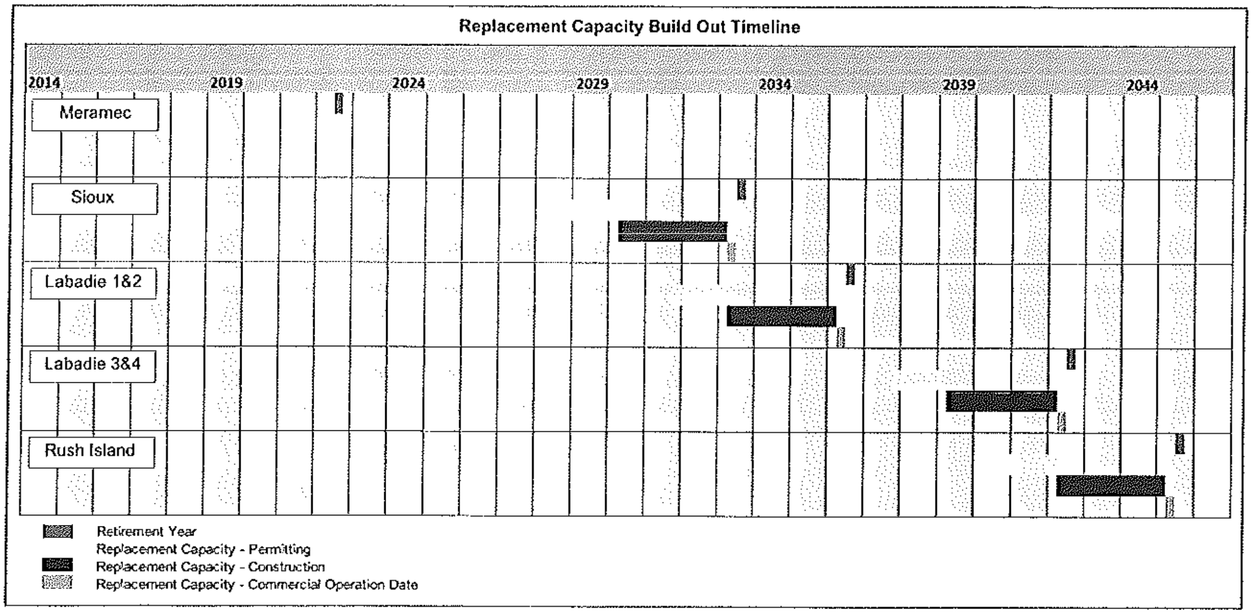

Figure 3-1 Replacement Capacity Construction Timeline

3.5 ESTIMATED RETIREMENT DATES

Our estimated life span and final retirement dates for Ameren Missouri's coal-fired plants shown in Table 3-4 are based on consideration of a number factors and assumptions including:

1. Actuarial analysis of Ameren Missouri'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 principles,
6. Onsite plant condition investigations,
7. Accommodation of a reasonable replacement capacity construction schedule, and
8. The retirement of the Company's Meramec Plant in 2022 as discussed in the Company's draft 2014 Integrated Resource ("IRP") and Environmental Compliance ("ECP") plans

Based on all of these factors, we find the nominal life span of Ameren Missouri's four plants amounts to 67 years. Using a nominal life span of 67 years, we estimate that Ameren Missouri will retire its four coal-fired plants over the 23 year period 2022 through 2045. Unit ages at final retirement range from nominally 61 to 70 years. For Ameren Missouri's plants to achieve these lives, expenditures (both environmental and non-environmental) will be required.

4 Plant Life Surveys

4.1 DEPRECIATION AND IRP SURVEY

As in our 2009 study, for the purpose of this 2014 report 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 26 states west of Ohio, excluding the Pacific coast.[13] The states we researched for our survey include Alabama, Arizona, Arkansas, Colorado, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, 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 states listed above.

4.1.2 IRP

The following information was taken from a report titled "A Brief Survey of State Integrated Resource Planning Rules and Requirements"[14] dated April 28, 2011:

- The following states require electric utilities to prepare and file IRPs: Arizona, Arkansas, Colorado, Delaware, Georgia, Hawaii, Idaho, Indiana, Kentucky, Minnesota, Missouri, Montana, Nebraska, Nevada, New Hampshire, New Mexico, North Carolina, North Dakota, Oklahoma, Oregon, South Carolina, South Dakota, Utah, Vermont, Viginia, Washington, and Wyoming
- States with no IRP rules: Alabama, Alaska, California, Connecticut, Florida, Illinois, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Mississippi, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Tennessee, Texas, West Virginia, and Wisconsin
  - Within this dataset, the following states have a filing requirement for long-term resource procurement plans: California, Connecticut, Florida, Illinois, Massachusetts, Michigan, Ohio, Pennsylvania, Rhode Island, Texas, and Wisconsin
- The State of Louisiana had an open investigation about whether to establish 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 Arizona, Colorado, Idaho, Indiana, Iowa, Kansas, Kentucky, Minnesota, Missouri, Montana, New Mexico, North Dakota, Nevada, Ohio, Texas,

[13] We focus on these states because of the predominance of the use of coal from the Powder River Basin.
[14] "A Brief Survey of State Integrated Resource Planning Rules and Requirements", Wilson, Rachel and Peterson, Paul. Synapse Energy Economics (Prepared for the American Clean Skies Foundation), April 28, 2011

Utah, and Wyoming. 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, and EV Power is 57.4 years (MW weighted) for coal-fired power plants. We find the minimum age at retirement of 42.7 years, the maximum age of 72.2 years, and a median age of 59.3 years. In Figure 4-1 we show the distribution of the age of generating units at planned retirement and the associated megawatts of capacity. We also show the age at our recommended retirement dates for the four Ameren Missouri plants to evaluate the reasonableness of our recommended retirement dates. As we show, our recommended retirement dates result in life spans considerably greater than those generally found for other utilities. Our recommended retirement dates result in an average age at retirement of 68.2 years for the Ameren Missouri plants. This average exceeds the average we find for utilities in the 26 states we surveyed by over 10 years (18.7 percent). In fact the average age at retirement we estimate for the Ameren Missouri plants (68.2 years) is about equal to the maximum age we find based on our survey.

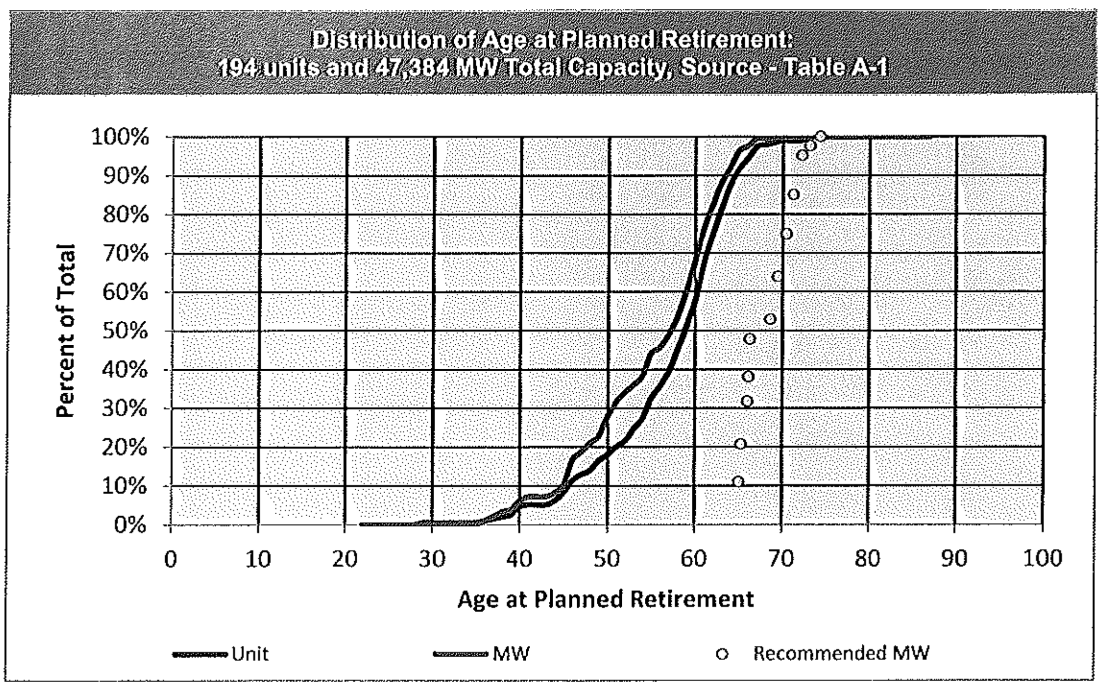

Figure 4-1 Distribution of Age at Planned Retirement

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 age of plants retired is 46.1 years and median age of plants retired is 48.1 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 12 percent of retired generating units and 5 percent of retired plant capacity experienced a life span of more than 62 years. We also show the age at our recommended retirement dates for the four Ameren Missouri plants to evaluate the reasonableness of our recommended estimated retirement dates. As we show, our recommended retirement dates result in life spans significantly greater than those actually experienced. Our recommended retirement dates result in an average age at retirement of 68.2 years for the Ameren Missouri plants. This average exceeds the average we find for plants actually retired (46.1 years) by 22 years (48 percent).

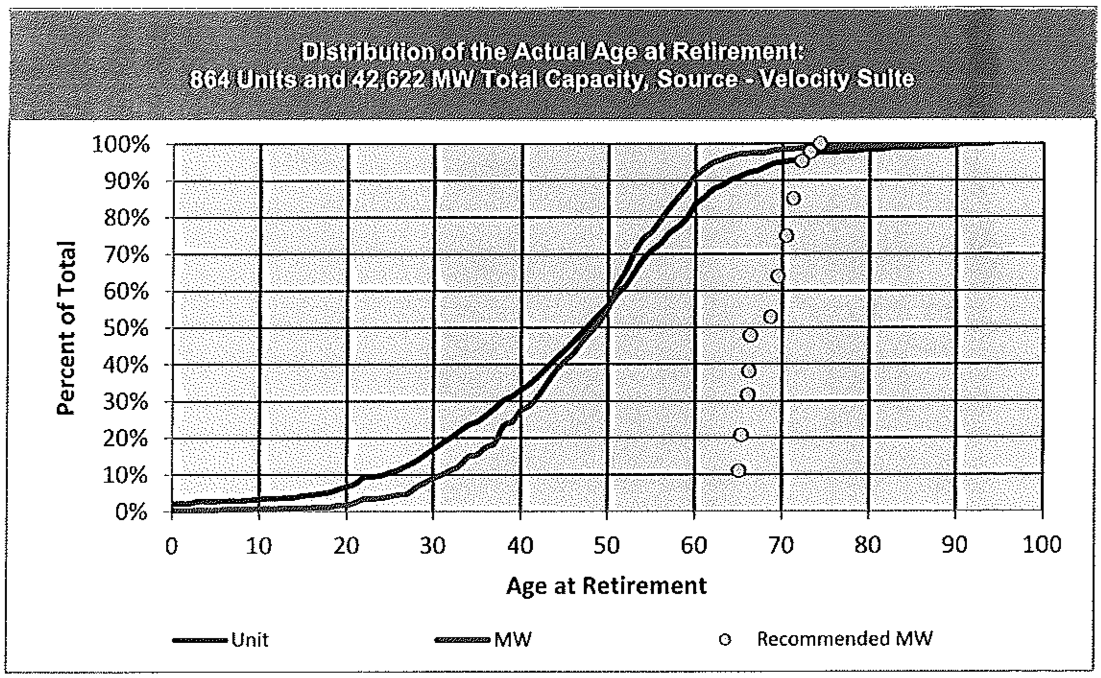

Figure 4-2 Distribution of Actual Age at Retirement

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 43.2 years and the median age is 44.5 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, 90 percent of existing generating units have been in service for less than 60 years, and 98 percent of generation capacity is less than 60 years old. We also show the age of the four Ameren Missouri plants for comparative purposes. As we show, the age of Ameren Missouri's existing plants is greater than those generally found for other utilities. The MW weighted average age for all plants amounts to 37.2 years whereas the average for the Ameren Missouri plants is 43.8 years. Our recommended retirement dates result in an average age at retirement of 68.2 years for the Ameren Missouri plants.

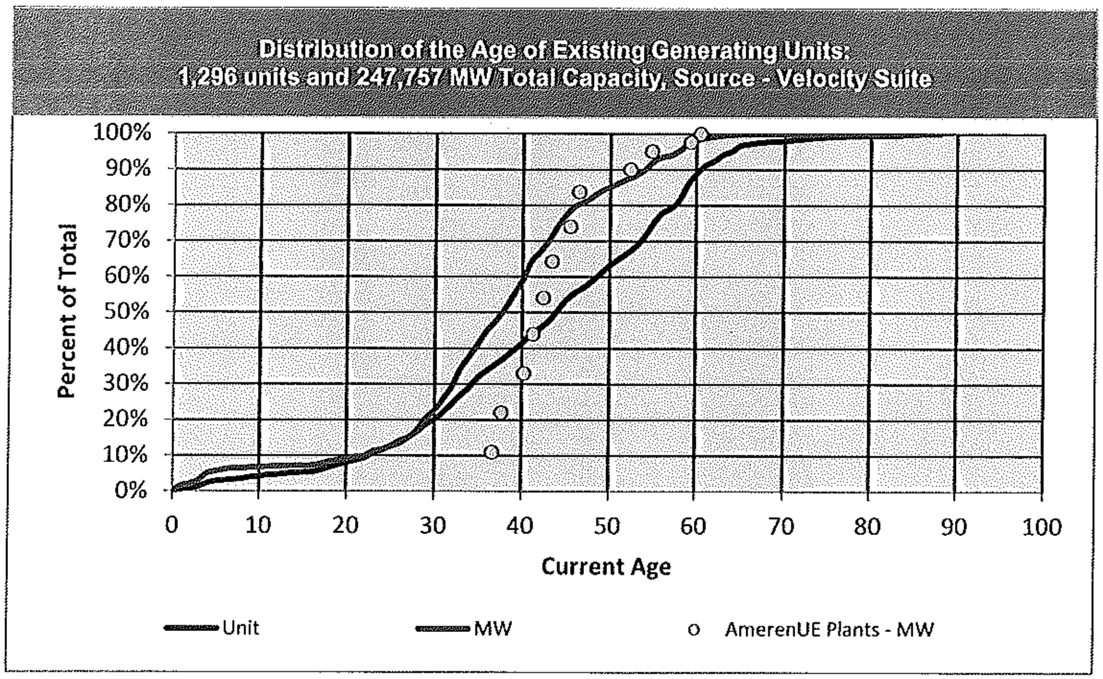

Figure 4-3 Distribution of Age of Existing Generating Units

5 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 previous 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 of the remaining life of a plant; rather a combination of hours connected to load, the pattern and practice of use, specific design, maintenance, and environment[15] 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. 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 initial 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.

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

Typical practice in the utility industry is to perform what manufactures term a "major overhaul" of steam turbines every 5 to 7 years. A typical overhaul in the early stages of a steam turbine's useful life 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.

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 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 of remaining life, rather a combination of hours connected to load, the pattern and practice of future 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."[16]

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.

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

Table 5-1
Example Component Replacement Schedule for a Typical High Temperature, High Pressure Boiler[17]

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."

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.[18] 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 primarily on failure mechanisms, the original design, the operating regime, fuel (boiler systems), and the maintenance practices.

Utilities regularly 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

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

replacement cost, or 3) when personnel are at risk.[19] 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 developing hot and cold starting procedures. These procedures are designed to carefully warm (and cool) the rotor so that the internal stresses generated from the temperature difference from external to internal do not prematurely induce cracking or brittle fracture.

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.

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

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. However, shut down procedures cannot always be followed since emergency trips of the steam turbine or other systems do not allow for the controlled reduction in metal temperatures in the boiler, turbine, and steam system.

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[20], 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).

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

5.2.3 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 NO_x formation can easily result in a reducing atmosphere in the furnace.

5.2.4 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.

5.2.5 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 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 effects 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.

5.2.6 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.

5.2.7 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 abrasive or 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.

5.3 OPERATING MODE

As the foregoing indicates, life of coal-fired power plant components is highly dependent upon the manner in which the plant is operated. A "base-loaded" plant that operates continuously at or near capacity is not subject to stresses incident to

- The heating and cooling of components due start-up and shut-down
- The complications incident to cyclical operations due changing output levels in order to follow load
- The temperature gradients incident to operating at lower load levels

All other factors equal, a base-loaded plant will have a greater life span than one that is subject to cyclical operations. Unfortunately, economics generally require that plants originally designed and initially operated as base loaded plants do not continue in base load operation through-out their life. Historically, as plants age, they tend to move down the dispatch curve so that newer more efficient plants can operate as base load plants. Such is the manner in which the Company's coal fired plants operate. As plants age, they are increasingly used to follow load which, all other factors equal, tends to reduce life.

6 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), Mercury and Air Toxics Standards (MATS), New Source Review (NSR), Greenhouse Gas regulation (GHG) 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. These initiatives aim to limit greenhouse gas emissions (specifically carbon dioxide), 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 Ameren Missouri'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)

The U.S. Environmental Protection Agency (EPA) has been seeking to establish a regulatory program to address long range transport of SO_2 and NO_x emissions from electric generating units (EGUs) affecting downwind fine particulate and ozone non-attainment areas in the eastern United States for quite some time. In 2005, the EPA promulgated the Clean Air Interstate Rule (CAIR) program to regulate annual SO_2 and NO_x emissions as well as seasonal NO_x emissions in 27 eastern states (including Missouri) under a cap-and-trade program. Utilities in the eastern United States could either install emission control equipment to reduce SO_2 and NO_x emissions and/or purchase emission allowances to maintain compliance with the three CAIR trading programs (annual NO_x, seasonal NO_x, and annual SO_2). The first phase of CAIR was designed to reduce annual SO_2 and NO_x emissions by 45% and 53% respectively, with even greater reductions to begin under a subsequent phase in 2015.

The CAIR rule was challenged by several states and other petitioners, most of which sought to have certain provisions of the rule revised or set aside. After ruling in July 2008 that CAIR had "more than several fatal flaws" and vacating the rule altogether, the District of Columbia (D.C.) Circuit Court of Appeals issued a four-page order on December 23, 2008 that temporarily restored CAIR and directed the EPA to draft a new rulemaking that addresses the legal problems identified by the court in its July ruling. In response to the court's directive, EPA promulgated the Cross-State Air Pollution Rule (CSAPR) in July 2011 which sought to impose even greater emission reductions. However, on December 30, 2011, just two days before it was scheduled to take effect, the D.C. Circuit Court stayed CSAPR then vacated the rule altogether in a 2-to-1 decision released August 21 2012. Together, these rulings prevented CSAPR from officially beginning its control periods and require EPA to continue administering the CAIR program until such time as a valid replacement is devised. The overall emission caps (and corresponding allowance allocations) for all three programs will be reduced in 2015, unless a replacement rulemaking is established.

6.2 MERCURY AND AIR TOXICS STANDARD (MATS)

EPA finalized a new rulemaking in December 2011, establishing Maximum Available Control Technology (MACT) standards for emissions of mercury (Hg) and other hazardous air pollutants (HAPs) from new and existing coal- and oil-fired power plants. Entitled the Mercury and Air Toxics Standard (MATS), the rule sets forth numerical limits for Hg, other metallic HAPs, and acid gas HAPs, while establishing work practice standards for emissions of organic HAPs (including dioxins and furans). For metallic HAPs, affected EGUs can either meet a particulate matter (PM) limit (as a surrogate for all non-Hg metallic HAPs), a total metals limit, or individual emission limits for ten different metallic HAPs (lead, arsenic, and others). For acid gasses, EGUs must either meet a surrogate hydrogen chloride (HCl) emission limit, or use an alternative SO_2 limit if units have add-on flue gas desulphurization (FGD) systems.[21] Specific limits and requirements are provided for EGUs firing traditional coals and mine mouth lignite units (technically "low rank virgin coal"), and all emission limits for affected existing EGUs are provided on both an input (lb/MMbtu or lb/Tbtu) and output (lb/MWh or lb/GWh) basis. For periods of startup and shutdown, the EPA finalized work practice standards in lieu of numeric emission limits. For malfunctions, the EPA finalized an affirmative defense for exceedances of the numerical emission limits that are caused by malfunctions.

The final MATS rule was published in the Federal Register and became effective on April 16, 2012. Pursuant to the Clean Air Act (CAA), existing affected sources will have three years to come into compliance with the new emission standards – which establishes a compliance deadline of April 16, 2015. State permitting agencies have authority under CAA §112(i)(3)(B) to allow an additional year for "installation of controls", which EPA opined in the final rulemaking could be interpreted to include situations where delayed unit retirement, replacement power or transmissions upgrades were needed to maintain electric reliability. Concurrent with the release of the final rule, EPA also issued an enforcement policy memorandum that provided for units to petition the agency for an Administrative Order (AO) for an extension from the MATS compliance deadlines where operation of the unit may be needed to maintain the reliability of the electric grid. The AO could be granted for either unit retirements or addition of controls, and would allow up to one year extension from the "MATS compliance date", which could be either the three year deadline from final rule publication or following a one year extension allowed by the state permitting authority. As a result, affected units will have at least three years from final rule publication, and under some circumstances four (with state extension) to five (with EPA AO) years until they must either meet the applicable standards or retire.

6.3 NEW SOURCE REVIEW

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

[21] The EPA clarified in its final rule making on MATS that a circulating fluidized bed (CFB) boiler in which limestone is injected with the fuel inherently qualifies as a FGD system and can therefore opt to comply with the alternate SO_2 standard.

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) can be a rigorous 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 15 years 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.

6.4 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[22] with Jefferson County[23] also being non-attainment for lead and SO2, 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

[22] In the December 5th, 2013 Missouri Air Conservation Commission Adoption of the Missouri Department of Natural Resources Recommendation for Area Boundary Designations for the 2012 Annual Fine Particulate Matter National Ambient Air Quality Standard, the State of Missouri recommends each county in the State for designation as attainment/unclassifiable under the 2012 Annual PM2.5 NAAQS.

[23] AmerenUE's Meramec and Rush Island Plants are considered located in Jefferson County for modeling purposes.

economic feasibility. The agency must periodically review its RACT rules to assure that they support the goal of attainment.

In its most recent 2011 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 2011 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.

6.5 GREENHOUSE GAS REGULATION

Perhaps the greatest environmental challenge to the operation of coal-fired generating plants is the implications incident to emission of carbon dioxide. The simple fact is that the combustion of coal results in the formation of carbon dioxide,[24] which is generally considered a greenhouse gas leading to among other things global warming.

When the Company constructed its coal-fired plants, carbon dioxide was not considered a problem. When the Company's plants were constructed, there were few environmental concerns with coal combustion, and to the extent there were concerns they related to "impurities" in the coal fuel. These impurities (most notably sulfur, resulting in the formation of sulfur dioxide which when combined with water vapor in the atmosphere produces sulfuric acid) can be controlled by various means. Carbon dioxide is inert and cannot be controlled by conventional chemical reactions.

Historically the United States has encouraged the implementation of voluntary programs to address greenhouse gas (GHG) emissions. Currently, however, the EPA is poised to initiate and finalize regulations governing GHG emissions under the Clean Air Act (CAA). Regulation of greenhouse gases could have a definitive impact on the life of the Company's coal-fired plants.

6.5.1 Federal Regulation

The EPA's Greenhouse Gas Reporting Rule was finalized and published in the Federal Register in 40 CFR Part 98 on October 30, 2009. The rule required the facility to have a monitoring plan in place as of April 1, 2010 dictating how it will record and report GHG emissions to the EPA. The Greenhouse Gas Reporting Rule also requires facilities to report greenhouse gas emissions for each year by March 31 of the following year.

On January 8, 2014, the EPA proposed federal performance standards for new power plant GHG emissions (NSPS TTTT) which wholly replace standards proposed in April 2012. The proposed regulation would require certain new electric generating units (EGUs) greater than 25 MW to meet output-based standards of between 1,000 and 1,100 pounds of CO_2 per megawatt-hour on a rolling 12-month basis. The NSPS TTTT as proposed, would only apply to CO2 emissions from future new fossil-fired EGUs and would, therefore, not apply to the existing Ameren sources.

[24] In fact the only product of the combustion of pure coal in ideal conditions is carbon dioxide.

However, on June 25, 2013, the President of the United States released an Administrative Order regarding Power Sector Carbon Pollution Standards, which not only recognizes that EPA will re-propose NSPS TTTT (which it officially published on January 8, 2014), but also directs EPA to "issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants". Currently, the EPA has indicated it will propose a standard for existing plants by June 2014 and finalize this standard by June 1, 2015. Ameren facilities will want to keep watch for any such regulations applying to existing facilities.

6.5.2 Other Regulation

Regionally, six Midwestern states joined the Midwest Greenhouse Gas Reduction Accord in November 2007. It is the third regional pact aimed at regulating greenhouse gases to reduce global warming. Missouri, however, did not sign as either a member or observer of this regional accord. According to the Center for Climate and Energy Solutions website, after releasing a model cap-and-trade rule in April 2010, the states and province in MGGRA did not continue pursuing their GHG goals through the Accord.

6.6 CLEAN WATER ACT SECTION 316 (A)

Section 316(a) of the Clean Water Act (CWA) establishes requirements for thermal attributes of wastewater discharges from regulated point sources. It authorizes the EPA or its delegated National Pollutant Discharge Elimination System (NPDES) permitting authority (Missouri Department of Natural Resources) to impose alternative effluent limitations for the control of the thermal component of a discharge in lieu of the effluent limits that would otherwise be required under other provisions of the CWA. Regulations implementing section 316(a) identify the criteria and process for determining whether an alternative effluent limitation (i.e., a thermal variance from the otherwise applicable effluent limit) may be included in a permit and, if so, what that limit should be. Before a thermal variance can be granted, the permittee must demonstrate that the otherwise applicable thermal discharge effluent limit is more stringent than necessary to assure the protection and propagation of the water body's balanced, indigenous population of fish and wildlife.

Currently, the Missouri Department of Natural Resources (MDNR) and EPA are working on new NPDES permits for Ameren Missouri Energy Centers. Early indications suggest the resulting proposed revisions to thermal effluent permit limitations and/or state water quality temperature standards during periods of high ambient river temperatures or low flow conditions may present a compliance challenge. If these potential revisions to the limitations cannot be met in the current configuration, a variance will need to be sought, which would require conducting environmental field studies focused on aquatic impacts coupled with an evaluation of hydrologic/thermal modeling of cooling water plume characteristics. If a 316(a) variance demonstration is not successful, the subject facilities (in particular the Labadie Energy Center) could potentially be required to reduce generation under certain operating conditions, or undertake infrastructure retro-fits to accommodate the installation of cooling towers. Cooling tower retrofits would require substantial engineering, design and construction, including possible replacement of condensers, which ultimately would increase parasitic load requirements and decrease overall plant capacity and/or efficiency.[25]

6.7 CLEAN WATER ACT SECTION 316(B)

Section 316(b) of the CWA requires the 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.

EPA promulgated rules to implement 316b applicable to new power generation facilities (Phase I) in 2001 and for existing (Phase II) facilities in 2004. During ongoing litigation over the Phase II rule, EPA suspended the rule in March 2007. On April 20, 2011, EPA issued its revised draft Phase II rule to establish Best Technology Available (BTA) criteria for design and operation of existing cooling water intake structures at existing power plants that: (1) have a total design flow of more than 2 million gallons per day (MGD); (2) withdraw water from rivers, streams, lakes, reservoirs, estuaries, oceans or other surface waters of the United States; and (3) use at least 25 percent of the withdrawn water exclusively for cooling purposes.

Under the proposed 2011 rule, regulated facilities would be required to meet EPA's proposed impingement BTA standards by either (1) meeting a 12% annual and 31% monthly averaged mortality rate standard based on weekly sampling, or (2) meeting an 0.5 foot per second maximum through screen intake velocity standard. Entrainment BTA requirements were to be established on a site-specific, case-by-case basis, with facilities withdrawing more than 125 MGD being required to conduct and submit a separate entrainment characterization study. EPA released a Notice of Data Availability on June 11, 2012 indicating that it may reconsider its impingement standards, and possibly specify pre-approved technologies as BTA in order to provide flexibility and streamline compliance options. EPA has subsequently missed several deadlines to issue the final rule, which currently is expected to be released in May 2014. Once finalized, regulated facilities would likely be subject to a compliance schedule established by the state permitting authority, which could provide up to 8 years to install BTA upgrades and attain compliance.

6.8 WASTE DISPOSAL

Coal combustion residues (CCRs) are fly ash, bottom ash, boiler slag and flue gas desulphurization materials that are generated from processes intended to generate power. As a result of the Bevill amendment to the Resource Conservation and Recovery Act (RCRA) and subsequent regulatory determinations by EPA in 1993 and 2000, CCRs are currently regulated as solid wastes under Subtitle D of RCRA. However, in the aftermath of the December 2008 spill from an ash pond at the TVA Kinston Plant, EPA is reconsidering its previous regulatory determinations.

The EPA published a proposed rulemaking on June 21, 2010 to either (a) reverse its Regulatory Determinations and list CCRs as "special wastes" subject to regulation under RCRA Subtitle C; or (b) leave its previous Determinations in place, and establish minimum criteria for continued regulation

[25] In its 2014 draft Integrated Resource Plan, Ameren Missouri included the estimated timing and cost (estimated at $185 to $244 million) of adding cooling towers to its Labadie Plant in the 2022 to 2024 time frame.

of CCRs under RCRA Subtitle D. EPA's proposed rule is not proposing to change the regulatory determination for beneficially used CCRs, and further does not address the placement of CCRs in mines.

Based on its final decision whether or not to retain or reverse its previous Regulatory Determination, EPA is proposing to regulate management of CCRs at power generation facilities under one of three alternatives:

1. Subtitle C Special Waste—Existing wet surface impoundments of CCRs that are not closed by the effective date of the final rule would become subject to all Subtitle C requirements (including siting, composite liners, run-on and runoff controls, groundwater monitoring, fugitive dust, financial assurance, corrective action, closure and post-closure care) as well as dam safety and stability requirements. The requirements would become effective and enforceable once RCRA authorized states have adopted the final rule under their own state laws, which typically takes two to five years to complete. Land disposal restrictions and treatment standards for all CCRs will force plants to convert from wet to dry ash handling systems, and closure of existing ash ponds/surface impoundments (unless they choose to operate in interim status and then fully remediate at end of life).
2. Subtitle D Solid Waste—EPA would establish national criteria for disposal of CCRs in surface impoundments and landfills, which would include location standards, composite liner requirements, groundwater monitoring and corrective actions for releases, closure and post-closure care requirements, and surface impoundment stability requirements. Existing ash ponds without liners would be required to be retrofitted with composite liners or to cease receiving CCRs and close within five years of the final rule's effective date.
3. D Prime—The same requirements for Subtitle D outlined immediately above would apply, however existing surface impoundments would not have to close or install composite liners. Instead under this option facilities could continue to utilize existing ash ponds for their useful life.

EPA has taken no further action on this rulemaking other than to release several Notices of Data Availability seeking additional comment on various data. In response to an October federal judge order, EPA has agreed to finalize its rulemaking by December 19, 2014. If and when the rulemaking is finalized, it will likely require existing ash management in wet surface impoundments to be discontinued, ash ponds to be permanently closed, and back-end of plant systems to convert from a wet to a dry ash handling system.

6.9 EFFLUENT GUIDELINES

The Clean Water Act (CWA) authorizes EPA to establish national technology-based effluent limitations guidelines and standards (ELGs) for discharges from different categories of point sources, such as power plants. Facilities that discharge directly to surface waters must obtain a NPDES permit that imposes effluent discharge limits and treatment requirements based on the ELGs.

The current ELGs for steam electric power plants were last updated in 1982. Noting that subsequent development of new generation technologies (e.g., coal gasification) and increased implementation of air pollution controls having altered existing waste streams or created new wastewater streams, EPA released a proposed revised ELG rulemaking in April 2013. EPA's proposed rule would establish new or additional requirements for wastewaters associated with FGD, fly ash, bottom ash, flue gas mercury control, combustion residual leachate from landfills and surface impoundments, nonchemical metal cleaning wastes, and gasification of fuels such as coal and petroleum coke. The proposed rule actually presents eight alternative ELGs for existing power plants discharging directly to surface waters, with four of these options identified as "preferred" alternatives.

In addition to the proposed requirements, the rule is also proposed establishing best management practices (BMP) requirements that would apply to surface impoundments containing coal combustion residuals (CCRs). It would impose many of the same requirements set forth in EPA's 2010 proposed CCR rulemaking for construction, operation and maintenance of CCR impoundments, including periodic structural integrity inspections and remedial action obligations (see discussion in subsection 6.7 above). EPA is scheduled to finalize its effluents guidelines rulemaking by September 30, 2015.

6.10 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-tiered 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 Plant Visit Considerations

From November 18 through December 4, 2013, Black & Veatch conducted site visits at the Meramec, Sioux, Labadie, and Rush Island Energy Centers. Detailed reports of our 2013 plant visits are included in Appendix B. Based on our findings from the site visits, we believe that Ameren Missouri's plants are generally in good condition for their age, although the Sioux plant faces several challenges with regards to plant operations (as discussed further in Appendix B-3). We find generally that, with continued maintenance and capital expenditures, economic factors will likely drive retirement decisions, not physical limitations.

While the plant site inspections provide valuable insight into the condition and potential challenges which each plant may face. The inspections and discussions with plant professionals do not necessarily provide the broad perspective needed to fully evaluate life span and remaining life. For example, plant professionals tend to have a vested interest in the continuing operation of the plant and a certain pride in its operation. While our plant site inspections indicate that the four plants are in generally good condition relative to other plants of a comparable age, the fact of the matter is that the four units in the Meramec plant range from 52 to over 60 years in age. The age and relatively small size of the units leads to the question of the viability of containing to operate these units beyond the short run.

With respect to Meramec, Ameren Missouri, as indicated in its draft 2014 Integrated Resource Plan, expects to retire this plant in 2022. In the interim the Company and plans to minimize expenditures in the plant in areas other than plant safety. The 2022 retirement date is dictated by the estimated timing of the need to add scrubbers to Units 3 and 4 of the plant. If scrubbers were added to the plant and a capital recovery period of 20 years were assumed as is the case for other scrubbers, Units 3 and 4 would be over 80 years old when retired.

While environmental considerations set the definitive estimated retirement date, physical and other practical factors contribute to the plant's retirement. As the plant continues to age, safety will increasingly become an issue relating to various systems. In addition, the ability to obtain replacement parts will increasingly become a problem.

Appendix A Power Plant Life Data

APPENDIX A-1
AGE AT PLANNED RETIREMENT

Appendix A-1
Age at Planned Retirement
Untis Currently in Service

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age	Remaining Life	Retirement Year	Retirement IRP	Retirement Age (a)
1	Number of Units				194						
2	Maximum			914.00		2010	70.87				73.0
3	Minimum			3.00		1943	3.21				29.5
4	Median			163.20		1960	53.12				59.3
5	Average			244.25			50.12				57.4
6	Standard Deviation			218.64			11.41				7.5
7	95% Confidence Limit										
8	Maximum			672.78			72.50				72.2
9	Minimum			(184.28)			27.75				42.7
10	Colbert	Alabama	Utility	200	1	1955	58.87	2.6	2016		61
11	Colbert	Alabama	Utility	200	2	1955	58.71	2.6	2016		61
12	Colbert	Alabama	Utility	200	3	1955	58.37	2.6	2016		61
13	Colbert	Alabama	Utility	200	4	1955	58.04	2.6	2016		61
14	Colbert	Alabama	Utility	550	5	1965	48.04	0.1	2013		48
15	Widows Creek	Alabama	Utility	140.6	1	1952	61.37	1.7	2015		63
16	Widows Creek	Alabama	Utility	140.6	2	1952	61.12	1.7	2015		63
17	Widows Creek	Alabama	Utility	140.6	4	1953	60.87	1.7	2015		63
18	Widows Creek	Alabama	Utility	140.6	6	1954	59.37	1.7	2015		61
19	Cholla	Arizona	Utility	113.6	1	1962	51.54			2028	66
20	Cholla	Arizona	Utility	288.9	2	1978	35.46			2033	55
21	Cholla	Arizona	Utility	312.3	3	1980	33.54			2035	55
22	Cholla	Arizona	Utility	414	4	1981	32.46			2042	61
23	Navajo	Arizona	Utility	803.1	NAV1	1974	39.54	6.1	2019	2026	52
24	Navajo	Arizona	Utility	803.1	NAV2	1975	38.62			2026	51
25	Navajo	Arizona	Utility	803.1	NAV3	1976	37.62			2026	50
26	Plum Point Energy	Arkansas	IPP	720	511	2010	3.21			2060	50
27	Arapahoe	Colorado	Utility	40	3	1951	62.87	0.1	2013	2013	63
28	Cherokee (CO)	Colorado	Utility	170.5	3	1962	51.87	2.1	2015	2016	55
29	Craig (CO)	Colorado	Utility	446.4	1	1980	33.37			2034	54
30	Craig (CO)	Colorado	Utility	446.4	2	1979	34.04			2034	55
31	Hayden	Colorado	Utility	190	1	1965	48.37			2030	65
32	Hayden	Colorado	Utility	275.4	2	1976	37.21			2030	54
33	Martin Drake	Colorado	Utility	50	5	1962	51.04	13.1	2026		64
34	Martin Drake	Colorado	Utility	75	6	1968	45.12	13.1	2026		58
35	Pawnee	Colorado	Utility	552.3	1	1981	32.04			2041	60
36	Valmont	Colorado	Utility	191.7	5	1964	49.87	4.1	2017	2017	54
37	W N Clark	Colorado	Utility	18.7	1	1955	58.21	0.1	2013		58
38	W N Clark	Colorado	Utility	25	2	1959	54.87	0.1	2013		55
39	Waukegan	Illinois	IPP	326.4	7	1958	55.46	1.1	2014		57
40	Waukegan	Illinois	IPP	355.3	8	1962	51.37	1.1	2014		53
41	Eagle Valley (H T Pritchard)	Indiana	Utility	50	3	1951	61.96	2.4	2016		64
42	Eagle Valley (H T Pritchard)	Indiana	Utility	69	4	1953	60.87	2.4	2016		63
43	Eagle Valley (H T Pritchard)	Indiana	Utility	69	5	1953	59.96	2.4	2016		62
44	Eagle Valley (H T Pritchard)	Indiana	Utility	113.6	6	1956	57.12	2.4	2016		59
45	Frank E Ratts	Indiana	Utility	116.6	1	1970	43.62	1.2	2015		45
46	Frank E Ratts	Indiana	Utility	116.6	2	1970	43.62	1.2	2015		45
47	Tanners Creek	Indiana	Utility	152.5	1	1951	62.71	1.5	2015	2015	65
48	Tanners Creek	Indiana	Utility	152.5	2	1952	61.04	1.5	2015	2015	63
49	Tanners Creek	Indiana	Utility	215.4	3	1954	58.96	1.5	2015	2015	61
50	Tanners Creek	Indiana	Utility	579.7	4	1964	49.37	1.5	2015	2015	51
51	Wabash River	Indiana	Utility	112.5	2	1953	60.29	1.5	2015	2015	62
52	Wabash River	Indiana	Utility	123.2	3	1954	59.21	1.5	2015	2015	61
53	Wabash River	Indiana	Utility	112.5	4	1955	58.87	1.5	2015	2015	61
54	Wabash River	Indiana	Utility	125	5	1956	57.54	1.5	2015	2015	59
55	Whitewater Valley	Indiana	Utility	33	1	1955	58.71	0.1	2013	2013	59
56	Fair Station	Iowa	Utility	25	1	1960	53.87	0.1	2013	2013	54
57	Fair Station	Iowa	Utility	37.5	2	1967	46.62	0.1	2013	2013	47
58	Univ of Iowa Main	Iowa	Commercial	3	GEN1	1947	65.87	0.1	2013		67
59	Univ of Iowa Main	Iowa	Commercial	3	GEN2	1956	57.87	0.1	2013		58
60	Univ of Iowa Main	Iowa	Commercial	15	GEN6	1974	39.87	0.1	2013		40
61	La Cygne	Kansas	Utility	893	1	1973	40.46			2032	59
62	La Cygne	Kansas	Utility	685	2	1977	36.54			2032	55
63	Quindaro	Kansas	Utility	81.6	ST1	1965	48.54			2022	57
64	Quindaro	Kansas	Utility	157.5	ST2	1971	41.96			2027	56
65	Riverton	Kansas	Utility	37.5	7	1950	63.46			2018	68
66	Riverton	Kansas	Utility	50	8	1954	59.46			2018	64
67	Big Sandy	Kentucky	Utility	280.5	1	1963	50.87	1.8	2015	2023	61
68	Big Sandy	Kentucky	Utility	816.3	2	1969	44.12	2.1	2015		46
69	Cane Run	Kentucky	Utility	163.2	4	1962	51.54	1.5	2015		53
70	Cane Run	Kentucky	Utility	209.4	5	1966	47.54	1.5	2015		49

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

[A]		[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age	Remaining Life	Retirement Year	Retirement ISP	Retirement Age (a)
71	Cane Run	Kentucky	Utility	272	6	1969	44.54	1.5	2015		46
72	Dale (KY)	Kentucky	Utility	27	1	1954	58.95	1.1	2014		60
73	Dale (KY)	Kentucky	Utility	27	2	1954	58.95	1.1	2014		60
74	Dale (KY)	Kentucky	Utility	81	3	1957	56.12	1.1	2014		57
75	Dale (KY)	Kentucky	Utility	81	4	1960	53.29	1.1	2014		54
76	Elmer Smith	Kentucky	Utility	163.2	1	1964	49.62	12.1	2025		62
77	Green River (KY)	Kentucky	Utility	75	3	1954	59.62	1.5	2015		61
78	Green River (KY)	Kentucky	Utility	113.6	4	1959	54.37	1.5	2015		56
79	B C Cobb	Michigan	Utility	156.3	4	1956	57.21	2.5	2016		60
80	B C Cobb	Michigan	Utility	156.3	5	1957	55.71	2.5	2016		59
81	Harbor Beach	Michigan	Utility	121	1	1968	45.62	1.5	2015		47
82	J C Weadock	Michigan	Utility	156.3	7	1955	58.54	2.5	2016		61
83	J C Weadock	Michigan	Utility	156.3	8	1958	55.87	2.5	2016		58
84	J R Whiting	Michigan	Utility	106.3	1	1952	61.37	2.5	2016		64
85	J R Whiting	Michigan	Utility	106.3	2	1952	60.96	2.5	2016		63
86	J R Whiting	Michigan	Utility	132.8	3	1953	60.04	2.5	2016		63
87	River Rouge	Michigan	Utility	292.5	2	1957	55.04	2.1	2015		58
88	River Rouge	Michigan	Utility	358.1	3	1958	55.12	2.1	2015		57
89	Trenton Channel	Michigan	Utility	120	7	1949	64.46	2.1	2015		67
90	Trenton Channel	Michigan	Utility	120	8	1950	63.79	2.1	2015		66
91	Trenton Channel	Michigan	Utility	535.5	9	1968	45.87	2.1	2015		48
92	Black Dog	Minnesota	Utility	113.6	3	1955	58.37	2.1	2015	2014	61
93	Black Dog	Minnesota	Utility	179.5	4	1960	53.21	2.1	2015	2014	55
94	Hoot Lake	Minnesota	Utility	54.4	2	1959	54.12			2020	61
95	Hoot Lake	Minnesota	Utility	75	3	1964	49.54			2020	56
96	Silver Lake (MN)	Minnesota	Utility	8	1	1948	65.29	2.1	2015		67
97	Silver Lake (MN)	Minnesota	Utility	12	2	1953	59.96	2.1	2015		62
98	Silver Lake (MN)	Minnesota	Utility	25	3	1962	51.04	2.1	2015		53
99	Silver Lake (MN)	Minnesota	Utility	54	4	1969	43.96	2.1	2015		46
100	Taconite Harbor Energy Center	Minnesota	Utility	84	GEN3	1967	46.87	2.1	2015		49
101	Asbury	Missouri	Utility	212.8	1	1970	43.45			2030	60
102	Asbury	Missouri	Utility	18.7	2	1986	27.67			2015	29
103	Hawthorne (MO)	Missouri	Utility	594.3	5	1969	44.54			2036	67
104	Iatan	Missouri	Utility	726	1	1980	33.54			2040	60
105	Iatan	Missouri	Utility	913.999	2	2010	3.22			2060	50
106	Montrose	Missouri	Utility	188	1	1958	55.37			2020	62
107	Montrose	Missouri	Utility	188	2	1960	53.62			2020	60
108	Montrose	Missouri	Utility	188	3	1964	49.54			2020	56
109	Colstrip	Montana	IPP	778	GEN3	1984	29.87			2046	63
110	Colstrip	Montana	IPP	778	GEN4	1986	27.62			2046	60
111	North Valmy	Nevada	Utility	277.2	1	1981	31.96			2021	40
112	North Valmy	Nevada	Utility	289.8	2	1985	28.54			2025	40
113	Reid Gardner	Nevada	Utility	114	1	1965	48.46	1.1	2014	2019	55
114	Reid Gardner	Nevada	Utility	114	2	1968	45.46	1.1	2014	2019	52
115	Reid Gardner	Nevada	Utility	114	3	1976	37.54	1.1	2014	2019	44
116	Reid Gardner	Nevada	Utility	294.8	4	1983	30.37	4.1	2017	2022	39
117	Four Corners	New Mexico	Utility	190	1	1963	50.54	0.1	2013	2012	51
118	Four Corners	New Mexico	Utility	190	2	1963	50.46	0.1	2013	2012	51
119	Four Corners	New Mexico	Utility	253.4	3	1964	49.29	0.1	2013	2012	49
120	Four Corners	New Mexico	Utility	818.1	4	1969	44.37	2.7	2016	2016	47
121	Four Corners	New Mexico	Utility	818.1	5	1970	43.37	2.7	2016	2016	46
122	San Juan Generating Station	New Mexico	Utility	369	2	1973	40.04	4.1	2017		44
123	San Juan Generating Station	New Mexico	Utility	555.001	3	1979	33.96	4.1	2017		38
124	Ashtabula	Ohio	IPP	256	5	1958	54.96	1.5	2015		57
125	Avon Lake	Ohio	IPP	86	7	1949	64.87	1.4	2015		66
126	Avon Lake	Ohio	IPP	680	9	1970	43.87	1.4	2015		45
127	Eastlake (OH)	Ohio	IPP	123	1	1953	60.21	1.5	2015		62
128	Eastlake (OH)	Ohio	IPP	123	2	1953	59.96	1.5	2015		62
129	Eastlake (OH)	Ohio	IPP	123	3	1954	59.29	1.5	2015		61
130	Lake Shore	Ohio	IPP	256	18	1962	51.45	1.5	2015		53
131	Miami Fort	Ohio	Utility	163.2	6	1960	53.04	1.1	2014	2015	55
132	Muskingum River	Ohio	Utility	219.6	1	1953	59.96	1.5	2015		62
133	Muskingum River	Ohio	Utility	219.6	2	1954	59.46	1.5	2015		61
134	Muskingum River	Ohio	Utility	237.5	3	1957	56.96	1.5	2015		58
135	Muskingum River	Ohio	Utility	237.5	4	1958	55.54	1.5	2015		57
136	Muskingum River	Ohio	Utility	615.2	5	1968	45.12	1.1	2014		46
137	O H Hutchings	Ohio	Utility	69	1	1948	65.37	1.5	2015		67
138	O H Hutchings	Ohio	Utility	69	2	1949	64.71	1.5	2015		66
139	O H Hutchings	Ohio	Utility	69	3	1950	62.96	1.5	2015		65
140	O H Hutchings	Ohio	Utility	69	5	1952	61.04	1.5	2015		63
141	O H Hutchings	Ohio	Utility	69	6	1953	60.29	1.5	2015		62
142	Picway	Ohio	Utility	106.2	5	1955	58.04	1.5	2015		60
143	Walter C Beckjord	Ohio	Utility	163.2	4	1958	55.37	1.4	2015		57
144	Walter C Beckjord	Ohio	Utility	244.8	5	1962	50.96	1.4	2015		52
145	Walter C Beckjord	Ohio	Utility	460.8	6	1969	44.37	1.4	2015		46
146	Northeastern	Oklahoma	Utility	473	4	1980	33.21	2.4	2016		36
147	Ben French	South Dakota	Utility	25	ST1	1961	52.87	0.6	2014		53

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

[A]		[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age	Remaining Life	Retirement Year	Retirement IRP	Retirement Age (a)
148	Allen Steam Plant (TN)	Tennessee	Utility	330	1	1959	54.54	5.1	2018		60
149	Allen Steam Plant (TN)	Tennessee	Utility	330	2	1959	54.54	5.1	2018		60
150	Allen Steam Plant (TN)	Tennessee	Utility	330	3	1959	54.12	5.1	2018		59
151	John Sevier	Tennessee	Utility	200	3	1956	57.79	2.1	2015		60
152	John Sevier	Tennessee	Utility	200	4	1957	56.12	2.1	2015		58
153	Johnsonville (TN)	Tennessee	Utility	125	1	1951	62.12	2.1	2015		64
154	Johnsonville (TN)	Tennessee	Utility	125	2	1951	62.04	2.1	2015		64
155	Johnsonville (TN)	Tennessee	Utility	125	3	1952	61.79	2.1	2015		64
156	Johnsonville (TN)	Tennessee	Utility	125	4	1952	61.62	2.1	2015		64
157	Johnsonville (TN)	Tennessee	Utility	147	5	1952	61.04	2.1	2015		63
158	Johnsonville (TN)	Tennessee	Utility	147	6	1953	60.79	2.1	2015		63
159	Johnsonville (TN)	Tennessee	Utility	172.8	7	1958	55.04	4.1	2017		59
160	Johnsonville (TN)	Tennessee	Utility	172.8	8	1959	54.87	4.1	2017		59
161	Johnsonville (TN)	Tennessee	Utility	172.8	9	1959	54.46	4.1	2017		59
162	Johnsonville (TN)	Tennessee	Utility	172.8	10	1959	54.29	4.1	2017		58
163	Harrington	Texas	Utility	360	1	1976	37.87			2040	65
164	Harrington	Texas	Utility	360	2	1978	35.87			2042	65
165	Harrington	Texas	Utility	360	3	1980	33.87			2044	65
166	J T Deely	Texas	Utility	486	1	1977	36.29	5.1	2018		41
167	J T Deely	Texas	Utility	446	2	1978	35.29	5.1	2018		40
168	Tolk	Texas	Utility	567.9	1	1982	31.87			2045	64
169	Tolk	Texas	Utility	567.9	2	1985	28.87			2049	65
170	Welsh Station	Texas	Utility	558	2	1980	33.62	3.1	2016		37
171	Carbon (UT)	Utah	Utility	75	1	1954	59.04	1.5	2015	2014	60
172	Carbon (UT)	Utah	Utility	113.6	2	1957	56.21	1.5	2015	2014	58
173	Hunter	Utah	Utility	488.3	ST1	1978	35.46			2042	64
174	Hunter	Utah	Utility	503.299	ST2	1980	33.46			2042	62
175	Hunter	Utah	Utility	495.6	ST3	1983	30.46			2042	59
176	Huntington (UT)	Utah	Utility	498	1	1977	36.46			2036	59
177	Huntington (UT)	Utah	Utility	498	2	1974	39.37			2036	62
178	KUCC	Utah	Industrial	50	1	1943	70.87	2.1	2015		73
179	KUCC	Utah	Industrial	25	2	1943	70.87	2.1	2015		73
180	KUCC	Utah	Industrial	25	3	1946	67.87	2.1	2015		70
181	Alma	Wisconsin	Utility	54.4	4	1957	56.62	2.1	2015		59
182	Alma	Wisconsin	Utility	81.6	5	1960	53.87	2.1	2015		56
183	Edgewater (WI)	Wisconsin	Utility	60	3	1951	62.37	2.1	2015		64
184	Edgewater (WI)	Wisconsin	Utility	330	4	1969	43.96	5.1	2018		49
185	Nelson Dewey	Wisconsin	Utility	100	1	1959	53.96	2.1	2015		56
186	Nelson Dewey	Wisconsin	Utility	100	2	1962	50.96	2.1	2015		53
187	UW Madison Charter St Plant	Wisconsin	Commercial	9.7	1	1965	48.87	0.1	2013		49
188	Dave Johnston	Wyoming	Utility	113.6	1	1959	54.79			2027	69
189	Dave Johnston	Wyoming	Utility	113.6	2	1961	52.87			2027	67
190	Dave Johnston	Wyoming	Utility	229.5	3	1964	48.96			2027	63
191	Dave Johnston	Wyoming	Utility	360	4	1972	41.37			2027	55
192	Jim Bridger	Wyoming	Utility	577.9	1	1974	39.04			2037	63
193	Jim Bridger	Wyoming	Utility	577.9	2	1975	37.96			2037	62
194	Jim Bridger	Wyoming	Utility	577.9	3	1976	37.21			2037	61
195	Jim Bridger	Wyoming	Utility	584	4	1979	34.04			2037	58
196	Naughton	Wyoming	Utility	163.2	1	1963	50.54			2029	66
197	Naughton	Wyoming	Utility	217.6	2	1968	45.12			2029	61
198	Naughton	Wyoming	Utility	326.4	3	1971	42.12			2029	58
199	Neil Simpson	Wyoming	Utility	21.7	5	1969	44.21	0.3	2014		45
200	Osage (WY)	Wyoming	Utility	11.5	1	1948	65.12	0.3	2014		65
201	Osage (WY)	Wyoming	Utility	11.5	2	1949	64.12	0.3	2014		64
202	Osage (WY)	Wyoming	Utility	11.5	3	1952	61.21	0.3	2014		62
203	Wyodak	Wyoming	Utility	362	1	1978	35.21			2039	61

APPENDIX A-2
AGE OF UNITS RETIRED

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
1	Number of Units				864			
2	Maximum			818.1		2011	2013	92.2
3	Minimum			0.3		1900	1900	0.0
4	Median			18.8		1949	1996	48.1
5	Average			49.3				46.1
6	Standard Deviation			83.2				16.6
7	95% Confidence Limit							
8	Maximum			212.3				78.7
9	Minimum			(113.7)				13.5
10	Gorgas 2 & 3	Alabama	Utility	69.00	4	1929	1977	49
11	Gorgas 2 & 3	Alabama	Utility	69.00	5	1944	1989	46
12	U S Alliance Coosa Pines	Alabama	Industrial	5.00	AOW1	1942	2008	67
13	U S Alliance Coosa Pines	Alabama	Industrial	5.00	AOW2	1942	2008	67
14	U S Alliance Coosa Pines	Alabama	Industrial	5.00	AOW3	1942	2003	61
15	U S Alliance Coosa Pines	Alabama	Industrial	5.00	AOW4	1942	2008	67
16	U S Alliance Coosa Pines	Alabama	Industrial	5.00	AOW5	1942	2008	67
17	Widows Creek	Alabama	Utility	140.60	3	1952	2013	61
18	Widows Creek	Alabama	Utility	140.60	5	1954	2013	59
19	Catalyst Paper Snowflake	Arizona	Industrial	27.20	GEN1	1961	2012	51
20	Catalyst Paper Snowflake	Arizona	Industrial	43.30	GEN2	1974	2012	38
21	Stockton Cogeneration Co	California	IPP	60.00	GEN1	1988	2012	24
22	Txi Riverside Cement	California	Industrial	12.00	GEN1	1954	2008	53
23	Txi Riverside Cement	California	Industrial	12.00	GEN2	1954	2008	53
24	Arapahoe	Colorado	Utility	44.00	1	1950	2002	53
25	Arapahoe	Colorado	Utility	44.00	2	1951	2002	52
26	Cameo	Colorado	Utility	25.00	1	1957	2010	54
27	Cameo	Colorado	Utility	50.00	2	1960	2010	51
28	Cherokee (CO)	Colorado	Utility	125.00	1	1957	2012	55
29	Cherokee (CO)	Colorado	Utility	125.00	2	1959	2011	53
30	Nucla	Colorado	Utility	11.50	1	1959	1900	60
31	Nucla	Colorado	Utility	11.50	2	1959	1900	60
32	Nucla	Colorado	Utility	11.50	3	1959	1900	60
33	Trigen Colorado	Colorado	IPP	0.40	VBPT	1997	2012	15
34	AES Thames	Connecticut	IPP	213.90	GEN1	1989	2011	21
35	Dover Energy (NRG)	Delaware	IPP	18.00	ST1	1985	2013	28
36	Indian River Generating Station (DE)	Delaware	IPP	81.60	1	1957	2011	54
37	Indian River Generating Station (DE)	Delaware	IPP	81.60	2	1959	2010	51
38	Seaford Delaware Plant	Delaware	Industrial	10.00	GEN1	1939	2010	71
39	Seaford Delaware Plant	Delaware	Industrial	10.00	GEN2	1939	2009	70
40	Seaford Delaware Plant	Delaware	Industrial	10.00	GEN3	1939	2010	71
41	Bayside Power Station	Florida	Utility	125.00	1	1957	2003	46
42	Bayside Power Station	Florida	Utility	125.00	2	1958	2003	45
43	Bayside Power Station	Florida	Utility	179.50	3	1960	2003	43
44	Bayside Power Station	Florida	Utility	187.50	4	1963	2003	40
45	Bayside Power Station	Florida	Utility	239.30	5	1965	2003	37
46	Bayside Power Station	Florida	Utility	445.50	6	1967	2004	36
47	Jefferson Smurfit Corp (FL)	Florida	Industrial	9.30	GEN4	1963	2003	41
48	Arkwright	Georgia	Utility	40.20	3	1943	2002	59
49	Arkwright	Georgia	Utility	49.00	4	1948	2002	54
50	Arkwright	Georgia	Utility	46.00	ST1	1941	2002	62
51	Arkwright	Georgia	Utility	46.00	ST2	1942	2002	61
52	Brown Williamson Tobacco Co	Georgia	Industrial	1.50	BWO1	1987	2006	20
53	Durango Georgia Paper Co	Georgia	Industrial	4.00	NO1	1941	2006	66
54	Durango Georgia Paper Co	Georgia	Industrial	6.70	NO2	1947	2006	60
55	Durango Georgia Paper Co	Georgia	Industrial	18.70	NO3	1955	2006	52
56	Harllee Branch	Georgia	Utility	359.00	2	1967	2013	46
57	International Paper Co Savannah	Georgia	Industrial	7.50	GEN3	1940	2001	62
58	International Paper Co Savannah	Georgia	Industrial	10.00	GEN6	1952	2001	50
59	International Paper Co Savannah	Georgia	Industrial	20.00	GEN7	1957	2001	45
60	Jack McDonough	Georgia	Utility	299.20	1	1963	2012	49
61	Jack McDonough	Georgia	Utility	299.20	2	1964	2011	47
62	Mitchell (GA)	Georgia	Utility	27.50	1	1948	2002	54
63	Mitchell (GA)	Georgia	Utility	27.50	2	1948	2002	54
64	Bunge Milling Cogeneration Inc	Illinois	Industrial	20.00	GEN1	1989	2010	20
65	Carlyle	Illinois	Utility	3.00	3	1949	1985	36
66	Crawford (IL)	Illinois	IPP	239.30	7	1958	2012	54
67	Crawford (IL)	Illinois	IPP	358.10	8	1961	2012	51

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

Line No.	[A] Plant	[B] State	[C] Plant Sector	[D] Capacity MW	[E] Unit	[F] Year in Service	[G] Retirement Year	[H] Age at Retirement
68	Dixon	Illinois	Utility	50.00	4	1945	1978	33
69	Dixon	Illinois	Utility	69.00	5	1953	1978	25
70	Fairfield (IL)	Illinois	Utility	1.80	1	1939	1975	36
71	Fairfield (IL)	Illinois	Utility	2.50	2	1942	1975	33
72	Fairfield (IL)	Illinois	Utility	4.00	3	1948	1975	27
73	Fisk Street	Illinois	IPP	25.00	11	1949	1977	29
74	Fisk Street	Illinois	IPP	173.00	18	1949	1977	29
75	Fisk Street	Illinois	IPP	374.00	19	1959	2012	53
76	Grand Tower	Illinois	IPP	85.70	3	1951	2001	50
77	Grand Tower	Illinois	IPP	113.60	4	1958	2001	43
78	Hutsonville	Illinois	IPP	75.00	3	1953	2011	59
79	Hutsonville	Illinois	IPP	75.00	4	1954	2011	58
80	Jacksonville Development Center	Illinois	Commercial	0.70	ST1	1945	2013	68
81	Jacksonville Development Center	Illinois	Commercial	0.70	ST2	1945	2013	68
82	Jacksonville Development Center	Illinois	Commercial	2.00	ST3	1945	2013	68
83	Joliet 9	Illinois	IPP	107.00	5	1950	1978	28
84	Lakeside	Illinois	Utility	20.00	4	1949	1982	34
85	Lakeside	Illinois	Utility	20.00	5	1953	1982	30
86	Lakeside	Illinois	Utility	37.50	6	1961	2009	49
87	Lakeside	Illinois	Utility	37.50	7	1965	2009	44
88	Marion	Illinois	Utility	33.00	1	1963	1900	63
89	Marion	Illinois	Utility	33.00	2	1963	1900	64
90	Marion	Illinois	Utility	33.00	3	1963	1900	64
91	Mascoutah	Illinois	Utility	2.00	1	1965	1976	11
92	Mascoutah	Illinois	Utility	1.50	2	1967	1976	9
93	Meredosia	Illinois	IPP	57.50	1	1948	2009	61
94	Meredosia	Illinois	IPP	57.50	2	1949	2009	61
95	Meredosia	Illinois	IPP	239.30	3	1960	2011	52
96	Moline	Illinois	Utility	12.00	ST3	1950	1976	27
97	Mt Carmel	Illinois	Utility	2.00	1	1941	1990	49
98	Mt Carmel	Illinois	Utility	7.50	3	1952	1983	32
99	Pearl Station	Illinois	Utility	22.00	1	1967	2012	45
100	Peru (IL)	Illinois	Utility	2.50	2	1938	1975	37
101	Peru (IL)	Illinois	Utility	1.00	ST1	1936	1975	39
102	Powerton	Illinois	IPP	55.00	1	1928	1974	47
103	Powerton	Illinois	IPP	55.00	2	1929	1974	46
104	Powerton	Illinois	IPP	105.00	3	1930	1974	45
105	Powerton	Illinois	IPP	105.00	4	1940	1974	35
106	R S Wallace	Illinois	Utility	25.00	3	1939	1985	47
107	R S Wallace	Illinois	Utility	40.30	4	1941	1985	45
108	R S Wallace	Illinois	Utility	40.20	5	1949	1985	37
109	R S Wallace	Illinois	Utility	85.90	6	1952	1985	33
110	R S Wallace	Illinois	Utility	113.60	7	1958	1985	28
111	Vermilion Power Station	Illinois	IPP	108.80	2	1956	2011	55
112	Vermilion Power Station	Illinois	IPP	73.50	ST1	1955	2011	57
113	Waukegan	Illinois	IPP	130.00	5	1931	1978	47
114	Waukegan	Illinois	IPP	121.00	6	1952	2007	56
115	Will County	Illinois	IPP	187.50	1	1955	2010	55
116	Will County	Illinois	IPP	183.70	2	1955	2010	56
117	4 AC Station	Indiana	Industrial	67.50	14TG	1963	1999	36
118	4 AC Station	Indiana	Industrial	67.50	15TG	1963	1999	36
119	Breed	Indiana	Utility	495.55	1	1960	1994	34
120	Crawfordsville	Indiana	Utility	5.00	1	1939	1970	32
121	Crawfordsville	Indiana	Utility	3.50	2	1928	1960	33
122	Crawfordsville	Indiana	Utility	4.50	3	1947	1976	30
123	Dean H Mitchell	Indiana	Utility	128.00	5	1959	2010	51
124	Dean H Mitchell	Indiana	Utility	128.00	6	1959	2010	51
125	Dean H Mitchell	Indiana	Utility	127.50	11	1970	2010	40
126	Dresser Station	Indiana	Utility	50.00	4	1941	1975	34
127	Dresser Station	Indiana	Utility	50.00	5	1944	1975	31
128	Dresser Station	Indiana	Utility	50.00	6	1945	1975	30
129	Edwardsport	Indiana	Utility	40.20	7	1949	2011	62
130	Edwardsport	Indiana	Utility	69.00	8	1951	2011	59
131	F B Culley	Indiana	Utility	46.00	1	1955	2006	52
132	Frankfort	Indiana	Utility	6.00	1	1941	1977	36
133	Frankfort	Indiana	Utility	10.00	2	1952	1977	25
134	Frankfort	Indiana	Utility	17.00	3	1962	1977	15
135	Jasper 1	Indiana	Utility	2.00	1	1938	1975	38
136	Jasper 1	Indiana	Utility	5.00	4	1949	1975	27
137	Johnson Street	Indiana	Utility	15.00	1	1934	1970	36
138	Johnson Street	Indiana	Utility	15.00	2	1934	1970	36
139	Johnson Street	Indiana	Utility	15.00	3	1934	1970	36
140	Johnson Street	Indiana	Utility	15.00	4	1948	1970	22

Appendix A-2
Age at Retirement of Units Retired from Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
141	Lawton Park	Indiana	Utility	15.00	2	1934	1975	41
142	Lawton Park	Indiana	Utility	15.00	3	1941	1975	34
143	Michigan City	Indiana	Utility	4.00	11	1930	1980	50
144	Noblesville	Indiana	Utility	50.00	ST1	1950	2003	53
145	Noblesville	Indiana	Utility	50.00	ST2	1950	2003	53
146	Perry K	Indiana	IPP	15.00	3	1924	1989	66
147	Perry K	Indiana	IPP	12.50	5	1938	1984	46
148	Perry K	Indiana	IPP	5.00	HS	1938	2000	62
149	Perry W	Indiana	Utility	11.63	7	1980	1997	18
150	Peru (IN)	Indiana	Utility	5.00	1	1933	1977	44
151	R Gallagher	Indiana	Utility	150.00	1	1959	2012	53
152	R Gallagher	Indiana	Utility	150.00	3	1960	2012	52
153	Smurfit Wabash	Indiana	Industrial	2.00	7240	1947	2001	55
154	Smurfit Wabash	Indiana	Industrial	2.00	8323	1947	2001	55
155	State Line Energy	Indiana	IPP	200.00	ST1	1929	1978	49
156	State Line Energy	Indiana	IPP	150.00	ST2	1938	1979	41
157	State Line Energy	Indiana	IPP	224.90	ST3	1955	2012	56
158	State Line Energy	Indiana	IPP	388.90	ST4	1962	2012	50
159	Twin Branch	Indiana	Utility	40.00	1	1925	1974	49
160	Twin Branch	Indiana	Utility	40.00	2	1925	1974	49
161	Twin Branch	Indiana	Utility	77.00	3	1940	1974	34
162	Wabash River	Indiana	Utility	112.50	1	1953	1995	42
163	Wahington (IN)	Indiana	Utility	5.00	1	1947	1977	31
164	Wahington (IN)	Indiana	Utility	5.00	2	1957	1977	21
165	Wahington (IN)	Indiana	Utility	3.00	3	1938	1977	40
166	Wahington (IN)	Indiana	Utility	5.00	4	1957	1977	21
167	Ames Electric Services Power Plant (Ia Ames)	Iowa	Utility	3.00	2	1932	1932	0
168	Ames Electric Services Power Plant (Ia Ames)	Iowa	Utility	3.00	3	1938	1938	0
169	Ames Electric Services Power Plant (Ia Ames)	Iowa	Utility	7.50	5	1950	1984	35
170	Ames Electric Services Power Plant (Ia Ames)	Iowa	Utility	12.60	6	1958	1986	29
171	Boone (IA)	Iowa	Utility	3.50	3	1947	1977	30
172	Boone (IA)	Iowa	Utility	3.50	4	1923	1977	54
173	Bridgeport (IA)	Iowa	Utility	23.00	1	1953	1981	28
174	Bridgeport (IA)	Iowa	Utility	23.00	2	1953	1981	28
175	Bridgeport (IA)	Iowa	Utility	25.00	3	1957	1981	24
176	Carroll (IA)	Iowa	Utility	5.30	1	1952	1980	29
177	Carroll (IA)	Iowa	Utility	5.30	2	1953	1990	37
178	Clinton (IA ADM)	Iowa	Industrial	7.50	GEN1	1954	2008	55
179	Clinton (IA ADM)	Iowa	Industrial	3.50	GEN2	1940	2008	69
180	Clinton (IA ADM)	Iowa	Industrial	9.40	GEN3	1965	2008	44
181	Clinton (IA ADM)	Iowa	Industrial	4.00	GEN4	1974	2008	35
182	Clinton (IA ADM)	Iowa	Industrial	7.00	GEN5	1991	2008	18
183	Denison (IA)	Iowa	Utility	1.50	3	1941	1941	0
184	Denison (IA)	Iowa	Utility	3.00	4	1950	1986	37
185	Des Moines (IA MWPWR)	Iowa	Utility	20.00	1	1925	1990	65
186	Des Moines (IA MWPWR)	Iowa	Utility	30.00	2	1926	1990	64
187	Des Moines (IA MWPWR)	Iowa	Utility	5.00	3	1949	1990	41
188	Des Moines (IA MWPWR)	Iowa	Utility	75.00	6	1954	1993	39
189	Des Moines (IA MWPWR)	Iowa	Utility	113.64	7	1964	1994	30
190	Eagle Grove	Iowa	Utility	8.00	1	1949	1980	31
191	Hawkeye	Iowa	Utility	8.00	1	1949	1981	32
192	Hawkeye	Iowa	Utility	11.50	2	1954	1981	28
193	Humboldt	Iowa	Utility	9.40	1	1950	1999	50
194	Humboldt	Iowa	Utility	9.40	2	1950	1999	50
195	Humboldt	Iowa	Utility	13.50	3	1951	1999	48
196	Humboldt	Iowa	Utility	20.30	4	1953	1999	46
197	Iowa State Univ	Iowa	Commercial	3.00	1	1949	2004	55
198	John Deere Dubuque Works	Iowa	Industrial	3.50	GEN2	1949	2010	61
199	John Deere Dubuque Works	Iowa	Industrial	3.00	GEN3	1989	2009	20
200	John Deere Dubuque Works	Iowa	Industrial	7.50	GEN4	1964	2010	47
201	Lansing	Iowa	Utility	15.00	1	1948	2004	57
202	Lansing	Iowa	Utility	11.50	2	1949	2010	62
203	Maynard Station	Iowa	Utility	54.40	7	1958	1988	30
204	Muscatine	Iowa	Utility	7.50	5	1944	1985	42
205	Muscatine	Iowa	Utility	12.50	6	1949	1985	37
206	Pella	Iowa	Utility	1.50	3	1948	1990	43
207	Pella	Iowa	Utility	4.00	4	1952	1992	40
208	Pella	Iowa	Utility	11.50	5	1964	2012	48
209	Pella	Iowa	Utility	26.50	6	1972	2012	40
210	Prairie Creek 1 4	Iowa	Utility	23.00	1	1950	1997	47
211	Prairie Creek 1 4	Iowa	Utility	23.00	2	1951	2010	60
212	Riverside (IA)	Iowa	Utility	2.50	ST2	1937	1983	46
213	Riverside (IA)	Iowa	Utility	20.00	ST3	1937	1983	46

Appendix A-2
Age at Retirement of Units Retired from Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
214	Riverside (IA)	Iowa	Utility	46.00	ST4	1949	1988	39
215	Sibley One	Iowa	Utility	2.50	1	1948	1984	37
216	Sixth Street (IA)	Iowa	Utility	10.00	1	1921	2010	90
217	Sixth Street (IA)	Iowa	Utility	6.00	2	1930	2010	80
218	Sixth Street (IA)	Iowa	Utility	15.00	4	1942	2010	68
219	Sixth Street (IA)	Iowa	Utility	7.50	5	1917	1981	64
220	Sixth Street (IA)	Iowa	Utility	10.00	6	1925	2010	85
221	Sixth Street (IA)	Iowa	Utility	15.00	7	1945	2010	66
222	Sixth Street (IA)	Iowa	Utility	28.70	8	1950	2010	60
223	Streeter	Iowa	Utility	5.00	4	1949	1984	36
224	Streeter	Iowa	Utility	5.00	5	1954	1984	31
225	Sutherland (IA)	Iowa	Utility	37.50	2	1955	2010	56
226	Webster City	Iowa	Utility	1.00	1	1921	1979	58
227	Webster City	Iowa	Utility	1.00	2	1928	1979	51
228	Webster City	Iowa	Utility	2.00	3	1939	1979	40
229	Webster City	Iowa	Utility	4.00	4	1950	1979	29
230	Webster City	Iowa	Utility	8.00	5	1960	1979	19
231	Lawrence Energy Center (KS)	Kansas	Utility	38.00	2	1952	2000	48
232	Lawrence Energy Center (KS)	Kansas	Utility	10.00	ST1	1939	1993	54
233	Neosho	Kansas	Utility	15.00	1	1924	1924	0
234	Neosho	Kansas	Utility	25.00	2	1927	1927	0
235	Cane Run	Kentucky	Utility	112.50	1	1954	1985	30
236	Cane Run	Kentucky	Utility	112.50	2	1956	1985	29
237	Green River (KY)	Kentucky	Utility	37.50	1	1950	2003	54
238	Green River (KY)	Kentucky	Utility	37.50	2	1950	2003	54
239	Henderson I	Kentucky	Utility	5.00	3	1951	1971	20
240	Henderson I	Kentucky	Utility	5.00	4	1951	1971	19
241	Henderson I	Kentucky	Utility	11.50	5	1956	2008	53
242	Henderson I	Kentucky	Utility	32.30	6	1968	2008	41
243	Owensboro	Kentucky	Utility	7.50	1	1939	1977	38
244	Owensboro	Kentucky	Utility	7.50	2	1939	1977	38
245	Owensboro	Kentucky	Utility	8.00	3	1945	1974	29
246	Owensboro	Kentucky	Utility	34.50	4	1954	1978	25
247	Paddys Run	Kentucky	Utility	25.00	1	1942	1979	37
248	Paddys Run	Kentucky	Utility	25.00	2	1942	1979	37
249	Paddys Run	Kentucky	Utility	69.00	3	1947	1981	34
250	Paddys Run	Kentucky	Utility	69.00	4	1949	1981	32
251	Paddys Run	Kentucky	Utility	74.70	5	1950	1983	33
252	Paddys Run	Kentucky	Utility	74.70	6	1952	1984	32
253	Pineville	Kentucky	Utility	37.50	3	1951	2002	51
254	Tyrone (KY)	Kentucky	Utility	75.00	3	1953	2013	60
255	R Paul Smith Power Station	Maryland	IPP	15.00	1	1900	1990	91
256	R Paul Smith Power Station	Maryland	IPP	35.00	2	1900	1990	91
257	R Paul Smith Power Station	Maryland	IPP	34.50	9	1947	2012	65
258	R Paul Smith Power Station	Maryland	IPP	75.00	11	1958	2012	54
259	Vienna	Maryland	IPP	6.00	1	1900	1900	0
260	Vienna	Maryland	IPP	6.00	2	1900	1900	0
261	Vienna	Maryland	IPP	8.00	3	1900	1900	0
262	Vienna	Maryland	IPP	8.00	4	1900	1900	0
263	Indeck Turners Falls Energy CNTR	Massachusetts	IPP	21.90	GEN1	1989	1999	10
264	Salem Harbor	Massachusetts	IPP	81.90	GEN1	1952	2011	60
265	Salem Harbor	Massachusetts	IPP	82.00	GEN2	1952	2011	59
266	Somerset Station	Massachusetts	IPP	74.00	5	1951	1994	42
267	Somerset Station	Massachusetts	IPP	100.00	SOM6	1959	2010	51
268	Advance	Michigan	Utility	7.50	1	1953	2000	47
269	Advance	Michigan	Utility	7.50	2	1953	2000	47
270	Advance	Michigan	Utility	22.00	3	1967	2000	34
271	Bayside (MI)	Michigan	Utility	2.50	1	1946	2002	57
272	Bayside (MI)	Michigan	Utility	5.00	2	1950	1999	50
273	Bayside (MI)	Michigan	Utility	7.50	3	1954	2002	49
274	Bayside (MI)	Michigan	Utility	14.00	4	1968	2002	35
275	Cargill Salt Inc	Michigan	Industrial	1.20	DCT	1935	2002	67
276	Cargill Salt Inc	Michigan	Industrial	0.70	DCTG	1935	2001	66
277	Coldwater	Michigan	Utility	5.00	6	1962	1999	38
278	Coldwater	Michigan	Utility	3.00	ST4	1940	1999	60
279	Coldwater	Michigan	Utility	3.00	ST5	1962	1999	38
280	Connors Creek	Michigan	Utility	2.00	41	1935	1981	47
281	Connors Creek	Michigan	Utility	2.00	42	1936	1981	46
282	Connors Creek	Michigan	Utility	2.00	47	1937	1981	45
283	Connors Creek	Michigan	Utility	2.00	48	1938	1981	44
284	Gladston (MI GSTONE)	Michigan	Utility	3.00	1	1955	1980	26
285	Gladston (MI GSTONE)	Michigan	Utility	3.00	2	1955	1980	26
286	J B Simms	Michigan	Utility	10.00	1	1961	1999	38

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	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
287	J B Simms	Michigan	Utility	10.00	2	1961	2005	45
288	James de Young	Michigan	Utility	8.00	1	1940	1983	44
289	James de Young	Michigan	Utility	8.00	2	1940	1983	44
290	Marysville	Michigan	Utility	30.00	2	1900	1972	73
291	Marysville	Michigan	Utility	10.00	3	1900	1972	73
292	Marysville	Michigan	Utility	30.00	4	1900	1972	73
293	Marysville	Michigan	Utility	30.00	5	1900	1972	73
294	Marysville	Michigan	Utility	50.00	6	1930	1995	65
295	Marysville	Michigan	Utility	75.00	7	1943	2011	69
296	Marysville	Michigan	Utility	75.00	8	1947	2011	65
297	Marysville	Michigan	Utility	2.00	43	1927	1981	55
298	Marysville	Michigan	Utility	2.00	44	1928	1981	54
299	Marysville	Michigan	Utility	2.00	45	1931	1981	51
300	Mistersky	Michigan	Utility	20.00	2	1927	1979	52
301	Mistersky	Michigan	Utility	20.00	3	1927	1979	52
302	Mistersky	Michigan	Utility	20.00	4	1927	1979	52
303	Muskegon	Michigan	Industrial	3.50	GEN2	1938	2010	72
304	Muskegon	Michigan	Industrial	19.10	GEN4	1968	2010	42
305	Muskegon	Michigan	Industrial	28.30	GEN5	1989	2010	21
306	Ottawa Street	Michigan	Utility	25.00	1	1940	1993	52
307	Ottawa Street	Michigan	Utility	25.00	2	1949	1993	44
308	Ottawa Street	Michigan	Utility	25.00	3	1951	1993	41
309	Ottawa Street	Michigan	Utility	4.00	5	1939	1988	50
310	Pennsalt	Michigan	Utility	2.50	11	1964	1985	22
311	Pennsalt	Michigan	Utility	5.00	12	1964	1985	22
312	Pennsalt	Michigan	Utility	6.00	14	1964	1985	22
313	Pennsalt	Michigan	Utility	6.00	15	1964	1985	22
314	Pennsalt	Michigan	Utility	7.50	16	1964	1985	22
315	Pennsalt	Michigan	Utility	7.50	17	1964	1985	22
316	Pennsalt	Michigan	Utility	2.50	18	1964	1985	22
317	Port Huron	Michigan	Utility	2.00	2	1966	1985	19
318	Port Huron	Michigan	Utility	4.00	3	1969	1985	16
319	Presque Isle	Michigan	Utility	25.00	1	1955	2006	51
320	Presque Isle	Michigan	Utility	37.50	2	1962	2006	45
321	Presque Isle	Michigan	Utility	54.40	3	1964	2010	46
322	Presque Isle	Michigan	Utility	57.80	4	1966	2010	43
323	Saginaw Station	Michigan	IPP	100.00	ST1	1920	1973	53
324	Smurfit Stone Container Corp (MI)	Michigan	Industrial	15.60	GEN1	1966	2009	43
325	Trenton Channel	Michigan	Utility	50.00	1	1924	1974	51
326	Trenton Channel	Michigan	Utility	50.00	2	1924	1974	51
327	Trenton Channel	Michigan	Utility	50.00	3	1924	1974	51
328	Trenton Channel	Michigan	Utility	50.00	4	1926	1974	49
329	Trenton Channel	Michigan	Utility	50.00	5	1926	1974	49
330	Trenton Channel	Michigan	Utility	50.00	6	1926	1974	49
331	Trenton Channel	Michigan	Utility	2.00	33	1927	1977	51
332	Trenton Channel	Michigan	Utility	4.00	42	1924	1977	54
333	Trenton Channel	Michigan	Utility	4.00	43	1924	1977	54
334	Trenton Channel	Michigan	Utility	4.00	44	1927	1977	51
335	Trenton Channel	Michigan	Utility	4.00	45	1930	1977	48
336	Wyandotte (MI)	Michigan	Utility	4.00	1	1939	1984	45
337	Wyandotte (MI)	Michigan	Utility	6.00	2	1942	1984	42
338	Alexandria (MN)	Minnesota	Utility	3.00	ST3	1949	1981	32
339	Benson (MN BENSON)	Minnesota	Utility	0.30	1	1940	1982	43
340	Benson (MN BENSON)	Minnesota	Utility	0.30	2	1929	1981	53
341	Black Dog	Minnesota	Utility	81.00	1	1952	2001	48
342	Black Dog	Minnesota	Utility	137.00	2	1954	2002	48
343	Blue Earth	Minnesota	Utility	1.50	2	1938	1984	46
344	Blue Earth	Minnesota	Utility	2.00	3	1944	1987	43
345	Canby	Minnesota	Utility	3.00	1	1931	1975	44
346	Canby	Minnesota	Utility	5.00	2	1942	1975	33
347	Crookston	Minnesota	Utility	5.00	1	1948	1975	27
348	Crookston	Minnesota	Utility	5.00	2	1949	1975	26
349	Detroit Lakes	Minnesota	Utility	2.00	2	1937	1982	46
350	Fairmont Energy Station	Minnesota	Utility	2.00	1	1935	1935	0
351	Fairmont Energy Station	Minnesota	Utility	3.00	2	1937	1937	0
352	Hibbing	Minnesota	Utility	5.00	1	1941	1984	43
353	Hibbing	Minnesota	Utility	2.50	2	1941	1983	42
354	Hibbing	Minnesota	Utility	1.50	4	1941	1995	54
355	Hibbing	Minnesota	Utility	2.00	7	1930	1930	0
356	Hibbing	Minnesota	Utility	3.00	R2	1936	1936	0
357	High Bridge	Minnesota	Utility	32.00	1	1924	1991	68
358	High Bridge	Minnesota	Utility	35.00	2	1928	1991	64
359	High Bridge	Minnesota	Utility	50.00	3	1942	1991	50

Appendix A-2
Age at Retirement of Units Retired from Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
360	High Bridge	Minnesota	Utility	50.00	4	1944	1991	48
361	High Bridge	Minnesota	Utility	113.60	5	1956	2007	51
362	High Bridge	Minnesota	Utility	163.20	6	1959	2007	48
363	Hoot Lake	Minnesota	Utility	7.50	1	1948	2005	57
364	Litchfield	Minnesota	Utility	3.00	ST1	1948	1990	42
365	Litchfield	Minnesota	Utility	1.00	ST2	1930	1977	48
366	Madison (MN)	Minnesota	Utility	1.00	1	1949	1970	22
367	Minnesota Valley	Minnesota	Utility	10.00	1	1900	1900	0
368	Minnesota Valley	Minnesota	Utility	10.00	2	1900	1900	0
369	Minnesota Valley	Minnesota	Utility	46.00	3	1953	2006	53
370	Moorhead	Minnesota	Utility	3.00	3	1940	1984	45
371	Moorhead	Minnesota	Utility	3.00	4	1948	1984	37
372	Moorhead	Minnesota	Utility	6.00	5	1952	1984	33
373	Moorhead	Minnesota	Utility	25.00	7	1970	1599	30
374	New Ulm	Minnesota	Utility	6.00	2	1946	1984	38
375	North Broadway	Minnesota	Utility	5.00	1	1931	1982	52
376	North Broadway	Minnesota	Utility	8.00	2	1936	1982	47
377	Ortonville	Minnesota	Utility	16.50	1	1950	1983	34
378	Riverside Repowering Project (MN)	Minnesota	Utility	35.00	2	1931	1987	56
379	Riverside Repowering Project (MN)	Minnesota	Utility	6.00	7	1949	1976	27
380	Riverside Repowering Project (MN)	Minnesota	Utility	238.80	8	1964	2009	45
381	Riverside Repowering Project (MN)	Minnesota	Utility	165.00	ST7	1987	2009	22
382	Sartell Mill	Minnesota	Industrial	20.40	ABB2	1982	2012	30
383	Sleepy Eye	Minnesota	Utility	1.25	4	1960	1985	26
384	Springfield (MN)	Minnesota	Utility	0.80	1	1937	1976	40
385	Springfield (MN)	Minnesota	Utility	1.00	2	1940	1994	54
386	Springfield (MN)	Minnesota	Utility	2.00	3	1946	1998	53
387	Springfield (MN)	Minnesota	Utility	4.00	4	1961	2002	42
388	Virginia	Minnesota	Utility	5.00	1	1949	1992	44
389	Virginia	Minnesota	Utility	1.00	2	1922	1990	68
390	Virginia	Minnesota	Utility	1.50	3	1930	1996	66
391	Virginia	Minnesota	Utility	2.50	4	1937	1996	59
392	Willmar	Minnesota	Utility	1.00	2	1928	1976	48
393	Willmar	Minnesota	Utility	4.00	ST1	1949	2006	57
394	Wright (MS)	Mississippi	Utility	2.50	5	1926	1981	56
395	Chamois	Missouri	Utility	15.00	1	1953	2013	60
396	Chamois	Missouri	Utility	44.00	2	1960	2013	53
397	Chillicothe	Missouri	Utility	1.50	3	1929	1980	51
398	Chillicothe	Missouri	Utility	2.50	4	1939	1982	43
399	Chillicothe	Missouri	Utility	5.00	5	1948	2004	56
400	Chillicothe	Missouri	Utility	6.00	6	1958	2004	46
401	Chillicothe	Missouri	Utility	2.50	4A	1938	2004	66
402	Coleman (MO)	Missouri	Utility	6.30	1	1959	1985	25
403	Columbia (MO CLMBIA)	Missouri	Utility	5.00	1	1938	1975	38
404	Columbia (MO CLMBIA)	Missouri	Utility	8.50	2	1947	1975	29
405	Columbia (MO CLMBIA)	Missouri	Utility	4.00	4	1929	1975	47
406	Fulton (MO)	Missouri	Utility	1.00	1	1935	1982	48
407	Fulton (MO)	Missouri	Utility	2.00	2	1940	1982	43
408	Fulton (MO)	Missouri	Utility	3.00	3	1949	1982	34
409	Fulton (MO)	Missouri	Utility	6.00	4	1959	1982	24
410	Grand Avenue	Missouri	Utility	30.00	8	1936	1982	46
411	Hannibal	Missouri	Utility	8.00	1	1936	1990	54
412	Hannibal	Missouri	Utility	10.00	2	1951	1990	39
413	Hannibal	Missouri	Utility	17.00	3	1937	1990	53
414	Hawthorne (MO)	Missouri	Utility	69.00	1	1951	1984	34
415	Hawthorne (MO)	Missouri	Utility	69.00	2	1951	1984	33
416	Hawthorne (MO)	Missouri	Utility	112.50	3	1953	1984	32
417	Hawthorne (MO)	Missouri	Utility	142.79	4	1955	2000	45
418	Missouri Chemical Works	Missouri	Industrial	8.60	GEN1	1943	2011	68
419	Missouri Chemical Works	Missouri	Industrial	8.60	GEN2	1943	2011	68
420	South River Station	Missouri	Utility	7.50	1	1952	1952	0
421	South River Station	Missouri	Utility	7.50	2	1953	1953	0
422	Southeast Missouri State Univ	Missouri	Commercial	6.20	GEN3	1972	2007	36
423	Univ of Missouri Columbia	Missouri	Commercial	6.20	GEN1	1961	2002	42
424	Univ of Missouri Columbia	Missouri	Commercial	12.50	GEN2	1974	2002	29
425	Univ of Missouri Columbia	Missouri	Commercial	19.80	GEN3	1986	2002	16
426	Univ of Missouri Columbia	Missouri	Commercial	14.50	GEN4	1988	2002	15
427	Fremont 1	Nebraska	Utility	3.00	1	1928	1976	49
428	Fremont 1	Nebraska	Utility	2.00	2	1924	1976	53
429	Fremont 1	Nebraska	Utility	3.00	3	1932	1976	45
430	Fremont 1	Nebraska	Utility	5.00	4	1946	1976	31
431	Fremont 1	Nebraska	Utility	10.00	5	1950	1976	27
432	Harold Kramer	Nebraska	Utility	45.50	1	1949	1991	42

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

Line No.	[A] Plant	[B] State	[C] Plant Sector	[D] Capacity MW	[E] Unit	[F] Year in Service	[G] Retirement Year	[H] Age at Retirement
433	Harold Kramer	Nebraska	Utility	45.50	2	1949	1991	42
434	Harold Kramer	Nebraska	Utility	45.50	3	1951	1991	40
435	Jones St	Nebraska	Utility	15.00	6	1917	1974	57
436	Jones St	Nebraska	Utility	20.00	7	1921	1974	53
437	Jones St	Nebraska	Utility	20.00	8	1925	1974	49
438	Jones St	Nebraska	Utility	25.00	9	1929	1974	45
439	Jones St	Nebraska	Utility	10.00	10	1937	1974	37
440	Mohave (NV)	Nevada	Utility	818.10	1	1971	2009	38
441	Mohave (NV)	Nevada	Utility	818.10	2	1971	2009	38
442	Tracy (NV)	Nevada	Utility	113.20	IGCC	1996	2002	6
443	Schiller	New Hampshire	Utility	50.00	5	1955	2006	52
444	Deepwater (NJ)	New Jersey	IPP	20.00	5	1942	1994	52
445	Deepwater (NJ)	New Jersey	IPP	27.20	7	1957	1994	37
446	Howard M Down	New Jersey	Utility	4.00	4	1936	1979	43
447	Missouri Avenue	New Jersey	IPP	29.00	6	1950	1974	25
448	Missouri Avenue	New Jersey	IPP	29.00	7	1950	1974	25
449	Raton	New Mexico	Utility	0.80	1	1937	1977	40
450	Raton	New Mexico	Utility	0.80	2	1937	1977	40
451	Raton	New Mexico	Utility	1.50	3	1937	1970	33
452	Raton	New Mexico	Utility	3.70	4	1951	1996	44
453	Raton	New Mexico	Utility	7.50	5	1961	2010	49
454	AES Greenidge	New York	IPP	20.00	1	1938	1985	47
455	AES Greenidge	New York	IPP	20.00	2	1942	1985	43
456	AES Greenidge	New York	IPP	50.00	3	1950	2009	60
457	AES Greenidge	New York	IPP	112.50	4	1953	2011	57
458	AES Westover	New York	IPP	30.00	6	1900	1972	72
459	AES Westover	New York	IPP	43.80	7	1943	2009	66
460	Danskammer Generating Station	New York	IPP	147.10	3	1959	2013	53
461	Danskammer Generating Station	New York	IPP	239.40	4	1967	2013	45
462	Deferiet New York	New York	Industrial	8.10	WEST	1946	2007	61
463	Hickling	New York	IPP	30.00	1	1948	2008	60
464	Hickling	New York	IPP	40.00	2	1952	2008	56
465	Huntley Generating	New York	IPP	80.00	63	1942	2003	61
466	Huntley Generating	New York	IPP	100.00	64	1948	2005	57
467	Huntley Generating	New York	IPP	100.00	65	1953	2007	54
468	Huntley Generating	New York	IPP	100.00	66	1954	2007	54
469	Jennison	New York	IPP	30.00	1	1945	2008	62
470	Jennison	New York	IPP	30.00	2	1950	2008	58
471	Kodak Park Site	New York	Industrial	6.30	11TG	1937	2007	70
472	Kodak Park Site	New York	Industrial	6.30	12TG	1941	2000	59
473	Kodak Park Site	New York	Industrial	10.40	13TG	1948	2007	60
474	Kodak Park Site	New York	Industrial	10.40	14TG	1948	2007	60
475	Kodak Park Site	New York	Industrial	17.50	15TG	1956	2007	51
476	Lovett	New York	IPP	179.50	LOV4	1966	2007	42
477	Lovett	New York	IPP	200.60	LOV5	1969	2008	39
478	Rochester Beebee	New York	Utility	81.60	12	1959	1999	40
479	Russell Station	New York	Utility	46.00	1	1948	2008	60
480	Russell Station	New York	Utility	62.50	2	1950	2008	58
481	Russell Station	New York	Utility	62.50	3	1953	2008	55
482	Russell Station	New York	Utility	81.60	4	1957	2008	51
483	Samuel A Carlson	New York	Utility	5.00	2	1924	1973	49
484	Samuel A Carlson	New York	Utility	15.00	3	1938	1983	45
485	Samuel A Carlson	New York	Utility	13.00	4	1930	1978	48
486	Buck Steam Station (NC)	North Carolina	Utility	35.00	1	1926	1981	55
487	Buck Steam Station (NC)	North Carolina	Utility	35.00	2	1926	1981	55
488	Buck Steam Station (NC)	North Carolina	Utility	80.00	3	1941	2011	70
489	Buck Steam Station (NC)	North Carolina	Utility	40.00	4	1942	2011	69
490	Buck Steam Station (NC)	North Carolina	Utility	125.00	5	1953	2013	60
491	Buck Steam Station (NC)	North Carolina	Utility	125.00	6	1953	2013	59
492	Cape Fear	North Carolina	Utility	31.25	3	1942	1994	52
493	Cape Fear	North Carolina	Utility	122.28	4	1943	1994	51
494	Cape Fear	North Carolina	Utility	140.60	5	1956	2012	56
495	Cape Fear	North Carolina	Utility	187.90	6	1958	2012	54
496	Cliffside	North Carolina	Utility	40.00	1	1940	2011	72
497	Cliffside	North Carolina	Utility	40.00	2	1940	2011	71
498	Cliffside	North Carolina	Utility	65.00	3	1948	2011	64
499	Cliffside	North Carolina	Utility	65.00	4	1948	2011	63
500	Dan River (NC)	North Carolina	Utility	70.00	1	1949	2012	62
501	Dan River (NC)	North Carolina	Utility	70.00	2	1950	2012	62
502	Dan River (NC)	North Carolina	Utility	150.00	3	1955	2012	57
503	Enka	North Carolina	Industrial	4.00	GE10	1948	2001	53
504	Enka	North Carolina	Industrial	4.00	GE11	1957	2001	44
505	Enka	North Carolina	Industrial	5.00	GE12	1959	2001	42

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
506	Enka	North Carolina	Industrial	0.30	GEN8	1984	2001	17
507	Enka	North Carolina	Industrial	3.00	GEN9	1937	2001	64
508	Kannapolis Energy PRTNR Spencer	North Carolina	IPP	1.00	GEN1	1939	2000	62
509	Kannapolis Energy PRTNR Spencer	North Carolina	IPP	2.50	GEN3	1965	2000	36
510	Kannapolis Energy PTNRS	North Carolina	IPP	7.50	GEN2	1950	2003	54
511	Kannapolis Energy PTNRS	North Carolina	IPP	15.00	GEN3	1971	2003	33
512	Kinston North Carolina Plant	North Carolina	Industrial	7.50	GEN1	1952	2008	57
513	Kinston North Carolina Plant	North Carolina	Industrial	7.50	GEN2	1952	2008	57
514	Lee	North Carolina	Utility	75.00	1	1952	2012	60
515	Lee	North Carolina	Utility	75.00	2	1951	2012	61
516	Lee	North Carolina	Utility	252.40	3	1962	2012	50
517	Plymouth (NC)	North Carolina	Industrial	7.50	TG4	1949	2002	53
518	Plymouth (NC)	North Carolina	Industrial	7.50	TG6	1956	2006	50
519	Riverbend (NC)	North Carolina	Utility	55.00	1	1929	1981	52
520	Riverbend (NC)	North Carolina	Utility	55.00	2	1929	1981	52
521	Riverbend (NC)	North Carolina	Utility	100.00	4	1952	2013	61
522	Riverbend (NC)	North Carolina	Utility	100.00	5	1952	2013	60
523	Riverbend (NC)	North Carolina	Utility	133.00	6	1954	2013	59
524	Riverbend (NC)	North Carolina	Utility	133.00	7	1954	2013	58
525	Tobaccoville Utility Plant	North Carolina	Industrial	40.30	GEN1	1985	2004	20
526	Tobaccoville Utility Plant	North Carolina	Industrial	40.30	GEN2	1985	2004	19
527	W H Weatherspoon	North Carolina	Utility	46.00	1	1949	2011	62
528	W H Weatherspoon	North Carolina	Utility	46.00	2	1950	2011	61
529	W H Weatherspoon	North Carolina	Utility	73.50	3	1952	2011	59
530	Beulah	North Dakota	Utility	2.50	1	1927	1985	59
531	Beulah	North Dakota	Utility	3.50	2	1927	1985	59
532	Beulah	North Dakota	Utility	7.50	3	1949	1986	37
533	Drayton (MNKOTA)	North Dakota	Utility	6.80	1	1965	2002	37
534	G F Wood	North Dakota	Utility	5.00	1	1949	1983	34
535	G F Wood	North Dakota	Utility	5.00	2	1950	1985	35
536	G F Wood	North Dakota	Utility	11.50	3	1951	1985	34
537	Heskett	North Dakota	Utility	75.00	2	1963	1900	64
538	Walhalla (ND ARCHDAN)	North Dakota	Industrial	2.00	GEN1	2000	2012	11
539	William J Neal	North Dakota	Utility	25.00	1	1952	1991	39
540	William J Neal	North Dakota	Utility	25.00	2	1952	1991	39
541	Acme (OH)	Ohio	IPP	25.00	1	1937	1992	56
542	Acme (OH)	Ohio	IPP	72.00	2	1951	1995	44
543	Acme (OH)	Ohio	IPP	35.00	4	1929	1992	64
544	Acme (OH)	Ohio	IPP	72.00	5	1941	1992	51
545	Acme (OH)	Ohio	IPP	112.50	6	1949	1992	44
546	Acme (OH)	Ohio	IPP	6.00	TOPR	1973	1992	19
547	Ashtabula	Ohio	IPP	46.00	6	1972	2003	30
548	Ashtabula	Ohio	IPP	46.00	7	1972	2003	30
549	Ashtabula	Ohio	IPP	46.00	8	1953	2002	49
550	Ashtabula	Ohio	IPP	46.00	9	1953	2003	50
551	Avon Lake	Ohio	IPP	35.00	1	1926	1983	57
552	Avon Lake	Ohio	IPP	35.00	2	1926	1983	57
553	Avon Lake	Ohio	IPP	35.00	3	1928	1983	55
554	Avon Lake	Ohio	IPP	35.00	4	1929	1983	54
555	Avon Lake	Ohio	IPP	50.00	5	1943	1983	40
556	Avon Lake	Ohio	IPP	233.00	8	1959	1987	28
557	Bay Shore	Ohio	IPP	140.60	2	1959	2012	54
558	Bay Shore	Ohio	IPP	140.60	3	1963	2012	49
559	Bay Shore	Ohio	IPP	217.60	4	1968	2012	44
560	Celina	Ohio	Utility	12.50	4	1970	1973	3
561	Columbus (OH)	Ohio	Utility	8.00	1	1929	1977	49
562	Columbus (OH)	Ohio	Utility	8.00	3	1925	1987	62
563	Columbus (OH)	Ohio	Utility	13.00	6	1950	1977	28
564	Columbus (OH)	Ohio	Utility	13.00	7	1957	1987	30
565	Columbus (OH)	Ohio	Utility	15.00	8	1966	1987	21
566	Conesville	Ohio	Utility	148.00	1	1959	2005	47
567	Conesville	Ohio	Utility	136.00	2	1957	2005	48
568	Conesville	Ohio	Utility	161.50	3	1962	2012	50
569	Dover (OH)	Ohio	Utility	4.00	2	1944	2007	63
570	East Palestine	Ohio	Utility	2.50	1	1945	1982	38
571	East Palestine	Ohio	Utility	1.50	2	1935	1982	48
572	East Palestine	Ohio	Utility	5.00	3	1950	1982	33
573	East Palestine	Ohio	Utility	7.50	4	1962	1982	21
574	Eastlake (OH)	Ohio	IPP	208.00	4	1956	2012	57
575	Eastlake (OH)	Ohio	IPP	680.00	5	1972	2012	40
576	Edgewater (OH)	Ohio	IPP	20.00	2	1924	1983	60
577	Edgewater (OH)	Ohio	IPP	69.00	3	1949	1993	44
578	Frank M Tait	Ohio	Utility	147.05	4	1958	1987	29

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

[A]		[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
579	Frank M Tait	Ohio	Utility	147.05	5	1959	1987	28
580	Goodyear	Ohio	Industrial	7.50	T 1	1975	2007	31
581	Goodyear	Ohio	Industrial	12.50	T 2	1977	2007	30
582	Goodyear	Ohio	Industrial	7.50	T 3	1984	2007	23
583	Goodyear	Ohio	Industrial	12.50	T 4	1953	2007	54
584	Gorge (OH)	Ohio	Utility	40.24	6	1943	1993	50
585	Gorge (OH)	Ohio	Utility	40.24	7	1948	1993	45
586	Hamilton	Ohio	Utility	3.00	1	1929	1975	46
587	Hamilton	Ohio	Utility	3.00	2	1929	1975	46
588	Hamilton	Ohio	Utility	7.50	3	1929	1986	57
589	Hamilton	Ohio	Utility	10.00	4	1976	1986	10
590	Lake Road (OH)	Ohio	Utility	85.00	11	1967	1993	26
591	Mad River	Ohio	IPP	25.00	1	1927	1985	58
592	Mad River	Ohio	IPP	20.00	2	1938	1985	46
593	Mad River	Ohio	IPP	23.00	3	1949	1985	36
594	McCracken Power Plant	Ohio	Commercial	5.00	NO1	1951	2005	55
595	McCracken Power Plant	Ohio	Commercial	3.10	NO2	1988	2005	18
596	Miami Fort	Ohio	Utility	65.00	3	1938	1982	43
597	Miami Fort	Ohio	Utility	65.00	4	1942	1982	40
598	Miami Fort	Ohio	Utility	100.00	5	1949	2008	58
599	Niles (OH ORION)	Ohio	IPP	132.80	UNT1	1954	2012	59
600	Niles (OH ORION)	Ohio	IPP	132.80	UNT2	1954	2012	58
601	Norwalk (OH)	Ohio	Utility	3.00	2	1938	1982	45
602	Norwalk (OH)	Ohio	Utility	3.00	3	1949	1982	33
603	Norwalk (OH)	Ohio	Utility	6.00	4	1957	1982	25
604	Norwalk (OH)	Ohio	Utility	18.00	5	1969	1982	14
605	O H Hutchings	Ohio	Utility	69.00	4	1951	2013	62
606	Ohio Univ Facilities Man	Ohio	Commercial	1.00	OUG1	1994	2009	15
607	Orrville	Ohio	Utility	1.50	5	1928	1984	57
608	Orrville	Ohio	Utility	2.50	6	1940	1984	45
609	Painesville	Ohio	Utility	3.00	1	1941	1983	42
610	Painesville	Ohio	Utility	3.00	2	1946	1983	37
611	Painesville	Ohio	Utility	25.00	6	1976	1989	13
612	Philo	Ohio	Utility	40.00	2	1928	1975	47
613	Philo	Ohio	Utility	109.00	3	1928	1975	47
614	Philo	Ohio	Utility	85.00	4	1942	1975	33
615	Philo	Ohio	Utility	85.00	5	1942	1975	33
616	Philo	Ohio	Utility	125.00	6	1957	1975	19
617	Picway	Ohio	Utility	30.00	3	1943	1980	37
618	Picway	Ohio	Utility	34.50	4	1949	1980	31
619	Piqua	Ohio	Utility	4.00	1	1933	1975	42
620	Piqua	Ohio	Utility	4.00	2	1933	1975	42
621	Piqua	Ohio	Utility	4.00	3	1940	2007	68
622	Piqua	Ohio	Utility	7.50	4	1947	2007	61
623	Piqua	Ohio	Utility	1.00	5	1947	1987	41
624	Piqua	Ohio	Utility	12.50	6	1951	2007	57
625	Piqua	Ohio	Utility	20.00	7	1961	2007	47
626	Piqua	Ohio	Utility	0.80	10	1987	2007	20
627	Poston	Ohio	Utility	44.00	1	1949	1987	38
628	Poston	Ohio	Utility	44.00	2	1950	1987	37
629	Poston	Ohio	Utility	69.00	3	1952	1987	36
630	Poston	Ohio	Utility	75.00	4	1954	1987	34
631	R E Burger	Ohio	IPP	62.50	1	1944	1994	50
632	R E Burger	Ohio	IPP	62.50	2	1947	1994	47
633	R E Burger	Ohio	IPP	103.40	3	1950	2011	62
634	R E Burger	Ohio	IPP	156.20	4	1955	2010	56
635	R E Burger	Ohio	IPP	156.20	5	1955	2010	56
636	Richard H Gorsuch	Ohio	Utility	50.00	1	1988	2010	22
637	Richard H Gorsuch	Ohio	Utility	50.00	2	1988	2010	22
638	Richard H Gorsuch	Ohio	Utility	50.00	3	1988	2010	22
639	Richard H Gorsuch	Ohio	Utility	50.00	4	1988	2010	22
640	Shelby Munic Light Plant	Ohio	Utility	12.50	1	1967	1999	32
641	Shelby Munic Light Plant	Ohio	Utility	12.50	2	1973	2011	39
642	Shelby Munic Light Plant	Ohio	Utility	5.00	3	1948	2011	64
643	Shelby Munic Light Plant	Ohio	Utility	7.00	4	1954	2011	58
644	Shelby Munic Light Plant	Ohio	Utility	12.50	1A	1968	2011	44
645	Smart Papers LLC	Ohio	Industrial	1.00	1	2009	2012	3
646	Smart Papers LLC	Ohio	Industrial	1.50	2	2009	2012	3
647	Smart Papers LLC	Ohio	Industrial	9.40	7	2009	2012	3
648	Smart Papers LLC	Ohio	Industrial	9.40	8	2009	2012	3
649	Smart Papers LLC	Ohio	Industrial	6.00	GEN3	1924	2012	89
650	Smart Papers LLC	Ohio	Industrial	1.50	GEN4	1927	2009	82
651	Smart Papers LLC	Ohio	Industrial	7.50	GEN5	1930	2012	83

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

Line No.	[A] Plant	[B] State	[C] Plant Sector	[D] Capacity MW	[E] Unit	[F] Year in Service	[G] Retirement Year	[H] Age at Retirement
652	Smart Papers LLC	Ohio	Industrial	10.50	GEN6	1930	2012	83
653	St Marys (OH)	Ohio	Utility	2.50	4	1946	1996	50
654	St Marys (OH)	Ohio	Utility	6.00	5	1957	2007	51
655	St Marys (OH)	Ohio	Utility	10.00	6	1967	2007	41
656	Tidd P FBC	Ohio	Utility	70.00	1	1903	1995	92
657	Tidd P FBC	Ohio	Utility	115.00	2	1948	1979	31
658	Toronto	Ohio	IPP	35.00	5	1940	2003	63
659	Toronto	Ohio	IPP	69.00	6	1949	2003	54
660	Toronto	Ohio	IPP	69.00	7	1949	2003	54
661	Walter C Beckjord	Ohio	Utility	115.00	1	1952	2012	60
662	Walter C Beckjord	Ohio	Utility	112.50	2	1953	2013	60
663	Walter C Beckjord	Ohio	Utility	125.00	3	1954	2013	59
664	Woodcock	Ohio	Utility	5.00	1	1938	1979	41
665	Woodcock	Ohio	Utility	5.00	2	1938	1979	41
666	Woodcock	Ohio	Utility	8.00	3	1941	1979	38
667	Woodcock	Ohio	Utility	10.00	4	1947	1979	32
668	Woodcock	Ohio	Utility	10.00	5	1950	1979	29
669	Amalgamated Sugar Nyssa	Oregon	Industrial	12.00	1	1987	2005	17
670	Amalgamated Sugar Nyssa	Oregon	Industrial	1.50	2	1942	2005	62
671	Amalgamated Sugar Nyssa	Oregon	Industrial	0.50	3	1942	2005	62
672	Armstrong Power Station	Pennsylvania	IPP	163.20	ARM1	1958	2012	54
673	Armstrong Power Station	Pennsylvania	IPP	163.20	ARM2	1959	2012	53
674	Crawford (PA)	Pennsylvania	Utility	35.00	1	1924	1978	54
675	Crawford (PA)	Pennsylvania	Utility	35.00	2	1926	1978	52
676	Crawford (PA)	Pennsylvania	Utility	42.00	3	1900	1977	77
677	Crawford (PA)	Pennsylvania	Utility	5.00	4	1900	1977	77
678	Cromby Generating Station	Pennsylvania	IPP	187.50	1	1954	2011	57
679	Eddystone Generating Station	Pennsylvania	IPP	353.60	1	1960	2011	51
680	Eddystone Generating Station	Pennsylvania	IPP	353.60	2	1960	2012	52
681	Elrama Power Plant	Pennsylvania	IPP	100.00	UNT1	1952	2012	60
682	Elrama Power Plant	Pennsylvania	IPP	100.00	UNT2	1953	2012	59
683	Elrama Power Plant	Pennsylvania	IPP	125.00	UNT3	1954	2012	58
684	Erie Mill	Pennsylvania	Industrial	4.00	GEN4	1936	2002	66
685	Erie Mill	Pennsylvania	Industrial	7.50	GEN6	1936	2002	66
686	Erie Mill	Pennsylvania	Industrial	19.00	GEN7	1971	2002	31
687	Erie Mill	Pennsylvania	Industrial	14.00	GEN8	1971	2002	31
688	F R Phillips	Pennsylvania	IPP	69.00	1	1943	2000	57
689	F R Phillips	Pennsylvania	IPP	81.00	2	1949	2000	50
690	F R Phillips	Pennsylvania	IPP	81.00	3	1950	2000	50
691	F R Phillips	Pennsylvania	IPP	179.00	4	1956	2000	44
692	Front Street (PA)	Pennsylvania	Utility	18.80	1	1953	1991	38
693	Front Street (PA)	Pennsylvania	Utility	10.00	2	1917	1991	74
694	Front Street (PA)	Pennsylvania	Utility	15.00	3	1928	1991	63
695	Front Street (PA)	Pennsylvania	Utility	28.80	4	1944	1991	47
696	Front Street (PA)	Pennsylvania	Utility	50.00	5	1952	1991	38
697	General Electric Erie PA Power	Pennsylvania	Industrial	5.00	STM2	1929	2003	75
698	General Electric Erie PA Power	Pennsylvania	Industrial	14.00	STM3	1949	2003	55
699	General Electric Erie PA Power	Pennsylvania	Industrial	9.00	STM4	1939	2003	65
700	Hatfields Ferry Power Station	Pennsylvania	IPP	576.00	1	1969	2013	44
701	Hatfields Ferry Power Station	Pennsylvania	IPP	576.00	2	1970	2013	43
702	Hatfields Ferry Power Station	Pennsylvania	IPP	576.00	3	1971	2013	42
703	Lock Haven Mill	Pennsylvania	Industrial	5.00	GEN1	1938	2002	64
704	Lock Haven Mill	Pennsylvania	Industrial	5.00	GEN3	1946	2002	56
705	Lock Haven Mill	Pennsylvania	Industrial	24.70	GEN4	1984	2002	17
706	Martins Creek	Pennsylvania	IPP	156.20	MC1	1954	2007	53
707	Martins Creek	Pennsylvania	IPP	156.20	MC2	1956	2007	52
708	Mitchell Power Station	Pennsylvania	IPP	299.20	3	1963	2013	50
709	New Castle Plant	Pennsylvania	IPP	35.00	1	1939	1993	54
710	New Castle Plant	Pennsylvania	IPP	35.00	2	1947	1993	46
711	Richmond Generating Station	Pennsylvania	IPP	165.00	12	1935	1983	48
712	Saxton	Pennsylvania	Utility	11.00	2	1900	1979	79
713	Saxton	Pennsylvania	Utility	37.00	3	1900	1979	79
714	Seward Generating Station	Pennsylvania	IPP	27.00	2	1942	1980	38
715	Seward Generating Station	Pennsylvania	IPP	35.00	3	1942	1980	38
716	Seward Generating Station	Pennsylvania	IPP	62.00	4	1950	2003	53
717	Seward Generating Station	Pennsylvania	IPP	156.20	5	1957	2003	47
718	Shippingport	Pennsylvania	Utility	100.00	1	1957	1982	26
719	Sonoco Products Co	Pennsylvania	Industrial	2.50	2	1952	2005	53
720	Titus	Pennsylvania	IPP	75.00	1	1951	2013	63
721	Titus	Pennsylvania	IPP	75.00	2	1951	2013	62
722	Titus	Pennsylvania	IPP	75.00	3	1953	2013	60
723	Warren (PA)	Pennsylvania	IPP	42.00	1	1948	2002	55
724	Warren (PA)	Pennsylvania	IPP	42.00	2	1949	2002	53

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

Line No.	[A] Plant	[B] State	[C] Plant Sector	[D] Capacity MW	[E] Unit	[F] Year in Service	[G] Retirement Year	[H] Age at Retirement
725	Williamsburg	Pennsylvania	Utility	6.00	1	1900	1990	90
726	Williamsburg	Pennsylvania	Utility	9.00	3	1900	1990	90
727	Williamsburg	Pennsylvania	Utility	28.30	5	1944	1991	47
728	Canadys Steam	South Carolina	Utility	136.00	1	1962	2012	51
729	Dolphus M Grainger	South Carolina	Utility	81.60	1	1966	2012	47
730	Dolphus M Grainger	South Carolina	Utility	81.60	2	1966	2012	47
731	H B Robinson	South Carolina	Utility	206.60	1	1960	2012	52
732	Jefferies	South Carolina	Utility	172.80	3	1970	2012	43
733	Jefferies	South Carolina	Utility	172.80	4	1970	2012	43
734	Lockhart	South Carolina	Utility	5.00	1	1921	1977	57
735	Urquhart	South Carolina	Utility	75.00	1	1953	2002	48
736	Urquhart	South Carolina	Utility	75.00	2	1954	2002	48
737	US DOE SRS (D Area)	South Carolina	IPP	9.40	HP 1	1952	2012	60
738	US DOE SRS (D Area)	South Carolina	IPP	9.40	HP 2	1952	2012	60
739	US DOE SRS (D Area)	South Carolina	IPP	9.40	HP 3	1952	2012	60
740	US DOE SRS (D Area)	South Carolina	IPP	12.50	LP 1	1952	2012	60
741	US DOE SRS (D Area)	South Carolina	IPP	12.50	LP 2	1952	2012	60
742	US DOE SRS (D Area)	South Carolina	IPP	12.50	LP 3	1952	2012	60
743	US DOE SRS (D Area)	South Carolina	IPP	12.50	LP 4	1952	2012	60
744	Kirk (SD)	South Dakota	Utility	5.00	1	1935	1993	57
745	Kirk (SD)	South Dakota	Utility	5.00	2	1935	1993	57
746	Kirk (SD)	South Dakota	Utility	5.00	3	1961	1993	31
747	Kirk (SD)	South Dakota	Utility	16.50	4	1956	1996	40
748	Lawrence (SD)	South Dakota	Utility	12.00	1	1948	1977	30
749	Lawrence (SD)	South Dakota	Utility	13.00	2	1949	1977	29
750	Lawrence (SD)	South Dakota	Utility	23.00	3	1951	1977	27
751	Mitchell (SD)	South Dakota	Utility	8.00	1	1948	1979	32
752	Mitchell (SD)	South Dakota	Utility	5.00	2	1929	1977	49
753	Mitchell (SD)	South Dakota	Utility	8.00	3	1948	1979	32
754	Mobridge	South Dakota	Utility	8.00	2	1950	1977	28
755	John Sevier	Tennessee	Utility	200.00	1	1955	2012	58
756	John Sevier	Tennessee	Utility	200.00	2	1955	2012	57
757	Kingsport Mill	Tennessee	Industrial	4.00	NO4	1937	1999	62
758	Lowland	Tennessee	Industrial	5.00	GEN1	1947	2005	59
759	Lowland	Tennessee	Industrial	5.00	GEN2	1947	2005	59
760	Lowland	Tennessee	Industrial	5.00	GEN3	1951	2005	55
761	Lowland	Tennessee	Industrial	0.30	GEN4	1985	2005	21
762	Lowland	Tennessee	Industrial	5.00	GEN5	1951	2005	55
763	Old Hickory Plant	Tennessee	Industrial	3.00	G10	1933	2002	69
764	Watts Bar Fossil	Tennessee	Utility	60.00	ST1	1942	1997	56
765	Watts Bar Fossil	Tennessee	Utility	60.00	ST2	1942	1997	56
766	Watts Bar Fossil	Tennessee	Utility	60.00	ST3	1943	1997	55
767	Watts Bar Fossil	Tennessee	Utility	60.00	ST4	1945	1997	53
768	Marshall (TX)	Texas	Industrial	2.00	8511	1921	2008	87
769	Marshall (TX)	Texas	Industrial	2.00	8512	2011	2012	1
770	Sandow 1 3	Texas	IPP	121.00	GEN1	1953	2006	53
771	Sandow 1 3	Texas	IPP	121.00	GEN2	1954	2006	53
772	Sandow 1 3	Texas	IPP	121.00	GEN3	1954	2006	53
773	Cedar	Utah	Utility	7.50	1	1945	1987	43
774	Cedar	Utah	Utility	7.50	2	1945	1987	43
775	Desert Power LP	Utah	IPP	43.00	GEN7	1999	2007	9
776	Geneva Steel	Utah	Industrial	50.00	GEN1	1944	2002	58
777	Hale	Utah	Utility	15.00	1	1936	1979	43
778	Hale	Utah	Utility	46.00	2	1950	1991	42
779	Provo	Utah	Utility	2.00	1	1940	1989	49
780	Provo	Utah	Utility	2.00	2	1940	1989	49
781	Provo	Utah	Utility	2.50	3	1941	1989	48
782	J Edward Moran	Vermont	Utility	10.00	2	1954	1985	31
783	Brantly	Virginia	Utility	6.00	1	1949	1980	31
784	Brantly	Virginia	Utility	11.00	2	1952	1980	27
785	Brantly	Virginia	Utility	11.00	3	1953	1980	27
786	Chesterfield	Virginia	Utility	69.00	2	1949	1981	32
787	Dan River (VA)	Virginia	Industrial	3.00	GEN1	1947	2006	59
788	Dan River (VA)	Virginia	Industrial	6.00	GEN2	1952	2006	54
789	Glen Lyn	Virginia	Utility	34.00	3	1924	1974	51
790	Glen Lyn	Virginia	Utility	34.00	4	1927	1974	48
791	Park 500 Philip Morris USA	Virginia	Industrial	6.10	TG2	1984	2013	29
792	Possum Point	Virginia	Utility	113.60	3	1955	2003	48
793	Possum Point	Virginia	Utility	239.30	4	1962	2003	41
794	Potomac River	Virginia	IPP	92.00	1	1949	2012	63
795	Potomac River	Virginia	IPP	92.00	2	1950	2012	62
796	Potomac River	Virginia	IPP	110.00	3	1954	2012	58
797	Potomac River	Virginia	IPP	110.00	4	1956	2012	57

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
798	Potomac River	Virginia	IPP	110.00	5	1957	2012	55
799	Rock Tenn Co (VA)	Virginia	Industrial	2.00	1	1977	2000	23
800	Waynesboro Virginia	Virginia	Industrial	3.00	GEN1	1929	2010	82
801	Waynesboro Virginia	Virginia	Industrial	3.00	GEN2	1929	2010	82
802	Waynesboro Virginia	Virginia	Industrial	3.00	GEN3	1929	2008	79
803	Waynesboro Virginia	Virginia	Industrial	3.40	GEN4	1947	2010	64
804	Longview (WA COWLITZ)	Washington	Utility	8.00	1	1900	1973	74
805	Longview (WA COWLITZ)	Washington	Utility	8.00	2	1900	1973	74
806	Longview (WA COWLITZ)	Washington	Utility	8.00	3	1900	1974	74
807	Longview (WA COWLITZ)	Washington	Utility	8.00	4	1900	1973	74
808	Longview (WA COWLITZ)	Washington	Utility	3.00	5	1900	1973	74
809	Washington State Univ	Washington	Commercial	2.00	GEN1	1963	2005	42
810	Albright	West Virginia	Utility	69.00	1	1952	2012	60
811	Albright	West Virginia	Utility	69.00	2	1952	2012	60
812	Albright	West Virginia	Utility	140.20	3	1954	2012	58
813	Cabin Creek (WV)	West Virginia	Utility	25.00	3	1919	1974	55
814	Cabin Creek (WV)	West Virginia	Utility	22.00	4	1921	1974	53
815	Cabin Creek (WV)	West Virginia	Utility	85.00	8	1942	1981	39
816	Cabin Creek (WV)	West Virginia	Utility	85.00	9	1943	1981	38
817	Phil Sporn	West Virginia	Utility	495.50	5	1960	2012	51
818	Rivesville	West Virginia	Utility	11.00	1	1900	1973	74
819	Rivesville	West Virginia	Utility	13.00	2	1900	1973	74
820	Rivesville	West Virginia	Utility	22.00	3	1900	1973	74
821	Rivesville	West Virginia	Utility	27.00	4	1900	1973	74
822	Rivesville	West Virginia	Utility	35.00	5	1943	2012	69
823	Rivesville	West Virginia	Utility	74.70	6	1951	2012	61
824	Willow Island	West Virginia	Utility	50.00	1	1949	2012	64
825	Willow Island	West Virginia	Utility	163.20	2	1960	2012	52
826	Windsor	West Virginia	IPP	60.00	7	1941	1975	34
827	Windsor	West Virginia	IPP	60.00	8	1941	1975	34
828	Alma	Wisconsin	Utility	15.00	1	1947	2012	65
829	Alma	Wisconsin	Utility	15.00	2	1947	2012	65
830	Alma	Wisconsin	Utility	15.00	3	1951	2012	61
831	Bay Front	Wisconsin	Utility	5.00	3	1925	1986	61
832	Blount Street	Wisconsin	Utility	34.50	3	1953	2011	58
833	Blount Street	Wisconsin	Utility	20.00	4	1938	2011	74
834	Blount Street	Wisconsin	Utility	23.00	5	1948	2011	63
835	Blount Street	Wisconsin	Utility	50.00	6	1957	2010	53
836	Blount Street	Wisconsin	Utility	50.00	7	1961	2010	49
837	Columbus Street	Wisconsin	Utility	5.00	2	1935	2003	69
838	Columbus Street	Wisconsin	Utility	10.00	3	1941	2003	63
839	E J Stoneman	Wisconsin	IPP	18.00	1	1952	2010	59
840	E J Stoneman	Wisconsin	IPP	35.00	2	1952	2010	59
841	East Wells	Wisconsin	Utility	15.00	1	1939	1982	44
842	Edgewater (WI)	Wisconsin	Utility	30.00	1	1931	1980	50
843	Edgewater (WI)	Wisconsin	Utility	30.00	2	1942	1985	43
844	Green Bay West Mill	Wisconsin	Industrial	1.50	GEN1	1929	2002	73
845	Green Bay West Mill	Wisconsin	Industrial	3.00	GEN2	1933	2002	69
846	Green Bay West Mill	Wisconsin	Industrial	3.00	GEN3	1940	2002	62
847	Green Bay West Mill	Wisconsin	Industrial	2.50	GEN4	1947	2002	55
848	Green Bay West Mill	Wisconsin	Industrial	25.00	GEN8	1977	2005	29
849	Menasha (MNSHA)	Wisconsin	IPP	4.00	1	1949	1989	41
850	Menasha (MNSHA)	Wisconsin	IPP	4.00	2	1949	1989	41
851	North Oak Creek	Wisconsin	Utility	120.00	1	1953	1989	36
852	North Oak Creek	Wisconsin	Utility	120.00	2	1954	1989	35
853	North Oak Creek	Wisconsin	Utility	130.00	3	1955	1988	32
854	North Oak Creek	Wisconsin	Utility	130.00	4	1957	1988	31
855	Port Washington	Wisconsin	Utility	80.00	1	1935	2004	69
856	Port Washington	Wisconsin	Utility	80.00	2	1943	2004	61
857	Port Washington	Wisconsin	Utility	80.00	3	1948	2004	56
858	Port Washington	Wisconsin	Utility	80.00	4	1949	2002	53
859	Port Washington	Wisconsin	Utility	80.00	5	1950	1991	41
860	Pulliam	Wisconsin	Utility	30.00	3	1943	2007	65
861	Pulliam	Wisconsin	Utility	30.00	4	1947	2007	60
862	Richland Center	Wisconsin	Utility	1.25	1	1937	1985	48
863	Richland Center	Wisconsin	Utility	1.50	2	1939	1985	46
864	Richland Center	Wisconsin	Utility	4.00	3	1953	1987	35
865	Richland Center	Wisconsin	Utility	7.50	4	1966	1987	22
866	Rock River	Wisconsin	Utility	75.00	1	1954	1999	46
867	Rock River	Wisconsin	Utility	75.00	2	1955	1999	44
868	Wildwood	Wisconsin	Utility	12.50	4	1962	1994	33
869	Wildwood	Wisconsin	Utility	16.50	5	1968	1994	27
870	Neil Simpson	Wyoming	Utility	3.00	1	1961	1980	19

Appendix A-2
Age at Retirement of Units Retired from Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Line No	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Retirement Year	Age at Retirement
871	Neil Simpson	Wyoming	Utility	1.00	2	1928	1980	52
872	Neil Simpson	Wyoming	Utility	2.00	3	1946	1946	0
873	Neil Simpson	Wyoming	Utility	2.00	4	1948	1982	35

APPENDIX A-3
AGE OF UNITS CURRENTLY IN SERVICE

Appendix A-3
Age of Coal-Fired Units Currently in Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
1	Number of Units				1,296		
2	Maximum			1,425.6		2013	88.9
3	Minimum			0.5		1925	0.4
4	Median			171.3		1969	44.5
5	Average			267.7			43.2
6	Standard Deviation			277.2			15.8
7	95% Confidence Limit						
8	Maximum			811.0			74.1
9	Minimum			(275.6)			12.2
10	Charles R Lowman	Alabama	Utility	66.00	1	1969	44
11	Charles R Lowman	Alabama	Utility	236.00	2	1978	35
12	Charles R Lowman	Alabama	Utility	236.00	3	1980	33
13	Colbert	Alabama	Utility	200.00	1	1955	59
14	Colbert	Alabama	Utility	200.00	2	1955	59
15	Colbert	Alabama	Utility	200.00	3	1955	58
16	Colbert	Alabama	Utility	200.00	4	1955	58
17	Colbert	Alabama	Utility	550.00	5	1965	48
18	E C Gaston	Alabama	Utility	272.00	1	1960	54
19	E C Gaston	Alabama	Utility	272.00	2	1960	53
20	E C Gaston	Alabama	Utility	272.00	3	1961	52
21	E C Gaston	Alabama	Utility	952.00	5	1974	39
22	E C Gaston	Alabama	Utility	244.80	ST4	1962	51
23	Gadsden	Alabama	Utility	69.00	1	1949	65
24	Gadsden	Alabama	Utility	69.00	2	1949	64
25	Gorgas 2 & 3	Alabama	Utility	125.00	6	1951	63
26	Gorgas 2 & 3	Alabama	Utility	125.00	7	1952	61
27	Gorgas 2 & 3	Alabama	Utility	187.50	8	1956	58
28	Gorgas 2 & 3	Alabama	Utility	190.40	9	1958	55
29	Gorgas 2 & 3	Alabama	Utility	788.80	10	1972	41
30	Greene County (AL)	Alabama	Utility	299.20	1	1965	48
31	Greene County (AL)	Alabama	Utility	269.20	2	1966	47
32	James H Miller Jr	Alabama	Utility	705.50	1	1978	35
33	James H Miller Jr	Alabama	Utility	705.50	2	1985	29
34	James H Miller Jr	Alabama	Utility	705.50	3	1989	25
35	James H Miller Jr	Alabama	Utility	705.50	4	1991	23
36	James M Barry Electric Generating Plant	Alabama	Utility	153.10	1	1954	60
37	James M Barry Electric Generating Plant	Alabama	Utility	153.10	2	1954	59
38	James M Barry Electric Generating Plant	Alabama	Utility	272.00	3	1959	54
39	James M Barry Electric Generating Plant	Alabama	Utility	403.70	4	1969	44
40	James M Barry Electric Generating Plant	Alabama	Utility	788.80	5	1971	42
41	Mobile Energy Services Co LLC	Alabama	IPP	43.10	GEN5	1985	28
42	U S Alliance Coosa Pines	Alabama	Industrial	12.50	AOW6	1968	46
43	Widows Creek	Alabama	Utility	140.60	1	1952	61
44	Widows Creek	Alabama	Utility	140.60	2	1952	61
45	Widows Creek	Alabama	Utility	140.60	4	1953	61
46	Widows Creek	Alabama	Utility	140.60	6	1954	59
47	Widows Creek	Alabama	Utility	575.00	7	1961	53
48	Widows Creek	Alabama	Utility	550.00	8	1965	49
49	Chena	Alaska	IPP	5.00	1	1952	61
50	Chena	Alaska	IPP	2.50	2	1952	61
51	Chena	Alaska	IPP	20.00	5	1975	38
52	Eielson Air Force Base Central	Alaska	Commercial	2.50	TG1	1952	61
53	Eielson Air Force Base Central	Alaska	Commercial	2.50	TG2	1952	61
54	Eielson Air Force Base Central	Alaska	Commercial	5.00	TG3	1955	58
55	Eielson Air Force Base Central	Alaska	Commercial	5.00	TG4	1969	44
56	Eielson Air Force Base Central	Alaska	Commercial	10.00	TG5	1987	26
57	Healy	Alaska	Utility	28.00	1	1967	46
58	Healy Clean Coal	Alaska	Utility	50.00	2	2000	14
59	Univ of Alaska Fairbanks	Alaska	Commercial	1.50	GEN1	1964	50

Appendix A-3
Age of Coal-Fired Units Currently in Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
60	Univ of Alaska Fairbanks	Alaska	Commercial	1.50	GEN2	1964	50
61	Univ of Alaska Fairbanks	Alaska	Commercial	10.00	GEN3	1981	33
62	Utility Plants Section	Alaska	Commercial	5.00	GEN1	1955	59
63	Utility Plants Section	Alaska	Commercial	2.50	GEN2	1945	69
64	Utility Plants Section	Alaska	Commercial	5.00	GEN3	1955	59
65	Utility Plants Section	Alaska	Commercial	5.00	GEN4	1955	59
66	Utility Plants Section	Alaska	Commercial	5.00	GEN5	1989	25
67	Battle River	Alberta	IPP	158.49	3	1969	45
68	Battle River	Alberta	IPP	158.49	4	1975	39
69	Battle River	Alberta	IPP	375.00	5	1981	33
70	Genesee (CAN)	Alberta	IPP	410.00	1	1994	19
71	Genesee (CAN)	Alberta	IPP	410.00	2	1989	25
72	Genesee (CAN)	Alberta	IPP	466.00	3	2005	9
73	H R Milner	Alberta	IPP	150.30	1	1972	42
74	Keephills	Alberta	IPP	427.00	1	1983	31
75	Keephills	Alberta	IPP	427.00	2	1984	30
76	Keephills 3	Alberta	IPP	495.00	3	2011	2
77	Sheerness	Alberta	IPP	389.00	1	1986	28
78	Sheerness	Alberta	IPP	383.00	2	1990	24
79	Sundance	Alberta	IPP	304.00	1	1970	44
80	Sundance	Alberta	IPP	304.00	2	1973	41
81	Sundance	Alberta	IPP	395.00	3	1976	38
82	Sundance	Alberta	IPP	433.00	4	1977	37
83	Sundance	Alberta	IPP	405.00	5	1978	36
84	Sundance	Alberta	IPP	433.00	6	1980	34
85	Apache Station	Arizona	Utility	204.00	ST2	1979	35
86	Apache Station	Arizona	Utility	204.00	ST3	1979	34
87	Cholla	Arizona	Utility	113.60	1	1962	52
88	Cholla	Arizona	Utility	288.90	2	1978	35
89	Cholla	Arizona	Utility	312.30	3	1980	34
90	Cholla	Arizona	Utility	414.00	4	1981	32
91	Coronado	Arizona	Utility	410.90	CO1	1979	34
92	Coronado	Arizona	Utility	410.90	CO2	1980	33
93	H Wilson Sundt Generating Station	Arizona	Utility	173.30	4	1967	46
94	Navajo	Arizona	Utility	803.10	NAV1	1974	40
95	Navajo	Arizona	Utility	803.10	NAV2	1975	39
96	Navajo	Arizona	Utility	803.10	NAV3	1976	38
97	Springerville Generating Station	Arizona	Utility	424.80	1	1985	28
98	Springerville Generating Station	Arizona	Utility	424.80	2	1990	23
99	Springerville Generating Station	Arizona	Utility	450.00	ST3	2006	7
100	Springerville Generating Station	Arizona	Utility	450.00	ST4	2009	4
101	Flint Creek (AR)	Arkansas	Utility	558.00	1	1978	36
102	Independence (AR)	Arkansas	Utility	850.00	1	1983	31
103	Independence (AR)	Arkansas	Utility	850.00	2	1984	29
104	John W Turk Jr Power Plant	Arkansas	Utility	609.00	ST1	2012	1
105	Plum Point Energy	Arkansas	IPP	720.00	ST1	2010	3
106	White Bluff	Arkansas	Utility	850.00	1	1980	33
107	White Bluff	Arkansas	Utility	850.00	2	1981	32
108	ACE Cogeneration Co	California	IPP	108.00	GEN1	1990	23
109	Argus Cogeneration Plant	California	Industrial	7.50	TG5	1947	66
110	Argus Cogeneration Plant	California	Industrial	27.50	TG8	1978	35
111	Argus Cogeneration Plant	California	Industrial	27.50	TG9	1978	35
112	California Portland Cement	California	Industrial	15.00	1	1985	28
113	California Portland Cement	California	Industrial	15.00	2	1985	28
114	Port of Stockton District Energy Facility	California	IPP	54.00	STG	1987	26
115	Rio Bravo Jasmin	California	IPP	38.20	UP9	1989	24
116	Rio Bravo Poso	California	IPP	38.20	UP8	1989	24
117	Carbon II	Coahuila	Utility	350.00	1	1993	20
118	Carbon II	Coahuila	Utility	350.00	2	1993	20
119	Carbon II	Coahuila	Utility	350.00	3	1995	18
120	Carbon II	Coahuila	Utility	350.00	4	1996	17
121	Jose Lopez Portillo (Rio Escondido)	Coahuila	Utility	300.00	1	1982	31
122	Jose Lopez Portillo (Rio Escondido)	Coahuila	Utility	300.00	2	1983	31
123	Jose Lopez Portillo (Rio Escondido)	Coahuila	Utility	300.00	3	1985	29
124	Jose Lopez Portillo (Rio Escondido)	Coahuila	Utility	300.00	4	1987	26
125	Arapahoe	Colorado	Utility	40.00	3	1951	63

Appendix A-3
Age of Coal-Fired Units Currently in Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
126	Arapahoe	Colorado	Utility	112.50	4	1955	59
127	Cherokee (CO)	Colorado	Utility	170.50	3	1962	52
128	Cherokee (CO)	Colorado	Utility	380.80	4	1968	46
129	Comanche (CO)	Colorado	Utility	382.50	1	1973	41
130	Comanche (CO)	Colorado	Utility	396.00	2	1975	39
131	Comanche (CO)	Colorado	Utility	856.80	3	2010	4
132	Craig (CO)	Colorado	Utility	446.40	1	1980	33
133	Craig (CO)	Colorado	Utility	446.40	2	1979	34
134	Craig (CO)	Colorado	Utility	463.40	3	1984	29
135	Hayden	Colorado	Utility	190.00	1	1965	48
136	Hayden	Colorado	Utility	275.40	2	1976	37
137	Lamar Plant	Colorado	Utility	25.00	4	1972	42
138	Lamar Plant	Colorado	Utility	18.50	AB	2009	5
139	Martin Drake	Colorado	Utility	50.00	5	1962	51
140	Martin Drake	Colorado	Utility	75.00	6	1968	45
141	Martin Drake	Colorado	Utility	132.00	7	1974	39
142	Nucla	Colorado	Utility	11.50	1	1959	54
143	Nucla	Colorado	Utility	11.50	2	1959	54
144	Nucla	Colorado	Utility	11.50	3	1959	54
145	Nucla	Colorado	Utility	79.30	ST4	1991	23
146	Pawnee	Colorado	Utility	552.30	1	1981	32
147	Rawhide	Colorado	Utility	293.60	ST1	1984	30
148	Ray D Nixon	Colorado	Utility	207.00	ST1	1980	34
149	Trigen Colorado	Colorado	IPP	7.50	GEN1	1976	37
150	Trigen Colorado	Colorado	IPP	7.50	GEN2	1977	37
151	Trigen Colorado	Colorado	IPP	20.00	GEN3	1983	30
152	Trinidad (CO)	Colorado	Utility	3.70	1	1950	64
153	Valmont	Colorado	Utility	191.70	5	1964	50
154	W N Clark	Colorado	Utility	18.70	1	1955	58
155	W N Clark	Colorado	Utility	25.00	2	1959	55
156	Western Sugar Coop Ft Morgan	Colorado	Industrial	3.00	ATB-2	1947	67
157	Bridgeport Station	Connecticut	IPP	400.00	3	1968	45
158	Indian River Generating Station (DE)	Delaware	IPP	176.80	3	1970	44
159	Indian River Generating Station (DE)	Delaware	IPP	442.40	4	1980	33
160	Big Bend (FL)	Florida	Utility	445.50	ST1	1970	43
161	Big Bend (FL)	Florida	Utility	445.50	ST2	1973	41
162	Big Bend (FL)	Florida	Utility	445.50	ST3	1976	38
163	Big Bend (FL)	Florida	Utility	486.00	ST4	1985	29
164	C D McIntosh Jr	Florida	Utility	363.80	3	1982	31
165	Cedar Bay Generating Co LP	Florida	IPP	291.60	GEN1	1993	20
166	Central Power & Lime Inc	Florida	IPP	125.00	GEN1	1988	25
167	Crist	Florida	Utility	93.70	4	1959	54
168	Crist	Florida	Utility	93.70	5	1961	52
169	Crist	Florida	Utility	369.70	6	1970	44
170	Crist	Florida	Utility	578.00	7	1973	40
171	Crystal River	Florida	Utility	440.50	1	1966	47
172	Crystal River	Florida	Utility	523.80	2	1969	44
173	Crystal River	Florida	Utility	709.20	5	1984	29
174	Crystal River	Florida	Utility	749.20	ST4	1982	31
175	Deerhaven Generating Station	Florida	Utility	250.70	2	1981	32
176	Indiantown Cogeneration Facility	Florida	IPP	395.40	GEN1	1995	18
177	Jefferson Smurfit Corp (FL)	Florida	Industrial	74.40	GEN6	1982	31
178	Lansing Smith	Florida	Utility	149.60	1	1965	48
179	Lansing Smith	Florida	Utility	190.40	2	1967	46
180	Polk Station	Florida	Utility	326.30	1	1996	17
181	Scholz	Florida	Utility	49.00	1	1953	61
182	Scholz	Florida	Utility	49.00	2	1953	60
183	Seminole (FL)	Florida	Utility	714.60	1	1984	30
184	Seminole (FL)	Florida	Utility	714.60	2	1985	29
185	St Johns River Power Park	Florida	Utility	679.00	1	1987	27
186	St Johns River Power Park	Florida	Utility	679.00	2	1988	25
187	Stanton Energy Center	Florida	IPP	464.50	1	1987	26
188	Stanton Energy Center	Florida	IPP	464.50	2	1996	17
189	Albany Brewery	Georgia	Industrial	6.00	ST1	1979	34
190	Bowen	Georgia	Utility	805.80	1	1971	42
191	Bowen	Georgia	Utility	788.80	2	1972	41

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
192	Bowen	Georgia	Utility	952.00	3	1974	39
193	Bowen	Georgia	Utility	952.00	4	1975	38
194	Hammond	Georgia	Utility	125.00	1	1954	59
195	Hammond	Georgia	Utility	125.00	2	1954	59
196	Hammond	Georgia	Utility	125.00	3	1955	58
197	Hammond	Georgia	Utility	578.00	4	1970	43
198	Harllee Branch	Georgia	Utility	299.20	1	1965	48
199	Harllee Branch	Georgia	Utility	544.00	3	1968	45
200	Harllee Branch	Georgia	Utility	544.00	4	1969	44
201	International Paper Co Savannah	Georgia	Industrial	71.20	GEN9	1981	32
202	Kraft	Georgia	Utility	54.40	2	1961	53
203	Kraft	Georgia	Utility	103.50	3	1965	49
204	Kraft	Georgia	Utility	50.00	ST1	1958	55
205	McIntosh (GA SAVNAH)	Georgia	Utility	177.60	1	1979	35
206	Mitchell (GA)	Georgia	Utility	163.20	3	1964	50
207	Plant Crisp	Georgia	Utility	12.50	1	1957	57
208	Savannah Sugar Refinery	Georgia	Industrial	3.00	GEN2	1959	55
209	Savannah Sugar Refinery	Georgia	Industrial	2.70	GENA	1948	66
210	Savannah Sugar Refinery	Georgia	Industrial	1.00	GENC	1946	67
211	Savannah Sugar Refinery	Georgia	Industrial	5.00	GEND	1985	29
212	Scherer	Georgia	Utility	891.00	1	1982	32
213	Scherer	Georgia	Utility	891.00	2	1984	30
214	Scherer	Georgia	Utility	891.00	3	1987	27
215	Scherer	Georgia	Utility	891.00	4	1989	25
216	Wansley (GPC)	Georgia	Utility	952.00	1	1976	37
217	Wansley (GPC)	Georgia	Utility	952.00	2	1978	36
218	Yates	Georgia	Utility	122.50	1	1950	63
219	Yates	Georgia	Utility	122.50	2	1950	63
220	Yates	Georgia	Utility	122.50	3	1952	61
221	Yates	Georgia	Utility	156.20	4	1957	56
222	Yates	Georgia	Utility	156.20	5	1958	56
223	Yates	Georgia	Utility	403.70	6	1974	39
224	Yates	Georgia	Utility	403.70	7	1974	40
225	Plutarco Elias Calles (Petacalco)	Guerrero	Utility	651.00	7	2010	4
226	AES Hawaii	Hawaii	IPP	203.00	GEN1	1992	22
227	Amalgamated Sugar Co LLC (The)	Idaho	Industrial	1.50	1500	1948	65
228	Amalgamated Sugar Co LLC (The)	Idaho	Industrial	2.50	2500	1948	65
229	Amalgamated Sugar Co LLC (The)	Idaho	Industrial	6.20	4000	1994	19
230	Amalgamated Sugar Co LLC Nampa	Idaho	Industrial	0.50	500	1950	63
231	Amalgamated Sugar Co LLC Nampa	Idaho	Industrial	2.20	2250	1948	65
232	Amalgamated Sugar Co LLC Nampa	Idaho	Industrial	6.00	6500	1968	45
233	A E Staley Decatur Plant Cogeneration	Illinois	Industrial	62.00	GEN1	1989	25
234	Baldwin Energy Complex	Illinois	IPP	625.10	1	1970	43
235	Baldwin Energy Complex	Illinois	IPP	634.50	2	1973	41
236	Baldwin Energy Complex	Illinois	IPP	634.50	3	1975	39
237	Coffeen	Illinois	IPP	388.90	1	1965	48
238	Coffeen	Illinois	IPP	616.50	2	1972	41
239	Corn Products International	Illinois	Industrial	22.50	TGO1	1991	23
240	Corn Products International	Illinois	Industrial	22.50	TGO2	1991	23
241	Dallman	Illinois	Utility	90.20	1	1968	45
242	Dallman	Illinois	Utility	90.20	2	1972	41
243	Dallman	Illinois	Utility	207.30	3	1978	35
244	Dallman	Illinois	Utility	280.00	4	2009	4
245	Decatur (IL ADM)	Illinois	Industrial	31.00	GEN2	1987	27
246	Decatur (IL ADM)	Illinois	Industrial	31.00	GEN3	1987	27
247	Decatur (IL ADM)	Illinois	Industrial	31.00	GEN4	1987	27
248	Decatur (IL ADM)	Illinois	Industrial	31.00	GEN5	1987	26
249	Decatur (IL ADM)	Illinois	Industrial	31.00	GEN6	1994	19
250	Decatur (IL ADM)	Illinois	Industrial	75.00	GEN7	1997	17
251	Decatur (IL ADM)	Illinois	Industrial	105.00	GEN8	2004	10
252	Duck Creek	Illinois	Utility	441.00	1	1976	37
253	E D Edwards	Illinois	Utility	136.00	1	1960	54
254	E D Edwards	Illinois	Utility	280.50	2	1968	45
255	E D Edwards	Illinois	Utility	363.80	3	1972	41
256	Havana	Illinois	IPP	488.00	6	1978	35
257	Hennepin Power Station	Illinois	IPP	75.00	1	1953	60

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
258	Hennepin Power Station	Illinois	IPP	231.30	2	1959	55
259	John Deere Harvester Works	Illinois	Industrial	2.00	GEN2	1940	73
260	John Deere Harvester Works	Illinois	Industrial	2.50	GEN4	1949	65
261	John Deere Harvester Works	Illinois	Industrial	3.00	GEN5	1951	62
262	John Deere Harvester Works	Illinois	Industrial	2.50	GEN6	1960	53
263	Joliet 29	Illinois	IPP	660.00	7	1965	49
264	Joliet 29	Illinois	IPP	660.00	8	1966	48
265	Joliet 9	Illinois	IPP	360.40	6	1959	54
266	Joppa Steam	Illinois	IPP	183.30	1	1953	60
267	Joppa Steam	Illinois	IPP	183.30	2	1953	60
268	Joppa Steam	Illinois	IPP	183.30	3	1954	60
269	Joppa Steam	Illinois	IPP	183.30	4	1954	59
270	Joppa Steam	Illinois	IPP	183.30	5	1955	58
271	Joppa Steam	Illinois	IPP	183.30	6	1955	58
272	Kincaid Generation LLC	Illinois	IPP	659.50	1	1967	46
273	Kincaid Generation LLC	Illinois	IPP	659.50	2	1968	45
274	Marion	Illinois	Utility	33.00	1	1963	50
275	Marion	Illinois	Utility	33.00	2	1963	50
276	Marion	Illinois	Utility	33.00	3	1963	50
277	Marion	Illinois	Utility	173.00	4	1978	35
278	Newton (IL)	Illinois	IPP	617.40	1	1977	36
279	Newton (IL)	Illinois	IPP	617.40	2	1982	31
280	Peoria (IL)	Illinois	Industrial	1.50	GEN1	1934	80
281	Peoria (IL)	Illinois	Industrial	1.50	GEN2	1934	80
282	Peoria (IL)	Illinois	Industrial	4.00	GEN3	1954	60
283	Peoria (IL)	Illinois	Industrial	4.00	GEN4	1985	29
284	Powerton	Illinois	IPP	892.80	5	1972	41
285	Powerton	Illinois	IPP	892.80	6	1975	38
286	Prairie State Energy Campus	Illinois	IPP	883.00	ST1	2012	1
287	Prairie State Energy Campus	Illinois	IPP	883.00	ST2	2012	1
288	Southern Illinois Univ	Illinois	Commercial	3.50	ST	1998	15
289	Tuscola	Illinois	Industrial	6.00	TG1	1953	60
290	Tuscola	Illinois	Industrial	6.00	TG2	1953	60
291	Tuscola	Illinois	Industrial	6.00	TG3	2001	13
292	Univ of Illinois Abbott	Illinois	Commercial	12.50	T10	2004	9
293	Univ of Illinois Abbott	Illinois	Commercial	12.50	T11	2004	9
294	Univ of Illinois Abbott	Illinois	Commercial	7.00	T12	2004	10
295	Univ of Illinois Abbott	Illinois	Commercial	7.50	T6	1959	54
296	Univ of Illinois Abbott	Illinois	Commercial	7.50	T7	1962	51
297	Waukegan	Illinois	IPP	326.40	7	1958	55
298	Waukegan	Illinois	IPP	355.30	8	1962	51
299	Will County	Illinois	IPP	299.20	3	1957	56
300	Will County	Illinois	IPP	598.40	4	1963	50
301	Wood River (IL)	Illinois	IPP	112.50	4	1954	59
302	Wood River (IL)	Illinois	IPP	387.60	5	1964	49
303	A B Brown	Indiana	Utility	265.20	ST1	1979	35
304	A B Brown	Indiana	Utility	265.20	ST2	1986	28
305	AES Petersburg (IN)	Indiana	Utility	670.90	4	1986	28
306	AES Petersburg (IN)	Indiana	Utility	281.60	ST1	1967	46
307	AES Petersburg (IN)	Indiana	Utility	523.30	ST2	1969	44
308	AES Petersburg (IN)	Indiana	Utility	670.90	ST3	1977	36
309	Bailly	Indiana	Utility	190.40	7	1962	51
310	Bailly	Indiana	Utility	413.10	8	1968	45
311	Cayuga	Indiana	Utility	531.00	1	1970	43
312	Cayuga	Indiana	Utility	531.00	2	1972	41
313	Central Soya Co Inc	Indiana	Industrial	2.00	3516	1950	63
314	Clifty Creek	Indiana	Utility	217.30	1	1955	59
315	Clifty Creek	Indiana	Utility	217.30	2	1955	59
316	Clifty Creek	Indiana	Utility	217.30	3	1955	58
317	Clifty Creek	Indiana	Utility	217.30	4	1955	58
318	Clifty Creek	Indiana	Utility	217.30	5	1955	58
319	Clifty Creek	Indiana	Utility	217.30	6	1956	58
320	Crawfordsville	Indiana	Utility	11.50	4	1955	59
321	Crawfordsville	Indiana	Utility	12.60	5	1965	49
322	Eagle Valley (H T Pritchard)	Indiana	Utility	50.00	3	1951	62
323	Eagle Valley (H T Pritchard)	Indiana	Utility	69.00	4	1953	61

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
324	Eagle Valley (H T Pritchard)	Indiana	Utility	69.00	5	1953	60
325	Eagle Valley (H T Pritchard)	Indiana	Utility	113.60	6	1956	57
326	Edwardsport	Indiana	Utility	618.00	IGCC	2013	0
327	F B Culley	Indiana	Utility	103.70	2	1966	47
328	F B Culley	Indiana	Utility	265.20	3	1973	40
329	Frank E Ratts	Indiana	Utility	116.60	1	1970	44
330	Frank E Ratts	Indiana	Utility	116.60	2	1970	44
331	Gibson Station	Indiana	Utility	667.90	1	1976	38
332	Gibson Station	Indiana	Utility	667.90	2	1975	39
333	Gibson Station	Indiana	Utility	667.90	3	1978	36
334	Gibson Station	Indiana	Utility	667.90	4	1979	35
335	Gibson Station	Indiana	Utility	667.90	5	1982	31
336	Harding Street	Indiana	Utility	113.50	5	1958	55
337	Harding Street	Indiana	Utility	113.60	6	1961	53
338	Harding Street	Indiana	Utility	470.90	7	1973	40
339	Jasper 2	Indiana	Utility	14.50	1	1968	45
340	Logansport	Indiana	Utility	18.00	4	1958	56
341	Logansport	Indiana	Utility	25.00	5	1964	50
342	Merom	Indiana	Utility	540.00	1	1983	30
343	Merom	Indiana	Utility	540.00	2	1982	32
344	Michigan City	Indiana	Utility	540.00	12	1974	40
345	Perry K	Indiana	IPP	15.00	4	1925	89
346	Perry K	Indiana	IPP	5.00	6	1938	75
347	Peru (IN)	Indiana	Utility	22.00	2	1959	55
348	Peru (IN)	Indiana	Utility	12.50	3	1949	64
349	R Gallagher	Indiana	Utility	150.00	2	1958	55
350	R Gallagher	Indiana	Utility	150.00	4	1961	53
351	R M Schahfer	Indiana	Utility	540.00	14	1976	37
352	R M Schahfer	Indiana	Utility	556.40	15	1979	34
353	R M Schahfer	Indiana	Utility	423.50	17	1983	31
354	R M Schahfer	Indiana	Utility	423.50	18	1986	28
355	Rockport	Indiana	Utility	1,300.00	1	1984	29
356	Rockport	Indiana	Utility	1,300.00	2	1989	24
357	Sabic Innovative Plastics Mt Vernon	Indiana	Industrial	5.50	1	1996	17
358	Sagamore Plant Cogeneration	Indiana	Industrial	7.40	GEN1	1984	29
359	Tanners Creek	Indiana	Utility	152.50	1	1951	63
360	Tanners Creek	Indiana	Utility	152.50	2	1952	61
361	Tanners Creek	Indiana	Utility	215.40	3	1954	59
362	Tanners Creek	Indiana	Utility	579.70	4	1964	49
363	Univ of Notre Dame	Indiana	Commercial	3.00	GEN1	1962	51
364	Univ of Notre Dame	Indiana	Commercial	1.70	GEN2	1952	61
365	Univ of Notre Dame	Indiana	Commercial	2.00	GEN5	1956	57
366	Univ of Notre Dame	Indiana	Commercial	5.00	GEN6	1967	47
367	Univ of Notre Dame	Indiana	Commercial	9.40	GEN7	2000	14
368	Wabash River	Indiana	Utility	112.50	2	1953	60
369	Wabash River	Indiana	Utility	123.20	3	1954	59
370	Wabash River	Indiana	Utility	112.50	4	1955	59
371	Wabash River	Indiana	Utility	125.00	5	1956	58
372	Wabash River	Indiana	Utility	387.00	6	1968	45
373	Wabash River	Indiana	Utility	304.50	IGCC	1995	18
374	Wade Power Plant	Indiana	Commercial	30.80	GEN1	1995	18
375	Wade Power Plant	Indiana	Commercial	10.60	GEN2	1969	45
376	Warrick	Indiana	IPP	166.60	1	1960	54
377	Warrick	Indiana	IPP	144.00	2	1964	50
378	Warrick	Indiana	IPP	144.00	3	1965	48
379	Warrick	Indiana	IPP	323.00	4	1970	43
380	Whitewater Valley	Indiana	Utility	33.00	1	1955	59
381	Whitewater Valley	Indiana	Utility	60.90	2	1973	40
382	Ag Processing Inc	Iowa	Industrial	8.50	EC	1982	32
383	Ames Electric Services Power Plant (Ia Ames)	Iowa	Utility	37.50	7	1968	46
384	Ames Electric Services Power Plant (Ia Ames)	Iowa	Utility	71.30	8	1982	32
385	Archer Daniels Midland Cedar Rapids	Iowa	Industrial	31.00	GEN1	1988	25
386	Archer Daniels Midland Cedar Rapids	Iowa	Industrial	31.00	GEN2	1988	25
387	Archer Daniels Midland Cedar Rapids	Iowa	Industrial	31.00	GEN3	1988	25
388	Archer Daniels Midland Cedar Rapids	Iowa	Industrial	31.00	GEN4	1988	25
389	Archer Daniels Midland Cedar Rapids	Iowa	Industrial	31.00	GEN5	1995	19

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
390	Archer Daniels Midland Cedar Rapids	Iowa	Industrial	101.10	GEN6	2000	13
391	Burlington (IA)	Iowa	Utility	212.00	1	1968	45
392	Cargill Inc Corn Milling Divis	Iowa	Industrial	20.00	GEN1	1952	61
393	Cargill Inc Corn Milling Divis	Iowa	Industrial	20.00	GEN2	1952	61
394	Clinton (IA ADM)	Iowa	Industrial	75.00	CFB1	2009	5
395	Clinton (IA ADM)	Iowa	Industrial	105.00	CFB2	2009	5
396	Des Moines (IA ADM)	Iowa	Industrial	7.90	GEN1	1988	26
397	Dubuque	Iowa	Utility	15.00	ST2	1929	85
398	Earl F Wisdom	Iowa	Utility	33.00	ST1	1960	54
399	Fair Station	Iowa	Utility	25.00	1	1960	54
400	Fair Station	Iowa	Utility	37.50	2	1967	47
401	George Neal North	Iowa	Utility	147.00	1	1964	50
402	George Neal North	Iowa	Utility	349.20	2	1972	42
403	George Neal North	Iowa	Utility	549.80	3	1975	39
404	George Neal South	Iowa	Utility	640.00	4	1979	34
405	Iowa State Univ	Iowa	Commercial	13.20	GEN3	1978	35
406	Iowa State Univ	Iowa	Commercial	6.20	GEN4	1960	53
407	Iowa State Univ	Iowa	Commercial	11.50	GEN5	1970	44
408	Iowa State Univ	Iowa	Commercial	15.10	GEN6	2005	9
409	Lansing	Iowa	Utility	37.50	3	1957	57
410	Lansing	Iowa	Utility	274.50	4	1977	37
411	Louisa	Iowa	Utility	811.90	1	1983	30
412	M L Kapp	Iowa	Utility	218.50	2	1967	47
413	Mt Pleasant	Iowa	Utility	3.00	4	1949	65
414	Muscatine	Iowa	Utility	25.00	7	1958	56
415	Muscatine	Iowa	Utility	75.00	8	1969	45
416	Muscatine	Iowa	Utility	175.50	9	1983	31
417	Muscatine	Iowa	Utility	18.00	8A	2000	13
418	Ottumwa (IA IPL)	Iowa	Utility	725.90	1	1981	33
419	Prairie Creek 1 4	Iowa	Utility	50.00	3	1958	55
420	Prairie Creek 1 4	Iowa	Utility	148.80	4	1967	47
421	Prairie Creek 1 4	Iowa	Utility	14.60	1A	1997	17
422	Riverside (IA)	Iowa	Utility	136.00	5	1961	52
423	Riverside (IA)	Iowa	Utility	5.00	3HS	1949	65
424	Streeter	Iowa	Utility	16.50	6	1963	50
425	Streeter	Iowa	Utility	35.00	7	1973	40
426	Univ of Iowa Main	Iowa	Commercial	3.00	GEN1	1947	67
427	Univ of Iowa Main	Iowa	Commercial	3.00	GEN2	1956	58
428	Univ of Iowa Main	Iowa	Commercial	15.00	GEN6	1974	40
429	Univ of Northern Iowa	Iowa	Commercial	7.50	GEN1	1982	31
430	Walter Scott Jr Energy Center	Iowa	Utility	49.00	ST1	1954	60
431	Walter Scott Jr Energy Center	Iowa	Utility	81.60	ST2	1958	55
432	Walter Scott Jr Energy Center	Iowa	Utility	725.80	ST3	1978	35
433	Walter Scott Jr Energy Center	Iowa	Utility	922.50	ST4	2007	6
434	Holcomb East	Kansas	Utility	348.70	1	1983	30
435	Jeffrey Energy Center	Kansas	Utility	720.00	1	1978	35
436	Jeffrey Energy Center	Kansas	Utility	720.00	2	1980	34
437	Jeffrey Energy Center	Kansas	Utility	720.00	3	1983	31
438	La Cygne	Kansas	Utility	893.00	1	1973	40
439	La Cygne	Kansas	Utility	685.00	2	1977	37
440	Lawrence Energy Center (KS)	Kansas	Utility	49.00	3	1955	59
441	Lawrence Energy Center (KS)	Kansas	Utility	114.00	4	1960	54
442	Lawrence Energy Center (KS)	Kansas	Utility	403.00	5	1971	43
443	Nearman Creek	Kansas	Utility	261.00	ST1	1981	32
444	Quindaro	Kansas	Utility	81.60	ST1	1965	49
445	Quindaro	Kansas	Utility	157.50	ST2	1971	42
446	Riverton	Kansas	Utility	37.50	7	1950	63
447	Riverton	Kansas	Utility	50.00	8	1954	59
448	Tecumseh Energy Center	Kansas	Utility	82.00	7	1957	56
449	Tecumseh Energy Center	Kansas	Utility	150.00	8	1962	52
450	Big Sandy	Kentucky	Utility	280.50	1	1963	51
451	Big Sandy	Kentucky	Utility	816.30	2	1969	44
452	Cane Run	Kentucky	Utility	163.20	4	1962	52
453	Cane Run	Kentucky	Utility	209.40	5	1966	48
454	Cane Run	Kentucky	Utility	272.00	6	1969	45
455	D B Wilson	Kentucky	Utility	566.10	UN1	1984	29

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
456	Dale (KY)	Kentucky	Utility	27.00	1	1954	59
457	Dale (KY)	Kentucky	Utility	27.00	2	1954	59
458	Dale (KY)	Kentucky	Utility	81.00	3	1957	56
459	Dale (KY)	Kentucky	Utility	81.00	4	1960	53
460	E W Brown	Kentucky	Utility	113.60	1	1957	57
461	E W Brown	Kentucky	Utility	179.50	2	1963	50
462	E W Brown	Kentucky	Utility	464.00	3	1971	42
463	East Bend	Kentucky	Utility	669.30	2	1981	33
464	Elmer Smith	Kentucky	Utility	163.20	1	1964	50
465	Elmer Smith	Kentucky	Utility	282.10	2	1974	40
466	Ghent	Kentucky	Utility	556.90	1	1974	40
467	Ghent	Kentucky	Utility	556.30	2	1977	37
468	Ghent	Kentucky	Utility	556.50	3	1981	33
469	Ghent	Kentucky	Utility	556.20	4	1984	29
470	Green River (KY)	Kentucky	Utility	75.00	3	1954	60
471	Green River (KY)	Kentucky	Utility	113.60	4	1959	54
472	HMP & L Station 2	Kentucky	Utility	200.00	GEN1	1973	40
473	HMP & L Station 2	Kentucky	Utility	205.00	GEN2	1974	40
474	Hugh L Spurlock	Kentucky	Utility	357.60	1	1977	36
475	Hugh L Spurlock	Kentucky	Utility	592.10	2	1981	33
476	Hugh L Spurlock	Kentucky	Utility	329.40	3	2005	9
477	Hugh L Spurlock	Kentucky	Utility	329.40	4	2009	5
478	J Sherman Cooper	Kentucky	Utility	113.60	1	1965	49
479	J Sherman Cooper	Kentucky	Utility	230.40	2	1969	44
480	Kenneth Coleman	Kentucky	Utility	205.00	GEN1	1969	44
481	Kenneth Coleman	Kentucky	Utility	205.00	GEN2	1970	43
482	Kenneth Coleman	Kentucky	Utility	192.00	GEN3	1971	42
483	Mill Creek (KY)	Kentucky	Utility	355.50	1	1972	41
484	Mill Creek (KY)	Kentucky	Utility	355.50	2	1974	39
485	Mill Creek (KY)	Kentucky	Utility	462.60	3	1978	35
486	Mill Creek (KY)	Kentucky	Utility	543.60	4	1982	31
487	Paradise (KY)	Kentucky	Utility	704.00	1	1963	50
488	Paradise (KY)	Kentucky	Utility	704.00	2	1963	51
489	Paradise (KY)	Kentucky	Utility	1,150.20	3	1970	44
490	R A Reid	Kentucky	Utility	96.00	GEN1	1966	48
491	Robert D Green	Kentucky	Utility	293.00	GEN1	1979	34
492	Robert D Green	Kentucky	Utility	293.00	GEN2	1981	33
493	Shawnee (KY)	Kentucky	Utility	175.00	1	1953	61
494	Shawnee (KY)	Kentucky	Utility	175.00	2	1953	60
495	Shawnee (KY)	Kentucky	Utility	175.00	3	1953	60
496	Shawnee (KY)	Kentucky	Utility	175.00	4	1954	60
497	Shawnee (KY)	Kentucky	Utility	175.00	5	1954	59
498	Shawnee (KY)	Kentucky	Utility	175.00	6	1954	59
499	Shawnee (KY)	Kentucky	Utility	175.00	7	1954	59
500	Shawnee (KY)	Kentucky	Utility	175.00	8	1955	59
501	Shawnee (KY)	Kentucky	Utility	175.00	9	1955	58
502	Shawnee (KY)	Kentucky	Utility	175.00	10	1956	57
503	Trimble Station (LGE)	Kentucky	Utility	566.10	1	1990	23
504	Trimble Station (LGE)	Kentucky	Utility	834.00	ST2	2010	3
505	Big Cajun 2	Louisiana	IPP	626.00	ST1	1981	32
506	Big Cajun 2	Louisiana	IPP	626.00	ST2	1982	31
507	Big Cajun 2	Louisiana	IPP	619.00	ST3	1983	31
508	Brame Energy Center	Louisiana	Utility	558.00	2	1982	31
509	Dolet Hills	Louisiana	Utility	720.70	1	1986	28
510	Roy S Nelson	Louisiana	Utility	614.60	6	1982	32
511	Brandon	Manitoba	Utility	105.00	5	1970	43
512	AES Warrior Run Cogeneration F	Maryland	IPP	229.00	GEN1	1999	14
513	Brandon Shores	Maryland	IPP	685.00	1	1984	30
514	Brandon Shores	Maryland	IPP	685.00	2	1991	23
515	C P Crane	Maryland	IPP	190.40	1	1961	52
516	C P Crane	Maryland	IPP	209.40	2	1963	51
517	Chalk Point	Maryland	IPP	364.00	ST1	1964	49
518	Chalk Point	Maryland	IPP	364.00	ST2	1965	49
519	Dickerson	Maryland	IPP	196.00	2	1960	54
520	Dickerson	Maryland	IPP	196.00	3	1962	52
521	Dickerson	Maryland	IPP	196.00	ST1	1959	54

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
522	Goddard Steam Plant	Maryland	Commercial	6.20	ST1	1957	56
523	Goddard Steam Plant	Maryland	Commercial	6.20	ST2	1957	56
524	Herbert A Wagner	Maryland	IPP	136.00	2	1959	55
525	Herbert A Wagner	Maryland	IPP	359.00	3	1966	47
526	Luke Mill	Maryland	Industrial	35.00	GEN1	1958	56
527	Luke Mill	Maryland	Industrial	30.00	GEN2	1979	35
528	Morgantown Generating Station	Maryland	IPP	626.00	ST1	1970	43
529	Morgantown Generating Station	Maryland	IPP	626.00	ST2	1971	42
530	Brayton PT	Massachusetts	IPP	241.00	GEN1	1963	50
531	Brayton PT	Massachusetts	IPP	241.00	GEN2	1964	49
532	Brayton PT	Massachusetts	IPP	672.60	GEN3	1958	55
533	Indian Orchard 1	Massachusetts	Industrial	5.70	TG	1985	29
534	Mount Tom	Massachusetts	IPP	136.00	1	1960	54
535	Salem Harbor	Massachusetts	IPP	165.70	GEN3	1958	55
536	B C Cobb	Michigan	Utility	156.30	4	1956	57
537	B C Cobb	Michigan	Utility	156.30	5	1957	57
538	Belle River	Michigan	Utility	697.50	ST1	1984	29
539	Belle River	Michigan	Utility	697.50	ST2	1985	28
540	Cargill Salt Inc	Michigan	Industrial	2.00	ACTG	1968	46
541	D E Karn	Michigan	Utility	272.00	1	1959	54
542	D E Karn	Michigan	Utility	272.00	2	1961	53
543	E B Eddy Paper	Michigan	Industrial	5.00	3TU	1969	44
544	Eckert Station	Michigan	Utility	44.00	1	1954	59
545	Eckert Station	Michigan	Utility	44.00	2	1958	55
546	Eckert Station	Michigan	Utility	47.00	3	1960	53
547	Eckert Station	Michigan	Utility	80.00	4	1964	49
548	Eckert Station	Michigan	Utility	80.00	5	1968	45
549	Eckert Station	Michigan	Utility	80.00	6	1970	43
550	Endicott Generating	Michigan	Utility	55.00	1	1982	31
551	Erickson	Michigan	Utility	154.70	1	1973	41
552	Escanaba	Michigan	Utility	11.50	1	1958	56
553	Escanaba	Michigan	Utility	11.50	2	1958	56
554	GM WFG Pontiac	Michigan	IPP	28.90	GEN1	1987	26
555	Harbor Beach	Michigan	Utility	121.00	1	1968	46
556	J B Simms	Michigan	Utility	80.00	3	1983	30
557	J C Weadock	Michigan	Utility	156.30	7	1955	59
558	J C Weadock	Michigan	Utility	156.30	8	1958	56
559	J H Campbell	Michigan	Utility	265.20	1	1962	51
560	J H Campbell	Michigan	Utility	403.90	2	1967	46
561	J H Campbell	Michigan	Utility	916.80	3	1980	33
562	J R Whiting	Michigan	Utility	106.30	1	1952	61
563	J R Whiting	Michigan	Utility	106.30	2	1952	61
564	J R Whiting	Michigan	Utility	132.80	3	1953	60
565	James de Young	Michigan	Utility	11.50	3	1951	63
566	James de Young	Michigan	Utility	22.00	4	1962	52
567	James de Young	Michigan	Utility	29.30	5	1969	44
568	Kimberly Clark Corp Munising M	Michigan	Industrial	6.20	M387	1930	84
569	Louisiana Pacific Corp	Michigan	Industrial	7.50	GEN1	1957	56
570	Mead Paper	Michigan	Industrial	27.20	NO7	1969	45
571	Mead Paper	Michigan	Industrial	54.00	NO9	1982	32
572	Menominee Aquisition Corp	Michigan	Industrial	1.50	ST1	1962	51
573	Menominee Aquisition Corp	Michigan	Industrial	2.50	ST2	1950	63
574	Monroe (MI)	Michigan	Utility	817.20	1	1971	42
575	Monroe (MI)	Michigan	Utility	822.60	2	1973	41
576	Monroe (MI)	Michigan	Utility	822.60	3	1973	41
577	Monroe (MI)	Michigan	Utility	817.20	4	1974	40
578	MSC Croswell	Michigan	Industrial	1.30	ST	1948	65
579	MSC Sebewaing	Michigan	Industrial	1.00	ST1	1979	34
580	MSC Sebewaing	Michigan	Industrial	1.50	ST2	1990	23
581	Pca Filer City Mill	Michigan	Industrial	8.00	TG2	1950	64
582	Pca Filer City Mill	Michigan	Industrial	11.50	TG3	1950	64
583	Presque Isle	Michigan	Utility	90.00	5	1974	39
584	Presque Isle	Michigan	Utility	90.00	6	1975	39
585	Presque Isle	Michigan	Utility	90.00	7	1978	35
586	Presque Isle	Michigan	Utility	90.00	8	1978	35
587	Presque Isle	Michigan	Utility	90.00	9	1979	34

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
588	River Rouge	Michigan	Utility	292.50	2	1957	56
589	River Rouge	Michigan	Utility	358.10	3	1958	55
590	Shiras	Michigan	Utility	12.50	1	1967	47
591	Shiras	Michigan	Utility	21.00	2	1972	42
592	Shiras	Michigan	Utility	44.00	3	1983	31
593	St Clair	Michigan	Utility	168.70	1	1953	60
594	St Clair	Michigan	Utility	156.20	2	1953	60
595	St Clair	Michigan	Utility	156.20	3	1954	59
596	St Clair	Michigan	Utility	168.70	4	1954	59
597	St Clair	Michigan	Utility	352.70	6	1961	53
598	St Clair	Michigan	Utility	544.50	7	1969	45
599	T B Simon Power Plant	Michigan	Commercial	12.50	GEN1	1965	48
600	T B Simon Power Plant	Michigan	Commercial	12.50	GEN2	1966	47
601	T B Simon Power Plant	Michigan	Commercial	15.00	GEN3	1974	39
602	T B Simon Power Plant	Michigan	Commercial	21.00	GEN4	1993	20
603	T B Simon Power Plant	Michigan	Commercial	24.00	GEN5	2006	8
604	Tes Filer City Station	Michigan	IPP	70.00	GEN1	1990	24
605	Trenton Channel	Michigan	Utility	120.00	7	1949	64
606	Trenton Channel	Michigan	Utility	120.00	8	1950	64
607	Trenton Channel	Michigan	Utility	535.50	9	1968	46
608	White Pine Electric Power, LLC	Michigan	IPP	20.00	GEN1	1954	59
609	White Pine Electric Power, LLC	Michigan	IPP	20.00	GEN2	1954	59
610	White Pine Electric Power, LLC	Michigan	IPP	20.00	GEN3	1954	59
611	Wyandotte (MI)	Michigan	Utility	11.50	4	1948	66
612	Wyandotte (MI)	Michigan	Utility	32.00	7	1986	27
613	ACS Crookston	Minnesota	Industrial	3.50	G1	1954	59
614	ACS Crookston	Minnesota	Industrial	3.00	G2	1975	38
615	ACS East Grand Forks	Minnesota	Industrial	2.50	G1	1990	23
616	ACS East Grand Forks	Minnesota	Industrial	5.00	G2	1990	23
617	ACS Moorhead	Minnesota	Industrial	3.00	G1	1948	65
618	ACS Moorhead	Minnesota	Industrial	2.00	G2	1961	52
619	Allen S King Plant	Minnesota	Utility	658.40	1	1958	56
620	Archer Daniels Midland Mankato	Minnesota	Industrial	6.10	GEN1	1987	26
621	Black Dog	Minnesota	Utility	113.60	3	1955	58
622	Black Dog	Minnesota	Utility	179.50	4	1960	53
623	Clay Boswell	Minnesota	Utility	75.00	1	1958	55
624	Clay Boswell	Minnesota	Utility	75.00	2	1960	54
625	Clay Boswell	Minnesota	Utility	364.50	3	1973	41
626	Clay Boswell	Minnesota	Utility	558.00	4	1980	34
627	Hibbing	Minnesota	Utility	10.00	3	1965	49
628	Hibbing	Minnesota	Utility	19.50	5	1985	28
629	Hibbing	Minnesota	Utility	6.40	6	1996	18
630	Hoot Lake	Minnesota	Utility	54.40	2	1959	54
631	Hoot Lake	Minnesota	Utility	75.00	3	1964	50
632	Potlatch (Crow Wing)	Minnesota	Industrial	0.60	VPLS	1959	55
633	Sherburne County	Minnesota	Utility	765.30	1	1976	38
634	Sherburne County	Minnesota	Utility	765.30	2	1977	37
635	Sherburne County	Minnesota	Utility	950.00	3	1987	26
636	Silver Bay Power Co	Minnesota	Industrial	50.00	GEN1	1955	58
637	Silver Bay Power Co	Minnesota	Industrial	81.60	GEN2	1962	52
638	Silver Lake (MN)	Minnesota	Utility	8.00	1	1948	65
639	Silver Lake (MN)	Minnesota	Utility	12.00	2	1953	60
640	Silver Lake (MN)	Minnesota	Utility	25.00	3	1962	51
641	Silver Lake (MN)	Minnesota	Utility	54.00	4	1969	44
642	Southern Minnesota Beet Sugar	Minnesota	Industrial	7.50	1	1976	37
643	Syl Laskin	Minnesota	Utility	58.00	1	1953	60
644	Syl Laskin	Minnesota	Utility	58.00	2	1953	60
645	Taconite Harbor Energy Center	Minnesota	Utility	84.00	GEN1	1957	57
646	Taconite Harbor Energy Center	Minnesota	Utility	84.00	GEN2	1957	57
647	Taconite Harbor Energy Center	Minnesota	Utility	84.00	GEN3	1967	47
648	Virginia	Minnesota	Utility	7.50	5	1954	59
649	Virginia	Minnesota	Utility	18.70	6	1971	42
650	Virginia	Minnesota	Utility	4.00	1A	1992	21
651	Willmar	Minnesota	Utility	18.00	3	1970	43
652	Willmar	Minnesota	Utility	2.00	4	2010	4
653	Willmar	Minnesota	Utility	2.00	5	2010	4

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
654	Jack Watson	Mississippi	Utility	299.20	4	1968	45
655	Jack Watson	Mississippi	Utility	578.00	5	1973	41
656	R D Morrow	Mississippi	Utility	200.00	1	1978	36
657	R D Morrow	Mississippi	Utility	200.00	2	1978	35
658	Red Hills Generating Facility	Mississippi	IPP	513.70	RHGF	2002	12
659	Victor J Daniel Jr	Mississippi	Utility	548.30	1	1977	36
660	Victor J Daniel Jr	Mississippi	Utility	548.30	2	1981	32
661	Anheuser Busch Inc St Louis	Missouri	Industrial	11.00	GEN1	1947	67
662	Anheuser Busch Inc St Louis	Missouri	Industrial	11.00	GEN3	1948	66
663	Anheuser Busch Inc St Louis	Missouri	Industrial	4.10	GEN4	1939	75
664	Asbury	Missouri	Utility	212.80	1	1970	43
665	Asbury	Missouri	Utility	18.70	2	1986	28
666	Blue Valley	Missouri	Utility	25.00	2	1958	56
667	Blue Valley	Missouri	Utility	65.00	3	1965	48
668	Blue Valley	Missouri	Utility	25.00	ST1	1958	56
669	Columbia (MO CLMBIA)	Missouri	Utility	16.50	5	1957	57
670	Columbia (MO CLMBIA)	Missouri	Utility	22.00	7	1965	49
671	GM Wentzville Assembly & Contiguous	Missouri	Industrial	3.00	ST1	1981	32
672	Grand Avenue Steam Plant	Missouri	IPP	5.00	ST	1998	16
673	Hawthorne (MO)	Missouri	Utility	594.30	5	1969	45
674	Iatan	Missouri	Utility	726.00	1	1980	34
675	Iatan	Missouri	Utility	914.00	2	2010	3
676	James River Power St	Missouri	Utility	22.00	1	1957	56
677	James River Power St	Missouri	Utility	22.00	2	1957	56
678	James River Power St	Missouri	Utility	44.00	3	1960	54
679	James River Power St	Missouri	Utility	60.00	4	1964	50
680	James River Power St	Missouri	Utility	105.00	5	1970	44
681	Labadie	Missouri	Utility	573.70	1	1970	43
682	Labadie	Missouri	Utility	573.70	2	1971	42
683	Labadie	Missouri	Utility	621.00	3	1972	41
684	Labadie	Missouri	Utility	621.00	4	1973	40
685	Lake Road (MO)	Missouri	Utility	90.00	4	1966	47
686	Marshall (MO)	Missouri	Utility	6.00	4	1956	57
687	Marshall (MO)	Missouri	Utility	16.50	5	1967	46
688	Meramec	Missouri	Utility	137.50	1	1953	61
689	Meramec	Missouri	Utility	137.50	2	1954	59
690	Meramec	Missouri	Utility	289.00	3	1959	55
691	Meramec	Missouri	Utility	359.00	4	1961	52
692	Missouri City	Missouri	Utility	23.00	1	1954	59
693	Missouri City	Missouri	Utility	23.00	2	1954	59
694	Montrose	Missouri	Utility	188.00	1	1958	55
695	Montrose	Missouri	Utility	188.00	2	1960	54
696	Montrose	Missouri	Utility	188.00	3	1964	50
697	New Madrid (Memphis)	Missouri	Utility	600.00	1	1972	41
698	New Madrid (Memphis)	Missouri	Utility	600.00	2	1977	36
699	Rush Island	Missouri	Utility	621.00	1	1976	38
700	Rush Island	Missouri	Utility	621.00	2	1977	37
701	Sibley (MO)	Missouri	Utility	55.00	1	1960	53
702	Sibley (MO)	Missouri	Utility	50.00	2	1962	52
703	Sibley (MO)	Missouri	Utility	419.00	3	1969	44
704	Sikeston	Missouri	Utility	261.00	1	1981	32
705	Sioux	Missouri	Utility	549.70	1	1967	47
706	Sioux	Missouri	Utility	549.70	2	1968	46
707	Southwest	Missouri	Utility	194.00	ST1	1976	37
708	Southwest	Missouri	Utility	300.00	ST2	2011	3
709	Thomas Hill	Missouri	Utility	180.00	1	1966	47
710	Thomas Hill	Missouri	Utility	285.00	2	1969	45
711	Thomas Hill	Missouri	Utility	670.00	3	1982	31
712	Centennial Hardin (MT)	Montana	IPP	115.70	ST1	2006	8
713	Colstrip	Montana	IPP	358.00	GEN1	1975	38
714	Colstrip	Montana	IPP	358.00	GEN2	1976	37
715	Colstrip	Montana	IPP	778.00	GEN3	1984	30
716	Colstrip	Montana	IPP	778.00	GEN4	1986	28
717	J E Corette Plant	Montana	IPP	172.80	GEN1	1968	45
718	Lewis & Clark	Montana	Utility	50.00	1	1958	55
719	Sidney MT Plant	Montana	Industrial	2.00	ST1	1950	63

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
720	Sidney MT Plant	Montana	Industrial	2.00	ST2	1950	63
721	Thompson River	Montana	IPP	16.00	ST1	2004	9
722	Adm Columbus Cogeneration	Nebraska	Industrial	71.40	ST	2010	3
723	Gerald Gentleman	Nebraska	Utility	681.30	1	1979	35
724	Gerald Gentleman	Nebraska	Utility	681.30	2	1982	32
725	Lincoln (NE)	Nebraska	Industrial	7.90	GEN1	1988	25
726	Lon Wright	Nebraska	Utility	16.50	6	1957	56
727	Lon Wright	Nebraska	Utility	22.00	7	1963	50
728	Lon Wright	Nebraska	Utility	91.50	8	1977	37
729	Nebraska City	Nebraska	Utility	651.60	1	1979	35
730	Nebraska City	Nebraska	Utility	738.00	2	2009	5
731	North Omaha	Nebraska	Utility	73.50	1	1954	59
732	North Omaha	Nebraska	Utility	108.80	2	1957	57
733	North Omaha	Nebraska	Utility	108.80	3	1959	55
734	North Omaha	Nebraska	Utility	136.00	4	1963	51
735	North Omaha	Nebraska	Utility	217.60	5	1968	46
736	Platte	Nebraska	Utility	109.80	1	1982	31
737	Scottsbluff Western Sugar	Nebraska	Industrial	5.00	ST	1987	26
738	Sheldon (NE)	Nebraska	Utility	108.80	1	1961	53
739	Sheldon (NE)	Nebraska	Utility	119.90	2	1965	49
740	Whelan Energy Center	Nebraska	Utility	76.30	1	1981	32
741	Whelan Energy Center	Nebraska	Utility	248.00	2	2011	2
742	North Valmy	Nevada	Utility	277.20	1	1981	32
743	North Valmy	Nevada	Utility	289.80	2	1985	29
744	Reid Gardner	Nevada	Utility	114.00	1	1965	48
745	Reid Gardner	Nevada	Utility	114.00	2	1968	45
746	Reid Gardner	Nevada	Utility	114.00	3	1976	38
747	Reid Gardner	Nevada	Utility	294.80	4	1983	30
748	TS Power Plant	Nevada	IPP	242.00	ST	2008	5
749	Belledune	New Brunswick	Utility	510.00	1	1993	20
750	Merrimack	New Hampshire	Utility	113.60	1	1960	53
751	Merrimack	New Hampshire	Utility	345.60	2	1968	46
752	Schiller	New Hampshire	Utility	50.00	4	1952	61
753	Schiller	New Hampshire	Utility	50.00	6	1957	56
754	B L England	New Jersey	IPP	136.00	1	1962	51
755	B L England	New Jersey	IPP	163.20	2	1964	49
756	Carneys Point Generating Plant	New Jersey	IPP	285.00	GEN1	1993	20
757	Hudson Generating Station	New Jersey	IPP	659.70	2	1968	45
758	Logan Generating Plant	New Jersey	IPP	242.30	GEN1	1994	19
759	Mercer Generating Station	New Jersey	IPP	326.40	1	1960	53
760	Mercer Generating Station	New Jersey	IPP	326.40	2	1961	52
761	Escalante	New Mexico	Utility	257.00	1	1984	29
762	Four Corners	New Mexico	Utility	190.00	1	1963	51
763	Four Corners	New Mexico	Utility	190.00	2	1963	50
764	Four Corners	New Mexico	Utility	253.40	3	1964	49
765	Four Corners	New Mexico	Utility	818.10	4	1969	44
766	Four Corners	New Mexico	Utility	818.10	5	1970	43
767	San Juan Generating Station	New Mexico	Utility	369.00	1	1976	37
768	San Juan Generating Station	New Mexico	Utility	369.00	2	1973	40
769	San Juan Generating Station	New Mexico	Utility	555.00	3	1979	34
770	San Juan Generating Station	New Mexico	Utility	555.00	4	1982	32
771	AES Somerset LLC	New York	IPP	655.10	GEN1	1984	29
772	AES Westover	New York	IPP	75.00	8	1951	62
773	Cayuga Power Plant	New York	IPP	155.30	CAY1	1955	58
774	Cayuga Power Plant	New York	IPP	167.20	CAY2	1955	58
775	Dunkirk Generating Station	New York	IPP	96.00	DUN1	1950	63
776	Dunkirk Generating Station	New York	IPP	96.00	DUN2	1950	63
777	Huntley Generating	New York	IPP	218.00	67	1957	56
778	Huntley Generating	New York	IPP	218.00	S68	1958	55
779	Kodak Park Site	New York	Industrial	15.00	17TG	1968	45
780	Kodak Park Site	New York	Industrial	12.50	22TG	1954	59
781	Kodak Park Site	New York	Industrial	25.60	41TG	1964	50
782	Kodak Park Site	New York	Industrial	25.60	42TG	1967	46
783	Kodak Park Site	New York	Industrial	25.60	43TG	1969	45
784	Kodak Park Site	New York	Industrial	25.60	44TG	1987	26
785	Trigen Syracuse Energy Corp	New York	IPP	90.60	GEN1	1991	22

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
786	Trigen Syracuse Energy Corp	New York	IPP	10.50	GEN2	2002	11
787	Asheville	North Carolina	Utility	206.60	1	1964	50
788	Asheville	North Carolina	Utility	207.00	2	1971	43
789	Belews Creek	North Carolina	Utility	1,080.10	1	1974	39
790	Belews Creek	North Carolina	Utility	1,080.10	2	1975	38
791	Canton North Carolina	North Carolina	Industrial	7.50	GEN8	1937	77
792	Canton North Carolina	North Carolina	Industrial	7.50	GEN9	1941	73
793	Canton North Carolina	North Carolina	Industrial	7.50	GN10	1946	68
794	Canton North Carolina	North Carolina	Industrial	7.50	GN11	1949	65
795	Canton North Carolina	North Carolina	Industrial	10.00	GN12	1952	62
796	Canton North Carolina	North Carolina	Industrial	12.50	GN13	1979	34
797	James E Rogers Energy Complex	North Carolina	IPP	570.90	5	1972	41
798	James E Rogers Energy Complex	North Carolina	IPP	909.50	6	2012	1
799	Dwayne Collier Battle Cogeneration	North Carolina	IPP	57.40	GEN1	1990	23
800	Dwayne Collier Battle Cogeneration	North Carolina	IPP	57.40	GEN2	1990	23
801	Elizabethtown	North Carolina	IPP	34.70	GEN1	1985	28
802	G G Allen	North Carolina	Utility	165.00	1	1957	56
803	G G Allen	North Carolina	Utility	165.00	2	1957	56
804	G G Allen	North Carolina	Utility	275.00	3	1959	54
805	G G Allen	North Carolina	Utility	275.00	4	1960	53
806	G G Allen	North Carolina	Utility	275.00	5	1961	52
807	L V Sutton	North Carolina	Utility	112.50	1	1954	59
808	L V Sutton	North Carolina	Utility	112.50	2	1955	59
809	L V Sutton	North Carolina	Utility	446.60	3	1972	41
810	Lumberton	North Carolina	IPP	34.70	GEN1	1985	28
811	Marshall (NC DUKE)	North Carolina	Utility	350.00	1	1965	49
812	Marshall (NC DUKE)	North Carolina	Utility	350.00	2	1966	48
813	Marshall (NC DUKE)	North Carolina	Utility	648.00	3	1969	45
814	Marshall (NC DUKE)	North Carolina	Utility	648.00	4	1970	44
815	Mayo	North Carolina	Utility	735.80	1	1983	31
816	Miller Coors Eden LLC	North Carolina	Industrial	5.50	TRB1	1978	36
817	Roanoke Rapids North Carolina	North Carolina	Industrial	22.50	GEN1	1966	48
818	Roanoke Valley 1	North Carolina	IPP	182.30	GEN1	1994	20
819	Roanoke Valley II	North Carolina	IPP	57.80	GEN2	1995	19
820	Roxboro	North Carolina	Utility	410.80	1	1966	48
821	Roxboro	North Carolina	Utility	657.00	2	1968	46
822	Roxboro	North Carolina	Utility	745.20	3	1973	40
823	Roxboro	North Carolina	Utility	745.20	4	1980	33
824	UNC Chapel Hill Cogeneration	North Carolina	Commercial	28.00	TG3	1991	22
825	ACS Drayton	North Dakota	Industrial	6.00	G1	1965	48
826	ACS Hillsboro	North Dakota	Industrial	13.30	G1	1990	23
827	Antelope Valley	North Dakota	Utility	434.90	1	1984	29
828	Antelope Valley	North Dakota	Utility	434.90	2	1986	27
829	Coal Creek	North Dakota	Utility	604.80	1	1979	34
830	Coal Creek	North Dakota	Utility	604.80	2	1980	33
831	Coyote	North Dakota	Utility	450.00	1	1981	33
832	Heskett	North Dakota	Utility	40.00	1	1954	59
833	Heskett	North Dakota	Utility	75.00	2	1963	50
834	Hillsboro	North Dakota	Utility	13.30	1	1986	27
835	Leland Olds 1 & 2	North Dakota	Utility	216.00	1	1966	48
836	Leland Olds 1 & 2	North Dakota	Utility	440.00	2	1975	38
837	Milton R Young	North Dakota	Utility	257.00	ST1	1970	43
838	Milton R Young	North Dakota	Utility	477.00	ST2	1977	37
839	Stanton (ND)	North Dakota	Utility	190.20	1	1967	47
840	Lingan	Nova Scotia	Utility	150.40	1	1979	35
841	Lingan	Nova Scotia	Utility	150.40	2	1980	34
842	Lingan	Nova Scotia	Utility	150.40	3	1983	31
843	Lingan	Nova Scotia	Utility	150.40	4	1984	30
844	PT Tupper	Nova Scotia	Utility	150.00	2	1973	41
845	Trenton	Nova Scotia	Utility	160.00	6	1991	23
846	Trenton	Nova Scotia	Utility	150.00	5A	2009	4
847	Ashtabula	Ohio	IPP	256.00	5	1958	55
848	Avon Lake	Ohio	IPP	86.00	7	1949	65
849	Avon Lake	Ohio	IPP	680.00	9	1970	44
850	Cardinal	Ohio	Utility	615.20	1	1967	47
851	Cardinal	Ohio	Utility	615.20	2	1967	46

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
852	Cardinal	Ohio	Utility	650.00	3	1977	36
853	Chillicothe (OH)	Ohio	Industrial	27.20	T 13	1978	35
854	Conesville	Ohio	Utility	841.50	4	1973	40
855	Conesville	Ohio	Utility	443.90	5	1976	37
856	Conesville	Ohio	Utility	443.90	6	1978	35
857	Dover (OH)	Ohio	Utility	8.00	3	1954	60
858	Dover (OH)	Ohio	Utility	19.50	4	1968	45
859	Eastlake (OH)	Ohio	IPP	123.00	1	1953	60
860	Eastlake (OH)	Ohio	IPP	123.00	2	1953	60
861	Eastlake (OH)	Ohio	IPP	123.00	3	1954	59
862	Gavin	Ohio	Utility	1,300.00	1	1974	39
863	Gavin	Ohio	Utility	1,300.00	2	1975	38
864	Hamilton	Ohio	Utility	25.00	8	1965	48
865	Hamilton	Ohio	Utility	50.60	9	1975	38
866	Heat Plant 770	Ohio	Commercial	1.20	HP	2003	11
867	Heat Plant 770	Ohio	Commercial	0.80	LP	2003	11
868	Ivorydale	Ohio	Industrial	12.50	GEN1	1965	48
869	J M Stuart	Ohio	Utility	610.20	1	1971	43
870	J M Stuart	Ohio	Utility	610.20	2	1970	43
871	J M Stuart	Ohio	Utility	610.20	3	1972	42
872	J M Stuart	Ohio	Utility	610.20	4	1974	39
873	Killen Station	Ohio	Utility	660.60	2	1982	31
874	Kyger Creek	Ohio	Utility	217.30	1	1955	59
875	Kyger Creek	Ohio	Utility	217.30	2	1955	58
876	Kyger Creek	Ohio	Utility	217.30	3	1955	58
877	Kyger Creek	Ohio	Utility	217.30	4	1955	58
878	Kyger Creek	Ohio	Utility	217.30	5	1955	58
879	Lake Road (OH)	Ohio	Utility	25.00	8	1941	73
880	Lake Road (OH)	Ohio	Utility	25.00	9	1953	61
881	Lake Road (OH)	Ohio	Utility	25.00	10	1953	61
882	Lake Shore	Ohio	IPP	256.00	18	1962	51
883	Miami Fort	Ohio	Utility	163.20	6	1960	53
884	Miami Fort	Ohio	Utility	557.10	7	1975	39
885	Miami Fort	Ohio	Utility	557.70	8	1978	36
886	Millercoors Trenton Brewery	Ohio	Industrial	13.80	GE	1992	22
887	Millercoors Trenton Brewery	Ohio	Industrial	8.00	MURR	1992	22
888	Morton Salt Rittman	Ohio	Industrial	1.50	GEN1	1978	35
889	Muskingum River	Ohio	Utility	219.60	1	1953	60
890	Muskingum River	Ohio	Utility	219.60	2	1954	59
891	Muskingum River	Ohio	Utility	237.50	3	1957	56
892	Muskingum River	Ohio	Utility	237.50	4	1958	56
893	Muskingum River	Ohio	Utility	615.20	5	1968	45
894	O H Hutchings	Ohio	Utility	69.00	1	1948	65
895	O H Hutchings	Ohio	Utility	69.00	2	1949	65
896	O H Hutchings	Ohio	Utility	69.00	3	1950	63
897	O H Hutchings	Ohio	Utility	69.00	5	1952	61
898	O H Hutchings	Ohio	Utility	69.00	6	1953	60
899	Orrville	Ohio	Utility	5.00	7	1949	65
900	Orrville	Ohio	Utility	7.50	8	1955	59
901	Orrville	Ohio	Utility	22.00	9	1961	53
902	Orrville	Ohio	Utility	25.00	10	1971	43
903	Orrville	Ohio	Utility	25.00	11	1971	43
904	Painesville	Ohio	Utility	7.50	3	1953	61
905	Painesville	Ohio	Utility	16.50	5	1965	49
906	Painesville	Ohio	Utility	22.00	7	1990	24
907	Painesville	Ohio	Utility	7.50	ST2	1949	65
908	Picway	Ohio	Utility	106.20	5	1955	58
909	Rittman Paperboard	Ohio	Industrial	3.00	GEN1	1928	86
910	Rittman Paperboard	Ohio	Industrial	5.00	GEN2	1940	74
911	Rittman Paperboard	Ohio	Industrial	6.00	GEN3	1946	67
912	W H Sammis	Ohio	IPP	190.40	1	1959	54
913	W H Sammis	Ohio	IPP	190.40	2	1960	53
914	W H Sammis	Ohio	IPP	190.40	3	1961	52
915	W H Sammis	Ohio	IPP	190.40	4	1962	51
916	W H Sammis	Ohio	IPP	334.00	5	1967	46
917	W H Sammis	Ohio	IPP	680.00	6	1969	45

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
918	W H Sammis	Ohio	IPP	680.00	7	1971	42
919	W H Zimmer	Ohio	Utility	1,425.60	ST1	1991	23
920	Walter C Beckjord	Ohio	Utility	163.20	4	1958	55
921	Walter C Beckjord	Ohio	Utility	244.80	5	1962	51
922	Walter C Beckjord	Ohio	Utility	460.80	6	1969	44
923	Wausau Paper Middletown	Ohio	Industrial	7.50	G3	1986	28
924	AES Shady Point Inc	Oklahoma	IPP	175.00	GEN1	1990	23
925	AES Shady Point Inc	Oklahoma	IPP	175.00	GEN2	1990	23
926	Grda 1 & 2	Oklahoma	Utility	540.00	1	1981	32
927	Grda 1 & 2	Oklahoma	Utility	594.00	2	1985	28
928	Hugo (OK)	Oklahoma	Utility	446.00	ST 1	1982	32
929	Muskogee	Oklahoma	Utility	572.00	4	1977	36
930	Muskogee	Oklahoma	Utility	572.00	5	1978	35
931	Muskogee	Oklahoma	Utility	572.00	6	1984	29
932	Muskogee Mill	Oklahoma	Industrial	25.00	GEN1	1978	36
933	Muskogee Mill	Oklahoma	Industrial	44.50	GEN2	1979	35
934	Muskogee Mill	Oklahoma	Industrial	44.50	GEN3	1982	31
935	Northeastern	Oklahoma	Utility	473.00	3	1979	34
936	Northeastern	Oklahoma	Utility	473.00	4	1980	33
937	Sooner	Oklahoma	Utility	569.00	1	1979	34
938	Sooner	Oklahoma	Utility	569.00	2	1980	33
939	Lambton GS	Ontario	IPP	520.00	3	1969	45
940	Lambton GS	Ontario	IPP	520.00	4	1969	45
941	Nanticoke	Ontario	IPP	505.00	5	1973	41
942	Nanticoke	Ontario	IPP	505.00	6	1973	41
943	Nanticoke	Ontario	IPP	505.00	7	1973	41
944	Nanticoke	Ontario	IPP	505.00	8	1973	41
945	Thunder Bay GS	Ontario	IPP	165.00	2	1981	33
946	Thunder Bay GS	Ontario	IPP	165.00	3	1981	33
947	Boardman (OR)	Oregon	Utility	601.00	1	1980	33
948	AES Beaver Valley Partners Beaver Valley	Pennsylvania	IPP	35.00	GEN2	1987	26
949	AES Beaver Valley Partners Beaver Valley	Pennsylvania	IPP	114.00	GEN3	1987	26
950	Bruce Mansfield	Pennsylvania	IPP	913.70	1	1976	38
951	Bruce Mansfield	Pennsylvania	IPP	913.70	2	1977	36
952	Bruce Mansfield	Pennsylvania	IPP	913.70	3	1980	33
953	Cheswick Power Plant	Pennsylvania	IPP	637.00	1	1970	43
954	Conemaugh	Pennsylvania	IPP	936.00	1	1970	44
955	Conemaugh	Pennsylvania	IPP	936.00	2	1971	43
956	G F Weaton Power Station	Pennsylvania	Industrial	60.00	GEN1	1958	55
957	G F Weaton Power Station	Pennsylvania	Industrial	60.00	GEN2	1958	56
958	Homer City Station	Pennsylvania	IPP	660.00	1	1969	44
959	Homer City Station	Pennsylvania	IPP	660.00	2	1969	44
960	Homer City Station	Pennsylvania	IPP	692.00	3	1977	36
961	Juniata Locomotive Shop	Pennsylvania	Commercial	2.00	GEN1	1955	58
962	Juniata Locomotive Shop	Pennsylvania	Commercial	2.00	GEN2	1955	58
963	Keystone (PA)	Pennsylvania	IPP	936.00	1	1967	46
964	Keystone (PA)	Pennsylvania	IPP	936.00	2	1968	45
965	Marcus Hook	Pennsylvania	Other	17.50	1	1970	44
966	Montour	Pennsylvania	IPP	820.00	MT1	1972	42
967	Montour	Pennsylvania	IPP	833.00	MT2	1973	41
968	New Castle Plant	Pennsylvania	IPP	98.00	3	1952	61
969	New Castle Plant	Pennsylvania	IPP	114.00	4	1958	55
970	New Castle Plant	Pennsylvania	IPP	136.00	5	1964	49
971	P H Glatfelter Co	Pennsylvania	Industrial	6.00	GEN1	1948	65
972	P H Glatfelter Co	Pennsylvania	Industrial	5.90	GEN2	1975	39
973	P H Glatfelter Co	Pennsylvania	Industrial	5.10	GEN3	1948	66
974	P H Glatfelter Co	Pennsylvania	Industrial	7.50	GEN4	1962	51
975	P H Glatfelter Co	Pennsylvania	Industrial	45.90	GEN5	1989	25
976	Portland (PA)	Pennsylvania	IPP	172.00	1	1958	55
977	Portland (PA)	Pennsylvania	IPP	255.00	2	1962	51
978	PPL Brunner Island	Pennsylvania	IPP	363.30	BI1	1961	52
979	PPL Brunner Island	Pennsylvania	IPP	405.00	BI2	1965	48
980	PPL Brunner Island	Pennsylvania	IPP	790.40	BI3	1969	44
981	Shawville	Pennsylvania	IPP	125.00	1	1954	59
982	Shawville	Pennsylvania	IPP	125.00	2	1954	60
983	Shawville	Pennsylvania	IPP	188.00	3	1959	54

Appendix A-3
Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
984	Shawville	Pennsylvania	IPP	188.00	4	1960	54
985	Sunbury Generation LLC	Pennsylvania	IPP	89.10	U1	1949	64
986	Sunbury Generation LLC	Pennsylvania	IPP	89.10	U2	1949	64
987	Sunbury Generation LLC	Pennsylvania	IPP	103.50	U3	1951	63
988	Sunbury Generation LLC	Pennsylvania	IPP	156.20	U4	1953	60
989	Tyrone (PA)	Pennsylvania	Industrial	2.50	TG3	1929	85
990	Tyrone (PA)	Pennsylvania	Industrial	4.50	TG4	1930	84
991	Tyrone (PA)	Pennsylvania	Industrial	3.00	TG5	1936	78
992	Tyrone (PA)	Pennsylvania	Industrial	7.50	TG6	1958	56
993	West Campus Steam Plant	Pennsylvania	Commercial	2.50	WC 2	1938	76
994	West Campus Steam Plant	Pennsylvania	Commercial	3.50	WC 3	1949	65
995	Aurora (PR)	Puerto Rico	IPP	227.00	1	2002	11
996	Aurora (PR)	Puerto Rico	IPP	227.00	2	2002	11
997	Boundary Dam	Saskatchewan	Utility	66.00	1	1959	55
998	Boundary Dam	Saskatchewan	Utility	66.00	2	1960	54
999	Boundary Dam	Saskatchewan	Utility	150.00	4	1970	44
1000	Boundary Dam	Saskatchewan	Utility	150.00	5	1973	40
1001	Boundary Dam	Saskatchewan	Utility	292.50	6	1977	36
1002	Poplar River	Saskatchewan	Utility	307.80	1	1983	30
1003	Poplar River	Saskatchewan	Utility	315.00	2	1981	33
1004	Shand	Saskatchewan	Utility	297.80	1	1992	21
1005	Canadys Steam	South Carolina	Utility	136.00	2	1964	50
1006	Canadys Steam	South Carolina	Utility	217.60	3	1967	46
1007	Cogeneration South	South Carolina	Utility	99.20	1	1999	15
1008	Cope	South Carolina	Utility	417.30	ST1	1996	18
1009	Cross	South Carolina	Utility	590.90	1	1995	19
1010	Cross	South Carolina	Utility	556.20	2	1984	30
1011	Cross	South Carolina	Utility	591.00	3	2007	7
1012	Cross	South Carolina	Utility	652.00	4	2008	6
1013	May Plant	South Carolina	Industrial	5.50	GEN1	1952	62
1014	May Plant	South Carolina	Industrial	5.50	GEN2	1952	62
1015	May Plant	South Carolina	Industrial	19.00	GEN3	1993	20
1016	McMeekin	South Carolina	Utility	146.80	1	1958	55
1017	McMeekin	South Carolina	Utility	146.80	2	1958	55
1018	Sonoco Products Co (SC)	South Carolina	Industrial	28.00	4	1957	56
1019	W S Lee	South Carolina	Utility	90.00	1	1951	63
1020	W S Lee	South Carolina	Utility	90.00	2	1951	62
1021	W S Lee	South Carolina	Utility	175.00	3	1958	55
1022	Wateree	South Carolina	Utility	385.90	1	1970	43
1023	Wateree	South Carolina	Utility	385.90	2	1971	42
1024	Williams (SC SCGC)	South Carolina	Utility	632.70	WIL1	1973	40
1025	Winyah	South Carolina	Utility	315.00	1	1975	39
1026	Winyah	South Carolina	Utility	315.00	2	1977	36
1027	Winyah	South Carolina	Utility	315.00	3	1980	34
1028	Winyah	South Carolina	Utility	315.00	4	1981	32
1029	Ben French	South Dakota	Utility	25.00	ST1	1961	53
1030	Big Stone	South Dakota	Utility	456.00	ST1	1975	39
1031	Allen Steam Plant (TN)	Tennessee	Utility	330.00	1	1959	55
1032	Allen Steam Plant (TN)	Tennessee	Utility	330.00	2	1959	55
1033	Allen Steam Plant (TN)	Tennessee	Utility	330.00	3	1959	54
1034	Bull Run (TN)	Tennessee	Utility	950.00	1	1967	46
1035	Corn Wet Milling Plant	Tennessee	Industrial	25.00	GEN1	1985	29
1036	Cumberland (TN)	Tennessee	Utility	1,300.00	1	1973	41
1037	Cumberland (TN)	Tennessee	Utility	1,300.00	2	1973	40
1038	Gallatin (TN)	Tennessee	Utility	300.00	1	1956	57
1039	Gallatin (TN)	Tennessee	Utility	300.00	2	1957	56
1040	Gallatin (TN)	Tennessee	Utility	327.60	3	1959	55
1041	Gallatin (TN)	Tennessee	Utility	327.60	4	1959	54
1042	John Sevier	Tennessee	Utility	200.00	3	1956	58
1043	John Sevier	Tennessee	Utility	200.00	4	1957	56
1044	Johnsonville (TN)	Tennessee	Utility	125.00	1	1951	62
1045	Johnsonville (TN)	Tennessee	Utility	125.00	2	1951	62
1046	Johnsonville (TN)	Tennessee	Utility	125.00	3	1952	62
1047	Johnsonville (TN)	Tennessee	Utility	125.00	4	1952	62
1048	Johnsonville (TN)	Tennessee	Utility	147.00	5	1952	61
1049	Johnsonville (TN)	Tennessee	Utility	147.00	6	1953	61

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Age of Coal-Fired Units Currently in Service
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	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
1050	Johnsonville (TN)	Tennessee	Utility	172.80	7	1958	55
1051	Johnsonville (TN)	Tennessee	Utility	172.80	8	1959	55
1052	Johnsonville (TN)	Tennessee	Utility	172.80	9	1959	54
1053	Johnsonville (TN)	Tennessee	Utility	172.80	10	1959	54
1054	Kingston	Tennessee	Utility	175.00	1	1954	60
1055	Kingston	Tennessee	Utility	175.00	2	1954	60
1056	Kingston	Tennessee	Utility	175.00	3	1954	59
1057	Kingston	Tennessee	Utility	175.00	4	1954	59
1058	Kingston	Tennessee	Utility	200.00	5	1955	59
1059	Kingston	Tennessee	Utility	200.00	6	1955	59
1060	Kingston	Tennessee	Utility	200.00	7	1955	59
1061	Kingston	Tennessee	Utility	200.00	8	1955	58
1062	Kingston	Tennessee	Utility	200.00	9	1955	58
1063	Tenn Eastman Division A Division of East	Tennessee	Industrial	6.00	TG10	1946	68
1064	Tenn Eastman Division A Division of East	Tennessee	Industrial	6.00	TG11	1949	65
1065	Tenn Eastman Division A Division of East	Tennessee	Industrial	6.00	TG12	1953	61
1066	Tenn Eastman Division A Division of East	Tennessee	Industrial	7.00	TG13	1960	54
1067	Tenn Eastman Division A Division of East	Tennessee	Industrial	10.00	TG14	1962	52
1068	Tenn Eastman Division A Division of East	Tennessee	Industrial	7.50	TG15	1963	50
1069	Tenn Eastman Division A Division of East	Tennessee	Industrial	10.40	TG16	1966	47
1070	Tenn Eastman Division A Division of East	Tennessee	Industrial	10.40	TG17	1966	47
1071	Tenn Eastman Division A Division of East	Tennessee	Industrial	10.40	TG18	1967	46
1072	Tenn Eastman Division A Division of East	Tennessee	Industrial	10.40	TG19	1970	44
1073	Tenn Eastman Division A Division of East	Tennessee	Industrial	10.40	TG20	1972	42
1074	Tenn Eastman Division A Division of East	Tennessee	Industrial	15.00	TG21	1969	44
1075	Tenn Eastman Division A Division of East	Tennessee	Industrial	15.40	TG22	1982	31
1076	Tenn Eastman Division A Division of East	Tennessee	Industrial	16.80	TG24	1983	30
1077	Tenn Eastman Division A Division of East	Tennessee	Industrial	18.00	TG25	1994	19
1078	Tenn Eastman Division A Division of East	Tennessee	Industrial	16.60	TG26	1994	19
1079	Tenn Eastman Division A Division of East	Tennessee	Industrial	6.00	TG07	1936	77
1080	Tenn Eastman Division A Division of East	Tennessee	Industrial	6.00	TG08	1939	74
1081	Tenn Eastman Division A Division of East	Tennessee	Industrial	6.00	TG09	1941	72
1082	Vanderbilt Univ	Tennessee	Commercial	6.50	GEN1	1988	25
1083	Vanderbilt Univ	Tennessee	Commercial	4.50	GEN2	1989	24
1084	Big Brown	Texas	IPP	593.40	1	1971	42
1085	Big Brown	Texas	IPP	593.40	2	1972	41
1086	Coleto Creek	Texas	IPP	622.40	1	1980	33
1087	Fayette Power Project	Texas	Utility	615.00	1	1979	34
1088	Fayette Power Project	Texas	Utility	615.00	2	1980	34
1089	Fayette Power Project	Texas	Utility	460.00	3	1988	26
1090	Gibbons Creek	Texas	Utility	453.50	1	1983	30
1091	Harrington	Texas	Utility	360.00	1	1976	38
1092	Harrington	Texas	Utility	360.00	2	1978	36
1093	Harrington	Texas	Utility	360.00	3	1980	34
1094	J K Spruce	Texas	Utility	566.00	1	1992	21
1095	J K Spruce	Texas	Utility	878.00	2	2010	4
1096	J T Deely	Texas	Utility	486.00	1	1977	36
1097	J T Deely	Texas	Utility	446.00	2	1978	35
1098	Limestone (NRG)	Texas	IPP	910.40	1	1985	28
1099	Limestone (NRG)	Texas	IPP	956.80	2	1986	27
1100	Martin Lake	Texas	IPP	793.20	1	1977	37
1101	Martin Lake	Texas	IPP	793.20	2	1978	36
1102	Martin Lake	Texas	IPP	793.20	3	1979	35
1103	Monticello (TX)	Texas	IPP	593.40	1	1974	39
1104	Monticello (TX)	Texas	IPP	593.40	2	1975	38
1105	Monticello (TX)	Texas	IPP	793.20	3	1978	35
1106	Oak Grove Steam Electric Station	Texas	IPP	916.80	ST1	2009	4
1107	Oak Grove Steam Electric Station	Texas	IPP	878.60	ST2	2010	4
1108	Oklaunion	Texas	Utility	720.00	1	1986	27
1109	Pirkey	Texas	Utility	721.00	1	1985	29
1110	San Miguel	Texas	Utility	410.00	1	1982	32
1111	Sandow 4	Texas	IPP	590.60	4	1981	33
1112	Sandow 5	Texas	Industrial	661.50	5	2009	4
1113	Sandy Creek Energy Station	Texas	IPP	925.00	ST	2013	1
1114	Tolk	Texas	Utility	567.90	1	1982	32
1115	Tolk	Texas	Utility	567.90	2	1985	29

Appendix A-3
Age of Coal-Fired Units Currently in Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
1116	Twin Oaks Power	Texas	IPP	174.60	1	1990	23
1117	Twin Oaks Power	Texas	IPP	174.60	2	1991	22
1118	W A Parish	Texas	IPP	734.10	5	1977	36
1119	W A Parish	Texas	IPP	734.10	6	1978	35
1120	W A Parish	Texas	IPP	614.60	7	1980	33
1121	W A Parish	Texas	IPP	654.00	8	1982	31
1122	Welsh Station	Texas	Utility	558.00	1	1977	37
1123	Welsh Station	Texas	Utility	558.00	2	1980	34
1124	Welsh Station	Texas	Utility	558.00	3	1982	32
1125	Bonanza	Utah	Utility	499.50	1	1986	28
1126	Carbon (UT)	Utah	Utility	75.00	1	1954	59
1127	Carbon (UT)	Utah	Utility	113.60	2	1957	56
1128	Hunter	Utah	Utility	488.30	ST1	1978	35
1129	Hunter	Utah	Utility	503.30	ST2	1980	33
1130	Hunter	Utah	Utility	495.60	ST3	1983	30
1131	Huntington (UT)	Utah	Utility	498.00	1	1977	36
1132	Huntington (UT)	Utah	Utility	498.00	2	1974	39
1133	Intermountain	Utah	Utility	900.00	ST1	1986	27
1134	Intermountain	Utah	Utility	900.00	ST2	1987	27
1135	KUCC	Utah	Industrial	50.00	1	1943	71
1136	KUCC	Utah	Industrial	25.00	2	1943	71
1137	KUCC	Utah	Industrial	25.00	3	1946	68
1138	KUCC	Utah	Industrial	82.00	4	1958	56
1139	Birchwood Power Facility	Virginia	IPP	258.30	1	1996	17
1140	Bremo Bluff	Virginia	Utility	69.00	3	1950	63
1141	Bremo Bluff	Virginia	Utility	185.20	4	1958	55
1142	Chesapeake	Virginia	Utility	185.20	3	1959	54
1143	Chesapeake	Virginia	Utility	112.50	ST1	1953	60
1144	Chesapeake	Virginia	Utility	112.50	ST2	1954	59
1145	Chesapeake	Virginia	Utility	239.30	ST4	1962	52
1146	Chesterfield	Virginia	Utility	112.50	3	1952	61
1147	Chesterfield	Virginia	Utility	187.50	4	1960	53
1148	Chesterfield	Virginia	Utility	378.00	5	1964	49
1149	Chesterfield	Virginia	Utility	693.90	6	1969	44
1150	Clinch River	Virginia	Utility	237.50	1	1958	55
1151	Clinch River	Virginia	Utility	237.50	2	1958	55
1152	Clinch River	Virginia	Utility	237.50	3	1961	52
1153	Clover	Virginia	Utility	424.00	1	1995	18
1154	Clover	Virginia	Utility	424.00	2	1996	18
1155	Cogentrix Hopewell	Virginia	IPP	57.40	GEN1	1987	26
1156	Cogentrix Hopewell	Virginia	IPP	57.40	GEN2	1987	26
1157	Cogentrix of Richmond Inc	Virginia	IPP	57.40	GEN1	1992	22
1158	Cogentrix of Richmond Inc	Virginia	IPP	57.40	GEN2	1992	22
1159	Cogentrix of Richmond Inc	Virginia	IPP	57.40	GEN3	1992	21
1160	Cogentrix of Richmond Inc	Virginia	IPP	57.40	GEN4	1992	21
1161	Glen Lyn	Virginia	Utility	100.00	5	1944	69
1162	Glen Lyn	Virginia	Utility	237.50	6	1957	57
1163	Hopewell	Virginia	Utility	71.10	1	1992	21
1164	Mecklenburg Cogeneration Facil	Virginia	Utility	69.90	GEN1	1992	21
1165	Mecklenburg Cogeneration Facil	Virginia	Utility	69.90	GEN2	1992	21
1166	Narrows (VA)	Virginia	Industrial	6.00	GEN1	1942	72
1167	Narrows (VA)	Virginia	Industrial	6.00	GEN2	1942	72
1168	Narrows (VA)	Virginia	Industrial	6.00	GEN3	1944	70
1169	Narrows (VA)	Virginia	Industrial	9.20	GEN4	1966	48
1170	Oilseed Plant	Virginia	Industrial	1.70	GEN1	1985	29
1171	Park 500 Philip Morris USA	Virginia	Industrial	13.00	TG3	1983	30
1172	Portsmouth Cogeneration Plant	Virginia	IPP	57.40	GEN1	1988	26
1173	Portsmouth Cogeneration Plant	Virginia	IPP	57.40	GEN2	1988	26
1174	Radford Army Ammunition	Virginia	Industrial	6.00	GEN1	1990	24
1175	Radford Army Ammunition	Virginia	Industrial	6.00	GEN2	1990	24
1176	Radford Army Ammunition	Virginia	Industrial	6.00	GEN3	1990	24
1177	Radford Army Ammunition	Virginia	Industrial	6.00	GEN4	1990	24
1178	Southampton	Virginia	Utility	71.10	1	1992	22
1179	Virginia City Hybrid Energy Center	Virginia	Utility	668.00	CFB	2012	1
1180	Virginia Tech Power Plant	Virginia	Commercial	6.30	WG01	1976	38
1181	Yorktown	Virginia	Utility	187.50	1	1957	56

Appendix A-3
Age of Coal-Fired Units Currently in Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
1182	Yorktown	Virginia	Utility	187.50	2	1959	55
1183	Centralia Complex	Washington	IPP	729.90	BD21	1972	41
1184	Centralia Complex	Washington	IPP	729.90	BD22	1973	40
1185	Alloy Steam	West Virginia	Industrial	40.00	GEN3	1950	63
1186	Bayer Cropscience Institute Plant	West Virginia	Industrial	6.30	ST1	1958	56
1187	Bayer Cropscience Institute Plant	West Virginia	Industrial	6.30	ST2	1961	53
1188	Fort Martin	West Virginia	Utility	576.00	1	1967	46
1189	Fort Martin	West Virginia	Utility	576.00	2	1968	45
1190	Harrison (WV)	West Virginia	IPP	684.00	1	1972	41
1191	Harrison (WV)	West Virginia	IPP	684.00	2	1973	40
1192	Harrison (WV)	West Virginia	IPP	684.00	3	1974	39
1193	John E Amos	West Virginia	Utility	816.30	1	1971	42
1194	John E Amos	West Virginia	Utility	816.30	2	1972	41
1195	John E Amos	West Virginia	Utility	1,300.00	3	1973	40
1196	Kammer	West Virginia	Utility	237.50	1	1958	55
1197	Kammer	West Virginia	Utility	237.50	2	1958	55
1198	Kammer	West Virginia	Utility	237.50	3	1959	55
1199	Kanawha River	West Virginia	Utility	219.60	1	1953	60
1200	Kanawha River	West Virginia	Utility	219.60	2	1953	60
1201	Longview Power	West Virginia	IPP	807.50	AB1	2012	2
1202	Mitchell (WV)	West Virginia	Utility	816.30	1	1971	43
1203	Mitchell (WV)	West Virginia	Utility	816.30	2	1971	43
1204	Mountaineer	West Virginia	Utility	1,300.00	1	1980	33
1205	MT Storm	West Virginia	Utility	595.67	1	1965	48
1206	MT Storm	West Virginia	Utility	595.67	2	1966	47
1207	MT Storm	West Virginia	Utility	522.00	3	1973	40
1208	Natrium Plant	West Virginia	Industrial	7.50	GEN3	1943	71
1209	Natrium Plant	West Virginia	Industrial	7.50	GEN4	1943	71
1210	Natrium Plant	West Virginia	Industrial	26.00	GEN6	1954	60
1211	Natrium Plant	West Virginia	Industrial	82.00	GEN7	1966	48
1212	Phil Sporn	West Virginia	Utility	152.50	1	1950	64
1213	Phil Sporn	West Virginia	Utility	152.50	2	1950	63
1214	Phil Sporn	West Virginia	Utility	152.50	3	1951	62
1215	Phil Sporn	West Virginia	Utility	152.50	4	1952	62
1216	Pleasants	West Virginia	IPP	684.00	1	1979	35
1217	Pleasants	West Virginia	IPP	684.00	2	1980	33
1218	Alma	Wisconsin	Utility	54.40	4	1957	57
1219	Alma	Wisconsin	Utility	81.60	5	1960	54
1220	Bay Front	Wisconsin	Utility	27.20	6	1957	57
1221	Biron Mill	Wisconsin	Industrial	17.00	GEN1	1964	49
1222	Biron Mill	Wisconsin	Industrial	7.50	GEN3	1947	66
1223	Biron Mill	Wisconsin	Industrial	15.60	GEN4	1957	56
1224	Biron Mill	Wisconsin	Industrial	21.50	GEN5	1987	27
1225	Columbia (WI)	Wisconsin	Utility	512.00	1	1975	39
1226	Columbia (WI)	Wisconsin	Utility	511.00	2	1978	36
1227	Edgewater (WI)	Wisconsin	Utility	60.00	3	1951	62
1228	Edgewater (WI)	Wisconsin	Utility	330.00	4	1969	44
1229	Edgewater (WI)	Wisconsin	Utility	380.00	5	1985	29
1230	Genoa No3	Wisconsin	Utility	345.60	ST3	1969	44
1231	Grandmother	Wisconsin	Industrial	6.30	GEN1	1948	65
1232	Grandmother	Wisconsin	Industrial	9.40	GEN2	1978	35
1233	Green Bay West Mill	Wisconsin	Industrial	28.20	GEN10	2005	8
1234	Green Bay West Mill	Wisconsin	Industrial	10.00	GEN5	1954	60
1235	Green Bay West Mill	Wisconsin	Industrial	18.70	GEN6	1963	51
1236	Green Bay West Mill	Wisconsin	Industrial	28.90	GEN7	1969	45
1237	Green Bay West Mill	Wisconsin	Industrial	43.20	GEN9	1985	28
1238	John P Madgett	Wisconsin	Utility	387.00	1	1979	34
1239	Menasha (MNSHA)	Wisconsin	IPP	7.50	3	1954	60
1240	Menasha (MNSHA)	Wisconsin	IPP	13.60	4	1964	50
1241	Menasha (MNSHA)	Wisconsin	IPP	6.90	5	2006	7
1242	Milwaukee County	Wisconsin	Utility	11.00	NA	1996	18
1243	Nekoosa Mill	Wisconsin	Industrial	6.00	TG6	1951	63
1244	Nekoosa Mill	Wisconsin	Industrial	16.00	TG8	1966	48
1245	Nelson Dewey	Wisconsin	Utility	100.00	1	1959	54
1246	Nelson Dewey	Wisconsin	Utility	100.00	2	1962	51
1247	Niagara Mill	Wisconsin	Industrial	2.50	1ST	1940	74

Appendix A-3
Age of Coal-Fired Units Currently in Service
EV Power - November 2013

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Plant	State	Plant Sector	Capacity MW	Unit	Year in Service	Current Age
1248	Niagara Mill	Wisconsin	Industrial	9.30	2ST	1964	50
1249	Oak Creek Power Plant	Wisconsin	Utility	701.30	1	2010	4
1250	Oak Creek Power Plant	Wisconsin	Utility	615.00	2	2011	3
1251	Pleasant Prairie	Wisconsin	Utility	616.50	1	1980	33
1252	Pleasant Prairie	Wisconsin	Utility	616.50	2	1985	28
1253	Pulliam	Wisconsin	Utility	50.00	5	1949	64
1254	Pulliam	Wisconsin	Utility	69.00	6	1951	62
1255	Pulliam	Wisconsin	Utility	81.60	7	1958	55
1256	Pulliam	Wisconsin	Utility	149.60	8	1964	49
1257	Rhinelander Mill	Wisconsin	Industrial	9.30	GEN6	1958	55
1258	South Oak Creek	Wisconsin	Utility	299.20	5	1959	54
1259	South Oak Creek	Wisconsin	Utility	299.20	6	1961	52
1260	South Oak Creek	Wisconsin	Utility	317.60	7	1965	49
1261	South Oak Creek	Wisconsin	Utility	324.00	8	1967	46
1262	Thilmany Pulp Paper	Wisconsin	Industrial	12.00	GEN4	1967	47
1263	UW Madison Charter St Plant	Wisconsin	Commercial	9.70	1	1965	49
1264	Valley (WI)	Wisconsin	Utility	136.00	1	1968	45
1265	Valley (WI)	Wisconsin	Utility	136.00	2	1969	45
1266	Waupun Correctional Inst CTR	Wisconsin	Commercial	1.00	1	1951	63
1267	Waupun Correctional Inst CTR	Wisconsin	Commercial	1.00	2	1951	63
1268	Weston	Wisconsin	Utility	60.00	1	1954	59
1269	Weston	Wisconsin	Utility	81.60	2	1960	53
1270	Weston	Wisconsin	Utility	350.50	3	1981	32
1271	Weston	Wisconsin	Utility	595.00	4	2008	5
1272	Whiting Mill	Wisconsin	Industrial	4.10	GEN4	1951	62
1273	Dave Johnston	Wyoming	Utility	113.60	1	1959	55
1274	Dave Johnston	Wyoming	Utility	113.60	2	1961	53
1275	Dave Johnston	Wyoming	Utility	229.50	3	1964	49
1276	Dave Johnston	Wyoming	Utility	360.00	4	1972	41
1277	Dry Fork Station	Wyoming	Utility	390.00	ST	2011	2
1278	General Chemical	Wyoming	Industrial	15.00	TG1	1968	46
1279	General Chemical	Wyoming	Industrial	15.00	TG2	1977	37
1280	Green River (WY)	Wyoming	Industrial	3.50	CG	1953	60
1281	Green River (WY)	Wyoming	Industrial	3.50	ST2	1953	60
1282	Green River (WY)	Wyoming	Industrial	4.00	ST3	1964	49
1283	Green River (WY)	Wyoming	Industrial	10.00	ST4	1972	41
1284	Green River (WY)	Wyoming	Industrial	10.00	ST5	1975	38
1285	Green River (WY)	Wyoming	Industrial	10.00	ST6	1975	38
1286	Jim Bridger	Wyoming	Utility	577.90	1	1974	39
1287	Jim Bridger	Wyoming	Utility	577.90	2	1975	38
1288	Jim Bridger	Wyoming	Utility	577.90	3	1976	37
1289	Jim Bridger	Wyoming	Utility	584.00	4	1979	34
1290	Laramie River	Wyoming	Utility	570.00	1	1981	32
1291	Laramie River	Wyoming	Utility	570.00	2	1981	33
1292	Laramie River	Wyoming	Utility	570.00	3	1982	32
1293	Naughton	Wyoming	Utility	163.20	1	1963	51
1294	Naughton	Wyoming	Utility	217.60	2	1968	45
1295	Naughton	Wyoming	Utility	326.40	3	1971	42
1296	Neil Simpson	Wyoming	Utility	21.70	5	1969	44
1297	Neil Simpson II	Wyoming	Utility	80.00	2	1995	18
1298	Osage (WY)	Wyoming	Utility	11.50	1	1948	65
1299	Osage (WY)	Wyoming	Utility	11.50	2	1949	64
1300	Osage (WY)	Wyoming	Utility	11.50	3	1952	61
1301	Torrington Western Sugar	Wyoming	Industrial	2.00	ST	1978	35
1302	Wygen	Wyoming	IPP	88.00	1	2003	11
1303	Wygen II	Wyoming	Utility	95.00	ST1	2008	6
1304	Wygen III	Wyoming	Utility	116.20	ST3	2010	4
1305	Wyodak	Wyoming	Utility	362.00	1	1978	35

Appendix B Plant Site Visit Memoranda

APPENDIX B-1 MERAMEC ENERGY CENTER SITE VISIT MEMORANDUM

CONFERENCE MEMORANDUM 001

Ameren UE
Coal Useful Life Study
Meramec Energy Center Site Visit

B&V Project 181958
B&V File Number 14.1101
December 6, 2013
Edited March 25, 2014

Meetings held on November 18, 2013, at Meramec Energy Center near Arnold, Missouri.

Recorded by: Jim Hurt
Edited by: Larry Loos

Attended by: Ameren Missouri:
Greg Presti – Supervising Engineer Environmental Projects
JoAnn Thee – Superintendent Technical Support
Mark Litzinger – Director, Meramec & Rush Island
Chuck Fedke – Superintendent Maintenance
Tom Hart – Supervisor Engineering
Chris Brown – General Supervisor Operations
Tina Metzger – Training Supervisor
Keith Stuckmeyer – Assistant Plant Manager

Black & Veatch
Jim Hurt
Larry Loos

Larry Loos and Jim Hurt visited the Meramec Energy Center on Monday, November 18, 2013 as part of a 2013 Useful Life Study being conducted by Black & Veatch's Management Consulting Division (MCD). The purpose of the visit was to view plant and equipment conditions; review historical and projected capital and O&M expenditures; review historical and projected unit operations; discuss plant maintenance practices; and identify issues which could potentially affect the life expectancy of the coal fired generating units at Meramec Energy Center.

Larry Loos provided a description of the purpose of the project for the group and discussions were held with the plant and Ameren corporate staff listed above. Tina Metzger provided a walk-down inspection of the Meramec units for Larry Loos and Jim Hurt. Ms. Metzger is very knowledgeable and provided a very well narrated tour of the power plant. At the time of the visit, all of the units were out of service.

The Meramec Energy Center is located at the confluence of the Meramec and Mississippi Rivers near Arnold, Missouri. Units 1 and 2 are identical units built in 1953 and 1954. Unit 3 was completed in 1959. Unit 4 was completed in 1961. The unit capacities listed in the table below were taken from the 2013 Capability Table provided by Ameren. The summer and winter capacities are as follows:

	Winter Output, Gross (Net), MW	Summer Output, Gross (Net), MW
Unit 1	135 (126)	128 (119)
Unit 2	135 (127)	128 (121)
Unit 3	285 (266)	277 (258)
Unit 4	376 (355)	355 (335)

The Meramec Facility was originally designed to operate as a base-load resource burning Illinois Basin coal. In 1997 the plant switched to Powder River Basin (PRB) subbituminous coal. Based on plant personnel comments, the units and coal handling systems were modified as required to safely burn PRB coal.

More recently the plant has increasingly operated in a cycling mode, with units ramped up and down several times a week. While we were there, Unit 3 was down as a result of turbine shroud issues related to cycling operations.

PRB coal is transported to the site by rail. Each unit train includes up to 135 railcars and delivers about 15,000 tons of PRB coal. Plant personnel stated that depending on loading conditions the plant may receive up to one train every other day. The Meramec Facility also has a barge loading and unloading facility at site. The coal loading system can potentially be used for loading of coal to barges for transport to other Ameren plants. The barge coal handling systems are not operable at this time but plant personnel stated that they could be placed back in service if needed.

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. Natural gas fired combustion turbine generators are located within the plant's coal loop. These units are not included in the scope of work of this project.

The purpose of the site visit by Black & Veatch to the Meramec power generation station was to perform a high level assessment of the condition of the plant and whether there are any issues that could affect the life expectancy of the facility.

During the site visit, Black & Veatch and Ameren personnel conducted a walk down tour of each unit to observe the condition of major equipment and facilities including the control room, boilers, precipitators, ash handling systems, turbine deck, steam turbine generators and associated equipment, major electrical equipment, major pumps and fans. Additionally, Black & Veatch met with plant personnel to discuss operations and maintenance of the units, capital projects that have been recently completed, or are planned in the future, and any known issues with major equipment.

During the site visit, Black & Veatch noted a few issues with respect to the plant:

- 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 waste-water treatment plant. This could possibly limit future operations or expansion of the plant.
- Retrofit of FGD systems at the plant is not currently planned. The future of the plant relative to developing environmental regulations is currently uncertain.
- The plant site has limited space for accommodating future expansion of the plant whether for FGD systems or additional generation without significant demolition of existing facilities.

Black & Veatch noted that the plant has maintained the equipment at the Meramec Facility through O&M practices and a capital expenditure program, typical of the industry. Some of the maintenance completed on the units include:

- Rewinding of the generators.
- Replacement of boiler superheater and reheater sections.
- Installation of Low NOx burners.
- Installation of new DCS systems.
- Changes to the coal handling systems.
- Fan changes
- Changes to the coal milling systems.
- Boiler membrane wall replacements.

Black & Veatch reviewed NERC GADS data provided by Ameren for 2008-2012. For a comparison of NERC GADS data for the Ameren coal units refer to the following table. This data is five year averages per plant for selected GADS performance parameters for the 2008 to 2012 timeframe. GADS industry data for 2002 through 2013 for 125 MW to 350 MW units firing 0.2 to 0.6 percent sulfur coal is also provided for comparison below.

	Sioux Plant Units 1 to 4	Rush Island Plant Units 1 &2	Meramec Plant Units 1 to 4	Labadie Plant Units 1 to 4
FOR	6.88	4.18	11.73	3.99
EFOR	9.33	6.52	14.24	6.50
EAF	83.34	87.92	82.80	87.26
NCF	63.13	76.43	68.82	81.70

	Meramec Plant FOR	Meramec Plant EFOR	Meramec Plant EAF	Meramec Plant NCF
2008	7.29	9.64	85.03	76.30
2009	12.06	13.79	82.19	70.80
2010	13.86	17.47	82.58	70.39
2011	8.19	10.05	88.23	72.86
2012	18.10	21.07	75.96	53.69
GADS Industry Average Data		5.89	84.94	64.28

The first of the preceding tables shows that the station average performance when compared to the other Ameren plants is substantially lower. The NERC GADS data in the second table for the plant from 2008 to 2012 generally shows decreasing availability, service hours, generation, and capacity factors with increasing forced outage rates. Based on interviews with plant personnel conducted during the site visit of the Meramec Facility along with technical information provided by Ameren during follow-up discussions and review of accounting records, Black & Veatch notes that Ameren has reduced capital expenditures as well as operations and maintenance expenses substantially in recent years. Given the reduction in expenditures and forecast further reduction in capital expenditures over the next several years as well as the continuing cycling operation of the plant severely limits the remaining physical life of the plant. In fact, whether existing levels of expenditures will allow continued operations until the planned retirement in 2022 may be an issue. The technical issues identified are typical for assets of this type and age and most, if not all, of the problems that could be encountered have technical solutions. However, the economic viability of investing funds to resolve these issues is questionable given the plant's age and potential environmental concerns.

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

- The units will operate in more of a cycling mode consistent Ameren Missouri's planned need for generation from units of this type and age.
- Information provided by Ameren Missouri personnel regarding the generating station is complete and accurate.
- Application of operations and maintenance programs, including capital expenditures necessary to continue operations safely and responsibly, consistent with industry practices for units of this type and age.
- Application of corrective action, and predictive / preventive maintenance programs that will enable Ameren Missouri 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 safe manner consistent with prudent industry practices.
- The capital expenditure estimates in the long term capital plan developed by Ameren Missouri will be periodically reviewed and adjusted as needed to remain consistent with planned retirement in 2022, changing regulations, or as differing operating conditions dictate, and implemented in a timely manner.

Black & Veatch does not foresee any technical reasons that would cause the currently operating generation assets at the Meramec Facility to be retired prior to the planned 2022 retirement, based on the reasons and assumptions noted above. Black & Veatch cannot opine as to whether there will be economic or environmental issues which might prevent operation of the generating assets in the near term.

APPENDIX B-2 RUSH ISLAND ENERGY CENTER SITE VISIT MEMORANDUM

CONFERENCE MEMORANDUM 002

Ameren Missouri
Coal Useful Life Study
Rush Island Energy Center Site Visit

B&V Project 181958
B&V File Number 14.1102
December 6, 2013
Edited March 25, 2014

Meetings held on November 19, 2013, at Rush Island Energy Center near Festus, Missouri.

Recorded by: Jim Hurt
Edited by: Larry Loos

Attended by: Ameren Missouri:
Greg Presti – Supervising Engineer Environmental Projects
Mark Litzinger – Director, Meramec & Rush Island
Jeff LaBrot – Consulting Engineer
Mark Schmitz – General Supervisor Planning
Kevin Stumpe – Superintendent Operations
Chris Maricic – Superintendent Technical Support

Black & Veatch
Jim Hurt
Larry Loos

Larry Loos and Jim Hurt visited the Rush Island Energy Center on Tuesday, November 19, 2013 as part of a 2013 Useful Life Study being conducted by Black & Veatch's Management Consulting Division (MCD). The purpose of the visit was to view plant and equipment conditions; review historical and projected capital and O&M expenditures; review historical and projected unit operations; discuss plant maintenance practices; and identify issues which could potentially affect the life expectancy of the coal fired generating units at Rush Island Energy Center.

Larry Loos provided a description of the purpose of the project for the group and discussions were held with the plant and Ameren Missouri corporate staff listed above. Chris Maricic provided a walk-down inspection of the Rush Island units for Larry Loos and Jim Hurt. Mr. Maricic provided a very well narrated walk down tour of the power plant. At the time of the visit, both of the units were in service.

The Rush Island Energy Center consists of two pulverized coal (PC) subcritical generating units located on the western bank of the Mississippi River near Festus, Missouri. The two units are identical in design and were built in 1976 and 1977, respectively. The unit capacities listed in the table below were taken from the 2013 Capability Table provided by Ameren Missouri. The summer and winter capacities are as follows:

	Winter Output, Gross (Net), MW	Summer Output, Gross (Net), MW
Unit 1	643 (612)	622 (591)
Unit 2	643 (612)	622 (591)

The Rush Island Facility was originally designed to burn Illinois coal. A decision was made to convert the units to Powder River basin (PRB) coal. Based on plant personnel comments, the units and coal handling systems were modified as required to safely burn PRB coal. PRB coal is transported to the site by rail. The Rush Island Facility also has a barge unloading facility, which gives a possible alternative coal transportation option. However, this system is not currently used. The plant uses fuel oil for start-up because natural gas is not available at the site.

During the site visit, Black & Veatch and Ameren Missouri personnel conducted a walk down tour of each unit to observe the condition of major equipment and facilities including the control room, boilers, precipitators, ash handling systems, turbine deck, steam turbine generators and associated equipment, major electrical equipment, major pumps and fans. Additionally, Black & Veatch met with plant personnel to discuss operations and maintenance of the units, capital projects that have been recently completed, or are planned in the future, and any known issues with major equipment.

Black & Veatch noted that both units were operating at full load and at a unity power factor. Based on the information provided by Ameren Missouri, Black & Veatch noted that the plant had made replacements and repairs consistent with our expectations for units of this type and age.

All major equipment in the plant has been maintained with periodic replacements and repairs as and when required. Black & Veatch did not find any significant issues with any of the systems within the plant.

The plant site was originally planned for four units; however only two have been completed. The plant has space available for expansion of the facility if so desired.

Black & Veatch noted that the plant has appropriately maintained and modified the existing equipment over the life of the plant. Some of the maintenance completed on the units and the plant include the following:

- Rewinding of the generators.
- Replacement of the generator step-up (GSU) transformers.
- Replacement of boiler sections.
- Replacement of the HP, IP and LP sections of the original Westinghouse steam turbines.
- Replacement of the excitation systems with GE static (solid state) exciters.
- Installation of new DCS system.
- Installation of Low NOx burners.
- Installation of new demineralization system.
- Currently modifying the ash pond/landfill for increased storage capacity.

Black & Veatch reviewed NERC GADS data provided by Ameren Missouri for 2008-2012. For a comparison of NERC GADS data for the Ameren Missouri coal units refer to the following table. This data is five year averages per plant for selected GADS performance parameters for the 2008 to 2012 timeframe. GADS industry data for 2002 through 2013 for 500 MW to 700 MW units firing 0.2 to 0.6 percent sulfur coal is also provided for comparison below.

	Sioux Plant Units 1 & 2	Rush Island Plant Units 1 & 2	Meramec Plant Units 1 to 4	Labadie Plant Units 1 to 4
FOR	6.88	4.18	11.73	3.99
EFOR	9.33	6.52	14.24	6.50
EAF	83.34	87.92	82.80	87.26
NCF	63.13	76.43	68.82	81.70

	Rush Island Plant FOR	Rush Island Plant EFOR	Rush Island Plant EAF	Rush Island Plant NCF
2008	2.32	3.91	94.23	83.64
2009	2.59	4.79	91.86	76.38
2010	4.80	8.78	78.94	70.55
2011	3.31	4.61	86.89	76.22
2012	7.78	10.51	87.82	75.45
GADS Industry Average Data		8.37	84.76	66.14

The first of the preceding tables shows that the station average performance when compared to the other Ameren Missouri plants is comparable to Labadie Plant and better than either the Sioux or Meramec plants. The NERC GADS data for the plant from 2008 to 2012 as shown in the second table and in the data provided in the Ameren Missouri Performance Summary Report, shows decreasing equivalent availability, decreasing capacity factors, and increasing forced outage rates. This performance is satisfactory for this plant in light of the plant's type and age.

Based on interviews with plant personnel conducted during a site visit of the Rush Island Facility along with technical information provided by Ameren Missouri, 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 improvement programs are continued. Major issues appeared to be fully disclosed and discussed; however, most of these issues are typical for assets of this type and age and all of these issues have technical solutions. It is also recognized that these are aging units that will experience equipment and systems failures over the years. Based on information available at the time, the (2001-2013) historical and long term forecast capital expenditure plan developed by Ameren Missouri 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 Ameren Missouri personnel regarding the generating station is complete and accurate.
- Application of operations and maintenance programs, including capital expenditures, consistent with industry practices for units of this type and age will continue.
- Application of corrective action, and predictive / preventive maintenance programs that will enable Ameren Missouri 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 Ameren Missouri will be periodically reviewed and adjusted as needed to remain consistent with changing regulations, or as differing conditions are found, and implemented in a timely manner.

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 based on the reasons and assumptions noted above. Black & Veatch cannot opine as to whether there will be economic or environmental issues which might prevent operation of the generating assets in the future. Assessment of economic or environmental issues was not included in the scope of work of this review.

APPENDIX B-3 SIOUX ENERGY CENTER SITE VISIT MEMORANDUM

CONFERENCE MEMORANDUM 003

Ameren Missouri
Coal Plant Life Assessment
Sioux Energy Center Site Visit

B&V Project 181958
B&V File Number 14.1103
December 6, 2013
Edited March 25, 2014

Meetings held on December 3, 2013, at Sioux Energy Center near West Alton, Missouri.

Recorded by: Walter Johnson and Jeff Stroessner
Edited by: Larry Loos

Attended by: Ameren Missouri:
Gary Mitchell –Engineer Environmental Projects
Karl Blank - Director Sioux Energy Center
Tim Henchel - Superintendent Administration
Pat Weir – Superintendent Technical Support

Black & Veatch
Walter Johnson
Jeff Stroessner

Walt Johnson and Jeff Stroessner visited the Sioux Energy Center on Tuesday, December 3, 2013 as part of a 2013 Useful Life Study being conducted by Black & Veatch's Management Consulting Division (MCD). The purpose of the visit was to view plant and equipment conditions; review historical and projected capital and O&M expenditures; review historical and projected unit operations; discuss plant maintenance practices; and identify issues which could potentially affect the life expectancy of the coal fired generating units at Sioux Energy Center.

Walt Johnson provided a description of the purpose of the project for the group and discussions were held with the plant and Ameren Missouri corporate staff listed above. Tim Henchel is very knowledgeable and provided a very well narrated tour of the facility. At the time of the visit, Unit 2 was out of service.

The Sioux Energy Center (Sioux Facility), which has 2 supercritical cyclone fired, power generating units, is located north of the city of St. Louis, Missouri on the south (west) bank of the Mississippi river. Unit 1 was built in 1967. Unit 2 was built in 1968. The unit capacities listed in the table below were taken from the 2013 Capability Table provided by Ameren Missouri. The summer and winter capacities are as follows:

	Winter Output, Gross (Net), MW	Summer Output, Gross (Net), MW
Unit 1	532 (497)	521 (486)
Unit 2	532 (497)	521 (486)

The Sioux Energy Center 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 Energy Center had also blended in pet coke as well as chipped rubber tires into the coal fuel, but this has not done so for several years. There is no natural gas supply at the Sioux Energy Center site.

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:
    - Capital projects that have been recently completed, or are, planned in order to maintain the economic viability of each respective 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 Energy Center, Black & Veatch noted a few challenging issues with respect to plant operations, which are being actively supervised:

- Sioux Energy Center is in the process of moving to 100% Powder River Basin (PRB) coal. Several capital projects are in process to prepare the units for this fuel change. To date, the increased use of PRB has resulted in some slagging issues, as well as bridging in the bottom ash tank. Sioux Energy Center has determined that these are manageable issues so long as they are regularly maintained through rodding and wall blowing.
- Barge unloading equipment is operational; however, Sioux Energy Center has not received any barge shipments for several months owing to the strategy of 100% PRB coal.
- Unit 2 turbine is currently operating with 1st Stage turbine blade damage, resulting in a 30 MW load reduction. This is slated for repair during the Spring 2014 outage.
- Unit 2 has been experiencing intermittent draft losses resulting from pluggage in the horizontal economizer and tubular air heater.
- Units are run in load following operation. Minimum loads have been reduced over time as the units were able to demonstrate that a reduction in minimum loads reduced operating cost margin. The Sioux units were tested for eight cyclone minimum load operation, with

improved cyclone firing at the lower load. The lower minimum loads remove the reliability issues related to cycling by allowing individual cyclones to be taken out of service.

- Cyclone wall tube leaks due to corrosion and thinning on wall exteriors have been a contributor to unavailability. Unit 2 wall tubes are scheduled to be addressed with cyclone wall tube replacements during the Spring-2014 outage. Unit 1 wall tubes are planned for replacement in 2015.
- There is limited space remaining in the on-site ash ponds for disposal. The plant has purchased an additional area of land and is being prepared for landfill of fly ash and scrubber waste.
- Twice annually the plant treats the circulating water intake for zebra mussels. Some zebra mussels have been discovered in the scrubber raw water, and Sioux Energy Center is working on a treatment plan to address this issue.
- The coal silos were originally designed for Illinois coal. This has been an issue since switching to PRB coal which has a lower heating value(i.e. higher throughput requirements) and does not flow as well as Illinois coal. The existing silos maintain only six hours of coal, and poor coal flow can result in low coal flow (plugging, rat holing, etc.) to the cyclones. The silos are planned for replacement / upgrade at some future time.
- Sioux Energy Center staff advised the bottom ash systems are in need of improvements, as are the coal handling conveyor systems. Some deterioration in the bottom ash system was noted as well as ergonomics concerns when rodding was required.

A few projects were noted at the Sioux generating station since Black & Veatch's visit for the 2013 Useful Life Study.

- Cyclone split secondary dampers and improved scroll projects on Units 1 and 2 are planned to be completed in 2015 and 2014 respectively for improved loss on ignition (LOI) when using 100% PRB coal in the future. The improved secondary dampers are designed to allow for improved boiler fire and NOx control simultaneously.
- Sioux Generating Station is a leader in Babcock & Wilcox's Flame Doctor combustion study/program. When fully operational, Flame Doctor is expected to utilize automated tuning of each burner for improved cyclone efficiency.
- The plant has been using oxygenated water since 1995 to improve the water tube life.
- The HP/IP turbines for both units were updated in 2003 with the GE dense pack turbine steam path design to improve turbine reliability and efficiency.
- Units 1 and 2 generator stators and rotors will be rewound in 2015 and 2014 respectively.
- The DCS system is currently on the third iteration, and is 5 years old. Typical life of a DCS system is ten years before upgrades are necessary due to obsolescence. Sioux Energy Center is currently in the process of replacing some obsolete cards as well as updating work stations. Sioux station is in the process of replacing the Generating, Unit, and Station transformers. Both generating transformers have been replaced. A new unit transformer on Unit 1 was ordered following a failure on the existing unit transformer. Several new station transformers were installed with the scrubber installations.

- Substation oil-filled breakers are being replaced vacuum breakers. Only a few have been replaced at the time of this report.
- The condensers were retubed and the Circulating Water pumps upgraded with the new scrubber installations.
- Rich Reagent Injection (RRI) and Selective Non-Catalytic Reduction (SNCR) systems were installed on both units in 2006 to reduce the level of NOx emissions but are typically not required to meet emission requirements.
- The water treatment system was replaced in 2007 to reduce O&M costs and to meet the additional water requirements associated with the scrubbers.
- Wet limestone FGD was installed on Units 1 and 2 in 2010. The new scrubber systems allow Sioux Generating Station an average removal rate of 95 to 99%. The scrubbers reduce the level of SO2 emissions and allow the station to gain sulfur credits and/or burn more Illinois basin coal. This gives the Sioux Energy Center more fuel flexibility and could result in a higher capacity factor in the future despite the higher auxiliary load; however, Sioux Energy Center is currently in the midst of a 100% PRG trial true-out period and plans to go to 100% PRB in the near future.
- Powder Activated Carbon (PAC) injection is planned for 2014 for mercury capture.

Sioux Energy Station is very proud of their PRO preventive and predictive maintenance strategies, as well as the Corrective Action Program (CAP). Based on the discussions, Black & Veatch would like to recognize these approaches and encourage continued diligence in these efforts.

Black & Veatch reviewed NERC GADS data provided by Ameren Missouri for 2008-2012 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 following tables provide a comparison of NERC GADS data for the Ameren Missouri coal units. The first table provides a comparison of five year average plant values for selected GADS performance parameters for the 2008 to 2012 timeframe. The second table provides year by year data for the Sioux units. GADS industry data for 2002 through 2013 for 500 MW to 700 MW units firing 0.2 to 0.6 percent sulfur coal is also provided for comparison below.

	Sioux Plant Units 1 to 4	Rush Island Plant Units 1 &2	Meramec Plant Units 1 to 4	Labadie Plant Units 1 to 4
FOR	6.88	4.18	11.73	3.99
EFOR	9.33	6.52	14.24	6.50
EAF	83.34	87.92	82.80	87.26
NCF	63.13	76.43	68.82	81.70

	Sioux Plant FOR	Sioux Plant EFOR	Sioux Plant EAF	Sioux Plant NCF
2008	6.29	6.75	83.53	66.41
2009	8.38	9.07	90.86	65.79
2010	2.78	5.01	83.79	65.7
2011	6.92	9.11	80.55	60.48
2012	9.91	16.8	77.84	57.08
GADS Industry Average Data		8.37	84.76	66.14

Based on interviews with plant personnel conducted during a site visit of the Sioux Energy Center along with technical information provided by Ameren Missouri, 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 improvement programs are continued. Major issues appeared to be fully disclosed and discussed; however, most of these issues are typical for assets of this type and all of these issues have technical solutions. It is also recognized that these are aging units that will experience equipment and systems failures over the years. Based on information available at the time, the (2009-2018) historical and long term forecast capital expenditure plan developed by Ameren Missouri and reviewed by B&V includes cost estimates for addressing these equipment and system issues.

B&V 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 Ameren Missouri 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 Ameren Missouri 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 Ameren Missouri will be periodically reviewed and adjusted as needed to remain consistent with changing regulations, or as differing conditions are found, and implemented in a timely manner.

Black & Veatch does not foresee any technical reasons that would cause the currently operating generation assets at the Sioux Energy Center to be retired prematurely based on the reasons and assumptions noted above. Black & Veatch cannot opine as to whether there will be economic or environmental issues which might prevent operation of the generating assets in the future. Black & Veatch was impressed with the knowledge of the staff, the practices demonstrated and unit performance at the Sioux Energy Center.

APPENDIX B-4 LABADIE ENERGY CENTER SITE VISIT MEMORANDUM

CONFERENCE MEMORANDUM 004

Ameren Missouri
Coal Plant Life Assessment
Labadie Energy Center Site Visit

B&V Project 181958
B&V File Number 14.1104
December 10, 2013
Edited March 25, 2014

Meetings held on December 4, 2013, at Labadie Energy Center.

Recorded by: Walter Johnson and Jeff Stroessner
Edited by: Larry Loos

Attended by: Ameren Missouri:
Gary Mitchell – Engineer Environmental Projects
Jim Dean – General Supervisor Operations
Greg Vasel – Superintendent Technical Support
Tony Balesteri – Consulting Mechanical Engineer

Black & Veatch
Walter Johnson
Jeff Stroessner

Walt Johnson and Jeff Stroessner visited the Labadie Energy Center on Wednesday, December 4, 2013 as part of a 2013 Useful Life Study being conducted by Black & Veatch's Management Consulting Division (MCD). The purpose of the visit was to view plant and equipment conditions; review historical and projected capital and O&M expenditures; review historical and projected unit operations; discuss plant maintenance practices; and identify issues which could potentially affect the life expectancy of the coal fired generating units at Labadie Energy Center.

Walt Johnson provided a description of the purpose of the project for the group and discussions were held with the plant and Ameren Missouri corporate staff listed above. Jim Dean and Tony Balesteri are very knowledgeable and provided a very well narrated tour of the facility. At the time of the visit, units were in service.

The Labadie Energy Center (Labadie Facility), which has 4 pulverized coal subcritical power generating units, is located south west of the city of St. Louis on the banks of the Missouri river near Labadie, Missouri. Units 1 and 2 were built in 1970 and 1971. Units 3 and 4 were built in 1972 and 1973, respectively.. The unit capacities listed in the table below were taken from the 2013 Capability Table provided by Ameren Missouri. The summer and winter capacities are as follows:

	Winter Output, Gross (Net), MW	Summer Output, Gross (Net), MW
Unit 1	645 (615)	622 (593)
Unit 2	645 (616)	622 (593)
Unit 3	645 (615)	622 (592)
Unit 4	645 (619)	622 (596)

The Labadie units currently burn Power River Basin (PRB) coal which is delivered to the site by unit train. A natural gas main supply is available at the south side of the site, but the plant is not currently tied into it.

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:
  - Capital projects that have been recently completed, or are, planned in order to maintain the economic viability of each respective 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 Black & Veatch noted a few challenging issues with respect to plant operations, which are being actively supervised:

- There was limited space remaining on-site ash for disposal of bottom ash and fly ash. An additional area of land has been purchased for future ash disposal. As of this report, Labadie Energy Center was able to recycle approximately 90% of the fly ash, and 20 – 25% of the bottom ash to an on-site Redi-Mix concrete producer.
- Some issues with the burners wearing out prematurely. Plant is investigating corrective options such as harder materials for improved wear.
- Inspections on all turbines were completed in 2013 in response to Alstom CIB 2DESER00109U01. Alstom is concerned with L-0 root cracks and air foil cracks, believed to be caused by high cycle fatigue resulting from high back pressure operation. Alstom's recommendation was for full blade out inspections. Turbine Engineering and Metallurgical Engineering & Welding Services developed an in-situ inspection plan for Alstom L-0 blades using a combination of visual, magnetic particle, and phased array testing. No indications were found on any of the blades or roots inspected at Labadie. Based on the testing results, there are no load restrictions on any of Labadie's turbines at this time.

- The final and horizontal superheat sections on all units are a reliability concern. There is no plan for replacement at this time.

A few projects were noted at the Labadie generating station since Black & Veatch's visit for the 2009 Useful Life Study.

- Unit 1 header will be replaced in 2014. Unit 3 header has also been planned for replacement; however, the replacement date has not been identified.
- Activated Carbon Injection for mercury control will likely be installed in 2015 on all units.
- New traveling water screens were installed in 2008. The screens have since been upgraded with magnetic drives for added protection. Changes were also made to accommodate 316b. Additionally, a redesigned debris filter was installed in 2012 to replace the unit installed in 2004.
- The electrostatic precipitators on units 1 and 2 are planned to receive new D-Boxes and C-Box upgrades. Units 3 and 4 will receive A, B, and C-Box upgrades. All upgrades are scheduled to be completed by 2016.
- 4160 volt breakers are approaching the end of their life cycle. Labadie has budgeted to replace these breakers in 2019.
- The DCS was upgraded to ABB 800XA controls on all units in 2012.
- All generation transformers have been replaced.
- An additional SOFA level in boilers 2 and 4 is currently being installed. Coupled with the Griffin Optimizers installed in 2011 through 2012, NOx appears to be well controlled.
- The 68" intake and condenser valves will likely require replacement within the next couple years, but have not been scheduled.
- Unit 4 bottom ash removal was upgraded with a submerged flight conveyors in 2012.
- The HP/IP turbines for both units 2 and 1 were replaced in 2001 and 2002, respectively and Units 3 and 4 had HP/IP turbine retrofits in 2003 to improve turbine reliability and efficiency.
- All LP turbine retrofits discussed in the 2011 IRP have been completed as of 2013.
- All unit condensers have been retubed with stainless steel for improved corrosion resistance.
- All units' boiler wall cleaning systems have been upgraded with hydrojets and water cannons. Water cannons in Unit 4 were removed and replaced with hydrojets in 2012.

Black & Veatch reviewed NERC GADS data provided by Ameren Missouri for 2008-2012 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 following tables provide a comparison of NERC GADS data for the Ameren Missouri coal units. GADS industry data for 2002 through 2013 for 500 MW to 700 MW units firing 0.2 to 0.6 percent sulfur coal is also provided for comparison below.

	Sioux Plant Units 1 to 4	Rush Island Plant Units 1 &2	Meramec Plant Units 1 to 4	Labadie Plant Units 1 to 4
FOR	6.88	4.18	11.73	3.99
EFOR	9.33	6.52	14.24	6.50
EAF	83.34	87.92	82.80	87.26
NCF	63.13	76.43	68.82	81.70

	Labadie Plant FOR	Labadie Plant EFOR	Labadie Plant EAF	Labadie Plant NCF
2008	2.83	2.83	86.44	81.85
2009	4.52	4.52	86.71	81.50
2010	4.47	4.47	91.78	86.23
2011	3.15	3.15	93.66	87.33
2012	5.10	5.10	77.76	71.66
GADS Industry Average Data		8.37	84.76	66.14

The first of the preceding tables shows that the station average performance is comparable to Rush Island and significantly better than Sioux and Meramec plants. The NERC GADS data in the second table for the plant from 2008 to 2012 shows decreasing availability, service hours, generation and capacity factors with increasing forced outage rates in 2012. These trends were largely the result of extending minor forced outages to address other maintenance issues.

Based on interviews with plant personnel conducted during a site visit of the Labadie power generating station along with technical information provided by Ameren Missouri, 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 maintenance programs are continued. Major issues appeared to be fully disclosed and discussed; however, most of these issues are typical for assets of this type and all of these issues have technical solutions. It is also recognized that these are aging units that will experience equipment and systems failures over the years. Based on information available at the time, the (2009-2018) historical and long term forecast capital expenditure plan developed by Ameren Missouri and reviewed by B&V 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 Ameren Missouri 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 Ameren Missouri 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 Ameren Missouri will be periodically reviewed and adjusted as needed to remain consistent with changing regulations, or as differing conditions are found, and implemented in a timely manner.

Black & Veatch does not foresee any technical reasons that would cause the currently operating generation assets at the Labadie Energy Center to be retired prematurely based on the reasons and assumptions noted above. Black & Veatch cannot opine as to whether there will be economic or environmental issues which might prevent operation of the generating assets in the future. Black & Veatch was impressed with the knowledge of the staff, the practices demonstrated and unit performance at the Labadie Energy Center.

Appendix C 2009 Actuarial Analysis

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                AmerenUE - Electric
PROGRAM OPTIONS IN EFFECT:
  MAXIMUM DATA FILE EXPERIENCE BAND        1913-2008
  TRAN CODES INCLUDED AS RETIREMENTS        0,0,3,7
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AmerenUE - Electric

ACCOUNT 311 STRUCTURES & IMPROVEMENTS

INPUT CONTROL TOTALS THROUGH 2008

TRAN CODE	TOTAL INPUT DATA AGED	UNAGED	TOTAL
0	15,551,130.77-		15,551,130.77-
3	5,010,932.15-		5,010,932.15-
7	26,908,405.06-		26,908,405.06-
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	242,657,711	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	891,502	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	99.29
4.5	219,925,794	132,710	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	442,098	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	153,349,509	490,047	0.0032	0.9968	95.99
21.5	151,570,704	1,137,358	0.0075	0.9925	95.68
22.5	149,278,305	426,339	0.0029	0.9971	94.96
23.5	147,913,527	230,243	0.0016	0.9984	94.68
24.5	146,604,297	220,003	0.0015	0.9985	94.53
25.5	137,969,039	805,269	0.0058	0.9942	94.39
26.5	136,361,422	428,652	0.0031	0.9969	93.84
27.5	134,786,960	632,342	0.0047	0.9953	93.55
28.5	131,262,186	1,072,398	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	89.59
40.5	55,624,314	173,839	0.0032	0.9968	88.91
41.5	47,617,438	343,731	0.0072	0.9928	88.63
42.5	47,266,854	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	32,397	0.0018	0.9982	87.48
45.5	46,742,666	78,137	0.0017	0.9983	87.32
46.5	46,624,530	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	35,234,470	842,304	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	11,499,515	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	3,072,068	0.6842	0.3158	19.43
61.5	1,333,196	613,343	0.4601	0.5399	6.14
62.5	719,498		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		

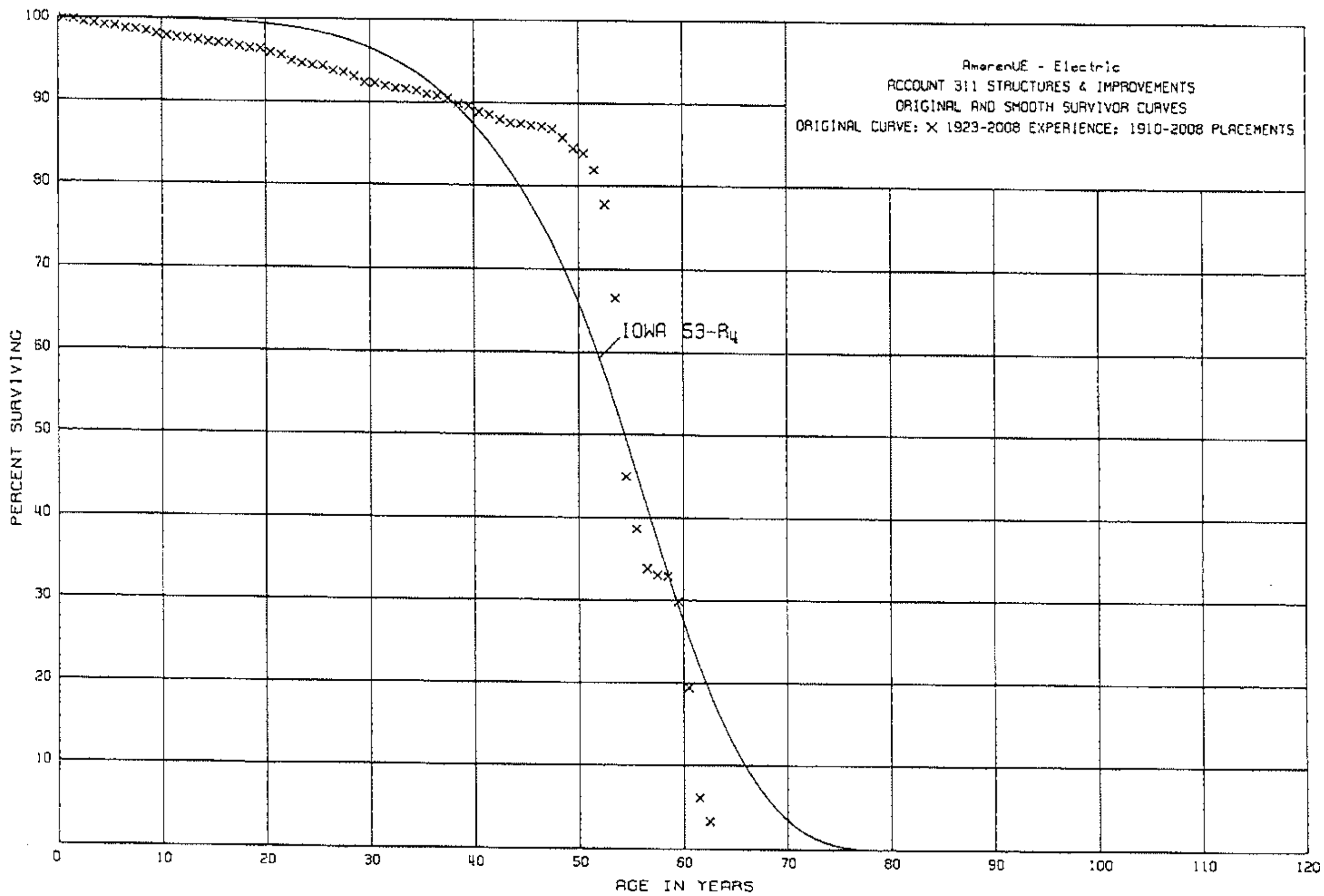
AmerenUE - Electric

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
79.5					
TOTAL	7,030,332,650	42,539,536			


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
AGE IN YEARS

AmerenUE - Electric

ACCOUNT 312 BOILER PLANT EQUIPMENT

INPUT CONTROL TOTALS THROUGH 2008

TRAN CODE	TOTAL INPUT DATA AGED	UNAGED	TOTAL
0	315,347,491.60-		315,347,491.60-
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 DATA	1,825,224,070.22		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

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	9,301,382	0.0060	0.9940	97.12
7.5	1,417,074,670	11,208,030	0.0079	0.9921	96.54
8.5	1,373,874,735	12,267,040	0.0089	0.9911	95.79
9.5	1,320,524,451	11,464,287	0.0087	0.9913	94.93
10.5	1,296,207,121	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	904,095,412	5,635,560	0.0062	0.9938	89.43
16.5	862,823,272	6,997,008	0.0081	0.9919	88.88
17.5	850,294,418	6,087,697	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	3,397,332	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	6,383,409	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	80.63
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	12,760,273	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	67.29
38.5	122,508,869	1,857,211	0.0152	0.9848	65.73

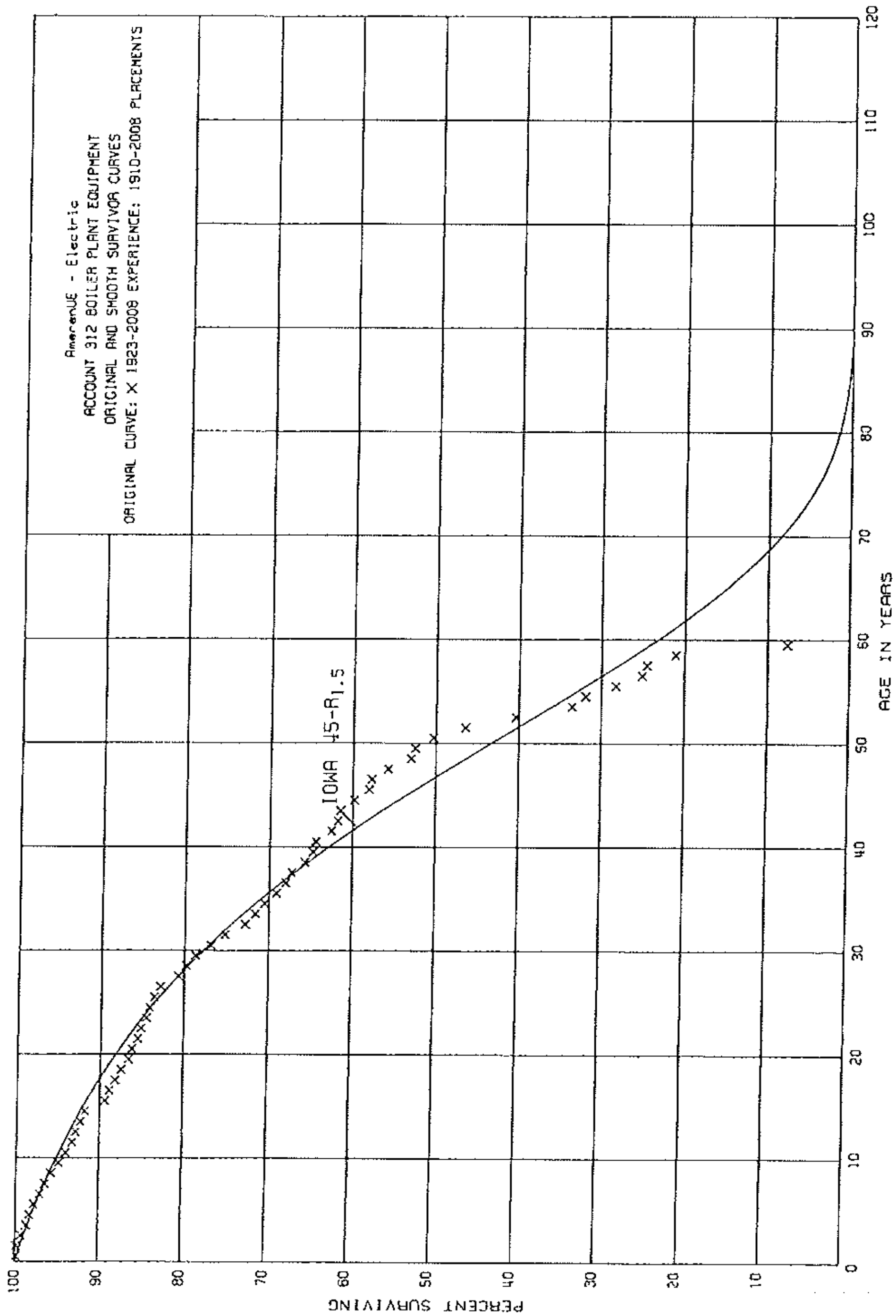
AmerenUE - Electric

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	71,150,539	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	49,959,713	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	2,404,397	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	1,059,156	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	144,508	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	159,590	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
PERCENT SURVIVING

AmerenUE - Electric

ACCOUNT 314 TURBOGENERATOR UNITS

INPUT CONTROL TOTALS THROUGH 2008

TRAN CODE	TOTAL INPUT DATA 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-

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 BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF 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	1,740,581	0.0034	0.9966	99.20
5.5	454,987,632	2,589,512	0.0057	0.9943	98.86
6.5	408,840,148	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	320,136,898	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	20,904	0.0001	0.9999	92.40
17.5	291,564,230	252,040	0.0009	0.9991	92.39
18.5	289,031,973	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	594,900	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	195,329	0.0007	0.9993	90.69
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	7,472,690	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	237,968,195	11,149,016	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	3,256,053	0.0166	0.9834	76.65
32.5	154,629,674	2,634,429	0.0170	0.9830	75.39
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

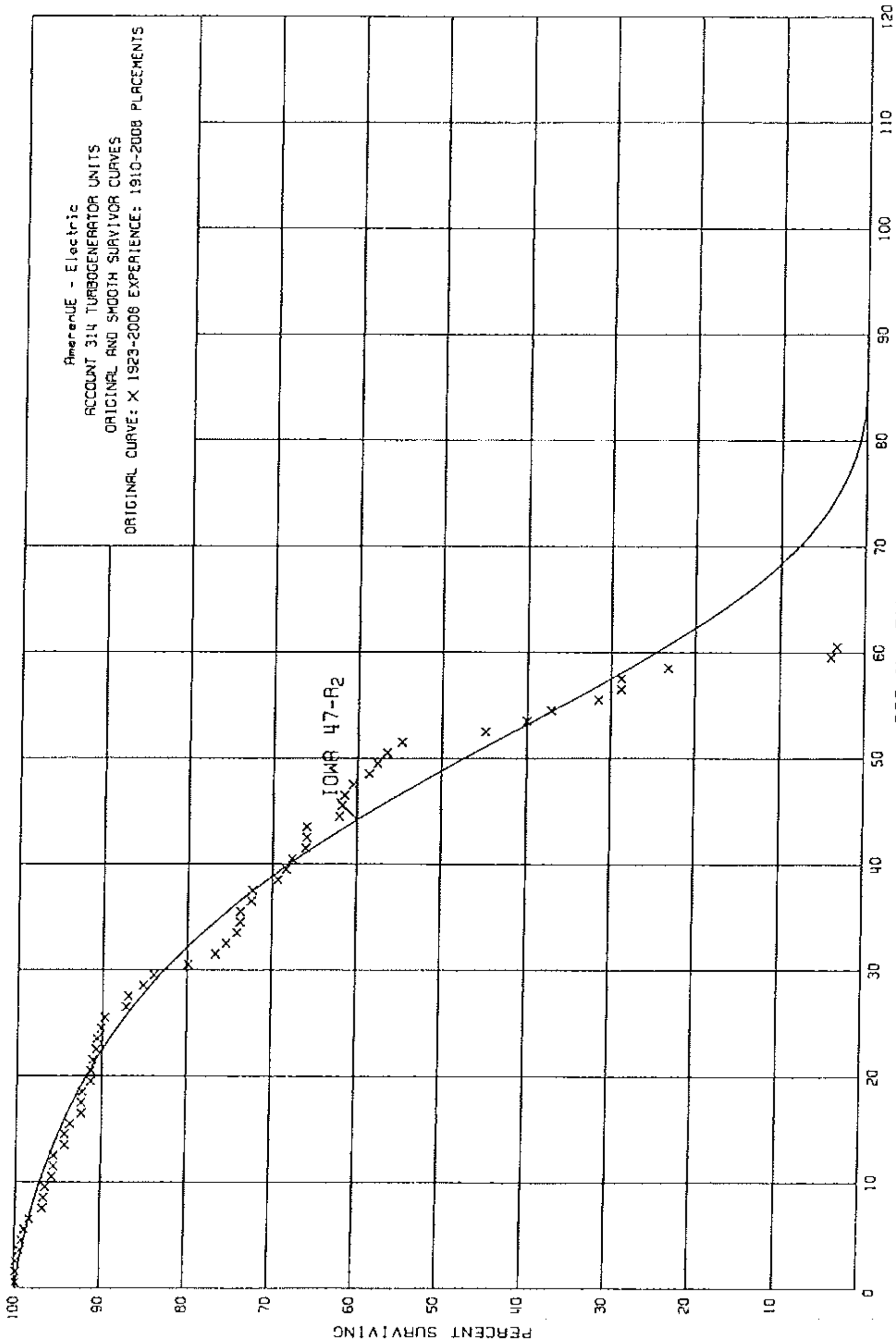
AmerenUE - Electric

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	81,501,293	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	42,095,089	1,361,641	0.0323	0.9677	60.50
48.5	31,423,538	501,081	0.0159	0.9841	59.55
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	1,609,153	0.0719	0.9282	39.95
54.5	15,769,195	2,363,952	0.1499	0.8501	37.08
55.5	5,856,448	510,899	0.0872	0.9128	31.52
56.5	5,382,529	988	0.0002	0.9998	28.77
57.5	5,395,037	1,065,592	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	1,470,978	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: X 1923-2008 EXPERIENCE: 1910-2008 PLACEMENTS
IOWA 47-R2
AGE IN YEARS
PERCENT SURVIVING

AmerenUE - Electric

ACCOUNT 315 ACCESSORY ELECTRICAL EQUIPMENT

INPUT CONTROL TOTALS THROUGH 2008

TRAN CODE	T O T A L AGED	I N P U T UNAGED	D A T A TOTAL
0	19,718,157.23-		19,718,157.23-
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	1,619,118	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	169,629,663	90,371	0.0005	0.9995	98.49
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	126,271,676	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	124,523,059	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	103,361,963	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	129,497	0.0014	0.9986	93.37
22.5	92,939,963	662,648	0.0071	0.9929	93.24
23.5	91,903,216	554,242	0.0061	0.9939	92.58
24.5	91,399,978	533,495	0.0058	0.9942	92.02
25.5	89,101,200	619,193	0.0069	0.9931	91.49
26.5	88,396,642	443,241	0.0050	0.9950	90.86
27.5	86,677,146	1,650,674	0.0191	0.9809	90.41
28.5	85,188,812	868,615	0.0102	0.9898	88.68
29.5	85,501,656	1,895,190	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

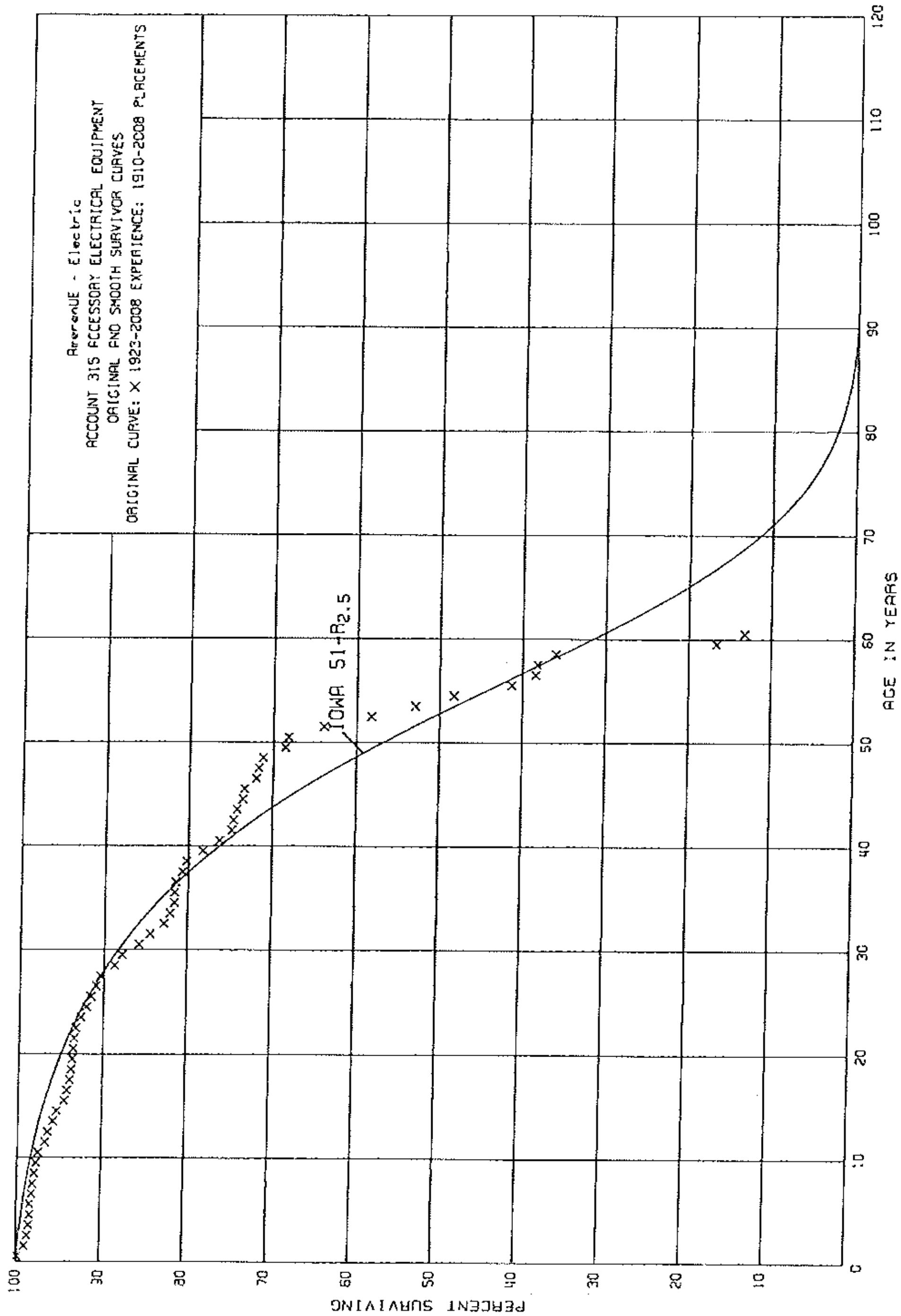
AmerenUE - Electric

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	590,875	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	23,067,990	31,915	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	134,924	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	16,763,155	1,048,315	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	347,698	0.0706	0.9294	41.32
56.5	4,578,172	28,998	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: X 1923-2008 EXPERIENCE: 1910-2008 PLACEMENTS
IOWA 51-R2.5
AGE IN YEARS
PERCENT SURVIVING

AmerenUE - Electric

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

INPUT CONTROL TOTALS THROUGH 2008

TRAN CODE	T O T A L I N P U T D A T A 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

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	61,577,613	517,921	0.0084	0.9916	99.72
2.5	58,455,010	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	885,175	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	190,192	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	42,350	0.0039	0.9961	72.50
28.5	10,346,427	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	31,499	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	499,832	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

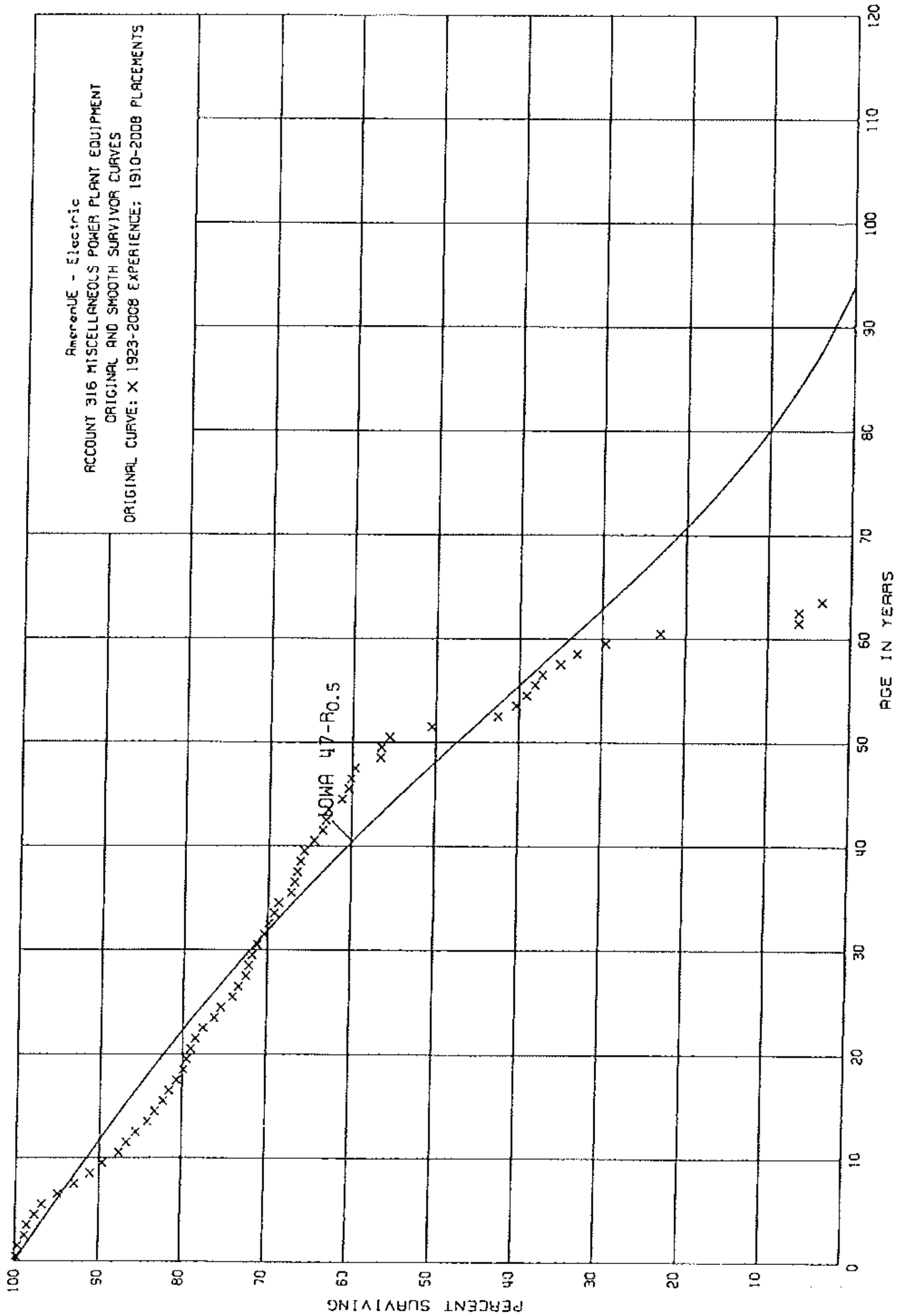
AmerenUE - Electric

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
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	1,033,201,739	11,250,316			


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
PERCENT SURVIVING

Appendix D List of Acronyms

ACI	Activated Carbon Injection (for mercury control)
AO	Administrative Order
AQC	Air Quality Control
BACT	Best Available Control Technology
BMP	Best Management Practices
BTA	Best Technology Available
CAIR	Clean Air Interstate Rule
CAP	Corrective Action Program
CCA	Clean Air Act
CCR	Coal Combustion Residue
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
ECP	Environmental Compliance Plan
EGU	Electric Generating Unit
ELGs	Effluent Limitations Guidelines
EPA	U.S. Environmental Protection Agency
FGD	Flue Gas Desulfurization (scrubbers)
GADS	Generating Availability Data System
GHG	Greenhouse Gas
GSU	Generator Step-Up
HAP	Hazardous Air Pollutants
HCl	Hydrogen Chloride
Hg	Mercury
IRP	Integrated Resource Plan
LAER	Lowest Achievable Emission Rate

LNBT	Low NOX Burner Technology
LOI	Loss of Ignition
MACT	Maximum Available Control Technology
MATS	Mercury and Air Toxics Standards
MDNR	Missouri Department of Natural Resources
MGD	Million Gallons per Day
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review
OA	Overflow Air
OEM	Original Equipment Manufacturer
PAC	Powder Activated Carbon
PC	Pulverized Coal
PM	Particulate Matter
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technologies
RCRA	Resource Conservation and Recovery Act
RRI	Rich Reagent Injection
SH	Superhearter
SNCR	Selective Non-Catalytic Reduction
SPE	Solid Particle Erosion

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	**Case No. ER-2014-0258**

AFFIDAVIT OF LARRY W. LOOS

STATE OF NE)
) ss
COUNTY OF Adams)

Larry W. Loos, being first duly sworn on his oath, states:

1. My name is Larry W. Loos and my office is located in Maricopa, Arizona and I am an independent contractor to Black & Veatch Corporation.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 15 pages and Schedule(s) LWL-1, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

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

Larry W Loos
Larry W. Loos

Subscribed and sworn to before me this 30 day of June, 2014.

Justine Kober
Notary Public

My commission expires:

General Notary - State of Nebraska
JUSTINE B. KOBER
My Comm. Exp. Aug. 19, 2017.